Joint Working Group B5/C6.26/CIRED

Protection of Distribution Systems with Distributed Energy Resources

Final Report

26.03.2015

Members of the Working Group

Convenor

Paul Myrda, Electric Power Research Institute, USA

CIRED Co-Chair

Wolfgang Gawlik, Vienna University of Technology, Austria

Members

Birgitte Bak-Jensen, Aalborg University, Denmark

Matthew Browne, Endeavour Energy, Australia

Roberto Calone, Enel Distribuzione, Italy

Roberto Cimadevilla González, ZIV, Spain

Andrew Craib, Eskom, South Africa

Gwénaël Donnart, SCLE SFE, France

Daniel Dumitrascu, EnergoBit, Romania

Marcel Engel, Netze BW GmbH, Germany

Radek Hanuš, PRE Distribuce, Czech Republic

Hans Hoidalen, Norwegian University of Science and Technology, Norway

Laurent Karsenti, ErDF, France

Andreas Kubis, TU Dortmund University, Germany

Hannu Laaksonen, ABB, Finland

Mika Loukkalahti, Helen Electricity Networks Ltd, Finland

Miguel Louro, EDP, Portugal

Hongfei Ma, DEIF A/S, Denmark

Pukar Mahat, Aalborg University, Denmark

Patrick McMullan, Ausgrid, Australia

Tamiru Shire, Netherlands

Manfred Wurm, Netz Niederösterreich GmbH, Austria

Xicai Zhao, Nari-relays Electric Co.,LTD, China

Table of Contents

1 Preface

The usage of Distributed Energy Resources (DER) in utilities around the world is expected to increase significantly. The existing distribution systems have been generally designed for unidirectional power flow, and feeders are opened and locked out for any fault within. However, in the future this practice may lead to a loss of significant generation where each feeder may have significant DER penetration. Also, utilities have started to investigate islanding operation of distribution systems with DER as a way to improve the reliability of the power supply to customers.

This report is the result of 17 months of work of the Joint Working Group B5/C6.26/CIRED "Protection of Distribution Systems with Distributed Energy Resources". The working group used the CIGRE report TB421 "The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation", published by WG B5.34 as the entry document for the work on this report. In doing so, the group aligned the content and the scope of this report, the network structures considered, possible islanding, standardized communication and adaptive protection, interface protection, connection schemes and protection concepts and future trends accordingly.

The report is structured as follows:

After this preface (chapter 1), the scope of the technical brochure according to the Terms of Reference (TOR) is stated (chapter 2). Then, in the glossary, symbols and abbreviations used throughout the technical brochure are listed (chapter 3).

The first main part of the report starts with a summary of the backgrounds on DER and current practices in protection at the distribution level (chapter 4). This chapter contains an analysis of CIGRE TB421, protection relevant characteristics of DER, a review of current practices for distribution system protection and a summary of country specific approaches for protection in distribution systems. These country specific protection approaches are given in more detail in the Annex in an aligned format.

The second main part of the report describes issues of protection of distribution schemes that include DER (chapter 5). It features the impact of DER on distribution system protection and sums up recommended best practices for reliable island detection.

The third main part offers a proactive approach to technology trends (chapter 6), under consideration of new applications of teleprotection and the use of communication (e.g. IP, PLC, BPL…). Moreover, protection schemes for future distribution networks that include DER are presented.

The report closes with a summary and an outlook (chapter 7), as well as a bibliography (chapter 8).

2 Scope

The scope of this technical brochure is to study the impact of DER on distribution system protection taking into account DER characteristics and the possibility of islanding operation, and to provide the guidelines to protect distribution systems with DER. The following topics are presented within the technical brochure.

1) Brief review of the current practice for distribution system protection
2) Listing of the protection relevant characteristics of DER (short-circuit current contribution, fault-ride-through capability, reactive power absorption during and after fault)
3) Review of the impact of DER on distribution system protection, including specific aspects of inverter-coupled DER units
4) Review of the protection of distribution systems during islanded conditions
5) Recommendations on protection for distribution systems with DER
6) Recommendations on protection for islanded distribution systems

The review and the recommendations are applied to the different types of existing medium voltage and low voltage distribution systems.

3 Glossary and Definitions

The following symbols and abbreviations are used throughout the technical brochure:

AD	Active Demand
AMR	Automatic Meters Reading
BPL	Broadband Power Line
COROCOF	Comparison of rate of change of frequency protection
DA	Distribution Automation
DER	Distributed energy resources
df/dt	frequency change rate protection
DG	Distributed generation/ distributed generators
DNO	Distribution network operator
DSO	Distribution system operator
FDIR	Fault Detection, Isolation and network Recovery
FRT	Fault ride through
GOOSE	Generic Object Oriented Substation Events
HAN	Home Area Network
HV	High voltage
IDMT	Inverse Definite Minimum Time
IED	Intelligent electronic devices
IP	Internet Protocol
ITA	Inverse Time Admittance
LoM	Loss of mains detection
LV	Low voltage
MV	Medium voltage
NAN	Neutral Access Network
NDZ	Non detection zones
OC	Over-current
PCCN	Protections et Contrôle-Commande Numérique
PLC	Power Line Communication
PSTN	Public switched telephone network
RAN	Regional Action Network
RES	Renewable energy sources
ROCOF	Rate of change of frequency
SV	Sampled values
THD	total harmonic distortion
TOR	Terms of reference
U/I	Under-impedance
WAN	Wide Area Network

4 Background on Distributed Energy Resources and current practices

As a general practice all over the world, protection concepts for electrical networks are designed and implemented to provide protection of people against electrical hazards, prevent damage to installations and limit stress on equipment, and uphold stability and supply reliability in the power system. Specific requirements for protection systems are selectivity, speed and sensitivity.

With an increasing number of distributed energy resources, basic assumptions for the design and implementation of protection systems are complicated, and protection concepts need to be adapted accordingly. Both CIGRE and CIRED are looking into these developments, and as one example of the outcome of these activities CIGRE report TB421 "The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation" was generated. This report is aimed to provide further insight into the matter.

4.1 Analysis of CIGRE TB421

The usage of DER in utilities around the world has increased and is expected to increase further especially with the realization of the move to smart grids. Distribution systems are generally designed for unidirectional power flow and feeders are opened and locked out for any fault within. However, this practice may lead to loss of significant generation in future where each feeder may have significant DER infeed. Additionally, utilities have started to look into islanding operation of distribution systems with DER as a way to improve the reliability of the power supply to customers. However, the difference between short circuit levels for cases where the distribution system is connected to the grid and while it is islanded, can be significant. This may result in malfunctioning of overcurrent (OC) protection or other protection schemes. In addition, the "plug and play" DER will continuously change the short circuit level and thus may impact today's overall protection schemes. Furthermore, the short circuit power contribution varies with the DER technology applied. Wind turbines contribute less current when their internal protection (crowbar protection) is activated and power electronic interfaced DER do not contribute as much fault current as conventional synchronous generation.

The working group used the CIGRE report TB421 "The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation", published by WG B5.34 as the entry document and coordinated their outputs with ongoing B5.43 activities "Coordination of protection and control of future networks".

4.1.1 Content and scope

The technical bulletin 421 (TB421) "The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation" covers guidelines, codes, regulations and practices with protection of DER in different countries. Future trends in islanding detection, intelligent power systems, wide area protection applications, substation communications & automation and wind farms for network stability are considered.

The scope of TB421 details the connection of large renewable generation (excluding nuclear) associated with the sub-transmission and transmission (above 35 kV) power networks, although producers connected to local MV networks (35 kV and below) are also considered in TB421 as reference because of the unclear limits in regulation and practices in some countries and due to the possible impact of their increasing penetration and effect on the transmission system performance[1]. Thus, this technical brochure specifically focusses on distribution networks and voltage levels below 35 kV.

Though distribution level DER connections are beyond the scope of TB421, the impacts on the HV system must always be assessed[2]. This technical brochure thus focuses on distribution level DER connections (and, to some extent, their possible impact on the HV system).

4.1.2 Network structure

TB421 states that it is commonly acceptable to establish different DER connection criteria for distribution networks generally radial up to 69 kV, and for (sub-) transmission meshed networks of voltage levels 100kV and above[3]. Thus, this technical brochure primarily focusses on radial networks.

However, as TB421 also states, in order to further increase the security of supply, DER units could be allowed to operate in an islanded mode in a meshed distribution network[4]. This is a reason that ring operation and protection issues related to ring operation should be considered. If more active network management schemes are used in future distribution networks, it will also possibly mean increased topology variations (including for example radial or ring operation of MV feeders) in which protection principles and settings adaptation may be required. In Denmark (and in South Africa at 11kV and 22kV in some cases), even though the distribution system can operate in ring configurations, they are almost always operated in radial configurations. Ring operation is not currently allowed by the French DSO ERDF.

ERDF, as well as the DSO in Romania, where island detection and trip is mandatory, do not consider operating in an islanded mode as a possible evolution of the protection scheme.

4.1.3 Islanding

With reference to the topic of islanding, TB421 mentions that there is an increased need for high performance anti-islanding protection[5]. The greater capability to withstand external faults without nuisance tripping should not affect the sensitivity for the islanding detection, so a compromise between sensitivity for islanding detection and stability under external disturbances is required[6]. Growing DER penetration levels of all sizes and connection voltages causes an increased need for high performance anti-islanding protection[7]. This technical brochure thus proposes recommended (best) practices for reliable islanding detection, e.g. communication based transfer trip schemes and passive local measurements based schemes.

---

[1] Cigre working group B5.34 TB421, p. 12
[2] Cigre working group B5.34 TB421, p. 24
[3] Cigre working group B5.34 TB421, p. 14
[4] Cigre working group B5.34 TB421, p. 109
[5] Cigre working group B5.34 TB421, p. 14
[6] Cigre working group B5.34 TB421, p. 25
[7] Cigre working group B5.34 TB421, p. 108

TB421 briefly mentions that some DER related applications of synchrophasors include islanding detection[8]. This subject is extended to islanding detection based on synchrophasors in chapter 5.1. Since PMU functions are included in many digital relays including those installed in DER units there is already the possibility to transmit information to the dispatching center, thus having all the data of synchrophasor based applications available.

4.1.4 Standardized communication and adaptive protection

TB421 states there is a trend for more standardized communications between protection relays of different manufacturers and refers to the recent IEC 61850 communications standard[9]. Furthermore, it suggests that intelligent protection schemes which can adapt their protection settings will play an important role in enabling stable operation and protection of islands[10]. Currently protection settings are seen to be very rigid for the changing conditions in the network so new adaptive solutions will be required in the future[11].

In chapter 4.3.2.6 of TB421, various protection considerations in relation to intentional islanding have also been discussed together with the possible need for adaptive protection when transition to islanded operation takes place. It has also been mentioned that the technology currently used in anti-islanding protection may be used to activate the appropriate change of protection settings[12].Moreover, in chapter 6.3.2 of TB421 protection adaptation has been considered as one of the future trends in protection systems[13].

This technical brochure thus considers both usage of IEC61850 in protection circuits as well as adaptive protection schemes, because in the future both short-circuit and earth-fault protection settings of MV feeder Intelligent Electronic Devices (IED) may need to adapt to changes in network topology resulting from increased utilization of active distribution network management schemes (depending on the utilized protection scheme). To support improved supply reliability, to deal with topology changes and to disconnect faulted sections rapidly, directional OC, distance and differential protection with high-speed communication based blocking schemes will be utilized increasingly in the short-circuit protection of future Smart Grids. The required future performance for transmitting blocking signals and voltage and current data from sensors could be achieved by utilization of IEC 61850 GOOSE and sampled value (SV) services, with increased usage of wireless 4G technologies in addition to fiber-optic based communication. However, the problem related to synchronization of SV data and the cost of SV usage and 4G technologies needs to be considered.

4.1.5 Interface protection

TB421 mentions that the interface protection relays must be provided with settings that ensure correct tripping for genuine disturbance conditions but prevent tripping under transient conditions from which the overall system will recover to stable operation[14].

This is very difficult to achieve for smaller DER and possibly not essential. Stability during faults can be of less a concern (or not at all) for distributed generation of relatively smaller

[8] Cigre working group B5.34 TB421, p. 96
[9] Cigre working group B5.34 TB421, p. 15
[10] Cigre working group B5.34 TB421, p. 16
[11] Cigre working group B5.34 TB421, p. 47
[12] Cigre working group B5.34 TB421, pp. 73 & 74
[13] Cigre working group B5.34 TB421, p. 93
[14] Cigre working group B5.34 TB421, p. 18

sizes (<5MVA) as there is no real impact on supply, and only a minor inconvenient impact to the generator (nuisance tripping). Often the other concerns associated with unintentional islanding outweigh this inconvenience at distribution level.

Another important issue identified in TB421 is that the interface protection must be coordinated with the remote utility protection[15]. This technical brochure thus considers selectivity and co-ordination of DER unit protection (islanding detection vs. FRT requirements) with MV network (feeder) protection. This aspect is related to reclosing co-ordination which has also been reported in chapter 5.5 of TB421[16].

Concerning chapter 5.4 of TB421 “Interface protection requirements and settings”, there has been some modification of the French legislation regarding FRT requirements for producers with maximum power above 5 MW (Figure 4-1).

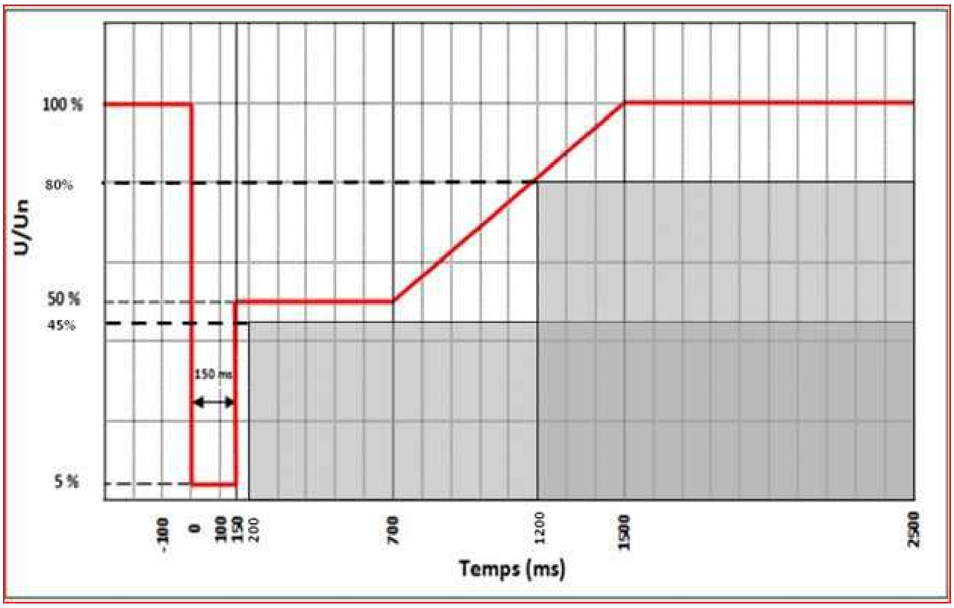


Figure 4-1: Modification of the French legislation regarding FRT requirements for producers with maximal power above 5 MW

There is therefore a correct coordination between undervoltage and FRT requirements.

Wind and photovoltaic generation over 1 MW are required in Romania to adapt to FRT conditions according to the following diagram (Figure 4-2).

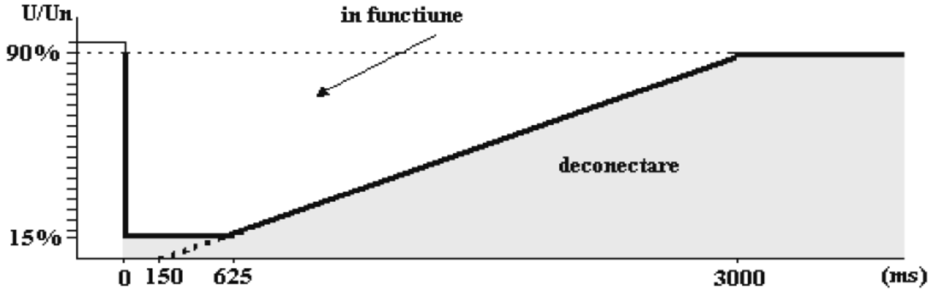


Figure 4-2: Requirements for FRT capability of wind and photovoltaic generation over 1 MW in Romania

15 Cigre working group B5.34 TB421, p. 27
16 Cigre working group B5.34 TB421, p. 89

RES less than 100 kVA and connected to the LV voltage are required to adapt to FRT conditions according to the following diagram (Figure 4-3) in South Africa.

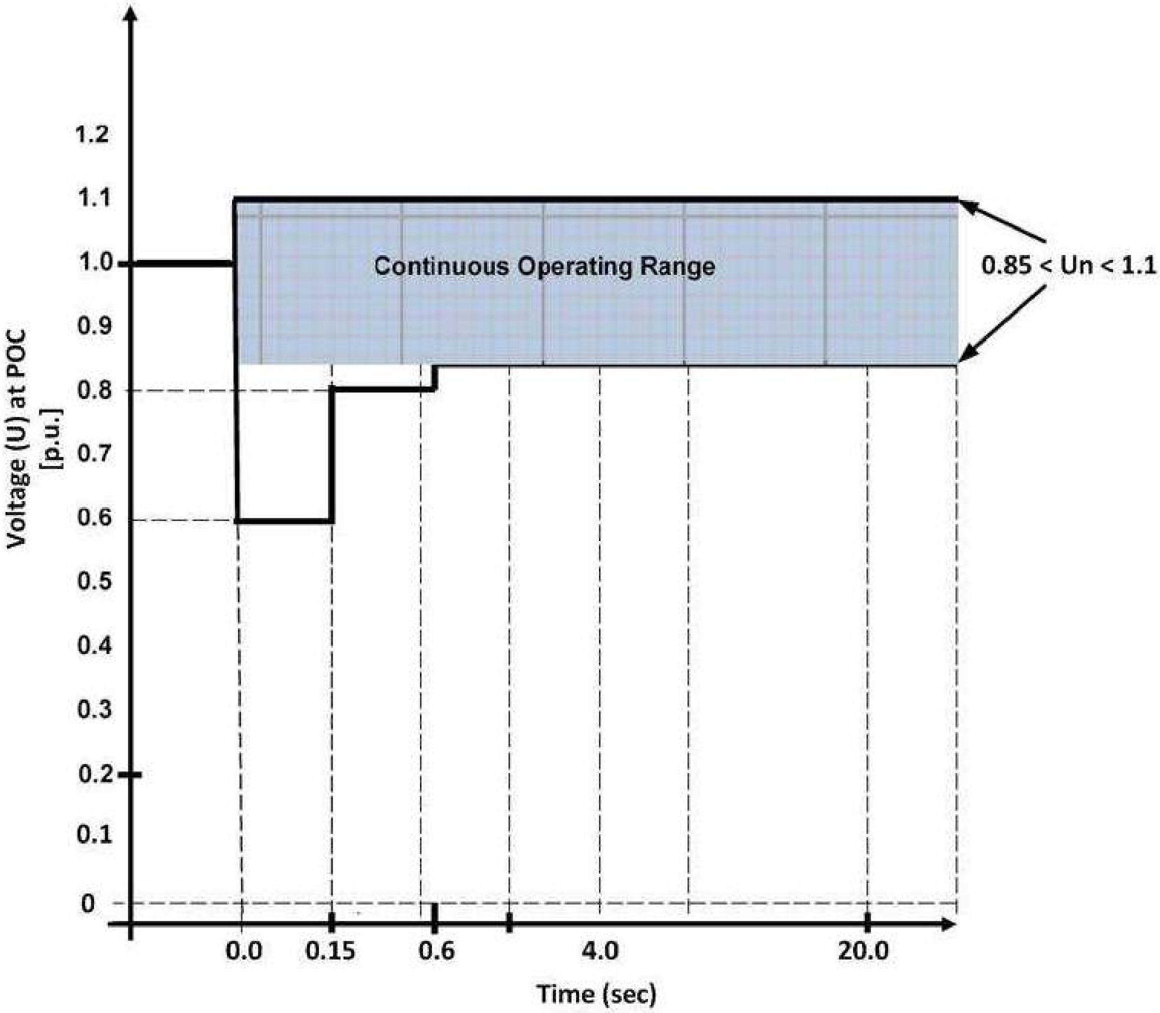


Figure 4-3: Requirements for FRT capability of RES < 100kVA and connected to LV in South Africa

RES greater or equal to 100 kVA are required to adapt to FRT conditions according to the following diagram (Figure 4-4) in South Africa.

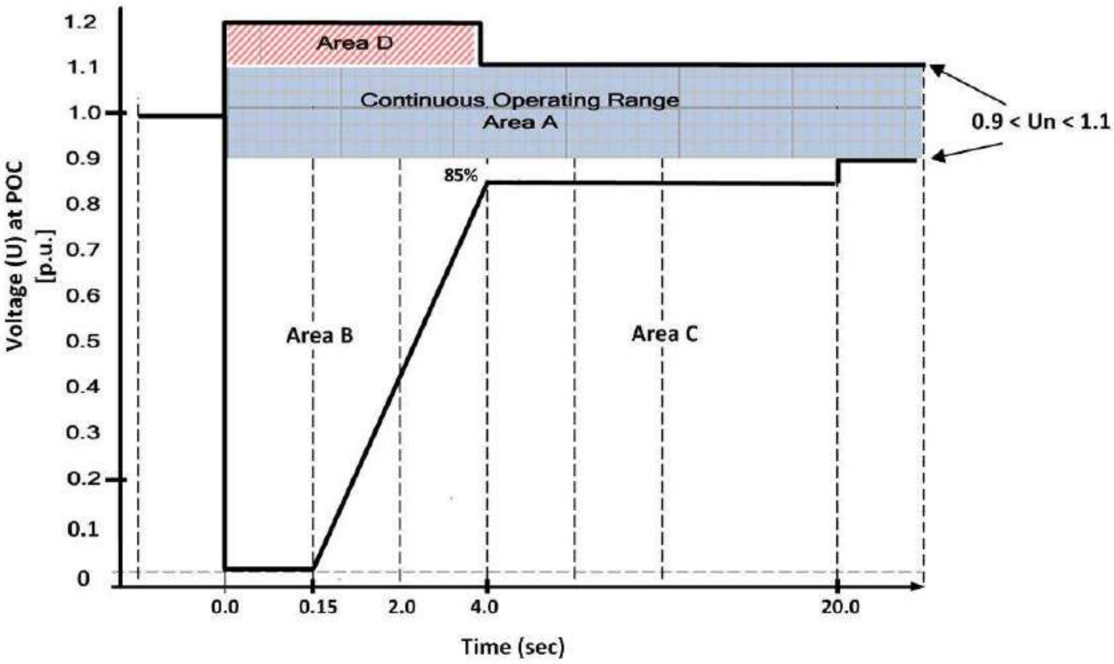


Figure 4-4: Requirements for FRT capability of RES ≥ 100kVA in South Africa

4.1.6 Connection schemes and protection concepts

With reference to the impact of renewable energy sources (RES) and short circuit contribution on distribution protection systems, TB421 states that to overcome problems like sympathetic tripping, a future trend may include the use of directional OC relays or even distance relays in distribution networks. Alternatively, current-differential protection may be used which eliminates any co-ordination problems but this protection application requires telecommunication links which are more costly[17].

Directional OC protection will most likely not work correctly in the future due to insufficient starting currents. Distance protection with under-impedance starting (U/I starting) might solve the problem, or most likely under-impedance starting. This would require the network topology and short circuit capacity at the relay to be known in advance. Differential protection could solve many problems, but will have other limitations (incl. cost).

A detailed comparison (with benefits and drawbacks) of possibly different applicable protection schemes in chosen example configurations (e.g. those presented in chapter 5.3 of TB421) could be interesting. These protection methods could be for example:

- Directional OC protection with adaptive settings (change of pre-calculated setting group when network topology changes e.g. from normal to island or real-time settings calculation)
- Distance protection, with regard to whether adaptation of settings is needed in some cases due to connection / disconnection of DER units
- Differential protection
- Zero sequence voltage protection

[17] Cigre working group B5.34 TB421, p. 97

Also the applicability of different (directional) earth-fault protection schemes to changing topologies including e.g. adaptation when the normally compensated (MV neutral grounding) network section becomes isolated (MV neutral grounding) during island operation etc., could be studied. In a first step, a review of current practices for distribution system protection is given in chapter 4.3 of this technical brochure.

Table 5-2 of TB421 also mentions "dedicated lines" and "non dedicated lines" as the most typical arrangements of DER connection. This technical brochure uses these configurations as the basis for recommendations.

4.1.7 Future trends

TB421 provides a list of protection and automation challenges for the integration of large scale DER in the power network especially for the distribution network as:

- Operation and protection of distribution networks might become more similar to transmission systems, which would solve many of the problems encountered in the distribution networks having greater integration of DER.
- New protection schemes able of coping with the lower short circuit due to an increasing usage of inverter based generators.
- More automation applications of DER connected to the distribution network; control capabilities, reconfiguration, synchronization and reclosing and advanced adaptive setting techniques.
- Development of powerful communication networks in the distribution system with data integration based on the standard IEC 61850. This could help to make adaptive protection schemes and intertripping based anti-islanding schemes more widely used in the distribution system.
- Reliable islanding detection and intentional islanding capability[18].

This technical brochure thus also deals with how the distribution networks become more similar to transmission networks, especially with regard to protection.

One of the most important changes to the distribution network due to the massive integration of DER is the bi-directional nature of fault currents. This implies the need to develop more complex protection schemes for the distribution network, which are able to deal with several contributions to the fault current similar to the situation in transmission networks. Nevertheless, it is not obvious that future distribution system protection should be the same as in the transmission system. The power contributions from different ends (sources) will usually be different compared to transmission networks, so distribution networks will have some specific features when compared to transmission networks. The future distribution network might still require a different protection scheme to that of a transmission network

[18] Cigre working group B5.34 TB421, p. 92

4.2 Protection characteristics of Distributed Energy Resources

This section summarizes a number of differences in protection characteristics of DER compared to "conventional" energy resources and the possible impact on current and future protection schemes. While there is no ideal behavior under short circuit and other protection conditions, the steady state, transient and sub-transient behavior of induction machines (i.e. synchronous and asynchronous generators and motors) directly connected to the grid is well known and is thus considered in the state of the art protection schemes.

4.2.1 Basic considerations

Generally, the short circuit current contribution of DER differs from these "conventional" energy resources in three ways:

- Firstly, the location of DER is different, i.e. distributed rather than central. Thus, short circuit contributions from DER originate from directions not necessarily considered in conventional protection schemes. This issue is similar to unexpected load flows under normal conditions and can result in phenomena such as "blinding" or "sympathetic tripping".
- Secondly, many DER are not directly connected synchronous or asynchronous machines, but coupled to the network via inverters. The magnitude of the short circuit current of these inverters is usually limited to values not much higher than the nominal current to protect the inverter itself. Accordingly, the short circuit capacity of grids dominated by inverter short circuit current sources is significantly lower than that of grids with rotating machines of the same rating.
- Thirdly, this lower short circuit contribution is also connected to a different time characteristic of the short circuit current. While rotating machines behave like a voltage source under short circuit conditions, inverters act more like a current source limited to nominal current, and the time characteristic of the current determined by the control scheme of the inverter.

Additionally, the capability to operate during and after faults in the system has not been a strong requirement for decentralized generation – on the contrary, it was and is often required that DER immediately disconnect under faulty grid conditions so that the well-established protection schemes can be maintained.

However, with a growing number of DER and an increasing importance of DER to provide short circuit capacity both during and after the fault, the Fault Ride Through (FRT) capability is of major concern.

Finally, some distributed generation connected to low voltage level may be hidden to the network operator, i.e. not officially declared and announced by the users. If the amount of hidden LV DER is high, its impact to LV level protection and safety may be critical.

4.2.2 Blinding and sympathetic tripping

In conventional passive distribution networks, the fault current is only provided by the connection point to the transmission network, which is a strong source. If the network is radial, the fault current has a unique path, is unidirectional and is generally much greater than the load current. Therefore, in these conventional networks protection schemes based on local measurements such as coordinated over-current relays provide good network protection (Blackburn, 1979) [13].

However, with DER connected to the system, the short circuit current contributions may originate from different paths than the central connection point and may result in “blinding” and “sympathetic tripping”.

Blinding is caused by the fact that DER fault currents have an impact on the voltage at their connection point. Thus, while the overall fault current at the fault location increases due to the DER fault current contribution, the fault current provided via the central connection point decreases.

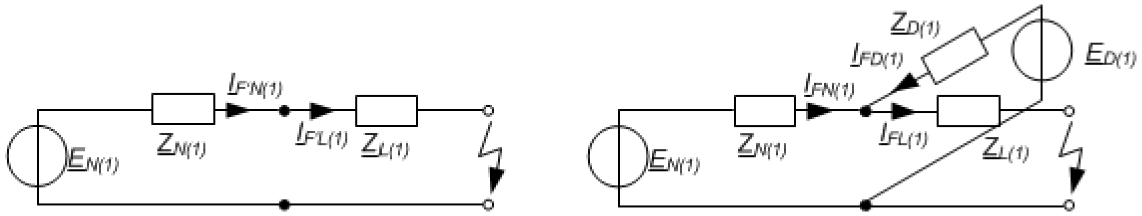


Figure 4-5: Fault currents without (left) and with (right) distributed generation (Index “D”), only positive sequence system shown.

In Figure 4-5, “blinding” is the phenomenon that while

$$\underline{I}_{FL(1)} = \frac{c \cdot \underline{E}_{(1)}}{\underline{Z}_{L(1)} + \underline{Z}_{N(1)} \,||\, \underline{Z}_{D(1)}} = \frac{c \cdot \underline{E}_{(1)} \cdot \left[\underline{Z}_{N(1)} + \underline{Z}_{D(1)}\right]}{\underline{Z}_{L(1)}\underline{Z}_{N(1)} + \underline{Z}_{N(1)}\underline{Z}_{D(1)} + \underline{Z}_{D(1)}\underline{Z}_{L(1)}} > \underline{I}_{F'L(1)},$$

i.e. the overall fault current with DER contribution is higher, the fault current provided from the central connection point is lower according to

$$\underline{I}_{FN(1)} = \underline{I}_{FL(1)} \cdot \frac{\underline{Z}_{D(1)}}{\underline{Z}_{N(1)} + \underline{Z}_{D(1)}} = \frac{c \cdot \underline{E}_{(1)}}{\underline{Z}_{L(1)} + \underline{Z}_{N(1)} + \underline{Z}_{L(1)}\underline{Z}_{N(1)} / \underline{Z}_{D(1)}} < \underline{I}_{F'N(1)}.$$

Blinding may result in delayed or unselective tripping, especially of overcurrent protection, and may also negatively affect distance protection as it can cause underreaching due to the infeed.

In addition to the effect of “blinding”, with a significant increase of DER, the short-circuit capacity of the transmission system will probably decrease because the number of large conventional power stations that provide the high fault levels will be reduced [56]. This would negatively impact the protection coordination in distribution networks with high DER penetration. [13]

In Figure 4-5, “sympathetic tripping” would be caused by the fact that the DER fault current contribution

$$\underline{I}_{FD(1)} = \underline{I}_{FN(1)} \cdot \frac{\underline{Z}_{N(1)}}{\underline{Z}_{N(1)} + \underline{Z}_{D(1)}}$$

may initiate a relay trip when the relay is placed in the connection path of the DER, even if the fault is not downstream to the path. Sympathetic tripping may be overcome by the application of directional relays.

4.2.3 Inverter based short circuit contribution

DC networks or increased use of convertors and invertors in the distribution grid will become a trend in DER related networks.

The fault current contribution of DER is strongly technology dependent [55]. Distributed generators based on rotating generators (synchronous or induction machine) will produce a relatively high current during a fault (a current level of about 200 to 400% of nominal current in a few cycles after the fault inception); while generators interfaced through power electronics will limit the DER current magnitude to a maximum of 1 to 2 p.u. during the fault [57]. Therefore coordination problems during normal operation are less likely with DER interfaced through inverters and with a strong main substation [13].

Voltage support by converter-coupled generation for unbalanced faults (single-phase-to-ground, phase-to-phase, and two-phase-to-ground) differs from the “expected” voltage support of directly-coupled synchronous generators in terms of magnitude and unbalance. This is because the converters involved are often current-controlled voltage sources whose contribution is, in most cases, balanced by control design and as required by current grid codes, resulting in positive-sequence contributions only [58].

DER units coupled by full converters allow injecting negative-sequence current if required [75]. This behavior would make the fault detection easier. Negative-sequence control of the DER as described in [58] allows for reduction of the overvoltages in the healthy phases and increase of the unbalanced current for easier fault detection. It can be expected that the future grid codes will specify asymmetrical current injection.

Furthermore, strict over-current limits are applied in order to protect the converters. According to [59] these limits can reach 1,3 p.u. for stator reactive current and 0,4 p.u. for the line-side converter reactive current. State-of-the-art balanced fast voltage control of converter-coupled generation for unbalanced faults might impact network protection, either by hindering fault detection/clearance (impact on sensitivity of the protective system) or by triggering undesired disconnection of the generation (impact on security of the protective system) due to:

- small resulting short-circuit phase currents, and thus
- reduced short-circuit power of the network which leads to deeper voltage dips in faulted phases at DER terminals, or
- overvoltage in healthy (non-faulted) phases.

As a result of the need for secure operation of the power system, provided by protection based on three-phase over- and under-voltage, over-current, distance (impedance, angle), and differential protection relays or any combination of those, then state-of-the-art balanced fast voltage control of converter-coupled generation for unbalanced faults requires further investigation [58].

A further difference between conventional networks and DER connected networks is the behavior of the fault transient. For instance, different transients generated by inverter controllers could affect some relays, e.g. the direction determination [13].

Short circuit calculation programs normally use traditional generator models, with a voltage source behind an impedance. These programs may not be able to give reliable results for converter-based generators. It might be very difficult to model inverter control in this type of programs, especially if they do not include the functionalities of electromagnetic transient calculation programs. Moreover, the control algorithms, including operation and control of the crowbar in certain wind generator units [74], will significantly differ between different converter manufacturers and these algorithms will not always be available for modelling due to intellectual property rights.

Moreover, DC networks or more and more use of convertors and invertors in the distribution grid will become a trend in DER related networks

4.2.4 Fault ride through capability

Recent Grid codes require increased network supporting functionalities during normal (parallel with utility network) operation from connected DER units to prevent unnecessary disconnection of DER units and to ensure for example the stability of the network. The most common network stability supporting functionalities are fault-ride-through(FRT) / low-voltage-ride-through (LVRT) and differing requirements for reactive fault current feed during upstream faults.

Traditionally, DER protection has been set to automatically disconnect whenever faults in the network are detected. With increasing importance of DER with regards to supporting the grid operation this approach is no longer feasible. Moreover, DER protection settings that automatically disconnect units whenever frequencies above 50,2 Hz (or 49,8 Hz) are detected in European grids, pose a serious threat to system stability in European grids as the total amount of installed DER versus base load increased significantly.

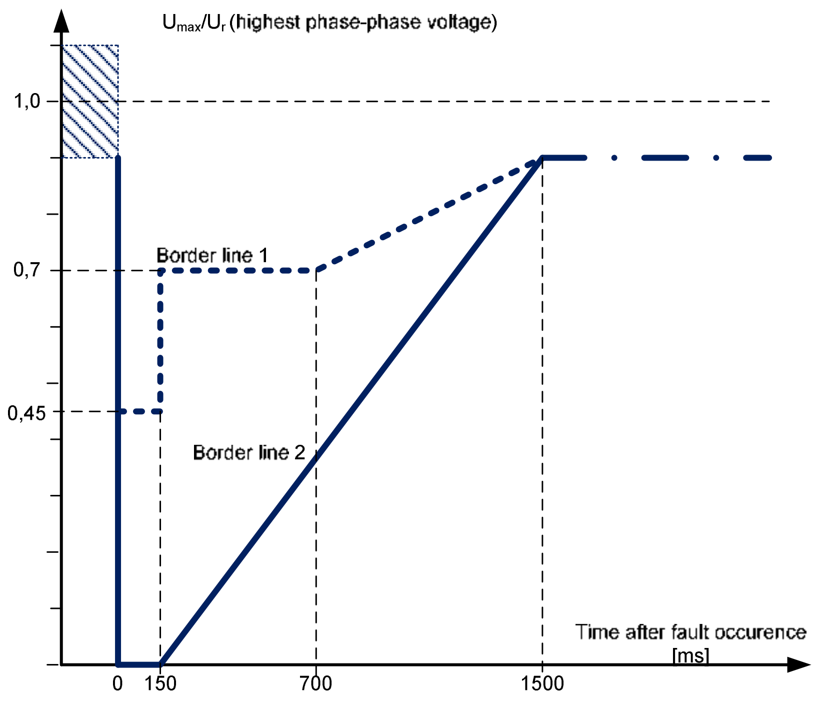


Figure 4-6: Typical fault ride through capability curve

New requirements for FRT capability have already been described in chapter 4.1.5.

Figure 4-6 shows a typical fault ride through capability curve. It is obvious that DER following this requirement will have an impact on protection scheme applications and settings.

4.2.5 Island capability

Both intended and unintended islanding situations must be detected by a loss of mains protection / reliable islanding detection method of the DER units. The most onerous situation is during an island operation (i.e. in microgrid mode), where the fault current could assimilate the load current. In these circumstances, overcurrent protection could become insufficient. In islanded microgrids, load current and inverter current capabilities cannot be neglected in the design of the protection system. The change of fault levels introduces a change in protection philosophy where the faults are less likely to damage network components but are still a danger to individuals.

Moreover, the fault behavior of the network will change over time if the distributed generators are switched or if the topology is altered to minimize the losses or prevent voltage problems. In a microgrid, the change of fault behavior is very large when the microgrid switches from the grid-connected mode to the islanded mode of operation. The inertia and short-circuit capacity of these islanded systems is much lower. [13]. Permanent relay settings will become less effective in some situations and methods for adaptive resetting of protection characteristics may be needed.

In a microgrid, most of the sources are connected via power electronic converters. These converters do not supply sufficient currents to operate current based protective devices in islanded mode because they have been designed to limit the fault current. Therefore protecting a converter dominated microgrid is a challenging technical issue under the current limited environment [60].

As mentioned above, due to the low thermal inertia of semiconductor switches, inverters are actively current limited and, because of their small fault current contribution, they lead unavoidably to various problems that have to be considered by the protection system [61]:

- Characteristics of the inverters under fault conditions may not be consistent with the existing protection devices;
- Throughout the whole microgrid, there may be different inverters with different characteristics;
- Even in the case of an individual inverter, its basic characteristics may differ depending on its design or application;
- There may be difficulties in characterizing inverter behavior for short-circuit studies, since this depends on the control strategy applied;
- There may be a significantly reduced fault current level when changed from grid-connected to islanded mode of operation.

Based on the above, one of the most important issues is to ensure that the behavior required from DER units, including fault-ride-through needs, is compatible with the developed LV microgrid protection system during faults in microgrid. In other words this means that when the protection of a microgrid operated in island mode is designed, one of the most important questions to answer is how converter based DER units will contribute to the fault current [15][25].

4.3 Review of current practices for distribution system protection

This chapter gives a short overview of the similarities and differences of the current practices for distribution system protection. An overview of the individual protection functions is provided by Table 4-1. In addition the country-specific protection schemes are shown in Appendix A - Country specific protection approaches.

Despite a general common protection scheme, which can be extrapolated from most of the contributions from countries, some general differences can be noticed. Here are the main themes which can be source of disparities between each country's practices:

- The functions developed within the protection scheme: for instance, some countries allow operating under a certain level of fault current whereas others prefer to eliminate every fault on the distribution network.
- The neutral treatment (isolated, low impedance, compensated).
- The network structure (meshed or non-meshed network).
- National regulatory legislation.
- The voltage level operated by the DSO.
- The kind of protection functions used in each protection scheme, distributed differently on the network.
- Telecommunication facilities at the utilities disposal.
- Protection functions' configurations (thresholds, temporization…), which depend on many factors (quality commitments of each DSO / DNO, penetration rate of DER…)

Basically the protection function can be classified into two categories. Firstly there is short circuit protection, which is supposed to prevent thermal and mechanical asset stress and damage caused by short circuit currents. Second, there is system protection, which protects power grid from inadmissible operating conditions.

In most cases short circuit protection against faults on the MV busbar is taken care of by an over-current protection function within the transformer protection system. Usually over-current protection is sufficient to protect feeders in radial networks, but some countries use distance protection due to meshed networks (e.g. Austria, Germany, Spain and Denmark).

As a special feature some DSOs also use reverse interlocking. This works by the feeder protection operating in a quicker tripping time for busbar faults, in case they do not detect a network fault in the respective feeder.

Depending on the neutral treatment line-to-earth-faults (phase-to-ground faults) can cause short circuit-like currents. In this case an extra earth fault protection ($I_{e>}$), which measures the zero sequence current or earth current, is required. At some DSOs (e.g. Finland) earth faults will also cause a trip of the feeder in compensated or isolated networks.

With long MV lines with low short circuit current at the end of the line (typical for rural areas) the transformer protection is not able to support backup protection for the feeders. This is why in some countries a local backup protection with circuit breaker failure detection at each affected feeder is used (e.g. Germany).

As an additional specialty countries such as France do not only use zero sequence current $I_{e>}$ for earth fault protection but rather a zero sequence wattmetric protection function ($P_{0>}$) for compensated networks.

The short circuit protection of the DER is comprehensively taken care by over-current protection (in some countries directional because of meshed operation). Alternatively fuses might be in place for low-power generators.

To realize the system protection, all countries have implemented different levels of over- and under frequency protection as well as voltage protection. These protection functions disconnect the DER from the distribution network once a deviation from the operational parameters is detected. However there are differences in the specific use of df/dt protection and ROCOF respectively. While some countries make these an integral part of their system protection (e.g. South Africa, Romania, Denmark and Australia), other countries do not use them because they have concerns of negative influence at future black-starts.

Another unique feature of some countries such as Austria and Germany is that an additional undervoltage/reactive power protection disconnects DER that receive inductive reactive power during faults in the transmission grid (e.g. wind power plants with induction machines).

Moreover, Italy makes use of further levels of frequency protection, which evaluate the zero, positive and negative sequence voltage as an extra criterion.

A (automatically) detected islanded network is treated very differently. In some countries one can find loss of mains (LoM) as additional protection functions (e.g. with impedance measurement or voltage vector shift protection) or a tele decoupling signal that trips the circuit breakers of large DER at the decoupled MV feeder (e.g. France).

Yet in some countries such islanded networks do not cause the DER to be disconnected provided that the frequency and voltage remain in the allowed bandwidth.

Legend for Table 4-1:

I>	overcurrent protection*
Ie>	earth fault protection
Z<	distance protection
U>	overvoltage protection*
U0>	zero sequence system - overvoltage protection
Ud>	positive sequence system - overvoltage protection
Ui>	negative sequence system - overvoltage protection
U<	undervoltage protection*
f>	overfrequency protection
f<	underfrequency protection
P>	direct power protection
P0>	homopolar system - direct power protection
df/dt	frequency change rate protection
Q-U	reactive power - undervoltage protection

Table 4-1: Overview of Country specific approaches (special features in *inverse*)

Country	neutral treatment	grid operation	MV busbar protection	MV feeder protection	MV DER overcurrent protection	MV DER decoupling protection	LV DER decoupling protection	treatment of islanded grid
Australia	solid earthed	non-meshed	I> *with reverse interlocking*	I>, Ie> AR	I>, Ie>	U>, U<, f>, f<, *ROCOF, voltage vector shift, neutral displacement*		*Transfer trip where load matching is possible and other LoM protections may be unreliable.*
Austria	comp.	*meshed* or non-meshed	*Z< with reverse interlocking*	*Z<*	I>	U>, U<, f>, f<, *Q-U*		
China	isolated / compensated / low impedance	non-meshed	I>, Ie> arc protection	I>>, I>, Ie>	I>	U>, U<, f>, f<, *ROCOF*	U>, U<, f>, f<, *ROCOF*	*transfer trip*
Denmark	comp.	non-meshed	I>directional	I>directional	I>	*U>>*, U>, U<, f>, f<, *ROCOF*		
Finland	comp./isolated	non-meshed	I> *with reverse interlocking, Ie>, arc protection*	I>, Ie>directional	I>, Ie>, fuse	*U>>*, U>, *U<<*, U<, f>, f<, *LoM*	U>, U<, f>, f<, *LoM*	
France	low imp. or comp.	non-meshed	I>, Ie>	I>, Ie>, *P0>*, I>directional	I>, Ie>	U0>, U>, U<, f>, f<, U< + FRT requirements + teleprotection	U>, U<, f>, f<, LoM (DIN VDE 0126-1-1/A1)	*tele decoupling (MV), impedance measurement (LV)*
Germany	low imp. or comp.	*meshed* or non-meshed	*Z<, f< & P> directional*	*Z<, I> (backup)* or I>directional, *I> (backup)*	*I>directional*	U>, U<, *Q-U*	U>, U<, f>, f<	
Italy	comp.	non-meshed	I>, *U>*	I>, I>directional,	I>, Ie>	U>, U<, Uen>, f>*, f<*, f>, f< _*with voltmetric release: U0>, Ud>, Ui>_		*transfer trip*
Netherlands	Low imp./ isolated	non-meshed	I>> I>, Ie> , some cases with reverse interlocking	I>>, I>, Ie>	I>, Ie>	U>, U<, f>, f<		
Norway	comp. /isolated	non-meshed	I> *with reverse interlocking*	*Z<* or I>	I>	U>, U<, f>, f<,		
Portugal	low imp.	non-meshed	I>, I>>, I>>>, Ie>, Ie>> and Ie> directional	I>, I>>	U>, U<, U<<, U<<<, U0>, U0>>, f>, f>>, f<, f<<	I>, I>>, I>>>, Ie>, Ie>> and Ie> directional	U>, U<, f>, f<	
Romania	low imp., comp. or isolated	non-meshed	I>, sometimes earth fault reverse interlocking and arc protection	I> or I>directional, Ie> or I>directional	I>, Ie>	U>, U<, f>, f<, *df/dt*		
South Africa	solid/resistively grounded	meshed or non-	I>, Ie>, arc protection	I>, Ie> (dir/non-dir) or pilot wire relay-	I>, Ie> or pilot wire relaying	U>, U<, U0>, f>, f<, *df/dt*		*transfer trip for specific network criteria*

Country	**neutral treatment**	**grid operation**	**MV busbar protection**	**MV feeder protection**	**MV DER overcurrent protection**	**MV DER decoupling protection**	**LV DER decoupling protection**	**treatment of islanded grid**
		meshed		ing				
Spain	Solid earthed, low imp., isolated, comp. (very few installations)	*meshed* or non-meshed	I>, Ie> or busbar differential (meshed MV)	I>>, I>, Ie>>, Ie>, Z< (for meshed MV), 67	I>, Ie>	U>, U<, U0> f>, f<,	U>, U<, f>, f<	*Transfer trip*

*with several levels and delay times

4.4 Country Specific Approaches

This chapter gives an overview of the relay protection settings used by the listed countries/companies in medium voltage distribution networks with DER. Many of the protection schemes are examples and the intention of the list is to provide a state of the art overview of relay protection. In practical situations adaptations of the settings are necessary. Detailed description of the country specific protection practices are given in the Appendix “Country specific protection approaches”.

In general relay protection of DER today is based on standard non-directional over-current protection in most countries. The majority of the assembled relay schemes are based on dedicated DER feeders where selectivity against other feeders is not adequately addressed. Under-voltage and/or under/over frequency protection is used to decouple DER in case of feeder faults. Directional over-current relays are generally not used for phase-faults, but are used for ground faults.

The over-current protections schemes of the feeders with DER have starting currents in the range 1,2- 1,67 of rated feeder currents. Coordination times of 0,3 seconds are typical. Distance protection (with over-current start) is used in Germany, Spain and Austria, and recommended in Norway. Directional over-current relays are used in Denmark and Romania as alternative solutions.

The DER decoupling protection is primarily composed of under/over voltage and under/over frequency relays. The settings here vary significantly and also depend on the DER ratings and fault-ride-through requirements. Instantaneous under-voltage protection (U/t<<) in the range of 0,4-0,8 pu referred to voltage at point of common coupling is reported.

Legend for Table 4-2:

Code	according to ANSI/IEEE C37.2-2008
Irt	rated current of main transformer
Irf	rated current of feeder
IrCT	rated current of current transformer
ImDG	maximum current in the line with DG/DER functioning at its nominal power
I	line current
If2	two-phase fault current (minimum)
Z1	positive sequence impedance of feeder
In	Neutral overcurrent (neutral current calculated or measured from the phase currents)
Ig	Ground overcurrent (ground current measured with a ground CT installed in the connection between the neutral of the power transformer and ground)
Ins	Sensible neutral overcurrent (neutral overcurrent measured with a toroidal CT embracing the three phases)
td	coordination time delay added referred to sub-sequent/downstream protection
tdf	time delay feeder (=t) protection added to some MV decoupling protection
t	absolute operating time, incl. response time (applies to most MV decoupling)
tdir, tnon	absolute time with directional and non-directional configuration
pu	per unit of rated voltage at point of common coupling
frt	fault ride through requirements/capabilities.

MV Decoupling syntax:

U>>	1,2pu/ 0,16 s	Fast disconnection (with a maximum of 0,16 s time delay) when the voltage at the point of common coupling goes above 1,2 pu referred to the nominal voltage at this point.

Table 4-2: Overview of the relay protection settings used by the listed countries/companies

Country	Main transformer protection	Feeder protection	MV decoupling U/t (PCC)	MV decoupling f/t
Australia	Code **51** I>> ≈1,5*Irt ΔI	Code **51** I> ≈1,2*Irf/ td=0,3-0,4s Range: new-old installation	U> 1,15pu/5s U< 0,8pu/5s	f> 52 Hz/5s f< 49,5Hz/2s
Austria	Code **21** Z<≈0,85*Z1/ t=0,4s I>> ≈1,4*Irt/ t=0,4 s	Code **21** Z<≈0,85*Z1/ t=0,05 +0,3-0,4 s Range: new-old installation I>> ≈1,4*Irf/ t=0,05 s	U> 1,15pu/0,1s U< 0,7pu/0,7s	f> 51,5Hz/0,1s f< 47,5Hz/0,1s
China	Code **51** I>, / t=0,3s I>, / t=0,6s	Code **51** I>>, / t=0s I>, / t=0,3s I>, / t=0,6s	Inverter type DG: U>> 1,30pu/ 0,2s U< 0,8pu/ 2,0s U<< 0,4pu/ 0,2s; Or coordinate with fault ride-through capability. Synchronous generator: U>> 1,30pu/ 0,2s U<< 0,8pu/0,2s; Asynchronous generator: U< 0,2Upu/2s U>> 1,30pu/0,2s	f>> 50,2Hz/0,2s f<< 48,75Hz/0,2s
Denmark	I> ≈1,4*Irt/ t=1,5s, (Inside) I>> ≈2-3*Irt/ t=0,1s, (MV side, blocks downstream relays) I>> ≈10*Irt/ t=0,05s, (HV side) ΔI>30% of Irt / t=0,2s	Code **67** I>=1,2*Irf/ t=0,4-0,8 s (rural-urban) I>>=2,5-4*Irf/ t=0,05 s Alt. Code **51** I>=2,5-4*Irf/ t=0,5s	Grid code section 4B	
Finland	HV: I>> 6*IrCT/ t=0,1s I> 1,2*IrCT/ t=1,4 s (backup) MV: I>> 3* IrCT/ t=0,1s I> 1,5*IrCT/ t=1,2s (backup) ΔI>30% of Irt / t=0,1 s Uo> 5-15 % (MV measurement bays)	Code **51** I>=1200-1800A/ t=0,65-0,8 s; typical U0>5% cos (isol.), I0>4-12 A U0>15% sin (comp.), I0>6 A Alarms or t>=0,3-0,5s.	U>> 1,15pu/ 0,15s; U> 1,10pu/ 1,5 s; U< 0,85/ 5 s; U<< 0,5pu/ 0,15 s; Micro (<50kVA): U> 1,1pu/0,2s; U< 0,85/0,2-1,0s; Gridcode 0,5-100 MVA: 0,25pu/0,25s 0,85pu/0,75s	f> 51 Hz/0,2s; f< 48 Hz/0,5s; LoM/0,15s; Micro (<50kVA): f> 51 Hz/0,2s; f< 48 Hz/0,2s; LoM, tLom < 5s;
France	I> 1,6*Irt/ t=1,3s	Code **51** I> 1,3*ImDG and I< 0,8*If2 / t≈0,5 s	U> 1,15pu/0,2s U< 0,8-0,85/1,2s >5MW tdf added @LV instantaneous	f> 50,5-52Hz/tdf+0,5s f< 47-49,5Hz/tdf+0,5s Applies to >5MW more strict below
Germany	Code **21/50**	Code **21**	U>> 1,15pu/ ≤0,1s	f> 51,5Hz/0,1s

Country	**Main transformer protection**	**Feeder protection**	**MV decoupling** **U/t (PCC)**	 **f/t**
	Z<; I>> 1,5 Irt/ tdir=1,2, tnon=1,2; directional- non-directional f/t<49-48 (& power forward); ΔI>30% of Irt	Z<; I>> 1,2*Irf; tdir=0,9s, tnon=1,2s; I>> / t=0,1 s	U> 1,08pu/ 60s (MV) U< 0,8pu/ 1,5s U<< 0,45pu / 0,3 s U< (& ind. Q) 0,85pu/0,5s	f< 47,5Hz/0,1s
Italy	Code **51** I> ≈1,4*Irt/ t=1,5s (ONAN) I> ≈1,6*Irt/ t=1,5s (ONAF) U>>1,15pu/ t=10s (alarm) U>>1,2pu/ t=60s (trip)	Code **51** I>=1,2*Irf or 0,85*If2 / t=1,0 s I>>800A/ t=0,25s I>>>1400/ t=0,05s	U>> 1,2pu/ 0,2 s U> 1,1pu/ 3,0 s U< 0,85pu/ 1,5 s U<< 0,4pu/ 0,2 s	f>> 51,5 Hz/ 0,15 s f> 50,2 Hz/ 1,0 s f< 49,8 Hz/ 4,0 s f<< 47,5 Hz/ 0,15 s
Nether- lands	Code **51** I> 1,5*Irt/ td=0,3s td=0,1s used in case of upward block- ing I>> 0,7*If2 ΔI	Code **51** I>=1,5*Irf/ td=0,3s I>> 0,7*If2 Continues for subsequent CBs	For U<1 kV & In>16 A: U< 0,8pu/ 2,0 s U<< 0,7pu/ 0,2 s <5MW no requirements 5-60 MW (U<110 kV): U< 0,8pu/ 0,3 s U< 0,7/min(0,3,0,9*KKT)	
Norway	Code **51** I> / td=0,2s ΔI	Code **51** I>=1,2*Irf/td=0,2-0,3s (new-old). Multiple feeders, add td for feeder with DER. Alternatively Code **21** Z1A:Z<0,8*Z1/ t=0,2 s Z1B:t=0,0 sec. (breaker close) Z2: Z<1,2*Z1/ t=0,3 s Backup: U/t, f/t	U>> 1,15pu/ 0,2s U> 1,1pu/ 1,5s U< 0,85pu/ 1,5s U<< 0,5*/0,2 *to be negotiated	f>> 51 Hz/0,2s f<< 48 Hz/0,2s
Portugal	Code **51** I> 1,3*Irt/ t=1,4s ΔI	Code **51** I>=1,4*Irf/ t=1,0s I>>=2,0*Irf/ t=0,5s I>>> 4|2|1,5 kA (10|15|30kV)/ t=0,1s	U> 1,15/<0,1s U< 0,85/1,5s U< 0,8/1,6s (frt) U<< 0,21/0s U<<<0,25/0,6s (frt)	f>> 51,5Hz/ <0,1s f> 50,5Hz/ 1,5s f< 49,5Hz/ 1,5s f<< 47,5/ <0,1s
Romania	Code **51** I>> ≈1,4*Irt	Code **51** I> 1,4*Irf/ td=0,4-0,5s (new-old) Alternatively Code **67** Directional if DER contributes more than 10% to the total fault current.	U> 1,1pu/ U< 0,9pu/ Individual time	f> 52Hz/ f< 47-47,5Hz/ Individual time df/dt

Country	Main transformer protection	Feeder protection	MV decoupling	
			U/t (PCC)	f/t
South-Africa	Code **51** I>≈1,5-1,7*Irt/ t=1,3s@Zs=0	Code **51** I>≈1,2Irf I>1,0*Ir for devices along feeder	<100 kVA: U>> 1,2pu/ 0,16 s U> 1,1pu/ 2,0 s U< 0,85pu/ 2,0 s U<< 0,5pu/ 0,2 s >100 kVA: U> 1,1pu/ <2,0 s U< 0,85pu/ <2,0 s	>0 kVA: f> 52Hz/ 4,0 s f< 47Hz/ 0,2 s df/dt >1,5Hz/s
Spain	Code **51** I>1,3*Irt *Solidly grounded* In> ≈ 75 – 120 A primary (51N) Ig>≈ 85 – 150 A primary (51G) *Low impedance grounded* In> ≈ 75 – 120 A primary or 0.1*IrCT (51N) Ig>≈ 18 – 200 A primary (51G) *Ungrounded:* Un>≈ 58 V (Ur=110/$\sqrt{3}$) or 30 V (Ur=110/3) (59N) t≈1,5 - 4 s	Code **51** I> ≈1,3*Irf (51) I>> ≈0,8*If2 (50) / 6* Irf (50 - ungrounded) *Solidly grounded:* In> ≈ 20 – 40 A primary (51N) In>>300 A (50N) Ins>4 – 10 A primary; t=50 s (51Ns) *Low impedance grounded:* In> ≈ 30 A primary or 0,06*IrCT (51N) In>>300 A primary or 8*Ir> (50N) Ins>2 – 10 A primary; t=7 - 50 s Z<0,8*Z1L (for meshed MV networks) 67N: back-up of 21G for meshed MV networks 87L for some underground feeders *Ungrounded:* Ins>≈ 0,12 – 1 A primary Un>≈ 58 V (Ur=110/$\sqrt{3}$) or 30 V (Ur=110/3) (67Ns) t≈ 0,25 – 0,4 s	U>/t 1,1*Ur / 1,5 s or 0,6 s U>/t 1,15*Ur / 0,2 s U</t 0,85·Ur / 1,5 s or 0,6 s Un>/t 0,35*Vr / 0,6 s or 1,2 s	f>/t 50,5 Hz or 51 Hz / 0,5 s or 0,2 s f</t 48 Hz / 3 s
USA	Determined on a case by case basis	Determined on a case by case basis	U>> 1,2pu/ 0,16 s U> 1,1pu/ 1,0 s U< 0,73pu/ 2,0 s U<< 0,42pu/ 0,16 s	f> 60,5Hz/ 0,16 s f< 58,0Hz/ 1,0 s Note: 60Hz is nominal frequency in the USA

5 Protection of Distribution System with Distributed Energy Resources

5.1 Impact of Distributed Energy Resources on distribution system protection

Due to current regulatory frameworks in countries and technical developments, the penetration of DER in distribution networks has increased continuously and it can be expected that this growth will continue in the future. This huge increase has an important impact on the protection schemes of the distribution networks.

5.1.1 Definition of Situation

In accordance with the title of this CIGRE / CIRED-JWG report “Protection of Distribution Systems with Distributed Energy Resources”, initially it is necessary to define a principle structure of the “distribution system” which is covered by this working group.

Based on this principle structure, all questions regarding the protection – both the current practice as well as any future recommendations – must relate to it.

Figure 5-1 shows an outgoing feeder of a typical MV distribution grid supplied from the busbar of a HV/MV-substation. It can be a ring (loop) which is usually operated radially. This single feeder (which can be subdivided by one or more switching stations) supplies a number of MV/0,4-kV-transformer stations for customers (public supply). It is also

- the grid connection to and the in-feed from DER-plants (e.g. small co-generation plants, small windmills, …)

and

- the grid connection of private grids.

Larger wind farms (green) are usually directly connected to the busbar. It should be noted that substations used exclusively for the infeed of wind farms are expressively not covered by this CIGRE/CIRED-JWG report.

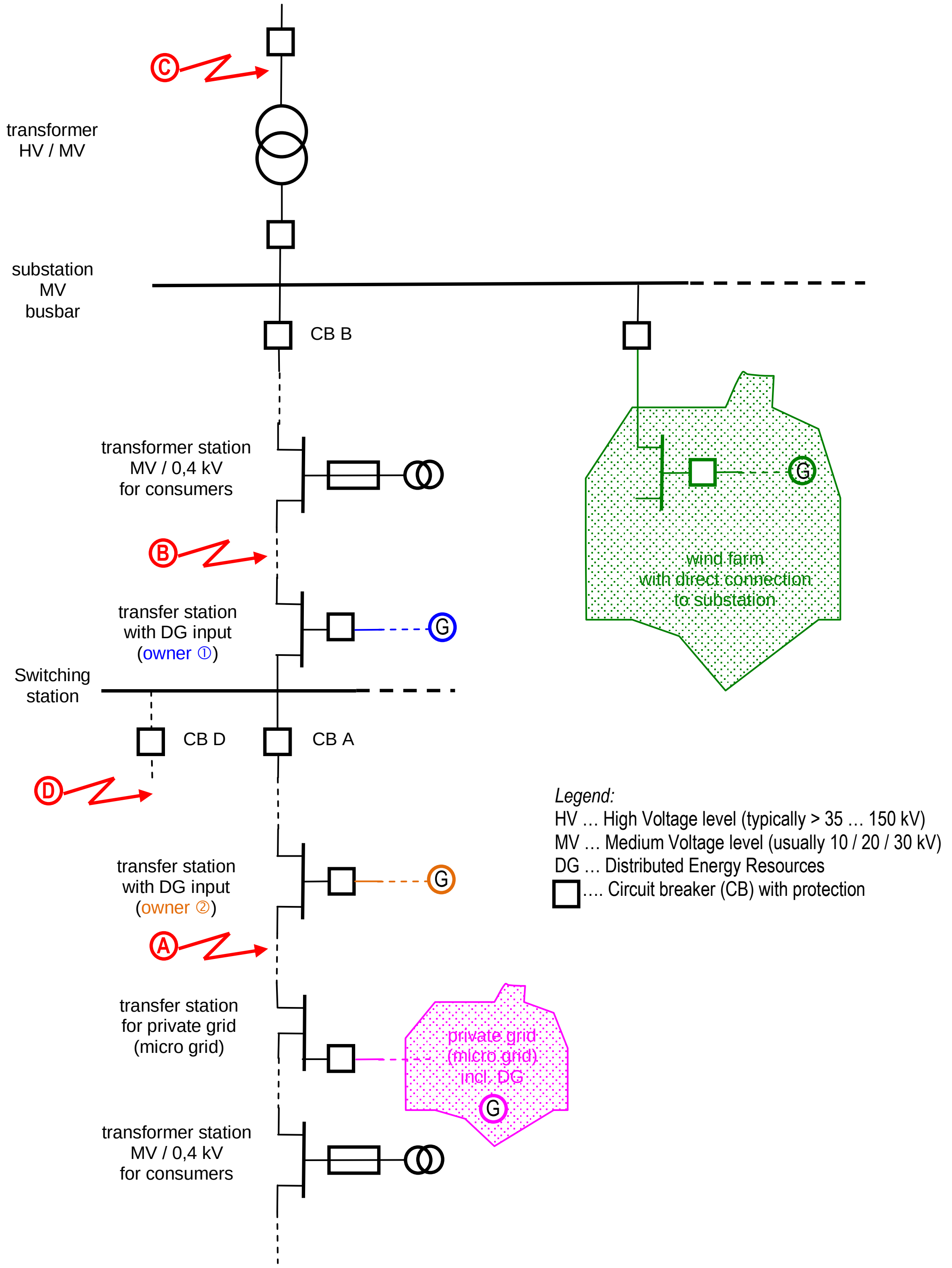


Figure 5-1: Principle structure of the “distribution system” covered by this working group

Assuming that the wind farm (green) as well as DER ① and ② have sufficient FRT capabili-ties, with respect to chapters 4.3 “Review of current practices for distribution system protection" and 4.4 "Country Specific Approaches" the classical phase and earth fault protection usually contains:

- feeder protection, consisting of
    - an over current protection (ANSI 50/51),
    - a directional earth fault protection (ANSI 67N) or a sensitive earth fault protection (ANSI 67Ns) or a zero sequence current protection (ANSI 50N/51N) – according to the neutral treatment of the grid

and

- as backup for MV feeder protection
    - a neutral displacement voltage protection.

5.1.2 Check of fault scenario for several fault locations

According to Figure 5-1 the following table results:

Table 5-1: fault scenario for several fault locations (common practice / future aspects)

Fault location	Fault scenario: common practice
A	1. short-circuit current contribution predominant from HV/MV-transformer 2. trip of CB A in switching station by its I>/t-protection 3. DER ② must trip, too – by means of its I>/t-protection (if short-circuit current contribution is able to start it) or U<-criterion of decoupling protection 4. OPEN QUESTIONS concerning the private (micro) grid → what trips the private (micro) grid in case of weak infeed? → islanding of the private (micro) grid → protection scheme in case of island operation? 5. wind farm (green) and DER ① should remain connected to the grid (if their FRT capability is sufficient)
B	1. short-circuit current contribution predominant from HV/MV-transformer 2. trip of CB B in substation by its I>/t-protection 3. DER ① must trip, too – by means of its I>/t-protection (if short-circuit current contribution is able to start it) or U<-criterion of decoupling protection 4. CB A in switching station remains closed if pick-up value of I/t-protection is less than short-circuit current contribution of DER ② and private (micro) grid → DER ② and private (micro) grid must decouple with U<-criterion. OR 4. CB A in switching station trips if short-circuit current contribution of DER ② and private (micro) grid is sufficient → islanding of the remaining grid area (DER ② and private (micro) grid and transformer station) → **Note, that the remaining grid area will lose its neutral treatment which usually is realized in the substation (in transformer star-point or by means of separate star-point transformer)!** **5.** wind farm (green) should remain connected to the grid (if its FRT capability is

Fault location	**Fault scenario: common practice**
	sufficient)
C	Generally: a fault in the HV-grid should not cause a trip of the substation. 1. Fault **C** (e.g. fault location is within the transformer differential protection zone) will be tripped by the transformer protection. 2. A) If the remaining grid is not able to keep in island mode, e.g. too less generation: f<- and/or U<-criterion will trip the DERs B) If the remaining grid remains in stable condition → unwanted islanding.
D	1. short-circuit current contribution predominant from HV/MV-transformer 2. trip of CB D in switching station by its I>/t-protection 3. CB A in switching station remains closed if pick-up value of I/t-protection is less than short-circuit current contribution of DER ② and private (micro) grid → DER ② and private (micro) grid must decouple with U<-criterion. OR 3. CB A in switching station trips if short-circuit current contribution of DER ② and private (micro) grid is sufficient 4. islanding of the remaining grid area (DER ② and private (micro) grid and transformer station) 5. **Note, that the remaining grid area will lose its neutral treatment which usually is realized in the substation (in transformer star-point or my means of separate star-point transformer)!** 6. wind farm (green) should remain connected to the grid (if its FRT capability is sufficient)

Remark: If the sample grid given in Figure 5-1 consists only of radial outgoing feeders (i.e. without it being meshed) then the fault scenario of fault location **A** is equivalent to fault location **B**.

5.1.3 Future Aspects

One of the most important changes caused by the massive integration of DER into the distribution network is the bi-directionality of fault currents. This implies the need to develop more complex protection systems on the distribution network, which are able to deal with several contributions to fault current.

All protection schemes where DERs are involved must be checked: There must be a large enough fault current to start the relevant protective devices:

- in all situations, e.g. low wind or sun,
- otherwise, other methods for starting must be considered (e.g. U-I-starting, underimpedance or similar) and must be available.

Specific additional protection:

To deal with these specificities, DSOs need to develop specific protection approaches, in addition to the usual ones described above. The following points list several new protection approaches required with reference to the above context (in addition, refer to Figure 5-2):

- HV neutral displacement voltage protection:
  additional decoupling protection in order to avoid the risk of islanding in case of phase faults at HV level
- islanding detection (tele-decoupling):
  detection of the opening of the MV feeder and communication to the DER facility de-coupling protection
- directional phase protection:
  protection which detects the sense of the fault current, in order to locate the fault and avoid unintentional tripping (i.e. when the fault occurs on another MV feeder)
- DER facility protection:
  protection against faults occurring within the installation
- DER facility decoupling protection:
  disconnection of the DER facility from the network when a MV network fault occurs

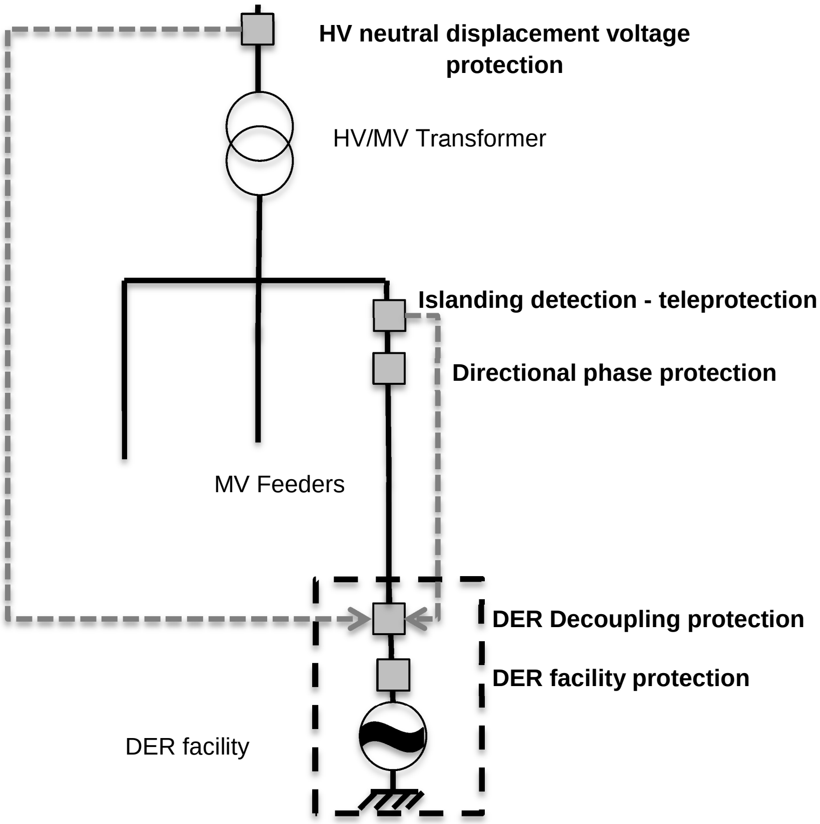


Figure 5-2: Specific additional protection in case of DER infeed

5.1.4 Summary

The sequences of the fault scenarios described in Table 5-1 can be summarized as follows:

1. In case of a fault in the supply grid all DER will decouple because of their U/f-protection.
2. The borders of the remaining grid are given due to its neutral treatment:
   a. The neutral impedance $\underline{Z}_N$ is directly connected to the neutral of the supplying transformer:
      In case of a transformer fault (fault location **C**) the remaining grid (brown dotted) will lose its neutral treatment. A continuation of the operation is only possible if the earth fault protection of the remaining grid is adapted to the new situation.

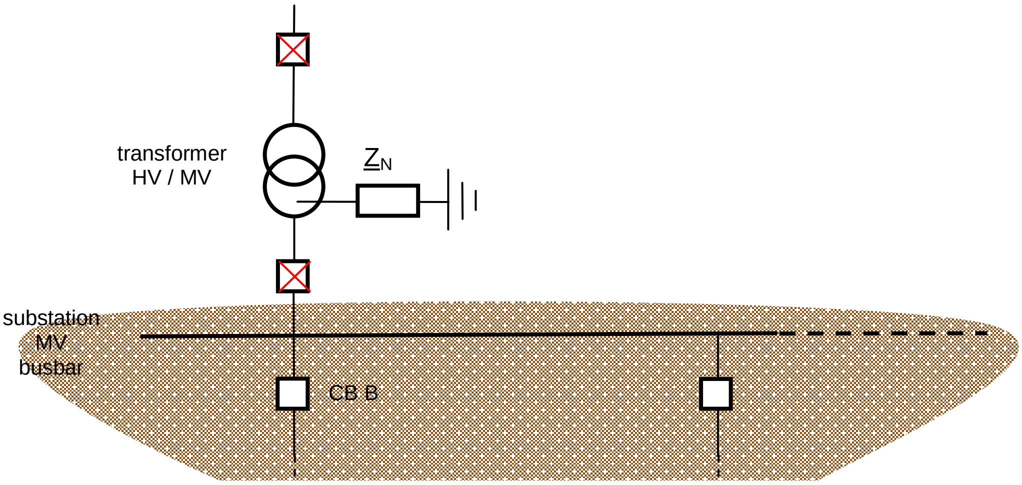


Figure 5-3: neutral treatment of the grid with neutral impedance directly connected to the star point of the transformer

   b. The neutral impedance $\underline{Z}_N$ is connected to a grounding (earthing) transformer ("Zig/Zag transformer"):
      In the case of a transformer fault (fault location **C**) the remaining grid (brown dotted) keeps its neutral treatment. Thus a continuation of the operation is possible.

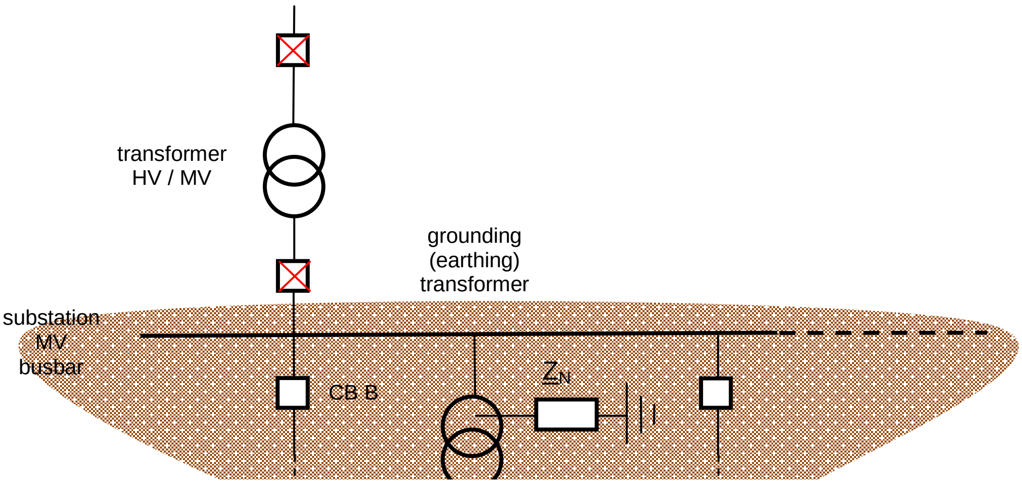


Figure 5-4: neutral treatment of the grid with neutral impedance connected to a grounding transformer

5.2 Recommended best practices for reliable island detection

A serious issue introduced by the current high penetration of DER is the so called "unintentional islanding" phenomenon. "Unintentional islanding" happens when a portion of the distribution network with installed DER is disconnected from the rest of the network. In such cases, voltage problems may arise and the localized frequency may not be in synch with the frequency of the main transmission network.

The probability of having an unintentional island is related to the amount of power generation connected to the distribution network and to the local loads. If there is a balance between dispersed production and load, the risk of unwanted islanding exists in cases where the feeder breaker is opened.

The basic problem with unwanted islanding after system disconnection is that parts of the network are energized whereas de-energisation is expected.

In general, instead of the term "unwanted islanding", it's more appropriate to talk about "uncontrolled islanding". In fact, during the islanding operation the main electric parameters are not under direct control of the DSO (voltage) or the TSO (frequency).

For safety reasons, European standard EN 50110-1 clause 6.2 Dead working summarized below has five essential rules and does not allow operation of the network under such conditions. For this reason no distinctions are usually drawn between detection of or protection against the islanding.

The actual rules require clear identification of the work location. After the respective electrical installations have been identified the following five essential requirements shall be undertaken in the specified order unless there are essential reasons for doing otherwise:

1. disconnect completely;
2. secure against re-connection;
3. verify that the installation is dead;
4. carry out earthing and short-circuiting;
5. provide protection against adjacent live parts

Depending on the power flow conditions, there are two different levels for the uncontrolled islanding: the first level is at the MV feeder level, the second level is at the HV/MV substation level. Depending on these levels, different approaches are possible in order to detect uncontrolled islanding condition. For instance, in the HV/MV substation level, in case of a grid operated in open ring, uncontrolled islanding detection is possible through the voltage signal presence on the network side of the feeder with the open breaker condition.

In order to avoid the unintentional islanding and out of sync reconnection which can cause large damages to the DG and the grid, the protection system must operate in a very short time by disconnecting the generators in a time that is shorter than the time of the first automatic reclosure.

For many reasons some portions of the network may be subjected to the risk of islanding: for example a network portion can be disconnected due to a fault protection intervention. Each country has a defined set of rules in order to achieve an adequate level of safety and reliability of the power system. In general the system must provide protection that avoids unwanted islands by disconnecting the generation units connected to the network portion of an island in as short as a time possible.

The common requirements are:

- The DER must be disconnected if the voltage or the frequency are out of a contractual range;
- The DER must be disconnected if one or more phases of the prevailing network (transmission network) are missing;
- In case of an automatic reclosure, the DER must be disconnected before the first reclosure.

The anti-islanding protection assures all of these requirements.

Up to now, according to the state of the art, there is no islanding detection system which is recognized as really efficient and shared by all the countries. Nevertheless, here is the state of the art.

There are three techniques to detect an unintentional island:

- Passive protection;
- Active protection
- Network communication based protection

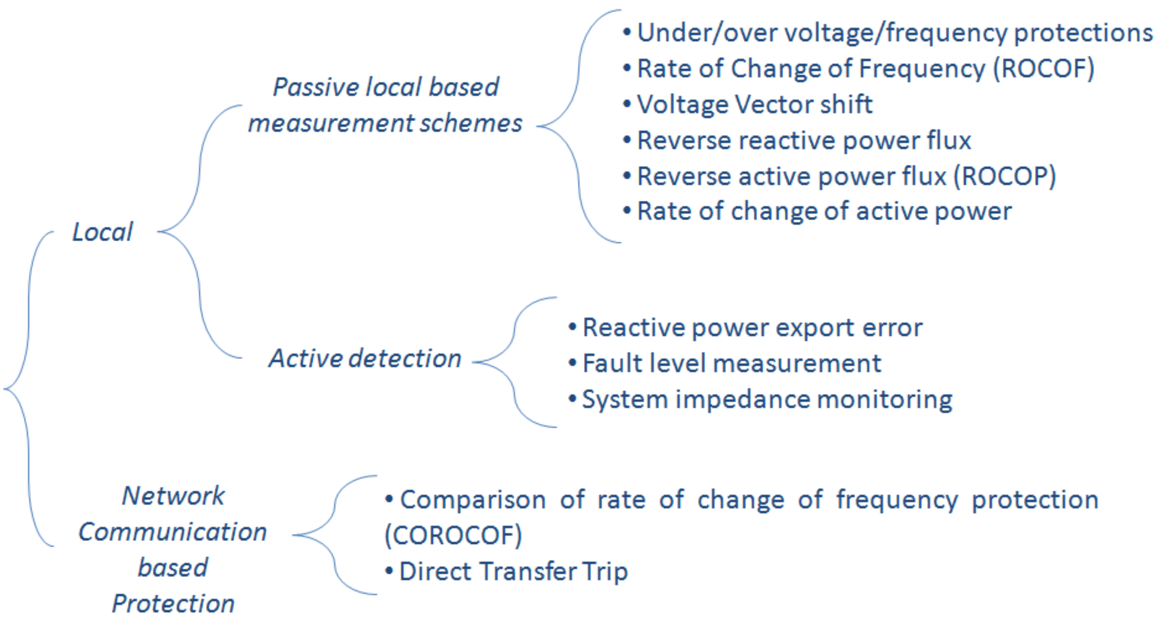


Figure 5-5: Techniques to detect an unintentional island

Another possibility is to detect the islanding with some synchrophasor measurements by comparing the phase of the DER voltage to the one of the substation.

5.2.1 Passive local based measurement schemes

The passive protection is a technique that use a stand-alone digital relay installed in the generation plant. The relay is equipped by a set of standard protection functions that are:

- Under and over frequency protection function (ANSI/IEEE C37.2 code 81);
- Under and over voltage protection function (ANSI/IEEE C37.2 code 27 and 59);

To assure the anti-islanding protection, in addition to these classical protection functions, other types of functions have emerged:

- Rate of Change of Frequency (ROCOF);
- Vector shift (jump);
- Inverse reactive power flux;
- Inverse active power flux;
- Rate of change of the active power.

5.2.1.1 Under/over voltage/frequency protections

When there is a change in the network (a portion of the network with distributed generation is cut off), the generation sees it as a load change and it results in a change of the electrical parameters (voltage and frequency). This possibility depends on the unbalance between the load and the generation before the fault. If there is a load unbalance, the under/over voltage or under/over frequency protections can operate. However, it should be noticed that active voltage and frequency control by the DER can sometimes delay the islanding detection. For that reason, the time response of these active regulations must be strongly studied before implementation.

Frequency measurement is usually performed by phasor vector change, [62], which makes it very susceptible to voltage variations like those arising from faults. Therefore, it is usual to use the line-to-line voltage measurement instead of single phase voltage measurement. The aim is to feed the algorithm with voltage with low transient component (there are more single phase faults than phase to phase faults). The ideal way should be frequency measurement for positive sequence voltage. Some manufacturers have a minimum operating time of about 80ms to prevent unwanted trips. This has proven to be a good practice according to the Portuguese experience.

The problems presented above also occur with other frequency measurement algorithms like “zero-crossing”.

5.2.1.2 Rate of Change of Frequency (ROCOF)

The deviation of the frequency from the rated system frequency indicates unbalance between the generated power and the load demand. If the available generation is large compared to the consumption by the load connected to the power system, then the system frequency is above the rated value. If the unbalance is large, then the frequency changes rapidly. In order to speed up the islanding decision, rate of change of frequency relay is used.

This type of relay has been known to have some issues which arise from each individual manufacturers implementations, [63]. The performance of ROCOF relays is related to the chosen algorithm for frequency measurement (“zero crossing” or Fourier Transform), the length of the measuring window (longer measuring windows have a better response to voltage disturbances but have higher operating times) and the algorithm used for the Rate Of Change calculation (ex.: linear fitting, polynomial fitting). The reader is advised to consult [63] for further information.

5.2.1.3 Voltage Vector shift

Due to the loss of the network contribution, the generator is called to vary its output to satisfy the energy balance.

The change in power output from the generator causes a shift of the voltage vector. This protection is based on measuring the period of the voltage, which is compared with the previous measure. In island operation, the duration of the period, which is proportional to the phase, changes due to the unbalance between generation and load at the first opening. The relay phase shift is sensitive to disturbances such as faults on other feeders or transmission network transients and therefore it is difficult to coordinate with other protections.

5.2.1.4 Reverse reactive power flux

In the case where the power factor of the generation plant is equal to one (e.g. photovoltaic power generation), when a network portion with DER is disconnected, there is a transient while the generator provides reactive power to the network.

The reverse reactive power flux protection is installed in the connection point between the distribution network and the generator.

5.2.1.5 Reverse active power flux

In some applications, the power generated is less than the load connected to the producer network. In this case a transient of active power that flows through the connection point between the producer network and the distribution network indicates a loss of network.

The reverse active power flux protection is installed in the connection point between the distribution network and the producer network.

5.2.1.6 Rate of change of active power

The monitoring of active power can be used to detect unwanted islanding. Indeed, a quick change of active power might be a signal of loss of the upstream network.

The rate of change of the active power protection is used in addition to the under/over voltage and under/over frequency protection.

5.2.2 Active detection

The active methods interact directly and continuously with the electrical system. Perturbations on the network are due to small variations of some electrical parameters set by appropriate DER controls. If the DER operates in parallel with the network, the method generates small changes that are not sufficient to trigger the relay, whereas in case of loss of the network the changes become significant and the DER is disconnected. The most common active protection functions to avoid the islanding are:

- Reactive power export error;
- Fault level measurement;
- System impedance monitoring

5.2.2.1 Reactive power export error

This relay interacts with the regulation system forcing the generator to provide a level of reactive power that can be maintained only if the transmission network is connected.

The operation occurs when there is a difference between the exported reactive power and the reference value for longer than a settable time. To avoid unwanted tripping in case of fluctuations of the source, the set interval is chosen greater than the duration of possible fluctuations.

5.2.2.2 Fault level measurement

The fault level in a certain point of the grid can be measured using a point-on-wave switched thyristor. The thyristors are controlled to be activated close to the voltage zero crossing, and the current through a shunt inductor is measured. The system impedance and the fault level can be quickly calculated (every half cycle) with the disadvantage of having the voltage shape slightly changed near the zero crossover.

5.2.2.3 System impedance monitoring

It is a method that detects the system impedance with active monitoring. A high frequency source (a few volts at few kHz frequency) is connected via a coupling capacitor to the interconnection point. The capacitor is in series with the equivalent network impedance. When the systems are synchronized, the parallel impedance Z_{DG} and $Z_{Network}$ is low, therefore the HF-ripple at the coupling point is negligible. After islanding, the impedance increases dramatically to Z_{DG} and the divided HF-signal is clearly detectable.

5.2.3 Protection based on a communication network (Communication based transfer trip schemes)

Recently a new approach has been used to manage the system protection on Smart Grids.

The major nodes are connected by a communication link. Via this link the devices interact in order, for example, to disconnect a DER from the HV/MV substation.

5.2.3.1 Comparison of rate of change of frequency protection (COROCOF)

If there is a communication network, the technique called COROCOF can be used.

The method is based on the comparison of frequency change rates in two or more point of the network.

The method is able to discriminate the frequency variations due to loss of network from other changes due to other causes.

A lock signal is transmitted by the transmitter relay to all relays located near the DER. The transmitter relay transmits this signal if the frequency change is generated by events not related to the loss of network.

5.2.3.2 Direct Transfer Trip

Another anti-islanding protection method which can be applied to prevent unintended islanding is Direct Transfer Trip (DTT). A signal to disconnect the generator is initiated by the utility line protection or circuit breaker open status. A typical arrangement is illustrated schematically in Figure 5-6.

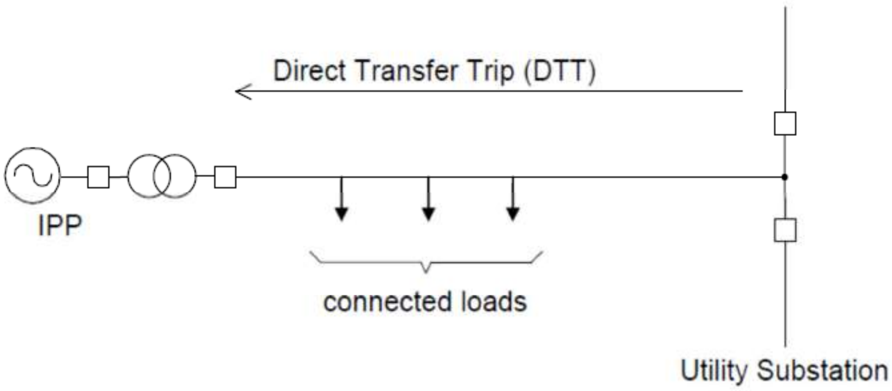


Figure 5-6: Typical arrangement for direct transfer trip (DTT)

The DTT is more reliable compared to the previously described local measurement based methods (passive methods) because it is not affected by the local power balance and it is also immune to the remote system events. However, it needs to be noted that the cost of providing adequate communication media may be prohibitive in some cases. Additionally, the network topology may require the transfer trip to be supplied from more than one location which adds to the cost and complexity of the scheme.

5.2.4 Future trend and recommendations

As already stated, in grids with distributed generation, uncontrolled islanding becomes possible.

In the past this problem was dealt with by intertripping of the distributed generators. With an increasing number of generators involved, this is not practical in modern MV and LV grids due to the need for low latency, redundant and highly available communication lines.

The preferred solution to prevent islanding networks is a reliable detection system at the DER connection point. As showed, there are several approaches developed to achieve this objective. To implement a really reliable detection, some sort of information about the network topology and/or the switching condition has to be provided. One way is to use separate communications with additional complexity. Another example could be a “grid alive signal” modulated on the voltage at the MV busbar and detected by the DER.

Another option is using the communication links which are a part of future smart grid and advanced meter scenarios: ping the meters and ask for a voltage reading.

Yet another option is to minimize the need for communication by measuring voltage at the place where the switching is done and expand the logic in the protection device of the MV feeder.

Today MV islands are typically unwanted, whereas larger HV islands may be used in grid-restoration scenarios after system blackouts.

With the increasing frequency of natural disasters these days, and the growing energy demand in developing countries with poor infrastructure, the need to retain microgrids in the system (as opposed to unwanted islanding), can get stronger. To follow this approach, it would be necessary to change rules such as redefining the DSO’s responsibility; and redesign of technologies mainly for the generators that uses static converters (inverters).

6 Proactive approach to technology trends

As far as distribution network protection schemes are concerned, apart from the many evolutions described in the previous chapter due to the growing connection of DER, the quick evolution of technology in this sector and the use of new techniques can also have a huge impact on the way DSOs protect the network.

Future European Grid Codes (especially ENTSO-E Network Codes – Requirement for Generators), currently in committee consideration within the European Union, can also have huge impacts on protection schemes. Enlargement of the frequency range, ability to provide static power regulation depending on the frequency, definition of specific Fault Ride Through requirements for different kind of generation and fast reactive current injection during fault are among the most important ramifications of these network codes.

6.1 New applications of teleprotection, use of communication

The new communication technologies are providing new opportunities for the development of the Smart Grids. In order to define the requirements for these technologies it's important to notice that protection schemes are also designed in order to protect the network from unsolicited islanding (like in France, Romania, Spain and Italy).
In general it's possible to distinguish between wired technologies and radio technologies.

- Wired technologies:
  - Copper Pair communications technologies
  - Power Line communications technologies
  - Fibre Optic communications technologies
- Radio technologies:
  - VHF/UHF
  - TETRA
  - WIFI
  - ZigBee
  - Z-WAVE
  - WIMAX
  - Cellular data services and Satellite

Table 6-1: Summary of advantages-disadvantages of wired technologies

Wired technology	Pro's	Con's
PLC	Existent infrastructure Full coverage (massive deployment) Shared channel for multicast Multiple services	Possible interference Hostile communication channel (attenuation, fading, noise) Repeaters needed Possible coupling problems No generalized open standards so far
Copper communication (xDSL)	Good transmission characteristics Efficient bandwidth use IP technologies well extended and tested High residential penetration Multiple services Open standards	No full coverage Connection availability not guaranteed no point-to-multi-point protocols
Fibre optic	Good transmission specifications (bandwidth, attenuation, …) Mature technology Open standards Scalable Multiple services	Point-to-point links (demanding for communication with LV consumers) Gateways required for medium change If not available, costly deployment

xDSL: High bit rate Digital Subscriber Line (HDSL), Single-Pair High-speed Digital Subscriber Line (SHDSL), Asymmetric Digital Subscriber Line (ADSL), Very high bit rate DSL (VDSL).

Table 6-2: Communication technologies – comparative evaluation

Technology	operator/ owner	cost	frequency band	Data rate	Area Network	Appli-cations
VHF/UHF radio	Utility	low	150 MHz / 400 MHz	narrowband	RAN	Voice, DA, AD
PMR (TETRA)	Utility	high	400 MHz	narrowband	RAN	Voice; DA, AD
WiFi	consumer, utility	low (only HAN)	2,4 GHz	broadband	(NAN) HAN	AMR, Home Automation
ZigBee	consumer, utility	low (only HAN)	2,4 GHz	narrowband	HAN	AMR, Home Automation
WiMAX	utility or 3rd party	low	5 – 60 GHz	broadband	RAN	DA, AD, AMR
public cellular data services	3rd party	medium	900/ 1800 MHz (GSM)	narrowband/ broadband	WAN, NAN	Voice; DA, AD, AMR
satellite communication	3rd party	low/ medium	2, 6, 12 GHz	narrowband	WAN	AD, AMR

With the assumption that, in case of islanding, the protection system has to act in the minimum possible time, the table below shows the appropriate technology to use in MV network.

Table 6-3: Appropriate technology to use in MV networks

Data rate	Delay	Copper Pair	PLC tech-nology	Fiber optic technology	VHF/ UHF radio	TETRA	WiFi	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.

With the assumption that, in case of islanding, the protection system have to act in a time up to 100ms, the table below show the appropriate technology to use in LV network.

Table 6-4: Appropriate technology to use in LV networks

Data rate	Delay	Copper Pair	PLC tech-nology	Fiber optic technology	VHF/ UHF radio	TETRA	WiFi	ZigBee	Wimax	Public data service	Satellite
1 Mbps	100ms	no	yes	no	no	no	yes/ no**	no	yes	yes	yes

** yes only if the system is cyber secured and technically achievable (with high developed telecommunication networks). no if these conditions are not met.

WiFi does not apply to long range links between DSO to HV/MV Substation (MV/LV Substation) and between HV/MV substations and MV/LV substations since for these links, very high power is used, compared to other wireless technologies such as VHF/UHF radios. WiFi is applicable in the scenario NAN of the architecture, especially in those areas where there are high concentrations of nodes. In areas like cities where there are a moderate concentration of nodes, deployment of a wireless mesh network based on WiFi can be a great solution. WiFi is also applicable in the scenario HAN architecture.

Situation in Italy:

In Italy, pilot tests are underway using PLC technology on LV network. In MV/LV substation a PLC transmitter is installed. The islanding condition is detected by the voltage presence with a circuit breaker opening condition. In case of islanding of the LV network an alarm message is sent to all LV producers that are connected to the line via a broadcast signal. The producers are provided with a PLC receiver that is connected to the interface protection. In case of an alarm being received, the protection switches the frequency thresholds to the narrower band. Currently there are several issues concerning interference with smart meters, and these will be fixed with an appropriate choice of PLC carrier frequency.

Situation in France:

Concerning the generators' decoupling protectionns in France, ERDF is experimenting with some new ways of communication for tele-action (called H4) which is to replace copper communications currently used in the MV network. The new communication technologies and protocols experimented with are:

- Optical Fibre, which seems to be the best solution concerning the transmission time but has some issues from the administrative point of view,
- Microwave Transmission, which could be a cheap and simple solution for installation close to the substation,
- Internet Protocol (IP), which is currently field tested.

A new CIGRE WG B5.50 has been created recently to deal with “IEC 61850 Based Substation Automation Systems – Users Expectations and Stakeholders Interactions”. IT is suggested that they could also consider the subject of using the standard for enhancing adaptive protection as well.

Concerning the IEC 61850 Protocol, along with the development of Digital Protection and Control Systems of substations ("PCCN"), more and more protection equipment are compatible with IEC 61850. Along with its adaptive strategy to the market, ERDF allows this equipment to communicate with each other using the IEC 61850 protocol. Indeed, both feeder protections and transformer protections are used by ERDF with IEC 61850 protocol (in around 100 substations), via gateways connecting each to the supervising network of the substation.

6.2 Protection schemes for future distribution networks with DER

The purpose of this section is to highlight in a few words the new challenges of distribution network protection related to new grid code requirements, active network management schemes and island operation. Both medium-voltage (MV) and low-voltage (LV) distribution networks as well as both directly connected rotating generator based DER units and converter interfaced DG units are covered. Also, some of the proposed protection schemes for smart grids, found in current literature, for island operated distribution networks are reviewed.

6.2.1 New Challenges for Protection

One of the key protection functionalities in the Smart Grids will be reliable detection of islanding. Although the trend in new grid codes is to require fault-ride-through (FRT) capability from DER units and possibly also to allow island operation, there is still a need to reliably detect the islanding situation in order for the operator to make the correct decisions, e.g. change the setting group of DER interconnection IED or change the control principles and parameters of DER unit [1].

In the forthcoming ENTSO-E network code (NC) for generators (RfG) [2], it has been stated that islanding detection should not be based only on the network operator's switchgear opening/ closing position signals. Moreover, if high-speed communication is used as a primary islanding detection method, the passive local islanding detection method is still needed as a back-up [1].

Larger non-detection zone (NDZ) and unwanted DER trips due to other network events (nuisance tripping) have been the major challenges with traditional, passive local islanding detection methods based on frequency (*f*), *df/dt*, vector shift (*VS*) or voltage (*U*). [1]

If the number of DER units in distribution networks increases, as expected, in the future, the possibility of achieving power balance in the distribution network will also increase. Therefore, the risk of distribution system segments operating in the NDZ of the traditional passive islanding detection methods will increase, too. In addition, the use of *f*, *U* and rate-of-change-of-frequency (ROCOF) for defining DER units' FRT requirements in the new grid codes (as in [2]), to enable utility grid stability supporting functionalities from DER units, will increase. [1]

Recent and forthcoming grid code requirements, such as the active power/frequency (*P/f*) regulation during over-frequency for all DER units and during under-frequency for larger DER units [2], [3] will enable DER units connected to MV and LV networks to control their active power even after islanding. This means that frequency deviations are instantly corrected and islanding may not be detected with the traditional, passive islanding detection methods. Therefore, the use of the traditional parameters for reliable and selective islanding detection may become even more difficult in the future than it is today. [1]

Due to the above-mentioned reasons, a new, future-proof, passive islanding detection algorithm and scheme has been proposed in [4] and [5], which is able to detect very fast and selectively islanding situations even in a perfect power balance without NDZ, and is also applicable to different type of DER units. [1]

In the future, it is possible that different active network management functionalities, like voltage control, island operation coordination, minimization of losses, etc. will be realized through centralized solutions at primary (HV/MV) and secondary (MV/LV) substations. Active network management may simultaneously affect to protection settings if for instance network topology is changed. Therefore, adaptive protection may be required. [1]

Traditionally, active network management and adaptive protection functionalities have been developed and operated independently [6]. However, in the future increasing attention should be paid to understand the level of active network management and protection functions coupling to be able to create future-proof solutions for the Smart Grids [7]. [1]

6.2.1.1 New Grid Code Requirements

In the future, ENTSO-E NC RfG [2] will provide a legal framework for DER units (> 0,8 kW) grid code requirements in Europe, but it will not replace local national grid codes. ENTSO-E NC RfG [2] divides the requirements for four type/size of DER units (power generating modules) i.e. Type A (DER units > 0,8 kW connected to voltage levels below 110 kV) and B, C and D, which have different maximum capacity thresholds for the five different synchronous areas. [1]

Frequency

In NC RfG [2] for DER units (Type A and larger), it has been stated that with regard to frequency ranges, a DER unit shall be capable of staying connected to the network and operating within the frequency ranges (some difference between synchronous areas) and time periods specified in Figure 6-1Figure 5-6. [1]

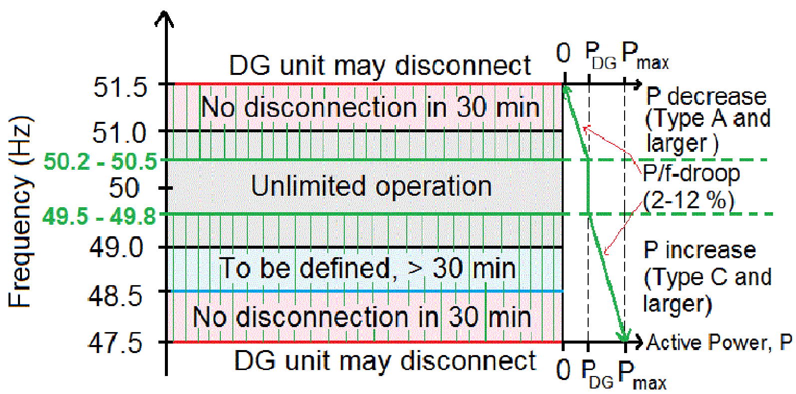


Figure 6-1. Frequency FRT (Nordic area) and support requirements for DER units (Type A and larger). [1], [2]

Frequency support – Active power control

In NC RfG [2] it is also stated that the DER unit (Type A and larger) shall be capable of reducing active power during over-frequencies (*P/f* -droop) starting from a point between 50.2 Hz and 50,5 Hz with a droop in a range of 2–12% (Fig. 1). In [3], similar requirements for the active power response of DER units to over-frequencies have been set as in [2]. The range of intentional delay is 0-2 seconds and the default setting is 0 s. [1]

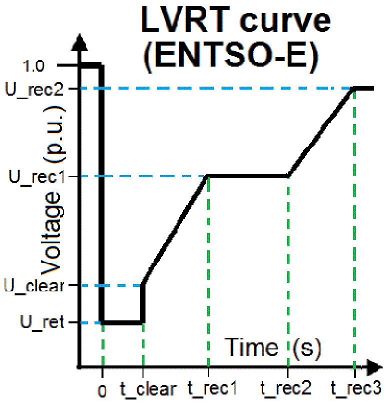
ROCOF/*df/dt*

In NC RfG [2], it is stated for DER units (Type A and larger) that, with regard to the ROCOF or *df/dt* withstanding capability, a DER unit shall be capable of staying connected to the network and operating at rates of change of frequency up to a value defined by the TSO. Possible ROCOF-based passive islanding detection should be coordinated with required ROCOF withstand capability [5], which may also be coordinated or prioritized with the voltage FRT curve. In [3], the required ROCOF withstand capability has been set up to 2,5 Hz/s. [1]

Voltage

In NC RfG [5] for Type B and larger DER units it has been stated that with regard to FRT capability of DER units, each TSO should define a voltage-against-time-profile (low-voltage-ride-through, LVRT, curve) as shown in Figure 6-2. [2], [1]

Voltage in [2] refers to the root-mean-square (rms) value of the positive sequence of the phase-to-phase voltages at fundamental frequency in per units (p.u.). [2]



DG unit TYPE B AND C			
Synchronous generators			
U_ret	0.05 - 0.3	t_clear	0.14 - 0.25
U_clear	0.7 - 0.9	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1- 0.7
U_rec2	0.85 - 0.9 & ≥U_clear	t_rec3	t_rec2- 1.5
Converter based DG			
U_ret	0.05 - 0.15	t_clear	0.14 - 0.25
U_clear	U_ret - 0.15	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1
U_rec2	0.85	t_rec3	1.5 - 3.0

DG unit TYPE D			
Synchronous generators			
U_ret	0	t_clear	0.14 - 0.25
U_clear	0.25	t_rec1	t_clear- 0.45
U_rec1	0.5 - 0.7	t_rec2	t_rec1- 0.7
U_rec2	0.85 - 0.9	t_rec3	t_rec2- 1.5

DG unit TYPE D			
Converter based DG			
U_ret	0	t_clear	0.14 - 0.25
U_clear	U_ret	t_rec1	t_clear
U_rec1	U_clear	t_rec2	t_rec1
U_rec2	0.85	t_rec3	1.5 - 3.0

Figure 6-2. Voltage FRT requirements for DG units (Type B and larger). [1], [2]

Reactive power exchange and control between distribution and transmission networks

In ENTSO-E NC for demand connection (DC) [8], it has been stated that all transmission connected distribution networks shall fulfill the requirements related to reactive power exchange and control. These include requirements like 1) the actual reactive power range specified by the DSO shall not be wider than 0,9 power factor of the larger of their maximum import capability, 2) DSOs shall have the capability at the connection point to not export reactive power (at nominal voltage) at an active power flow of less than 25% of the maximum import capability, and 3) TSO shall have the right to require DSOs to actively control the exchange of reactive power at the connection point as part of a wider common concept for the management of reactive power capabilities for the benefit of the entire network. [8], [1]

6.2.1.2 Active Network Management – Need for Protection Adaptation

To fulfil increasing energy efficiency and reliability requirements, active control and management of distribution networks, including control of DER, will be in key role in future Smart Grids.

For instance, ERDF is currently studying and testing a local voltage regulation system based on reactive power management for two DER plants. It sets a target value for the reactive power, that is determined from a reactive power/voltage characteristic $Q=f(U)$, and provides injection / absorption of reactive power to the production facility in certain situations (those where the network is constrained by low or high voltage). However, it should be noticed that active voltage and frequency control by the DER can sometimes delay the islanding detection. For that reason, the time response of these active regulations must be strongly studied before implementation. As for the local voltage regulation currently studied by ERDF, simulations and tests show that using a “dead band” in the $Q=f(U)$ characteristic and an average voltage measure allow not to delay the islanding detection.

A centralized voltage management is also currently tested in ERDF’s network on a pilot scheme where the substation is equipped to test several Advanced Network Functions. It consists of state estimators calculating optimized voltage target values at the primary substation. Such regulation systems could allow a decrease in the voltage rise in the network due to high production and avoid unintentional decoupling of production facilities.

Advanced automatic functions are also implemented in closed loop in ERDF control centers: Automatic Fault Detection, Isolation and network Recovery (FDIR) help the operator to efficiently handle faults on the network, minimize duration of outages and improve customers’ quality of service.

With active network management, the capacity utilization of lines can be improved, large voltage deviations can be avoided, system losses and interruptions can be minimized. Active network management requires more information (measurements) from different points in the distribution network (Figures 6-3 and 6-4) as well as utilization of fast and cost-efficient communication technologies and further development of standardization (IEC 61850 related standards). Real-time information about distribution network status (voltage, frequency etc.) is required for example during voltage and frequency deviations to create network supporting active and reactive power commands for DER units. Information about distribution network status for control and monitoring purposes will be obtained in the future increasingly from sensors across the network through high-speed wireless 4G networks and optical fibers. [9], [10]

Active network management may simultaneously affect the protection settings if for instance network topology is changed. On the other hand, e.g. due to earth-faults in some network location, topology may be changed and this may have an effect on active network management functionalities such as voltage control or loss minimization. Therefore, dependencies between active network management and protection functionalities require careful planning and development to create future-proof solutions for future Smart Grids. In future, it is likely that these different active network management functionalities like voltage control, island operation coordination, minimization of losses etc. will be realized through centralized solutions at HV/MV (MV level management by DMS/SCADA or grid automation controller or IED) and MV/LV (LV level management by IED, RTU or MicroSCADA) substations (Figure 6-3). Also an intelligent coordination hierarchy between management of MV and LV level active zones will be essential from a total concept point of view. Centralized monitoring (including proactive protection) and earth-fault locating as well as different events or measurement reporting functionalities are becoming more and more important from an asset management point of view (Figure 6-3). For example, with real-time cable temperature monitoring the network capacity utilization could be maximized without exceeding thermal limits. [9], [10]

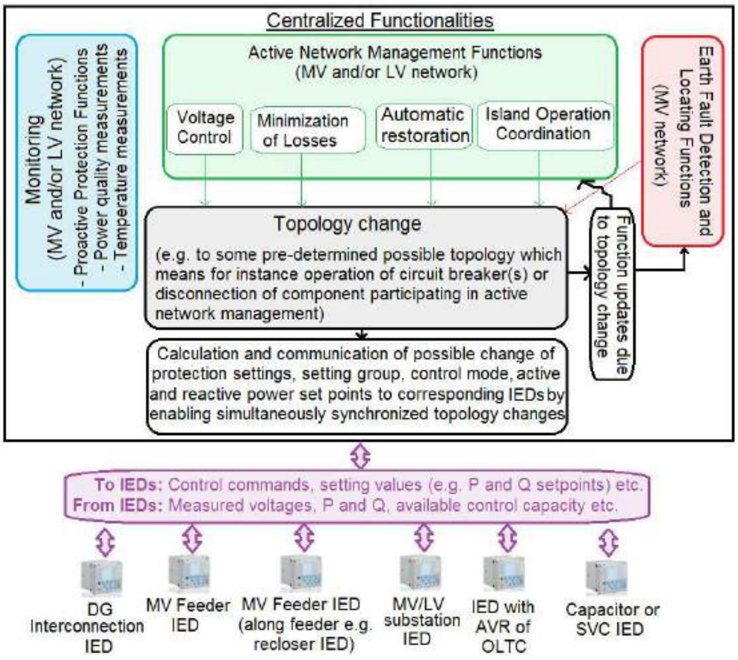


Figure 6-3. An example about some possible centralized functionalities at HV/MV and MV/LV substations. [9], [10]

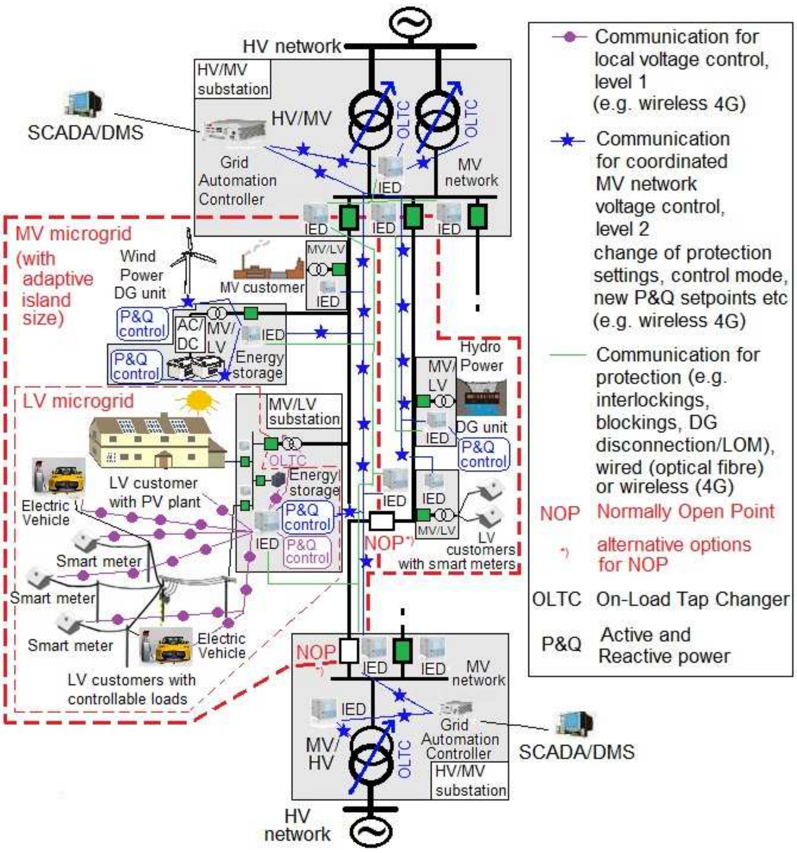


Figure 6-4. Smart Grid compatible IEDs with appropriate communication capabilities and new functionalities will play key role in enabling future active network management and protection concepts. [9], [10]

In the future, both short-circuit and earth-fault protection settings of MV feeder IEDs must adapt to the changes in the network topology resulting from increased utilization of active distribution network management schemes. From the MV feeder IEDs' short-circuit protection settings point of view, the most challenging issue is the change in the short-circuit level due to topology changes like for example

- large DER unit connected or disconnected,
- radial MV feeders or meshed MV feeders,
- utility grid connected or island operated

or due to automatic load restoration when the normally open point (NOP) in a meshed distribution feeder is automatically moved for load restoration purposes following a fault. To support improved supply reliability, to be able to deal with topology changes and disconnect faulted section very rapidly, distance and differential protection with high-speed communication based blocking schemes will be utilized increasingly in the short-circuit protection of future Smart Grids [11], [12]. In reality, the required future performance for transmitting blockings and voltage and current samples from sensors could be achieved by utilization of 61850 GOOSE and SV services and possibly with wireless 4G technologies. From MV feeder IEDs' earth-fault protection point of view, it is essential that their settings and protection principles can also adapt to changes in MV network earthing method e.g. when changing from centrally compensated utility grid connected operation to isolated island operation. [9], [10]

Adaptation of MV feeder IED protection settings can be done by changing pre-defined setting groups or by changing settings in real-time by central controller (e.g. grid automation controller). In the case of islanding protection adaption of MV feeder IEDs could also be based on local detection of CB status change or multi-criteria based islanding detection etc. On the other hand, if the size of the intended island could also be adaptive i.e. dependent on current power balance situation, then the MV feeder IED could also be "locally aware" of the transition possibility to island operation, in that point, and thereby activate those protection functions in IED which are needed for successful transition to island operation (e.g. high-speed operation in large voltage dips, fault current through IED or not, detection of healthy or faulty island). They could also be predefined as different setting groups which are activated centrally by grid automation controller when needed. Therefore, it needs to be defined as part of the proposed adaptive protection scheme how the logic related to it will be centralized or de-centralized. [9], [10]

6.2.1.3 Island Operation

During island operation, for example LV microgrid, high fault currents from the utility grid are not present. Also, most of the DER units that are connected to LV microgrids will likely be converter interfaced and have limited fault current feeding capabilities. Due to that, during microgrid island operation, conventional distribution system protection schemes which assume a single path for the fault current and a high fault current level when compared to the load current, could be less efficient and may have slower fault clearing time, be less sensitive as well as perform a less selective operation. This means that the system reliability is expected to decrease if the current protections are not adapted. [13] Therefore, traditional fuse based over-current protection with a single setting group will not be able to guarantee selective tripping for all type of faults that can occur. Due to that, the traditional protection of LV network will not be applicable for LV microgrids and therefore new adaptive protection system must be developed. However, the adaptive LV microgrid protection system must be economically feasible and therefore cannot be too complex [14]. [15]

Microgrid protection must respond to both utility grid and microgrid faults. During utility grid faults, protection isolates the microgrid from the utility grid as rapidly as necessary to protect the microgrid loads (Figure 6-5). For faults during island operation, the protection isolates the smallest possible section of the radial feeder to eliminate the fault. After isolation from the utility grid (Figure 6-5), local generators are the only fault current sources in the electric island and the fault current level depends on the types, sizes and locations of DER; but it is generally lower than the fault current from the utility grid. [16]

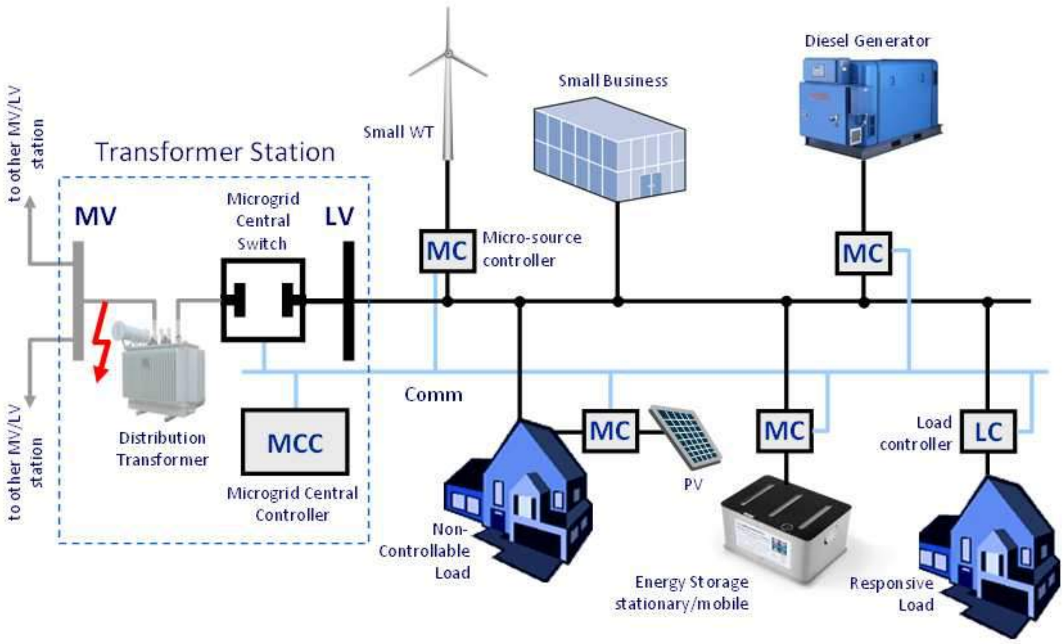


Figure 6-5. Microgrid protection isolates the microgrid from the utility grid as rapidly as necessary to protect the microgrid loads. [16]

In the development of the new protection scheme for microgrids, several issues must be considered, for example

- The number of protection zones in microgrid,
- Speed requirements for microgrid protection in different operational states and configurations and
- Protection principles for parallel and island operation of the microgrid. [15]

In addition, the developed protection scheme for microgrid must be supported by the technical choices made in the microgrid operation and control issues. Some of the key issues related to the LV microgrid protection are briefly reviewed based in [17] from which more detailed information can be found. The size and number of microgrid protection zones will define the needed amount of protective devices (PDs) for microgrid protection. The size of microgrid protection zone must be such that it fulfils the requirements of customers and at the same time is economically feasible. [15]

There are some fundamental structural choices that will determine the speed requirements and operation principles of LV microgrid protection and conversely these speed requirements will define certain structural choices needed to fulfill the speed requirements. There are two main reasons for speed requirements of LV microgrid protection: stability and customer sensitivity. Stability needs to be maintained after sudden changes i.e. after islanding due to fault in MV network during parallel operation with utility grid or after fault in LV microgrid during island operation. One essential issue related to operation principles of LV microgrid protection is control of converter based DER units during faults. It should be compatible with the proposed microgrid protection system. [15]

As stated by [18], the protection issues for microgrids cannot be properly resolved without a thorough understanding of microgrid dynamics before, during and after islanding. Specifically directly connected rotating machines are very sensitive to lose stability in voltage dips caused by faults in island operated microgrid and so they may jeopardize the stability of the whole microgrid. For that reason, if there are directly connected rotating machines connected, protection should operate in islanded microgrid rapidly for every kind of fault and e.g. if microgrid customers have fuses with high rated currents, there is a risk that customer protection may operate too slowly in island operation due to low fault currents, which in turn may cause instability in island operated microgrid after fault clearance. [15]

In cases where overcurrent based protection is utilized during island operation, protection and control functions of IEDs in microgrid may need real-time information about network topology, the status of DER units (on or off), state of charge of storage systems, and also number and size of loads connected to the microgrid. These conditions have to be updated and checked continuously in order to guarantee that protection settings are suitable for current configuration [14]. [15]

Based on the above and as mentioned in [18], the high-speed operation of the protection devices is very crucial for reliable operation of the microgrid protection system. Utilization of high-speed telecommunication is expected to be an essential part of future smart grid protection system to achieve fast and selective protection both in grid connected and islanded modes of operation. The same communication protocols and standards used in HV / MV network can be applied directly to the LV microgrids. However, due to the smaller scale of LV microgrid's, the costs of protection devices must also be lower than the cost of devices used in the HV/MV network. [15]

One important issue, which is required to enable stable transition from normal grid connected operation to island operation, is coordination of IED protection settings with DER unit FRT requirements (especially low-voltage-ride-through, LVRT). To prevent unnecessary tripping, faulty lines should be disconnected first by the protection system and only after that should the DER units be disconnected according to their FRT / LVRT profile. Fast operation of protection is required and emphasized if there are several protection zones. To achieve this communication based protection methods and schemes are often required to ensure selective operation [19]. Some further discussion about issues related to protection of microgrids can be also found in [13], [15], [20]-[24].

Neutral Earthing in MV microgrids

While protecting MV microgrids, issues related to earthing / neutral grounding method must also be considered. For example, from the MV feeder IEDs earth-fault protection perspective it is essential that their settings and protection principles can also adapt to changes in MV network earthing method e.g. when changing from centrally compensated utility grid connected operation to isolated island operation. [9], [10]

DER Unit Fault Behavior and Effect on Protection Scheme during Island Operation

It is also important to ensure that the behavior required from DER units, including fault-ride-through needs, during faults in microgrid is compatible with the developed LV microgrid protection system. In other words this means that when protection of island operated microgrid is designed one of the most important questions to be resolved is how converter based DER units will contribute to the fault current feeding. [15], [25]

Usually control mode change of one or more DER units connected to the distribution network is required after changing from normal to island operation. Traditionally this means that under normal operation DER unit is in active(P)/reactive(Q) power control and after islanding the control mode is change to voltage(U)/frequency(f) control (or voltage/speed control). However, control schemes which do not require changing after transition to / from island operation have also been proposed. For example in [24], an enhanced control strategy was proposed which improves the performance of a DER unit under network faults and transient disturbances, in a multi-unit microgrid setting. The proposed control strategy does not require the detection of the mode of operation and switching between different controllers (for grid-connected and islanded) modes, and it enables the adopted DER units to ride through network faults, irrespective of whether they take place within the host microgrid or impact the upstream grid. [24]

From the island operated LV microgrid protection point of view, it is essential to know how converter based DER units will contribute to the fault current. Grid codes and standards for smart grids with island operation capability are necessary for the development of future smart grids protection solutions to reduce complexity and to avoid the need for too many case specific alternatives. [15], [25]

6.2.2 Example Case of CIGRE / CIRED JWG – Protection Needed for Successful Transition to Intended Island Operation

In following, the same example case of this CIGRE/CIRED JWG presented in Chapter 5 (Figure 5-1) has been used to define the protection needs (functions, time selectivity) when intentional island operation and especially successful transition to island operation is considered.

From island operation perspective (in addition to grid code FRT requirements from DG units during normal grid connected operation) it is required that the wind farm (green) as well as DER ① and ② have sufficient FRT capabilities. Figure 6-6 shows possible intended islands and MV feeder short-circuit protection at CB1-CB4 (Figure 6-6) which is assumed to be directional like the earth-fault protection. In the following, the time selectivity issues (Figure 6-7) are discussed, with different fault scenarios (faults A-E in Figure 6-6), regarding successful transition to island operation.

In Figure 6-7 protection time selectivity issues, general time delay setting principles and the role of high-speed communication when a) islanding is not allowed and b) islanding is possible are shown. Figure 6-7 also illustrates the role of high-speed communication based interlockings/blockings (as well as transfer trip based islanding detection) in reliable and selective operation of future distribution networks with multiple consecutive protection zones and the possibility for intended island operation.

In Figures 6-6 and 6-7 the idea is that the possible operation principles of directional short-circuit protection in forward direction can be

1) Directional overcurrent protection with fixed time delay (and high-stage / low-stage settings)
2) Distance protection with fixed time delay (in forward direction)

Similarly in Figures 6-6 and 6-7 the possible operation principles of directional protection in reverse direction (for intentional islanding) can be

1) Undervoltage with fixed time delay (and high-stage / low-stage settings) AND current direction detection in reverse direction. Function pick-up/start is only based on undervoltage (i.e. not in overcurrent, because fault current levels of inverter-based DER units can be fairly low as discussed in previous chapters)
2) Distance protection with fixed time delay (in reverse direction)

From Figures 6-6 and 6-7 it can be seen that selectivity problems can be possible if communication based interlockings/blocking for example are NOT used (Figure 6-7a)), because coordination between LVRT curve of DER units (defined by grid codes) and required time differences between CB2 and CB3 in forward direction may be hard to be achieve. This naturally depends from the number of consecutive protection zones and the allowed time difference between operation time delays of CB2 and CB3.

Transition to intentional island operation IS only possible (Figure 6-7b)) if active and reactive power unbalance at CB1, CB2, CB3 or CB4 is small enough (or enough, rapidly controllable active and reactive power units exist in the possible island (1.-4.b in Figure 6-6). before protection start/operation of CB1-CB4 in reverse direction). If this is not the case transition to island operation should not be allowed. Here it is worth mentioning that the new grid codes (like forthcoming ENTSO-E Network Code RfG) enable / support transition to intentional island operation because of *P/f*-droop control requirements of DER units during overfrequency situations (underfrequency based load shedding schemes could have similar kind of effect) and possibly also due to voltage control (*Q*/*U*-control) requirements.

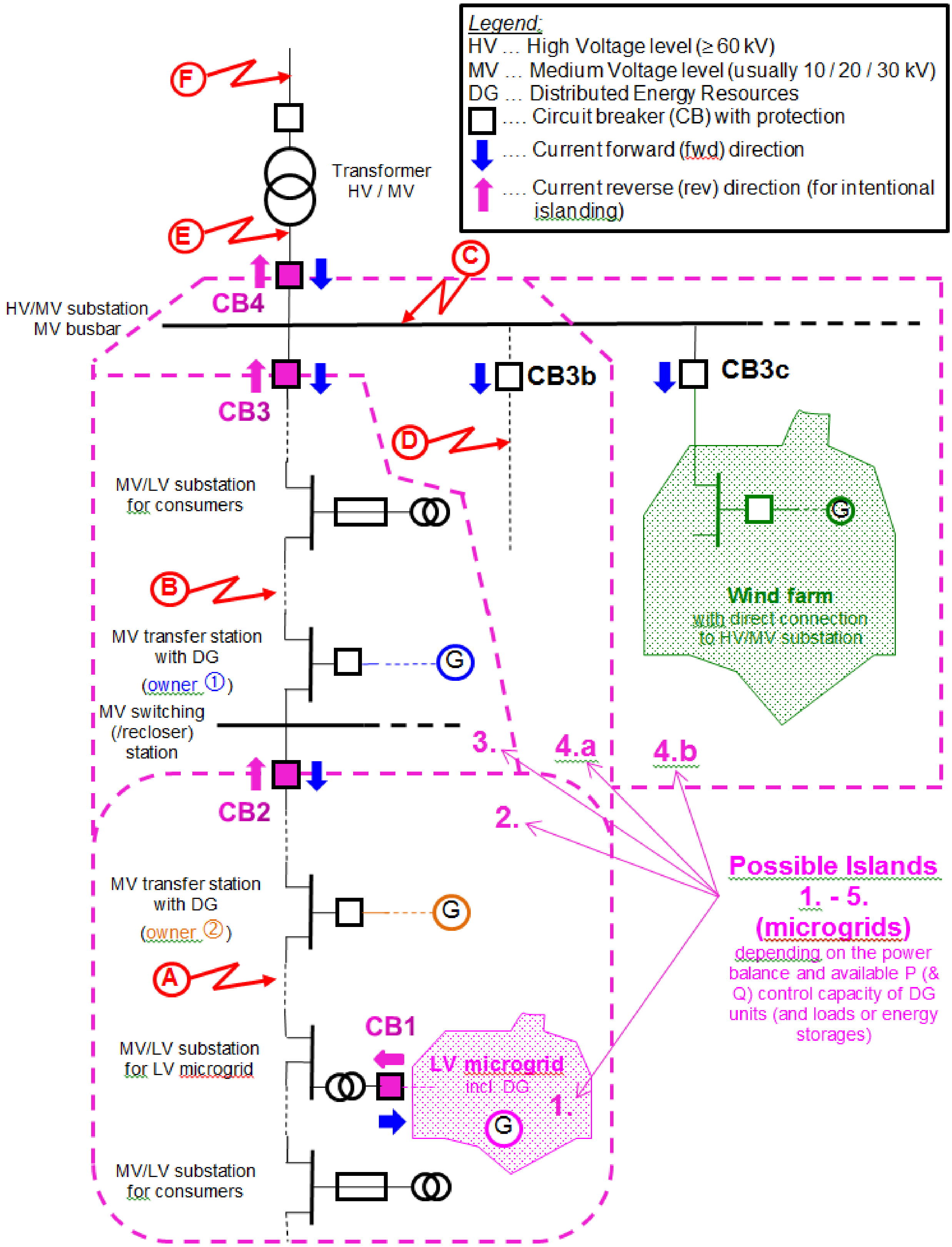


Figure 6-6. Possible intended islands 1.-4.b (see also Figure 6-7).

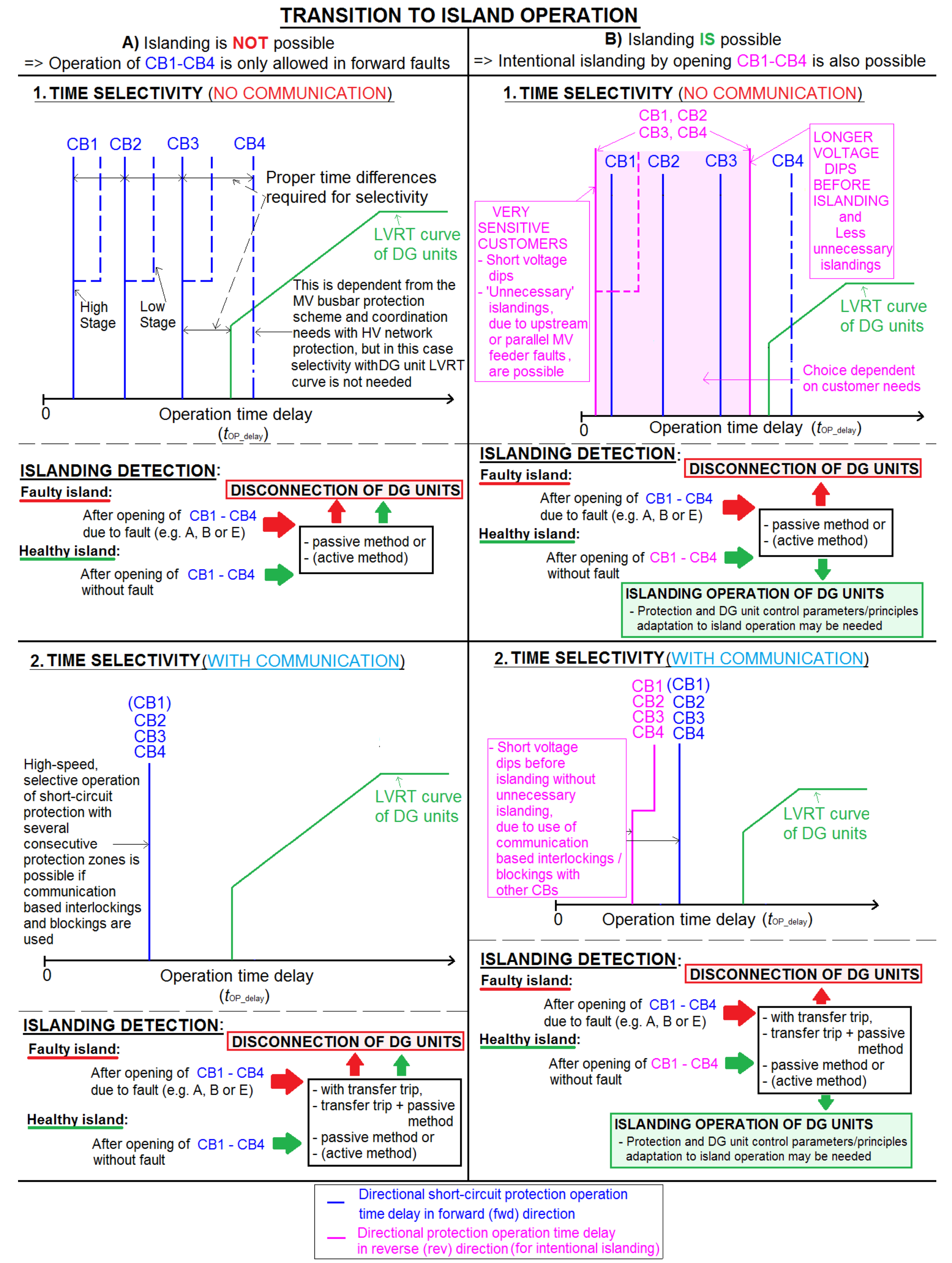


Figure 6-7. Protection time selectivity issues, setting principles and the role of high-speed communication when a) islanding is NOT allowed and b) islanding IS possible (see also Figure 6-6).

In the above discussion and in Figure 6-7, only short-circuit protection has been considered, but naturally also earth-fault protection principles and settings have to be proper during both normal and island operation. Therefore it should be noted here that after opening CB 2, CB 3 or CB 4, the MV network neutral earthing method may change e.g. from compensated to isolated and MV feeder IEDs earth-fault protection settings and protection principles also needs to adapt to these changes.

In the following, the protection operation principles during different faults A-E in the example network shown in Figure 6-6 are described. It is also assumed that high-speed communication is assumed to be available/possible and islanding IS possible (Figure 6-7b) 2. Time selectivity (with communication) if power generation / consumption are close to each other behind the possible island connection point CB.

In case of fault A in Figure 6-6 (see also Figure 6-7):

- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - o If active and reactive power unbalance at CB1 is small enough (i.e. stable transition to island operation is possible) as stated above
    - o CB1 could also sent signal to LV microgrid DER units to change their control mode etc. after operation
- CB 2 will operate in forward direction
    - o CB 2 sends simultaneously interlocking signal to CB 3 (and CB4) to prevent their false operation and
    - o CB2 can also send communication based transfer trip (faulty island) disconnection signal to DER unit ②

Wind farm and DER unit ① will remain connected according to LVRT curve of DER units (Figure 6-7).

In case of fault B in Figure 6-6 (see also Figure 6-7):

- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - o If active and reactive power unbalance at CB1 is small enough
    - o CB1 could also sent signal to LV microgrid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - o If active and reactive power unbalance at CB2 is small enough
    - o CB2 could also sent signal to DER unit ② to change control mode etc. after operation
- CB 3 will operate in forward direction
    - o CB 3 sends simultaneously interlocking signal to CB 4 to prevent false operation and
    - o CB3 can also send communication based transfer trip (faulty island) disconnection signal to DER unit ①

Wind farm will remain connected according to LVRT curve (Figure 6-7).

In case of fault C in Figure 6-6 (see also Figure 6-7):

- MV busbar fault
- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - o If active and reactive power unbalance at CB1 is small enough

    - CB1 could also sent signal to LV microgrid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - If active and reactive power unbalance at CB2 is small enough
    - CB2 could also sent signal to DER unit ② to change control mode etc. after operation
- CB3 may also operate in reverse direction and disconnect either part of the MV feeder (beginning of the feeder, 3. in Figure 6-6) OR whole MV feeder (2.&3. in Figure 6-6) to island operation
    - Depending on the active and reactive power unbalance at CB3 and CB2
    - Co-ordination with islanding of part of MV feeder by opening CB2 may be beneficial/required
    - CB3 could also sent signal to DER unit ① (AND/OR DER unit ② depending on the power balance situation) to change control mode etc. or to disconnect
- CB 4 will operate in forward direction

Wind farm will be disconnected according to LVRT curve (Figure 6-7). Also directional short-circuit protection in reverse direction could be included in CB 3c in order to disconnect the wind farm more rapidly in case of busbar faults like fault C (Figure 6-6). However, in case of upstream faults (like fault E and F in Figure 6-6) this reverse direction protection at CB 3c should be blocked by communication to enable fault-ride-trough support from wind farm according to grid codes (e.g. LVRT curve).

<u>In case of fault D in Figure 6-6 (see also Figure 6-7):</u>

- Parallel MV feeder fault
- CB3b will operate in forward direction (Figure 6-6) and simultaneously send interlocking signal to other CBs (e.g.) to avoid unnecessary islandings and to ensure selectivity

DER units ① and ② as well as wind farm will remain connected according to LVRT curve (Figure 6-7).

<u>In case of fault E in Figure 6-6 (see also Figure 6-7):</u>

- HV/MV transformer fault => intentional islanding can take place
    - Possible indication about intentional islanding possibility from HV/MV transformer protection IED to MV feeder IEDs
- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - If active and reactive power unbalance at CB1 is small enough
    - CB1 could also sent signal to LV microgrid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - If active and reactive power unbalance at CB2 is small enough
    - CB2 could also sent signal to DER unit ② to change control mode etc.
- CB3 may also operate in reverse direction and disconnect either part of the MV feeder (beginning of the feeder, 3. in Figure 6-6) OR whole MV feeder (2.&3. in Figure 6-6) to island operation
    - Depending on the active and reactive power unbalance at CB3 and CB2
    - Co-ordination with islanding of part of MV feeder by opening CB2 may be beneficial/required
    - CB3 could also sent signal to DG unit ① (AND/OR DER unit ② depending on the power balance situation) to change control mode etc. or to disconnect

- Alternatively CB4 may also operate in reverse direction and disconnect
  1) All MV feeders (4.b in Figure 6-6) to island operation
  2) Some of the MV feeders (e.g. (4.a in Figure 6-6)) to island operation
     - Simultaneously disconnection signal from CB4 is sent to MV feeder CBs (e.g. (CB3c in Figure 6-6)) which cannot be included into int. island
     - Wind farm remains connected according to LVRT curve (Figure 6-7) unless disconnection signal to CB3c (Figure 6-6) is sent by CB4
  - This intentional island scheme is a bit more complex due to increased number of possible island sizes
  - Size of the island depends on the active and reactive power unbalance at CB4, CB3 and CB2 and
     - Needs (central) co-ordination with islanding of part of or whole MV feeder by opening CB3 or CB2
     - Signals to DER unit ① and ② to change control mode etc. after operation or to disconnect will be sent based on the planned island size (which depends from the power balance situation before fault C)

In case of fault F in Figure 6-6 (see also Figure 6-7):

- HV network fault => intentional islanding should not take place, MV and LV network connected DER units should ride-through HV network faults and possibly also support HV network according to grid code requirements (for example by reactive power injection)
  - Possible indication about HV network fault could be sent from HV/MV transformer protection IED to MV feeder IEDs to indicate that in this case intentional islanding is not possible/allowed
     - Instead FRT and HV network support of DER units is preferred
  - However, if very sensitive customers (sensitive to voltage dips) are connected to MV or LV network then similar actions could take place as described above for fault

6.2.3 Protection Schemes for Intentional Island Operation

Several solutions have been proposed for the protection of intentional island operated microgrids in current literature. Some of the solutions are discussed in the following sections.

6.2.3.1 Directional Overcurrent or Symmetrical Components based Schemes

Directional overcurrent protection can be used to protect the distribution system with bidirectional current flow. One problem with the overcurrent protection is that faults closer to the source might take a longer time to clear. However, this problem can be overcome with the modern microprocessor-based devices, by having shorter coordination margin, and instantaneous over-current protection. Still, there could be protection co-ordination issues because of changing fault current due to DER or change in network configuration. An advance solution could be adaptive directional over-current protection based on the status of the generators and networks' topology.

Adaptive Directional Overcurrent Protection

In adaptive protection, relays still carry out the protection function using local measurements. However, their settings are updated locally or remotely via communication links. Apart from the additional voltage transformer (VT) and microprocessor based relays, this scheme may also require a central controller and a communication link to the relays; but this communication doesn't need to be very fast nor very reliable.

In the solution of [26], relays detect the islanding condition themselves and reconfigure their neighbors if they detect a topology change [13]. Paper [26] proposes the use of adaptive protection, using local information, to overcome the challenges of the overcurrent protection in distribution systems with distributed generation. The trip characteristics of the relays are updated by detecting operating states (grid connected or island) and the faulted section. The paper also proposes faulted section detection using time overcurrent characteristics of the protective relays. [26]

The adaptive feature was also proposed in [14] for the protection of microgrids; where directional overcurrent relays are reconfigured by a remote central unit in case of grid separation (islanding) or grid reconnection to consider for the change of short-circuit level. The central unit is constantly aware of the network topology and the connected generators. [13]

Paper [27] has also presented an adaptive protection scheme for distribution networks that include large number of DER and are able to dynamically change configuration. Based on the real-time analysis of the current state of the distribution system, it adjusts the active setting groups of the field protection devices according to the changes in the network topology. A centralized controller installed at the substation with IEC 61850 based communications is used for data integration from the medium voltage feeder and DER IEDs and performs the control function. The decision to modify the settings is made based on the logic programmed into this controller (substation computer or RTU) with IEC 61131-3 compatible programming languages. [27]

The adaptive protection scheme presented in paper [27] together with microgrid control system has also been developed and adapted for a real demonstration at Hailuoto island in Finland. [28]

As a result of the different proposals, it has been concluded in [29] that the main challenges with regard to a possible implementation of an adaptive protection system may be:

- The need for communication infrastructure
- The need for prior knowledge of all possible microgrid configurations
- The possible necessity to update or upgrade many protection devices (fuses, etc.) that are currently used in the existing power system (especially on LV network)

Current Symmetrical Components

Protection scheme proposals based on current symmetrical components try to enhance the performance of traditional overcurrent protection [29].

For example, in [30], a possible solution for fault detection in islanded microgrids based on current symmetrical components has been presented. It proposes to use zero-sequence current detection in the event of an upstream phase-to-earth fault (coordinated with unbalanced loads) and negative sequence current for phase-to-phase faults. [29]

In [31], a pilot instantaneous overcurrent protection scheme has been briefly described, based on two routines, which can perform instantaneous protection for local line and remote bus-bar, regardless of the DER location. In [32], a communication assisted protection selectivity strategy with three structural levels has been proposed, to be applied with voltage-restrained directional overcurrent protection [29].

Paper [33] has proposed a strategy for protection in LV microgrids based on microprocessor-based overcurrent relays and directional elements, which is stated to be adequate for both modes of operation (grid-connected and islanded) and it should not require communications and it is independent of the fault current magnitude. [29]

6.2.3.2 Distance Protection

Distance protection uses admittance or impedance measurements in order to detect the fault and trip adequately. In reference [34], it has been stated that distance protection seems to be a potential protection scheme for island operated MV networks. On the other hand, papers [35] and [36] as well as reference [37] have proposed using an admittance relay with inverse time tripping characteristics (Inverse Time Admittance, ITA), capable of detecting faults in both grid-connected and islanded operation modes. Apart from adding inverse time characteristics to each zone of protection, it also has the ability to isolate the faults occurring at either side of the protected circuit, since it can also operate for reverse faults. However, the reach settings should be different for forward and reverse faults. [29], [34]

In paper [19], comparison between directional overcurrent and distance protection has been simulated considering 3-phase short-circuit faults only. The simulations showed that distance protection is able to selectively distinguish between faults in the MV and LV networks. Further, based on the simulations and the analysis, it was stated that overcurrent protection cannot be used if fault current levels within the island are close to the maximum load current. Therefore, distance protection may be suitable to be used in island operation. However, when the scope is expanded to cover also two phase and possibly also earth faults the viability of distance protection must be further studied [19]

6.2.3.3 Voltage based Protection Schemes

Due to lack of high fault currents, it has been proposed by [38] and [39] that voltages could be used for protection of an islanded microgrid. For example paper [39] proposed a method which was based on a voltage measurement comparison: the location where the lowest voltage level is measured is tripped [13]. However, it is difficult to realize selective microgrid protection during island operation with voltage or current relays alone [40]. [15]

In [41] the same authors as in [39] also proposed to utilize the total harmonic distortion (THD) of voltage to improve the protection system in microgrids with inverter-interfaced DER units, for ground faults. After identifying the type of fault by monitoring the variation of the fundamental frequency (50 Hz), the voltage THD of different feeder relays was analyzed in order to determine the faulted zone. [29]

In order to avoid the difficulty of the previous methods associated with detecting the oscillation waveform of the voltage variation, instead of using the voltage magnitude, [42] propose to use only voltage positive sequence. In [43], it has been claimed that a distinction among the three fault types can be made only considering the positive/direct and negative/inverse sequence voltage components, without using the zero sequence / homopolar information. Reference [44] proposed a very similar approach by determining the fault occurrence and the fault zone, based on a busbar voltage measurement and its subsequent transformation from abc coordinates to dq coordinates. [29]

In [45], the reduction in system voltage has been also used to implement the under-voltage back-up protection scheme for current differential protection.

Main problems with voltage-based methodologies during island operation, based on [29], are:

- Minor differences in voltage drop among the relays located at both ends of short lines lead to protection operation failures, due to reduction of the voltage gradient
- Problems with practical application of some of these methodologies, as well as with possibly needed communication infrastructure, when high number of DER units are present
- Methods may be strongly dependent on the network architecture and on the definition of “protection zone” for the relay associated with each generator
- Problems in detection of high impedance faults.

6.2.3.4 Current Differential

In [45], it was stated that the current differential protection was chosen for the microgrid (Figure 6-8). It is not sensitive to bi-directional power flow, changing fault current level and the number of DER connections. It was also stated that current differential protection provides the required protection for both grid connected and islanded modes of operation and the protection is not affected by a weak infeed where it can detect internal faults even without having any DER connected [45].

The use of differential protection for microgrids with low fault current level has been suggested also in [23], [46], [47], [48] and [49] to protect inverter-dominated microgrids. However, differential protection might be expensive since protective devices must be placed on every line segment of the network. Therefore [49] proposes to form protection zones consisting of several line segments [13].

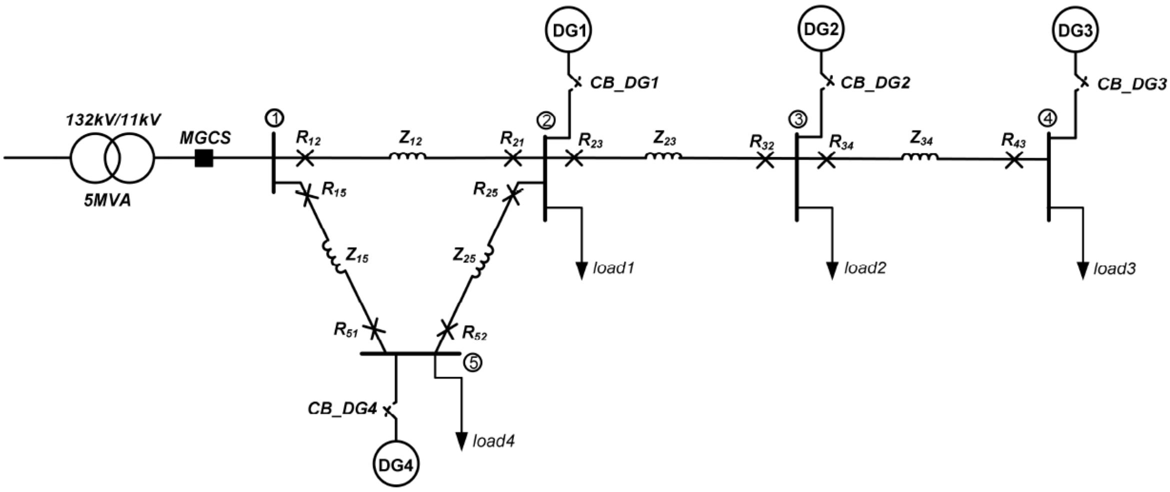


Figure 6-8. Schematic diagram of the microgrid from [45]

In addition, here it is worth mentioning that the topology of the sample network i.e. schematic diagram in [45] (Figure 6-8) is chosen to be very well suited for differential protection also during island operation. In general, current differential protection is not very well suitable for protection of islanded part of distribution network having radial topology and many protection zones (i.e. for protection of ‘last’ protection zones with open end / CB).

6.2.3.5 Protection Schemes based on Combination of both Voltage and Directional Overcurrent Functions

In [43], a microgrid protection strategy based on voltage and current measurements was proposed in addition to a voltage based protection scheme. Also in [50] as well as in [51], the use of voltage measurement based fault detection has been considered and a potential solution for small micro-grids is presented in the form of voltage controlled overcurrent devices to enable the use of lower current threshold settings.

In addition, in references [15], [17], [20], [21] and [34] microgrid protection schemes based on use of both voltage and directional overcurrent are analyzed. However, these schemes are based on utilization of high-speed communication for interlocking / blocking purposes to ensure selective operation of protection during island operation. In the following these proposed schemes for LV and MV microgrids are presented.

LV microgrids

Different kind of protection methods and principles for microgrids has been proposed. One problem in some of the proposed solutions for LV microgrid protection is that their applicability is limited to microgrids with only converter connected DG units. Therefore, these solutions may overlook others e.g. requirements on operational speed of protection to maintain stability of LV microgrid with directly connected rotating machines after fault clearance.

According to [15] key fundamental properties required from the future LV microgrid protection systems include,

i) Adaptivity,
ii) Utilization of fast standard based communication (IEC 61850),
iii) Fast operation in deep voltage dips due to faults to maintain stability in healthy part of LV microgrid,
iv) Fast operation to fulfill needs of very sensitive customers,
v) Selective operation in every kind of faults and
vi) Unnecessary operation of PDs and disconnection of DER units must be avoided.

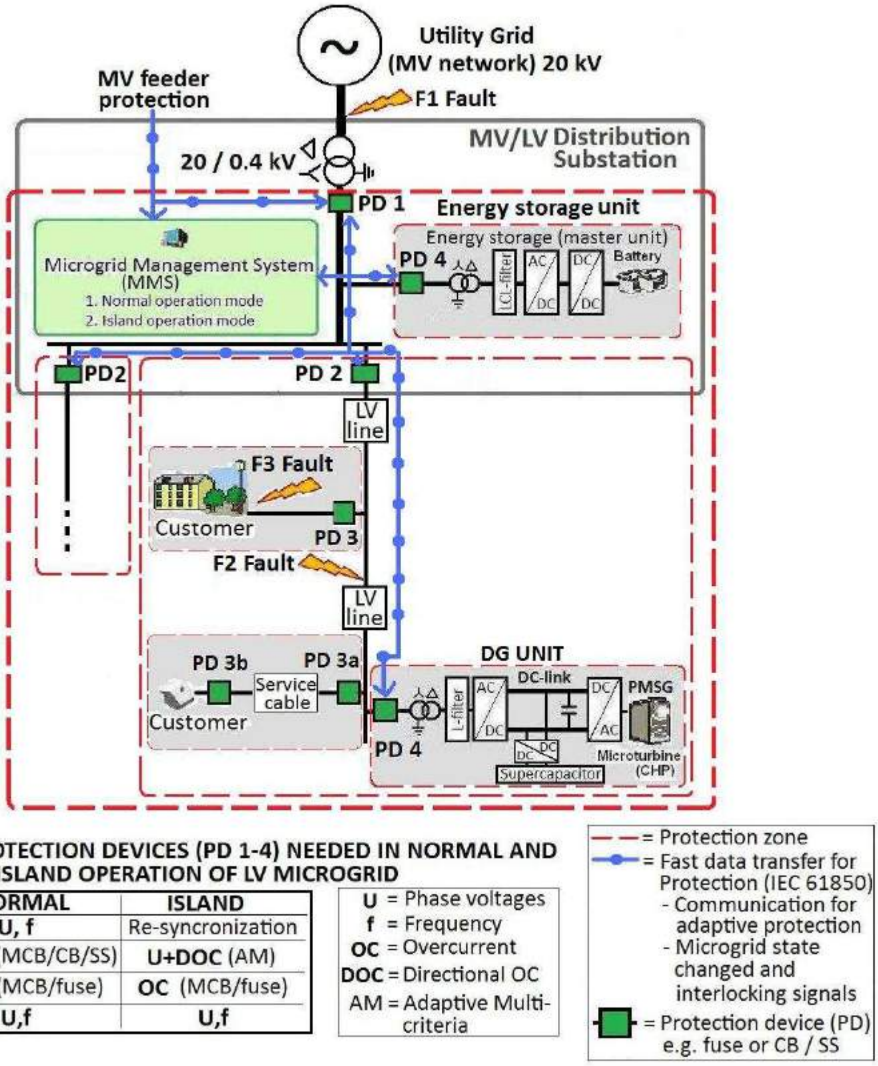
In the following, two different proposed protection schemes for LV microgrids based on utilization of both voltage and current (with direction detection) are shortly presented and more details can be found from the references. The main difference of the proposed protection schemes is that the first one (Proposed Scheme 1) relies on extensive use of high-speed communication and the other (Proposed Scheme 2) is not based on use of communication.

Proposed Scheme 1

In references [15], [17], [20] and [21] the following scheme for protection of LV microgrids has been proposed.

The main structural choices of the proposed LV microgrid protection system are summarized in Figure 6-9. In Figure 6-9, type of protection devices (PD 1-4) chosen are presented. Here it should be mentioned that when measurements from active and reactive power flow between utility grid and LV microgrid are needed during normal operation, also current measurements needs to be included in PD 1 (Figure 6-9). However, from the proposed protection system point of view the current measurements at PD 1 were not necessarily needed. Properties of the examined LV microgrid e.g. type, number and location of fault current feeding

DER units made it difficult to realize selective protection for PD 2s during island operation which is only based on current or voltage relays. Therefore, protection algorithm of PD 2s during island operation of LV microgrid was chosen to be multi-criteria based where both voltage and current measurements has been utilized (Figure 6-9). In addition, the protection algorithm of PD 2s should be able to adapt to the current network configuration as well as to the states of the DER units during island operation (Figure 6-9). In practice a microgrid management system (MMS) could be used to change settings and pick up limits of protection devices (PD 2s) when microgrid configuration changes.



TYPE OF PROTECTION DEVICES (PD 1-4) NEEDED IN NORMAL AND ISLAND OPERATION OF LV MICROGRID

	NORMAL	ISLAND
PD 1	U, f	Re-syncronization
PD 2	DOC (MCB/CB/SS)	U+DOC (AM)
PD 3	OC (MCB/fuse)	OC (MCB/fuse)
PD 4	U,f	U,f

Figure 6-9. Number of protection zones and type of protection devices (PD 1-4) needed in normal and island operation of LV microgrid. [15], [17], [20] and [21]

After LV microgrid transition from normal to island operation, MMS will send state changed signal from normal to island operation to different PDs of the microgrid to adapt to the changed microgrid configuration (Figure 6-9). PD 1 is changed to be ready for future synchronized re-connection back to utility grid and the re-synchronization requires that phase voltages are measured from both sides of PD 1. Protection settings of PD 2s are changed to the ones needed in island operation. To avoid malfunction of PD 2s, the protection settings of PD 2s are not changed from normal to island operation settings before all possible transients and oscillations in voltages, currents and frequency are stabilized after transition to island operation. MMS will also send state changed from island to normal operation signals to PD 2s and PD 4s after successful re-connection back to utility grid (Figure 6-9).

Role of MMS is also important in power balance management of island operated microgrid e.g. after fault F2 at LV feeder, MMS must immediately send, after operation of LV feeder protection (PD 2), new set point values for those DER units that are still connected at the healthy part of the microgrid or disconnection signal to some less critical customer loads.

During islanded operation of a microgrid, possible oscillations due to sudden changes in the microgrid configuration need to be taken into account for the protection concept to achieve selective protection and to avoid unnecessary tripping of protection. This could be done by using communication based interlocking signals.

Fast real-time communication is needed for microgrid protection purposes between protection devices (PD 1 and 2) and also with master unit and DER units during microgrid island operation. In addition MMS needs to be able to communicate in real-time with all these microgrid components as well as with customer loads. Communication should be based on common standard like IEC 61850. Active microgrid components in the PCC of microgrid (PD 1, master unit and MMS) are also responsible for synchronized re-connection of the microgrid back to utility grid (Figure 6-9).

More information for example about the functions needed for LV microgrid protection in the proposed scheme as well as details about the operation curves of PDs in the proposed LV microgrid protection system during normal and island operation can be found from [15], [17].

Proposed Scheme 2

In [24] and [52], strategies for the coordination of protective devices, in typical radial distribution networks with DER, were proposed. Expanding on the idea presented in [24], in [33] and [52] protection strategies based on microprocessor based relays for low-voltage microgrids has been proposed. One of the salient features of this protection scheme is that it does not require communications or adaptive protective devices. In addition, it is stated in [33] that the proposed scheme is to a large extent independent of the fault current magnitude, the microgrid operational mode, and the type and size of the DER, subject to the modified relay setting for the grid-connected mode of operation. [24]

MV microgrids

In [24] and [53], communication-assisted protection strategies have been proposed, which should be implementable by commercially available microprocessor-based relays, for protection of inverter-based medium-voltage microgrids. Proposed scheme also includes a backup protection strategy to manage communication network failures. In [24] it is also stated that the proposed protection strategy is independent of the fault current levels; type, size, and location of the DERs; and the operational mode of the microgrid. [24]

6.2.3.6 Protection of Meshed Microgrids

In [54], another protection strategy has been considered to provide the appropriate protection for meshed microgrids. An inverse time admittance relay is presented to detect and isolate faults in both grid connected and islanded operation of a meshed microgrid. These relays do not require any communication overlay in the microgrid. Moreover, current differential protection scheme is proposed for a meshed microgrid using communication channels. It has been shown that the current differential protection can provide selectivity and high level of sensitivity for internal faults while discriminating from the external faults effectively. The speed of the communication and the data synchronization between the local and remote relay are very important in current differential applications. However, with the use of modern digital communication systems, a reliable and a secure protection scheme can be provided for a meshed microgrid. [54]

6.2.4 Protection During Island Operation - Options

Based on above

- Selectivity with LV network faults must be ensured during MV network island operation and therefore (in addition to selection of pick-up limit different from high load current) traditional directional overcurrent based schemes are more difficult to apply during island operation with more than one / multiple protection zones in the island operated MV network
- Probably the most suitable protection schemes during island operation, especially with inverter-based DER units having low short-circuit current contribution, are impedance/admittance based schemes or schemes based on both voltage and current (directional)

7 Summary and outlook

Penetration of DER in utilities around the world has steadily increased and is expected to increase further. Existing distribution systems have generally been designed for unidirectional power flow, and feeders are opened and locked out for any fault within. However, this practice may lead to loss of significant generation in the future where each feeder in the system may have significant DER penetration. Also, utilities have started looking into islanding operation of distribution systems with DER as a way to improve the reliability of the power supply. However, the difference between short circuit levels when the distribution system is connected to the grid and while it is islanded, can be substantial. This may result in malfunction of the overcurrent protection or other protection schemes. In addition, the plug and play DER will continuously change the short circuit level and may also have an impact on the protection schemes. Furthermore, the short circuit power contribution varies with DER technology. Wind turbines contribute less current when their internal protection (crowbar protection) is activated and power electronic interfaced DER do not contribute as much fault current as conventional synchronous generation.

CIGRE TB421 “The impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation”, established by WG B5.34 served as entry document for the work on this report. The joint working group aligned content and scope, the network structures to be considered, possible islanding, standardized communication and adaptive protection, interface protection, connection schemes and protection concepts and future trends accordingly, even if the scope was quite different (distribution networks instead of transmission networks in WG B5.34).

There are some differences in protection relevant characteristics of DER compared to “conventional” energy resources and the possible impact on current and future protection schemes.

Generally, the short circuit current contribution of distributed energy resources differs from “conventional” energy resources in three ways: First, the location of DER is different, i.e. distributed rather than central. Short circuit contribution of DER comes from directions not necessarily considered in conventional protection schemes. Second, many DER are not synchronous or asynchronous machines directly connected to the grid, but coupled via inverters. The magnitude of the short circuit current of these inverters is usually limited to values not much higher than the nominal current to protect the inverter itself. Accordingly, the short circuit capacity of grids dominated by inverter short circuit current sources is significantly lower than from rotating machines. Third, this lower short circuit contribution is also connected to a different time characteristic of the short circuit current. While rotating machines behave like a voltage source under short circuit conditions, inverters act more like a current source limited to nominal current, and the time characteristic of the current determined by the control scheme of the inverter.

Additionally, the capability to operate during and after faults in the system has been less of a requirement for DG – to the contrary, it was and is often required from DER to disconnect under faulty grid conditions so that the well-established protection schemes can be maintained. However, with a growing number of DER and an increasing importance of DER to provide short circuit capacity both during and after the fault, the FRT capability is of major concern, and fault contribution of DER may not be neglected any more.

There are various similarities and differences of the current practices of distribution system protection. This report focused on the main reasons for disparities (e.g. network structure, national legislation or neutral treatment) and typical protection function for busbar, feeder or DER protection. Moreover an overview of the individual protection function of different countries is given in a tabular listing.

Relay protection of DER today is based on standard non-directional over-current protection in most countries. Under-voltage and/or under/over frequency protection is used to decouple DER in case of feeder faults. Directional over-current relays are sometimes used for phase-faults, but are mainly used for ground faults.

The over-current protections schemes of the feeders with DER have starting currents in the range 1,2- 1,67 of rated feeder currents. Coordination times of 0,3 seconds are typical. Distance protection (with over-current start) is used in Germany, Spain and Austria, and recommended in Norway. Directional over-current relays are used in Denmark and Romania as alternative solutions.

The DER decoupling protection is primarily composed of under/over voltage and under/over frequency relays. The settings vary significantly and depend also on the DER ratings and fault-ride-through requirements. Instantaneous under-voltage protection (U/t<<) in the range of 0,2-0,8 pu referred to the voltage at the point of common coupling is reported.

The principle structure of the “distribution system” which is covered by this working group has been defined as follows: private grids are connected in different ways to a typical medium voltage outgoing feeder of a substation for public supply.

By means of this defined structure the current practice in case of a fault is discussed. The interaction between overcurrent/time-protection and the decoupling protection (consisting of over-/under-voltage and over-/under-frequency-protection) is shown for different fault locations.

An important question is the source of the short circuit current in such structures: it can be assumed that its main part, which is able to start the protection devices, is coming from the grid. Depending on the contribution of the short circuit current of the DER it can be possible that a micro grid with DER will disconnect selectively because of the overcurrent/time-protection. However, in any case it is common usage that the disconnection of DER will appear by means of the decoupling protection.

One further aspect is the neutral treatment of the grid. Under normal operation the grid works with its designated neutral treatment. Depending of the fault location it can happen that remaining parts of the grid will lose their original neutral treatment. In these cases it is necessary to adapt the setting of the protection devices according to the “new” neutral treatment. In other words: the borders of the remaining grid are determined because of its neutral treatment.

One of the most important changes caused by the massive integration of DER into the Distribution network is the bi-directionality of fault current (if existing sufficiently). This implies the need to develop more complex protection schemes on the Distribution Network, able to deal with the different fault current situations.

The high penetration of DER is also changing the design paradigm of the Medium Voltage networks. Initially the direction of the active power was from the high to the low voltage level, but due to the increasing generation connected to the medium voltage (low voltage) network, this assumption is no longer true.

New issues are arising concerning the new scenarios. One of them is that of “unintentional islanding”. “Unintentional (or uncontrolled) islanding” happens when a portion of the distribution network with a relevant DER is disconnected from the rest of the network. In such case, voltage problems arise and frequency is no more synchronous with the frequency in the transmission network.

Depending on the power flow conditions, there are two different levels for the uncontrolled islanding: the first level is at the MV feeder level, the second level is at the HV/MV substation level.

Different approaches are possible in order to detect a non-controlled islanding. To avoid the unintentional islanding the protection system must operate very quickly by disconnecting the generators in a time shorter than the time of the first automatic reclosure.

Each country has defined a set of rules in order to achieve an adequate level of safety and reliability of the power system. In general the system must provide protections that avoid unwanted islands by disconnecting the generation units connected to the network portion of an island as quickly as possible.

Up to now, there is no islanding detection system, especially for low voltage networks, which is recognized as really efficient and used by all the countries. There are passive and active techniques to detect an unintentional island; furthermore a communication network can be used if present.

Future European Grid Codes can have huge impacts on protection schemes, in particular: enlargement of the frequency range, ability to provide static power regulation depending on the frequency, definition of specific Fault Ride Through requirements for different kinds of generation and fast reactive current injection during fault.

The new communication technologies are providing new opportunities for the development of the Smart Grids. Two technologies are being considered: wired technologies and radio technologies.

With the assumption that, in case of islanding, the protection system has to act in the minimum possible time, the appropriate technologies to use on MV networks are Fiber Optic (currently field tested in France), Copper Pair, VHF/UHF radio (cheap and simple solution for installation close to the substation) and Public Data service. For LV networks, PLC technology (currently field tested in Italy and also used in Spain), Wifi (if the system is cyber secured) and Public Data service seem to be the most appropriate technologies. However, it is highly required to use reliable communication media for protection.

Concerning Substation Automation Systems, more and more protection equipment is compatible with the new protocol IEC 61850. For instance, both feeder protection and transformer protection are sometimes used by ERDF with IEC 61850 protocol, via gateways connecting each to the supervising network of the substation.

Future distribution network protection, both in MV and LV networks, will meet increasing amount of challenges due to new grid code requirements, active network management schemes and intended island operation.

The trend in new grid codes is to require FRT capability from DER units and possibly also allow island operation. Therefore, reliable islanding detection will be increasingly important in the future, to be able to make the correct decisions, like for example change the setting group of IEDs or change the control principles and parameters of DER unit.

Active network management may simultaneously affect the protection settings if for instance network topology is changed and protection adaptation may be required. On the other hand, e.g. due to earth-fault in some network location, topology may be changed and it may have an effect on active network management functionalities such as voltage control or loss minimization. Therefore, dependencies between active network management and protection functionalities require careful planning and development to create future-proof solutions for future Smart Grids.

During intended island operation high fault currents from the utility grid are not present. Besides, most of the DER units connected to microgrids will be converter interfaced and have limited fault current feeding capabilities. Due to that, during intended island operation, conventional distribution network protection schemes cannot guarantee correct operation of protection in terms of detection time, sensitivity and selectivity.

It is also important to ensure that the behavior required from DER units during faults in island operated microgrid is compatible with the applied microgrid protection scheme. From the protection scheme perspective, it is essential to know how the converter based DER units will contribute to the fault current.

Several schemes have been proposed for protection of intentional island operated microgrids in current literature. For example schemes that are based on directional overcurrent or symmetrical components, distance protection, voltage, current differential or combination of both voltage and directional overcurrent functions.

In general, it can be stated that selectivity with LV network faults must be ensured during MV network island operation and therefore (in addition to selection of pick-up limit different from high load current) traditional non-directional overcurrent based schemes are more difficult to apply during island operation with more than one / multiple protection zones in the island operated MV network. Probably most suitable protection schemes for intended island operation, especially with inverter-based DER units having low short-circuit current contribution, are impedance/admittance based schemes or schemes based on both voltage and current (directional).

8 Bibliography

8.1 Standards

- BDEW - Technical Guideline: Generating Plants Connected to the Medium-Voltage Network (June 2008)
- Electric Networks, Ina Lehto: TECHNICAL APPENDIX 1 TO THE GUIDELINES 'CONNECTING AN ELECTRICITY GENERATION INSTALLATION TO THE DISTRIBUTION NETWORK' – CONNECTING AN INSTALLATION WITH A NOMINAL RATED CAPACITY OF UP TO 50 kVA. ET, 28.2.2012. Available at: http://energia.fi/sites/default/files/technical_appendix_1_-_up_to_50_kva_updated_20130228.pdf
- Electric Networks, Ina Lehto: TECHNICAL APPENDIX 2 TO THE GUIDELINES 'CONNECTING AN ELECTRICITY GENERATION INSTALLATION TO THE DISTRIBUTION NETWORK' – CONNECTING AN INSTALLATION WITH A NOMINAL RATED CAPACITY OF OVER 50 kVA. ET, 16.12.2011. Available at: http://energia.fi/sites/default/files/technical_appendix_2_-_over_50_kva.pdf
- Fingrid: Technical requirements for power plants - VJV2013 (in Finnish, not finally accepted). Fingrid, 29.4.2013. Available at: http://www.energiamarkkinavirasto.fi/files/Voimalaitosten%20j%C3%A4rjestelm%C3%A4tekniset%20vaatimukset%20VJV2013.pdf
- ENTSO-E: ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators. 8 March 2013, Available at: https://www.entsoe.eu/major-projects/network-code-development/requirements-for-generators/
- REN 0303 Tekniske funksjonskrav til tilknytnings- og nettleieavtale for innmatingskunder i distribusjonsnettet, 2011, www.ren.no
- REN 3008 Kraftproduksjon - Krav til vern i nettet ved tilknytning av produksjon, 2010, www.ren.no
- Statnett SF "Funksjonskrav i kraftsystemet (FIKS) - Veileder", 2012 http://issuu.com/statnett/docs/statnett_fiks_
- P.O. 12.3 Requisitos de respuesta frente a huecos de tensión de las instalaciones eólicas e instalaciones fotovoltaicas de potencia superior a 2 MW
- R.D. 1699/2011 Conexión a red de instalaciones de producción de energía eléctrica de pequeña potencia
- R.D. 661/2007 Regulación de la actividad de producción eléctrica en régimen especial

8.2 References and scientific publications

[1] Laaksonen, H. "Reliable Islanding Detection with Active MV Network Management." CIRED Workshop 2014, Rome, Italy, June 11-12, 2014.

[2] ENTSO-E, 2013, "ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators (NC RfG)," 8 March 2013.

[3] CENELEC, WG DRAFT, 2012, Combined document CLC/FprTS 50549-1 and CLC/FprTS 50549-2, Version 15th of December 2012.

[4] H. Laaksonen, 2012, "New Multi-criteria-based Algorithm for Islanding Detection in Smart Grids", *IEEE PES ISGT Europe 2012*, Berlin, Germany.

[5] H. Laaksonen, 2013, "Advanced Islanding Detection Functionality for Future Electricity Distribution Networks", *IEEE Transactions on Power Delivery,* vol. 28, no. 4, 2056-2064.

[6] F. Coffele, M. Dolan, C. Booth, G. Ault, G. Burt, 2012, "Coordination of Protection and Active Network Management for Smart Distribution Networks", *CIRED Workshop 2012*, Lisbon, Portugal.

[7] Z. Jiang, J. Fan, J. Mcdonald, 2012, "Advanced Distribution Automation Management for Active Distribution Systems", CIGRE Session 2012, Paris, France.

[8] ENTSO-E, 2012, “ENTSO-E Network Code on Demand Connection (NC DC)”, 21 December 2012.

[9] Laaksonen, H.,”IED Functionalities Fulfilling Future Smart Grid Requirements”, International Journal of Distributed Energy Resources and Smart Grids (DER Journal), Vol. 9 No. 3, July-September 2013.

[10] Laaksonen, H. & Suomi, F., “New Functionalities and Features of IEDs to Realize Active Control and Protection of Smart Grids”, CIRED 2013, Stockholm, June 10-13, 2013.

[11] Amantegui, J. Leitloff, V. Adams, R. Chano, S. Adamiak, M. Apostolov, A. Brand, K. P. Patriota, I., “Coordination of protection and automation in future networks”, Cigrè International Symposium: THE ELECTRIC POWER SYSTEM OF THE FUTURE - Integrating supergrids and microgrids, Bolo-gna, Italy, 13-15 September, 2011.

[12] Nair, N. K. C. Bowe, N., “Enabling future meshed operation for distribution networks”, CIGRE Session 2012, Paris, France, 26-31 August, 2012.

[13] Pierre Janssen, “Monitoring, protection and fault location in power distribution networks using system-wide measurements”, PhD thesis, 2013, available at: http://theses.ulb.ac.be/ETD-db/collection/available/ULBetd-10152013-111608/unrestricted/PhD_thesis_Pierre_Janssen_final.pdf

[14] Oudalov, A., Fidigatti, A., Degner, T., Valov, B., Hardt, C., Yarza, J. M., Li, R., Jenkins, N., Awad, B., Van Overbeeke, F., Hatziargyriou, N. & Lorentzou, M., “Novel protection systems for microgrids”, Final version of partial report for WORK PACKAGE C (TC2: Technical requirements for network protection) on More MicroGrids EU-project, 2009.

[15] Laaksonen, H., “Technical Solutions for Low-Voltage Microgrid Concept”, Ph.D. thesis. Dept. of Electrical and Energy Engineering, University of Vaasa, Acta Wasaensia, 241, Vaasa 2011. 271 pages. Available at: http://www.uva.fi/materiaali/pdf/isbn_978-952-476-345-5.pdf

[16] [A. Oudalov, “New Technologies for Microgrid Protection”,Santiago 2013 Symposium on Microgrids, 2013, Available at: http://der.lbl.gov/sites/der.lbl.gov/files/santiago_oudalov.pdf.

[17] Laaksonen, H. & Kauhaniemi, K., “Smart Protection Concept for LV Microgrid”, International Review of Electrical Engineering (IREE), Vol. 5 No. 2, March–April 2010.

[18] Chowdhury, S., Chowdhury, S.P. & Crossley, P., “Microgrids and Active Distribution Networks”, Published by The Institution of Engineering and Technology, London, United Kingdom: Athenaeum Press Ltd, Gateshead, Tyne & Wear, 2009.

[19] Voima, S., Laaksonen, H. & Kauhaniemi, K. Adaptive Protection Scheme for Smart Grids. The IET 12th International Conference on Developments in Power System Protection (DPSP) 2014, Copenhagen, Denmark, March 31 - April 3, 2014.

[20] Laaksonen, H., “Protection Principles for Future Microgrids”, IEEE Transactions on Power Electronics, Vol. 25, No. 12, December 2010.

[21] Laaksonen, H., Kauhaniemi, K. & Voima, S., “Protection System for Future LV Microgrids”, CIRED 2011, Frankfurt, Germany, June 6–9, 2011.

[22] Feero William E., C. Dawson Douglas and Stevens John, “White Paper on Protection Issues of The MicroGrid Concept”, [Report]. - [s.l.] : Consortium for Electric Reliability Technology Solutions, 2002.

[23] Conti Stefania, Raffa Lorenzo and Vagliasindi Umberto, “Analysis of protection issues in autonomous MV micro-grids”, [Conference] // 20th International Conference on Electricity Distribution. - Praga : [s.n.], 2009. - pp. 1-5.

[24] Zamani, M. A., “PROTECTION AND CONTROL OF ACTIVE DISTRIBUTION NETWORKS AND MICROGRIDS”, PhD thesis, The University of Western Ontario, London, Ontario, Canada, 2012.

[25] Laaksonen, H. & Kauhaniemi, K. & Voima, S., "DG Unit Fault Behavior and Protection of LV Microgrid", International Review on Modelling and Simulations (IREMOS), Vol. 3 No. 3, June 2010.

[26] P. Mahat, Z. Chen, B. Bak-Jensen, and C.L. Bak, "A Simple Adaptive Overcurrent Protection of Distribution Systems With Distributed Generation", IEEE TRANSACTIONS ON SMART GRID, VOL. 2, NO. 3, SEPTEMBER 2011.

[27] [27] D. Ishchenko, A. Oudalov, and J. Stoupis, "Protection Coordination in Active Distribution Grids with IEC 61850", IEEE 2012.

[28] Laaksonen, H. & Ishchenko, D. & Oudalov, A. Adaptive Protection and Microgrid Control Design for Hailuoto Island, IEEE Transactions on Smart Grid, 6.3.2014.

[29] G. Buigues, A. Dyśko, V. Valverde, I. Zamora, and E. Fernández, "Microgrid Protection: Technical challenges and existing techniques", International Conference on Renewable Energies and Power Quality (ICREPQ'13), Bilbao (Spain), 20-22 March, 2013: http://www.icrepq.com/icrepq'13/262-buigues.pdf .

[30] H. Nikkhajoei, et al., "Microgrid fault protection based on symmetrical and differential current components", 2006.

[31] L. Bin, et al., "Design of protection and control scheme for microgrid systems", in Universities Power Engineering Conference (UPEC), 2009 Proceedings of the 44th International, 2009, pp. 1-5.

[32] R. J. Best, et al., "Communication assisted protection selectivity for reconfigurable and islanded power networks", in Universities Power Engineering Conference (UPEC), 2009 Proceedings of the 44th International, 2009, pp. 1-5.

[33] M. A. Zamani, T. S. Sidhu and A. Yazdani, "A protection strategy and microprocessor-based relay for low-voltage microgrids," IEEE Trans. on Power Delivery, vol. 26, no. 3, pp. 1873-1883, Jul. 2011.

[34] Voima, S., Kauhaniemi, K. & Laaksonen, H., "Novel Protection Approach for MV Microgrid", CIRED 2011, Frankfurt, Germany, June 6–9, 2011.

[35] M. Dewadasa, "Protection for distributed generation interfaced networks", Electrical Engineering, Faculty of Built Environment and Engineering, Queensland University of Technology, Queensland (Australia), 2010.

[36] M. Dewadasa, et al., "Control and protection of a microgrid with converter interfaced micro sources", in Power Systems, 2009. ICPS '09. International Conference on, 2009, pp. 1-6.

[37] Dewadasa, M., "Protection of distributed generation interfaced networks", Thesis, Queensland University of Technology, Queensland, Australia, 2010.

[38] Laaksonen, H. & Kauhaniemi, K., "Fault Type and Location Detection in Islanded Microgrid with Different Control Methods Based Converters", In Proceedings of 19th International Conference and Exhibition on Electricity Distribution. Vienna, Austria, 2007.

[39] Al-Nasseri, H. & Redfern, M. A., "A New Voltage based Relay Scheme to Protect Micro-Grids dominated by Embedded Generation using Solid State Converters", In Proceedings of 19th International Conference on Electricity Distribution. Vienna, Austria, 2007.

[40] Oudalov, A. & Fidigatti, A., "Microgrid protection and modern protection Devices", Final report as part of WORK PACKAGE C (TC2: Technical requirements for network protection) on More MicroGrids EU-project, 2008.

[41] Al-Nasseri, H. & Redfern, M. A., "Harmonics Content Based Protection Scheme for Microgrids Dominated by Solid State Converters", In Proceedings of 12th Middle East Power Systems Conference. Nile Cruise, Aswan, Egypt, 2008.

[42] C. Hou, et al., "A study of voltage detection based fault judgement method in micro-grid with inverter interfaced power source", in The International Conference on Electrical Engineering, Shenyang (China), 2009, pp. 1-5.

[43] T. Loix, et al., "Protection of microgrids with a high penetration of inverter-coupled energy sources", in Integration of Wide-Scale Renewable Resources Into the Power Delivery System, 2009 CIGRE/IEEE PES Joint Symposium, 2009, pp. 1-6.

[44] W. Xiao-ping, et al., "Research on the relay protection system for a small laboratory-scale microgrid system", in Industrial Electronics and Applications (ICIEA), 2011 6th IEEE Conference on, 2011, pp. 2712-2716.

[45] M. Dewadasa, Member, A. Ghosh, and G. Ledwich, "Protection of Microgrids Using Differential Relays"

[46] Casagrande, E., Woon, W.L., Zeineldin, H.H., Svetinovic, D. "A Differential Sequence Component Protection Scheme for Microgrids With Inverter-Based Distributed Generators": http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6678658&sortType%3Dasc_p_Sequence%26filter%3DAND%28p_IS_Number%3A6693741%29

[47] Sortomme E, Venkata S.S and Mitra J, "Microgrid protection using communication assisted digital relays", [Journal] // IEEE Transactions on Power Delivery. - 2010. - pp. 2789-2796.

[48] Brahma S.M., "Fault location in power distribution system with penetration of distributed generation", [Journal] // IEEE Transactions on Power Delivery. - 2011. - 99 : Vol. 1.

[49] Venkata S.S. [et al.], "Advanced and adaptive protection for active distribution grid", [Conference] // 22nd International Conference on Electricity Distribution (CIRED). - Stockholm : [s.n.], 2013.

[50] R. M. Tumilty, et al., "Approaches to Network Protection for Inverter Dominated Electrical Distribution Systems", in Power Electronics, Machines and Drives, 2006. The 3rd IET International Conference on, 2006, pp. 622-626.

[51] Tumilty, R. M., Elders, I. M., Burt, G. M. & McDonald, J. R., "Coordinated Protection, Control & Automation Schemes for Microgrids", International Journal of Distributed Energy Resources 3: 3, 225–241, 2007.

[52] M. A. Zamani, T. S. Sidhu and A. Yazdani, "A strategy for protection coordination in radial distribution networks with distributed generators," in Proc. IEEE Power and Energy Society General Meeting, 8 pages, Jul. 2010.

[53] M. A. Zamani, A. Yazdani and T. S. Sidhu, "A communication-assisted protection strategy for inverter-based medium-voltage microgrids," accepted for publication in IEEE Trans. on Smart Grid, 12 pages, Nov. 2012.

[54] M. Dewadasa, A. Ghosh, "Microgrid Operation and Control: DELIVERABLE 6: Protection of Meshed Microgrids", CSIRO Intelligent Grid Research Cluster- Project 7, Available at: http://igrid.net.au/resources/downloads/project7/P7%20M6%20Meshed%20Microgrid%20Protection.pdf

[55] Firouz Yousef [et al.], "A review of transient effects of different types of distributed generation units on overcurrent protection system", [Conference] // International Conference on Electricity Distribution (CIRED). - Stockholm : [s.n.], 2013.

[56] Bollen Math H.J., "The Smart Grid: Adapting the Power System to New Challenges", [Book]. - [s.l.] : Morgan & Claypool, 2011. - 182 p.

[57] Plet Cornelis A. [et al.], "Fault Response of Grid-Connected Inverter Dominated Networks", [Conference] // Power and Energy Society General Meeting. - Minneapolis : [s.n.], 2010. - pp. 1-8.

[58] J. C. Boemer, B. G. Rawn, M. Gibescu, E. Coster, M. A. M. M. van der Meijden, and W. Kling, "Contribution of Negative-Sequence Controlled Distributed Generation to Power System Stability under Unbalanced Faults: A Discussion Paper", ISGT Europe 2012.

[59] C. Feltes, S. Engelhardt, J. Kretschmann, J. Fortmann, F. Koch, and I. Erlich, "Comparison of the grid support capability of DFIG-based wind farms and conventional power plants with synchronous generators", Power & Energy Society General Meeting, 2009, PES '09, IEEE, pp. 1-7, 2009.

[60] Dewadasa, M.; Ghosh, A; Ledwich, G., "Protection of microgrids using differential relays," *Universities Power Engineering Conference (AUPEC), 2011 21st Australasian* , vol., no., pp.1,6, 25-28 Sept. 2011

[61] G. Buigues, A. Dyśko, V. Valverde, I. Zamora, and E. Fernández, "Microgrid Protection: Technical challenges and existing techniques", International Conference on Renewable Ener-

gies and Power Quality (ICREPQ'13), Bilbao (Spain), 20-22 March, 2013: http://www.icrepq.com/icrepq'13/262-buigues.pdf .

[62] A. G. Phadke, J. S. Thorpe et M. G. Adamiak, «A new measurement technique for tracking voltage phasors,» IEEE Transactions in Power Apparatus and Systems, Local System Frequency, and Rate of Change of Frequency, vol. 102, n°%15, pp. 1025-1038, 1983.

[63] C. F. Ten et P. A. Crossley, «Evaluation fo ROCOF relay performance on networks with distributed generation,» chez Developments in Power System Protection, 2008. DPSP 2008, Glasgow, 2008.

[64] BDEW - Technical Guideline: Generating Plants Connected to the Medium-Voltage Network (June 2008)

[65] MEDIUM VOLTAGE DISTRIBUTION NETWORK QUESTIONNAIRE ANSWERS (University of Vaasa 2004) in Appendix of Långland H. MSc thesis "Medium voltage network analysis for modelling"

[66] Electric Networks, Ina Lehto: TECHNICAL APPENDIX 1 TO THE GUIDELINES 'CONNECTING AN ELECTRICITY GENERATION INSTALLATION TO THE DISTRIBUTION NETWORK' – CONNECTING AN INSTALLATION WITH A NOMINAL RATED CAPACITY OF UP TO 50 kVA. ET, 28.2.2012. Available at: http://energia.fi/sites/default/files/technical_appendix_1_-_up_to_50_kva_updated_20130228.pdf

[67] Electric Networks, Ina Lehto: TECHNICAL APPENDIX 2 TO THE GUIDELINES 'CONNECTING AN ELECTRICITY GENERATION INSTALLATION TO THE DISTRIBUTION NETWORK' – CONNECTING AN INSTALLATION WITH A NOMINAL RATED CAPACITY OF OVER 50 kVA. ET, 16.12.2011. Available at: http://energia.fi/sites/default/files/technical_appendix_2_-_over_50_kva.pdf

[68] Fingrid: Technical requirements for power plants - VJV2013 (in Finnish, not finally accepted). Fingrid, 29.4.2013. Available at: http://www.energiamarkkinavirasto.fi/files/Voimalaitosten%20j%C3%A4rjestelm%C3%A4tekniset%20vaatimukset%20VJV2013.pdf

[69] ENTSO-E: ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators. 8 March 2013, Available at: https://www.entsoe.eu/major-projects/network-code-development/requirements-for-generators/

[70] A. Petterteig et.al. "Tekniske retningslinjer for tilknytning av produksjonsenhet, med maksimal aktiv effektprod. mindre enn 10 MW I distrbusjonsnettet", SINTEF Energy Research TR A6343.01, 2006.

[71] REN 0303 Tekniske funksjonskrav til tilknytnings- og nettleieavtale for innmatingskunder i distribusjonsnettet, 2011, www.ren.no

[72] REN 3008 Kraftproduksjon - Krav til vern i nettet ved tilknytning av produksjon, 2010, www.ren.no

[73] Statnett SF "Funksjonskrav i kraftsystemet (FIKS) - Veileder", 2012 http://issuu.com/statnett/docs/statnett_fiks_

[74] Fault current contribution from wind plants, JWG Transmission & Distribution Committee Electric; Machinery Committee; Power System Relaying Committee, http://www.pes-psrc.org/Reports/Fault%20Current%20Contributions%20from%20Wind%20Plants.pdf

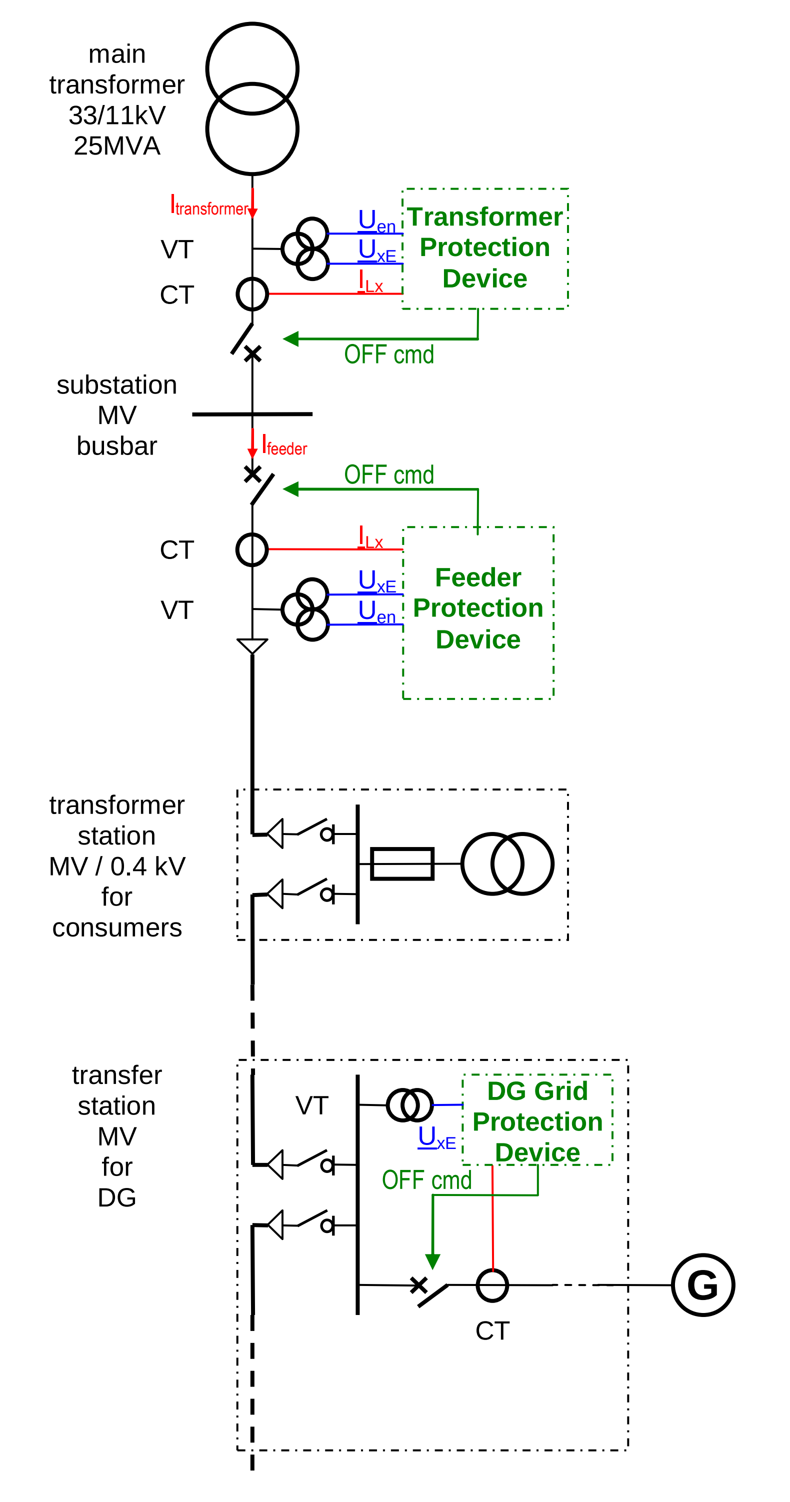
[75] V. Diedrichs, H. Lorenzen, I. Mackensen, S. Gertjegerdes: "Asymmetrical Current Injection addressed by ENTSO-E Draft Network Code", Proc. 11th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms, Lisbon, November 2012.

Appendix A Country specific protection approaches

A.1 Australia

A.1.1 Protection Device of Outgoing Feeder = overcurrent protection

Neutral treatment: Solidly earthed star winding at source substation.



Transformer protection (33/11kV, 25MVA):
Transformer: 33/11kV, 25MVA
I>> ≈ $1{,}5 \cdot I_{r,transformer}$
Differential

Busbar protection:
Zone interlocked bus blocking scheme.

Feeder protection:
I>> ≈ 400A
I_E>> ≈ 240A
I_{SEF}>> ≈ 4A (sensitive earth)
Normal load: 240A
Emergency load: 360A
(t_{discr} ≈ 0,4 s for old prot. and CBs, t_{discr} ≈ 0,3 s for new prot. and CBs)

Generator protection:
Generator: 415V/11kV, 1.25MVA
Transformer: Y/Y/D. 11kV star point unearthed for parallel operation, and earthed for islanded operation
U>/t 1,15·Uc / 5,0 s
U</t 0,80·Uc / 5,0 s
f>/t 52,0 Hz / 5,0 s
f</t 49,5 Hz / 2,0 s

VVS 10deg
ROCOF 0,2Hz/s, 0,5s
NVD 15%, 7,0s
I>> ≈ 80A
t>> = IEC SI, TMS 0,15
I_E>> ≈ 20A
t_E>> = IEC SI, TMS 0,20
I_{SEF}>> ≈ 4A
t>> < 10s

A.1.2 Description

Endeavour Energy operates a 3 wire system sourced from a solidly earthed star winding. The distribution system voltages are 11kV and 22kV. The transformers are normally in the range 15MVA to 45MVA and have a primary voltage of 33kV, 66kV or 132kV. There are normally 2 or 3 transformers, and these are often operated in parallel and result in a busbar fault level in the range 2kA to 14kA.

At new sites, the busbar is most often protected by a zone interlocked busbar blocking scheme. At some sites, high impedance or low impedance busbar differential protection is employed.

The distribution feeders are protected by Inverse Definite Minimum Time (IDMT) overcurrent, IDMT earthfault (residual overcurrent) and fixed time sensitive earthfault (residual overcurrent) protection systems. At new sites the former 2 are duplicated. Auto reclose is enabled on all feeders with any overhead component, and is set to single shot at 10 seconds. Many feeders have line reclosers installed and the recloser utilises the same functions as on the feeder, but with more recloses (up to 3 shots), and sometimes with an attempt at fuse saving.

Where a feeder has embedded generation which can exceed the zone interlocked busbar blocking scheme pickup, a directional overcurrent relay needs to be installed to prevent the generator fault contribution from blocking high speed operation of the busbar blocking scheme for a busbar fault. Distribution substations are generally protected by fuses on the HV side which range from 3,15 A to 100 A. Larger 1 MVA or 1,5 MVA distribution substations are protected by HV side circuit breakers.

Embedded generation is normally connected via a delta winding (on the distribution feeder) side to ensure that sensitive earthfault protections will not operate spuriously. Embedded generators which are not capable of matching/supporting the minimum load on the segment of the feeder (any segmentation following protection device operation) are generally required to have most of the following protections installed:

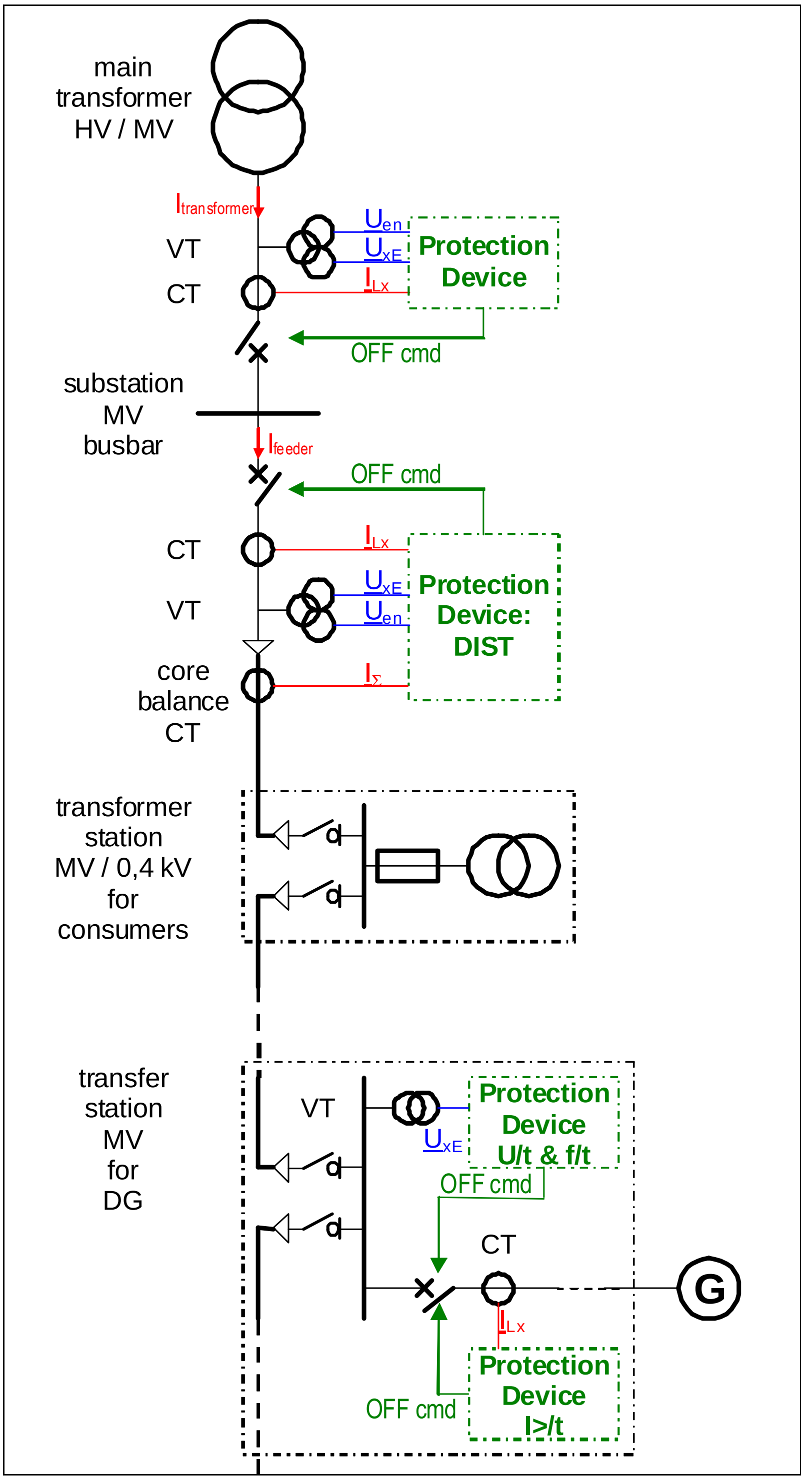
- Overcurrent
- Neutral displacement
- Rate of change of frequency
- Voltage vector shift
- Underfrequency
- Overfrequency
- Undervoltage
- Overvoltage

Embedded generators which are capable of matching/supporting the minimum load on the segment of the feeder (any segmentation following protection device operation) are generally required to have communication systems to the supply substation to ensure that the generator or generator infeed connection is disconnected from the network whenever the supply substation circuit breaker opens.

A.2 Austria

A.2.1 Protection Device of Outgoing Feeder = distance protection

Neutral treatment: Petersen Coil earthed, WITHOUT turn-off in case of an earth fault



MV protection of main transformer (DIST):
$I>> \approx 1,4 \cdot I_{r,transformer}$
Z1: ≈ 0,85·Z1 of smallest outgoing feeder
t1 = 0,4 s
t→ = highest t→ of outgoing feeder + 0,4 s
reverse interlocking for busbar protection: t = 0,15 s

Distance protection:
$I>> \approx 1,4 \cdot I_{r,feeder}$
Z1: ≈ 0,85·Z of next I>/t-prot.
t1 = 0,05 s
t→ = t>> of transfer station + t_{discr}
($t_{discr} \geq 0,4$ s for old prot. and CBs, $t_{discr} \leq 0,3$ s for new prot. and CBs)

U/t- and f/t-protection:

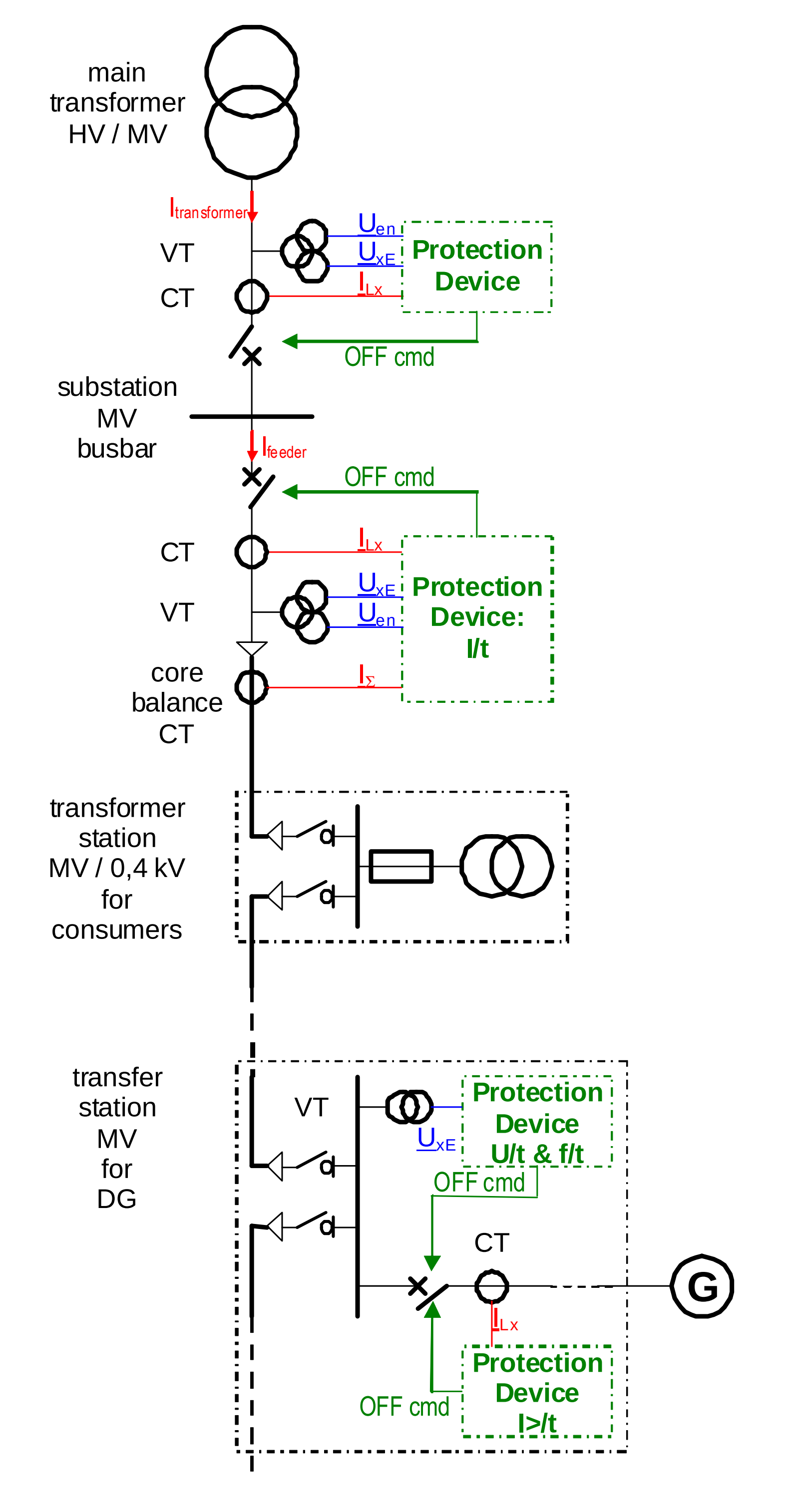
U>/t	1,15·Uc / < 0,1 s
U</t	0,70·Uc / 0,7 s
f>/t	51,5 Hz / < 0,1 s
f</t	47,5 Hz / < 0,1 s

(Uc = voltage at PCC)

I>/t-protection:
$I>> \approx 1,4 \cdot I_{r,DG}$
t>> = “0”

A.2.2 Protection Device of Outgoing Feeder = over current / time -protection

Neutral treatment: Petersen Coil earthed, WITHOUT turn-off in case of an earth fault



MV protection of main transformer (DIST):
$I>> \approx 1{,}4 \cdot I_{r,transformer}$
Z1: ≈ 0,85·Z1 of smallest outgoing feeder
t1 = 0,4 s
t→ = highest t>> of outgoing feeder + 0,4 s
reverse interlocking for busbar protection: t = 0,15 s

I/t-protection:
$I>> \approx 1{,}4 \cdot I_{r,feeder}$
$t>> = t>>$ of transfer station + t_{discr}
($t_{discr} \geq 0{,}4$ s for old prot. and CBs, $t_{discr} \leq 0{,}3$ s for new prot. and CBs)

U/t- and f/t-protection:

U>/t	1,15·Uc / < 0,1 s
U</t	0,70·Uc / 0,7 s
f>/t	51,5 Hz / < 0,1 s
f</t	47,5 Hz / < 0,1 s

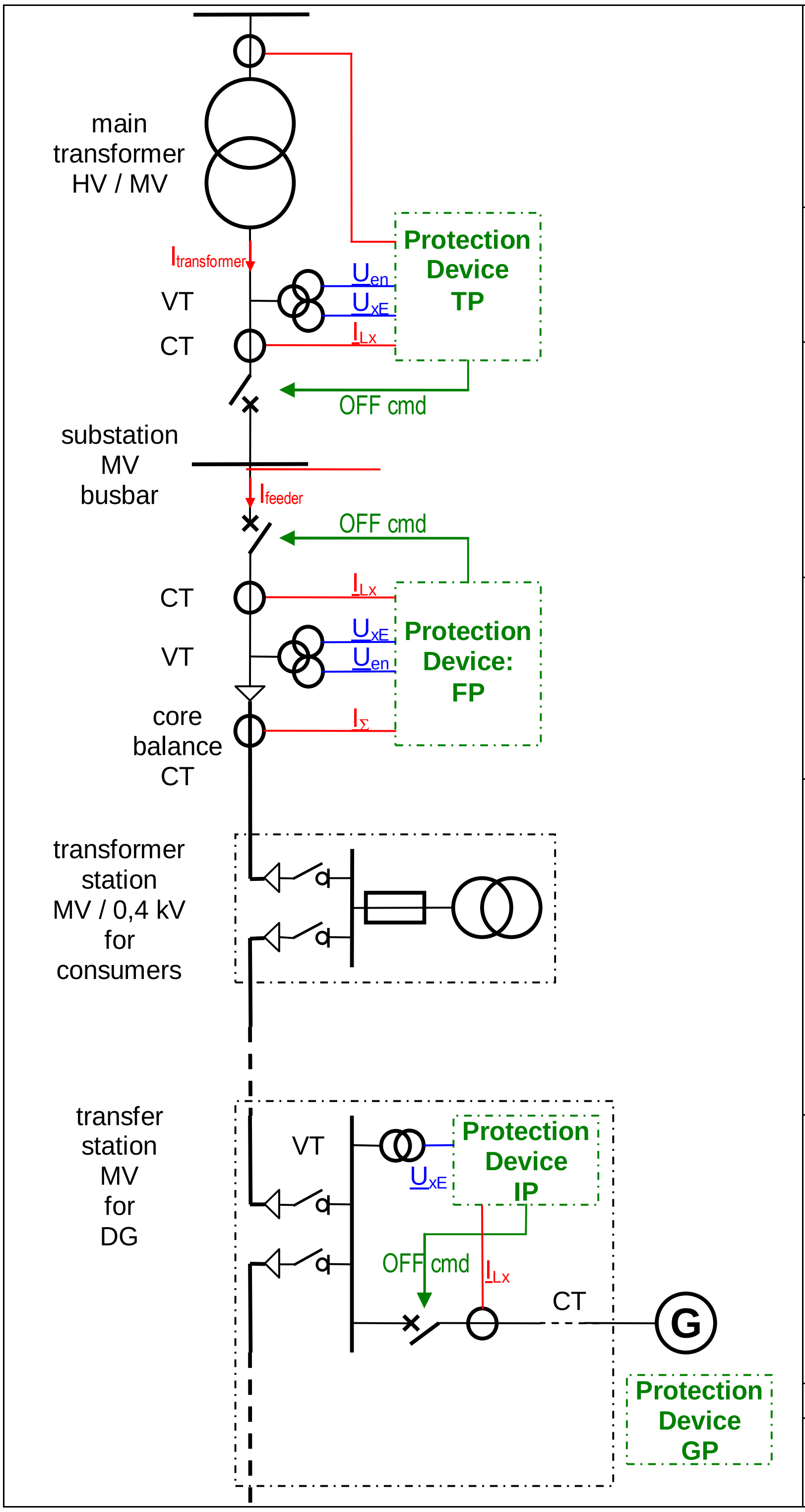
(Uc = voltage at PCC)

I>/t-protection:
$I>> \approx 1{,}4 \cdot I_{r,DG}$
t>> = “0”

A.3 China

A.3.1 Protection Scheme for MV Distribution Networks

Neutral treatment: isolated / compensated / low impedance.



MV protection of main transformer:
I>, 0,3s
I>, 0,6s

MV protection of Feeder (FP):
I>>, 0s
I>, 0,3s
I>, 0,6s
I_{DIFF}> or Z<(optional)

Interface protection:
U>/t 1,15·Uc / < 0,1 s
U</t 0,80·U_N / 2,0 s
U</t 0,40·U_N / 0,2 s
f>/t 50,2 Hz / < 0,2 s
f</t 48,75 Hz / < 0,2 s
Anti-islanding, less than 2s

A.3.2 Description of protection scheme

A.3.2.1 General

In China, DG is defined as a generation located in the vicinity of the user, which power can be locally consumed on 10 kV (distribution system voltage) and below (220V/380V) system that connect to the main grid, and the total installed capacity at individual POINT OF DG CONNECTION is not more than 6 MW.

A.3.2.2 MV protection of main transformer

Protection functions for a typical transformer (31,5MVA, 38,5±2×2,5% /11KV, Y/△-11) are:

- Buchholz protection;
- differential protection;
- instantaneous overcurrent protection;
- (voltage controlled) time-delayed overcurrent protection.

For transformer with capacity less than 10MVA, differential protection may not be applied under the assumption that the sensitivity of overcurrent protection is good enough.

Undervoltage and negative sequence overvoltage control element may be applied on over-current protection for sensitivity purpose. Typical settings for voltage control element are: $Upp<0,7U_N$, $U2>0,06U_N$.

MV (10KV) protection of main transformer include two stages (voltage controlled) time-delayed overcurrent protection, with time delay of 0,3s and 0,6s respectively.

A.3.2.3 MV protection of Feeder

Typically instantaneous overcurrent and time-delayed (directional) overcurrent protection are equipped on feeder.

Distance or differential protection may be applied for system stability purpose.

A.3.2.4 Interface protection

General

An interface protection relay shall be installed at the POINT OF DG CONNECTION with the following functions:

- two stages (directional) overcurrent protection;
- zero sequence overcurrent protection;
- undervoltage and overvoltage protection;
- underfrequency and overfrequency protection;
- anti-islanding protection;
- decoupling.

Anti-islanding protection

For inverter type DG, which operating character determines that they can run continuously under islanding, anti-islanding protection is essential to prevent islanding and protect the maintenance staff and primary equipment. Anti-islanding protection shall be able to detect the islanding state and disconnect DG from main grid quickly when islanding happens. Anti-islanding protection shall coordinate with interconnection line protection at main grid side. The operate time of anti-islanding protection shall not be longer than 2s.

For synchronous or asynchronous generator type DG, which operating character determines that they cannot run continuously under islanding, anti-islanding protection is not necessary. While the clearance time of DG shall coordinate with interconnection line protection in order to prevent asynchronous reclosing. The power system security and stability can be guaranteed suppose the fault clearance time coordinates with interconnection line protection.

Voltage protection

The settings of voltage protection for DG shall meet the requirements described in the following table.

Requirements on DG voltage	
Voltage on POINT OF DG CONNECTION	Requirements
$U < 50\% U_N$	Maximum clearance time shall not exceed 0,2s (0,1s)
$50\% U_N \leq U < 85\% U_N$	Maximum clearance time shall not exceed 2,0s
$85\% U_N \leq U < 110\% U_N$	Run continuously.
$110\% U_N \leq U < 135\% U_N$	Maximum clearance time shall not exceed 2,0s
$135\% U_N \leq U$	Maximum clearance time shall not exceed 0,2s (0,05s)
Note: 1. U_N is the rated voltage point of interconnection 2. Maximum clearance time is the duration from the instant that abnormal condition occurs to the instant that DG stop outputting.	

Typical settings for voltage protection are:

DG type	Voltage Level	Settings
Inverter type	10kV	<0,8U_N, 2,0s; <0,4U_N, 0,2s; >1,30U_N, 0,2s Or coordinate with fault ride-through capability of inverter.
Inverter type	220V/380V	<0,2U_N, 10s; >1,30U_N, 0,2s
Synchronous generator type		<0,8U_N, 0,2s; >1,30U_N, 0,2s
Asynchronous generator type		<0,2U_N, 0,2s; >1,30U_N, 0,2s

Frequency protection

The settings of frequency protection for DG shall meet the requirements described in the following table.

Requirements on DG frequency	
Frequency	Requirements on fault-through ability
<48Hz	Inverter type DG: according to the lowest frequency permitted by inverter itself, or requirement of control center. Synchronous or asynchronous generator type DG: not less than 60s, or shorter when necessary provided that the power grid stability is ensured.
48Hz-49,5Hz	Not less than 10 min

49,5Hz-50,2Hz	Run continuously
50,2Hz-50,5Hz	DG can run at least 2 min and has the capability to reduce active power output following the command from control center, or stop supplying in 0,2s. Re-connecting of DG in outage is not permitted.
>50,5Hz	Stop supplying to main grid in less than 0,2s. Re-connecting of DG in outage is not permitted.

Typical settings for frequency protection are: >50,2Hz, 0,2s; <48,75Hz, 0,2s.

Reverse power protection

For DG which is not permitted to output electricity to main grid, reverse power protection is installed. When reverse current is larger than 5% of DG rated output, DG shall reduce its output in 2s until full stop.

Re-closure

Auto-reclosing function is equipped in the interface protection relay:

- for inverter type DG: live-check scheme, 0,85$U_{N.}$
- for asynchronous (induction) generator type DG: live-check scheme, 0,85$U_{N.}$
- for synchronous generator type DG: synchronism-check scheme.

A.3.2.5 DG protection

General

Power transformer, inverter, synchronous or asynchronous generator of DG shall be equipped with reliable relaying protection.

In addition, relaying protection for DG shall be able to detect short-circuit fault (including single phase to ground fault) and phase open fault that occurs at main grid side, and disconnect DG from main grid in this case.

Synchronous or asynchronous generator type DG

Step-up transformer of DG shall be equipped with differential protection or instantaneous overcurrent protection as main protection and time-delayed (voltage controlled) overcurrent protection as backup protection.

Generator shall be equipped with differential protection or (voltage controlled) instantaneous overcurrent protection as main protection, and time-delayed overcurrent protection as backup protection.

Inverter type DG

At DG side of POINT OF DG CONNECTION, the following protection functions are necessary:

- (directional) overcurrent protection;
- undervoltage / overvoltage protection;
- underfrequency / overfrequency protection;
- anti-islanding protection;

- live-check paralleling.

There are two types of anti-islanding protection for inverter type DG – active one and passive one. Schemes of active anti-islanding protection include frequency offset, active power variation, reactive power variation, impedance change caused by pulse current injection, etc. Schemes of passive anti-islanding protection include voltage phase angle jitter, 3rd harmonic voltage variation, rate of change of frequency, etc.

Residual overcurrent protection for DG connected to 220V/380V system

Residual overcurrent protection for DG connected to 220V/380V system is essential for personnel safety and apparatus security.

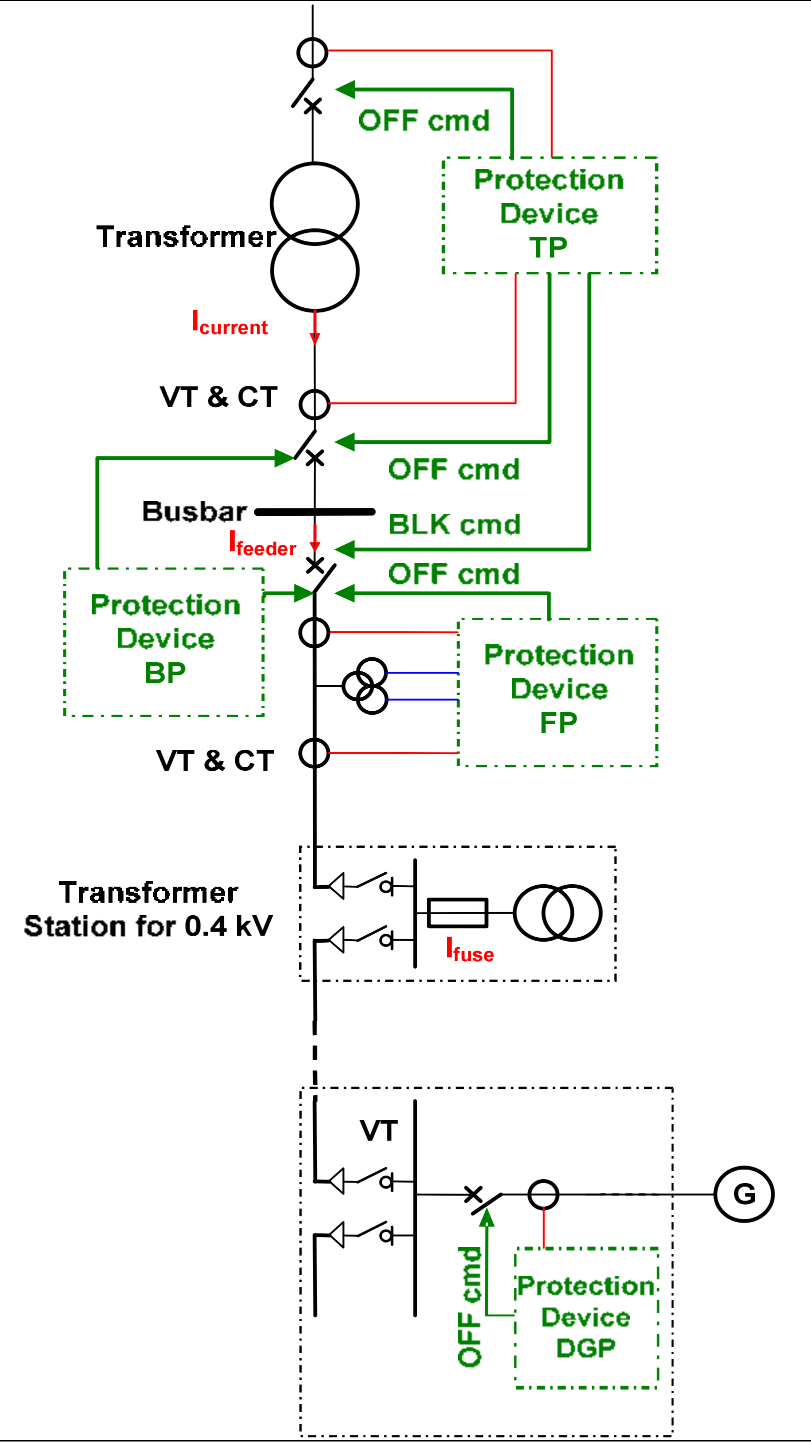
Re-connecting

After disconnection caused by a disturbance, re-connecting of DG is not permitted until the grid voltage and frequency return to normal limit. When the grid voltage and frequency return to normal limit, DG which outputs at 380V can be re-connected automatically after a certain intended delay, which is not less than 20s and shall be specified by control center; DG which outputs at 10kV (6kV) - 35kV level shall be re-connected only if it is commanded by control center.

A.4 Denmark

A.4.1 Protection Device of Outgoing Feeder

Neutral treatment: Petersen coil



MV protection of main transformer: Protection (TP):
Differential Protection – CODE 87
More than 30% I difference
t_{discr} = 0,2 s
Over Current Protection – CODE 51
Fault inside transformer
I>> ≈ 1,4·$I_{r,transformer}$
t_{discr} = 1,5 s
Fault in LV side
I>> ≈ 2-3·$I_{r,transformer}$
t_{discr} = 0,1 s
Block downstream relay[19]
Fault in HV side
I>> ≈ 10·$I_{r,transformer}$
t_{discr} = 0,05 s

Bus-bar protection (BP)[20]:
Directional Over Current Protection – CODE 67
I> = 1,2·I_r (in forward direction)
t_{discr} = 1 s
I>> = 2,5-4·I_r (in forward direction)
t_{discr} = 0,05 s
CODE 51 – if VT is out of service
I> = 2,5-4·I_r (in any direction)
t_{discr} = 0,5 s

Bus-bar protection (FP):
CODE 67
I> = 1,2·I_r (in forward direction)
t_{discr} = 0,4 s (countryside)
t_{discr} = 0,4 s (city are)
I>> = 20·I_{Fuse} (in forward direction)
t_{discr} = 0,02-0,03 s
CODE 51 – if VT is out of service
I> = 1,2·I_r (in any direction)
t_{discr} = 1 s

DG Protection (DGP):
According to grid code – See section 4B

Protection up to 60A via Fuses

[19] Communication between relays via 200V DC wires
[20] Communication between the breakers if there is problem with upstream breaker

A.4.2 Protection Scheme for MV Distribution Networks

A.4.2.1 Transformer Protection

- Differential protection
  - o Trips circuit breaker (CB) for 30% difference in current reading in current transformers for 200ms
- Digital overcurrent relay
  - o Trips CB for 10·I for 50 ms in HV side of the transformer
  - o Trips CB for 1,4·I for 1-1,5 s inside the transformer
  - o Trips CB for 2-3·I for 100 ms in the LV side of transformer
  - o Blocks downstream relays when it trips

A.4.2.2 Bus-Bar Protection

- Communication between relays via 220V DC wires
- Overcurrent protection
  - o Trips CB for 1,2·I for 1 s in forward direction
  - o Trips CB for 2,5-4·I for 50 ms in forward direction
  - o Trips CB for 2,5-4·I for 500 ms in backward direction
  - o Relays are blocked when the voltage transformer (VT) malfunctions and fault is cleared by other relays
  - o Breakers notify adjacent breakers if there is the problem

A.4.2.3 Line/Feeder

- 2 step directional relay
  - o Trips CB for 1,2·I for 0,4s (in country side) and 0,8s (in city area) in forward direction
  - o Trips CB for 20·I for 20-30ms in forward direction
  - o Trips CB for 1,2·I for 1s in any direction when VT malfunctions

A.4.2.4 DG protection

- Generation unit protection
  - o Refer to grid code in section 4B
- Lines and cable protection
  - o Trips CB for 1,4·cable rating for 20 ms towards the DG side from PCC
  - o Trips CB for 1,4·cable rating for 0,5 s towards the utility side from PCC

A.4.2.5 Others

- Single phase faults need to be located within 2 hours
- Petersen coil is used to ground the system and it is short circuited to locate the fault

A.5 Finland

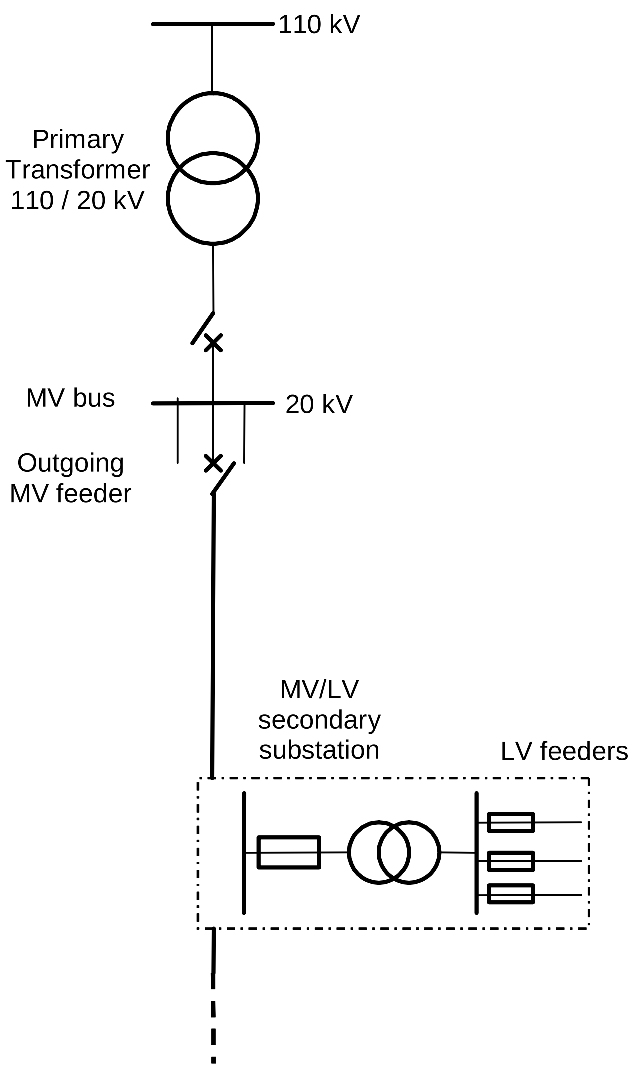
A.5.1 Protection Practices and Settings for MV Networks in Finland [65]

In following table summary from typical MV network topology and protection practices which have been used in Finland are summarized.

PRIMARY SUBSTATION (HV/MV)								
		HV level range (kV)		*HV short circuit power range (GVA)*			*Number of transformers*	
GENERAL INFORMATION	Urban	110		1,5-10			2 (1-3)	
	Rural	110		0,5-2,5			1 (1-2)	
		Power range (MVA)		*Vector group*			*Number of MV feeders*	
PRIMARY DISTRIBUTION TRANSFORMER	Urban	25 (20–40)		YNd11			10	
	Rural	16 (10–25)		YNd11			7	
		Isolated		*Compensated (reactance grounding)*				
MV NEUTRAL GROUNDING (%)	Urban	70		30				
	Rural	80		20				
		Over current protection		*Earth fault protection*			*Back-up O/C and E/F*	*Transformer differential*
PRIMARY DISTRIBUTION TRANSFORMER (HV/MV) PROTECTION	Urban	Yes		Yes			Yes	Yes
	Rural	Yes		Yes			Yes	
		Coordination with feeder		*Coordination with Feeder by blocking*			*Arc protection*	
BUS PROTECTION	Urban/Rural	Yes		Yes			Yes	
MEDIUM VOLTAGE (MV) NETWORK								
MV LEVELS	Urban	20 (10-20) kV						
	Rural	20 (20-30) kV						
		Overhead network					*Underground cable*	
TYPE OF MV NETWORK (%)	Urban	25					75	
	Rural	90					10	
		Radial (Fig. 2a)		*Open loop (Fig. 2b)*			*Link arrangement (Fig. 2c)*	*Meshed (Fig. 2d)*
MV NETWORK TOPOLOGY (%)	Urban	5		20			55	10
	Rural	20		30			50	
		Total feeder conductor length (km)		*Feeder cross section area (mm^2)*		*Load (MVA)*	*Number of secondary substations (MV/LV)*	*MV/LV transformer power (MVA)*
OUTGOING FEEDER PROFILE	Urban	7(-30)		185(-240)		3(-8)	10	1 (0,2-2,5)
	Rural	30(-100)		40-150		2(-5)	21	0,1 (-0,5)
	Earth-fault current range (A)							
MV NETWORK FAULT CURRENTS	Urban	20-200						
	Rural	10-60						
		Definite time current relays	*Non-directional over current relays*	*Earth fault relays*	*Directional earth fault relays*	*Reclosers at substation*	*Typical relay settings*	*Reclosing practice: –dead time –time between two reclosings*
OUTGOING FEEDER PROTECTION	Urban	Yes	Yes	Yes	Yes		I>1200 A t>0,8 s	
	Rural	Yes	Yes	Yes	Yes	Yes	I>250 A t>0,6 s I>>1500 A t>>0,15 s	- 0,2–0,4 s - 30–120 s

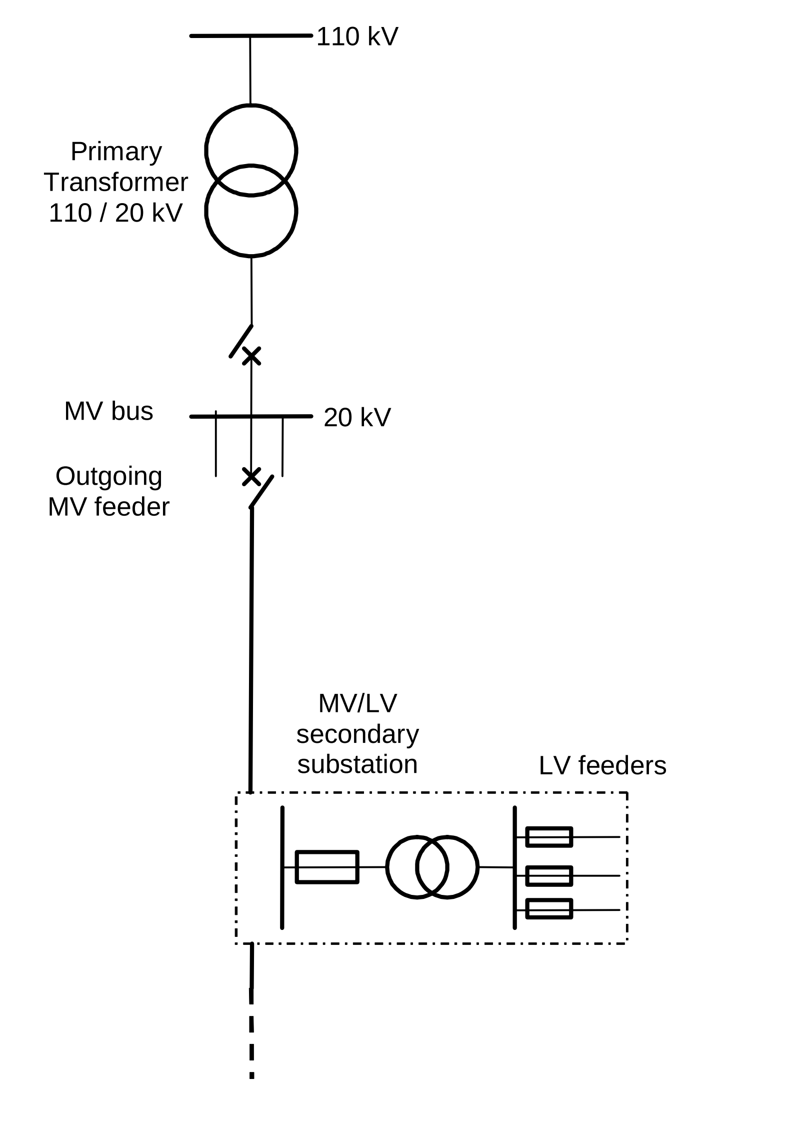
A.5.1.1 Typical Protection Scheme for Primary Substation and MV Network (Urban)

MV Neutral Grounding: Isolated

<table>
<tr><td rowspan="4">
</td>
<td>Primary (HV/MV) Transformer Protection:
Overcurrent protection
Earth-fault protection
Differential transformer protection</td></tr>
<tr><td>Bus protection:
Coordination with MV feeder
Coordination with MV feeder by blocking
Arc protection</td></tr>
<tr><td>Outgoing MV feeder protection:
I>1200 A
t>0,8 s
(Directional) earth fault protection</td></tr>
<tr><td>LV feeder protection:
Overcurrent protection with fuses</td></tr>
</table>

A.5.1.2 Typical Protection Scheme for Primary Substation and MV Network (Rural)

MV Neutral Grounding: Isolated



Primary (HV/MV) Transformer Protection: Overcurrent protection Earth-fault protection
Bus protection: Coordination with MV feeder Coordination with MV feeder by blocking Arc protection
Outgoing MV feeder protection: I>250 A t>0,6 s I>>1500 A t>>0,15 s Reclosing practice: (Dead time – time between two reclosings) 0,2–0,4 s 30–120 s (Directional) earth fault protection
LV feeder protection: Overcurrent protection with fuses

A.5.1.3 Trends in protection of MV networks in Finland

- Rural old over-headlines are replaced by cables
- MV neutral grounding practice is changing more and more from isolated to compensated (reactance grounding)
- Usage of directional over-current protection (without and with communication based interlockings/blockings) and reclosers are coming also more common in the near future
- In addition, at the moment very few DG units connected to the network but in the near future for example the amount of wind power is expected to increase (However, it will probably be mainly connected to 110 kV and above voltage levels)

A.5.2 Protection Scheme for DG Units

A.5.2.1 Finnish grid code requirements for DG units

The Finnish distribution system is operated mostly as a 20 kV network, although some networks with 10 kV or 45 kV "sub-transmission" levels exist as well. At the moment there are around 100 distribution network operators (DNOs) ranging from some major companies to very small local operators. The Finnish transmission system is operated by Fingrid mostly on voltage levels greater or equal to 110 kV.

DG units up to 50 kVA [2] and over 50 kVA [3]

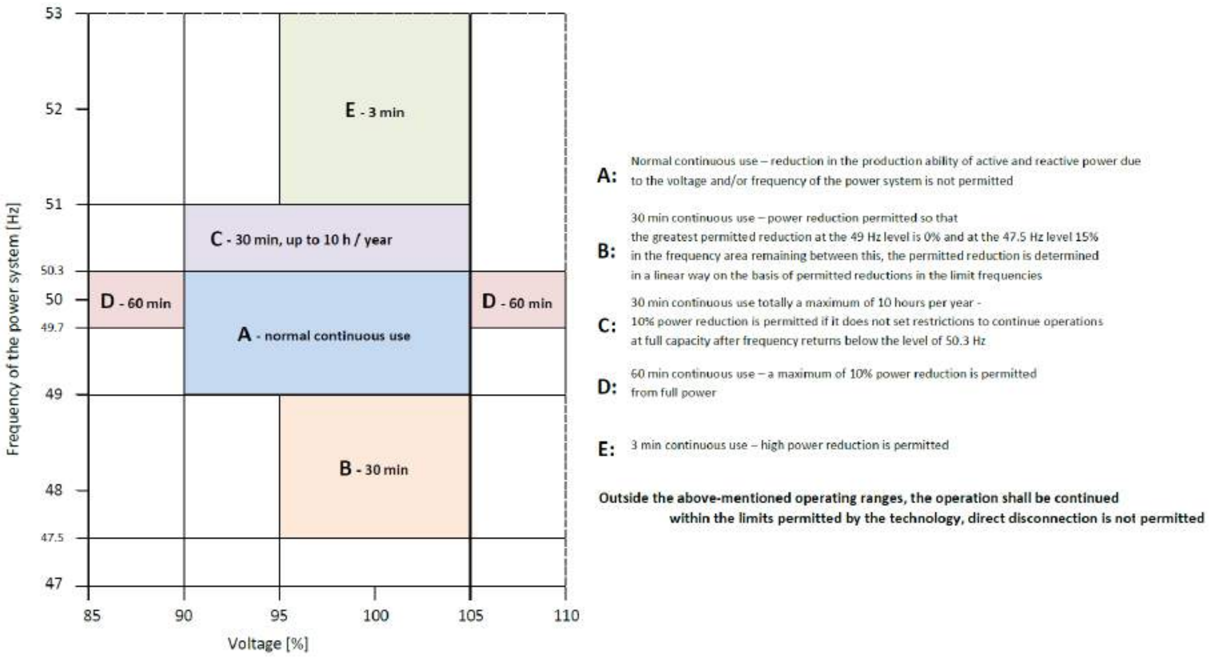
Requirements for connection and protection of DG units <50 kVA [66] and >50 kVA [67] have been published for DNOs by the Finnish Electricity Association "Energiateollisuus" (Electric Networks).

Generation installations of up to 50 kVA must be equipped with protection devices that disconnect the generation installation or isolated generation fed by the generation installation from the public network if the feed to the network is cut off or if the voltage or frequency at the equipment connection point deviates from the normal reported values. The set values of protection are presented in following table, in which Ur means the normal nominal rated voltage of the distribution network. The system operator in Finland may deviate from the values case by case. Before connection of the DG unit to network information concerning the installation must be delivered to the system operator e.g. information about the implementation of protection to prevent isolated/island operation (method and operating time of Loss of mains protection). [66]

If the generation installation disconnects from the network due to the functioning of the protection device, it can reconnect to the network only after the network voltage and frequency have returned back to the limits permitted by the set values for protection and have remained within these limits for a certain minimum period. This minimum period is 20 seconds for installations connected to the network with an inverter and 3 minutes for other generation installations. In addition to the equipment that fulfil the requirements set in [66], also equipment < 50 kVA that fulfil the technical requirements set in German application guide VDE-AR-N-4105, are accepted to be connected to the distribution network. [66]

Protection settings for DG units [66]	
Function	<50 kVA
U>>	-
U>	1,10·Ur / ≤ 0,2 s
U<	0,85·Ur / ≤ 0,2 s
U<<	-
f>	51,0 Hz / ≤ 0,2 s
f<	48,0 Hz / ≤ 0,2 s
loss of mains	≤ 5 s

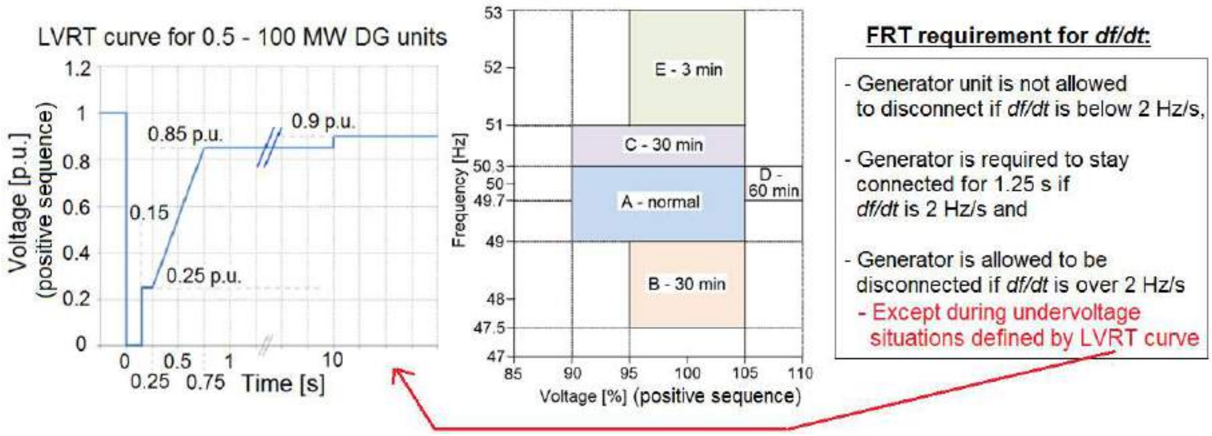
The set values for the protection of DG units with a nominal rated capacity of over 50 kVA are determined separately in each case. The set limits for the under- and overvoltage and the under- and overfrequency protection of the DG units > 50 kVA must be in line with the permissible limits of the frequency and/or voltage deviation lasting for 30 minutes or longer, as presented in [68] and below [67]:



The operating delays must be based on the generation installation's ability to operate at under- and overfrequency and at under- and overvoltage conditions. The operating delays of protection must be agreed separately with the system operator of the connection point. Information about the protection settings of the generation installation must be delivered to the system operator of the generation installation as part of the documentation delivered on the installation. The generation installation must be equipped with protection that prevents island operation. A description of protection that prevents island operation must be delivered to the system operator of the connection point, and the protection settings must be agreed on separately with the system operator of the connection point. [67]

DG units 500 kVA – 100 MVA [4]

Fingrid has also recently defined their own initial (not finally accepted) grid code (Technical requirements for power plants - VJV2013) requirements for 500 kVA – 100 MVA generator units [68] including for example different fault-ride-through (FRT) requirements regarding to frequency, voltage and rate-of-change-of-frequency *df/dt*. These FRT requirements should be taken into account in the future when the corresponding protection settings for DG units are determined. In these some of the requirements of the possible forthcoming ENTSO-E grid code [69] has been tried to take into account. Also in [68] it has been stated that before connection of the DG unit to network information concerning the installation must be delivered to the system operator e.g. about the protection principle to prevent island operation.



No different recommendations are given for DG units connected via dedicated lines or connected directly to the substation.

Future views about Finnish grid code requirements for DG units

In Europe the ENTSO-E grid code RfG [69] is envisaged to go through the European Commission's Comitology procedure later this year 2013 or in the beginning of 2014. It provides legal framework for DG grid code requirements and if it is approved, new national grid code must be defined according to ENTSO-E grid code RfG 3 years after approval. This means in Finland that the not finally accepted Technical requirements for power plants – VJV 2013 [68] has to be again fully updated based on ENTSO-E grid code RfG [69] until 2017(?). However, it should be noted that ENTSO-E grid code RfG [69] will not replace local national grid codes in Europe.

ENTSO-E grid code RfG [69] divides requirements for four type/size of DG units (Power Generating Modules) i.e. Type A (DG units > 0,8 kW connected to voltage levels below 110 kV) and B, C and D:

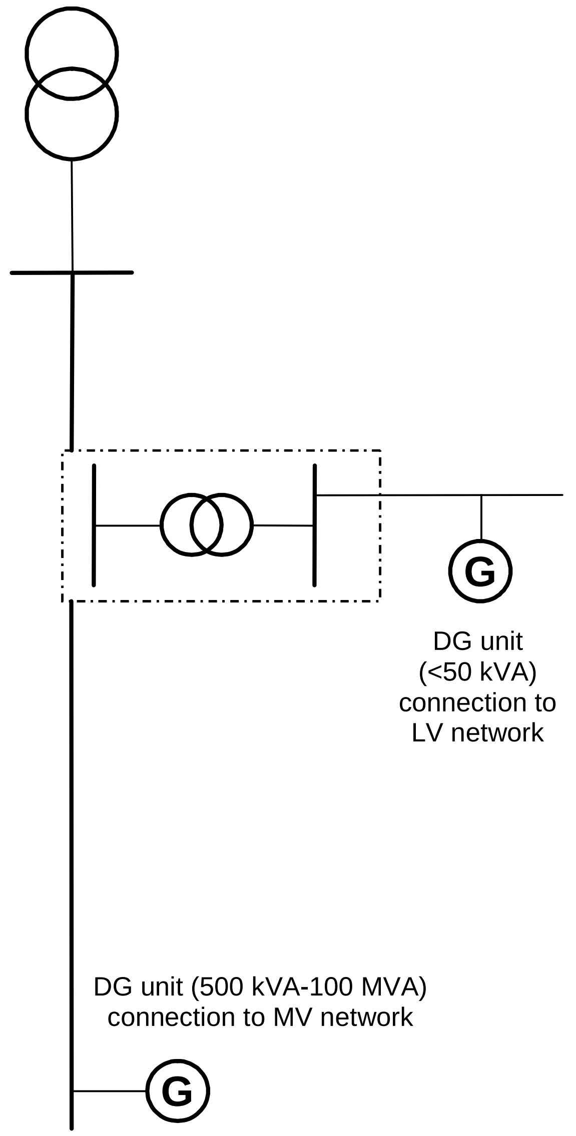
Synchronous Area	maximum capacity threshold from which on a Power Generating Module is of Type B	maximum capacity threshold from which on a Power Generating Module is of Type C	maximum capacity threshold from which on a Power Generating Module is of Type D
Continental Europe	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Great Britain	1 MW	10 MW	30 MW
Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

In addition, ENTSO-E grid code RfG [69] further divides the requirements into the two categories. Category-1-requirements (exhaustively described by RfG) include: frequency ranges (including limited frequency sensitive mode) and voltage ranges. Category-2-requirements (not exhaustively described by RfG, specified in national level) include among others: reactive power and FRT. Based on ENTSO-E grid code RfG [69] voltage related FRT voltage curves may also be different for synchronous generators (Synchronous Power Generating Modules) and inverter connected DGs (Power Park Modules).

One interesting issue in the future is to see that what impact CENELEC (EUROPEAN COMMITTEE FOR ELECTROTECHNICAL STANDARDISATION) possible forthcoming standards

1. CLC/FprTS 50549-1 “Requirements for generating plants larger than 16 A per phase to be connected in parallel with a low-voltage distribution network” and
2. CLC/FprTS 50549-2 “Requirements for generating plants to be connected in parallel with a medium-voltage distribution network”

may have on national grid codes in Europe when compared to the requirements set by the forthcoming ENTSO-E grid code RfG [69].

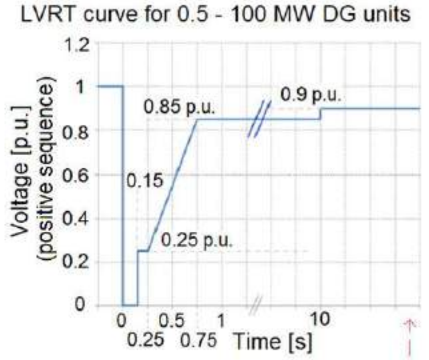


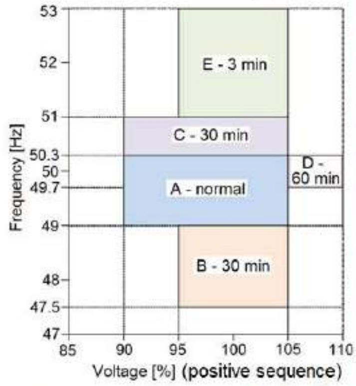
Protection of DG units <50 kVA [2]:

U>/t	1,10·Ur / < 0,2 s
U</t	0,85·Ur / 0,2 s
f>/t	51,0 Hz / < 0,2 s
f</t	48,0 Hz / < 0,2 s

Loss of mains up to 5 s
(Ur = nominal rated voltage)

Protection of DG units 500 kVA – 100 MVA [4]:





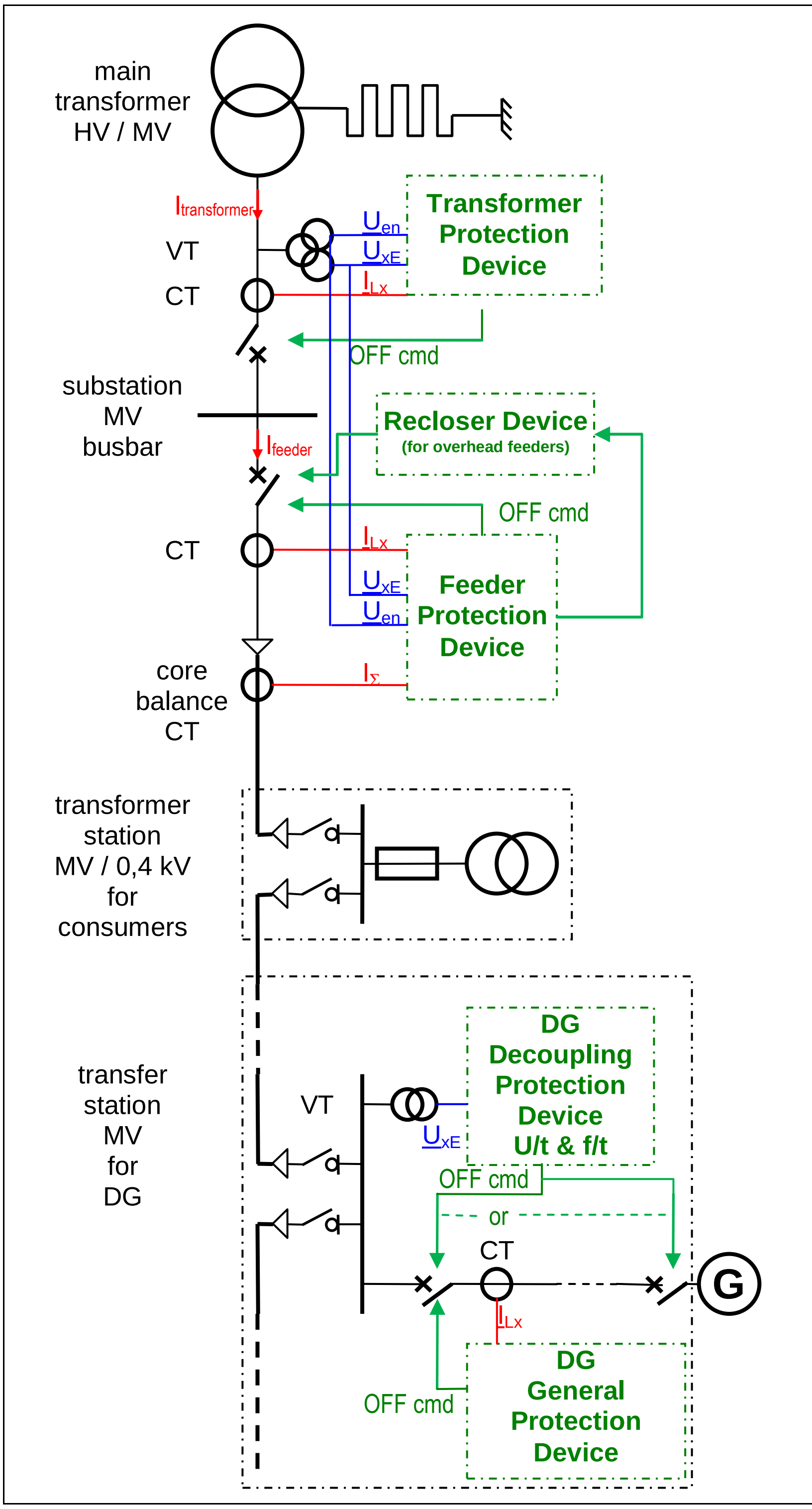
FRT requirement for *df/dt*:

- Generator unit is not allowed to disconnect if *df/dt* is below 2 Hz/s,
- Generator is required to stay connected for 1.25 s if *df/dt* is 2 Hz/s and
- Generator is allowed to be disconnected if *df/dt* is over 2 Hz/s
  - Except during undervoltage situations defined by LVRT curve

A.6 France

A.6.1 Protection Scheme Device of Typical Outgoing Feeder MV

Neutral treatment: Low impedance grounding (12, 40, 80 or (40+j40)Ω) or compensated neutral



Transformer Protection Device : 20/36/40/70 MVA 225-90-63kV / 20-15 kV

Overcurrent Protection $I > 1{,}6 \cdot I_{n\ Transformer}$

t < 1,3s

Homopolar Current Protection (PAH)

$I_0 = 1{,}2 \cdot I_{0\ max\ Feeder}$

t > 1,2 s

(+ Homopolar Voltage Protection (PVH) for compensated neutral transformer :V_0 = 40%Vn)

Feeder Protection Device :

Overcurrent Protection (OC) (directional or not, depending on the network and the DG maximal Power)

$1{,}3 \cdot I_{max\ DG} < I < 0{,}8 \cdot I_{sc\ min}$

t ≈ 0,5 s

Homopolar Wattmetric Prot. (PWH) (For networks with compensated neutral)

$P_0 \approx$ 8kW

t ≈ 1 s

Homopolar Current Protection (PAH)

$I_0 = 1{,}2 \cdot I_{0\ max\ Feeder}$

t > 0,5 s

Decoupling Protection for MV DG U/t- and f/t-protection:

$V_0 > 0{,}1 \cdot$Un ; t = feeder trip delay + 0,5 s

U < 0,8~0,85·Un ; t = 1,2 s

U >1,15·Un ; t = 0,2 s

f < 47~49,5 Hz ; t = feeder trip delay + 0,5 s or instantaneous

f > 50,5~52 Hz ; t = feeder trip delay + 0,5 s or instantaneous

For DG with maximal Power > 5 MW: (U</t 0,45·Un / 0,2 s -> on Producer's request)

+ FRT requirements (see document thereafter)

+ Anti-islanding Teleprotection

Decoupling Protection for LV DG U/t- and f/t-protection:

U</t	0,8~0,85·Un / instantaneous
U>/t	1,15·Un / instantaneous
f</t	47,5~49,8 Hz / instantaneous
f>/t	50,2~50,6 Hz / instantaneous

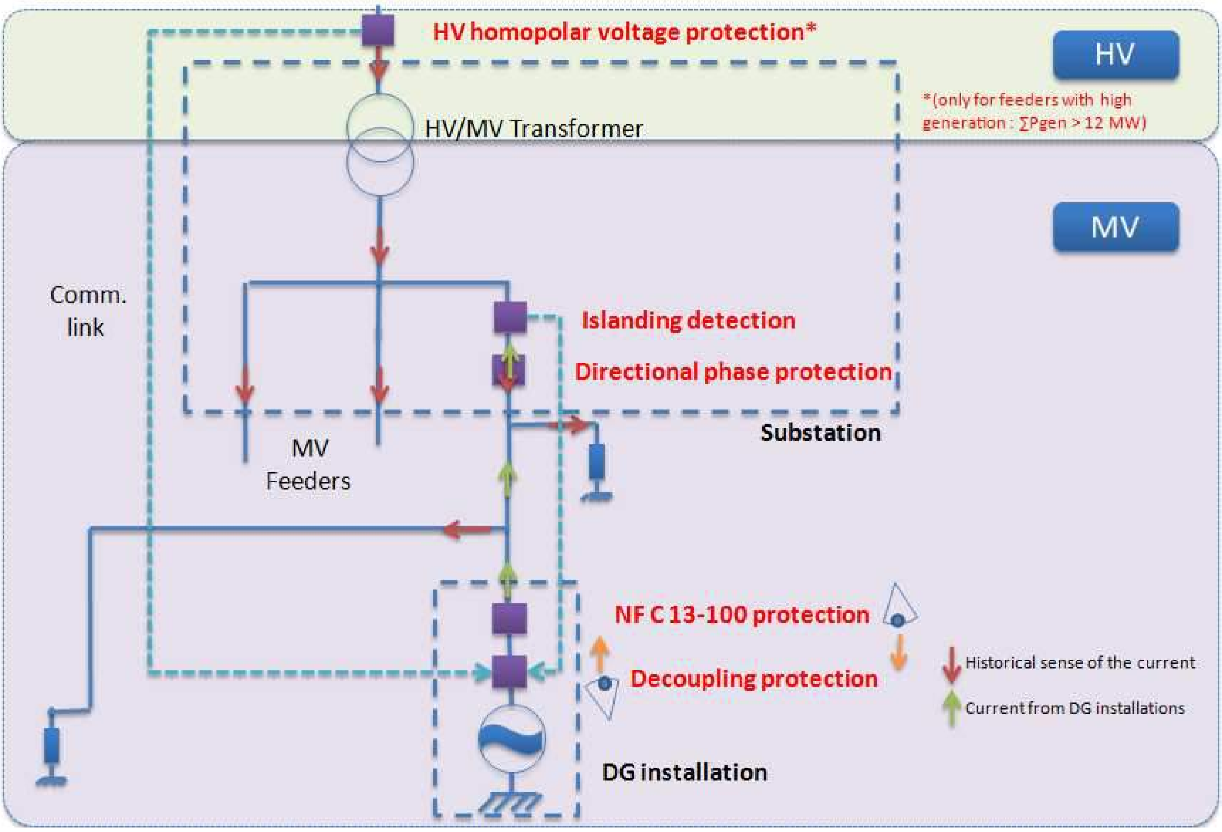
DG General Protection (C 13-100)

OC protection:	**PAH:**
$8 \cdot I_{max\ DG} < I < 0{,}8 \cdot I_{sc\ min}$	$12\% \ Io < Io_{maxFeeder}$
t ≈ 0,2 s	t ≈ 0,2 s

(+PWH 40kW/0,5s for compensated neutral)

A.6.2 Textual description

The following graphic explains the different kinds of protections used on the distribution network at MV level in addition to classical network protection (Overcurrent Protection (OC), Homopolar Wattmetric Protection (PWH), Homopolar Voltage and Current protection (PVH and PAH) :

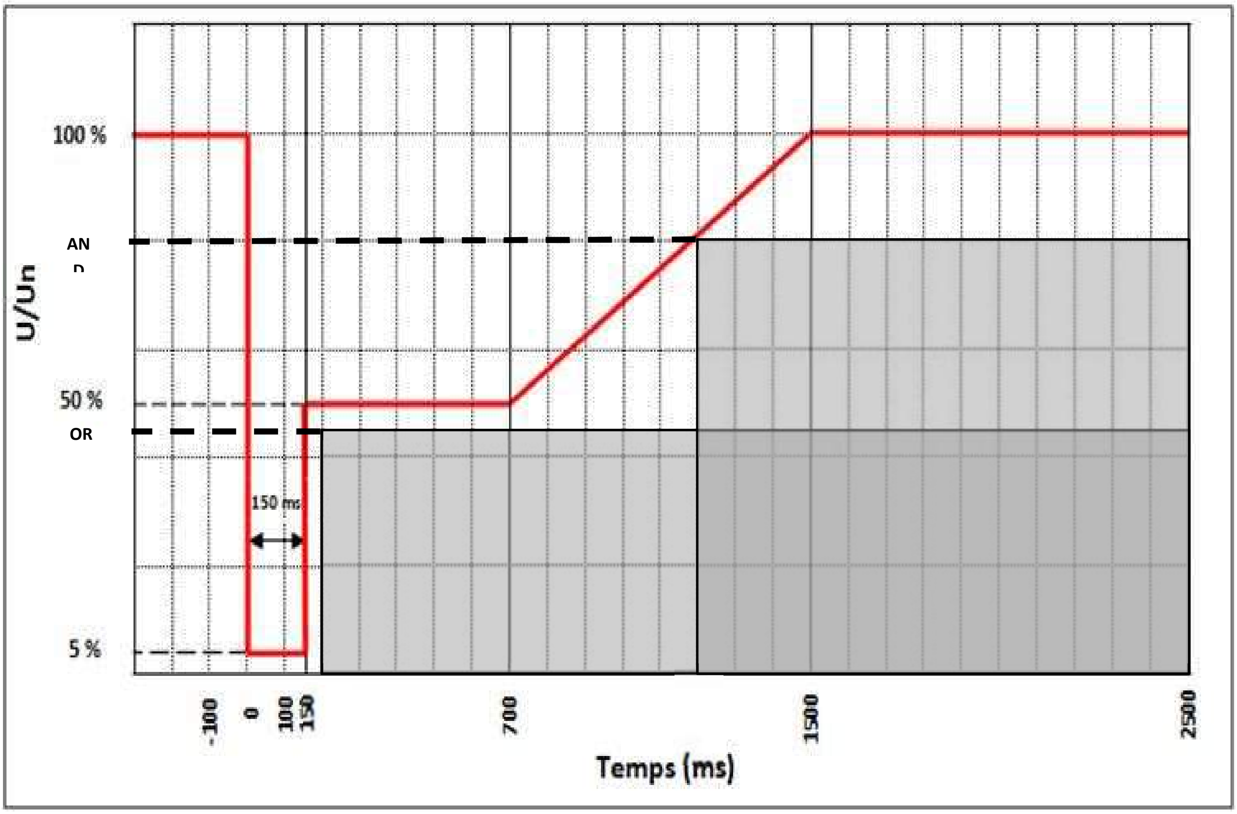


- **HV homopolar voltage protection** : Additional decoupling protection to protect in case of phase fault at HV level
- **Islanding detection (tele-decoupling)**: Detects the opening of the MV feeder and send the information to the DG installation decoupling protection
- **Directional phase protection** : Protection in order to know the location of the fault and avoid unintentional tripping (i.e. : when the fault occurs on another MV feeder)
- **NF C-13-100 Protection** : To trip when faults occur within the installation
- **Decoupling protection** : Disconnects the DG installation from the network when a MV network fault occurs

In addition to classical phase and earth faults protections (OC, PWH, PAH, PVH).

A.6.3 FRT – Requirements

Since December 23, 2010 (French legislation), installations with **Power above 5 MW** must stay connected to the network in the normal frequency range [47Hz – 52Hz], during the following fault:



There is therefore a correct coordination between Undervoltage and Fault Ride Through requirements.

A.6.4 MV decoupling protection synthesis

The following table describes the different “Hx-protections” used on ERDF MV network as decoupling protection for Distributed Generators. Each “Hx protection” is a multi-function protection, with different thresholds and temporization depending on the kind of detected fault.

MV decoupling protections	*Type H.1*	*Type H.2*	*Type H.3*	*Type H.4*	*Type H.5*
G , Power of generators	250 kVA < G < 25% of feeder average load	G > 25% of feeder average load	G > 25% of feeder average load	G ≥ 5MW	G ≥ 5MW
Type of the feeder	Underground or overhead feeder	Underground feeder without reclosing	overhead feeder with reclosing	Underground or overhead feeder	Dedicated Underground feeder without reclosing
Functions					
Detection of the single-phase MV faults	$V_0 > 10\% V_n$ 60 ms < Time < 100 ms	$V_0 > 10\% V_n$ Time = feeder trip delay + 0,5 s			
Detection of the phase to phase MV faults	U < 85% Um 60 ms < Time < 100 ms		U < 85% Um Time = feeder trip delay + 0,5 s	U < 80% Um Time = 1.2 s	
Detection of islanding				Teleprotection	
	$U < 85\% U_m$ 60 ms < Time < 100 ms		$U < 85\% U_m$ Time = feeder trip delay + 0,5 s	$U < 80\% U_m$ Time = 1.2 s	
	$U > 115\% U_m$ 60 ms < Time < 100 ms			$U > 115\% U_m$ Time = 0,2 s	
	F < 47,5 Hz 60 ms < Time < 180 ms		F < 49,5 Hz 60 ms < Time < 180 ms	F < 47 Hz Time = feeder trip delay + 0,5 s	
	F < 51 Hz 60 ms < Time < 180 ms		F < 50,5 Hz 60 ms < Time < 180 ms	F > 52 Hz Time = feeder trip delay + 0,5 s	
Detection of voltage dips *(loss of synchronisation)*	U < 85% Um 60 ms < Time < 100 ms		U < 25% Um 60 ms <Time < 100 ms	U < 45% Um Time = 0,2 s	

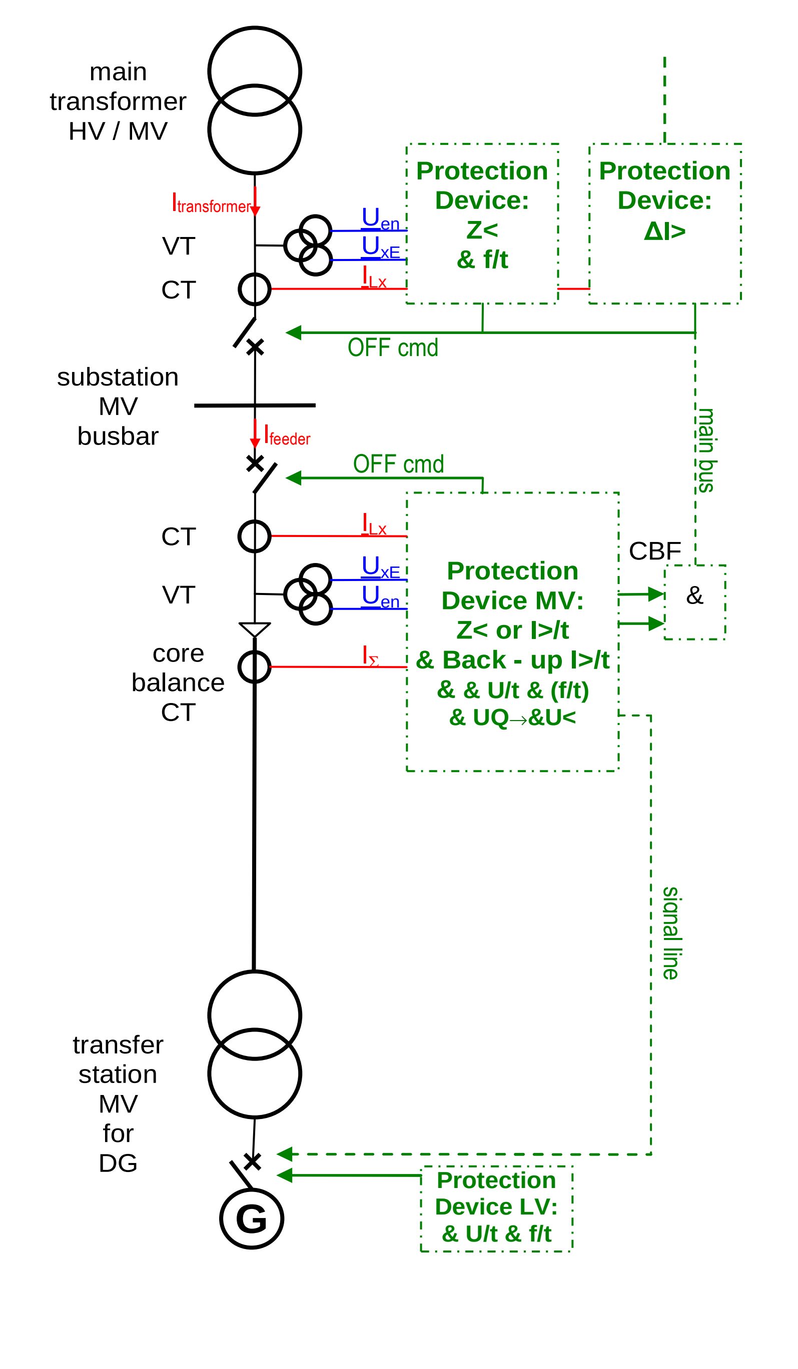
A.6.5 LV decoupling protection synthesis

The following table describes the different decoupling protections used on ERDF LV network for Distributed Generators. This decoupling protection can be intern (B.1) or extern (DIN VDE) to the installation.

<table>
<tr><th>LV
decoupling protections</th><th>B.1</th><th>ENS DIN VDE 0126</th><th colspan="2">ENS DIN VDE 0126-1-1 and DIN VDE 0126-1-1/A1 VFR 2013-VFR 2014</th></tr>
<tr><td>Detection of the single-phase MV faults</td><td colspan="4">Non-existing</td></tr>
<tr><td>Detection of the phase to phase faults and phase to neutral LV faults</td><td>$V < 85\% V_N$
60 ms < Time < 100 ms</td><td>$U < 80 \% V_N$
Time < 0,2 sec</td><td colspan="2">$V < 80\% V_N$
Time < 0,2 sec</td></tr>
<tr><td rowspan="4">Detection of islanding</td><td>$V < 85\% V_N$
60 ms < Time ≤ 100 ms</td><td>$V < 80\% V_N$
Time < 0,2 sec</td><td colspan="2">$V < 80\% V_N$
Time < 0,2 sec</td></tr>
<tr><td>$V > 115\% V_N$
60 ms <Time ≤ 100 ms</td><td>$V > 115\% V_N$
Time < 0,2 sec</td><td colspan="2">$V > 115\% V_N$
Time < 0,2 sec</td></tr>
<tr><td>F < 49,5 Hz
60 ms <Time ≤ 180 ms</td><td>F < 49,8 Hz
Time < 0,2 sec</td><td colspan="2">F < 47,5 Hz
Time < 0,2 sec</td></tr>
<tr><td>F > 50,5 Hz
60 ms < Time ≤ 180 ms</td><td>F > 50,2 Hz
Time < 0,2 sec</td><td colspan="2">Until 30.08.2013 :
F > 50,2 Hz
From 01.07.2013 to 30.06.2014 :
F > 50,4 Hz
From 01.05.2014 :
F > 50,6 Hz
Time < 0,2 sec</td></tr>
<tr><td rowspan="2">Loss of main</td><td rowspan="2">Non-existing</td><td rowspan="2">$Z_{rac} <$ 1,25 then 1,75Ω
$\Delta Z_{rac} > + 0,5\ \Omega$
Time < 5 s</td><td colspan="2">Two possibilities</td></tr>
<tr><td>$Z_{rac} <$ 1,25 then 1,75Ω
$\Delta Z_{rac} > + 1\ \Omega$
Time < 5 s</td><td>Oscillating circuit
Time < 5 s</td></tr>
</table>

A.7 Germany

A.7.1 DER at substation busbar - (apparent) power >=1MVA



MV protection of main transformer:

Z< protection:

$I>> \approx 1,5 \cdot I_{r,transformer}$

$t_{end,directional} = 1,2$ s

$t_{end,nondirectional} = 1,2$ s

f/t-protection:

f<=49..48 Hz (& power flow fwd)

ΔI> protection:

$\Delta I>= 0,3 \cdot I_{r,transformer}$

MV protection of feeder:

Z< protection:

$t_{end,directional} = 0,9$ s

$t_{end,nondirectional} = 1,2$ s

$I>> \approx 1,2 \cdot I_{r,feeder}$ max 80% $I_{fault,2p}$

Back-up I>/t-protection:

$t_{Back\text{-}up\ I>/t}=0,9$ s

MV decoupling protection:

U/t- and f/t-protection:

U>>/t 1,15·U_c / ≤ 0,1 s

U>/t 1,08·U_c / 1 min

U</t 0,8·U_c / 2,7 s

(U_c = voltage at PCC)

Reactive power low voltage protection:

Q→&U< 0,85 U_c / 1,5s (MV CB)

Q→&U< 0,85 U_c / 0,5s (LV CB)

LV decoupling protection:

U/t- and f/t-protection:

U>>/t 1,15·U_{LV} / ≤ 0,1 s

U</t 0,8·U_{LV} / 1,5 s

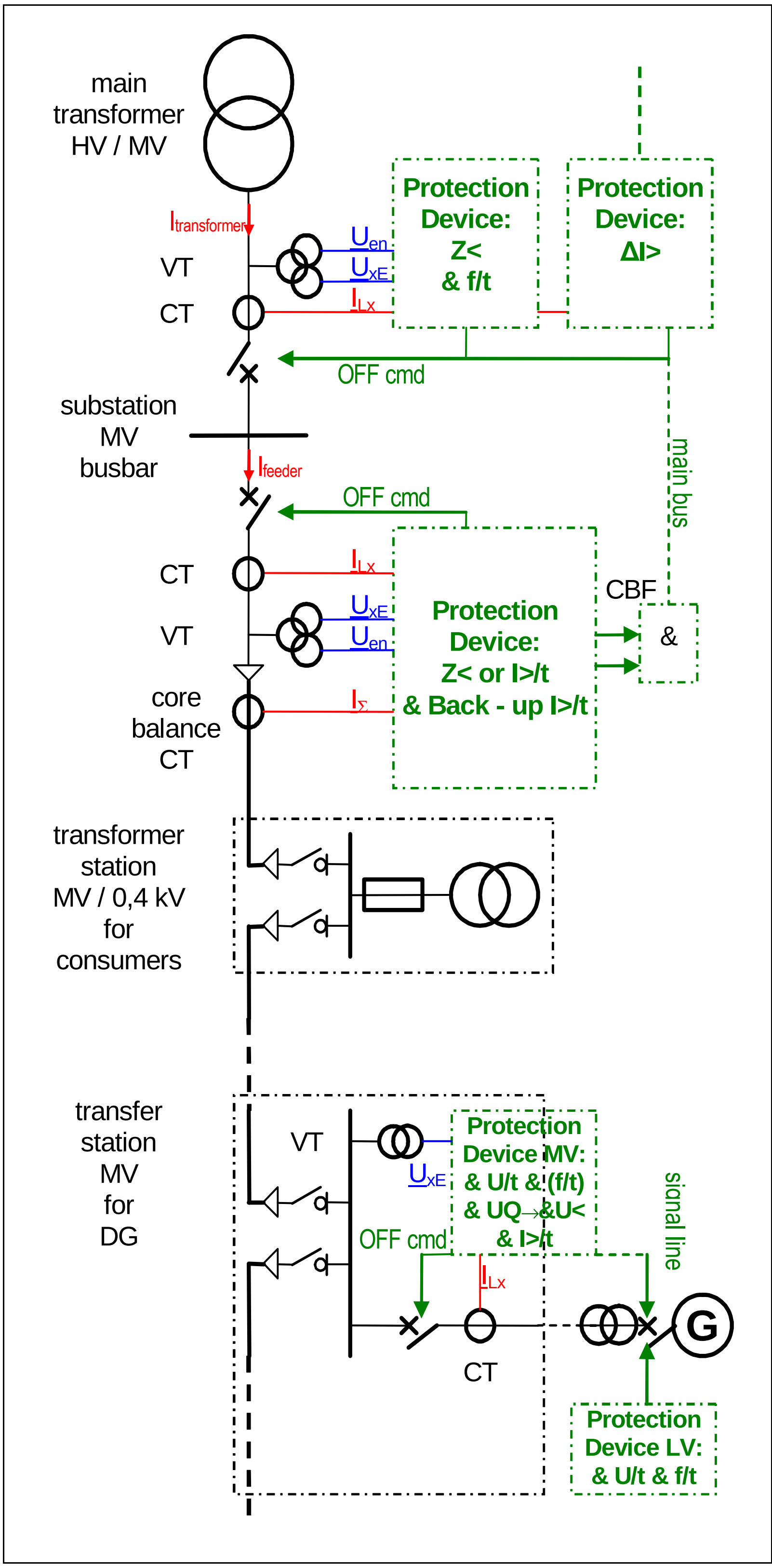
U<</t 0,45·U_{LV} / 0,3 s

f>/t 51,5 Hz / ≤ 0,1 s

f</t 47,5 Hz / ≤ 0,1 s

(U_{LV} = Lowvoltage)

A.7.2 DER at MV grid - (apparent) power >=1MVA



MV protection of main transformer :

Z< protection:

$I{>>} \approx 1{,}5 \cdot I_{r,transformer}$

$t_{end,directional} = 1{,}2$ s

$t_{end,nondirectional} = 1{,}2$ s

f/t-protection:

f<=49..48 Hz (& power flow fwd)

ΔI> protection:

$\Delta I{>} = 0{,}3 \cdot I_{r,transformer}$

MV protection of feeder:

Z< protection:

$t_{end,directional} = 0{,}9$ s

$t_{end,nondirectional} = 1{,}2$ s

$I{>>} \approx 1{,}2 \cdot I_{r,feeder}$ max 80% $I_{fault,2p}$

Back-up I>/t-protection:

$t_{Back\text{-}up\ I>/t} = 0{,}9$ s

I>/t-protection:

I>> = various

t>> = 0,1s

MV decoupling protection:

U/t- and f/t-protection:

U>>/t	$1{,}15 \cdot U_c$ / ≤ 0,1 s
U>/t	$1{,}08 \cdot U_c$ / 1 min
U</t	$0{,}8 \cdot U_c$ / 2,7 s

(U_c = voltage at PCC)

Reactive power low voltage protection:

Q→&U<	0,85 U_c / 1,5s (MV CB)
Q→&U<	0,85 U_c / 0,5s (LV CB)

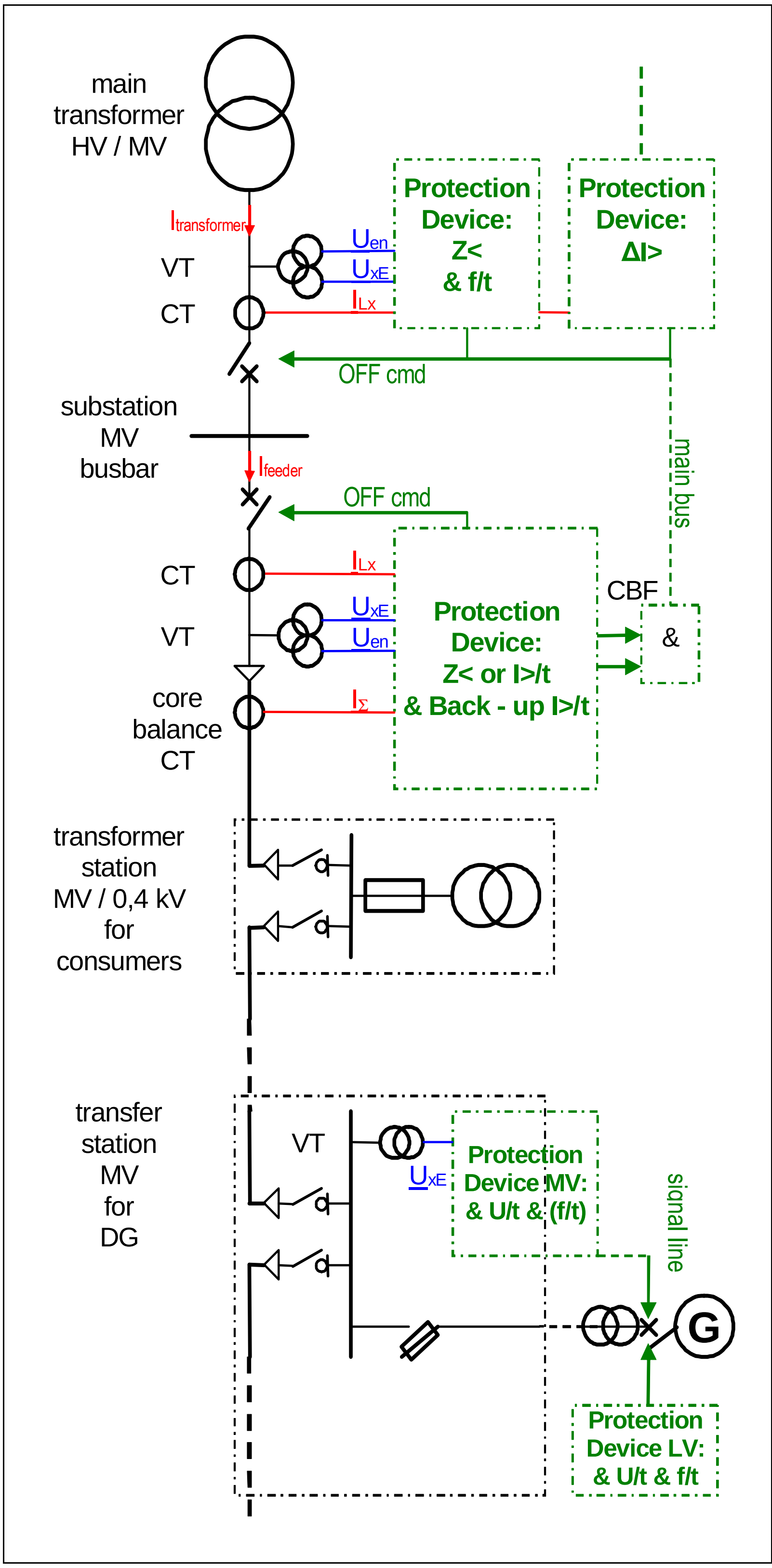
LV decoupling protection:

U/t- and f/t-protection:

U>>/t	$1{,}15 \cdot U_{LV}$ / ≤ 0,1 s
U</t	$0{,}8 \cdot U_{LV}$ / 1,5 s
U<</t	$0{,}45 \cdot U_{LV}$ / 0,3 s
f>/t	51,5 Hz / ≤ 0,1 s
f</t	47,5 Hz / ≤ 0,1 s

(U_{LV} = Lowvoltage)

A.7.3 DER at MV grid - (apparent) power <1MVA



MV protection of main transformer:

Z< protection:

$I>> \approx 1{,}5 \cdot I_{r,transformer}$

$t_{end,directional} = 1{,}2$ s

$t_{end,nondirectional} = 1{,}2$ s

f/t-protection:

f<=49..48 Hz (& power flow fwd)

ΔI> protection:

$\Delta I >= 0{,}3 \cdot I_{r,transformer}$

MV protection of feeder:

Z< protection:

$t_{end,directional} = 0{,}9$ s

$t_{end,nondirectional} = 1{,}2$ s

$I>> \approx 1{,}2 \cdot I_{r,feeder}$ max 80% $I_{fault,2p}$

Back-up I>/t-protection:

$t_{Back\text{-}up\ I>/t} = 0{,}9$ s

I>/t-protection:

fuse

MV decoupling protection:

U/t- and f/t-protection:

U>>/t	$1{,}15 \cdot U_c$ / ≤ 0,1 s
U>/t	$1{,}08 \cdot U_c$ / 1 min
U</t	$0{,}8 \cdot U_c$ / 2,7 s

(U_c = voltage at PCC)

LV decoupling protection:

U/t- and f/t-protection:

U>>/t	$1{,}15 \cdot U_{LV}$ / ≤ 0,1 s
U</t	$0{,}8 \cdot U_{LV}$ / 1,5 s
U<</t	$0{,}45 \cdot U_{LV}$ / 0,3 s
f>/t	51,5 Hz / ≤ 0,1 s
f</t	47,5 Hz / ≤ 0,1 s

(U_{LV} = Low voltage)

A.7.4 Description of the protection schemes

A.7.4.1 MV-feeders protection scheme

Directional over-current protection or distance protection is used as the main function to protect MV feeders. In case of CB-failure or failure of a protection system, the distance protection at the transformer is used as back-up.

In MV grids with less short-circuit power, a second over-current protection relay and a CB-failure protection may be needed at the feeders.

A.7.4.2 Dynamic voltage support

Dynamic voltage support means voltage control in the event of sudden voltage drops within the high and extra-high voltage grids with the aim to avoid unintentional disconnections of large infeeds and thus voltage collapse.

That means that generating plants must be able in technical terms:

- not to disconnect from the grid in the event of grid faults,
- to support the voltage during a short-circuit fault by feeding a reactive current into the grid,
- not to consume reactive power after fault occurrence than before. [1]

A.7.4.3 DER protection scheme

There are different needs for protection functions depending of the maximum power of the DER and the connection concept (see A.7.1 to A.7.3).

Protection scheme at the DER transfer station can be divided into three categories:

- short-circuit protection device at the transfer point
- primary protective disconnection device at the transfer point
- protective disconnection devices at the different generators

Short-circuit protection

Short-circuit protection of the generating plant is required for clearing of short-circuits near the connection point. In addition, it serves as back-up protection in the event of faults within the generating units and in the power grid. The minimum requirements to support short-circuit protection is a directional (definite time-delay) over-current protection relay – a distance relay is recommended.

Primary protective disconnection device

The following devices are required as primary protective disconnection equipment at the connection point:

- reactive power plus under-voltage protection Q->& U<: The generating plant is disconnected from the network after 0,5 s, if all three line-to-line voltages at the network point of connection are below 0,85 Uc (logical AND connection) and if the generating plant simultaneously consumes reactive power. Optional the time delay can be extended to 1,5s if there is a trip command transfer to the generator’s CBs with a maximum time delay of 0.5s.

- rise-in-voltage protection U>> and U>: Three phase voltages between conductors, logical OR
- under-voltage protection U<: Three phase voltages between conductors, logical OR

Protective disconnection devices at the generators

The following protection equipment is required at the generating units:

- rise-in-voltage protection U>>: Three phase voltages between conductors ,logical OR
- under-voltage protection U< and U<<: Three phase voltages between conductors, logical OR
- rise-in-frequency protection f>
- under-frequency protection f<

Note: Lines with automatic reclosure (AR)

Generally: In the case of automatic reclosure, the plant operator must be prepared for the recovery voltage at the network connection point may be asynchronous to the voltage of the generating plant. [64]

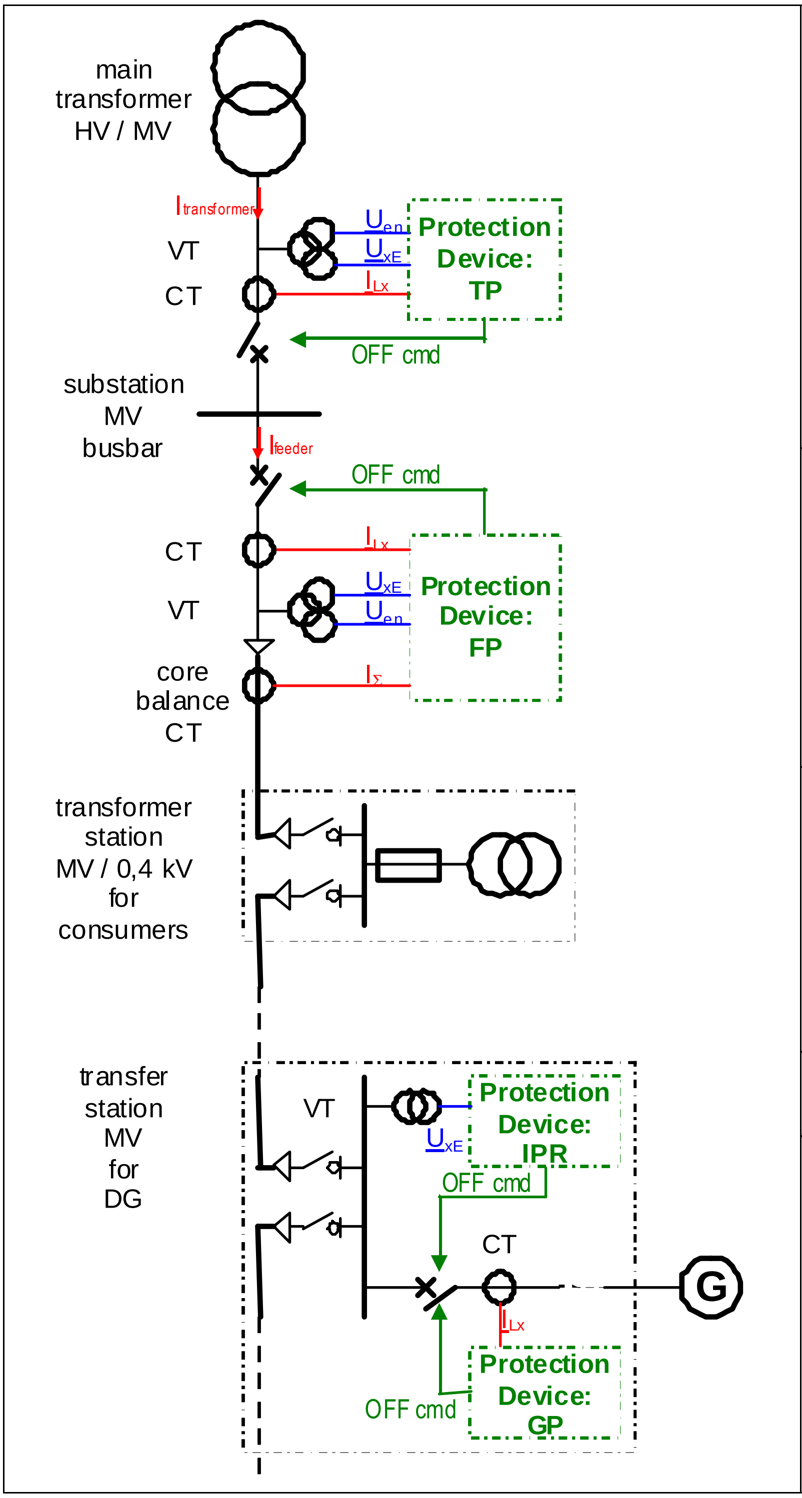
During dead time of AR the DER must be able:

- to stay at the medium-voltage grid with <u>no</u> feeding of any power (zero power mode)
- or if zero power mode isn’t available: to disconnect with U<< in less than 100ms

A.8 Italy

A.8.1 Protection Device of Outgoing Feeder

Neutral treatment: **Earthed impedance (Petersen coil)**



MV protection of main transformer: TRAFO Protection (TP):

CODE* 51

$I>> \approx 1{,}4 \cdot I_{r,transformer}$ (if ONAN)

$t_{discr} = 1{,}5$ s

$I>> \approx 1{,}6 \cdot I_{r,transformer}$ (if ONAF)

$t_{discr} = 1{,}5$ s

CODE 59

$U>> = 1{,}15 \cdot U_r$

$t_{discr} = 10$ s (Alarm)

$U>> = 1{,}2 \cdot U_r$

$t_{discr} = 60$ s (Trip)

CODE 59

$U_{en} >> (5 \div 15)\% \cdot U_{r\ (PH-E)}$

t_{discr}: depending from the MV network automation rules

Feeder protection (FP):

CODE 51

$I> = \min(1{,}2 \cdot I_r;\ 0{,}85 \cdot I_{sc(ph-ph)})$

$t_{discr} = 1$ s

$I>> = 800$ A

$t_{discr} = 0{,}25$ s

$I>>> = 1400$ A

$t_{discr} = 0{,}05$ s **(CODE 50)**

CODE 67N

See A.8.3.1

DG Protection: Interface Protection Relay (IPR)

See A.8.3.2

User Protection: General protection (GP)

See A.8.3.3

* ANSI/IEEE C37.2-2008

A.8.2 Protection Device of Outgoing Feeder

Neutral treatment: **Earthed impedance (Petersen coil)**

A.8.2.1 MV protection of main transformer (TP)

The breaker on the MV side of the transformer is connected to the following protections:

- Buchholz transformer
- Buchholz on load tap changer
- Oil overtemperature
- Overcurrent
- Zero-sequence overvoltage;
- MV overvoltage

A.8.2.2 Feeder Protection (FP)

There is one protection panel for each MV feeder, performing the following functions:

- directional earth fault protection;
- special protection against re-striking and evolving earth faults;
- no directional over-current protection;
- programmable recloser;

The protection system to be adopted on MV feeders against the phase to earth faults, depends on the neutral point condition. In case of neutral earthed impedance the system is more complex than in insulated neutral point condition.

A.8.2.3 DG Protection: Interface Protection Relay (IPR)

The IPR realizes the following functions:

- maximum voltage (59, with two thresholds);
- minimum voltage (27, with two thresholds);
- maximum homopolar voltage (Uen) MV side (59.N, delayed);
- maximum frequency (81 >.S1 with voltmetric release);
- minimum frequency (81<.S1 with voltmetric release);
- maximum frequency (81>.S2);
- minimum frequency (81<.S2);
- voltmeter release function based on the following functions:
    - maximum residual voltage (59 Uen, voltmetric release to activate restrictive thresholds 81>.S1 and 81<.S1);
    - maximum inverse sequence voltage (59Ui, voltmetric release to activate restrictive thresholds 81>.S1 and 81<.S1);
    - maximum direct sequence voltage (27Ud, voltmetric release to activate restrictive thresholds 81>.S1 and 81<.S1).
    - User Protection: General protection (GP)

The GP consist of a relay that performs:

- maximum phase current protection, double-pole version at least, with three thresholds, one dependent-time and the other two, independent-time; since the first threshold is used to prevent overload, the second is used to effect delayed tripping and the third to effect rapid tripping. For simplicity's sake, these thresholds will be referred to using symbols:

- o first threshold (overload), used for the detection of minor overload events which originated on the user plant, indicated below as threshold I>;
- o second threshold (threshold 51, with intentional time delay), used for the detection of polyphase short-circuit impedance faults (i.e., major overload) in the User plant, indicated below as threshold I>>;
- o third threshold (threshold 50, instantaneous), used for the detection of bolted polyphase short short-circuit events in the User plant, indicated below as threshold I>>>

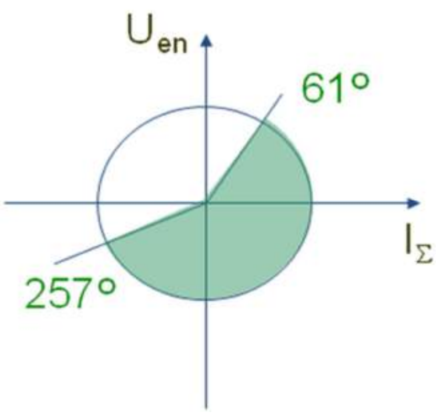
- maximum zero-sequence current protection with two thresholds, or (when the contribution to the capacitive single-phase to earth fault current of the User's MV network exceeds 80% of the control current established by the Distributor for 51N protection) directional earth fault protection with two thresholds and maximum zero-sequence current protection with one threshold.
- For maximum zero-sequence current protection:
  - o first threshold, used for the detection of single-phase to earth faults (bolted or impedance) in the User plant, indicated below as threshold I0>;
  - o second threshold, used for the detection of cross-country faults, with one of the fault points on the User plant, indicated below as threshold I0>>
- For directional protection of maximum zero-sequence current:
  - o first threshold, used for the detection of single-phase to earth faults during compensated neutral operation, indicated below as threshold 67N.S1;
  - o second threshold, used for the detection of single-phase to earth faults during isolated neutral operation, indicated below as threshold 67N.S2;

A.8.3 Notes

A.8.3.1 67N

67N.S1:

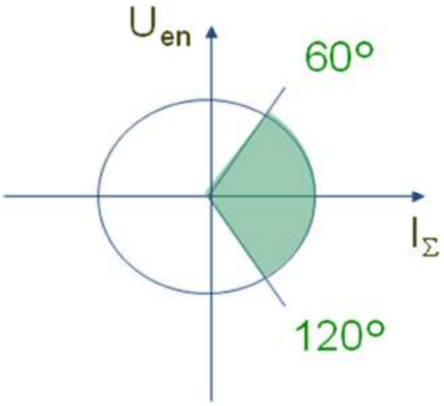
Fault with a single phase to ground: neutral point *compensated (Petersen coil)*



$U_{en} = (5 \div 6)\% \cdot U_{r\ (PH\text{-}E)}$
$I_{\Sigma} = 2$ A
$t_{discr} \geq 1$ s (depending from the MV network automation rules)

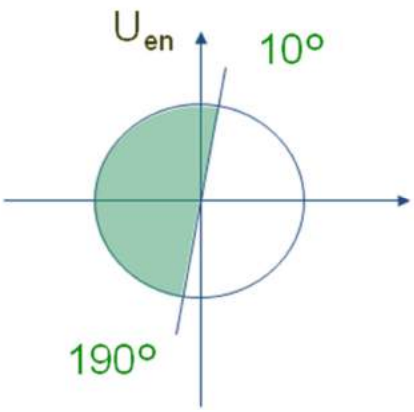
67N.S2:

Fault with a single phase to ground: neutral point: *insulated*



U_{en} = (2 ÷ 15)% $\cdot U_{r\ (PH-E)}$ (depending from the network extension)
I_Σ = (1÷2) A (depending from the network extension)
$t_{discr} \geq 0{,}4$ s

67N.S3:
Fault with two phases to ground (cross-country-fault, no depending from neutral state)

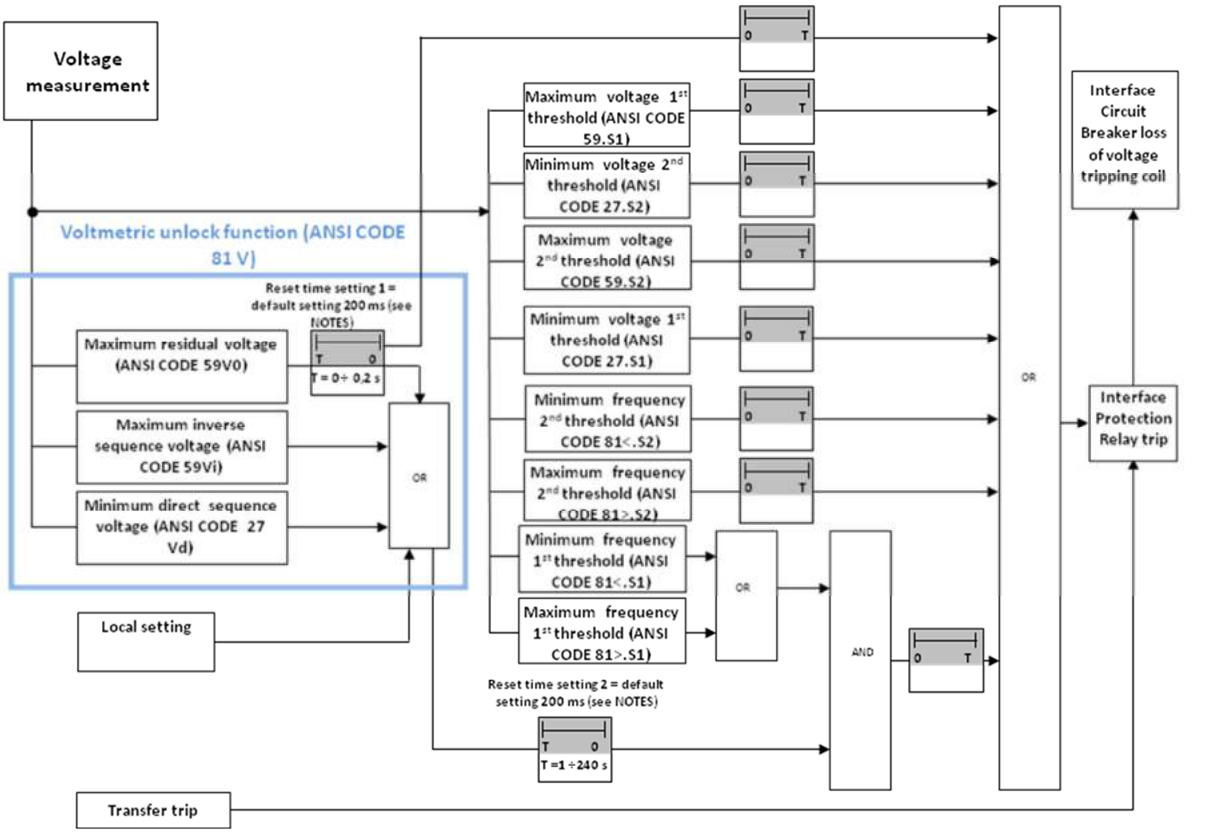


U_{en} = 2% $\cdot U_{r\ (PH-E)}$
I_Σ = 150 A
$t_{discr} \geq 0{,}1$ s

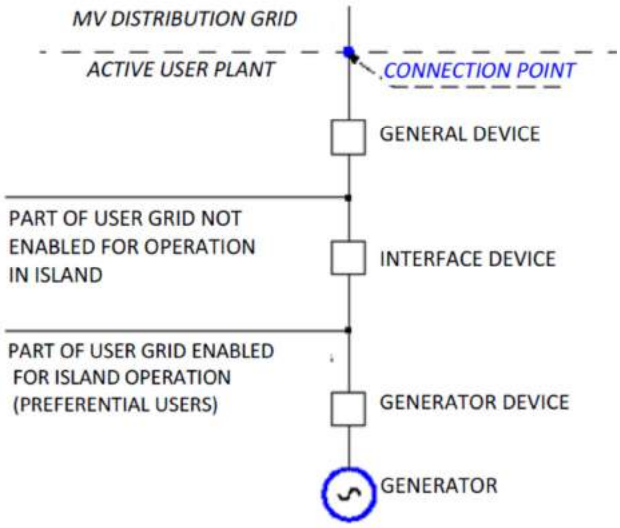
A.8.3.2 Italian Standard CEI 0-16

Protection function	Default threshold value	Default relay operate time	Maximum opening time of the output-break circuit (interface CB with tripping command operated from a voltage absence coil)
Maximum voltage U>.S1 (ANSI CODE 59.S1), 10 minutes mean function (according to EN 61000-4-30, Class S, but adopting a moving window with refresh time ≤ 3 s)	1,10 U_r	Start time ≤ 3 s, not adjustable. Delay time setting = 0 ms Depending on voltage values during the moving window. Maximum value 603 s.	Depending on voltage values during the moving window. Maximum 603,70 s.
Maximum voltage U>.S2 (ANSI CODE 59.S2)	1,20 U_r	200 ms	270 ms
Minimum voltage U<.S1 (ANSI CODE 27.S1) (1)	0,85 U_r	1500 ms	1570 ms
Minimum voltage U<.S2 (ANSI CODE 27.S2) (1)	0,4 U_r	200 ms	270 ms
Maximum frequency f>.S2 (ANSI CODE 81.S2) (2)	50,2 Hz	150 ms	170 ms
Minimum frequency f<.S2 (ANSI CODE 81.S2) (2)	49,8Hz	150 ms	170 ms
Maximum frequency f>.S1 (ANSI CODE 81.S1) (2)	51,5 Hz	1,0 s	1,07 s
Minimum frequency f<.S1 (ANSI CODE 81.S1) (2)	47,5 Hz	4,0 s	4,07 s
Maximum residual voltage U_0> (ANSI CODE 59V_0) (3)	5 % $U_{r\,(PH-E)}$ (4)	For protection use: 25 s For voltmetric unlock use (ANSI CODE 81V): 0 ms (equal to start time:70 ms)	For protection use: 25,07s For voltmetric unlock use: equal to start time (1)
Maximum inverse sequence voltage U_i > (ANSI CODE 59 V_i) (1)	15% $U_r/U_{r\,(PH-E)}$ (5) (indicative, depending on the network)	For voltmetric unlock use (ANSI CODE 81V): 0 ms (equal to start time: 70 ms)	Equal to start time
Minimum direct sequence voltage U_d< (ANSI CODE 27 V_d) (1)	70% $U_r/U_{r\,(PH-E)}$ (5) (indicative, depending on the network)	For voltmetric unlock use (ANSI CODE 81V): 0 ms (equal to start time:70 ms)	Equal to start time
Transfer trip		<150 ms	<220 ms

Threshold active only for inverters and rotating generators connected to distribution network with AC/AC converters.
For rotating generators directly connected U<.S2: operate time 70 ms, threshold value 70%, U<.S1: excluded .
For voltage values below 0,2 U_r, f>.S1, f>.S2 & f<.S1, f<.S2 protections shall be disabled.
Function used both for tripping and for voltmetric unlock function.
Regulation in % of nominal residual voltage $U_{r\,(PH-E)}$ in case of a phase to earth fault with 0 Ω fault resistance derived directly from an open delta winding or calculated internally the IPR from phase to earth voltages derived from non iron core voltage transducers.
Regulation in % of nominal phase to earth or phase to phase voltage, according to voltage measurements methods.



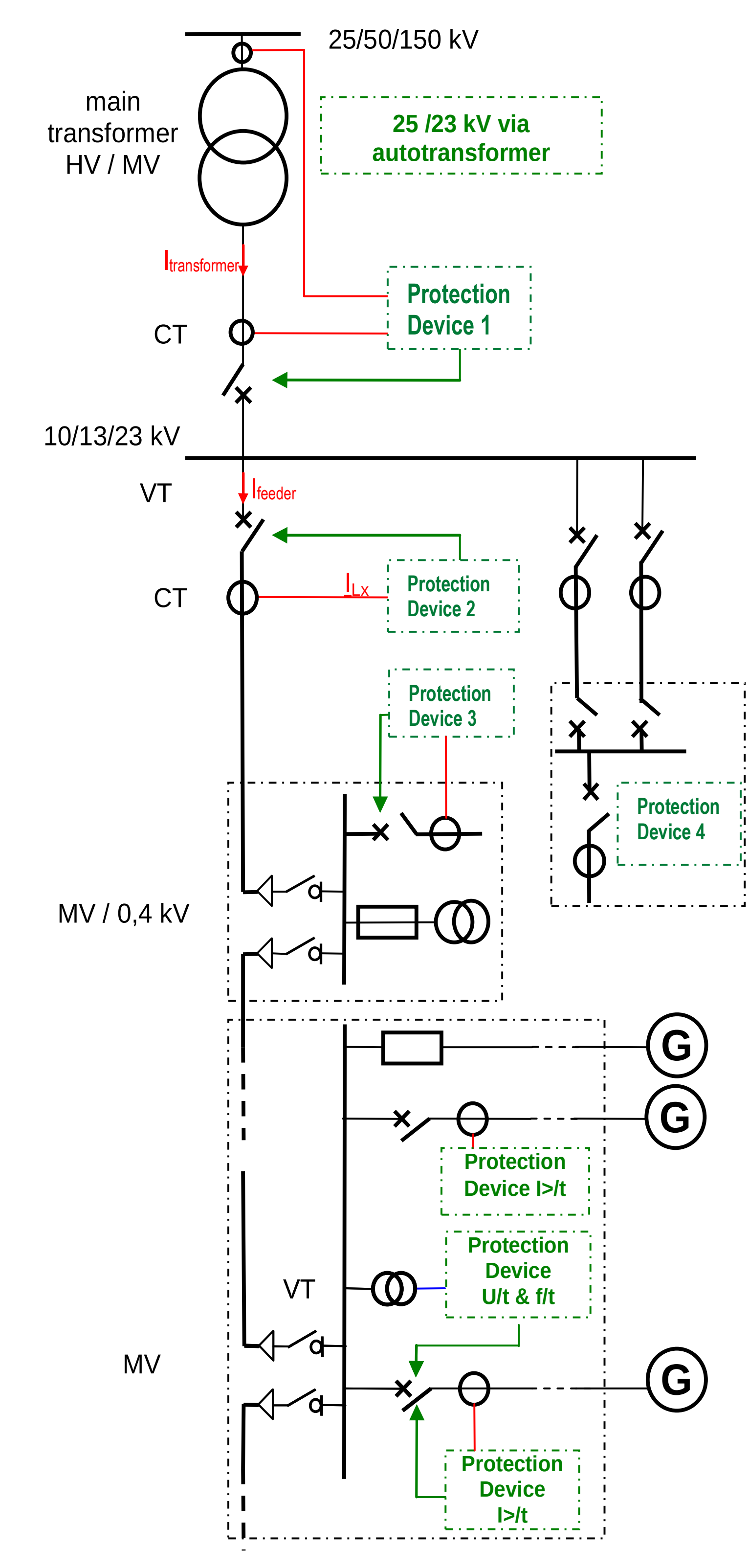
A.8.3.3 Italian Standard CEI 0-16



General Protection
(CODE 51)
51.S1
I >, t_{discr} : value and suppression time to be agreed with the Distributor.
51.S2 I>> 250 A / t_{discr} = 0,5 s
51.S3 I>>> 600 A / t_{discr} = 0,120 s
(CODE 51N)
51N.S1 (used only if 67N.S2 is not present)
I_{Σ} > 2 A / t_{discr} = 0,17 s
51N.S2 (used only if 67N is present. S2. Fault with two phases to ground, no depending from neutral state)
I_{Σ} >> 140 % of the single-phase to earth fault current specified by the Distributor
t_{discr} = 0,17 s
(CODE 67N)
67N.S1 (selection of earth faults in compensated neutral systems)
I_{Σ} = 2 A / U_{en} = 5% ·$U_{r\,(PH\text{-}E)}$/ t_{discr} = 0,450 s
trip area: 60°÷ 250°
67N.S2 (selection of earth faults in isolated neutral systems)
I_{Σ} = 2 A / U_{en} = 2% ·$U_{r\,(PH\text{-}E)}$ / t_{discr} = 0,17 s
trip area: 60°÷ 120°
The minimum settings given here refer to most widely used voltage levels (15 kV and 20 kV); similar settings are required for the other voltage levels.

A.9 Netherlands

A.9.1 Protection Device of Outgoing Feeder



Protection device 1
23 kV en 25 kV net impedance grounded net and 13 kV via zigzag transformer grounded
50/51/51N/63/87T/84T
51N (Ie>) –>120 A
51 (I>) -> 1,5 $I_{r,trafo}$
50 (I>>) -> 0,7 * I''_k (phase – phase)
Ie>, I> and I>> time setting depending on the setting of the underlying net with t_{discr} = 0,3 s . In case where quasi-rail protection with upward blocking is used t>> 0,1 s
10 kV net is ungrounded
50/51/63/87T/84T
51 (I>) -> 1,5 $I_{r,trafo}$
50 (I>>) -> 0,7 * I''_k (phase – phase)
I> and I>> time setting depending on the setting of the underlying net with t_{discr} = 0,3 s

Protection device 2:
I> 1,5·$I_{r,feeder}$
I>> 0,7 * I''_k (phase – phase)
Ie > 120 A for impedance grounded net
t_{discr} = 0,3 s

Protection device 3:
I> 1,5·$I_{r,feeder}$
I>> 0,7 * I''_k (phase – phase) – 0 s
Ie > 120 A – 0 s for impedance grounded net
t_{discr} = 0,3 s

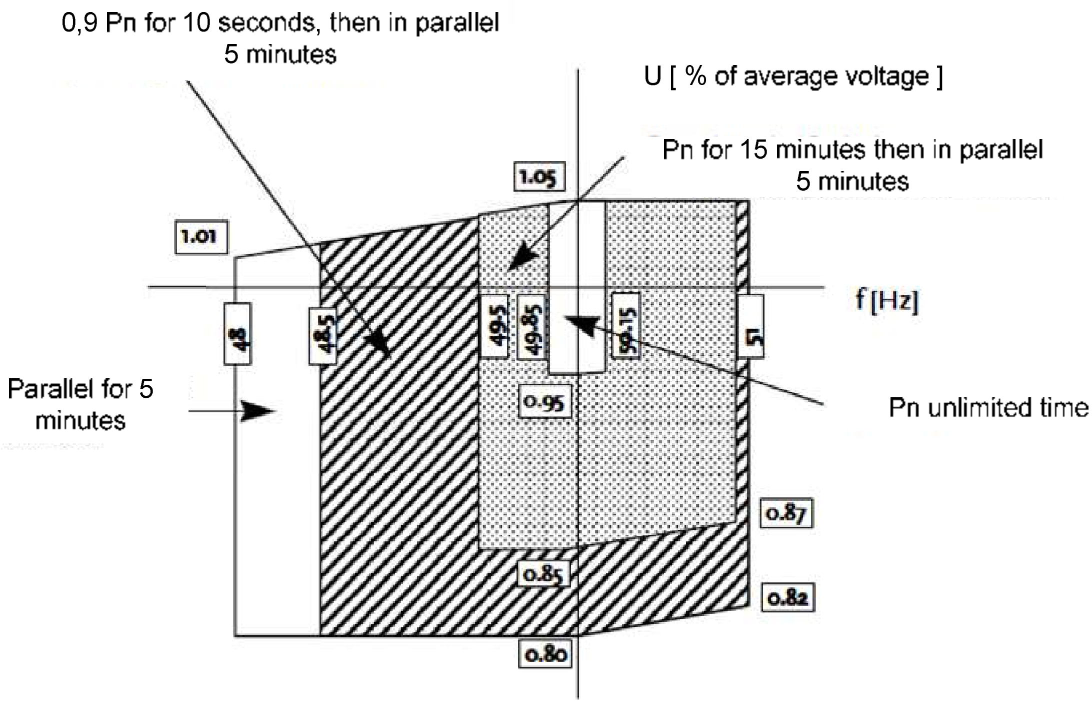
Protection device 4:
In the 10 kV and 13 kV net mostly directional overcurrent relays for the feeder
In the 25 kV net line differential protection
In the 23 kV net a mix of directional overcurrent and line differential protection

U/t- and f/t-protection:
Generators (wind generator, synchronous and all sort of generators) with a rating less than 5 MW
There are no requirements in the Dutch grid code for voltage and frequency protection, fault ride through for generators less than 5 MW
The developer or the generator owner decide the U/t & f/t settings
Generators with a rating 5 MW – 60 MW except wind generators
U</t 0,8 ·Uc / 0,3 s
U</t 0,7 ·Uc/ min(0,3 ; 0,9* KKT)

Remarks:

- There are no fault ride through requirements in the Dutch grid code for all generator types with a rated capacity less or equal to 5 MW.
- There are no fault ride through requirements in the Dutch grid codes for wind generators and parks independent of the rated capacity of the wind park or wind generator
- So far, in practice most of the wind generators under voltage protection are set at U</t 0,8 p.u , t=100 msec. So far such fast isolation of wind generators during a fault enabled us to use overcurrent protection in its simplest form.
- For relatively big generators inter-locking is used to avoid island operations. This is typical in our 25 kV net

Generators connected to a net with voltage less than 110 kV



A.10 Norway

A.10.1 Description of protection schemes

Protection of distribution systems in Norway can be said to be in a transition period, depending on the penetration level of distributed sources. The classical protection scheme is to use over-current protection and rely on disconnection of all distributed sources based on local under-voltage/frequency protection. Alternatively by increased time delay settings for feeders with distributed sources. A research project called Energy 2020 at SINTEF Energy Research [70], a REN recommendation [71] and best practice from nearly 30 years of relay protection application planning at Jacobsen Elektro resulted in a REN recommendation [72] that increasingly is being followed.

A.10.1.1 MV Protection of Main Transformer (TP)

- Recent TSO demands [73] require differential protection on main transformer, whereas traditional protection schemes (for smaller units) may consist of only overcurrent protection. Buchholz relay for gassing protection is also used.
- Over-current protection on both sides. The MV over-current protection functions as simplified bus-bar protection with a typical time delay of 0,2 sec and blocked by the over-current or distance relays on the feeders. As well as back-up of feeder protection. The functional requirements from the TSO [73] give maximum allowed disconnection times of 0,4 sec for short-circuit faults in the high voltage network, whereas for faults in the low voltage network the maximum disconnection time is 1,0 sec.
- With increasing fault contribution from distributed sources distance protection are used on the transformer secondary instead of overcurrent protection.
- Ground fault protection based on $3U_0$.

A.10.1.2 Outgoing feeder protection (FP)

- Short circuit protection, alternative 1: Over-current protection. Coordination time typically 0,3 sec. (or 0,2 sec. for new installations). Starting current set to typically 1.2*In of the current transformers (or the component with the lowest rated current or 30% below 2-phase SC at line end). Fore several feeders the one with distributed sources are given an extra coordination time delay.
- Short circuit protection, alternative 2: Directional over-current protection.
- Short circuit protection, alternative 3: Distance protection with impedance pick-up. Zone 1A; 80% reach time delay 0,2 sec., zone 2; 120% reach and time delay 0,4-0,5 sec. [72]. A zone 1B with zero time delay could be used in case of short circuit during connection. The delay of zone 1A is in order to coordinate with fuses on the distribution transformers. Over-current back-up/overload protection delayed according to Alt. 1, and at least faster than overcurrent protection on main transformer.
- Over/under voltage/frequency protection on the bus bar as back-up for DG relays.
- Ground fault protection in isolated systems based on directional over-current relays based on I0 and U0. In resonance grounded system U0 is used as a ground fault criterion and a parallel resistance is connected during fault to increase the wattmetric I0. Time delays set typically to 0,5 sec for insulated neutral and up to 5 sec for resonance earthed. Setting of U0 and I0 start has to be analyzed in each case and depends on natural asymmetry and conductive line charging. Required disconnection time is 10 sec. for fault resistance of 1000 Ω in cable networks and 3000 Ω in overhead line networks.
- Distribution transformers are typically protected by MV fuses.
- Automatic/Routine reconnections are not used in pure cable systems. On feeder with distributed sources, synchronization check must be used for closing the circuit breaker.

A.10.1.3 DG-protection: U/t and f/t protection

The setting is proposed in [70,72] and is followed in most cases with separate source and network owners.

Function	Limits	Maximum disconnection time*
U>>	1,15 pu	0,2 sec
U>	1,10 pu	1,5 sec
U<	0,85 pu	1,5 sec
U<<	0,5 pu **	0,2 sec
f>	51 Hz	0,2 sec
f<	48 Hz	0,2 sec

* including breaker operation time

** In [70, 72] the voltage limit is said to be set by the utility company. 0,5 pu is given in [71] and said to be common practice in [72]. Reference [72] discusses the selectivity problem with this setting and also the frequency settings.

A.10.1.4 DG-protection: Over-current protection

A Norwegian court decision gave the control of the connection point to the utility companies adding an extra MV circuit breaker. Over-current protection is normally installed to handle and disconnect internal faults in the DG-unit. The over-current relay is coordinated with the feeder over-current or distance protection.

A.10.1.5 DG-protection: Other internal protection

The table below shows which electrical protection functionality may be considered for use in the power plant. The table sets out the options for micro, mini and small power stations.

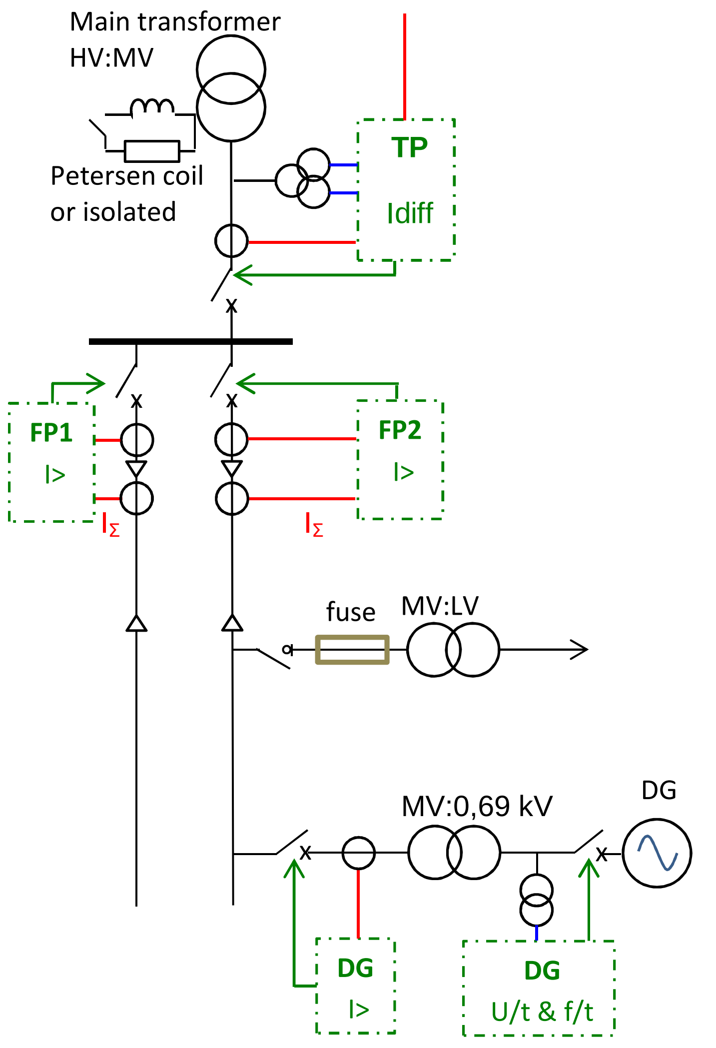
Abbreviations:
o: The protection must be used
s: The protection is used for synchronous generators
v: Use of the protection is to be assessed
vs: Use of the protection is to be assessed for synchronous generators

Electrical protective functions	**Micro** **< 100kW**	**Mini** **100-1000kW**	**Small** **1000-10000kW**
Differential protection, unit		v	o
Earth fault protection, generator voltage level	o	o	o
Earth fault protection, grid voltage level	o	o	o
Earth fault protection, rotor			vs
Over-current/under-voltage protection	o	o	o
Over-voltage protection	o	o	o
Under-voltage protection	o	o	o
Over-frequency protection	o	o	o
Under-frequency protection	o	o	o
Loss of grid (ROCOF or Vector Shift)	v	v	v
Reverse power protection	v	v	v
Overload protection	o	o	o
Over-excitation protection			v
Under-excitation protection			s
Asymmetry protection			o

A.10.2 Protection schemes

A.10.2.1 Protection Device of Outgoing Feeder = over-current protection

Neutral treatment: Petersen Coil earthed, Resistance added in case of an earth fault



MV protection of main transformer TP:

I> reverse interlocking for busbar protection: t = 0,2 s

DIFF

Feeder protection FP:

I>: Constant time
FP1: I>1,2 $I_{n,min}$
t=0,2 sec
FP2: I>1,2 $I_{n,min}$
t=0,3 sec.

U/t and f/t back-up

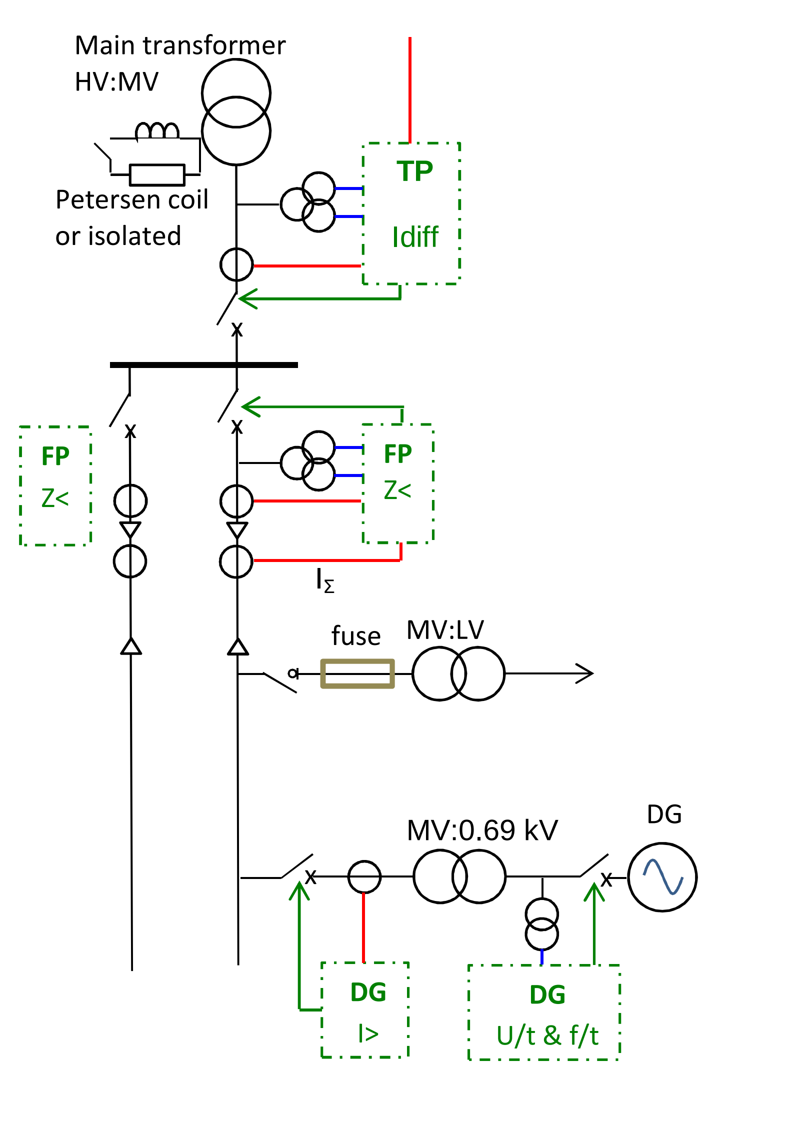
DG-Protection:

U/t and f/t protection see A.10.1.3
U>> 1,15 pu/ 0,2 sec
U> 1,10 pu/ 1,5 sec
U< 0,85 pu/ 1,5 sec
U<< 0,5 pu **/ 0,2 sec
f> 51 Hz/ 0,2 sec
f< 48 Hz/ 0,2 sec
**To be negotiated

I> protection see A.10.1.4 and A.10.1.5
Normally used as overload protection with time delay above regulator response time. Differential protection used for units larger than 1-2 MVA.

A.10.3 Protection Device of Outgoing Feeder = distance protection

Neutral treatment: Petersen Coil earthed, Resistance added in case of an earth fault



MV protection of main transformer TP

I> reverse interlocking for busbar protection: t = 0,2 s

DIFF

Feeder protection FP

DIST: Impedance start Z<

Z1A: Z<0,8*Z_{feeder}
t= 0,2 sec
Z1B: t=0,0 sec. (breaker close)
Z2: Z<1,2*Z_{feeder}
t= 0,3 sec.

U/t and f/t back-up

DG-Protection:

U/t and f/t protection see A.10.1.3
U>> 1,15 pu/ 0,2 sec
U> 1,10 pu/ 1,5 sec
U< 0,85 pu/ 1,5 sec
U<< 0,5 pu **/ 0,2 sec
f> 51 Hz/ 0,2 sec
f< 48 Hz/ 0,2 sec

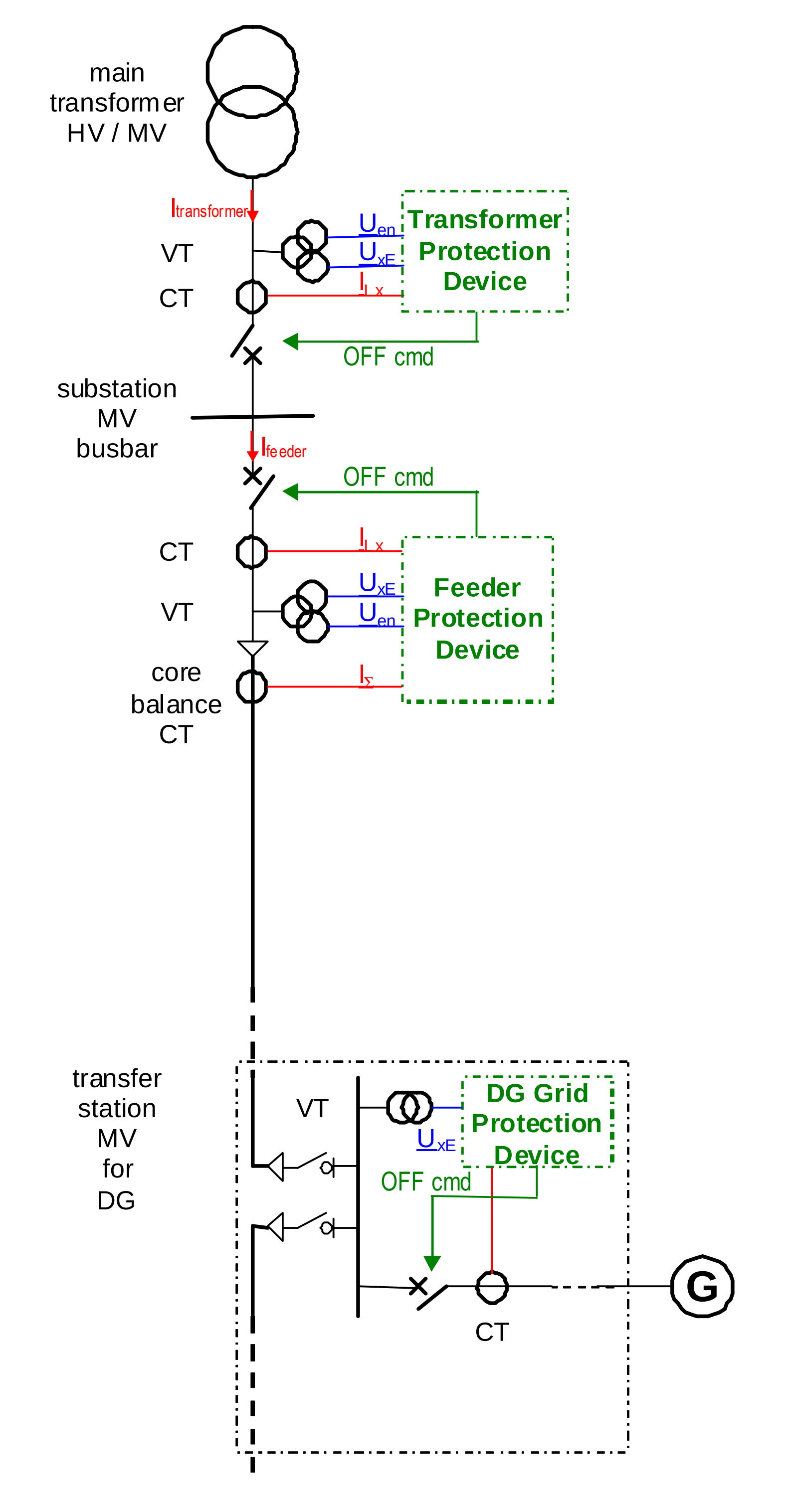
I> protection see A.10.1.4 and A.10.1.5
Normally used as overload protection with time delay above regulator response time.

Differential protection used for units larger than 1-2 MVA.

A.11 Portugal

A.11.1 Protection Device of Outgoing DG dedicated Feeder = Overcurrent protection

Neutral treatment: Low Impedance Grounding (300A and 1000A)



Transformer Protection Device:
$I> = 1{,}3 \cdot I_{r,transformer}$
$t(I>) = 1{,}4s$
Differential

Feeder Protection Device:
$I> = 1{,}4 \cdot I_{r,feeder}$
$t(I>) = 1{,}0s$
$I>> = 2{,}0 \cdot I_{r,feeder}$
$t(I>>) = 0{,}5s$
I>>> = 4|2|1,5kA (10|15|30 kV)
t(I>>>) = 0,1s
I0> = 2A
TM(I0>) = 0,4 (IEC LTI)
I0d> = 40A
t(I0d>) = 0,5s
I0>> = 90A
t(I0>>) = 0,15s
Slow automatic reclosures only

DG Grid Protection Device:

U>/t	$1{,}15U_C$ / <0,1s
U</t	$0{,}85\|0{,}80U_C$ / 1,5|1,6s†
U<</t	$0{,}21\|0{,}25U_C$ / 0,0|0,6s†
U<</t	N.U.|$0{,}18U_C$ / N.U.|<0,1s†
U0>/t	$0{,}1U_C$ / 1,0s
U0>>/t	$0{,}7U_C$ / <0,1s
F>/t	N.U.|50,5Hz / N.U.|1,5s†
F>>/t	51,5Hz/ <0,1s
F</t	N.U.|49,5Hz / N.U.|1,5s†
F<</t	47,5Hz/ <0,1s
I>/t	$1{,}3 \cdot I_{r,DG}$ / 1,5s
I>>/t	$4{,}0 \cdot I_{r,DG}$ / <0,1s

Remarks:

1. † - without/ with Fault Ride Through capability
2. N.U. – Not used

The protection system of the MV network in Portugal has 3 levels: Transformer protection; Feeder protection; and DG protection.

Transformer MV overcurrent protection is the first level and is mainly intended as a backup to the feeders phase overcurrent protection. Starting current is set 30% above the rated current to allow transformer overloading. There is a SCADA alarm when the current is above 110%I_{Rated} and the Dispatch centre will divert loads without the need for tripping.

There is also a backup protection for the feeder's zero sequence overcurrent protection which is not represented in the figures. The zero sequence overcurrent backup will trip the transformer in 3s, for non-resistive faults, and in 180s, for resistive faults.

Feeder protection is performed by 6 protection functions: 3 phase overcurrent; and 3 zero sequence overcurrent. The goal of the 3 phase overcurrent functions is to insure the feeder's protection while minimizing fault duration times, and subsequently the voltage dips duration. I>> is made to coordinate with the transformer's I> in order to prevent transformer unwanted trips with simultaneous faults in two or more feeders.

Earth fault protection for non-resistive faults is insured by the I0>> function which provides a fast trip to minimize fault damage. Resistive faults are cleared by the I0d> with a higher time setting to improve correct direction location probability. Detection of broken conductors and extremely resistive faults are the objectives of function I0>, this leads to large fault clearing times.

Automatic reclosing in rural (manly aerial) feeders has 3 cycles (one fast and two slow) and is not used in urban (cable) feeders.

DG protection's main goal is to prevent unintentional islanding and the protection functions associated are chosen and set accordingly. There are factors which may alter the protection settings such as: Low Voltage Ride Through (LVRT) capability; direct link to the substation; Direct tripping from the substation feeder through a communication link. DG units connected to networks, which are also feeding other clients, must be tripped with low time settings. DG units connected through a dedicated line and with fault ride through capability don't need such strict time settings which makes them more unlikely to suffer unwanted trips. In this case the DG protection is coordinated with the feeder protection to allow a slower tripping. It is assumed that no fast reclosing cycles are present in the DG feeder.

If the DG has LVRT then interconnection protection is coordinated with the LVRT curve and is set not to trip with voltage dips within the curve. If the DG is placed in a network with other clients then there may be the need for a direct trip through a communication channel.

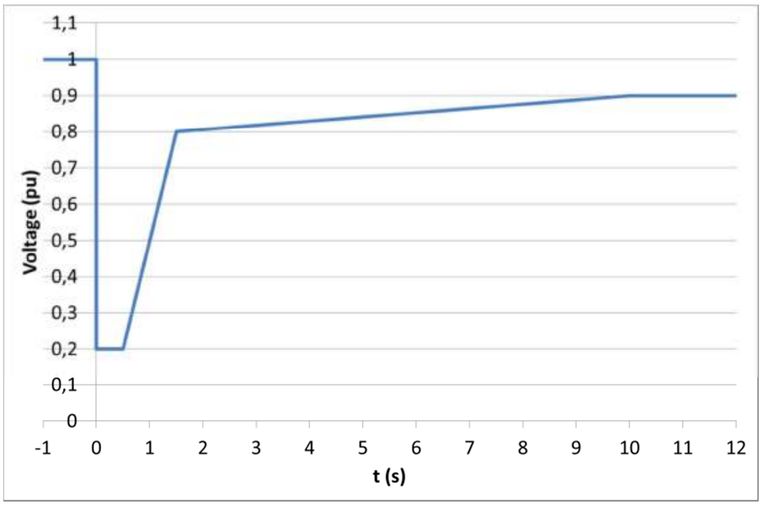
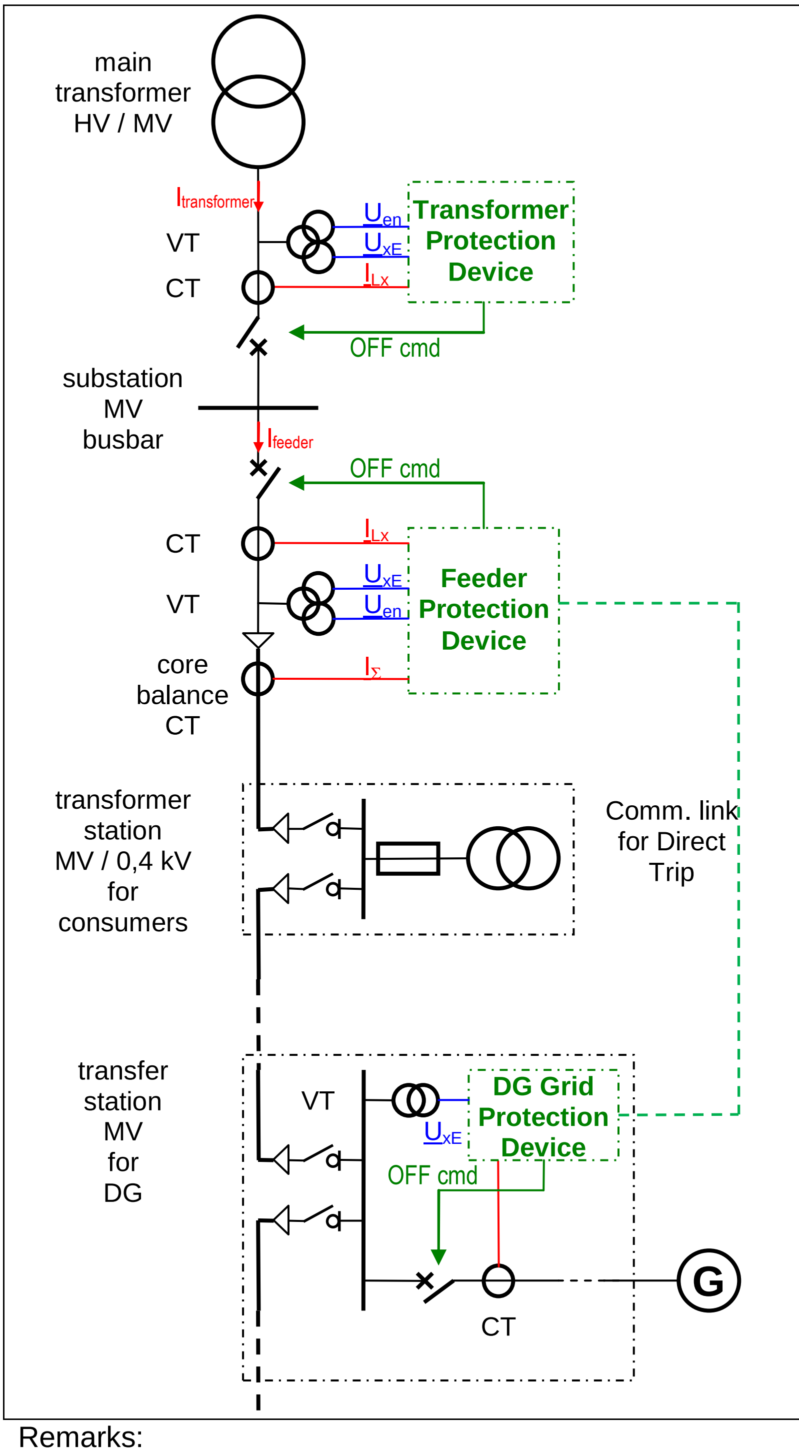


Figure A-1: Fault Ride Trough curve in the Portuguese grid code

A.11.2 Protection Device of Outgoing Feeder = Overcurrent protection

Neutral treatment: Low Impedance Grounding (300A and 1000A)



Transformer Protection Device:
I> = 1,3·$I_{r,transformer}$
t(I>) = 1,4s
Differential

Feeder Protection Device:
I> = 1,4·$I_{r,feeder}$
t(I>) = 1,0s
I>> = 2,0·$I_{r,feeder}$
t(I>>) = 0,5s
I>>> = 4|2|1,5kA (10|15|30 kV)
t(I>>>) = 0,1s
I0> = 2A
TM(I0>) = 0,4 (IEC LTI)
I0d> = 40A
t(I0d>) = 0,5s
I0>> = 90A
t(I0>>) = 0,15s
Fast and slow automatic reclosures if aerial line

DG Grid Protection Device:
U>/t 1,15U_C / <0,1s
U</t 0,85|0,85|0,80U_C / <0,1|1,5|1,6s‡
U<</t N.U.|0,21|0,25U_C / N.U.|<0,1|0,6s‡
U<</t N.U.|N.U.|0,18U_C / N.U.|N.U.|<0,1s‡
U0>/t 0,1U_C / <0,1|1,0|1,0s‡
U0>>/t N.U.| 0,7U_C|0,7U_C / N.U.| <0,1s |<0,1s‡
F>/t 50,5Hz / N.U.|N.U.|1,5s‡
F>>/t N.U.|N.U.|51,5Hz / N.U.|N.U.|<0,1s‡
F</t 49,5Hz / N.U.|N.U.|1,5s‡
F<</t N.U.|N.U.|51,5Hz / N.U.|N.U.|<0,1s‡
I>/t 1,3·$I_{r,DG}$ / 1,5s
I>>/t 4,0·$I_{r,DG}$ / <0,1s

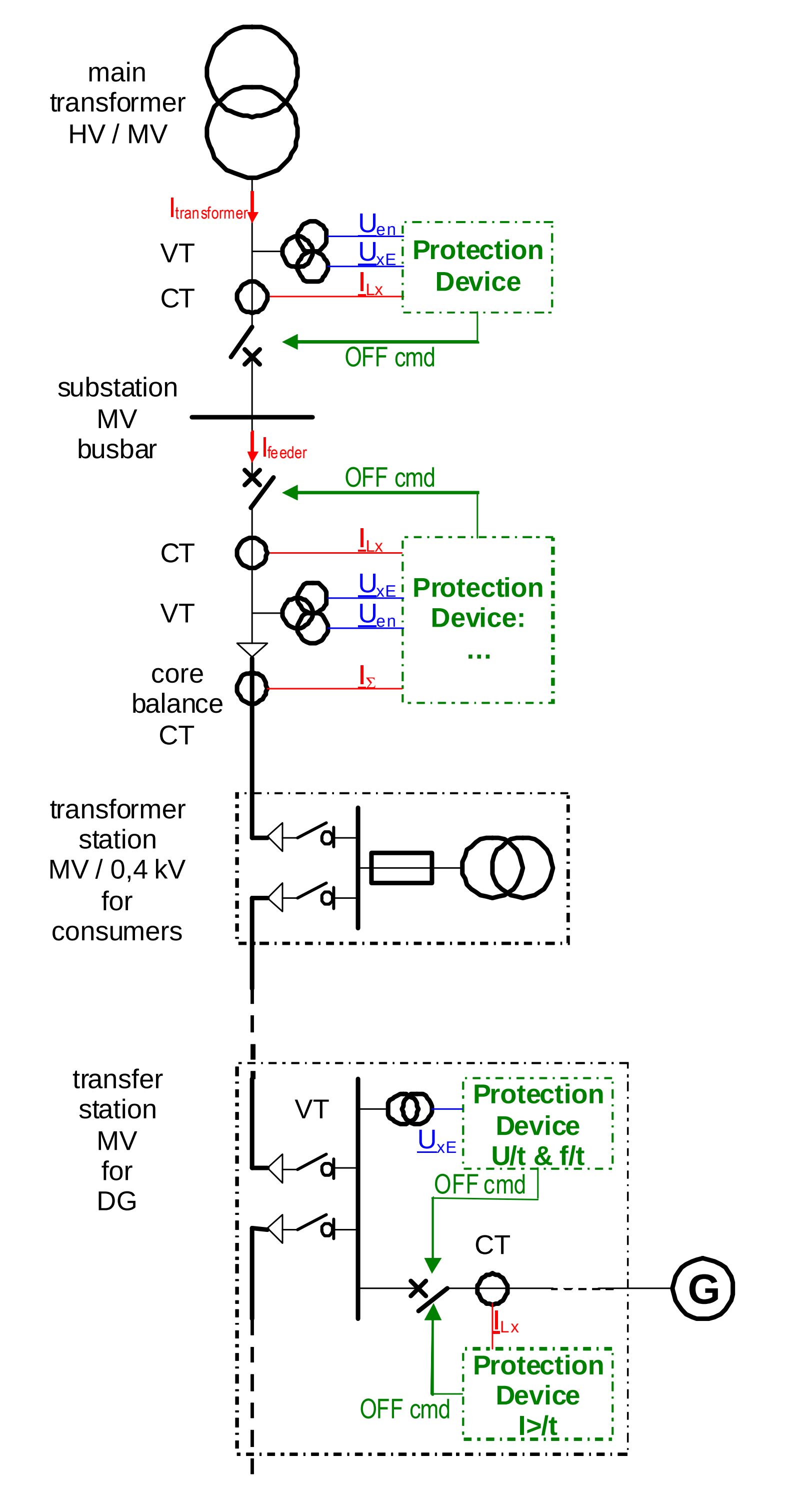
Remarks:

1. ‡ - without Direct Tripping | with Direct Tripping | with fault ride through capability
2. N.U. – Not used

A.12 Romania

A.12.1 Protection Device of Outgoing Feeder = overcurrent protection[1]

Neutral treatment: Petersen coil, Resistor or Unearthed



MV protection of main transformer (…):
$I>> \approx 1{,}4 \cdot I_{r,transformer}$

Feeder protection:
$I>> \approx 1{,}4 \cdot I_{r,feeder}$
($t_{discr} \geq 0{,}5$ s for old prot. and CBs, $t_{discr} \leq 0{,}4$ s for new prot. and CBs)
50P or 67P (67 if the contribution to fault current from DG is over 10% of total fault current)
Earth fault protection depending on neutral treatment and accordingly to the ground fault current level (50N, 67N or 67NS). Network is sized to work with 1ph-gnd for Petersen coil.

U/t- and f/t-protection:

U>/t	$1{,}1 \cdot Uc$ / < t^2
U</t	$0{,}9 \cdot Uc$ / t^2
f>/t	52 Hz / <t^3
f</t	47 or 47,5 Hz / < t^3
df/dt³	

(Uc = voltage at PCC)

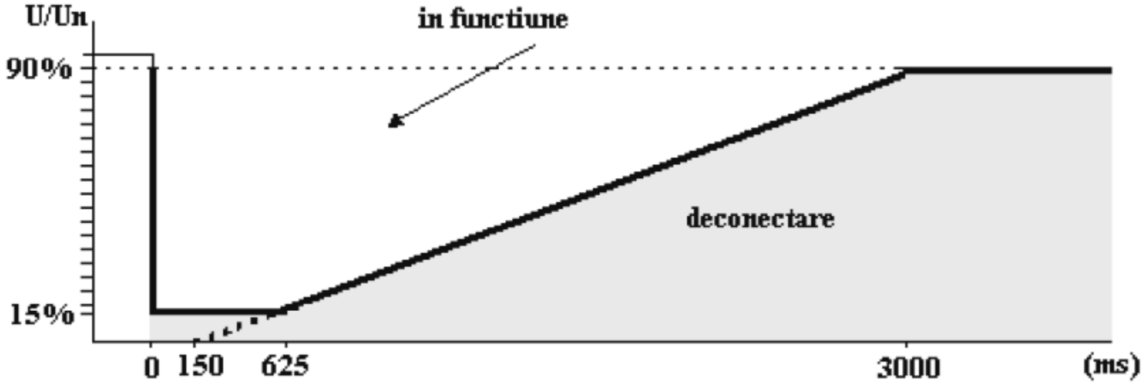
I>/t-protection:
$I>> \approx 1{,}4 \cdot I_{r,DG}$
t>> = "0"

Notes:

1. In most of the cases the required protection is the overcurrent one. Other protection requirements could be imposed if the selectivity of the protection scheme is not

achieved using overcurrent protection. Directional overcurrent protection is required if the contribution from the DG end to the fault current on the MV busbar is indicative above 10% of the total fault current.

2. The voltage requirements for connecting DG (> 1MW) to the utility grid are asking to provide the possibility to operate between 0,9 – 1,1 Uc continuously. There is no Romanian grid code condition to impose certain settings for U>/t or U</t, so in the table have been considered the limit values of the range required for continuous operation. Since there is no requirement imposed by the grid code for the time settings, these should be set according to each particular case (considering also the FRT requirements below).
3. The frequency requirements for connecting DG to the utility grid are asking to provide the possibility to operate between 47,5 Hz – 52 Hz continuously. There is no Romanian grid code condition to impose certain settings for f>/t or f</t, so in the table have been considered the limit values of the range required for continuous operation.
   Since there is no requirement imposed by the grid code for the time setting related to f>/t, these should be set according to each particular case. In the case of f</t, for wind generators there is a requirement to allow the operation in the 47,5Hz – 47 Hz range for at least 20s, while for photovoltaic generation there is no such requirement. This means, for wind generators two steps of f</t might be used, one set just over 47 Hz and with 20 s time set, while the other could be set just below 47 Hz with the time setting according to each particular case. For photovoltaic generation the f</t could be set at 47 Hz with the time setting according to each particular case.
   The requirements of the grid code and specific conditions to connect wind generators or photovoltaic generation to the grid also impose to accept frequency variations with a rate of change of frequency of 0,5 Hz/s for wind generators and 1 Hz/s for inverters of photovoltaic generation.
   Depending on the power, wind generation and photovoltaic generation have to be monitored from a dispatching centre (> 5 MW monitored) or not and also should contribute or not to the power-frequency regulation (>5 MW have to provide P-f regulation according to specific requirements).
   Wind and photovoltaic generation over 1 MW are required to adapt to FRT conditions according to the following diagram:



During the voltage sags the DG has to supply active power according to the voltage level and to maximize the injected reactive current without violating its operating limits. It has to generate the maximum reactive current for at least 3s.

<u>Remark:</u>

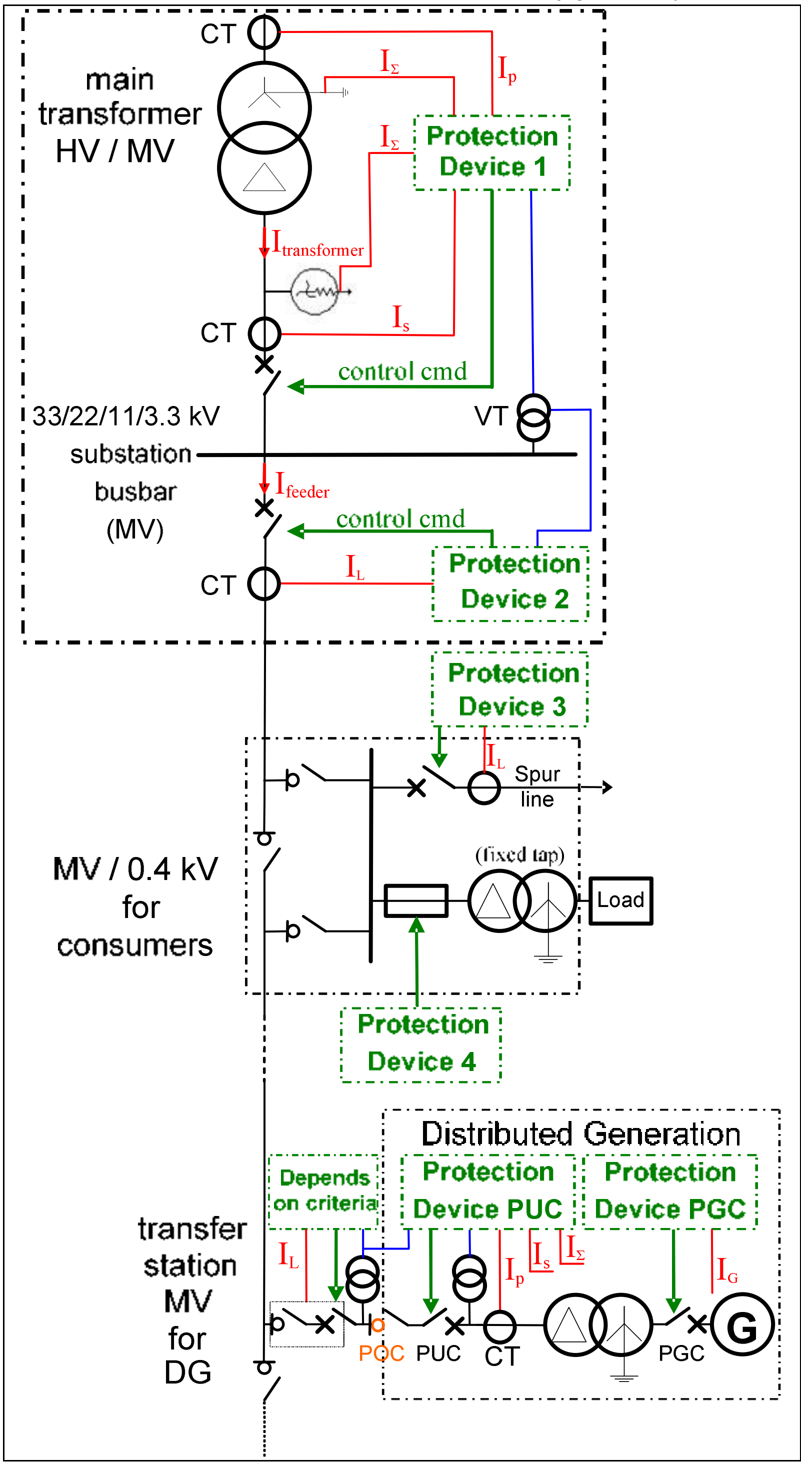
The requirements mentioned are not particular to one distribution operator (DO) – these are requirements imposed in Romania by ANRE (The National Regulatory Agency for Energy) and are mandatory to comply with for any DO and DG supplier. There is also a mandatory requirement in the conditions to connect to grid for DG suppliers, to detect islanding and not allow islanding operation.

A.13 South Africa

A.13.1 Protection Devices for a MV Network

Typical protection devices for a substation and MV network with DG coupled in rural environment:

Neutral Treatment: Grounded via NEC/NER /AT or directly grounded (OHS Act does not allow an ungrounded network)



Protection Device 1: HV/MV Trfr

Transformer differential protection 87T

HV/MV REF (internal low or external high impedance)

51 (I>) ≈ 1,5-1,7·$I_{r,transformer}$
(asymptote: 1,3s at 0 source impedance)
50 (I>>) ≈ 1,3·$I_{3phase\ max}$
(maximum 3phase through fault)
51N (Ie>) ≈ 360A limit
(NER rated 360A 10s, cont.10A)
SEF = 10A, 120s DEF
T_{discr} = 500ms

Protection Device 2: Feeder

Ring fed feeders = directional protection

51 (I>) ≈ 1,2·$I_{r,feeder}$
51N (Ie>) ≈ 60-80A
(graded with downstream)
SEF = 3-6A, 3-15s DEF
T_{discr} ≥ 300ms

Protection Device 3: Recloser

51 (I>) ≥ Load
(100% kVA installed)
51N (Ie>) ≈ value to grade at fault level
(graded with downstream/upstream)
SEF = 3-6A, 3-15s DEF
T_{discr} ≥ 300ms

Protection Device 4: Fuses

Grade with load

Transfer Station:

Different Standards & Codes dependant on type & MVA size are applicable:

Category A(i) & A(ii) RPPs

U/t- and f/t-protection:

U>/t 1,10 < Uc < 1,20 / 2,0s
U>/t 1,20 ≤ Uc / 0,16s
U</t 0,50·> Uc / 0,2s
U</t 0,50·< Uc < 0,85 / 2,0s
U/t 0,85 ≤ Uc ≤ 1,10 / cont.

Category A(iii), B & C RPPs

U/t- and f/t-protection:

U>/t 1,10 < Uc < 1.20 / 2,0s
U</t 0·= Uc / 0,15s (fault ride through)
U</t 0 ·< Uc ≤ 0,85 linear curve with max 2.0s
U/t 0,9 ≤ Uc ≤ 1,10 / cont

f>/t 52,0 Hz / = 4,0 s
f</t 47,0 Hz / < 0,2 s
df/dt > 1,5 Hz/s disconnect
(Uc = voltage at PCC)

Remarks:

1. The gazetted RSA Electricity Regulation Act makes provision for the Regulator to publish compliance 'Codes' which are referred to below.
2. Embedded Generation(EG) > 0MVA connected to MV or HV networks & EG > 10MVA connected at any voltage level to the Distribution network shall in addition to the Distribution Code also comply with the protection & control requirements of the Transmission Grid Code. This code is detailed and is applied to all historic large generation. EG > 50MVA excluding Renewable Power Plants (RPPs), shall comply with the governor requirements of the Transmission Grid Code. Note that the MVA rating above refers to the total connected plant rating.
3. All RPPs shall comply with the RPP Grid Code. This code takes precedence.
4. All EG (which includes RPPs) connected to the Utility's (Eskom) MV or HV networks shall conform to its interconnection standard for embedded generation.

A.13.2 Utility Interconnection Standard

The most pertinent requirements of the standard at MV and HV levels are:

1. All EG shall connect via an isolating transformer.
2. There shall be a minimum of two EG circuit breakers in series.
3. The Utility shall always own, at a minimum, one circuit breaker per feeder.
4. Synch check, live line/dead line block are a requirement where EG cannot prove they do not have an islanding capability.
5. Where the backbone has unit protection applied, the EG and link shall also have unit protection applied.
6. In cases where there is a radial feed to the EG and local independent loads are connected at MV/HV voltages on the same feeder (non-dedicated), transfer trips (TT) to the weak in-feed have been used (from the remote 'distance' protection to allow for auto-reclose). The EG in these instances have been small hydro.
   For RPPs currently being connected at MV or HV levels, there are a number of criteria which govern the protection interconnection requirements, with the most stringent being applied to those that are connecting to non-dedicated feeders.
   Inclusive in these protection requirements is transfer trip which is used in some cases (with fibre/microwave based communication used for HV networks and alternative communication based methods used for MV networks). Transfer trips where applied, are used in addition to the anti-islanding localised protection and do not replace it. In these cases the localised anti-islanding protection may be set less sensitively, thereby reducing nuisance tripping.

* RSA: Republic of South Africa

A.13.3 Requirements

The RPP Grid Code is divided into the following categories:

a) Category A: 0 - x < 1 MVA (only LV connected)

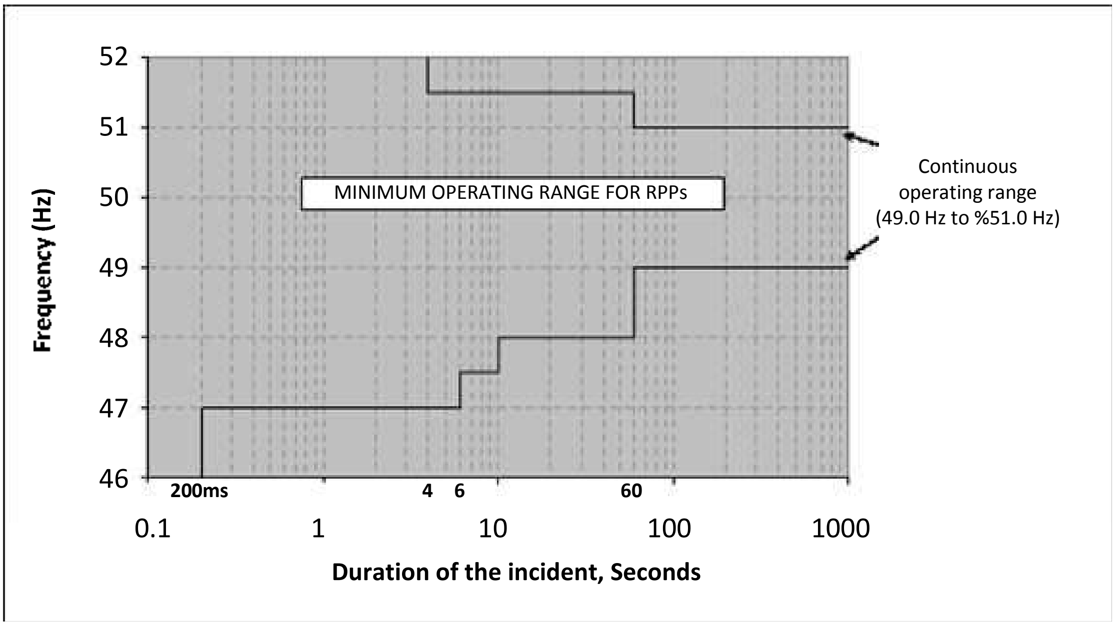
(i) Cat A1: 0 - x – 13,8kVA (ii) Cat A2: 13,8 < x < 100 kVA (iii) Cat A3: 100 – x < 1 MVA

b) Category B: 1 MVA – x < 20 MVA, also includes RPPs with rated power < 1 MVA connected to MV.

c) Category C: 20 MVA ≤ x

The code is presently under review.

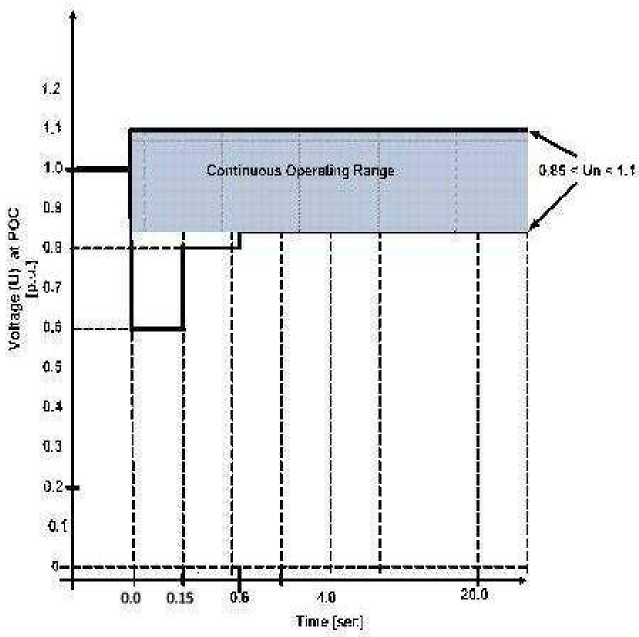
The frequency, the voltage and the reactive requirements of the code are presented in the following diagrams (*extracted from Code version 2.6 Date November 2012*):



Minimum frequency operating range of a RPP during a system frequency disturbance

With reference to the above diagram, when the frequency is less than 47.0Hz for longer than 200ms, the RPP may be disconnected and when the frequency is greater than 52Hz for longer than 4s, the RPP shall be disconnected from the grid.

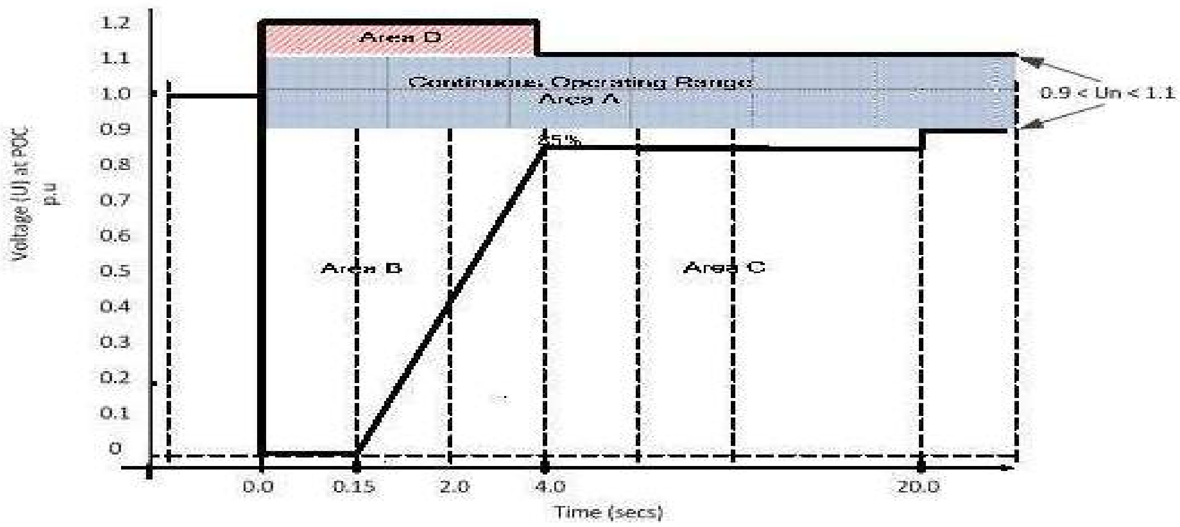
The voltage ride through capabilities and maximum disconnection times for RPPs of Category A1 and A2 are given by the following:



V range (%)	**Max Trip time** (s)
V< 50	0.2
50 ≤ V < 85	2
85 ≤ V ≤ 110	Continuous
110 < V < 120	2
120 ≤ V	0.16

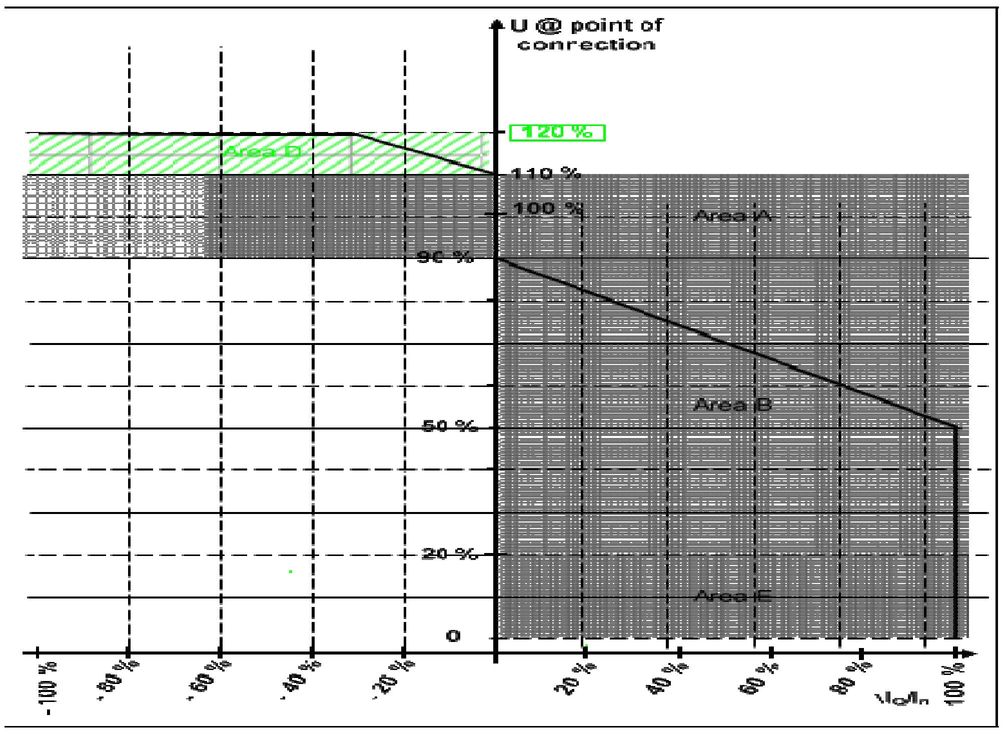
VRT capability for Category A1 and A2

The voltage ride through capabilities and maximum disconnection times for RPPs of Category A3, B and C is given by the following diagram with the bold line representing the minimum voltage of all the phases (for symmetrical and asymmetrical faults):



VRT capability for Category A3, B and C

In connection with symmetrical fault sequences in areas B and D above, the RPP shall have the capability of controlling the reactive power with the following compliance:



Requirements for reactive power support during volt drops or peaks at the POC

Area A: Stay connected and support normal production.

Area B: Stay connected and provides maximum voltage support by supplying a controlled amount of reactive current.

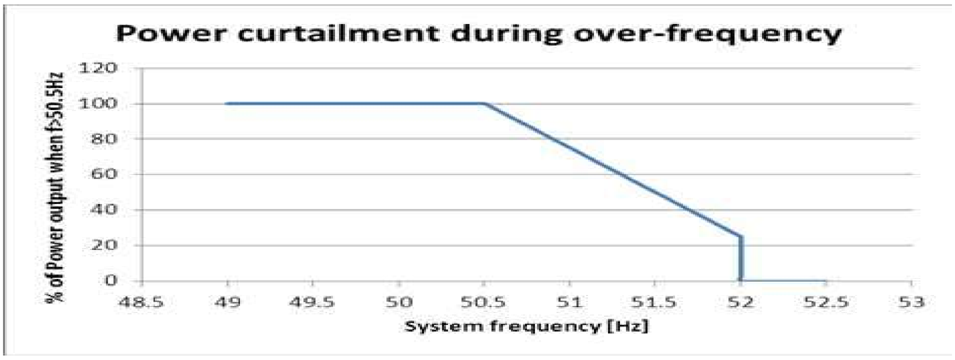
Area C: Disconnection is allowed.

Area D: Stay connected and provides maximum voltage support by absorbing a controlled amount of reactive current within the designed capability of the RPP.

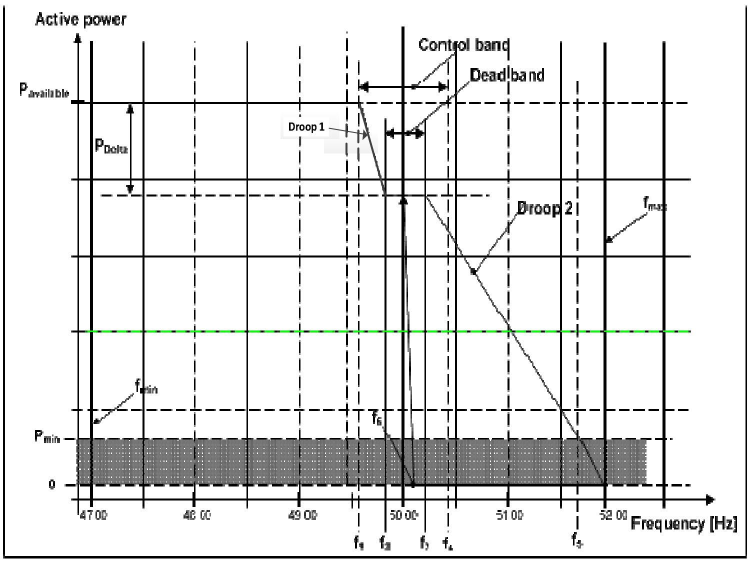
Area E: Once the voltage at the POC is below 20%, the RPP shall continue to supply reactive current within its technical design limitations. Disconnection is allowed after the VRT capabilities depicted in the above diagram have been met.

The supply of reactive power has the first priority in area B, while the supply of active power has second priority. If possible, active power shall be maintained during voltage drops, but a reduction in active power within the RPP's design specifications is acceptable.

The power-frequency response curve for Category A RPP's includes mandatory active power reduction and is given by the following figure:



The power-frequency response curve for Categories B and C is given by the following figure:

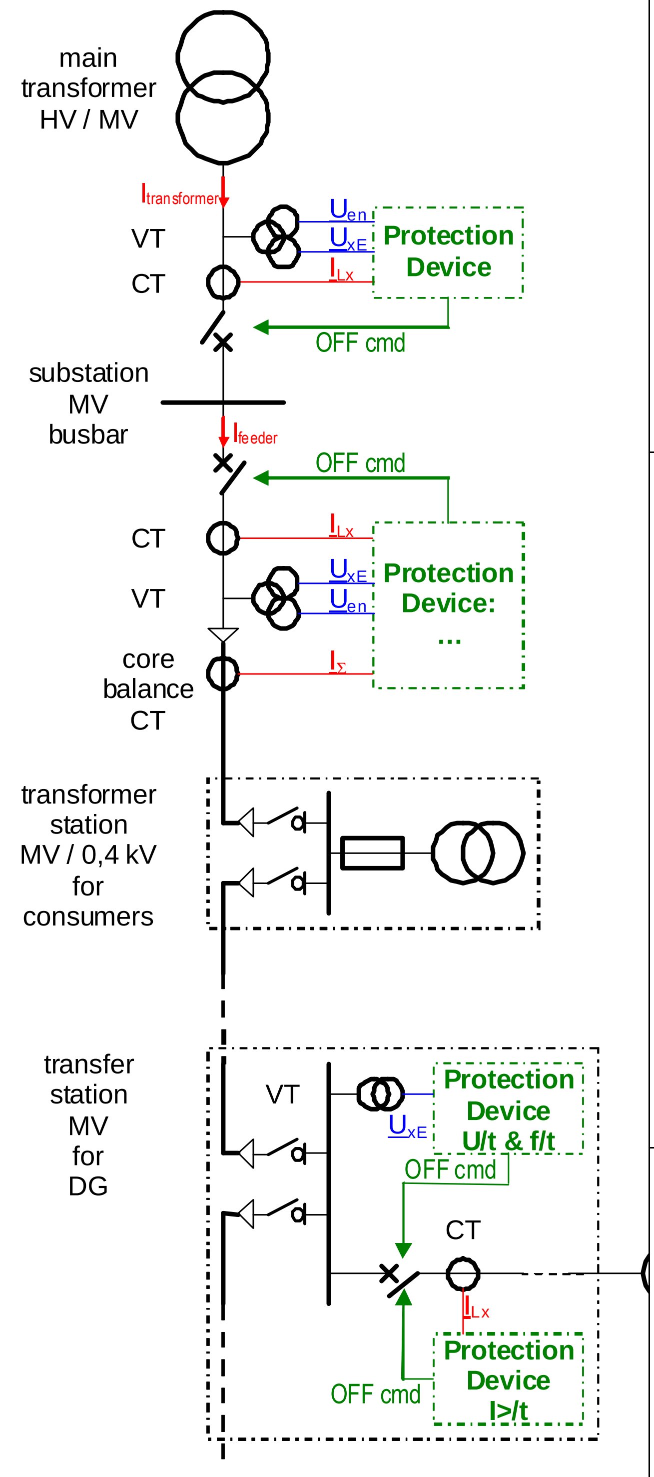


Parameter	Hz
f_{min}	47
f_{max}	52
f_1	SO
f_2	SO
f_3	SO
f_4	50.5
f_5	52
f_6	50.2

A.14 Spain

A.14.1 Protection Device of Outgoing Feeder = overcurrent protection

Neutral treatment: solidly grounded (solid or limiting reactance of 4 ohms); low impedance grounded (zig-zag transformer grounding which limits the current to 300, 500,575 or 1000 A or resistance grounding of 6 ohms which limits the current to 1000 A); Ungrounded; Petersen coil (very few installations)



MV protection of main transformer (…):
Solidly grounded:
Iph>1,4*Ir,transformer (51)
In> ≈ 75 – 120 A primary (51N)
Ig>≈ 85 – 150 A primary (51G: note 1)
Low impedance grounded (zig-zag and resistance):
Iph>1,4*Ir,transformer (51)
In> ≈ 75 – 120 A primary or 0,1*Ir,CT (51N)
Ig>≈ 18 – 200 A primary (51G: note1)
Thermal image: in the ground CT (49)
Un>≈set to detect 15 A ground current. Gives an alarm after 30 s
Ungrounded:
Iph>≈ 1,3*Ir,transformer (51)
Un>≈ 58 V (Ur=110/√3) or 30 V (Ur=110/3) (59N) (note 2)
t≈1,5 - 4 s

Feeder protection:
Solidly grounded:
Iph>≈1,3*Ir,feeder (51)
Iph>>≈0,8*Icc0%phph (50)
In> ≈ 20 – 40 A primary (51N)
In>>300 A or function of line length (50N)
Ins>4 – 10 A primary; t=50 s (51Ns)
Low impedance grounded (zig-zag and resistance):
Iph>≈1,3*Ir,feeder (51)
Iph>>≈0,8*Icc0%phph (50)
In> ≈ 30 A primary or 0,06*Ir,CT (51N)
In>>300 A primary or 8*In> (50N)
Ins>2 – 10 A primary; t=7 - 50 s (51Ns)
Z< for meshed 30 kV networks: Z=0,8*Z1L
67N as back-up of 21G for 30 kV meshed networks
87L for some underground feeders
Ungrounded:
Iph>≈1,3*Ir,feeder (51)
Iph>>≈6* Ir,feeder (50)
Ins>≈ 0,12 – 1 A primary
Vn>≈ 58 V (Ur=110/√3) or 30 V (Ur=110/3) (67Ns) (note 2)
t≈ 0,25 – 0,4 s

DER Protection:
U>/t 1,1*Ur / 1,5 s or 0,6 s (depending on the DER power)
U>/t 1,15*Ur / 0,2 s
U</t 0,85·Ur / 1,5 s or 0,6 s (depending on the DER power)
Un>/t 0,35*Vr / 0,6 s or 1,2 s
f>/t 50,5 Hz or 51 Hz (depending on the DER power) / 0,5 s or 0,2 s
f</t 48 Hz / 3 s
Ur: rated phase-phase voltage at connection point
Vr: rated phase-ground voltage at connection point
I>/t-protection:
I> ≈ 1,2·$I_{r,DG}$
I>> =8*$I_{r,DG}$
Transfer trip

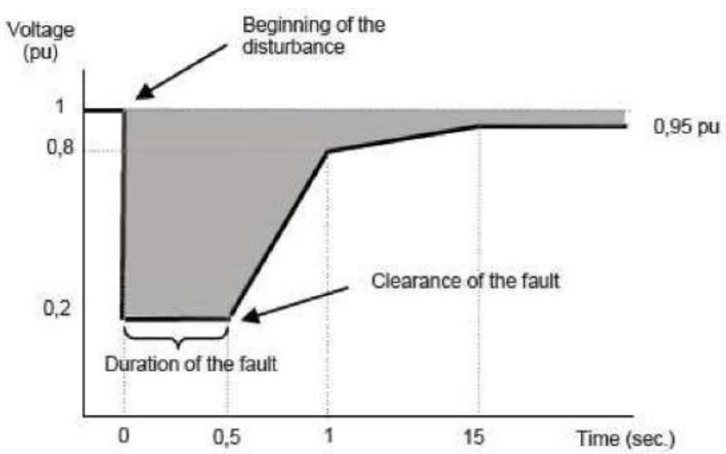
Note 1: toroid current transformer on connection from neutral to ground
Note 2: The directional unit for ungrounded networks use the following characteristic:

In this characteristic the values for I_l and for V_h are the ones given for Ins> and Vn>. The typical values for I_h and V_l are: $I_h = 3*I_l$ y $V_l = 2,2$ V (Ur=110/3).

The Spanish distribution network can be briefly described as follows and divided in:

- Meshed: with voltages of 132, 110, 66, 50, 45 and 30 kV. The 30 kV network is connected to the 132 kV / 220 kV network by means of a Y-D transformer and an artificial ground connection is created with a zig-zag transformer. All the transformer generating lower voltages are Dy. The 30 kV network is three-wire only grounded with the zig-zag, connected in the substation,
- Radial:
  - - 45 kV solidly grounded: connected to the 132 kV / 220 kV network by means of Yyn transformers with neutral solidly grounded. The transformers generating lower voltages are Dyn or Dz.
  - - Solidly grounded below 30 kV (20, 15, 13 and 11 kV): the network is supplied with a Dyn transformer solidly grounded or with a limiting reactance of 4 ohms. Load transformers are Dyn or Dz.
  - - Zig-zag grounded below 30 kV (25, 20, 15, 11 kV): this network is supplied by a Yd transformer. A zig-zag transformer is connected directly to ground or via a resistor. The fault current is limited to 300, 500, 575 or 1000 A. Load transformers are Dyn or Dz.
  - - Resistance grounded (25-20 kV): supplied by Yyn transformer grounded with a 6 ohm limiting resistor (1000 A limitation).
  - - Ungrounded (25, 20, 15 and 10 kV): supplied by Yyd, Yd or Yy transformers. Load transformers are Dyn or Dz.

Fault ride through capability



A.15 USA

Published Protection requirements for greater than 2500 KVA to 10 MVA Generators connected to the Distributions System

This design is for Generation Facilities with the following characteristics:

Generation is not to be intentionally exported on to the utility T&D system.

---and---

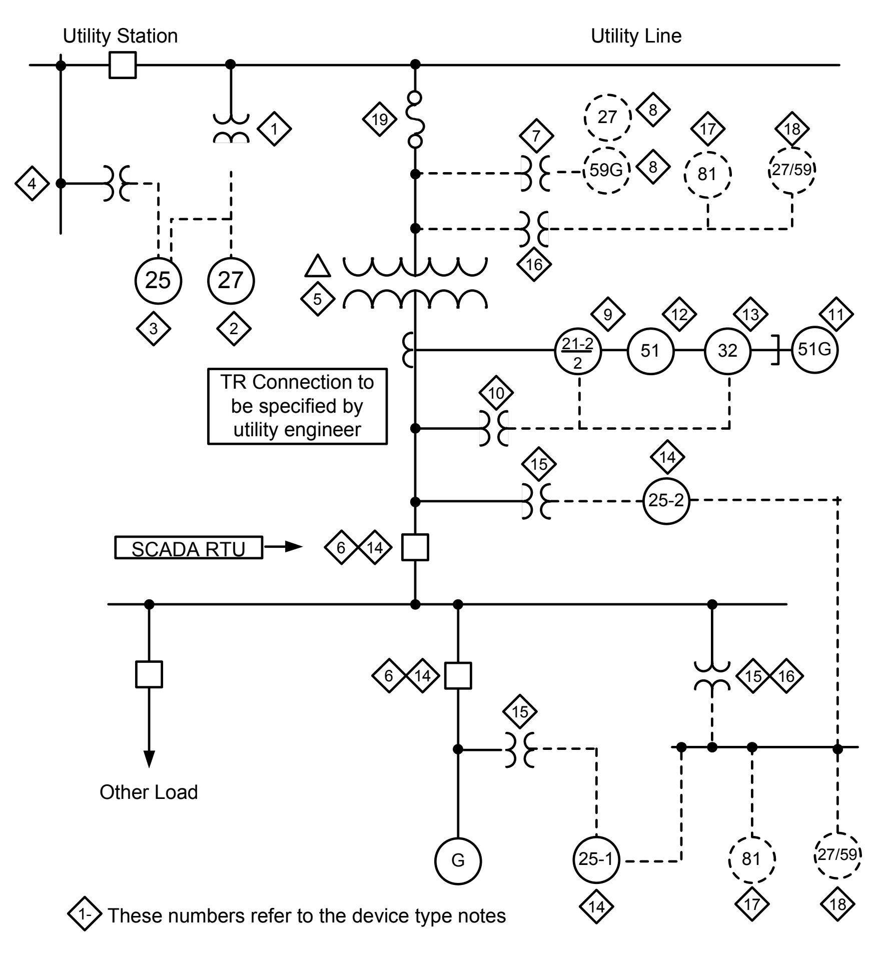
a. Total generation is greater than or equal to 50% of the minimum line section load.

---or---

b. Total generation is greater than 2000 KVA and less than 10 MVA.

---or---

c. Special system constraints warrant using this design.



Transformer Protection Device:

Feeder Protection Device:

6. Device Type: Breaker Failure Backup Tripping (i.e. LBB)
8. Device Type: Over or Undervoltage Relays Device #:59G or 27
9. Device Type: Impedance Relay Plus Timer Device #: 21-2/2

DG Grid Protection Device:

2. Device Type: Undervoltage Relay Device #: 27
3. Device Type: Synchrocheck Relay Device #: 25
11. Device Type: Ground Overcurrent Relay Device #: 51G
12. Device Type: Overcurrent Relay Device #: 51
13. Device Type: Directional Power Relay Device #: 32
14. Device Type: Synchronizing Relay Device #: 25
17. Device Type: Under/over Frequency Relay Device #: 81U/O
18. Device Type: Under/over voltage relay Device #: 27/59

A.15.1 Interconnection Configuration

Utility will determine the bus and line configurations and protection requirements that are necessary to interconnect the generation to the T&D System, as requested by the Generation Interconnection Customers. In order to perform such an analysis, utility will require technical information on the Generation Interconnection Customers generator(s) and proposed interconnection location to the system. In the case where the customer wishes to participate in the energy market, the market operator will also be involved in the interconnection study. These interconnection configurations are site dependent. Examples of typical interconnection configurations and general relay requirements for these configurations are discussed in the sections below. Once the appropriate configuration is determined, utility will provide the Generation Interconnection Customers with the scope, schedule and cost of the interconnection facility.

A.15.2 Requirements

Medium-sized generators (2000 -10,000 KVA) can supply relatively large amounts of energy to the point of fault; therefore, additional protective functions are required. A generator connected to a utility supply line section with a minimum load less than twice the rating of the generator also stands a very good chance of islanding after the line protective equipment opens with or without the fault remaining on the line. There are also instances where special system constraints may require using this design. If there are multiple generators on a single utility supply line section a different scheme may be required.

A.15.3 Highlighted Protective Relaying Functions

A point of fault electrical arc will not be extinguished until the line protective equipment and generator is tripped, totally de-energizing the line section. Automatic reclosing of the source circuit breaker will not be able to restore service unless the arc is extinguished. For these reasons, phase and ground fault detecting relays, in addition to voltage and frequency relays, are required at the generator point of interconnection. Voltage supervision of automatic reclosing and synchronism check supervision of manual closing is required for the utility circuit breaker or re-closer at the line section source to minimize the risks of equipment damage and personal injury should an attempt be made to close the source circuit breaker or recloser with the generator still on line. If the power transformer at the interconnection is delta-connected on the utility supply, then a single phase-to-ground fault will not draw fault current once the line section protective equipment opens; however, the system will be over-voltaged. To prevent this from happening, voltage sensing on the utility supply side of the power transformer is required.

This design is for Generation Facilities with the following characteristics:

Generation is not to be intentionally exported on to the utility T&D system.

---and---

a. Total generation is greater than or equal to 50% of the minimum line section load.

---or---

b. Total generation is greater than 2000 kVA and less than 10 MVA.

---or---

c. Special system constraints warrant using this design.

Relay requirement/recommendation and installer are dependent upon utility/Generation Interconnection Customers property line location. Required relays are to be approved by utility.

A.15.4 Protective Device Numbering

The following requirements and examples, the nomenclature and numbering of protective devices will follow the standards set forth in ANSI C37.2. This standard numbering should also be used by the customer on information provided to utility showing customer equipment. All relays are to be utility grade relay and to be approved for use on the utility system.

A few of the more commonly used devices are shown in the following list:

Device Numbers	
2	Timer
4	Master Contactor
21	Distance Relay
25	Synchronizing or Synchronism Check
27	Under-voltage
32	Power Direction
40	Loss of Field Detection
46	Current Balance
47	Voltage Phase Sequence
50FD	Phase Instantaneous Over-current Fault Detector
51	Time Over-current
51G	Ground Time Over-current
51N	Neutral Time Over-current
51V	Voltage Restrained/Controlled Time Overcurrent
59	Overvoltage
59G	Overvoltage Type Ground Detector
67V	Voltage Restrained/Controlled Directional Time Overcurrent
79	Reclosing Relay
81O	Over-frequency
81U	Under-frequency
87	Current Differential

A.15.5 Additional notes pertaining to each device type

1. Device Type: Voltage Transformer

   Number Required: 3 connected grounded-wye/grounded-wye

   Purpose: Provide voltage for manual and automatic closing of source station breaker.

2. Device Type: Undervoltage Relay Device #: 27

   Number Required: 3 (may be part of auto-reclosing relay-device type 79)

   Purpose: Provide voltage supervision for closing of source station breaker. Breaker may be closed if all 3 phases are dead.

3. Device Type: Synchrocheck Relay Device #: 25

Number Required: As required (depends on type)

Purpose: Provide voltage and phase angle supervision for manual and supervisory closing of source station breaker. Breaker will be manually closed for any of the following indicated conditions, as requested by:

___Live Bus - Live Line Synchronized
___Live bus - Dead Line
___Dead Bus - Live Line
___Dead Bus - Dead Line
___Not Required

4. Device Type: Voltage Transformer

   Number Required: Depends on type of synchrocheck relay

   Purpose: Provide bus voltage for synchrocheck relay

5. Device Type: Power Transformer

   Number Required: As needed

   Winding configuration is to be specified by utility engr.

6. Device Type: Breaker Failure Backup Tripping (i.e. LBB)

   Number Required: 1 (may consist of several relays)

   Purpose: Provide for tripping of Generation Interconnection Customers generator breaker (or other designated back-up breaker) in the event that the Primary interface breaker fails to trip. This relay ito be initiated by any customer line fault relay.

7. Device Type: Voltage Transformer

   Number Required: 3 connected grounded-wye line side and either broken-delta or grounded-wye on secondary side. This is required when a delta primary or secondary interconnection transformer is present.

   Purpose: Provide voltage to 59G or 27 relays for faults involving ground on the utility system. Preferred connection is broken-delta; but if feeder loading is unbalanced to the point that three times zero sequence voltage is normally significant, then the secondary side should be connected grounded-wye. If this VT is to provide voltage also for impedance relays or directional relays and is to be used for a 59G relay, then the VT may be a three winding type with the third winding connected grounded-wye or the broken-delta connection may be provided by using an aux. VT (grounded-wye/broken-delta) if the main VT is grounded-wye/grounded-wye. The 27 relay could be part of the 27/59 relaying (specified in note 21) if the 27/59 VT’s are located on the primary side of the interconnection transformer. This relaying is to provide a relay failure output to trip a selected customer breaker between the utility system and the customers generator or a back-up relay is to be installed.

8. Device Type: Over or Undervoltage Relays Device #:59G or 27

   Number Required: 1 if 59G or 3 if 27 relay

   Purpose: Provide tripping of customer breaker(s) in the event of a fault on the utility system involving ground. If the VT's are connected broken-delta, then the relay used is the 59G overvoltage type. If the VT's are connected grounded-wye on the secondary, then the relays used are the 27 undervoltage relays.

9. Device Type: Impedance Relay Plus Timer Device #: 21-2/2

   Number Required: 1 Impedance relay plus 1 timer

   Purpose: Provide for tripping of customer breaker in the event of a phase fault on the utility system. This relay is used in a Zone 2 mode. The timer should be capable of providing a trip time in the 0,5 second to 2 seconds range.

10. Device Type: Voltage Transformer

    Number Required: 3 connected grounded-wye/grounded-wye

    Purpose: Provide voltage for impedance relays and power directional relays.

11. Device Type: Ground Overcurrent Relay Device #: 51G

    Number Required: 1

    Purpose: Provide for tripping of customer breaker in the event of a fault involving ground on the customer system. This relay may be in the transformer neutral.

12. Device Type: Overcurrent Relay Device #: 51

    Number Required: 3 or 1 3-phase

    Purpose: Provide for tripping of customer breaker in the event of a phase fault on the customer system.

13. Device Type: Directional Power Relay Device #: 32

    Number Required: 1 or 3 depending on type

    Purpose: Provide for tripping of customer breaker if the transformer size is smaller than generator, to limit power out if necessary to prevent damage to other customers, or to limit power out because of utility system constraints. This relay is not used for fault detection.

14. Device Type: Synchronizing Relay Device #: 25

    Number Required: As required by the number of generator and transformer breakers needing synchrochecking. Additional synchronizing relays or interlocks may be required at other circuit breakers that could initiate paralleling of the generator to the utility system. Not needed for most induction-type machines.

    Purpose: Provide for proper closing of breakers when the customer generator(s) are to be paralleled to the utility system.

15. Device Type: Voltage Transformer

    Purpose: Provide voltage for synchronizing relays. May be one connected phase-to-phase or may be a part of a 3-phase voltage transformer package.

16. Device Type: Voltage Transformer

    Number Required: 3 connected grounded-wye/grounded-wye

    Purpose: Provide voltage for under/over voltage and under/over frequency relays. These voltage transformers are to be connected on the primary or secondary side of power Transformer. One location only as specified by the utility engineer.

17. Device Type: Under/over Frequency Relay Device #: 81U/O

    Number Required: 1

    Purpose: Provide tripping of customer breaker in the event the frequency fails to be maintained. This relay would be expected to operate if the customer should become isolated on the utility line and not be able to maintain the load. The relay is to have a minimum of one over-frequency and two under-frequency elements with a definite time type characteristic capable of providing a trip time in the 0,1 second to 2 second range. The setting is to conform to IEEE 1547 section 4.2.4 (Note utility reclosing exception in this document), unless dictated by other utility system constraints. Frequency relays are to be connected to VT's on the primary or secondary side of power Transformer. One location only as specified by the utility engineer.

18. Device Type: Under/over voltage relay Device #: 27/59

    Number Required: Depends on type

    Purpose: Provide tripping of customer breaker in the event the feeder or line voltage cannot be maintained within acceptable limits. This relay should be a definite-time characteristic or an instantaneous type with a timer. The relay is to have a minimum of two over-voltage and two under-voltage elements with capable of providing a trip time in the 0,1 second to 2 second range. The setting is to conform to IEEE 1547 section 4.2.3 (Note utility reclosing exception in this document), unless dictated by other utility system constraints. Voltage relays are to be connected to VT's on the primary or secondary side of power Transformer. One location only as specified by the utility engineer.

19. Device Type: Interrupting Device

    Number Required: As needed

    Purpose: May be a fuse or circuit breaker. Circuit breaker must not be dependent upon A.C. power for tripping.

20. Device Type: Relay Failure Protection

    Number Required: As needed

    Purpose: To provide back-up relay protection should the primary relays fail. The relay fail contact of microprocessor relays set up to trip the generator breaker of other designated breaker can fulfil this requirement. If a PLC is installed at the site that performs critical generator functions, a back-up PLC is to be installed or a health check output is to be wired in to trip the generator breaker for the failure of the PLC.

21. Device Type: Automatic Transfer Inhibit Scheme

    Number Required: 1

    Purpose: Where the Generation Interconnection Customers is fed from two or more utility primary lines through a primary selective transfer scheme (ATO), the scheme must be inhibited from operating until the generator is isolated from the utility line.

22. Device Type: Circuit Breaker Trip Coil Monitor

    Number required: As needed per the number of generators

    Purpose: Where possible the interconnect circuit breaker trip coil is to be monitored to detect a failed trip coil and alarm the condition

23. Device Type: Relay Setting Note (Line Impedance)

    Purpose: to assist the Generation Interconnection Customers in setting protective relays at their site

    Impedance of interconnect transformer:

    Line Impedance between the Generation Interconnection Customers and the utility substation:

    Line impedance for which the DR must see and clear faults:

24. Device Type: Remote Terminal Unit (RTU)

    Number Required: 1 for utility & (1 for market operator as required)

Purpose: To monitor and control the transfer trip equipment, to monitor Generation Interconnection Customers circuit breaker status's, to monitor generator analogues and to monitor interconnection point analogues. The Generation Interconnection Customers is to supply an acceptable lockable space for the installation of the RTU equipment. Generation Interconnection Customers is to provide a dedicated circuit from his DC battery to power the RTU.