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D5.1 – Validation set-up report: Description of scenarios, tests and validation indicators

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Contributions of partners

Description of the contribution of each partner organization to the work presented in the deliverable.

Partner	Contribution
UdG	- Close collaboration throughout the entire redaction of the deliverable; Definition of KPI-02
UPC	- Close collaboration throughout the entire redaction of the deliverable; Definition of KPI-01, CI-01, KPI-05, CI-03; Review
SIN	- General feedback on KPI-04
JR	- Review
ICOM	- Feedback on the structure and general content of the deliverable; Review
EYPESA	- Redaction of the deliverable: definition of the list of KPIs, definition of KPI-03, KPI-04, KPI-06, KPI-07, KPI-09, CI-02
CS	- Description of KPI-08

Table of contents

Acronyms and abbreviations

AMI	Advanced Metering Infrastructure
BAU	Business As Usual
COX	Control Centre Room (Centre de Control de Xarxa)
CI	Control Indicator
DCU	Data Concentrator Unit
DMS	Distribution Management System
DSO	Distribution System Operator
EMU	Electrical Measurement Unit
EPU	Electrical Protection Unit
ESG	Electrical Switchgear
ESB	Enterprise Service Bus
FN	False Negative
FP	False Positive
FDA	Fault Detection Application
GW	Gateway
GM	Grid Meter (meter installed at DCU)
HLUC	High Level Use Case
HLUC	High Level Use Case
ILEM	Intelligent Local Energy Manager
KPI	Key Performance Indicator
LV	Low Voltage
LVGOI	LV Grid Observability Infrastructure
MAPE	Mean Percentage Error
MV	Medium Voltage
MDC	Meter Data Collector
MDMS	Meter Data Management Unit
PMU	Phasor Measurement Unit
PV	Photo-Voltaic
PCC	Point of Common Coupling
PED	Power Electronics Device
PRIME	PoweR line Intelligent Metering Evolution
PQM	Power Quality Monitor
PSU	Power Supply Unit
RDB	Reading Data Base
RTU	Remote Terminal Unit
RMS	Root Mean Square
SS	Secondary Substation
SGAM	Smart Grid Architecture Model
SM	Smart Meter
SCADA	Supervisory Control and Data Acquisition
SG	Switchgear
TN	True Negative
TP	True Positive
TPR	True Positive Rate
UC	Use Case

Executive Summary

This report is the first document redacted within the work package dedicated to the validation of RESOLVD in the real environment (WP5). It provides an initial description of the pilot set-up, both in terms of physical configuration and of guidelines for the tests execution. It was prepared following a collaborative approach, to have a more holistic and shared vision of what the consortium wants to achieve during the validation phase of the project.

The network that will host the new technology is composed of two low voltage lines, deriving from two different secondary substations, that will be linked through the construction of a third line, giving birth to a ring-shaped structure. Three switchgears will be installed at three strategic points, and permit the grid reconfiguration scenarios, through remote control. The Power Electronics Device (PED) will be installed in one of the two secondary substations, connected to one of the two feeders under consideration. The Wide Area Monitoring System (WAMS) field infrastructure, composed of Phase Measurement Units (PMUs) and Power Quality Meters (PQMs) encompasses not only the LV network of the pilot, but also the MV lines and secondary substations upstream. Such a set-up makes it possible to demonstrate with more quality the contribution of the PMU devices in fault detection and localization scenarios. To monitor the status of the network and to control the grid actuators (PED and switchgears) from the SCADA system, the communication infrastructure needs to be upgraded.

Based on the pilot hardware infrastructure describing the components, the study moves to the analysis of key performance indicators (KPIs) and to the tests or calculations that are necessary to perform in order to evaluate them.

The final list of KPIs is based on what had been established in the initial DoA and adapted to the more recent specifications of use cases (included in WP1) and technologies (included in WP2, WP3 and WP4). EyPESA, responsible partner of this report, sets the validation objectives and priorities, according to what is considered more interesting to demonstrate from the point of view of the DSO. Functional tests are not included in this report.

Apart from the KPIs, that specify the expected positive benefit of the technology, some control indicators (CI) were defined, to monitor the side effects of RESOLVD, and make sure that the positive impact remains higher than the negative impact.

CIs and KPIs can be subdivided into three categories, depending on the higher-level objective pursued by each one. The first category is related to "efficiency": in this group all the indicators regarding losses and optimal operation of the network are included. The second category is "planning" and includes the indicators of hosting capacity and the ones associated to operational and capital expenditures. The third group refers to the KPIs and CIs that measure the quality of service for final customers, a category that could comprise, for example, the reduction of supply interruptions or the waveform quality.

The list of KPIs is the following:

Category "Efficiency":

- KPI-01: Power losses reduction due to waveform quality improvement
- KPI-02: Improvement of the energy profile in the secondary substation
- CI-01: Efficiency rate of the PED and the energy storage system

Category "Planning":

- KPI-03: Increase of DERs hosting capacity in LV network
- KPI-04: Reduction of DSO investment
- CI-02: DSO operation expenditures with respect to the BAU solutions

<u>Category "Quality of Service":</u>

- KPI-05: Percentage improvement in line voltage profiles with power injection and consumption
- KPI-06: Number of prevented critical events in the LV grid due to forecasting and remote control of grid actuators
- KPI-07: Quality of online event detection in LV grid
- KPI-08: Quality and time needed for awareness and localization of grid fault in MV grid
- KPI-09: Quality of LV grid operation in island mode
- CI-03: Waveform quality in LV grid

For each KPI and CI a definition is provided, together with the reasons why it should be included in the analysis. In addition, the methodology to evaluate it is presented: this could include simple calculations and theoretical simulated analysis, or tests and measurements performed in the pilot area.

1. Introduction

1.1. Objectives

The purpose of this document is to present the electrical specifications and characteristics that will be validated with the help of the test network. This will be done through the identification of the interaction points between the installed technology and several devices that are part of the new grid concept.

In addition, it will report the issues and criteria related to the integration and interaction with legacy systems and will include the set of performance indicators and acceptance criteria that will be used for validation. Finally, the report can be used as a guideline for the planning and operation of the tests.

1.2. Report structure

The document is structured in the following way: firstly, the introduction and general objectives are presented in this chapter (Chapter 1). Then, in Chapter 2, the pilot is described in detail, including the characteristics of the new lines and switchgears, the PED and batteries location, the description of the communication infrastructure and all the issues related to the WAMS technology installed. Finally, in Chapter 3, the key performances indicators (KPIs) are defined and described presenting the methodology used for their evaluation, which includes formulas, input data, and possible grid configurations.

2. Pilot description

The pilot area of RESOLVD is located in L'Esquirol, a village in the north of Catalunya. It is composed of two low voltage (LV) three-phase lines, deriving from two different Secondary Substations (SS), which will be called SS-A and SS-B. In Figure 1 the blue arrows represent the supply points, while the yellow circles stand for the PV installations. Only line 2 (L2) of SS-A and line 2 (L2) of SS-B will be part of the pilot area.
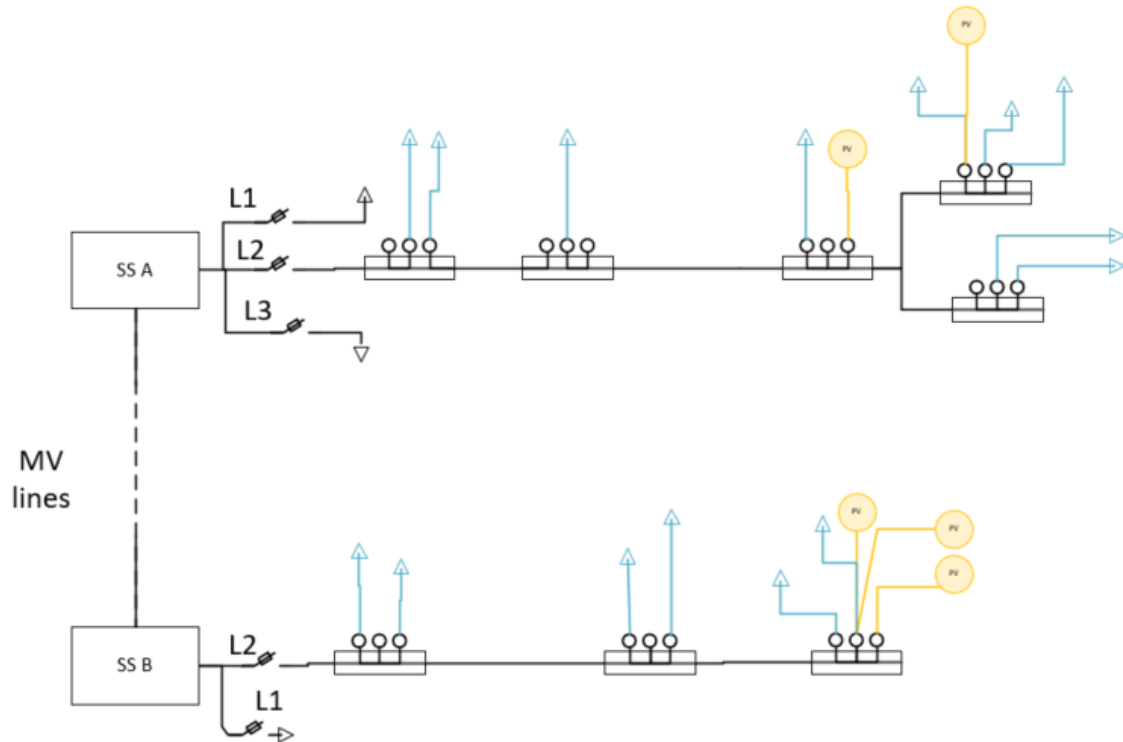

Figure 1: Schematic of the pilot area of RESOLVD

In Table 1, the values of rated power of the transformer and the total contracted and generation power installed are summarized. It should be noted that the MV/LV transformers are oversized with respect to the load of the area. This is because some years ago, the two substations had to supply also two high-load factories that have now closed.

Table 1: Rated power and contracted power values of SS-A and SS-B

Secondary Substation	SS A	SS B
Transformer rated power	250 kVA	630 kVA
Total contracted power	138.6 kW	127.8 kW
Contracted power of line in the pilot	58.3 kW	56.9 kW
PV power installed in the pilot	12.5 kW	9.9 kW

The selected hosting area for the RESOLVD technology will undergo some changes in order to test certain specific scenarios and use cases.

2.1. New line and link box

First, the two radial lines will be connected through a link cable that permits to create a ring shape. In Figure 2 the link line is indicated in orange, together with the link box that permits the connection. The three red circles mark the points where the fuses will be substituted by motorized switchgears with overcurrent protection and which also allow remote control and

reconfiguration of the grid moving border, for example to avoid a congestion or to permit self-healing manoeuvres.
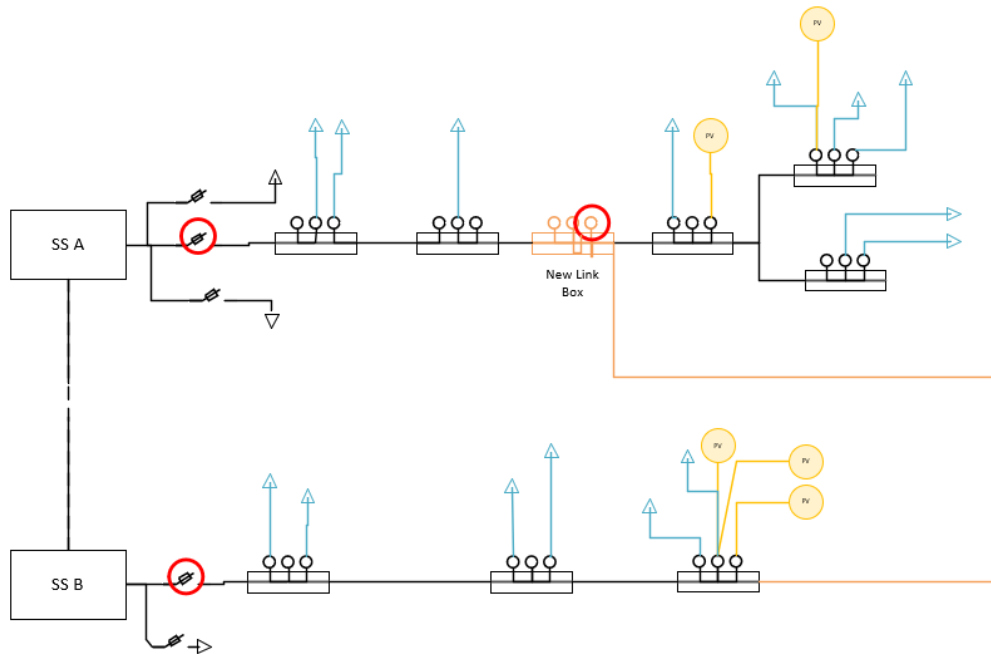
Figure 2: Changes to the configuration of the pilot area

Figure 2 can be simplified with the schematic below (Figure 3). This scheme will be used to represent the possible grid configurations that can be implemented during the test phase.
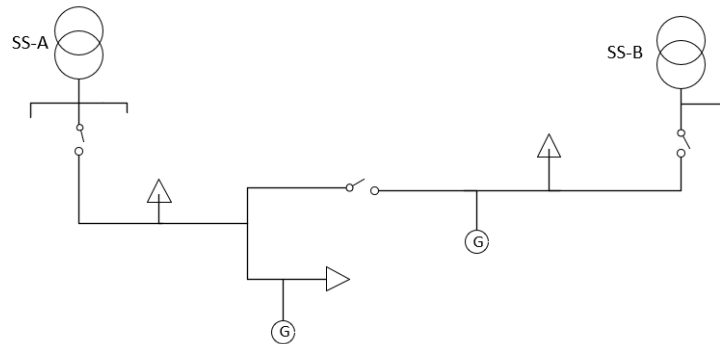
Figure 3: Simplified schematic of the pilot area

The two three-phase transformers of the secondary substations are of different type: one is delta connected and the other is star connected. For this reason, in order to couple their operation in ring configuration, it will be necessary to substitute one of them.

In order to better analyze the energy exchanged between the pilot area, the batteries and the rest of the grid, and to evaluate the performance and efficiency of the technology, it was also decided to install smart meters at the beginning of the two feeders and in the point of common coupling (PCC) of the PED.

2.2. PED and Energy Storage System (ESS)

The PED and the batteries developed and provided by UPC, will be installed in SS-B. This location has been selected for space reasons, as it consists of a two floor-building, with an empty second floor, as it can be seen in Figure 6. Figure 4 indicates the electrical PCC of the technology.
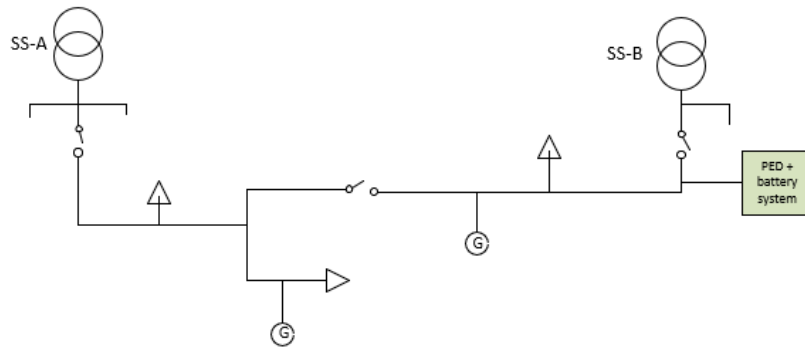
Figure 4: Location of connection with PED

The Lithium-ion and Lead-acid batteries, indicated in blue in Figure 6, will be installed on the second floor. To sustain and distribute their weight over the floor, a metallic support will be constructed and located under the energy storage system.

Another issue encountered is related to the insertion of the batteries into the building, as the window that can be seen on the façade, could be too small. For this reason, it will be necessary to assemble the modules of the two storage devices on site.

Figure 5:A picture of SS-B where the PED and the batteries will be installed

The PED will be located on the ground floor, so that it will be easier for the user to control it.

The batteries and the BMS will be electrically connected to the PED by a cable that will go through the floor.

All the communication connections will converge into the communication box, located on the first floor, on the opposite side of the PED.

Figure 6: Plan of the floors and vertical sections of SS-B, indicating the positions of PED and batteries

2.3. PMUs and PQMs

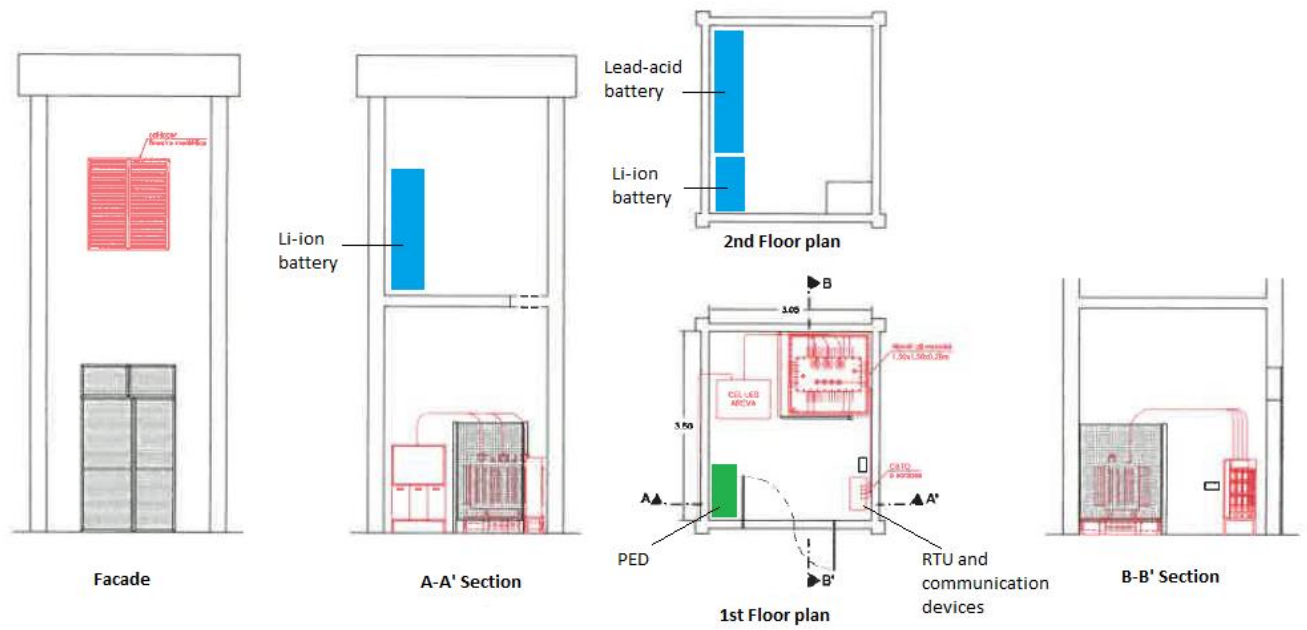The in-field components of the Wide Area Monitoring System (WAMS) provided by ComSensus are the Phase Measurement Unit (PMU) and the Power Quality Meter (PQM).

These technologies will be installed on both the low voltage and on the medium voltage side, as described in the scheme of Figure 7.

Even though the RESOLVD pilot is focusing on the LV segment of the network, EyPESA will expand the pilot, encompassing MV level to demonstrate with more quality the contribution of the PMU devices in fault detection and localization.

Figure 7 represents with blue lines the MV network upstream of the LV pilot area (black lines). The circles labelled with a "T" are the poles of the network. The boxes labelled as SS-A, SS-B, SS-C, SS-D, SS-E and SS-F are the secondary substations composing the MV network and connected to the Primary Substations (PS).

The red labels indicate the locations of PMUs and PQMs and the voltage level of the point of connection.
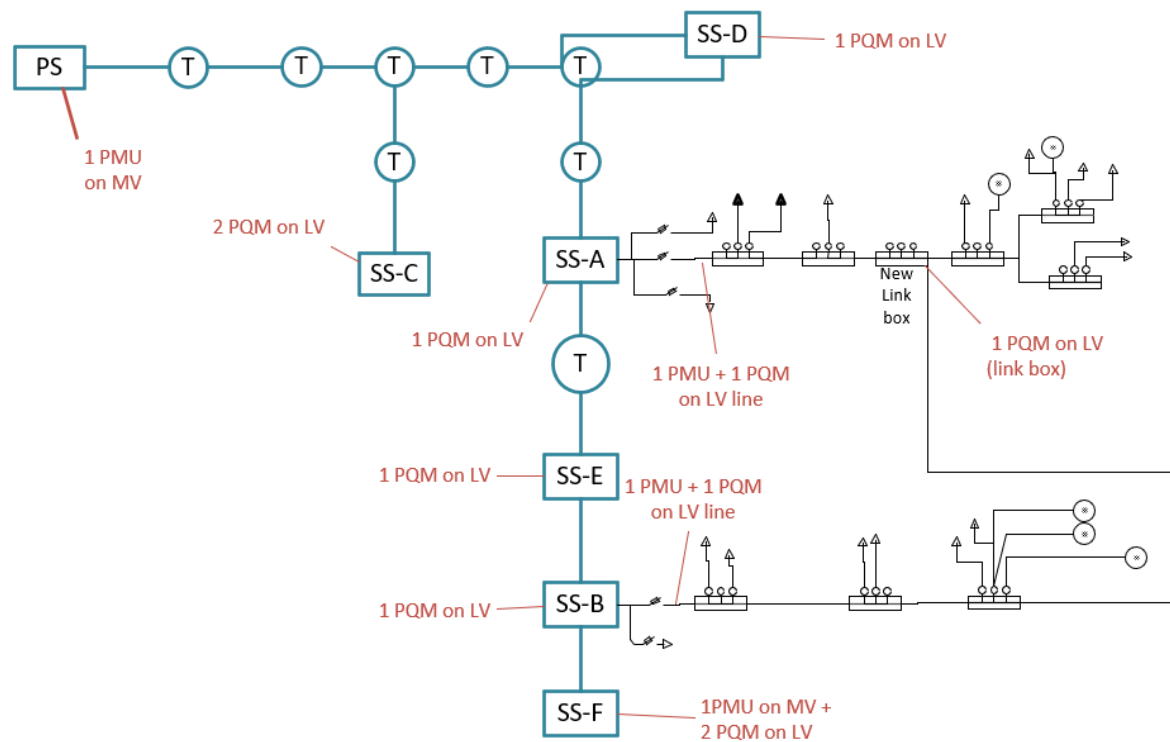
Figure 7: Location of PMUs and PQMs in the pilot area and in the upstream MV network

Starting from the medium voltage side, there will be two PMUs connected to the two end points of the network (PS and SS-F) at MV level, and 1 or 2 PQMs in each of the 6 secondary substations, connected at the output of the transformer (LV level), to measure the load flow of each node of the network.

PMUs and PQMs analyze the power waveform and thus need connected voltage and current measurements inputs. The voltage and current ranges permitted by these devices necessitate the installation of voltage and current transformers.

The reason why in SS-C and in SS-F, two PQMs are needed, is because in these substations there are two parallel LV boards at different voltage levels, one at 400 V line to line and the other at 230 V line to line.

The LV PMUs voltage measurement inputs are rated 430 Vac rms line to line and 110 Vac rms through voltage transformers with a 5250V/110V ratio, thus, in the case of the two PMUs installed at MV level, it is necessary to use voltage measurement transformers. In the case of the primary substation an equivalent equipment is already present, while for SS-F, it will be necessary to install a new one.

Measurement transformers are needed also for the current inputs, both for PMUs and PQMs at MV and LV level.

The communication will be ensured by the presence of an embedded gateway in each PQM. In the case of the PS, where there is no PQM, an *UNO-2372G* embedded PC will be installed. The WAMS technology will operate on an independent network with respect to the DSO's LAN, to ensure a faster and more effective communication.

Each of these devices will be fed through a Power Supply Unit (PSU).

Within the PED, a PQM will be installed, to improve the measurement capabilities of the power electronics technology.

The installation of an extra PQM device on L2 of SS-B could be necessary, to permit an effective calculation of the KPIs related to the performance of the PED.

2.4. Communication infrastructure

The objective of this section is to present the elements forming the communication architecture, and how they will be connected to each other.

The following scheme presents the overall infrastructure of the project to remind that the grid pilot area will be connected to the ESB through three points:

- The WAMS: a software collecting and processing all the data from PMUs and PQMs;
- The SCADA: managing the communication with all the grid elements associated to the technical operation and control of the grid;
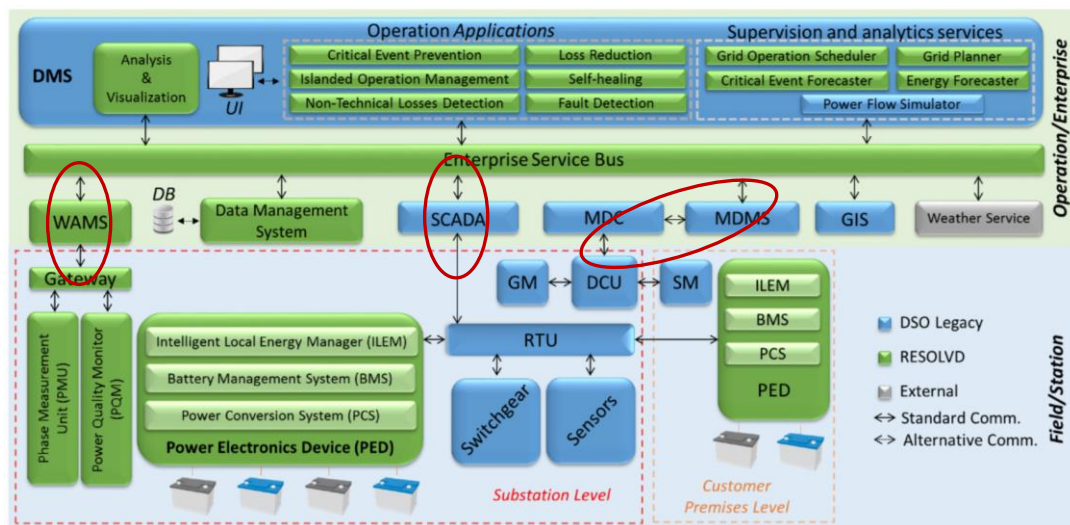- The MDMS: providing the data coming from smart meters.

Figure 8: RESOLVD component layer

Regarding the MDMS, the communication infrastructure in the field doesn't need to be upgraded, as the current technology installed, composed of data concentrator units (DCU) and smart meters (SM), already permits the collection of consumption and generation data, for billing purposes. The only modification that was necessary to implement to the normal business process of data collection, was to increase the frequency of data polling (from one hour to 15 minutes) and request also voltage and current values from the metering devices.

When looking at the WAMS, communication is handled via the GW developed by CS.

The communication associated to the SCADA, whose field infrastructure is located in the two secondary substations and in the new link box, will need to be upgraded, to permit remote monitoring and control of the grid actuators (switchgears and PED). To do so, RESOLVD will use EyPESA's standardized telecommunications and automation architecture.

The communication architecture is composed of the following sub-systems:

- Supervisory Control and Data Acquisition system (SCADA);
- DRN: A router that works with PLC, GPRS and fiber optic ports;
- Intelligent Local Energy Manager (ILEM);
- Power Electronics Device (PED);
- Remote Terminal Unit (RTU);
- Electrical LV Switchgears (ESG);
- Electrical Measurement Units (EMU): similar to power quality analyzers;
- Electrical Protection Units (EPU);
- Power Quality Meters (PQM);
- Phase Measurement Unit (PMU);
- Battery Management System (BMS);
- Gateway (GW): part of the WAMS;
- Meter Data Management System (MDMS).

The ILEM is a subcomponent of the Power Electronics Device, but in this analysis, they have been kept as separated to clarify the communication chain.
The following diagram shows the hierarchic order of the various devices being used in the design of the RESOLVD communication system.
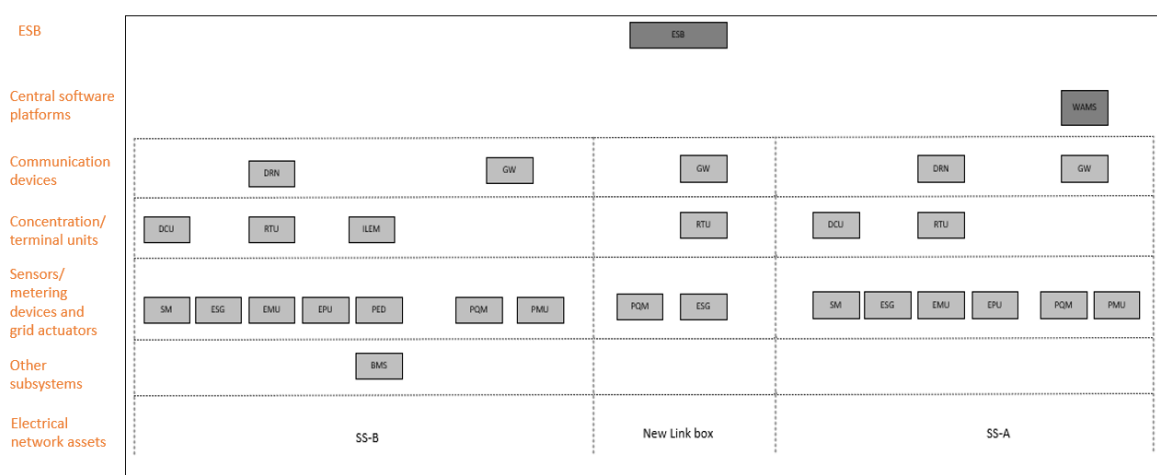
Figure 9: The communication infrastructure of RESOLVD pilot

Some possible data flows are explained hereunder.

One example is the flow of setpoints and schedules to control switchgear and batteries, coming from the ESB, as depicted in the following figure.
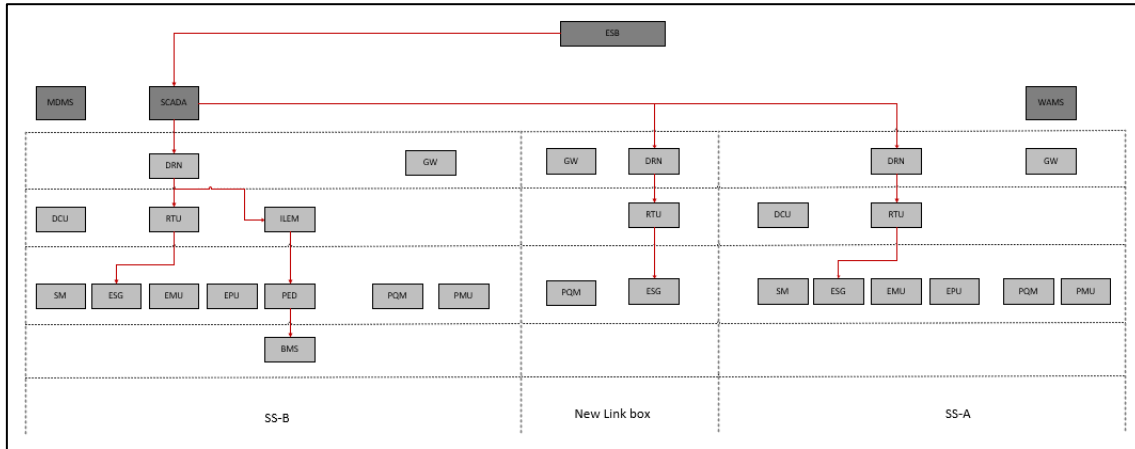
Figure 10: Data flow from ESB to switchgears and PED

Consumption and generation data from customers' smart meters are collected through the data flow described in Figure 11.
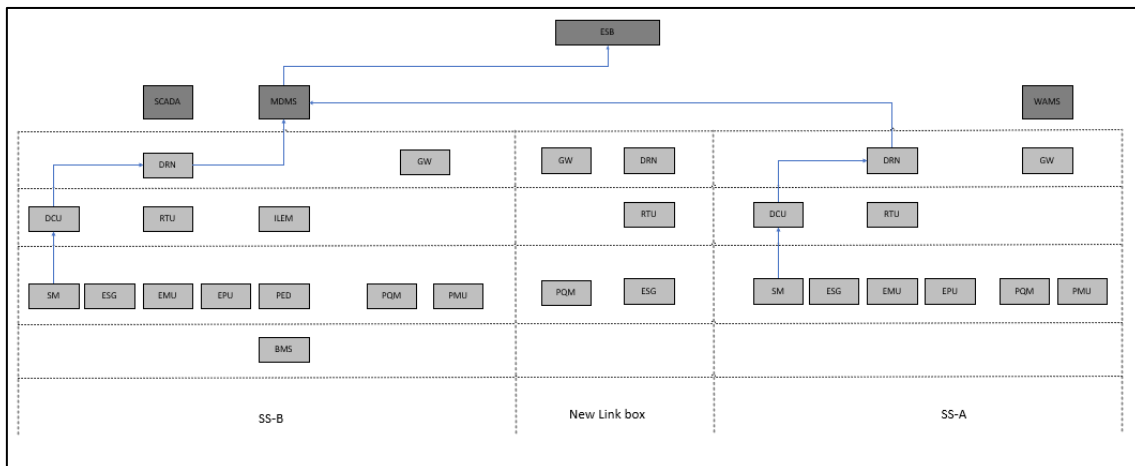
Figure 11: Data flow from smart meters to ESB

Figure 12 represents the flow of data from PMUs and PQMs to the ESB, passing through the WAMS.
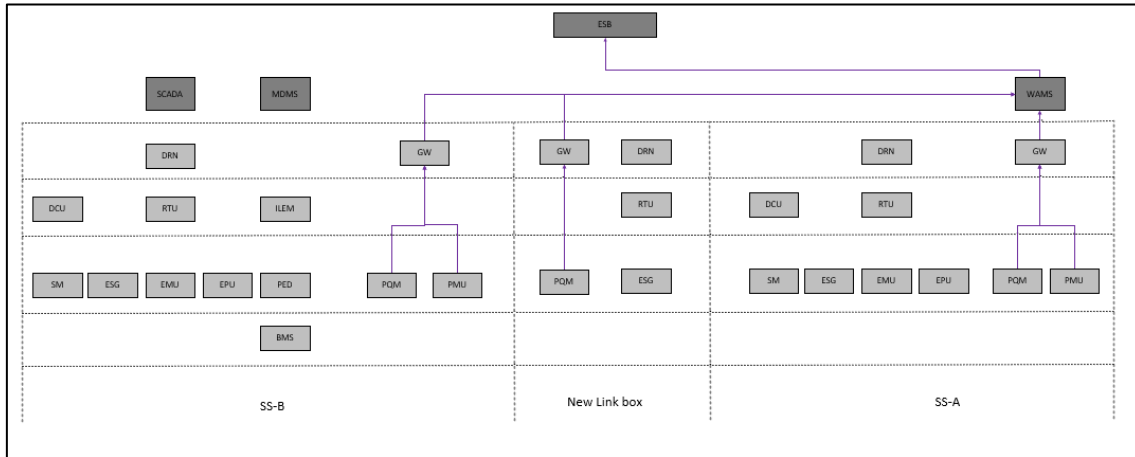
Figure 12: Data flow from PMUs and PQMs to ESB

Figure 13 represents the flow of data to collect the status of different devices installed in the field of the pilot area.
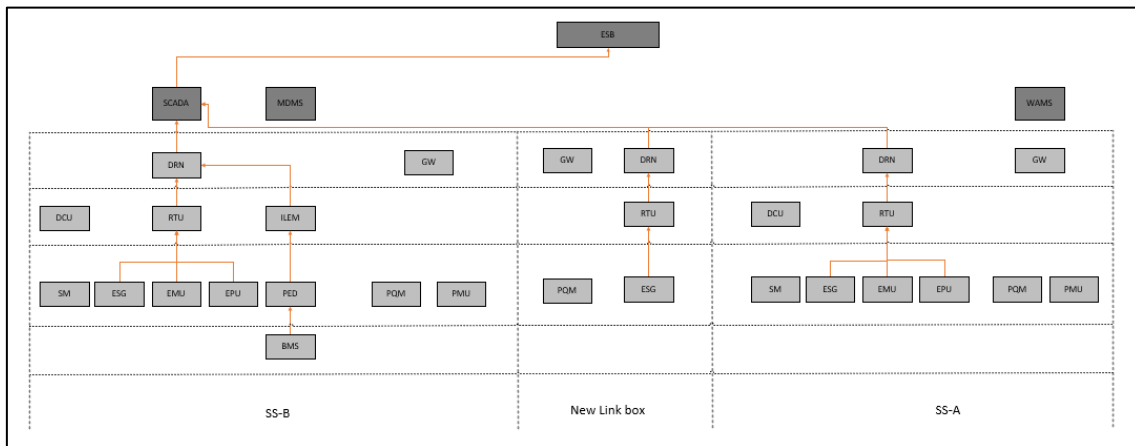
Figure 13: Data flow from electrical metering and switching devices to SCADA and ESB

The protocols used in the different locations of the pilot (SS-A, SS-B and new link box) are represented in the following figures.
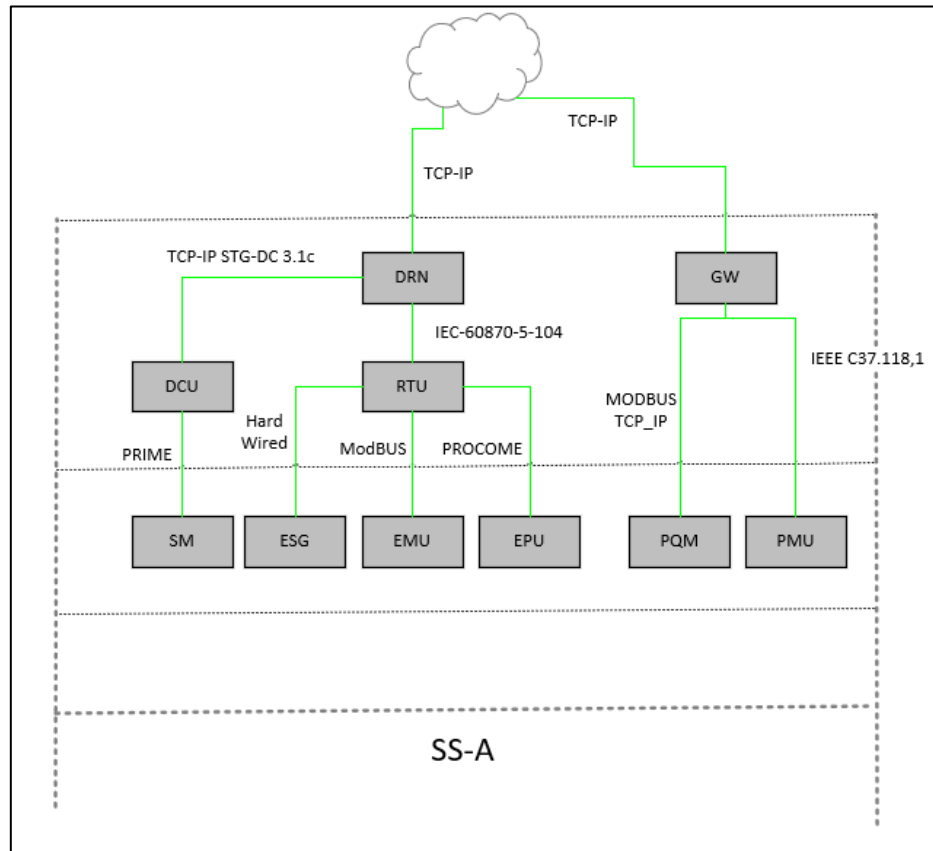
Figure 14: Protocols used for communication infrastructure of SS-A
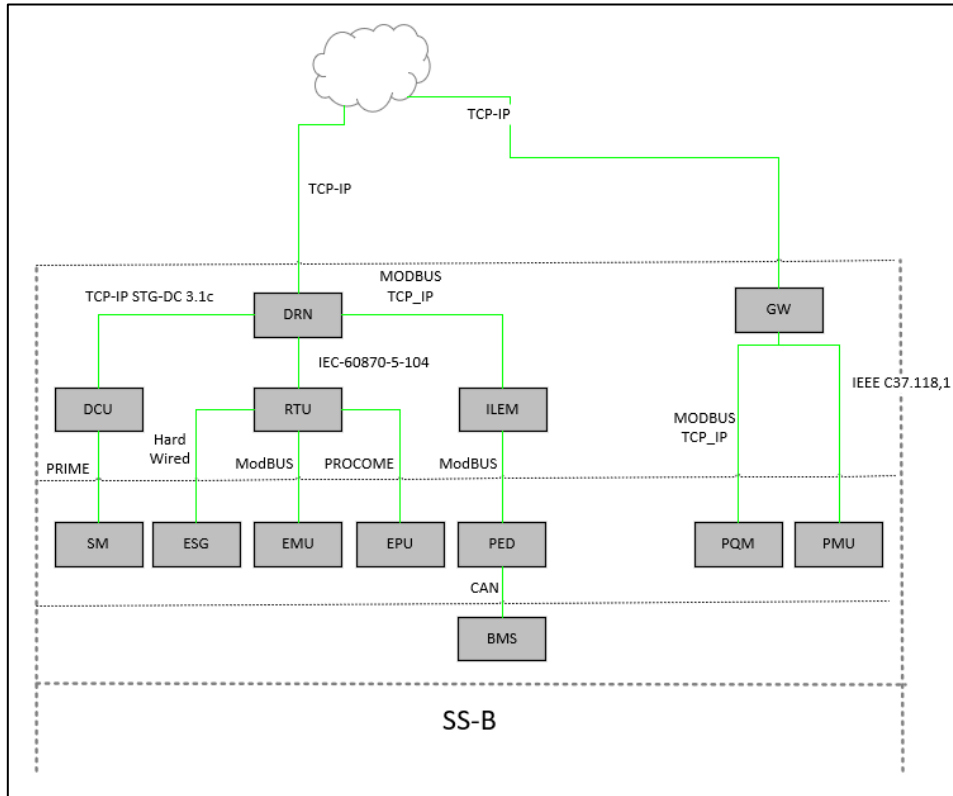
Figure 15: Protocols used for communication infrastructure of SS-B
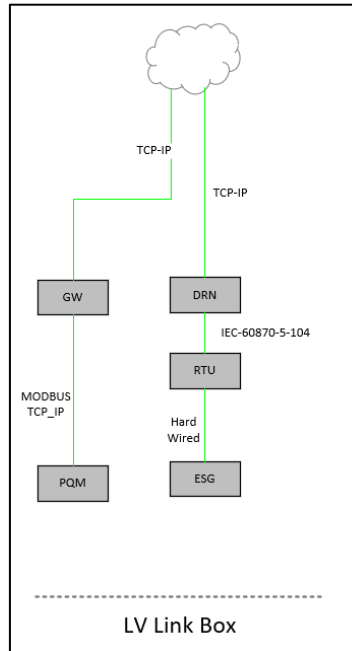
Figure 16: Protocols used for communication infrastructure of LV link box

3. Project-level KPIs and control indicators

In this section the criteria to evaluate the impact of the project will be outlined. In order to validate the benefits of the technology for the distribution grid, the most relevant performance indicators are listed and the calculation method is specified. KPIs are related to a positive effect that the RESOLVD technology is supposed to offer. In addition to this category, a second group of control indicators (CI) is provided. The latter will help monitor the side effects that such a technology could have on the grid performance and to guarantee complete transparency to this analysis.

The KPIs and control indicators are subdivided into the following three categories:

The category of "efficiency" includes indicators related to power losses and improvement of the local load-generation balance, that have a positive environmental impact, since the local energy generation comes from renewable sources.

The second category concerns the planning activity of the DSO, proposing a methodology to calculate the released hosting capacity for DERs and new loads, while monitoring the investment and operational costs that this technology represent for the distributors.

The third category, "quality of supply", encloses a series of indicators of different nature, but all aiming to measure the level of improvement of the service offered to final customers, including power quality and reduction of interruptions.

The fourth column in Table 2 provides a first indication of the units that will be used for each KPI.

Each indicator will be described through:
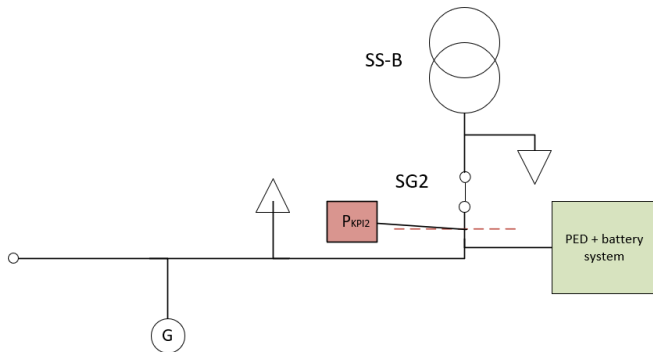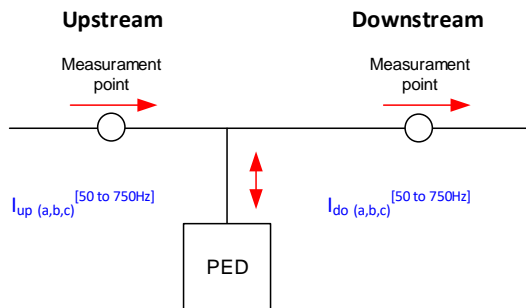
- A general **definition**, explaining the general background and relevance of such an analysis for the DSO and the relation with the project use cases;
- The **methodology**, specifying the formula used, the data needed for the calculation and the way to collect this data, the grid scenario under consideration to validate the use case (when necessary), the tests (detailing the variation from the original business flow) and the project partner responsible for calculating the indicator.

KPIs and control indicators are summarized in the following table (Table 2).

Table 2: RESOLVD KPIs

Category	Indicator	Title	Unit
Efficiency	KPI-01	Power losses reduction due to waveform quality improvement	%, kWh/year
	KPI-02	Improvement of the energy profile in the secondary substations	- Losses T&D [%] - Locally generated energy use [%] - Maximum peak [%]
	CI-01	Efficiency rate of the PED and the energy storage system	%
Planning	KPI-03	Increase of DERs hosting capacity in LV network	%/kW with respect to current maximum limit
	KPI-04	Reduction of DSO investment	% with respect to situation without RESOLVD
	CI-02	DSO operation expenditures with respect to the BAU solutions	% with respect to situation without RESOLVD
Quality of service	KPI-05	Percentage improvement in line voltage profiles with power injection and consumption	% V/kW – V/kVA
	KPI-06	Rate of prevented critical events in the LV grid due to forecasting and remote control of grid actuators	- Precision of forecasting [%] - TPR of forecasting [%] - Effectiveness of the mitigation action [%]
	KPI-07	Quality of online event detection in LV grid	- Precision [%] - True-Positive Ratio [%] - Time [s]
	KPI-08	Quality and time needed for awareness and localization of grid fault in MV grid	- Efficiency [%] - Localization accuracy [%] - Time [s]
	KPI-09	Quality of LV grid operation in island mode	- Duration [hours] - Reason for island mode interruption - Waveform quality
	CI-03	Waveform quality in LV grid	Fulfillment/unfulfillment of waveform quality standards

3.1. KPI-01: Power losses reduction due to waveform quality improvement

KPI_01: Power losses reduction due to waveform quality improvement	
Responsible Partner: UPC	Unit: [%] and [kWh/year]
Definition	

General background

The objective of this KPI is to evaluate the power transport loss reduction due to the improvement of the waveform quality. The improvement of the waveform quality refers to the compensation of reactive currents, the cancelation of harmonic currents and the balancing of three-phase currents of the power flow upstream via the PED. In this sense, it is expected that the whole current demanded at the secondary substation, thus the losses associated to transmission and distribution, decrease.

Specific definition in the project validation

In the pilot area, the point established as the border between primary and secondary distribution system will be the connection point of the LV feeder in SS-B, right upstream the PCC of the PED, as indicated by the dotted red line in the following figure:

Figure 17: Point established as the border between primary and secondary distribution system (red dotted line)

This point has been chosen because it delimits the area where RESOLVD can have an impact with respect to the KPI and it will be called P_{KPI1}. The energy exchanged in this point in both directions, will be proportional to the transport losses.

Related use case

The use case related to this KPI is HLUC 03: *Improving power quality and reducing losses through power electronics.*

Methodology

General description of the methodology

The test is based on the real measurement of the current reduction of the three phases in the pilot area of reference. It is important to note that the measurements should be taken with two identical power quality analyzers (e.g. two PQMs), installed upstream and downstream the PCC of the PED, as shown in Figure 18. Thanks to this configuration it is possible to have a representation of the impact of the PED on the power quality.

Figure 18: Configuration of analysers with respect to PED, to measure the power quality improvement

Therefore, through the two power quality analysers located upstream and downstream, the PED it is possible to pick the three phases RMS currents, for posteriori treatment. The expected information for each instant of time (t) and phase (x) is included in Table 3.

Table 3: Measured currents in KPI-01

Input	Description
$I_{50Hz}(t,x)$	Fundamental three-phase RMS currents (at 50 Hz).
$I_{150Hz}(t,x)$	Third harmonic three-phase RMS currents (at 150 Hz)
$I_{250Hz}(t,x)$	Fifth harmonic three-phase RMS currents (at 250 Hz)
$I_{350Hz}(t,x)$	Seventh harmonic three-phase RMS currents (at 350 Hz)
$I_{450Hz}(t,x)$	Ninth harmonic three-phase RMS currents (at 450 Hz)
$I_{550Hz}(t,x)$	Eleventh harmonic three-phase RMS currents (at 550 Hz)
$I_{650Hz}(t,x)$	Thirteenth harmonic three-phase RMS currents (at 650 Hz)
$I_{750Hz}(t,x)$	Fifteenth harmonic three-phase RMS currents (at 750 Hz)

Formula

The KPI_1 is a percent value of losses reduction. The following equation shows that the electrical losses (P_{losses}) are proportional to the product of conductor resistance or the system equivalent resistance (R_{eq}) and the square of the total current (I_T).

$$P_{losses} = R_{eq} \cdot I_T^2$$

Therefore, it is assumed that for both situations (with and without PED contribution) the equivalent resistance is the same.

$$KPI\_01 = \frac{I_{T_{upstream}}^2}{I_{T_{downstream}}^2}$$

Then, it is necessary to calculate the total current which can be obtained with the following formula:

$$I_T = \sqrt{\begin{array}{l} I_{50Hz}^2 + I_{150Hz}^2 + I_{250Hz}^2 + I_{350Hz}^2 + \\ I_{450Hz}^2 + I_{550Hz}^2 + I_{650Hz}^2 + I_{750Hz}^2 \end{array}}$$

Finally, note that there are three-phase currents, so, it is necessary to add them in a unique term and also, it is necessary to analyses the evolution of KPI along the time.

Input data
All the input data are collected through power quality analyzers or PQMs.
- $I_{50Hz}(t,x)$
- $I_{150Hz}(t,x)$
- $I_{250Hz}(t,x)$
- $I_{350Hz}(t,x)$
- $I_{450Hz}(t,x)$
- $I_{550Hz}(t,x)$
- $I_{650Hz}(t,x)$
- $I_{750Hz}(t,x)$

Steps	Responsible Partner
1. Current measurements	CS/EyPESA
2. Calculation of PED contribution	UPC

Grid configurations considered
In the first configuration, switchgears SG1 and SG2 will be closed, while SG3 will be open. In this case, the PED will improve the power quality related to the loads and DERs connected normally to line 2 of SS-B.
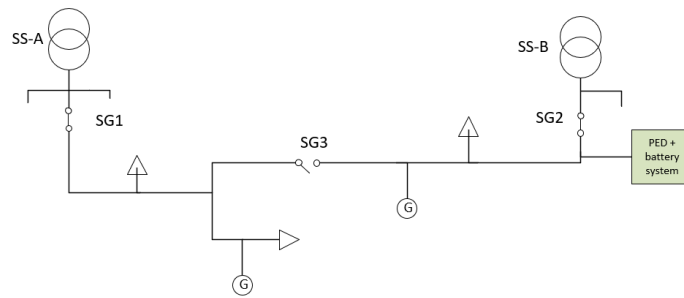
Figure 19: Configuration with SG2 and SG1 closed, SG3 open

In the second configuration, switchgears SG2 and SG3 will be closed, while SG1 will be open. In this case, the PED will improve the power quality related to the loads and PV connected normally to both the lines of the pilot area. For this reason, a higher power loss reduction is expected.
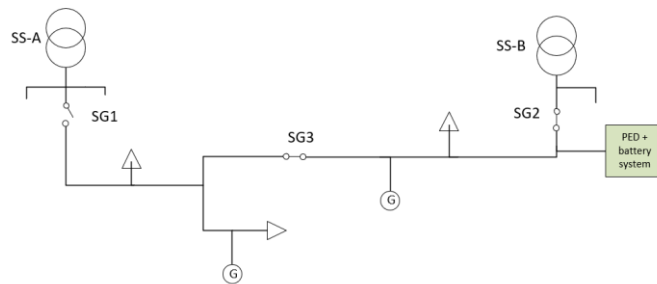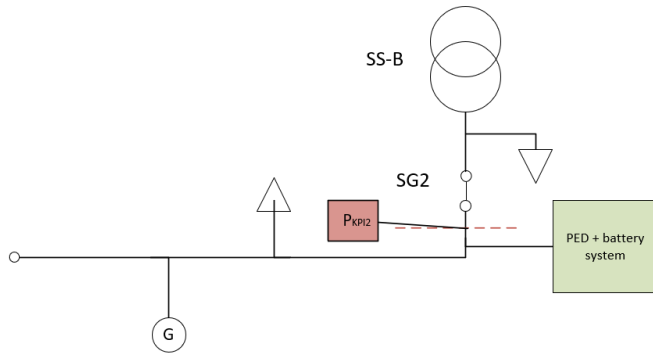
Figure 20: Configuration with SG2 and SG3 closed, SG1 open

Test Planning
The tests associated to this KPI will run for a limited period of time (e.g. one week). Data will be collected continuously, throughout this time. It is necessary to run this test, while all the other operation modes are off, to avoid spoiling the measurements.

3.2. KPI-02 Improvement of the energy profile in the secondary substations

KPI_02: Improvement of the energy profile in the secondary substations	
Responsible Partner: CS	Units: Losses T&D [%] Locally generated energy use [%] Maximum peak [%]
Definition	

General background

The presence of high peaks on the power profile of the substations has disadvantages such as high-power losses in the transmission lines, an increase in maintenance costs or high emissions of carbon dioxide. The integration of battery storage systems in the grid is the most promising strategy to modify the load demand profile of an aggregation of prosumers. Performing peak shaving on the distribution feeders can have several benefits at different levels, reducing the commented disadvantages and even the economic costs, since typically with a high demand of energy the price is higher.

Specific definition in the project validation

This KPI aims to evaluate the impact of RESOLVD tools associated with the modification of the net energy profile of the secondary feeders.

In the pilot area, the point established as the border between primary and secondary distribution system will be the point of connection of the LV feeder in SS-B, right upstream the PCC of the PED, as indicated by the dotted red line in the following figure:

Figure 21: Point established as the border between primary and secondary distribution system (red dotted line)

The net energy profile of the feeder (if the transport losses within the feeder are neglected) is the balance between consumption, generation and contribution of the PED (that includes also the battery system).

$$\vec{E}_p = \vec{E}_D - \vec{E}_G + \vec{E}_{PED}$$

$\vec{E}_p$: energy flux in the point identified in Figure 21, values can be directly measured with a PMU or a smart meter installed at the point;

$\vec{E}_D$: demanded energy for consumption;

$\vec{E}_G$: energy generated by DERs;

$\vec{E}_{PED}$: energy exchanged by the PED.

This formula helps us understand that the PED will play a key-role in the energy profile at the secondary substation.

Related use case

The use case related to this KPI is HLUC 04: *Reduction of power losses through local storage utilization.*

Methodology

General description of the methodology

It is possible to calculate three sub-indicators, as follows:

1) The reduction of transport losses due to a reduction of imported energy, through improved energy management;
2) The reduction of exported energy in proportion to the energy generated;
3) The reduction of power peaks.

In the following section, the sub-indicators will be described more in detail:

1) When the consumption is higher than generation the secondary distribution network is importing energy and $E_p(i) > 0$. The imported energy during the window of time $[0, T]$ is

$$\text{Imported Energy} = \sum_{\substack{i=0 \\ \text{s.t. } E_p>0}}^{i=T} E_p(i)$$

This term is assumed to be proportional to the main losses of the network associated to the transmission and distribution lines.

$$\text{Losses T\&D} \propto \text{Imported Energy}$$

Keeping in mind that to be precise, an exhaustive study about the life cycle and manufacturing of all the components should be performed, a calculation of reduction of CO2 will be done, considering only the emissions that occur in the production of this energy if the imported demand diminishes.

$$CO_2 \text{ Emissions} \propto \text{Imported Energy}$$

The change amount of imported energy (IE) with the utility grid can then give us a rough approximation about the impact of these factors.

$$\text{KPI}_{\text{IE}} = \frac{\text{IE}_{\text{Resolvd}} - \text{IE}}{\text{IE}}$$

2) When $E_p(i) < 0$ the generation exceeds the amount of demand and the remaining energy is exported to other costumers. The energy generated within the grid can also be evaluated.

$$\text{Exported Energy} = \sum_{\substack{i=0 \\ \text{s.t. } E_p<0}}^{i=T} E_p(i)$$

$$\text{Produced Energy} = \sum_{i=0}^{i=T} E_G(i)$$

We consider the difference with the amount of produced energy (PE) in the grid and the exported (EE) associated to the amount of locally generated energy use.

$$\text{Locally generated energy use} = \frac{\text{PE} - \text{EE}}{\text{PE}} \propto -\text{EE}$$

Therefore, the relative change in exported energy caused by RESOLVD is directly related to the amount of energy locally consumed.

$$\text{KPI}_{\text{EE}} = -\frac{\text{EE}_{\text{Resolvd}} - \text{EE}}{\text{EE}}$$
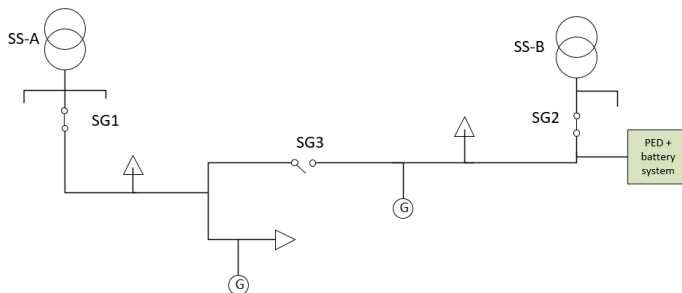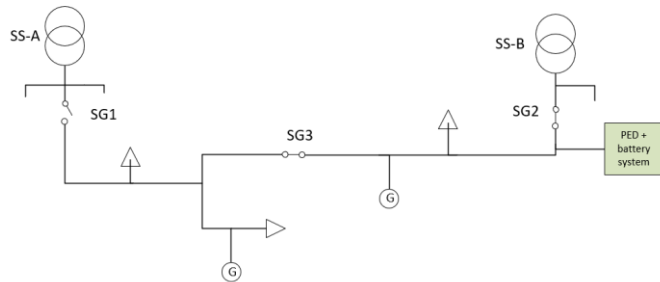
3) Performing periodic peak loads reductions is also important, since the maintenance costs can be postponed or reduced. Even though, the specific relation and impact is hard to describe and formulate, we simply consider the reduction of the max peak (MP) of a day.

$$MP = \max\{\vec{E}_p\}$$

The associated indicator:

$$\text{KPI}_{\text{MP}} = \frac{\text{MP}_{\text{Resolvd}} - \text{MP}}{\text{MP}}$$

In summary, the change of the energy profile is represented with these three factors each one related to some benefits:

KPI$_{IE}$	Losses T&D
KPI$_{EE}$	Locally Generated energy use
KPI$_{MP}$	Maximum peak

Input data

$\vec{E}_p$: energy flux in the point identified in Figure 21, values can be directly measured with a PMU or a smart meter installed at the point;

$\vec{E}_D$: demanded energy for consumption, can be measured through smart meters;

$\vec{E}_G$: energy generated by DERs, can be measured through smart meters;

$\vec{E}_{PED}$: energy exchanged by the PED, values can be measured through a PQM or a smart meters.

Steps	Responsible Partner
Collection of data from smart meters	EyPESA
Collection of data from PQMs/PMUs	CS
Calculation of KPIs	UdG

Grid configurations considered

In the first configuration, switchgears SG1 and SG2 will be closed, while SG3 will be open.

Figure 22: Configuration with SG2 and SG1 closed, SG3 open

In the second configuration, switchgears SG2 and SG3 will be closed, while SG1 will be open.

Figure 23: Configuration with SG2 and SG3 closed, SG1 open

Test Planning

The third sub-KPI, associated to peak reduction, is very time consuming, therefore, to take an average value, this should be evaluated with multiple samples of different time windows.

On the other hand, KPI$_{IE}$ and KPI$_{EE}$ can be simply evaluated through a long time period.

3.3. CI-01: Efficiency rate of the PED

CI_01: Efficiency rate of the PED	
Responsible Partner: UPC	Units: [%]
Definition	

General background
In order to monitor the losses of the PED, the efficiency of this system will be measured, and the results will be reported following the methodology of this control indicator.

Specific definition in the project validation
In order to monitor the losses of the PED, the efficiency of this system will be measured through the first control indicator. The tests will be performed in a laboratory environment.

Related use case
No specific use case is related to this KPI.

Methodology

General description of the methodology
The objective of this KPI is to evaluate the efficiency or power loss of the PED. The PED is built as an addition of three power electronic blocs. Therefore, three different efficiency coefficients must be calculated for the two isolated DC-DC converters or Dual Active Bridge (DAB) converters and one for the inverter. Taking into account that it is not expected to obtain a constant parameter, these efficiency coefficients will be evaluated under different operating points of the PED.

Formula
Firstly, from the DC bus voltage and battery voltage (U_{BUS} and U_{BAT}) and from the DC bus current and battery currents (I_{DC} and I_{BAT}), the efficiency coefficients (η_{DAB}) of each DAB can be calculated as follows.
When active power is delivered to the grid,

$$\eta_{DAB1} = \frac{U_{BUS} \cdot I_{DC1}}{U_{BAT1} \cdot I_{BAT1}}$$

$$\eta_{DAB2} = \frac{U_{BUS} \cdot I_{DC2}}{U_{BAT2} \cdot I_{BAT2}}$$

Additionally, through the following expression it is possible to calculate the performance of the inverter (assuming that the reactive power is null) when active power is delivered to the grid.

$$\eta_{inv} = \frac{U_{PCC\,a}^{rms} \cdot I_{PCC\,a}^{rms} + U_{PCC\,b}^{rms} \cdot I_{PCC\,b}^{rms} + U_{PCC\,c}^{rms} \cdot I_{PCC\,c}^{rms}}{U_{BAT1} \cdot I_{BAT1}}$$

And when active power is delivered by the grid,

$$\eta_{DAB1} = \frac{U_{BAT1} \cdot I_{BAT1}}{U_{BUS} \cdot I_{DC1}}$$

$$\eta_{DAB2} = \frac{U_{BAT2} \cdot I_{BAT2}}{U_{BUS} \cdot I_{DC2}}$$

Similarly, through the following expression it is possible to calculate the performance of the inverter (assuming that the reactive power is null) when active power is delivered by the grid.

$$\eta_{inv} = \frac{U_{BAT1} \cdot I_{BAT1}}{U_{PCC\,a}^{rms} \cdot I_{PCC\,a}^{rms} + U_{PCC\,b}^{rms} \cdot I_{PCC\,b}^{rms} + U_{PCC\,c}^{rms} \cdot I_{PCC\,c}^{rms}}$$

Input data:

The calculation of the efficiency coefficients will be conducted at the laboratory, as a one of the PCS validation tasks.

Assuming that the efficiency only makes sense when active power is taken into account, it will be evaluated when it is exchanging power with the grid, i.e. providing support to the grid. Then, voltage and currents will be measured on both batteries' sides, the bus side and the PCC side, as it can be seen in the following figure.
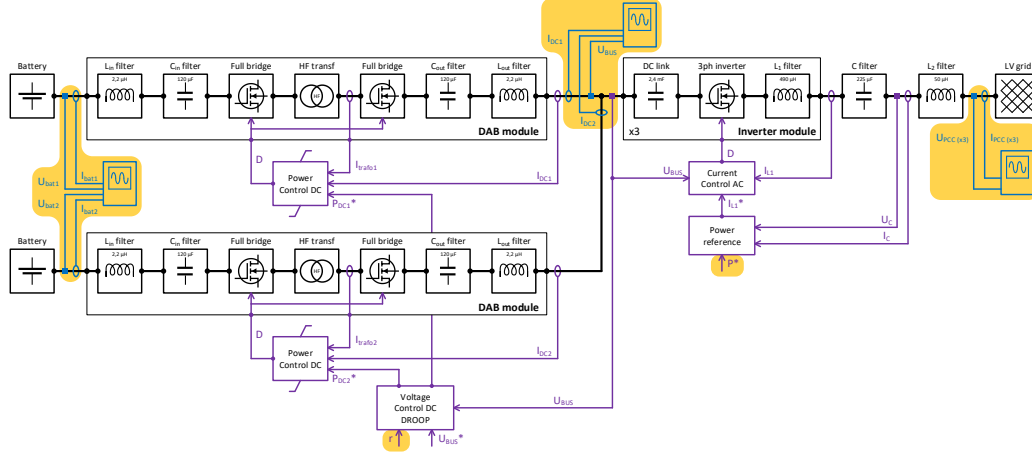
Figure 24: PED scheme

Steps	Responsible Partner
Perform described tests in the lab	UPC
Collect data from the oscilloscopes	UPC
Calculate the efficiency coefficients	UPC

Grid configurations considered

As it can be expected, the efficiency is not linear and depends on the power exchanged. Therefore, different scenarios will be conducted. The following table shows the different scenarios and will be used to collect all the data.

When power is delivered to the grid, it is positive, and when it is consumed from the grid, it is negative. The sharing ratio r indicates the % value of the referenced power requested by the battery 1. Battery 2 will deliver the remaining part.

Table 4: scenarios to calculate CI-01

P_{AC}^* (kW)	r (%)	U_{BAT1} (V)	I_{BAT1} (A)	P_{BAT1} (kW)	U_{BAT2} (V)	I_{BAT2} (A)	P_{BAT2} (kW)	U_{BUS} (V)	I_{DC1} (A)	I_{DC2} (A)	U_{PCCa} (V)	I_{PCCa} (A)	U_{PCCb} (V)	I_{PCCb} (A)	U_{PCCc} (V)	I_{PCCc} (A)	η_{DAB1} (%)	η_{DAB2} (%)	η_{inv} (%)
2	100																		
4	100																		
6	100																		
8	100																		
10	100																		
12	100																		
14	100																		
16	100																		
18	100																		
20	100																		
22	90.9																		
24	83.3																		
26	76.9																		
28	71.4																		
30	66.6																		
32	62.5																		
34	58.8																		
36	55.5																		
38	52.6																		
-2	100																		
-4	100																		
-6	100																		
-8	100																		
-10	100																		
-12	100																		
-14	100																		
-16	100																		
-18	100																		
-20	100																		
-22	90.9																		
-24	83.3																		

As can be seen in Table 4, the different scenarios range from the maximum power up to the

minimum. On the one hand, the maximum power (positive) delivered to the grid, is limited up to 38 kW. Although DAB converter maximum power is 20 kW, the Lead-acid battery maximum discharge power is limited to 18 kW. On the other hand, the minimum power (negative) consumed from the grid, is limited up to -24 kW. Again, although DAB converter maximum power is 20 kW, the Lead-acid battery maximum charge power is limited up to 4 kW.

Test Planning

Tests will be performed in the UPC labs.

3.4. **KPI-03 Increase of DERs hosting capacity**

KPI_03: Increase of DERs hosting capacity in LV network	
Responsible Partner: EyPESA	Units: % with respect to situation without RESOLVD
Definition	

General background

According to the CIRED Report [1], the DER hosting capacity is described as "an objective measure or metric […] to define the maximum DER capacity that can be installed without provoking any technical problems".

The complexity of this topic resides in the definition of a one-fits-all criteria or methodology that permits to identify this limit, as each grid presents a different model and configuration, customer density, load curves etc. and should be analysed in an individual way, through simulation models. In addition to this, the problems related to the installation of DERs can vary by nature and effects. M. Bollen and S. Ronenberg in [2] state that hosting capacity cannot be described with a unique value, but it varies according to the methodology used and the assumptions made to simplify the grid model. To protect citizens from electrical outages and problems derived from an excessive and uncontrolled installation of DERs, each country defines and regulates the maximum hosting capacity based on rules-of-thumb criteria. S. Ismael [1] have summarized these criteria for sample countries. For example, in Spain, the total DG rated power should be lower the 50% of the transformer rated power, lower than 50% of the thermal limit of the affected feeders and lower than 10% of the short circuit capacity of the point of common coupling (PCC).

These rates of installed capacity are not common for the Spanish territory, and in general it is unlikely, nowadays, to have technical issues related to DERs generation. The same applies to the RESOLVD pilot area.

The main risks associated to the DERs installation are over-voltages, feeder over-loading, reduction of waveform quality and increase of protection faults [1]. RESOLVD can generate a benefit on the first two problems.

Specific definition in the project validation

The methodology is simplified and only the problem of feeder overloading is taken into account. The analysis is made following the method defined in [3].

The comparison is made between the situation "without RESOLVD" and the situation "with RESOLVD". In the first case, the contribution of PED is excluded from the calculation, while it is included in the second case. It is expected to observe an improvement between the first and the second calculations, and this difference will provide the result of this KPI.

The calculation of maximum Hosting Capacity (HC) is made for different points of the grid.

Related use case

The use case related to this KPI is HLUC 01 *Prevention of congestion and over/under voltage issues through local storage utilization and grid reconfiguration*.

Methodology

General description of the methodology

The methodology is based on the following assumptions:
- The loading limit of the radial network considered depends on the maximum power consumption of the loads located downstream the point considered. This could be related to a physical limit of the feeders;
- Generators do neither generate nor consume reactive power;
- The networks considered are of radial type.

Formula

The formula to calculate the maximum generation hosting capacity is extracted by the formula of power flow in a generic point A of the network considered.

$$S(t)_A = \sqrt{\left(P_{gen}(t) - P_{cons}(t)\right)^2 + Q_{cons}^2(t)}$$

Where $S(t)_A$ is the apparent power flow calculated in point A, $P_{gen}(t)$ is the active power derived from all the generators in point A and downstream the point A, $P_{cons}(t)$ is the active power derived from all the loads in point A and downstream the point A, $Q_{cons}(t)$ is the reactive power derived from all the loads in point A and downstream the point A.

The maximum power flow S_{max}, in the situation of null distributed generation, is given by the following formula:

$$S_{max} = \sqrt{P_{cons,max}^2 + Q_{cons,max}^2}$$

Where $P_{cons,max}$ and $Q_{cons,max}$ are the maximum active and reactive power values that can be consumed by all the loads located in a specific point or downstream that point

The condition that it is always necessary to fulfill is the following:

$$S(t)_A < S_{max,A}$$

The worst-case scenario, associated to $P_{gen}(t)=P_{gen,max}$, occurs when the apparent power consumption is at its minimum, thus when $S_{cons}(t) = S_{cons,min}$

$$\sqrt{\left(P_{gen,max} - P_{cons,min}\right)^2 + Q_{cons,min}^2} < \sqrt{P_{cons,max}^2 + Q_{cons,max}^2}$$

From this formula it is possible to extract a definition for $P_{gen,max}$, as follows:

$$P_{gen,max} = \sqrt{P_{cons,max}^2 + Q_{cons,max}^2 - Q_{cons,min}^2} + P_{cons,min}$$

This formula will be applied to different grid scenarios and to the situation with and without the PED contribution. Given that the PED could start consuming active and reactive energy behaving like a load, the value of $P_{gen,max}$ will grow.

$$KPI\_5 = \frac{P_{gen,max}^{RESOLVD} - P_{gen,max}^{\overline{RESOLVD}}}{P_{gen,max}^{\overline{RESOLVD}}} * 100$$

Where $P_{gen,max}^{RESOLVD}$ is the maximum hosting capacity with RESOLVD and $P_{gen,max}^{\overline{RESOLVD}}$ is the maximum hosting capacity without RESOLVD.

Input data:
- $P_{cons,max}$ is given by the maximum contracted active power in a certain point of the grid (taking in consideration that location and all the loads downstream)
- $Q_{cons,max}$ is given by the is given by the maximum contracted reactive power in a certain point of the grid (taking in consideration that location and all the loads downstream). In absence of a contracted reactive power, this value will be approximated with a hypothetical power factor.
- $Q_{cons,min}$ is given by the minimum sum of the reactive power values measured at each consumption point located downstream or in the point A.
- $P_{cons,min}$ is given by the minimum sum of the active power values measured at each consumption point located downstream or in the point A.
- Active and reactive power values of smart meters are obtained from the EF calculation and validated by field measurements.
- Data from PED could be collected through smart meters (if it is clear that it is possible to install one) or through other types of sensors

Steps	Responsible Partner
Identify the point A, under consideration and a grid scenario	EyPESA
Identify the values of $P_{cons,max}$ and $Q_{cons,max}$	EyPESA
Identify a certain period of time X, long enough to be statistically valid and during which a certain optimization objective is pursued	EyPESA
Throughout this period collect data from smart meters of loads and generators	UdG
Throughout this period collect data from PED	UPC
Calculate $Q_{cons,min}$ and $P_{cons,min}$ in the case without	EyPESA

RESOLVD	
Calculate $Q_{cons,min}$ and $P_{cons,min}$ in the case with RESOLVD	EyPESA
Calculate	EyPESA
Calculate $P_{gen,max}$ in the cases with and without RESOLVD	EyPESA
Calculate KPI_5	EyPESA
Grid configurations considered	
The grid configurations considered will depend on the scenario, to demonstrate the increased hosting capacity and will be defined in a second phase.	
Test Planning	
Tests related to this KPI will be planned in a second phase.	

3.5. KPI-04: Reduction of DSO investment

KPI_4: Reduction of DSO investment	
Responsible Partner: EyPESA	Units: % with respect to situation without RESOLVD
Definition	

General background

This analysis has the objective to demonstrate the reduction of investment costs for a DSO, if the RESOLVD technology is adopted instead of another Business-As-Usual (BAU) solution.

The complexity of this study resides in the following issues, that should be considered:

1) Most of the problems that RESOLVD tackles, currently do not exist in the pilot area under analysis, nor in other points of Estabanell's network, because the DSO has already addressed them when they raised and corrected them through network upgrade. Future scenarios of distributed generation or consumption capacity are taken into account.
2) For some use cases there is just no alternative technology able to substitute the value offered by RESOLVD.
3) Some of the value brought by RESOLVD, do not represent an obligation for the DSO at the moment, thus it is hard to imagine that this stakeholder has to purchase a technology which is not "necessary".
4) Some of the use cases offered by the DSO are more of interest for other stakeholders, for example the battery, could be a source of flexibility of an energy aggregator.
5) RESOLVD provides of a group of technologies that can solve multiple problems at once, while in the BAU case, each technology solves one problem at a time.
6) The lifespan of RESOLVD is shorter than the one of the BAU solution.

Specific definition in the project validation

The issues analyzed in the previous section, can be addressed making the following assumptions:

a) The future scenario imagined includes the installation of enough distributed generation capacity in the low voltage grid of the pilot area, to make necessary a grid upgrade. A particular scenario of this kind will be defined.
b) If no technology exists, which can bring the same value of RESOLVD, the more similar device or solution will be considered.
c) There will be a change in the regulation that will oblige DSOs to reach the results obtained through RESOLVD
d) It is considered that the part of the investment associated to use cases that bring a benefit to other stakeholders, are going to be recovered somehow by the DSO itself.
e) It is assumed that all the problems tackled by this project are to be solved.
f) The different lifespans are considered in the comparison.

Related use case

The use case related to this KPI is HLUC 09: *Planning of the commissioning of power electronics and local storage*

| **Methodology** | |

General description of the methodology

This KPI is independent from any real tests of the technology, and it consists of a simple calculation.

First of all, the problems tackled by RESOLVD are considered:

- 1. Congestion issues
- 2. Over/undervoltage issues
- 3. Poor power quality upstream the PED
- 4. Power interruption, making grid reconfiguration necessary
- 5. Power interruption, making island-mode necessary
- Etc.

For each of these problems, a RESOLVD and a BAU solution are identified. The investment

cost is referenced and annualized, as the example presented in the table below:

Table 5: Table to calculate KPI-05

Problem	RESOLVD solution		BAU solution	
	Type of solution	Cost of the solution [€/year]	Type of solution	Cost of the solution [€/year]
P1. Congestion issues	RESOLVD solution P1 (e.g. PED, Batteries, Software platform and services, switchgears, […])	RESOLVD Cost P1	BAU solution P1 (e.g. installation of assets with higher capacity)	BAU Cost P1
P2. Over/undervoltage issues	RESOLVD solution P2	RESOLVD Cost P2	BAU solution P2	BAU Cost P2
P3. Poor power quality upstream the PED	RESOLVD solution P3	RESOLVD Cost P3	BAU solution P3	BAU Cost P3
P4. Power interruption, making grid reconfiguration necessary	RESOLVD solution P4	RESOLVD Cost P4	BAU solution P4	BAU Cost P4
P5. Power interruption, making island-mode necessary	RESOLVD solution P5	RESOLVD Cost P5	BAU solution P5	BAU Cost P5
Others	…	…	…	…
Total	RESOLVD solution	RESOLVD total cost / lifespan	BAU solution P1 + BAU solution P2 + BAU solution P3 + BAU solution P4 + BAU solution P5	BAU Cost P1 + BAU Cost P2 + BAU Cost P3 + BAU Cost P4 + BAU Cost P5

The difference between the total RESOLVD cost and the total BAU cost, will provide the result for this KPI.

In addition, it will be possible to make a sensibility analysis, to understand how this KPI varies, when the production costs of the RESOLVD solution decreases, due to economy of scale and technology advancements.

Moreover, this analysis permits to make a comparison between the two costs for each single problem considered, to identify what investments are the more meaningful in relation to their cost/benefit ratio.

Formula

To calculate the annuity A of the investment cost, the following formula is used:

$$A = \frac{C}{LS}$$

Where C is the cost of each solution considered, and LS is the lifespan of that solution.

To calculate KPI 6, the following formula applies:

$$KPI\_5 = \frac{A_{tot,BAU} - A_{tot,RESOLVD}}{A_{tot,BAU}} * 100$$

Where $A_{tot,BAU}$ is the total annualized cost of the BAU solutions and $A_{tot,RESOLVD}$ is the total annualized cost of the RESOLVD solution.	
Input data: - References of costs and lifespan for RESOLVD technologies - References of costs and lifespan for BAU solutions	

Steps	Responsible Partner
Collect input data	EyPESA
Calculate KPI-05	EyPESA
Perform sensibility analysis	EyPESA

Grid configurations considered	
The grid scenarios considered will reflect a critical situation of the grid, with a significant presence of DERs installed, that create all the problems described above.	
Test Planning No test is necessary.	

3.6. CI-02 DSO operation expenditures with respect to the BAU solutions

CI-02: DSO operation expenditures with respect to the BAU solutions	
Responsible Partner: EyPESA	Units: % with respect to situation without RESOLVD

Definition

General background
This control indicator aims to monitor the operational costs (OPEX) associated to the RESOLVD technology and make sure they do not overcome the operational costs of a BAU solution.

Specific definition in the project validation
In order to compare OPEX of RESOLVD and the ones of a BAU solution, we need to make the same assumption made for the KPI-05: if no technology exists, which can bring the same value of RESOLVD, the more similar device or solution will be considered

Related use case
This KPI is not directly related to any HLUC.

Methodology

General description of the methodology
This CI is independent from any real tests of the technology, and it consists of a simple calculation.
First of all, the problems tackled by RESOLVD are considered:
- 1. Congestion issues
- 2. Over/undervoltage issues
- 3. Poor power quality upstream the PED
- 4. Power interruption, making grid reconfiguration necessary
- 5. Power interruption, making island-mode necessary
- Etc.

For each of these problems, a RESOLVD and a BAU solution are identified. The yearly operational cost is referenced, as the example presented in the table below:

Table 6: Table to calculate CI-02

Problem	RESOLVD solution		BAU solution	
	Type of solution	Annual OPEX [€/year]	Type of solution	Annual OPEX [€/year]
P1. Congestion issues	RESOLVD solution P1 (e.g. PED, Batteries, Software platform and services, switchgears, […])	RESOLVD OPEX P1	BAU solution P1 (e.g. installation of assets with higher capacity)	BAU OPEX P1
P2. Over/undervoltage issues	RESOLVD solution P2	RESOLVD OPEX P2	BAU solution P2	BAU OPEX P2
P3. Poor power quality upstream the PED	RESOLVD solution P3	RESOLVD OPEX P3	BAU solution P3	BAU OPEX P3
P4. Power interruption, making grid reconfiguration necessary	RESOLVD solution P4	RESOLVD OPEX P4	BAU solution P4	BAU OPEX P4
P5. Power interruption, making island-mode	RESOLVD solution P5	RESOLVD OPEX P5	BAU solution P5	BAU OPEX P5

necessary				
Others	…	…	…	…
Total	RESOLVD solution	RESOLVD OPEX	BAU solution P1 + BAU solution P2 + BAU solution P3 + BAU solution P4 + BAU solution P5	BAU OPEX P1 + BAU OPEX P2 + BAU OPEX P3 + BAU OPEX P4 + BAU OPEX P5

The difference between the total RESOLVD cost and the total BAU OPEX, will provide the result for this CI.

Moreover, this analysis permits to make a comparison between the two costs for each single problem considered, to identify what investments are the more meaningful in relation to their cost/benefit ratio.

Formula

This CI is calculated through the following formula

$$KPI\_5 = \frac{OPEX_{tot,BAU} - OPEX_{tot,RESOLVD}}{OPEX_{tot,BAU}} * 100$$

Where $OPEX_{tot,BAU}$ is the total annual operational cost of the BAU solutions and $OPEX_{tot,RESOLVD}$ is the annual operational cost of the RESOLVD solution.

Input data:
- References of costs for RESOLVD technologies
- References of costs for BAU technologies

Steps	Responsible Partner
Collect input data	EyPESA
Calculate CI-02	EyPESA

Grid configurations considered

The grid scenarios considered will reflect a critical situation of the grid, with a significant presence of DERs installed, that create all the problems described above.

Test Planning

No test is necessary.

3.7. KPI-05: Percentage improvement in line voltage profiles with power injection and consumption

KPI_5: Percentage improvement in line voltage profiles with power injection and consumption	
Responsible Partner: EyPESA	Units: % with respect to situation without RESOLVD
Definition	

General background

One of the objectives of this project is to control the voltage level in LV distribution network. Due to an increasing presence of distributed generation, the voltage is becoming more difficult to control and over/undervoltage issues are more and more frequent. Through the power electronics technology it is possible to exchange power with the grid, thus regulating the voltage level when a voltage variation is detected or forecasted.

Specific definition in the project validation

The objective of this KPI is to evaluate the capacity of the PED to smooth the voltage variations, by exchanging power with the grid. The main idea is to increase or decrease the voltage in the point of common coupling (PCC) of the PED in order to compensate the consumption/generation variations.

This KPI provides the measured value of "voltage per power", depending on the configuration of the grid, and for both the case of active and reactive power contribution. To permit these tests it is necessary to estimate the grid equivalent resistance and impedances.

Related use case

The use case related to this KPI are

- HLUC 02: Voltage control through local reactive power injection
- HLUC 01: Prevention of congestion and over/under voltage issues through local storage utilization and grid reconfiguration.

Methodology

General description of the methodology

This test aims to calculate the voltage per power gain through the grid equivalent resistance and inductance. Ideally, to perform the test the PED should be connected alone in the distribution system, however, the consumers cannot be switched off without sacrificing their supply.

Therefore, the test can be performed when the consumption and generation is almost null or have an opposite pattern that the test will perform (e.g. inject power to the grid when the consumption is higher than generation, or extract power from the grid when the generation is higher than consumption).

The following figure depicts the pilot system and also presents the grid parameters equations in function of the possible configurations.

1) At the beginning of the LV line (SG2 closed)

$$R_{eq} = R_{traformer} + R_{MVgrid}$$
$$X_{eq} = X_{traformer} + R_{MVgrid}$$

2) At the end of the LV line (SG2 opened)

$$R_{eq}' = R_{eq} + R_{LVline}$$
$$X_{eq}' = X_{eq} + R_{LVline}$$

Figure 25: Grid scheme and parameters in function of possible scenario

To carry out the grid parameters estimation, it is required to measure the exchanged power and the voltage at the PCC, as the Figure 26 depicts. Additionally, for the particular case of the end line, it is also interesting to pick up the beginning of the line measurements.
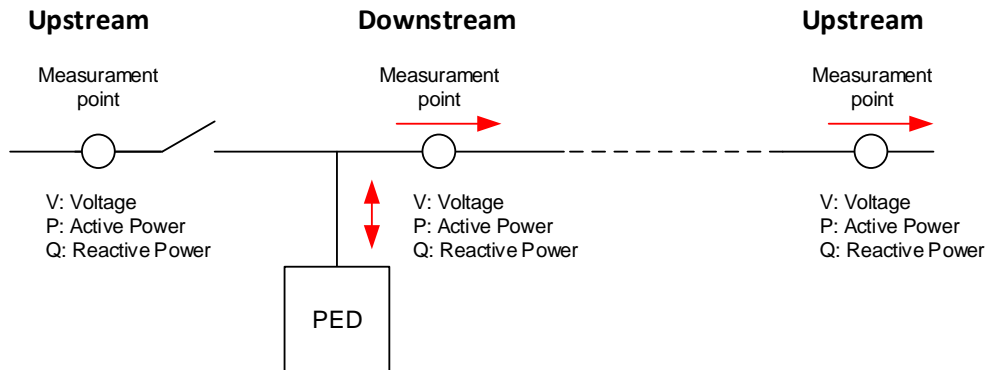
Figure 26: Strategic points to be considered to control the voltage through power injection

The measurements can be made with power quality analyzers (e.g. PQMs). Moreover, to distinguish correctly the PED contribution it is important that the consumptions are minimum during the test in order to observe correctly the voltage variation created by the PED. Therefore, when the PED is connected in the beginning of the system the power profile which flows through the transformer can be as it is depicted in the following figure.
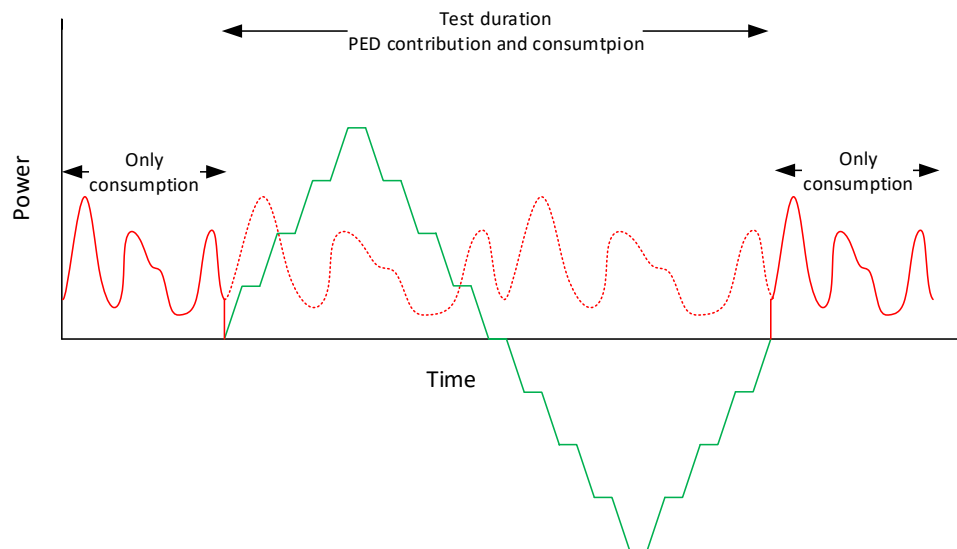
Figure 27 Power downstream of the transformer (when the PED is in the beginning of line) in continuous line the final power profile, in discontinuous line the load profile during test duration. In red line, the load profile and in green line the PED profile.
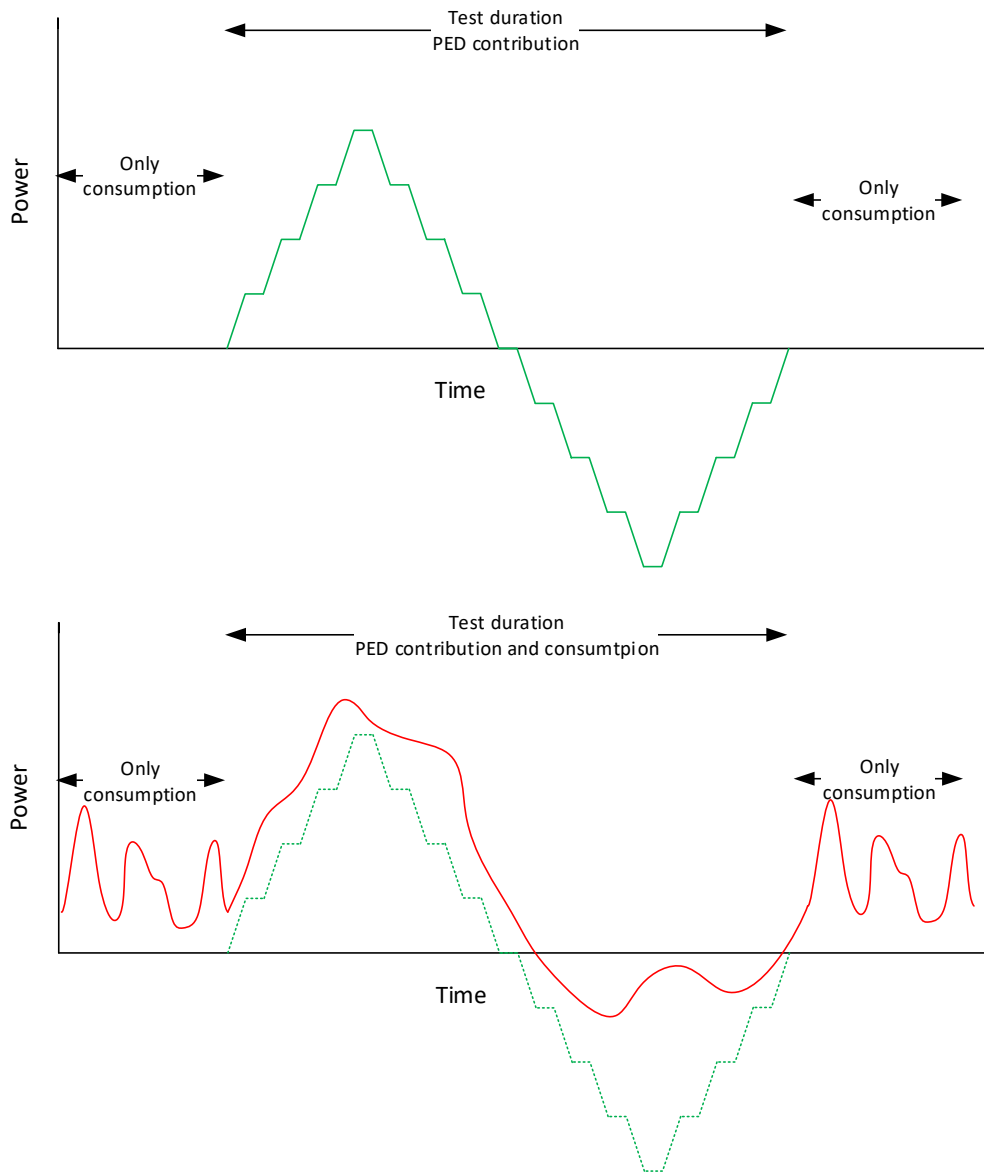
Figure 28 Power downstream of the PED and transformer (when the PED is in the end of line) in continuous line the final power profile, in discontinuous line the PED profile during test duration. In red line, the load profile and in green line the PED profile.

Formula

It is important to note that the equivalent voltage of the grid is not constant but it is assumed that the variations are small. In addition, the upper grid configuration can be modified during the operation varying the grid parameters, however, it is assumed that the grid parameters will remain similar.

The following equation permits determine the grid parameters through the input data (voltage, active and reactive power). Assuming that V is approximately (1 pu), then it is possible to estimate the rest of parameters for different conditions.

$$V - V_{pcc} = \frac{R \cdot P + Q \cdot X}{V^2}$$
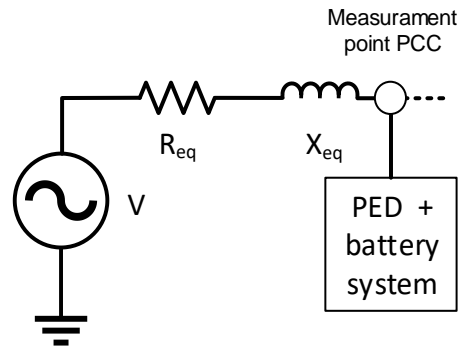
Figure 29: Simplified model electrical system under consideration

Input data:

The input data is measured downstream the PED and transformer. The expected information for each instant of time (t) is the following.

Input	Description
$V_{abc}(t)$	Three-phase RMS voltage
$P_{abc}(t)$	Three-phase active power
$Q_{abc}(t)$	Three-phase reactive power

Steps	Responsible Partner
Current measurements	CS/EyPESA
Calculation of PED contribution	UPC

Grid configurations considered

Figure 30: Configuration with switchgears SG1 and SG2 closed, SG3 open

Figure 31: Configuration with switchgears SG2 and SG3 closed, SG1 open

Figure 32: Configuration with switchgears SG1 and SG3 closed, SG2 open

Test Planning
Since the tests in the real environment have more practical difficulties, however it is plan to find moments where the consumption and generation is low in order to perform these analyses, point by point.

3.8. KPI-06: Rate of prevented critical events in the LV grid due to forecasting and remote control of grid actuators

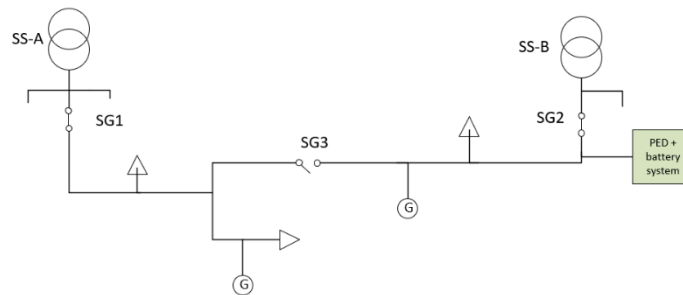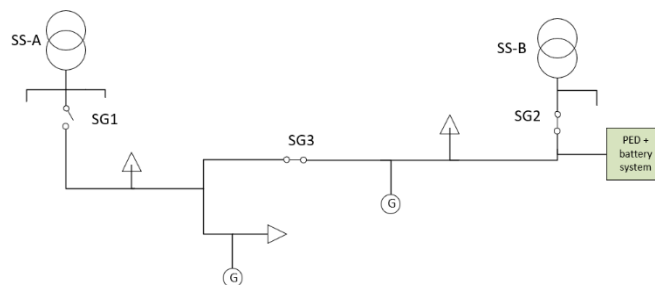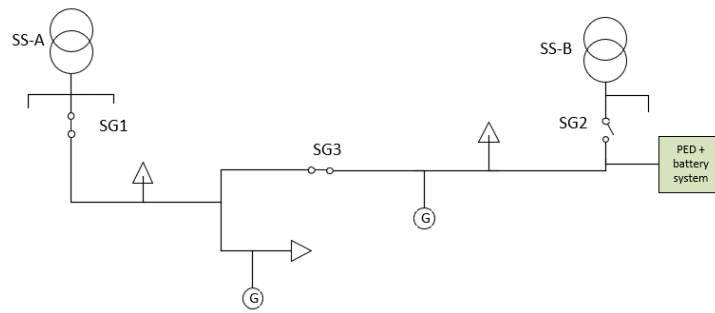| KPI_06: Rate of prevented critical events in the LV grid due to forecasting and remote control of grid actuators	
Responsible Partner: UdG	Precision of forecasting% TPR of forecasting % Effectiveness of the mitigation action %
Definition	
General background Nowadays, in the distribution grid of Estabanell, there isn't a technology devoted to predicting a critical event (current congestion, overvoltage or undervoltage) in none of the voltage levels, thus it is not possible to prevent them. In addition, the remote monitoring and control allowed is limited to a part of the MV grid, but nothing is present at LV level. RESOLVD is going to introduce the functionalities of critical event prediction and prevention through remote control in the low voltage grid. To measure the performance of this service, the business flow considered is split into two phases: the efficiency of the event forecasting and the effectiveness of the mitigation action implemented to prevent the event, through remote control of grid actuators (PED and switchgears).	
Specific definition in the project validation The effectiveness of event forecasting and event prevention will be tested and evaluated in two different moments: in a first phase the precision and true positive rate (TPR) of the forecasting are measured, and in a second phase the effectiveness of the schedule execution is tested.	
Related use case The use case related to this KPI is HLUC 01: *Prevention of congestion and over/under voltage issues through local storage utilization and grid reconfiguration.*	
Methodology	
General description of the methodology This KPI will be calculated through tests performed on the real environment. The infrastructure of the LV grid hosting the pilot is oversized with respect the amount of generation and consumption installed. For this reason, it is very unlikely that any current congestion occurs during the validation period of the project. To emulate the generation of a current congestion, it will be necessary to consider a lower saturation limit (for example 20% of the real saturation limit). The same applies to voltage variations: even through these events are more frequent than current congestions, they would not be enough in number to permit a collection of statistically relevant results, and for this reason, the voltage of admissible voltage variations will be "virtually" narrowed (for example from ±7% to ±3%). These "virtual limits" are associated to particular points of the grid, where PMUs or PQMs can be installed, permitting the verification of the forecasting and prevention actions. Event forecasting effectiveness: The CEF is configured with the new "virtual limits" of the grid assets. The alarm of the forecasted event for a certain moment t_e is generated and forwarded to the operator through the DAP/ESB. The PMUs and PQMs, strategically located in the point of the grid in which the event is detected, continuously measure current and voltage values and forward this data to the Supervision and Analytics Services through the ESB. A parallel task, within the Supervision and Analytics Services (manual or automatic) verifies the correctness (true-positive results) of the forecasted event by comparing the online measurement data received from the PMU/PQMs in the moment t_e and the alarm previously generated. Moreover, another task is counting and registering all the events really occurring in the grid. These are obtained through the analysis of the measurement data coming form PMUs and PQMs. With these results, two factors will be measured: the precision and the true-positive	

rate (TPR) of the forecasting.

In this test, the business flow of HLUC 1 is interrupted after the generation of the alarm, thus no mitigation action is calculated nor implemented.

An example of the table for the collection of data, that would permit this calculation is included in Annex II.

Effectiveness of the mitigation action:

In a second phase, the whole business flow is executed. The comparison is made between the same factors of the previous test (forecasted events and measured events), but in this case, since the mitigation actions is executed, a higher number of avoided congestions is expected.

An example of the table for the collection of data, that would permit this calculation is included in Annex II.

Formula

Event forecasting effectiveness:

The critical event forecasting service is supposed to predict the event, with a certain precision and effectiveness. The software can create alarms of events that are later verified by the PMU/PQM measurement (True Positive result), but can also create false alarms, when the event is not actually occurring (false positive result). In the same way, the software could miss to forecast a real event (false negative result). The possible combinations between relevant events and detected events are summarized in the following table:

		Relevant events	
		True	False
Detected events	True	True positive (TP)	False positive (FP)
	False	False negative (FN)	True negative (TN)

The precision, which measures "how useful" the alarms are, can be calculated through the following formula:

$$Precision = \frac{TP}{TP + FP}$$

The TPR, which measures "how complete" the results are, can be calculated through the following formula:

$$TPR = \frac{TP}{TP + FN}$$

Effectiveness of the mitigation action:

In this case the ratio is made between the critical events avoided (CE_a) and the critical events forecasted (CE_f).

$$Mitigation\ action\ effectiveness = \frac{CE_a}{CE_f}$$

Input data:
7) Critical event forecast alarm, including t_e and location
8) Aggregated (3-p) voltage values from PMUs and PQMs
9) Aggregated (3-p) current values from PMUs and PQMs

Steps	Responsible Partner
Critical event forecast alarm is generated and recorded (with partial and complete business flow)	UdG
Aggregated (3-p) values of voltage and current are measured by PMUs and PQMs (with partial and complete business flow)	CS
The measurements are translated into a binary value to indicate the presence or absence of the critical event (with partial and complete business flow)	UdG
Precision, TPR and Effectiveness of mitigation actions are	EyPESA

calculated.

Grid configurations considered

The following figure presents an example of a line (red in the figure), with modified "virtual limits", in which a critical event is forecasted and where measurements can be taken through PMUs and PQMs.
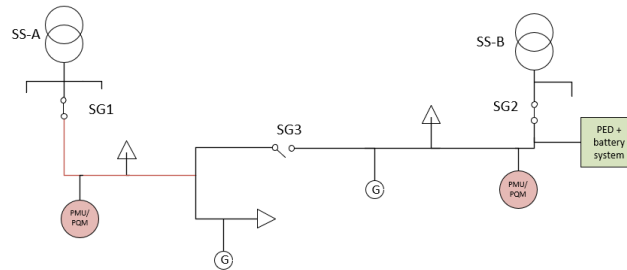

Figure 33: Possible grid configuration to caluclate KPI 10

Test Planning

The first set of tests, to measure the forecasting efficiency can be tested during one week and the second set of tests, to measure the execution effectiveness, can be tested during the following week.

3.9. KPI-07: Quality of online event detection in LV grid

KPI_07: Quality of online event detection in LV grid	
Responsible Partner: UdG	Unit: Precision [%] True-Positive Ratio [%] Time [s]
Definition	

General background

In the current situation, when a fault occurs in low voltage (LV) lines, the only way to detect it, is through the call of a client that has suffered a supply interruption. To improve their service, DSOs aim to detect supply interruptions as soon as they occur, in order to localize, solve the fault and reconnect the clients in a shorter time.

From the data collected by the WAMS infrastructure, it is possible to monitor the grid status. These data are analysed through statistical models and an alarm is generated when a fault/event is detected.

Non-planned power interruptions in the low voltage grid can occur due to short-circuits and natural causes (e.g. weather, birds, rats). It is defined interruption one fault that disconnects clients for more than three minutes (see Annex II).

Specific definition in the project validation

This KPI aims to evaluate the quality of the LV fault detection service, considering the accuracy of the detection, through the factors of precision and True-Positive Rate (TPR), and measuring the time needed between the moment in which the fault occurs and the moment in which the alarm is generated.

Related use case

The use case related to this KPI is HLUC 05: *Self-healing after a fault*

Methodology

General description of the methodology

This KPI will be measured through simulations and tests in the real environment.

1) Tests in the real environment: it is necessary to emulate the occurrence of a disconnection of a part of the grid, without affecting the service to final customers. The test will start with a grid configuration that includes both lines of the pilot area, connected through the closed switchgear in the middle (Figure 34). The latter is then disconnected, emulating the blow of a fuse in the middle of a low voltage line (Figure 35) and the loss of a part of the clients. It is expected that the PMUs, PQMs collect data about a sudden change in load, that are then processed by the Self-healing application, generating an alarm for the operator.

2) Simulation: in order to test the service with other types of faults, it will be necessary to run simulations. Data coming from the PMUs and PQMs, will be modified creating fake faults, that are then processed by the fault detection service, generating alarms. These simulations will permit to have a wider sample of events and obtain statistically valid results.

Tests will be run, in the real and simulated environment, and the results will be evaluated with three factors, described in the following section:
  ➢ Precision [%]
  ➢ True positive rate [%]
  ➢ Time [s]

Formula

Precision and TPR calculation:

The detection application is supposed to detect the event, with a certain precision and effectiveness. To measure these two factors, a certain set of relevant events is considered. The software can create alarms for events that are part of this set (true positive result), but can also create false alarms, when the event had not been simulated (false positive result). In the same way, the software could miss to detect a real event or (false negative result). The possible combinations between relevant events and detected events are summarized in the following table:

Table 7: Possible combinations between detected events and relevant events

		Relevant events	
		True	False
Detected events	True	True positive (TP)	False positive (FP)
	False	False negative (FN)	True negative (TN)

The precision, which measures "how useful" the alarms are, can be calculated through the following formula:

$$Precision = \frac{TP}{TP + FP}$$

The TPR, which measures "how complete" the results are, can be calculated through the following formula:

$$TPR = \frac{TP}{TP + FN}$$

Detection time measurement:

As far as the detection time is concerned, this will be calculated between the moment in which the event occurs and the generation of the alarm for the operator.

$$Detection\ time = t_a - t_e$$
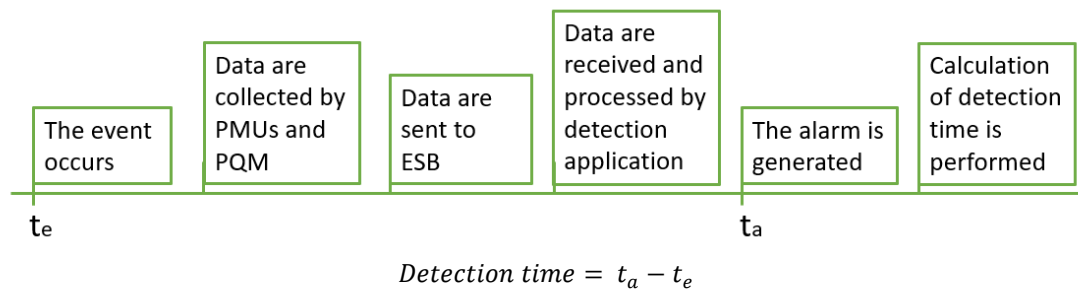
Input data
In the real environment tests, the objective is to measure the detection time and to verify the functional execution of the service. In the simulation tests, precision and TPR will be calculated.

Detection time measurement:
t_e is measured by PMUs and PQM and forwarded, together with the data file, to the detection application, through the ESB.
t_a is measured together with the alarm, by the detection application
A parallel task, within the Fault Detection Application (FDA), or within the DAP, calculates the difference between the two values and stores the results in the DAP. This task could be performed automatically or manually.
Precision and TPR calculation:
Within the simulation process, some counters are configured, to count the number of relevant events simulated ($TP + FN$), the number of events detected ($TP + FP$), and the numbers of TPs, in which the detection of an event, corresponds to an actual relevant event that has been previously simulated.
The precision and TPR values are updated at each cycle and forwarded to the DAP. This task could be automatic or manual.

Steps	Responsible Partner
Detection time measurement	
t_e is measured by PMUs and PQM	CS
t_e is forwarded, to the detection application.	CS

t_a is measured together with the alarm	UdG
The detection time is calculated	UdG/ICOM
The detection time value is registered	ICOM
Precision and TPR calculation	
Relevant events are simulated, and a counter is established	UdG/CS
Events are detected and a counter is established	UdG
Check between relevant and detected events	UdG
Update of the precision and TPR factors	UdG
Register of the results	ICOM/EyPESA

Grid configurations considered

Test in real environment (example)
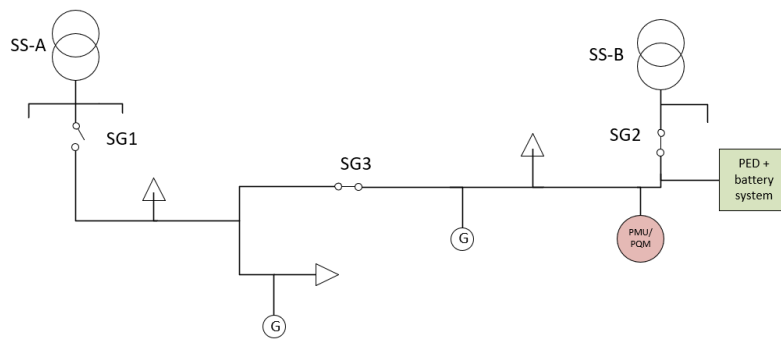
Figure 34: Initial configuration of the grid, before the emulation of the event
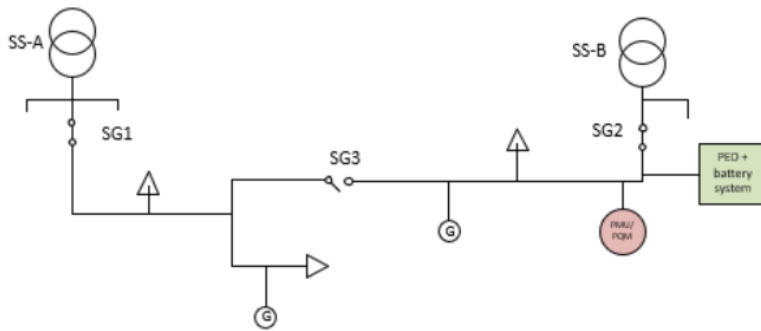
Figure 35: Configuration of the grid, after the emulation of the event

Simulated tests: some example of the events that can be simulated
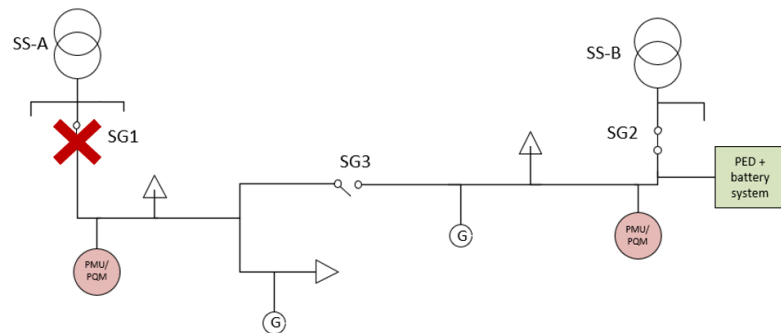
Figure 36: Fault occurring in the low voltage board or upstream
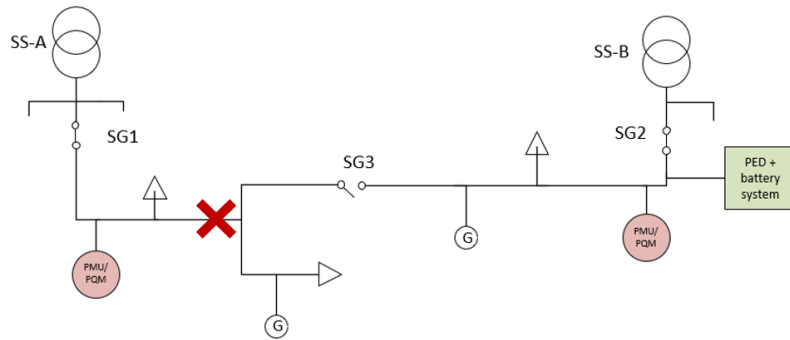
Figure 37: Fault occurring in a fuse along the feeder

Test Planning
Since the tests in the real environment have more practical difficulties, they will be run to measure the detection time and to validate the functional performance of the business flows. Simulation tests can be run at any moment, and they can be useful to calculate the precision and TPR factors. The number of simulations is determined by the statistical relevance of the results.

3.10. KPI-08: Quality and time needed for awareness and localization of grid fault in MV grid

KPI_08: Quality and time needed for awareness and localization of grid fault in MV grid	
Responsible Partner: CS	Units: Efficiency [%] Localization accuracy [%] Time [s]
Definition	

General background

When a fault occurs in medium voltage lines, it can result in a blackout of, not only the MV part of the network, but also of all corresponding low voltage feeders that stem from it and do not have option to operate in island-mode. In the case of a fault, even approximate localization can be helpful for repairing crews, so that they do not need to check the entire part of disconnected MV network, but rather the proximity of bus recognized as faulted. With narrowed perimeter of possible fault locations, power restoration can be expedited and network indices - such as System Average Interruption Duration Index (SAIDI) - improved.

From data collected by PMUs and PQMs it is possible to determine the MV bus that experienced a fault or, at least, the closest bus to a fault, should that emerge between two buses.

Specific definition in the project validation

This KPI aims to evaluate the quality of fault localization algorithm in MV lines, considering both the accuracy and efficiency as well as the time between the fault occurrence and the moment at which the localization algorithm returns results.

Related use case

This KPI is indirectly related to HLUC 05: *Self-healing after a fault.* In the initial specifications of this HLUC, only LV faults had been considered, while in this analysis the scope has been widened to enclose faults occurring in MV lines.

Methodology

General description of the methodology

The detection application is supposed to detect the event based on primary substation relay characteristics and data of PMU installed at that bus. Once the fault is recognized, fault localization application, that requests data from strategically located PMUs and PQMs in network, is run and the location of fault is calculated. Results are then forwarded to the operator, notifying him of a bus that is closest to fault. Even though fault localization is expected to perform in quasi-real time, the time needed between detecting the fault and actual generation of a warning to operator will be monitored, to check how much delay the entire communication interface introduces. Once the fault is successfully eliminated, the repair crew can report back to operator the actual fault location and the precision of localization application can be assessed.

Formula

The accuracy of the algorithm is defined as:

$$Accuracy \ [\%] = \left(1 - \frac{|LOC_{calc} - LOC_{act}|}{l}\right) \cdot 100$$

where LOC_{calc} and LOC_{act} are the distances from primary substation to calculated and actual location of a fault respectively and l is the length of the entire observed MV feeder (from primary substation to end of feeder). Note that since the algorithm can only return buses as fault locations, the accuracy will always be less than 100% for the faults that emerge between two buses. For the same reason we will consider that the algorithm operated successfully when the fault takes place between two buses but will be closer to calculated bus.

The Efficiency is defined as

$$Efficiency \ [\%] = \frac{\sum_{i=1}^{N} n_i}{N} \cdot 100$$

where N is the number of all events for which fault location was calculated and n_i is successfulness of algorithm for each particular case (meaning that n_i is 1 or 0 when the

algorithm was or was not successful respectively).

Lastly, the time needed will be calculated between the fault inception moment and the moment in which the application returns result of a faulted bus, and it can be expressed as:

$$t = t_{stop} - t_{start} = t_1 + t_2 + t_3 + t_4$$

Where:
- t_1 is the time needed for data to get from the PMU to the fault detection application, and to detect the fault;
- t_2 is the running time of the fault localization application;
- t_3 is the time needed to get data from other PMU and PQMs;
- t_4 is the time needed for data to get from fault localization application to the operator.
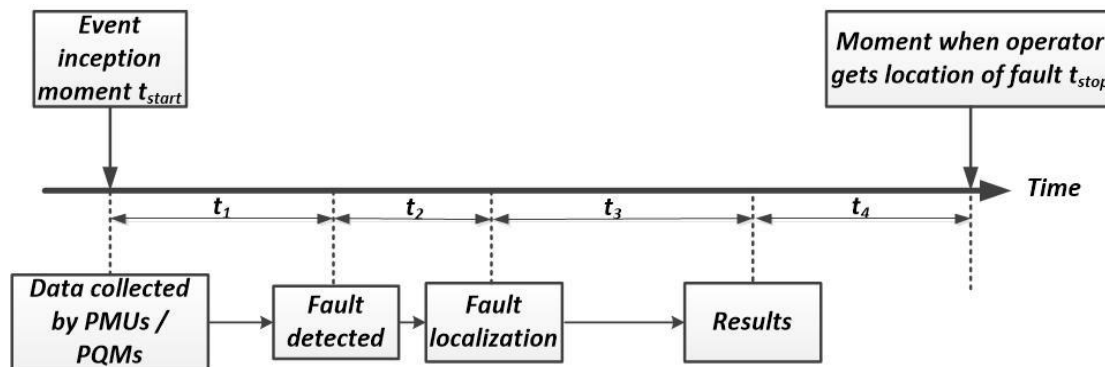
Input data:
3) Aggregated voltage and current values from PMUs
4) Active and reactive power values from PQMs

Steps	Responsible Partner
Aggregated values of voltages, currents and powers are measured by PMUs and PQMs	CS
Measured values are forwarded to fault detection application	CS/ICOM
After fault is detected, fault location is calculated, and inception moment of a fault extracted	UdG
Fault location is forwarded to DSO and time of the loop calculated	CS/UdG/EyPESA

Grid configurations considered
This test will consider the MV grid configuration presented in Figure 7.

Test Planning
Since intentional disconnection of consumers is not allowed, the fault localization algorithm performance in real environment will only be possible to assess, after an actual event in MV network. However, estimating the time of the loop (from detecting a fault to reporting fault location) to be completed could be tested with tweaking of fault detection criterion.

3.11. KPI-09: Quality of the LV grid operation in island mode

KPI_09: Quality of the LV grid operation in island mode	
Responsible Partner: EyPESA	Units: Duration [hours] Reason for island mode interruption Waveform quality
Definition	
General background As indicated in WP1, one of the objectives of this project is to demonstrate the possibility to operate the LV grid in island mode. This type of operation is possible thanks to the energy capacity provided by the batteries in the PED. The island mode could be initiated for self-healing purposes, in case for example of a fault occurred in a point upstream the secondary substation, to reconnect the clients that have undergone the interruption. Moreover, in the future, the island mode could become a type of normal operation, within the context of energy communities and local markets, for which the independency from the main grid could be initiated for economic/environmental reasons.	
Specific definition in the project validation In the phase of project validation, the island mode will be tested and monitored. The quality of the island mode operation, will be evaluated according to three sub-indicators: - Its duration: the island could last during the entire planned period, indicated by the Island Power Management Application (IPMA) or it could end beforehand, due to an unplanned event; - The reason for its interruption: the best-case scenario consists in ending the island as planned, but the interruption could also occur due to a short-circuit, because of unexpected depletion of the energy in the batteries or for other reasons. - The quality of the waveform, making sure it respects the standards defined in EN-50160 (see CI-03)	
Related use case The use case related to this KPI is HLUC 06: *Power management in intentional controlled-island mode*	
Methodology	
General description of the methodology The three sub-indicators will be analyzed as follows: - Duration: simple measurement of the time elapsing between the beginning and the end of the island. - Reason for its interruption: analysis and continuous monitoring of the state of the island to identify the cause of its interruption; - Waveform: analysis and continuous monitoring of waveform quality through the WAMS infrastructure or other power quality analysers installed.	
Formula $$KPI\ 9_{duration} = \Delta t$$ $$KPI\ 9_{Cause\ Interruption} = [planned; short\ circuit; battery\ depletion; others]$$ $$KPI\ 9_{Waveform} = [fulfilled\ /\ notfulfilled]$$	
Input data: Duration: internal clock of the operation application Reason for its interruption: data from PED, smart meters, PMUs and PQMs, other sensors. Waveform: Data from the WAMS infrastructure (PMUs/PQMs) or other power quality analyzers.	
Steps	**Responsible Partner**
Island mode is initiated, following the business flow defined in	EyPESA

HLUC 06 and safety standards	
The pilot area is monitored by the operator through real time data coming from PMUs, PQMs and other sensors	CS/EyPESA
Data about waveform quality are recorded and compared to the standards	CS/EyPESA
The island mode ends in an unexpected manner	EyPESA
The reason for unplanned interruption of the island mode is analyzed and recorded	EyPESA
The island mode ends as planned; the results are recorded	EyPESA

Grid configurations considered

The two possible island grid configurations are the following:
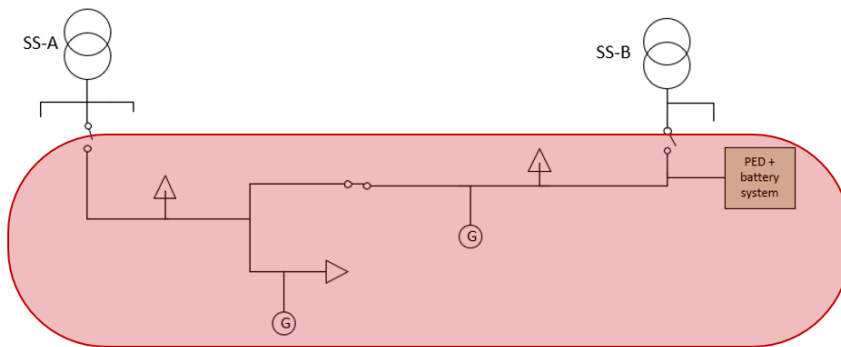
Figure 38: Grid configuration for the island mode, that includes both the feeders of the pilot area
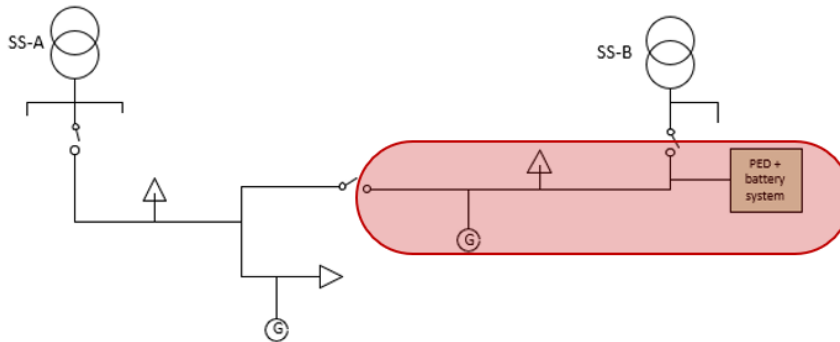
Figure 39: Grid configuration for the island mode, that includes one of the two feeders of the pilot area

Test Planning

The island mode tests require a high level of awareness and close monitoring from the operator side, during the whole duration of the test, thus the number of these tests will be planned in detail in a second phase. If a high risk of unsafety or significant power interruption is foreseen, in association to this test, its execution could be postponed or cancelled.

3.12. IC-03: Waveform quality in LV grid

IC_03: Waveform quality in LV grid	
Responsible Partner: UPC	Units: Fulfillment/unfulfillment of waveform quality standards
Definition	

General background
The objective of this control indicator is to analyse the waveform quality in the LV grid, in which the RESOLVD technology is installed, to make sure that the standards are fulfilled.

Specific definition in the project validation
Several aspects which are related to the waveform quality of supplied voltage are considered. The output of this CI is obtained evaluating the RMS voltage every 10 minutes during a long period.

Related use case
Not directly related to any use case.

Methodology

General description of the methodology
The control indicator is based on the real measurement of the voltage in order to analyze if it fulfils the current regulation. Note that the measurements should be taken with a power quality analyzer (e.g. PQM).
This control indicator considers several aspects which are related to the waveform quality of supplied voltage. Two "sub-indicators" are considered:

1) Fundamental voltage waveform

- The three-phase values have to be enclosed between 0.9 pu and 1.1 pu at least in 95% of cases according to EN-50160.
- The three-phase values have to be enclosed between 0.85 pu and 1.1 pu at least in 100% of cases according to EN-50160.
- The difference among three-phase (using the three-phase indirect sequence values) has to be less than 0.02 pu.

2) Non fundamental voltage waveform

The second set of aspects are related to the average amplitude values of non-fundamental voltage waveforms:
- The Total Harmonic Distortion of voltage waveforms have to be lower than 8% in 100% of cases according to EN-50160.
- The Individual Harmonic Distortion of voltage waveforms have to be lower than the value indicated in the following table.

Table 8: Individual Harmonic Distortion limit

Odd harmonics				Even harmonics	
Not Triplen Harmonic		Triplen Harmonics			
Order k	Harmonic voltage (pu)	Order k	Harmonic voltage (pu)	Order k	Harmonic voltage (pu)
5	0.06	3	0.05	2	0.02
7	0.05	9	0.015	4	0.01
11	0.035	15	0.005	6 to 24	0.005
13	0.03	21	0.005		
17	0.02				
19 to 25	0.015				

Formula

The CI_3 provides a report. An example is attached in Annex IV. It evaluates the main aspects of EN-50160 during a whole week.

Input data:
1) The first analysis only requires the following inputs:
   - A table with the RMS voltage measurement of the three-phases (to ground). The measurement time step must be at least every 10 minutes.

2) The second analysis, which is more complex, requires in addition these extra inputs:
   - A table with the Individual Harmonic Distortion (IHD) voltage measurement of the three-phases (to ground). In particular, the individual harmonic RMS voltages from harmonic 2 to 25, including both odd and even harmonics.
   - A table with the Total Harmonic Distortion (THD) of voltage measurement of three-phase (to ground).

Through power quality analysers it is possible to monitor the three-phase RMS voltages and the individual harmonic distortion, for posteriori treatment. The expected information for each instant of time (t) and phase (x) is the following.

Table 9: Information for each instant of time (t) and phase (x) to be collected for CI-03

Input	Description
$V_{50Hz}(t, x)$	Fundamental three-phase RMS voltages (at 50 Hz).
$HDI\_V_{100Hz}(t, x)$ **to** $HDI\_V_{1250Hz}(t, x)$	Individual Harmonic Distortion RMS voltages (for 100 Hz to 1250 Hz)
$THD\_V \ (t, x)$	Total Harmonic Distortion RMS voltages

To evaluate the first sub-indicator, the data collection must be carried out through a voltmeter, while for the second sub-indicator, a power quality analyser must be installed (e.g. a PQM).

Through this data, it will be possible to evaluate also how external factors can affect the waveform, such as PED, season, etc. Also, smart meter information can be used in order to perform analysis of voltage power quality.

Steps	Responsible Partner
Install power analyzers	UPC/EyPESA
Collect data from power analyzers	UPC/EyPESA
Calculate results	UPC

Grid configurations considered

Any network configuration can be analyzed.

The proposal is to deploy various devices to monitor strategic and/or random nodes of the pilot network during a year

Test Planning

The calculation of this KPI will be performed in a specific and limited time slot during the validation period, however, the power analyzers will collect data continuously.

4. Conclusions

In this report a first description of the planned pilot area was included. The different hardware technologies developed throughout the first phase of the project, will be installed in the LV side of Estabanell network. The pilot is composed of two LV feeders deriving from two different secondary substations. The two lines will be connected at the two extremes and forming a LV ring-shaped structure, that can be reconfigured via switchgears. The PED and battery system will be located in one of the two secondary substations, connected at the feeder under the project's scope. WAMS sensors will be installed both on LV and MV side. The communication infrastructure will need to be upgraded to permit monitoring and control of the pilot network.

The second part of the report includes an analysis of the key performance indicators (KPIs) and control indicators (CIs). This section has resulted as crucial for the definition of the tests and scenarios that will be implemented in the validation phase.

Moreover, the analysis has also helped to remark the necessity to collect specific sets of data throughout the last period of the project, to be able to evaluate the actual performance of the technology. Some of this data will need to be collected through extra sensors and meters strategically located.

Another important factor to take into account is the planning of testing activities: within WP5, the consortium will need to establish a timeline for validation and collection of results.

References

[1]   S. M. Ismael, S. H. E. Abdel Aleem, A. Y. Abdelaziz, and A. F. Zobaa, "State-of-the-art of hosting capacity in modern power systems with distributed generation," Elsevier Ltd, Jan. 2019.

[2]   M. H. J. Bollen and S. K. Rönnberg, "Hosting capacity of the power grid for renewable electricity production and new large consumption equipment," *Energies*, vol. 10, no. 9, 2017.

[3]   F. H. Math H. J. Bollen, *Integration of Distributed Generation in the Power System*. New York, United States: IEEE Press Series on Power Engineering, 2014.

Annex I: Table for pilot data recording to calculate KPI 2

This table needs to be repeated three times: once for the overall pilot area, once for the part of the grid included between SG1 and SG3 and a third one for the grid included between SG2 and SG3.

Date/hour	Forecast		Real		PED schedule		Configuration schedule		ε_{for}	$\varepsilon_{exec_{PED}}$	$\varepsilon_{exe_{SG}}$
	EF_D	EF_G	E_D	E_G	Setpoints Calculated	Executed	Control signals calculated	SG			
20-01-01 01:00-1:59											
20-01-01 02:00-2:59											
20-01-01 03:00-3:59											
20-01-01 04:00-4:59											
20-01-01 05:00-5:59											
20-01-01 06:00-6:59											
20-01-01 07:00-7:59											
20-01-01 08:00-8:59											
20-01-01 09:00-9:59											
20-01-01 10:00-10:59											
20-01-01 11:00-11:59											
20-01-01 12:00-12:59											
20-01-01 13:00-13:59											
…											

Where:

3) EF_D is the total energy demand forecasted for a certain hour in the pilot area;
4) EF_G is the total energy generation forecasted for a certain hour in the pilot area;
5) E_D Is the energy demand measured in the pilot area;
6) E_G Is the energy generation measured in the pilot area;
7) PED schedule/calculated is the setpoint established by the GOS
8) PED schedule/executed is the energy really exchanged between PED and measured in the real grid
9) ε_{for} is the effectiveness of the forecasting
10) $\varepsilon_{exec_{PED}}$ Is the effectiveness of the execution of the schedules of the PED
11) $\varepsilon_{exe_{SG}}$ Is the effectiveness of the execution of the schedules of the reconfiguration

Annex II: Table for pilot data recording to calculate KPI 10

<u>Forecasting precision and TPR</u>

Date/hour (Time of the event)	Forecast			Measured			TP	FP	FN	Precision	TPR
	I	V	CE (1-yes; 0-no)	I	V	CE (1-yes; 0-no)					
20-01-01 01:00-1:59											
20-01-01 02:00-2:59											
20-01-01 11:00-11:59											
20-01-01 12:00-12:59											
20-01-01 13:00-13:59											
…											

<u>Effectiveness of the mitigation action</u>

Date/hour (Time of the event)	Forecast			Measured			Ce_a	Effectiveness of mitigation action
	I	V	Ce_f (1-yes; 0-no)	I	V	Ce_m (1-yes; 0-no)		
20-01-01 01:00-1:59								
20-01-01 02:00-2:59								
20-01-01 11:00-11:59								
20-01-01 12:00-12:59								
20-01-01 13:00-13:59								
…								

Annex III: Information and statistics about historical record of power outages in the pilot area

A critical event can be a congestion and line over/under voltage.

Note 1: Since the grid is currently over dimensioned, a hypothetic scenario with critical events should be created for the evaluation of the KPI related to reduction of interruption.

Note 2: It is probable that the impact of RESOLVD on these KPIs will not be significant, since the ESS is located on the top of the grid and there is only one switch.

The analysis is based on the historical (at least several years) supply interruptions in the pilot and estimates those interruptions that could be avoided (or reduced) operating the grid in island mode.

It is assumed that the use cases of network reconfiguration and operation in island mode will work as expected.

Examples of situations in which we can actuate with RESOLVD:
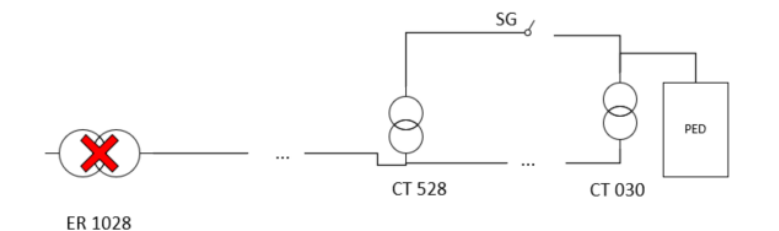
Upstream fault in both secondary substations. An island can be created and all the customers of CT 030 reconnected using the battery of the PED, or even all the clients in both secondary substations, if closing the switchgear in the middle.
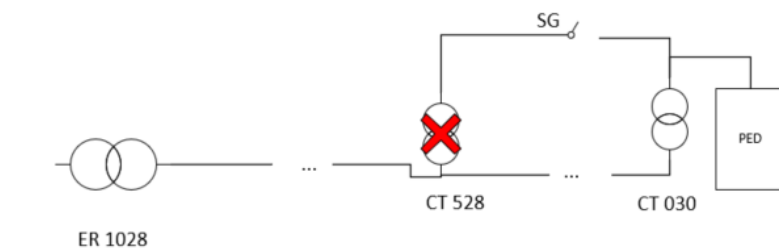
Fault in CT 528. Customers are reconnected closing the switchgears between the two lines.
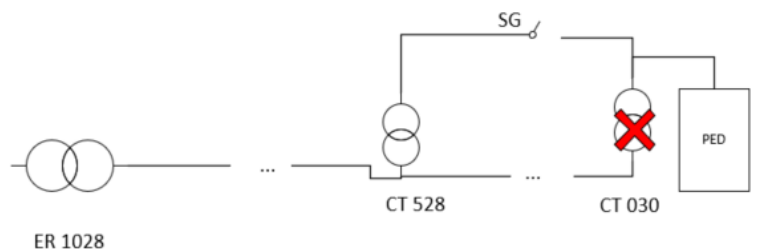
Fault in CT 030. Customers reconnected closing the switchgears between the two lines or PED used to generate an island.
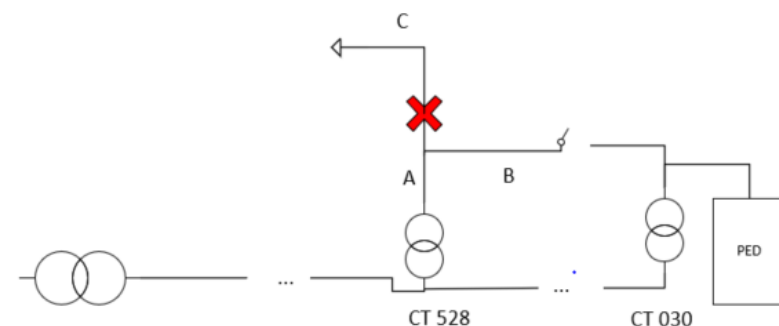
Fault in a ramification of the low voltage line. The service can be maintained for all the customers on segments A and B, but the customers on segment C cannot be reconnected.

Analyzing the data collected about supply interruptions in the last 8 year, the following information can be extracted:

1. Supply interruptions due to a fault in the primary substation

The primary substation from which the pilot area depends is the E.R. 1028 L'Esquirol, fed by another distribution system operator. Since 2012, this primary substation has registered 200 faults but only 29 (~15%) of them can be considered supply interruptions as they had a duration longer than 3 minutes.

The longest interruption lasted 81 minutes, while the average duration is 17 minutes.

Most of these events are caused by the third party feeding the transformer upstream, while the rest is due to planned switching operations and internal faults or external causes (e.g. weather, animals).

These supply interruptions affected all the connected customers depending from this primary substation, including the clients of the two secondary substations of the pilot area. Some of these situations were solved by supplying from another primary substation, making use of the ring configuration of the MV network.

2. Supply interruption due to a fault in the secondary substation of the pilot

Moving to the analysis of the two secondary substations, the number of registered faults in the same time span is even lower. For C.T. 528 (SS-A), only three events are registered, one being a planned switching operation (duration: 18 minutes) and the other two, due to a fault (duration: 283 minutes) and to the damage of some cables for natural causes (duration: 6 hours).

As far as C.T. 030 (SS-B) is concerned, three events are registered, all caused by planned switching operations. The duration varies between 130 and 257 minutes.

It can be noted that, in this case the duration of the fault is longer. The reason to this is that secondary substations cannot count on remote monitoring and control technologies. The control center operators become aware of the problem only when a client calls them to inform that there is no light in the dwellings. The operation to locate the fault and correct is quite time consuming when there is no remote observability of the low voltage grid situation.

3. Analysis of the individual supply interruption

In the following paragraph, the individual quality of supply for the customers connected in the pilot area is discussed. The sample client considered derives from the average conditions between CT 528 (SS-A) and CT 030 (SS-B).

From 2012 to May 2019, the clients had 32 supply interruptions with a total duration of 19.2 hours, and an average of 2,6 hours per year.

Three of these interruptions depended from the secondary substations, while the others from the upstream primary substation.

Number of interruptions per origin

Graph 1: Origin of supply interruption, considering the number of events, for an average client in the pilot area

Duration of interruptions per origin

Graph 2: Origin of supply interruption, considering the total duration of events, for an average client in the pilot area

Interruptions per type of cause
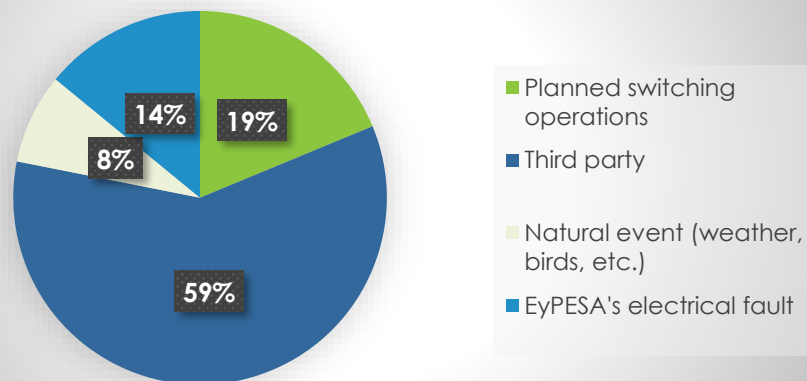
Graph 3: Cause of supply interruption, considering the number of events, for an average client in the pilot area

Duration of interruption per type of cause

- Planned switching operations
- Third party
- Natural event (weather, birds, etc.)
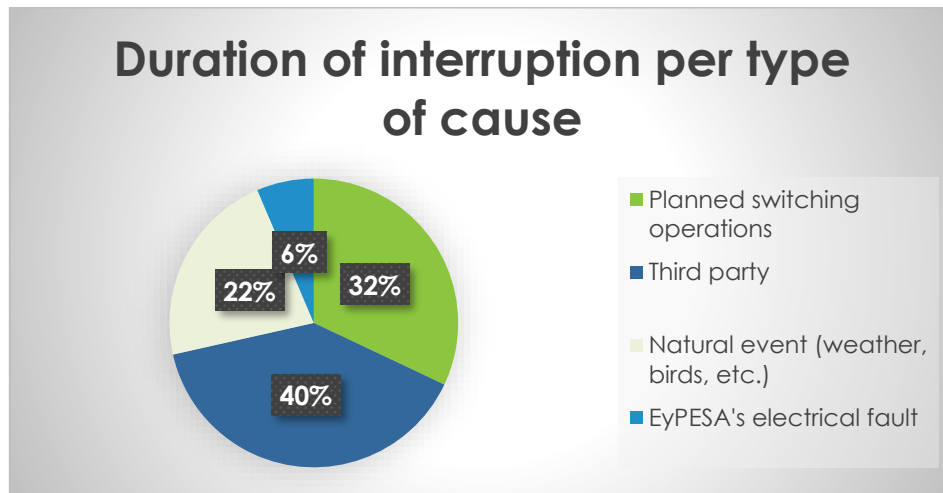- EyPESA's electrical fault

6% 22% 32% 40%

Graph 4: Cause of supply interruption, considering the total duration of events, for an average client in the pilot area

Number and duration of events per year

[number] [hours]

Duration — Number of events
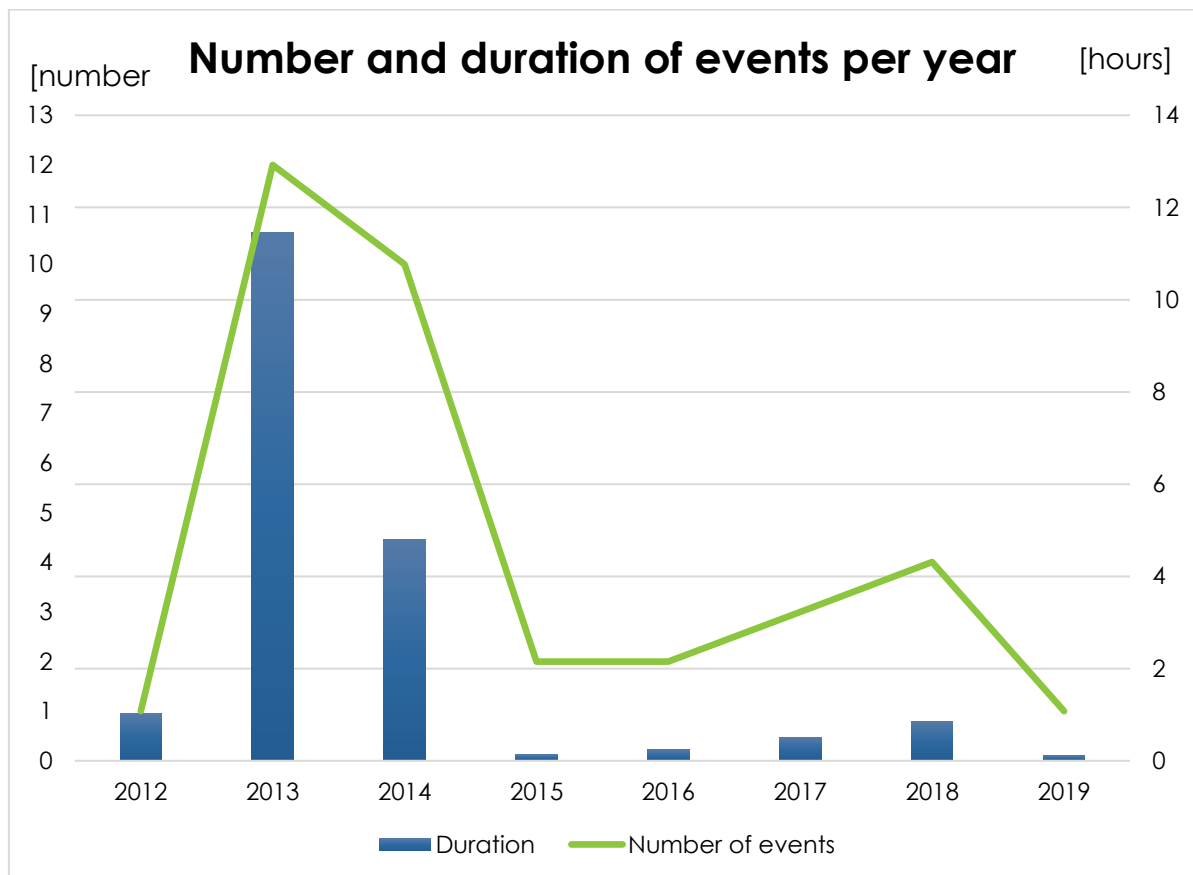
Graph 5: Historical record of supply interruptions or the clients of the pilot area, in number of events and duration

Annex IV: Example of voltage waveform quality report

In this annex a voltage waveform quality report is attached, this report is performed according to EN-50160 and it is performed with a power quality analyzer (Dranetz PX-5). The report treats whole aspects related to the standard. In addition, the report is performed with real data collected in the pilot during the week from 30/07/2018 to 06/08/2018.

Event #20581 06/08/2018 00:00:00,000
EN50160 Completed - Pass

EN50160 COMPLIANCE REPORT
Site: DRANSET_01, Week #2 (30/07/2018 00:00:00,0 to 06/08/2018 00:00:00,0)
Nominal Voltage (Un) = 230 V

Power Frequency

Range	Threshold	Compliance			
50 Hz +1%/-1%	99.5%	100.0%			**PASSED**
50 Hz +4%/-6%	100.0%	100.0%			**PASSED**

Supply Voltage Variations

		Compliance:			
Range	Threshold	CHA	CHB	CHC	
230 V +10%/-10%	95.0%	100.0%	100.0%	100.0%	**PASSED**
230 V +10%/-15%	100.0%	100.0%	100.0%	100.0%	**PASSED**

Rapid Voltage Changes
Not available

Flicker

		Compliance:			
Range	Threshold	CHA	CHB	CHC	
<1	95.0%	97.6%	98.8%	98.8%	**PASSED**

Supply Voltage Unbalance

Range	Threshold	Compliance	
0-2%	95.0%	100.0%	**PASSED**

Harmonics
All shown figures are 95% values

	Limit(% of Un)	A	B	C	Status
THD	<8.00%	3.00%	2.90%	2.86%	**PASSED**
H02	<2.00%	0.04%	0.06%	0.08%	**PASSED**
H03	<5.00%	1.18%	0.89%	0.84%	**PASSED**
H04	<1.00%	0.04%	0.05%	0.10%	**PASSED**
H05	<6.00%	1.36%	1.45%	1.32%	**PASSED**
H06	<0.50%	0.05%	0.06%	0.11%	**PASSED**
H07	<5.00%	1.81%	2.09%	1.88%	**PASSED**
H08	<0.50%	0.06%	0.04%	0.10%	**PASSED**
H09	<1.50%	0.38%	0.30%	0.19%	**PASSED**
H10	<0.50%	0.09%	0.05%	0.11%	**PASSED**
H11	<3.50%	1.78%	1.40%	1.73%	**PASSED**
H12	<0.50%	0.14%	0.06%	0.13%	**PASSED**
H13	<3.00%	0.60%	0.56%	0.69%	**PASSED**
H14	<0.50%	0.08%	0.05%	0.08%	**PASSED**
H15	<0.50%	0.16%	0.14%	0.15%	**PASSED**
H16	<0.50%	0.06%	0.03%	0.04%	**PASSED**
H17	<2.00%	0.10%	0.08%	0.12%	**PASSED**
H18	<0.50%	0.05%	0.03%	0.03%	**PASSED**
H19	<1.50%	0.07%	0.05%	0.05%	**PASSED**
H20	<0.50%	0.04%	0.02%	0.03%	**PASSED**
H21	<0.50%	0.08%	0.07%	0.07%	**PASSED**
H22	<0.50%	0.03%	0.02%	0.03%	**PASSED**
H23	<1.50%	0.05%	0.05%	0.04%	**PASSED**
H24	<0.50%	0.03%	0.02%	0.02%	**PASSED**
H25	<1.50%	0.05%	0.04%	0.03%	**PASSED**

Supply Voltage Mains Signalling
75Hz - 2550Hz   **PASSED**
2550Hz - 100kHz Unavailable from this instrument.

EN50160 COMPLIANCE REPORT - ADDITIONAL INFORMATION
Site: DRANSET_01, Week #2 (30/07/2018 00:00:00,0 to 06/08/2018 00:00:00,0)

Supply Voltage Dips, Interruptions and Overvoltages
(EN50160 does not specify limits for this category, these are informative figures)

Magnitude	10-100 msec	0.1-0.5 Sec.	0.5-1 Sec.	1-3 Sec.	3-20 Sec.	20-60 Sec.	1-3 Min	>3 Min
Dips:								
0% - 10%	-	-	-	-	-	-	-	-
10% - 15%	-	-	-	-	-	-	-	-
15% - 30%	-	-	-	-	-	-	-	-
30% - 60%	-	-	-	-	-	-	-	-
60% - 99%	-	-	-	-	-	-	-	-
Interruptions:								
99% - 100%	-	-	-	-	-	-	-	-
Swells:								
0% - 110%	-	-	-	-	-	-	-	-
110% - 120%	-	-	-	-	-	-	-	-
120% - 140%	-	-	-	-	-	-	-	-
140% - 160%	-	-	-	-	-	-	-	-
160% - 200%	-	-	-	-	-	-	-	-
200% -	-	-	-	-	-	-	-	-

Transient Overvoltages
(EN50160 does not specify limits for this category, these are informative figures)

Magnitude	Counts
0% - 110%	-
110% - 120%	-
120% - 140%	-
140% - 160%	-
160% - 200%	-
200% -	-

Interharmonic Voltage
(EN50160 does not specify limits for this category. All shown figures are 95% values)

	A	B	C
TID	0.50%	0.26%	0.37%
IH00	0.04%	0.03%	0.03%
IH01	0.05%	0.04%	0.04%
IH02	0.03%	0.02%	0.02%
IH03	0.03%	0.03%	0.02%
IH04	0.04%	0.03%	0.03%
IH05	0.05%	0.04%	0.03%
IH06	0.06%	0.05%	0.04%
IH07	0.08%	0.06%	0.05%
IH08	0.10%	0.06%	0.07%
IH09	0.12%	0.07%	0.10%
IH10	0.17%	0.08%	0.13%
IH11	0.21%	0.09%	0.16%
IH12	0.20%	0.09%	0.17%
IH13	0.15%	0.06%	0.12%
IH14	0.11%	0.05%	0.09%
IH15	0.09%	0.04%	0.07%
IH16	0.08%	0.04%	0.06%
IH17	0.07%	0.03%	0.05%
IH18	0.07%	0.03%	0.05%
IH19	0.06%	0.03%	0.04%
IH20	0.06%	0.03%	0.04%
IH21	0.05%	0.03%	0.04%
IH22	0.05%	0.03%	0.04%
IH23	0.05%	0.03%	0.03%
IH24	0.05%	0.03%	0.03%
IH25	0.04%	0.03%	0.03%