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

Deliverable: D2.1

Grid flexibility services definition

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Abbreviations and Acronyms

Abbreviation	Meaning
AMI	Advanced Metering Infrastructure
CEER	Council of European Energy Regulators
DER	Distributed Energy Resources
DSO	Distribution System Operator
EHV	Extra High Voltage
FACTS	Flexible Alternating Current Transmission Systems
FSP	Flexibility Service Provider
HV	High Voltage
LV	Low Voltage
MV	Medium Voltage
NRA	National Regulatory Authority
OLTC	On-load tap changer
RES	Renewable Energy Sources
UMEI	Universal Market Enabling Interface

Executive Summary

The increasingly challenging EU decarbonisation objectives and the trends of decentralisation, digitalisation and democratisation, will not only contribute to the connection of higher shares of generation capacity from Renewable Energy Sources (RES) but also the electrification of transport and heating, which leads to the connection of new loads, e.g., electrical vehicles and heat pumps.

On the other hand, the 'Clean Energy for all Europeans Package', more specifically EU Directive 2019/944 [2] asks the DSO's to enable and facilitate pro/consumers in participating to demand response and other services.

This transition will have a considerable impact on the power sector, especially on the distribution grids where most of these changes will have a direct impact. Therefore, DSOs face new challenges in the way they plan and operate the distribution system, namely the additional complexity of the power flows within their grids. To better approach these challenges and to strengthen the distribution system, DSOs need better controllability, flexibility and observability over the variable supply and demand.

The EUniversal Project aims at enabling the transformation of the energy system into a new multi-energy and multi-consumer concept guaranteeing a sustainable, secure and stable electricity supply by bringing forward a universal, adaptable and modular approach through a Universal Market Enabling Interface (UMEI) to interlink active system management with electricity markets and the provision of flexibility services.

As a first step in the development of the UMEI, Task 2.1's aims to define the flexibility services considering the DSOs needs in different time frames, from real time operation to long-term planning. This definition will be done considering transparent, non-discriminatory, technology agnostic and market-based procedures in order to find the most cost-effective solution for each identified need.

In order to guarantee that the flexibility services being specified would in fact help the DSOs in their day-to-day operations, the work on this task started with a clear identification and characterisation of the DSOs' needs, namely by specifying the type of events that occur in distribution grids and possible procedures to be adopted to solve those technical issues. This was followed by the identification of the flexibility services to solve those needs and their specification with a wide range of requirements that take into consideration technical characteristics and operational requisites.

The next table summarises the identified DSO's needs and the services defined to solve them.

Table 0. Summary of DSO's need and respective services

DSO Needs	Flexibility Service
Physical congestion	Corrective and Predictive Congestion Management
Control of voltage violation	Corrective and Predictive Voltage Control
Support to network planning	Support to Network Planning
Phase balancing	Corrective and Predictive Voltage Control
Support to planned and unplanned operations	Corrective and Predictive Congestion Management, Corrective and Predictive Voltage Control, Islanding, Emergency Load Control and Mobile Generation Capacity
Support to extreme events	Corrective and Predictive Congestion Management, Corrective and Predictive Voltage Control, Islanding, Black Start, Emergency Load Control and Mobile Generation Capacity
Support to islanding	Islanding

1 Introduction

1.1 Context

Flexibility in the grid has been identified as a key enabler for the transition to sustainable, low-carbon and climate-friendly energy systems. Along with this transition, distribution grids will face new paradigms in the way they operate, relying more on flexibility and smart-grids' functionalities to safely increase distribution hosting capacity of renewable-based generation and accommodate the load from new loads, resulting for example from EV charging, as well as new consumption patterns (e.g. self-consumption). As stated in "A Toolbox for Electricity DSOs" report [1], flexibility will create complex power flows in the distribution networks, thus demanding new solutions that transform the challenges into real opportunities for the sector and for society. Consequently, there is also the need to increasingly manage the grids by fully exploiting the potential of available flexibility sources.

This complex system will demand flexibility to actively adjust new demand profiles to the supply variations in renewable generation or to the available capacity in the distribution grids, moving away from the general principle where 'generation follows demand'. These issues cannot be solved only through the current means and will require innovative tools based on smart grid technologies as well as the adoption of algorithms for increased observability, thus enabling enhanced grid automation and control.

Based on the definition of new services that will give support to the needs of DSOs and TSOs, active neutral market facilitation will need to encompass the activities to ensure the conditions for the uptake of flexibility offers and new business models, and for the large-scale participation of consumers. In fact, the Directive (EU) 2019/944 of The European Parliament and of The Council [2] states that citizens need to be key players in the energy transition, benefiting from the technologies, from new services and tools, from the possibility of actively participating in the markets, and from a cost-effective energy system. In this context, a flexible, robust and smart citizen-centred power network connected with heating, gas and transport networks is a key factor in the energy transition, while advancing in the security of supply and affordability.

Finally, the different actors, namely grid operators, market operators, aggregators and even customers, need to work together and coordinate their activities to ensure seamless and effective integration of flexibility services in the day-to-day operation of the future electricity system.

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, for the implementation of real mechanisms for active consumers', prosumers' and energy communities' participation to the energy transition.

The development and implementation of the UMEI concept rely on the following four structural pillars: (1) Flexibility enabling technologies and solutions; (2) Smart Grid Solutions; (3) Flexibility market mechanisms, products and platforms; (4) Universal Market Enabling Interface.

As a first step towards the definition of needed flexibility enabling technologies and solutions [pillar (1)], the flexibility services need to be identified and mapped, according to their attributes, to tackle different distribution grid needs in terms of characteristics, impacts, response time, etc. Thus, an assessment of potential services to be provided to the DSO in future grid scenarios is needed.

1.2 Objectives of Task 2.1 and relationship with other tasks

Within the EUniversal's work plan, Work Package 2 (WP2) aims to specify and develop a fully interoperable, adaptive, evolutive, technology neutral and replicable DSO interface for flexibility services providers, enabling the standard provision of flexibility and the uptake of existing and new market solutions.

As a first step to achieve the WP2 objectives, it is of utmost importance to define the specifications of the flexibility services to be procured by DSOs. Starting from the identification of the DSO needs in different time frames, from long-term planning to real time operation, this report defines the specifications of the services that would satisfy these needs. This specification was performed considering that the provision of these services should be market-based when possible, under transparent, non-discriminatory and technology agnostic procurement mechanisms in order to find the most cost-effective solution for each service need.

The work on this task started from the analysis made in Deliverable 1.2, which provides a first identification of DSO needs and services and flexibility and TSO-DSO coordination mechanisms, based on the most relevant European projects and initiatives.

Among other uses, this deliverable, namely the identification of the DSO needs and the specification of the flexibility services to satisfy these needs, will support the definition of the set of business use cases to be designed in Deliverable 2.2 and will also feed Deliverable 3.2 that will match the flexibility solutions with the DSO needs. These interactions are depicted in the following scheme:

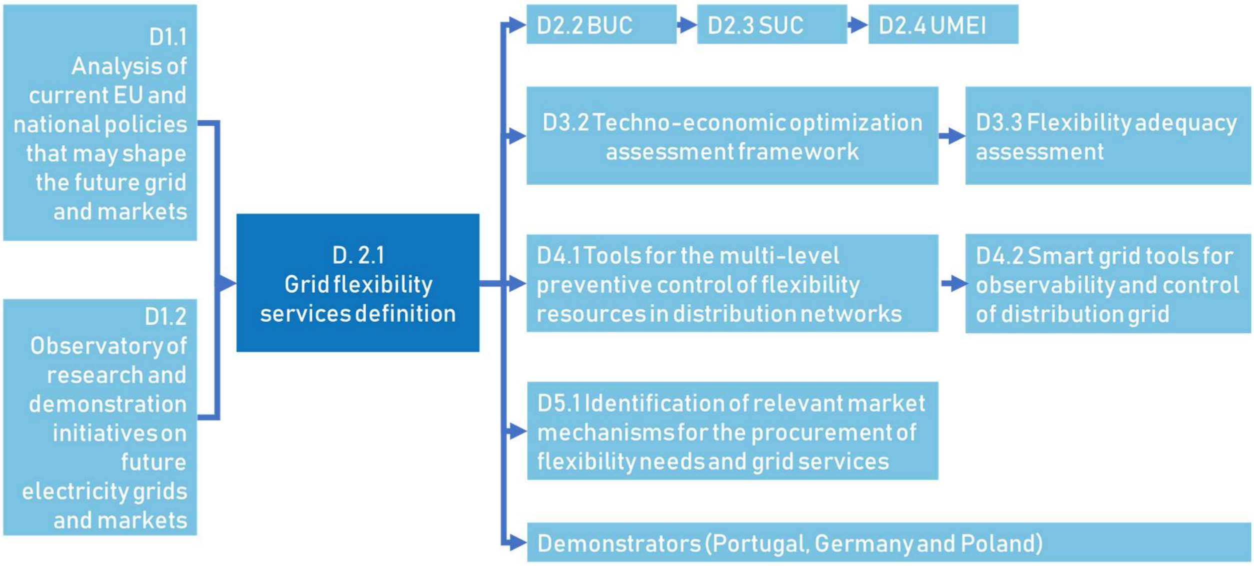


Figure 1. Interactions with other WPs

1.3 Methodology

The work of this task was organized in two main phases:

- Phase 1: identification and characterisation of the DSO needs;
- Phase 2: identification and specification of the flexibility services to solve the identified needs.

In phase 1, the partners involved (mostly DSOs) identified the type of events that occur in their grids and that trigger the need of specific actions to maintain a safe grid operation. This allowed to identify and characterise their main needs, as well as to provide an initial insight on the potential procedures to solve the technical problems associated to these needs. This work is detailed in Chapter 2.

In phase 2, a systematic approach was applied to specify the flexibility services to solve the DSO needs identified in phase 1. These services were specified considering the characterisation of the triggering events as well as the technical requirements that the provision of these services should comply with, in order to effectively contribute to the solution of the problems associated to the corresponding need.

The following scheme details the work steps involved in each of the defined phases.

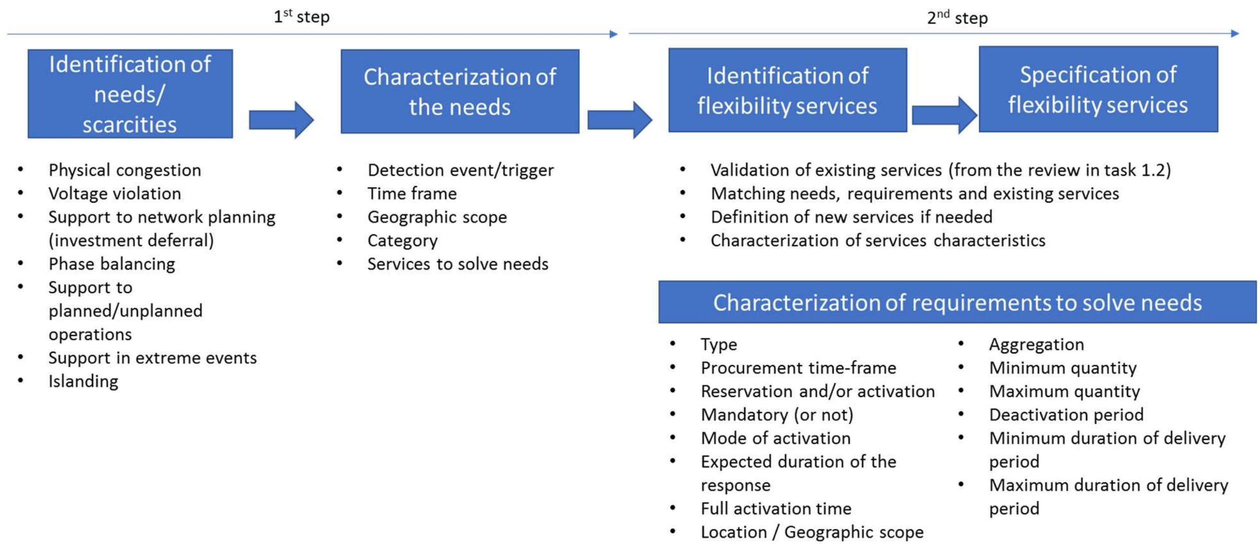


Figure 2. T2.1 work phases

Between phase 1 and 2 a dedicated workshop was held to trim the DSO needs identified in phase 1 and to allow the DSOs to present their vision on the future provision of flexibility services. This provided valuable insights for the following work on the definition of the flexibility services, but also for other tasks such as the development of the business use cases.

The next chapters detail the DSO needs that were identified (chapter 2.) and the services that were specified to solve those needs (chapter 3.). Additionally, a perspective on how these services can be procured is presented in Chapter 4.

2 DSO needs

The following DSO's needs have been identified and will be described in the following sections,

- Physical congestion
- Control of voltage violation
- Support to network planning
- Phase balancing
- Support to planned and unplanned operations
- Support to extreme events
- Support to islanding

2.1 Physical congestion

According to the Commission Regulation (EU) 2015/1222 [3] *'physical congestion' means any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system*.

In general, grid congestions are caused by exceeding the power capacity of an asset (current-related) or because the defined voltage interval for an entire network area is not maintained (voltage-related). In this section the focus is on current related congestions. Voltage violation is described in section 2.2 due to special requirements and services.

Current-related capacity is described by upper limits for the operating parameters of a given grid equipment. For example, in case of HV below 110kV, the thermal limiting current of a line is the maximum current the line accepts based on its thermal characteristics. This current is such that, due to the ohmic resistance, it heats the line only to such an extent that a critical value for the conductor temperature is not exceeded (we also have to take ambient temperature into account). Exceeding the limits can damage the assets and make them age more quickly or lead to overhead lines sags larger than their allowed distance to ground. The damage or complete destruction of equipment can lead to dangerous situations which can endanger public safety, for example, by starting a fire [4].

The operation of a power supply network is designed to be fail-safe and thus safety-limited, with higher redundancy in higher voltage levels. This means that the network can continue to operate, within the required parameters, even if some network equipment fails, depending on the criterion used. The most common criterion for such a safety-limited operation is the so-called (n-1) operation or "operation taking into account the (n-1) criterion" [5]. Therefore, network operators in safety limited operation do not usually use the full capacity of their network equipment to cope with unplanned outages. However, the increased requirements due to higher RES feed-in and the need to minimise overall grid costs for the end user leads to a higher capacity utilisation of the networks which could lead to a decrease of safety margins.

It should be mentioned that (n-1) does not apply to LV. Although current overload of an LV network element results in a (local) blackout, the costs of applying (n-1) to LV grids would be too high compared to the costs of such local blackouts.

The overload of assets in the network can have different triggers, which also vary in the detection time frame and the associated effective services. While faults such as short circuits normally require a fast and automated response, network planning is used to analyse future scenarios and plan measures to reduce and avoid bottlenecks in the long term. In between intraday and day-ahead measures take effect which help to resolve (n-1)-situations or forecasted deviations [6].

A further type of distinction can be found when one differentiates according to the geographical scope of the bottleneck. This is largely dependent on the voltage level of the congestion and varies from local to cross-regional impacts. An overview of possible classifications can be found in Table 2.1.

Table 2.1. Categorisation and characterization of Physical Congestion

Detection event / Trigger	Time Frame	Geographic Scope	Category
Failure	Real time, intraday	Cross-regional (HV) / Regional (MV) / Local (LV)	Active power management
Forecast infeed / load	Intraday, day(s) ahead		
Construction planning / maintenance	Months/years ahead		

2.2 Voltage violation

Voltage magnitude is one of the main parameters that determine the quality of electricity supplied by power networks. Voltage limits are strictly defined by various national and international regulations. According to the Standard EN50160 [7], the range of acceptable deviation from the nominal value is within + - 10%, during a percentage of an observation period. Maintaining the voltage value within the permissible interval set by the standard is one of the main tasks of system operators. The value of voltage in the network strongly influences the grid performance and should be closely monitored. A deviation from the permissible supply voltage level will affect the correct operation of different types of loads and DER, namely electronic loads, induction machines and inverter-based DER. In extreme cases, severe voltage disturbances can lead to voltage collapse, compromising system stability.

The two main voltage quality problems in the network are undervoltage (voltage level below the acceptable lower limit) and overvoltage (exceeding the voltage level above the upper acceptable limit). Voltage dips are also a power quality problem, resulting from disturbances occurring in the upstream network (faults in HV and transmission networks), that can result in the disconnection or malfunction of loads and generation connected in MV and LV networks.

Maintaining the voltage level is often considered a local problem, when compared for example to system frequency regulation. Electricity system operators have several tools to keep the voltage within the acceptable range. These include various technical devices that directly affect the voltage value: Transformer tap changer and compensatory assets (e.g., FACTS, shunt reactors, capacitor banks), that can be controlled either through local distribution substation automation or centralized control strategies (e.g. DMS tools such as OPF). Network reconfiguration is also adopted to ensure adequate voltage magnitudes, changing the network topology by using remotely controlled switches in the MV grid or, more recently. Also, power factor control, Q-V strategies or even DER curtailment is also foreseen in European and national network codes [8], defining generator connection requirements. Still, network reconfigurations may lead to problems related to maintaining the voltage within the MV network. Outages (including scheduled works) may lead to the introduction of abnormal / emergency network configuration. As a result, some power lines may be significantly long. In extreme situations, it may not be possible to maintain the voltage at the required level for such long lines.

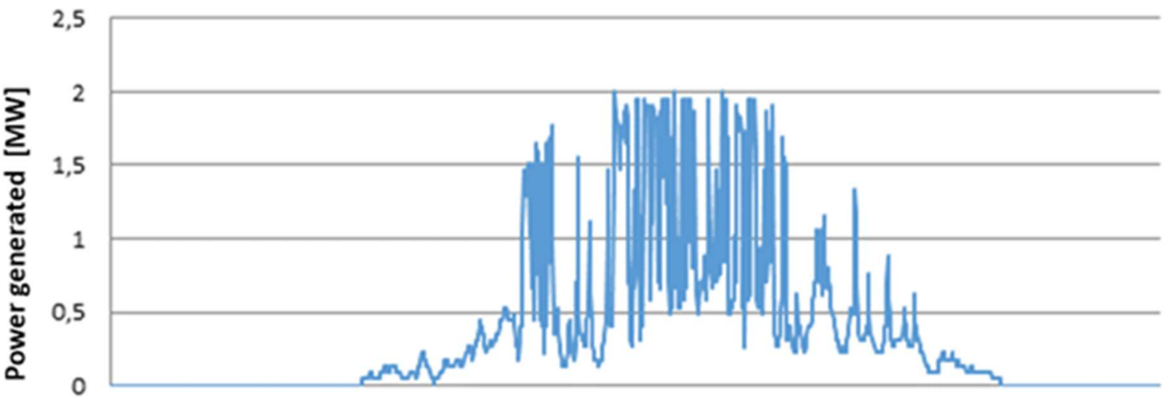
Due to the specific nature of the voltage variations, it is very important to have a proper procedure and approach to voltage control. It is critical to identify and determine when corrective actions are required to avoid a situation that poses a threat to network operation. Slight and temporary deviations are acceptable and not considered by the operators, since some of the voltage disturbances are transient, returning to stable and admissible values after some time. This also means, that the control strategies need to consider appropriate dead zones, avoiding unnecessary actions.

The conventional voltage control tools and DSO assets were designed to control voltages in typically radial MV and LV networks with unidirectional power flows, from supply to consumption nodes. However, the large-scale integration of RES-based generation together with meshed topologies imposes additional challenges to voltage regulation, requiring a more coordinated voltage control considering also additional resources connected throughout the MV and LV feeders [9]. On the other hand, the flexibility of DER can also be exploited to provide grid support and ensure adequate voltage control in both MV and LV network, avoiding the need for installing additional equipment.

Voltage regulation in LV networks presents specific characteristics and challenges. The typically low X/R ratio of LV cables and connection of single-phase loads and generation, together with the integration of generation and load from EV charging, increases the possibility of both overvoltage and undervoltage problems. The capability of controlling LV network voltages is limited to the MV/LV substation, typically with MV/LV power transformers with manual regulation, adjusted offline. For example, lowering the voltage by changing the transformer ratio may eliminate an overvoltage problem at the beginning of the power line but may also cause the voltage at the end of the circuit to be below the admissible range. On the other hand, in off-peak load and high PV generation operation scenarios, reverse power flows (from the end of the feeder to the substation) can occur, increasing voltage in the end of the feeder. In this case, the overvoltage may lead to the disconnection of the PV installation and the control in the transformer taps will not be efficient, decreasing voltage in all LV nodes, when the problem is focused in just one feeder. Therefore, specific voltage control strategies are required for LV networks, either implemented locally or with more coordinated approach [10], [11].

Regarding MV networks, the adoption of meshed topologies requires a more coordinated approach for voltage control, that was typically focused in the HV/MV substation voltage regulation local automation functions. Also, the large-scale integration of RES-based generation in MV networks, particularly PV plants, can cause rapid voltage changes, due to rapid fluctuations in PV power output caused by cloud transient. For example, Figure 3 shows the fluctuation of power generated during one particular day for a solar farm connected to an MV network (DSO ENERGA material, own study). Under these situations, traditional voltage regulation, based on transformer tap changing in the primary substation, is not able to keep up with frequent changes in the voltage in the network [12].

Table 2.2. resumes DSOs voltage violation needs.



Detail from 12h to 13h of the same day:

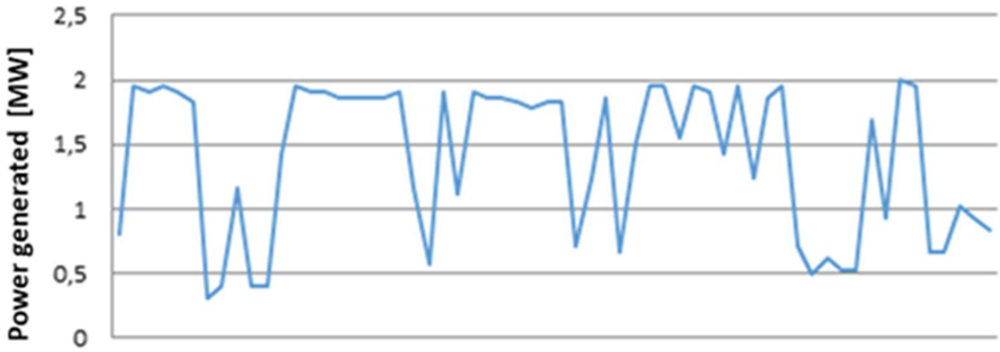


Figure 3. Example of solar power generated in one day

Table 2.2 Identified DSOs voltage violation needs

Detection event / trigger	Time frame	Geographic scope	Category
Failure	Real time, intraday	Regional (MV) / Local (LV)	Active and reactive power management
Forecast infeed/load	Intraday, day(s) ahead		
Forecast deviation	Real time, intraday		
Construction planning / maintenance	Day(s) ahead, long term planning		

HV and MV networks have a good capacity to detect voltage limit violation, through their control centres. HV networks are typically characterized by high observability, considering a good real-time monitoring and control capability. At the MV level, strong investments in network monitoring and automation are extending observability from the HV/MV substation to the network feeders and to MV/LV substation. However, as referred previously voltage control strategies are mainly local based in substation voltage automatic regulation. In order to deal with high uncertainty in operation due to high RES-based integration, new predictive tools are being integrated at the Advanced Distribution Management Systems (ADMS), that with load and generation forecasts can help anticipate potential voltage problems and take adequate actions a-priori.

On the other hand, LV networks currently have very limited observability and a small number of active elements that DSOs can use to regulate voltage. In most cases, without properly metered distribution networks, the DSOs are not able to detect voltage problems and can only rely on reports from customers. Although smart meter data is usually not available in real time, it is an important source of data to analyse and predict voltage violation risks in LV feeders. Thanks to the use of remote reading meters installed as a part of the AMI, it is becoming possible to obtain information about the voltage value in each network node. Even so, the adoption at the LV network of conventional voltage control strategies may not be technically and economically viable. In addition to the OLTC at the MV/LV substation, demand response strategies taking advantage of LV consumers/prosumers flexibility could help solve technical restrictions related with the voltage at LV networks.

2.3 Support to network planning

The energy transition will have a significant impact on the electric distribution grid, with the progressive electrification of various sectors such as transport, together with the growth of intermittent distributed generation and storage connection. Significant changes in consumption and production could result in simultaneous demand or supply exceeding networks' capacities, thereby causing congestions in the distribution system.

Due to the challenging schedules planned within the energy transition, it will probably not be possible to build the necessary power grid infrastructure according to the business as usual, due to the time it takes to build power lines and the limitations of the suppliers and service providers. Therefore, active grid management using flexibility combined with grid extensions where needed, will present itself as the only practical solution to connect the necessary loads and generation needed to reach the targets of the energy transitions within the necessary time.

In terms of medium to long-term grid planning, flexibility can improve efficiency in the development of the network as it can be used as a complement or alternative to traditional grid investments, avoiding potentially unnecessary grid expansions with high costs to the system, as long as it proves to be the most economically viable option to solve the needs.

DSOs should be able to use flexibility as a tool to solve current or forecasted situations of reduced network capacity, related to overloaded assets or voltage limits violations. The history (cost and effectiveness) of flexibility services that were activated in the real-time grid operation, can be used as an input for long-term planning to do a cost-benefit analysis for decision-making between grid investment or flexibility solutions.

Network development plans can be an effective way to inform potentially interested parties where demand of flexibility is or will be needed describing capacity availability or reservation options.

2.4 Phase balancing

Voltage unbalance is mainly a voltage quality problem that occurs in LV distribution networks, due to the uneven distribution of loads and generation units between the three-phases of the network, causing non-equal currents to flow in the phase and neutral conductors, and consequently unsymmetrical voltage drops. Voltage unbalance will vary along the day according to the loads in the three-phases of the network.

This issue is expected to worsen in the future with the additional load resulting from EV charging, single-phase self-consumption and microgeneration solutions.

The negative and zero sequence components in voltage and currents, caused by load unbalance, will adversely impact the operation of the LV system, causing excessive heating and losses in three-phase induction machines, increased harmonic distortion and excessive currents in three-phase power electronic devices, reducing feeders capacity [13].

Observability of LV networks is critical for the identification of this problem. The use of AMI together with the monitoring of MV/LV substations are important to identify the problem and determine the most adequate control actions. Traditional solutions are based on reconfiguring the distribution network by manually switching of LV consumers/prosumers between the network phases. However, voltage unbalance can occur during specific periods where the use of load flexibility could also help to mitigate the load unbalance between phases. In this case, managing the power flow in the three-phases of LV feeders independently will help ensure the single-phase voltages within their limits and mitigate voltage unbalance.

Current DERs are equipped with smart inverters that, besides remote-control capabilities, can also incorporate different grid supporting functions for voltage control and phase balancing. There is potential for three-phase DER with voltage balancing functionalities to change the negative sequence currents in order to compensate the voltage unbalance. This will not significantly affect the power dispatch capability of the inverters, changing mainly the reactive current output [15]. More typical voltage control strategies consider changing the active and/or reactive power output as a linear function of the voltage measured locally by the inverter [10].

2.5 Support to planned/unplanned operations

In the daily operation of the grid it is necessary to take planned, but in some cases, also unplanned actions and cope with service interruptions, caused by permanent faults. In this case, network reconfiguration will restore service to a part of the affected consumers, sometimes with limited power supply capacity; or in case it is not possible, the use of mobile generators is considered to ensure full or partial service.

Any interruption has implications for the quality of service, namely for energy delivery. Flexibility can be an important tool to avoid disconnection of customers, either residential or business ones, or even reduce occasional weekend power cuts to perform planned operations. With an adequate flexibility service, customer's flexibility can be the solution to avoid a power cut to their premises.

During this maintenance actions, using flexibility could help to solve the constraints in the connection to the remaining network and to minimize the additional amount of power needed in case of full network disconnection. In this latter case, flexibility is important to minimise the amount of fuel spent or to allow the use of smaller generator sets.

2.6 Support in extreme events

Although the occurrence of extreme events is rare, it can have massive impacts on the operation of the network. In cases of foreseeable events, the DSO can take advantage of the flexibility to make sure the maximum number of clients are being serviced.

Extreme events are characterized as having a low probability of occurrence but a high probability of causing damages to the network within a large area. They usually consist of severe storms with high-speed wind gusts.

During extreme events several parts of the network are damaged and unable to provide power to the clients. There are usually backup units, but these are limited and can also be damaged during extreme events.

Most of the time there is limited network backup, through other feeders, to ensure continuity of service to a large number of consumers. An optimised load distribution can be achieved using flexibility making sure that the maximum number of clients can have electric power. Otherwise, the outage may affect many clients needlessly.

Flexibility is, therefore, an important tool for DSOs to be able to maximize the continuity of service to their clients.

2.7 Support to islanding

With a great push for decentralised energy sources and current advances in power electronics, it is possible to provide electricity even in cases where the network fails.

Sometimes, sections of the grid get separated due to the breakdown of one or several network components. However, in a scenario of heavy penetration of DER the necessary resources exist to balance load, or at least a part of it, and generation (this is a requirement for a stable frequency operation). With the capabilities of modern power electronics and adequate grid management of load and DER, it is possible for the isolated grid to supply electric power to the connected clients.

There are several flexibility services that are required to operate a part of the grid in an isolated mode such as frequency control and voltage control. An additional service is required to establish an island from an outage scenario, which is called “black start”. This capability can also be used to help the network recover from a widespread “blackout”.

The island stability requires a balance of all generation and load within the isolated part of the grid. Therefore, in order to have a stable island, the DSO has an important role in defining the limits of load and generation for each period.

End-clients are the main beneficiaries of islanding operation.

In this case, there is a need for local frequency and voltage control systems to stabilise the micro grid and correct potential instabilities, and with flexibility these systems can control generation and load to maintain the requested voltage and frequency setpoints.

3 Definition of the grid flexibility services

In this chapter, the necessary services to solve the identified needs are proposed and its main characteristics identified.

3.1 Matching of DSO needs and flexibility services

The next table gives an overview of the services proposed to match the DSO needs identified in the previous chapter.

Table 3.1 Categorisation of Physical Congestion

Needs / scarcities	Detection event/trigger	Time Frame	Flexibility Service
Physical Congestion	Failure	Operation Timeframe (real-time, on hourly basis)	Corrective Congestion Management
	Exceedance of thermal limits due to the forecasted load and generation situation	Short-term (daily or intraday)	Corrective, Predictive Congestion Management
Voltage Violation	Failure	Operation timeframe (real-time, on hourly basis)	Corrective Voltage Control
	Voltage dips		
	Voltage band violations due to the forecasted load and generation situation e.g. under and over voltages, PV voltage fluctuation	Short-term (daily or intraday)	Predictive Voltage Control
Support to Network planning	Long-term forecasts of load and generation development	Long term	Support to Network Planning
Phase Balancing	Uneven connection of single-phase loads/generation e.g. EV charging or one phase PV inverters	Operation Timeframe, Short-Term	Corrective and Predictive Voltage Control
Support to planned operations	Grid reconfiguration due to scheduled (maintenance) work	Short-term – medium term (daily, weekly)	Predictive Congestion Management, Islanding and Mobile Generation Capacity

Needs / scarcities	Detection event/trigger	Time Frame	Flexibility Service
Support to unplanned operations	Grid reconfiguration due to failure	Operation Timeframe (real-time, on hourly basis)	Corrective Congestion Management, Corrective Voltage Control, Islanding, Emergency Load Control and Mobile Generation Capacity
Support to extreme events	Grid reconfiguration due to failure	Operation Timeframe (real-time, on hourly basis)	Corrective Congestion Management, Emergency Load Control and Mobile Generation Capacity
	Voltage band violations		Corrective Voltage Control and Mobile Generation Capacity
	Network Failure		Islanding
	Blackout		Black start
Support to islanding	Network Failure	Operation Timeframe (real-time, on hourly basis)	Islanding

3.2 Requirements for the identification and specification of services

The specification of the flexibility services developed within EUniversal is based on the characterisation of the needs or system scarcities of Chapter 2 and on the review of the flexibility services and products conducted in Task 1.2 and provided in Deliverable D1.2., to be published. Based on the needs and their triggering events and on the conventional procedures usually adopted to solve the technical problems associated, it was possible to obtain a first list of technical requirements to define how flexibility can provide grid support during distinct operation conditions.

It is important to say that this work is also based on the insights of the DSOs working in the EUniversal project.

Considering the technical characteristics and operation requirements of different voltage levels, the needs identified might lead to different technical requirements for the services to be provided by the flexibility resources.

Table 3.2. Requirements identified for the specification of flexibility services.

Parameter	Description	Examples
Procurement time-frame	Identification of the timeframe for the procurement of flexibility in solving the problem (moment when the service is contracted)	-Real-time operation -Short-term operation -Operational Planning -Medium-term/seasonal planning -Long-term planning
Reservation and/or activation	Procurement of flexibility requires reservation in advance (e.g. day-ahead) or will be activated in real-time, or both.	-Reservation and activation -Activation when needed
Mandatory (or not)	The participation of the mobilized flexibility is mandatory or not. After the clearing the flexibility requested by the DSO needs to ensure its response. Penalties may apply in case of non-delivery.	In case its mandatory, penalties will be applied. In case is not mandatory, the service can be remunerated according to the participation of the DER.
Mode of activation	Flexibility can be activated manually at the request of the operator or automatically by the operator in case of local control strategies (at the inverter or other local controller) to change the reference power/voltage of flexible resources	Manual / automatic [14]
Expected duration of the response	Time usually needed to solve the technical problem, and for which is expected the flexibility to participate. Evaluates de capability of DER to provide the requested service. Necessary to define the bids and market procurement.	Seconds, minutes, 1-3 hours
Full Activation time	The period between the activation request by the system operator and the corresponding full delivery of the concerned product.	Seconds, minutes, 1-3 hours
Location/ Geographic scope	Identification if the response needs to be provided by node or if can be provided in a wider scope. Relevant to understand the possibility and way of aggregating resources	Region, Substation, Feeder, Point of connection
Aggregation	Allowing resources to aggregate to meet the minimum quantities at a specific location. If the aggregator doesn't have automatic control of flexible devices, this could have an impact on the time needed for activation.	
Minimum quantity	Define the minimum power that can be provided in each offer.	From 1 kW to 1 MW
Maximum quantity	Define the maximum power that can be provided in each offer.	From 1 kW to 1 MW
Deactivation period	Time expected for the flexibility resource to end delivering service after receiving a deactivation signal	From seconds to minutes
Minimum duration of delivery period	Minimum time for the duration of the service provision	15 minutes
Maximum duration of delivery period	Maximum time for the duration of the service provision	3 hours

3.3 Congestion management

Congestion management procedures considering DER flexibility are not only referred to in codes and regulations, but frequently on research papers and project deliverables, as a means to improve the operation and development of power networks. Particularly to the DSOs, according to Article 32 of the Directive (EU) 2019/944 [2], "*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.*".

Additionally, Article 16 of the Regulation (EU) 2019/943 [16], states that "*network congestion problems shall be addressed with non-discriminatory market-based solutions which give efficient economic signals*". Still, as stated in Article 32 of the Directive (EU) 2019/944 [2], DSOs shall procure flexibility services in accordance with market-based procedures unless "*the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion*".

Congestion management is part of the development and operation of power networks, from the planning phases to the day-to-day operations. Therefore, as stated in CEER's report C19-DS-55-05 "*DSO congestion management can take place long before, prior to, during or after existing wholesale market clearing and as far as just before the (gate) closure of the balancing market. Flexibility markets could thus represent a variety of auction and trading platforms.*" [17]. According to the TSO-DSO Report [18] the congestion management process can be differentiated into several phases, involving various roles and actions. These are:

1. Preparatory phase: Product definitions and initial pre-qualification.
2. Forecasting phase: Planning of grid utilisation and identifying potential congestions.
3. Market phase: Bids collection and evaluation, both in long-term and short-term contracts (availability or capacity products) and short-term products/services (activation of energy products), up until real time.
4. Monitoring & activation phase: Activation of bids for congestion management and system operator co-operation up to real time.
5. Measurement & settlement phase: Validation of delivery

For such a complex process, it is of utmost importance to define the characteristics of services that can support the DSOs in minimising their congestion problems.

Considering that different congestion management approaches can be used for different timeframes, from planning to real time operations, the services should reflect the different circumstances of each operational situation. For instance, for congestions that are caused by failures and subsequent corrective actions (e.g. switching state changes, ad-hoc active power intervention such as load shedding), DSOs need a service that is available for fast activation. While for congestions that are forecastable (e.g. redispatch, countertrading as well as the use of active power flexibility) grid- or market-related measures can be procured.

Based on this distinction, further requirements and parameters can be set. These concerns, among other aspects, the question of reservation and the local impact of the congestion management service. In addition, products that can be assigned to corrective congestion management are generally more obligatory than those for predictive congestion management, given that they may also be procured on the market in many cases due to the longer time available.

Less significant differences can be found in the quantity limits, which depend more on the power electronic equipment itself, the duration of the delivery period and in the activation mode [14].

The following table summarises the technical requirements for a Corrective Congestion Management Service and a Predictive Congestion Management Service. Additional to the short time services defined, congestion management services may also be considered in long term network planning processes. This will be analysed in the service Support to Network Planning, which will be further defined in Section 3.5.

Table 3.3. Technical requirements for Corrective and Predictive Congestion Management Services

Parameter	Corrective Congestion Management	Predictive Congestion Management
Procurement time-frame And service timeframe	Operation Timeframe (real-time, on hourly basis)	Short-term (daily or intraday)
Reservation and/or activation	Reservation not sensible as service is mostly necessary for emergencies and scenarios with higher uncertainty. Therefore, activation when needed (directly to the service provider, for the next 15min)	Reservation and activation possible (based on requirements and availability)
Mode of activation	Manual	Manual
Expected duration of the response	The duration is restricted by thermal limits taking also into account the activation time of a resource.	As soon as the forecasts permit an evaluation of the measures but no later than gate closure time or regulatory imposed limits
Activation time	Activation time should be aligned with thermal limits. Timeframes should be defined depending on the power ramping	Activation time should be aligned with thermal limits. Timeframes should be defined depending on the power ramping
Locational need/ Geographic scope	Local (feeder, transformer, connection point) or regional (e. g. whole LV grid + overlaying MV feeder) or even cross regional (probably only for HV). DSO will activate (non-reserved) clients to solve the congestion issue.	Local (feeder, transformer, connection point) or regional (e. g. whole LV grid + overlaying MV feeder) or even cross regional (probably only for HV). DSO will let the market know which FSPs may solve the issue.

Parameter	Corrective Congestion Management	Predictive Congestion Management
Mandatory (or not)	Mandatory	Procured on market or mandatory measures imposed by regulation
Aggregation	Restrictedly applicable	Aggregation from lower voltage levels is possible but may be limited dependent on market requirements and the technical characteristics of the congestion issue
Minimum quantity	Based on the limits of power electronic equipment / measurement error	Based on the limits of power electronic equipment / measurement error
Maximum quantity	Limited to the installed capacity	Limited to the installed capacity
Deactivation period	Depends on the power Ramping	15min, considering available data
Minimum duration of delivery period	15min, considering available data (at the moment)	15min, considering available data (at the moment)
Maximum duration of delivery period	No limitation	No limitation

If flexibility should be used for congestion management, it is essential to develop corresponding products to combine these criteria with the technical possibilities of flexibility resources, the market design and regulatory requirements. It is worth mentioning that the availability of flexibility for congestion management purposes will increase with the gradual uptake of the market (driven by system needs) and the increasing penetration of distributed resources, supporting short-term liquidity and resulting in higher procurement of products closer to real-time [19].

It should also be noted that according to Article 13 of the Regulation (EU) 2019/943 [16], "*non-market-based redispatching of generation, energy storage and demand response may only be used where:*

a) no market-based alternative is available;
b) all available market-based resources have been used;
c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or
d) the current grid situation leads to congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to

address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8).".

3.4 Voltage control

Voltage control services have similar characteristics to congestion management (in section 3.3). The main difference is that in addition to active power control, reactive power control or even a combination of both are considered. The system operators can also use their own resources to regulate the voltage in the daily operation, namely through on-load tap changer control.

Voltage control strategies are be defined from a planning horizon to real time operations. For voltage problems that are caused by network failures and related corrective actions, DSOs need a service with fast activation and active for a long time. In the case of voltage problems that are forecastable (regardless of the time horizon), DSOs have many more possibilities to optimize (technically and economically) the control actions to solve the problem.

The scope of the services and their parameters may also vary according to the voltage level, as shown in the table below. As discussed in section 2.2, voltage control particularly at LV networks need to take into consideration the controllable resources available and the specific characteristics of these networks.

The general technical assumptions for voltage control services are the same but the key parameters can be significantly different depending on the voltage level. For example, both the amount of power and the duration of the service may vary substantially depending on the voltage level (also the inductive MV/HV lines versus more resistive LV lines has a large impact on which services (P vs Q) are more suited.). In addition, due to the nature of voltage problems, which may occur locally or cover a larger area and include several voltage levels at the same time, the scope of services may be significantly different. A lot of forecastable problems may occur cyclically and repeat at specific times, e.g., in summer with high insolation. In those cases, it would be necessary to purchase flexibility services frequently and over long periods of time.

Phase balancing can either be performed locally by three-phase or single-phase DER through specific voltage balancing strategies based on local control functions (typically implemented locally at the power electronic interfaces of the three-phase DER units) or by changing the active and reactive power flow in the three-phases of the system. In this sense, the phase balancing will be tackled through voltage control services in coordination with voltage control strategies.

Table 3.4 describes the technical requirements for voltage control services.

Table 3.4. Technical requirements for a Corrective and Predictive Voltage Control Services

Parameter	Corrective Voltage Control	Predictive Voltage Control
Procurement time-frame And service timeframe	Operation Timeframe (close to real-time)	Short-term (daily, intraday or days ahead)
Reservation and/or activation	Activation when needed (directly to the service provider, for the next 15min)	Reservation and activation is possible (based on requirements and availability)
Mode of activation	Manual (the inverters can change kVA/kvar set point) Automatic (by using fixed voltage set point or a fixed curve in inverters)	Manual
Expected duration of the response	MV: from seconds up to 1h LV: up to 6h (e.g. at the peak of photovoltaic generation)	MV: from seconds up to 1h LV: up to 6h (e.g. at the peak of photovoltaic generation)
Activation time	Activation time should be aligned to the scale of the problem. Timeframes should be defined depending on the level of voltage violation.	Activation time should be aligned to the scale of the problem. Timeframes should be defined depending on the level of voltage violation.
Locational need/ Geographic scope	Locally (Substation, feeder, transformer, connection point)	Locally (Substation, Feeder, transformer, connection point)
Mandatory (or not)	Mandatory	Procured on market or redispatch
Aggregation	Aggregation is possible but only within one connection point. In operation timeframe there is no time to perform complex analysis of the impact of distributed flexibility providers from lower voltage levels	Aggregation is possible, but not in the form of simple power summation. It is necessary to perform an analysis, especially if the aggregated sources are connected at a different voltage level than the one for which the problem occurs.

Parameter	Corrective Voltage Control	Predictive Voltage Control
Minimum quantity	Based on the limits of power electronic equipment / measurement error	Based on the limits of power electronic equipment / measurement error
Maximum quantity	Limited to the installed capacity	Limited to the installed capacity
Deactivation period	Depends on the power Ramping	15min, considering available data
Minimum duration of delivery period	15min, considering available data (at the moment)	15min, considering available data (at the moment)
Maximum duration of delivery period	No limitation	No limitation

3.5 Support to Network Planning

The use for flexibility should be explicitly considered during the networking planning, as an alternative to grid investments.

Regarding long-term network planning, using flexibility as a tool to solve either unexpected or forecasted physical congestions related to reduced network capacity (overload or voltage violation) allows a more efficient network development, as it can be either a complement or even an alternative to traditional grid investments, especially those that intend to solve occasional constraints.

To solve the identified/predicted long-term network capacity constraints, a service combining both congestion management and/or voltage control would be needed, albeit with some differences in its technical characteristics (mostly temporal changes), as explained below.

Those services would consider a time frame of 1 to 3 years, larger than the timeframes for both congestion management and voltage control described above, which are more focused on the short term.

The flexibility reservation should be done in advance, considering the identified/predicted congestions, and activated by the control centres when the time arrives if continues to be necessary. The reserved flexibility could be mandatory or not, depending on the risk/consequence associated with the identified/predicted congestion.

Considering the identified needs for an increase of the network capacity and the planning time-frame services design to support network planning will defer from congestion and voltage services characterized in sections 3.3 and 3.4, namely regarding geographical scope or the duration and quantity needed. Table 3.5. summarises the technical requirements for the Support to Network Planning services:

Table 3.5. Technical requirements for Services aimed to Support Network Planning

Parameter	Support Network Planning
Procurement timeframe	1-3 years
Reservation and/or activation	Reservation in advance. Activated by operation.
Mode of activation	Manual
Full Activation time	Activation time should be aligned with thermal limits. Timeframes should be defined, related to planning criteria
Locational need/ Geographic scope	Substation, Feeder, Transformer, POC (equal and/or lower voltage level)
Mandatory (or not)	Depends on the risk associated with the congestion
Aggregation	Allow aggregation from equal and/or lower voltage level
Minimum Quantity	Based on the limits of power electronics equipments / measurement error
Maximum Quantity	Installed capacity
Duration of delivery period	Several Hours

3.6 Islanding

The islanding service enables parts of the grid to function independently, which is essential in cases where it becomes impossible to provide energy to these areas (due to faults in lines, transformers and other equipment). Although typically the distribution networks, until the secondary substation level, display a N-1 resilience level (meaning that, as a planning criterion, the failure of an individual asset will not cause a prolonged outage) sometimes there are grid zones with prolonged outages. The causes typically include more than one failed asset or an outage occurring at a time where scheduled maintenance is occurring in the backup asset. Repair works typically take a long time, during which the grid users are left without power supply.

In this case, the flexibility of DER, particularly distributed storage units, could ensure power supply to all or a part of the clients affected by the service interruption, forming a small microgrid (MG), if endowed with adequate control functionalities.

Islanding services are, therefore, very important for clients and DSOs alike, potentially improving the reliability and resilience of the system.

Nevertheless, because of the technical complexities, in many cases setting up a microgrid is more expensive than more classic grid reinforcement/(n-1) measures (stronger lines, redundant equipment, …). Also, the microgrid area must contain sufficient production and/or demand flexibility to achieve energy balance. That condition is only rarely met. Hence, microgrid functionality more interesting in specific niche circumstances (remote village or island with a lot of local renewable production and a long and weak main grid connection).

Ensuring a successful microgrid islanding operation is quite challenging. The sudden islanding of the MG may cause high unbalances between local load and generation, which must be compensated by fast acting storage devices in coordination with local generation and flexible loads. Being an inertia-less system, due to the inexistence of rotating masses directly connected to the microgrid, it requires the implementation of specific frequency and voltage control strategies that exploit DER resources controllability and the control of its power electronic grid coupling devices [20].

In that case, DER need to incorporate specific grid support functions associated with frequency and voltage regulation mechanisms, namely:

1) Frequency and voltage regulation capability, provided by a grid forming unit capable of establishing the islanded grid voltage in magnitude and phase and fast frequency and voltage regulation (e.g frequency/active power and voltage/reactive power drop characteristics)
2) Synthetic/digital inertia, that can be provided by the grid forming unit(s) together with frequency regulation strategies or by other DER with specific inertia emulation functionalities
3) Frequency support, where the unit is capable of locally changing the power output as a function of the microgrid frequency (e.g. active power/frequency drop characteristics)
4) Voltage support, being capable of changing the power output as a function of the microgrid voltage (e.g. active or reactive power/voltage drop characteristics)
5) Load reserve capacity
6) Generation reserve capacity

In order to operate the islanded system, the microgrid requires that at least one DER unit (preferable a distributed storage unit or, alternatively, a fast-responding generator) operates as a grid forming unit and thus establishes voltage in magnitude and phase and can provide fast frequency and voltage regulation to ensure the power balance within the islanded system. Additionally, other DER units and flexible loads connected to the microgrid can also support the operation of the grid forming units, supporting voltage and frequency regulation (services 2 to 4) as well as helping to manage the reserve capacity (services 5 and 6) to ensure maximum stability and security during the autonomous operation.

Services 5 and 6 can be provided by using the services already defined for congestion management and voltage control in this document.

Table 3.6 describes the technical requirements for islanding.

Table 3.6. Technical requirements for Islanding (services 1 to 4)

Parameter	**Islanding service**
Procurement timeframe And service timeframe	Short-term (Planned or forecasted events)
Reservation and/or activation	Activation when needed (can also reserve certain capabilities)
Mode of activation	Manual or automatic in case of unplanned faults
Expected duration of the response	1-3 hours
Activation time	Immediate after islanding (immediate after switch opens)
Locational need/ Geographic scope	Locally within the microgrid area (typically HV/MV, MV feeder section or MV/LV substations)
Mandatory (or not)	Not mandatory
Aggregation	Not applicable
Minimum quantity	A minimum quantity could be established for the frequency and voltage regulation
Maximum quantity	Limited to the installed power of the provider
Deactivation period	<1 min after reconnecting to the main grid
Minimum duration of delivery period	15min, considering available data (at the moment)
Maximum duration of delivery period	Limited to energy capacity of the provider
Block loading size	Capability of grid forming units to respond instantaneously to load increase/decrease

The Islanding service has been successfully demonstrated in real distribution networks in H2020 projects such as SENSIBLE [18], where it was shown that distributed energy storage units can help supply both LV and MV network feeder sections through adequate coordination of local frequency and voltage control strategies, complemented by network monitoring and adequate energy management of storage devices.

Maintaining a stable island will then result from the coordinated operation of the different DERs providing the abovementioned grid support functions (a situation where a provider can supply all services will be rare in a heavy DER penetration scenario). However, although the microgrid can operate with more than one grid forming unit (multi-master operation mode) control requirements will be more complex in that case.

The DSO is in charge of ensuring that all these services operate coherently to maintain the stability of the island, ensure the operation within the technical limits and a safe reconnection to the main grid. The DSO has the role of the orchestrator of the assets within the islanding zone and will need to adopt adequate automation to ensure seamless islanding and reconnection to the main grid.

In case several DSOs exist in the islanding area there should be an inter-DSO agreement on how islands are managed, in which the responsibilities of each DSO are stated and the communication between them is explained.

This is relevant in operation scenarios where a large share of flexibility resources are integrated into the distribution network as in this case faults can occur in multiple locations and at different voltage levels.

When a zone of the grid is working in islanding mode it is not connected to the synchronous grid. Therefore, if any of the assets is providing services to the TSO (with pre-validation by the DSO) the TSO must be informed of the provider's inability. There is also the need to ensure the provider does not receive orders from the TSO that can endanger the stability of the network.

When working in islanding mode there is the possibility that the FSPs within the island zone are prevented from supplying the pre-contracted services. Adequate market rules should be implemented to make sure that the providers are not negatively affected by the islanding situation. However, if the service is not provided and the cause is unrelated to the island, penalties should apply as usual.

Typically, the DSOs are not expected to operate in islanding mode losing all the benefits of being connected to the European synchronous network. It is a service intended for the unexpected situation and, therefore, only used in real-time activation. There may be exceptions to allow for planned works, where islanding may constitute the best option. In this latter scenario, predictive islanding is possible.

3.7 Black Start

When islanding is not viable, or in case of a partial of general blackout in the main grid, due to extreme events, existing or innovative mobile storage systems could restore service to a local microgrid until reconnection to the main grid is possible.

In terms of technical requirements, these systems need to have black start capability in addition to being able to provide fast frequency and voltage services described for the Islanding service.

Adequate communication between the DSO and all parties involved is also required to guarantee stability during restoration procedures and ensure that the active and reactive powers are within limits.

Similarly, to the conventional power system, the island restoration procedure [21] consists of pre-established guidelines and operating routines, running step by step. However, when compared to conventional power system restoration, the microgrid service restoration procedure will benefit from a considerable problem size reduction, and hence the reduction of the number of controllable variables.

The first step of the procedure will require the black start unit(s) to energize the microgrid at no-load conditions ($P=0$, $Q\neq0$). As foreseen in the islanding service (section 3.6), besides the unit with black start and grid forming capabilities, other flexible DER can also provide support during the rebuilding process [22], helping regulating frequency and voltage during the reconnection of loads and generators.

Table 3.7 summarizes the technical requirements for black start.

Table 3.7. Technical requirements for Support to Black start

Parameter	Black start
Procurement timeframe And service timeframe	Short-term (Planned or forecasted events)
Reservation and/or activation	Activation when needed (also possible reservation of units with black-start capabilities.)
Mode of activation	Manual
Expected duration of the response	Depends of the time to reach the location where it is needed if provided by mobile systems
Activation time	Activation time should be aligned with the provider constraints. Timeframes should be stated by the provider and can be a parameter for selection.
Locational need/ Geographic scope	Locally (typically at MV/LV Substation)
Mandatory (or not)	Not mandatory
Aggregation	Not applicable
Minimum quantity	A minimum quantity could be established for the frequency and voltage regulation
Maximum quantity	Limited to the installed power of the provider
Deactivation period	<1 min after reconnecting to the main grid
Minimum duration of delivery period	>30 minutes
Maximum duration of delivery period	Limited to energy capacity of the provider

3.8 Emergency load control

In extreme cases, when it is not possible to accommodate the demand and all other solutions cannot provide the required amount of load shedding services, while avoiding generation curtailment, the DSO may need to request interruption of the required amount of load from the grid to maintain stability and prevent further problems. The load chosen to be mandatorily curtailed should comply with an order of societal merit making sure the least important loads are the first to be shed. For example, hospitals, police stations and firefighter's headquarters are usually the last in that order of merit.

Due to the emergency and the need for all customers to provide it, this type of service should not be supplied by market mechanisms. but be defined instead as a regulatory mandate and should be manually activated ensuring that certain types of priority loads are not interrupted. Indeed, it is assumed that all market-based options have been depleted before using this mandatory service.

Mandatory generation shedding services for all types of generators are already stated in the European Regulation 2016/631 (RfG) [8] which constitutes the acceptance by the legislator that these services are necessary for grid operation.

Distribution grid stability requires that this emergency control can only be safely carried out by the relevant DSO. In case, of needs by other system operators these should be met by the relevant system operator who will select the adequate loads to ensure the smallest possible impact to grid users while meeting the needs and making sure there is no overshoot of the needs which may arise from overloads or over/undervoltage caused by "blind" activations that do not take into account the network status..

3.9 Mobile generation capacity

In case of low availability of generation and load flexibility, mobile generation or storage units can be mobilised and connected to a certain point in the grid to provide additional power to supply more customers with power in case of a fault or avoid undervoltage and stability problems in case of planned operations or forecasted severe weather event.

This service can be supported by a market or by long-term bilateral agreements with providers. Both approaches are possible and have their own specificities for both the buyer and provider.

Table 3.8. summarises the technical requirements for Mobile Generation Capacity for a market scenario.

Table 3.8. Technical requirements for Support to Mobile Generation Capacity

Parameter	**Mobile generation capacity**
Procurement time-frame And service timeframe	Short-term (Planned or forecasted events)
Reservation and/or activation	Activation when needed (also reservation of the mobile unit)
Mode of activation	Manual
Expected duration of the response	Depends of the time to reach the location where it is needed
Activation time	Activation time should be aligned with the provider constraints. Timeframes should be stated by the provider and can be a parameter for selection.
Locational need/ Geographic scope	Locally (Substation, feeder, transformer, connection point)
Mandatory (or not)	Not mandatory
Aggregation	Not applicable
Minimum quantity	Based on the limits of power electronic equipment / measurement error
Maximum quantity	Limited to the installed power of the provider
Deactivation period	Depends on the power Ramping
Minimum duration of delivery period	30min, considering available data (at the moment)
Maximum duration of delivery period	No limitation

4 Procurement process

The DSO needs described in Chapter 2, which all relate to keeping current and voltage within the defined limits, shall be fulfilled by procuring services in a market-based way according to the Electricity Regulation and Directive, unless strategic gaming or low liquidity does not allow such solution (see Art. 13 Electricity Regulation).

Even if enough flexibility is available, lack of sufficient volumes during rare situation may necessitate reinforcement and grid investments. That means that the procurement of flexibility reserves should be such that a base line of flexibility is available at a decent cost with a multiyear horizon. This is something that is very hard to realize with day ahead/intraday markets alone, especially when there are competing offers for flexibility for balancing purposes.

Under the assumption that these obstacles can be overcome, DSOs need to interact with flexibility markets to procure the relevant services. The following points need to be considered when designing such a procurement process:

- Current and voltage problems can both be solved with active and reactive power. Therefore, the selection of the most efficient services to solve both DSO needs is interdependent.
- Unlike frequency control, DSO needs can only be solved with locational services. The impact of the service towards the specific need has to be known by the selecting algorithm accounting for the contribution of each resource to solve the problem. This information is called sensitivity. In radial grids and for current problems, the sensitivity can be binary (0 or 1), but for voltage problems in all grid topologies and for current problems in meshed grids, the sensitivity is in a range from 0 to 1. This can result in markets with apparently sufficient liquidity, but that when locational constraints are taken into account, still not sufficient capacity is available.
- Network reconfiguration, i.e. changing the topology of the grid via switching or changing the taps of the transformers, can also solve the DSO needs. Especially in meshed grid structures, the minimum costs of flexibility use and losses can be found in a mixture of network reconfiguration and the use of services.
- The use of flexibility services can cause new current and voltage problems. There might also be an interdependence between two radial grids which are interconnected at a higher level.
- DSOs are responsible for the economic, secure, reliable and efficient operation and development of the electricity distribution system in their area (Art. 31 of Electricity Directive). Therefore, apart from their system operation role, DSOs need to defend the costs of flexibility use towards their national regulator.
- Flexibility can be used for both balancing and congestion management. The signals from those two markets can contradict. Those two types of markets may also compete for flexibility, which may have unwanted side effects in terms of available flexibility at the time when needed and/or gaming of aggregators.
- common markets could be considered (including multiple buyers such as DSOs, TSO, or even commercial parties), so that the system view can be considered which could potentially lead to lower overall system costs.

For these technical and regulatory reasons, the design of the procurement process needs careful consideration. Two main options are possible: the selection of the flexibility services by a third party, such as a third market platform, or by the DSOs themselves on such a market platform. Based on the points mentioned above, the following consequences occur for the different options:

Market operator selecting the flexibility services

- Market operators need grid information to select the most efficient flexibility bids. If the problems and related solutions are simple (e.g. overload at MV/LV transformer which can only be solved with active power), the grid information needed can be small. However, when it comes to more complex situations (e.g. using active and reactive power for both voltage and current problems or having these needs in meshed grids), more grid information for the given grid topology is needed, such as sensitivities per flexibility towards each critical grid element and the constraints of the different grid elements. The more critical grid elements exist, the more information is needed by the market operators. Therefore, information sharing mechanisms among DSOs and market operators must be adequately structured and implemented. Nevertheless, clearing a market with such a big number of constraints, even when the grid constraints are linearized, is a hard challenge.
- If network reconfiguration is a potential mitigation measure, the optimum of such solution and flexibilities activation can be an interdependent mixture of both solutions. Consequently, in order to derive the most efficient solution, either iterations between the market operator and the DSO are needed or the market operator needs to receive comprehensive grid information, which depicts the electrical properties of the grid including the network reconfiguration options. In this case, the market operator must be able to conduct a full power flow analysis.
- If the market operator selects flexibility bids day-ahead or intraday, potentially until close to real-time, to solve grid problems, thus deciding on which remedial action needs to be carried out to keep operational security constraints within the limits, allocation of grid operation responsibilities need to be reconsidered. For example, in case the DSOs keep their final responsibility, they then need to perform a final grid assessment of the options selected by the market operator. If they detect deficiencies, iteration(s) are needed. It can be debated to which extent such an iterative process is efficient.
- If DSOs are still responsible for the costs of the flexibility activated use to solve grid problems in their system, discrepancies between the party selecting the most efficient bids and the party paying for the bids may occur. This can lead to challenges for DSOs to defend their costs towards the regulatory authorities. There can also be a challenge in incentivising the improvement of the algorithm, especially if lock-in effects exist for the DSO. The DSO can also place an explicit buy order on the flexibility market to cope with this issue, thereby making sure that flexibility is only bought on the market if it is less expensive then alternatives. The market should be designed in such a way that this challenge does not occur.

DSOs selecting the flexibility services

- Apart from TSO/DSO coordination, there is no need to exchange grid information to select the flexibility bids to solve grid problems. DSOs can combine the information from their grid assessment with the algorithm for selecting flexibility bids. This structure works for simple and complex grid situations, from LV to HV, also including network reconfiguration and the combination of active/reactive power to solve both current and voltage problems. Therefore, switching and selection of flexibilities is at one actor.
- There are no challenges with regard to governance and regulation, since the responsibility for safe and economic system operation and the fulfilment of this task is not divided among actors. DSOs can more easily defend their actions towards the regulator.
- Iterations between the market operator and the DSOs to find the optimal and secure solution are avoided, also for complex grid structures. Therefore, data exchange needs between the DSOs and market operators are reduced, which can also reduce the likelihood of failures, increasing the resilience of the system.
- The fact that DSOs operates their own flexibility markets, being themselves active market participants and responsible for grid reinforcements, could lead to conflicts of interest and discriminatory access for other market parties, which may require strict audit process and transparency mechanisms.

Considering these, the selection of flexibility services by the market operator for solving grid problems can lead to significant challenges from a regulatory and technical perspective. The challenges especially occur when the market operator is supposed to select flexibility bids for more complex grid situations (e.g. in meshed grids or for optimising both voltage and current via active and reactive power). The consideration of network reconfiguration options in the optimisation process adds complexity. For these reasons, allocating the task of selecting the flexibility services to DSOs seems to be less challenging and more future-proof, also considering the increasing digitalisation of distribution grids, increasing switching options. Further analysis is needed to compare the different options and design aspects of the procurement process, considering the requirements of the flexibility services as introduced in this report and to assign roles and responsibilities in the most efficient way.

5 Conclusions

Flexibility will play a key role in the energy transition. This will have a considerable impact on the power sector, particularly on distribution networks. In addition, what also became clear is the fact that, despite some already existing challenges, the potential of these services is yet to be explored. In that regard, all the involved partners have made an effort to envision what they foresee as the future of the operation of the distribution grids.

Thus, considering that the DSOs will face new challenges in their activities, it was easy to understand that without proper identification of the DSO's needs it would not have been possible to design relevant services that would help to solve them. Consequently, the first phase in this task was to develop a clear identification of the DSO needs. As a result, the following needs were identified as the most relevant ones for the current and also for the future operation of distribution grids:

- Physical congestion
- Voltage violation
- Support to network planning
- Phase balancing
- Support to planned/unplanned operations
- Support to extreme events
- Support to islanding

Based on these needs, the respective services to solve them were identified and characterized. This characterization was realized by defining a set of technical requirements for each service, such as the procurement and service timeframes, reservation and/or activation, mode and time of activation, among other ones. Along with the discussions, several services were considered, from ones that could only be used to solve a need, to others that might be used to solve several needs. In this analysis some of them were discarded considering they overlapped with the characteristics of other services that had already been defined. In the end, in addition to the traditional congestion management and voltage control services, some new ones were also defined, such as support to network planning, islanding, black start, emergency load control and mobile generation capacity.

The procurement and service timeframes stood out as requirements that had a considerable impact on the services' definitions, namely on the need for reservation and on the activation time and mode. Consequently, some of the services were divided into predictive and corrective services, reflecting their target to solve forecasted issues or unexpected, near to real time ones.

Moreover, considering the wide range of events in distribution grids and the need to be transparent and non-discriminatory, the service requirements were defined as broad as possible within the technical limitation of the DSOs activities, so they would not exclude any possible provider. Additionally, despite the fact that these services should be procured in a market-based way, in this task we focused on defining the services that would solve the DSO needs. The services were defined keeping in mind that they should be market-based. Still, in some cases, namely for emergency services, a market-based option would not always be possible. Further detail on these will be explored in other tasks of EUniversal project, in particular in Work Package 5.

It should also be highlighted that there are other relevant aspects to be considered in the further development of flexibility services, namely the observability of the distribution grid by means of improved monitoring combined with innovative tools (from WP4) and standardized interfaces between the different partners – through the UMEI (from WP2).

In conclusion, this report provides valuable insights on the requirements of the flexibility services which will be further studied in the EUniversal project and which is considered as a first step towards the development of the UMEI.

6 External Documents

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