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Final Report

Technical requirements for the operation of microgrids in both interconnected and islanded modes

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Technical requirements for the operation of microgrids in both interconnected and islanded modes

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Executive summary

The concept of microgrids is closely linked to the starting of the electricity system developments from the 19^{th} century, where a generation source, either thermal or hydro, supplied an industrial load. At the dawn of the 21^{st} century, the microgrid concept is being recovered, driven by important drivers, from the decarbonization, to the decentralization and the digitalization of energy systems, pushing forward a end users-centric energy transition.

Considering the significant increase in projects and initiatives in Europe on microgrids connected to the distribution grid, CIRED launched a working group to address the topic of the *technical requirements for the operation of microgrids in both interconnected and islanded modes*. The work of this working group started in January 2019 and finished in February 2021. Although the focus of the present report is on technical requirements, economic and cost-benefit analysis cannot be ruled out regarding the viability of the discussed solutions. A parallel CIRED working group focusing on business models of microgrids has been put together, both working groups being in interaction, whose report is highly recommended to complement the analysis and complete the big pictures on microgrids. Economic viability is relevant, but other criteria than the technical and economic ones shall be considered before moving on with such microgrids usage in the future. Considerations of resilience, environmental issues, social acceptance and end users behavior (i.e. studying the effect of non-conventional loads) should be part of the decision making process related to allowing the temporary operation of microgrids within distribution grids.

The report aims at providing recommendations on lessons learned from a selected representative and complementary panel of real-life existing demonstration (mostly full scale). The group also took advantage of past projects from where real site conclusions were obtained as well as the expertise within the working group, to guarantee a report with practical conclusions on top of a synthetic state of art. From Portugal to Spain, from France to Czech Republic, several microgrid demonstration were identified as top tier projects, covering a wide scope of applications. All projects were analyzed based on the objectives of the demonstrator, focusing exclusively on the use cases with microgrid-based operation applications. Among others, the WG studied the deployed assets, the modes of operation, the obtained results and conclusions and mostly the technical lessons learned, i.e. what would be needed to generalize such demonstrator in a daily life operation of a distribution grid. A first take-away message of the present report consist then on highlights on the site assets, from energy storage to distributed generation functionalities, requirements in terms of automation, protection and control as well as telecommunications systems.

After the assessment of the selected demonstrators, the next two chapters of the report focus on the two main operation modes of microgrids (islanded and grid-connected) and the transition between them. The transient states comprise the synchronization and disconnection transition stages where several technical requirements came up. The first chapter proposes a theoretical and technical summary of what already exists at a relatively high degree of industrial maturity and scientific knowledge. This “state of art” oriented chapter shall serve the purpose of ground basis of the last chapter, shaped around a set of requirements, or rather recommendations. These are functionally shared among microgrid components, from the power inverters, protection systems and distributed energy resources to other generation sources, including customers-owned applications. A special attention is given to protection systems, namely considering that most of the distribution grids, due to their original operation principles may not be ready for microgrids operation, in a simple plug-and-play manner.

Subsequently, technical requirements were identified, so that distribution grids could become microgrids under certain circumstances. The technical analysis on microgrid requirements are divided into five main domains:

1. Protection systems, from operation, to coordination and performance;
2. Power electronics, from its design, functionalities and role;
3. Power quality requirements focusing on voltage and power flow control;
4. Storage and other sources with grid-forming capability, from application to integration;
5. Communication, monitoring and control, where the design of the infrastructure, the control strategies and the operation interfaces are outlined.

Note that the proposed recommendations do not constitute a set of requirements to be included altogether in a standardization process. That was not the goal of the CIRED working group (though there was an interaction with the IEC task force on microgrids). They were rather intended to open the discussion per domains and may be incompatible between them or not relevant depending on the considered use case. For instance, it shall not be necessary to change the complete traditional protection system if the islanding process is triggered once a year for maintenance. In addition to safety issues, the time horizon plays a significant role. The islanded operation could indeed last for hours to days, requiring various declination of equipment and most probably not only local production but also storage facilities.

Microgrids technology is available as can be seen in the assessed European demonstrators and in more operational cases in other rural areas of the planet (Asia, Africa, South America, etc.) were microgrids have been extensively deployed. In Europe, microgrids have not been largely deployed since the integrated interconnected distribution grid concept that has been built over decades, currently operates securely with reasonable costs and acceptable safety levels. Excluding economics, most of the technology is available or at least industrially mature, though requiring improvement and generalization in standards on particular components. However, the technical changes in the grid infrastructure would be significant and the benefits of such operation would have to be carefully assessed before transitioning to a system where safety issues could be more complex to handle. Nevertheless, for future distribution grids where distributed grid operation principles, active prosumers and even more distributed generation increase in variability and complexity, microgrids could act as a powerful tool ensuring some resilience while providing flexibility to distribution system operators looking forward to a more sustainable, safe, end user aware and reliable energy system.

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Chapter 1

Scope of the work and main definitions

Microgrids covers a large variety of category (based on voltage, power size, energy micro-sources, coverage, applications, etc.) and a clarification of the corresponding architecture is not easy to produce. It is anyway important to specify the category of microgrids considered in the presented work, as scales and applications heavily influence technology choices.

- A Medium voltage (MV) isolated microgrid with multiple power sources and tens of MV sizes (e.g. at the level of an island) can be designed and operated in ways that are similar to the conventional grid.
- On the other hand, a microgrid at the scale of a building can be as simple as an Uninterruptible power supply (UPS) system, possibly with more unbalanced issues with respects to the rather balanced MV.
- In the middle, we have microgrids (that could be hybrid AC/DC or even full DC), with some rotating machines or not, i.e. with 100 % of Inverter-based generation (IBG), with possibly the local interaction of multi-energy vectors.
    - Without discussing diesel generators, in some countries, there is widespread usage of micro-Combined heat and power (CHP) plants, which may be a game changer in microgrids architectures. As an illustration, a MW-scale CHP could supply hot water, heating, and a significant part of the power for a large energy community or part of a campus. Such CHP plants can be a natural grid-forming device and other distributed resources (e.g. rooftop Photovoltaic (PV)) can simply feed its power in island as in grid-connected mode.
    - A more complex case would be urban microgrids with no dominant sources, i.e. completely powered by decentralized PV and storage systems. A major challenge for such cases would be scalability, without talking about social and economic issues.
    - Lastly, the connection to the main grid is subject to discussion, as well as the fact that, while in grid-connected mode, the microgrid is operated by the Distribution system operator (DSO) or a third-party entity.

1.1 Scope of the report

This report focuses on technical requirements for the operation of microgrids in both interconnected and islanded modes. The notion of microgrid is understood here as a portion of a distribution grid (thus mostly electrical energy based) owned by a DSO. The considered microgrid is normally operated in grid-connected mode and could disconnect for any valid criteria and a given time horizon. DC microgrids are thus not considered in this work. This puts away also "autonomous energy community" solutions, multi-energy systems as well as low-frequency variation regulations presenting no power outage even during load shedding actions (though rapidly discussed in Chapter 4). This choice, among others, was concluded first to limit the size of the report, as well as the selected demonstrators to assess[1], second considering the time allocated to the Working group (WG), and third the expertise that would have been necessary within the members of the Working group (WG) to cover such a large subject. Subjects of interest for further studies are highlighted in the text, notably in Chapter 4.

Many questions arise when considering islanding part of a distribution grid. Once defined the area to disconnect, for instance with the help of long-term planning studies, the criteria motivating the transition, the technical capacity to realize it as well as the possible usages of such flexibility are to be discussed. This means being able to define why, when, how and in what conditions transitions from grid-connected to islanded mode are possible and/or need to be operated. The technical aspects of those questions are presented in this report. Chapter 2 assesses representative demonstrators and synthesizes their lessons learned. Chapter 3 considers technical aspects of transition between grid-connected and islanded operation by considering industrial state of the art. Chapter 4 finally presents requirements and recommendations to make such transition operational for DSO in the future.

Note that technical issues of purely isolated microgrids (e.g. off-grids), like small-signal and transient stability, voltage and frequency control, Fault ride through (FRT) as well as power and Energy management system (EMS) are out of the scope of this report. The same is true for virtual power plant infrastructures based for instance on self-regulation of dispatchable loads. Indeed, those topics are not specific to grid-connected microgrids transitioning to islanded mode on a temporary basis. For those dedicated topics, please refer to the consequent existing literature, some of which is cited in the report for information. Finally, the economic issues related to the discussion presented in this report represent the scope of a parallel CIRED WG (2019-2), whose report is recommended in complement to the present one [1].

In the following sections of this chapter, we propose a set of definitions for terms that have not reached yet a global consensus. The idea is to set the mind in which those terms are used throughout the present report, without having the ambition to be a reference outside of the work conducted by the current WG.

1.2 Terminology

1.2.1 Modes of operation

Three major modes of operation can be defined for microgrids.

Isolated: Such microgrids are never connected to the main grid. This category regroups islands or areas too far away from the main grid to benefit from a connection for frequency and voltage references. Such microgrids are out of the scope of this WG.

Islanded: In this report, this term is used for microgrids that should be capable of seamless transition from and to the grid-connected mode of operation [2], [3].

[1] One of the presented demonstrator in Chapter 2 (Grid4EU Vrchlabí from Czech Rep.) proposes a multi-energy vector system with power-to-gas capability via a CHP unit.

Grid-connected: (or interconnected) is self-explanatory.

1.2.2 Intentional and unintentional islanding

The grid-connected to islanded mode transition can be classified into intentional and unintentional (or planned and unplanned) categories [4].

Intentional islanding refers to the transition to and operation of previously clearly defined electrical islands. The boundaries of these islands are intentionally set. These electrical islands:

- Include loads and Distributed energy resources (DER);
- Have the ability to disconnect from and connect to the upstream system;
- Usually contain one or more local storage facilities;
- Are intentionally planned.

The intentional islanding can be scheduled or not, being the latter in the form of an expected (but unplanned in a timely manner) disconnection of the electric island from the upstream grid due to an abnormal grid condition. A planned islanding transition should be conducted by minimizing the power flow at the Point of common coupling/connection (PCC) (close to zero), so that the transient during the islanding switching is as smooth as possible. This should rely on a capacity by the DSO to control (directly or indirectly) the grid-connected generators, or controllable loads (notably in the islanded microgrid during that period). In many cases, the planned islanding (i.e. controlling the PCC power flow close to zero) is achieved by an Energy storage system (ESS) connected at the PCC. The same ESS can also form the grid during the islanded operation. The disconnection must be planned based on the forecasted balance between local consumption and generation in the microgrid. When unplanned, the transition is done with a power flow not necessary close to zero, thus creating larger variations of electric quantities, and possibly more difficulty to ensure a stable operation of the created island (with or without ESS).

By contrast, unintentional islanding refers to the transition to and operation of electrical islands that have not been previously clearly defined. The boundaries of these islands are those solely defined by the islanding event. An unintentional islanding could be considered very useful when looking for continuity of supply, like in the case of an islanded enabled microgrid, which could switch its operating mode if a failure in the MV grid is detected. In that case, the grid-forming units must switch its control mode as fast as possible so that the transient could be as smooth as possible. In this situation, the transient is always bigger when comparing with the planned operation and the stability more difficult to ensure. Unintentional islanding should also consider necessary load shedding to meet the power balance in the created island for stability purposes. As the islanding mainly occurs due to unwanted grid conditions, voltage and frequency should be monitored and used as automated criteria to disconnect the microgrid from the main grid. Maintaining uninterruptible loads in the microgrid while coping with the transient is one of the main technical challenges associated with such use case, clearly oriented toward grids resilience.

In this report, the word *"islanding"* is used for the transition between the two modes and the word *"islanded"* for the mode itself (i.e. after the transition).

1.2.3 IBG-based sources in AC microgrids

Power generation was initially developed around Synchronous generators (SG) technology. However, inverters interfacing energy sources and the grid are becoming more and more common. The integration of Variable renewable energy sources (VRES) is indeed stimulating the evolution of generation interface technologies and needs of interoperability.

In operation in AC microgrids, power converters can be classified into grid-feeding, grid-supporting, and grid-forming power converters, as shown in Figure 1.1 [5]–[7].

Grid-forming converters can be represented as an ideal AC Voltage source converter (VSC) with a low output impedance, setting the voltage amplitude E^* and frequency ω^* of the local grid by using a proper control loop (voltage and frequency regulation). A standby UPS is an example of this type of power inverter. Power sharing among grid-forming converters is a function of the value of their output impedances and could lead to interaction if not designed properly. In a microgrid, the AC voltage generated by the grid-forming power converter is used as a reference for the rest of the connected grid-feeding power converters. In industrial applications, these power converters are fed by stable DC VSC driven by batteries, fuel cells, or other stable primary sources.

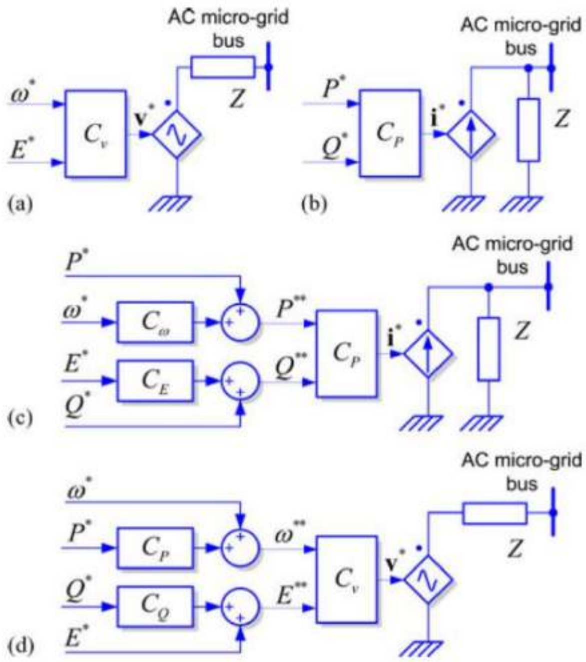

Figure 1.1 – *Simplified representation of grid-connected power converters. (a) grid-forming, (b) grid-feeding, (c) Current-source-based grid-supporting, and (d) Voltage-source-based grid-supporting [5].*

On the other hand, the grid-feeding power converters are mainly designed to deliver power to an energized grid (power output regulation). They can be represented as an ideal current or power source (actually there are a superposed open or closed-loop power controls) connected to the grid in parallel with high impedance or its dual circuit. It is important to outline that the current source should be perfectly synchronized with the AC voltage at the connection point, in order to regulate accurately the active and reactive power exchanged with the grid. Grid-feeding power converters are typically current-controlled VSC, presenting high parallel output impedance. These converters are suitable to operate in parallel with other grid-feeding power converters in grid-connected mode. Currently, most of the power converters belonging to Distributed generation (DG) systems operate in grid-feeding mode, like PV and wind systems. However, they can participate in the control of the microgrid AC voltage amplitude and frequency by adjusting the references of active and reactive powers to be delivered.

Finally, the grid-supporting converters can be represented either as an ideal AC-current-controlled VSC in parallel with a shunt impedance, or as an ideal AC-voltage-controlled VSC in series with a link impedance (usually the control consists of P/f and Q/V droops). These converters regulate their output current/voltage to keep the voltage amplitude E^* and the grid frequency ω^* close to their rated values by controlling the active and reactive powers delivered to the grid. An example of this type of power inverter is a line-interactive UPS system.

1.2.4 Additional definitions

Some general definitions can also be made for switches for later use.

Isolator: are opened/closed under no load;

Load breaker switch (LBS): are opened/closed under rated load;

Circuit breaker (CB): are opened/closed under fault load.

"Continuity of supply" is meant in this report as the ability to supply power to all loads within the microgrid while transitioning from one mode to the other. Finally, by *"seamless transition"*, we refer to transitions between two grid states without the disconnection of any element of the grid or outage (if not written otherwise), but without ruling out disturbances.

Ranges of allowable trip-clearing time-settings for non-traditional operations is one of the subjects of this WG, discussed in Chapter 4 as recently standardized [8].

Chapter 2

Illustration and lessons learned from selected demonstrators

This chapter reports the main outcomes of surveys conducted by WG members on a number of microgrid demonstrators, which are implemented and operated within local distribution grids across Europe. The demonstrators assessed in this chapter have been selected based on their relevance with regards to the main topic of this WG, availability of information at the time of data collection and the interest of the lessons learned regarding the discussions occurring in Chapter 3 and Chapter 4. Only part of the covered aspects by the demonstrators are presented in the present chapter. We indeed have focused on the experiments in line with the transition between grid-connected and islanded modes.

The data collection has been done via individual interview, targeting persons in charge of the technical operation of the demonstrators when possible. A set of questions was drafted to constitute a survey-like canvas for the interview, covering a large set of subjects, from component to system, technical issues and practical aspects. The set of questions is provided for information in Appendix A.

Only six demonstrators are presented in more detail in this chapter. Other targeted demonstrators, either presenting similar lessons learned, or with less available information for the overall comprehension of the study case have been integrated in Chapter 4 when relevant.

The choice of those demonstrators has been motivated by the following reasons. They display a large variety of possibilities to properly and seamlessly conduct the transition between the grid-connected and islanded modes for microgrids. All of them had a focus on the technical aspects of that transition that could be used in this report, providing enough information to the WG for synthesis. Note that economics aspects, even if sometimes discussed in the scope of the demonstrators, are not presented in this report. Please refer to the parallel CIRED WG on this aspect. The main themes considered in this chapter are listed here:

1. Context and objectives of the demonstrator;
2. Demonstrator grid composition;
3. Equipment used for the islanding use case;
    a) Automation and control;
    b) Protection;
    c) Measurement;
    d) Supervision;

   e) Telecommunication;

4. Modes of operation of the islanding use case;
   a) Grid-connected operation;
   b) Transition from grid-connected to islanded operation;
   c) Islanded operation;
   d) Transition from islanded to grid-connected operation;
   e) Black-start;
5. Islanding tests results.

The set of demonstrators is listed in Table 2.1 together with basic information.

TABLE 2.1 – *List of the six selected demonstrators for detailed assessment.*

Name	Country	Project	In use	Information
San Agustín	Spain	N.A.	Y	ease-storage.eu/news/micro-grid-of-san-Agustín-de-guadalix-for-the-operation-of-distributed-resources/
Caravaca	Spain	6.2017 - 12.2019	Y	iberdrola.com/press-room/news/detail/i-de-launches-first-battery-storage-system-electricity-grids-spain pv-magazine.com/2019/11/27/iberdrola-switches-on-3-mwh-battery-in-spain/ saurenergy.com/solar-energy-news/iberdrola-commissions-lithium-ion-energy-storage-system-in-spain
Grid4EU Vrchlabí	Czech Rep.	11.2011 - 1.2016	Y	cez.cz/en/media/press-releases/europes-state-of-the-art-smart-grid-project-starts-officially-includes-cez-groups-smart-region-69990 virtualniprohlidky.cez.cz/smart-region-Vrchlabi-aj
Grid4EU Nice Grid	France	01.2012 - 12.2016	N	enedis.fr/nice-grid-0
INTERFLEX Nice Smart Valley	France	2017 - 2019	N.A.	interflex-h2020.com/interflex/project-demonstrators/france/
SENSIBLE Évora	Portugal	01.2015 - 12.2018	Y	https://www.projectsensible.eu/demonstrators/evora/

This chapter concludes with a section on the lessons learned from the demonstrators, specifically focusing on three main aspects: the grid composition, the equipment used for the islanding transition and the available modes of operation of the use case. The lessons learned target demonstrators and project managers and do not constitute a requirement list to operate microgrids in both grid-connected and islanded modes, though they are meant to complement the recommendations and requirements proposed in Chapter 4.

2.1 Demonstrators

2.1.1 San Agustín (Spain)

2.1.1.1 Context and objectives of the demonstrator

The San Agustín demonstrator is located in the town of San Agustín de Guadalix (Madrid area), where the Iberdrola Group [9] has a training center known as "Iberdrola Campus". A microgrid has been developed in the campus, with the aim of testing the new role the DSOs may have in the distribution grids of the future. These shall be more dynamic grids, adapted to the flexibility of each user and operated to its full capacity. With that purpose in mind, the San Agustín demonstrator was conceived to allow:

1. The operation of a part of the distribution grid as a microgrid, which can be temporarily islanded from the main grid;
2. The active participation of DERs in the microgrid in order to provide flexibility.

The San Agustín demonstrator is currently in operation. Inside the Iberdrola Group, the subsidiary i-DE Redes Eléctricas Inteligentes [10] (named "i-DE" from now on) is in charge of the management of the demonstrator. i-DE is one of the main DSOs of the Spanish territory.

2.1.1.2 Demonstrator grid composition

Figure 2.1 shows a diagram of the San Agustín demonstrator, i.e. the Iberdrola Campus microgrid. This microgrid is composed by three secondary substations connected using a ring topology. Each secondary substation contains three parallel transformers that feed a Low voltage (LV) switchboard. In turn, each LV switchboard is connected to a Battery energy storage system (BESS), a PV plant and to a part of the loads of the Iberdrola Campus.

As observed on the diagram, various islands can be created in the demonstrator. For instance, it is possible to create a LV island containing the LV grid fed by one of the secondary substations (blue area of the diagram). It is also possible to create a MV island, containing the LV grids fed by two or three secondary substations and the MV lines connecting these substations (red area of the diagram).

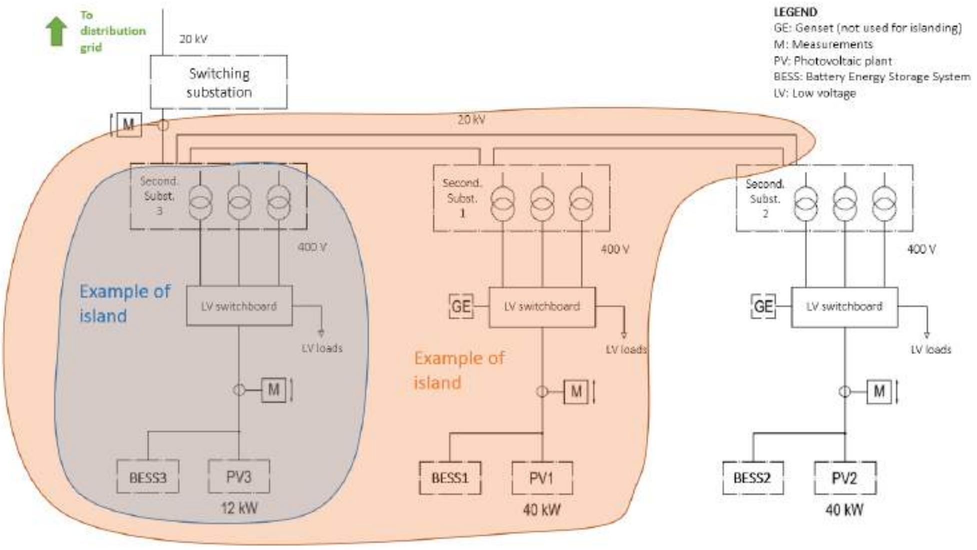

Figure 2.1 – *San Agustín demonstrator – Diagram of the grid (image provided by i-DE).*

As mentioned earlier, there are three BESSs installed in the demonstrator, which were supplied by three different providers. However, all the providers were given the same specifications to design their system. This was done with the aim of comparing the performance of the three BESSs solutions and to check their interoperability. Hereafter the main characteristics of the three BESSs are listed:

- Each BESS has a rated power of 250 kW and an energy capacity of 175 kWh. The rated power was chosen so the total BESS power would be enough to feed the typical load of the campus. In turn, the total energy capacity was chosen in order to meet the energy need of the tests foreseen for the demonstrator. Accordingly, the resulted power-to-energy ratio is 1.43.
- The three BESSs use Li-Ion cells. Two batteries are NMC Oxide and another one is Lithium Iron Phosphate.
- All the BESSs can implement the same control modes. For the islanded use case, the following modes are used:

  Power control: The BESS operates in grid-feeding mode (behaving as a current source). It injects or absorbs a specific amount of active and reactive power, determined by external commands.

  Voltage control: The BESS operates in grid-supporting mode (behaving as a current source). It helps regulating the voltage of the grid it is connected to, implementing either a P/V droop, a Q/V droop or a combination of both.

  Frequency control: The BESS operates in grid-supporting mode (behaving as a current source). It helps regulating the frequency of the grid it is connected to, implementing a P/f droop.

  Island: The BESS operates in grid-forming mode (behaving as a voltage source). It delivers an output voltage with a specific amplitude and frequency, determined by external commands.

Moreover, a droop control has been added to the "Island" control mode of one of the three BESSs. This makes the BESS change the value of its output voltage and frequency according to the active and reactive power it has to deliver or absorb. This forces the potential grid-supporting resources to change their active and reactive power outputs, thus contributing to the power balance of the island.

Besides from the BESSs, three PV plants were connected to the microgrid: one plant of 12 kW installed on the ground, and two PV plants of 40 kW each installed on rooftops. These plants have classical PV inverters that work in grid-feeding mode only.

Finally, the loads of the microgrid are common office load of the buildings in the campus (e.g.: heating, air conditioning, lighting, ICT equipment). The maximum consumption of the whole campus is about 800 kW.

2.1.1.3 Equipment used for the islanding use case

2.1.1.3.1 Automation and control. To island the microgrid, there is a CB installed at the PCC of the microgrid with the MV distribution grid (named "Islanding CB"). This element can be locally or remotely controlled.

The other equipment directly involved in the islanding are the control systems of the three BESSs. In each BESS, there are one or multiple automation devices which are needed and configured to control the different system components. For example, it is necessary to configure the control functions of the inverters, and it is also necessary to configure a battery management system, which monitors the battery cells and ensures their safe operation.

In the San Agustín demonstrator, commercial Programmable logic controller (PLC)s were used to build the control systems of the three BESSs. Each BESS provider customized the configuration of the PLCs according to the requirements of the project.

The automation and control devices are directly commanded by operators located in a i-DE control center. Accordingly, the operators can send the required commands to perform the transition from grid-connected to islanded operation and vice-versa.

2.1.1.3.2 Protection. When implementing the microgrid, the existing protection scheme of the Iberdrola Campus grid had to be revised to ensure its proper functioning according to the new possible operating modes, namely grid-connected and islanded operation.

The main problem encountered with the new protection scheme relates to the creation of islands comprising only the LV grid of one of the secondary substations of the campus. These are 3-phase LV grids, and a TT system with distributed neutral. The neutral currents are provided by the transformers installed in the secondary substations (Δyn group). In addition, the LV neutral is connected to the ground just at the LV side of these transformers, and thanks to this connection and to Residual current devices (RCD) installed upstream of the LV loads, the ground faults can be detected. The problem appears if the LV islands are created by opening CBs located downstream of the secondary substations (i.e. leaving the transformers out of the island). In that case:

- There is no element providing neutral currents so single-phase loads cannot operate;
- The are no ground currents and, therefore, ground faults are not detected by the RCD;
- The LV neutral and phase voltages lose reference so dangerous overvoltages can appear.

To avoid these problems, the implemented solution was to always create LV islands by opening a CB located upstream of the secondary substations.

2.1.1.3.3 Measurement. No special measuring equipment are installed for the islanded use case. The operation relies on measuring devices typically found in i-DE's distribution grids.

2.1.1.3.4 Supervision. A reduced Supervisory control and data acquisition (SCADA) was developed for the San Agustín microgrid, using a standard commercial solution. In addition, the microgrid was integrated in the SCADA used in i-DE control centers. This allows i-DE operators to supervise and control the elements of the microgrid.

2.1.1.3.5 Telecommunication. The microgrid elements (BESSs, PV plants, etc.) were integrated into the private Ethernet network installed in the Iberdrola Campus. No special requirements (e.g. latency requirements) were needed to be implemented for the islanding.

When the demonstrator was developed, no work was done to ensure the communication system redundancy and cybersecurity, since both were already guaranteed in the private Ethernet network the demonstrator was integrated into.

2.1.1.4 Modes of operation of the islanding use case

2.1.1.4.1 Grid-connected operation. In this mode, the BESSs need to be controlled as current sources (since the voltage and the frequency are imposed by the distribution grid). Therefore, each BESS can be configured either in "Power control" mode, in "Voltage control" mode or in "Frequency control" mode. The operation mode and the configuration parameters are set by i-DE operators.

2.1.1.4.2 Transition from grid-connected to islanded operation. In the San Agustín demonstrator, a seamless transition to islanded operation can be achieved: i.e. during the transition, there are no power cuts and all the loads remain connected. The islanding transitions were intentional and scheduled. The following procedure is executed to perform the transition.

1. An i-DE operator changes the topology of the microgrid to obtain the foreseen islanded area (e.g., if the island must only contain two of the secondary substations, the third one is disconnected, see Figure 2.1). The microgrid is not yet disconnected from the main grid.
2. The i-DE operator changes the mode of operation of one of the BESS to "Island mode" and this BESS starts behaving as a grid-forming unit. If any other BESS is included in the islanded area, it is operated as a current source.
3. The i-DE operator checks that the BESSs is able to sustain the island. In particular, the operator checks:
   a) That the rated power of the grid-forming BESS is enough to cover the power imbalance existing in the islanded area right before the opening of the Islanding CB. If it is not the case, the power setpoints of the other BESSs of the islanded area can be changed;
   b) That the total power and energy of the BESSs inside the islanded area is enough to feed the microgrid loads during the planned island duration.
4. The i-DE operator opens the Islanding CB, disconnecting the microgrid from the main grid. A voltage and frequency perturbation appears, due to the power imbalance existing in the islanded area before the disconnection. This perturbation is damped by the grid-forming BESS, which delivers/absorbs the exceeding/lacking power.

2.1.1.4.3 Islanded operation. In this mode, the grid-forming BESS ensures the voltage and frequency stability. If necessary, the i-DE operators can actuate other elements of the microgrid to ensure that the grid-forming BESS has enough power and energy to perform this task. In particular, the operators can:

- Connect or disconnect loads and/or PV inverters;
- Change the setpoints of the BESSs working as current sources.

2.1.1.4.4 Transition from islanded to grid-connected operation. The San Agustín demonstrator does not have a synchronized reconnection capability. The transition from islanded to grid-connected operation is performed according to the following steps.

1. An i-DE operator reconnects the islanded area to the main MV grid without ensuring the synchronization of both voltage waveforms first.
2. Closing the Islanding CB without synchronization is equivalent to creating a small Short-circuit (SC). In a few milliseconds, both the grid-forming and the grid-feeding BESSs detect the overcurrent and stop their inverters, to protect them.
3. Once the BESS is stopped, the voltage of the islanded area suffers a significant disturbance, mainly due to the re-magnetization of the MV/LV transformers at the new voltage. The voltage of the microgrid recovers a sinusoidal waveform with a possible distortion during the first few cycles. However, in the tests conducted in the San Agustín demonstrator, the loads were not disrupted by this disturbance.

2.1.1.4.5 Black-start. The San Agustín demonstrator does not cover black-start capability.

2.1.1.5 Islanding test results

Figure 2.2 and Figure 2.3 present some recordings for a series of islanding tests executed in the San Agustín demonstrator. Figure 2.2 shows the voltage and frequency, whereas Figure 2.3 shows active and reactive powers of the two connected BESSs. Two of the three BESSs were used during these tests, which will be called "BESS *A*" and "BESS *B*" in the report. The yellow dashed lines displayed on the figures mark the various events that took place during the tests. The net consumption of the islanded area (without the contribution of the BESSs) was approximately 130 kW and –50 kVAr.

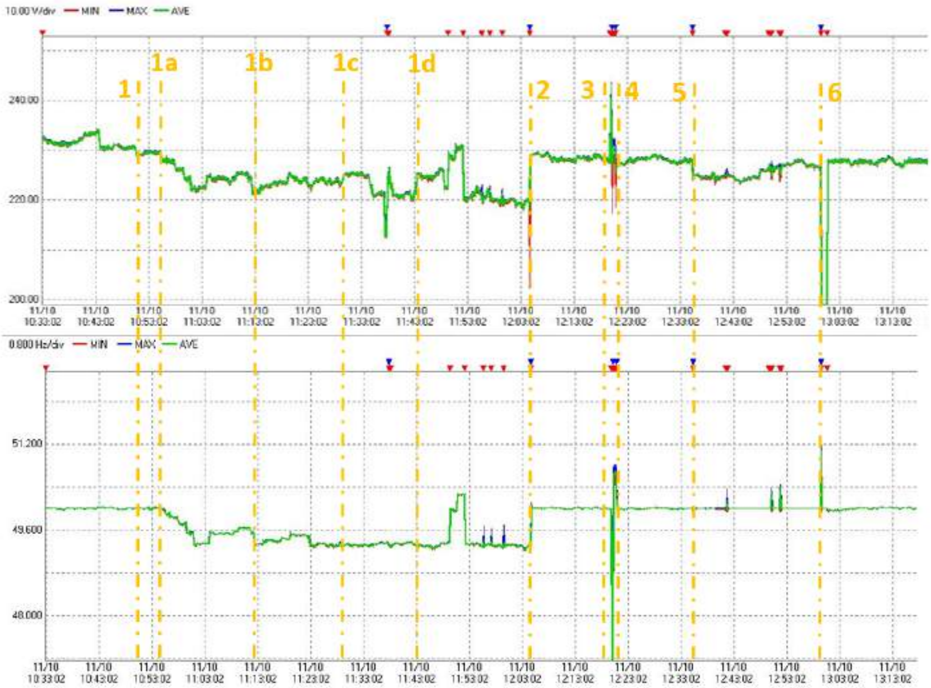

FIGURE 2.2 – *San Agustín demonstrator – Voltage and frequency curves recorded during islanding tests (provided by i-DE). Measures taken in LV (400 V).*

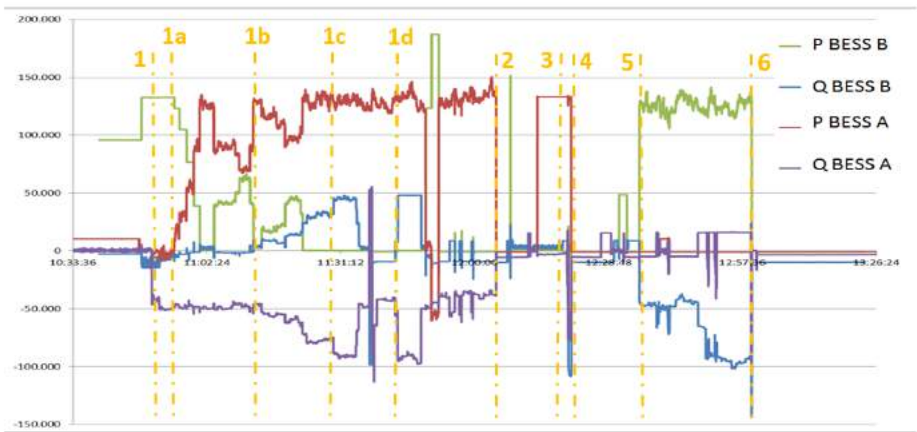

FIGURE 2.3 – *San Agustín demonstrator – Active and reactive power curves recorded during islanding tests (provided by i-DE). A positive value means that the BESS delivers power, a negative value means that the BESS absorbs power.*

It is important to note that the grid-forming mode of BESS A and BESS B is not configured in the same way. BESS B has a "simple" grid-forming mode: it tries to keep a constant voltage and frequency, providing the active and reactive power required in the island and not provided by other sources. However, in the BESS A, a droop control is added to the grid-forming control. In consequence, the BESS A changes the value of the voltage and frequency according to the active and reactive power it has to deliver or absorb. This is to force the potential grid-supporting resources to change their active and reactive power outputs, and contribute to the power balance of the island.

Hereafter is the description of the events observed on Figure 2.2 and Figure 2.3:

- Before islanding, the BESS B was configured in grid-feeding mode, with the setpoints P = 130 kW (the island active power consumption) and Q = 0 kVAr. The BESS A was configured in grid-forming mode and did not deliver active or reactive power at first. Therefore, 50 kVAr were exported from the islanded area to the main grid.
- At (1), the islanding CB was opened and the transition to islanded operation was successfully completed. The BESS A started absorbing the reactive power that was exported to the main grid before the islanding.
- During the islanded operation (between (1) and (2), around 1 h and 10 min), the setpoints of the BESS B were changed several times to study the response of the BESS A:
  - When the active power injected by the BESS B to the grid was decreased, the BESS A increased the active power output. In addition, the voltage and the frequency of the island decreased. The opposite events occurred if the active power of the BESS B was increased. This can be clearly seen between (1a) and (1b).
  - When the reactive power injected by the BESS B to the grid was decreased, the BESS A decreased the reactive power absorbed from the grid. In addition, due to a Q/V droop, the BESS A decreased the voltage of the islanded area. The opposite events occurred if the reactive power of the BESS B was increased. This can be clearly seen between (1c) and (1d)
- At (2), the islanded area was connected to the main grid (unsynchronized reconnection). Right after the Islanding CB was closed, the BESS A automatically stopped, when an overcurrent is detected by its internal converter protections. Figure 2.4 shows the voltage waveforms during this reconnection. At the instant of the reclosing, there was a significant disturbance in the voltage waveform. Then the waveforms recovered a sinusoidal waveform, but with a considerable deformation for the first few cycles, not related to the BESS behavior but to the transformers' core saturation, due to a new magnetization at a different voltage.
- Before the next islanding, the BESS A was configured in grid-feeding mode, with the setpoints P = 130 kW (the island active power consumption) and Q = 0 kVAr. The BESS B was configured in grid-forming mode and did not deliver active or reactive power at first. Therefore, before islanding, 50 kVAr were exported from the islanded area to the main grid.
- At (3), the Islanding CB was opened, but the transition was not successful. Right after the opening of the Islanding CB, the voltage and the frequency began to flicker. Due to this instability, the islanded area was reconnected to the main grid approximately 1 min after the islanding, at (4). The flickering can be observed in more detail in Figure 2.5. It was later found out that the control loop of the BESS A has a gain that depends on how weak or strong is the system to which the BESS is connected. Because of the grid changes that occur with the transition to islanded operation, this gain destabilizes the island when another BESS is the grid-forming unit.

- Before the final islanding, the BESS *A* was disconnected and the BESS *B* was configured in grid-forming mode. This BESS did not deliver active or reactive power at first. In consequence, before islanding, the islanded area imported 130 kW and exported 50 kVAr to the main grid.
- At (5), the Islanding CB was opened and the transition to islanded operation was successfully completed. The BESS *B*, started injecting/absorbing the active and reactive power requested by the islanded area.
- At (6) the island was finished by disconnecting the BESS *B* and reconnecting the islanded area to the main grid (to avoid an unsynchronized reconnection).

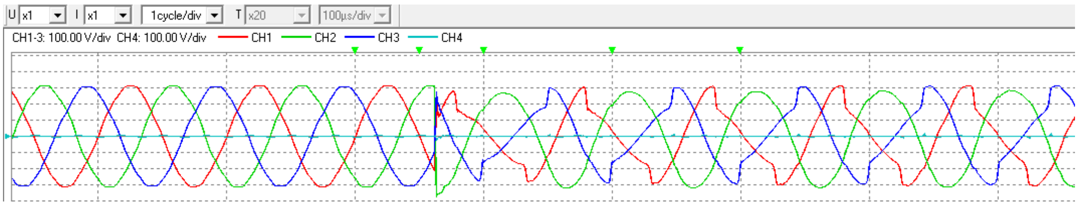

FIGURE 2.4 – *San Agustín demonstrator – Voltage waveforms recorded during an unsynchronized reconnection to the main grid (provided by i-DE), LV (400 V).*

2.1.2 Caravaca (Spain)

2.1.2.1 Context and objectives of the demonstrator

The Caravaca demonstrator was developed by i-DE [10], one of the main DSOs in the Spanish territory. This demonstrator is based on a radial 20 kV line (named "Archivel"), which supplies several villages in the Murcia region located in the south east of the Iberian Peninsula. The motivation of this project comes from the fact that multiple branches at the end of the line often suffer continuity of supply incidents.

The possibility of deploying new lines to improve the continuity of supply was analyzed, but it was discarded since the lines would have crossed an environmentally protected area and it would have been very difficult to obtain the necessary licenses to carry out the works; therefore, the installation of a BESS was identified as an appropriate solution to address the problem instead.

In addition to resolve the above mentioned grid problems, which has to be considered as the main objective, this project was viewed as an opportunity to develop a demonstrator that would allow i-DE to learn about storage and islanding of a portion of the grid; therefore, the following secondary objectives were set for the Caravaca demonstrator. This report focuses in particular to items 3 and 4.

1. To investigate BESSs operations within real grid conditions.
2. To check how BESSs work with DG, e.g. capacity of collaboration in maintaining an island together, integration problems, interactions, etc.
3. To successfully island a part of the distribution grid in order to continue supplying consumers during grid incidents or during planned interventions.
4. To study the issues that may arise when islanding a part of a distribution grid; e.g impact on the final consumer, difficulties in creating an island without passing through zero, difficulties in black-start, grid synchronization.

The Caravaca demonstrator was deployed from 2017 to 2019 and still under operation.

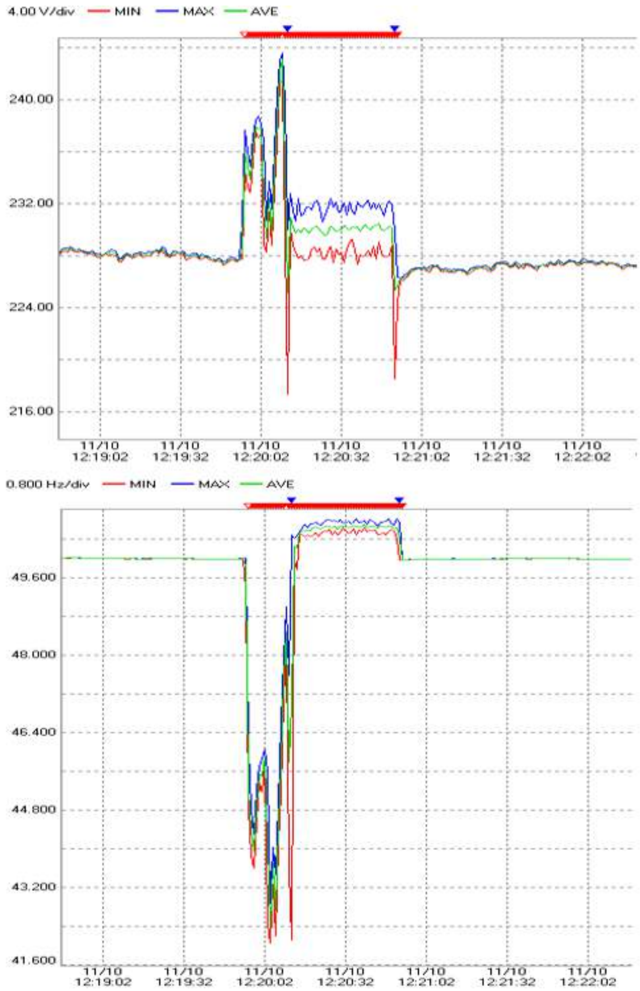

Figure 2.5 – *San Agustín demonstrator – Voltage and frequency curves recorded during an unsuccessful transition to islanded operation (provided by i-DE). BESS A working in grid-feeding mode and BESS B working in grid-forming mode, LV (400 V).*

2.1.2.2 Demonstrator grid composition

Figure 2.6 shows the simplified single-line diagram of the Archivel line, which is fed from a 60 kV/20 kV primary substation ("Caravaca substation"). Apart from the loads fed by the line, two other elements in the Archivel line are a PV plant and the BESS deployed for the Caravaca demonstrator.

During the islanded events, the BESS and part of the Archivel line are islanded from the rest of the MV grid. More precisely, the BESS can be islanded with any or a combination of the branches depicted on Figure 2.6. The main features of the BESS are the following:

- The BESS has a rated power of 1.2 MW and an energy capacity of 2 MWh. The rated power was chosen to allow the BESS to supply/absorb the maximum net consumption/generation of all the branches that can be included in the islanded area. The energy capacity was chosen to allow islanded events of several hours (up to 10 h). A bigger energy capacity was avoided to limit the volume of the battery cells (practical choice).
- The battery cells are Li-Ion (NMC).
- The BESS Power conversion system (PCS) can be controlled in several modes. For the islanding use case, the following modes are used:

Island: The BESS operates in grid-forming mode (behaving as a voltage source): it delivers an output voltage with a specific amplitude and frequency, determined by external commands. In addition, a P/f and a Q/V droops have been implemented in this mode, with the aim of setting a communication link between the BESS and other grid-supporting DERs (although, for the moment, there is no such component in the demonstrator). For example, when the battery injects active power to the grid, it decreases the frequency. This is a signal for the grid-supporting DERs to increase their active power production and, therefore, to contribute to the active power balance of the island. The contrary happens if the BESS absorbs active power.

Power Control: The BESS operates in grid-feeding mode (behaving as a current source): it injects or absorbs a specific amount of active and reactive power, determined by external commands.

Black-start: The BESS operates in grid-forming mode (behaving as a voltage source) and the voltage is progressively increased from 0 until its nominal value, to avoid inrush currents generated by transformer energization.

Frequency Control: The BESS operates in grid-supporting mode (behaving as a current source): it helps regulating the frequency of the grid it is connected to, implementing a P/f droop.

Voltage Control: The BESS operates in grid-supporting mode (behaving as a current source). It helps regulating the voltage of the grid it is connected to, implementing either a P/V droop, a Q/V droop or a combination of both.

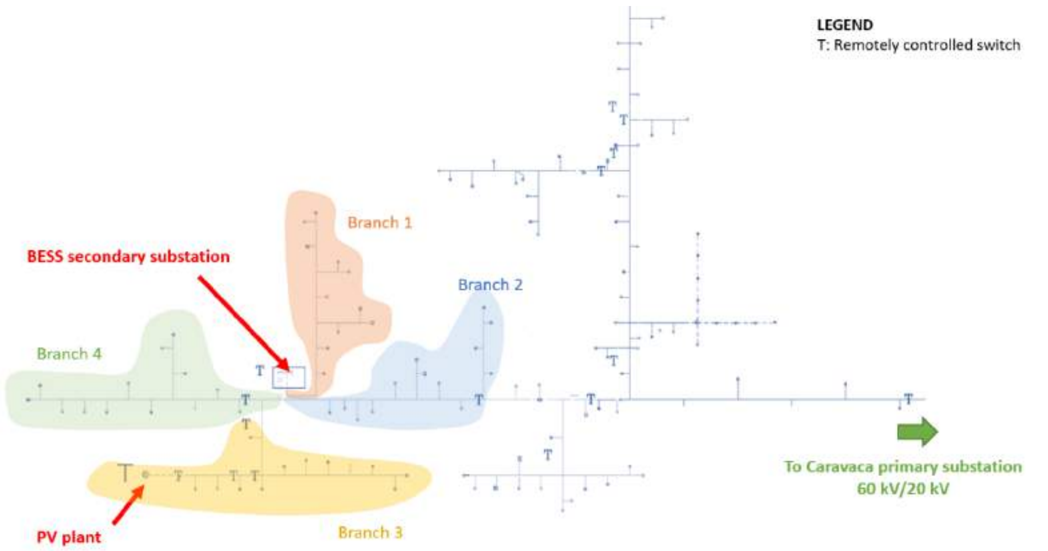

Figure 2.6 – *Caravaca demonstrator – 20 kV Archivel line diagram (provided by i-DE).*

Figure 2.7 presents a detailed diagram of the secondary substation where the BESS is installed. The PV plant of the Archivel line has a rated power of 1.25 MW. It has traditional PV inverters which can only operate in grid-feeding mode. Since the plant belongs to a company external to i-DE, the DSO does not have any control over these PV inverters apart the capability to remotely connect/disconnect the PV plant from the MV grid.

Finally, the loads supplied by the Archivel line are typical of a rural area. They are non-controllable loads: i-DE can only act on them by connecting/disconnecting the secondary substations that are equipped with remotely controlled switches.

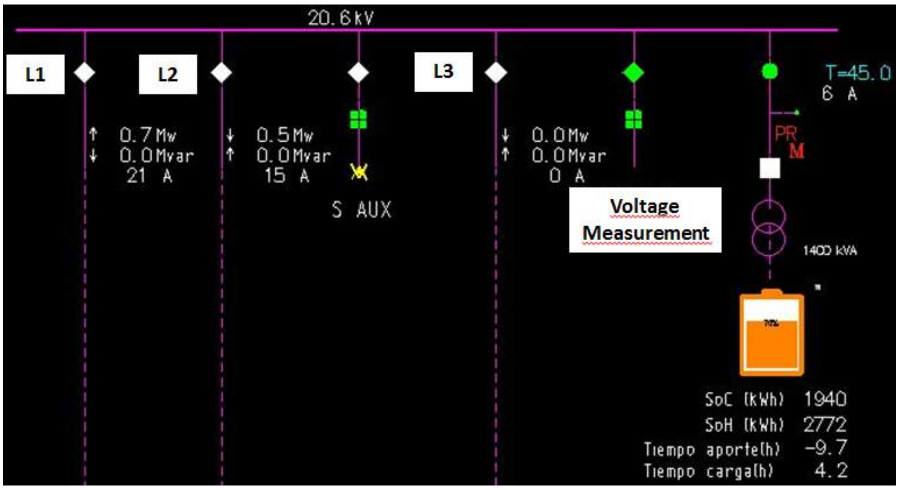

Figure 2.7 – *Caravaca demonstrator – SCADA snapshot of the secondary substation of the Archivel line where the BESS is installed (provided by i-DE).*

2.1.2.3 Equipment used for the islanding use case

2.1.2.3.1 Automation and control. The following automation devices are implemented in the Caravaca demonstrator to enable the islanding transition.

- Remotely controlled LBSs that create the island when they are opened. The LBSs to open depend on which branche(s) is/are included in the island.
- The control system of the BESS: The hardware elements used to compose this control system are commercial products (standard PLCs), but their software was specially configured by the BESS supplier for the Caravaca demonstrator.

In this demonstrator there is no microgrid controller. Operators located in an i-DE control center execute manually all the functions typically performed by control devices for the management of transition phases (e.g. sending commands to the BESS in order to perform a seamless islanding).

2.1.2.3.2 Protection. The protection scheme of the Archivel line was revised during the development of the Caravaca demonstrator and adapted to guarantee the proper operation both in grid-connected and islanded modes.

On one hand, some changes had to be made at the MV level. The neutral of the Archivel 20 kV line is grounded, by means of a low impedance reactor, in the Caravaca primary substation. Among the protections installed in this substation, there are overcurrent relays (50, 51, 50N and 51N), to detect phase faults, and a sensitive ground current relay (51NS), to detect high impedance ground faults. Since the primary substation is upstream of the islanded area, when the islanding takes place, the MV neutral of the islanded area becomes isolated and the aforementioned protection relays are kept out of the island. In addition, while in island mode, the SC current is considerably reduced because the grid is not available to supply the fault. This is why using overcurrent relays is not useful. Therefore, the MV protection scheme had to be adapted for the islanding transition:

- For ground faults, a maximum zero-sequence voltage relay (59N) was installed in the BESS secondary substation. This is a typical commercially available relay used by i-DE.
- For phase faults, the BESS acts as an overcurrent relay: its control system detects an overcurrent and shuts it down, deenergizing the islanded area.

It must be stressed that the 59N relay of the BESS secondary substation was properly coordinated with the 51NS relay of the Caravaca primary substation, to ensure the protection scheme would continue working properly in grid-connected operation. More specifically, the 59N protection was configured with a bigger delay than the 51NS protection. Therefore, if a ground fault happens on the MV line during grid-connected operation, the 51NS acts first. Delaying the 59N protection means that, in islanded operation, ground faults could last for several seconds. However, since the islanded area does not have underground cables, the ground fault current is reduced. This was thus not considered as a risk.

On the other hand, the protection scheme of the LV feeders of the islanded area was revised. These LV feeders have 4-wires (three phases and neutral) with the neutral directly grounded. There are fuses installed at the head of the feeders. In addition, there are overcurrent and RCD installed upstream of the clients loads, which conductive parts are grounded (TT system).

After the analysis, it was concluded that it was not necessary to change the LV protection scheme since, for any possible fault happening in LV, one of the protection systems installed in the islanded area would actuate.

However, this protection scheme has a non-resolved issue: the selectivity is not maintained. For example, if a customer has a fault during islanded operation, the BESS may detect the overcurrent before the client protections leading to a generalized black-out of the island. Therefore, it is necessary to delay the BESS trip to ensure the coordination with the LV relays. The BESS should be able to feed a fault long enough to allow the overcurrent protections of the grid to operate faster (at least the LV fuses), without bringing down the island. However, once this fault ride through capability is enabled, the quality of supply may decrease since the voltage amplitude may be reduced, giving rise to voltage dips of longer duration than the normal ones in distribution grids.

2.1.2.3.3 Measurement. The measuring equipment used in the Caravaca demonstrator is typically used in i-DE distribution grids (e.g. MV voltage and current transformers).

2.1.2.3.4 Supervision. The BESS installed in the Archivel line was integrated in the SCADA system used by i-DE to monitor and supervise its distribution grid. That way, i-DE operators can control and monitor the Caravaca demonstrator from an i-DE control center, using the DSO conventional systems.

2.1.2.3.5 Telecommunication. It was necessary to enable a communication between the BESS secondary substation and the i-DE control center. Since this substation was located far away from the nearest telecommunication nodes, radio was used (IEC-104 protocol).

- A radio link (in the 15 GHz band and with a capacity of 20 Mbps) was installed between the BESS secondary substation and a transponder that belongs to i-DE ("La Paca transponder").
- To connect the La Paca transponder with the i-DE main communication network, it was also necessary to expand the communication channels between the transponder and the surrounding i-DE primary substations (a new link in the 15 GHz band was installed).

In addition, the Modbus protocol is used for the communication between the BESS and the switchgear of the secondary substation the BESS was installed in.

No specific requirement of latency was specified for the radio link, given that the only user of this link was the Caravaca BESS demonstrator.

A special function has been defined to address the potential outage of the communication link between the BESS and the i-DE control center. After 5 min without energy in the main grid and absence of communication with the control center, an automatic black-start procedure is launched by the BESS and an island is created. However, this functionality is currently switched off. Besides from the fact that this telecommunication outage is rare, this has been done to avoid exposing i-DE maintenance operators to electric risks. As a matter of fact, i-DE maintenance teams were not trained to handle elements that can energize the grid autonomously. In parallel, conventional i-DE procedures are used to ensure cybersecurity.

2.1.2.4 Modes of operation of the islanding use case

2.1.2.4.1 Grid-connected operation. In this mode, the BESS must behave as a current source (since the voltage and the frequency are imposed by the distribution grid); therefore, the BESS can be configured either in “Power control” mode, in “Voltage control” mode or in “Frequency control” mode. The operation mode and the configuration parameters are set by an i-DE operator.

2.1.2.4.2 Transition from grid-connected to islanded operation. A seamless transition to islanded operation is achieved: i.e. during the transition, there are no power cuts and all the loads and PV inverters remain connected. The islanding transitions were intentional and scheduled. The following procedure is executed to perform the transition.

1. An i-DE operator changes the topology of the Archivel line to obtain the foreseen islanded area. The islanded area is not yet disconnected from the main grid.
2. The i-DE operator changes the mode of operation of the BESS to “Island” mode and it starts behaving as a grid-forming unit.
3. The i-DE operator checks that the BESS is able to sustain the island. In particular, the operator checks:
   a) That the BESS rated power is enough to cover the power imbalance existing in the islanded area right before the opening of the Islanding CB. This should always be the case, since the BESS was sized with this purpose.
   b) That the BESS rated power and energy is enough to feed the islanded area during the planned island duration.
4. The i-DE operator opens the Islanding CB, disconnecting the microgrid from the main grid. A voltage and frequency perturbation appears, due to the power imbalance existing in the islanded area before the disconnection. This perturbation is damped by the BESS, which delivers/absorbs the exceeding/lacking power.

In case of unintentional islanding, the anti-islanding system of the converter disconnects it from the main grid.

2.1.2.4.3 Islanded operation. In this mode, the grid-forming capability is performed automatically by the BESS control system (no command from the i-DE control center is needed).

As explained before, the BESS has been sized to deliver/absorb the maximum expected net consumption/generation of the islanded area. So, theoretically, its power rating should be enough to take over any power imbalance that may occur during islanded operation.

In any case, the i-DE operators can disconnect the PV plant or some secondary substations to preserve the island stability.

2.1.2.4.4 Transition from islanded to grid-connected operation. Currently, the BESS does not have a synchronized reconnection capability. The transition from islanded to grid-connected operation is performed according to the following steps.

1. An i-DE operator reconnects the islanded area to the main MV grid without ensuring the synchronization of both voltage waveforms first.
2. Closing without synchronization is equivalent to creating a small SC. In less than 2 ms, the PCS of the BESS detects the overcurrent and stops, to protect its IGBTs.
   - During this time, the voltage of the islanded area can suffer a significant disturbance, due mainly to the angular difference between the islanded and the main grids. However, the tests performed have proved that the loads of the demonstrator are not disrupted.
   - Once the BESS is stopped, the voltage recovers a sinusoidal waveform.

None of the islanding tests performed in the Caravaca demonstrator have damaged the BESS because of the unsynchronized reconnection (the PCS always disconnects before excessive overcurrents appear). Although, the equipment is subjected to stress, which, in principle, could lead to its accelerated deterioration, the overcurrent is limited both in magnitude and in duration, so it could be solved by an appropriate sizing.

2.1.2.4.5 Black-start. The BESS deployed for the Caravaca demonstrator has black-start capability. For that, it has an UPS that guarantees the operation of its control electronics for several hours. The steps followed for the black-start operation are the following:

1. An i-DE operator makes sure that the islanded area is disconnected from the main grid and that all the secondary substations are connected to the islanded area.
2. The i-DE operator sends a command to the BESS, to switch to "Black-start" mode (grid-forming mode).
3. The control system of the BESS energizes the islanded area following a ramp-up strategy: it increases progressively the voltage until it reaches its nominal value.

This strategy prevents the inrush currents that would appear due to the energization of secondary substation transformers.

The black-start tests performed in the Caravaca demonstrator (not displayed in this report) prove the correct functioning of this strategy with stable grid. However, another black-start strategy was also tested:

1. First, the island was created following the three steps presented above, but with part of the secondary substations disconnected.
2. Once the islanded area was properly energized, the rest of the secondary substations was connected progressively.

However, it was not completely successful. Sometimes, when adding an extra secondary substation to the islanded area, the inrush current made the BESS disconnect (even with a single secondary substation).

2.1.2.5 Islanding tests results

Figure 2.8 and Figure 2.9 present the voltage, the reactive power and the frequency recorded during a series of tests undertaken in the Caravaca demonstrator. Hereafter is the description of the events that can be observed in the figures:

First, the PV plant of the Archivel line was disconnected from the islanded area and four islanding tests were successfully carried out. During these tests, the BESS was configured as the grid-forming unit of the area. It can be observed that, without PV production, the voltage was more stable and closer to the nominal value in islanded operation than in grid-connected operation. Even so, the voltage deviation in grid-connected operation was not excessive (maximum deviation of 0.03 p.u.).

The frequency remained almost equally stable in islanded operation and in grid-connected operation. Nevertheless, the frequency in islanded operation was approximately 49.5 Hz. This is because the BESS of the Caravaca demonstrator has a P/f droop configured in addition to the grid-forming control. This droop made the BESS to lower the frequency whenever it injects active power into the island.

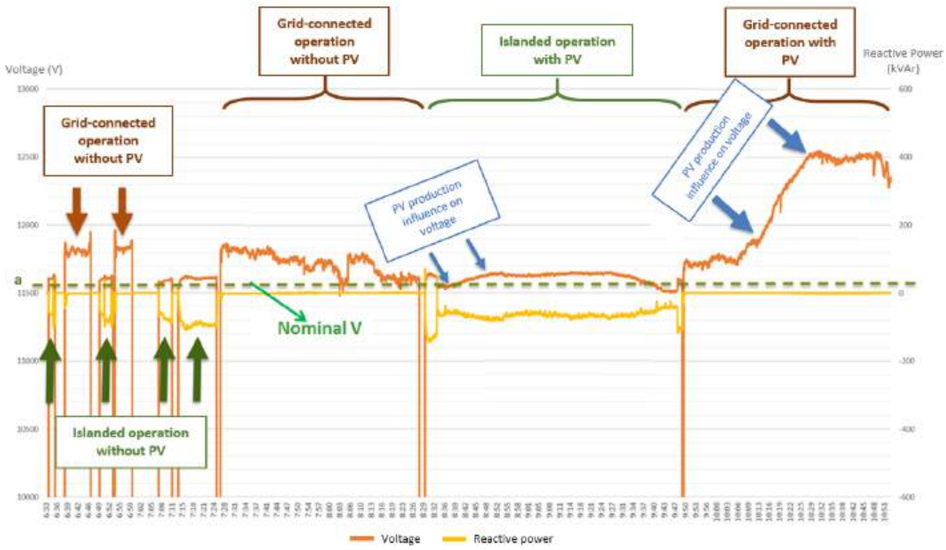

FIGURE 2.8 – *Caravaca demonstrator – Voltage and reactive power curves recorded during islanding tests (provided by i-DE).*

Around 08:30, the PV plant was reconnected to the islanded area and a new islanding test was carried out, with the BESS working in grid-forming mode. The islanded operation was ended at 9:50 approximately.

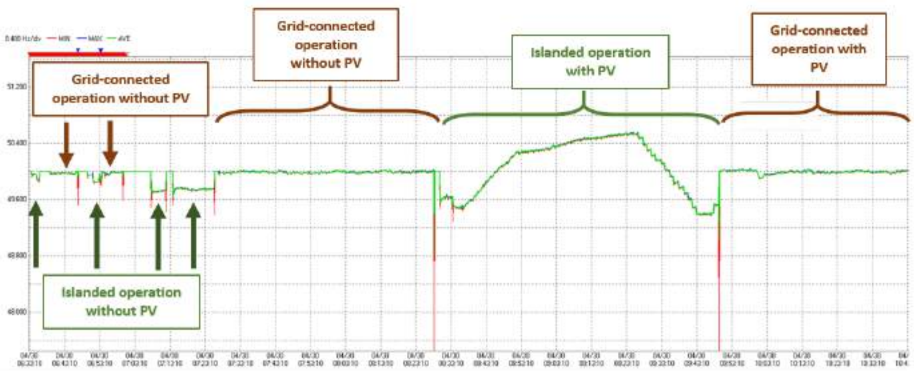

FIGURE 2.9 – *Caravaca demonstrator – Frequency curve during islanding tests (i-DE).*

Thanks to this test, it became more evident that the voltage was more stable in islanded operation than in grid-connected operation. This was due to the voltage regulation executed by the BESS when working in grid-forming mode. In islanded operation, the variations of the PV production caused voltage deviations. However, these deviations were very limited (maximum deviation of 0.01 p.u. with respect to the nominal voltage). In contrast, in grid-connected operation, the increase in the PV production lead to a voltage deviation of 0.08 p.u.

The PV production did not affect the stability of the frequency in grid-connected operation. However, the frequency experienced considerable excursions in islanded operation (from 49.5 Hz to 50.5 Hz). This is because a P/f droop has been added to the grid-forming control of the BESS. As a consequence, when the PV production fluctuates, the active power of the BESS fluctuates too and it changes the island frequency accordingly.

Voltage measurements were conducted in MV (20 kV). A positive reactive power is a power injected by the BESS to the grid.

Figure 2.10 shows the voltage waveforms during one of the transitions from grid-connected to islanded operation. The voltage disturbance was negligible, and the customers did not perceive the change of operating mode. This was checked both at the point of the Archivel line were the BESS is located and at distant points.

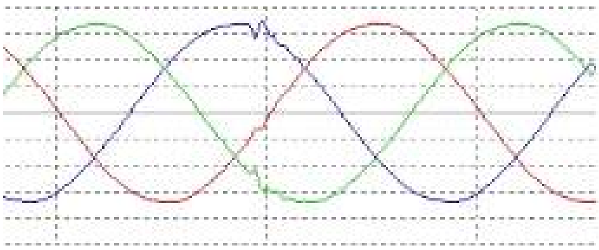

FIGURE 2.10 – *Caravaca demonstrator – Voltage waveforms recorded during a seamless transition from grid-connected to islanded operation, 100 V/vertical division and 20 ms/horizontal division (provided by i-DE).*

Figure 2.11 shows the voltage waveforms during one of the reconnections of the island to the main grid. The Caravaca demonstrator does not have synchronized reconnection capability. Therefore, the Islanding CB is closed without checking if the voltage of the island and of the main grid are synchronized. This causes an overcurrent in the PCS (blue rectange), which disconnects in less than 2 ms (the displayed current includes the effect of the filter, longer than the IGBT currents) with a current limited to 150–160 % of the PCS nominal current. In the reconnection shown on Figure 2.11, an initial voltage disturbance can be appreciated, corresponding to the phase shift of the voltage, in addition to the effect of transformer magnetization with inrush currents (red rectangle) that do not affect the PCS. Other measurements confirmed that the customers supply was not cut during this transition, moreover it was observed that the customers do not even detect any light flicker.

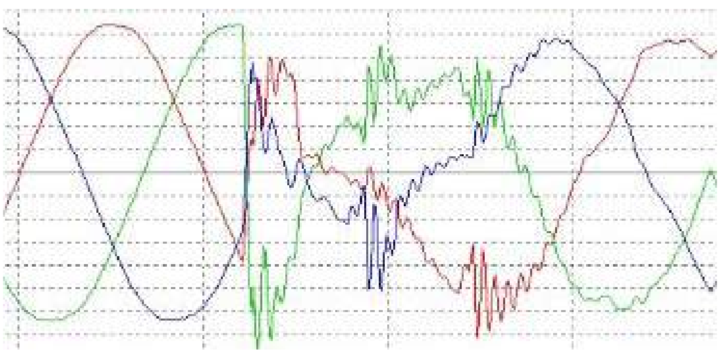

FIGURE 2.11 – *Caravaca demonstrator – Voltage waveforms recorded during an unsynchronized reconnection to the main grid. Upper part: Voltage 100 V/vertical division and 20 ms/horizontal division, lower part: Current 25 A/vertical division (i-DE).*

The tests performed in the demonstrator show that the BESS system has not been damaged by the unsynchronized reconnection. Although, the equipment is subjected to stress, which, in principle, could lead to its accelerated deterioration, the overcurrents is limited both in magnitude and in duration, so it could be solved by an appropriate sizing.

2.1.3 GRID4EU – Vrchlabí (Czech Republic)

2.1.3.1 Context and objectives of the demonstrator

The Vrchlabí demonstrator was developed in the context of the GRID4EU project, which aimed at developing a "large-scale demonstration of advanced smart grid solutions with wide replication and scalability potential for Europe" [11]. More specifically, the project consisted of six demonstrators built by six different DSOs around Europe. Among these, ČEZ Distribuce [12] developed a demonstrator comprising the whole distribution grid of Vrchlabí (a town in Czech Republic). The main objective of the Vrchlabí demonstrator was to test the improvement of quality parameters in three use cases:

1. Automatic failure management in a LV grid;
2. Automatic failure management in a MV grid;
3. Automatic islanding operation.

This report mostly focuses on the third use case. The aim of this use case was to test the capability of a predefined grid to disconnect from the surrounding MV grid and to keep operating in a stable way in case of a failure in the upstream grid.

The project ran from 2011 to 2016 and the demonstrator is still in operation.

2.1.3.2 Demonstrator grid composition

Concerning the "Automatic Islanding Operation" use case, a particular area of the town was chosen (called "Liščí Kopec"). This area includes a CHP unit, which is used to provide electric power supply during islanding transition. Figure 2.12 and Figure 2.13 show two diagrams of the Vrchlabí 35 kV MV grid. In particular, Figure 2.13 reports a SCADA snapshot and provides a more accurate representation of the grid.

The CHP plant connected to the MV substation TU-1435 is the only generation unit of the area. Hereafter its main characteristics are reported.

- It has a rated electric power output of 1560 kW_e and a rated thermal power output of 1720 kW_t.
- It is composed by a natural gas combustion engine, a SG and several water circuits (heating system). The power diagram of the SG is shown on Figure 2.14.
- Its control system is a standard commercial product typically found in CHP units. This system allows implementing different control modes of the SG. In particular, two modes are used for the islanding use case:
  - In grid-connected operation, the output power of the generator is regulated.
  - In islanded operation, the control mode used is voltage and frequency regulation, since the CHP SG is the grid-forming unit of the islanded area.
- The gas inlet of the CHP combustion engine had to be modified to allow the proper operation within the microgrid. Specifically, the CHP unit needed to withstand the gas pressure dynamic changes that happen in the transition from grid-connected to islanded operation.

The problem was detected in the preliminary islanding tests of the CHP unit. Right after the disconnection of the islanded area from the main MV grid, the frequency of the island

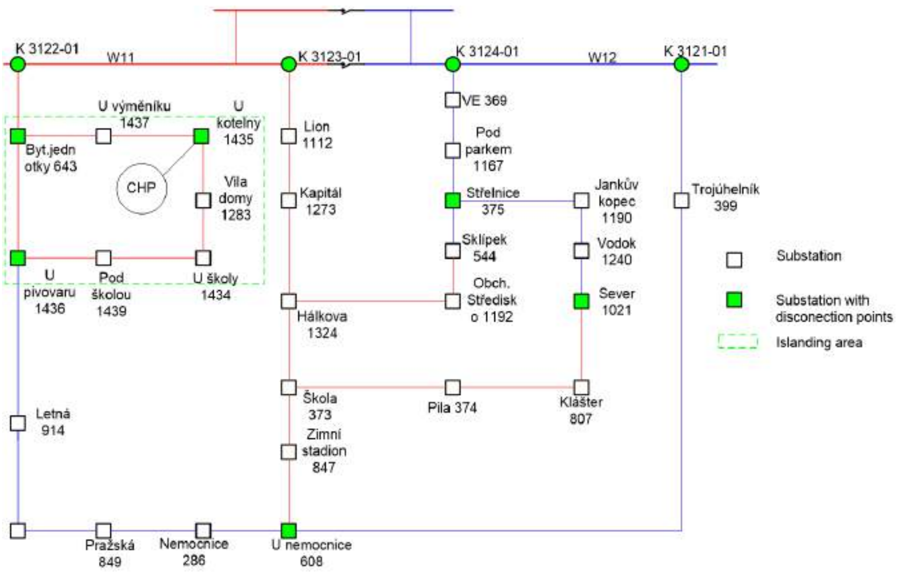

FIGURE 2.12 – *Vrchlabí demonstrator – MV grid and islanded area (Liščí Kopec) [13].*

(or the CHP SG speed) would suffer important oscillations due to the power imbalance in the area. If the rotation speed of the SG was excessive, the CHP control system would close the engine gas inlet valve, in order to decrease the generator rotation speed. This would lead to an increase of the pressure in the gas inlet pipe (located upstream of the valve) and, in consequence, to the closing of the gas pressure regulator (located upstream of the pipe).

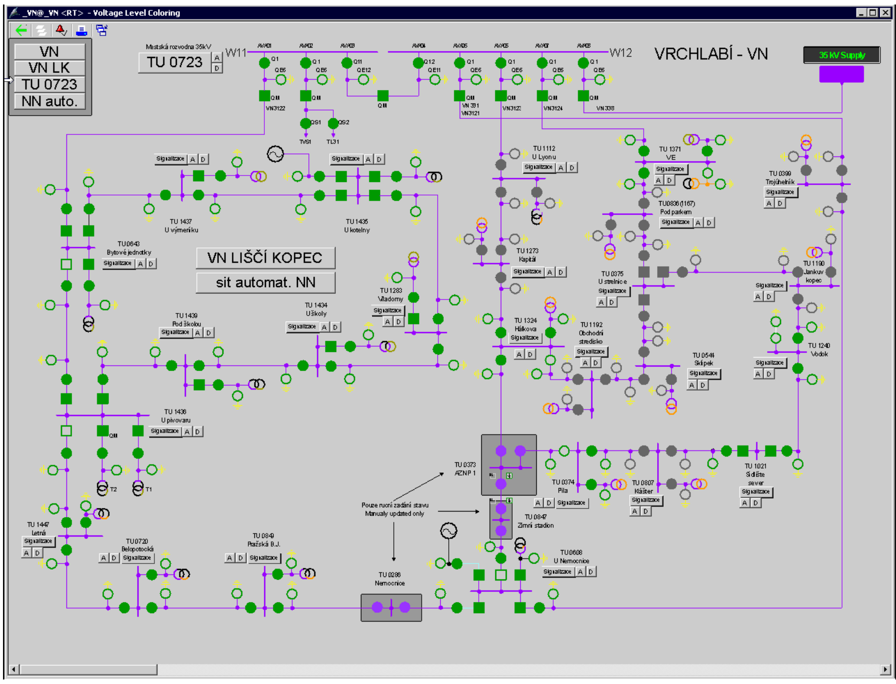

FIGURE 2.13 – *Vrchlabí demonstrator – SCADA snapshot of the MV grid [13].*

Afterwards, when the rotation speed would decrease too much, the CHP control system would react by re-opening the engine gas inlet valve, which would lead to the decrease of the pressure in the gas inlet pipe because the upstream gas regulator had been previously closed. In consequence, the alarm "gas pressure decrease" would activate and the CHP unit would automatically shut-down.

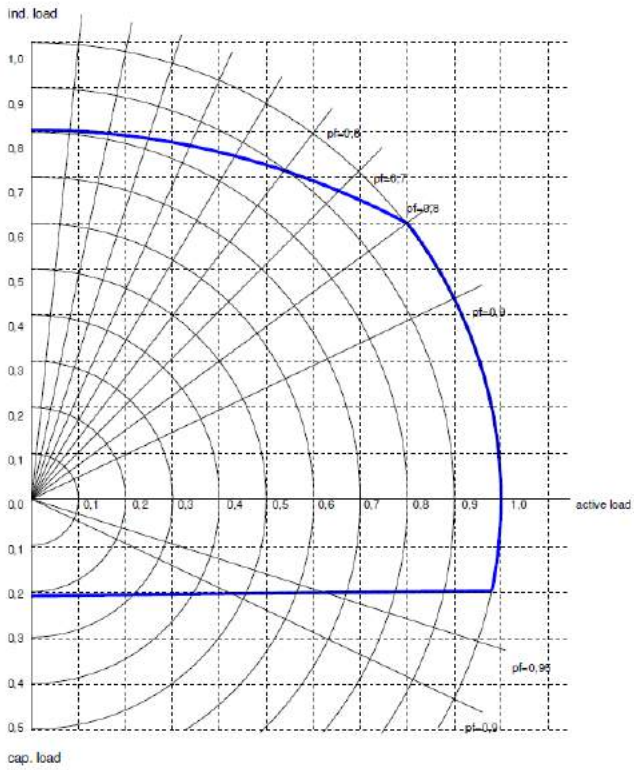

FIGURE 2.14 – *Vrchlabí demonstrator – Power diagram of the SG of the CHP unit installed in the islanded area, 1 p.u. corresponding to 1560 kVA [13].*

To avoid this, the engine gas inlet valve was upgraded. A bypass was performed to avoid the fast closing of this valve. The disadvantage of this modification is that it is not convenient for the generator speed regulation and, in addition, can shorten the lifetime of the engine.

The CHP unit has also a water boiler, which is used as a flexible load for the islanding use case. It allows increasing or reducing the load of the islanded area by steps of 100 kW.

The rest of the loads of Liščí Kopec are typical loads from a semi-urban area. A study was undertaken in 2011 to characterize the consumption of the area. The active and reactive power peaks happened in winter with values of 1270 kW and 270 kVAr consumed by the islanded area. It was thus proved that the CHP unit had enough capacity to supply the area of Liščí Kopec.

2.1.3.3 Equipment used for the islanding use case

2.1.3.3.1 Automation and control. The following automation and control devices are used in the different stages of the islanding use case:

- Three secondary substations (TU-0643, TU-1435 and TU-1436) are equipped with MV remotely controlled switches. These allow to connect/disconnect the CHP unit from the islanded area and to connect/disconnect the islanded area from the rest of the MV Vrchlabí grid.
- All the LV feeders at all secondary substations are equipped with remotely controlled switches (circuit breakers). These allow the progressive increase of the load of the island (functionality used for the black-start of the islanded area).
- A synchrotact secures the seamless reconnection of the island with the superior distribution grid. A standard, commercially available synchrotact was installed.
- The control system of the switching load is installed in the islanded area (boiler).

- The CHP unit power control system, as explained in Section 2.1.3.2, controls the CHP SG according to different control modes (output power regulation or voltage and frequency regulation). The hardware and software composing this system are standard elements commonly found in CHP units.
- An Islanding Controller called "Automation unit of Islanded Operation" (or "AIO" in the context of the GRID4EU project) sends commands to the other automation devices, to the islanded area measuring equipment and to the islanded area protection devices. This Islanding Controller is in charge of coordinating the actions of all these elements in order to automatically implement different operation strategies depending of the operating mode of the islanded area (e.g. grid-connected mode, islanded mode).

The Islanding Controller was specially developed for the Vrchlabí demonstrator because in 2011 there was no commercial solution adapted to the requirements of the project. More specifically, the hardware components of the developed Islanding Controller are standard commercial products, but the software was customized for the project.

2.1.3.3.2 Protection. In the Vrchlabí demonstrator, the main problem regarding grid protection is that the SC current is much lower in islanded operation than in grid-connected operation. For that reason, the MV protection scheme had to be adapted. However, this was not the case in LV since the same protection scheme works properly in both grid-connected and islanded operation.

The solution chosen for MV was to install adaptative protection relays. That way, the settings of the relays can be changed whenever a transition from grid-connected to islanded operation is performed and vice-versa. This task is automatically performed by the Islanding Controller, which communicates with all the protection relays. This is possible thanks to the fast fiber-optic communication implemented in the demonstrator. All the adaptative protection relays used in the Vrchlabí demonstrator are standard commercial products.

2.1.3.3.3 Measurement. In order for the Islanding Controller or for the ČEZ Distribuce operators to properly control and monitor the operation of the islanded area, several measurements are taken at MV and LV levels (frequency, Rate of change of frequency (ROCOF), voltage, rate of change of voltage, currents and powers). Standard measuring equipment typically found in ČEZ Distribuce grids is used.

2.1.3.3.4 Supervision. The ČEZ Distribuce operators use a SCADA to send commands to the Islanding Controller and to monitor the demonstrator. Initially, a local dedicated SCADA was installed in the Vrchlabí demonstrator. It was a commercial product. Recently (after the end of the project), the demonstrator was integrated into the ČEZ Distribuce SCADA.

2.1.3.3.5 Telecommunication. Figure 2.15 presents the telecommunication network developed for the Vrchlabí demonstrator. Since the transitions from grid-connected operation to islanded operation (and vice-versa) are rapid, a fast communication is necessary to perform them successfully. Therefore, ethernet communication using fiber optic infrastructure is used to link the Islanding Controller with the rest of the devices of the islanded area (e.g. switches, protection relays). This communication is compliant with the IEC-61 850 protocol. All the fiber optic routes have a backup.

The communication between the demonstrator and the superior ČEZ Distribuce SCADA is achieved via wired networks (i.e. the MAN and WAN networks of Figure 2.15). In addition, a backup GPRS link has been established to ensure this communication. These links allow sending information about the demonstrator state to the SCADA and also allow the ČEZ Distribuce operators to send commands to the Islanding Controller.

The telecommunication solution was developed according to cybersecurity methods valid in the years 2011–2013. No penetration tests were executed since the regular operation of the demonstrator was not planned at that time. The initial purpose of the project was only to demonstrate the technology.

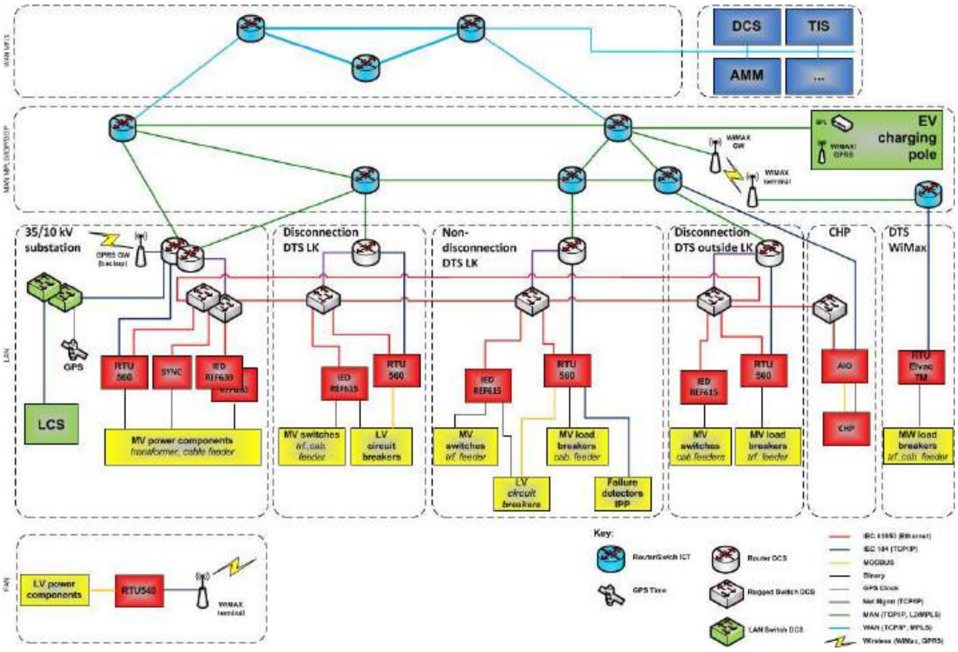

Figure 2.15 – *Vrchlabí demonstrator – Diagram of the telecommunication network [13].*

2.1.3.4 Modes of operation of the islanding use case

2.1.3.4.1 Grid-connected operation. In this mode, the CHP control system is commanded by local operators, who run the unit according to requests of the central heating system of the Vrchlabí town and other users. As explained above, the control mode used for the SG is the regulation of its output power.

2.1.3.4.2 Transition from grid-connected to islanded operation. In the Vrchlabí demonstrator, a seamless transition from grid-connected to islanded operation is achieved: i.e. during the transition, there are not power cuts and all the loads remain connected. The following procedure is executed to perform the transition.

1. A ČEZ Distribuce operator command the Islanding Controller to start the islanding.
2. The Islanding Controller opens the necessary MV switches to disconnect the islanded area from the main grid (see Figure 2.13):
   a) First, the feeder between substations TU1447 and TU1436 is disconnected;
   b) Then, the feeder between substations TU0723 and TU0643 is disconnected.
3. The Islanding Controller changes the operation mode of the CHP unit to voltage/frequency regulation. That way, the CHP unit rejects the voltage and frequency perturbations that may appear during the transition because of the existing power imbalance in the islanded area before the disconnection. If necessary, the Islanding Controller connects/disconnects part of the switching load to avoid too big frequency excursions.

2.1.3.4.3 Islanded operation. The power balance in the island is maintained via the CHP unit (commanded by the Islanding Controller), which works in voltage/frequency regulation mode. If frequency perturbations appear, the Islanding Controller can connect/disconnect part of the switching load to help stabilizing the frequency. If this is not enough, it can also connect/disconnect LV feeders.

2.1.3.4.4 Transition from islanded to grid-connected operation. Thanks to the use of a synchrotact, a seamless transition from islanded operation to grid-connected operation is achieved. The following procedure is executed to perform the transition.

1. A ČEZ Distribuce operator sends a command to the Islanding Controller in order start the reconnection procedure, and this device transmits the command to the synchrotact.
2. The synchrotact compares the voltage waveform of the island and of the MV main grid. To synchronize both waveforms, it sends control commands to the CHP unit.
3. Once the waveforms are synchronized, the synchrotact sends a command in order to reconnect the islanded area to the main grid.
4. After a successful reconnexion the CHP local operators can take control of the CHP unit.

2.1.3.4.5 Black-start. The black-start operation is usually initiated by a ČEZ Distribuce operator who sends a command to the Islanding Controller. There is also the possibility of enabling a fully automated black-start in which the Islanding Controller launches the procedure when it detects an outage in the upstream MV grid. After that, the following procedure is executed to perform the black-start:

1. The Islanding Controller disconnects the islanded area from the rest of the MV Vrchlabí grid, disconnects the CHP unit from the islanded area and opens the LV feeders of the area.
2. The Islanding Controller sends a command to black-start the CHP unit.
3. After the successful black-start of the unit, the Islanding Controller closes the LV circuit breaker in the CHP unit facility (the CHP LV grid and the MV/LV transformer are energized). Then, the Islanding Controller connects the switching load.
4. Then, the Islanding Controller connects the feeder between the secondary substation TU-1435 and the CHP unit (the MV grid of the islanded area is energized, see Figure 2.13).
5. The Islanding Controller gradually connects the LV feeders. If necessary, the Islanding Controller can connect/disconnect the switching load to avoid too big frequency oscillations.

2.1.3.5 Tests results

2.1.3.5.1 Islanding test. Figure 2.16, Figure 2.17 and Figure 2.18 present some recordings performed during an islanding test within the Vrchlabí demonstrator. Hereafter, a description of the events observed during the test and reported in the figures is given.

- Before switching to islanded operation, the CHP unit was working in power regulation mode, generating around 1580 kW (maximum active power) and absorbing around 70 kVAr. The islanded area, excluding the contribution of the CHP unit, was consuming around 400 kW and generating around 330 kVAr due to capacitive lines. Therefore, the islanded area was exporting approximately 1180 kW and 260 kVAr to the main grid.
- The islanded area was disconnected from the main grid at 0:25:28. Since this area was exporting active and reactive power before the disconnection, the frequency and the voltage of the island experienced a sudden increase. The Islanding Controller reacted by

changing the control mode of the CHP to speed regulation and connecting the flexible load. This increased the active power consumption of the island to 630 kW approximately.

- At 0:25:39, the flexible load was disconnected, decreasing the active power consumption of the island back to 400 kW approximately.
- After some voltage and frequency oscillations, both magnitudes stabilized around their nominal values.
- After this transition, the island operation was maintained for 4 h and 3 min.

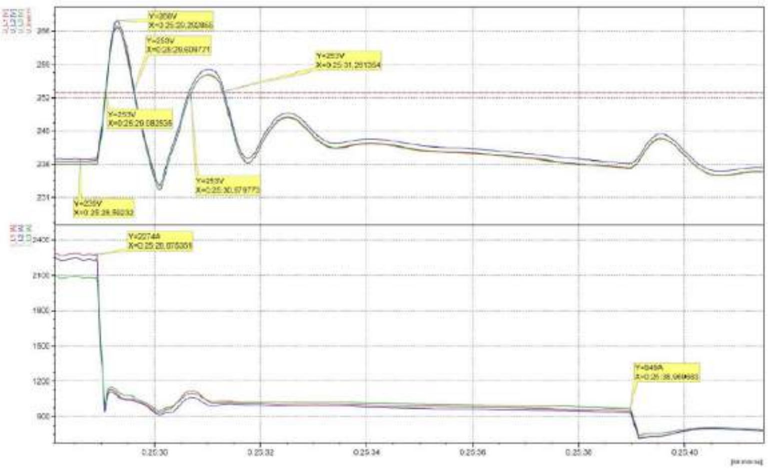

FIGURE 2.16 – *Vrchlabí demonstrator – Voltage and CHP current curves recorded at the beginning of the islanding test [13]. The measurements were taken in the CHP facility, on the LV side.*

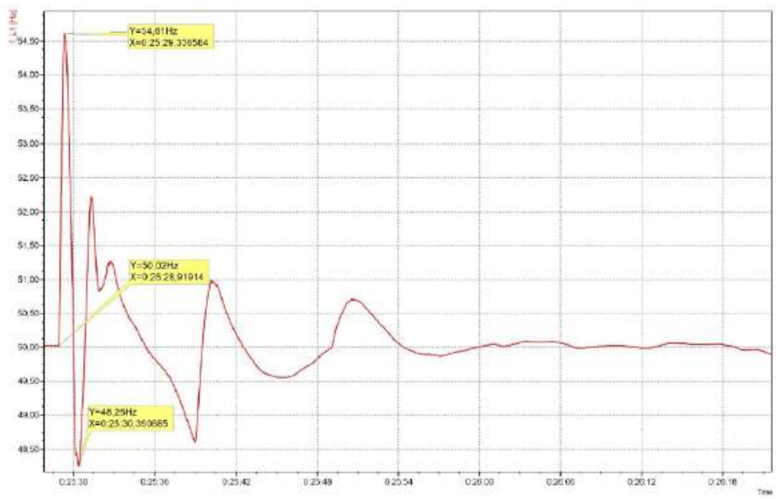

FIGURE 2.17 – *Vrchlabí demonstrator – Frequency curve recorded at the beginning of the islanding test [13].*

It can be concluded that the islanding test was successful. According to the standard EN-50 160, the power quality was maintained during the transition and all the islanded operation. Although considerable voltage and frequency excursions occurred during the transition, these lasted a very short period of time.

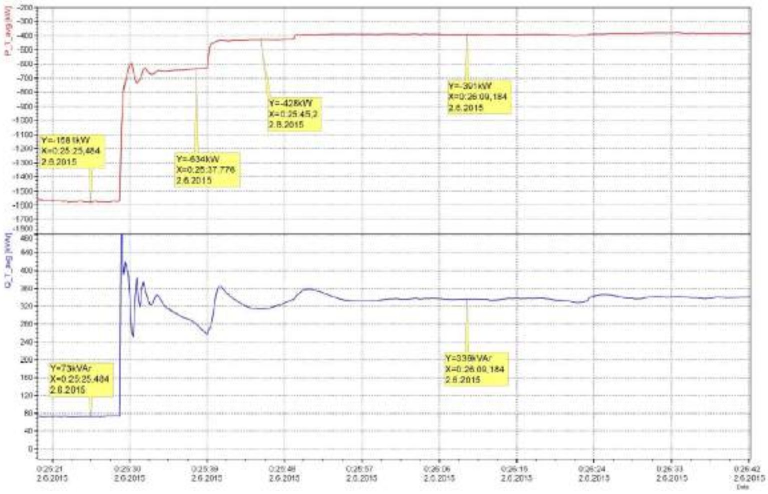

Figure 2.18 – *Vrchlabí demonstrator – CHP active and reactive power curves recorded at the beginning of the islanding test [13]. For both magnitudes, a negative value corresponds to a power injected by the CHP unit to the grid.*

2.1.3.5.2 Black-start test. Figure 2.19, Figure 2.20 and Figure 2.21 present some recordings performed during a black-start test within the Vrchlabí demonstrator. Hereafter, a description of the events observed during the test and reported in the figures is given.

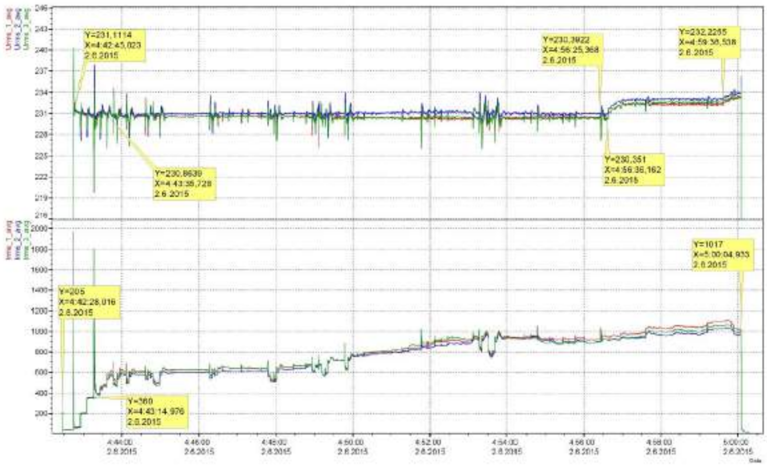

Figure 2.19 – *Vrchlabí demonstrator – Voltage and CHP current curves recorded during the black-start test [13]. The measurements were taken in the CHP facility, on the LV side.*

- Before starting the CHP unit, the Islanding Controller disconnected the islanded area from the main grid. Then, it opened all the CBs of the secondary substations of the islanded area. Finally, the Islanding Controller disconnected the CHP unit from the area (by opening the MV feeder connecting the secondary substation TU-1435 to the CHP).
- At 4:42:45, the Islanded Controller started the CHP unit. After that, the LV grid and transformer within the CHP facility were energized. Then, the flexible load (water heater) was connected and the active power delivered by the CHP unit increased.
- Around 4:48:10, the feeder between the CHP facility and the secondary substation TU-1435 was closed. In consequence, this substation and the whole 35 kV grid of the islanded area were energized.

- The LV feeders were gradually reconnected to the islanded area by closing the CBs placed at the secondary substations. The last LV feeder was reconnected at 4:56:25.
- The test finished at 4:59:57.

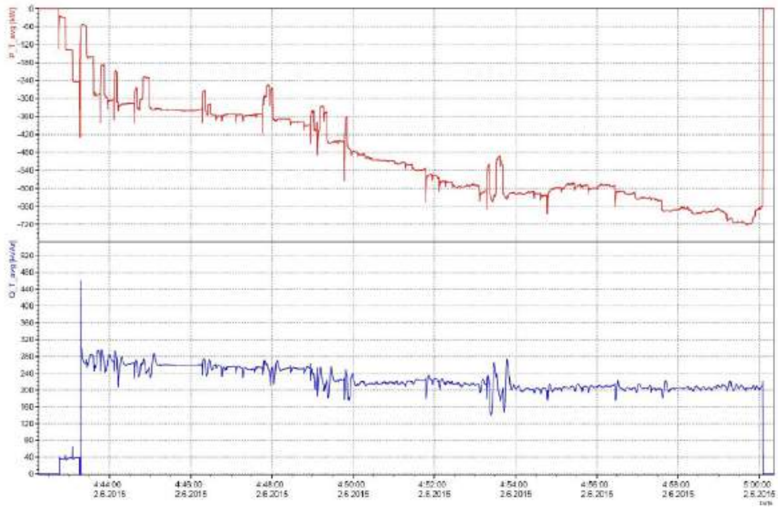

FIGURE 2.20 – *Vrchlabí demonstrator – CHP active and reactive power curves recorded during the black-start test [13]. For both magnitudes, a negative value corresponds to a power injected by the CHP unit to the grid.*

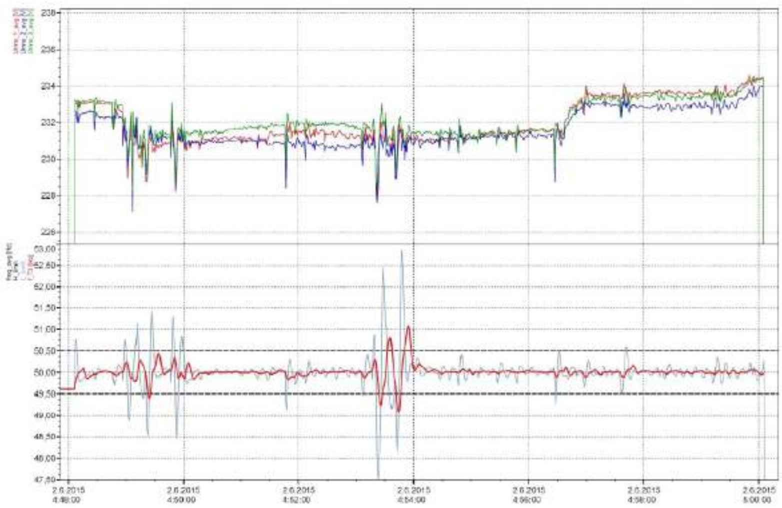

FIGURE 2.21 – *Vrchlabí demonstrator – Voltage and frequency curves recorded during the black-start test [13]. Measurements from the secondary substation TU-1435, in LV.*

It can be concluded that the black-start procedure was successful. The voltage and frequency excursions that took place remained within the power quality limits stated by the standard EN-50 160.

2.1.4 GRID4EU – Nice Grid (France)

2.1.4.1 Context and objectives of the demonstrator

The Nice Grid demonstrator was developed in the GRID4EU project, and its development was led by Enedis [14], the main French DSO. The major objectives of the demonstrator were [11]:

- To design a large-size smart grid with storage devices and a massive integration of PV production enabling to test several distributed resources control levels;
- To quantify the impact of coordinated actions over the grid capacity to absorb the transited energy, while maintaining the quality and security expected on the regional grid;
- To favour the emergence of new consumers' sustainable behaviors, testing the supply-demand adjustment according to grid flexibility constraints and deposits.

To achieve those objectives, several use cases were defined. The last one is discussed here.

1. Peak demand reduction;
2. Massive integration of PV production in LV grids;
3. Encouragement of residential customers to adopt smarter habits;
4. Islanding of a LV area.

The Nice Grid demonstrator was located in the Provence-Alpes-Côte d'Azur region, which is characterized by a high penetration of PV generation. More specifically, the distribution grid of Carros town (11,500 inhabitants) was chosen to implement the demonstrator. Before this, all the solutions designed for the Nice Grid demonstrator were validated in the "Concept Grid" [15], a smart grid testing facility that belongs to EDF R&D [16].

The GRID4EU project lasted from January 2012 until December 2015, but the French consortium decided to extend the project and the Nice Grid demonstrator remained in operation until the end of 2016. At present it is no longer in operation.

2.1.4.2 Demonstrator grid composition

For the islanding use case, a particular district of Carros was chosen: i.e. the 1^{st} Street District located in the industrial area of the town. Figure 2.22 and Figure 2.23 show two diagrams of the distribution grid supplying the 1^{st} Street District. This area was chosen due to the high concentration of PV generation, which caused significant reverse power flows from LV to MV grid. In islanded operation, an excessive PV may be beneficial since the surplus energy can be stored in a BESS and released later, thus extending the island duration.

The islanded area consists of a LV grid with a BESS, PV plants and industrial consumers. The BESS was specifically installed for the GRID4EU project. Some of its features are:

- The BESS had a rated power of 250 kVA and an energy capacity of 620 kWh;
  - The maximum power was limited to 250 kVA since it corresponded to the maximum admissible current of the LV feeders of the 1^{st} Street District. For this reason, the BESS power was not enough to supply/absorb the maximum net consumption of the LV grid. Therefore, islanding tests were only possible in mid-season (when there was not too much PV power and/or not too much consumption);
  - The battery capacity was, to a large extent, determined by the battery provider, since the company only offered a few battery models with very specific sizes;
- The battery cells were Li-Ion (NCA);
- The BESS control system and the PCS, composed by four parallel inverters, were commercial products that had to be partially customized for the project. More specifically:
  - The control system was adapted so the BESS would behave as a voltage source (otherwise, the chosen commercial inverters behave as current sources);
  - A neutral connection was added to the inverters AC side, so the BESS could manage unbalanced loads.

FIGURE 2.22 – *Nice Grid demonstrator – First street district and its distribution grid [17].*

The three PV plants, 140 kWp, 90 kWp and 200 kWp respectively, were already installed before the project. The inverters of these plants only operate in grid-feeding mode. However, as the plants belong to private users, Enedis did not have control over the inverters and could only connect/disconnect them.

In the context of the GRID4EU project, a control strategy was designed to reduce the PV production in case the BESS reached its maximum State of charge (SoC) during the islanded operation. In this strategy, the BESS control system would send a signal to the PV plants by reducing the islanded area frequency. After measuring this frequency reduction, the PV plants would reduce its production by means of a P/f droop implemented in the PV inverters control system. This control strategy was successfully implemented in laboratory tests (using the platform "Concept Grid"). In addition, it was verified that some of the commercial PV inverters installed in the Nice Grid demonstrator had a built-in P/f function, which was disactivated. However, the P/f control strategy was never tested in the field, since the activation of this function was not straightforward and the PV inverters did not belong to Enedis. The loads supplied by the LV grid had the following characteristics:

- There were eight industrial clients with a maximum total active power consumption of 230 kW (winter peak);
- The loads were very varied: cooling, lighting, computers, induction motors, etc.;
- Enedis did not have control over these loads, and could only connect/disconnect the industrial clients.

2.1.4.3 Equipment used for the islanding use case

2.1.4.3.1 Automation and control. The following automation equipment was used for the islanding transition:

- A remotely controlled CB (named "Islanding CB") that allowed to island the LV grid from the rest of the grid was installed right downstream of the MV/LV transformer. To avoid problems during the resynchronization, a rapid CB was selected having less than 0.1 s between the moment when the CB received a command and the moment when its closing was completed (the rapid selected CB was standard and commercially available);
- The control system of the BESS;

- An Islanding Controller, which was specifically conceived for the Nice Grid demonstrator. It was an automation unit which communicated and sent commands to the Islanding CB and the BESS. It also communicated with the measuring devices of the islanded area. Its function was to coordinate the actions of all these elements, to automatically implement different operation strategies, depending on the operating mode of the area (e.g. grid-connected or islanded). It was composed by a PLC, an HMI, and an electronic board to allow the Islanding Controller to communicate with the other devices.

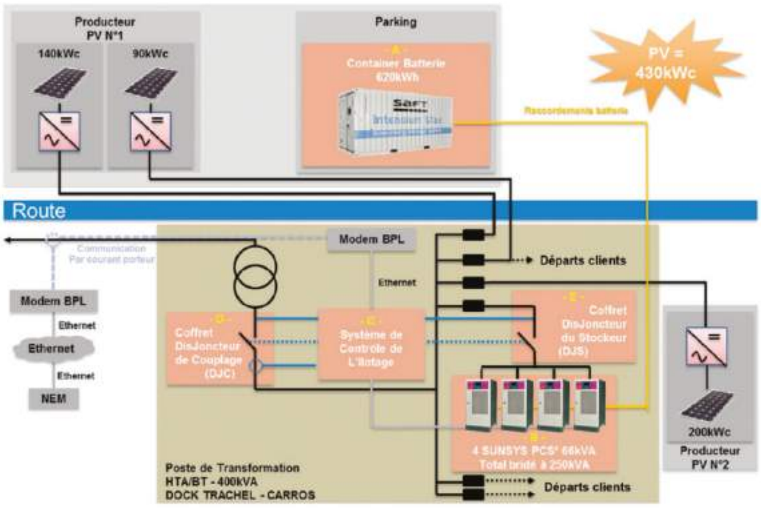

Figure 2.23 – *Nice Grid demonstrator – Diagram of the islanded area [17].*

2.1.4.3.2 Measurement. All the measurements needed to control de islanded area were taken with conventional measuring equipment. As explained before, there were communication links between these devices and the Islanding Controller which collected and processed the measurements.

2.1.4.3.3 Supervision. In the Nice Grid demonstrator, the Islanding Controller automatically performed most of the actions for the islanding transition. However, Enedis operators needed to have some control over the islanded area, since some tasks had to be conducted manually (e.g., order to start a scheduled islanding). In addition, these operators had to monitor the island voltage and frequency. To do so, the Islanding Controller HMI was implemented.

Enedis operators could only perform these control and supervision tasks locally, at the secondary substation were the Islanding Controller was installed. The islanding equipment was not integrated in the SCADA normally used by Enedis operators to supervise the distribution grid of Carros, since it was technically complicated and the Nice Grid project was temporary. In addition, it was advantageous to always have operators on-site during the islanding tests. As a matter of fact, in case of incident, the reaction time was minimized and this was considered essential because of the industrial clients within the islanded area.

2.1.4.3.4 Protection. The protection scheme of the islanded area was typical of a LV grid:

- The neutral cable was distributed;
- In the section of the LV feeders that belongs to Enedis:
  - There was an overcurrent protection at the head of each feeder (fuse), downstream of the MV/LV transformer;

  - The neutral was grounded at several points along the feeders.
- Inside the clients' installations:
  - The neutral was isolated;
  - There were overcurrent and differential protections installed upstream of the loads.

This protection scheme did not have to be adapted for the islanded operation. Indeed, it was proved that for all potential SCs, either the protections of the clients would actuate or the BESS would auto-disconnect because its internal protections would detect the undervoltage and actuate. In addition, it was highlighted through field tests that the BESS could deliver enough current to activate the clients overcurrent protections. However, the SC current was not enough for the fuses at the head of the LV feeders to actuate.

The major inconvenience of this protection scheme was that the selectivity was not maintained in islanded operation. For example, the BESS protections would actuate for a fault that should have been resolved by disconnecting one feeder, and this would lead to a generalized outage of the island. Nevertheless, this was not considered a big issue in the Nice Grid demonstrator, since it was a temporary project and islanding was only performed for testing purposes and not during normal operation.

2.1.4.3.5 Telecommunication. For the "Islanding of a LV area" use case of the Nice Grid demonstrator, a very simple telecommunication network was implemented. The Islanding Controller was connected to the BESS, to the Islanding CB and to the measuring devices using wired Ethernet links. This was possible since all the mentioned elements were very close since they were actually placed in the same secondary substation. This Ethernet network was isolated since the Islanding Controller did not need to be connected with a superior Enedis SCADA system. Indeed, as explained above, all the supervision and control tasks were undertaken using the HMI of the Islanding Controller.

It was not necessary to impose high speed constraints for the islanding transition to work properly (e.g., to achieve a proper resynchronization of the islanded area to the main grid). Moreover, since the telecommunication network was isolated, no cybersecurity assessments were undertaken. Finally, the telecommunication outage was not considered a relevant risk since all the telecommunication links were wired connections implemented in the secondary substation where operators were always present during the islanding tests.

2.1.4.4 Modes of operation of the islanding use case

2.1.4.4.1 Grid-connected operation. In this mode, the BESS was controlled by Enedis operators. If they wanted to perform what was called a "scheduled islanding", the operators had to prepare the BESS the day before (D-1). To do that:

1. The operators analyzed the feasibility of performing the intended islanding (which started at a specific time and lasted a specific number of hours);
2. If the intended islanding for the next day was feasible, the operators sent the necessary commands for the BESS to achieve the required SoC at the beginning of the islanding.

2.1.4.4.2 Transition from grid-connected to islanded operation. A seamless transition from grid-connected to islanded operation was achieved, without needing to disconnect any of the loads of the islanded area. As explained before, any scheduled islanding was prepared by Enedis operators the day before the event (D-1). Then, on the day and time scheduled for the event, the following procedure was executed.

1. An Enedis operator sent the Islanding Controller an order to start the islanding procedure;

2. The Islanding Controller commands the BESS to provide/absorb the net power consumed/produced in the islanded area. With this, the current flowing through the Islanding CB decreased to zero (or a very low value), which allowed for a smoother transition;
3. After that, the Islanding Controller sent a command to open de islanding CB.

2.1.4.4.3 Islanded operation. In this mode, the Islanding Controller ensured the voltage and frequency stability by commanding the BESS PCS, which worked as a voltage source.

2.1.4.4.4 Transition from islanded to grid-connected operation. In case of a scheduled islanding, the transition back to grid-connected operation was performed automatically by the Islanding Controller. This system would initiate the transition once the scheduled islanded period was finished. The following resynchronization procedure was executed:

1. The Islanding Controller compared the voltage waveform of the island and of the MV main grid. To synchronize both waveforms, it sent control commands to the BESS PCS;
2. Once the waveforms were synchronized, the Islanding Controller sent a command to close the islanding CB, reconnecting the islanded area to the main grid.

However, if the power or energy limits of the BESS were reached during islanded operation, the BESS would automatically disconnect, leading to an outage in the islanded area.

2.1.4.4.5 Black-start. The Nice Grid demonstrator had black-start capability. If the islanded area was operating in grid-connected mode and there was an outage in the main grid, the Islanding Controller automatically performed a black-start. This process was called an "unintended islanding" and consisted on the following steps:

1. Once the Islanding Controller detected the outage of the main grid, it opened the BESS CB and waited for 3 min (to allow for a potential main grid restoration);
2. If the 3 min passed without the main grid restoration, the Islanding Controller checked the capacity of the installation to ensure a black-start;
3. If it was feasible, the black-start procedure started:
    a) The Islanding Controller sent a command to open the islanding CB;
    b) Then, the Islanding Controller commanded the BESS (working as a voltage source) to increase its output voltage to approximately 20 % of the nominal voltage;
    c) After that, the Islanding Controller sent a command to close the BESS (energizing the whole islanded area);
    d) The Islanding Controller commanded the BESS PCS to progressively increase its output voltage to the nominal value. This was done to avoid inrush currents.

Once the black-start sequence was finished, the Islanding Controller ensured the voltage and frequency stability by commanding the BESS PCS. The islanded operation could be finished because of two different reasons:

- If the BESS reached its power or energy limits before the main grid was restored, the Islanding Controller stopped the islanded operation (islanded area again in black-out);
- If the main grid was restored, the Islanding Controller detected it and performed the reconnection of the islanded area to the main grid, following the resynchronization procedure described in Section 2.1.4.4.4.

2.1.4.5 Islanding tests results

This section describes the results obtained during two islanding tests conducted in the Nice Grid demonstrator: the first test corresponded to a scheduled islanding (seamless transition from grid-connected to islanded mode) and the second corresponded to an unintended islanding (outage followed by a black-start of the islanded area). More specifically, the Key performance indicator (KPI)s calculated with the measurements recorded during the tests are presented.

Table 2.2 presents the voltage deviation obtained during the islanding tests. More specifically, the KPI is computed as the standard deviation of each phase-neutral voltage with respect to its nominal value (230 V). The input data used for the KPI computation are phase-neutral voltage measurements taken each 200 ms at the point of connection of the BESS.

TABLE 2.2 – *Nice Grid demonstrator – Voltage deviation during the islanding tests [18].*

Test	Duration of islanding	Voltage deviation during islanding Relative standard deviation (%) Evaluation criterion ≤10 % (according EN-50 160)								
		To islanding			Islanding			Grid-connecting		
		Ph.1	Ph.2	Ph.3	Ph.1	Ph.2	Ph.3	Ph.1	Ph.2	Ph.3
Scheduled islanding	5 h	1.70 %	2.17 %	1.69 %	0.68 %	0.63 %	0.81 %	0.62 %	0.99 %	0.56 %
Unintended islanding	2 h	N.A.	N.A.	N.A.	0.29 %	0.24 %	0.25 %	0.65 %	0.73 %	0.67 %
Average on three phases		1.86 %			0.48 %			0.71 %		

It is important to clarify that the values obtained during the black-start (transient towards islanding in the unintended islanding test) are not considered because the large voltage increase (from 0 V to 230 V) would distort the results.

On average, during the islanding period, the voltage did not deviate more than 0.48 % from its nominal value. Regarding the transients, the average value of the voltage deviation increased to 1.86 % and 0.71 %. However, these values are considerably smaller than the threshold indicated by the norm EN-50 160.

Table 2.3 presents the frequency deviation obtained during the tests. The KPI is computed as the standard deviation of the frequency of one phase with respect to its nominal value (50 Hz). The input data used for the KPI computation are measurements recorded each 200 ms at the point of connection of the BESS. The values obtained during the black-start are not considered, since the large voltage variation would distort the results.

On average, during the islanded period, the frequency deviated 0.07 % from its nominal value. The deviation increased to 0.16 % during the transition from islanded to grid-connected operation, but this value is still small with respect to the threshold from the norm EN-50 160.

Finally, Table 2.4 presents the Total harmonic distortion (THD) rate obtained during the tests. The input data used for the KPI evaluation are phase-neutral voltage measurements taken each 200 ms at the point of connection of the BESS. The values obtained during the black-start are not considered, since the large voltage increase would distort the results.

The table shows that the threshold imposed by EN-50 160 was satisfied both during islanding and during the transitions to/from grid-connected operation.

Table 2.3 – *Nice Grid demonstrator – Frequency deviation during the islanding tests [18].*

Test	Duration of islanding	Frequency deviation while islanded (Phase 1) Relative standard deviation (%) Evaluation criterion ≤1 % (according EN-50 160)		
		Islanding	Islanded	Grid-connecting
Scheduled islanding	5 h	0.04 %	0.10 %	0.14 %
Unintended islanding	2 h	N.A.	0.03 %	0.18 %
Average		0.04 %	0.07 %	0.16 %

Table 2.4 – *Nice Grid demonstrator – THD during the islanding tests [18].*

THD rate (%) Evaluation criterion ≤8 %, up to 40^{th} harmonic (according EN-50 160)									
Test	Transient to islanded								
	V_1			V_2			V_3		
	min	avg	max	min	avg	max	min	avg	max
Scheduled islanding	2.71	2.99	4.69	2.33	2.47	3.92	1.82	2.59	4.57
Unintended islanding	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Average on three phases	2.68								
Test	Islanding								
	V_1			V_2			V_3		
	min	avg	max	min	avg	max	min	avg	max
Scheduled islanding	1.62	2.33	3.22	0.99	1.62	2.47	0.89	1.46	2.4
Unintended islanding	0.7	1	1.6	0.8	1	1.4	0.7	0.9	1.2
Average on three phases	1.38								
Test	Transient towards main grid								
	V_1			V_2			V_3		
	min	avg	max	min	avg	max	min	avg	max
Scheduled islanding	1.72	2.15	2.84	1.21	1.84	2.68	1.01	1.75	2.99
Unintended islanding	2.15	2.47	3.37	1.11	1.62	3.17	1.38	1.82	3.5
Average on three phases	1.94								

2.1.5 INTERFLEX – Nice Smart Valley – Lérins Islands (France)

2.1.5.1 Context and objectives of the demonstrator

Nice Smart Valley is the French demonstrator of the Interflex project [19], whose general objective was to investigate the use of local flexibilities to relieve distribution grid constraints. The Nice Smart Valley demonstrator was developed by a consortium led by Enedis, the main French DSO [14]. Three use cases were defined for the demonstrator:

1. Development of a MV islanded system to reduce the impact of outages on the grid;
2. Research of viable business models for grid-connected BESS, based on a multiservice approach which combines ancillary services, electrical grid constraints management, self-consumption and cloud storage;
3. Implementation of flexibility mechanisms to manage distribution grid constraints.

Actually, Nice Smart Valley is composed of three different demonstrators (one for each use case). The demonstrator regarding the islanded operation, which is the main interest of this report, was implemented on the grid of the Lérins archipelago (France). This archipelago consists of two islands, Sainte Marguerite and Saint Honorat, located near the city of Cannes. The specific objectives of the Lérins Islands demonstrator were:

- To design and test an operational solution allowing a DSO to operate a MV islanded microgrid based on BESSs without rotating machines. The islanding would be used in case of an outage on the main grid;
- To design the contractual relationships between the DSO and third-party aggregator, so that the usage of DER by the DSO complies with the Clean Energy Package (restrictions regarding storage ownership for regulated bodies). For example, the DSO can use BESSs owned by a third party by creating a new service and a new contractual framework;
- To determine the conditions of profitability of the designed solution.

Before the construction of the demonstrator, the solutions designed were validated in the "Concept Grid" [15], a smart grid testing facility that belongs to EDF R&D [16].

The Interflex project was operational between 2017 and 2019.

2.1.5.2 Demonstrator grid composition

The Lérins Islands are supplied by a 10 kV submarine cable of 1.5 km, placed on a shallow bottom. This archipelago was chosen for demonstrator because in case of an incident causing the loss of the submarine cable, an excessive time was needed to recover the power supply of the islands. The time of routing and installation of auxiliary gensets can be quite long (around 24 h) and repairing the cable might take several weeks. The MV grid of the archipelago is composed by five secondary substations: one in the Saint Honorat Island and four in the Sainte Marguerite, as shown on Figure 2.24.

As shown on Figure 2.24, two BESSs were installed for the Interflex project: the first storage facility, named "Master BESS", is owned and maintained by Enedis, and the second storage facility, named "Slave BESS", is owned and maintained by a third-party aggregator, the company ENGIE [21]. One of the main tasks of the project was to define the contractual relationships between Enedis and ENGIE, so that the Clean Energy Package would be respected, Enedis wishing to improve the continuity of supply of the Lérins Islands grid[1].

Hereafter, some of the main characteristics of the Master BESS are reported.

[1] After studying different possibilities, the following solution was chosen. An aggregator A (ENGIE) has installed a storage facility (the Slave BESS) on the islands, but this system is not enough to secure the electric supply. Since no other aggregator intends to develop a storage facility (Clean Energy Package restriction), the

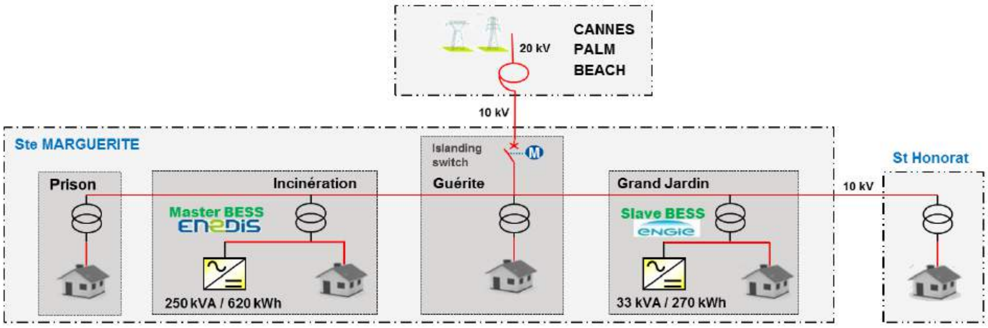

Figure 2.24 – *Nice Smart Valley demonstrator – Diagram of the distribution grid [20].*

- The BESS had a rated power of 250 kVA and an energy capacity of 620 kWh. No sizing task had to be performed for this BESS since it was not specifically manufactured for the Lérins Islands demonstrator. The BESS was conceived for a previous research and development project (the Nice Grid demonstrator presented in Section 2.1.4);
- The battery cells are Li-Ion (NCA);
- The PCS is the same that was used for the Nice Grid demonstrator. It is composed by four parallel commercial inverters that were partially customized for the Nice Grid project. More specifically, a neutral was added to the AC side of the inverters, so the BESS could manage unbalance LV loads;
- The BESS control system, named “Master PLC”, allows to implement different control modes depending on the mode of operation of the demonstrator:
  - In grid-connected operation, the Master BESS is controlled in grid-feeding mode. The active and reactive power commands are set by a third-party aggregator, which uses the BESS according to its own objectives (e.g. to maximize economic benefit through peak shaving). This aggregator is ENGIE, the company that owns and manages the Slave BESS, but it could be another aggregator. A contract was signed between the DSO and ENGIE to regulate how the aggregator can use the Master BESS during grid-connected operation;
  - In islanded operation the Master BESS is controlled in grid-forming mode, ensuring the voltage and frequency stability of the island. This functionality is automatically performed by the Master PLC (ENGIE losses control over the Master BESS).

DSO shall install another BESS on the islands (the Master BESS). In grid-connected operation, the BESSs must be operated in the following manner:

- The DSO uses the services of an aggregator B to add value to the Master BESS (in this case, the aggregator is still ENGIE, but it could be a different one). ENGIE operates the BESS according to its own objectives, but it must ensure that the energy available is always 50 % or more of the BESS capacity in order to guarantee enough energy for islanded events;
- The aggregator A uses the Slave BESS according to its own objectives.

In islanded operation, the BESSs must be operated in the following manner:

- The DSO gains control of the Master BESS, which becomes the grid-forming unit of the island;
- If needed, the DSO may ask to take control over the Slave BESS, with the aim of ensuring the power balance of the islanded area. The aggregator A is remunerated only if it accepts to offer this service. The company is not obliged to do so nor to guarantee the availability of part of its storage for islanding. The DSO must not execute more than two charges/discharges per day on the Slave BESS (to avoid premature ageing).

Hereafter, some of the main characteristics of the Slave BESS are reported.

- The BESS has a rated power of 33 kVA and an energy capacity of 274 kWh;
- The battery cells are Li-Ion;
- The BESS PCS consists on an inverter of 100 kVA (derated to 33 kVA);
- The BESS control system, named "Slave PLC", allows to implement different control modes depending on the mode of operation of the demonstrator:
    - In grid-connected operation, the Slave BESS is controlled in grid-feeding mode. The active and reactive power commands are sent to the Slave PLC by the BESS owner (ENGIE), who manages the BESS according to its own objectives;
    - In islanded operation, the Slave BESS is also controlled in grid-feeding mode. Generally, ENGIE continues setting the active and reactive power commands. If the SoC of the Master BESS is too low, the Master PLC can send a request to the Slave PLC in order to use the Slave BESS to ensure the power balance of the islanded area. If the request is accepted by ENGIE, the Master PLC sends active and reactive power commands to the Slave PLC.

Regarding the loads of the archipelago:

- There are 56 users among whom five have nominal powers between 36 and 250 kVA;
- The economic activity of the islands relies mainly on tourism, so most of the loads are the typical of a semi-urban area. However, there is also a winery and a small shipyard;
- The consumption goes from 60 kVA to 250 kVA in winter, and from 90 kVA to 450 kVA in summer (peak due to tourism);
- None of these loads is controllable by ENEDIS operators, which can only connect/disconnect groups of users.

Finally, regarding the generation, there are no power production plants in the Lérins Islands. In grid-connected operation, all the power consumption must be covered by the BESSs and with the power imports from mainland. In islanded operation, all the power consumption must be delivered by the BESSs.

Comparing the BESSs sizes to the consumption of the Lérins Islands, it is clear that the two BESSs installed are not enough to sustain islanded events during the time required to repair the feeding submarine cable (2-3 weeks). In fact, islanding is not possible in some periods of the year, since the instantaneous power consumed in the Lérins Islands can surpass the rated power of both BESSs. In the periods when an islanded operation is possible, the BESSs could theoretically sustain islanded events of up to 8 h depending on the consumption profile the day of the event. In practice, islanding tests lasting up to 4 h have been performed.

Nevertheless, despite not having achieved long islanded durations, the two installed BESSs were enough to test and validate the selected solution for the islanded operation of the Lérins Islands, which was the main objective of the demonstrator. A scientific work associated with the project, on the scalability and replicability analysis of the island microgrid concept showed (via a theoretical analysis) that it is technically possible to achieve an islanded duration of 21 days in the Lérins Island. However, even if PV, BESS and DSM are used, the solution would be "too cumbersome and expensive to be realized in practice" at that location [22].

2.1.5.3 Equipment used for the islanding use case

Figure 2.25 shows the different devices installed in the Lérins Island demonstrator, which are described in the following sections.

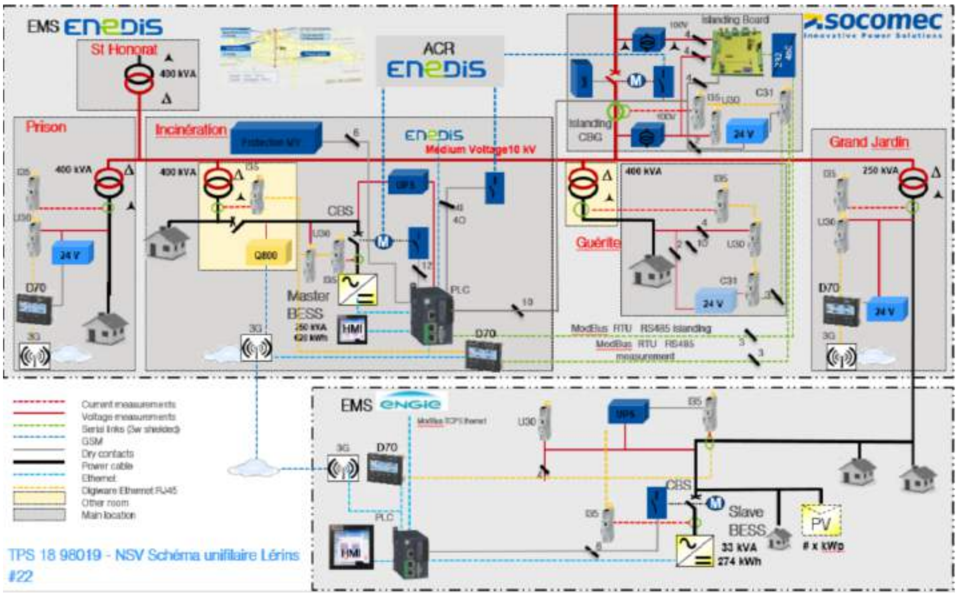

FIGURE 2.25 – *Nice Smart Valley demonstrator – Diagram of the MV grid, including the automation, measurement, telecommunication and supervision equipment installed in the demonstrator. Although it was initially planned to install PV plants on the islands (as shown on the image), this was finally not done [20].*

2.1.5.3.1 Automation and control. The following automation devices are used for the different stages of the islanding transition.

- A remotely controlled CB (named “Islanding CB”), installed at the PCC of the Lérins Islands grid with the 10 kV cable coming from mainland;
- An electronic board (named “Islanding Board”) which piloted the changes from grid-connected operation to islanded operation and vice-versa, ensuring seamless transitions. To do that, it received the measurements taken upstream and downstream of the Islanding CB, it processed them and it sent commands to the Master PLC and the Islanding CB. This electronic board was specifically developed for the Lérins Island demonstrator;
- The two PLCs controlling respectively the Master and the Slave BESS. Both devices were standard commercially available PLCs, and their software had been specifically configured for the project.

2.1.5.3.2 Protection. Since the islanded area comprised both MV and LV lines, the protection schemes of both levels were revised and adapted to ensure that they would work properly in islanded operation. At the LV level:

- The original protection scheme was the one typically found in a French LV grid:
  - The neutral was distributed;
  - In the section of the LV feeders that belongs to the DSO there were:
    - ⋆ Overcurrent protections at the head of each feeder (fuse), right downstream of the MV/LV transformers;
    - ⋆ Grounded neutral (at several points along the feeders).
  - Inside the users’ installations there were:
    - ⋆ Isolated neutral;
    - ⋆ Overcurrent and differential protections upstream of the loads.

- The analysis concluded that this protection scheme was enough for islanded operation:
  - It was proven that a fault in any location of the LV feeders would be correctly detected either by one of the LV fuses or by the current saturation and disconnection of the Master BESS;
  - It should be clarified that the fault detection through inverter saturation only worked because the Master BESS was rather small in comparison with the islanded area consumption. If this were not the case, it would have been necessary to adapt the LV protection scheme;
  - It is also important to stress that relying on BESS saturation for LV fault detection presented a disadvantage. Indeed, a LV fault led to the outage of the whole islanded area. If the fault had been detected by a local protection device, the affected LV feeder would be disconnected and the rest of the islanded grid would continue operating.

At the MV level:

- The original protection scheme was the following:
  - 3-wire lines (3 phases, non-distributed neutral);
  - Neutral connected to ground through a small impedance in the primary substation.
- Since the primary substation feeding the Lérins Island was located upstream of the Islanding CB (in mainland), the connection of the MV neutral to ground was lost when the Islanding CB was opened. Because of this, the MV protection scheme had to be adapted for the islanded operation. More precisely:
  - A maximum homopolar voltage relay (59N) was installed to detect phase-ground and phase-phase-ground faults. The Master PLC activated the relay in islanded operation and deactivated it for grid-connected operation. This relay was a commercially available product;
  - Other faults were detected through the saturation and disconnection of the Master BESS inverters.

2.1.5.3.3 Measurement. To achieve seamless transitions between the grid-connected and the islanded operation, typical MV measuring devices (i.e. voltage and current transformers) were installed upstream and downstream of the Islanding CB. The secondary circuits of these transformers were connected to the Islanding Board.

Besides this, specialized measuring devices were installed in LV to properly monitor the islanded area. More specifically, there was a commercial multi-metering equipment in each secondary substation and in the PCC of the BESSs with the grid. In addition, part of this multi-metering equipment was used to transfer to the Master PLC the measurements taken around the Islanding CB. The equipment consisted of:

- Current sensors and an electronic module to collect and analyze current measurements. The module allows, for example, to detect imbalances or to perform harmonic analysis;
- An electronic module to take and process voltage measurements. The module allows, for example, to perform harmonic analysis or to detect voltage dips and surges;
- A concentrator that collects the measurements from the previous modules (using Ethernet communication), displays them on a local interface and sends them to the cloud (using a modem and an antenna for GSM communication).

2.1.5.3.4 Supervision. As explained in Section 2.1.5.3.5, the Lérins Island demonstrator was communicating with the Enedis control center of Toulon. More precisely, the demonstrator was integrated in the SCADA used by the operators of this control center, which allowed them to supervise the functioning of the demonstrator and to execute control actions.

This integration was not straightforward because the SCADA could not represent BESSs. Moreover, since the Master BESS was Enedis' property, it could not be represented as a production plant. As a matter of fact, the production plants have a quite simple representation, since they do not belong to the DSO and are not controlled with the Enedis SCADA. It needed to be represented as an Enedis operating asset so to allow Enedis operators to be able to monitor and control the complete BESS installation.

2.1.5.3.5 Telecommunication. Two kinds of communication were implemented in the Lérins Islands demonstrator: one named "hard real-time communication" and another one named "soft real-time communication".

The hard real-time communication aimed at establishing a very fast communication channel between the Master PLC and the devices installed around the Islanding CB (i.e. islanding board and measurement devices). This fast data exchange was needed to properly synchronize the islanded area and the grid voltage during the transition from islanded operation to grid-connected operation.

Due to the communication speed requirement, serial RS485 links were used. However, several problems were encountered:

- For instance, due to the cable length (more than 600 m), the signal was slightly perturbed by the cable reflections;
- Another important problem was the appearance of a common mode between the transmitters and the receivers of the RS485 links. Some switching events (e.g., Islanding CB closing, Master BESS contactors closing) led to significant perturbations of this common mode voltage. In consequence, the RS485 gateways had to be reinforced with additional surge protections and filters.

It was concluded that these problems would have been avoided with an optical fiber, which would have provided a high enough band-rate for the synchronization purpose.

The soft real-time communication aimed at interconnecting the measuring devices installed in the islanded area, the control devices (Master and Slave PLC) and the control centers of Enedis and ENGIE. This communication allowed to implement the operation strategies designed for the demonstrator (e.g., it allowed Enedis operators to supervise the measurements of the islanded area, it allowed the Master PLC to send commands to the Slave PLC).

3G/4G GSM was chosen for the soft real-time communication. Ethernet links were connecting the measurement data concentrators and the PLCs to modems and antennas located in different areas of the island. The modems communicated to a cloud via 3G/4G GSM. This cloud was also accessible by Enedis' and ENGIE's control centers (see Figure 2.25).

Radio communication was chosen to avoid long cables in the Lérins Islands (landscape preservation constraint). More specifically, 3G/4G GSM was chosen because it is a technology of common use since the infrastructure already exists and commercial modems can be used. Also, the information bandwidth is enough, and the data volume is not limited (there is just a higher price to pay if the volume increases).

Although the GSM communication was rather easy to implement, it presented the drawback of not being fully controllable, since it relayed on infrastructure used for public purposes. For example, the communication bandwidth may decrease if there are too many tourists on their island using their cellphones.

To have a safer and more reliable communication between the Master PLC and the Slave PLC in islanded operation, the grid frequency could have been used as a communication vector.

The Master PLC would decrease the grid frequency if it SoC was too low. Then, the Slave BESS would measure this frequency decrease and react by increasing its power output.

2.1.5.4 Modes of operation of the islanding use case

2.1.5.4.1 Grid-connected operation. As explained above, in grid-connected operation the Master BESS and the Slave BESS worked in grid-feeding mode. The active and reactive power commands of both BESSs were set by ENGIE (aggregator independent of Enedis), who tried to maximize the economic value extracted from both storage facilities. However, it had to always ensure that the energy stored in the Master BESS was at least 50 % of its capacity, to be able to sustain a potential islanding event.

2.1.5.4.2 Transition from grid-connected to islanded operation. Two types of transitions were possible. In both cases, the transition was executed in a seamless way without the need of power cuts and load shedding. The first transition consisted on the following steps:

1. An Enedis operator verified if the islanding was possible by checking the SoC of the BESSs and the consumption predictions for the Lérins Islands;
2. The operator sent a command to the Islanding Board to start the islanding procedure;
3. The Islanding Board measured the current flowing through the Islanding CB. Then, it sent power commands to the Master BESS in order to balance the power generation/consumption of the islanded area. This propitiated a smoother transition;
4. Once the current flowing through the Islanding CB was null, the Islanding Board opened the CB and sent a command to the Master PLC. Then, the Master BESS started working in grid-forming mode, ensuring the voltage and frequency stability of the islanded area. The control of the Master BESS in grid-forming mode was performed by the Master PLC in a fully automatic way (no operator commands are needed).

If a faster transition was needed, the next steps may be executed:

1. An Enedis operator verified if the islanding was possible by checking the SoC of the BESSs and the consumption prediction for the Lérins Islands;
2. The operator opened the Islanding CB and sent a command to the Master PLC, which started controlling the Master BESS in grid-forming mode. This control was performed in a fully automatic way and no operator commands were needed. Since there might be power flowing through the Islanding CB before its opening, considerable voltage and frequency excursions may take place during the transition. Nevertheless, the Master BESS ensured that the voltage and the frequency remained within acceptable limits.

2.1.5.4.3 Islanded operation. As stated above, the Master BESS started working as the grid-forming unit of the demonstrator for the islanded operation. The Slave BESS continued working in grid-feeding mode and, in principle, ENGIE continued to set the active and reactive power commands.

If the Master BESS discharged below a predefined threshold (named "SoC premin"), the Master PLC sent a support request to the Slave PLC. In this way, the Slave BESS helped the Master BESS to maintain the power balance of the islanded area. In practice:

1. The Master PLC checked if the Slave BESS had enough stored energy;
2. In that case, the Master PLC sent a request to the slave PLC defining the power the Slave BESS had to deliver/absorb and for how long;

3. If ENGIE accepted to deliver the requested support service, the Slave BESS changed its power output according to the received instruction. The Master BESS had not to require the Slave BESS to perform more than two complete cycles (2 charges/day and 2 discharges/day), to avoid premature ageing.

The islanding was disabled if:

- Any of the two BESSs reached their minimum SoCs;
- The total consumption of the island was over the maximum power of the BESSs. If this had to be avoided, Enedis operators had to manually disconnect a part of the load. No automation limited the load.

2.1.5.4.4 Transition from islanded to grid-connected operation. The transition back to grid-connected operation was performed in a seamless way thanks to a resynchronization process. In practice, the steps executed were the following.

- The operators sent a command to the Islanding Board to start the resynchronization procedure;
- The Islanding Board monitored the voltages upstream and downstream of the islanding CB. Then, it sent commands to the Master BESS to try to synchronize both voltages;
- Once both voltages were synchronized, the Islanding Board sent a command to close the Islanding CB.

2.1.5.4.5 Black-start. When the grid of the Lérins Islands was operating in grid-connected mode and there was an outage in the main grid, the islands could recover the power supply thanks to the black-start capability of the demonstrator. The procedure consisted of the following steps.

1. Once an Enedis operator detected an outage on the main grid, the operator opened the Master BESS CB and waited some minutes, in case the main grid could be rapidly restored. The operator also verified the feasibility of the black-start by checking the SoC of the BESSs and the consumption prediction for the Lérins Islands;
2. If the black-start was technically possible and the waiting time was over, the operator sent a command to the Master PLC in order to start the black-start procedure;
3. The black-start procedure was performed by the Master PLC in an automated way:
   a) The Master PLC sent a command to open the Islanding CB;
   b) Then, the Master PLC commanded the Master BESS (working in grid-forming mode) to progressively increase its output voltage to 80 V (approximately 20 % of 400 V, the nominal voltage);
   c) After that, the Master PLC sent a command to close the Master BESS CB (energizing the whole islanded area);
   d) The Master PLC commanded the Master BESS to progressively increase its output voltage to the nominal value. Thanks to this voltage ramp, the energization of the grid transformers and inductive loads did not generate inrush currents that the Master BESS PCS could not withstand.

Once the black-start sequence was finished, the Master PLC ensured the voltage and frequency stability by commanding the Master BESS.

There was also the possibility for the black-start procedure to start automatically. In that case, the Islanding Board would detect the outage of the main grid and sent the command to start the procedure. However, this functionality was normally deactivated for safety reasons.

2.1.5.5 Islanding tests results

This section presents the results obtained in one of the islanding tests performed in the Lérins Islands demonstrator. Figure 2.26 presents the waveforms recorded at the beginning of the test. Hereafter, a description of the various events that can be observed on the image (marked with green dashed lines) is reported.

- Initially, the grid of the Lérins Islands was connected to the distribution grid. The islands consumption was about 150 kW and 200 kVAr;
- At (1), the DSO operators send a command for the Islanding Board to start the islanding procedure. The Islanding Board measures the current circulating through the Islanding CB and send a command to the Master BESS to change its production and cancel this current. To do so, the Master BESS increases its active and reactive power output following a slow ramp. A current increase can be observed between (1) and (2);
- Some seconds later, the Islanding Board verifies the absence of current in the Islanding CB and send a command to open it. At (3), the Islanding CB is opened, islanding the demonstrator from the main grid. Thanks to the power balance executed before the islanding, no considerable voltage or current excursions occurred during the transition.
- However, it can be observed that the voltage suffers a progressive decrease after the opening of the Islanding CB. This is because the voltage is slightly high during grid-connected operation. Therefore, after the transition to islanded operation, the Master BESS (grid-forming unit) decreases the voltage to its nominal value.

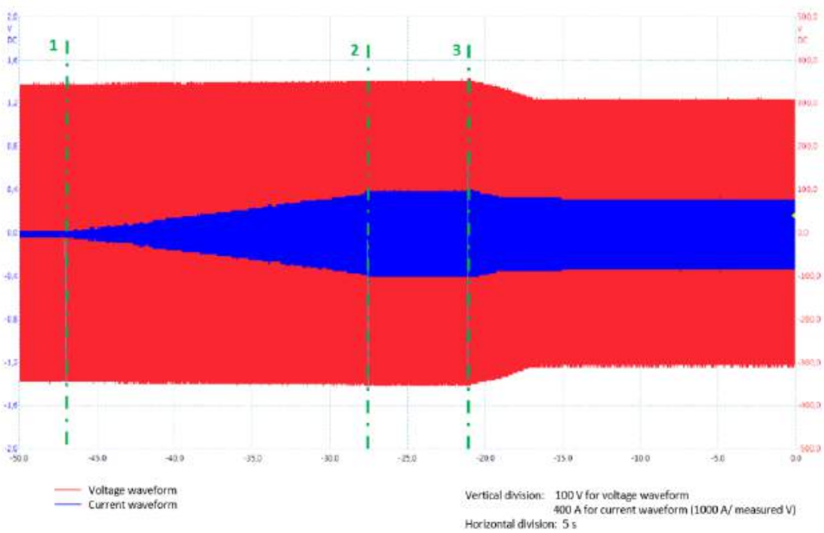

FIGURE 2.26 – *Nice Smart Valley demonstrator – Voltage and current waveforms at the beginning of the islanding [20]. Measurements from the Master BESS terminals, LV (400 V).*

Figure 2.27 presents the waveforms recorded at the end of the islanding test. Hereafter, a description of the various events that can be observed on the image (marked with green dashed lines) is reported.

- At (4), the DSO operators send a command to the Islanding Board in order to start the reconnection procedure. Right after this, the Islanding Board starts monitoring the voltage waveforms upstream and downstream of the Islanding CB. At the same time, it is sending commands to the Master BESS, which acts on the island voltage to synchronize with the main grid.

- Once the synchronization is achieved, the Islanding Board sends a closing command to the Islanding CB. This CB closes at (5). It can be observed on Figure 2.28 that the converter current suffers a small peak, but this has no incidence on the voltage.
- At (6), the PCS of the Master BESS is instantaneously stopped and restarted working in grid-feeding mode, with its setpoint set to 100 kW – charging (see Figure 2.29).

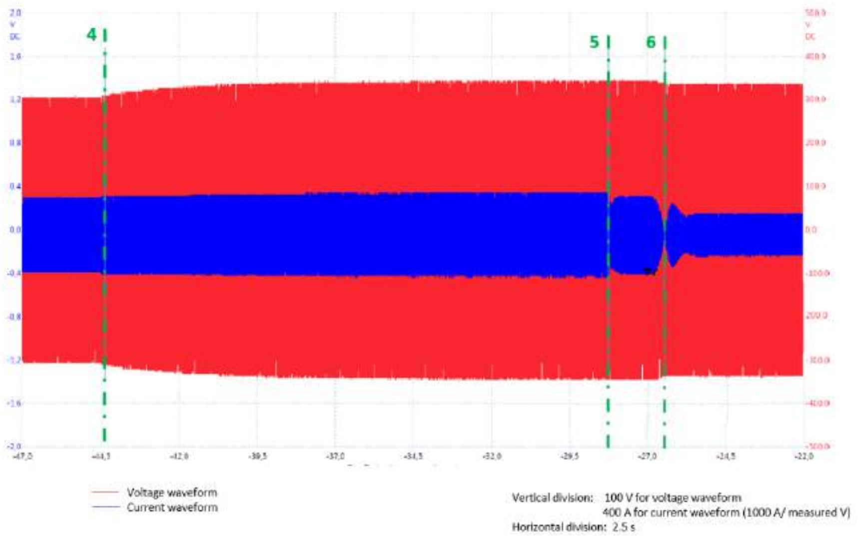

Figure 2.27 – *Nice Smart Valley demonstrator – Voltage and current waveforms at the end of the islanding test [20]. Measurements from the Master BESS terminals, LV (400 V).*

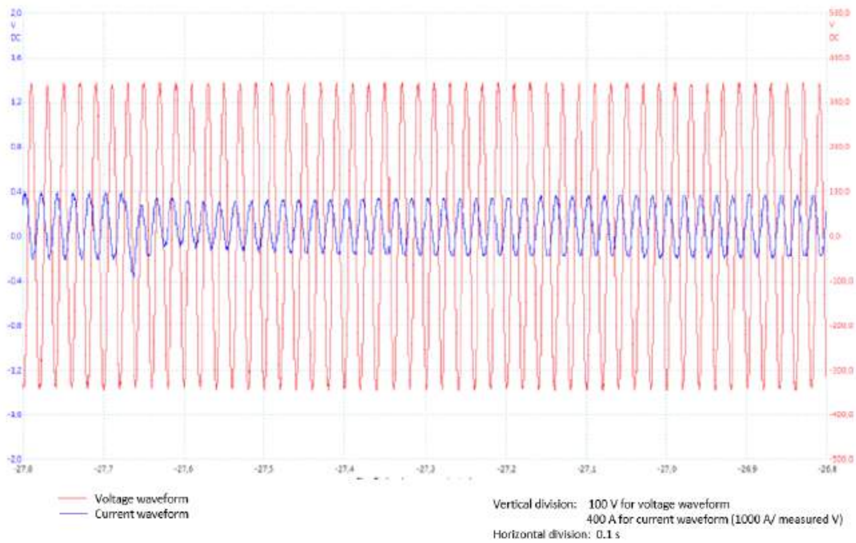

Figure 2.28 – *Nice Smart Valley demonstrator – Zoom of Figure 2.27 around (5) [20].*

Furthermore, multiple KPIs were computed using the measurements of the Lérins Islands islanding tests. Table 2.5 gathers several tables presented in [20], which include the KPIs formulas and the expected thresholds.

These KPIs were evaluated in 12 of the islanding tests conducted in the Lérins Islands demonstrator (in these tests, varied islanded durations were achieved, from 30 min to almost 4 h). Table 2.6 presents the worst value obtained for each KPI in all the 12 tests.

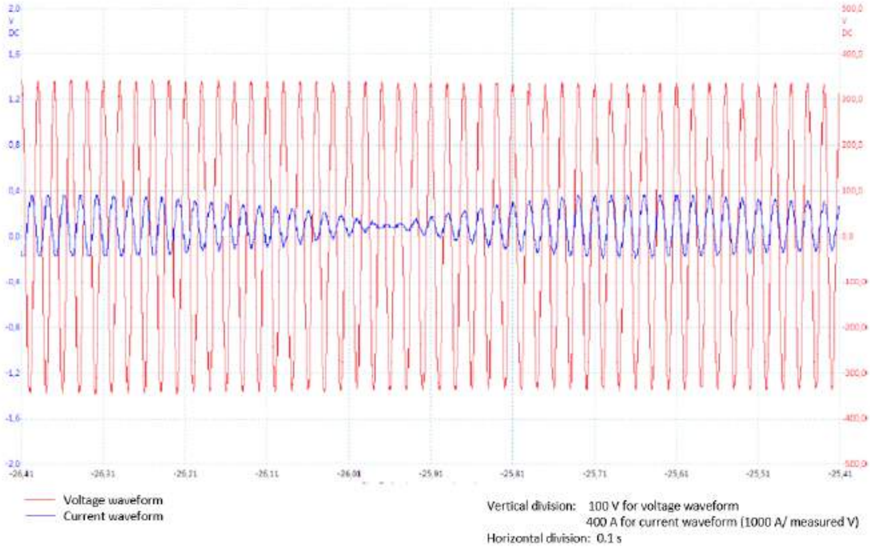

FIGURE 2.29 – *Nice Smart Valley demonstrator – Zoom of Figure 2.27 around 6) [20].*

TABLE 2.5 – *Nice Smart Valley demonstrator – KPIs formulas and thresholds applied to the results of the islanding tests [20].*

KPI 1 Voltage deviation during islanding

KPI Formula	$V_I(\%) = \frac{\lvert V_t - V_{set}\rvert}{V_{set}} \cdot 100$ (Measurement and calculation every 10 min). Where: $V_I(\%)$ is the voltage deviation during islanding V_t is the average magnitude of the voltage at time t (one measurement every 10 minutes according to EN 50160) V_{set} is the MV/LV transformer voltage set point
Expectations	Enedis - $V_I(\%) \leq 10\%$, 95% of the time

KPI 2 Frequency deviation

KPI Formula	$f_I(\%) = \frac{\lvert f_t - f_n\rvert}{f_{set}} \cdot 100$ (Measurement of the average frequency over 10 seconds). Where: $f_I(\%)$ is the frequency deviation during islanding f_t is the measurement of the frequency for each time step t f_{set} is the set frequency value of the grid forming unit (50 Hz)
Expectations	Enedis - $50 \pm 1\%$, 95% of the time $50 + 4\% / -6\%$, 100% of the time f shall be measured every 10s

KPI 3 Total harmonic distorsion

KPI Formula	$THD(\%) = \frac{\sqrt{\sum_{h=2}^{40} (U_h)^2}}{U_1} \cdot 100$ Where: $THD(\%)$ is the total harmonic distortion U_h is the RMS value f the *h*th harmonic (n=1 is the fundamental)
Expectations	Enedis - $THD(\%) \leq 8\%$

KPI 4 Voltage unbalance

KPI Formula	$VUF(\%) = \frac{V_n}{V_p} \cdot 100$ Where: V_n is the negative sequence voltage component V_p is the positive sequence voltage component The positive and negative sequence voltage components are obtained by resolving three phase unbalanced line voltages Vab, Vbc and Vca. The two balanced components are given by $\begin{cases} V_p = \frac{V_{ab} + a \cdot V_{bc} + a^2 \cdot V_{ca}}{3} \\ V_n = \frac{V_{ab} + a^2 \cdot V_{bc} + a \cdot V_{ca}}{3} \end{cases}$ Where $a = 1\angle 120^\circ$ and $a^2 = 1\angle 240^\circ$.
Expectations	Enedis - $VUF(\%) \leq 2\%$

TABLE 2.6 – *Nice Smart Valley demonstrator – Worst KPI values during the islanding tests [20].*

Voltage deviation	Frequency maximum value	Frequency minimum value	Voltage THD	Voltage unbalance
6.04 %	50.06 Hz	48.83 Hz	2.61 %	1.94 %

Even the worst values of voltage deviation, voltage THD and voltage unbalance respected the thresholds imposed by Enedis. Regarding the frequency, the maximum recorded value only exceeded the nominal frequency by 0.12 % (this respected by far the 50 Hz±1 % range). On the other hand, the minimum recorded value was of 50 Hz – 2.34 %. This value did not respect the 50 Hz±1 % range, but it did enter in the 50+4 %/− 6 % range. In addition, looking at the minimum frequency recorded at each of the 12 tests (and not only the worst value), it was observed that in 11 out of 12 tests, the minimum frequency was above 49,82 Hz (50 Hz – 0.36 %). It can be concluded that the 48.83 Hz value was an outlier.

2.1.6 SENSIBLE – Évora (Portugal)

2.1.6.1 Context and objectives of the demonstrator

The Portuguese demonstrator developed for the SENSIBLE project [23], is located in Évora, south of Portugal. The general aim of the SENSIBLE project was to understand to what extent energy storage and energy management technologies can bring economic benefits to distribution grids, communities and commercial buildings.

The Évora demonstrator was developed by a consortium led by SIEMENS [24], where EDP Labelec [25] (Engineering Centre of EDP) and E-Redes [26] (main Portuguese DSO) led the demonstration stage of the project. The demonstrator was implemented in the distribution grid of Valverde, a small rural village located in the Municipality of Évora.

Five different use cases were defined for the demonstrator:

1. Flexibility and DSM with market participation;
2. Optimization of the MV distribution grid operation using available storage resources;
3. Optimization of the operation of storage devices in the LV grid;
4. Islanding operation of a LV grid;
5. Development of a microgrid emergency balance tool.

The last two use cases are the main interest of this report. The specific objectives of the "Islanding operation of a LV grid" use case were:

- To ensure secure transitions between the grid-connected and islanded operations modes;
- To ensure the system stability during islanded operation;
- To optimize the islanded operation.

The "Development of a microgrid emergency balance tool" use case aimed to create a coordination tool to support the LV islanding. This coordination tool ensured the generation and consumption balance in the LV island, by exploiting the grid BESSs and the flexibility provided by residential consumers (which had resources such as flexible loads, micro-generation and storage). It also aimed at optimizing the dispatch of the grid-forming BESS, crucial to extend the islanded operation. The objectives of the tool were:

- To minimize the non-supplied energy and the time of service interruptions;
- To ensure the islanded area had enough capacity to perform frequency regulation;
- To maintain frequency excursions within admissible limits;
- To maintain voltage within admissible limits and minimize voltage unbalance.

Before implementing the developed solutions in the Valverde grid, they were validated in the smart grid testing facilities of INESC-TEC [27] and of EDP Labelec [25]. One of the main advantages of laboratory validation was that the solutions could be tested under extreme grid scenarios which could not have been recreated in the real grid of Valverde.

The SENSIBLE project was developed from 2015 until 2018. The Évora demonstrator is currently in operation for usage in other R&D projects, but no more islanding test events are foreseen for the moment, although the assets are still on site.

2.1.6.2 Demonstrator grid composition

Figure 2.30 shows a simplified diagram of the grid architecture of the Évora demonstrator (not all the LV elements are represented). The elements depicted in color are those that were installed or refurbished for the Évora demonstrator, while the grid existing before the demonstrator was deployed is depicted in black. The demonstrator was composed by the following elements.

- The final section of a MV feeder;
- Two public secondary substations (named "SS_A" and "SS_B"), and their LV feeders;
- One private secondary substation (named "SS_C"), which fed the facilities of the University of Évora. In this secondary substation there was also a BESS (480 kVA/360 kWh), which was installed in a previous EDP project. This BESS could also be used for the SENSIBLE project, but not for the "Islanding of a LV grid" use case.

The island tested within the SENSIBLE project comprised the LV grid fed by the SS_A (the island was created by opening a CB placed downstream of the transformer). The rated power of the SS_A transformer was 250 kVA. Before the deployment of the demonstrator, there SS_A fed 111 LV clients (mainly residential customers) and the peak power of the secondary substation was 146 kVA.

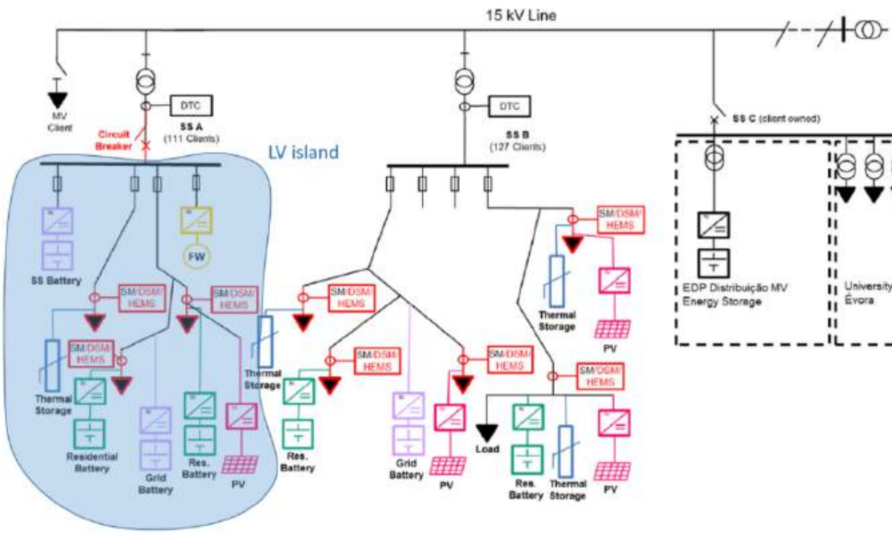

FIGURE 2.30 – *Évora demonstrator – Grid architecture [28].*

Figure 2.30 also shows that there was some smart grid equipment installed in the grid before the development of the Évora demonstrator: smart meters, deployed for all the customers of the demonstrator, and two Distribution transformer controllers (DTC), one for each public secondary substation. These devices were installed for the EDP inovGrid project [29], but were also used for the SENSIBLE project. They are described more in detail in Section 2.1.6.3.

In addition, various grid elements were added for the SENSIBLE project. Hereafter are described the elements installed in the SS_A LV grid.

Several residential customers were transformed into flexible customers. For that, various controllable generation and consumption systems were installed in customer's households (behind the meter). More specifically, there were:

Home energy management system (HEMS): 25 units;

Residential batteries: 3.3 kW, 15 units;

PV system: 1.5 kWp, 25 units;

Electrical water heaters: 2 kW, 15 units;

Smart plugs: 2 kW, 2 units each client;

Residential prototype: 10 kW/20 kWh.

Each PV system had an installed power of 1.5 kWp, each BESS had an energy capacity of 3.3 kWh, each water heater had a rated power of 2 kW and each smart plug had a rated power of 2 kW too. All these systems were directly purchased in the market.

In each household, there was a HEMS that controlled these elements through active and reactive power commands (the HEMS used is described in Section 2.1.6.3). In islanded operation, the flexibility provided by these clients was used, for example, to ensure the stability of the system or to maximize the duration of the islanded events. Three grid BESSs were installed:

- One BESS (named "ESS_1") was connected to the LV busbar of SS_A. It had a rated power of 50 kW and an energy capacity of 100 kWh. The battery cells were Li-Ion;
- Two BESS (named "ESS_2" and "ESS_4") were installed along the LV feeders. These were, respectively, a 30 kW/22 kWh BESS and a 10 kW/20 kWh BESS. For both BESSs, the battery cells were Li-Ion.

In the context of the SENSIBLE project, the main purpose of these BESSs was to enable the islanded operation of the SS_A LV grid. Therefore, their sizing was mainly based on the characteristics of the typical outages happening in the MV grid, since the outage of the upstream grid would be the most constraining event leading to an island. Ideally, the total storage power should have been equal to the peak power of the LV grid, so that the islanding could happen at any time of the year. However, it was found that a total power of 80 kVA was enough to cover the consumption of the grid during 90 % of the year. Regarding the energy, an historical analysis revealed that 95 % of the outages lasted less than 30 min. Therefore, a total energy capacity of 80×0.5 kWh = 40 kWh would be enough to cover most of the outages. Nevertheless, the total capacity of the three installed BESS is considerably higher: 142 kWh. This is because it was also necessary to take into account the technical limitations imposed by the Li-Ion technology (i.e. not all power/capacity ratios can be achieved in Li-Ion cells) and the minimum capacity constraints imposed by the BESSs providers. The three BESSs could be controlled in different ways:

- ESS_1 could be controlled in two ways:
    - In grid-connected operation, it was controlled in grid-feeding mode, behaving as a current source;
    - In islanded operation, it was controlled in grid-forming mode, behaving as a voltage source. In addition, this control mode had droops configured, which made the BESS increase or decrease the value of the frequency or the voltage according its power output. Therefore, it could be considered that ESS_1 performed the primary control of the island voltage and frequency;

- ESS_2 and ESS_4 only worked in grid-feeding mode, behaving as current sources.

Both the inverters and the control systems of ESS_1 and ESS_2 were commercially available products. However, they had to be partially modified for the SENSIBLE project (e.g., a neutral was added to the AC side of ESS_1, in order for this BESS to feed unbalanced loads during islanded operation). The inverter and the control system of ESS_4 were especially developed for the SENSIBLE project. This was because these components were provided with special functionalities that were tested during the SENSIBLE project (e.g., a local control algorithm to manage the power based on local frequency and voltage measures). However, these special functionalities were not used in the islanding use case.

In addition, it was initially planned to install a 125 kVA super-capacitor in the SS_A, which would have been installed in parallel with ESS_1. This was not done in the end since the laboratory tests showed that the integration of both storage systems was not mature enough. The tests proved the difficulty of integrating two parallel grid-forming inverters operated through droop control and in an unbalanced way.

2.1.6.3 Equipment used for the islanding use case

Figure 2.31 depicts the ICT architecture of the Évora demonstrator. In the following sections, the elements relevant for the islanding of the SS_A LV grid are described (the flywheel is not discussed in this report).

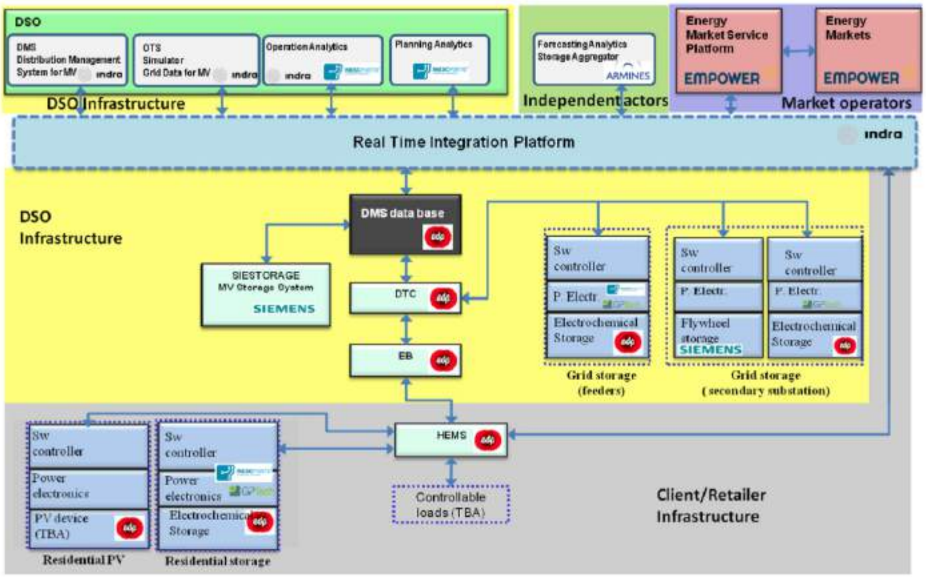

FIGURE 2.31 – *Évora demonstrator – ICT architecture [28].*

2.1.6.3.1 Automation and control.

DSO devices installed in the grid. To enable the islanding transition, it was necessary to change the topology of the SS_A. The pole-mounted substation was substituted by a prefabricated secondary substation, with the objective of keeping the new installed equipment in close premises for security and safety reasons. To build this secondary substation, the standard switchgear scheme normally used by E-Redes was not completely followed. Two main changes were made:

- A remotely controlled CB (called "Islanding CB") was installed between the transformer and the LV busbar (instead of a LBS). This CB gave the LV grid of the SS_A the capability of disconnecting from the upstream grid when there was a fault;
- At the head of each LV feeder, a CB was installed (instead of a fuse). Because of their sizing, the fuses did not allow maintaining the protections selectivity in islanded mode.

Figure 2.32 shows a diagram of the SS_A. Another control device installed in the SS_A was the DTC. As explained above, this device was installed in the substation before the SENSIBLE project. This commercial product (E-Redes usual smart grid equipment) has two main functions:

- To be a middleware between E-Redes central systems and the smart meters installed in the LV grid fed by the secondary substation. In particular, it collects the measurement data from all the smart meters and sends it upstream (to the E-Redes central systems, via the real-time integration platform, described below). It also sends to the smart meters the configuration commands coming from upstream;
- To monitor and control the LV grid fed by the secondary substation. For that purpose, it can be connected to various measuring and automation devices.

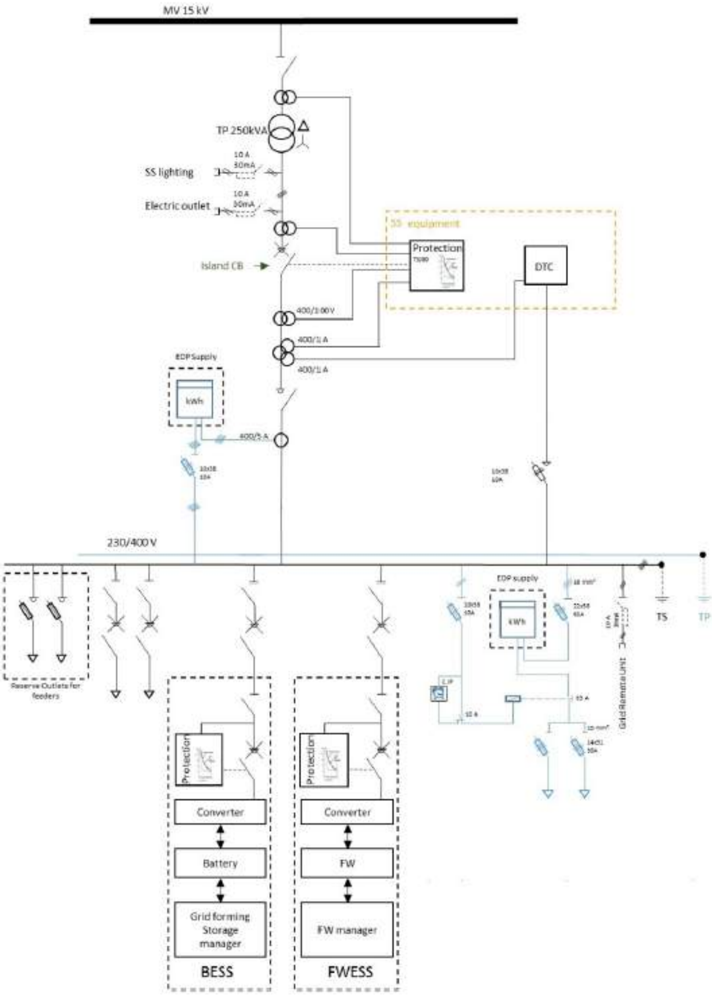

Figure 2.32 – *Évora demonstrator – Secondary substation "SS_A" switchgear diagram [30].*

However, the device was adapted to fulfill the objectives of the islanding use case. The following modifications were conducted:

- Two new features were added to the DTC:
  - Firstly, EDP and EFACEC developed and implemented a finite-state algorithm in the DTC. This algorithm controled the different phases of islanded operation (i.e.: transition from grid-connected to islanded mode, islanded mode and transition back to grid-connected mode);
  - Secondly, the DTC was adapted to be able to operate grid-tied BESSs (ESS_1, ESS_2 and ESS_4), by sending setpoint commands and receiving status data (e.g., SoC, voltage, current, active power, reactive power).
- The DTC was connected to the following devices of the SS_A grid:
  - The Islanding CB, to connect/disconnect the islanded area from the main grid;
  - The measurement equipment installed right upstream and downstream of the Islanding CB, to monitor the islanded area and the main grid during the transitions between grid-connected and islanded operation;
  - To the grid-tied BESSs (ESS_1, ESS_2 and ESS_4);
  - To protection relays, to monitor the operation and protection state of the LV grid.
- Finally, an Islanding Manager was associated to the DTC. This was a PLC, which performed a secondary control during the islanded mode. In particular, it changed the setpoints of ESS_1, ESS_2 and ESS_4, to restore the nominal frequency or voltage in the island. That way, it eliminated the voltage and frequency steady state errors that could not be eliminated with the droops of ESS_1.

Other key automation and control devices were integrated in each grid BESS.

Client devices installed in the grid. As stated above, some of the LV clients of the SS_A were transformed into flexible consumers by installing in their households controllable elements such as PV systems, residential BESSs, electric water heaters or smart plugs. In each of these households, there was a HEMS, that was a gateway that monitored and operated all the controllable energy systems. More specifically, each HEMS:

- Collected the measurements of the controllable devices installed in the household and the related consumption, by communicating with the household smart meter. Then, it processed these measurements and quantified the flexibility capability of the customer (i.e. its capacity to increase or reduce its net consumption). Finally, it sent this information to the E-Redes central systems (i.e., to the energy market service platform, ESP, and grid operation tools, via the real-time integration platform);
- Operated all the controllable devices installed in the household, following commands received from the high-level systems. For example, during islanded operation, the DSO E-Redes used the flexibility provided by the LV customers to ensure the stability of the island or to maximize its duration. To know how to make the best use of the customers flexibility, the microgrid emergency balance tool was executed (described below).

Other DSO systems. The real-time integration platform performed real-time data acquisition and processing. Its main advantage was that it was able to handle very large volumes of data with a very low latency. It can be seen as a communication bus that can interact with publishers (elements which provide data to the bus) and subscribers (elements which are awaiting data from the bus). The Distribution Management System (DMS) Database was another DSO system with two main functions:

- It was a middleware or interface between the real-time integration platform and the systems installed in the grid (more specifically, the DTC);

- It hosted a LV SCADA and a MV SCADA which allowed E-Redes operators to supervise the operation of the demonstrator.

Finally, the last automation and control systems relevant for islanded operation were the DSO tools (enclosed in a green rectangle on Figure 2.31). The most relevant tool for the islanding use case was the microgrid emergency balance tool. The main objectives were:

- To ensure the islanded area had enough capacity to maintain the frequency and voltage for a predefined islanded duration;
- To minimize the energy not supplied and the time of service interruption.

For that, it worked in the following way:

- Before islanding, the tool performs a continuous monitoring of the LV grid:
  - In case an unplanned islanding occurs, such as the opening of the CB without balancing the generation/consumption of the LV grid, it estimates the severity of the disturbance that would occur and the best control commands to send to the grid BESSs;
  - If a planned islanding is configured by E-Redes operators, it defines the control commands to send to the grid BESSs in order to balance the generation/consumption of the LV grid before the transition.
- In islanded mode, the tool performs the tertiary control of the islanded area:
  - The tool adapts the setpoints of the grid BESSs acting in grid-feeding mode (ESS_2 and ESS_4), to save the energy stored in the grid-forming BESS (ESS_1);
  - If higher technical constraints appear in the island, it can also send control commands to the flexible customers.

2.1.6.3.2 Measurement. As explained previously, a smart meter was installed in each of the LV client facilities of the demonstrator. The model of smart meter used was a commercial product (E-Redes usual smart grid equipment), with advanced metering capabilities (e.g., load profile, quality of service).

In addition, measuring equipment (typical voltage and current transformers) was installed upstream and downstream of the Islanding CB, as well as in each BESS cabin, to monitor the islanded area and the main grid during the transitions between grid-connected and islanded operation.

2.1.6.3.3 Supervision. A SCADA system was specially developed for E-Redes operators to monitor the LV grid of the demonstrator (see Figure 2.33), since at the time E-Redes did not had any SCADA system for the LV grid.

2.1.6.3.4 Protection. During the development of the Évora demonstrator it was necessary to revise the protection scheme of the SS_A LV grid to ensure that the safety of the people and of the grid equipment was maintained both in grid-connected and islanded operation. Hereafter the most important aspects of the revised protection scheme are described.

It was necessary to ensure that, in case of a fault in the MV grid, the SS_A LV grid would be disconnected from it. This is to avoid the BESSs and DERs installed in the LV grid to keep feeding the fault. For that, a protection relay was associated to the Islanding CB. An overcurrent detection function and a maximum homopolar function (59N) were configured in the relay. This last function was necessary for the phase-ground faults in MV to be detected at the Islanding CB (installed in LV), since the MV/LV transformer was of type delta-star.

The protection scheme was completed with some CBs.

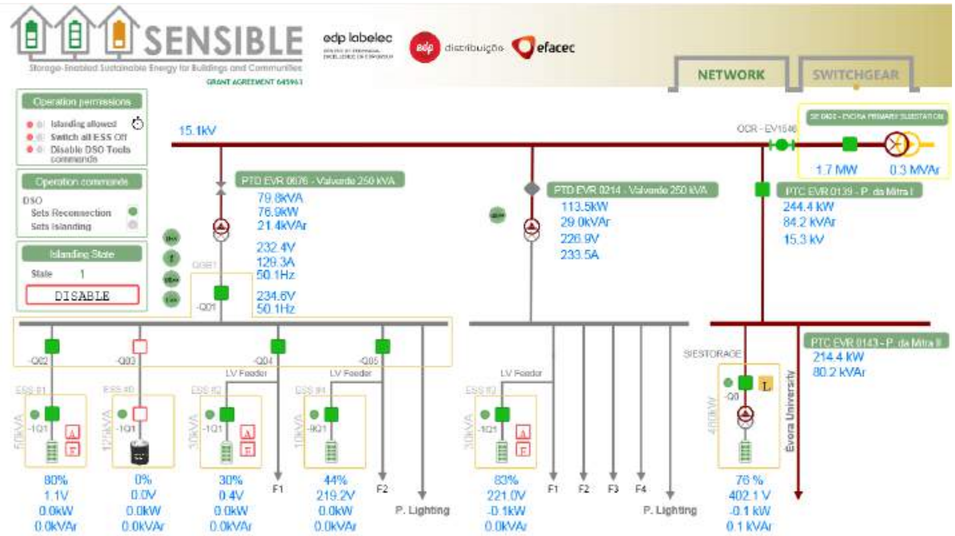

FIGURE 2.33 – *Évora demonstrator – Snapshot of the LV SCADA interface (E-Redes).*

- CBs with automatic overcurrent trip, installed at the head of each LV feeder;
- CBs combined with protection relays, installed at PCC of the BESSs with the grid. Apart from an overcurrent detection function, other functions were configured in these protection relays: over/undervoltage and over/underfrequency.

It is important to emphasize that particular attention had to be put in the configuration of these protections in order to ensure the proper functioning and selectivity of the protection scheme [31]. This was a particularly complex task because:

- The actions to undertake in order to isolate the fault change depending on the state of the islanded area (grid-connected or islanded) and of the location of fault;
- The magnitude of the SC current is different in grid-connected and in islanded mode. To avoid this, ESS_1 was designed to provide a maximum fault current of 3 times its nominal current in islanded mode. This led to a higher SC current in islanded mode.

2.1.6.3.5 Telecommunication. Two kinds of communication links enabled the islanded operation of the SS_A LV grid:

- The connexion between the DTC and the grid ESS_1 was done through wired links (Ethernet). A wired connection was chosen since the transitions between grid-connected and islanded operation require a fast communication;
- A wireless technology (GPRS) was used to connect the DTC and E-Redes central systems, as well as the DTC and the other ESS devices. Finally, smart meters and HEMS connections were also based on GPRS.

2.1.6.4 Modes of operation of the islanding use case

2.1.6.4.1 Grid-connected operation. In grid-connected operation, the BESSs installed in the LV grid of SS_A may be used for different purposes. Their operation setpoints were chosen directly by E-Redes operators or using a tool developed for the optimization of the dispatch of the BESSs in grid-connected operation. This tool allowed to optimize the BESSs dispatch with different purposes (e.g., to improve the grid voltage profile or to minimize technical losses), but a minimum SoC was always respected so that the islanding of the SS_A would be feasible if a fault occurred.

In addition, the microgrid emergency balance tool performed a continuous monitoring of the SS_A LV grid during grid-connected operation. As explained above, it undertook two tasks:

- It determined what would be the best commands to send to the grid BESSs (ESS_1, ESS_2 and ESS_4) if an unplanned islanding occurred (in order to reject the resulting perturbation and achieve a stable islanded operation);
- On the other hand, if an E-Redes operator scheduled a planned islanding, it defined the control commands to send to the grid BESSs in order to balance the generation/consumption of the LV grid before the transition.

2.1.6.4.2 Transition from grid-connected to islanded operation. The Évora demonstrator is capable of achieving seamless transitions to islanded operation in both planned and unplanned islanding events. In case of a planned event, the following procedure was executed.

1. An E-Redes operator schedules an islanded event;
2. Before the scheduled opening of the Islanding CB, the microgrid emergency balance tool calculates which setpoints must be configured in the grid BESSs in order to balance the generation and consumption of the islanded area. It sends the setpoint commands to the grid BESSs;
3. The finite-state machine running in the DTC executes the transition (i.e. it commands the opening of the Islanding CB and changes the control mode of ESS_1 to grid-forming), ensuring the safety of the process.

In case of an unplanned islanding event (the Islanding CB is opened unexpectedly), for example, if there was a fault in the MV grid of the demonstrator. A considerable disturbance may appear in the islanded area, since the production and the generation of the area were probably not balanced before the opening of the CB;

In that case, the finite-state machine running in the DTC detected the opening of the Islanding CB. To reject the potential disturbance, it changed the setpoints of ESS_1 according to the values calculated by the microgrid emergency balance tool right before the opening of the Islanding CB. It also changed the control mode of ESS_1 to grid-forming.

2.1.6.4.3 Islanded operation. In islanded operation, the voltage and frequency stability of the islanded area were achieved through a decentralized control.

1. The primary control was performed by ESS_1 (grid-forming mode with droops);
2. The secondary control was performed by the Islanding Manager. It changed setpoints of the ESS_1, ESS_2 and ESS_4 to restore the nominal frequency or voltage in the island. In that way, it eliminated the voltage and frequency steady state errors that could not be eliminated with the droops of ESS_1;
3. The tertiary control was performed by the microgrid emergency balance tool, which adapted the setpoints of ESS_2 and ESS_4, to save the energy stored in ESS_1. In this way, the feasible duration of the island was increased. If further technical constraints appeared, the tool could also change the setpoints of the flexible consumers.

2.1.6.4.4 Transition from islanded to grid-connected operation. The transition back to grid-connected operation was performed by the finite-state machine running in the DTC, according to the following procedure.

1. It compared the voltage waveforms upstream and downstream of the Islanding CB;
2. To synchronize both waveforms it sent control commands to ESS_1;
3. Once both waveforms were synchronized, it sent a command to close the Islanding CB.

2.1.6.4.5 Black-start. This feature was not a requirement for the Évora demonstrator.

2.1.6.5 Islanding tests results

This section describes the results obtained during a LV islanding test undertaken in the Évora demonstrator. Figure 2.34 to Figure 2.39 report recordings at the beginning of the test during the transition from grid-connected to islanded operation and during the first minute of the island. Hereafter, a description of the main events observed in the figures is reported.

- At the beginning of the test, the LV grid fed by the SS_A was operating in grid-connected mode. The three BESSs were delivering power outputs according to previous setpoints;
- The DSO operators verified that the grid conditions were proper to proceed with the islanding test. In particular, they validated that the islanded area load was below the maximum power of ESS_1 (grid-forming unit during islanded operation). They also validated that the SoC of ESS_1, ESS_2 and ESS_4 was at least 80 % (the last two would work in grid-feeding mode during islanded operation).
- After that, the DSO operators sent an opening order to the Islanding CB. Then the LV grid fed by the SS_A was islanded from the distribution grid. In the next figures, the opening of the CB is marked with vertical red rectangles. It can be observed that:
  - ESS_1 responded immediately and started to deliver the power needed to guarantee the power equilibrium of the island;
  - The voltage and the frequency suffered initial excursions but, thanks to the regulation executed by ESS_1, both magnitudes were rapidly stabilized. During the initial excursion and the first minute of the island, the maximum voltage and frequency deviations were restricted (-0.052 p.u. and 0.049 Hz).
- About 1.5 min after the transition, the microgrid Emergency Balance Tool changed the power setpoints of ESS_2 and ESS_4 (marked with vertical yellow rectangles). This was aimed at saving the energy stored in ESS_1 (grid-forming unit). In consequence, ESS_1 reduced its power output, ensuring again the power balance of the island.

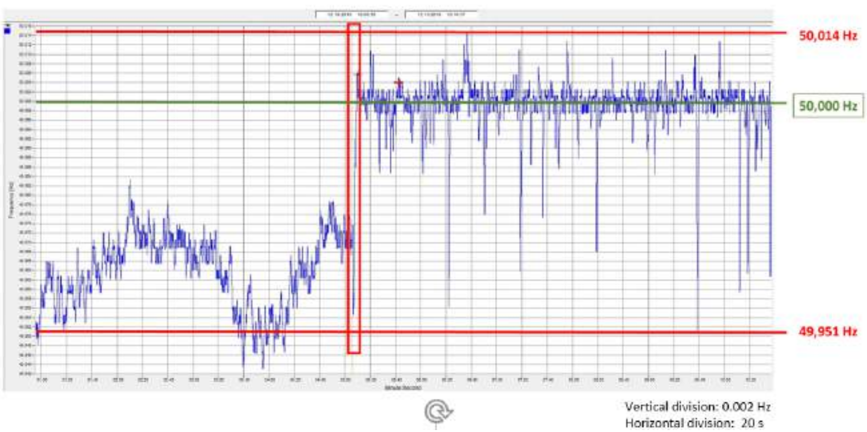

Figure 2.34 – *Évora demonstrator – Frequency at the beginning of the LV islanding [32].*

FIGURE 2.35 – *Évora demonstrator – Voltage curves recorded at the beginning of the LV islanding test [32]. Each curve corresponds to one phase. The measurements were taken in the ESS_1 facility, in LV (400 V).*

FIGURE 2.36 – *Évora demonstrator – ESS_1 apparent power curves recorded at the beginning of the LV islanding test [32]. Each curve corresponds to one phase.*

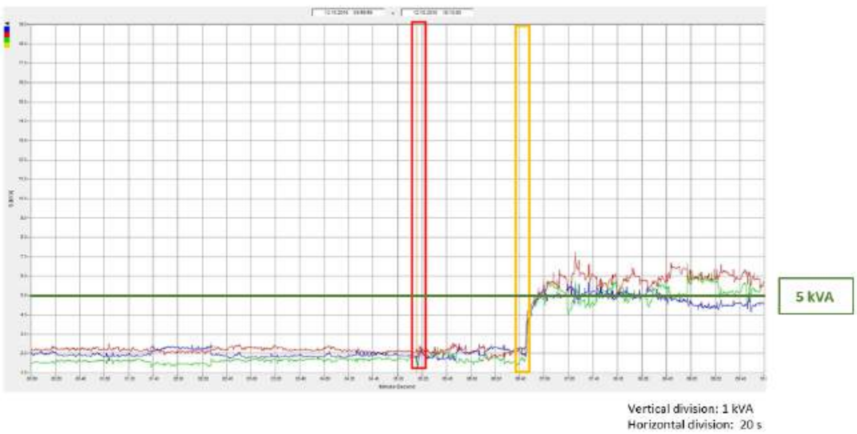

FIGURE 2.37 – *Évora demonstrator – ESS_2 apparent power curves recorded at the beginning of the LV islanding test [32]. Each curve corresponds to one phase.*

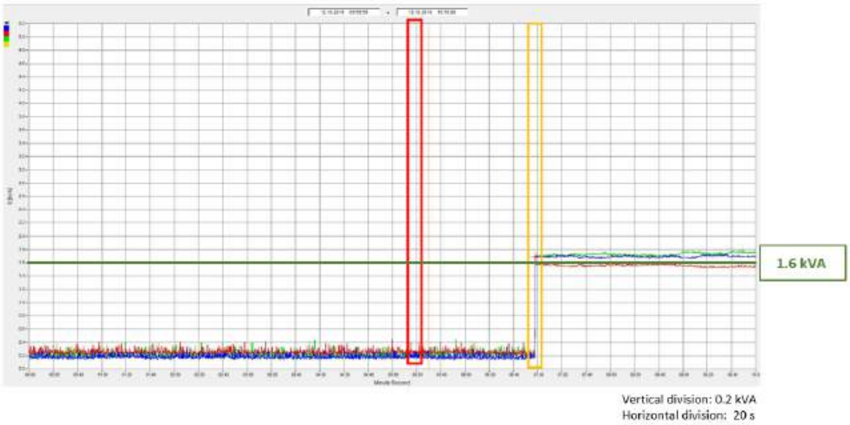

FIGURE 2.38 – *Évora demonstrator – ESS_4 apparent power curves recorded at the beginning of the LV islanding test [32]. Each curve corresponds to one phase.*

Figure 2.39, Figure 2.40 and Figure 2.41 depict the curves recorded at the end of the test during the last minute of islanded operation and the reconnection of the island to the main grid. Hereafter, a description of the main events observed in the figures is reported.

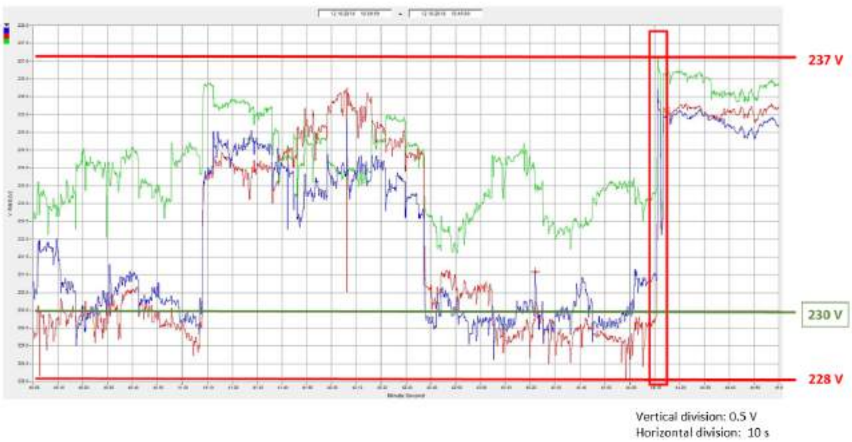

FIGURE 2.39 – *Évora demonstrator – Voltage curves recorded at the end of the islanding test (synchronized reconnection to the main grid) [32]. Each curve corresponds to one phase. The measurements were taken in the ESS_1 facility, in LV (400 V).*

- The DSO operators sent a reconnection order to ESS_1. Then, this system synchronized the voltage waveform of the island with the one upstream of the Islanding CB;
- Once the voltage amplitude, frequency and angle synchronization were achieved for the three phases, the ESS_1 reported synchronization. The synchro-check function installed in the Islanding CB was then activated;
- The finite state machine running in DTC managed all the process ensuring the safety of the reconnection process;
- When the synchro-check verified the synchronism, it closed the Islanding CB (event marked with a vertical red rectangle on the figures). It can be observed that, as well on the islanding transition, the voltage and frequency excursions experienced during the reconnection were limited.

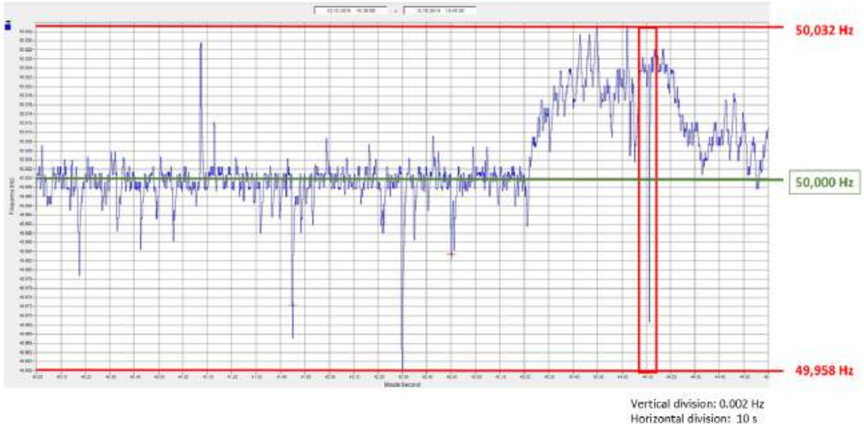

FIGURE 2.40 – *Évora demonstrator – Frequency curve recorded at the end of the islanding test (synchronized reconnection to the main grid) [32].*

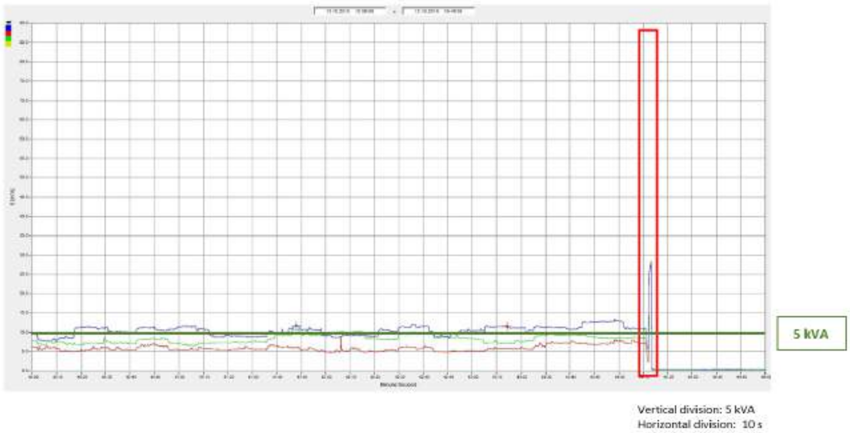

FIGURE 2.41 – *Évora demonstrator – ESS_1 apparent power at the end of the islanding test (synchronized reconnection to the main grid) [32]. Each curve represents one phase.*

2.2 Lessons learned from the demonstrators

The aim of this chapter is to provide a technical description of a set of recent microgrid demonstrators implemented in European distribution grids. The common element to all demonstrators is that they can be operated in both grid-connected and islanded modes. However, the technical solutions implemented to achieve this differ from one demonstrator to another.

Accordingly, this section synthetizes and compares the main characteristics of the described demonstrators, highlighting the main lessons extracted from each project.

2.2.1 Demonstrators grid composition

2.2.1.1 BESSs

To operate a grid in islanded mode, it is necessary to have one element capable of imposing the voltage and the frequency. In five out of six demonstrators, a BESS has been chosen to perform this grid-forming role. In addition, some demonstrators relied on other BESSs in parallel, working either in grid-feeding or grid-supporting mode.

Utility scale BESSs are complex systems, which integrated different components: multiple battery cells, a PCS (composed of one inverter or multiple parallel inverters), a control system, a fire extinguisher system, and an air-conditioning system.

In all the demonstrators analyzed, the installed BESSs were specially designed, or at least customized, for each project. As a matter of fact, the BESSs components (e.g. cells, inverters) can be found in the market and it is not needed to develop them from scratch. However, they must be adapted to fulfill the requirements of each project. In particular:

- *The PCS must be adapted for the BESS to fulfill the grid-forming functionality.* For example, the Nice Grid BESS used commercial PV inverters that were customized by:
  1. Adding a neutral connection to their AC side (the island was created in LV and no other element provided neutral currents to the unbalanced loads);
  2. Changing their control (by default, the PV inverters only worked in grid-feeding).
- *The control system must be customized for the BESS to fit into the control architecture of each demonstrator.* As explained in Section 2.2.2.1, the architectures used in the demonstrators analyzed are very different between each other.

Among the project managers of the demonstrators that were interviewed, several stressed that there is a *need for a higher standardization of BESSs.* As a matter of fact, the implemented BESSs are considerably customized and this clearly led to problems during the installation and commissioning phases. In addition, some managers pointed out that they were *unable to find a BESS provider offering a complete and finished product.* In consequence, acquiring and set up a complete BESS forced them to focus on management issues rather than on technical/research aspects. For instance, they had to be in close contact with both the cells provider and the PCS/control system provider, they had to sign a contract with the air-conditioning system provider, and they had to sign a contract with the fire-extinguisher system provider, etc. Another important message sent by the demonstrators managers is that, *although BESSs are theoretically low maintenance systems, they require constant monitoring.* In particular, this results from the high sensitivity of battery cells to temperature.

On another note, it is important to highlight the *BESS control issues that have been detected in the San Agustín demonstrator.* One of the objectives of this demonstrator was to compare the performance of BESSs supplied by different providers and to check their interoperability. For that, they commissioned three BESSs supplied by three different providers, which were given the same design specifications. As explained in Section 2.1.1.5, a *relevant interoperability issue has arisen*: when BESS *B* works in grid-forming mode and BESS *A* works in grid-feeding mode, the transition to island operation is not achieved, since the voltage and the frequency start to flicker. The reason behind is that the control loop of BESS *A* has a gain that depends on how weak or strong is the grid. Because of the grid changes that occur with the transition to islanded operation, this gain destabilizes the island when another BESS is the grid-forming unit. In addition, it has been found that the grid-forming controls implemented by the different providers are not equally effective: some BESS are able to maintain the frequency and the voltage at the requested value, while others can only keep them within certain margins, but without precision. These control issues may become an important obstacle for the DSOs to ensure stability in islanded operation.

One element leading to those problems is the fact that the parameters of the control loops (in current source for BESS *A* in that case) are only accessible to the manufacturer. This is a limitation for the (local) DSO in managing IBG during grids configuration changes. Another element would be the anti-islanding protections with various algorithms, notably increasing frequency and voltage variations instead of damping them, thus leading to island failure.

The simultaneous operation of different equipment (with different control strategies) can produce problems of coexistence, especially in microgrids in islanded mode, as the stability provided by the main grid is missing. To establish some kind of market for flexibility to ensure the security of the island, the DSO could impose strong connection requirements, specifying minimum standard going quite deep in control details (to avoid for instance the gain configuration issue detected in San Agustín). Another possibility would be for the DSO to own IBG (or aggregated equipment) within the island that would act as a master during islanded mode. The feedback from San Agustín showed this could be insufficient if not oversized compared to other grid-feeding units that could destabilize the island.

Additional lessons were learned from the demonstrators, going slightly away from the scope of this WG, but summarized here as they still present some interest.

On the regulatory side, the French demonstrator Nice Smart Valley addressed the restrictions imposed by the Clean Energy Package concerning the ownership of storage by regulated bodies. Batteries operations are not covered by current operation rules of Enedis. In order to ensure the safe operation and to be able to take advantage of existing skills at Enedis, it has been necessary to find a way to integrate the battery in the operation rules to guarantee that the safety level is as good as during the operation of any grid infrastructure. In the norm NF UTE C18-5103, the notion of "utility facilities" refers to the public electricity distribution grid, which integrates the notion of concession agreement. According to that definition, batteries cannot be currently considered as "utility facilities". The battery must then be considered as an "installation operated by Enedis". The operation manager accreditations were therefore updated, to enable Enedis operation teams to work (or to authorize subcontractors to work) on the installations. In that context, a specific operation agreement has been written, setting the operation procedure. This document describes:

- Electrical data and wiring diagram;
- Operations procedures (authorization, working process, protection program);
- Technical data and safety system;
- Normal operation mode;
- Fail operation mode (in case of incident).

Economic aspects for the storage facility have been also looked into for some of the demonstrators (San Agustín, Caravaca, Nice Grid). The cost of storage was still too high to propose a cost-effective solution, except in particular cases where other constraints (like difficulty in obtaining licenses, environmental protection zones, etc.) prevented more traditional solutions to be implemented. However, a strong decreasing cost trend could make what is currently uneconomic viable in the future. Small installations are also often expensive compared to the average cost of storage on the market.

On a more practical aspect, it has been noted in Caravaca that the battery part requires more intense cooling than the electronics. Separating it from the electronics reduced the consumption of the whole. The automatic extinguishing system could also be exclusive for the battery part for better energy efficiency.

Lastly, the efficiencies of storage systems have been measured in San Agustín and other demonstrators, underlining that, in addition to the battery's own efficiency, there are other factors that reduce its output (long connection distances, intermediate transformers...). The distance between generation, storage and consumption is relevant. DSOs could optimize performances by coordinating the location and size of the equipment. This is true for other equipment of course, but the location of storage facility is a relevant research perspective in grids with ancillary services depending on the considered time horizon (from Fast frequency response (FFR) to, in the future, seasonal storage).

2.2.1.2 CHP unit

The Vrchlabí demonstrator used the SG of a CHP plant to perform the grid-forming role in islanded operation. In this case, a standard control system was used (no changes were needed for the plant to work in grid-forming mode). However, as explained in Section 2.1.3.2, *the gas inlet of the CHP combustion engine had to be modified.* This was necessary for the CHP unit to withstand the gas pressure dynamic changes that happen in the transition from grid-connected to islanded operation.

2.2.1.3 PV plants

Except for Vrchlabí, all the demonstrators include PV plants with traditional PV inverters (i.e., inverters that only work in grid-feeding mode). In general, these inverters withstand the transitions from grid-connected to islanded operation and vice-versa: they do not disconnect because of the actuation of one of their internal protections (under/overvoltage, under/overfrequency, anti-islanding protection, etc.). However, this was not the case in the Nice Grid demonstrator. It was detected that, during the transitions from grid-connected to islanded operation, *some of the PV inverters of the islanded area auto-disconnected momentarily and restarted some seconds later* (when the system was in islanded operation). These disconnections did not impede the transition to be achieved, since the grid-forming BESS had enough power to counterbalance the corresponding perturbations. It is believed that the PV inverters auto-disconnected because of the actuation of their active anti-islanding protections.

On another note, the Nice Grid project also aimed at adding a P/f droop to the PV inverters working in grid-feeding mode. The objective was to reduce the PV production if the grid-forming BESS reached its maximum SoC in islanded operation. In practice, the grid-forming BESS would send a signal to the PV plants by reducing the islanded area frequency. After measuring this frequency reduction, the PV plants would reduce their production by means of the implemented droop. At the end, this functionality could not be tested on the field. However, *it was found out that several PV inverters installed in the demonstrator had a built-in P/f droop, which was deactivated (and these inverters are commercial products that can be easily found in French or other European distribution grids).* However, it is sometimes necessary to contact the inverter manufacturer to activate the P/f functionality (it is not an option that can be configured by the user to our knowledge).

2.2.2 Equipment used for the islanding use case

2.2.2.1 Automation and control

The control and automation architectures of the microgrids implemented in the demonstrators analyzed are very varied. In particular, we can distinguish:

- Microgrids with a low automation degree. It is the case, for example, of Caravaca. In this demonstrator, the DSO operators execute manually most of the tasks needed to perform the transition from grid-connected operation to islanded operation and vice-versa. For that, the operators send commands to the grid-forming BESS and to the Islanding CB (there is not a superior automation unit in charge of commanding these systems);
- Microgrids with a medium automation degree. It is the case, for example, of Nice Grid. In this demonstrator, there was an Islanding Controller that allowed to automatize the tasks needed to perform the transitions. However, this Islanding Controller commanded a reduced number of devices, which were all located in the same secondary substation: the grid-forming BESS, the Islanding CB and the surrounding measuring equipment;
- Microgrids with a high automation degree. It is the case, for example, of Vrchlabí. In this demonstrator, the Islanding Controller commands a wide set of automation equipment distributed throughout all the islanded area: the CHP unit and its flexible load, MV and LV CBs, protection relays with adaptative settings, etc. Another clear example is Évora. As observed in Figure 2.31, this demonstrator relays on a complex control and

automation structure composed by grid BESSs, flexible households, a DTC, a real-time integration platform and DSO Optimization Tools.

Each type of architecture offers advantages. *An architecture implying a low automation degree can be deployed at lower cost* (and could be as well considered as a low-tech alternative on some aspects). In consequence, these architectures are attractive for temporarily microgrids (e.g., microgrids that are built for a research project and that are dismantled once the project finishes). They can also be attractive for microgrids deployed over an existing distribution grid (to minimize the number of changes to make in the existing grid). In addition, *the reduced number of automation devices prevents the reliability problems caused by false signals*. Finally, simple control and automation architectures *allow for simple telecommunication networks*. For example, the Nice Grid islanding demonstrator used a closed Ethernet communication network, in which cybersecurity and outage risks were avoided.

On the other hand, the *architectures implying a high automation degree allow implementing advanced functionalities*. For example, the Islanding Controller of the Vrchlabí demonstrator changes the settings of the grid protections whenever there is a transition from grid-connected to islanded operation or vice-versa. Another example is the Évora demonstrator, in which the advanced automation and control architecture allows to implement a hierarchical control of the island voltage and frequency. Another advantage of high automation is that it *alleviates the tasks of the DSOs*, while providing the first step of a plug-and-play control infrastructure (auto-adaptive to internal variations, including for instance ageing of components).

2.2.2.2 Measurement

For the islanding use case, all the analyzed demonstrators make use of *standard measuring devices typically found in distribution grids* (e.g. voltage and current transformers).

2.2.2.3 Supervision

In general, the microgrids developed in the analyzed demonstrators were integrated in the superior SCADAs used by the DSOs. In some cases, a SCADA was specifically developed for the microgrid, but using a commercial system.

The only relevant issue concerning these supervision systems appeared in the Lérins Islands demonstrator: integrating the microgrid into Enedis SCADA was not straightforward because the *system was not prepared to represent BESSs*. In addition, the BESS was Enedis property. Therefore, it could not be represented as a production plant: the production plants have a quite simple representation, since they do not belong to the DSO and are not controlled with the Enedis SCADA.

2.2.2.4 Protection

All the analyzed demonstrators were developed in previously existing grids, in which the protection schemes were designed for grid-connected operation. Therefore, these schemes had to be revised and in some cases modified to ensure the protection of people and of grid assets in islanded operation. Hereafter are described the main protection issues that arose in the analyzed demonstrators.

- *If the island is created in MV, the connection of the MV neutral to ground and the MV protection relays may be placed outside of the islanded area. In consequence, in islanded operation, there is no protection against MV faults.* This was the case for the Caravaca demonstrator and the Lérins Island demonstrator. To resolve this, in both demonstrators:
  - The MV neutral was kept isolated (regardless of the regulation per country. For instance, it does not comply with French rules at the moment), but a maximum

  zero-sequence voltage relay (59N) was installed inside the islanded area. This allows to detect ground faults;
  - For phase faults, the BESS acts as an overcurrent relay: its control system detects a current saturation and auto-disconnects, de-energizing the islanded area.

- *If the island is created in LV, it must be ensured that*:
  - *A connection of the LV neutral to ground is kept within the island.* This is necessary for the clients' RCD to detect ground faults. It is also necessary for the phase voltages to be referenced to ground (otherwise, dangerous overvoltages may appear);
  - *There is an element providing neutral currents within the island.* This is necessary for unbalance loads to operate.

In the San Agustín demonstrator, this was resolved by keeping the MV/LV transformer within the LV island. In the Nice Grid demonstrator, the connection of the LV neutral to ground was done in several points along the LV grid (not only at the MV/LV transformer) and the BESS inverters provided the neutral currents.

- Another important issue is that the magnitude of the *SC current may be considerably lower in islanded operation than in grid-connected operation.* In consequence, *the protection scheme installed for grid-connected operation may not actuate*;
  - This was the case for the Vrchlabí demonstrator. The solution chosen was to install adaptive protection relays, whose settings are changed whenever there is a transition from grid-connected operation to islanded operation or vice-versa;
  - Another possible consequence of the reduced SC current is that, even if a protection device actuates, *the selectivity of the protection scheme may be lost.* This was the case for the LV island created in the Nice Grid demonstrator. In this island, the faults were cleared either by the actuation of a client protection device or by the current saturation and disconnection of the grid-forming BESS. However, the SC current was not enough to trigger the fuses installed at the head of the LV feeders. A fault that should have been cleared by disconnecting a single feeder would thus lead to the disconnection of the grid-forming BESS and the outage of the island;
  - In Nice Grid and in other demonstrators, this was left as an unresolved issue: since the islanding was only going to be used for testing purposes, maintaining the selectivity was not essential. However, this issue must be completely resolved if the islanding is used in normal operation;

- When installing a new relay to complete the protection scheme for islanded operation, *it must also be ensured that the selectivity of the protection scheme is not perturbed in grid-connected operation.* For example, in the Caravaca demonstrator, a delay had to be imposed to the 59N relay installed.

2.2.2.5 Telecommunication

Telecommunication solutions differ from one demonstrator to the other. Most of the time the choices were linked to the particularity of the experimental installations, to ensure the operation of the demonstration with minimal risks. As no demonstrator analyzed was dedicated on telecommunication, we cannot provide strong lessons learned in this report. This should however constitute clear further investigations.

The Vrchlabí and the Lérins Island demonstrators used fast communication links, installed for the project. It was thought necessary for the synchronized reconnection. However, the telecommunication rapidity was not demonstrated to be key to achieve a proper reconnection to our knowledge.

Caravaca relied as well on linked communication to control the grid-forming unit, and ensure a reactive installation for the demonstration.

2.2.3 Modes of operation of the islanding use case

2.2.3.1 Transition from grid-connected to islanded operation

In all the analyzed demonstrators, a seamless transition from grid-connected to islanded operation is achieved (i.e. a transition where power cuts are avoided and loads remain connected).

In some demonstrators, the active and reactive power of the island are balanced before the opening of the Islanding CB. This is done with the aim of minimizing the voltage and frequency perturbations that appear after the opening of the Islanding CB. These perturbations are rejected by the grid-forming unit of the island.

In other demonstrators, the Islanding CB is directly opened and the all power imbalance of the island is quickly provided by the grid-forming unit. In consequence, the voltage and frequency perturbations may be higher, but they are rejected as well by the grid-forming unit.

Some demonstrators (such as Évora) are even designed to perform both kinds of transition. The first type of transition is executed in planned islanding events. The second type is executed when the Islanding CB is suddenly opened (e.g., if there is a fault in the upstream grid).

2.2.3.2 Transition from islanded to grid-connected operation

Most of the analyzed demonstrators achieve a *seamless transition from islanded operation to grid-connected operation*, by executing a synchronized reconnection of the islanded area to the main grid. For that, *standard commercial synchrotacts are often used.*

However, the San Agustín and the Caravaca demonstrators do not have the capability to perform a synchronized reconnection: the Islanding CB is closed without checking if the voltage of the island and of the main grid are synchronized. This is equivalent to causing a SC. In less than 2 ms, the grid-forming BESS detects the overcurrent and stops its inverter, to protect it (during this time, the voltage of the islanded area suffers a significant disturbance). Once the BESS is stopped, the voltage of the microgrid recovers a sinusoidal waveform (with a possible distortion during the first cycles, due to the transformers magnetization).

The tests undertaken in San Agustín and in Caravaca proved that the unsynchronized reconnection did not cause the disconnection of the islands loads nor damaged to the BESSs installed in the demonstrators. Although, the equipment is subjected to stress, which, in principle, could lead to its accelerated deterioration, the overcurrent is limited both in magnitude and in duration, so it could be solved by an appropriate sizing.

2.2.3.3 Black-start

Several demonstrators have a black-start capability, which allows to energize the islanded area after an outage. In all the demonstrators, which use BESSs, the *grid-forming BESS performs the black-start by progressively increasing the island voltage up to its nominal value.* This prevents in-rush currents (mainly due to the energization of transformers), which would cause the auto-disconnection of the BESS.

In some demonstrators (e.g., Caravaca) there is the possibility to configure an automatic black-start (i.e., once the outage is detected by the grid-forming unit or the Island Controller, the black-start begins automatically). However, this functionality is currently switched off in the Caravaca demonstrator. This has been done to avoid exposing i-DE maintenance operators to electric risk since, for the moment, *the DSO operators are not completely prepared to handle elements that can energize the grid autonomously.*

2.2.3.4 Power quality during the transitions and islanded operation

In almost all the test results shown, the voltage and the frequency are kept within acceptable limits during the transitions and in islanded operation. This did not seem to be a concern in the analyzed demonstrators. On the contrary, *it was sometimes noted that the voltage and frequency stability was better in islanded than in grid-connected operation.* It was the case, for instance, of Caravaca. Interestingly, an increase power quality could then be considered as a criteria to switch to islanded mode in that context.

On another note, multiple demonstrators have defined KPIs to evaluate the power quality in islanded operation and during the transitions to/from grid-connected operation. The most common KPIs are:

- Voltage deviation;
- frequency deviation;
- Voltage THD.

In these demonstrators, *the thresholds used to evaluate the adequacy of the KPIs are based on the norm EN-50 160.* However, the sampling rules indicated by this norm are not always respected. These rules have been set to measure the voltage quality in normal operation and, therefore, consider too long periods. For example, for LV, it states that the RMS values should be averaged over 10 min and that, during a week, 95 % of these values should be within 230 V±10 %. However, in the case of islanding, some tests only last a few minutes. *It would be desirable to adapt these sampling rules for the islanding tests.* That way, all the demonstrators could use the same rules to compute their KPIs and the results would be easier to compare.

Chapter 3

Operating microgrids in grid-connected and islanded modes

This chapter concerns the technical aspects of the two-ways transition between islanded and grid-connected operation of microgrids that are part of a distribution grid. Are presented in this chapter what is already available with no or limited industrial developments, standard and state of art. Elements needing extensive developments, innovative research and significant investments are discussed in Chapter 4, which is focusing on requirements and recommendations for microgrids that are part of future distribution grids to seamlessly transition from grid-connected to islanded modes. The link between the microgrid and the overall system (up to the Transmission system operators (TSO) level) is only considered in this report up to the PCC, sometimes considering multiple PCC or exchanges between multiple microgrids, in order to avoid enlarging too much the scope of the report.

After a discussion on the principle of resilience for power systems, making the way for flexible microgrids, a rapid overview of the entities, which can initiate islanding, and on what criteria, is proposed. The core of the chapter covers technical aspects of the microgrids to handle the transition and to operate in islanded mode, and then to reconnect to the main grid. Addressed aspects range from control systems to protections, including grid-forming components, and communication systems. Economic, social and environmental aspects are out of the scope of the present work. Finally, despite microgrids can be managed under several frameworks, this report considers that the DSO operates the microgrid in both modes if not said otherwise.

3.1 Why disconnect from the main grid?

Microgrid operation can be a very useful tool in case of extreme occurrence, like weather events, but also in less extreme situations, when reliability is necessary, and the local distribution grid may be affected. Where there is no more availability of the local distribution grid, if an isolation capacity is available and if a microgrid can be set up, the power can still be distributed to the customers, while the distribution grid is restored.

The operation in islanded mode can result from scheduled or unscheduled events (i.e. intentional or unintentional islanding). Scheduled transitions are intentional events for which the time and duration of the planned island are known and disconnection from the utility grid occurs seamlessly. Unscheduled transitions are inadvertent events that may be initiated by faults in the utility grid, which causes power quality deterioration that triggers microgrid protection equipment thus leading to automatic and passive sectioning from the utility grid.

Islanding part of a distribution grid uncovers technical challenges that are mostly known, and for which technical solutions are mainly available. On the contrary, their cost and practical implementation are still elements to be correctly addressed. Typical technical challenges are the following:

- Balance between supply and demand;
- The protection plan, which must be adapted in particular to:
  - Possibly enlarging the range of electric quantities due to increased variability;
  - Guarantee the selectivity with the creation of a "neutral" point when going to islanded mode with a limited SC power;
- The transition between grid-connected and islanded mode. This may involve approaches that range from shutting down the microgrids or to installing dynamic systems to control the transition, with all the problems of a small, low-inertia grid (less stability and possibly lower energy quality);
- Setting up a dedicated control system for the microgrid also communicating with the main grid.

As discussed in the present and the following chapters, many technical aspects arise when considering those operational situations. In particular, the analysis starts with the main criteria to disconnect from the main grid. It is indeed of interest to first determine (from the technical point of view) why islanding a microgrid that normally operates in grid-connected mode, could be of interest, before considering how to conduct that operation.

3.1.1 Microgrids for more resilient power systems

Power grid resilience and reliability are both frequently, and often interchangeably, referenced in conversations about keeping the lights on, but, there are remarkable differences between reliability and resilience.

Reliability: It can be defined as the ability of the power system to deliver electricity in the quantity and with the quality requested by end users and is generally measured by interruption indices defined by the IEEE Standard 1366 [33]. Reliability is quantified statistically. It means that lights are always "on" in a consistent manner. This is a binary view of the performance of the grid where power systems are either functional or failing. Reliability is compulsory and is related to the rate recovery. It presents high probability with low consequences: SAIDI/SAIFI exclude storm data.

Resilience: Stemming from the root "resilio", meaning to leap or spring back, it is concerned with the ability of a system to recover and, in some cases, transform from adversity. Resilience is a continuum and confidence is specified.

Reliability and resilience are affected by both the ability to withstand a disturbance and the time to recover. Reliability is not risk-based and due to its binary nature, confidence is not specified. However, resilience has low probability with high impact. It is risk-based and considers threats and system vulnerability consequences.

In reliability, the focus is on measuring the impact on the system, while in resilience, the focus is on measuring the impact on the society. Different definitions of resilience are presented in [34], in which one definition for critical infrastructure is stated as:

> *...the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event.*

Resilience approaches emphasize the idea that disruptive events can occur and that systems should be designed to bounce back to mitigate the impact. One of the critical requirements of a resilient power grid is a rapid and effective electric service restoration. Microgrids have been widely considered as possible provider of services to help DSO strengthening the resilience of electrical infrastructures against effects of disruptive events (e.g. natural disasters). Some examples are [35]:

- Microgrids can be automatically disconnected from the grid, delivering energy to its connected loads for critical infrastructures or group of customers, thus avoiding an entire black-out and improving the continuity of service (in most countries, the DSO is not allowed to prioritize between customers, which could have to need regulation update);
- Microgrids are able to automatically reconnect to the grid after synchro-check conditions;
- Microgrids deliver backup power to hosted loads before the entire grid recovery;
- Microgrids can contribute to local and system-wide ancillary services (congestion management, frequency reserve, black-start capability, power quality, etc.).

Although microgrid solutions for DSO are still at early stages, there are significant volumes of research programs, pilots and first deployments on site, supported by large DSOs, and government agencies around the world towards the deployment of microgrids as a relevant solution that contributes to energy systems reliability and resilience.

3.1.2 Criteria to disconnect from the main grid

Islanded operations of microgrids can be analyzed in multiple configurations, where two especially representative cases can be distinguished. The first case refers to grids (mainly in rural areas), where the extension of traditional distribution grids would be very expensive (so mostly reliability is looked for). The second case involves grids where resilience is especially important and where combine DG with possible storage (or diesel generator) capabilities (mobile or not) is relevant to enable the islanding transition in case the main grid fails for reasons like extreme events, maintenance, etc. While in very remote areas, there may be a possible cost benefit rational when comparing with conventional grid reinforcement/development due to reliability improvements, in the resilience improvement framework it may not be relevant to look for Cost benefit analysis (CBA) since regulation, as of now, may not pay off such investments.

3.1.2.1 Continuity of service and non-conventional sources integration

Microgrids can be an alternative to improve continuity of supply in radial distribution grids in rural areas, where traditional reinforcements cannot be carried out. They can indeed be located in hard-to-reach environments or naturally protected areas where the permits to build new lines are difficult to obtain. Currently, when a contingency occurs in such a feeder, it is isolated, and there is a loss of supply for all customers located downstream until the service is restored (so possibly more than the duration of the fault).

Microgrids can be optimally designed in order to supply the consumers that could not be supplied from the original source (normally the upstream substation) after a contingency. [36] illustrates such scenario, where the location, the type (storage, PV systems, diesel groups, etc.) and the size of the DER technologies in charge of feeding the microgrids have been chosen according to a multi-criteria optimization in which both the investment in these new technologies and the increase of reliability are evaluated. The design considers the existence of tele-controlled switches to partition the grid and optimization is carried out in two steps following a bottom-up approach. First, at the microgrid level, involving one or several grid partitions, and second, at the grid level, involving the entire microgrid. The combination of diesel units and batteries seems to be the most cost-effective option to increase the reliability of the grid. Moreover, the results show that selecting solar PV installations for this purpose is in most cases not profitable (we could not rely on PV alone, during an outage, with the same security as the main grid). This conclusion is mainly due to two reasons. First, the PV high investment cost, and second the PV production in sunny hours of the day may not be coincident with the outage repair time. Finally, it has been shown that if battery investment costs would drop significantly with respect to current values, the microgrid solutions would mainly be based on batteries, for greenhouse gases emissions considerations.

On a larger perspective, the key question, at the long-term planning stage, is to decide what section of the grid should be considered for the definition of the microgrid area (i.e. where to open the CB)? In a social and economic perspective, this could be linked with the development of local energy communities, including the advantages of processing multi-energy vectors, for increased storage capabilities, for instance relying on power-to-gas technologies.

3.1.2.2 Mitigating extreme events

In recent years, climate change has been the roots of many extreme natural disasters all over the world. Most of these extreme events have serious impacts on power systems, especially distribution grids. The resilience of power systems facing such disasters could be at stakes. Distribution lines, substations, DER, and end users can be seriously damaged by strong winds and flooding, such as during super-storms or hurricanes. For example, approximately 8.35 million customers were reported to be without power in 2012, after Hurricane Sandy struck the East Coast of the US. Tremendous economic losses and significant life risks are the consequences of severe weather-related power outages, highlighting the importance of an enhanced power grid resilience [37].

The main goal of existing restoration strategies is improving the reliability of distribution systems and they are designed based on a set of pre-specified fault scenarios, usually a single fault rather than multiple simultaneous ones. It is worth noting that anticipating the effects of a major disaster on a distribution system is impossible. Restoring the interrupted loads after an extreme natural event is much more difficult relative to a typical outage caused by a tree contact or a car accident. Generally, multiple faults, a large number of interrupted customers, lack of power sources also at bulk-system level, and weak transmission/distribution grids are the consequences of a catastrophic outage [37].

Minimizing the outage duration of loads, based on their priorities and demand sizes are the main objectives of restoration by microgrids. Most recovery activities greatly depend on a reliable power supply. However, a natural disaster can cause widespread and severe damage to power grids, including the generating assets. Therefore, the microgrid-based restoration problem is to dispatch microgrids in the distribution system to restore critical loads under emergency situations [38]. The contribution of microgrids to the system restoration after disruptive events can be complemented by using mobile energy resources. Conditions and constraints to be considered include:

- Capacity differences of mobile supplies;
- Priorities of critical loads;
- Damage on the distribution system elements;
- Road network damage/congestion;
- Radial topology requirements, operational constraints, and so on.

Constrained by equipment or firmware requirements, only a fraction of the nodes in distribution systems can be acceptable as candidate nodes for mobile resources allocation and connection. The microgrid-based restoration problem consists essentially in dispatching microgrids in the distribution system to restore critical loads under emergencies.

As an illustration, Figure 3.1 shows a conceptual resilience curve, constructed based on [39], for clearer statements. R is an index of the resilience level of the system, t_{MG} is the timing of when microgrids participate in the system restoration. The time period between t_r and t_{ir} would be considered as operating time of the conventional restoration strategies. The conventional restoration schemes may be of limited effect for a distribution grid struck by a natural disaster, i.e., the enhancement from R_{pe} to R_{pr} is small. In this case, mobile energy supplies are desirable resources to enhance the resilience level of the system from R_{pr} to $R\prime_{pr}$ in the restoration state after the event. The isolated outage regions and some areas that cannot be sufficiently restored by the surviving power access are mainly the concerned areas of mobile energy supply dispatch. Hence, in spite of the similarity between concerned time periods of mobile energy supply dispatch with the conventional distribution system restoration, their concerned outage areas are different with limited overlaps. These two kinds of restoration actions are related yet independent to some extent. However, it is possible to coordinate them in a straightforward way [40]:

- Apply conventional restoration strategies for outage areas that could be sufficiently recovered by these strategies.
- Dispatch mobile energy supplies and conduct microgrid formation after the arrival of mobile energy supplies for isolated outage areas without power sources.
- Firstly, apply conventional strategies for outage areas insufficiently recovered by conventional restoration strategies, and then transfer to coordinated restoration strategies after the arrival of mobile energy resources.

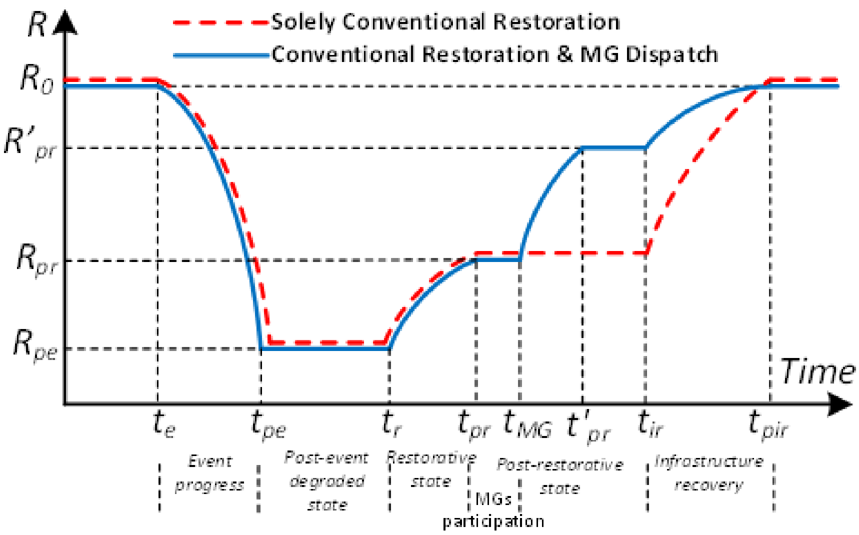

Figure 3.1 – *A conceptual resilience curve associated with an event.*

3.1.2.3 Other criteria

As discussed in Chapter 2 and in references [41], [42], other operational criteria can also be used to justify the temporary islanded operation of a microgrid. This is for instance the case of the demonstrator from the SENSIBLE project, were the improvement of voltage profile, the minimization of VRES curtailment, the minimization of losses, and the minimization of non-distributed energy were monitored. From that set of criteria, we can emphasize an interesting motivation in the capacity to ensure locally power quality (refer to the Section 2.2.3.4 in Chapter 2). Though not a common criterion to disconnect, power quality is relevant. This topic is discussed in Section 3.1.3.

The use of flexibility levers to isolate part of the grid for preventive/planned maintenance is another interesting criterion. In that context, DSO could use storage facilities, owned or remunerated, mobile or not, to enhance their capacity of action on their grid while minimizing the use of diesel generators [43], [44]. Current costs tend to show that such study case would be more beneficial from the CO_2 equivalent emissions perspective rather than a more traditional CBA.

Other criteria to isolate part of a distribution grid affect planning choices (from the operational to the long-term planning ones). Hybrid criteria are for instance socially and politically motivated ones, via the rise of semi-autonomous local energy communities favoring local DER production. Other criteria could rather focus on the local resources and losses optimization in addition to costs and environmental impacts, etc. In that context, value creation, asset optimization, local or global electricity market participation (for example via transactive energy systems) are the main drivers, through a more proactive control of the load curve.

Cyber-attacks could as well force the microgrid to go in islanded mode (in that case, it would be unintentional islanding). Within the IEC-61 850 standard future use, every single piece of information shall indeed be digital, including electrical values like frequency. As an illustration, if a malware, able to forge a false value of the frequency of the grid, is detected on the microgrid side, the Intrusion detection system (IDS) might take the decision to go to islanded mode while the cybersecurity threat is not cleared (depending on the power station role and localization in the power grid).

Lastly, forming a single or multiple microgrids is also a discussion that could take place, based on recommendation of standards, like for example the IEEE Standard 1547.4, [8].

Most of the presented criteria are out of the scope of this working group. We focus on the technical requirements to island, once we agree we can and want to disconnect from the main grid. Nevertheless, the main levers that would lead to the actual implementation of the capacity to isolate part of the distribution grids for any given duration in the future will consist of a compromise between technical constraints, social acceptance, economic viability and environmental relevance.

3.1.3 Power quality

To ensure the reliability of the energy system, the measurement of power quality is mandatory (meaning here quality of service in general, not only continuity of supply). It can be a criterion to disconnect from the main grid, for detecting islanding locally (planned or not), or at least represent KPIs once islanded. For microgrids transitioning from grid-connected to islanded mode, the challenges are mostly related to the sudden increased proportion of IBG in the temporary microgrid, which is weaker, with lower inertia, than the main grid (islanded operation can affect power quality). Power quality is a complex problem, addressed for example in the EN-50 160 standard, which contains unbalanced operation, flickers, harmonics, frequency and voltage ranges and limits. The ranges of parameters may vary depending on the mode of the considered microgrid (grid-connected, islanded or during the transition). At the light of the role of power quality and the extent of the theme in analyzing it, it is relevant to know the power quality related standards in order to consider specific elements for microgrids.

3.1.3.1 The perspective of EN-50 160

The EN-50 160 is a European standard that describes and specifies, at the consumer's delivery point, what are the principal characteristics that must follow the voltage delivered by the distribution public grid [45]. This standard must be followed in every point when the grid is operated in islanded or grid-connected mode. When the microgrid reconnects to the main grid, it has to be synchronized and has to follow this standard. Yet, it might be necessary to introduce some adjustment for the transition when both parts of the grid disconnect or synchronize. This standard defines limits of voltage supply for three different voltage levels (LV, MV and HV) for continuous phenomena and voltage events.

3.1.3.1.1 Continuous phenomena. Continuous phenomena are deviations from the nominal value that occur continuously over time. Such phenomena occur mainly due to load patterns, changes of load and nonlinear loads. The main sets of limits for continuous phenomena are summarized in Table 3.1, Table 3.2 and Table 3.3.

TABLE 3.1 – *EN-50 160 sets of limits for continuous phenomena, THD.*

	LV	MV	HV
THD, %	≤8	≤8	under consideration
Inter-harmonics limit	Levels are under consideration[1]	Levels are under consideration[1]	no values are provided[2]
Signaling voltage	See Figure 3.2[3]	See Figure 3.2[3]	no values are provided[4]

[1]Levels are under consideration due to development of the application of frequency converters and similar control equipment.
[2]No values are provided due to low resonance frequency of the HV grid.
[3]For 99 % of a day the 3 s mean value of signal voltages shall be less than or equal to the values given in tables for LV and MV voltage levels.
[4]Due to the low resonance frequency of the HV grid, no values are provided for main signaling voltages.

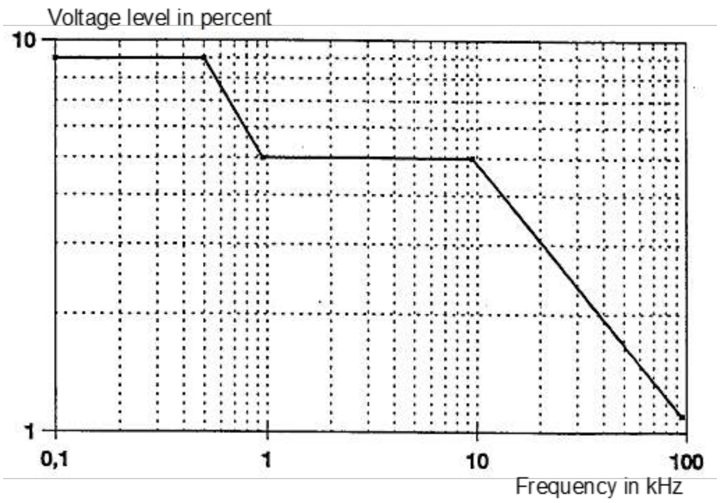

FIGURE 3.2 – *EN-50 160, signaling voltage versus frequency.*

Table 3.2 – *EN-50 160 sets of limits for continuous phenomena, voltage and frequency.*

Parameter	Voltage levels	Grid-connected mode		Islanded mode	
		Down limit	Up limit	Down limit	Up limit
Frequency, Hz	LV, MV, HV	49.5[1] 47[2]	50.5[1] 52[2]	49[1] 42,5[2]	51[1] 57.5[2]
Voltage, % U_n	LV, MV	-10[3,4,5]	10[3,4,5]	-15[3,4,5]	10[3,4,5]
Flicker	LV, MV, HV	0[6]	1[6]		
Voltage Unbalance, %	LV, MV, HV	0[7]	3[7]		

[1] 99.5 % of a year for grid-connected mode, during 95 % of a week for islanded mode.
[2] 100 % of the time
[3] For LV. During each period of one week, 95 % of the 10 min mean RMS values of the supply voltage shall be within the range of ±10 % U_n; and all 10 min mean RMS values of the supply voltage shall be within the range of +10 %/-15 % U_n.
[4] For MV. At least 99 % of the 10 min mean RMS values of the supply voltage shall be below the upper limits of +10 % U_c. At least 99 % of the 10 min mean RMS values of the supply voltage shall be above the lower limits of -10 % U_c. None of the 10 min mean RMS values of the supply voltage shall be outside the limits of ±15 % U_c.
[5] For HV. As the number of end users supplied directly from HV grids is limited and normally subject to individual contracts, no limits for supply voltage variations are given in this standard. Existing product standards for HV equipment should be considered.
[6] Each period of one week for 95 % of the time.
[7] The limit should be met during each period of one week, 95 % of the 10 min mean RMS values of the negative phase sequence component.

Table 3.3 – *EN-50 160 sets of limits for continuous phenomena, harmonics.*

Odd harmonics						Even harmonics		
Not multiples of 3			Multiples of 3					
Order	Relative magnitude		Order	Relative magnitude		Order	Relative magnitude	
	LV, MV[5]	HV[3,4,5]		LV, MV[5]	HV[3,4,5]		LV, MV[5]	HV[3,4,5]
5	6.0 %	5 %	3	5.0 %[2]	3 %[2]	2	2.0 %	1.90 %
7	5.0 %	4 %	9	1.5 %	0.013	4	1.0 %	1.00 %
11	3.5 %	3 %	15	0.5 %	0.005	6, ..., 24	0.5 %	0.50 %
13	3.0 %	3 %	21	0.5 %	0.005			
17	2.0 %	u.c.						
19	1.5 %	u.c.						
23	1.5 %	u.c.						
251	1.5 %	u.c.						

[1] No values are given for harmonics of order higher than 25, as they are usually small, but largely unpredictable due to resonance effects.
[2] Depending on the grid design, the value for the third harmonic order can be substantially lower.
[3] Harmonics not multiple of 3 of order higher than 13 are under consideration.
[4] In some countries, limits for harmonics are already in place.
[5] Under normal operating conditions, during each period of one week, 95 % of the 10 min mean RMS values of each individual harmonic voltage shall be less than limit.

3.1.3.1.2 Voltage events. Voltage events are sudden and significant deviations from the normal or the desired wave shapes. They typically occur due to unpredictable events (e.g. faults) and external causes (e.g. weather conditions or third party actions). Only indicative values can be provided for voltage events at present and they are in Annex B of EN-50 160. For information, the main types of voltage events are mentioned bellow:

- Interruptions of the supply voltage;
- Supply voltage dips, caused by faults;
- Supply voltage swells, caused by switching operations and load disconnections. This should be observed in islanding and synchronizing back from/to the main grid;
- Transient overvoltages caused by lighting or by switching the system, caused by lightning or switching operations and load disconnections. This should be observed in islanding and synchronizing back from/to the main grid.

3.1.3.2 Elements from the CIRED/CIGRE C4.24 WG

Power Quality was discussed in the Microgrids Chapter of the CIRED/CIGRE C4.24 2018 joint WG [46]. Some highlights, in line with the present WG, are summarized below.

The main grid provides its strength as reference for both the system voltage and frequency in grid-connected mode. Within the microgrid, active and reactive power issues may arise at the level of DERs. When microgrids are operated in islanded mode, frequency and voltage stability becomes a localized problem. The change in the SC capacity at the PCC of large polluting loads could make agreed emissions no longer applicable. The characteristic impedance of the microgrid also changes. This can lead to system resonances that simply do not exist in grid-connected mode. Disturbances during mode transition (from grid-connected to islanded mode and vice-versa) are:

- Phase angle jumps in supply voltage (more likely during unplanned transitions);
- Voltage sags or swells, as a consequence of load/generation unbalance and unplanned disconnection of sensitive loads;
- Frequency variations, due to load/generation unbalance.

The level of the active and reactive power disturbances during the transition depends on the transition strategies, the ratio of machines to IBG and the control scheme of these units. The connection conditions are key for power quality and may vary from the common values (for instance set at the national level by TSO) depending on the ratio of the main impedance to the power of the generators. Power quality is also impacted for example when some DER units switch from voltage to current control, causing voltage stability problems due to the delay in the detection of unintentional islanding.

In islanded mode, higher dynamics and wider ranges of interactions between loads and DERs result in more pronounced, frequent and longer voltage and frequency variations, further augmented by the reduced SC power and inertia of microgrids. The power electronics interfaces of DER based on IBG might cause undesirably high levels of harmonics. In addition, self-commutated pulse-width modulation controlled inverters typically produce supraharmonics. Identified harmonic disturbances are linked to an increase in the level of distortion (current and voltage) due to the share of IBG and changes in the resonances observed in the microgrid (variation of electrical characteristics, increased high-level harmonic content). Mitigation solution are proposed in the scientific literature, most of them being costly and problem-specific (resonance minimization or harmonic mitigation).

Power quality requirements must be considered when operating a microgrid, with possible compromises in mind regarding the reduction of the SC power, available generation and inertia characteristics. Nevertheless, state-of-art power electronics controls or active filter management, focusing on specifics harmonics for instance, could managed phase balancing as well as sensitiveness to voltage disturbances. Major issues seem to be economic rather than technical. As a reminder, increasing the power quality was a relevant criterion to disconnect a microgrid for only one demonstrator presented in Chapter 2.

3.2 Islanding: from grid-connected to islanded operation

The main feature of microgrids is their ability to act as a single controllable entity with respect to the main grid. This includes the possibility to enable operation in both grid-connected and islanded modes. Accordingly, this section provides an overview of the technical aspects of the transition from grid-connected to islanded mode and the islanding transition. Though this section covers both islanding and islanded operations, the focus is rather on the transition, as there exists already a large panel of excellent and recent literature related to islanded operation of microgrids, referenced in this report. Notably, the following documents (in addition to in-text references) have been useful in writing this section:

IEC TS 62898-1: Guidelines for general planning and design of microgrids [47];

IEC TS 62898-2: Technical requirements for operation and control of microgrids [48];

IEC TS 62898-3-1: Microgrids – Part 3-1: Technical requirements – Protection and dynamic control [49];

IEC TS 62898-3-2: Microgrids – Part 3-2: Technical requirements – Energy management systems (work in progress);

IEEE Std 1547.4(a): IEEE Guide for design, operation, and integration of distributed resource island systems with electric power systems [4], [8];

IEEE Std 2030.7: IEEE Standard for the specification of microgrid controllers [50];

IEEE-PES Technical Report 66: Microgrid stability definitions, analysis and modeling [2].

No matter the type of islanding, the capability to operate in islanded mode entails specific requirements that need to be intentionally planned. Indeed, when operating as an island, the microgrid should be in a stable state as when grid-connected, thus also sharing very similar operation objectives. Nevertheless, the absence of the main grid results in large differences:

- The operation shall be self-sustained either for a limited duration or permanently. This includes frequency regulation, which is the TSO responsibility. In a microgrid it would be handled locally and by the DSO if no new entity is dedicated to that task;
- The sizing and dispatch management of DG and storage shall ensure targeted energy and power supply performances;
- Load priority, critical load, controllable load as well as DSM (i.e. load management schemes) should be implemented;
- There shall be at least one (or one group of) controllable power source(s) to provide the reference of frequency and voltage;
- Dedicated EMS schemes and logic shall be implemented;
- In islanded mode the configuration, power flow, neutral grounding and SC current values change. Hence the microgrid protection setting values shall be reconfigured accordingly;
- In parallel to a dedicated management of fault, specific elements also need to be considered for the management of disturbances during operation (dynamic control);

- The islanded mode might experience severe deviations from power quality standards;
- The microgrid shall be capable of monitoring voltage, frequency and phase angle of the main grid to synchronize back.

After the transition from grid-connected and islanded mode, we should differentiate between short and long-term islanded operation, e.g. due to maintenance works (hours) or due to extreme events (many hours, days). The capacity to sustain a long-term operation of an islanded microgrid directly depends on the capacity to ensure the power balance for the given duration (with the help of storage facility, local energy production, etc.). The next subsections provide an overview of the above-mentioned elements according to main themes:

Monitoring, control, and communication systems: The correct operation of a microgrid is achieved though an appropriate installation and usage of monitoring, control, and communication systems that exploits the capabilities of controllable equipment in order to perform the whole set of functions that allow different operating modes as well as real-time operation and operational planning. Typically, the control of the microgrid is a hierarchical control. The control system embraces various levels, from device control functions to Microgrid energy management systems (MEMS), relying on measurements and information exchanges. The primary control is usually a local, decentralized control. For islanded operation, at least one of the controllable elements should be an element imposing voltage and frequency (e.g, synchronous generator or inverters operated in grid-forming mode) [5]. Secondary controls can be centralized or distributed and aim at bringing frequency and voltage back to their nominal values or in order to prepare the resynchronization close to grid frequency and voltage values together with a zero phase angle difference. The tertiary control embraces the MEMS and is usually a centralized control. Further and in order to reduce the impact on the loads, sufficient power and energy capacity must be available locally. Exchanging information between components and exchanging references and measurements between the microgrid and the main grid are critical to its proper operation. The islanding transition relies on an increase in the need of communication and is therefore highly dependent on a strong information infrastructure, but as well more at risk regarding cybersecurity. Communication can be based on several technologies depending on the needs and the pre-conditions on site.

Protection: Grid-connected and islanded microgrids shall have the corresponding protective relaying functions to prevent equipment damage and guarantee safe operations. When microgrid transfers between operating modes, the configuration, power flow, neutral grounding and SC current values can change. Therefore, the microgrid protection setting value shall be reconfigured accordingly. The control of inverters affects protection performances in islanded mode as well [51].

Grid-forming devices: Notably relying on storage systems, grid-forming units are necessary to ensure the voltage and frequency control while the main grid is not present. The largest IBG is usually designed and controlled to that purpose if no rotating machine is available, the other components being controlled as grid-following units. Storage is critical, if not essential, to maintain the islanded operation in managed conditions. It allows microgrid mitigating the volatility of renewable energy, providing load management, supplying demand during islanded mode, and reaching targeted microgrid reliability. When storage is present (almost systematically in the studied demonstrators of Chapter 2), it is usually considered as the grid-forming unit, justifying to merge both aspects in the same subsection of the present report.

3.2.1 Monitoring, control and communication

3.2.1.1 Monitoring systems

Methods and components exist for detecting unplanned islanding as well as to verify that a planned islanding has been correctly operated. Voltage and frequency measurements, as well as control loops between the main grid operation system and the microgrid management system, are usually implemented at the level of the grid-forming unit in case of islanding.

In case of unintentional islanding, Anti-islanding protections of DER should detect the island and cease to energize the electrical island and trip within 2 s of the formation of an island [4], [8]. Anti-islanding protections can be classified into two large groups: remote and local protections. Local anti-islanding protections can be in turn grouped into passive, active and hybrid protections. The performance of anti-islanding protections is quantified by the Non detection zone (NDZ) and response times. Standard test procedures exist to evaluate anti-islanding protections. National regulations are technology neutral but usually impose maximum detection times [52]–[55].

Observability is the ability to deduce the internal states of a system on the information provided by its outputs. In control theory, observability is a mathematical twofold (following a direct conceptual mapping) to controllability, i.e. the ability to control internal states of a system by manipulating inputs. In the absence of appropriate monitoring services, which ensure observability, intermittent and low-inertia behavior as well as independent demand-side actions can menace secure operation, control, and protection of active distribution systems [56], [57].

3.2.1.2 Control systems

When the microgrid operates in grid-connected mode, islanded mode or transitions between them, the most important tasks are to ensure the normal operation of sensitive loads and not to impair the integrity or the safety of the distribution grid. This is achieved through proper control performances of the microgrid operation, which in turn is obtained through the microgrid control system. Stability is a key issue when dealing with microgrids, where the capacity of stabilization from the main grid is not present. Indeed, system strength, inertia, power capacity, and Phase-locked loop (PLL) dynamics can contribute to stability issues in microgrids. Dedicated control chains based on droop features are necessary for primary control objectives in case of rapid variation of the loads. For secondary control purposes, a special chain should be implemented dividing the load/generation by the available assets and restoring nominal voltage and frequency. Controls ranging from centralized (in demonstrators) to completely decentralized (in recent scientific researches) can be considered at that stage.

In general, tasks and requirements related to microgrids control can be organized in a set of functions that define the full range of the capabilities of the microgrids to reach and maintain a stable operation. These functions are diverse in the sense that they cover both real-time power control and energy management for the different operating modes. Moreover, since there are many possible configurations for microgrids depending upon location and purpose, the specific requirements and functions of the microgrids and related control systems differ.

Nevertheless, these requirements and functions can be organized according to a general framework based on hierarchic position and operational time-horizon. A typical perspective organizes the control functions of a microgrid according to three layers [58]–[60]:

Local control (0-level control): It includes fundamental control hardware for internal voltage and current control loops of power sources and storage, single and three-phase inverters, as well as management of other controllable elements (e.g. loads, transformers, breakers, PLL, etc.) [5], [59], [61]. Local control addresses real-time operation control (ranges of milliseconds and less). Settings of the control parameters of the different loops need to be tuned carefully since the stable control, in islanded operation, of an inverter feeding a load might lead to instability when the same inverter is connected to a strong grid [62]. Seamless transitions from islanded to grid-connected modes and vice-versa are needed from the controls.

Automatic control (primary control): Usually droop-based, as illustrated in Figure 3.3, it operates in order to compensate stability issues that can be due to control systems or power balance stability [58], [63]. Control systems stability refers to deviations of the system-level voltage and frequency, which are caused by inadequate local control schemes, by poor tuning of equipment controllers and by ineffective load sharing. Power balance stability issues refer to events such as loss of generation units, violation of generation unit power limits, and unplanned load switching. The automatic control is addressed by the dynamic control layer of the control system (and/or by the MEMS according to the relevant time frames) and operates in the range of seconds and milliseconds.

MEMS (secondary/tertiary controls): It is the highest control level that addresses optimal operational planning according to the operating modes (grid-connected, islanded mode) and which generally operates over the longest time frames (minutes and more), in interaction with the main grid operator. MEMS may also partly interact with the dynamic control, such as during black-start, or for the second control, to bring back parameters into nominal ranges.

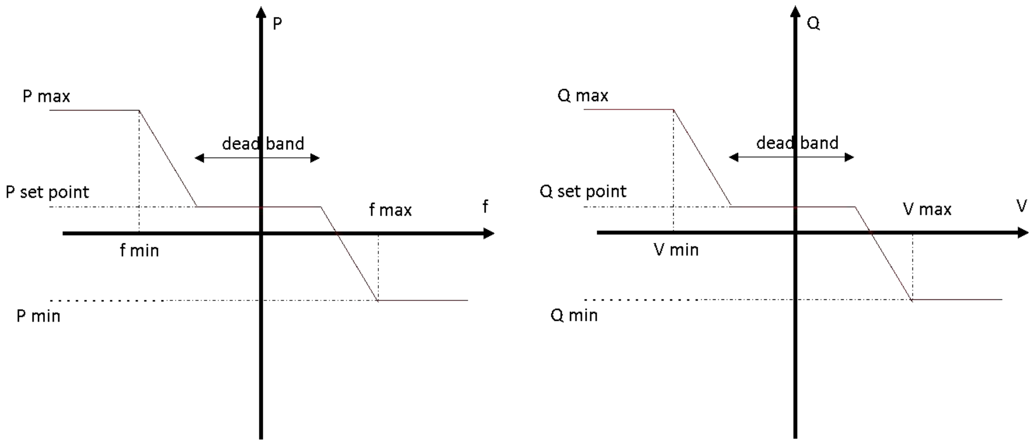

FIGURE 3.3 – *Automatic control characteristics by droop features.*

Organizing the control system according to this hierarchic structure reflects the traditional control structure of large power systems. Nevertheless, microgrid typical elements such as short feeder lengths, low X/R ratios, significant shares of VRES based on power electronic (i.e. IBG), and low system inertia, make the required performances of the microgrid control systems significantly vary from that of a conventional power system. The hierarchic structure of the controller is also a way to increase the resilience of the control system of the microgrid, by being able to operate on a good but not perfect level in case of a various set of issues. This is indeed better than having to close the operations due to issues in the control or communication systems. Furthermore, the required capability to operate in different modes (grid-connected and islanded) exacerbates the mentioned elements and poses further challenges.

Stability once islanded, which is out of the scope of this WG, represents a significant volume of scientific and technical literature, ranging from angle stability (transient and small signal), frequency stability, voltage and frequency FRT [2], [64]–[71]. Grid codes and industrial developments are also available on that topic [72].

Additional specific observations are given in the literature. Not being directly recommendation for the technical operation of temporary islanded microgrids within distribution grids, we choose to keep them here rather than in Chapter 4, even if the main points are further discussed in Chapter 4. Most of the observations highlight the necessity of a dedicated WG on monitoring and communication systems for microgrids that are considered within the scope of the present report.

- When operating in islanded mode, the microgrid needs to monitor and control the generation output and the load demand to ensure the power balance. This is achieved by controls operating at multiple time frames. The purpose is to supply power to the load while contributing to maintain acceptable frequency and voltage values.
- Involved functions are: economic dispatch, unit commitment, optimal power flow, short-term operational planning look-ahead (15 min to 1 h), long-term operational planning, forecasting (load and resource availability), load management (load shedding, demand response or DSM). The dispatch control can be either in the form of a look-up table or an optimization function setting the active and reactive power at the generating buses (even based on artificial intelligence and dynamic optimization in some advance cases).
- The optimization function, for the islanded operation, shall aim at the power supply continuity of critical loads through, for instance, the management of the available storage system. Actually, appropriate control approaches for the management of storage facilities are needed to ensure the reliable power supply and the stable operation during events such as loss of generating units or excess generation. Moreover, the storage can also be operated to provide frequency reserves.
- Power balance also require an appropriate control method for effective load sharing among power sources. Some of the available options are droop-based methods, adaptive methods and central control techniques.
- Frequency stability issues are a major concern in islanded mode, due to the characteristically low inertia of the energy system and high proportion of VRES. The low X/R ratios of microgrid feeders, resulting in strong coupling between voltage and frequency, is also another issue worsening the frequency stabilization in microgrids. Due to the strong coupling between voltage and frequency in microgrids, frequency and voltage changes are also reflected as variations of load power.
- The microgrid system frequency control shall be coordinated with the primary control of IBGs and the voltage and frequency dependence of the loads of the microgrid. The generation units involved in microgrids are typically small and few, which means disconnection of one of the units could cause notable changes in the system frequency with a high ROCOF. Conventional frequency control techniques may not be fast and capable enough to address these challenges. Hence, specially designed frequency control should be available to ensure frequency stability in microgrids operating in islanded mode.
- Typically, frequency control can be achieved by adopting a reference microgrid generator or storage resource while having other sources adjusting their active power output through frequency droop control.
- When in islanded mode, one of the power source has to provide voltage control. This needs to be coordinated with other regulating devices in the system. A coordination of the set points of different power sources, of capacitor banks and voltage regulators to maintain the desired voltage profiles is required.
- Grid-forming converters can impose voltage and frequency values, which can be adapted through appropriate local controls monitoring active and reactive power balance. Grid-following converters can support frequency and voltage control as well by monitoring

frequency and voltage values and acting on their active and reactive power output.

- Line voltage regulators, within the island, may present reverse power flows. If the regulator control does not respond appropriately during reverse power flow conditions, then damaging voltage levels may be produced. Displaced load may also cause the voltage regulator to mis-operate if line-drop compensations are used, or the compensation computation needs to be adjusted, as many regulators do not consider current directionality. The voltage impact of the shunt capacitor may also be affected by the amount of SC duty in islanded mode versus in grid-connected operation. Loss of load, when in islanded mode, may cause sudden voltage changes and needs to be addressed if necessary.
- When considering inverter technologies, voltage source mode may be preferred to current source mode for a system planned for islanding. In this mode, the operation of the inverter more closely emulates that of a synchronous machine and may contribute to improved power quality by active harmonic suppression and voltage regulation. Different controls have been proposed including droop controls, VSG-based controls, etc. Standard droop control exhibits some inconvenient for resistive grids. However, there exist solutions including for instance virtual impedances, virtual transformations, adaptive voltage droop, etc. that mitigate the problem of resistive grids for power-frequency control based on inverters. The droop controls can also be used to suppress harmonics by setting the references of the voltage harmonics equal to zero.
- Finally, it is worthwhile to highlight the typical three alternatives to implement the control strategy:

  Centralized control: It provide commands to the entire system in what is effectively a master-slave configuration between the central system and distributed devices;

  Distributed control: It is accomplished with independent controls communicating with one another. This strategy uses intelligent devices that are strategically located to detect the conditions and initiate the required actions. A hybrid version between centralized and distributed control is also possible, called decentralized, where key nodes in the grid remain with master-like capacities;

  Decentralized control: It is accomplished with independent controls without communication with other devices.

3.2.1.3 Communication systems

The communication system of a microgrid depends on the control and protection system design as well as the number and type of devices involved.

3.2.1.3.1 Protocols. Many different communication configurations and protocols are available. The selection of the communication configuration depends on the control objective, implementation and maintenance costs. Further, implementation-specific factors such as available communication options, size of data traffic, number of involved devices, etc. affect the selection, too. Communication configurations can be classified into three groups (whose characteristics are presented below): tightly coupled, loosely coupled, and broadcast/multicast communications. Tightly coupled communications require the highest availability for the grid, where assets in loosely coupled and broadcast systems are able to manage their operation independently. Microgrid control systems that feature local asset control and a lower expectation for availability may be acceptable [73], [74].

Tightly-coupled: High availability of the communications channel is required. Many communication configurations are point-to-point, but LANs are also possible. IEC-61 850-7-420 provides object models for the types of information that could be exchanged. A common protocol for tightly coupled interactions is Modbus, although MMS and web services could also be used.

Loosely-coupled interaction: Reasonable availability of the communications system is required. Local devices can manage and control their output. The communication network could be a LAN and/or a WAN. IEC-61 850-7-420 and, more recently, IEC-61 850-90-7 can provide the object models 17 for exchanging this information. These object models can be mapped to MMS, web services, DNP 3.0, Smart energy profile (SEP), Modbus, and others. Note that, according to the US Department of Energy, the USA is now moving from DNP 3.0 (IEC-60 870-*) to IEC-61 850 SCSM implementations [75].

Broadcast and multicast: Reasonable availability is necessary, with the quality of service based on contractual and/or financial requirements for ensuring that DER systems receive the broadcast/multicast messages. DER systems would manage and control their own behavior in case of absence of messages. The communication network would be a WAN. IEC-61 850-7-420 and, more recently, IEC-61 850-90-7 can provide the object model for broadcasting/multicasting this information. These object models can be mapped to MMS, web services, DNP3, SEP, Modbus, and others.

Several protocols are employed to enable communication. A protocol suite consists of layered architecture where each layer performs its functionality using one or more protocols. The Open system interconnection (OSI) model is the benchmark communication architecture. Relevant protocol suites and protocols are listed next [76]:

- Internet protocol suite:

  Application layer: NTP, HTTP, Modbus, DNP3, etc.
  Transmission layer: TCP;
  Internet layer: IP;
- Modbus;
- DNP3;
- SEP 2.0;
- IEC-61 850;
- IEC-60 870-5-104 and IEC-60 870-5-101 (older than IEC-61 850 but still used quite a lot).

Note that IEC-61 850 is not a protocol per se. It is a standard which describes generic interface (ACSI), with “operational mapping”, Specific communication service mapping (SCSM) for each type of communication (process, automation, etc.) and process (PV, hydro, etc.). In this standard, protocols like DNP3, Modbus or web services, used in a given process, are all viewed as SCSM (for instance, IEC-61 400-25-1 is a SCSM for wind power plant). Some SCSM implementations are indeed directly included (like IEC-61 850-9-2 or 61 850-8-1) The IEEE Std 1547-2018 sets forward that proprietary communication interfaces may be developed and used to interface to a DER but the standardized local DER communication interface shall always be an available option.

With respect to the enabling communication technology, in general it is possible to distinguish between wired technologies and radio technologies.

- Wired technologies:
  - Copper Pair communications technologies;
  - Power Line communications technologies;
  - Fiber Optic communications technologies.

- Radio technologies:
  - VHF/UHF;
  - TETRA;
  - Wi-Fi;
  - ZigBee;
  - Z-WAVE;
  - WiMAX;
  - Cellular data services and satellite.

The maturity level of some of the discussed enabling technologies is illustrated in Figure 3.4.

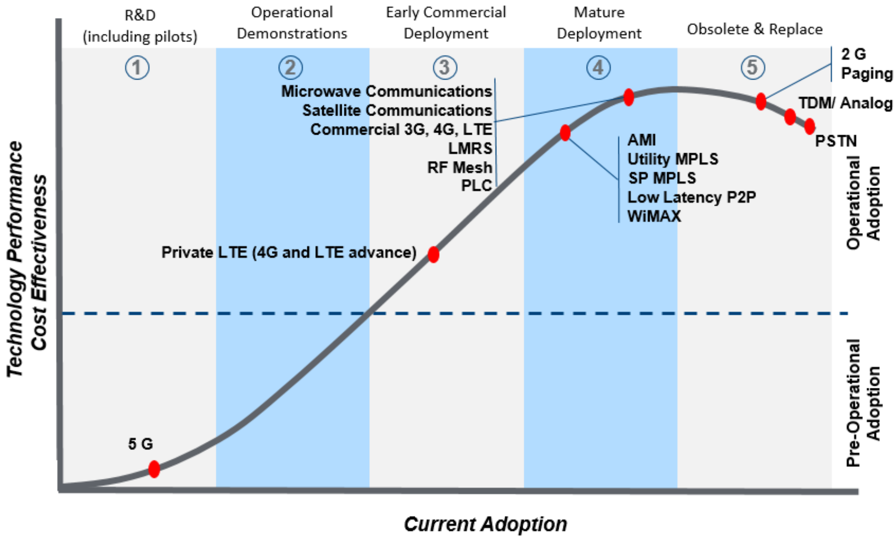

FIGURE 3.4 – *Maturity level of communication technologies [75].*

Pilot tests in Italy used PLC technology. In France, optical fiber and microwave transmission are under test. Communication performance requirements are very important and must align to the functions and associated time dimensions being supported. Several key aspects:

- Bandwidth;
- Throughput;
- Latency;
- Reliability and availability.

Common requirements between devices and operational systems are displayed in Table 3.4.

As an illustration, in case of protections and with the assumption that the protection system has to act in the minimum possible time in presence of an islanding event, Table 3.5 shows appropriate technologies to use in MV grids.

Communication architecture, technologies and protocols are not yet well established. Multiple technologies coexist, where the heterogeneity is justified by the different needs. It is important to achieve agreement on usage and interpretation of exchanged messages between different protocols and technologies. The publication of standards such as IEEE Std 2030-2011, IEEE Std 1547.3 and IEC-61 850 goes in that direction. IEEE Std 2030-2011 provides alternative approaches and best practices for interoperability. IEEE Std 1547.3 tackles interoperability of DG in an interconnected system. IEC-61 850 aims at a universal communication infrastructure in power systems.

Table 3.4 – *Common performance requirements between devices and operational systems [75].*

Distribution application	Bandwidth	Latency
Advanced smart meters	10 kbps	5 s
Grid sensor	10 kbps	5 s
Recloser/SCADA devices	10 kbps	100 ms
Capacitor bank	10 kbps	10 s
DER <50 kW	10 kbps	5 s
EV Charging	10 kbps	10 s

Table 3.5 – *Communication technologies for protections in MV grids [77].*

Data rate	Copper pair	PLC	Optic fiber	VHF/UHF radio	TETRA	ZigBee	WiMAX	Public data service	Satellite
>1 Mbps	yes	no	yes	yes*	no	no	yes	yes	no

*VHF/UHF can be a viable solution for installations close to the substation.

3.2.1.3.2 Security. This subsection does not distinguish cybersecurity from information security. The cybersecurity concerns are not the same when considering users or electrical data. For users, we need strong authentication and confidentiality, especially in the case of grid operators, which brings GDPR directly on sight. For electrical data, the main concern are integrity and availability. Confidentiality has been put aside in the IEC-61 850 standard mainly because of the current state of available technologies, which today do not permit to keep both timing requirements and the confidentiality of data [78].

Moreover, if a private operator, i.e. different from the operator of the main grid, handles the microgrid, then responsibilities in case of cybersecurity issues might cause long discussion on both sides. The needs of microgrid operations, especially about going to or from islanded mode, are somehow in opposition with the needs of cybersecurity. Last but not least, IEC-62 443 and IEC/dTR-63 069 include technical controls to ensure that security does not interfere with safety requirements (in other words, IEC-62 443-2 and IEC/dTR-63 069 prioritize safety over security) [79].

3.2.2 Protections

Protection system needs specific attentions in microgrids. For instance, differently from traditional distribution grids, fault currents in microgrids can vary a lot according to the location of the fault. This follows from the presence of IBG and from the fact that microgrids can change their architecture as well as they can switch between different operating modes. Accordingly, fixed relay settings usually adopted in traditional power grids appear inappropriate especially when the microgrid can be operated in both grid-connected and islanded modes. Therefore, different protection systems from the conventional ones may be required. In some cases, protection systems may need to be adjusted dynamically based on the operating state of the microgrid, as seen in some demonstrators presented in Chapter 2.

Moreover, it is important to highlight that, in microgrids, protection and dynamic control are closely related and need to be coordinated with each other. In fact, since the initial characteristics of faults are very similar to initial characteristics of transient and dynamic disturbances, to be able to distinguish the two types of incidents is critical for proper operation.

Focusing on the islanded operation mode of microgrids, the following specific elements for protection systems need to be considered.

- If the grounding system in islanded mode is different from the grounding system in grid-connected mode, ground fault protection settings and selectivity must be suitable for the different locations of ground fault current sources.
- If the SC current in islanded mode is significantly lower than in grid-connected mode (this typically occurs because of the fault current is only provided by IBG VRES), protection schemes used for grid-connected mode might not be sensitive enough for the islanded mode. Specific protections could be required, in addition to conventional overcurrent functions used for the grid-connected mode. Furthermore, the FRT capacity of the inverter can be considered as the last protection device of microgrids: the shutdown of all power supply. A necessary checking should be conducted in order to confirm the acceptability by other equipment connected to the same microgrid. The SC current being an issue in almost all cases, this often also requires another selectivity plan during islanded operation than in grid-connected mode.
- The opening of the PCC can modify the selectivity rules of protections in the microgrid.
- During the islanded mode, over/under voltage situations can occur according to the different system configurations, the size and type of the power sources, the connection modes and the adjusting methods of transformers. Accordingly, while the configuration of line protections does not need to be changed, the setting values and time limits need to be adapted to the islanded operation mode.
- The management of grid-connected or islanded modes can require a setting change to ensure detection and selectivity in each mode. These adaptive settings can be managed by group selection features, or features that are more complex. In the microgrid, there must be one set of hardware protection and at least two sets of algorithms and software.

Various protection schemes have been proposed to accommodate the features of microgrids.

Adaptive: They seem to be more effective to any change occurring in the microgrid architecture and operating modes. Centralized and decentralized categories can be identified.

Centralized ones are based on a centralized architecture, structured around a radial communication network. They adopt the IEC-61 850 standard and are characterized by a high reliability and a low latency. Nevertheless, if communication is lost, the protection scheme fails due to the absence of a backup communication network. Moreover, depending on the microgrid complexity, these schemes may reveal inefficiencies related to computational efforts and communication delays.

Decentralized ones are able to provide high performance, but their implementation requires a complete upgrade of the existing schemes with high integration costs.

Differential: They involve partial upgrade, or an extension of protection schemes usually adopted in distribution grids.

3.2.2.1 Common types of fault

3.2.2.1.1 Phase faults. In microgrids, detection of the following faults is made difficult justifying advanced protection scheme to be developed:

Bi-directional flow of SC current: SC sources can be distributed in different locations, which is already a reality in HV transmission grids, where more sophisticated protection systems are used, such as distance and differential protections.

Low SC current: Depending on the operating mode, the minimum SC current could be close to or even below the maximum load current, especially for feeders near the main busbars (where the sources are connected) or feeders between busbars connected to DG. For terminal feeders close to loads, this problem does not exist since the ratio between the minimum SC and the nominal value is high enough to discriminate a SC current and a load current.

Different operating modes: Fault detection and selectivity must be ensured in all possible operating modes. Please refer to lessons learned from demonstrators in Chapter 2 on selectivity and Chapter 4 for additional recommendations on those aspects.

3.2.2.1.2 Earth faults. The ground fault protection system is directly connected to the grounding system. The protection system must be designed in accordance with the grounding system. In the presence of microgrids, there are two specific challenges with respect to ground fault detection [77].

First challenge. The grounding system must be well managed in all possible operating modes. The the distribution grid generally defines the grounding system in grid-connected mode. The protection system, on the other hand, is generally based on the same principle, but with greater selectivity between the protections of the distribution grid and of the microgrid.

In islanded mode, if the ground connection is within the main grid, above the PCC, the ground connection is lost and the microgrid starts to operate in isolated grounding system. Depending on the grounding system within the microgrid island, a new grounding must be managed within the microgrid itself in order to master the circulation of the ground fault currents. In any case, it is recommended to ensure the neutral to ground connection in one single location to facilitate fault detection and selectivity.

As an illustration, the brown dotted microgrid in Figure 3.5 loses its neutral treatment once disconnected from the main grid. A continuation of the operation is only possible of the ground fault protection of the remaining grid is designed to detect possible ground faults in this circumstance.

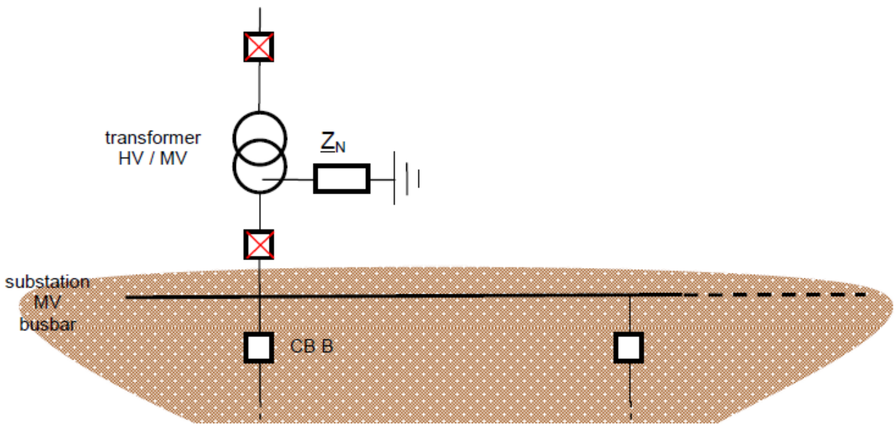

Figure 3.5 – *Microgrid (Brown dotted area) with a loss of neutral point directly connected to the star point of the transformer.*

In the case of Figure 3.6, the remaining grid after disconnection keeps its neutral treatment. A continuation of the operation is possible with the proposed strategy to detect ground faults.

Second challenge. Depending on the selected grounding system, the detection of ground faults and their selectivity can be simpler than the detection of phase faults and their selectivity. When the neutral is grounded in only one location, the ground connection remains the only source of SC current of the ground fault current. In any case, in LV microgrids the protection against ground faults must comply with the selectivity and the operating time defined by the local regulations or the international standard (the IEC-60 364 series for instance).

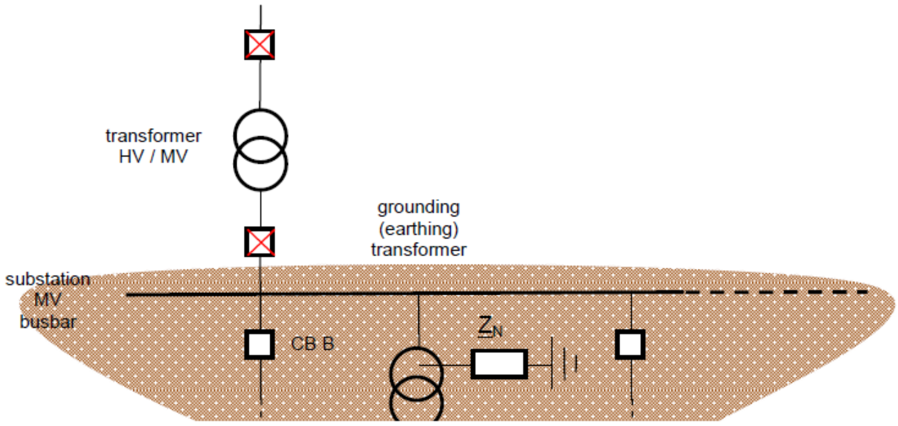

FIGURE 3.6 – *Microgrid (Brown dotted area) maintaining the same grounding system (neutral impedance connected to a grounding system).*

3.2.2.2 Fault detection

Any type of fault expressed in the previous section may occur. It is therefore necessary that the protections act immediately in order to guarantee the supply to the maximum number of customers. For protections to act in this way, it is vital that fault detection devices and systems are equipped with all the necessary functions. The minimum fault location functions are presented below, for passive local-based measurements schemes. The passive protection is a technique that uses a standalone digital relay installed at the PCC. The relay is equipped with a set of standard protection functions that may be the following [80].

3.2.2.2.1 Frequency (81m, 81M and 81R). Frequency functions are used to ensure protection in the event of major load-generation unbalances causing large frequency deviations. The function operates when the frequency or the ROCOF are higher or lower than a set value. Underfrequency is detected with the 81m function while the identification of an overfrequency is done with the 81M function. In addition, in order to study the ROCOF, the function 81R is available. This function studies the stability of the grid in case of fast frequency changes.

Factors such as the system generation and load scenario, the inertia of the synchronous machines and the strength of the grid, determine the setting of the threshold values of the ROCOF. Thus, there is no single value. The biggest challenge is the difficulty to distinguish between local islanded and grid disconnection situations. It is therefore necessary to set an appropriate threshold value. However, if the setting value is too high, it reduces the sensitivity of the protection.

3.2.2.2.2 Overcurrent directional function (67 and 67N). The function works for a set value of overcurrent circulating in a fixed direction. Among the different subdivisions that this function present, at least 67 (AC overcurrent directional relay) and 67N (neutral directional overcurrent relay) may be relevant for microgrids.

Overcurrent protection is used not only to measure the magnitude of the current but also its direction; that is, the direction of the transmitted flow of the power, for which the system voltage is taken as a reference. Therefore, it is applicable to the bi-directional flow of the SC.

The 67N function is applicable for the detection of ground faults according to the selected grounding system. It is required to distinguish the capacitive current of the healthy feeder and the fault current of the faulty feeder. It is particularly useful for the detection of limited ground fault current (impedance or isolated star point grounding system) or for the grounding of the Petersen coil.

An advanced solution could be an adaptive directional overcurrent protection based on the status of the generators and the topology of the grid.

3.2.2.2.3 Overcurrent function: instantaneous (50 and 50N) and time delayed (51 and 51N). The instantaneous relay (50) operates immediately when there is an excessive current value. The function 50N is implemented to detect the cases of instantaneous overcurrent of the neutral.

The relay 51 operates when the current in a circuit exceeds a given value. There is an inverse relation between the current and the operation time defined as a tripping curve. The relay 51N is also used to analyze the overcurrent time of the neutral.

Both 50 and 51 can be used when the microgrid is connected to the grid, i.e. when the main grid mostly provides the SC current. The neutral overcurrent functions (50N and 51N) are applicable in microgrids with a single grounding neutral, presenting the same restrictions as in conventional systems. The time selectivity of the 51N can be used when a neutral to ground connection is managed in a single location. In order to guarantee a better performance of the protection, the sensitivity of these relays must be defined according to the requirements set by national and international standards.

3.2.2.2.4 Voltage based protections. Due to the lack of high currents, voltages could be used for protection in the case of islanded mode of the microgrid. Low voltage function (27) makes the relay operating with a given minimum voltage value and has to be timed. It is a useful relay both for the internal protection of the control systems of inverters and for the fault detection at the PCC.

The zero sequence overvoltage function (59N) is appropriate to detect ground fault protections when the microgrid transition to isolated mode and during the islanded operation. Temporization is needed to coordinate with the CB at customer's installations.

3.2.2.3 Advanced devices

Additional elements are being investigated regarding protections, partly discussed in Chapter 4. Among them, we could cite protections based on communication schemes, that would require an additional (fast enough) communication network to operate, but also increasing the sensitivity to cybersecurity. We could also mention adaptive settings for protections, i.e. changing based on external signal (or even local measurements), adapting their protection scheme to predefined modifications in the operational settings of the electrical environment. It could be based, for instance, on the detection of the transition from grid-connected to islanded mode.

3.2.3 Grid-forming components and storage systems

Grid-forming devices participate actively in forming the grid voltage, thus grid-forming power sources act as voltage sources without direct control of current (Figure 1.1, a). On the other hand, power sources in grid-following mode act as current sources (Figure 1.1, b). They use a PLL and a current control loop, do not control voltage and frequency and thus reduce indirectly the system inertia (when inverter-based).

Sufficient penetration of grid-forming power sources is a fundamental aspect for the microgrid stability and its reliable operation. Power sources in grid-forming control mode can be both types, synchronous and non-synchronous (inverter based). The grid-forming device should be a power source, which can provide the energy (active and reactive power) required from the grid. Synchronously connected power sources must have a primary mover, which requires a predictive amount of energy (diesel-generator, combined heat and power units, small-scale steam or gas turbines with synchronous machine, some hydro/wind turbines, etc.). For non-synchronously connected power sources, the same condition must be met at the DC side of the power source to fulfill the microgrid demands. Typically, these sources may be non-synchronously connected co-generation units, battery units with DC-AC inverter interface or renewable power sources (usually wind or solar power) with some energy storage at the DC side of power source [81].

3.2.3.1 Grid-forming power source

The strategy for active and reactive power flow control between two voltage buses connected via lines impedance can be derived from the complex power equation.

$$S = P + jQ = \hat{V}\hat{I}^* \tag{3.1}$$

For HV and MV grids, the lines impedance are generally inductive rather than resistive. It can be observed that the voltage angle is coupled mainly with the active power and voltage magnitudes differences. They represent the reactive power between two buses, see Figure 3.8.

If we define the grid frequency deviation $(\omega - \omega_0)$ and the voltage deviation $(V_1 - V_0)$, we can define the basic equations for a grid-forming power source control scheme as follows:

$$\omega_1 - \omega_0 = -k_p(P - P_0) \tag{3.2}$$

$$V_1 - V_0 = -k_q(Q - Q_0) \tag{3.3}$$

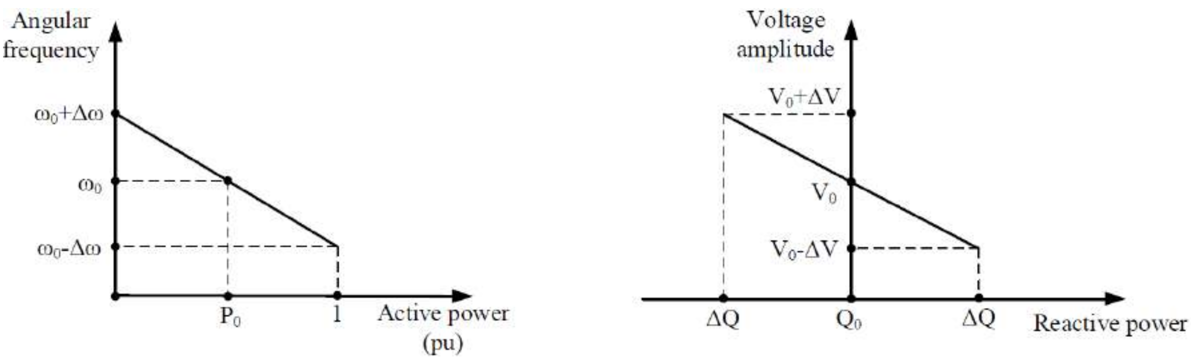

FIGURE 3.7 – *Droop control of grid-forming power sources, P/ω (left) and Q/V (right) [82].*

For LV grids (most of the microgrids), where the lines impedance are resistive rather than inductive, the relationship between active and reactive power and voltage magnitude and angle is more intertwined and illustrated in Figure 3.8.

Typical ranges of R/X ratios of impedance for LV, MV and HV power grids are as follows:

- The LV grids R/X ratio ranges from 1 to 3;
- The MV grids R/X ratio ranges from 0.2 to 1;
- The HV grids R/X ratio is lower than 0.3.

Thus, independent active and reactive power control is one of the most challenging issues in LV power grids control. Decoupled control techniques for active and reactive power are required for power sources. Their active and reactive power capability is defined by a PQ diagram, which is specified by the manufacturer. The limit is determined by the maximum apparent power (Figure 3.9).

A wide PQ diagram means that the power source has high reactive power capability. The PQ diagram of synchronous power sources is wider than the one of non-synchronous power sources for instance, though PQ diagrams of modern battery inverters are very similar to the ideal PQ diagram presented in Figure 3.9. Therefore, PQ diagram of power sources for grid-forming or supporting modes must be taken into account in the design procedure of microgrids.

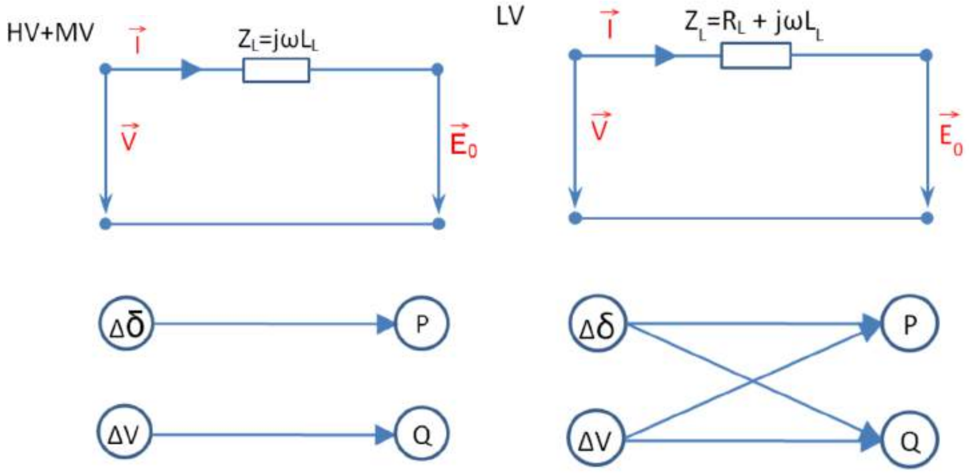

Figure 3.8 – *Active and reactive power control, HV and MV (left) and LV levels (right).*

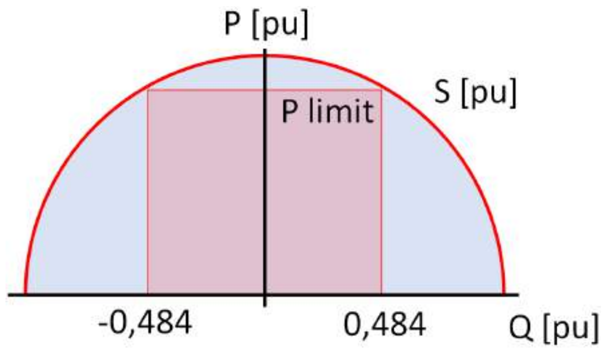

Figure 3.9 – *Example of ideal PQ diagram.*

3.2.3.2 Efforts to accommodate variability of renewable energy production

Also most islanded microgrids rely on fossil-based synchronous generators to provide a voltage and frequency reference, efforts are needed to tackle the challenges associated with the integration of VRES. The first one would be on the predictability of the resource, currently dealt with relying on AI techniques and the largest possible set of data. Efforts are also needed on regulatory aspects, for instance on FRT, where recent standards and grid codes mandate frequency and voltage FRT capabilities state for all technologies of generating units in order to support the grid stability [8], [83], [84]. In parallel, operators have started to require DER to be capable of functioning in wider ranges of frequency and voltage. For instance, IEEE C.50.13 [85] and IEC-60 034-3 mandate that synchronous generators shall be thermally capable of continuous and limited operation within prescribed ranges of voltage and frequency [86]. Furthermore, the requirements of the majority of grid codes are more demanding, such as the case of the Nordic grid code as illustrated in Figure 3.10.

Most standards require DER to be capable of providing ancillary services according to their size and connection point. These requirements include voltage control, frequency control, black-start capability, in addition to frequency and voltage FRT. For instance, IEEE 1547-2018 requires that DER are capable of responding to voltage variations within the normal operating range through voltage-reactive power control and voltage-active power control [4]. The required voltage and reactive power control functions include a constant power factor mode, a voltage-reactive power mode, an active-reactive power mode, and a constant reactive power mode, whereas the voltage and active power control function includes voltage-active power (volt-watt) mode. However, the usage of such functions remains in the hands of the power system operator.

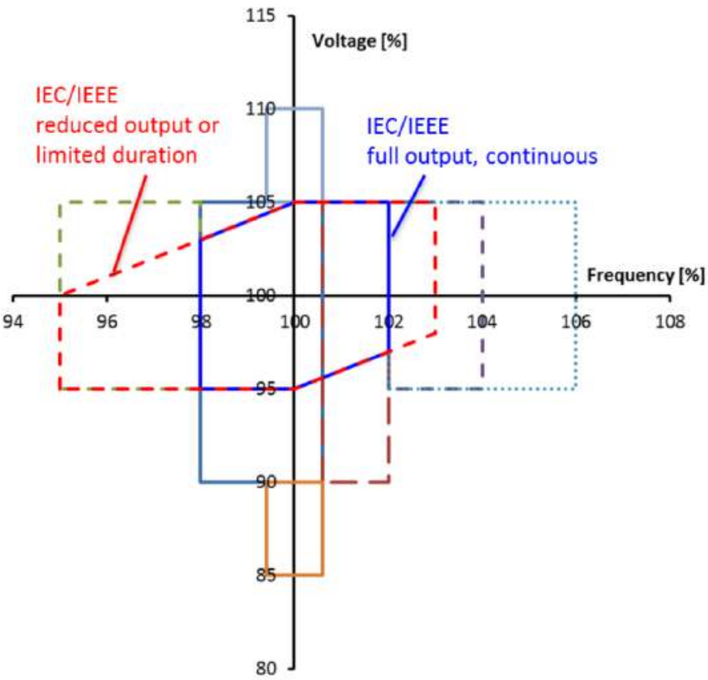

FIGURE 3.10 – *Comparison of the requirements of IEC/IEEE vs. the Nordic grid code [86].*

3.2.3.3 Synchronous grid-forming power sources

Rotating machines are traditionally providing inertia to the grid, i.e. time to act while filtering various electrical oscillations. In microgrids, only low-power generation could be found (for instance small hydro production or diesel generators in isolated villages), mostly based on synchronous machines (even if induction machines are being also considered in low-cost and low-tech developments), and not necessarily presenting the main contribution to the local energy mix of the microgrid once islanded.

Figure 3.11 proposes the traditional control system of a grid-forming synchronous machine, at the basis of the three-layered frequency and voltage controls. This technology is well known, robust and reliable, and above all, with a life duration that cannot compare to power electronics. Rotating machines allow a natural “decentralized” control with inertial and frequency response. The modeling of synchronous machines (at various precision levels) is necessary to provide virtual inertia and VSG via power-electronic converters, at least using the swing equation [87]–[89]. Note that the droop-based active power controls is, under certain conditions, equivalent to a VSG implementation.

Rotating machines could provide a natural grid-forming capacity, if present in the microgrid. In islanded microgrids, synchronous machines could be found in the form of CHP, diesel generators, small gas turbines, small hydro/wind production, etc. Such machines are mostly used with diesel generators in islands and developing countries. CHP and other primary sources are being considered to improve the environmental impact of its usage, in complement to local PV production when available. A promising solution (including from the economic point of view) would be in multi-energy systems, notably power to gas solutions. Refer to the literature for information about speed governors, excitation systems and general models [86], [90], [91].

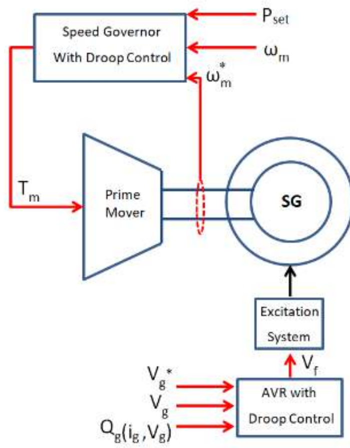

Figure 3.11 – *Grid-forming synchronous generator control system.*

3.2.3.4 Non-synchronous grid-forming power sources: storage systems

Storage facilities, as devices with key attribute to store energy (electric, thermal, chemical, electrochemical and mechanical) can be a decisive component for microgrids. Particularly during islanded mode, a microgrid is a small power grid with small SC power, where power flow fluctuations strongly affect key electric parameters like voltage and frequency and other power quality parameters. The main sources of power flow fluctuations are renewable power sources with non-predictive generation, the consumption of loads, where active and reactive powers are non-constant in time and depend on frequency and voltage in many cases. A storage facility offers many benefits for microgrids. It helps improving the power quality and the microgrid stability in islanded mode. In cases of uninterruptible power systems, a storage facility may help with FRT times to initialize generators for power supply of critical loads (diesel generators notably) or may even supply critical loads (such as master source) for a predefined period. When in grid-connected mode, the storage facility will be useful to address energy markets or provide ancillary services to the main grid, etc. Further, storage devices allow MEMS to reduce the need and use of conventional generation due to low VRES conditions, reducing generation-based emissions. However, despite its potential significant role for the operation of microgrids, energy storage still presents a sufficiently high cost to prevent the demonstrators presented in Chapter 2 to be economically viable.

When considering the islanded operation, at the planning stage of storage, the types and capacity of storage devices should be determined based on the reliability and power quality requirements, as well as the investment and operating costs. A spectral analysis of fluctuating load patterns and renewable energy resources is helpful to assess the amount of storage needed, which can be co-optimized with its associated control. Recent literature tends to propose hybridization of storage technologies to ensure a response at various time horizons (for FFR requirements, virtual inertia as well as steady state responses). Furthermore, an important requirement to be considered at the planning stage, which is typically applied to storage when a master/slave control scheme is adopted, is its capability to operate as grid-forming power source. Among the energy storage inverters in a microgrid, the one with the largest capacity shall be able to adopt the V/f control mode to establish and maintain the system voltage and frequency, if there are no other controllable power sources.

When considering the control of the islanded operation, the storage acts as a flexible resource whose charge and discharge is managed according to the load prediction results and the primary energy source forecast to balance power generation and load demand. The MEMS shall control storage according to the following basic functions:

- When the output power of generating units cannot meet the load demand, the energy storage shall start the power compensation;
- When the output power of generating units exceeds the load demand, the redundant power shall be adopted by the energy storage devices;
- According to the operating state of each energy storage (SoC and SoH), the MEMS shall decompose the total power control instruction of energy storage devices and distribute it to each individual storage unit.

Further functions that pertain to the control of storage (e.g., in islanded operation) are:

- Detect and monitor the working state of the storage dynamically;
- Estimate the change in the actual capacity of the storage;
- Prevent the storage from overcharging and over discharging;
- Balance exploitation of the storage batteries to achieve higher performances throughout the storage lifetime.

Large differences are identified between technologies. Therefore, the best storage technology should be chosen for particular application. Key parameters and advantages/disadvantages are available in the literature [81]. Technical parameters are necessary to select the proper storage and its associated control, but the cost of the storage facility (including its entire environment) remains the main issue preventing a widespread development. Current trends show a decrease in the investments costs for such technologies, but the decrease in price should decrease significantly more to allow a generic profitable real-life installation (again including its entire environment). Note that this is clearly linked with the optimization criteria of the MEMS and the capacity/willingness of end users to provide some flexibility regarding their aggregated load curve.

Storage facilities have been almost systematically used in the demonstrators assessed in Chapter 2, to ease the transition between islanded and grid-connected modes, mostly concentrating on electrochemical technologies. Adapting the technology, or operating the transition without storage is technically sound, but would necessitate additional elements, for instance multi-energy vector integration, advanced power electronic controls, or even a lowering in the accepted levels of energy quality (degraded mode).

3.3 Resynchronization: from islanded to grid-connected operation

Once the conditions requiring the microgrid to operate in islanded mode are no longer present, and if the main grid is available as well, it is time to reconnect both grids, notably synchronizing the frequency on both sides (if synchronization was lost during the islanding). Resynchronization is usually part of the secondary control in a microgrid. The main goal is to keep the difference in voltage, frequency and phase angle between the microgrid PCC and the main grid within an acceptable range of values. This ensures a smooth resynchronization and avoids larger power/voltage oscillations when the microgrid is synchronized to the main grid.

3.3.1 Main aspects of the resynchronization

During the different steps in the resynchronization control strategy, communication, various measurements, PLL controllers and protections settings play an important role to ensure a stable transition following the standards and grid codes presented in the previous sections. Some important or additional aspects during resynchronization are presented below [4], [50], [92]–[96].

3.3.2 System stability

System stability is one of the major concerns during resynchronization. The distributed effort of controlling voltage and frequency with multiple controllable sources can lead to controller interactions. That can result in voltage and frequency oscillations in the microgrid. The controller/converter interactions are one of the points of attention discussed in Chapter 4, notably illustrated by the lessons learned from the Simris demonstrator. The control speeds of various controllable sources must be coordinated accordingly to avoid such oscillations. The mix of power electronic as well as conventional generators make it more challenging to coordinate the distributed efforts. Other than control speed, location of the sources, rating and even the dynamics of the loads can have influence in the resynchronization stability. The communication medium can also play a role with its delay, latency and errors, without talking about security.

3.3.2.1 Grid code and standard

The available microgrid related standards are:

- IEEE 2030.7-2017 Standard for the specification of microgrid controllers;
- IEEE 2030.8-2018 Standard for the testing of microgrid controllers;
- IEEE 1547-2003 Standard for interconnecting distributed resources with electric systems;
- IEEE 1547.4-2011 Standard for design, operation, and integration of distributed resource island systems with electric power systems.

From the first reference, the resynchronization steps are listed below and presented in Table 3.6, with the associated parameters, metrics and testing approaches.

1. Resynchronize, set/match voltage, phase angle, and frequency within prescribed limits specified by applicable grid codes or requirements;
2. Set local controllers and protection devices appropriately;
3. Reconnect;
4. Transition to steady state connected mode and restore noncritical loads appropriately.

It is important that during the process, the microgrid voltage and frequency are maintained within acceptable limits based on these standards and local grid codes, as once reconnected, the microgrid, as part of the DSO operated grid, must follow the MV to LV grid standards.

3.3.2.2 The role of PLLs

The main role of the PLL is to synchronize the sources to the measured grid voltage. The dynamics of the PLL depend on the PLL controller gains and SC ratio of the grid. Various measures of feed-forward control gain scheduling have been reported to improve the PLL stability, particularly in microgrids (or weak grid) scenarios, which are characterized by a high impedance. Before and during the resynchronization with phase matching and phase jump at breaker closing, the change of control modes of the sources involves the use of the PLL outputs in the control. Thus, appropriate measures are necessary in tuning the PLL so a stable operation can be achieved during and after the resynchronization of the microgrid.

TABLE 3.6 – *Requirements, characteristics and metrics related to resynchronization [50].*

Elements of the function	Function characterization	Parameters and metrics	Testing approach
Step 3 – Moving to island mode	Execute preplanned actions such as load shedding (implement a black-start if required)	PCC opening	Verifying PCC opening, reaction time
Step 4 – Returning to normal operation	Transition to steady state islanded dispatch mode	V, f within range, power quality values below thresholds – dispatch orders	Observe V, f, transient response (rise time, settling time, overshoot) and power quality levels
Reconnection			
Step 1 – Initiation	Resynchronize, match voltage, phase angle, and frequency within prescribed limits	Difference (V, phase angle), ROCOF or ROCOA difference, within limits	V, phase angle, ROCOF or ROCOA difference, response time
Step 2 – Returning	Set local controllers and protection devices appropriately	Signals sent, changes implemented	Verify signals as required
Step 3 – Moving to grid-connected mode	Reconnect	PCC closing	PCC closed, verify initial P, Q flow, reaction time
Step 4 – Moving to normal operation	Transition to steady state connected dispatch mode and restore non critical loads	V, f within range, power quality values below thresholds – dispatch orders for grid-connected mode	Verify final P, Q flow, settling time, observe power quality levels

3.3.2.3 The role of energy storage

The energy storage plays a key role in controlling voltage and frequency in islanded operation (when no diesel or gas generator is available), as a main source with a controllable primary energy source. In the same spirit, it is most likely one of the main sources to control the voltage and frequency for resynchronization. Storage units, and in particular their inverter controls, play an important role in controlling the PCC voltage, frequency and phase angle difference. Overall storage plays a key role in stable microgrid operation from islanded to grid-connected modes. The distribution of resynchronization effort among storage and other sources should be done considering the state of charge and ratings. It is important to maintain the storage ability to resynchronize the microgrid with the help of other sources. This responsibility is further coordinated in multiple storage scenarios where more than one storage units is employed for resynchronization responsibility.

3.3.2.4 Protection settings

The IEEE standard for microgrids controllers does not describe a unique protection strategy. However, various schemes have been proposed in the literature and tested for microgrids protection. The main challenge is the variation of the fault current due to the change in connected DG, the grid connection, etc. Notably, the change in the tripping time of the over current elements with changes in the fault current is challenging for the stability. Another issue is the change or loss of sources of grounding. This could clearly affect ground fault detection.

While adaptive protection is one of the approaches to modify the protection setting based on microgrid/main grid connection, communication-based microgrid protections can help detecting fault locations irrespective of the fault current value. It is important to design the protection strategy of a microgrid based on all possible operation conditions to make it safe. It is also important to coordinate with the protection of the upstream grid.

The transient behavior of IBGs is an issue when synchronizing the microgrid, as the inverters may trip due to frequency/voltage excursions. Transient behavior of protections is also at stakes here, as discussed in Chapter 4. On the other hand, it is likely that a microgrid is confronted with generation deficiency after a few hours of operation, especially in emergencies.

3.3.3 Key steps of the resynchronization [50], [93], [96]

3.3.3.1 Initiate resynchronization (operator)

The operator can initiate the resynchronization when both the main grid and the microgrid are in satisfactory states to proceed, in terms of steady state operations. Once initiated, the process of resynchronization can be achieved manually by throwing a switch with help of a synchro-check check relay or it can be done with an automatic synchronizer to achieve the desired voltage/frequency necessary for synchronization.

3.3.3.2 Match voltage, frequency and phase (within acceptable limits) with measurement and control

For a smooth resynchronization, it is important to match the voltage, frequency and phase on either side of the breaker connecting the microgrid to the main grid. The control is done on the microgrid side to match the parameters at the PCC. One of the key challenges in microgrids, compared to the resynchronization of a single generator, is the parallel operation of multiple sources. The key challenges are:

1. The distribution of the voltage and frequency control effort among various sources;
2. The coordination of power electronics and conventional generators;
3. The response of the sources and loads not participating in the resynchronization process;
4. The stable control during the resynchronization.

3.3.3.3 Set the local controller and the protection devices

In microgrids, there is usually a centralized controller and there are primary controllers for the sources and loads. While the centralized controller coordinates the overall synchronization process in the microgrid by distributing the effort among the sources, each source participating in the voltage/frequency control must change its control mode according to the local controller. Protection setting are also changed for breakers in the microgrid. This is done to avoid tripping during and after the grid connection (when a much larger fault current is anticipated)

3.3.3.4 Reconnection

The connection is made by closing the breaker. A manual method could be time consuming, particularly when the frequency difference is rather small. An automatic method, however, needs to be more advanced (compared to a simple automatic synchronizer used for a single machine) for all the coordination among various sources.

3.3.3.5 Restore normal operations with changes in the control of power electronics, loads, etc.

When the breaker is closed, connecting the microgrid to the main grid and the steady state is achieved in power flow, voltage and frequency, the normal operation is restored. Once the normal operation restored, the control mode of the sources may be changed to grid-connected for improved set-point regulation. The voltage and frequency control of the sources participating in the resynchronization are deactivated because of this mode change, more noncritical loads are connected. In addition, the control of energy storage is changed from “resynchronizing” mode (where it plays an important role to control voltage and frequency at the PCC as local grid-forming unit) to grid-connected mode (mostly for charging and voltage/frequency regulations only outside a bandwidth for weak grids). There could be a challenge in the mode change depending on the inverter, possibly requiring rebooting for instance, thus preventing a seamless transition.

3.4 Conclusion and summary of the chapter

This chapter discusses the technical aspects of the two-ways transition between islanded and grid-connected operation of microgrids that are part of a distribution grid. This is done mostly from a state of art perspective, using extensive references to existing standards, grid codes, task forces technical reports and reference scientific literature. The presented technical aspects are in line with the lessons learned from the demonstrators presented in Chapter 2.

Resilience and reliability of power systems are defined to illustrate the relevance of considering microgrids that can be operated in islanded mode for a while. The main criteria justifying disconnecting from the main grid are discussed, making the way for flexible microgrids. The chapter also covers technical aspects of the microgrids to handle the transition to islanded mode islanding, and then to reconnect to the main grid. Discussions range from control systems to protections, including grid-forming components, and monitoring, control and communication systems.

In most of the presented technical aspects, the conclusion is that existing devices are usually not sufficient by default, but could be improved to fill the gap: the technical challenges are in range of industrial developments and standard for basic operation of islanded microgrids. The economic viability of such installation does not seem to be guaranteed, even before going into innovative scientific developments, helping increasing the reliability of those future temporary microgrids. This means that profitability may not be the main criteria leading to the development of such solutions. It could be the affiliation to local energy communities, the choice to decrease the (physical and electrical) distance between energy producer and consumers, the willingness to limit the environmental footprint of the consumed energy, enhance the resilience of the power system, allow maintenance of the grid with a limited impact on end users, etc. Social and environmental criteria are in range of such technical solutions in most of the cases and represent significant levers for the spread of the islanded operation of grid-connected microgrids, waiting for profitability in well-designed scenarios.

Assuming those criteria to be cleared, the next and last chapter of the report summarizes technical requirements per categories of components of microgrids, indirectly answering to the question: what would be needed to allow such operational practice in the future?

Chapter 4

Technical requirements for microgrids to operate in both grid-connected and islanded modes

The last chapter of this report focuses on what would be needed to allow part of distribution grids to transition smoothly from islanded to grid-connected modes (and vice-versa), under different operational occasions and not only in lab and real-life demonstrators. The presented aspects of the chapter do not constitute a mandatory set of requirements to check methodically. Various recommendations are rather outlined that should be considered in function of the study case defining the operational context of the implemented microgrid. For instance, it shall not be necessary to change the whole protection plan if the islanding process is triggered once a year (or less) for maintenance, as the CBA is irrelevant. But in other contexts, where the islanding process is activated on a more regular basis, an adaptation of the protection plan would make sense, in addition to safety issues. The time horizon plays a significant role here as well. The islanded operation could last for hours to days, requiring a large declination of equipment and most probably not only local production but also storage facilities.

The main sections of this chapter focus on key technical aspects, from protections, power electronics, storage facilities and grid-forming units to the associated monitoring, communication and control systems. In those sections are proposed expertise from the WG members, lessons learned from the demonstrator (some of which presented in Chapter 2) and external recommendation when they were considered justified and properly referenced.

4.1 Protections

In this section, the influence of the creation of temporary microgrids on the protection plan is discussed, from a people but mainly from a components point of view. Changing the complete protection set is highly costly if not used regularly, justifying a complete CBA before implementing a solution, in relation with the actual usage of energy in the defined microgrid. Such CBA is out of the scope of this report. Technical requirements are presented mostly regardless of their economic viability, as the economic aspects are dealt with in another parallel CIRED WG (2019-2) [1]. This WG notably proposes a multi-criteria evaluation matrix designed as a decision support tool to assess the potentiality of technical upgrades to a microgrid. This represents an excellent complementary work to the current report.

4.1.1 Operation

As discussed in Chapter 3, the operational protection of microgrids transitioning from grid-connected to islanded mode, raises many technical issues. The first one would be to assess if existing grid codes and standards are sufficient, for instance at the PCC, or new requirements should be standardized directly at the level of the components (in the line with the NDZ for instance). A very simple idea would be to aggregate two separate grid codes, one per mode (islanded and grid-connected) and just design protections that switch modes, based on external signal arriving from local dispatching centers or directly triggered by local measurements. The issue here would be the protection coordination and their performances, as well as their grounding systems.

The protection system requirements are usually based on the electrical safety requirements, the important function being to secure at least the same safety level in islanded mode. As seen in the lessons learned from the demonstrators in Chapter 2, the selectivity is, to some degree, affected during islanded operation to keep costs at a reasonable level. For instance, if there is a second fault during islanding (during a fault on the main grid side) there might be a bigger area disconnected than in normal operation.

It is also of interest to look for additional requirements for interconnected and islanded operation capability: in terms of selectivity, need of additional protection devices, replacement of traditional fuses or relays, and CBs, etc.

Lastly, the question of augmented ranges on electrical quantities (like frequency and voltage in isolated microgrids) is already widely discussed in the scientific literature, notably when isolated rather than islanded (as defined in Chapter 1). This is directly linked with the accepted power quality in the studied microgrid and that DSO have standards to follow when grid-connected, it would be possible to consider adaptable ranges that would be switched when a transition between modes is detected, but at what cost/use ratio? Indeed, enhanced reliability cannot be easily determined when the range of electrical quantities vary depending on the connection to a main grid. The benefit in terms of resilience is also difficult to assess. Those points are discussed in the following sections of the chapter [72], [97].

4.1.1.1 General requirements

There is a general design of the distribution protection criteria known as “3S”, each of the three “S” indicating a different requirement:

Sensitivity: The protection system must be able to identify an unusual condition that exceeds a nominal value of the threshold. Protections schemes used for grid-connected mode might not be sensitive enough for islanded mode, due to the decreasing of fault currents levels for instance. In spite of the limited SC current rating of the IBG, a fault must be detected with a shorter operating time than thermal overload protection. Specific protections could be required, in addition to conventional overcurrent function used for the grid-connected mode. Furthermore, for ground faults, a minimum sensitivity must be ensured to meet the requirements regarding the maximum touch voltage defined by local regulations or international standards. Regarding ground faults, it must be taken into account that there is the possibility of a change in the grounding system when switching from grid-connected to island mode, thus requiring self-adaptation of the protections.

Selectivity: The protection should only disconnect the smallest part of the grid containing the fault from the system, to minimize the consequences of the fault situation. In grid-connected mode, protections inside the microgrid must remain stable in case of faults in the grid. In case of a SC inside the microgrid in islanded mode, the protection system should isolate only the faulty part. Protection at the PCC must disconnect the microgrid from the main grid only if the fault is located on the feeder connecting to the main grid, which supplies the microgrid. The opening of the PCC can decrease the selectivity rules between protections inside the microgrid. The management of grid-connected or islanded modes can require a setting adaptation to ensure the right detection and selectivity in each mode.

Speed: Protective relays must respond to fault conditions in the shortest possible time to avoid damaging the equipment and thus to maintain the stability and overall security of the system.

In addition, the "3S" criteria can be extended to include the following:

Dependability: Reliability is composed of security and dependability in power systems. We consider here the degree of confidence with which the protection will act correctly. In addition, the protection system must be designed to systematically and adequately perform its intended function while it is experiencing a fault.

Security: It is the degree of certainty with which the protection will *not* operate *incorrectly* facing a fault for which it should *not* act. The DGs need to fulfill the grid connection requirements from the local grid operator. The FRT include voltage against time curve, current injection and post-fault behavior. The settings of the protection systems should refer to the FRT settings to ensure the generators are not tripped before the grid protections, especially during the islanding transition.

Redundancy: A protection system has to control the redundant function of the relays in order to improve reliability. Redundant functionalities are planned and called back-up protection. Redundancy is also achieved by combining different protection principles.

Cost-protection ratio: It is relevant to achieve the highest protection at the lowest cost.

4.1.1.2 New challenges

The protection of a microgrid brings up new technical challenges:

- Current protection systems in distribution grids are designed for radial architectures with unidirectional power flows and are generally based on maximum current principle, detected by fuses and CBs to eliminate faults. The presence of DER in the MV and LV grids means that power flows are now bidirectional. If the grid is radial, the fault current has a unique path, but in microgrids, the SC current contributions may originate from different paths, which may result in the protections not tripping or wrongly tripping.
- Due to the connections and disconnections of generators, storage systems and loads within the microgrids, the topology is not constant. There is a notable intermittence of some generation resources, generally renewable, such as PV or wind farms, domestic wind turbines, etc.
- The connection of some of the local generation and most storage technologies to the LV grid is done by power electronic converters. The capacity of these inverters to generate SC current is very limited by default (when not oversized for instance). They cannot produce more than 1.2 to 1.5 times the nominal current of the generator in the event of a fault, which results in the following:
    - Small resulting SC currents;
    - Reduced SC power of the grid which leads to deeper voltages dips in faulted phases;
    - Overvoltage in healthy phases.
- The characteristics of each inverter may differ depending on its design or application, and its behavior depend on the applied control strategy, the internal protections, the

PLL implementation, and so on. Impedances also vary accordingly, which complicates the work of protections and their design.

- Permanent relay settings become less effective in some situations, and methods for adaptive resetting may be needed.
- In islanded mode particularly, the FRT capability of the inverters of DERs plays a role of last protection devices in case when overcurrent protection cannot be tripped because of very low SC current. It is necessary to make good coordination between FRT capability and thresholds of protection devices used in microgrids in that context. This is one of the *main technical requirement* regarding protections upgrade to enable microgrids to seamlessly transition from grid-connected to islanded mode.
- Selectivity is also a difficult issue once islanded. In current demonstrators (as shown in Chapter 2) all faults were detected with the help of the saturation of the grid-forming inverter, but the selectivity was intrinsically lost.

4.1.2 Coordination

To ensure the correct coordination in the protection system, it is necessary to take into account the different types of protection existing in the grid today [72], [98]. A typical illustration of this topic would be on UFLS, where the islanding procedure should be decided considering predefined events in the main grid.

4.1.2.1 HV/MV grids

In most cases, SC protection against faults in the MV busbar is taken care of by an overcurrent protection function within the transformer protection system. Usually, overcurrent protection is sufficient to protect feeders in radial grids, but some countries use distance protection due to meshed grids.

Depending on the neutral treatment, ground faults can cause different fault currents. Earth fault protection measuring the zero sequence current is required in some cases. For compensated or isolated grids, zero sequence voltage is an option. Relays are usually equipped with the automatic CB re-closing function.

It is key to remember that existing elements in distribution grids such as Fault circuit indicators (FCI) should not act correctly in islanded mode, due to the low SC current.

4.1.2.2 LV distribution lines

In secondary substations, where fuses are installed today, CBs could be installed considering the low SC power of the grid as well as different configurations or operating modes.

Also, in cases were delta/star transformers are installed in secondary substations, a zero-sequence protection is necessary at the MV side, so that, in cases where a reverse power flow and a ground fault occur to the MV grid, the fault can be detected and eliminated, by isolating the LV grid.

4.1.2.3 Generators

The SC protection of generators is taken care of by overcurrent protections. All countries have implemented different frequency as well as voltage protections. These protection functions disconnect the generators from the distribution grid once a deviation from the operational parameters is detected. In addition, the converters have their own intrinsic protections to protect the electronics. It would make sense to consider integrating those protections in the set of the microgrid, notably through a generalized standardization for such components, once connected in the considered situation.

4.1.2.3.1 Anti-islanding protections. The performance of the microgrid mainly depends on a timely and accurate operation of the used detection method. The NDZ is one of the indices to characterize the operational capability of a microgrid. The NDZ is defined as a region that is not easily detected by conventional protection relays. It is often admitted that the size of the NDZ is a good indicator of the efficiency of the protection algorithm: the smaller the NDZ, the better the protection. Usually, the NDZ is evaluated on the basis of an active and reactive power mismatch range in which the voltage and frequency relays cannot detect the islanding condition in a timely manner. If the power mismatches ΔP and ΔQ at the PCC are small enough, the frequency and voltage fluctuations after the islanding occurrence do vary sufficiently to allow detecting the islanding condition. The NDZ boundary limits can thus be defined, and one can discriminate the area of critical and non-critical operating conditions.

4.1.2.3.2 SC currents. Regarding generators protections, on the one hand, it is necessary to ensure the coordination with protections of the distribution grid in both modes of operation (grid-connected and islanded). Therefore, settings used to detect faults during an island should not affect the selectivity of the protection system when operating in grid-connected mode. On the other hand, in islanded-mode, it is needed to coordinate with LV system protections, including fuses and end-users CBs so as not to bring down the island when not necessary.

Furthermore, generators have to meet the various grid codes and all their implications when there is a fault. All this translates into a direct effect on generators time settings. They have to be able to not disconnect instantly due to an overcurrent when there is a fault, when there is no balance between generation and consumption, or during the connection of transformers. For IBG, this translates into the following:

- The operation as a Current source converter (CSC) shall be limited to meeting maximum and minimum voltage levels:
  - When the maximum voltage adjusted is exceeded, the voltage is controlled, limiting the current to the value closest to its power setting;
  - For voltages lower than the limit adjusted, the inverter remains connected, limiting the current to the nominal value of the equipment.
- When operating as a VSC (if possible), the current shall be limited to the nominal value. This behavior shall have priority over the maintenance of the voltage. A particular case of this operation is the behavior in case of SC.

The generators must withstand SCs over a minimum period of time without disconnecting from the main grid. The objective is that they provide current to the fault (single-phase, three-phase or other) to help detect the origin of the fault.

4.1.2.4 End-users

The coordination with domestic LV CBs or fuses in end-users installations must be ensured. It is a difficult task in islanded mode. The generators must hold out long enough so that, in the event of a fault inside an installation, the domestic CB, or fuse, is the one that clears the fault. For instance, it is already quite difficult to coordinate with a 32 A fuse in islanded mode with the low SC currents.

In the lessons learned from demonstrators presented in Chapter 2, it is stated that a more sensitive protection was added in the grid to detect and clear faults in customers' installations, providing a less selective solution but at least a safe and not too expensive one. Inverters' saturation was also used to that purpose, with a loss of selectivity as well.

4.1.3 Performance for various fault locations

The grid's behavior depends on its grounding system. The most critical case takes place in grids with low impedance grounding in which both ground faults and phase-to-phase faults lead to feeder tripping.

In Figure 4.1, it is explained how the most common faults in a microgrid connected to a low impedance grounded grid are resolved.

In this type of grids, the fault current can be higher than the nominal current of a LBS, so two different cases can be considered:

- Behavior with CB;
- Behavior with LBS.

In addition, low-impedance grounded grids usually have automatic reclosing systems, especially for ground faults, so the effect of the reclosing sequence has to be considered.

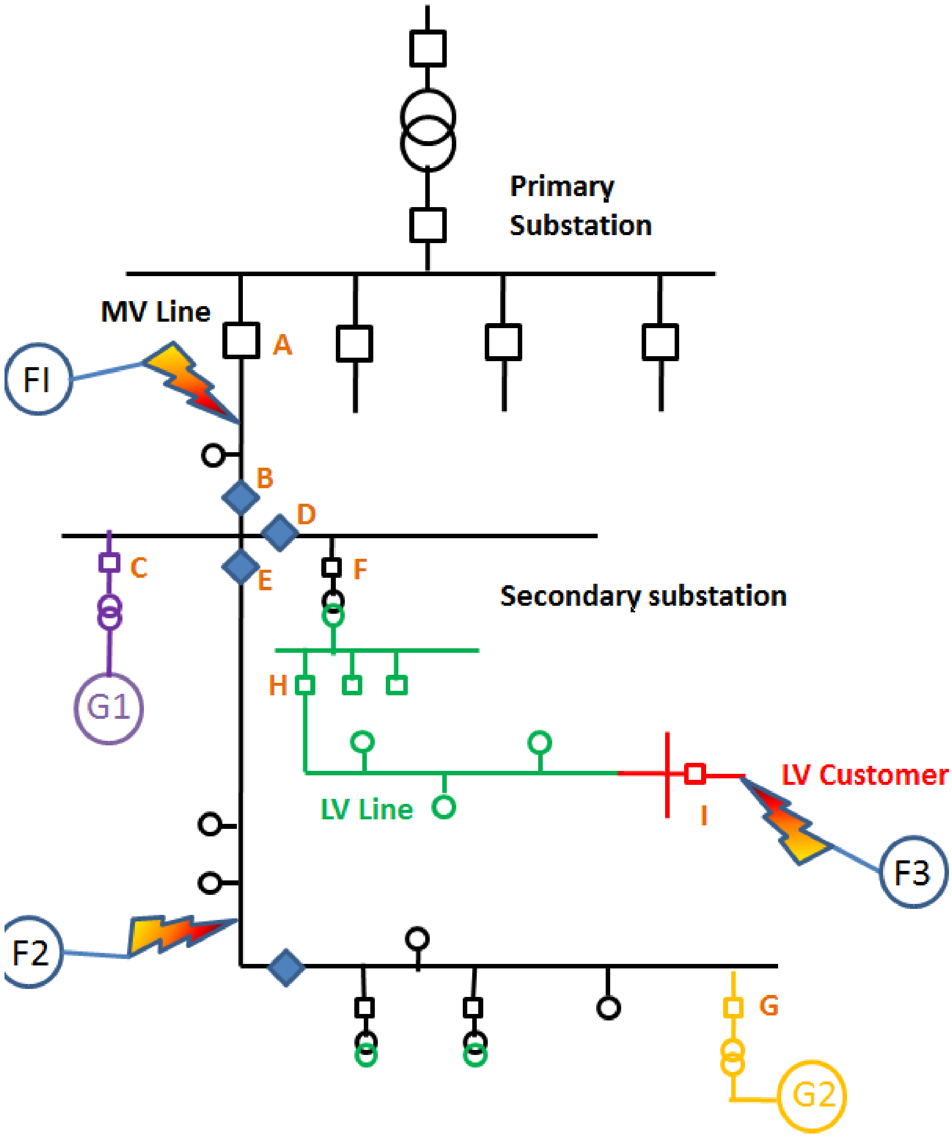

FIGURE 4.1 – *Microgrid with two DER (G_1 and G_2) and three fault locations (F_1, F_2 and F_3).*

Different operating elements are represented in Figure 4.1:

- A, C and G are MV CBs;
- B is the switching element at the PCC of the microgrid. It may be a CB or a LBS;
- D and E are LBS;
- F and H are MV and LV fuses, as usual practice in distribution grids;
- I is a CB at the customers installation.

Sensing the current direction is an important point here. As already discussed, bidirectional flow of SC current takes place during the microgrid operation. Most of today's commonly used grids are operated considering that SC current flows are only unidirectional, with only one SC source. The concept of islanded microgrid changes this idea, as SC sources can be distributed in various locations. This distributed generation is already a reality in HV transmission grids, where more sophisticated protection systems are used, such as directional, distance and differential protections. Thus, the overcurrent protective device from Figure 4.1 is considered non-directional for the following analysis with different fault locations and circumstances.

4.1.3.1 Grid-connected mode – Fault F_1

4.1.3.1.1 CB at the PCC (B=CB with protection system). In case of fault in the part of the distribution grid F_1, the protection devices at the primary substation A clear the fault, causing an interruption. Different approaches can be used:

1. The protection system (overcurrent, impedance, etc.) of the PCC trips, initiating an island:
   - With an interruption, followed by a black-start;
   - Without interruption, with advanced features. The transition from grid-feeding to grid-forming modes that require an appropriate protection coordination of A to B.
2. The protection system of the PCC B does not trip initially;
   - In case of successful reclosing from A, the line is fed by the substation;
   - In case of ineffective reclosing from A, a long under-voltage is detected, so B is opened to create an island.

Regarding the PCC protection system, if the fault is detected using a generic overcurrent relay, it can lead to major problems, since most of the DER in the microgrid are connected by power electronics with strong SC current limitations. A directional overcurrent relay on the interconnection CB is a feasible solution only if the current is used for fault detection. Alternatively, the voltage drop (magnitude and duration) and/or the system frequency (instantaneous value and ROCOF) can be used as other indicators for the tripping of the PCC breaker.

For fault sensitivity problems, typical solutions are adaptive directional overcurrent protection (67), undervoltage protection (27) and underfrequency protection (81M). Those solution would make sense in the context of islanded microgrids if the number of transitions (and the associated duration) increase significantly per year, compared to anything we have seen, even in the demonstrators assessed in Chapter 2.

4.1.3.1.2 LBS at the PCC (B=LBS). If the element in the interconnection is a LBS, which can be motorized but insufficient capacity to break the possible fault currents, the procedure in case of fault is the same as described in the second option in the previous paragraph if the protection system of the PCC B does not trip initially:

- In case of successful reclosing from A, the line is fed by the substation;
- In case of ineffective reclosing from A, a long under-voltage is detected, so B is opened to create an island.

4.1.3.2 Grid-connected mode – Fault F_2

4.1.3.2.1 CB at the PCC (B=CB). When the fault occurs on the microgrid side, the first thing that happens is the opening of the CB of the PCC B without having to wait for the opening of the main grid CB A. In other words, there is a need for coordination between the two CBs. Therefore, the interconnection CB remains open until the fault scenario is solved. If, the grid feeder protection A trips instantaneously, the use of another CB in line requires time delaying the CB A.

Since an internal fault within the microgrid area has been detected, the island is initiated.

4.1.3.2.2 LBS at the PCC (B=LBS). If, on the other hand, a LBS is located at the interconnection, the first thing that happens is the opening of the grid's main CB. Then, once the head CB A in the feeder is open and the location of the fault on the microgrid side has been identified, the LBS is permanently open until the fault has been cleared. The direction of the fault is detected thanks to the functions of the control automatism which analyses the values of the voltage sensors located before and after the LBS or by a fault passage indicator function in the LBS. In addition, the protection system can be equipped with multiple ANSI functions such as 67N and 67P, making the detection process faster and easier.

Since an internal fault within the microgrid area has been detected, the island is initiated.

4.1.3.3 Grid-connected mode – Fault F_3

Should a fault occur within an end-user's facility, the smallest possible portion should be disconnected to ensure maximum power-supply to other end-users.

At LV levels, the simplest protection functions are embedded in the LV switchgear, but the protection systems must also meet specific requirements linked to safety, based on local regulations or international standards (e.g. IEC-60 364 series).

4.1.3.4 Islanded mode – Fault F_2

Regarding grounding faults, the grounding system remains isolated, so there is no contribution to grounding other than the capacitive impedance of the cables. Overcurrent relays cannot be used then. Installed relays would have to be those for isolated or resonant grids (e.g. watt-metric). Selectivity is limited by the number of elements (either CB or LBS) that are equipped with this kind of protection. A simpler option is the use of zero sequence over-voltage protections (59N), although this is a non-selective system that disconnects the island for any ground fault at any MV point of the microgrid.

In case of a phase-to-phase fault, since the SC current is limited, overcurrent relays of most generators do not trip and fuses do not work properly, requiring complex protection schemes (differential or impedance protection) infrequent in MV feeders. In most cases, the adopted solution is the use of under-voltage protection (27), also non-selective.

4.1.3.5 Islanded mode – Fault F_3

In the event of fault F_3, a low fault current is supplied by the local DERs. The closest switch to the fault must ensure that this line is disconnected from the microgrid. If the switch does not trip, due to insufficient current, the elements of the microgrid would have to trip due to undervoltage. If greater sensitivity or reliability is desired, it may be necessary to replace the fuses with motorized switching elements.

It is also advisable to increase the FRT capabilities, including a duration of current contribution to the SC sufficient for the protections used in the LV system.

4.1.4 Maintenance

Increasing the usage of protection (including switching modes, automatically or not) due to repetitive transitions between grid-connected and islanded mode must have an impact on the ageing of the equipment, thus their maintenance. Without any additional information on the subject, we could only recommend to design protections with a sufficient number of cycles and upgrade maintenance protocols.

4.2 Power electronics

In a hypothetical system where there are no Synchronous generators (SG) at all, the frequency is fully decoupled from the power balance of the system, except if supplementary controls are in force. In this case, no element of the grid responds naturally to power imbalance (voltage-dependent loads balance active power through voltage variations; reactive power balance of loads and lines determines frequency) and a control system must be in place to preserve the power balance at every instant. Here, the electrical frequency may still be a global variable, but is not anymore a physical variable associated to the rotating magnetic field of SG. Instead, it is a controlled variable [99].

Since IBGs do not naturally respond to power variations, specifically designed controls are necessary. The inertial response can be implemented as a control loop, and is thus subject to delays, malfunctioning, saturation, and other unexpected dynamics that may lead to instabilities. In addition, some strategies are dependent on communication systems and are, in general, neither fully reliable nor easy to implement.

In future low-inertia power systems, the roles of SG have to be replaced (or at least complemented) by other grid-forming units. The current strategy of IBGs as grid followers will no longer work because the reference of voltage and frequency is required. The interaction of multiple grid-forming unit is a subject of high interest, still to be fully covered by the scientific literature.

4.2.1 Design

Advance integration of renewable energy and storage facility mostly rely on static converters. Current configuration of microgrids lead often to a drastic increase of the contribution of IBG in the energy mix once islanded. In this context, the main characteristics of power electronics should be considered to mitigate the security and stability of the created temporary weak grid.

4.2.1.1 Sizing inverters

The main issues regarding the design of inverter concerns VRT, protection settings and oversizing to compensate low SC currents [100]–[102]. As already discussed, compared to a traditional SG, IBG can typically provide up to 1.5 times their nominal current in case of fault (with the possibility to have a higher overload of the inverter for a short time, still not enough to burn a traditional fuse), when the SG provide from 10 to 15 times that current. In this condition, to fulfill existing requirements of fault detection devices, oversizing the static converter (and the primary source components) is a solution that can be selected with in mind a compromise with the associated capital cost within a balanced CBA. Indeed, this would lead to e.g. a PV installed capacity largely unexploited, and a high cost of power electronics for a low resulting power produced to ensure the security of the system. It is not the object of this WG to balance the security of the energy system (notably considering a set of probable event) and its economic viability, but this subject is at the core of the enabling elements for the future developments of such installations. Researchers suggest to accommodate the technically stability of the microgrid in islanded mode with for instance flexible power point tracking, and balancing reserves while an injected production to the main grid in grid-connected mode ensures some economic benefices. On the technical side, a large set of solution (from the device to the system of system) exist to ensure the feasibility of microgrids relying on up to 100 % of IBG.

One of the main issues regarding the choice of the characteristics of power electronics are linked with the protections. The loss of main/anti-islanding protections was highlighted in the demonstrators presented in Chapter 2 when facing external faults and perturbations, with focuses on low VRT and NDZ. The selectivity regarding faults was sometimes lost, but the control of the inverters (notably their saturation) was also used to help trigger on most, if not all, of the traditional faults.

Another aspect needing attention is the design of power electronics converters control, and more precisely the interaction of their control loops (from the internal level to the local environment, i.e. the other inverters connected to the microgrid). Once multiple devices are present in the microgrid, the main questions that arise are on the choice of the grid-forming, and grid-feeding units as well as on the share of the SC ratio. Those aspects need a communication network with dedicated services for fast information exchange as well as dedicated standards, notably when targeting 100 % IBG microgrids [103]–[119].

4.2.1.2 Scalability and plug-and-play

In a fully decentralized microgrid powered by hundreds of distributed PV and storage facilities, the system cannot be designed and operated in the conventional way. On the one hand, the sources in such microgrids may be fully owned by consumers with no expert knowledge at all. They wish their devices work in a plug-and-play style. On the other hand, the operator still needs to have an extent of controllability and observability on these decentralized devices in a scalable way. There is no prior experience on such issues, which might require some discussions on the following points.

Stability: In a system with hundreds of distributed devices, the conventional methodology for stability analysis and design might no longer work and it would be helpful to set up some common standards ensuring the stability as long as every device complies [120].

Operation: When devices plug-in or plug-out, how does a microgrid operator set-up its operation scheme accordingly? Does it make sense to define a systematic and automatic way to reconfigure the operation scheme that can easily scales for hundreds of devices?

Protection: Many protection parameters need to be hand tuned by operators which is not scalable for hundreds of sources. How to design a scalable protection scheme?

Market for power and ancillary services: The pricing in the main grid is mainly based on the power market. What happens once islanded? Is a market mechanism required as an optimization criterion? How then to make the market scalable for the plug-and-play distributed resources? Experiments linked to energy communities and peer-to-peer exchanges, for instance relying on block-chain technologies are currently underway, and should help clear some of the issues raised by this point.

On those aspects, one of the main lessons learned from the demonstrators is that DSOs greatly benefit from the external support and expertise of the company in charge of power electronic devices, when its R&D department is capable and flexible enough to correctly accompany the implementation of the islanded microgrid, by understanding and following correctly the operational needs of the DSO. Expertise is available in the private sector in designing and controlling power electronics elements to interface storage systems, PV production and so on in such context.

No technical problems seem unsolvable (including managing a wide range of old and new technologies) even if specific developments await completion. Most of the solutions rely on multi-purpose power electronics devices and the advanced operation of inverters, i.e. increasing the complexity of the system of systems and its overall management. Note that some study looks into low-cost and low-tech responses to the presented issues, notably accepting a small decrease in power quality in predefined situations.

Regarding social and economic alternative models at the local scale, research and experiments are still ongoing. They heavily rely on tools that come from the ICT domain, like AI, benefiting from the exponential volume of created data, but at what cost?

4.2.2 Operation, ancillary services and protection

Islanded microgrid systems represent weak or low-inertia power systems and the high penetration of inertia-less PV and wind energy systems has a severe effect on the frequency stability as well as the overall security of the temporary microgrid. The rapid changes in the generation can cause frequency variations in the system that can, if outside the limits of standards, rapidly compromise the stability of the system if not mitigated properly. Mitigation tools comprise notably ancillary services of advanced devices, like virtual inertia, black-start capability, additional internal protections, over/under-VRT, voltage/frequency controls, most of which needing to be activated only during the islanded mode.

A large variety of solution exist in the scientific and technical literature, not all of them needing to be implemented at the same time. The actual difficulty lies in the design of the overall system, and the choice of the relevant solutions, in the light of a given study case [121]–[125]. It could even be considered on a long time horizon that frequency shall not be that critical for the stability assessment of 100 % IBG microgrids.

4.2.2.1 Virtual inertia and frequency related controls

There are no specific standards defined for frequency limits for temporary isolated microgrid systems, see Figure 4.2. This is highly dependent on the generation and the load mix in a particular microgrid system. From a generator point-of-view, frequency standards like the ISO 8528-5 can provide a guideline for the frequency limits. With the small amount of SG in isolated microgrids, the frequency excursions and ROCOF are greater and the need for virtual inertia (which can be provided in various forms) is of high importance. In such isolated microgrids, to implement virtual inertia, either dedicated ESSs can be used, or inertia can be emulated by operating PV/wind below their maximum power point for instance considering flexible power point tracking [88], [126]. Some (new of decommissioned) SG could be used as well as synchronous condenser, though only providing inertia to the system.

The IEEE 1547-2018 requires that DER are capable of responding to voltage variations within the normal operating range through voltage-reactive and voltage-active power control [4]. The required voltage and reactive power control functions include constant power factor mode, voltage-reactive power mode, active-reactive power mode, and constant reactive power mode, whereas the voltage and active power control function includes voltage-active power (volt-watt) mode. However, the usage of such functions remains in the hands of the operator.

One of the ways to help stabilizing the grid frequency is through virtual inertia, which has been the subject of many research efforts, e.g. [127], [128]. On short time scales, SGs maintain the power balance through instantaneously available physical storage in the form of inertia, and later through their primary control, which takes effect more slowly. In contrast, IBG works differently: the analogy of SG's inertia is the energy stored on the DC-side capacitor, which is typically much smaller compared to the SG's inertia of the same power capacity (additional storage capacities could be included, possibly hybrid to address various time constants), the so-called matching-control makes use of this analogy. On the other hand, power electronic sources can be actuated on much faster time scales and thus contribute to power balancing, provided that the DC-side energy supply is capable of supporting this. Consequently, the lack of physical inertia can potentially be compensated through fast DC-side energy storage equipped with appropriate control strategies.

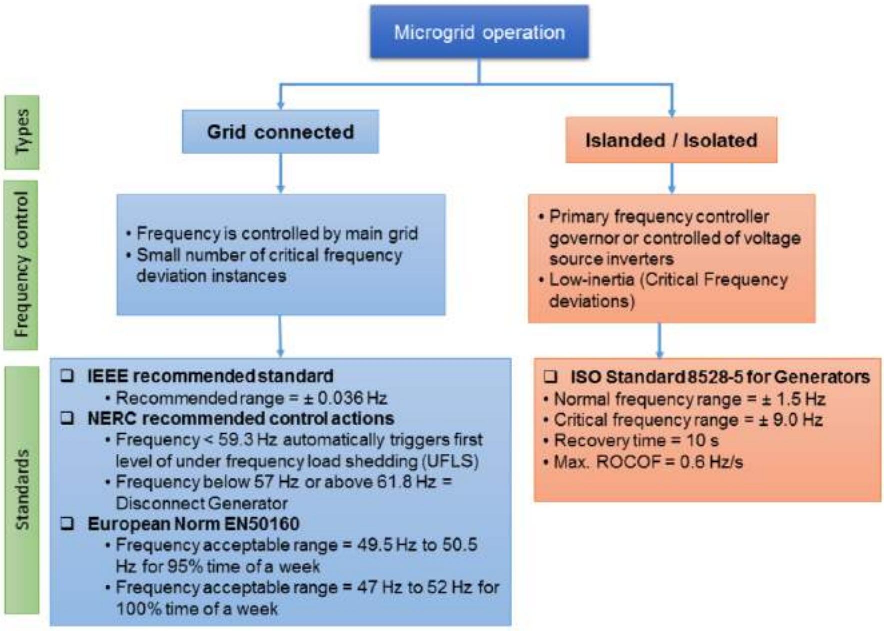

Figure 4.2 – *Frequency standards for microgrid systems [129].*

In contrast to SGs, frequency changes have to be detected first by the control systems. Applied filtering might lead to time delays and thus reduce the performance of emulated inertial response [130]. If the delays are too long, then the virtual inertia do not provide mitigation to the initial ROCOF during an event. If the delay happens to lead to a phase lag that is 180 degrees different to the equivalent true inertial response, then the output power modulation provided by the virtual inertia can operate in complete anti-phase to the rotor swings of a real SG, encouraging traditional rotor oscillations, and thereby degrading grid stability [131].

A standard on virtual inertia provision would be of great interest in that context, as there are different solution and a large variety of implementations. Among others, EirGrid incentivizes fast responses with response times down to 150 ms within the provision of FFR [132]. Among those types of virtual inertia, we could cite the models based on the SG directly [133], [134], on the swing equation [135], [136], on the frequency-power response [137], [138] and relying on a droop approach [139], [140]. A summary table highlighting the key features and weaknesses of various virtual inertia control topologies is presented in Table 4.1.

Contrary to SGs, which have inherent synchronization mechanism, the Virtual synchronous generator (VSG) need a synchronization unit. Currently, some strategies use a PLL to provide the phase and frequency of the grid voltage as to attain smooth synchronization. However, PLLs may cause many problems leading to reduced performance, increased complexity, or even instability [134]. A VSG can synchronize itself with the grid using an embedded synchronization mechanism and therefore the PLL can be removed (synchronverter) [141]. Aside from higher frequency noise due to static switching, there is no difference between the electrical appearance of an electromechanical SG and a completely electrical VSG, within the unsaturated operating region, from the grid's point of view. As the inverters behave (theoretically) similarly to SGs, legacy practices in power systems are not much altered.

Table 4.1 – *Summary of virtual inertia control topologies [129].*

Control	Key features	Weaknesses
SG model	Accurate replication of SG dynamics; Frequency derivative not required; PLL used only for synchronization.	Numerical instability concerns; Typically voltage-source implementation; No overcurrent protection.
Swing equation	Simpler model compared to SG-based; Frequency derivative not required; PLL used only for synchronization.	Power and frequency oscillations; Typically voltage-source implementation; No overcurrent protection.
Frequency-power response	Straightforward implementation; Typically current-source implementation; inherent overcurrent protection.	Instability due to PLL, particularly in weak grids; Frequency derivative required, system susceptible to noise.
Droop approach	Communication-less; Concepts similar to traditional droop control of SG.	Slow transient response; Improper transient active power sharing.

4.2.2.2 Virtual impedance and harmonics mitigation

A wide variety of auxiliary functions, represented in Figure 4.3, can be realized by implementing a virtual impedance in the controller structure. A virtual impedance is a possibility to alter the control of an inverter so that it seems as if an additional impedance has been inserted between the inverter and the load in the physical circuit. In simple terms, the effective impedance between the inverter and the load can be changed via the control structure. It can be used to attenuate subsynchronous oscillations [142], decoupling of active and reactive power flows, and the improved reactive power sharing in the operation of paralleled converters [143] or for damping low-order harmonics in distribution power systems [144] to name a few use cases. An overview of the various possible applications of virtual impedances is provided in [145], [146].

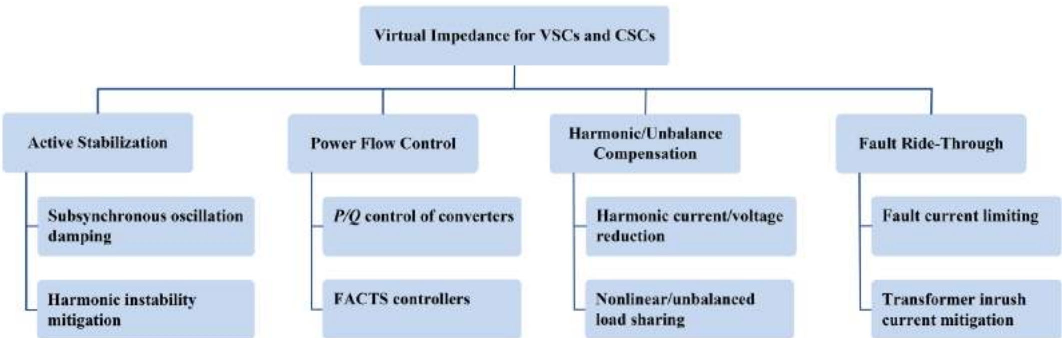

Figure 4.3 – *Classification of virtual impedances for VSCs and CSCs [145].*

Besides its implementation, the main issue would be to select the most relevant function considering the characteristics of a given islanded microgrid and its environment. It is, in this context, not realistic to look for the best function fiting a general model of islanded microgrid.

Another approach to improve the power quality is the decomposition of signals into harmonics with the aim of controlling them. With the aid of phasors, the harmonic components of power signals can be represented in stationary or synchronous frames. In the case of synchronous reference frames each harmonic component is transformed into a DC component (frequency shifting) [147]. Harmonics appear as ripples on the DC signal and can easily be filtered out [148]. The same can be done in the stationary reference frame by means of the proportional resonant controller. The basic functionality of this controller is to introduce an infinite gain at a selected resonant frequency for eliminating steady-state error at that frequency, and is therefore conceptually similar to an integrator whose infinite DC gain forces the DC steady-state error to zero. Besides single frequency compensation, selective harmonic compensation can also be achieved by cascading several resonant blocks tuned to resonate at the desired low-order harmonic frequencies to be compensated for [149]. For instance, in [150], the proportional resonant controller was used to control both positive- and negative-sequence components to compensate for the effects caused by the unbalanced utility grid voltages, which is a function of interest in some cases of islanded microgrids, but once again, would not require to be generalized to all of them.

One of the major challenges for proper operation of the whole system occurs when a voltage sag is transmitted through the grid. Depending on the depth and duration of the voltage sag, the grid codes force disconnection of the DG. Converters are able to support the power system during a fault by auxiliary functions and ride through the fault. The active power [151] and reactive power [152] during a grid fault can be controlled by different strategies which calculate the reference current for the current control loop according to the requirements. Thus other goals can be achieved like, compensation of unbalanced faults [151], [153], mitigation of harmonics [152] or current limiting [154], [155], most of which are relevant to microgrids in the scope of this work.

4.2.2.3 Going further

Other control strategies include stiff grid-forming inverters widely utilized in UPS. It behaves similarly to a perfect voltage source, which ensures that the terminal voltage and frequency are maintained at nominal values at any moment. Consequently, load sharing and synchronization could be among major problems when multiple grid-forming units operate in the grid, particularly with the absence of a global controller and fast communication systems.

Additional services would aim at active stabilization mechanisms, possibly targeting dedicated harmonics or unbalance compensation that could prove interesting when the microgrid present significant unbalanced generation or production once islanded. Black-start capacities and over/under-VRT are already integrated in recent standards that just have to be unlocked when the generation and storage units are present. Participating to UFLS is finally another interesting requirement to look into, depending on the site implementation [68].

Lastly, it would be relevant to define levels of operation, for instance from normal (most of the time) to extreme (very low probability) when devices unlock capabilities (with an associated time limit) to operate outside standard limits, as a compromise to increase the chances to preserve the stability of the system facing harsh events, and improve its reliability.

4.3 Highlights on power quality related issues

The issues related to power quality in islanded microgrids was addressed in the CIRED joint WG C4.24 [46]. Increasing the scope to microgrids transitioning from grid-connected to islanded modes should not dramatically change the perspective of that existing expertise work.

As a support for the discussion, we propose in this section illustrations of some relevant aspects of power quality for islanded microgrids. The presented highlights come from demonstrators assessment, not necessarily discussed in the lessons learned from Chapter 2 because they constitute already some elements of requirements worth investigating for future standardization or any other operational developments.

Power quality is a complex problem, standardized for example in the EN-50 160, which contains unbalanced operation, flickers, harmonics, frequency and voltage ranges and limits. In the case of microgrids almost exclusively based on power electronics, power quality may be affected especially by harmonic distortion, notably when these power electronics operate at low power, where these devices induced more harmonics. Mitigation measures to keep power quality considering EN-50 160 standard shall be applied, namely installation of filters if necessary, or virtual impedances, among more advanced solutions. As an illustration, the operational constraints in terms of voltage characteristics of electricity supplied by public distribution systems required by EN-50 160 are reproduced in Figure 4.4. For various reasons, the range is very strict for interconnected systems in steady state, while it is a bit less strict for islanded grids. Momentary voltage and frequency deviations are allowed in wider ranges. As the inertia is typically much lower in islanded grids, the permissible frequency deviations are relatively wider in islanded systems.

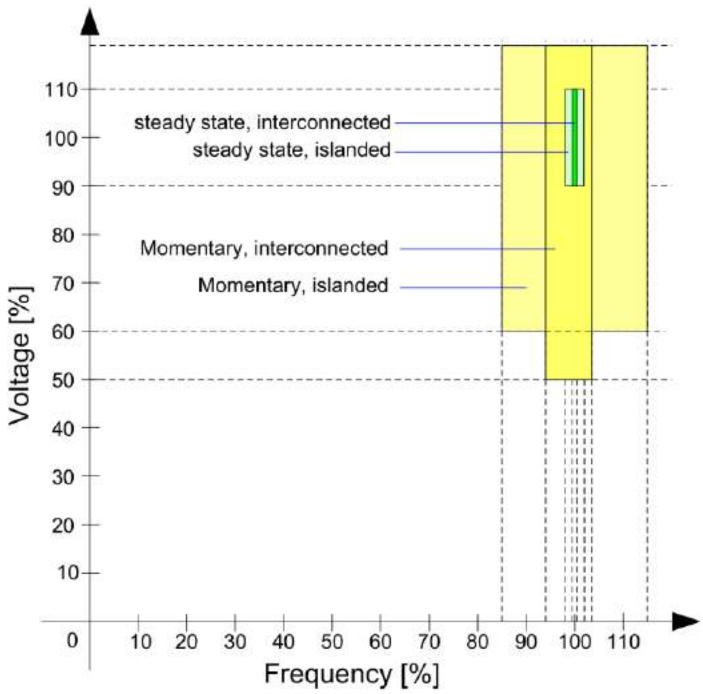

Figure 4.4 – *Voltage characteristics of electricity supplied by public distribution systems required by EN-50 160 [45].*

Even for momentary variations, the permissible limits are small compared to the total area possibly covered, i.e. all areas where the frequency is lower than 84 % are not permitted, neither 0–50 % of voltage. The strict operational ranges are imposed to guarantee the power quality of electric supply in order to obtain satisfactory performances of electrical and electronic appliances. Here, the focus is on the load side, to make sure that the loads are functioning properly according to what is expected by the customers, which is related to power quality.

The criteria to island a microgrid from the main grid (without talking about purely isolated microgrids) varies across the globe. Consequently, the operational ranges should adapt to the main objectives, especially in microgrids functioning with significant levels of VRES. The operation and management of such power systems may be different from the conventional ones, on a per site basis. Several adjustments are necessary to that end, as the grid codes may be unique only for a handful of cases. For instance, it could make sense to utilize the degraded ranges (i.e. wider voltage and frequency ranges) only shortly for maintaining the power balance in the system and for reducing the investment and operation costs. The approach indeed needs to take into account the impact on the devices in the grid and the public acceptance.

4.3.1 Behavior of non-intentional islanded grid with grid-feeding generators

A microgrid operated in islanded mode implies a balance between generation and consumption, both in terms of active and reactive power. In case of non-intentional islanding with DER, it is frequently assumed that this kind of balance is hardly reached, given that DER, such as PV plants, do not have power regulation or provide reactive power by default. Also, power electronics capacity being lower than the distribution grid, the capacity of the microgrid to withstand unbalanced operation is reduced, inducing more frequent voltage unbalances.

However, according to field tests carried out by i-DE (Iberdrola), it has been seen that, starting from a rough balance at the beginning of the event, the exact balance of active power is reached by means of consumption modification, which depends on the voltage (when loads behave approximately as constant impedances, a voltage variation implies a quadratic load variation). By changing the voltage, generation and consumption match (even phase by phase) and islanding is possible. On the contrary, if the generation is clearly lower than consumption, the voltage decreasew and the generation trips. If the generation is clearly higher than the consumption, voltage increases so the generation trips as well.

Regarding reactive power, in the field tests it could be seen that inverters were not able to keep a stable power factor during islanding behavior. The addition of reactive power produced by the inverters and the transient behavior of loads made the balance possible.

Figure 4.5 proposes an illustration of measurements from field tests in MV systems. They showed that some parameters were more unstable during islanding than connected to the main grid, but the RMS voltage, its distortion and unbalance magnitudes, remained within normal limits. The active power of one inverter decreased constantly according to the declining irradiance of the evening. At the same time, reactive power of individual inverters suffered a strong fluctuation, as can be seen in the difference between maximum and minimum values. Voltage fluctuated, but within limits. Frequency also fluctuated but not as much as expected, since consumption-generation balance is not done by frequency adjustment, as with traditional SG, but by means of voltage modification.

Although there were some frequency changes, see Figure 4.6, their magnitude was too small or short to be detected with ROCOF settings compatible with system stability constraints.

In addition, the almost perfect waveform shown in Figure 4.7 were monitored.

This behavior has a complex influence in microgrids with several generators, with a generator operated in grid-forming mode and the others in grid-feeding mode.

Grid-forming generators try to maintain constant the voltage magnitude and the frequency, typically by means of a V/Q and f/P regulation, respectively. However, many grid-feeding generators were installed before the requirement of a f/P droop and they unintentionally link the voltage and frequency through their regulation. This can be seen in Figure 4.5. This kind of interactions must be taken into account, especially when the ratio between grid-forming and grid-feeding generators is low.

The presented experiments have the main interest to highlight the capacity (on a short time horizon) of existing components to handle the islanding while ensuring an acceptable power quality. The main issue, as discussed in this chapter for almost all components, are the notion of *replicability*, of *scalability* and *longevity*. In those terms (frequent islanding event with variable and long islanded operation), power electronics components shall need dedicated

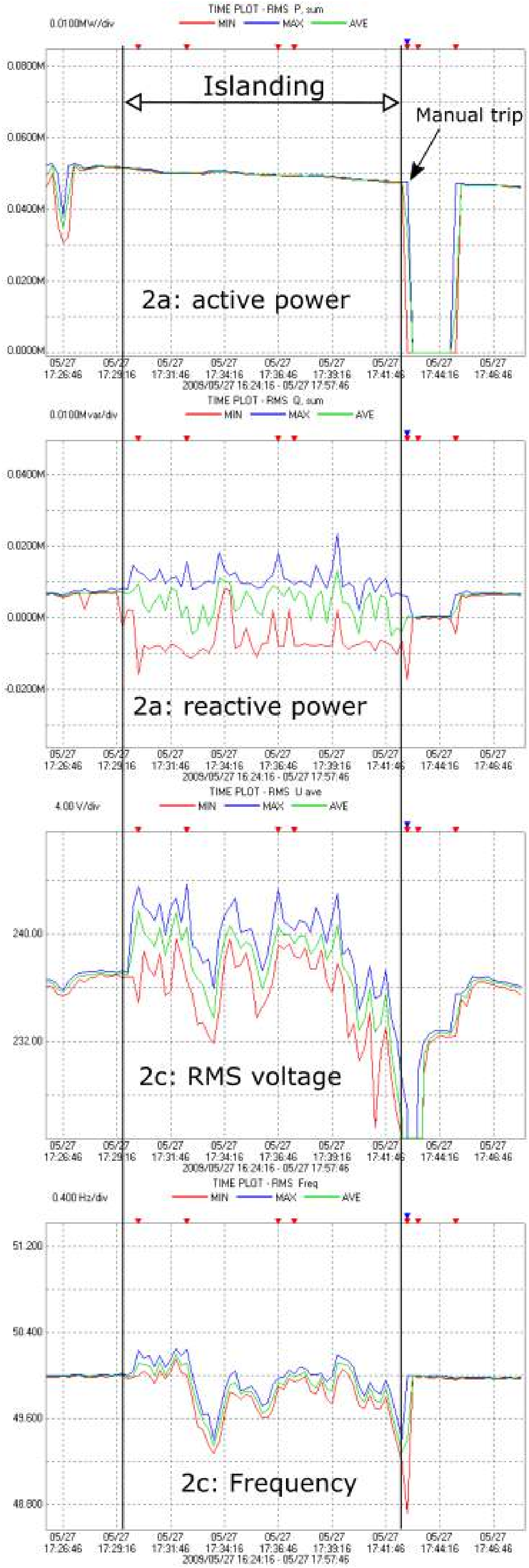

Figure 4.5 – *Active and reactive power, RMS voltage and frequency. Fluctuation can be seen as the difference between the maximum (blue) and the minimum (red) values.*

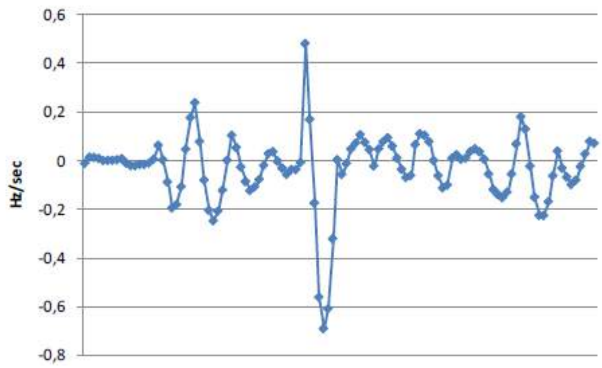

Figure 4.6 – *Worst case of ROCOF in consecutive cycles.*

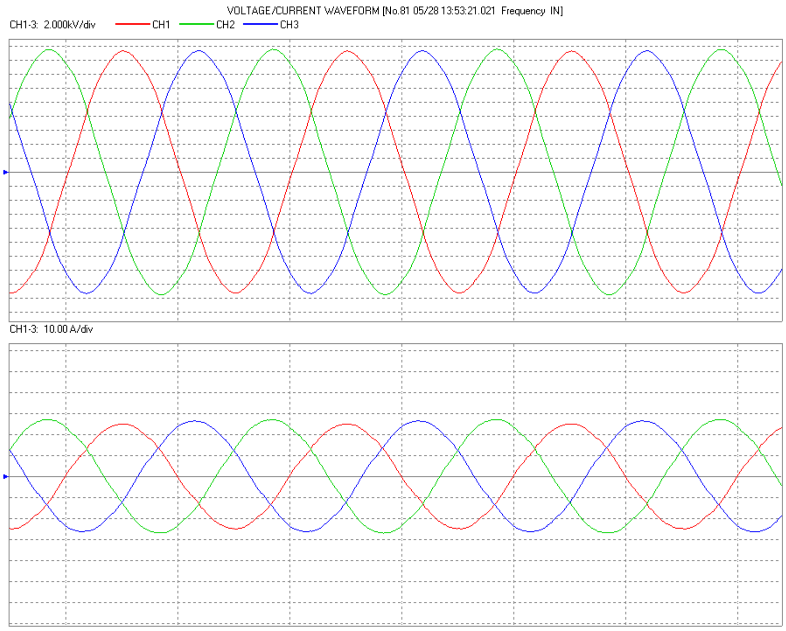

Figure 4.7 – *Voltage and current at the PCC with the MV grid.*

designs, with additional ancillary services, dedicated protections as well as specific filters for power quality, all of which would not be part of a global standard easily.

4.3.2 Overvoltages generated by solar plants

The second illustration is also provided by i-DE (Iberdrola), from fields test conducted during the work of the WG.

4.3.2.1 On the LV side

Severe overvoltages are an extreme case of the behavior described in Section 4.3.1, that takes place when generation is several times higher than load. In this case, voltage increases so much that damages are possible (depending on voltage magnitude and duration).

Damages take place typically when a switch upstream of the inverter (from LV to HV), opens in such way that one or several inverters become isolated from the rest of the grid. In our case, this happens if the microgrid is disconnected from the main grid without changing the mode of the generators from grid-feeding to grid-forming.

Measurements from field tests proved that the opening of any of the switches upstream of the inverter gives rise to an important overvoltage, as can be seen in Figure 4.8. The figure shows the waveform of voltages and currents during the opening of a LV switch that isolates two 25 kW inverters. It can be observed that the inverter trips almost instantaneously. Until then, there is a severe overvoltage (for a power electronic device), up to about twice the nominal voltage. This overvoltage appears when the inverter feeds and over-excites the inverter's transformer and the ancillary services transformer.

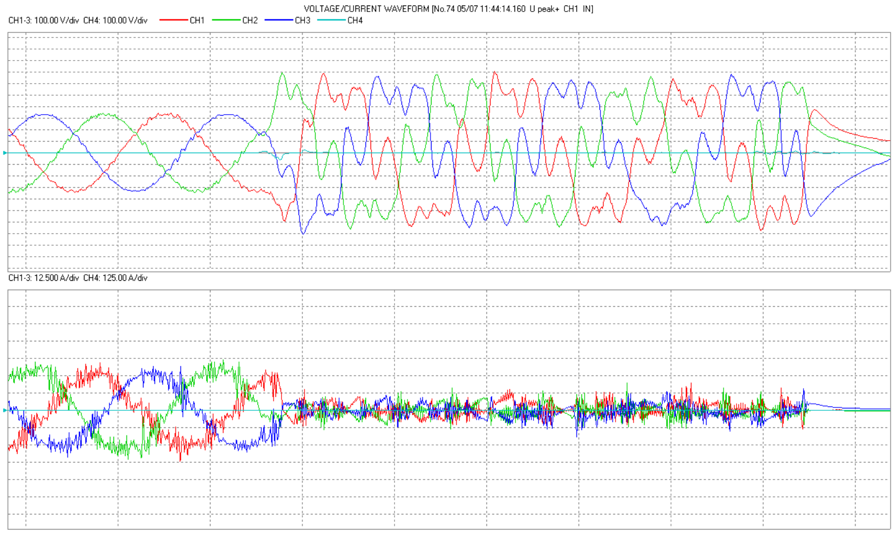

Figure 4.8 – *Overvoltage leading to revenue meter damage during LV switching off (voltages and currents).*

However, some aspects have to be taken into consideration.

- All the inverters complied with current standards, since none of the existing standards deals with this event.
- Although all the tested inverters produced some overvoltages, not all of them were high enough to damage meters. Clear differences could be observed between different brands.
- Not only meters, but other electronic devices suffered damages. Meters were more prone to be damaged simply because in large PV plants they are usually the only electronic device present other than the inverter.

Those points lead to the need of more precise standards on such event, which would be required if such islanding process would be generalized for microgrids in the future, as more and more sensitive devices and sensors are connected.

4.3.2.2 On the MV side

Figure 4.9 and Figure 4.10 shows the switching of the MV CB, which disconnects four 100 kW inverters. In this case, the inverters keep on energizing 50 transformers, 100 kVA each; giving rise, equally, to an overvoltage.

This overvoltage means an excessive stress for other electronic device, such as revenue meters, as well as power supplies.

It has been proved that some inverter configurations are more prone to create severe overvoltages than others are. Thus, the use of DC/DC choppers is a possible solution to limit the overvoltage, as explained in [156]. Only limited experiments and publication could not lead to a clear requirement, but it would be recommended to look into power electronics design and structures configuration to minimize extend of overvoltages. For those inverters configurations that generate overvoltages, other solutions are possible:

- Overvoltage supervision, focused on the AC side, to stop rapidly the inverter switching in case of overvoltage;
- Particularly rated surge suppressors to reduce the voltage to peak values within the admissible limits for all the equipment connected to the grid.

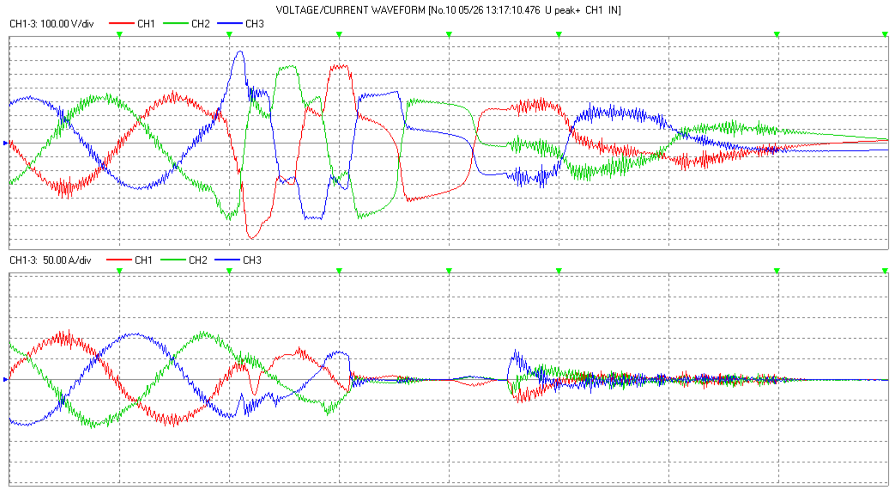

FIGURE 4.9 – *Overvoltage, LV side of first MV/LV transformer due to MV switching-off.*

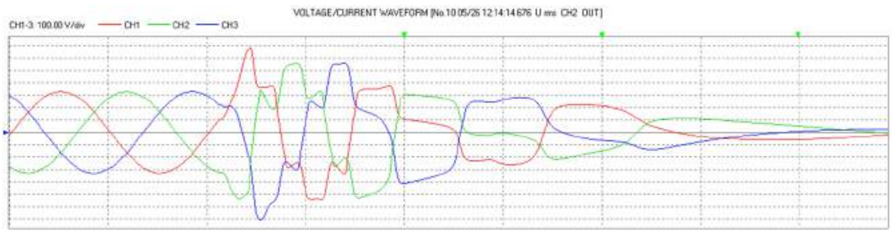

FIGURE 4.10 – *Overvoltage transmitted to MV.*

Although these solutions do not provide an optimum overvoltage value, they can reduce significantly the damage risk, being applicable to existing equipment.

4.3.3 Power flow and voltage regulation

Voltage regulation systems can be affected in substation (it modifies the behavior of compounding systems). They can also be affected in feeders (the voltage increases in case of long feeders and the behavior of on-pole voltage regulators is modified).

The resulting low or negative power in substation transformers can create some problems in the control systems, which require changes in control and protection criteria. This could need generalization in case of frequent planned islanding transitions. In transformers with current compensation, the generation can compensate the load consumption in the lines, thus regulating the voltage down when it should be regulated up.

Considering feeders, the necessity of considering voltage variations in long rural lines arises. If a line voltage regulation is used, a change in the power flow direction can be interpreted as a change in the grid configuration and the voltage regulator can change the steps in the wrong direction. More adaptive regulations would then be required.

4.3.4 Voltage instability due to controller interactions

System stability is one of the major concerns during resynchronization. The distributed effort of controlling voltage and frequency with multiple controllable sources can lead to controller interactions. That can result in voltage and frequency oscillations in the microgrid, for example at sub-synchronous frequencies that are difficult to deal with. The controller/converter interactions are one of the points of attention discussed in this chapter, notably illustrated by the lessons learned from the Simris demonstrator (not included in Chapter 2).

The goal of the H2020 Interflex Swedish demonstrator field trials in Simris was to demonstrated that an electrical system can host a penetration of up to 100 % of power obtained from renewable sources (PV and a wind turbine) by using field-proven and market available technologies [156]. For this pilot project, the small village of Simris in the south of Sweden was connected and disconnected from the main grid in a seamless way while being sourced in times solely by renewable energy coming from a local wind turbine, a PV farm, and rooftop PV installations of the local households.

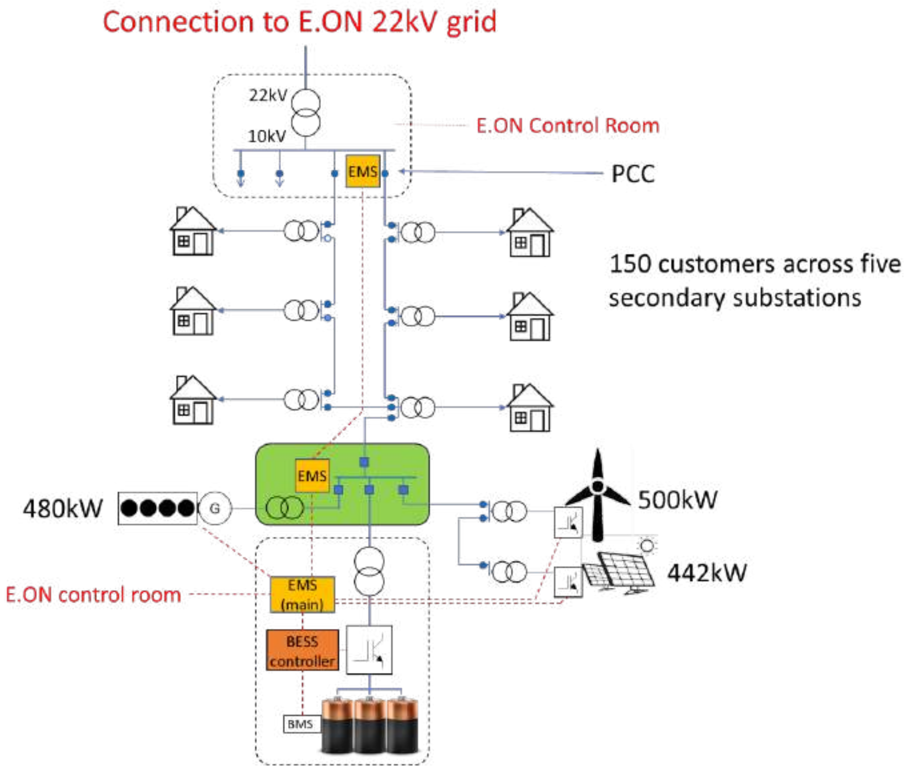

FIGURE 4.11 – *Simris demonstrator – Overview [157].*

As presented in Figure 4.11, the microgrid consisted of an existing 10 kV distribution system which contains seven substations of 10/0.4 kV of which five supply 150 customers. The feed in point to the microgrid is via a 20/10 kV substation from a 10 kV bay. The bay is equipped with a power breaker, voltage and current transformers, and relay protection devices. The battery was the only power electronics interfaced source, which was operating in grid-forming mode. For commissioning and technology testing purposes such as protections and new microgrid algorithms, a so-called "mini-island" grid was created which consisted of all generation and storage assets. The 150 customers were replaced in the mini-island by a 480 kW resistive load bank. The field trials were able to demonstrate that the battery system can manage 100 % IBG with zero inertia, and also integrate conventional generation from a reciprocating engine when needed, while maintaining voltage, frequency and THD within the required specification [156], [157]. This is coherent with the lessons learned presented in Chapter 2, discussing the technical feasibility of such installation in the selected demonstrators. The issues are rather related to the change of paradigm: from demonstration to real-life, increasing the scope of issues beyond technical ones.

During commissioning tests while being in islanded mode in the so-called mini-island (no customers) the BESS was able to maintain frequency and voltage stability for low generation levels while being the only unit operating in grid-forming mode. However as soon as the generation power increased, a voltage instability took place until the system was tripped. The oscillations occurred consistently at a power level of around 120 kW when the power was supplied either by the solar generation or the backup generator. The stability testing did not include the wind turbine, as its control was not enabled at the time of the test.

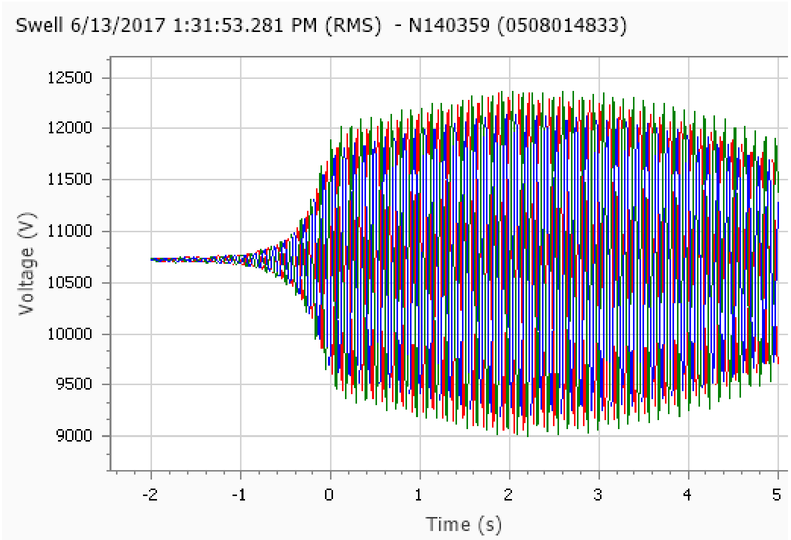

FIGURE 4.12 – *Simris demonstrator – Instability of the MV voltage during system commissioning (13th June 2017).*

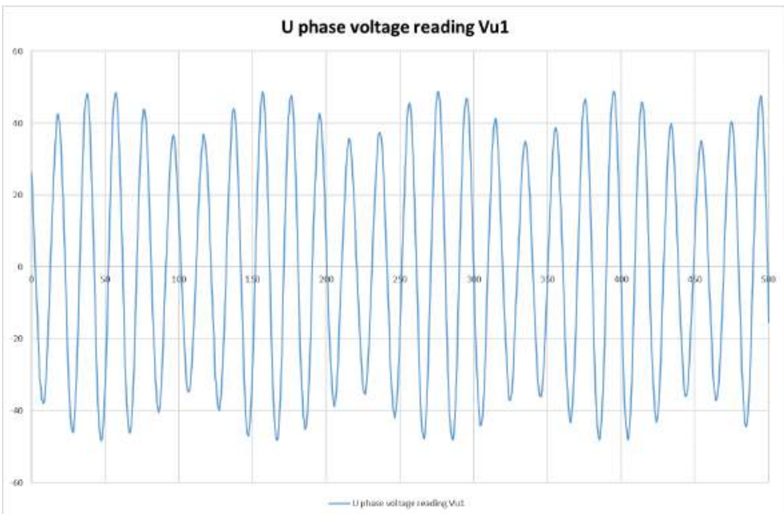

FIGURE 4.13 – *Simris demonstrator – Voltage readings while islanded during instability.*

The system was tested with the load bank at different power levels to test whether this had any effect on the stability. The result showed no impact of the load bank on the instability. The system became unstable at the same power generation levels regardless of the load power.

The supplier of the power electronics apparently resolved the voltage instability. The solution was to change the inverter internal control parameters to increase system stability. Nevertheless, not to jeopardize the customer supply, no exhaustive testing was undertaken to establish the system stability margins in islanded operation.

The main risk with the stability issue and the approach to resolve it was that the core control loops for the power electronics are critical intellectual property of the inverter's supplier, meaning only he can model the system's dynamic response and tune the required parameters. This model ideally requires all grid parameters and the control loops of the other renewable generators supplying power to the system.

Simris demonstrated that a specific combination of power electronics and renewable could operate in a stable manner, as it could not be determined whether the stability issue and resolution are specific and unique to the used power electronics, or whether other inverter suppliers would have suffered from similar or different issues. The generalization and replicability to other power electronic combinations, generation and load levels is not valid. This points out a clear need of technical simulations tools able to handle, in the same modeling environment and at the level of power electronics devices, both "black-boxes" and open source models, for example with functional mock-up interface. Being able to use a standard that defines a container and an interface to exchange dynamic models from various backgrounds allows indeed for complete transient stability simulation while avoiding intellectual property issues with the inverters suppliers on the components choices and controllers design. That capacity would help operators better managing their power system, notably in islanded mode.

For information, testing in March 2018 showed that the instability was, at very high power generation levels, still present, leading to a system tripping at 600 kW, as shown in Figure 4.14.

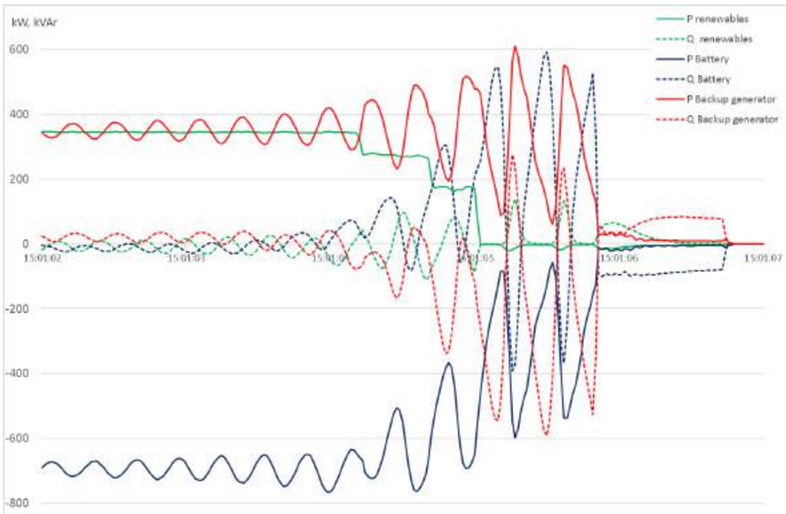

Figure 4.14 – *Simris demonstrator – Voltage instability at high generation levels leading to a system tripping from the mini-island.*

The documented use case from Simris shows that even utilities still lack the necessary diagnostic tools to identify the presence of impedance-related instability, even though the main source for the voltage instability is well known in the power electronics community. Interaction between the inverter and the equivalent grid impedance (as seen by the power converter) has been identified as one of the most likely causes for the reported instability and power quality problems [158]. This dynamic instability problem has to be looked into.

The so-called converter interactions have been extensively studied in DC systems [159]. The output currents and voltages can be monitored and recorded to facilitate post-fault diagnostics. However, the reason for instability may be hard to identify based on current and voltage waveforms alone. Utilities argue that detailed stability studies are only possible when using open converter models, which manufacturers typically do not provide. In this context a major work advantage of the impedance method is that it does not rely on analytic converter functions but it can be measured a-priori [159] at the terminal or even online [160] and is therefore generally applicable with common off-the-shelf components.

Stability is preserved if the inverter's impedance is shaped to have a larger magnitude than the grid's impedance at all frequencies or if both the grid and inverter impedances remain passive [161]. That is, the real parts of both impedances remain positive at all frequencies. However, the grid impedance varies over time and may experience multiple resonances which makes impedance design of grid-connected converter a challenging task.

Moreover, the inverter's impedance is affected by control delays and necessary control functions, such as grid synchronization using a PLL, which may introduce negative resistance-like behavior. A small stability margin may cause poorly damped oscillations in grid's current and voltage during faults and transients, whereas, zero or negative stability margin causes instability [162], [163].

4.4 Storage facility and grid-forming units

Once islanded, if relying on traditional equipment and control, the microgrid needs a way to provide a frequency and voltage within predefined and/or acceptable ranges to all components. A compromise between ranges (thus power quality) and stability of the island (or its duration) could be discussed per microgrid (notably depending on the needs of the end-users). The scientific and industrial consensus point out grid-forming units as the elements in charge of ensuring the stability of frequency and voltage. Other non-grid-forming units just follow the control signal (that can be frequency or other quantities). A grid-forming inverter is an inverter, which has the capability to form a grid, i.e. to provide the voltage and frequency reference to the grid. This approach typically requires controllable and fast response energy storage on the DC side. A grid-forming inverter can be modeled as a voltage source series with low impedance. It should be capable of providing a reference and support for frequency and voltage, robust synchronization mechanism, and performing black-start, all of which are traditionally offered primarily by SGs [5], [58], [59], [99], [164].

4.4.1 Storage facilities

In a time where energy transition is the actual mindset, storage is vital as a buffer for renewable volatility. Storage is a key element when operating microgrids in islanded mode, where renewables are considerably present. Without rotating machines, the grid-forming unit is almost systematically associated with a storage facility. This is one of the take away message from the demonstrators assessment provided in Chapter 2. Though ageing is considered and the sizing is based on end-of-life capacity, the remaining issue today is the cost level but its evolution is still in prognosis to decrease. Its sizing is related to frequency stability [165], [166]. In Chapter 2, only one demonstrator did operate without storage, in a scenario that was not compatible with excessive flexibility (and time) once islanded. Several demonstrators have proven that microgrids can be deployed without conventional generators, once a storage facility is available. Storage systems are de facto seen as almost indispensable grid-forming entity of microgrids, allowing smooth transitions like UPS systems in other somehow related configurations.

Storage operation regimes affect the asset's lifetime. In cases where batteries are present as a storage technology, the use of complementary source like supercapacitors or flywheel is important so that batteries lifetime can be spared due to the peak response in case of a quick load variation. Hybrid combination of storage technology is indeed considered in the scientific literature.

Economic aspects of storage systems are out of the scope of this WG, focusing on technical requirements (though they are fundamental regarding any economic viability). It is nevertheless interesting to cite the Clean Energy Package (DIRECTIVE EU 2019/944) on common rules for the internal market for electricity (art. 62-63).

> *System operators should not own, develop, manage or operate energy storage facilities although exception are allowed where energy storage facilities are fully integrated grid components that are not used for balancing or for congestion management. They should not be required to comply with the same strict limitations for system operators to own, develop, manage or operate those facilities, subject to approval by the regulatory authority. Such fully integrated grid components can include energy storage facilities such as capacitors or flywheels, which provide important services for grid security and reliability, and contribute to the synchronization of different parts of the system.*

In the case of microgrids, where storage systems present a key role (ensuring microgrid stability), DSO shall be involved in its operation, assuming not being the owner of the storage asset by default, as stipulated in regulations. This implies developing in DSO teams strong competences in operation and management of storage and power systems devices, which were not necessarily present traditionally. On the long term, those components shall integrate planning studies, maintenance and other more system-oriented teams. Gaining those competence do not mean manufacturing the components (neither its control), but mainly being able to interact as an expert end-user with the actual producers of such devices (and their associated controls) through the definition of clear technical specifications.

4.4.1.1 Aggregated and distributed applications of storage facilities

Storage facility systems can operate in both ways: sources and loads. Due to power electronic interface like DC-DC or DC-AC converters, storage facility can be used on both sides (AC or DC) of applications. In this context, two main configurations are known: aggregated (illustrated in Figure 4.15) and distributed (illustrated in Figure 4.16). An aggregated storage facility is a large central energy storage system with high power capacity. A distributed storage facility is much smaller and is usually placed nearby power sources or consumption sites. An aggregated storage facility can be used as the grid-forming power source of the microgrid. Huge power capacity and DC-AC converter interfaces provide very fast response for active and reactive power regulation. The PQ diagram of storage facilities should be as wide as possible, to supply the maximum current for active or reactive power, thus contributing to a stable and reliable voltage and frequency control [81].

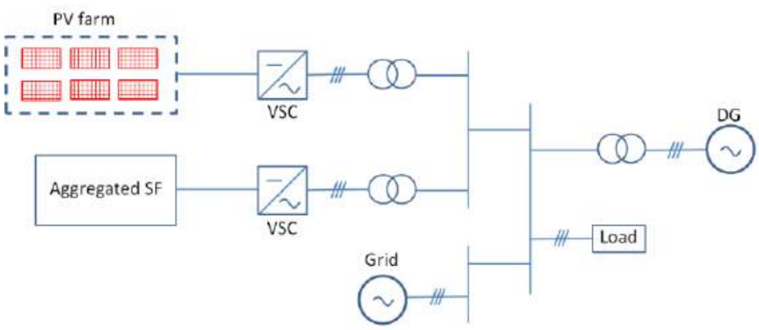

FIGURE 4.15 – *Aggregated storage facility system.*

In both configurations, the size of the storage system is effectively chosen in relation with the topology of the microgrid as well as other practical design criteria like position, surrounding electrical environment, services provided (short-term stability or longer term power balance) among others. Hybridizing technologies, with different characteristics in terms of power and energy capacity, is a relevant way to enhance the capacities of installed facilities. The sizing event for such devices could be SC currents rather than generator loss (ROCOF).

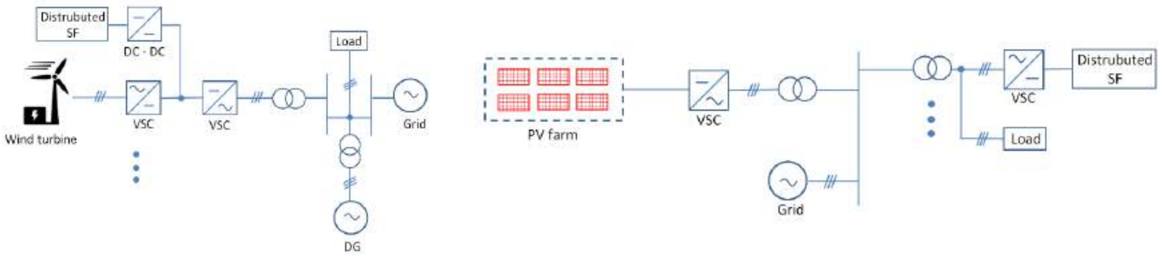

Figure 4.16 – *Distributed storage facility on the generator (left) and load sides (right).*

The ageing of the various storage technologies as a function of very large sets of cycles and modes of usage is still a work in progress. Being able to define a quantifiable criteria linking usage and ageing would certainly allow a much easier CBA, depending on the storage owner and significantly improve the predictive, planned and unplanned maintenance of the systems, contributing to its overall economic viability.

4.4.1.2 Key features of storage facility integration

The following subsections present features that microgrids switching from grid-connected to islanded mode would benefit from if ever implemented within storage facilities regulation systems. It is not mandatory for the storage unit of a microgrid to cumulate all of the presented configurations, as most of them would present an interest on a site-specific basis, but it is relevant to consider them while designing the component that could act as the grid-forming unit of the islanded microgrid. The discussion on the location of the grid-forming unit as well as the interaction between multiple such units (possibly going up to the interaction between multiple microgrids) is linked to the presented features [106], [107], [167].

4.4.1.2.1 Standalone storage system as grid-forming power source with DC-AC interface. Power storage systems with DC-AC inverter interface are mainly fourth quadrant devices therefore, they can provide power flows of active and reactive power both from the microgrid and to the microgrid. Thus, they can provide a wide range of voltage and frequency regulation functions at the AC side of microgrid. DC-AC inverter must contain functions for battery power management to properly get integrated in microgrids with maximum efficiency.

DC-AC inverter with storage system should contain functions that are compatible or in line with at least virtual inertia provision. Implemented control system of storage inverters are usually complex, and can contain functions for grid-supporting mode as well as smart battery management and grid-forming capacity (frequency and voltage regulation) depending on the size/location of the associated storage facility [81]. The activation of those modes could be automatic for simple ones (e.g., triggered based on only local measurements) or manual for more complex ones (e.g. switching to grid-forming mode during an intentional islanding).

4.4.1.2.2 Hybrid grid-forming power source with DC-AC interface. Grid-forming power sources could present hybrid topologies, with storage and generation capacities. The basic rule for considering a power source as a grid-forming device is that it must supply the required amount of active and reactive power to loads whenever needed. Hybrid structures of power

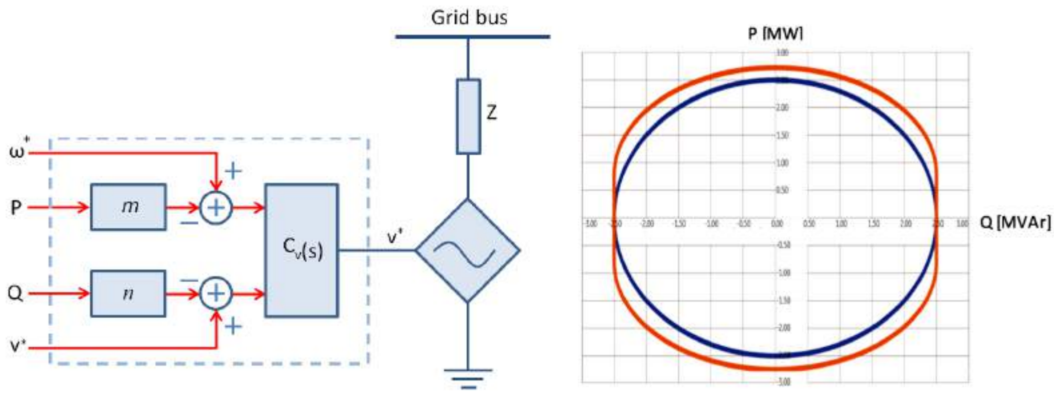

Figure 4.17 – *Standalone grid-forming inverter where m and n are droop coefficients (left). PQ diagram of storage inverter illustrating various operational conditions, here function of the temperature (right).*

sources aim at enlarging the response time of grid-forming systems, notably regarding the time adequacy between energy production and consumption when dealing with renewable energy sources. Storage system should supply the DC side of the power source in synergy with the renewable power source technology. As an illustration, Figure 4.18 shows the ESS connected to the DC side of a renewable power source. The advantage of such hybrid system is that the required storage capacity is lower than for a standalone system for the same application [81].

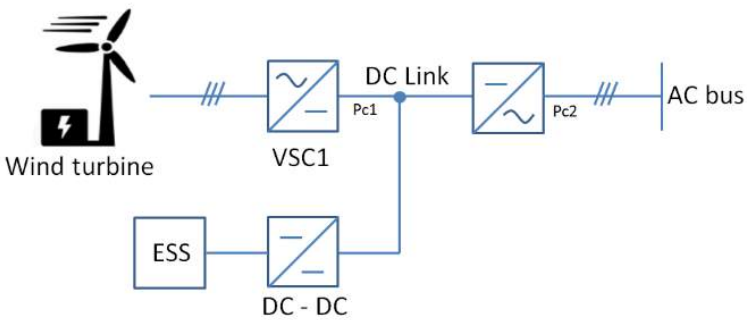

Figure 4.18 – *Hybrid grid-forming power source.*

4.4.1.2.3 Storage system as grid-supporting system with DC-AC interface. Storage system with a DC-AC interface are universal devices, where functions are mostly defined by the control systems of converters. The abilities of the control system depends on the control software, which can then target and implement a wide range of functions. Grid-supporting functions can be implemented into control systems to improve the stability, the security and reliability of the microgrid. For DC-AC inverters interfacing the DC side of power devices with the AC side of the grid, the support functions are limited by the PQ diagram, which is defined by the manufacturer (normally following the specifications provided by the microgrid operator). It is thus a design constraint that directly affects the cost of the inverter. In that context, the power storage can be used for the supporting functions presented in Table 4.2.

The supporting functions can be divided in two main groups: autonomous and non-autonomous, as shown in Figure 4.19. Their usage partly depends on the microgrid philosophy among other practical aspects. The main difference rely in the microgrid control system.

Autonomous regulation functions measure the state variables at the PCC. Regulation parameters, like the deadband and the steepness of regulations, are set by predefined functions. Regulation characteristics are defined with some key points at the x and y axis, as illustrated in Figure 4.20. Non-autonomous regulation is commanded by the higher-level control system, for example from the central control system of the microgrid (in most of the analyzed demonstrators of Chapter 2, those were the closest DSO control center). Its outputs commands should be results of optimal calculations and other needs of the microgrid (as well as the main grid in grid-connected mode, in order to provide advanced flexibility levers and ancillary services to the grid). In general, support functions target directly or indirectly frequency and voltage. Similarity with on-grid support function is evident. Functions can be used within both operation modes with modifications due to topology and variation in impedances, global inertia, SC current, etc. Two sets of parametrization of regulation functions for each operating mode of microgrids are thus recommended.

TABLE 4.2 – *Grid-supporting regulation functions.*

Description	Type	Autonomous	Control system
Voltage set point	V=reference value	No	Higher central
Power Factor set point	PF=reference value	No	Higher central
Reactive Power set point	Q=reference value	No	Higher central
Active power set point	P=reference value	No	Higher central
Reactive power compensation at PCC	Q_{PCC}=0	No	Higher central
Reactive power-Voltage control	$Q = f(V)$	Yes	Internal
Power Factor-Voltage control	$PF = f(V)$	Yes	Internal
Frequency control	$P = f(f)$	Yes	Internal
High VRT	$I_{reactive} = f(V)$	Yes	Internal
Low VRT	$I_{reactive} = f(V)$	Yes	Internal

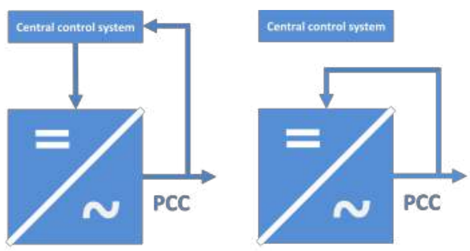

FIGURE 4.19 – *Autonomous and non-autonomous regulation function, principle.*

Reactive power compensation could be seen as a special feature (i.e. sites and configurations specific). In the case of the parallel operation of microgrids, reactive power flow should happen from the PCC to the main grid (for instance it the case of long cables, low consumption and maximum power generation). Storage system associated with power electronics can be controlled to compensate this unwanted reactive power flow as well as other more peculiar issues related to power quality and security like harmonics, unbalance operation, etc.

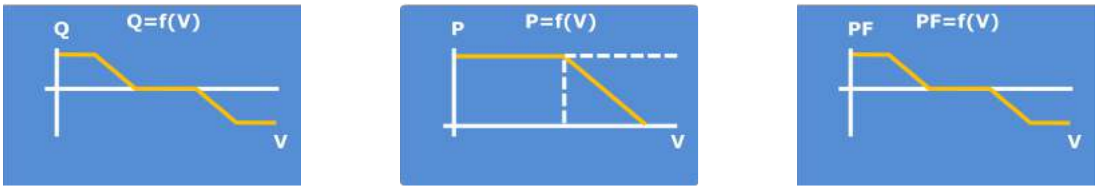

FIGURE 4.20 – *Illustration of regulation parameters graphical defintion.*

4.4.1.2.4 Storage system as part of UPS. In the renewable sources oriented microgrids, generating power (such as solar and wind power) is variable. When power sources suddenly stop generating electric power, back-up generators such as diesel generators are initialized (after fulfillment of predefined conditions). These are usually initialized within seconds. For ride through of this initialization time, storage system plays a key role in supplying the loads, going up to replacing as well the diesel generators for greenhouse gas emission considerations. Nowadays, questions about continuous power supply of some critical infrastructure are topical. Therefore, UPS systems in microgrids is a highlighted issue, though relying on well-known industrial equipment, illustrated in the use case of Figure 4.21.

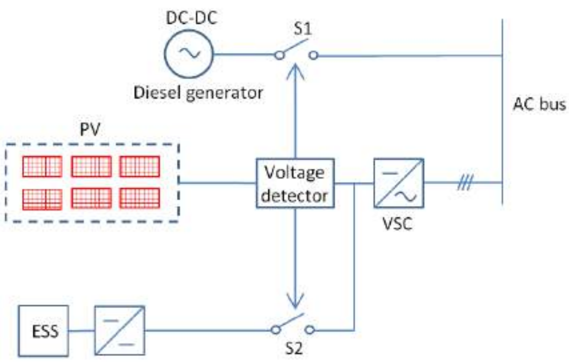

FIGURE 4.21 – *Example of UPS configuration.*

When solar power output decreases under defined threshold, a support generation (like a diesel generator and/or a storage system) are initialized. At first, the VSC is supplied by the storage system with DC-DC converter. A diesel-generator could complement the power supply on a long-term duration, when the storage system state of charge passes below a threshold defined in the Microgrid center controller (MGCC). Later on, the storage switches to charging mode when the conditions are stable again. Voltage detection at the DC side of the VSC can be applied for triggering the switch. Switching mode must be optimized with respect to generators, to avoid for example frequently starting sequences of diesel-generators (decreasing their life expectancy) [81].

4.4.1.2.5 Storage system on the load side – Load leveling and peak shifting. The main goal of load leveling and peak shifting is to minimize the impacts of loads variations on the voltage and frequency in the microgrid while increasing its balancing capacity between local generation and consumption. These methods indirectly stabilize outputs of grid-forming generators and may help with active power reserve in the renewable sources oriented microgrids. Loads themselves cannot be necessarily regulated, so the connected storage facilities can optimize the load profiles supplied by the generators in the microgrid.

Peak shifting method controls the charging of storage facilities utilizing superfluous power generation during low load periods. During the high load periods, the storage system is discharged to provide power and thus shift peaks. Load leveling method can be used for loads when the power demand changes dramatically. Weak microgrids are sensitive to large and fast load variations. Such variations may cause changes of references set points of the generators. Storage systems equipped with a load leveling control mode close to the load can smooth and settle their electrical characteristics by smart charging and discharging. These methods may have some economic benefits in cases where high and low cost tariffs of power supply are applied. Both control methods are illustrated in Figure 4.22 [81].

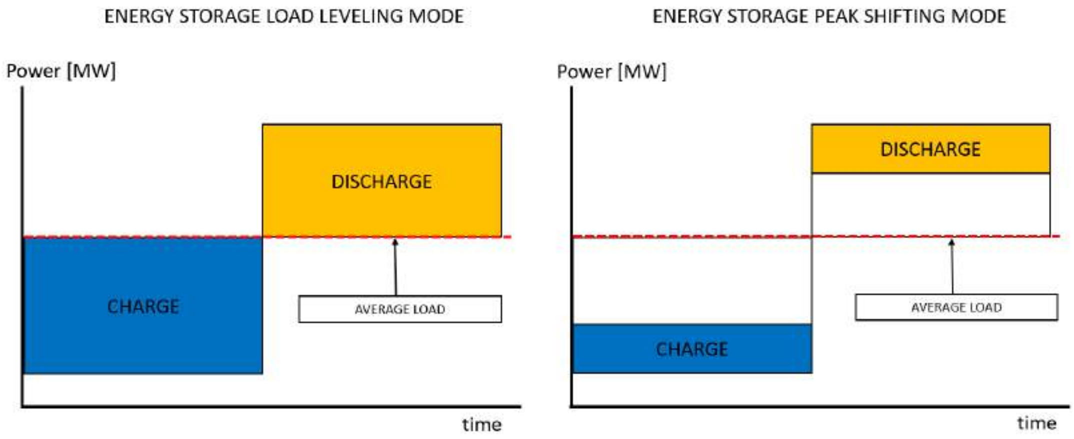

FIGURE 4.22 – *Principle of load leveling (left) and peak shifting control using storage (right).*

4.4.1.2.6 Storage system on the generator side – Suppression of the fluctuations. In some cases, disturbances in output currents may be recorded due to unstable characteristic of renewable sources generations. Cloud covering the PV panels or wind changes are typical causes. The output of renewable sources may change extremely rapidly, causing sudden droops of the generation. With the appropriate storage system integration (a large capacity is not needed in most cases) in the power source concept, renewable generation may be a more stable and reliable power source for the microgrid, thus limiting the need of additional resources as well as easing the control challenges.

Several control methods are known to that end. For instance, the ramp rate control is a storage system control method, which is designed to limit the rapid change of the output power of renewable sources (refer to Figure 4.23, left). If the desired rate of change of power can be reached, the power output of the renewable source is more predictable for the microgrid system controllers, thus increasing its reliability (and incidentally the possible duration of the islanded mode).

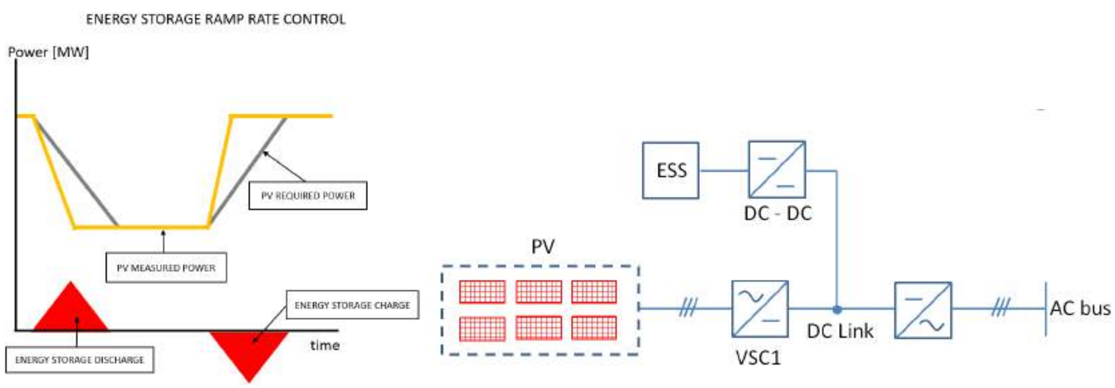

FIGURE 4.23 – *Examples of storage system controls at the generator side: Ramp rate control (left) and constant power control mode (right).*

The constant power control is another example of interesting (though needing more equipment) control method for the storage unit of the microgrid (refer to Figure 4.23, right). The power at the DC side of the interfacing DC-AC inverter is the sum of the power sources outputs and the storage system outputs. The shared DC-link is used. This concept is very similar to hybrid grid-forming topology (with multiple storage technologies).

When the storage system is operating in filtering mode, its behavior is similar to a low-pass filter. The main goal of this mode is to smooth the output power of renewable sources. Fast dynamic responses of storage systems are ideal for that purpose. Storage systems can compensate the differences between the generated outputs of the power sources and the required outputs calculated from the filter function. If the filtering function is too often solicited by the power supply, the resulting frequent charging and discharging can reduce the storage system lifetime. A dead-band for the control system must therefore be implemented [81].

4.4.2 Synchronous grid-forming devices

Currently, most isolated microgrids rely on fossil-based SGs to provide voltage and frequency reference, when simple operation and reliable devices are necessary so that minimum operation and maintenance efforts are required. A will to decrease the carbon footprint of local generation should lead to a decline of dispatchable SGs in islanded microgrids. Efforts are thus needed to deal with the associated challenges, like improving the predictability of the production. Providing regulatory efforts is as well important, as discussed in this chapter, to specify more stringent operations and flexibility requirements for generating equipment in order to assure the power system operation and stability. For all technologies of DER, both traditional SGs and VRES connected through inverters, new capabilities with regard to FRT, frequency range and control, ramp rates requirement, reactive range and voltage control start to be required [168]. Implementing those elements possibly leads to a large retrofit campaign of older generation of DER to comply with the most recent standards (for instance being capable to remain connected in the range 47.5 Hz – 51.5 Hz) as well as propose advanced ancillary services [4]. The usage of such functions remains in the hands of the power system operator, which could beneficiate from a more rigorous regulatory framework to help make the most of available flexibility levers.

In addition to grid-forming inverter technologies (like virtual SGs), and rotating machines actually generating power for the islanded microgrid, another possibly is to consider synchronous condensers. Those machines are not connected to any mechanical loads or turbines, hence not dispatchable. Other key features of synchronous condensers may help stabilize the grid, such as high SC current and voltage recovery capability, inertial response, and the capability to provide the reference of voltage. As a robust response to the increase of variability of renewable energy production, projects of conversion of old SGs to synchronous condensers have marked the revival of these systems [169].

As the majority of IBG are of grid-following and grid-supporting type, synchronous condenser technology could be a straightforward solution to the grid stability problem, where the VRES connected via IBG are responsible for power generation and the SG for grid stability and the reference of voltage and frequency. Researchers and engineers master this concept and the construction of the machines, as the technology is already mature. The traditional inherent behavior of SGs and power systems based on the swing equation is still applicable here, hence familiarity with the traditional power system engineering practice. An important downside of active power losses has to be taken into account in the operation.

In traditional power systems, dispatchable SGs play a central role: voltage and frequency reference, energy producer (coming from mechanical power), and short-term storage through rotating inertia. However, with more VRES, the elements which assume these roles have to be rethought, as one role can be assigned to different elements in the power system. Works are being conducted to that matter, testing various solutions with the objective to minimize the need of storage and communication systems. Rotating machine have the capacity to play a significant role to that matter, ensuring both grid-forming capabilities, providing time to the operator to react, and smoothly adapting to frequency and voltage variations.

While there will still be rotating machines (like diesel generators), new technology to ensure a stable operation (in terms of reactive power production, etc.) should be developed to help mitigate inherent transient issues of purely IBG-based microgrids. Interactions with VSG/IBG is a key subject, notably regarding the SC currents and impedances aspects. Hybrid operations are recommend, notably with the presence of synchronous condenser for increased reliability, while relying on competences that are already present in operational teams, used to work with rotating machines. Considering a central grid-forming unit made of a rotating machine presents significant interest in current researches, behaving naturally correctly on most of the technical criteria IBGs try to emulate.

4.5 Monitoring, communication and control

The management of all elements of the microgrid transitioning from grid-connected to islanded mode rely on an essential set of monitoring, communication and control systems. The operation of the microgrid relies indeed on the capacity of the management system to observe electrical quantities and react to their variable condition, providing references to flexible and active components with communication links. Various time horizons are considered here, based on classifications discussed in Chapter 3, ranging from transient issues to market balancing, and up to long-term design principle for balancing energy production and consumption.

The points discussed in this section mainly concern the transition from grid-connected to islanded mode for microgrids, as there exist a tremendous amount of work on the islanded mode (mostly for isolated microgrids) and grid-connected mode (traditional distribution system operation). This subject is worth further investigation, notably within a dedicated WG.

4.5.1 ICT infrastructure

Power grids were designed around conventional elements such as electrical machinery (rotating machines, transformers), distribution lines, and loads. Those elements are the heart of a electrical grids. A number of more intelligent elements are being integrated into power systems. They include communicating/smart meters, actuators, fast switching devices, powerful sensors, advanced functions of grid supervision and control, and storage facilities.

ICTs for power grids exist as embedded software, whether at the level of components or control centers, and means of physical communications [170]. A particular interest is associated with the following functions:

- The smart meter with its different variants: broadband bidirectional communication, possibility of load control tools and energy service;
- Advanced devices for energy management, either linked to smart meters or extension of ADSL potentials;
- The intelligence associated with various domestic, tertiary, or industrial consumption components. The typical example is decentralized and intelligent load shedding based on the grid frequency or voltage;
- Observability, supervisory control and grid management linked with electricity production and consumption;
- The intelligence carried by devices in the electrical grid characterizing the following process: measure, analyze, decide, act, and communicate. It is the main concern of the whole distribution automation.

Collection of large amount of data further enables new functionalities for operation and control thanks to the on-going digitalization. Designing microgrid requires complex controllers due to the addition of a large set of DERs (PV, wind, CHP unit, etc.) which are to be included in the global infrastructure, possibly on a dynamic basis (for instance with plug-and-play components and self-updating state estimation). The microgrid controllers should comply with international standards such as IEEE 2030.7 [50] and wide specifications defined within the scope of Microgrid energy management systems (MEMS). The main functions of the controller target the transition from grid-connected to islanded mode and the associated stable operation after the transition, for instance relying on active and reactive power management. The transition should be instantaneous, so fast enough communications between the main nodes are required.

The microgrid controller infrastructure could be structured from centralized to decentralized controllers (with distributed being a hybrid solution). The MGCC defines the power demand, external conditions, load and consumption forecasts and auxiliary services of the microgrid. Loads and generations not included to the central controller must perform autonomously by defined conditions and if needed are shed on demand by the MGCC.

Communication protocols and the associated physical layer shall be defined in accordance with reference like IEC-61 968, in terms of data models for instance [171]. The communications shall be defined depending on the control strategy, notably on data latency requirements.

Primary control: Fast wired physical layers shall be preferable comparing with wireless ones;

Secondary and tertiary control: As latency is less important, other physical layers for communication shall the used from GPRS to PLC in some cases;

PLC communication types: International standards shall be defined, following for instance the work of Prime Alliance [172].

From the demonstrators' lessons learned presented in Chapter 2, usually, for the communication between the PCC and the ESS/grid-forming unit, the speed is critical, which justified the selection of optical fiber. For the communication between the other nodes in the microgrid, the speed and availability is not as critical since these are safeguarded by local control and "fail-safe" modes at the local level. The split of the control system into several layers and the ability to operate safely during a communication failure usually provides the possibility to use existing communication infrastructures on the island, which is a good test for the demonstrator (excluding cybersecurity considerations).

At the MV level, it is possible to find reliable communications supports, from GPRS to fiber in case of telemetering, remote terminal unit, etc. At the LV level, the roll out of smart meters shall be used to provide part of load data requirements. It is to be noted that data from smart meters are collected on a slower rate than what would be needed for decentralized real-time control. In addition, non-technical issues, like the GDPR are of high importance in their usage. The situation is even more complex when there are other party involved, as sharing the data between the DSO and other actors is not straightforward. Data protection and the current EU regulation on energy storages are very likely preventing DSO to empower temporary microgrids solutions. Enhancing the capacity of DSO to temporary island part of their grid (for any reason already discussed in Chapter 3) would require regulatory changes.

4.5.2 Monitoring systems

Monitoring systems ensure the observability of microgrids, coping with intermittent and low-inertia behavior as well as independent demand-side actions that can menace secure operation, control, and protection of active distribution systems. Monitoring is also key to load shifting and other energy consumption related flexibility levers that shall help balancing the operation of the microgrid in islanded mode. More related to social acceptance, economic viability and business models, load curve management strategies play a significant role in the capacity of a microgrid to last in islanded mode.

There are many ways to make a microgrid observable. For instance, in the transmission grid, Phasor measurement unit (PMU) are used to make the voltage magnitudes and angles at the measured nodes visible. Transferring this technology to microgrids is a challenge, since a microgrid is located in a distribution grid and therefore the following issues must be addressed.

1. Voltage angle differences between locations in a distribution grid are up to two orders of magnitude smaller than in the transmission grid (tenths rather than tens of degrees) [173].
2. Distribution system measurements will be fraught with much more noise from which the angle signal must be extracted.
3. The costs must be lower to make a business case for the installation of multiple PMUs in a distribution grid, as compared to the transmission grid, judging with the nodes numbers.
4. Yet the number of available empirical data points, compared to the number of grid nodes, is much smaller in distribution than in transmission systems, given that advanced metering infrastructure do not communicated in real-time [174]. For this reason micro-synchrophasors, or micro-PMU are designed for direct measurement of voltage, phase and angle at the distribution level to support a range of diagnostic and control applications [175].

Expected data requirements for the observation of dynamic processes such as islanding and resynchronization of microgrids are given in Table 4.3. High sampling rates are not important for obtaining angular resolution, which depends rather on the accuracy of the time stamp, but are needed for understanding transients and harmonics events occurring in sub-cycles.

Table 4.3 – *Expected data requirements for dynamic circuit behavior [174].*

Sampling rate (per cycle)	Angle resolution (milli-degrees)	Spatial resolution (placement)	Data volume (Bandwidth)	Communication speed
2–512	10–50	Dense	High[1]	Usually high

[1]but could be intermittent.

Microgrid balancing and synchronization is an application with a longer strategic time horizon, but one where the use of voltage angle as a control variable is expected to be crucial. Generation and load within a power island can be balanced through conventional frequency regulation techniques, but explicit phase angle measurements may prove to be a more versatile indicator. In particular, angle data may provide for more robust and flexible islanding and resynchronization procedures for microgrids. A convenient property of PMU data for matching frequency and phase angle is that the measurements on either sides need not be at the identical location as the physical switch between the island and the grid. A self-synchronizing island that matches its voltage phase angle to the main grid could be arbitrarily disconnected or paralleled, even without momentary interruption of the load. Initial tests of such a strategy with angle-based control of a single generator were found to enable smooth transitions under continuous load with minimal discernible transient effects [173].

When operating in islanded mode, voltage and frequency measurements are critical. For frequency, only one point of measurement is necessary, since this measure should not vary too much. Note that the transient frequency can vary in larger microgrids and so the ROCOF at different locations. Other than at the PCC, ROCOF relays at load points could be an interesting idea to ensure minimum transients (loss of main grid, UFLS and generator frequency response). For voltage, several measuring points should be considered since it may vary considerably, more specially in LV grids. For synchronization purposes, frequency and voltage measures should be considered in both sides of the PCC.

The IEC-61 850 standard, recommended for such installations, has been designed to exchange in real time sampled value (frequency, voltage, current, etc.) between substations, as well as tripping information [176]. In regard of these capabilities, the observability of both the microgrid and the main distribution grid is possible. The remaining operational question are:

- Should both the microgrid and the main power grid have the capacity to decide to switch to islanded mode?
- Should both sides agree before switching?

Those choices affect the protection's design, as well as the requirements on the importance and the location of intelligence (to understand in the sense of capacity to take action). They also affect the security of the microgrid, as for instance a two-side agreement will lead to delays and could also prevent the switch in case of communication error, or even cybersecurity issues. This also means that an operator should not necessarily validate the switching decision. As discussed in Chapter 2, the current state of implementation of those situations (only observed in demonstrators, even if at a real-life scale) shows that those questions are not answered yet. Choices were made to enable the demonstrations to take place, thus agreeing by default on a preliminary knowledge at least on the DSO side. Even if linked to some practical constraints, those choices go beyond solely technical requirements.

In islanded mode, it may be a good idea to keep the microgrid synchronized with the main distribution grid. This was enabled in the IEC-61 850-90-5 standard, meaning that sampled values can travel on wide area network and not only local area network [176]. In that configuration, the islanded microgrid still has the digital information from the main power grid, even if it is disconnected, from the electrical grid point of view.

Monitoring systems are technically available and mostly standard. The main issues in fact concern more the data ownership and operational decisions on who monitors what, and what choice is made from that. To that regards, providing only technical requirements shall be rapidly limited regarding this aspect of the discussed subject.

4.5.3 Control strategies

The required capability to operate in different modes (grid-connected and islanded) exacerbates control challenges. Actually, in the case of grid-connected operation, the grid, with simplified contribution from the microgrid control functions, addresses the task of stabilizing voltage and frequency. In addition, when operating in islanded mode, power balancing requires accurate power sharing mechanism to establish the balance of power in the event of a sudden mismatch in the active power. Therefore, focusing on microgrid operating in islanded mode, the following main tasks need to be addressed:

1. Power supply and demand balancing;
2. Voltage and frequency stability;
3. Power quality regulation.

Once islanded, control strategies are required to ensure a secure operation of the microgrid up to resynchronization. With regard to VRES, balancing with storage, or combined cycle plants, seem to get a large consensus to assure power supply. In the case of very high level of VRES, DSM, in addition to batteries, come in for balancing active power production and consumption. Demand response can be accomplished with the support of communication or local measurements. ICT plays an important role in this function, and the scientific literature is dense on the subject, which is not in the scope of the WG.

Inverters have no natural interactions with the AC grid. The interactions between the IBG, the other resources, and the grid are therefore determined by the chosen control approach. An important limitation of inverters that has to be taken into consideration is the narrow limits of current overshoots, as opposed to high overloading and overcurrent capability of SGs. Also, the low X/R ratio of distribution line impedance might affect the load sharing accuracy of inverters, typically resulting in unbalances, poorly compensating nonlinear and unbalanced loads. The droop characteristics for DER should consider voltage and frequency dependencies of load responses to ensure a proper sharing and avoid instability [46].

In the islanded mode, maintaining high electrical energy security in the presence of high levels of VRES is possible with the help of technologies such as storage systems, but it is proven costly. A compromise between reliability, economic cost, and sustainability is therefore necessary, with the focus on meeting the main objective of the MEMS. For example, if the priority is to achieve optimum sustainable energy use at affordable cost, compromises in reliability should be needed. They would require end-users behavior adjustment.

Alternative perspectives align with the DSM philosophy, about the view on maintaining the power balance in a power system. Instead of only ensuring that the generation side is capable of meeting the load demand; the loads must follow the available power generation. In addition, the implementation should not depend on pre-determined load shedding, local measurements, or fast communication systems, which marks a distinguishing point from a typical DSM implementation. Consequently, this strategy is relatively affordable and cost-effective. These features are highly desired in post-disaster recovery and low human development index community cases. However, a tradeoff in power quality is inevitable.

Depending on the site and end-users specificities, a large panel of frameworks are available. Control strategies can range from strictly centralized (at the closest dispatching center, like in some demonstrators discussed in Chapter 2) to fully decentralized (for instance based on peer-to-peer transactive energy systems) as well as hybrid versions of those two extrema (distributed) [60]. One solution cannot be put forward another in this context, as the involved actors influence its design and implementation. Decentralized operation is technically within reach, but requires a significant shift regarding the traditional operation of distribution systems that necessitates precautious steps to mitigate the overall security of the system (without talking about cybersecurity, bandwidth usage, monitoring needs and so on). The next question addresses the interaction between the various controls that should be implemented per site. Depending on the control strategy, there shall be strict requirements on the interoperability of the devices, first relying on common standards and communication protocols and second, being compatible with scalability and pug-and-play issues.

A good transition control strategy would be for instance a central main controller with distributed controllers available as back-up. The distributed controllers both provide the ability to act faster for any issue that is more local (like voltage variation where there might be only one ESS providing support) but the main benefit of the local controllers is to provide safe operation both with and without communication. The mix of central and local control can also reduce some of the traffic volumes even if the main reason behind its choice would be first the reliability and the resilience of the solution.

In that context, one of the most crucial design decision regarding the control system is on the choice of the grid-forming capacity of the islanded microgrid and its interaction with the main grid. Without too much technical difficulties, one or multiple grid-forming units should be defined, with the possibility that their role evolves in time (under conditions to define that should be possible to detect), thus needing external signals and a strong communication network. The interaction of control systems and the impact on power quality and microgrid stability is finally a direct consequence of the mentioned choices.

To open up on MEMS, the automation system depends on the control layers, in relation with the available data and the interfaces. The definition of the platforms depends on the stakeholders and shall rely on social, economic (and perhaps environmental) criteria, under technical constraints. Once you consider multiple microgrids in grid-connected mode that could disconnect temporarily and exchange information and energy when interesting, a significant scientific literature is currently being produced, for instance regrouped under the Distributed energy resources management system (DERMS) keyword. DERMS typically requires the integration of various systems, such as DMS, Outage management systems (OMS) and SCADA. The benefices from such developments are mostly on the technology-agnostic capacity (with the help of standards) and the design targeting scalability (thus performance, relying on a fast responsive communication network for real-time control). Regulatory and market structures under which DERMS operate require standardization.

Lastly, we could finish on the definition of the optimization criteria in control strategies. The issue is in the end the management of priorities in terms of energy consumption, which is more related to social and economic criteria rather than technical ones (except maybe when looking at the losses as a function of load profiles). There is an ideological prism to conclude on, making the connection between very innovative research currently going on (local energy communities, block-chain technology for peer-to-peer energy exchanges, AI, fully decentralized control and the selection/activation of flexible loads under uncertainty for instance) and the pragmatic management of consumption in demonstrators, as seen in Chapter 2. Those multi-domain considerations represent an entry point between the work conducted in this WG, on technical criteria, and another parallel CIRED WG, focusing on the economic aspects of those operations, that is recommended to read in complement to this report.

4.5.4 Outage management

The communication infrastructure should be based on technology that is available during an outage. If this cannot be provided in a cost efficient way, the control system needs to have logic to handle communication outage without threatening its function or the safety of any user. For telecommunication, the communication is lost when the back-up of the antenna runs out, the back-up times vary and need to be verified for the specific sites. For critical nodes it could be worth evaluating hard wired communication and in the risk analysis evaluate if that need some form of back-up communication (if the cable is damaged).

The basis of the control and communication system choices need to be based on a risk analysis: define what functions are critical, what functions needs communication to work and what are the consequences of a fault on the overall system's security. The control logic can be split to be able to work locally if communication is lost, keeping the solution live but with less optimization. Regarding the communication, the back-up times can be negotiated and/or private networks used however this increases the costs.

This calls for additional works on critical infrastructures and their mutual interactions. In that field of research and development, cybersecurity as well as information security could also play a role. Standards are required that would define clear benchmark scenarios helping securing such infrastructure.

For example, different operator handling the main power grid and the islanded microgrid would diverse the entities responsibilities in case of cybersecurity issues that might cause long discussion between lawyers from both sides to determine who is actually responsible. The needs of microgrid operations, especially about going to or from islanded mode, are somehow in opposition with the needs of cybersecurity. IEC 62443 and IEC/dTR 63069 include technical controls to ensure that security does not interfere with safety requirements [177], [178]. In that context, several questions are open:

- In case of emergency (like restoring a critical service), it might be requested that a special procedure overrides the security. In that case, the procedure as well as the type of emergency should be clearly defined;
- How to define situation requiring considerations of cybersecurity that override the default system, to (re)gain access to and use the protection, automation and control systems' assets? What are the requirements to do so, and the associated procedure?

There is a lot to discuss on the topic of security, which are not directly in line with the scope of this WG. What should be looked into would be the risk analysis for the DSO, defining what level of protection has to be set to ensure a proper security of operation of the designed system. Several ways to get there are available, all needing a strong expertise and most probably a deeper analysis of a dedicated WG.

4.6 Conclusion

The complexity of operating a part of a distribution grid as a microgrid lies in the fact that everything still needs to work as before and, by default, no changes at the customers' sites are allowed. Most of the existing demonstrators have been performed at industry sites, campuses, small remote grids, islands that are to a large degree self-sufficient, etc. Very few cases show an ordinary distribution grid changed to a microgrid. This presented challenges for both the DSO and the involved suppliers.

The main driver of this chapter is to discuss technical solutions that can be of benefit for the DSO to handle the changing demands on the distribution grids with the help of microgrids that can switch from grid-connected to islanded modes. The increase of local production and non-conventional loads like electric vehicle chargers does fundamentally change how the grid is used and how energy is transferred, but still uncovers different operational challenges that could be handled in an efficient way by temporary microgrids. Technologies like storage facilities could be part of the solution, in addition to upgraded protections, advanced controllers and adapted power electronics, all those components from the physical layer being embedded within proper monitoring, communication and control systems.

A large set of technical recommendation are discussed in this chapter, following the physical infrastructure (protections, power electronics, grid-forming units, power quality) and the ICT layer. Most of them do not need to be validated neither all the time nor in all situations, but they underline general issues.

The standardization of the operational constraints regarding components connected to islanded microgrids still needs updates regarding protections, interoperability, local control capacities, communication and control for ancillary services, etc. Models of IBG remain a problem for DSO to study the stability of the future microgrids and their safe operation. Online characterization tools could be a workaround but the possibility for the manufacturer to provide them (even in a "black-box" format) would be relevant. In that context, diagnostic tools to identify the presence of various instability (like impedance-based) that are not common in other contexts would be of high interest.

Market regulations is also something that should play a significant role in how and when this technology can be beneficial to DSOs in the future. This needs to be followed and evaluated as well as the technical development. However, in most cases it is easier to develop new technology rather than to change regulations, but proper business models are key for social acceptance. To that regard, a parallel CIRED WG is looking into those issues, which report do complement perfectly the current work of this WG.

Chapter 5

General conclusion

Microgrids may offer significant advantages for end-users and utilities in the current context of energy transition. Territories served by traditional distribution grids up until now could benefit from relying on an intermediary distributed management system at the scale of microgrids. More specifically, microgrids able to operate both connected to the grid and in islanded mode could improve the resilience and quality of service of current distribution grids. Interconnection of microgrids could be a sophisticated solution in emergencies and restoration of distribution grids after severe events, but also propose an alternative solution for continuity of supply during maintenance. Lastly, microgrids could be elementary cells that would accompany the energy transition and the evolving distribution grids facing an increase in renewable energy penetration as well as in non-conventional loads, like electric vehicles, as illustrated in Figure 5.1.

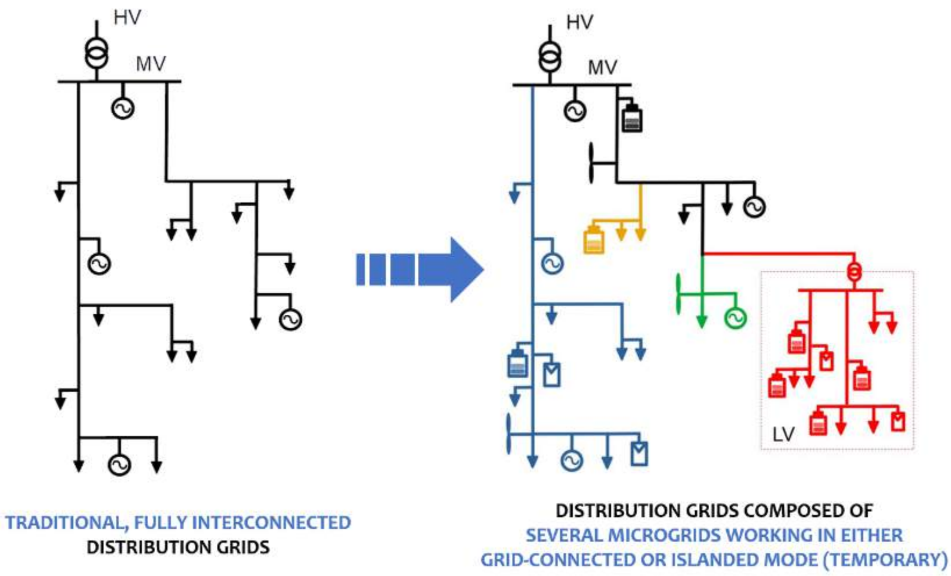

Figure 5.1 – *Distribution grids evolving in multiple temporary microgrids.*

The introduction of these microgrids would however impact the control, operation and protection schemes of distribution systems. Accordingly, technical solutions must be developed, to ensure that the microgrids does not harm people safety, power quality or costs performance.

5.1 Objective of the working group

The main goal of this working group was to build a document gathering the technical requirements needed to properly introduce the concept of microgrids in distribution grids in which the decentralized generation increases significantly and the communication infrastructure is offering new possibilities. These requirements concern the monitoring and control infrastructure, the protection systems and the design of less traditional components such as inverter-based generators that will likely dominate microgrids once islanded. The proposed recommendations target distribution system operators and other involved stakeholders, in order to help them conceive the grid standards and operational rules for the future distribution grids.

The report focuses on microgrids able to operate both in grid-connected and islanded modes. Off-grid systems are not specifically covered by the report although they share common issues regarding the relative high penetration of inverter-based generation that naturally present a low inertia characteristic once isolated, thus challenging their operation.

This choice is done knowing that there exist already an extensive literature on the subject, mostly referenced in this report.

5.2 Take away message from the report

The report has been divided in three main parts of equal interest: demonstrators assessment, state of art and recommendations.

5.2.1 Demonstrators lessons learned

The Chapter 2 proposes illustrations and lessons learned from a set of demonstrators. The idea was not to propose a list of all existing demonstrators but rather to limit the number of demonstrator to allow going deeper into their individual assessment. Thus each demonstrator covers different aspects of the scope of the working group and members of the working group have conducted one-to-one interviews with projects manager (when possible targeting technical and operative persons) on that complementary selection of demonstrators.

An large set of questions was used for interviews, which canvas is proposed in Appendix A.

The presentation of each demonstrator follows the same structure, ranging from its technical characteristics and design (Automation and control, protection, monitoring, supervision and telecommunication) to the technical actions needed for the operation of the islanding use case, including some relevant experimental results for illustration purposes. From the assessment of the selection of demonstrators, lessons learned are drawn.

5.2.1.1 Grid composition

Most of the demonstrators relied on at least one battery facility to build a grid-forming unit while islanded. This opened a series of technical issues, stressing the need for a higher standardization. Although the battery energy systems are theoretically low maintenance, they required constant monitoring, forcing grid operators to focus on management issues rather than on technical/research aspects (to make everything work around the storage facility, like cooling, power electronics, protections, and so on).

Some difficulties arose in that context to find providers offering a complete and finished product thus affecting the operational teams (they had to learn the competences). Regulatory issues have been highlighted as well as the absence of economic viability, but those aspects were outside of the scope of the working group.

Most of the demonstrators had local photovoltaic production, with some minor disconnection issues. Interestingly, PV inverters already propose services (not activated by default) that could help stabilizing the microgrid once islanded (a built-in P/f droop notably). Only one demonstrator proposed a multi-energy unit (combined heat and power) that presented interest though had to be tuned for the demonstrator. That aspect of islanded microgrids should be further investigated.

5.2.1.2 Equipment used for the islanding use cases

The control and automation architectures of the microgrids implemented in the analyzed demonstrators were very varied, ranging from low to high automation degree (from mostly manual operations to a wide set of automation equipment distributed throughout all the islanded area). An architecture implying a low automation degree can be deployed at lower cost, but architectures implying a high automation degree allow implementing advanced functionalities, like changing the settings of the grid protections or implementing a hierarchical control of the island voltage and frequency.

This would alleviate the tasks of the distribution system operators but at a cost that should be justified by a frequent use of the islanded mode (i.e. for more than just extreme events).

One minor issue has been detected on the supervision of storage facility, because the system was not prepared to represent them (it is neither a producer nor a load).

All the analyzed demonstrators were developed in previously existing grids, in which the protection schemes were designed for grid-connected operation. Therefore, these schemes had to be revised to ensure the protection of people and of grid assets in islanded operation. The connection of the neutral to the ground was for instance considered at various voltage level for fault detection. Short-circuit current may be considerably lower in islanded operation than in grid-connected operation, in consequence the protection scheme installed for grid-connected operation may not actuate. The selectivity of the protection scheme could also be perturbed by either the islanded or the grid-connected operation, but maintaining the selectivity was not always essential in the scope of demonstrator, which could not be the case in operation.

Telecommunication solutions differ from one demonstrator to the other. Most of the choices were linked to the particularity of the experimental installations, to ensure the operation of the demonstration with minimal risks. As no analyzed demonstrator was dedicated to telecommunication, the working group could not provide strong lessons learned in this report. This should however clearly constitute further investigations.

5.2.1.3 Modes of operation of the islanding use case

A seamless transition from grid-connected to islanded operation was achieved in all the analyzed demonstrators (i.e. power cuts are avoided and all the loads remain connected), with or without ensuring the active and reactive power balanced of the island before the opening of the circuit-breaker. A seamless transition from islanded operation to grid-connected operation was also experimented in most of the demonstrators, relying typically on standard commercial synchrotacts or sometimes nothing (accepting a rougher transition).

Black-start capabilities were successfully implemented in some demonstrators, but also disabled in others, to avoid exposing maintenance operators to electric risk, knowing that they may not yet be prepared to handle elements that can energize the grid autonomously.

Lastly, in almost all the test results shown, the voltage and the frequency are kept within acceptable limits during the transitions and in islanded operation. This did not seem to be a concern in the analyzed demonstrators. On the contrary, it was sometimes noted that the voltage and frequency stability was better in islanded than in grid-connected operation.

5.2.2 State of art

Chapter 3 discusses the technical aspects of the two-ways transition between islanded and grid-connected operation of microgrids that are part of a distribution grid. This is done mostly from a state of art perspective, using extensive references to existing standards, grid codes, task forces technical reports and reference scientific literature. Are presented in this chapter what is already available with no or limited industrial developments.

Resilience and reliability of power systems are defined to illustrate the relevance of considering microgrids that can be operated in islanded mode for a while. The main criteria justifying disconnecting from the main grid are discussed, making the way for flexible microgrids. The chapter also covers technical constraints for microgrids to handle the transition to islanded mode, and then to reconnect to the main grid. Discussions range from control systems to protections, including grid-forming components, monitoring, control and communication systems.

In most of the presented technical aspects, the conclusion is that existing devices are usually almost sufficient, and could be improved to fulfill the needs: the technical challenges are in range of industrial developments and standard for basic operation of islanded microgrids. The economic viability of such installation does not seem to be guaranteed, even before going into innovative developments, helping increasing the reliability of those future temporary microgrids. This means that profitability may not be the main criteria leading to the development of such solutions. Social and environmental criteria could represent significant levers to compensate economic ones, assuming that technical constraints are raised, which is clearly within reach, as proof of concepts were demonstrated already a few years ago.

5.2.3 Recommendations

Chapter 4 focuses on the needs to allow part of distribution grids to transition smoothly from grid-connected to islanded modes (and vice-versa), under different (planned and unplanned) operational occasions and not only in lab and life-scale experiments. Indeed, most of the existing demonstrators have been performed at industry sites, campuses, small remote grids, or small islands, all of which to a large degree self-sufficient. The complexity of operating a part of a distribution grid as a microgrid lies in the fact that everything still needs to work as before and, by default, no changes at the customers' sites are allowed.

The main driver of this chapter was to discuss technical solutions that can be of benefit for the operator to handle the changing demands on the distribution grids with the help of microgrids that can switch from grid-connected to islanded modes. The technical recommendation are discussed following the physical layer (protections, power electronics, grid-forming units, power quality) and the information layer (monitoring and control). Most of them do not need to be validated all the time or in all situations. They rather underline general issues.

The standardization of the operational constraints regarding components connected to islanded microgrids still needs updates regarding protections, interoperability, local control connection settings, communication and control for ancillary services, etc. Models of inverters and storage facilities remain a problem for grid operators to study the stability of the future microgrid and its safe operation before and after the islanding. Online characterization tools could be a workaround but the possibility for the manufacturer to provide models to some extend (even in a "black-box" format) would be relevant.

The presented aspects of the chapter do not constitute a mandatory set of requirements to check methodically. Various recommendations are rather outlined to be considered as a function of operational context. For instance, it should not be necessary to change the whole protection plan if the islanding process is triggered only rarely, for maintenance. In other contexts, where the islanding process is activated on a more regular basis, an adaptation of the protection plan would make sense, in addition to clearing safety issues. The time horizon plays a significant role here as well. The islanded operation could last for hours to days, requiring a declination of equipment (from local production to storage facilities).

Market regulations is also something that should play a significant role in how and when this technology can be beneficial to distribution grids operator in the future. However, in most cases it is easier to develop new technology rather than to change regulations, but proper business models are key for social acceptance. To that regard, a parallel CIRED working group (2019-2, which work was designed to complement the current one) is proposing an insight into economic viability of microgrids, notably building a multi-criteria evaluation matrix designed as a decision support tool to assess the potentiality of technical upgrades to a microgrid.

Appendix A

Canvas of questions for the assessment of the selected demonstrators

The set of questions constituting the canvas survey to interview demonstrators technical management persons is reported in this appendix. The grouping of questions are highlighted according to the identified main themes.

A.1 Scope of the demonstrator

1. For the report of the WG, can you provide us with a technical description of the demonstrator (pictures, network configuration, number and size of components, number and size of microgrids, information on energy, telecommunication and control layers)?
2. Can you briefly describe the general objectives of the experiment? Which are the drivers/motivations for the DSO to have a part of the distribution grid with capabilities to islanding operation?
3. Was the demonstrator purely focused on the transition from interconnected to islanded of a portion of a distribution grid as well as its synchronization back to the main grid? Were there other specific objectives of the experiment that relate to the DSO drivers/motivations?
4. Were you conducting experiments on planned and/or unplanned islanding?
5. Which were the main reasons/justifications for focusing on the transition from interconnected to islanded mode (e.g., were you trying to detect islanding to better prevent it, to improve continuity of supply, or to assess its future relevance in the context of energy transition for distribution grids)?
6. What voltage level was considered (specify the voltage level if known or specify if MV or LV)? I.e. where did you put the CB(s)? Was there multiple microgrids?
7. For the report of the WG, could you provide us with experimental measurements highlighting the transition between inter-connected and islanded modes, illustrating technical relevant measures motivating the demonstrator?

A.2 Operation

A.2.1 Transition

1. What was the considered time horizon for the islanded operation (provide the value of the target in terms of minutes/hours/days if knows or at least indicate if minutes/hours/days)? How was it defined (motivation/justification)? Was it defined by a storage system, or temporary equality between local consumption and production?
2. What stability had you in mind for this demonstrator (transient, short, and/or long-term)?
3. For the transition between inter-connected and islanded modes, from the technical point of view, had you to put in place extra steps for management (measurements, decentralized control units, etc.) and/or components (protection, telecommunication, storage, local generation components, etc., discussed below)?
4. What measurements and control loops were put in place to detect and follow up with the islanding process? For instance, did you had one unit switching from grid-following to grid-forming mode or did you have a fully decentralized control infrastructure?
5. Have you managed the transition: with all loads connected from the start, or with successive stages and a zero crossing?
6. How did you manage the resynchronization? On what criteria? Which are the main steps of resynchronization procedure?
7. Did carry out black-start tests? If yes, could you describe the procedure?

A.2.2 Telecommunication

1. Did you have specific technical requirements regarding telecommunication and control (latency, speed, etc.)? If yes, please specify.
2. What infrastructure was used for data management and interfaces and automation systems?
3. Who were the involved stakeholders in that process (DSO, TSO, end-users, academia, etc.)?
4. Who defined and then was in charge of the various platforms?
5. Did you developed a dedicated distributed energy management system for the demonstrator (DERMS)? If yes, why?
6. Have you directly considered the outage of the communication system?
7. Did you work on critical infrastructure and/or cybersecurity in this demonstrator?
8. Which communication protocols have been used?

A.2.3 Control

1. Can you describe the main elements of the control architectures for voltage control, frequency control, power/energy management in interconnected and islanded operations? How about their interactions?
2. Did you apply a centralized or a decentralized control? At which control hierarchy level did you use centralized or decentralized controls?
3. Did you rely on international standards for measurements, communication and control? If yes, which one?
4. What automation system was put in place for the demonstration? Developed just for the demonstrator, or industrial one?

5. Did you use Artificial intelligence (AI) techniques at some point (for prediction, classification, dynamic optimization and so on)?
6. In the end, what were the main technical difficulties you encountered during the operation of the demonstrator?

A.3 Components

A.3.1 Protections

1. What were the specific technical requirements regarding protections that were put in place to make the operation of the experiment possible?
2. Did you use "on the shelf" protection material or did you modify industrial/lab material for the needs of the experimentation conducted for the demonstration? I.e. did you change the protection plan or follow some grid code (and if yes which one)?
3. Did you had two modes for the protection and if yes, how did you manage the switch? With an external signal (for example a command for planned islanding), with a local measurement and reactive control (for example for unplanned islanding)? Other?
4. Had you a protection coordination system? Did you measure some performances regarding the islanding?
5. Had you grounding systems?
6. Have you considered augmented ranges for possible enhanced resilience?
7. Have you encountered technical difficulties with the protections? If yes, of what kind (communication, control, selectivity, detection, people safety, etc.)?
8. Did you have requirement on the level of protection and safety of the installation? This leads to some additional standard? Or what type of protection and safety?
9. Do you think your protection system would require more maintenance if used more frequently (remotely or not?) if the usage done during the demonstration was translated in real-life operation?
10. Do you think power quality would decrease with that configuration of protections?

A.3.2 Power electronics

1. Which are the inverter-based sources in your demonstrators (generation, storage and/or load)? To what extent (in % of installed power)?
2. Did you implement particular technical requirement for inverter-based sources: grid-forming capacity, virtual inertia, black-start capability, additional internal protections, low voltage ride through, voltage/frequency controls?
3. Did you need to oversize any of the inverter-based sources in order to meet expected requirements/capabilities? Why?
4. Has power quality been monitored during islanded operation? Has the power quality been negatively impacted during the islanding period? If yes, was it a problem on the considered time horizon?
5. What kind of power quality problem did you encounter: unbalanced operation, flickers, harmonics, increased variation of frequency/voltage, other? Did you solve some of them with dedicated control of the power electronics?
6. The grid-forming unit(s) was/were activated after detection of the islanding process automatically or through wired connection (external signal)?

7. Was grid-forming capacity needed? Only one unit was in charge or more? Was it evolving in time (if yes under which criteria)?

A.3.3 Rotating machines

1. Did you had any rotating machines involved in the control of the microgrid? If yes, for what purpose (diesel generators, reactive power production, synchronous condenser, etc.)?
2. Did you have some interaction with virtual synchronous generators or some hybrid configuration in that sense?
3. Would you recommend, or validate the micro grid's operation in islanded mode or during the transition without the help of any real rotating machine?
4. Did you had experimental scenario involving short-circuits? If yes, what were the context and the objective of the tests?

A.3.4 Storage system

1. Was a storage system present in the experiment and why? Which were the main purpose and tasks of the storage?
2. Which storage technology did you implement? Why? Have you considered the ageing of the storage system as a possible issue during the life of the micro-grid? Did you consider any particular options to deal with it (oversizing, technical capabilities, particular control strategies)? Do you think it would be a problem (rather economic probably) if generalized to real-life operations?
3. Did you have multiple storage facilities and or multiple types for various time horizon (and stability categories)?

A.4 Other elements

1. If you had to provide recommendation for future demonstrators (or even real-life implementations), on what would you put your main emphasis: traditional electrical engineering components, telecommunication network, industrial informatics, measurements, control, informatics (AI-related techniques, like forecasting for instance), inverter-based components, storage systems, cybersecurity, other?
2. Do you think additional standards would be required to make that operation generalizable to real-life installation in distribution grids?
3. Do you want to add anything we might have not covered during the discussion?

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Acronyms

NDZ Non detection zone. 82, 104, 107, 112

NMC Nickel manganese cobalt. 10, 16

O

OMS Outage management systems. 139

OSI Open system interconnection. 86

P

PCC Point of common coupling/connection. 3, 10, 43, 44, 58, 71, 79, 89–92, 97, 99–101, 104, 105, 107, 109, 110, 120, 130, 135, 136

PCS Power conversion system. 16, 21, 23, 33, 37, 41, 42, 47, 49, 63, 64

PLC Programmable logic controller. 11, 18, 35, 41–47, 56, 87, 88, 135

PLL Phase-locked loop. 82, 92, 97, 98, 106, 114, 115, 126

PMU Phasor measurement unit. 136

PV Photovoltaic. 1, 4, 9–12, 16, 17, 20–23, 33, 34, 42, 43, 53, 56, 64, 66, 73, 74, 86, 95, 105, 111–113, 118, 121, 123, 132, 135

R

RCD Residual current devices. 11, 19, 68

RMS Root mean square. 70, 78, 118, 119

ROCOA Rate of change of angle. 99

ROCOF Rate of change of frequency. 27, 84, 91, 99, 109, 113, 114, 118, 120, 128, 136

S

SAIDI System average interruption duration index. 72

SAIFI System average interruption frequency index. 72

SC Short-circuit. 12, 18, 21, 27, 36, 58, 68, 69, 72, 79–81, 85, 89–92, 96, 98, 104–107, 109–112, 128, 130, 133, 134

SCADA Supervisory control and data acquisition. 11, 18, 19, 24, 25, 27, 35, 36, 45, 57, 58, 67, 139

SCSM Specific communication service mapping. 86

SEP Smart energy profile. 86

SG Synchronous generators. 3, 24–28, 65, 111, 113–115, 118, 126, 133, 138

SoC State of charge. 34, 36, 42, 46, 47, 56, 59, 60, 66, 97

SoH State of health. 97

T

U

V

W