Adaptive Protection Solutions for
Future Active Power Distribution Networks

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Abstract

Power distribution networks are undergoing a continuous evolution from being passive to active in nature, with increasing penetration of distributed generation and the introduction of active network management schemes to facilitate increased distributed generation connections, automatically manage and reconfigure the network, optimise voltages and power losses and improve power supply reliability. The purpose of the research presented in this dissertation is to investigate the protection challenges that this evolution will introduce to the functions of protecting distribution networks, to develop new solutions and implement and demonstrate them in the laboratory.

To analyse the potential problems that may be introduced to traditional protection systems, a detailed analysis of the impact of distributed generation, network automation and islanded operation has been undertaken using a hardware in the loop simulation of a network model representative of typical UK rural distribution networks. This analysis has demonstrated certain protection challenges (and disproved others) associated with overcurrent and loss of mains protection of future active power distribution networks.

Two solutions to the demonstrated challenges have been developed: a new adaptive overcurrent protection system with automatic settings calculation, which overcomes the demonstrated sensitivity, selectivity and coordination problems associated with overcurrent protection; and a novel adaptive inter-tripping scheme with back-up passive loss of mains protection, which overcomes the demonstrated sensitivity and stability problems associated with loss of mains protection.

The developed protection solutions have been implemented on commercially available hardware and tested using an hardware in the loop simulation environment. The performance of both solutions has been compared to traditional overcurrent and loss of mains protection systems, which are configured in accordance with UK distribution network operator protection policy. The results of this comparison have shown the effectiveness of the developed solutions in overcoming the demonstrated protection problems associated with future active power distribution networks.

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Glossary of Terms

AIT	Adaptive Inter-Tripping
ANM	Active Network Management
ANSI	American National Standards Institute
APC	Adaptive Protection Controller
AR	Auto Recloser
CB	Circuit Breaker
CS	Circuit Switch
DFIG	Doubly-Fed Induction Generator
DG	Distributed Generation
DNO	Distribution Network Operator
DNP	Distributed Network Protocol
DT	Definite Time
DTL	Definite Time Lag
EF	Earth Fault
ENA	Energy Networks Association
FCL	Fault Current Limiter
GOOSE	Generic Object Oriented Substation Event
HIL	Hardware In the Loop
HV	High Voltage
IDMT	Inverse Definite Minimum Time

IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IGBT	Insulated-Gate Bipolar Transistor
LAN	Local Area Network
LOM	Loss Of Mains
NC	Normally Closed
NDZ	Non Detection Zone
NOP	Normally OPen
NVD	Neutral Voltage Displacement
OCR	Over Current Protection
OLE	Object Linking and Embedding
PHIL	Power Hardware In the Loop
PLC	Power Line Carrier
PMAR	Pole Mounted Auto Recloser
PV	PhotoVoltaic
ROCOF	Rate Of Change Of Frequency
ROCOP	Rate Of Change Of Power
RTDS	Real Time Digital Simulator
SCADA	Supervisory Control And Data Acquisition
SEF	Sensitive Earth Fault
TMS	Time Multiplier Setting
VT	Voltage Transformer

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Chapter 1:

Introduction

1.1 Motivation and objectives of research

Following privatisation and re-structuring of the UK electricity supply industry in 1990 [1.1], electricity distribution networks have changed from being passive to active in nature, with an increasing penetration of generators connected to the distribution network (i.e. at voltages at and below 132kV). The overall penetration level of such generation, commonly termed Distributed Generation (DG), is continuously growing and is expected to increase significantly in the future. The 2009 EU Renewable Energy Directive [1.2] has set a target for the UK to ensure that 15% of its energy consumption is from renewable sources by 2020. Considering that, in 2009, the penetration level was only 3% (as a percentage of overall installed capacity), the scale of the increase over the coming years represents a huge challenge and will require strong contributions from the electricity, heat and transport sectors of industry. The Government's Renewable Energy Strategy suggests that by 2020, approximately 30% of the electricity supplied could be from renewable sources, compared to around 6.7% in 2009 [1.3]. This increase of renewable electricity generation is expected to be achieved by connecting large scale off-shore wind farms to the transmission network and by increasing the penetration of renewable DG at distribution voltages.

As the DG penetration increases, a number of problems arise; for example, voltage levels could vary within networks in unexpected ways, existing lines may become overloaded, limiting the ability to connect further DG, etc. Therefore, active network management (ANM) schemes have been and will continue to be introduced to facilitate increased DG connections while avoiding high network reinforcement costs, or, at least, to reduce or defer reinforcement capital expenditure, manage the network voltage, minimise power losses, etc. [1.4]. Furthermore, in some areas, for example zones that are geographically isolated from major urban areas, increases in DG penetration will decrease dependence on centralised traditional generation. This may present opportunities for intentionally islanded operation to become a reality in order to provide improvements in the reliability of the power supply [1.5].

The increase of DG, the introduction of ANM and the potential islanded operation of networks will all act to change the design, operation and behaviour of distribution networks from how they were before the 1990s, and these changes will have a significant impact on the protection system [1.6-1.8].

Distribution network operators (DNOs) and researchers are asking themselves a number of pertinent questions in order to understand the extent of the impact of these changes:

- How does the protection system respond to earth and phase faults in distribution networks with DG? At what DG penetration levels do problems associated with blinding, false tripping and incorrect grading of protection arise?
- Does the introduction of ANM schemes affect the overcurrent protection – and what is the extent and exact nature of any introduced problems?
- Does the increased penetration of DG cause loss of mains (LOM) protection sensitivity and stability problems? If so, how can such problems be solved?
- What is the impact of islanded operation, if allowed, on the network protection system? Does the change in fault level due to islanding cause introduce problems to the network protection?

The literature discusses all of these questions and presents simulation studies to demonstrate several potential problems. The authors of [1.9-1.13] showed that DG affects the sensitivity and the operating time of the over-current relays (OCRs), while the authors of [1.14] proved that changes in network topology compromise the coordination between OCRs. The impact of islanding was analysed in [1.15, 1.16], where the authors assessed the amount of fault level reduction during islanded operation (compared with grid-connected operation) and proved that it causes slow operating times and possible blinding of OCRs under certain situations. However, the network examples and the protection settings used to demonstrate these problems appear to represent particular cases where these protection problems are more likely to happen and there is not enough evidence presented, in terms of the overall likelihood and exact nature of the problems being experienced, to cater for a representative wide range of realistic conditions.

Accordingly, the first objective of this research is to investigate exhaustively the potential problems associated with the protection of future networks (some of which are discussed in the literature) and demonstrate them in a realistic simulation environment. To facilitate realism and credibility of the investigation and results, a hardware in the loop (HIL) simulation with actual protection hardware configured to represent a particular UK DNO's protection policy is used to investigate the impact of DG, ANM and islanded operation on a typical UK rural distribution network during earth and phase fault conditions.

Demonstrating the problems is an important step towards appreciating fully the extent of such problems in the future; however, DNOs and researchers are not only interested in understanding the nature of future problems. They are also asking themselves the following questions:

- How can all of these different problems be overcome?
- Is it possible to enhance presently used overcurrent protection systems without requiring replacement with distance or unit protection schemes? If so, how can be this enhancement achieved?
- How can the presently-employed loss of mains protection systems be enhanced to improve sensitivity and selectivity? How can LOM be made more flexible to cope with variations in network operation modes?

Against this background, new technologies in the fields of protection relaying and communications have already been developed and are increasingly becoming commercially available. The problem is that DNOs are not taking advantage of these technologies, but are continuing to apply the protection policies that were originally created for electromechanical protection relays employed within a passive network context. Presently, most DNOs in the UK (and elsewhere in the world) utilise a mix of electromechanical, digital and numerical protection relays for protection of distribution networks, with a gradual replacement of electromechanical with numerical relays; however they are still largely employing the same protection characteristics, settings, etc. as their electromechanical predecessors.

Communication has been implemented in several UK distribution networks to allow remote control of network switches and pole mounted auto reclosers (PMARs) to facilitate the use of ANM solutions [1.17]. However, communication with the protection relays is not normally included, perhaps due to somewhat conservative policies within the industry and a tendency to ensure that, at distribution level, a protection relay must use only local electrical measurements and should not require communication facilities to execute its functions.

Modern commercially available protection relay and communications technologies present the potential for revolutionising power system protection practices at the distribution level – this is a necessity if the penetration of DG and ANM continues to grow at the levels anticipated in the future.

The second objective of this research work is to develop protection solutions to the demonstrated problems, taking advantage of available technologies and industry standards. The solutions that have been developed can be divided into two main applications: overcurrent protection; and LOM protection.

Finally, the third objective of this research work is to implement and demonstrate these solutions using commercially available hardware in conjunction with a HIL simulation environment to prove their effectiveness. The implementation and demonstration activities also facilitate detailed and objective quantification of the performance advantages and disadvantages compared to traditional protection systems when operating within a wide range of future scenarios.

1.2 Research Context

Protection relay technology has evolved significantly in the last three decades. Electromechanical relays, while still in use in many applications, have been succeeded progressively by static electronic relays, digital relays and numerical relays.

The earliest forms of protection relays were electromechanical relays and they have been in use for more than 100 years [1.18]. They work on the principle of a mechanical force causing operation of a relay contact in response to a stimulus. Static protection relays, i.e. relays that have no moving parts, were introduced at the beginning of the 1960s as an analogue electronic replacement for electromechanical relays, with some additional flexibility in settings and some saving in space requirements [1.19]. Around 1980, digital protection relays were introduced, replacing the analogue circuits used in static relays with microprocessors and microcontrollers [1.20], and in the following years numerical protection relays have been introduced as a natural development of digital relays due to numerous technological advances[1.21].

At present, commercially available protection relays for distribution networks are numerical and a typical relay has many protective and associated functions, a wide range of protection settings, the possibility of remotely modifying protection and switching between setting groups and the capability of communicating with other devices, which may be other protection relays or other devices used in the control and operation of the distribution network. Numerical protection relays are also called intelligent electronic devices (IEDs), a term which is used to denote a category of devices in the power industry that perform protection, control, monitoring and automation functions, and that can communicate over local and wide area SCADA systems.

Modern protection IEDs therefore offer significantly more functionality than their electromechanical ancestors, but this extensive functionality is typically under-utilised.

For a passive distribution network, it could be argued that the performance of electromechanical protection relays is acceptable and, therefore, DNOs could substitute electromechanical relays with moderns relays configured to provide identical performance. However, for an active distribution network, with increased DG penetration, ANM solutions and potentially incorporating new modes of operation (including islanded operation), it is necessary to develop new solutions. Since numerical protection relays are extremely flexible and have extensive (often unexploited) functionality, it is important to investigate and take advantage of their potential to facilitate the new solutions that are required.

DNOs and researchers have been considering application of adaptive protection concepts for many years. This concept was introduced in 1988 to improve the performance of distance protection on transmission networks and later in distribution networks to adapt overcurrent protection performance to, for example, cater for the introduction of DG [1.22-1.25]. However, the majority of adaptive overcurrent protection systems proposed in the literature are relatively simple schemes that adapt to a single (often significant) change, where two or more groups of protection settings are calculated to optimally protect the network when it is in discrete operational states; for example to cater for when DG is connected and when it is not. However, the reality is that distribution networks are evolving to become highly complex active power networks, where there may be in the order of tens of (or more) different operational states, many with different protection requirements (in terms of settings, and possibly operating times, where critical clearance times may reduce as a consequence of reductions in overall levels of system inertia). Many of the adaptive schemes proposed in the literature to date would not have the flexibility to provide effective protection for the range of scenarios that may be encountered in future.

Accordingly, there is the need for an adaptive overcurrent protection system that is not limited to a discrete (and usually small) number of scenarios, but that can automatically adapt to any possible network scenario, without the requirement for pre-calculated protection settings. This is necessary, as when the network becomes ever-more complex, defining network scenarios and calculating the optimum settings would become a complicated, time-consuming and possibly intractable procedure. Furthermore, this procedure would require to be repeated and/or recalibrated following any network upgrade, addition of DG, modification of ANM schemes, etc.

Another major area of research activity in the field of protection of active distribution networks is LOM protection. On-going research is necessary as it is difficult to achieve an effective balance between sensitivity and stability under all operational conditions with presently- adopted passive LOM protection relays, most of which use local measurements of frequency and/or voltage to execute the protection function [1.26].

One of the major concerns is that, during a severe system disturbance, a large number of DG units connected to the distribution network could be unnecessarily removed from service by passive LOM protection relays. This could potentially have adverse consequences on system stability and availability [1.27]. Furthermore, if there is an actual islanded condition, there is the potential for this to remain undetected if the generator output voltage and frequency are not significantly disturbed by the opening of the interface circuit breaker [1.28]. This is often referred to as the non-detection zone (NDZ) with reference to LOM protection.

At present, LOM protection relays are categorised as active and passive. Active LOM relays introduce a small perturbation into the power system, which results in a significant difference between the measured responses under islanded or interconnected conditions [1.29-1.31]. Passive LOM relays operate by monitoring system parameters at the interface point of a DG unit, which should, but do not always, undergo a significant change during the transition from interconnected to islanded mode [1.28, 1.31-1.33].

Passive techniques are the most commonly adopted LOM protection solution, with the advantageous features of high sensitivity and high speed of detection, but with disadvantages of possible spurious operation during transients, or failure to detect islanded condition in certain situations, often when the island load closely matches the generation output within the island prior to the LOM event [1.34].

The most accurate means of detecting LOM is through the use of remote techniques, normally effected through inter-tripping and requiring communication facilities. These techniques may offer improved reliability compared to local techniques and therefore some utilities insist on remote LOM protection, often using redundant, diverse communication channels. However, in the past, LOM, protection solutions based on communication have not been widely utilised due to the cost of the communication infrastructure and the fact that each DG installation may require several point-to-point links with each and every location that could cause an island to be formed (i.e. the breaker(s) at that location, when opened, would have the potential to form an island that the DG resides within).

With developments in communication technologies over recent years, it is now possible to develop and implement LOM protection in a new way, where communication can be an important element to accelerate the protection, and increase both sensitivity and stability. However, in parallel with this, it is necessary to develop a LOM protection system with acceptable levels of reliability and which does not directly depend on the availability of the communication system.

1.3 Principal Research Contributions

In terms of the novelty of the research undertaken and presented in this thesis, the principal contributions can be summarised as follows:

- Provision of detailed analysis, increased insight and understanding of the impact of DG, ANM and islanded operation on the protection system of a typical UK distribution network. This analysis has:
    - Confirmed and quantified some of the problems described in the literature, such as the problem of false tripping during phase and earth faults in adjacent feeders and the problem of loss of adequate coordination between overcurrent protection devices as a consequence of changes to network topology (e.g. due to the operation of ANM schemes).
    - Proved that the problem of blinding of overcurrent protection as a consequence of the connection of DG is highly unlikely and provided further insight into the impact of the fault current contribution of DG during network faults. The simulations have demonstrated that during phase faults the impact is minimal and blinding is very unlikely to happen, while during earth faults, DG actually has the "opposite" effect, i.e. rather than increasing the risk of blinding, DG acts to improve the sensitivity of the overcurrent protection for earth faults. This is due to the fact that DG is normally connected by a star/delta step-up transformer (at 11kV and above) and therefore the fault current contribution increases the zero sequence fault current component measured by the upstream OCR, increasing its protection sensitivity.
- The development of a novel adaptive overcurrent protection system, which differs from other adaptive protection solutions presented in the literature in terms of its possession of increased levels of flexibility, realism in terms of the application context, and comprehensive coverage of all events that may influence the behaviour of the protection system. It also differs from the majority of other adaptive protection solutions presented in the literature as it is not based on pre-calculated protection settings, but uses software to

calculate automatically the optimum protection settings in response to detected changes in the network configuration (and presence of DG). It is also more comprehensive with respect to other adaptive protection solutions presented in the literature because it does not consider only one problem, such as DG connection or islanded operation, but it considers simultaneously all events that may influence the behaviour of the protection system, such as connection/disconnection of DG, ANM actions and islanded/grid connected operation.

- The development of an adaptive LOM protection system that revolutionises the current approach to LOM, offering significant improvements in terms of both sensitivity and stability. This is achieved by amending, in real time, the protection settings of the LOM protection relays and by introducing an adaptive inter-tripping scheme that does not necessarily employ expensive point-to-point communication facilities. Furthermore, the adaptive LOM protection system allows islanded operation of a section of distribution network, with LOM protection also being provided within the power island using LOM protection relays (with amended protection settings) and by inter-tripping which is adapted to the specific islanded scenario. This delivers an LOM solution which is ready for future situations where intentionally islanded operation may (or may not – e.g. islanding may be permitted within certain boundaries, but further "sub-islanding" within that island may not) be permitted.
- The demonstration of the practical feasibility of both the adaptive overcurrent and LOM protection systems on commercially available hardware, using standard communication protocols, including DNP3 for the SCADA system and IEC61850 for the communication between the IEDs. The implementation in the laboratory is underpinned by hardware in the loop (HIL) simulation, where a typical UK distribution network has been modelled using an RTDS simulator.
- The development and demonstration of a generic testing methodology for adaptive protection systems on a HIL platform. This technique is an evolution of traditional dynamic type testing techniques [1.35], where additional inputs

to the simulation have been added to test not only responses to faults and true/false LOM conditions, but the adaptability of the adaptive overcurrent protection system to DG, ANM actions and islanded/grid connected operation, and the adaptability of the adaptive LOM protection system to islanded/grid connected operation and loss of communication.

1.4 Associated Publications

Journal Papers:

1. F. Coffele, C. Booth, A. Dyśko, and G. Burt, "Quantitative Analysis of Network Protection Blinding for Systems Incorporating Distributed Generation," *IET GTD*, 10.1049/iet-gtd.2012.0381, 2012.
2. S. M. Blair, F. Coffele, C. D. Booth, and G. M. Burt, "An Open Platform for Rapid-Prototyping Protection and Control Schemes with IEC 61850," *IEEE Transactions on Power Delivery*, in Press.
3. F. Coffele, C. Booth, A. Dyśko, and G. Burt, "An Adaptive Overcurrent Protection Scheme for Smart Distribution Networks," *IEEE Transactions on Smart Grid*, submitted for publication.
4. K. Jennet, C. Booth, F. Coffele. A. Roscoe, "An Empirical Inverter Model for Investigation of Sympathetic Tripping in Power Systems with Distributed Generation," *IEEE Transactions on Smart Grid*, submitted for publication.

White Papers:

1. I. Abdulhadi, X. Li, F. Coffele, P. Crolla, A. Dyśko, C. Booth, G. Burt, "International White Book on DER Protection: Review and Testing Procedures," *DERLab white papers*, [Online], Available: http://www.der-lab.net/.

Refereed Conference Papers:

1. F. Coffele, P. Moore, C. Booth, A. Dyśko, G. Burt, T. Spearing, and P. Dolan, "Centralised Loss of Mains protection using IEC-61850", presented at *10th IET DPSP*, Manchester, 2010.
2. F. Coffele, C. Booth, G. Burt, C. McTaggart, and T. Spearing, "Detailed analysis of the impact of distributed generation and active network

management on network protection systems," presented at *CIRED,* Frankfurt, 2011.

3. C. Booth, F. Coffele, and A. Dyśko, "Testing the Performance of Loss of Mains Protection for Networks Incorporating Distributed Generation," presented at *the International PTS,* Klaus, Austria, 2011.
4. Abdulhadi, F. Coffele, A. Dyśko, C. Booth, and G. Burt, "Adaptive protection architecture for the smart grid," presented at *ISGT Europe*, Manchester, 2011.
5. Abdulhadi, F. Coffele, A. Dyśko, C. Booth, and G. Burt, "Performance verification and scheme validation of adaptive protection schemes," presented at *44th CIGRE Session 2012*, Paris, 2012.
6. K. Jennett, F. Coffele, and C. Booth, "Comprehensive and Quantitative Analysis of Protection Problems Associated with Increasing Penetration of Inverter-Interfaced DG," presented at *11th IET DPSP*, Birmingham, 2012.
7. F. Coffele, M. Dolan, C. Booth, G. Ault, and G. Burt, "Coordination of protection and active network management for smart distribution networks," presented at *CIRED*, Lisbon, 2012.

1.5 Thesis Outline

Chapter 2 describes how UK distribution networks were originally designed and how since the 1990s and in the future they are (and will continue to be) evolving from being simple passive power networks to being active networks incorporating ANM schemes, extensive DG, controllable loads, energy storage, etc. This chapter presents a review of trends with respect to connection of renewable and non-renewable DG in the UK, along with a summary on the implementation of ANM schemes in present and future active distribution networks.

In chapter 3, a detailed and critical literature review is presented in the form of two major elements. Firstly, the challenges that are (and will be) presented to the function of protection that arise from the connection of DG, the introduction of ANM schemes and routine islanded operation of the protected network are analysed, with an accompanying critique of the associated literature. The principal protection problems discussed include sensitivity, selectivity and grading of overcurrent protection, and stability and sensitivity of the loss of mains protection. Secondly, the main body of the literature review focusses on the solutions that have been proposed to overcome the identified problems, such as the use of adaptive OC protection to modify protection settings to cater for different network scenarios, active and remote LOM protection solutions to address the problems associated with LOM protection stability and sensitivity, and employment of fault current limiters to limit DG fault current contribution.

Chapter 4 presents the results of detailed analyses of the impact of DG, ANM and islanded operation on network performance and consequently on protection systems. This has been undertaken to fill an identified gap in the understanding (as evidenced through a lack of such information in the literature) of the potential for, and nature of, these protection problems. The chapter opens with an analysis of the problem of false tripping of overcurrent protection (using protection settings as applied by DNOs), identifies and explains the conditions where false tripping will happen and finally presents solutions as to how such problems may be avoided. The chapter then progresses to analyse the problem of blinding of overcurrent protection, concluding that, contrary to the vast majority of published work, DG will not lead to blinding of overcurrent protection during earth faults, and that, for phase faults, it is only possible for blinding to occur in the presence of DG in extreme cases. Finally, the chapter demonstrates the range of potential impacts that network topology changes may have on the grading between overcurrent protection devices for a number of scenarios.

In chapter 5, an innovative adaptive overcurrent protection system, developed during the course of this research, is presented. This system is more flexible and more comprehensive with respect to other adaptive protection systems proposed in the literature. It is more flexible because it does not use pre-calculated settings and therefore can adapt to several network scenarios, and it is more comprehensive because it does not consider only a single factor that may require adaptation of settings. Many reported systems only consider the status of DG connected to the network, but the developed system considers simultaneously all factors that may impact on the overcurrent protection system. The architecture and operational algorithm of the adaptive protection system is also described in detail in this chapter; there are several functional layers within the architecture, and each of the functional elements within the layers is described in detail. Guidance as to how the architecture's functional elements can be implemented in hardware and software is provided, and an overview of how the transition from traditional to adaptive overcurrent protection systems may be best managed is included. To conclude chapter 5, results are presented relating for a number of scenarios that illustrate the improved performance of the system when compared to a traditional overcurrent protection scheme.

Chapter 6 presents an adaptive LOM protection system that can co-exist with and offer major performance improvements to prevailing approaches to LOM, offering significant benefits in terms of both sensitivity and stability. This is achieved by real time amendment of the LOM protection relays' settings and introducing an adaptive inter-tripping scheme. The architecture of the adaptive LOM protection system is presented, along with a description of how the architecture can be implemented in hardware and software. The chapter then explains the adaptive LOM protection algorithm, the adaptive inter-tripping algorithm and how the adaptive inter-tripping scheme and the individual passive LOM protection relays are coordinated. Examples of operation are included and performance is quantified for a range of situations and assumed communications delays; the HIL simulation environment is used to generate these case studies and results. Information relating to how communication errors and communication failures are managed is also presented.

Chapter 7 provides a generic view of how adaptive protection can be tested with the objective of providing guidance to others in the field of testing and validation of adaptive protection schemes. Firstly, an overview of how protection relays and protection schemes are presently tested is presented, with focus on dynamic type testing. Subsequently, a description of how dynamic type testing can be adopted to test adaptive protection system and guidelines on necessary additional inputs to the testing technique is presented. The proposed dynamic type testing methodology is applied to test the adaptive protection systems described in chapters 5 and 6, which are both implemented in the distribution network example described in appendix A. Then, the performance of the adaptive protection solutions is compared with traditional protection schemes (designed in accordance with UK DNO protection policies) to quantify the improvements in the protection performance.

Finally, Chapter 8 presents the conclusions of this thesis. It initially summarises the main findings of the investigation into the protection of future active distribution networks. Following on from this, it describes the novelty of the adaptive overcurrent protection and adaptive LOM protection solutions presented in this thesis, explains the main advantages respect to other existing protection solutions and comments on the dynamic validation results which show the effectiveness of the presented protection solutions. Finally, it describes the future research work that will follow on from what is presented in this thesis, which primarily consists of demonstration of both the adaptive overcurrent protection and adaptive LOM protection solutions in a “power hardware in the loop” environment at the Power Networks Demonstration Centre presently being constructed at the University of Strathclyde.

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Chapter 2:

Evolution of UK electrical distribution networks

2.1 Chapter overview

This chapter describes the UK electrical distribution network, how it has evolved since the early 1990s from being a passive to an active system and how it is expected to change in the near- and longer-term future.

The structure of the distribution network at the different voltage levels are presented initially. The overcurrent protection schemes that are presently used to protect the network from faults are then described, giving also an overview on different types of faults that might occur and their probability.

Finally, the behaviour, under fault/transient conditions, of different types of DG is discussed, and an overview of how different types of interfacing transformer winding connections and earthing arrangements may impact upon DG behaviour during network transient conditions is presented.

2.2 Traditional UK distribution networks

Until around 1990, the UK electrical power system was highly centralised, i.e. most of the electricity was generated in large power stations to benefit from economies of scale and these were normally located either close to the fuel source, e.g. coal, or close to river or sea for cooling water requirements. Almost 80 per cent of the electricity was generated in 39 coal-fired stations and the remaining 20 per cent was generated using 9 oil, 11 gas turbine, 10 nuclear and 7 hydro power stations [2.1].

In the majority of cases, generators were located relatively distant from the concentrations of loads and power was transported through the transmission network and then distributed to the loads through the distribution network.

The power flow at distribution level was typically unidirectional and therefore the distribution network was designed as a passive system to transport power from the transmission network to the customers through different voltage levels as shown in Figure 2.1.

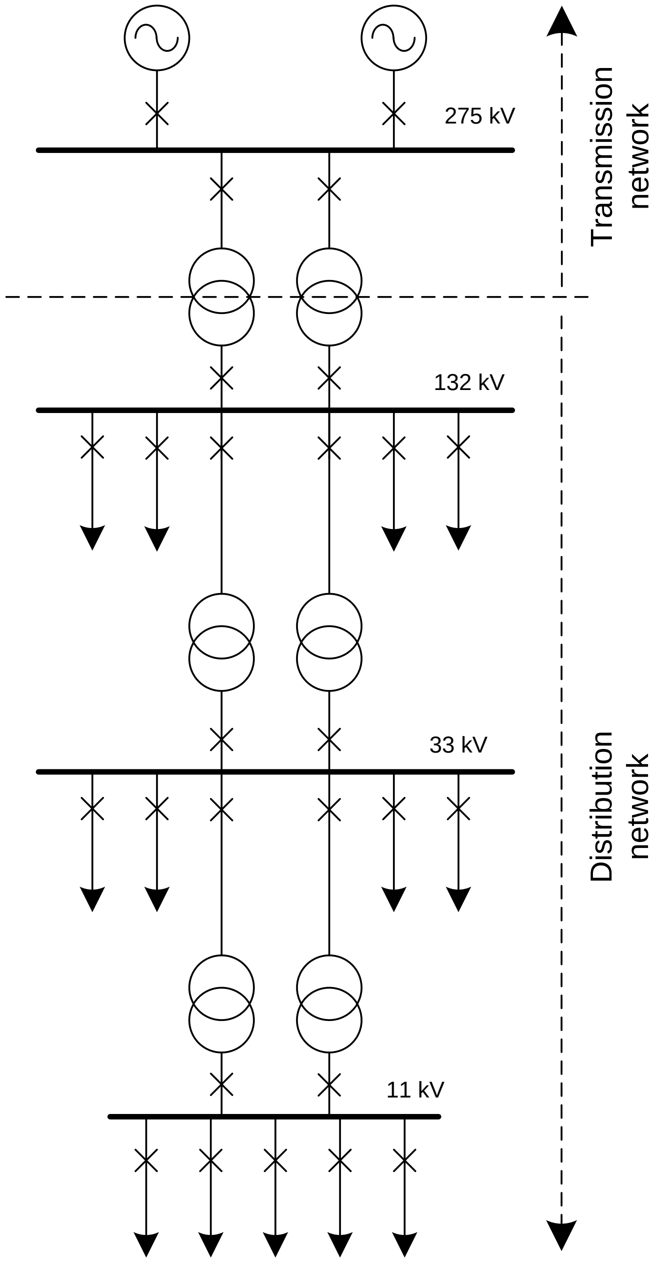

Figure 2.1 Traditional passive UK power network

The network was designed with different configurations according to voltage level, load concentration and geographical topology. From 132kV to 33kV the network configuration was normally designed with a meshed/interconnected topology (with a small number of exceptions), while at 11kV the typical network design was radial or loop topology.

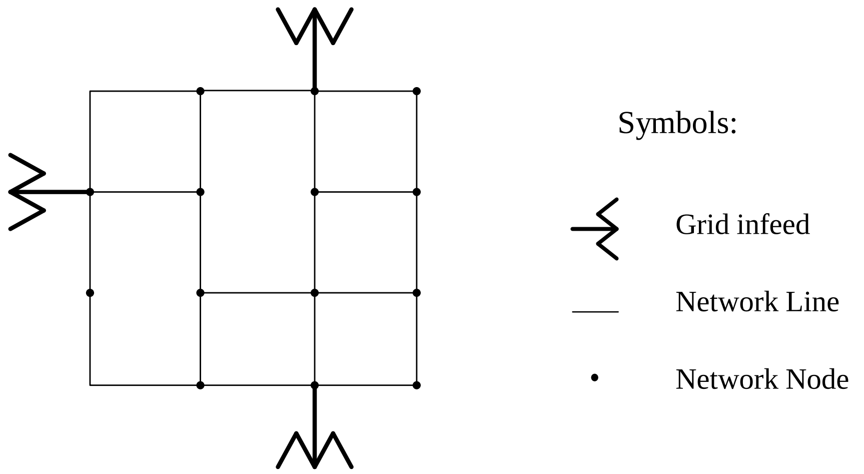

Figure 2.2 Meshed and interconnected network configuration

Meshed and interconnected networks, shown in Figure 2.2, provide increased security of supply to individual substations and are more efficient in terms of utilisation of circuit and transformer capacities. However, meshed networks require more substation equipment, e.g. circuit breakers and protection relays, when compared with radial and looped networks.

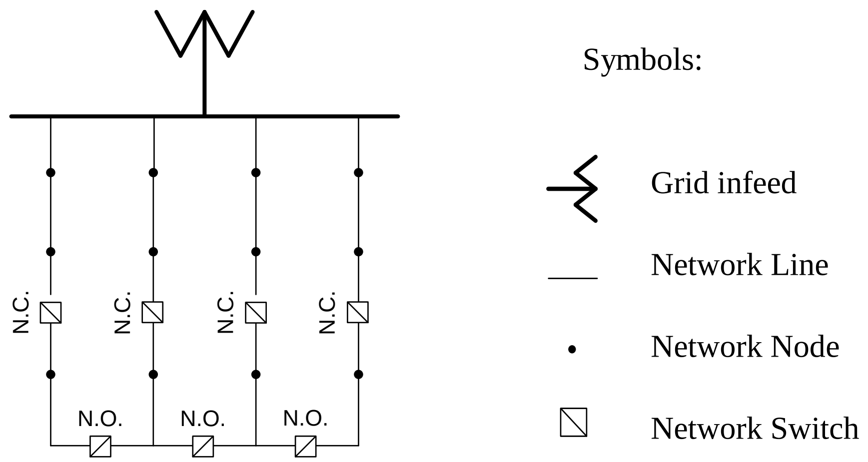

Figure 2.3 Radial/loop network configurations

Radial/loop networks, shown in Figure 2.3, are normally operated in a partially split fashion, using normally open points to reduce fault levels to within acceptable values. Operating with open points also facilitates improved control of voltages and power flows. Subject to loading capacity of individual feeder sections, these configurations can accept the loss of one interconnector without interruption of supply to any substation.

The radial/loop configuration, shown in Figure 2.3, is normally adopted at 11kV in the UK. Under normal operating conditions, the network can be operated radially and when there is a fault on one of the feeders, the position of the normally open points can be modified to provide back-up supply to the loads affected by the initial fault.

2.3 Distribution network protection

Short circuits occur when the path of the load current is changed ("shortened") due to breakdown of insulation, which may be due to a number of reasons:

- Insulation ageing
- Temperature variation
- Weather conditions: wind, rain, hail, snow, ice, etc.
- Chemical pollution
- Foreign objects, e.g. trees
- Overvoltages due to switching transients or control malfunctions
- Human error

Faults are classified as single phase to earth, two phases to earth, phase to phase and three phase faults. Accumulated experience of the utilities shows that all faults are not equally likely. Single phase to earth faults (L-G) are most likely whereas the three phase fault (L-L-L). Table 1 shows the probability distribution for different fault types.

Table 2.1 Fault statistics with reference to fault type [2.2]

Fault type	Probability of occurrence
L-G	85%
L-L	8%
L-L-G	5%
L-L-L	2%

Furthermore, the probability of faults on different parts of the network is different. The overhead lines and outdoor equipment, which are exposed to most of the previously listed causes of insulation weakening, are most likely to be subjected to faults, while underground networks and indoor equipment are least likely to be subjected to faults. Table 2.2 shows the probability of faults on different elements.

Table 2.2 Fault statistics with reference to power system elements [2.2]

Power system element	Probability of faults
Overhead lines	50%
Underground cables	9%
Transformers	10%
Generators	7%
Switchgears	12%
CT, VT, relays, control equipment, etc.	12%

A protection system capable of interrupting the fault current promptly is of vital importance to avoid fires, explosions, damage to utility equipment and possibly compromised system stability (although at distribution level this is not so important in traditional networks due to the considerable impedance between faults and generators – although in networks with DG this is clearly not the case). Furthermore, fast and selective protection systems can reduce the impact of faults on reliability and power quality.

Overall supply reliability and availability can be improved by reducing the number and duration of the interruptions to the customer supply. To do so, the protection system has to be selective and in many cases automatically reclose the circuit breaker(s) to restore supply when the fault is not permanent. Power quality can be improved with faster tripping to reduce the duration of voltage sags. Furthermore, effective coordination can reduce the number of unnecessary supply disconnections.

The general philosophy to design the protection system of a network is to divide the system in separate zones that can be individually protected and disconnected on the occurrence of a fault. For example a typical 11kV distribution network can be divided into zones as shown in Figure 2.4.

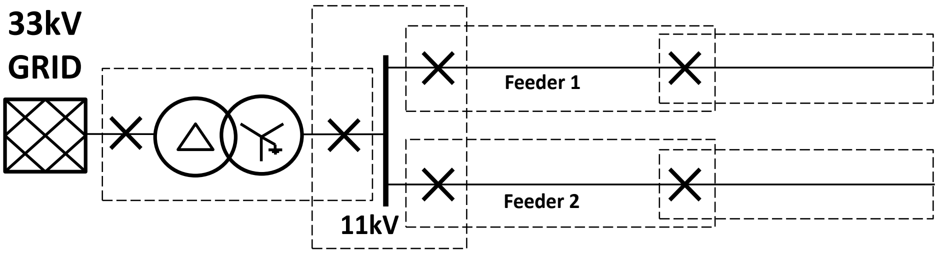

Figure 2.4 Protection zones

At the occurrence of a fault in one of the zones, the protection relay/s protecting that zone is/are responsible for tripping the circuit breaker/s and clearing the fault. Different types of protection relays are normally used depending on the voltage level. Distance and/or differential protection is normally adopted to protect meshed network at 33kV and higher voltages, while overcurrent protection is commonly used to protect 11kV networks.

The devices used to protect 11kV networks are overcurrent relays, automatic reclosers, automatic sectionalisers (or smart links) and fuses.

2.3.1 Overcurrent protection

Overcurrent protection is the most common form of protection used to react to excessive fault currents in distribution networks. Overcurrent protection characteristic curves can be divided into three groups: definite current or instantaneous; definite time; and inverse time. Figure 2.5 illustrates the protection characteristic curves.

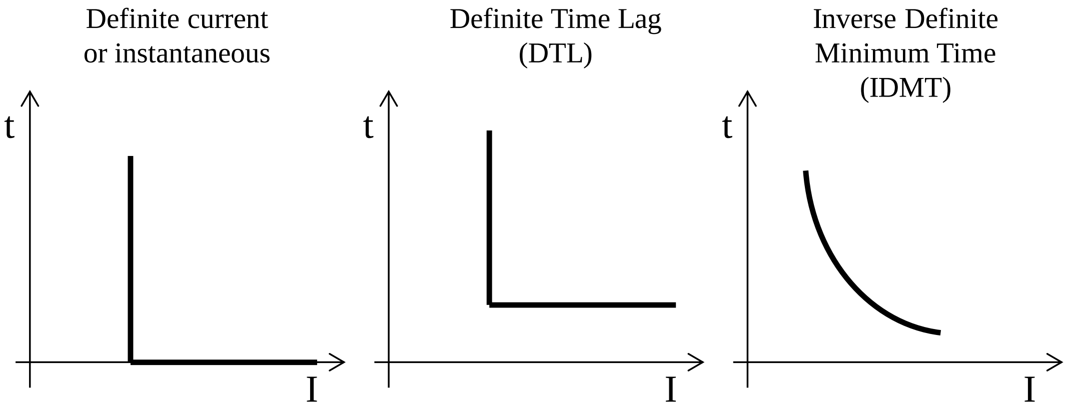

Figure 2.5 Overcurrent protection characteristics

Definite current characteristic, also known as instantaneous characteristic, operates instantaneously when the current reaches a defined value, the pick-up current. This is used in combination to the other protection characteristics to provide a fast tripping of the protection in the case of relatively high fault currents. For example, in distribution networks where the source impedance is small in comparison with the protected circuit impedance, an instantaneous characteristic can be combined with an Inverse Definite Minimum Time (IDMT) characteristic to reduce the tripping time at high fault currents and to improve the overall overcurrent system operating times and coordination.

Definite Time Lag (DTL) characteristic operates with a time lag after the current reaches a defined value, the pick-up current. This type of characteristic is used to give each of the relays controlling a circuit breaker a (pre-defined) time delayed mode of operation to ensure that the breaker nearest to the fault opens first before other relays situated upstream towards the source. The main disadvantage with this method of discrimination is that faults close to the source, involving relatively higher fault currents, may be cleared in a relatively long time.

Inverse Definite Minimum Time (IDMT) characteristic operates in a time that is inversely proportional to the fault current. The advantage of IDMT over DTL characteristics is that, for very high currents, much shorter tripping times can be obtained without compromising the protection coordination. IDMT relays are generally classified in accordance with their characteristic curve that indicates the speed of operation; based on this they are commonly defined as being inverse, very inverse, or extremely inverse.

2.3.2 Automatic Reclosers

Automatic Reclosers (AR) are switchgear devices with an overcurrent protection IED able to detect phase and earth fault conditions, to interrupt the fault current and then automatically reclose to re-energise the feeder. If the fault is permanent, when the AR attempts to reclose, the presence of the fault results in subsequent tripping and after a defined number of reclose-trip cycles the automatic recloser “locks out”. If the fault is temporary in nature, which is the case for more than 80% of faults in overhead distribution networks, the AR prevents the feeder being unnecessarily removed from service.

ARs are normally designed to have multiple IDMT characteristics curves, typically one fast and two or three delayed, so that if the fault is transient, then it can be cleared at the first operation, while if it is permanent (or semi-permanent, for example vegetation or other material that can be "burned away" with multiple reclose operations) and it is downstream of a fuse, the fuse blows during the second or third operation and isolates the faulted zone of the feeder. If there are no fuses between the AR and the fault, the AR locks out after three or four reclose attempts.

ARs are normally used at the following points on a distribution network:

- In substations, at the head of the feeders, to provide primary protection for the feeder;
- Along the feeders, to split the feeder into two or more sections, to limit the number of disconnected loads for a fault;
- On spurs, to prevent the tripping of the feeder for faults in spurs.

ARs situated along feeders and at the head of spurs are normally mounted on poles and therefore are usually termed Pole Mounted Auto Reclosers (PMARs).

2.3.3 Automatic Sectionalisers

An Automatic Sectionaliser (AS), known also as a "smart link", is a device with the ability to measure the current and detect phase and earth faults and isolate (but not interrupt) the faulted section of the distribution network once an upstream AR has interrupted the fault current. The AS counts the number of operations of the upstream AR and after a defined number of cycles, and while the AR is open, opens and isolates the faulty section of the distribution network, allowing the AR to reclose on the next attempt and restore supplies to upstream loads.

An AS does not have a DTL or IDMT characteristic and therefore it can be used where coordination between protection devices is difficult to achieve, for example between two protection devices with very close (in terms of current/time characteristic settings) protection characteristics when an additional step in coordination is required. ASs are normally used at the head of the spurs of feeders or along spurs, and in some cases they might be used also on main feeders.

2.3.4 Fuses

A fuse is an overcurrent protection device consisting of a strip of metal that melts and breaks the circuit when the current exceeds a defined value. When an AR is situated upstream of the fuse, both devices are normally coordinated to “save” the fuse for transient faults and blow the fuse for permanent faults. This is done by using a fast and two or more slow tripping characteristics as explained in section 2.3.2.

Fuses can be divided into different classes depending on their melting curve. They can be defined as fast or slow fuses depending on the speed of operation ratio, which is the ratio of minimum melt current that causes fuse operation at 100ms to the minimum melt current for 300s operation. For example, fuses of type K (fast fuses) have a speed ratio between 6 and 8, while fuses of type T (slow fuses) have a speed ratio between 10 and 13 [2.3].

2.4 Evolution of UK distribution networks

After the privatisation and re-structuring of the electricity supply industry in 1990 [2.4], the UK distribution network has been subject to an increasing number of connections of generators to the distribution network at different voltage levels. This has the effect of changing distribution network from being passive systems, as shown in Figure 2.1, to becoming active systems, as shown in Figure 2.6.

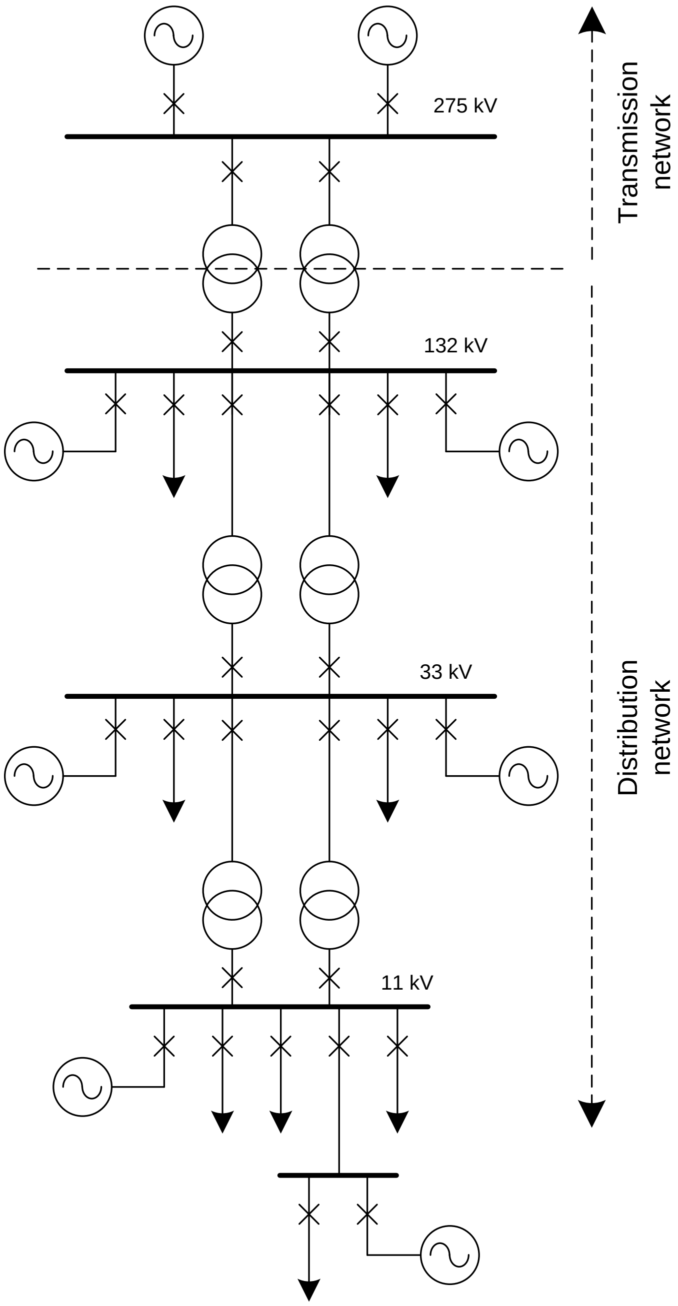

Figure 2.6: Active UK distribution network

Generators connected to the distribution network are typically referred to as Distributed Generation (DG). DG includes generation from renewable sources, e.g. wind generation, photovoltaic, hydro, etc., as well as generation from non-renewable sources, e.g. Combined Heat and Power (CHP) using combined cycle gas turbines [2.5].

The penetration level of DG has been growing notably since 1990 because of their potential to reduce emissions from burning fossil fuels, decrease network energy losses and potentially increase security and quality of energy supply. In 2009, DG accounted for 17.9% of the total UK installed power capacity of 78,255 MW [2.6], and it is expected to continue to grow in the future [2.7]. Figure 2.7 presents a breakdown of the various types and overall capacities of DG connected to the UK distribution network in 2009. Section 2.5 presents an overview of the various type of DG, of their means of interconnection to the distribution network, of their typical response to electrical faults on the network and of the DG protection interface.

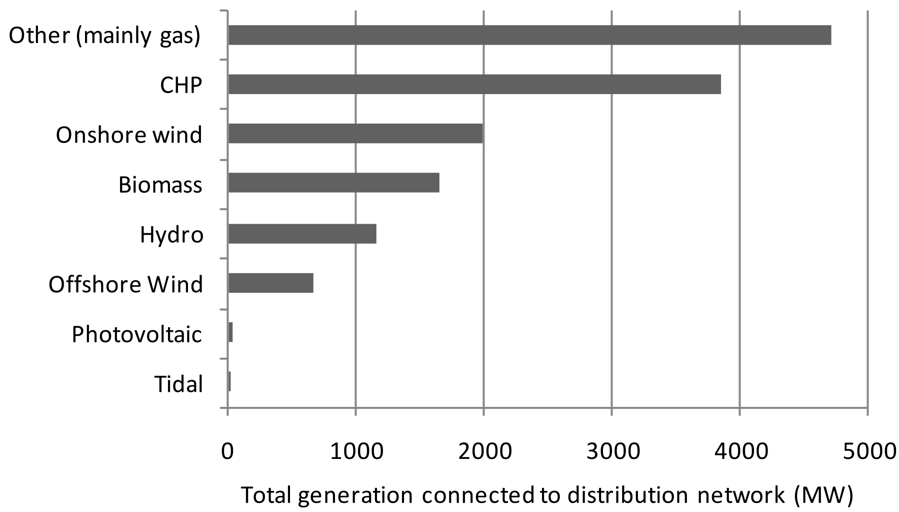

Figure 2.7 DG connected to UK distribution networks in 2009 [2.6]

The increased penetration of DG may cause problems to present operating regimes employed by DNOs, as these networks were designed for delivery of power from bulk generation points to customer loads through passive distribution networks. Distribution networks may be susceptible to more frequent and severe voltage fluctuations and thermal constraint infringements due to the connection of DG. To overcome these problems and facilitate increased connection of DG, Active Network Management (ANM) solutions have been developed. Section 2.6 presents an overview of the first schemes implemented to actively manage DG units and of more recently developed ANM schemes.

As the amount of DG connected to the distribution network increases, islanded operation of parts of the distribution network becomes possible. Current design and operation of networks discourages the operation of these islands for safety and security reasons. However, intentional islanded operation would bring benefits to customers, DNOs and generators; therefore the present operation policies are likely to be reviewed in the future to permit islanded operation in some distribution networks with high penetrations of DG. Section 2.7 presents an overview of the present approach to islanded operation (which is not permitted) and discusses advantages and technical challenges of intentional islanded operation.

2.5 Distributed generation

Distributed generation include different types of renewable and non-renewable generation which include:

- **Combined cycle gas turbine (CCGT)**, which is presently the most popular type of DG connected to the UK network. It has attracted several investments in the 1990s and it resulted in the much-reported "dash for gas" [2.8]. The key drivers to the investments in CCGT were: the privatisation of the electricity industry and the high interest rates at that time, which favoured "quick-to-build" gas turbine power stations over the larger but "slower-to-build" coal and nuclear power stations; the decline in wholesale gas prices; and the technical advances in CCGT generation technology [2.8]. In the UK there are a number of CCGT connected at 66kV and 132kV networks and since distribution network is per definition up to 132kV, some of the CCGT plants are considered to be part of DG.
- **Combined Heat and Power (CHP)**, which is the second most dominant type of DG, as illustrated in Figure 2.7. The main driver to build CHP, rather than conventional, power plants is that, while conventional power generation plants dissipate most of the waste heat into the natural environment, CHP

captures the heat to use it for domestic or industrial heating purposes, achieving efficiencies up to 90% [2.9]. The total capacity of CHP plants connected in 2010 to the distribution network was 3,845MW and it is expected to grow in the following years [2.10].

- **Wind power**, which is the fastest-growing renewable technology with an average global growth over the last 5 years of more than 30% annually[2.11]. The number of operational wind farms in the UK in 2012 is 342, with a total power capacity of 6.66 GW, of which 4.78GW are onshore and 1.86GW are offshore [2.12]. In order to achieve renewable targets, within the next 4 years (by 2016) there will be 8 GW of wind energy capacity installed, with a total of 18 GW by 2020. In terms of contribution to net UK electricity production offshore wind supplies around 1.5% today, and it is expected to grow to between 7% and 8% in 2016 and to around 17% in 2020[2.13].
- **Biofuels**, which includes biomass and biogas, have grown in terms of installed capacity in the UK from 0.91 GW in 2000 to 1.93 GW in 2009, with a mean annual grow of 9%. At present, biofuels provide less than 3.5 per cent of the UK electricity, but have a realistic potential to supply up to 6 per cent of UK electricity by 2020 [2.14].
- **Hydro**, which counts many generators in the UK ranging from a couple of hundreds of W up to many MW, with a total installed power capacity of 1.5GW plus pumped storage stations with a total power capacity of 2.7GW [2.15]. Most of the hydropower generators are located in Scotland but the largest of all, Dinorwig, is in North Wales[2.16].Most of the Scottish hydropower was established during the last century allowing Scotland to pursue ambitious renewable energy and climate change targets, with hydropower accounting for 10 per cent of the electricity generated in Scotland and nearly half of renewable generation, in 2008 [2.17]. A study commissioned by the Scottish Government through the Hydro Sub Group of the Forum for Renewable Energy Development in Scotland (FHSG) during the first half of 2008 has calculated that further 2.5GW of potential hydropower capacity exists, of which 0.7 GW is economically feasible to develop[2.17].

- **Photovoltaic and Tidal**, which are presently only a small contribution to the total UK installed power generation, but represent two growing sectors and can play a crucial role in increasing renewable energy generation. Photovoltaics represent a growing business, particularly for small scale installations [2.18].Tidal power generation has the potential to become a viable option for large scale generation. One example of large scale tidal demonstration is the 10MW tidal project within the Sound of Islay, which will be developed by Scottish Power Renewables [2.19].

2.5.1 Connection of DG to the distribution network

The power capacity of a DG unit can vary from less than 1kW to 100MW and there are many different categories of DG, as shown in Figure 2.8 . The total power capacity of a DG power plant depends on the number of DG units, e.g. a wind farm composed of 100 wind turbines of 3MVA has a power plant capacity of 300MVA.

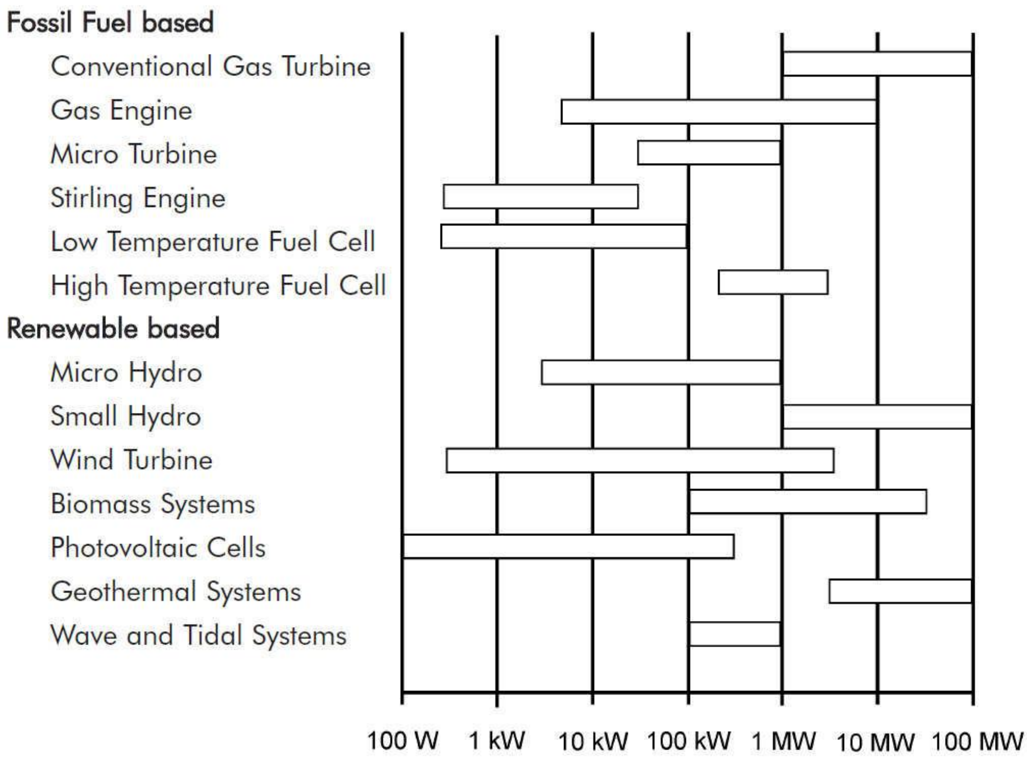

Figure 2.8 Overview of DG power capacity and use [2.20]

DG can be categorised into the following four categories, depending on the type of interface to the main AC network:

- Induction generators
- Doubly fed induction generators (DFIG)
- Synchronous generators
- Other types of DG with power electronic interfaces (e.g. PV, fuel cells, storage)

From the point of view of the protection system, the behaviour of a DG power plant during faults or transients in the network depends on which of the four categories the DG power plant belongs to.

2.5.1.1 ***Induction Generators***

Induction generators used in DG have normally a power rating between 0.01MW and 1MW. When there is a short circuit close to the generator, the system voltage will be severely depressed and the excitation will collapse, as the induction generator's excitation is directly derived from the power system that it is connected to. This has the consequence of decreasing any fault current contribution from the induction generator to a negligible value , usually 100-300ms following fault inception[2.21].

2.5.1.2 ***DFIG Wind Turbines***

DFIG wind turbines have a typical rating between 0.5-3MVA. Their behaviour during faults or transients is highly dependent on the design of the generator and its interfacing power electronics. The fault current contribution can reach peak values of four to six times the rated current and then decrease quickly to zero in 100 to 200ms. However, the control of the DFIG is normally designed to disconnect the unit from the network within 25 to 100ms when the short circuit is close to the generator [2.22].

2.5.1.3 ***Synchronous Generators***

Synchronous generators used in DG applications can be divided into small (0.5-5MVA), medium (5-25MVA) and large (>25MVA) categories [2.23]. The contribution of synchronous generators to fault currents varies with time after fault inception. The contribution generally begins with a maximum sub-transient value (for a duration of up 50ms following fault), then reduces to a transient value and finally subsides to the steady-state short-circuit current (which can be sustained indefinitely until the fault is cleared) [2.23].

The sub-transient current is determined by the sub-transient reactance of the generator, which in turn is defined by the electrical and mechanical properties of the machine and prime movers. The transient and steady-state short-circuit currents depend strongly on the design of the excitation system and control of the machine[2.23]. The durations of sub-transient and transient current levels are also defined by time constants, which again relate to physical properties of the machine and prime movers.

2.5.1.4 Types of DG with power electronic couplings

Power electronic converters are used in several types of DG and have a rating that can vary from 1-10 kW for a domestic photovoltaic DG unit to more than 1MW for wind turbines with full converter interfaces. At the high end of the range, there are applications where the rating of the power electronic converter can reach in excess of 1GW, e.g. the 2GW UK-France Channel DC link [2.22]. In contrast to induction, DFIG and synchronous generators, the current supplied during faults or transients is not determined by the converter's construction but by its control system. Without control, converters would tend to supply a large current for situations where the voltage drops at the converter terminals; if this were not quickly restricted, then thermally-initiated breakdown of the semiconductor devices would result [2.24].

The control of the power electronic converter limits the current to avoid damage to semiconductor devices and can be designed to completely cease conduction or to maintain conduction at a restricted level of current to satisfy "fault ride through" capabilities. The maximum fault current that the converter can supply without damaging the semiconductors depends on the design of the converter. The authors of [2.25] have demonstrated that a ratio of 1.6 between maximum and rated current is sufficiently high to provide a good fault ride through capability and low enough to avoid the use of seriously overrated power electronic devices.

Induction and synchronous generators are used in the simulations presented in chapter 4 to investigate the impact of distributed generation because these generators, in particular synchronous generators, provide the higher fault current respect to DFIG and power electronic converters.

The same generator models are then used in chapter 5 and 6 to prove the advantages of the developed adaptive protection solutions and in chapter 7 for the testing and comparison between the developed adaptive protection solutions and traditional overcurrent and loss of mains protection schemes.

2.5.2 DG interfacing transformer

Depending on capacity, DG plant can be connected to different voltage levels in the network:

- 400V: Small generation rated at up to 1MW – 1MW represents the largest standard 11kV/400V transformer used in UK distribution systems;
- 11 kV: Generation rated at up to 12 MW, which is limited by the maximum standard switchgear current rating;
- 33 kV and higher voltages: Generation rated at greater than 12 MW.

The generator can be directly connected to the distribution network, for example at LV, while in other cases an interfacing (step up) transformer is required to step up the voltage, as shown in Figure 2.9.

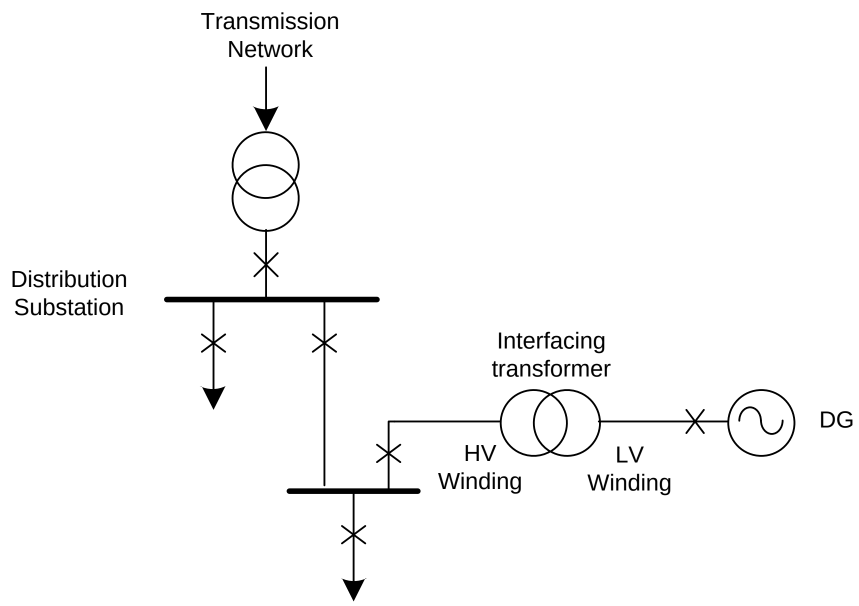

Figure 2.9 DG interfacing transformer

There are five types of interfacing transformer commonly used, which are summarised in Table 2.3. The transformer configurations 1, 2 and 3 do not allow the passage of zero sequence currents. However, transformer configurations 4 and 5 provide an earthed source to the network and to limit the fault current, earthing resistors or reactors can be used if necessary.

Table 2.3 DG interconnection transformer types

	HV Winding	LV Winding
1	Δ	Y⏚
2	Y	Δ
3	Δ	Δ
4	Y⏚	Y⏚
5	Y⏚	Δ

2.5.3 DG interface protection

The DG interface protection arrangement dependents on the voltage level, the rated power of the DG, the operation mode of the DG and the nature of the network which the DG is connected to. The mandatory requirements for protection of DG are generally set out in the Distribution Planning and Connection Code (DPC7) of the Distribution Code [2.26] and guidance to the technical requirements for the connection and protection of DG for a series of cases at different voltage levels is given by the engineering recommendation ER G59/2 [2.27]. The main function of the DG protection interface described in the ER G59/2 is to prevent the DG supporting an islanded section of the distribution network and to avoid nuisance tripping during transients on the network.

Figure 2.10 illustrates a DG connection to a HV distribution network and the protection functions installed both at the utility and at the DG side. Table 2.4 reports the ANSI device numbers used in Figure 2.10.

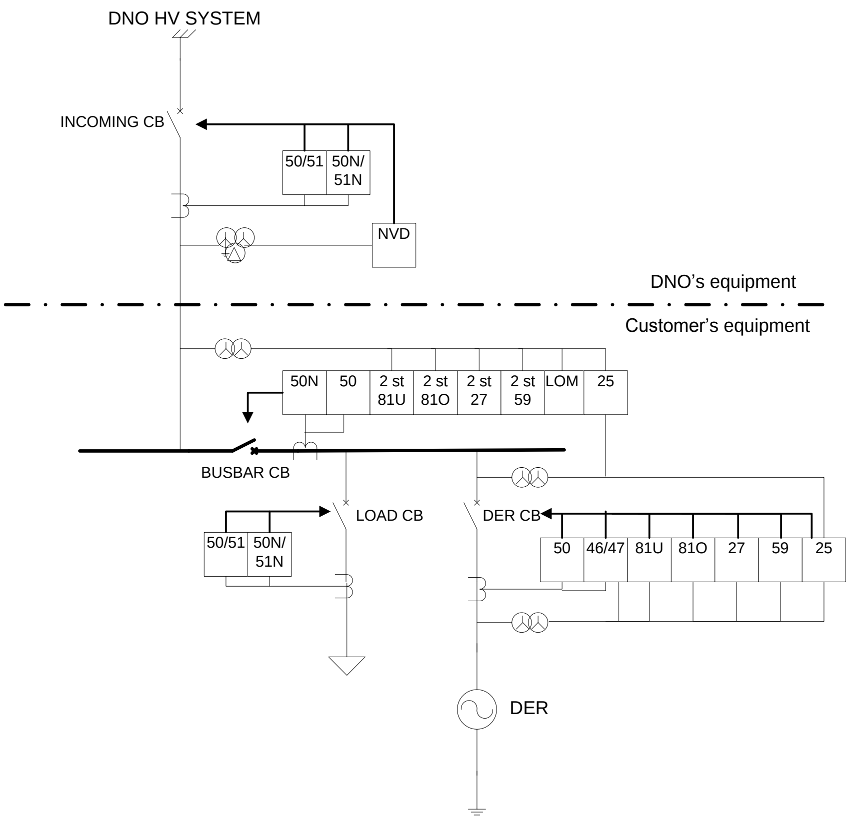

Figure 2.10 Protection interface for DG connected to HV system [2.27]

Table 2.4 ANSI Standard device numbers used in Figure 2.10

ANSI	Protection function
25	Synchronizing or Synchronism-Check Device
27	Undervoltage Relay
46	Reverse-phase or Phase-Balance Current Relay
47	Phase-Sequence or Phase-Balance Voltage Relay
50	Instantaneous Overcurrent Relay
51	AC Inverse Time Overcurrent Relay
59	Overvoltage Relay
81	Frequency Relay

The utility installs overcurrent protection upstream of the common coupling point (CCP), and may also install Neutral Voltage Displacement (NVD) protection in some cases.

Downstream of the CCP, the customer is responsible for the DG protection. Besides normal generation protection, the DG owner must install protection to disconnect the generating plant from the distribution system in the event of the loss of one or more phases of the distribution network supply. This is important to ensure that the distribution network is earthed, that customers are not supplied with voltages and frequencies outside of statutory limits and to avoid re-closure under out-of-synchronism conditions.

The minimum requirements and conditional requirements for interface protection at utility and customer sides are shown in Table 2.4. Appendix C reports the protection settings for LOM protection recommended by G59/2.

Table 2.4 Minimum requirements for protection arrangements [2.26]

	Utility equipment	DG side equipment
Minimum requirements	Instantaneous overcurrent (50/50N) Time overcurrent (51/51N)	Under/over voltage (27, 59) Under/over frequency (81 U/O)
Conditional requirements	NVD relay	Inter-tripping scheme Synch-check relay

2.6 Active Network Managment

The common DNOs' approach to the connection of new DG is to make sure that the network is capable of facilitating 100% generation export. However, as the number of DG connections increases, network capacity becomes restricted due to rating of lines and cables and therefore a number of DG units have been installed where the DNO has the ability and permission to trip the generator through inter-tripping schemes under certain conditions. Furthermore, the connection of DG may cause fluctuation of the voltage and increase the fault level beyond the maximum fault interruption capability of the network switchgear.

A number of schemes have been implemented by the UK DNOs since the 1990s to overcome power flow and voltage problems:

- To limit the power generation of DG in case of overload of a line, inter-tripping schemes to open the connecting circuit breakers of one or more DG units and in some case 33% - 66% reduction signals have been implemented. The engineering technical report ETR24 [2.28] gives guidelines to DNOs for actively managing power flows associated with DG.

- To actively control the voltage profile of 132kV, 33kV and 11kV networks, Automatic Voltage Control (AVC) schemes have been installed that can control transformer tap-changers. Furthermore, line voltage regulators and line or substation capacitors are installed, in some cases, to improve the voltage control of the distribution network.

The hard-wired logic developed to actively control the DG power generation can be built to be fail-safe and fast, but this short term solution has a major limitation in that to connect new DG to the distribution network, the hard wired logic must be reconfigured or otherwise new hard-wired schemes have to be added, creating a complex system of hard-wired logic that might schemes that may become difficult to manage.

As DG penetration increased in the 2000s, researchers have been working to develop new solutions to manage active distribution networks. The authors of [2.29] have defined Active Network Management (ANM) as a real-time monitoring and control system able to manage all the active devices in a distribution network. An example of use of ANM schemes is to facilitate increased DG connection by actively managing power flows and voltages while avoiding network reinforcements, or at least, reducing or deferring reinforcement capital expenditure.

Since the introduction of ANM systems to control power flows and voltage profiles, they have evolved to include new functionalities such as: fault level management, post-fault restoration, minimisation of power losses and load shifting. This is achieved by controlling all the active devices, which include generators, circuit breakers, network switches, etc. [2.30]. For example, to perform post-fault restoration, the ANM is capable of remotely controlling circuit breakers and network switches to automatically reconfigure the network, minimising the number of disconnected customers.

The introduction of ANM scheme permits further increase in the penetration of DG and improves the quality of service to the customers, for example by reducing the duration of power supply disconnections. However it also introduces some disadvantages, because its action may affect the correct operation of the distribution network protection system. This problem is analysed in chapter 4 of this thesis and it is considered in the development of the adaptive overcurrent protection system presented in chapter 5.

2.7 Islanded operation

Distribution network have not been originally designed to support islanded operation, therefore DNOs generally do not permit this. In fact, as explained in section 2.5.3, the DG owner is responsible for implementing LOM protection as part of the DG protection interface to disconnect the DG in case of disconnection from the mains.

The main transient or continuous hazards associated with unintentional islanded operation are:

- Non detection of earth faults due to the network operating in an unearthed fashion;
- Non detection of phase faults due to low fault level;
- Out of phase circuit breaker closing due to automatic or inadvertent manual reclosure;
- Frequency fluctuations above and below the statutory limits due to system acceleration/deceleration as a consequence of system underload/overload and relatively low installed generation capacity and system inertia (compared to grid-connected operation);
- Voltage fluctuations above and below the statutory limits due to phase unbalance;
- Flicker above limits due to low fault level and high flicker emission; and
- Harmonics above limits due to low fault level and high harmonic emission.

Since it is the responsibility of the DNO to protect the network and its customers from these hazards, DNOs are normally opposed to the concept of islanding, demanding immediate disconnection of all DG units.

However, as the DG penetration increases, the use of DG to supply portions of the network or critical loads (Intentional Islanded operation) could potentially bring benefits to the customers, by reducing the number of customer minutes lost and the number of interruptions per customer, i.e. it increases the power supply reliability [2.31].

Reliability improvement is the motivation for planned islanding in Canada. BC Hydro has been one of the leaders in this area having successfully operated a planned islanding project for over a decade [2.32], and has gone as far as developing an islanding guideline, which is published on their corporate website [2.33].

In the future, the present DNO approach to islanding will change. Initially, DG will be required to support the network during transients because, as the DG penetration increases, fast DG disconnection would cause network instability, i.e. it might cause cascade of DG disconnection with the potential to lead to blackouts. Subsequently, in some distribution networks, islanded operation might be allowed to increase the reliability of supply.

As this transition from the present scenario, where DG is disconnected as soon as an unintentional islanded operation occurs, to the future scenario of intentional islanded operation, the present overcurrent protection system and DG protection interface will be required to evolve to overcome a number of protection problems.

2.8 Chapter summary

Firstly, this chapter has described the UK electrical distribution network as originally designed. It has given an overview of the faults that may occur in a distribution network and it has described a typical overcurrent protection system.

Secondly, this chapter has shown how the connection of DG has changed the distribution network from being passive active in nature and how it is expected to change further in the near- and longer-term future. The main types of renewable and non-renewable DG that are connected to present distribution networks have been described, giving an overview of the present DG penetration and expected growth up to 2020.

After having explained the behaviour of DG during transient and faults, this chapter has presented the typical connection of DG to the distribution network, describing the main types of interfacing transformers and the typical UK DG interface protection arrangements.

Finally the chapter has presented Active Network Management (ANM) schemes, which have been recently developed to facilitate increased DG connection controlling power flows and voltage profiles, and how they are evolving to include new functionalities, such as: fault level management, post-fault restoration, minimisation of power losses and load shifting. The chapter has also discussed intentional islanding operation which is becoming a possible option to improve supply reliability in some distribution networks and introduce how islanded operation and ANM might have an impact on the protection system.

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Chapter 3:

Review of protection challenges and proposed solutions for future active distribution networks

3.1 Chapter overview

Distribution networks are changing from being passive to active systems due to the connection of increasing numbers of DG units. Furthermore, to facilitate the increased connection of DG, Active Network Management (ANM) schemes are being introduced to control power flows, voltage profiles and to introduce new functionalities such as: fault level management, automatic supply restoration, network power losses minimisation, etc. [3.1-3.3]. Finally, as DG penetration increases to suitable levels, intentionally islanded operation of distribution networks may become an attractive option to improve supply reliability [3.4, 3.5].

Chapter 2 presented the UK distribution network as it has been originally designed and summarised how it has evolved since 1990; this chapter reviews the protection challenges associated with this evolution of the distribution network.

This chapter firstly presents an overview of several research activities that have been undertaken to understand the impact of DG, ANM and islanded operation and then proceeds to review a number of potential solutions to these problems that have been proposed by the research community.

3.2 Review of protection challenges associated with future active distribution networks

The introduction of DG to the distribution network impacts upon power flows, voltage conditions and fault current levels. These impacts can be positive or negative: for example, one positive impact is the reduction of sustained low voltages at consumers' locations and mitigation of voltages sags, which is discussed and demonstrated in [3.6]. Other possible positive impacts include reduction of power losses, release of additional network capacity, etc. [3.7].

In terms of negatives, the introduction of DG can significantly impact on the distribution network's protection systems. DG introduces additional sources of fault current, which may increase the total fault level within the network, while possibly altering the magnitude and direction of fault currents measured by the protection systems. The contribution of a single DG is normally not significant, but the aggregate contribution of many DG units can lead to a number of problems including: blinding of protection, false tripping, mis-coordination between relays, auto reclosers and fuses, mis-coordination between network and DG interface protection [3.8].

As the level of DG penetration increases, the role of DG in the distribution network becomes more important for the stability of the network. Accordingly, any mal-operation of the DG interface protection may have serious consequences. A critical element of the DG interface protection is loss of mains (LOM), or anti-islanding, protection [3.9].

This section reviews the protection challenges that are presented in the literature and comments on aspects that appear not to be fully addressed or solved.

3.2.1 False tripping of overcurrent relays

When there is a fault on a feeder within an active distribution network, all DG units connected to the network in that vicinity will contribute to the fault. For example, considering Figure 3.1, DG1 and DG2 contribute to the fault on the adjacent feeder. This means that in an active distribution network, all feeders with DG connected to them will be subject to fault current during a fault in the local network, while in a passive distribution network, fault current flows only from the source to the faulted feeder. Subsequently, the overcurrent relays (OCRs) on non-faulted feeders measure a fault current (and a voltage drop, in the case of DG interface protection), which could lead to cause false tripping.

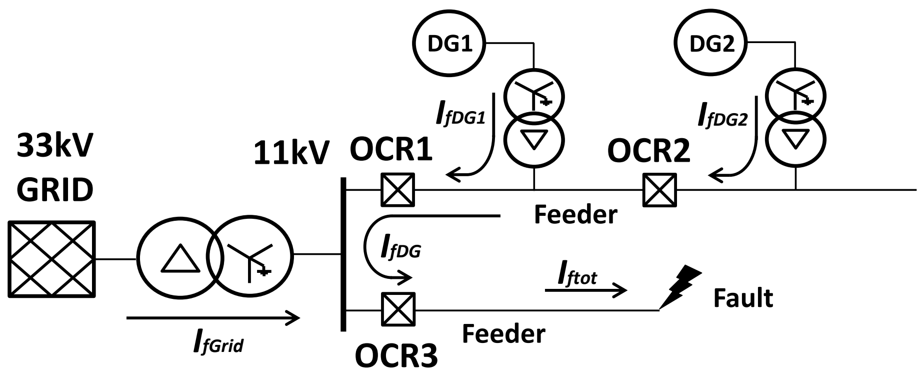

Figure 3.1 False tripping of OCR protection

Considering Figure 3.1, the correct operation of the overcurrent protection system is that OCR3 operates as soon as possible to isolate the faulted feeder and OCR1 and OCR2 should not operate. When DG1 and DG2 are connected to the distribution network, their fault current contribution can theoretically cause false tripping of OCR1 and OCR2, which should not operate. This protection mal-operation problem has been presented in [3.10] and [3.11].

False tripping due to the connection of inverter based DG is analysed in [3.12], where the authors demonstrate that this problem seldom happens for inverter-interfaced DG, but that it could be a potential problems for synchronous DG. [3.13] analyses the problem considering induction and synchronous DG, and presents a simple example to demonstrate that false tripping can be an issue in certain circumstances. The advice on solving this problem, as stated in [3.11] and [3.13], is to employ directional overcurrent protection.

However, the network examples and the protection settings chosen in these papers appear to represent particular cases where false tripping is more likely to happen and could be viewed as being somewhat contrived in order to illustrate a particular problem, which in reality may not be experienced regularly, or even at all. The advice to implement directional overcurrent protection would indeed solve the problem, but it would be expensive and utilities may prefer to seek a more cost-effective solution.

It is apparent that the literature does not present a detailed study on false tripping in typical distribution networks with high penetration of DG, with only a select number (sometimes extreme in terms of representing typical cases) of examples being analysed. Moreover, the overcurrent protection settings are not examined to ascertain whether grading between OCRs is achievable without the use of directional relays. To address this shortcoming in the published work, a detailed analysis on false tripping is presented in chapter 4 of this dissertation.

3.2.2 Loss of OCR grading

When there is a fault in a feeder with DG, the total fault current comprises the fault contributions from the grid and the individual DG units, as shown in figure 4.

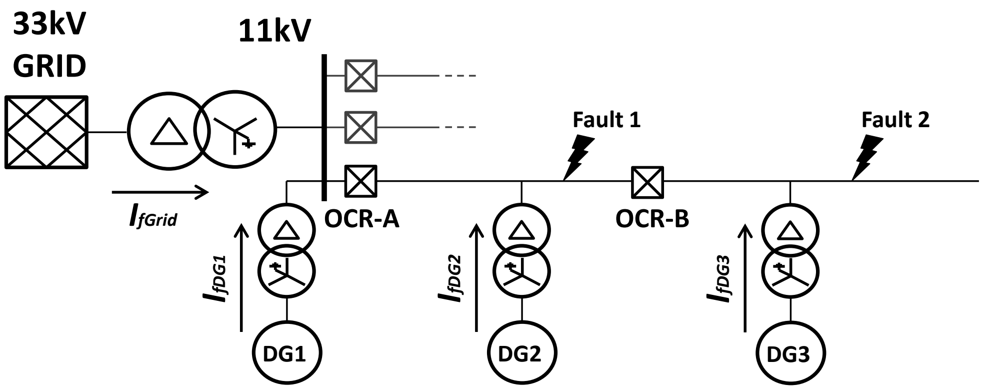

Figure 3.2 Loss of OCR grading

For fault 1, OCR-A should trip and disconnect the entire feeder, while for fault 2 only OCR-B should trip and disconnect only the element of the feeder to the right of its location. Automatic re-closure can be implemented in overhead networks to restore supply when the fault is not permanent, for example when an over voltage transient causes an arc between to form between overhead conductors, automatic re-closure disconnects a feeder section (or the full feeder) to extinguish the arc, and then restores the supply by reclosing the appropriate circuit breaker.

The connection of DG can cause loss of OCR grading. This problem has been investigated in [3.14], where the authors demonstrated that:

- In case of fault 1: DG1 increases the fault current for phase-phase faults, but this does not create a problem if there is enough headroom in the rating of the circuit breaker to interrupt the higher fault current; DG2 does not have an impact on the operation of OCR-A, while DG3 might cause operation OCR-B, however OCR-A should always trip and disconnect the entire feeder to clear the fault.
- In case of fault 2: DG1 and DG2 increase the fault current through each of the CBs, which can be a problem if there is not enough headroom in the rating of the CBs. DG1 may cause faster operation of both OCRs A and B, potentially reducing the grading margin between them. Depending on the protection

settings and the fault current contribution from DG1, the grading time could be reduced to an unacceptably small value.

In summary, the effect of DG on OCR-OCR grading can result in problems as demonstrated in [3.14], however there are other factors that can cause loss of OCR-OCR grading that are not discussed in the literature. One of the main factors is the introduction of ANM schemes, which act to change the configuration of the network, e.g. post-fault automatic network reconfiguration.

3.2.3 Blinding of overcurrent protection

When DG is connected downstream of an OCR and upstream of the fault position, the DG increases the fault current flowing to the fault, while simultaneously decreasing the fault current measured by the OCR.

This can be explained considering Figure 3.3, where a DG unit is connected between OCR2 and a bolted fault at the end of the feeder. The fault current contribution from the DG unit does increase the fault current flowing from the point where DG is connected (point C) and the faulted point (point F), and therefore does increase the voltage at point C. Consequently, the current flowing from the grid to point C decreases.

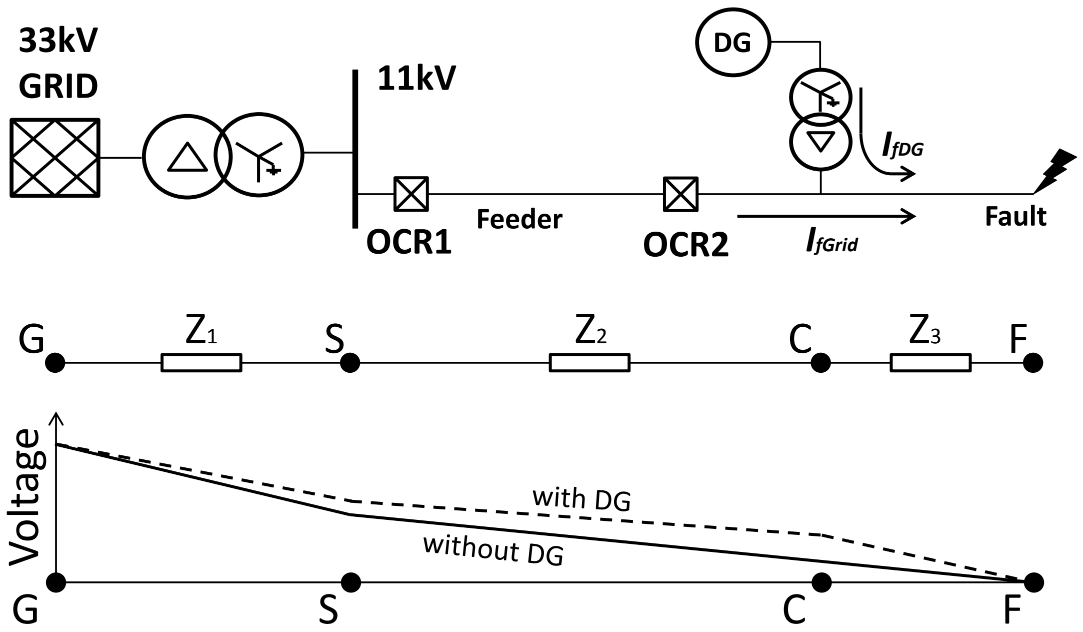

Figure 3.3 Blinding of OCR protection

This may cause a slower operation of the OCR and could, theoretically, lead to non-operation of the OCR. This protection non-operation has been named "blinding of overcurrent protection" in [3.12] and [3.13], and "overcurrent protection under reach" in [3.10], [3.15], and [3.16].

While the concept of blinding presented in the literature is theoretically correct, the exact situations that may lead to this problem have not been fully investigated and reported. A very simple numerical example has been presented in [3.17], but the network model has not been fully representative of a typical distribution network and the faults are simulated assuming a range of fault resistances, for which the rationale has not been fully described.

It seems that the literature does not present a detailed study on the blinding/under reach of overcurrent protection where the network, the DG and the faults are precisely and realistically modelled to demonstrate exactly under which condition this problem may be experienced. A detailed analysis of this problem is presented in chapter 4 of this dissertation.

3.2.4 Loss of recloser-fuse grading

In overhead networks, most of the faults are not permanent and therefore multi-shot auto-reclosing is commonly adopted. When spurs are protected by fuses as shown in Figure 3.4, the auto-recloser (AR) at the head of the feeder and the pole mounted auto-recloser located part-way along the length of the feeder (PMAR) are normally set with one or more "fast" , that is very short time delays to open the breaker, trips, followed by one or more "slow" trips.

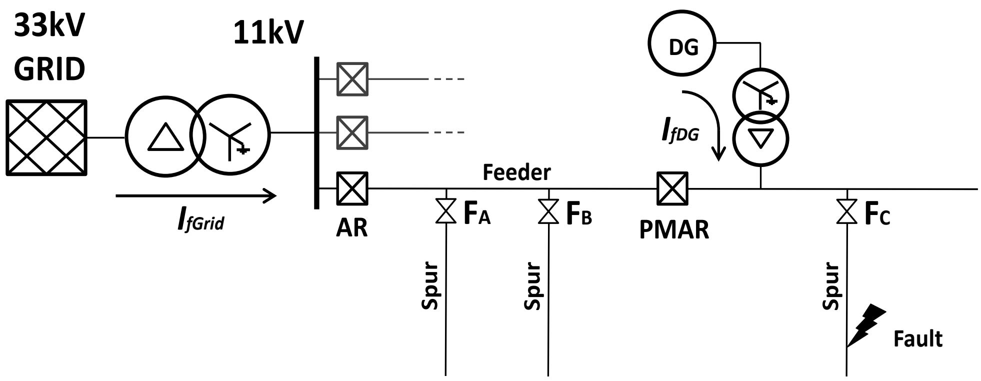

Figure 3.4 Loss of recloser-fuse grading

The slow trips use a longer delay from fault (or from the time of closure on to an existing fault) to circuit breaker opening; this is used in an attempt to burn away any material that may be in the fault path or to blow the protection fuse closest to the fault if there is one between the recloser and the fault, thereby clearing the fault and allowing a successful subsequent re-closure.

In a typical application depicted in Figure 3.4, the AR may be deployed with two fast and two slow trips and the downstream PMAR may use two fast and one slow trip. The fast and slow overcurrent protection characteristics of the AR and PMAR are coordinated to ensure that for faults downstream of the PMAR, only the PMAR trips. The overcurrent protection characteristics of the AR or PMAR and fuses are coordinated as shown in Figure 3.5 so that the fast protection characteristic “saves” the fuse while the slow protection characteristic while lead to the blowing of fuse F_C for a permanent fault on its spur.

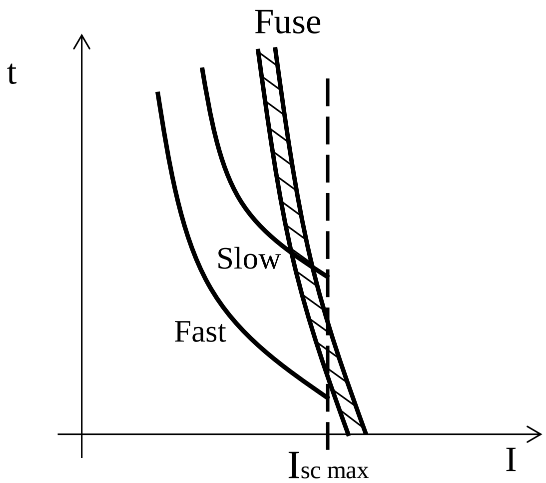

Figure 3.5 Recloser fuse coordination

The benefit of this arrangement, termed arrangement 1 for comparative purposes, is that the fast tripping saves the fuse from blowing. For example, considering the fault shown in Figure 3.4, the fast tripping of the PMAR interrupt the fault current before the fuse blows and if the fault is not permanent, then the PMAR successfully recloses and the fuse does not need to be replaced to restore the supply to the spur that experienced a transient fault.

If the fault is permanent, the multiple reclosures on to the fault and the slow tripping after the second re-closure allows fault current to flow for a long enough time for fuse F_C to blow – and backup is provided (by a trip and lockout of the PMAR) in the event of the fuse failing to clear the fault for whatever reason.

Alternatively, the AR and PMAR can be set with a different arrangement that favours the fuse operating; in such cases only slow tripping characteristics (arrangement 2) would be used as presented in [3.18]. The benefit of allowing the fuse to blow is that there may be less disruption of other customers on other spurs downstream of the PMAR location during the fault and subsequent multiple reclosures involved in a "fuse saving" scheme.

If DG is connected to the network between an upstream AR or PMAR and a downstream fuse as shown in Figure 3.4, then the current through the fuse increases, while the current through the AR or PMAR decreases for three phase and phase to phase faults located downstream of the fuse. This may cause coordination problems in that the fuse may blow before the first fast tripping operation of the AR or PMAR, when arrangement 1 is adopted, as demonstrated in [3.19] and [3.20].

A simulation case using a synchronous 3.5 MVA DG unit has been presented in [3.20] to show the changes in fault currents due to the connection of the DG unit. The author demonstrated that if arrangement 1 is adopted, DG can cause loss of recloser-fuse coordination as described above. If arrangement 2 is adopted, the presence of the DG during fault conditions increases the tendency of the fuse blowing faster, before the first trip of the AR, which is in fact beneficial to the protection scheme, since the arrangement has the objective of encouraging fuse blowing.

3.2.5 Compromise of fuse-fuse grading

The connection of DG varies the fault current flowing in the network and therefore may impact negatively on the grading between fuses at different network locations.

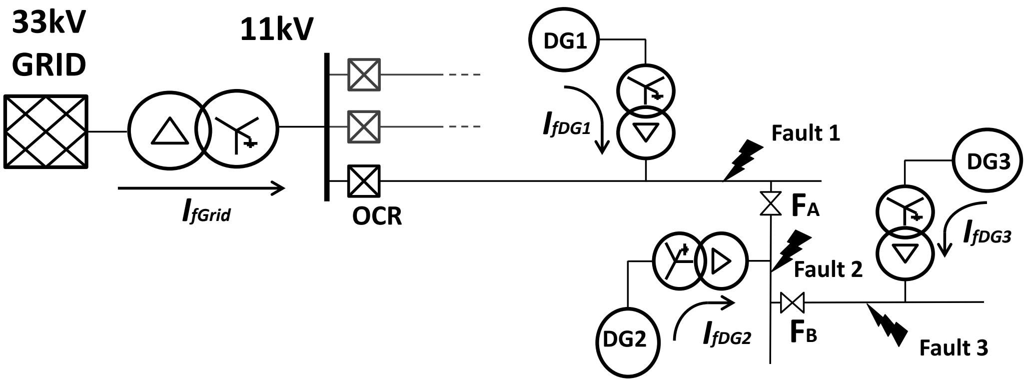

Figure 3.6 Loss of fuse-fuse grading

Figure 3.6 shows an example where fuses A and B have been specified without consideration of the impact of DG, which may have been connected to the network subsequent to the original specification and installation of fuses for protection.

The authors of [3.14] analysed the impact of DG in different locations on the coordination of fuses:

- If DG is connected upstream of both of the fuses (i.e. DG1 in Figure 3.6), there are no problems experienced for either faults 1 or 2. However, for fault 3, the fault current through each of the fuses A and B increases and grading may be affected; even if fuse B operates correctly before fuse A, fuse A may be damaged by the time that fuse B blows, leading to the possibility of mal-operation problems in future if the fuse is weakened .
- If DG is connected between the fuses (DG2 in Figure 3.6), then fault 1 may cause damage or blowing of fuse A, while faults 2 and 3 do not cause any fuse-fuse coordination problem.
- If DG is connected downstream of the fuses (DG3 in Figure 3.6), faults 1 and 2 may cause damage or blowing of fuses A and B, while there is no problem for fault 3 in this instance.

3.2.6 Sensitivity and Stability Problems for Loss of mains (LOM) protection

One of the major concerns is that, during a severe system disturbance, e.g. three phase fault or phase to phase fault at the source end of an adjacent feeder, a large number of DG units connected to the distribution network could be unnecessarily removed from service by passive LOM protection relays. This could potentially have adverse consequences on system stability, as evidenced by an event on 27th May 2008 in the UK, when after the generation loss of 345MW, a series of generators disconnected from the grid exacerbating a major frequency drop, which was recovered by disconnecting 500,000 consumers through the operation of an automatic under frequency load shedding scheme [3.21]. Figure 3.7 shows the frequency deviation and the loss of a series of main generators and DG units.

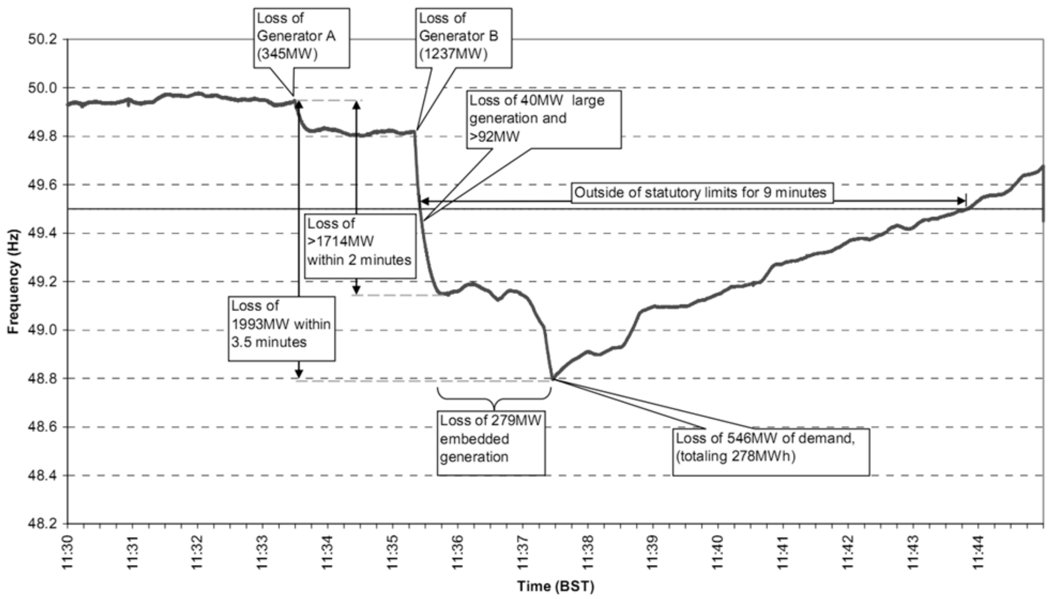

Figure 3.7 UK power network frequency deviation measured on 27th May 2008 [3.21]

Considering that forecasts indicate that there will continue to be a marked growth in DG penetration, the problem of LOM mal-operation is expected to become greater in severity for the UK electrical power system in the future as demonstrated in [3.22, 23].

The purpose of LOM protection is to disconnect the generator when the connection to the main system is lost. For example, considering Figure 3.8, if CB-1 is open, then the LOM protection of the generator must trip CB-DG to avoid unintentional islanded operation of feeder 1. At the same time, the LOM protection must be selective and stable and should not trip CB-DG when transients are experienced in the local network (for example, the worst case may be for a fault downstream of CB-DG on Feeder 1 or a fault close to the source of Feeder 2).

Unfortunately, it is difficult to achieve complete balance between the required sensitivity and stability under all operational conditions when applying passive LOM detection methods [3.9].

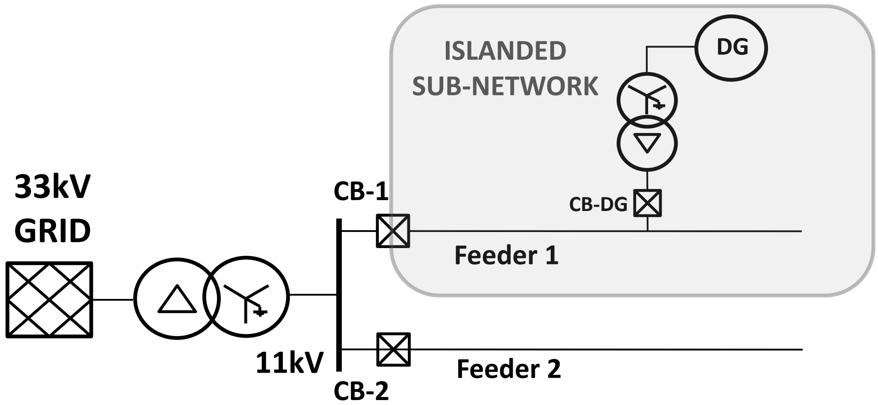

Figure 3.8 Loss of mains protection

If there is a fault in feeder 2, the voltage sag at the connection point of the DG unit and the transient in measured frequency (as measured by the LOM relay) can lead to mal-operation of the LOM protection applied to DG1 when passive techniques based on measurements taken at the DG terminals are used. Such LOM techniques include rate of change of frequency (ROCOF), voltage vector shift, under/over voltage, and under/over frequency [3.24].

The opposite problem to mal-operation is non-operation of the LOM protection, and this is also a serious problem. If, for example, there is an actual islanding (or loss of mains - these terms are often used interchangeably in the literature) event caused by the opening of CB-1 in Figure 3.8, and the local generation output closely matches local load, there is the potential for an islanded condition to remain undetected by passive LOM protection if the generator output voltage and frequency is not significantly disturbed by the opening of the interface circuit breaker [3.25]. This is often referred to as the non-detection zone (NDZ) with reference to LOM protection.

If the LOM protection fails to detect the islanded condition, there are many potential hazards associated with safety, power quality and system integrity, which include: line worker safety; public safety; unearthed or incorrectly earthed system operation; inadequately controlled voltage and frequency within the island; low system fault levels and potential non-operation of short circuit protection systems; and unsynchronised reclosing of the interface between the islanded system and the main system, with potentially grave consequences in terms of system damage and widespread instability. Because of these hazards, it is very important to quickly and accurately detect and react to islanding situations [3.18].

When islanded conditions are detected, the common practice is to disconnect the DG unit(s) in the island as quickly as possible. Existing practices and regulations governing DG connection do not normally allow islanded operation [3.26], [3.27]; such requirements limit the benefits that may be offered by DG, in terms of potentially enhancing supply reliability and supporting the power system during major disturbances.

With the ever-increasing level of DG penetration within distribution networks, the continued justification for the current practice of not allowing islanding is questionable. However, to allow intentionally islanded operation, all associated risks must be identified and mitigated [3.28], [3.29].

3.3 Review of proposed and developed protection solutions

The solutions to the protection challenges reviewed in section 3.2 can be divided into two categories. The first category includes proposed solutions to the problems introduced by DG and active network management systems to distribution network overcurrent protection systems. The second category includes solutions to provide proper LOM protection under all situations, and this can be sub-divided to include local (based on single measurements from the DG interface) and remote (or multiple measurements, perhaps based on measurements from the DG interface and from elsewhere in the network) techniques. Local techniques are then further sub-divided into active (which may inject a signal into the network and observe a response) and passive (which only observe the network behaviour from measurements) solutions.

3.3.1 Solutions to overcurrent protection problems

One solution to the problems caused by the fault current contribution of the DG units is to minimise or even completely eliminate their fault current contribution. This solution has been proposed in [3.30, 3.31], where the authors demonstrated how the addition of a fault current limiter (FCL) can restrict the current of a DG unit during faults and allow an unrestricted flow of power during normal operation.

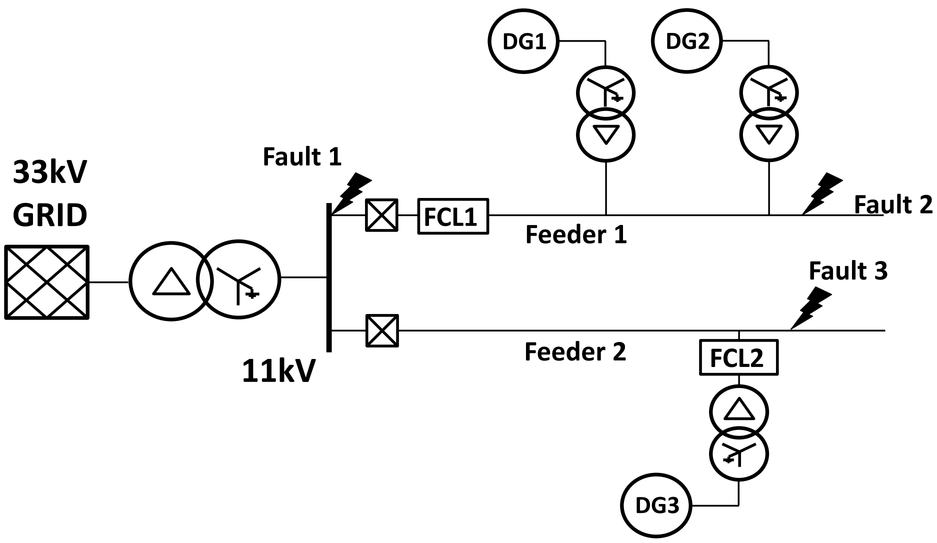

Figure 3.9 Installation of fault current limiters

FCLs can be located at the connection point of the DG or at some point on the feeder or spur, they must have extremely low impedance that does not interfere (or cause voltage drops and losses) with the system during normal operation. When there is a fault, they must take extremely fast action by inserting a relatively high value of impedance in series with the DG to limit the fault current. Furthermore, they must limit the fault current contribution from the DG and allow fault current to flow in the opposite direction [3.31]. For example considering feeder 1 in Figure 3.9, FCL1 must reduce the fault current from DG1 and DG2 to fault 1 and fault 3, while it has to permit the fault current to flow to fault 2, so that the OCR of feeder 1 can trip and clear the fault.

Passive FCLs, which include series inductors [3.32] and superconducting FCLs [3.33], do not possess directional operating characteristics, as they limit fault currents in both directions inherently. To address the issue of directionality, solid state limiters, which include resonance based devices [3.34], and impedance switch-in limiters [3.35], can be controlled to act only when the fault current is flowing in one direction (e.g. from the DG to the network). These solutions require the addition of a control circuit, which identifies the direction of the fault current and can discriminate between faults upstream and downstream the FCL, only limiting current when required to do so.

A negative aspect of solid state limiters is that they introduce switching losses (as the power flows through power electronic switches) during steady state operation. The authors of [3.36] have demonstrated that the losses can be reduced of 70% by using thyristors, which have low on-state losses compared to the solid state limiters that use Insulated-gate bipolar transistors (IGBT).

This hybrid mechanical/solid-state FCL has been demonstrated to reduce the impact of DG on the coordination of the network overcurrent protection. In terms of tripping times, it has been shown that the inclusion of the FCL resulted in tripping times remaining within 15% of the original tripping times (i.e. prior to installation of DG). It is also mentioned that the FCL has an additional benefit of reducing the stress on the DG units during local network short circuits [3.37].

However, FCLs are expensive and sometimes cannot be used. One example where FCLs are not likely to be used is when the distribution network has a weak fault current contribution from the transmission network and the distribution network operator (DNO) require DG units to have strong “fault ride through” (FRT) capabilities to improve the stability of the network.

Another more pragmatic solution to the problems caused by the fault current contribution of DG units is to upgrade the rating of circuit breakers where necessary and/or substitute the overcurrent protection system with a protection system based on a different technique.

A distribution network protection scheme based on an alternative protection technique has been proposed in [3.38, 3.39]. The proposed method involves dividing the distribution system into independent zones and installing circuit breakers and associated protection devices between these zones as shown in Figure 3.10.

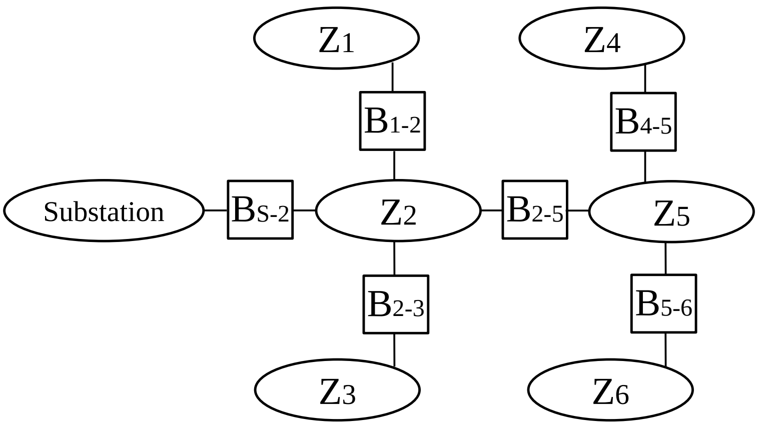

Figure 3.10 Division of the distribution network in zones and location of protection devices [3.39]

Each protection device, installed in an individual protection zone, monitors the currents measured at all DG locations in the protection zone and communicates with the other protection devices. The authors have demonstrated that the protection system is able to locate the faulted protection zone(s) through comparing actual measured currents with the results of offline calculations. This solution, presented and demonstrated using DigSILENT and MATLAB, is theoretically valid but it requires synchronized values of measured currents from all of the protection relays in the network, as well as measurements from all DG locations and from all loads, which in a 11kV distribution network would entail a massive investment in hardware. Accordingly, it is deemed very unlikely that a DNO would consider this solution as viable. Furthermore, the proposed protection technique relies on the comparison between measured currents and results of offline calculations, which might be unfeasible in an actual distribution network, as the number of possible fault scenarios would be huge and even if a database with all the simulations has been created, the comparison process would be complex and possibly prohibitively time consuming.

A distribution network protection scheme based on distance relaying techniques has been proposed in [3.40]. The operation of the system is demonstrated through power system simulations carried out using PSCAD and EMTDC, and it is proposed that distance relaying can minimise the problems caused by the connection of DG and can provide shorter fault-clearing times respect to overcurrent protection. While this solution is technically sound and may overcome some of the problems discussed in section 3.2, the substitution of the overcurrent protection system with distance protection at 11kV is unlikely to be considered by DNOs because of the cost to substitute all the overcurrent protection relays installed at 11kV with distance protection relays and to install other necessary hardware, e.g. voltage transformers. Furthermore, the relatively short feeder lengths, possibly high complexity of networks and changes of network topologies may render distance protection unusable due to uncertainty over measured impedance, fault location and consequential tripping decisions.

A further approach to overcome the problems discussed in section 3.2 is the enhancement of the existing overcurrent protection system through extending it to include adaptive functionality.

The concept of adaptive protection has been introduced in 1988 to improve the performance of distance protection on transmission networks [3.41, 3.42]. In 1999, the IEEE Guide for Protective Relay Applications to Transmission Lines defined the concept of adaptive protection as a protection philosophy that permits, and seeks to make adjustments automatically, to various protection functions to make them more attuned to prevailing power conditions[3.43].

Since its introduction, there has been an increasing interest in the application of the adaptive protection concept at the distribution level, to adapt the functionality and performance of overcurrent protection in reaction to prevailing conditions.

The feasibility of adaptive protection systems for distribution networks has been analysed in [3.44, 3.45]. Overcurrent relays and the necessary changes to make them suitable for use in an adaptive relaying system, and further elements required for the adoption of adaptive protection, were investigated. The authors concluded that the adaptive relaying concept can be implemented by using microprocessor based relays with multiple protection setting groups and a suitable communications infrastructure to transfer network configuration information to the relays.

An adaptive overcurrent protection system that could be implemented by using microprocessor based relays with multiple settings has been analysed in [3.46]. The authors studied a distribution network with DG and proposed a method to calculate the optimum protection settings using different setting groups, with different groups being selected dependent on the connection of DG units in the network. The method has been verified through MATLAB simulations and proven to be effective.

However, a limitation of the proposed adaptive overcurrent protection system is that if the number of DG units increases, the number of scenarios to be analysed increases and at a certain point it becomes infeasible to calculate four (the number of groups used in the case studies presented in the paper) protection setting groups for each protection relay that would be optimum for all possible network scenarios. Furthermore, if other important factors were considered, for example network topology changes, the number of scenarios would be multiplied by the number of possible network configurations, making the protection settings calculation even more complicated. Finally, a disadvantage of this solution, that has been not considered by the authors, is that modern distribution networks are in a continual state of evolution and every time a distribution network changes (e.g. connection of a DG unit or upgrade of a line), the protection settings calculation exercise should be repeated and certain protection relays may require to be reconfigured.

Another adaptive overcurrent protection system based on microprocessor protection relays has been presented in [3.47]. The author has investigated how the functionalities of modern IEC 61850-compliant protection relays can be used to enhance the overcurrent protection system.

The first enhancement proposed by the author is based on the use of pre-calculated protection setting groups to adapt the overcurrent protection characteristics to different network configuration, similar to the solution proposed in [3.46]. For example, considering Figure 3.11, the status of the DG circuit breaker (i.e. closed or open) creates two scenarios with different levels and directions of fault current. The DGOCR can be configured to communicate the circuit breaker status to the OCRs of the distribution networks using ICE-61850, and these can be configured to automatically switch between two pre-calculated protection setting groups.

The second proposed enhancement is the use of blocking and tripping signals using IEC61850 GOOSE messaging to avoid false tripping and to adapt to the loss of individual protection relays. For example, when there is a fault at the end of feeder 1 in Figure 3.11, the OCRs of the faulted feeder, OCR1 and OCR2, send a blocking signal to the OCR in the adjacent feeder, OCR3, to avoid false tripping. An example of the use of tripping signals is when for the same fault, and there is a case where the CB controlled by OCR2 doesn't work, OCR2 sends a tripping signal to OCR1 to accelerate its operation.

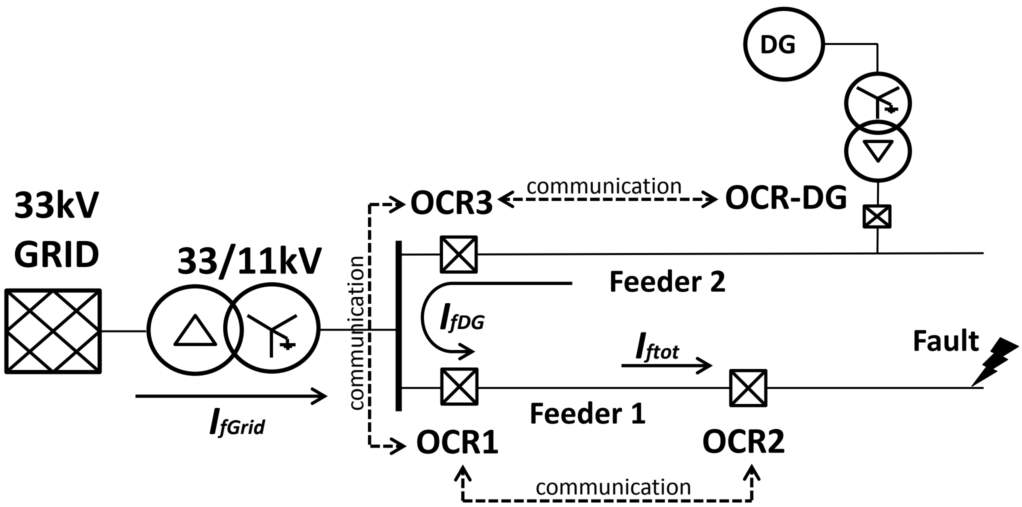

Figure 3.11 Adaptive overcurrent protection using IEC61850 protection relays

Adaptive overcurrent protection systems can be also developed to solve protection problems that are not due to the connection of DG, but that are caused by islanding operation and by the implementation of ANM solutions that change the network topology.

The authors of [3.48, 3.49] have proposed an adaptive overcurrent protection scheme where all the protection relays have two pre-calculated protection setting groups, one for grid connected and one for islanded operation. The authors have simulated the adaptive protection system and demonstrated that the problem of blinding of overcurrent protection, which is a particular problem introduced by islanding due to the significantly reduced fault level (compared to grid connected mode), can be overcome.

Similarly, the authors of [3.50] have analysed the impact of network automation and suggested that the problem can be solved using an adaptive overcurrent protection system, where all the protection relays have pre-calculated protection settings groups associated with two or more network topology configurations.

A number of proposed adaptive overcurrent protection systems in the literature consider one cause of protection problems (DG, islanding operation, or ANM) and demonstrate how using pre-calculated protection setting groups can solve the protection problems. These systems are definitely adequate solutions to the problems addressed; however they are limited to adapt to in response to a single source of problems, while in an actual network there might be multiple issues, arising from the presence of multiple DG units, routine operation in islanded mode, and the actions of ANM schemes.

The difficulty in considering DG, ANM and islanding operation together is that the number of possible scenarios is large and it becomes unfeasible to pre-calculate protection settings and create protection setting groups for the different scenarios.

Chapter 5 presents an adaptive overcurrent protection scheme that is capable of monitoring the network, calculating the optimum protection settings and applying them on to protection relays in response to any change in operating conditions: due to DG connection/disconnection, ANM actions and/or grid connected/islanded operation. Therefore the proposed solution does not need pre-calculated protection settings.

3.3.2 Solutions to LOM protection problems

The main philosophy adopted in the solutions presented in the literature to detect an islanded situation is to monitor the DG unit's output parameters and/or main power system parameters with the objective of detecting whether an islanded situation has occurred. For example, a number of techniques monitor voltage and/or frequency and disconnect the DG unit when there are observed changes in the measured parameters that violate certain thresholds. Presently, there are several LOM detection techniques, which can be categorised as shown in Figure 3.12.

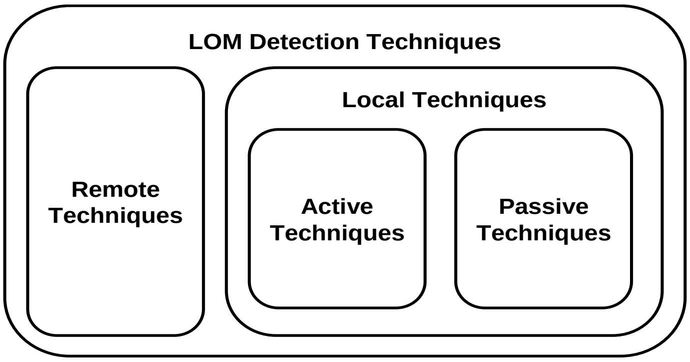

Figure 3.12 LOM detection techniques

Local techniques are based on the measurement of system parameters at the DG site and can be subdivided into categories concerned with active and passive methods.

3.3.2.1 Local active LOM detection techniques

These techniques introduce a small perturbation into the power system. The response to the perturbation is significantly different if the DG is islanded from the network compared to when it is operating in grid connected mode.

The main advantage of active techniques is that an islanded situation can be detected even when there is a perfect match between local generation output and the local load immediately prior to islanding. Islanding under such conditions typically cannot be sensed by passive detection techniques. Active techniques have also been shown to be able to remain stable under non-LOM disturbances [3.51].

The main disadvantages of active techniques are the introduction of perturbations to the system, which has a risk of degrading the power quality. Furthermore, the dependence of the protection on the device that introduces the perturbation into the power system might reduce the reliability of the LOM protection solution.

Various active island detection techniques have been proposed, the most common are: fault level monitoring, reactive power export error detection and source impedance measurement.

Fault level monitoring is a scheme that measures the short circuit current and reduction in supply voltage when a shunt inductor is connected to the network using a thyristor switch. This causes a short pulse of current to flow in the inductor and an accompanying voltage disturbance, which are used to calculate the fault level. In the case an LOM condition, the calculated value will drop to a value significantly smaller than to the expected fault level when grid connected. This scheme provides a fast protection with minimum operating times of approximately 10 ms [3.52].

The reactive power export error detection technique is based on setting the DG unit to generate a precise amount of reactive power and monitoring the output. In case of LOM conditions, the set amount of reactive power the DG should generate cannot be maintained because it would cause an overvoltage in the islanded system. The relay operation is triggered when the difference between the setting and the actual reactive power being generated exceed a predefined threshold for a time period greater than a set value. To avoid spurious operation, the time setting is chosen to be between 2 to 5 seconds. This LOM protection is relatively slow compare to other LOM protection techniques and therefore it is normally used as back up protection [3.53].

Source impedance measurement LOM protection is based on the fact that utility fault level is considerably larger than the power island fault level, which corresponds to the utility source impedance being significantly smaller than the impedance of the network during LOM. By monitoring the impedance, it is possible to detect LOM and disconnect the DG units. The authors of [3.54] have proposed an impedance measurement device developed for LOM protection. The device is based on a voltage divider as shown in Figure 3.13, where Z_2 is the system impedance and Z_1 is a coupling capacitor. A small high frequency signal of a few volts at (for example) a 1 kHz range is used as input to the voltage divider, V_{in}, and the voltage output is filtered to measure the voltage component at 1kHz and consequently calculate Z_2.

In case of LOM, the calculated Z_2 significantly decreases and therefore by monitoring the value of Z_2 the source impedance measurement LOM protection device can detects the LOM event and disconnect the DG units in the power island.

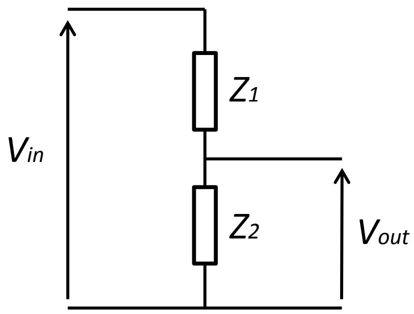

Figure 3.13 Source impedance measurement voltage divider

Active LOM protection techniques have the main advantage that they are capable of detecting LOM when in the power island local load and generation are close and therefore there will not be major fluctuations in voltage and frequency upon transition from grid connected to islanded modes of operation. However, active LOM protection technique are not normally adopted to protect generators because the active element used to introduce a perturbation in the system needs maintenance and in case of its failure, the LOM protection fails.

3.3.2.2 Local passive LOM detection techniques

Passive techniques operate by monitoring system parameters such as voltage, frequency, voltage angle, real and reactive power levels, harmonic distortion, etc., as measured at the interface point of a DG unit. When an islanded situation occurs, these parameters usually vary greatly from the values observed during grid connected conditions, or they undergo a significant change during the transition from interconnected to islanded mode. Accordingly, it is often possible to differentiate between both conditions.

Passive techniques possess an advantageous feature in that relatively high sensitivity and high speed of detection are possible; moreover they do not introduce any disturbance to the system and they do not need communication channels.

A disadvantage is that spurious operation can occur if there is a sudden load change, generation disconnection, a fault in a local (or even remote) line, or any other event causing a change in the measured parameters not associated with a genuine islanded scenario, but masquerading as such. Moreover, passive techniques normally fail to detect islanded condition in certain situations, often when the island load closely matches the generation output within the island prior to the LOM event; this is sometimes referred to as the "LOM dead zone" [3.55].

Many passive island detection techniques have been developed; the most common including under- and over-frequency, under- and over-voltage, rate of change of frequency, rate of change of power and voltage vector shift (VS).

The most common passive LOM protection techniques are based on under- and over-voltage and under- and over-frequency. In many small DG units these LOM techniques provide an acceptable level of protection, but they operate only if LOM produces a change of load large enough to cause voltage and frequency fluctuations.

Rate of Change of Frequency (ROCOF) protection is based on monitoring the voltage waveform measured at the DG connection to calculate frequency and disconnecting the DG from the network when the measured rate of change of frequency exceeds a threshold level for longer than a predetermined time period.

The settings for under- and over-frequency, under- and over-voltage and ROCOF are chosen so that the relay will operate for fluctuations associated with LOM, but not for those fluctuations governed by the stability characteristics of the utility, in order to avoid unwanted operation when there are transients on the utility system that do not result in LOM. Appendix C presents the protections settings recommend by G59/2 that apply in the UK [3.56].

Rate of Change of Power (ROCOP) protection is based on monitoring voltages and currents measured at the DG connection point and calculating the instantaneous active power. The protection disconnects the DG from the network when the change in active power generated by the DG unit exceeds a threshold level for longer than a set time period.

The main problem with this method is that, in some cases, it might operate unnecessarily, for example during starting of motor loads or switching of capacitor banks. To avoid false tripping, ROCOP should be combined with another LOM detection technique. For example, the authors of [3.57] have proposed a method based on composition rate of change of power and under-voltage for DG with capacitor banks. The proposed method is to monitor the ROCOP and if its value exceeds the threshold value than the protection system disconnects the capacitor bank of the DG unit. If it is a true LOM event, the voltage would fall subsequently, causing the under-voltage protection element to trip, while if the DG has been connected to grid, the voltage would not decrease significantly because of the reactive power supplied by the grid.

Finally, vector shift LOM protection is based on the monitoring of the frequency of the power system at the connection point of the DG. In case of LOM, this will result in a sudden change of the frequency, which increases in cases where the generator load has dropped or decreases in cases where the generator load has increased. The change in frequency is measured by the vector shift relays as a shift in degrees. If this vector shift is larger than a certain set point, the relay disconnects the DG unit [3.58].

These passive LOM protection techniques are widely applied because they use local measurements and they do not require an active element that introduces a disturbance to the system. However, passive LOM protection techniques have two main problems: instability during transients in the network and insensitivity to true LOM conditions in cases where the local load and generation output levels are closely matched, which is normally known as the Non-Detection Zone (NDZ).

3.3.2.3 Remote LOM detection techniques

Remote techniques are based on communication between the utility, normally from the circuit breaker(s) that, when opened, could result in an island being formed, and the DG's protection and control system. These techniques may offer improved reliability compared to local techniques and therefore some utilities insist on remote LOM protection, often using redundant, diverse communication channels. There is often a business case for deployment of remote techniques when there are many large generation connections within relatively close proximity. However, due to the associated high expense, remote techniques are seldom chosen over local techniques and the adoption of remote techniques is often a source of contention between DG operators and the utility when the terms of connection are being negotiated. There are two main remote techniques in common use: transfer trip; and power line signalling [3.25].

The basic concept of transfer tripping is to monitor the status of circuit breakers that could potentially island a section of distribution system. This method requires communication channels between the utility equipment and the DG; as already stated this increases costs for DG developers.

Another remote technique uses power line carrier (PLC) signalling, where a signal generator on the main system "side" of the interface circuit breaker(s) continuously broadcasts a (normally high frequency, relative to the power system frequency) signal along the distribution system feeders using the power line as the signal path. Tuned signal receivers at the DG units monitor the presence of the signal and if the signal is not present, then the generator is disconnected from the network, under the assumption that the path to the main network has been lost [3.59, 3.60].

The second scheme works on the same principle as the first, except that a blocking scheme is employed and the power line itself is used as the communications medium. Utilities will generally view blocking schemes with caution, because if the blocking signal is lost (not due to a LOM condition, but perhaps due to a communication system failure) then several DG units may be tripped unnecessarily. This can be overcome by providing communications channel redundancy and diversity; but this of course further increases the cost of the system.

Other LOM protection techniques based on communication have been proposed. One publication discusses methods of using the internet as a communication media to provide inter-tripping schemes [3.61]. Another interesting idea is to include the LOM protection function within other protection relays, for example line differential protection relays, to realise a fast and reliable LOM protection without the necessity of adding new devices [3.62].

Different public communication infrastructures are available today and they can be used for LOM protection. The authors of [3.61, 3.63] have tested trials of LOM protection that use the public cable and wireless broad band communication network. The results of the tests demonstrate that the public communication network can be used for LOM protection because the latency for bi-directional communication is less than 100ms in practically all cases.

Remote LOM protection techniques are the most accurate method to detect islanding and are normally combined with passive LOM protection as back up protection. Commonly, remote LOM protection schemes have been implemented for main DG power plants as hardwired inter-tripping schemes. As the DG penetration increases, the use of remote LOM protection means that the number of hardwired inter-tripping schemes increases and this creates a complex system of stand-alone inter-tripping schemes with several redundant communication channels.

Any time that DG units are added or the network is upgraded to add new lines or to introduce new ANM schemes, all of the stand-alone inter-tripping schemes must be reviewed and this creates a barrier to the effective and efficient evolution of the network.

3.4 Chapter summary

The main protection challenges reviewed in this chapter have not, in the opinion of the author, been fully and objectively presented in the literature. Many authors report on the nature of the problems that are they are attempting to overcome, often using a single example and/or anecdotal evidence. However, there has been no exhaustive and objective study of the potential problems introduced by DG, ANM and islanding operation that has produced extensive quantified results, with many authors focussing on the solutions before, or even without, fully investigating the problem. Therefore, before developing and reporting solutions, a detailed analysis of the protection challenges and potential problems has been carried out as part of this research and the findings from these investigations are presented in chapter 4.

Adaptive overcurrent protection has been suggested as a valid solution for many years, but the literature review shows that while several solutions have been proposed, a basic adaptive protection system based on predefined setting groups is the only mature and reliable solution that can be confidently deployed in distribution networks and that has the greatest chance of being accepted by an increasingly pressured industry. Chapter 5 presents an adaptive overcurrent protection scheme that is capable of monitoring the network, calculating the optimum protection settings and applying them to the protection relays any time there is a change (requiring protection settings to be changed) due to DG connection/disconnection, ANM activity and/or grid connected/islanded operation. The proposed solution does not need pre-calculation of protection settings and therefore is a much more flexible and comprehensive adaptive protection system solution when compared to the majority of adaptive protection solutions presented in the literature.

LOM protection represents another major challenge that has been reported in many publications. The literature review in this chapter highlights several developed solutions and concludes that remote techniques are the most reliable, but have problems with flexibility and extensibility and, if applied in distribution networks with high penetrations of DG, they are at risk of becoming over complex, being composed of several stand-alone inter-tripping schemes, which would be difficult to maintain and extend as the distribution network evolves and more DG is introduced. Passive techniques are relatively cheaper, but sensitivity and selectivity are difficult to achieve under all operational scenarios. To build on this review and propose a solution to the reported problems, Chapter 6 presents an adaptive inter-tripping scheme with back-up passive LOM protection that revolutionises the current approach to LOM, offering significant improvements in terms of both sensitivity and stability. This is achieved by amending, in real time, the protection settings of the LOM protection relays and by introducing an adaptive inter-tripping scheme that does not necessarily employ expensive point-to-point communication facilities. Furthermore, the adaptive LOM protection system allows islanded operation of a section of distribution network, with LOM protection also being provided within the power island using LOM protection relays (with amended protection settings) and by inter-tripping which is adapted to the specific islanded scenario.

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Chapter 4:

Detailed analysis of the impact of DG and ANM on power system protection

4.1 Chapter overview

The connection of an increasing number of DG units and the introduction of ANM solutions will create a number of protection challenges. Section 3.2 of the previous chapter has presented a review of the protection problems due to the connection of DG discussed in the literature and comments on three specific overcurrent protection problems that seem to have not been fully and objectively investigated by the research community, which are: false tripping of OCRs, blinding of OCRs and compromise or even total loss of protection grading. Furthermore, it appears that the impact of ANM solutions on the overcurrent protection systems has been relatively ignored, with many researchers focusing attention predominantly on the potential impact of DG.

To fill these perceived "gaps" in the research and available literature, a detailed analysis of these overcurrent protection problems, with respect to impact of both DG and ANM, has been carried out as part of this research and the main findings from these investigations are presented in this chapter.

To gain a realistic and comprehensive evaluation of these problems, the distribution network model described in appendix A, representative of a typical 11kV UK rural distribution network, has been employed. The protection system of the network has been designed with reference to a protection policy sourced from UK network operators. The overall analysis is therefore reflective of present networks in the UK; details of the protection design are given in appendix B. Section 4.2 describes the investigation methodology adopted.

Section 4.3 describes the main results of the investigation relating to the potential for false tripping of OCRs due to faults in adjacent feeders and demonstrates precisely when false tripping may occur. The section also proposes and demonstrates how this problem can be solved without the implementation of directional overcurrent protection, which is suggested as a unique solution to this problem in [4.1] and [4.2].

Section 4.4 presents the main results of the investigation relating to blinding of OCRs due to the connection of DG and demonstrates, through quantified analyses, that this mal-operation, which is reported as a potential problem in [4.3-4.6], is very unlikely to occur in practice, only representing a risk in somewhat unlikely scenarios.

Finally, section 4.5 presents the main results of the investigation relating to degradation or loss of overcurrent protection grading as a consequence of both ANM schemes, which may change network configuration, and as a result of the impact of DG on network fault behaviour during faults.

4.2 Investigation Methodology

The distribution network model has been initially modelled using IPSA Power [4.7] for the first stage of investigation and subsequently modelled using the RTDS [4.8] for the second stage of investigation and validation of the performance of actual protection devices:

- **Initial investigation**
  IPSA Power software has been used to model the test case network and to simulate faults (phase-earth, phase-phase-earth, phase-phase and three-phase) to perform an initial investigation of the impact of DG and ANM schemes on the network protection system. More details on this first stage of investigation are presented in section 4.2.1.
- **Detailed investigation**
  The RTDS has been used to simulate, in real time, the test case network. The protection system has been integrated with the RTDS using hardware in the loop, that is, using actual protection relays interfaced to the RTDS, to perform detailed investigations of: false tripping, blinding and degradation of the grading of the overcurrent protection scheme. More details on this second stage of investigation are included in section 4.2.2

4.2.1 Initial investigation

The initial investigations have been performed using IPSA Power software for the fault simulations. A separate programme, written in Python 2.7 [4.9], has been developed to automatically execute all fault simulations (programme A), read the results from the IPSA Power software and calculate the protection system response (programme B) and evaluate the protection system performance (programme C). Figure 4.1 presents an overview of the algorithm that is used to perform the investigations.

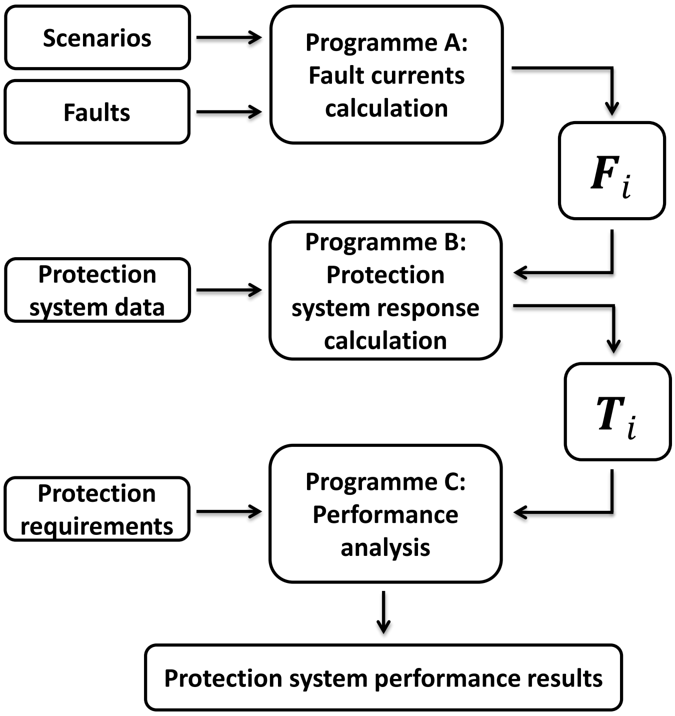

Figure 4.1 Protection performance investigation methodology: stage 1

Programme A accesses the IPSA Power fault calculation tool through its application programme interface (API), simulates a series of faults (through instructing IPSA) for different network scenarios and saves the fault currents that would be measured by each protection device for every simulated fault in the fault current matrix $\boldsymbol{F_i}$, where *i* is the identifier of the simulated scenario, *n* is the number of protection devices and *m* is the number of simulated faults.

$$\boldsymbol{F}_i = \begin{bmatrix} I_{f11}^i & \cdots & I_{f1m}^i \\ \vdots & \ddots & \vdots \\ I_{fn1}^i & \cdots & I_{fnm}^i \end{bmatrix} \tag{4.1}$$

Subsequently, programme B reads $\boldsymbol{F_i}$ and the protection system data, which includes the settings of each protection device, and calculates the operating time of each device for every fault. The results are then saved in the operating time matrix $\boldsymbol{T_i}$. This matrix contains a record of the operating time of each protection device for each fault.

$$\boldsymbol{T}_i = \begin{bmatrix} t_{11}^i & \cdots & t_{1m}^i \\ \vdots & \ddots & \vdots \\ t_{n1}^i & \cdots & t_{nm}^i \end{bmatrix} \tag{4.2}$$

Finally, programme C analyses $\boldsymbol{T_i}$ and compares its contents with the protection performance requirements to evaluate if the performance of each protection device is acceptable or if there are problems, such as non-operation, mal-operation, excessive operating time and mis-coordination between devices. The protection performance requirements are sourced from UK DNO protection policy documents, which, in summary, state that each fault should be isolated by disconnecting the minimum section of the network within 2s.

The results from the initial investigations have been found to be different with respect to what is commonly reported in the literature. In particular, the research reported in this dissertation contradicts reported findings with respect to false tripping, protection blinding and degradation or loss of protection grading. Accordingly, these three specific protection problems have been further investigated in the second stage of investigation.

4.2.2 Detailed investigation

The second stage of investigation has been performed using real time digital simulation to simulate the network model described in appendix A. Commercially available protection relays have also been employed as "hardware in the loop" to gain a realistic simulation of a distribution network and to facilitate a credible demonstration of the protection system response to events in a network incorporating DG.

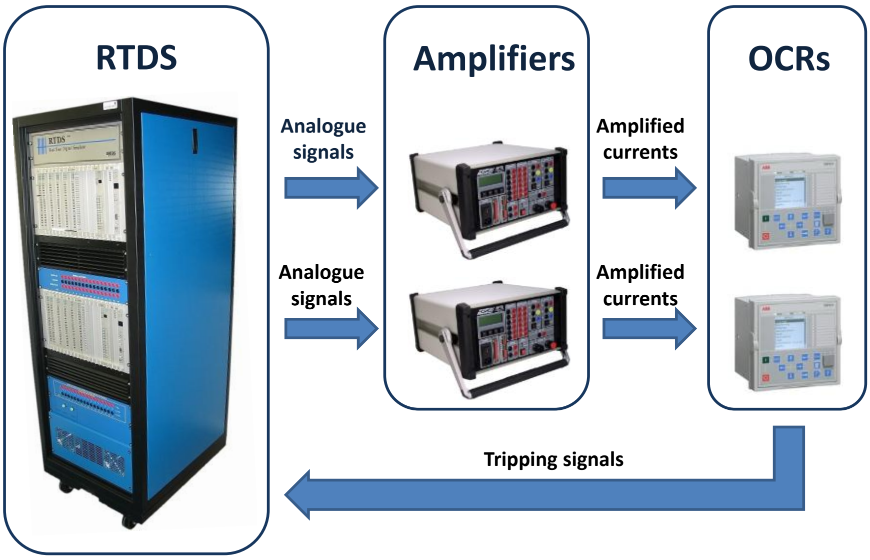

Figure 4.2 Laboratory-based protection demonstration and testing arrangement

Figure 4.2 illustrates the laboratory-based protection demonstration and testing arrangement. The protection relays receive voltage and current from the RTDS, amplified to the appropriate (CT and VT secondary output) levels, and communicate with the RTDS via binary inputs and outputs, for example to send tripping signals to circuit breakers and to receive indications of switchgear status from the simulator.

The main advantage of using this arrangement is that it is extremely realistic (having been used and validated by many users throughout the world) and therefore it is possible to obtain results that are very reliable, as the possibility of simulation errors (particularly with respect to the protection response) is greatly reduced. Similar analysis could be performed using PSCAD, DigSilent, or other simulation software. However, the real time, hardware in the loop approach was chosen as this is the same arrangement that was used to develop solution to the problems (presented later in chapters 5 and 6).

The methodology used for the second stage of investigation is based on:

- creation of a number of possible scenarios by varying fault infeed, DG and network topology;
- simulation of earth, phase to phase and three phase faults with varying location, fault resistance and fault duration;
- analysis of the performance of the protection system.

The following sections, 4.3, 4.4 and 4.5, report the main findings of this investigation, regarding false tripping, blinding and degradation or loss of protection grading.

4.3 False tripping of overcurrent protection

The connection of DG to a feeder within a distribution network has the potential to cause mal-operation of the overcurrent protection on that feeder for faults in adjacent feeders due to the fault current contribution of the DG. This mal-operation, commonly referred to as “false tripping”, is analysed in several papers and these are reviewed in section 3.2.1 of this dissertation.

The network examples presented in the reviewed papers [4.1] and [4.4] appear to represent particular cases, sometimes involving rather extreme and unlikely scenarios, where false tripping is demonstrated to be more likely to happen than not. Moreover, the chosen overcurrent protection settings are not discussed in detail to establish whether a more optimal coordination of OCRs would be able to solve the problem.

To address this shortcoming in the published work, a detailed analysis of the potential for false tripping has been undertaken, considering a typical UK distribution network. The results, reported in this section, demonstrate that optimised overcurrent protection settings can prevent false tripping in typical UK distribution networks, even when the grid infeed fault level at 33kV is reduced from typical high levels of 500MVA to levels as low as 50MVA.

4.3.1 Location of DG and fault

The DG connection point and the fault location have been chosen to represent the “worst-case” scenarios that are deemed most likely to result in false tripping. The objective is to investigate whether proper protection coordination can prevent false tripping in the worst-case scenarios using standard non-directional overcurrent protection. This will prove or disprove whether false tripping can be avoided in all possible scenarios without changing the nature of the standard protection system.

The conditions that have been simulated to represent the worst-case scenarios are:

- DG connected to the shortest feeder (feeder C in Figure 4.3), through step up transformers located at distances of 0.7 km and 1.4 km from the beginning of the feeder, as shown in Figure 4.3. The total installed DG capacity is equal to 100 % of the feeder load rating, i.e. 4.8 MVA in this case. This generation capacity is provided by 2 synchronous generators of 2.4 MVA or 4 induction generators of 1.2 MVA. Both synchronous and induction generation technologies have been simulated and idealised sources have not been used.

- Phase and earth faults simulated as occurring at or near to the beginning of the immediately adjacent feeder B. Four locations have been selected as shown in Figure 4.3, at 0.1km, 0.5km, 1km and 1.5km from the beginning of the feeder.
- One of the two transformers of the network substation is disconnected, reducing the fault level at the 11kV busbar.
- The grid infeed fault level at 33kV is reduced from 500MVA to 50MVA, which is the worst scenario.

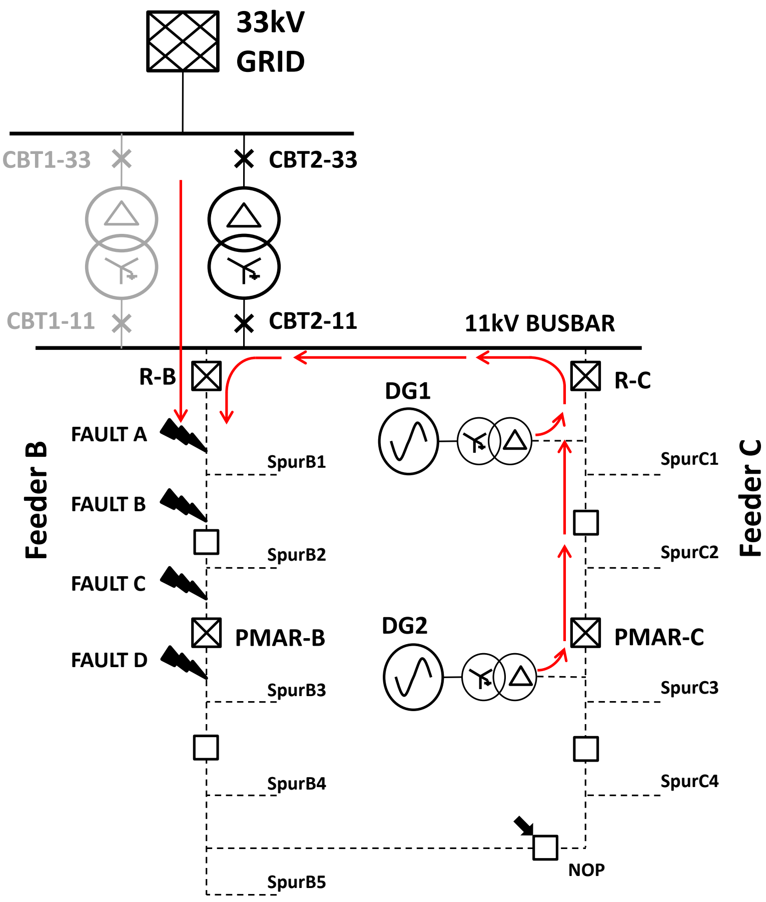

Figure 4.3 DG connection and fault location

4.3.2 Phase fault simulation results

The simulations in the laboratory have demonstrated that false tripping may occur when DTL overcurrent protection is applied with settings reported in appendix B. This protection mal-operation can be avoided by amending the protection settings to ensure proper grading between the OCRs at the sources of the feeders. This is achievable through using IDMT instead of DTL phase fault protection for feeders where DG is connected, or indeed for all feeders regardless of whether DG is connected or not.

To demonstrate this assertion, a number of phase fault scenarios have been simulated in real time and the performance of commercially available overcurrent relays has been recorded using IDMT and definite time delay overcurrent protection settings.

4.3.2.1 Results of phase fault simulations with DTL overcurrent protection

An initial set of simulations has been carried out with two synchronous DG of 1.8MVA connected to feeder C through 2.5 MVA 3.3/11kV step up transformers, as shown in Figure 4.3. Table 4.1 presents the operation of the multi-shot auto-reclosers and of the pole mounted auto-reclosers with and without DG.

Table 4.1 DTL overcurrent protection operating time with and without synchronous DG

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.248	-	-	-	0.246	-	0.248	0.113
	B	0.246	-	-	-	0.247	-	-	0.110
	C	0.246	-	-	-	0.248	-	-	0.123
	D	-	0.100	-	-	-	0.101	-	-
300	A	0.246	-	-	-	0.247	-	0.248	0.111
	B	0.248	-	-	-	0.247	-	-	0.112
	C	0.247	-	-	-	0.247	-	-	0.120
	D	-	0.101	-	-	-	0.101	-	-
100	A	0.247	-	-	-	0.247	-	0.249	0.109
	B	0.247	-	-	-	0.246	-	0.249	0.111
	C	0.246	-	-	-	0.248	-	-	0.117
	D	-	0.101	-	-	-	0.101	-	0.120
50	A	0.248	-	-	-	0.246	-	0.248	0.111
	B	0.247	-	-	-	0.246	-	0.248	0.109
	C	0.247	-	-	-	0.247	-	-	0.112
	D	-	0.102	-	-	-	0.102	-	0.117

A second set of simulations has been carried out with four DG of 1200kVA connected to feeder C through two 2.5MVA 3.3/11kV step up transformers, configured with two generators per transformer. Table 4.2 summarises the operation of the multi-shot auto-reclosers and of the pole mounted auto-reclosers, with and without DG connected.

Table 4.2 DTL overcurrent protection operating time with and without induction DG

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.246	-	-	-	0.248	-	-	0.111
	B	0.247	-	-	-	0.247	-	-	0.119
	C	0.246	-	-	-	0.247	-	-	-
	D	-	0.100	-	-	-	0.101	-	-
300	A	0.247	-	-	-	0.246	-	-	0.114
	B	0.247	-	-	-	0.247	-	-	0.122
	C	0.248	-	-	-	0.247	-	-	-
	D	-	0.100	-	-	-	0.100	-	-
100	A	0.246	-	-	-	0.246	-	-	0.113
	B	0.246	-	-	-	0.247	-	-	0.122
	C	0.248	-	-	-	0.247	-	-	-
	D	-	0.102	-	-	-	0.101	-	-
50	A	0.246	-	-	-	0.247	-	-	0.114
	B	0.246	-	-	-	0.247	-	-	0.116
	C	0.246	-	-	-	0.247	-	-	0.121
	D	-	0.103	-	-	-	0.101	-	-

Table 4.1 and Table 4.2 demonstrate that there is a risk of false tripping when there is a high DG penetration level and the protection settings have been calculated without consideration of the impact of DG. This false tripping arises as there is a lack of coordination between the OCRs protecting adjacent feeders.

Table 4.1 shows that the connection of synchronous DG to feeder C causes false tripping of the multi-shot auto-recloser R-C and of the pole mounted auto-reclosers PMAR-C when there are faults near the beginning of feeder B, see red numbers in Table 4.1.

Upon analysing table 4.2, it is clear that false tripping is experienced under the same conditions with induction DG but only PMAR-C is affected; this is due to the fact that induction DG only contributes fault current for a few cycles immediately following the occurrence of the fault; the effect of this is that R-C begins to operate, but resets when the induction DG contribution ceases, which is within R-C's operation delay time period of 250ms.

4.3.2.2 Results of phase fault simulations with IDMT overcurrent protection

Table 4.3 and Table 4.4 present the tripping times for the reclosers and the PMAR using IDMT, in the presence of and without synchronous and induction DG.

Comparing the protection operation times for when DG is, and is not, connected (shown in Table 4.3 and table 4.4), it is clearly visible that neither R-C nor PMAR-C experience false tripping, even with a very low grid fault level infeed of 50MVA.

From the tables, it is also notable that the operation time of R-B and PMAR-B decreases when DG is connected, due to the action of DG fault current contribution increasing the total fault current flowing in feeder B.

Table 4.3 IDMT overcurrent protection operating time with and without synchronous DG

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.702	-	-	-	0.698	-	-	-
	B	0.718	-	-	-	0.714	-	-	-
	C	0.752	-	-	-	0.745	-	-	-
	D	-	0.300	-	-	-	0.295	-	-
300	A	0.705	-	-	-	0.704	-	-	-
	B	0.725	-	-	-	0.719	-	-	-
	C	0.764	-	-	-	0.752	-	-	-
	D	-	0.305	-	-	-	0.300	-	-
100	A	0.741	-	-	-	0.738	-	-	-
	B	0.784	-	-	-	0.757	-	-	-
	C	0.855	-	-	-	0.818	-	-	-
	D	-	0.336	-	-	-	0.318	-	-
50	A	0.879	-	-	-	0.843	-	-	-
	B	0.933	-	-	-	0.871	-	-	-
	C	1.005	-	-	-	0.934	-	-	-
	D	-	0.386	-	-	-	0.347	-	-

Table 4.4 IDMT overcurrent protection operating time with and without induction DG

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.700	-	-	-	0.698	-	-	-
	B	0.718	-	-	-	0.718	-	-	-
	C	0.750	-	-	-	0.747	-	-	-
	D	-	0.300	-	-	-	0.299	-	-
300	A	0.707	-	-	-	0.703	-	-	-
	B	0.725	-	-	-	0.724	-	-	-
	C	0.762	-	-	-	0.758	-	-	-
	D	-	0.305	-	-	-	0.304	-	-
100	A	0.744	-	-	-	0.738	-	-	-
	B	0.785	-	-	-	0.776	-	-	-
	C	0.854	-	-	-	0.845	-	-	-
	D	-	0.336	-	-	-	0.334	-	-
50	A	0.873	-	-	-	0.857	-	-	-
	B	0.935	-	-	-	0.916	-	-	-
	C	1.005	-	-	-	0.993	-	-	-
	D	-	0.388	-	-	-	0.391	-	-

The use of IDMT, as opposed to DTL overcurrent protection, with the settings reported in appendix B, prevents false tripping from occurring in the simulated worst case scenarios and therefore it can generally be used to minimise the risk of false tripping in a typical UK distribution network.

The calculation of protection settings can be difficult, especially for distribution networks with high DG penetration and ANM solutions that may change the network topology – the changing network topology may become more frequent in the future as overall levels of DG and automation (e.g. to facilitate increased DG, reduce customer interruptions and outage durations) continue to increase. Chapter 5 presents an adaptive protection system that consider all of the relevant factors that may influence the protection system performance and modifies the protection settings as the network status changes.

4.3.3 Earth fault simulation results

Earth fault protection commonly uses DTL overcurrent protection characteristics, as shown in appendix B. The laboratory simulation results have demonstrated that false tripping may occur for earth faults, similar to the cases demonstrated in the previous subsection for phase faults when DTL overcurrent is applied.

A set of simulations has been carried out with two synchronous DG of 1.8MVA connected to feeder C through 2.5 MVA 3.3/11kV step up transformers, as shown in Figure 4.3. Table 4.5 and Table 4.6 presents the operation times of the auto-reclosers and of the PMAR for 0Ω and 5Ω faults, with and without DG being connected to the network.

Table 4.5 shows that there is false tripping of auto-recloser R-C and the pole mounted auto-recloser PMAR-C (operating time in red), when the 0Ω fault is located at the head of the adjacent feeder B. As the fault location is moved to a more distant position, the earth fault contribution from the DG decreases and false tripping desists. The simulation results have shown that resistance of the fault is greater than 5Ω, then false tripping will not be experienced, as shown in Table 4.6.

Table 4.5 DTL earth fault 7 protection operating time for 0Ω earth fault (with and without DG)

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.322	-	-	-	0.322	-	0.332	0.175
	B	0.326	-	-	-	0.324	-	-	-
	C	0.324	-	-	-	0.322	-	-	-
	D	-	0.166	-	-	-	0.162	-	-
300	A	0.322	-	-	-	0.322	-	0.332	0.175
	B	0.324	-	-	-	0.324	-	-	-
	C	0.325	-	-	-	0.322	-	-	-
	D	-	0.163	-	-	-	0.162	-	-
100	A	0.322	-	-	-	0.322	-	0.334	0.178
	B	0.323	-	-	-	0.323	-	-	-
	C	0.322	-	-	-	0.325	-	-	-
	D	-	0.163	-	-	-	0.163	-	-
50	A	0.322	-	-	-	0.324	-	0.334	0.180
	B	0.324	-	-	-	0.323	-	-	-
	C	0.322	-	-	-	0.323	-	-	-
	D	-	0.163	-	-	-	0.167	-	-

Table 4.6 DTL earth fault 7 protection operating time for 5Ω earth fault (with and without DG)

Grid infeed fault level (MVA)	Fault position	Without DG				With DG			
		R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time	R-B tripping time	PMAR-B tripping time	R-C tripping time	PMAR-C tripping time
500	A	0.325	-	-	-	0.322	-	-	-
	B	0.323	-	-	-	0.322	-	-	-
	C	0.324	-	-	-	0.327	-	-	-
	D	-	0.163	-	-	-	0.163	-	-
300	A	0.327	-	-	-	0.322	-	-	-
	B	0.326	-	-	-	0.322	-	-	-
	C	0.324	-	-	-	0.327	-	-	-
	D	-	0.163	-	-	-	0.163	-	-
100	A	0.327	-	-	-	0.323	-	-	-
	B	0.327	-	-	-	0.323	-	-	-
	C	0.324	-	-	-	0.325	-	-	-
	D	-	0.163	-	-	-	0.165	-	-
50	A	0.324	-	-	-	0.323	-	-	-
	B	0.324	-	-	-	0.323	-	-	-
	C	0.325	-	-	-	0.324	-	-	-
	D	-	0.163	-	-	-	0.163	-	-

The literature, reviewed in section 3.2.1, suggests the use of directional overcurrent protection as a solution to false tripping. This solution does solve the problem, however there are two problems with directional protection: firstly, in order to implement a directional solution, all of the non-directional overcurrent protection relays would require to be replaced with directional units and VTs would need to be installed; secondly, if the network topology changes, the directionality of the overcurrent protection would require to be changed.

4.4 Blinding of overcurrent protection

The connection of DG to a distribution network feeder can reduce the fault current measured by the OCR when the generator is connected between the OCR and the fault location. The literature reviewed in section 3.2.1 claims that in certain cases this can lead to non-operation of the OCR. This phenomenon is commonly referenced to in the literature as "blinding" of the overcurrent protection.

The impact of DG on the fault current levels measured by the OCRs depends on a number of factors which include grid infeed fault level, DG penetration level and capacity, DG location, DG technology, fault location and fault resistance. All of these parameters are very important in determining how much the OC protection may be affected by DG and establishing exactly when the presence of DG will lead to blinding of the OC protection.

The analyses presented in the literature do not consider all of these factors, but often use simple networks where the parameters seem to represent particular cases, sometimes extreme, and some of the parameters, e.g. the fault resistance, are not fully explained and/or justified.

This section presents a detailed study of the impact of DG on OC protection using a typical UK rural distribution network and considering all of the relevant factors. The results demonstrate that when the overcurrent settings are properly calculated, blinding of OC protection will not happen, even in the worst scenario with grid infeed fault level at 33kV reduced from 500MVA to 50MVA, synchronous DG with a penetration of 100 per cent of the network load rating, and with one of the pair of transformers in the network substation removed from service.

4.4.1 Fault resistance

Fault resistance is a very important parameter for this study and must be correctly represented and quantified, as selecting an erroneous value for this parameter could affect the results of the analysis and render them unrealistic. As discussed in the literature review in section 3.2.3, the fault resistance values used in several of the reviewed papers are not fully justified and this compromises the validity of the presented studies. For example, an analysis of the overcurrent protection reach reduction is presented in [4.10] used a simulated fault resistance with constant values of between 5Ω and 15Ω, and demonstrated blinding of protection for resistance values above 10 Ω. However, the values of fault resistances used in this publication are perhaps too high (certainly for phase-phase faults) and therefore the conclusions are different from the findings reported in this dissertation.

To enhance the realism of the investigations and findings, this subsection describes the rationale for the range of phase and earth fault resistances that have been used in the simulations.

Fault resistance is not a constant value, but it is acceptable to use a constant value if it can be proved that this value is representative of the average resistance of the fault. The simulations performed in this study include both constant resistance and variable resistance faults; the results of both sets of simulations are compared.

4.4.1.1 Phase fault resistance

To evaluate a realistic fault resistance value, it is important to consider how a phase to phase fault in an overhead distribution network originates. Normally, it can be initiated by lighting, swinging and clashing of the conductors or by an external object which results in an electrical arc between the short circuited phase(s) and/or earth.

The arc resistance can be calculated using the Warrington formula (4.3) or by using one of the two formulae (4.4), (4.5) presented in [4.11], which have been developed based on simulations of high current arcs in the high power test laboratory at FGH-Mannheim in Germany [4.12].

Each of the three formulae for calculating arc resistance are presented below:

- Warrington formula: $R_W = \frac{28688.5}{I^{1.4}} L$ (4.3)
- Terzija formula 1: $R_1 = (1080.4 \div 1350.5) \frac{L}{I}$ (4.4)
- Terzija formula 2: $R_2 = \left(\frac{855.3}{I} + \frac{4501.6}{I^2}\right) L$ (4.5)

Where I [A] is the fault current and L[m] is the length of the arc.

Considering that the typical distance between two conductors for an 11kV overhead line is 1200mm [4.13], the arc resistance can be calculated as a function of the fault current. The length of the arc could be less than 1200mm if the conductors are closer due to an external object, e.g. a tree, or more than 1200mm due to the irregular shape of the arc. For example the arc may rise in the air and elongate if not quickly interrupted.

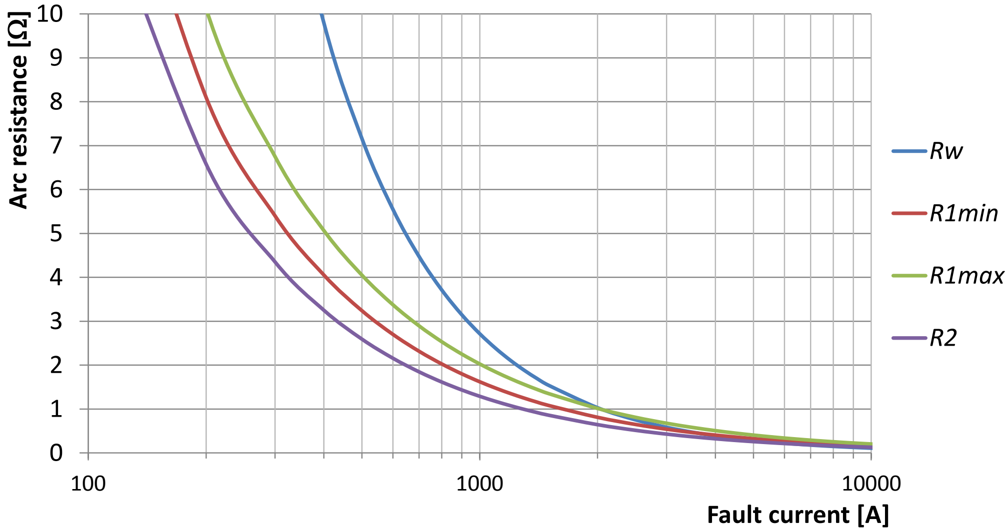

Figure 4.4 Arc resistance for L=1.5m

Figure 4.4, shows the arc resistance calculated by the three equations in function to the fault current for an arc length of 1.5m. It is clear that the Warrington formula gives higher resistances than the formulas proposed in [4.11].

If equations (4.4) and (4.5) are utilised, which are more accurate for currents under 2000A than the Warrington formula as demonstrated in [4.11], the arc resistance could be estimated to be between 1Ω and 5Ω assuming the arc was 1.5m long.

To calculate the realistic range of fault resistances, the fault currents obtained simulating the arc in the Real Time Digital Simulator (RTDS) using the model proposed in [4.14], and using a constant resistance have been compared.

The simulation results showed that the fault currents had slightly different shapes in the two simulations because the resistance of the arc was modelled to be constant in one case and to vary in function of the fault current in the other case.

To define an equivalence between the arc length and the fault resistance in the simulated network, the true RMS value of the two simulation has been used as a comparison reference as shown in Figure 4.5.

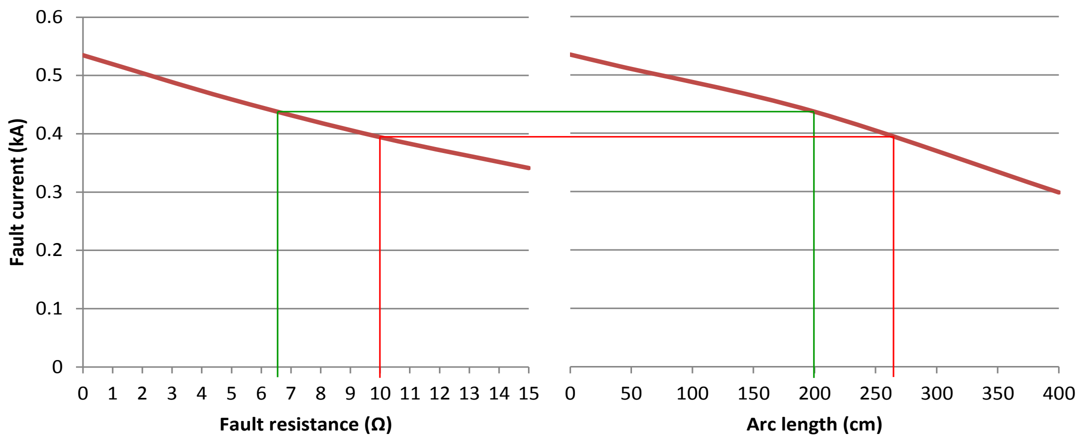

Figure 4.5 Comparison between fault resistance and fault arc lenght

The green line, in Figure 4.5, shows that an arc of 200cm in length will give rise to a similar level of fault current for when a constant resistance of 6.4Ω is simulated, while the red line shows that a fault resistance of 10Ω is equivalent to an arc length of 265cm. This arc length is slightly more than twice the normal distance between two phases, which is 120cm.

The range of resistance for the simulation has therefore been selected to range between 0Ω and 10Ω; where 0Ω corresponds to the case where the conductors touch each other during swinging or because of an external object; and 10Ω corresponds to a maximum arc length of 265cm.

4.4.1.2 Earth fault resistance

Earth faults can be caused by external objects that form a fault current path from the conductor to earth or can occur when a conductor breaks and falls to the earth. The fault current during a high resistance fault can be very low, for example 25A in the case of a broken conductor contacting dry grass, 15A for wet sand and almost 0A for dry sand or dry asphalt [4.15, 4.16]. Earth fault protection and sensitive earth fault protection are normally used to detect earth fault (or residual/unbalanced) currents with operating thresholds in the range of 20A to 30A, as shown in Appendix B.

Considering the minimum earth fault current that can be detected (20A or 30A in this case), then the maximum detectable earth fault impedance is approximately 190Ω for earth fault protection and 280Ω for sensitive earth fault protection, therefore the simulate earth fault resistance has been selected to range between 0Ω and 300Ω.

4.4.2 Simulated scenarios

A number of scenarios have been created to investigate the impact of DG, where DG location, DG capacity and fault location have been chosen to represent the worst case scenario, while fault infeed and fault resistance has been varied within realistic ranges of values.

4.4.2.1 Fault type and location

Considering that typically 80% of all faults on overhead systems are single phase to earth in nature, with a further 15% being phase to phase [4.17], only these fault categories have been considered in this dissertation. Furthermore, the fault types considered are relatively more likely to cause blinding than three phase and multiple phase to earth faults, so the analyses presented here can be viewed as comprehensive. Hereinafter, "phase to phase faults" will be referred to as "phase faults", with "single phase to earth faults" being referred to as "earth faults".

The faults have been located at the far end of the final spur on the longest feeder, i.e. the end of spur A10 connected to feeder A shown in Figure 4.6. This effectively represents the worst-case location in the network example, i.e. the fault location most likely to result in blinding.

4.4.2.2 Grid fault level

The grid fault level is another important factor with respect to blinding. As the grid fault level drops, the potential impact of the DG on the network protection increases. In the simulation, the 33kV fault level has been varied from 500MVA down to 50MVA (which, based on [4.18-4.20], represents a very low infeed level in the UK) to represent different fault level infeed scenarios.

4.4.2.3 Fault resistance

Considering the fault resistances range that are discussed in section 4.4.1 for phase faults and earth faults, it is considered appropriate to the simulation purpose to assume that the fault resistance is varies between 0Ω and 10Ω for phase faults and between 0Ω and 300Ω for earth faults.

4.4.2.4 DG location and capacity

With reference to Figure 4.6, the DG units have been connected downstream of PMAR-A and upstream of the fault; the effect of this is to increase the total fault current at the point of fault and decrease the fault current measured by PMAR-A.

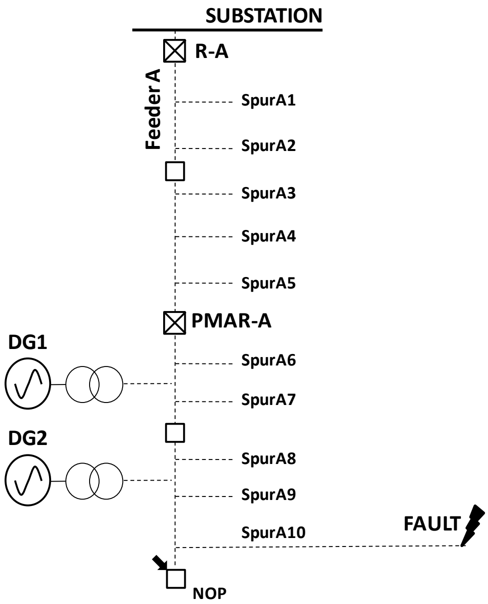

Figure 4.6 DG connection and fault location

As the DG capacity increases, the likelihood of a potentially detrimental impact on the network protection also increases. Therefore, the worst condition that has been chosen is a DG penetration of 100% of the load rating of the feeder, which represents DG with a collective capacity of 7.2MVA being connected to the feeder in this case. Assuming that approximately half of the overall DG capacity is connected between CB-A and PMAR-A, the other half of the overall capacity connected downstream of the PMAR is rated at 3.6MVA. This combined capacity is simulated using 2 synchronous generators each rated at 1.8 MVA.

4.5 Simulation results

The protection settings have been designed to accurately represent present-day UK networks and adhere to a protection policy that has been supplied by a UK DNO. The log-log graphs with the protection characteristics and a table that summarises all protection settings are reported in appendix B. Earth fault protection is based on DTL characteristics, while phase fault protection is based on either IDMT (protection settings A, see table 4 in appendix B) or DTL characteristics (protection settings B, see table 4 in appendix B).

The following sections present the results for the earth fault investigations and for the phase fault investigations establishing how the maximum detectable fault resistance changes in cases where DTL characteristics are used, and how operating times change in cases where IDMT characteristics are used.

4.5.1 Earth faults

Earth faults have been simulated in all of the scenarios described in section 4.4.2 to investigate the impact of DG on earth fault (EF) and sensitive earth fault (SEF) protection functions, which are based on DTL protection characteristics.

The maximum fault resistance that can be detected by the EF and SEF protection with and without DG under varying fault infeed conditions is shown in Figure 4.7.

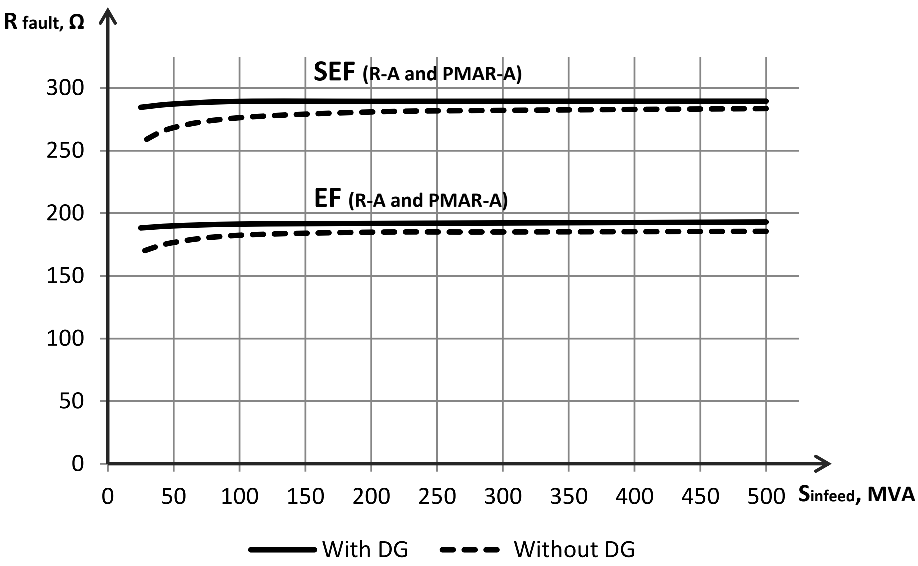

Figure 4.7 R-A and PMAR-A maximum detectable earth fault resistance

The dashed lines represent the SEF and EF protections' maximum detectable fault resistance, which is the same for R-A and PMAR-A due to the fact that the pickup current is the same for both devices (as presented in Figure 4.6).

The solid lines represent the maximum detectable fault resistance when DG is connected to the feeder. This increases due to the fact that the DG increases the total fault current and the fault current measured by both OCRs.

The fault current contribution of the DG can be explained using symmetrical component analysis, which is shown in Figure 4.8.

E_A is the phase A to ground voltage; Z_1, Z_2 and Z_0 are the positive, negative and zero sequence impedance of the system without *DG*, $E_{A\text{-}DG}$ is the phase A to ground voltage of the DG unit; and $Z_{1\text{-}DG}$, $Z_{2\text{-}DG}$ and $Z_{0\text{-}DG}$ are the positive, negative and zero sequence impedance components of the DG and its interface transformer. I_{1grid}, I_{2grid} and I_{0grid} are the positive, negative and zero sequence current components flowing in the grid; $I_{1\text{-}DG}$, $I_{2\text{-}DG}$ and $I_{0\text{-}DG}$ are the positive, negative and zero sequence current components from the DG unit; and I_{fault} is the total fault current.

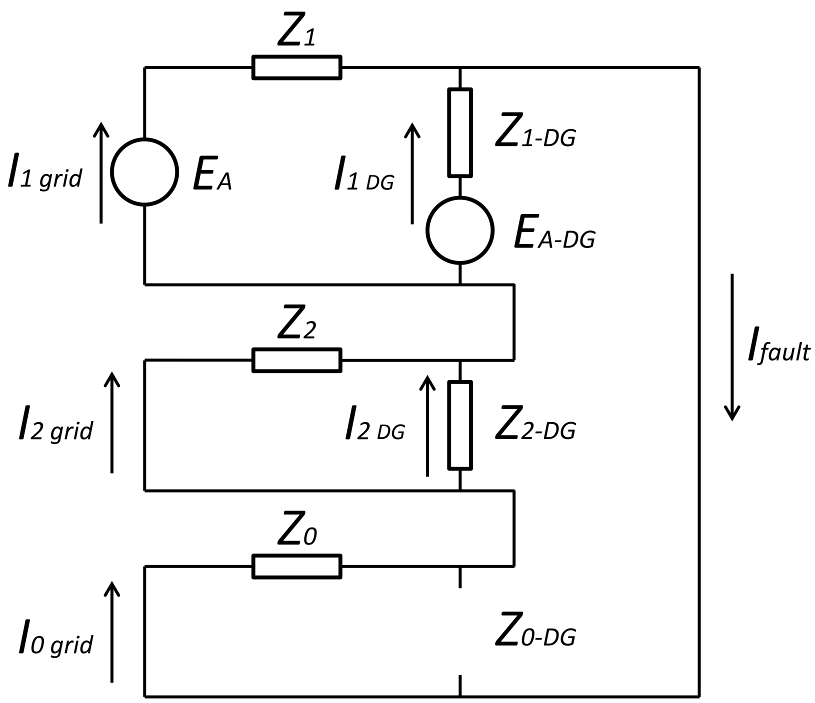

Figure 4.8 Earth fault current symmetrical components analysis

The winding connection of the interface transformer, which is delta-star, means that the zero sequence impedance is infinite, impeding the zero sequence component to flow through the transformer. The DG contributes to the positive and negative sequence components of the fault current, which flows on the non-faulted phases as illustrates in Figure 4.9.

The DG unit increases the total earth fault current and due to the DG transformer winding connection, this fault current contribution flows through the earthing of the substation transformer.

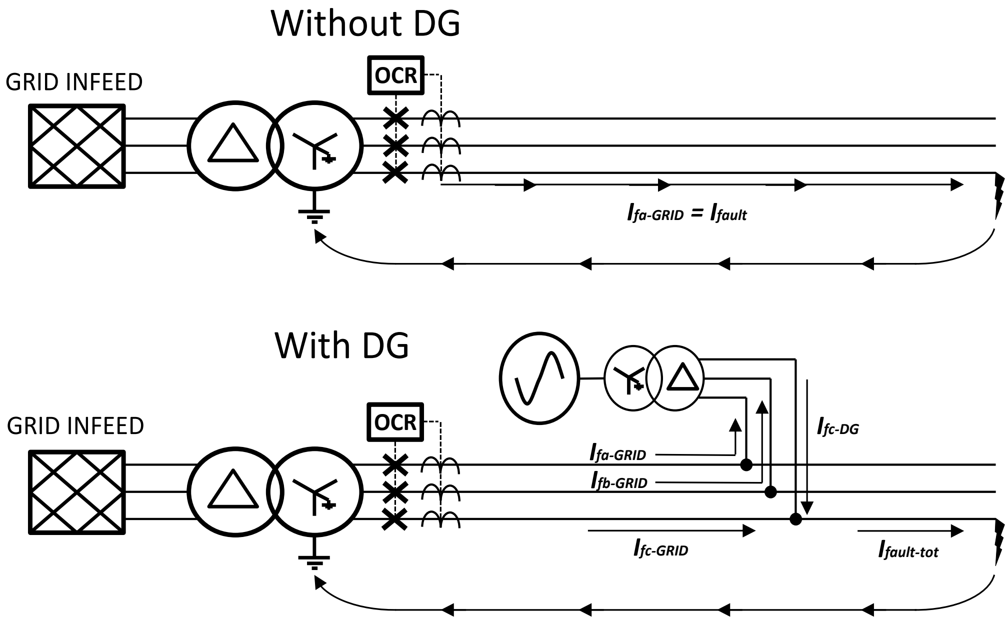

Figure 4.9 Earth fault current with and without DG contribution

The fault current measured by the OCR is given by equations 4.6 and 4.7.

Without DG: $$I_{measured} = I_{fa-GRID} = I_{fault} \tag{4.6}$$

With DG: $$\begin{aligned} I_{measured} &= I_{fa-GRID} + I_{fb-GRID} + I_{fc-GRID} \\ &= I_{fc-GRID} + I_{fc-DG} = I_{fault-tot} \end{aligned} \tag{4.7}$$

The measured fault current in the presence of DG is not just the fault current contribution of the grid but the sum of the grid and DG fault contributions. This explains the increased sensitivity of EF and SEF protection shown in Figure 4.7.

4.5.2 Phase to phase faults

Considering a phase to phase fault, the fault current contribution can be explained using symmetrical component analysis, as shown in Figure 4.10. The DG does contribute to both positive and negative current sequence in parallel to the grid and therefore increases the total fault current while decreasing the grid fault current contribution. Figure 4.11 shows the phase to phase fault current path with and without DG in the test case network.

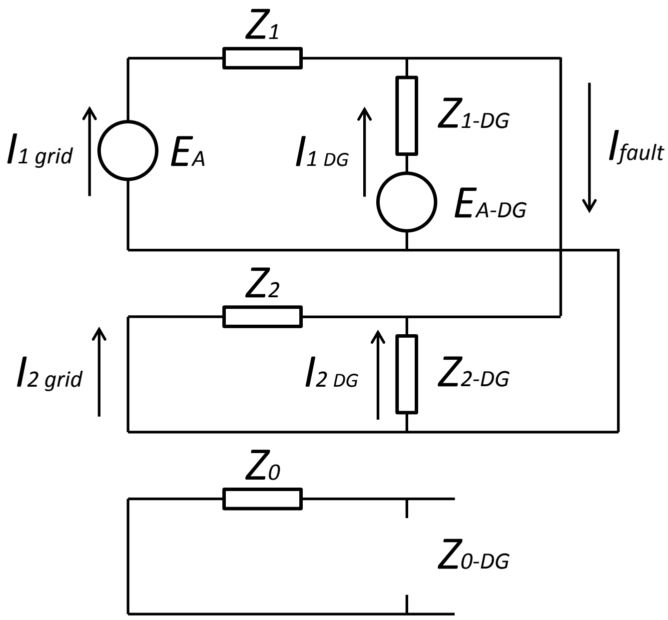

Figure 4.10 Phase to phase fault symmetrical component analysis

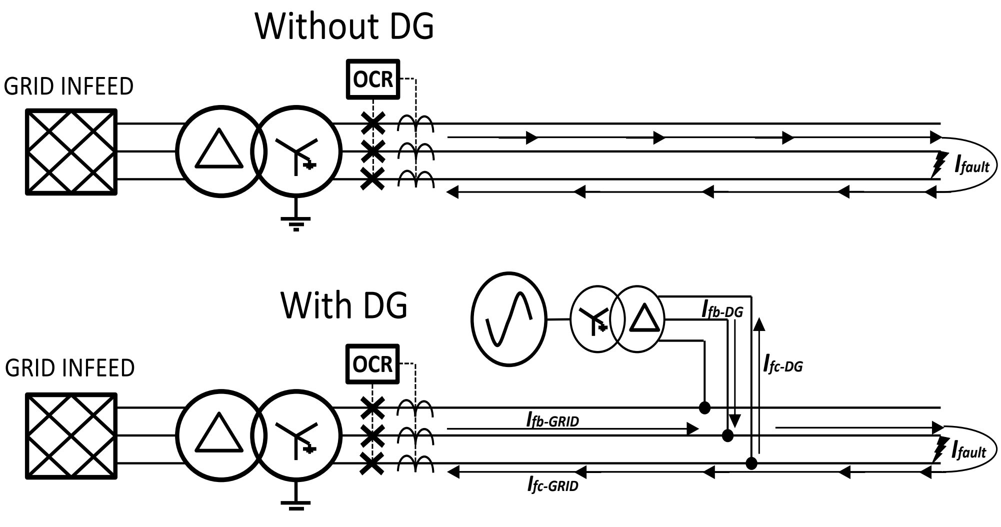

Figure 4.11 Phase to phase fault current with and without DG contribution

The fault current measured by the OCR is equal to the fault contribution from the grid and equal to the total fault current in the case without DG, as shown in equation 4.8. When DG is connected to the feeder, the total fault current increases but the measured fault current decreases and this is given by equation 4.9.

Without DG: $$I_{measured} = I_{fb-GRID} = I_{fc-GRID} \tag{4.8}$$

With DG: $$I_{measured} = I_{fb-GRID} = I_{fc-GRID} = I_{fault} - I_{fc-DG} \tag{4.9}$$

Similar scenarios to those used for the earth fault investigations have been simulated using phase to phase faults to investigate the impact of DG on the phase overcurrent protection function. As previously mentioned, this protection function can be based on DTL or IDMT characteristics, depending on the individual DNO's protection policy.

Beginning with the DTL protection characteristics, a series of simulations have been performed to find the maximum detectable fault resistance with and without DG, while varying the 33kV fault level.

Figure 4.12 and Figure 4.13 illustrate the maximum detectable phase to phase fault resistance with and without DG for R-A and PMAR-A respectively, where the solid lines represent the maximum detectable fault resistance without DG and the dotted lines represent the case with DG.

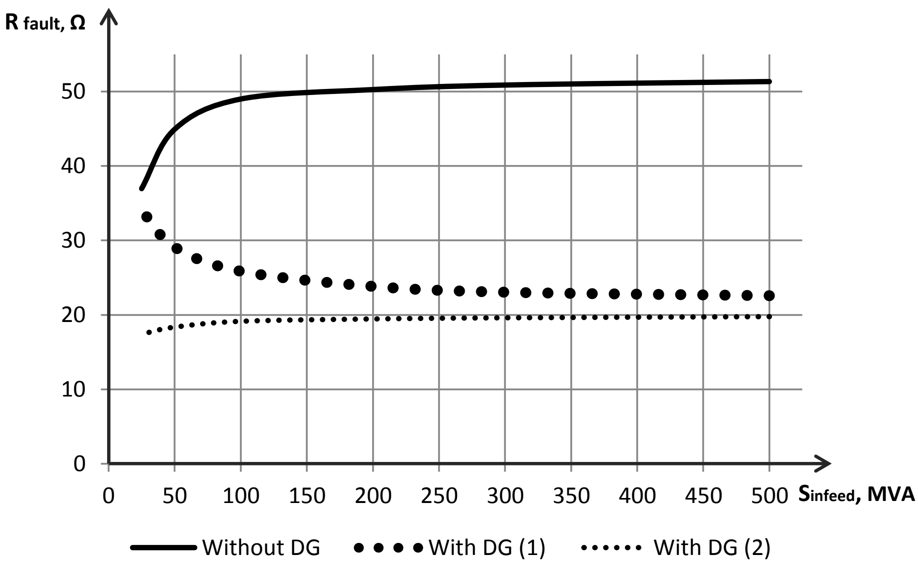

Figure 4.12 PMAR-A maximum detectable phase to phase fault resistance

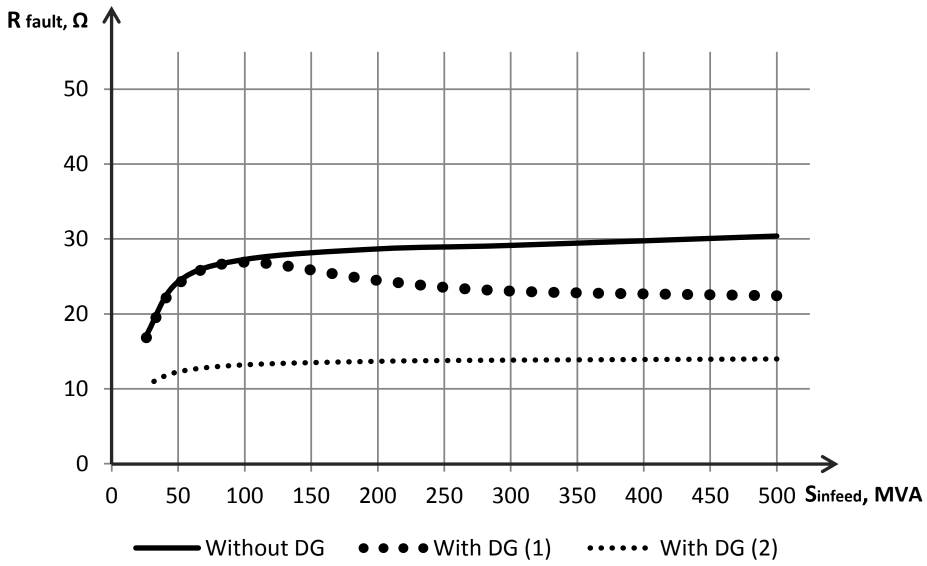

Figure 4.13 AR-A maximum detectable phase to phase fault resistance

The results marked as DG(1) represent the situation where the DG interface protection operates correctly, whereas DG(2) represent the situation where the DG interface protection fails to operate.

The results presented in Figure 4.12 and Figure 4.13 show clearly that the connection of DG reduces the maximum detectable phase to phase fault resistance, because the DG unit increases the total fault current at the fault, but reduces the fault current contribution from the grid.

The dotted lines DG(1) in Figure 4.12 and Figure 4.13 show the impact of DG where the DG protection interface has been simulated with the protection settings reported in Appendix B. The impact of DG is minimised by the over current protection which typically quickly disconnects the DG.

The effect of DG is highest in the case where the DG protection interface fails to operate, as can be seen for the plot of DG(2). However, it should be noted that non-operation of the DG overcurrent protection is highly unlikely; but protection failures must, of course, be considered. Considering the range of phase to phase fault resistance between 0Ω and 10Ω, as discussed in section 5; when the DTL protection characteristics are used, there is no risk of blinding and the tripping time does not vary, as DTL protection operates with a fixed time delay.

When IDMT protection characteristics are used, the operation time of PMAR-A and AR-A may vary significantly. Simulations have been performed with and without DG, while varying the 33kV fault level, to investigate the impact of DG on IDMT protection characteristics.

Table 4.7 shows the operation times recorded for PMAR-A and R-A under various scenarios. The operation (or otherwise) of the DG interface protection, which includes overcurrent, under and over voltage, under and over frequency and ROCOF, has not been reported in the table. However, it should be noted that in all the test cases, the under voltage protection has operated, which is correct and in alignment with the requirements specified in G59/2 [4.21].

Table 4.7 Primary protection (PMAR-A) and back-up protection (R-A) operating time for a range of fault levels and DG capacities

	Fault level = 500 MVA		Fault level = 300 MVA		Fault level = 100 MVA		Fault level = 50 MVA	
DG	no	yes	no	yes	no	yes	No	yes
R fault (Ω)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)	PMAR time (sec)
0	0.525	0.600	0.538	0.617	0.588	0.677	0.672	0.785
2.5	0.578	0.693	0.587	0.704	0.638	0.779	0.729	0.895
5	0.641	0.791	0.649	0.805	0.704	0.881	0.798	1.017
7.5	0.708	0.902	0.716	0.916	0.775	1.000	0.879	1.142
10	0.784	1.158	0.795	1.185	0.853	1.260	0.965	1.292
R fault (Ω)	R-A time (sec)	R-A time (sec)	R-A time (sec)	R-A time (sec)	R-A time (sec)	R-A time (sec)	R-A time (sec)	R-A time (sec)
0	1.348	1.602	1.389	1.665	1.561	1.890	1.869	2.334
2.5	1.526	1.951	1.556	1.994	1.742	2.309	2.095	2.851
5	1.751	2.360	1.783	2.421	1.997	2.781	2.390	3.519
7.5	2.013	2.888	2.044	2.959	2.291	3.420	2.773	4.342
10	2.328	4.457	2.379	4.661	2.645	5.277	3.224	5.559

The operating times of R-A and PMAR-A increase due to the connection of DG. In the worst scenario, i.e. when the 33kV fault level is set to 50MVA and the fault resistance is equal to 10**Ω**, the PMAR-A operating time increases from 0.965s to 1.292s, and the back-up protection (R-A) operating time increases from 3.224s to 5.559s.

4.6 Degradation or loss of overcurrent protection grading

The connection of DG to a distribution network feeder can clearly change the operation time of overcurrent protection devices when faults occur. This was demonstrated in section 0. Section 3.2 reviewed the impact of DG on OCR-OCR, OCR-fuse and fuse-fuse grading; this seems to be broadly investigated and reported upon in the literature.

Considering that UK utilities are currently substituting spur fuses with smart links, the protection system used as the basis of the investigations reported in this dissertation has been designed with smart links as shown in appendix A. Because of this design choice, the problems related to coordination between auto-reclosers and fuses are not apparent, as the smart links have no current/time dependencies, merely operating in response to upstream protection clearing faults from the system.

The impact of DG on the OCR-OCR grading can be summarised with reference to two application scenarios. If the DG and the fault are co-located on the same feeder, then in the worst-case scenario, the tripping time is longer and the grading margin between PMAR and multi shot auto recloser increases, and therefore it does not affect the protection grading.

If the DG and the fault are located on different feeders, the total fault current increases and the grading margin the between AR and PMAR could decrease. However the fault contribution from the grid is typically much higher than the contribution from the DG and therefore the change in the operation time is minimal and often negligible.

However, the literature seems to focus only on the impact of DG, without considering the impact of ANM system solutions. These schemes can vary the network topology and, as a consequence, the performance of the protection system.

This section presents the main findings of the analysis of the potential impact of ANM schemes on protection system performance and shows how ANM can, in certain circumstances, lead to mal-operation and loss of grading within the overcurrent protection system.

4.6.1 Configuration of the simulations

To analyse the impact of DG and ANM solutions on the protection system, two feeders, A and B, are considered with two DG units connected to each feeder as shown in Figure 4.14.

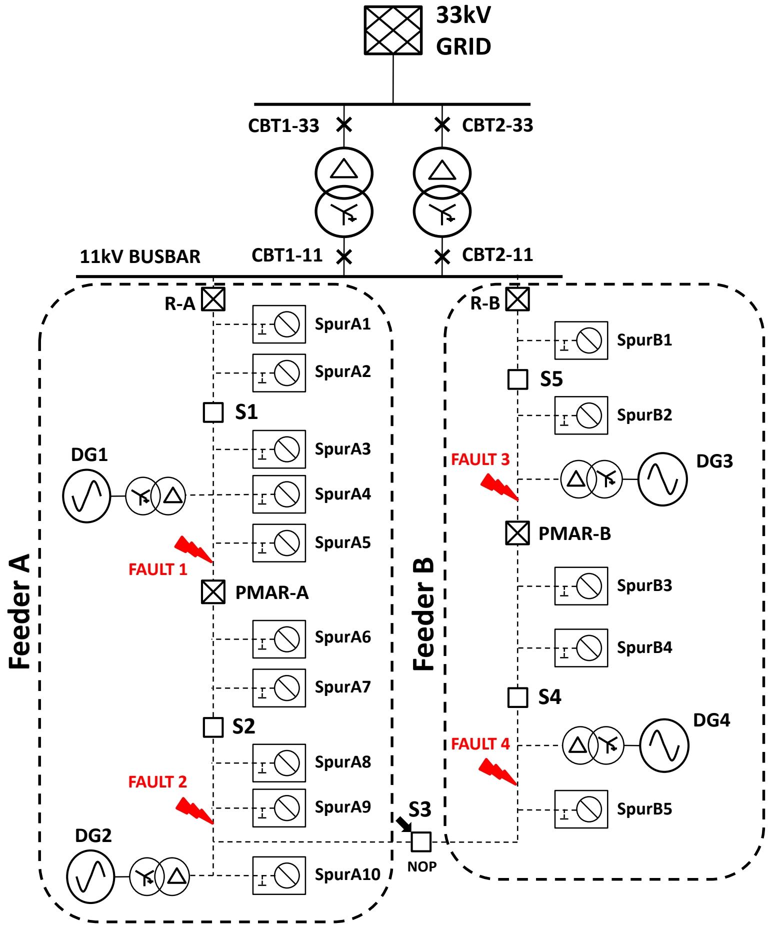

Figure 4.14 System used to analyse impact of DG and ANM on overcurrent protection

Overcurrent protection is provided by the ARs (AR-A and AR-B) and by the PMARs (PMAR-A and PMAR-B). The protection settings are summarised in appendix B.

The DG penetration level is simulated from 0 to 100% of each feeder's load rating, i.e. 0-7.6MVA for feeder A and 0-4.8 MVA for feeder B. This generation capacity is connected at two points on each feeder, as shown in in Figure 4.14.

The actions of ANM solutions are simulated by simulating changes to the configuration of the network, obtained by shifting the normally open point (NOP) from S1 to S5 to simulate automatic network reconfiguration activities.

Phase to phase and earth faults have been simulated at four locations, varying the fault resistance from 0Ω to 10Ω for phase faults and from 0Ω to 100Ω for earth faults. The fault level at 33kV has been set to 500MVA with both transformers at the network substation in service.

4.6.2 Simulation results

The simulations have demonstrated that, when ANM solutions change the topology of the network, there are cases where protection system operation can be incorrect. Table 4.8 shows the operation time of the RAs and PMARs for three network configurations, obtained by shifting the position of the NOP, shown in Table 4.8, to its alternative locations of S1, S3 and S5, when a phase to phase fault (0Ω - 10Ω) occurs.

Table 4.8 Impact of network topology changes on protection operation times and grading

	R Fault [Ω]	S1 is open				S3 open (normal configuration)				S5 open			
		R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]	R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]	R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]
FAULT 1	0.001	-	0.647	1.020	0.493	0.790	-	-	-	0.789	-	-	-
	2.5	-	0.737	1.123	0.533	0.925	-	-	-	0.920	-	-	-
	5	-	0.844	1.244	0.581	1.112	-	-	-	1.105	-	-	-
	7.5	-	0.972	1.363	0.628	1.336	-	-	-	1.319	-	-	-
	10	-	1.134	1.501	0.679	1.614	-	-	-	1.576	-	-	-
FAULT 2	0.001	-	-	0.860	0.426	1.088	0.498	-	-	1.078	0.493	-	-
	2.5	-	-	0.975	0.473	1.234	0.547	-	-	1.222	0.543	-	-
	5	-	-	1.089	0.522	1.431	0.614	-	-	1.399	0.609	-	-
	7.5	-	-	1.217	0.570	1.690	0.701	-	-	1.657	0.690	-	-
	10	-	-	1.348	0.624	2.016	0.801	-	-	1.954	0.780	-	-
FAULT 3	0.001	-	-	0.831	0.414	-	-	0.835	0.415	1.119	0.506	-	-
	2.5	-	-	0.937	0.461	-	-	0.944	0.462	1.279	0.563	-	-
	5	-	-	1.048	0.504	-	-	1.069	0.512	1.488	0.636	-	-
	7.5	-	-	1.174	0.552	-	-	1.201	0.565	1.748	0.719	-	-
	10	-	-	1.298	0.604	-	-	1.347	0.623	2.071	0.817	-	-
FAULT 4	0.001	-	-	0.625	-	-	-	0.628	-	1.499	0.640	-	0.507
	2.5	-	-	0.729	-	-	-	0.739	-	1.721	0.708	-	0.554
	5	-	-	0.843	-	-	-	0.856	-	1.998	0.794	-	0.605
	7.5	-	-	0.958	-	-	-	0.982	-	2.315	0.896	-	0.667
	10	-	-	1.082	-	-	-	1.113	-	2.484	1.008	-	0.733

Table 4.9 shows the operation time of the RAs and PMARs for the same three network configurations as before when a phase to earth fault (0Ω - 100Ω) occurs.

Table 4.9 Impact of network topology changes on protection operation times and grading

	R Fault [Ω]	S1 is open				S3 open (normal configuration)				S5 open			
		R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]	R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]	R-A [s]	PMAR A [s]	R-B [s]	PMAR B [s]
FAULT 1	0.001	-	0.240	0.400	0.240	0.399	-	-	-	0.400	-	-	-
	10	-	0.239	0.400	0.239	0.402	-	-	-	0.398	-	-	-
	20	-	0.239	0.402	0.242	0.401	-	-	-	0.400	-	-	-
	30	-	0.244	0.404	0.244	0.401				0.400			
	50	-	0.246	0.406	0.245	0.404				0.404			
	75	-	0.250	0.410	0.250	0.409	-	-	-	0.406	-	-	-
	100	-	0.253	0.413	0.253	0.408	-	-	-	0.412	-	-	-
FAULT 2	0.001	-	-	0.400	0.240	0.400	0.240	-	-	0.398	0.238	-	-
	10	-	-	0.400	0.240	0.398	0.238	-	-	0.402	0.242	-	-
	20	-	-	0.402	0.242	0.401	0.241	-	-	0.401	0.241		
	30	-	-	0.402	0.241	0.404	0.242	-	-	0.402	0.242		
	50	-	-	0.403	0.243	0.405	0.245	-	-	0.403	0.243	-	-
	75	-	-	0.408	0.248	0.407	0.247	-	-	0.408	0.248	-	-
	100	-	-	0.410	0.250	0.407	0.247	-	-	0.409	0.249	-	-
FAULT 3	0.001	-	-	0.399	0.239	-	-	0.400	0.240	0.401	0.241	-	-
	10	-	-	0.399	0.239	-	-	0.399	0.239	0.401	0.241	-	-
	20	-	-	0.400	0.240	-	-	0.399	0.239	0.401	0.241		
	30	-	-	0.400	0.242	-	-	0.403	0.243	0.403	0.242		
	50	-	-	0.405	0.245	-	-	0.401	0.241	0.403	0.243	-	-
	75	-	-	0.408	0.248	-	-	0.405	0.248	0.410	0.250	-	-
	100	-	-	0.408	0.248	-	-	0.413	0.253	0.410	0.249	-	-
FAULT 4	0.001	-	-	0.398	-	-	-	0.399	-	0.402	0.242	-	0.242
	10	-	-	0.399	-	-	-	0.401	-	0.403	0.243		0.243
	20	-	-	0.399	-	-	-	0.399	-	0.400	0.240		0.240
	30	-	-	0.402	-	-	-	0.400	-	0.406	0.246	-	0.243
	50	-	-	0.404	-	-	-	0.404	-	0.407	0.247	-	0.244
	75	-	-	0.406	-	-	-	0.407	-	0.411	0.251	-	0.249
	100	-	-	0.407	-	-	-	0.407	-	0.409	0.249	-	0.249

When S3 is set as the NOP, the operation of the overcurrent protection system, with the protection settings presented in appendix B, is correct and this is clear from analysis of the data in the central columns of the table above. The numbers shown in grey are the operating times of the backup protection, the number shown in black and red are the operation time of the primary protection, where black signifies correct operation and red is indicative of false operation.

When S1 is set as the NOP, then for fault 1, the order of correct protection tripping should be: PMAR-A first, then PMAR-B back up protection if required. However, since the overcurrent protection settings are calculated to cater for a different configuration (i.e. with the NOP at S3), in this case PMAR-B trips before PMAR-A, as shown in Table 4.8 and Table 4.9 for phase and earth faults respectively.

This would cause unnecessary disconnection of customers connected between PMAR-A and PMAR-B, and also incorrect disconnection of DG2 and DG4.

Moreover, in the worst-case scenario, where DG2 and DG4 are masking, or "hiding" an element of the overall feeder load and the total load is higher than the rating of feeder B, then after the automatic re-closure, AR-B and PMAR-B may trip due to their overload current settings.

When S5 is set as the NOP, then for fault 4, the order of correct protection tripping should be: PMAR-B first, then PMAR-A as back up protection if required. However, since the overcurrent protection settings are calculated to cater for a different configuration (i.e. with the NOP at S3), in this case there a greatly reduced, and almost negligible, grading margin between PMAR-B and PMAR-A.

In the worst case, where the fault resistance is zero, both PMARs would trip, causing unnecessary disconnection of customers connected between PMAR-A and PMAR-B, and incorrect disconnection of DG2 and DG4.

As the rating of feeder A is higher than the rating of feeder B, when PMAR-A recloses there is no overload on the feeder and hence no tripping of protection on overload. Therefore, the consequences of coordination degradation in this case are unnecessary temporary disconnection of costumers and disconnection of DG2 and DG4.

4.7 Chapter summary

This chapter has presented a detailed analysis of the impact of DG and ANM on protection, focusing on three problems that are not properly investigated in the literature, which are the problems of false tripping, blinding, and loss of coordination between OCRs.

The simulations has demonstrated that both induction and synchronous DG can cause false tripping, and synchronous generation has the potential to be relatively more detrimental to the protection system when compared with induction generation. However, the use of IDMT overcurrent protection, as opposed to DTL overcurrent protection, may prevent false tripping from happening if correctly applied.

The problem of blinding has been disproved, even under realistic worst case scenario conditions. The simulation results show that the connection of DG acts to improve SEF and EF protection sensitivity and does not affect the phase fault protection sensitivity or its discrimination. When IDMT protection characteristics are used for phase fault protection, the operating time slightly increases in the presence of DG. The increases in protection operating time have been quantified for several scenarios and it can be concluded that these increased times would not cause significant problems.

It was demonstrated that ANM schemes affect the correct coordination between OCRs when they modify the network topology of the network. An example has been used to show how the protection system responds to phase and earth faults when the network topology is changed.

To address this problem and the impact of DG and islanded operation discussed in the literature review, an adaptive overcurrent protection system with automatic protection settings calculation has been developed and it is presented in chapter 5, while to address the problems of sensitivity and selectivity of LOM protection discussed in the literature review, an adaptive inter-tripping scheme with passive LOM protection system has been developed and it is presented in chapter 6.

4.8 References

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Chapter 5:

Adaptive over-current protection with automatic settings calculation

5.1 Chapter overview

The concept of adaptive protection was introduced at the beginning of 1990s to improve the performance of distance protection [5.1, 5.2]. In 1999, the IEEE Guide for Protective Relay Applications to Transmission Lines [5.3] defined the concept of adaptive protection as:

> *"A protection philosophy that permits, and seeks to make adjustments automatically, in various protection functions to make them more attuned to prevailing power conditions."*

Since its introduction, there has been an increasing interest in the application of this adaptive protection concept at distribution voltage levels, to adapt overcurrent protection to, for example, cater for the introduction of DG and/or to permit islanded operation [5.4-5.7], as reviewed in section 3.2.1.

This chapter presents an adaptive overcurrent protection system with automatic settings calculation that has been developed and demonstrated in the laboratory using simulation and actual protection equipment. The main differences between this adaptive protection system and the adaptive protection solutions proposed in the literature are twofold:

- Firstly, it is more flexible because it does not use pre-calculated settings, which is a limitation to the flexibility of the adaptive protection solutions proposed in [5.7, 5.8]. Since distribution networks are becoming increasingly complex with the introduction of DG, ANM and possibly intentionally islanded operation, the number of possible scenarios increases and in some case it is impossible to pre-calculate settings for each scenario and define a number of setting groups to cover all scenarios.
- Secondly, it is more comprehensive because it does not consider only the impact of DG connection or islanded operation, which seems to be the only problems addressed by the proposed adaptive protection solutions in the literature [5.4-5.8]. The adaptive protection system developed through this research also considers other factors that have a similar, and in some cases

more severe impact on the protection system, which are all possible changes in the network topology, connection/disconnection of lines, etc.

This chapter firstly defines the methodology used to develop the adaptive overcurrent protection system, then it describes the adopted system architecture, which is divided into several functional layers, based on the type of data used and the required response time, and subsequently it explains how the different functional elements within the architecture can be implemented in hardware and software and presents guidelines on the transition from a traditional to an adaptive overcurrent protection system.

Secondly it presents the algorithm of the adaptive protection system, explaining in detail how the protection settings are calculated, verified and then applied to the OCRs.

Finally, it shows how the adaptive protection system has been implemented in the laboratory using actual protection relay devices and presents simulation results to demonstrate how the scheme improves the protection performance compared with a traditional overcurrent protection scheme.

5.2 Methodology

Following up the investigation and demonstration of the problems that traditional overcurrent protection system will face in future active power distribution networks, an adaptive overcurrent protection system with automatic protection settings calculation has been developed to improve both selectivity and speed of operation.

The adaptive overcurrent protection system has been developed considering the equipment installed in present UK distribution networks and the available commercial protection hardware to provide a protection solution that could be implemented in a trial test in the near future. Section 5.3 presents the architecture of the developed adaptive overcurrent protection system and section 5.4 gives guidelines on the migration from present overcurrent protection systems to the developed solution.

The adaptive protection scheme has been implemented in commercially available hardware and demonstrated in a HIL simulation environment explained in section 5.6, to prove the advantages respect to traditional overcurrent protection schemes.

Finally, the protection solution has been tested through hundreds of fault simulations to quantify the improvement in performance. The testing has been reported in chapter 7 together with the testing of the adaptive inter-tripping scheme with passive back-up LOM protection presented in chapter 6.

5.3 Adaptive protection system architecture

The adaptive overcurrent protection architecture is composed of execution, coordination and management layers. The separation of functional layers is based on the data used and the required response time for each functional group:

- The source of the data used by the different functional elements may be local or remote. The execution layer functions use local substation data, the management layer function utilises wide area data, while the coordination layer functions use a combination of local and wide area data.
- The required time response for different functional elements within the adaptive protection system may vary from several milliseconds at the execution layer level to several minutes at the management layer level.

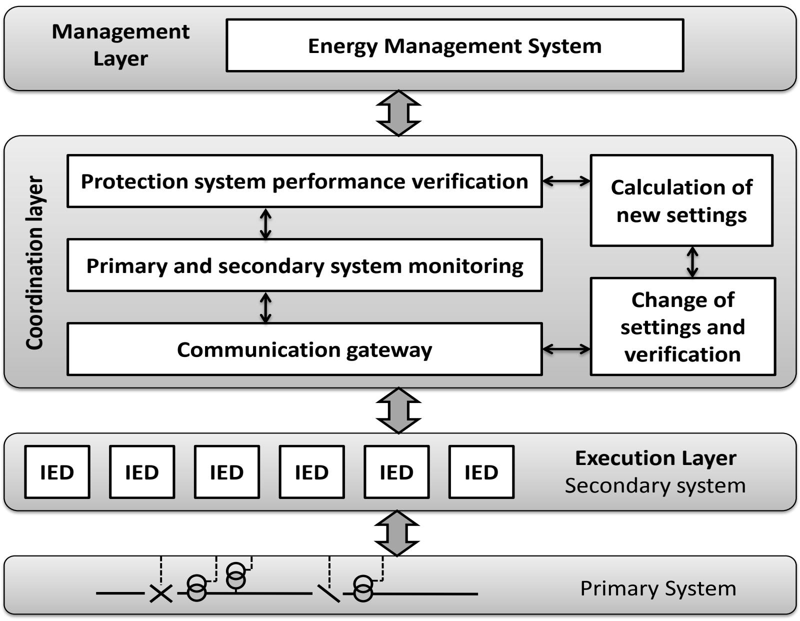

Figure 5.1 Adaptive protection system architecture

Figure 5.1 illustrates the adaptive overcurrent protection architecture. The primary system is at the foot of the diagram, and includes lines, transformers, generators, circuit breakers, network switches, current and voltage transformers, etc. Above this is the execution layer, which includes the IEDs installed in the network (e.g. OCRs), with interfaces between these layers consisting of hardwired links for provision of measurement data and tripping commands or IEC 61850 process bus communication.

Above the execution layer is the coordination layer, which is responsible for monitoring and coordinating the IEDs. Finally, at the top there is the energy management layer, which is responsible for managing the overall network.

5.3.1 The execution layer

Considering an overcurrent protection system, the execution layer is composed of OCRs, which are responsible for analysing the electrical parameters received by CTs (and in some cases VTs), in order to correctly detect and clear the faults through tripping of CBs.

The execution layer, in the case of a simple overcurrent system, is an autonomous layer, i.e. the tripping decisions are taken locally using local data without any communication with the coordination or other layers. This means that in case of communication failure between the execution layer and the coordination layer, the overcurrent protection is not affected (although if its settings were to be changed remotely, this would not be possible upon failure of the coordination layer or failure of the communications link between these layers).

The implementation of the adaptive protection system is achieved by the introduction of enhanced functionality to the coordination layer, which is not present in a traditional protection system.

5.3.2 The coordination layer

The coordination layer contains five functional blocks:

- **Communication Gateway:** This is a network node equipped for interfacing with IEDs that use different communication protocols, such as: DNP3[5.9], Modbus[5.10], IEC60870-5-103[5.11], IEC61850[5.12]. Therefore it contains protocol translators to provide system interoperability and uses Object Linking and Embedding (OLE) for Process Control OPC[5.13] to communicate with the blocks in the coordination layer and with the management layer.

- **Primary and secondary system monitoring:** if a change in the primary is detected, this block interrogates the "online verification of protection system performance" block to verify if the change is likely to compromise the protection performance based on the present settings of the overcurrent protection relays in the secondary system.
- **Protection system performance verification:** This verifies the performance of the protection system against performance requirements and can be interrogated by the "monitoring of primary and secondary systems" block immediately after a change in the network is detected, or by the network management level before a proposed change is applied.
- **Calculation of new settings:** This calculates the optimum protection settings for a defined network configuration. The technique used to calculate the protection settings is described in section 5.5.2. The new protection settings are verified by the "online verification of protection system performance" block and then sent to the "change of settings and verifications" block.
- **Change of settings and verification:** This sends the new settings to the IEDs through the gateway and then verifies that the proposed settings have been received by and applied to the IEDs.

The coordination layer also communicates with the energy management layer. One example of communication between these two layers is when there is a post fault reconfiguration of the network or other network configuration changes, for example to enable maintenance activities to be carried out, and the management layer communicates the new configuration as explained in the following subsection.

5.3.3 The management layer

The management layer receives data from the primary and secondary systems and contains functional blocks for receiving and interpreting the received data in order to monitor the network and take network management decisions as and when required.

These functional blocks would normally reside in a network control room, where, typically, engineers manually (with the assistance of various systems) monitor and control the distribution network.

When the management layer is required to change the network status, for instance to restore the supply to a number of loads disconnected after a permanent fault, it is important that the coordination layer is informed because it is required to verify how the new network configuration will impact upon the protection system. If it is ascertained that the protection system will be compromised as a result of proposed changes, then the protection settings must be changed immediately after the network configuration is changed.

5.4 Hardware and software implementation

The developed adaptive overcurrent protection solution is based on the concept of monitoring the network and changing the protection settings of the OCRs as the network changes, rather than using fixed protection settings that may be calculated in advance, but often result in a non-optimised compromise for the various scenarios that may be encountered.

Considering the test case distribution network, described in appendix A, the traditional overcurrent protection system is composed of overcurrent protection relays with fixed settings. Communication to the OCRs is not necessary; however a communications infrastructure might be available to monitor the network through a SCADA system and to allow remote control of network switches and PMARs.

To move from a traditional system to the developed adaptive overcurrent system, it is necessary to change some of the protection devices and improve the communication infrastructure to satisfy the following points:

- all the OCRs must be numerical relays with communication capabilities to enable monitoring of their status and changes to be made to their protections settings (utilities are presently replacing electro-mechanical OCRs with numerical OCRs);
- the communication network must include connections to all OCRs;

- a new device, termed the "adaptive protection controller" (APC), must be introduced to host the new functional blocks of the coordination layer.

Figure 5.2 shows the test case distribution network with the hardware that should be installed in the network for the implementation of the developed protection system.

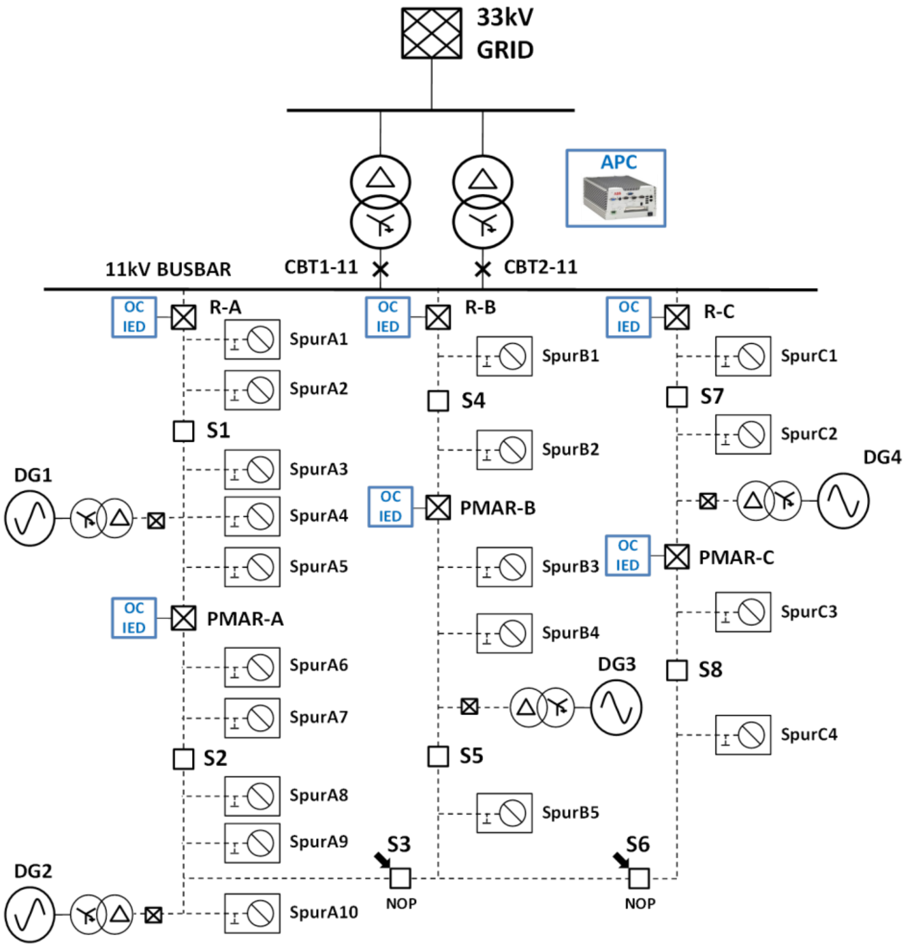

Figure 5.2 Implementation of the adaptive overcurrent protection system

5.5 Adaptive overcurrent protection algorithm

The developed adaptive overcurrent protection solution has been developed to be both reactive and proactive in response to changes in the network configuration, where reactive means that the system reacts to solve matters as they arise, e.g. unplanned/uncontrolled connection/disconnections of DG, or unplanned changes to network configuration due to faults, etc.; while proactive means that the system acts to solve the matters before they become an issue, e.g. any planned network reconfiguration, or planned disconnection of lines for maintenance, etc.

Figure 5.3 shows the reactive adaptive overcurrent protection algorithm and Figure 5.4 illustrates the pro-active adaptive overcurrent protection algorithm. Note that in the figure, F is the matrix of the fault currents, T_0 represents the matrix of the protection operating time considering present settings and T_0 is the matrix of the protection operating time considering new settings.

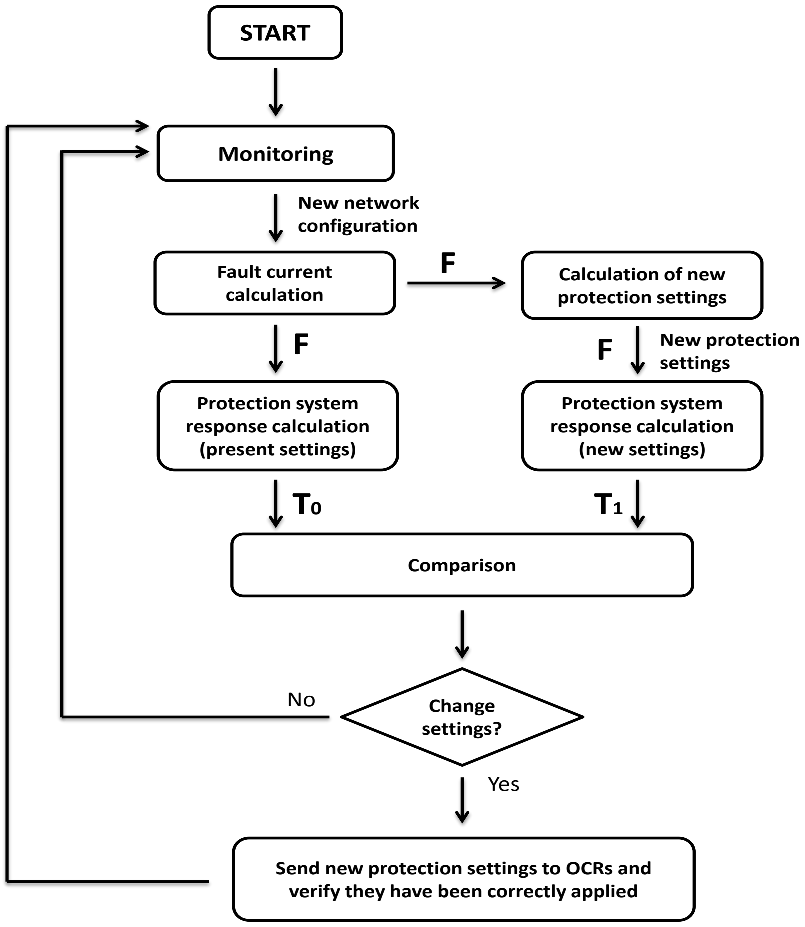

Figure 5.3 Reactive adaptive overcurrent protection algorithm

The reactive algorithm, shown in Figure 5.3, reacts to unanticipated changes in the network, while the proactive algorithm, shown in Figure 5.4, is initiated by a request from the network management layer to verify the protection system performance for a new, anticipated, network configuration prior to a planned network change.

In cases where it is established that new protection settings should be applied, the adaptive protection system send the updated settings to the OCRs immediately after the network management system changes the network configuration.

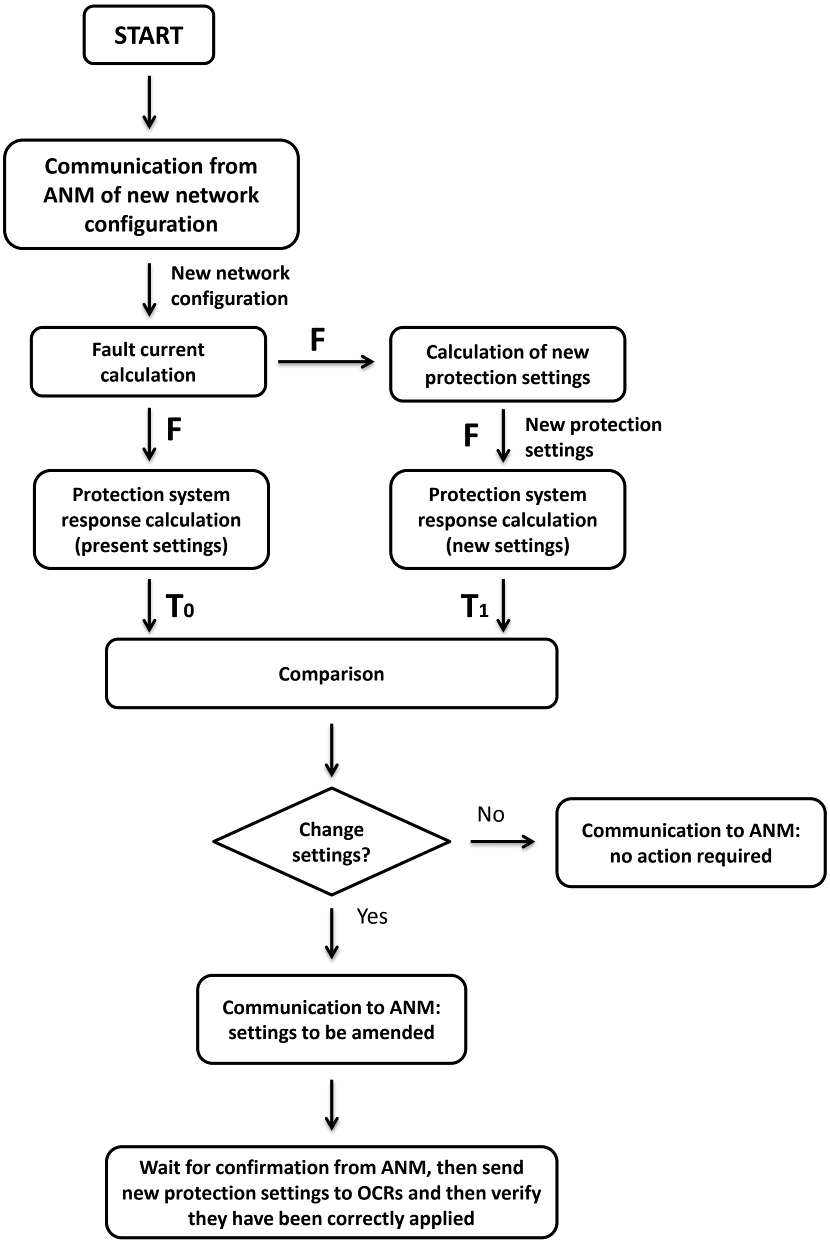

Figure 5.4 Proactive adaptive overcurrent protection algorithm

The main difference between the reactive and proactive adaptive overcurrent protection algorithms is in the way they are initiated. The reactive algorithm is initiated by the monitoring block, which monitors the network configuration and, if the network topology changes, and/or the DG changes status (i.e. connected/disconnected) and/or the network switches between grid connected/islanded modes, it communicates the new network configuration to the fault current calculation block. For the pro-active algorithm, it is the ANM system that would communicate the intended new network configuration to the fault current calculation block in advance of any change to the configuration being made.

The central element of each algorithm is identical and includes:

- fault current calculation, described in subsection 5.4.1;
- calculation of new protection settings, described in subsection 5.4.2;
- protection system response calculation and comparison, described in subsection 5.4.3.

If a decision is made to not apply any new settings, then the reactive system returns to the monitoring block and waits for a new change in the network; while if the decision is to apply the new settings, then the settings are applied as described in subsection 5.4.4.

For the proactive algorithm, if no new settings are required, then this fact is communicated to the ANM system. If new settings are required, then this fact is communicated to the ANM and when the ANM confirms that the network has been changed, the settings are applied as described in subsection 5.4.4.

The main advantage of the developed adaptive overcurrent protection system with automatic protection settings compared to an adaptive protection system based on a look-up table are its better flexibility, manageability and updateability. It is more flexible because it does automatically calculate and apply the protection settings without the requirement to identify a defined number of network scenarios and pre-calculate the protection settings for each of them as explained more in detail in section 5.5.2. It is easily manageable and updateable because if the network changes it is sufficient to provide information about the change instead of requiring a complete re-thinking of the adaptive protection scheme as it would be in the case of look-up table. For instance, if new automation schemes are added, then there is no need to update the protection scheme because there are not predefined network scenarios, while if the network is upgraded with new DG units or new lines, then it is sufficient to update the network file without the necessity to re-define the network scenarios and do the protection settings grading exercise for all the network scenarios.

5.5.1 Fault current calculation

Considering the actual network configuration, the status of the DG connection and the operational status of the network (grid connected or islanded), a series of faults are simulated to calculate the fault current measured by the OCRs for each fault scenario.

Figure 5.5 shows the test case network with the thirteen fault locations used by the algorithm block "fault current calculation".

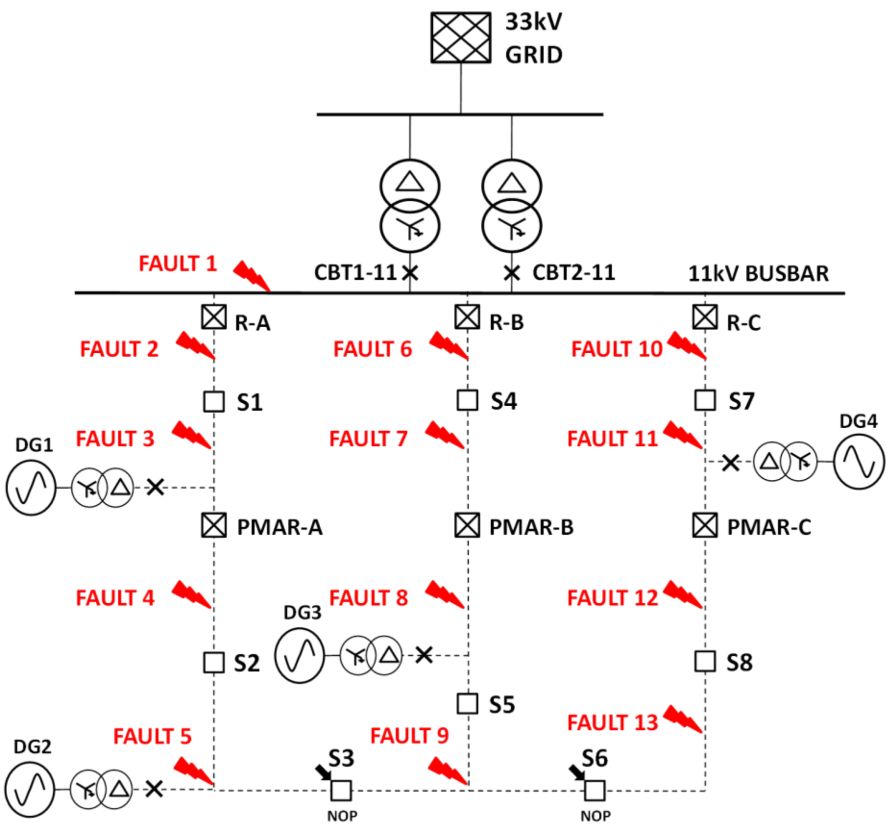

Figure 5.5 Example of fault locations used by the algorithm block "fault current calculation"

A programme, written in Python 2.7[5.14], has been developed to automatically execute all fault simulations and calculate the protection system response.

The program accesses the IPSA Power fault calculation tool through its application programme interface (API), simulates earth and phase faults (through instructing IPSA to execute the appropriate simulations) and saves the fault currents that would be measured by each protection device for every simulated fault. These are saved into two fault current matrices, which are named $\boldsymbol{F_e}$ for the earth fault currents and $\boldsymbol{F_p}$ for the phase fault currents.

$$\boldsymbol{F_e} = \begin{bmatrix} I_{fe11} & \cdots & I_{fe1m} \\ \vdots & \ddots & \vdots \\ I_{fen1} & \cdots & I_{fenm} \end{bmatrix} \tag{5.1}$$

$$\boldsymbol{F_p} = \begin{bmatrix} I_{fp11} & \cdots & I_{fp1m} \\ \vdots & \ddots & \vdots \\ I_{fpn1} & \cdots & I_{fpnm} \end{bmatrix} \tag{5.2}$$

Where *n* is the number of protection devices and *m* is the number of simulated faults.

5.5.2 Protection settings calculation technique

Protection settings for the overcurrent protection are normally calculated by utilities through undertaking a traditional "Upstream to Downstream" current-time Grading (UDG) exercise as shown in Figure 5.6. This calculation technique considers the maximum fault current and calculates the protection settings with the objective of ensuring a grading time interval (GTI) greater than a predefined Minimum Grading Margin (MGM), which is normally 0.25 s for numerical protection relays.

For example, considering Figure 5.6, the protection settings of OCR B are calculated considering the maximum fault current in the line B-C to ensure that the GTI between the operation time of OCR A and OCR B is greater than the MGM, which is 0.25 s in this case.

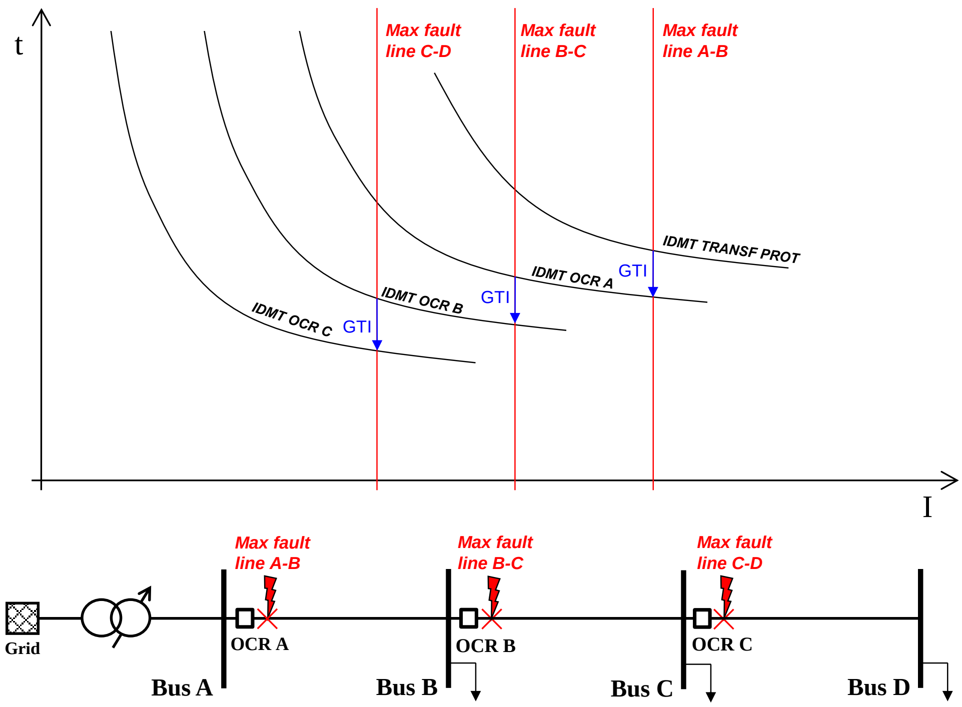

Figure 5.6 Upstream to downstream grading (UDG) technique

The UDG technique has been used in appendix A.2 to calculate the protection settings to represent the present protection policy adopted by utilities in the UK. Appendix A.2 contains the logarithmic graphs for the UDG calculation and a table that summarise all the protection settings.

The UDG technique is widely used by DNOs because it facilitates a quick calculation of protection settings. This technique normally results in a relatively large grading margin between the last downstream network protection device and the loads' (or LV systems') protection systems. Accordingly, if loads are added or changed, it is very likely that the distribution network protection settings will not require modification. When there are network upgrades, such as addition of new lines or refurbishment/upgrading of existing elements of the system or a new DG unit is connected to the network, protection settings normally need to be reviewed.

As discussed previously, the main advantage of the UDG technique is that it permits a fast calculation of the protection settings; however one of the disadvantages is that it does not provide the fastest possible protection operation times for all relays.

To improve the quality of the power distribution service (e.g. by minimising the risk of unnecessary DG disconnection and protection coordination problems), it is desirable to change the approach used in the calculation of the protection settings to minimise the operation time. This can be achieved by adopting a Downstream to Upstream current-time Grading (DUG) technique, as shown in Figure 5.7.

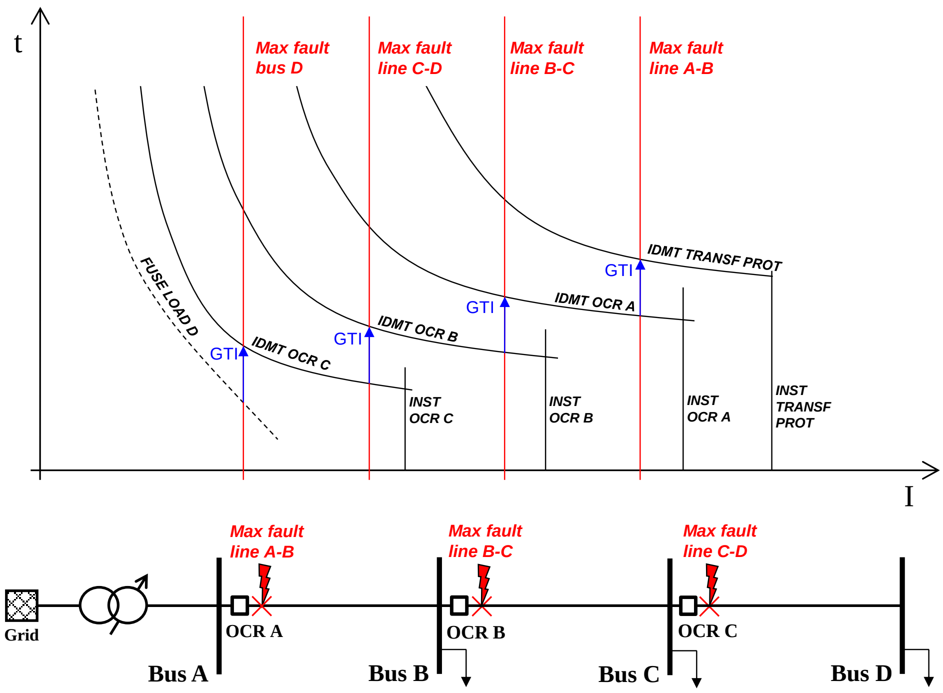

Figure 5.7 Downstream to upstream grading (DUG) technique

With this technique, the protection settings of the OCRs are calculated starting from the load protection, therefore each OCR is graded with its downstream OCR instead of its upstream OCR, as would be the case when using the UDG approach. For example, considering Figure 5.7, the protection settings of OCR B are now calculated considering the maximum fault current in the line C-D to guarantee that the GTI between the operation time of OCR B and OCR C is major than the MGM, which is again assumed to be 0.25s.

Another important aspect to consider is that that a distribution network may change in its network topology, fault level, DG connection, etc. This must be considered during the protection settings calculation. The traditional approach is to use fixed protection settings and to do so, it is necessary to calculate the protection settings for the different scenarios and then find a set of settings that guarantee that all GTIs are greater than the MGM. The calculated protection settings can be defined as the protection settings of the worst scenario, because the protection settings calculated for that scenario can be applied to all the other scenarios, with knowledge that there will be no other scenarios where the protection settings will not be fit for purpose.

As distribution networks become ever-more complex (with the introduction of DG and ANM systems, the UDG technique becomes more and more complicated to be applied as the number of possible scenarios significantly increases. In some case the calculation of a set of protection settings becomes infeasible and the solution may be to define two or more setting groups associated with two or more scenarios, for example one for grid connected and one for islanded operation, as proposed in [5.8]. However, if the number of scenarios increases to a large number, then the use of setting groups becomes not feasible, too.

The developed approach for the calculation of the protection settings as a result of the research reported here differs from presently adopted approaches through:

- using a DUG instead of a UDG technique; and
- using variable protection settings instead of fixed protection settings or setting groups.

The main advantage of using a DUG technique combined with variable protection settings is that the mean operating time of the overcurrent protection system is reduced and correct grading is always guaranteed, which leads to the following four improvements:

- reduction of stress on network current carrying components during faults;
- shorter duration of voltage sags during faults in adjacent feeders;
- reduction of unnecessary tripping of DG units; and
- reduction of unnecessary disconnection of loads.

The following subsections 5.4.2.1and 5.4.2.2 describe how the DUG technique is applied to calculate phase and earth fault protection settings.

5.5.2.1 IDMT protection settings

The IDMT phase and earth fault protection settings calculation is divided into two steps:

1. **Choose the inverse characteristic for the phase fault overcurrent protection**

   IEC 60255 [5.15] defines three inverse definite minimum time (IDMT) characteristics: standard inverse (SI), very inverse (VI) and extremely inverse (EI). The equations relating time to input current (when expressed as a multiple of the relay's setting, or pickup, current) for these characteristics are presented below:

Table 5.1 IDMT characteristics (IEC 60255) [5.15]

Relay Characteristic	Equation
Standard inverse	$t = TMS \times \frac{0.14}{(I/I_s)^{0.02} - 1}$
Very Inverse	$t = TMS \times \frac{13.5}{I/I_s - 1}$
Extremely inverse	$t = TMS \times \frac{80}{(I/I_s)^2 - 1}$

Where TMS is the time multiplier setting and I_s is relay setting current.

If the downstream device uses a SI characteristic, only SI can be used for the upstream device or coordination cannot be ensured for all input currents. If the downstream device uses a VI, then VI and SI can be used for upstream devices. And finally if the downstream device uses an EI characteristic or is a fuse, then all protection characteristics can be used for upstream devices, but normally EI or VI are preferred in such cases.

2. **Calculate the relay setting current and the time multiplier setting**

Once the IDMT characteristic equation has been selected, the relay setting current I_s and time multiplier setting *TMS* can be calculated.

The first step is to determine a point of the IDMT characteristic to guarantee correct grading with the downstream protection. For example considering OCR A in Figure 5.8, a point of the characteristic is determined to guarantee that the GTI between OCR A and OCR B for a three phase fault just downstream OCR B is greater than the MGM.

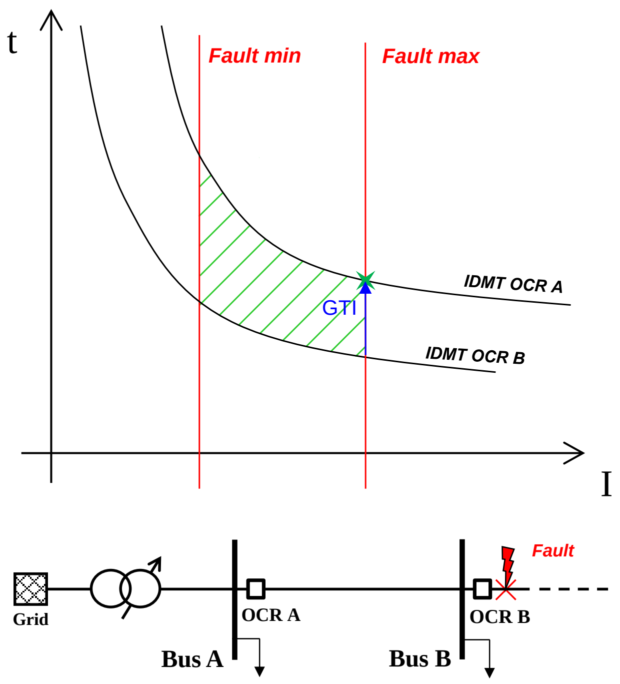

Figure 5.8 Example of application of the DUG technique

Once a point of the IDMT of OCR A characteristic is fixed, the protection settings I_s and *TMS* are calculated using an iterative approach restricting the *TMS* to within a range of values which normally depends on the protection relay technical characteristics, for example between 0.1 to 0.6 with steps of 0.01, and the relay setting current to comply with both of the constraints in equation 5.3 for phase fault protection settings and with the constraint in equation 5.4 for earth fault protection settings.

$$k_1 I_{load-MAX} \leq I_{s-phasefault} \leq k_2 I_{fault\_L-L-\min} \qquad (5.3)$$

$$I_{s-earthfault} \leq k_2 I_{fault\_L-G-\min} \qquad (5.4)$$

Where:

- $I_{load-MAX}$ is the maximum load current measured by OCR B;
- $I_{fault\_L-L-\min}$ and $I_{fault\_L-G-\min}$ are the minimum line to line and line to ground fault current measured by OCR B;
- $I_{s-phasefault}$ and $I_{s-earthfault}$ are the pick-up currents for phase and earth fault protection;
- k_1 is a constant to guarantee a margin between maximum load current and pick-up current, e.g. to guarantee a margin of 20% the constant should be 1.2.
- k_2 is a constant to guarantee a margin between the pick-up current and the minimum fault current, e.g. to guarantee a margin of twenty per cent the constant should be 0.8.

5.5.2.2 DTL protection settings

Definite time delay (DTL) phase fault protection settings are calculated using two steps:

1. **Relay setting current**

   The relay setting current I_s is calculated using a similar approach to that used in subsection 5.4.2.1 to comply with both of the constraints in equation 5.3 for phase fault protection settings and with the constraint in equation 5.4 for earth fault protection settings.

2. **Definite time delay**

   The definite time delay (DTL) is calculated to guarantee that the GTI between one OCR and the downstream OCR is greater than the MGM. For example if the

MGM is 160ms, and the downstream DTL is 160ms, then the DTL will be 320ms, and for the further upstream OCR it will be 480ms.

5.5.3 Protection system response evaluation

After the new protection settings have been calculated, the matrixes $\boldsymbol{F_e}$ and $\boldsymbol{F_p}$ are used to calculate the operating time of each protection device for each earth and phase fault using both the presently-applied protection settings and the new calculated protection settings. The results are then saved in the operating time matrixes $\boldsymbol{T}_{0e}$ and $\boldsymbol{T}_{0p}$ for the present protection settings and $\boldsymbol{T}_{1e}$ and $\boldsymbol{T}_{1p}$ for the new protection settings.

$$\boldsymbol{T}_{ie} = \begin{bmatrix} t_{11}^{ie} & \cdots & t_{1m}^{ie} \\ \vdots & \ddots & \vdots \\ t_{n1}^{ie} & \cdots & t_{nm}^{ie} \end{bmatrix} \tag{5.5}$$

$$\boldsymbol{T}_{ip} = \begin{bmatrix} t_{11}^{ip} & \cdots & t_{1m}^{ip} \\ \vdots & \ddots & \vdots \\ t_{n1}^{ip} & \cdots & t_{nm}^{ip} \end{bmatrix} \tag{5.6}$$

where:

- *i* is 0 (present settings) or 1 (new settings);
- *n* is the number of protection devices being considered; and
- *m* is the number of simulated faults.

To compare the protection system responses ($\boldsymbol{T}_{0e}$ and $\boldsymbol{T}_{0p}$) and ($\boldsymbol{T}_{1e}$ and $\boldsymbol{T}_{1p}$), a programme written in Python 2.7 has been developed. This programme analyses both matrices in order to:

1. Verify that the operation time of the OCRs is within the limits specified in the protection policy requirements, or otherwise quantify the number of faults where the operating time exceeds the limit requirement;
2. Verify that the grading margin between protection devices is always greater than the MGM, or otherwise quantify the number of faults where the grading margin is less than the MGM;
3. Calculate the mean operation time for each matrix considering all phase faults and all earth faults respectively.

Considering Figure 5.9, step 1 (as shown above) verifies that, for the fault shown in the figure, the operation time of OCR C is less than the limits specified in the protection requirements (e.g. a typical operation time limit is 2s in a standard utility protection policy).

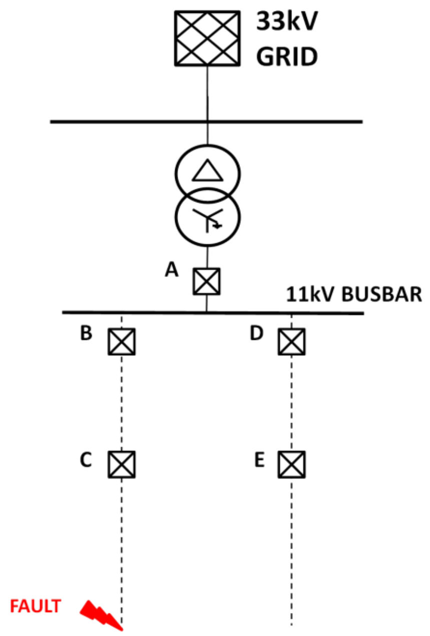

Figure 5.9 Verification of the overcurrent protection system time response

Step 2 in the matrix analysis process verifies that the difference of the operation time between C and the back-up protection B is greater than the MGM specified in the protection requirements (a typical grading margin is 250ms for IDMT characteristics and 160ms for DTL characteristics).

The first and second analysis steps have a higher priority with respect to the third step, therefore:

- If the results of the two first analysis steps are better for ($\boldsymbol{T}_{0e}$ and $\boldsymbol{T}_{0p}$) than for ($\boldsymbol{T}_{1e}$ and $\boldsymbol{T}_{1p}$), then the new protection settings are discarded and the third analysis step is not carried out as it is unnecessary.
- If the results of the two first analysis steps are better for ($\boldsymbol{T}_{1e}$ and $\boldsymbol{T}_{1p}$) than for ($\boldsymbol{T}_{0e}$ and $\boldsymbol{T}_{0p}$), then the new protection settings are applied without the third analysis step being executed.

In cases where both ($\boldsymbol{T}_{0e}$ and $\boldsymbol{T}_{0p}$) and ($\boldsymbol{T}_{1e}$ and $\boldsymbol{T}_{1p}$) results respect the maximum operating time verified in step one and the MGM verified in step two for all the faults, then a third step is necessary to verify if there is a variation in the mean operating time between using the present protection settings and the new protection settings.

The mean operation time for earth and phase faults, with present settings and new settings, are calculated using the following equations:

$$t_{0e-mean} = \frac{\sum_{i=1}^{i=n}\left(\sum_{j=1}^{j=m} t_{ij}^{0e}\right)}{nm} \tag{5.7}$$

$$t_{0p-mean} = \frac{\sum_{i=1}^{i=n}\left(\sum_{j=1}^{j=m} t_{ij}^{0p}\right)}{nm} \tag{5.8}$$

$$t_{1e-mean} = \frac{\sum_{i=1}^{i=n}\left(\sum_{j=1}^{j=m} t_{ij}^{1e}\right)}{nm} \tag{5.9}$$

$$t_{1p-mean} = \frac{\sum_{i=1}^{i=n}\left(\sum_{j=1}^{j=m} t_{ij}^{1p}\right)}{nm} \tag{5.10}$$

Following on from this, the weighted mean time $t_{0\text{-}mean}$ and $t_{1\text{-}mean}$ are calculated using the following equations:

$$t_{0-mean} = k_e\, t_{0e-mean} + k_p\, t_{0p-mean} \tag{5.11}$$

$$t_{1-mean} = k_e\, t_{1e-mean} + k_p\, t_{1p-mean} \qquad (5.11)$$

where:

- k_e is the weighting factor for earth faults, e.g. 0.8, since earth faults are more common than phase faults.
- k_p is the weighting factor for phase faults and it is equal to (1 - k_e), e.g. if k_e is 0.8, then k_p is 0.2.

Finally, both of the mean operation times are compared using equation 5.12. If the condition shown below in 5.12 is satisfied, then the new protection settings are applied.

$$t_{1mean} < t_{0mean} - \Delta t_m \tag{5.12}$$

Δt_m is a constant time margin, e.g. $\Delta t_m = 0.02s$; (this is the value used in this study) if the improvement in mean operation times is less than this, then the adaptive overcurrent protection does not change the protection settings.

5.5.4 Writing of new protection settings and verification

There are different possible approaches that can be used to apply new protection settings to the OCRs. The particular approach used is dependent on the communication capabilities of the OCRs.

Two main approaches are possible:

- using fixed protection setting groups;
- using variable protection setting groups.

The first approach, as stated above, uses fixed protection setting groups, i.e. four or more protection setting groups with fixed protection settings are defined to provide four or more levels of protection settings and the adaptive protection system selects the protection setting group that represents the closest match to the specific calculated protection settings. This approach might be more acceptable to DNOs to counter any fears relating to use of variable protection settings, but it would limit the advantages of using the adaptive overcurrent protection system.

The second approach is based on the use of variable protection setting groups, i.e. setting groups with variable protection settings are modified by the APC and selected to apply the calculated protection settings.

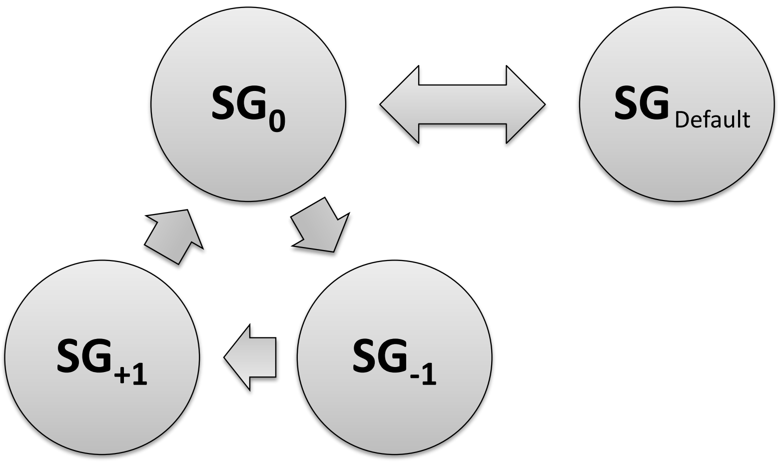

Figure 5.10 Protection setting groups with variable protection settings

Figure 5.10 shows three setting groups, SG_0 is the active setting group, SG_{-1} is the setting group with the protection settings used before the last protection settings adaptation and SG_{+1} is the setting group where the APC sends the new protection settings, then verifies that they have been received correctly and finally activates the setting group. After the new setting group is activated, it becomes SG_0 and the setting group that was SG_0 becomes SG_{-1}.

If the network returns to the previous configuration the APC uses SG -1 instead to write all the protection settings on to SG_{+1}. Then SG_{-1} becomes SG_0 and SG_0 becomes SG_{-1}.

If communication between the APC and the protection relay is lost, the protection relay automatically activate the $SG_{Default}$, and the APC assumes that the protection settings applied by that protection relays are the default protection settings.

The utilisation of a back-up protection setting group means that in case of communication failure between the APC and one or more protection relays, or the communication failure of the entire communication infrastructure, or failure of the APC, the overcurrent protection system operates as a traditional overcurrent protection system with fixed protection settings.

5.6 Laboratory implementation and demonstration

The developed adaptive protection solution has been implemented and demonstrated in an HIL laboratory environment, shown in Figure 5.11, in order to verify its effectiveness and compare its performance with a traditional overcurrent protection system.

The HIL laboratory environment has been designed to provide a simulation that very closely matches the actual hardware and software implementation discussed in subsection 5.3, and the new elements, i.e. execution and coordination layer hardware, have been chosen from commercially available hardware. OCRs from ABB and Alstom have been configured and implemented in the simulation and the adaptive overcurrent protection software has been installed on an ABB COM600 substation computer.

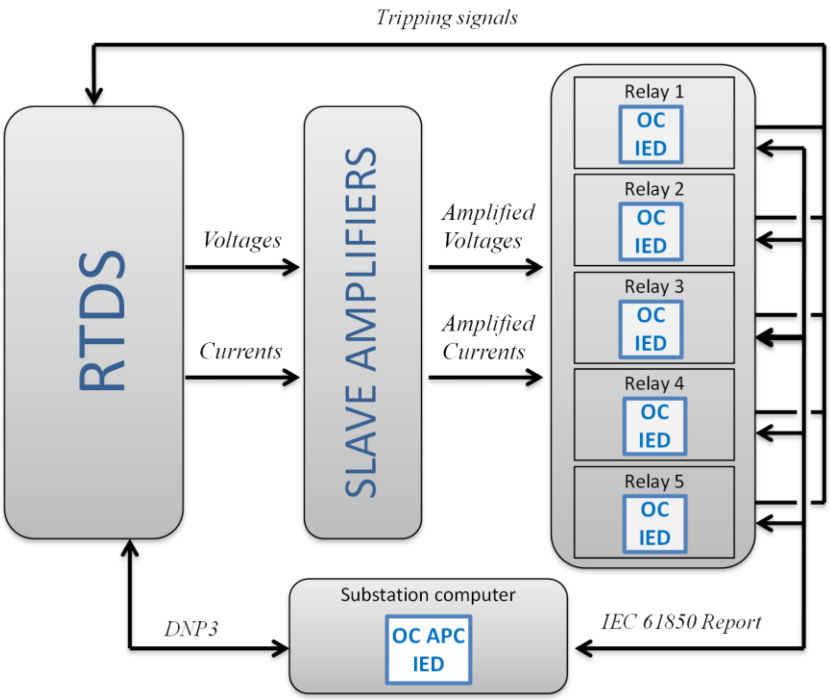

Figure 5.11 Laboratory implementation of the adaptive overcurrent protection system

The real time digital simulator (RTDS) is used to simulate the primary system behavior in real time during normal and faulty conditions. The output currents of the simulated CTs are amplified using slave amplifiers to inject the OCRs, which operate as if they were connected to a real distribution network. In the presence of a detected fault, the OCRs send tripping signals to the RTDS as an input to the simulation (with tripping of circuit breakers in the simulated primary system), effectively closing the simulation loop.

A DNP3 master installed in the substation computer is used to communicate with the RTDS to:

- gather periodically the status information of CBs, PMARs, network switches, etc., which is then used by the adaptive overcurrent protection software installed in the substation computer to monitor the network and detect changes to initiate the reactive adaptive overcurrent protection algorithm described in section 5.5;
- provide a communication link to the ANM simulated in the RTDS so that the ANM can send to the APC information about its own network actions and initiate the pro-active adaptive overcurrent protection algorithm when required.

In order to demonstrate the effectiveness of the developed adaptive overcurrent protection system a number of scenarios described in subsection 5.6.1 have been simulated, where the adaptability of the protection system is demonstrated, with a number of phase and earth faults, as described in subsection 5.6.2, being simulated to verify the protection system performance.

5.6.1 Network scenarios

The network scenarios, shown in Table 5.2, have been generated to input the following stimulus to the adaptive overcurrent protection system:

- Change of fault level: due to change of fault level at 33kV and number of in-service transformers at the 33/11kV distribution substation; normally both transformers are in operation, but in some cases one may be disconnected;
- Islanded operation of the 11kV network, which assumed to be permitted if the all four of the DG units are in service;
- 11kV distribution network topology, which can be varied by shifting the normally open points (NOP) as necessary, e.g. to restore supply to loads of a parallel feeder that has experienced an upstream permanent fault;

- Connection/disconnection of the DG units (all four are assumed to be either all in service, or all out of service).

Three different condition of fault level are simulated which are: 33kV level of 300MVA and 2 transformers in service, 33kV level of 100MVA and one transformer in service, and not connected (NC) to the mains.

Table 5.2 lists the sixteen simulated scenarios summarising the fault level, the number of substation transformers in service, the network topology and the connection or disconnection of the DG.

Table 5.2 Network scenarios for HIL simulation

Sce-nario No.	33kV fault level (MVA)	Substation transformers in service	Normal Open Points	DG units in service
1	300	2	S3, S6	No
2	300	2	S1, S6	No
3	300	2	S4, S6	No
4	300	2	S5, S7	No
5	300	2	S3, S6	Yes
6	300	2	S1, S6	Yes
7	300	2	S4, S6	Yes
8	300	2	S5, S7	Yes
9	100	1	S3, S6	Yes
10	100	1	S1, S6	Yes
11	100	1	S4, S6	Yes
12	100	1	S5, S7	Yes
13	NC	NC	S3, S6	Yes
14	NC	NC	S1, S6	Yes
15	NC	NC	S4, S6	Yes
16	NC	NC	S5, S7	Yes

Scenarios 1-4 are representative of four different network configurations. When the NOPs are SW3 and SW6, the network configuration is normal as shown in Fig. 1.

The other three network configuration are when feeder B is extended to supply part of feeder A (NOPs SW1 and SW6), and when it is extend to supply part of feeder C (NOPs SW5and SW7).

Scenarios 5-8 are similar to scenarios 1-4, but with the connection of all DG units. Scenarios 9-12 represent situations where the fault level is reduced to 100MVA and only one transformer is in service. Finally, scenarios 13-16 represent islanded operation with all DG units in service.

5.6.2 Fault simulations

In order to verify the protection system response of the developed adaptive overcurrent protection system, a series of faults have been simulated for each network scenario, at nine different locations, as shown in Figure 5.12.

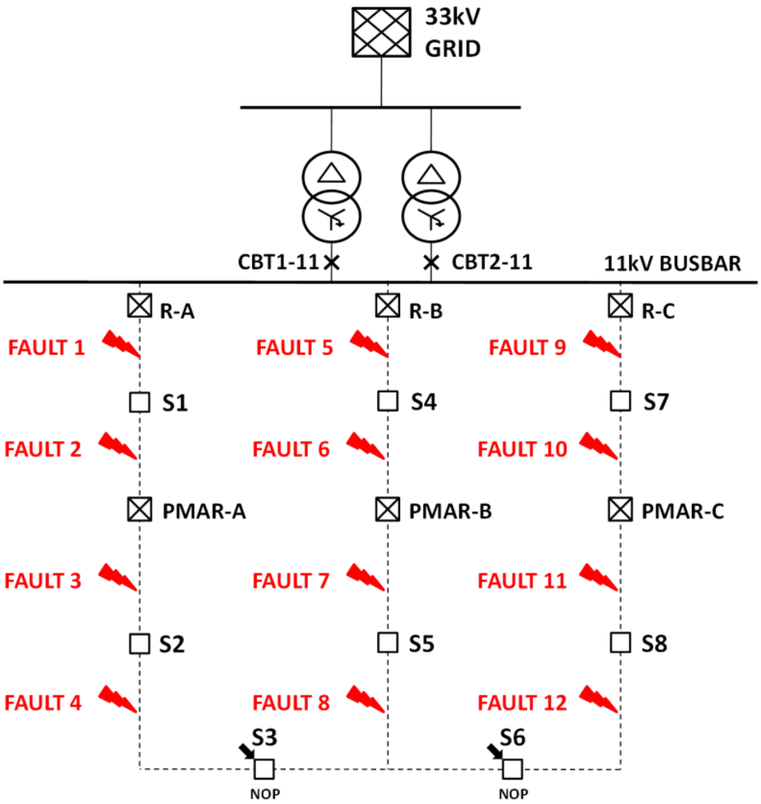

Figure 5.12 Fault locations for HIL simulation

The faults simulated at each location include phase to phase faults with a fault resistance between 0Ω and 10Ω, and phase to earth faults with a fault resistance between 0Ω and 100Ω.

5.7 Simulation results

The sixteen network scenarios described in subsection 5.5.1 have been simulated and the protection settings automatically calculated by the adaptive overcurrent protection software have been recorded and are reported in appendix D.

The adaptive overcurrent protection system response to the faults described in subsection 5.5.2 has been compared to the response of the overcurrent protection system with traditional fixed protection settings (from appendix B). The results of this comparison show that the adaptive overcurrent protection system reduces the protection operating time, improves the protection sensitivity, reduces false tripping problems and improves protection selectivity.

The following sections present some simulation results to demonstrate the advantages of adopting the developed adaptive overcurrent protection system (compared to a traditional overcurrent protection system) when there are variations in the network topology, when DG is connected to the network and when islanded operation is permitted. More comprehensive simulation results are presented in chapter 7.

5.7.1 Network topology changes

Considering scenario 1 and 3 in Table 5.2, when the network switches from one scenario to the other, the adaptive overcurrent protection system calculates the protection settings for the new scenario and applies them to the OCRs. Table 5.3 and Table 5.4 report the automatically calculated protection settings of ARs and PMARs for both scenarios.

The difference between scenario 1 and scenario 2 is the change of network configuration, i.e. the fact that the NOP is shifted from SW3 to SW4. The change of network topology affects both fault current magnitude and the route of fault current flow in case of faults on feeders A and B. The new protection settings are therefore different for OCRs AR-A, PMAR-A, AR-B and PMAR-B, as can be seen by comparing Table 5.3 and Table 5.4.

Without the developed adaptive protection system, i.e. using fixed protection settings, the overcurrent protection operation speed and selectivity would be adversely affected, as described in the proceeding text.

Table 5.3 Phase and earth fault protection settings for scenario 1

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	400	0.16	1000	0.32	30	0.32
OCR-PMAR-A	SI	250	0.1	625	0.16	30	0.16
OCR-AR-B	SI	350	0.2	875	0.32	30	0.32
OCR-PMAR-B	SI	220	0.1	550	0.16	30	0.16
OCR-AR-C	SI	300	0.28	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table 5.4 Phase and earth fault protection settings for scenario 3

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	400	0.17	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.12	625	0.32	30	0.32
OCR-AR-B	SI	250	0.1	625	0.16	30	0.16
OCR-PMAR-B	SI	160	0.1	400	0.16	30	0.16
OCR-AR-C	SI	300	0.28	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

For example a 0Ω phase to phase fault between PMAR-B and S4, fault 4 in Figure 5.12, causes simultaneous tripping of PMAR-A and PMAR-B. The simulation of the fault is shown in Figure 5.13, which starting from the top shows the current measured by AR-A, PMAR-A and PMAR-B which is different in the pre-fault condition and almost the same during the fault. At the foot of the figure there are the position of AR-A, PMAR-A and PMAR-B, and the tripping signals from the OCRs, which are wrongly simultaneous causing the unnecessary disconnection of load and DG connected between PMAR-A and PMAR-B.

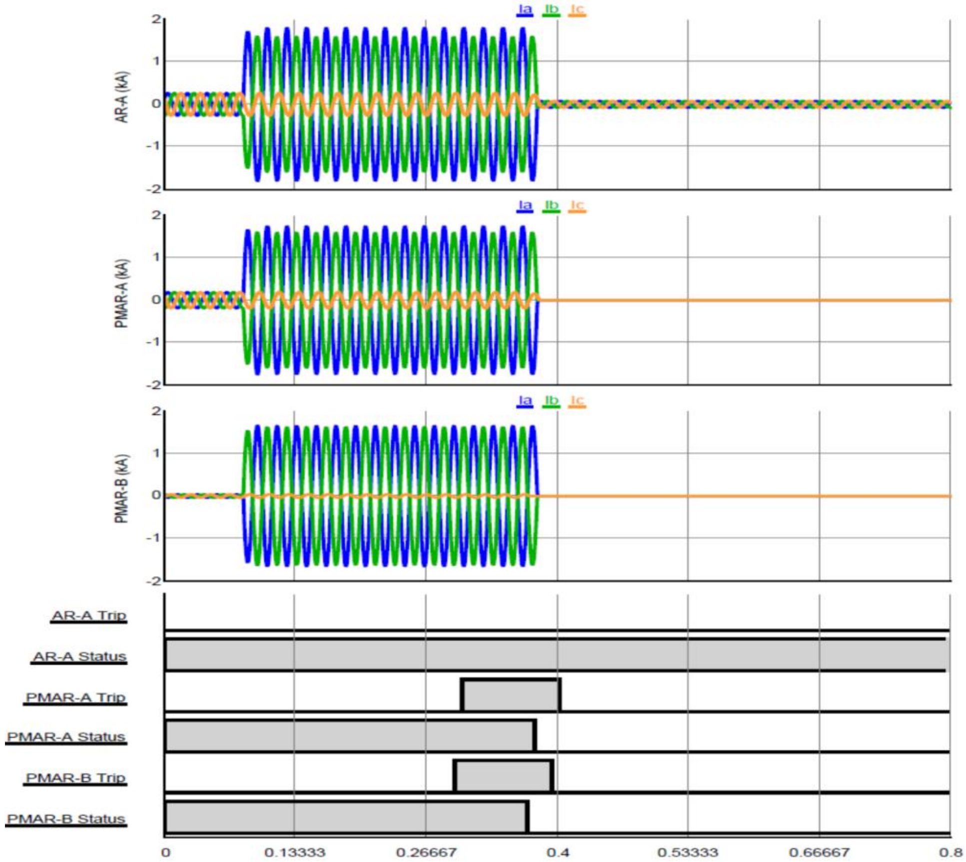

Figure 5.13 Fault 4 in scenario 3 without adaptive over-current protection

With the developed adaptive overcurrent protection system, the protection settings reported in are applied to the OCRs, thereby solving the problem of loss of coordination between PMAR-A and PMAR-B. Figure 5.14 shows, starting from the top, the current measured by AR-A, PMAR-A and PMAR-B which are identical to Figure 5.13 during the pre-fault and fault condition, but are different after the fault is cleared, because PMAR-A is not tripped and therefore continues to supply the loads between feeder A and B. At the foot of the figure there are the position of AR-A, PMAR-A and PMAR-B, and the tripping signals from the OCRs, which shows the correct operation of the protection system respect to Figure 5.13 in which both PMAR-A and PMAR-B were tripped.

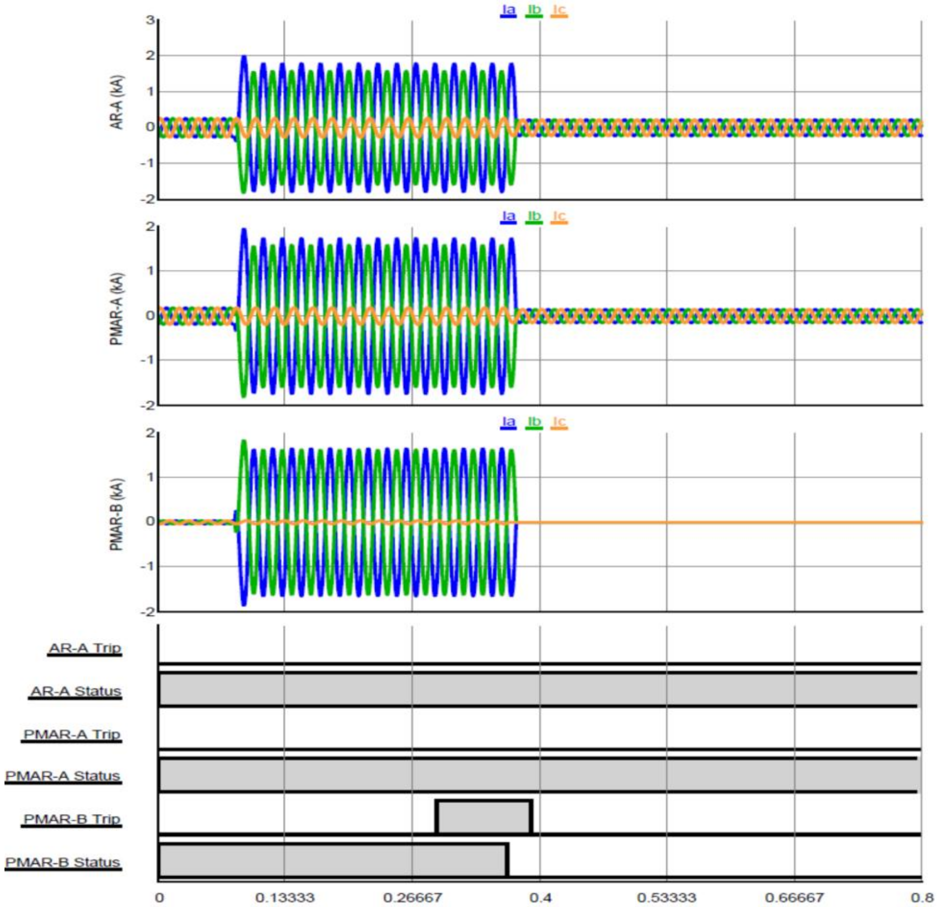

Figure 5.14 Fault 4 in scenario 2 with adaptive over-current protection

5.7.2 Connection of DG units

The connection of DG units usually increases the network fault level, changes the magnitude and sometimes the paths of fault currents and therefore may cause false tripping and adversely affect the coordination between OCRs.

An example of false tripping of a traditional overcurrent protection system with DTL protection characteristics (see appendix B) is in scenario 6 of Table 5.2, when there is a fault on feeder A (fault 1). As shown in Figure 5.15, PMAR-B trips before AR-A due to the fault current contribution of DG2 and DG3, which means that PMAR-B and AR-A are not correctly coordinated in the presence of DG.

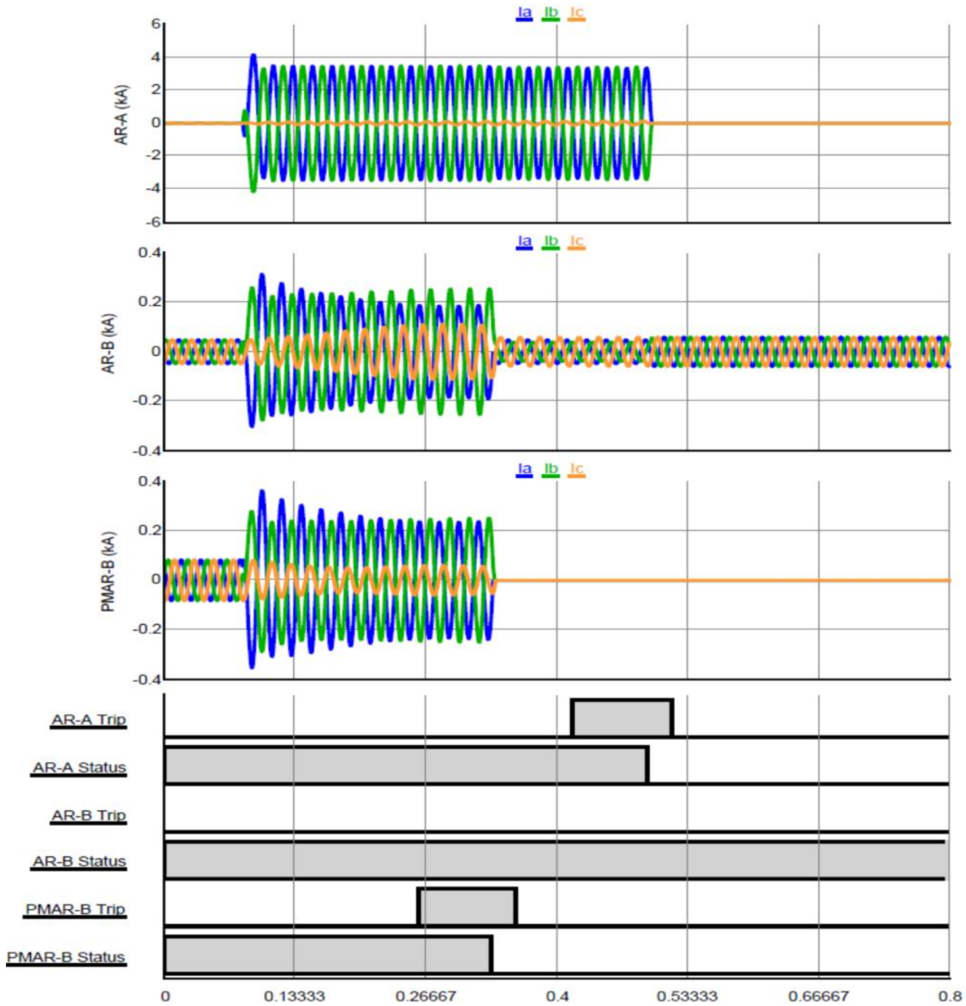

Figure 5.15 Fault 1 in scenario 6 without adaptive overcurrent protection system

To overcome this issue, the literature suggests the use of directional overcurrent protection, which does solve the problem but requires additional measurements and possibly new relays (and may not solve all of the potential protection problems introduced by future active networks). The developed adaptive overcurrent protection system does not require directional protection relays, but uses instead a combination of IDMT and DTL overcurrent protection, where the DTL pickup current is always higher than the fault current contribution of the DG connected to a feeder and therefore this approach overcomes the false tripping problem without the requirement for directional overcurrent protection.

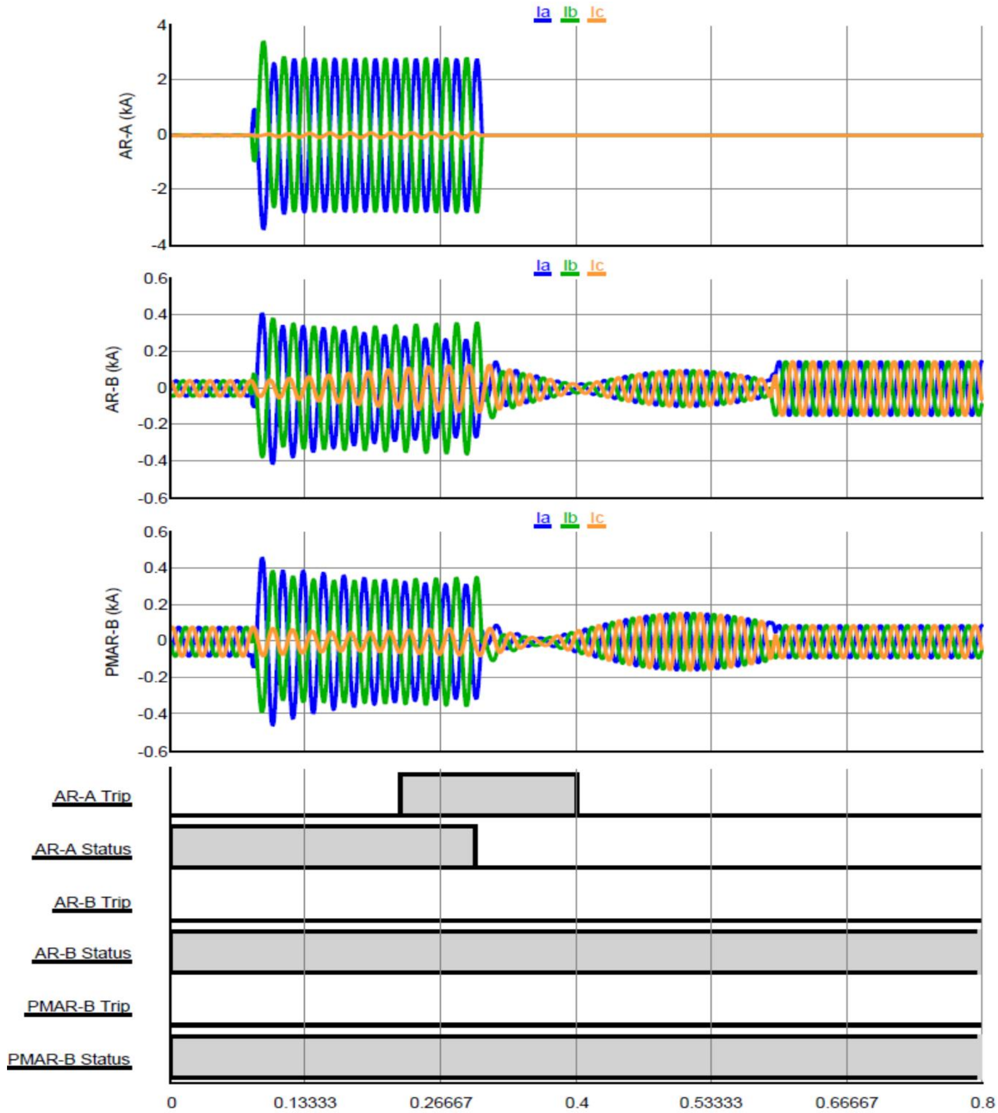

Figure 5.16 Fault 1 in scenario 6 with adaptive overcurrent protection system

Comparing the fixed protection settings of PMAR-B in appendix B and the protection settings in Table 5.5, the DTL pickup current is increased from 150A to 650A, and an additional IDMT protection is added with pick up current of 260A and

TMS of 0.10. The DTL protection characteristic of PMAR-B provides fast tripping for faults on feeders B that involve high fault current and does not results in false tripping during faults in adjacent feeders, while the IDMT protection characteristic with a pick up current of 160A guarantees good sensitivity to resistive faults.

Table 5.5 Phase and earth fault protection settings for scenario 6

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	200	0.1	500	0.16	30	0.16
OCR-PMAR-A	SI	150	0.1	375	0.16	30	0.16
OCR-AR-B	SI	350	0.23	875	0.48	30	0.48
OCR-PMAR-B	SI	260	0.1	650	0.32	30	0.32
OCR-AR-C	SI	300	0.29	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

5.7.3 Islanded operation

This example considers the case where the network changes from grid connected to islanded operation, and as a consequence of this, the fault level changes significantly. For example, from scenario 1 to scenario 9 of Table 5.2, the fault level at the 11kV bus bar decreases from 130MVA to 32MVA.

The reduction of the fault level affects both the speed and sensitivity of the overcurrent protection, and slower operation of the overcurrent protection may lead to disconnection of the DG supplying the network.

For example, simulating a fault downstream PMAR-B (fault 6 in scenario 10) results in the overcurrent operation of the traditional overcurrent system being too slow as shown in Figure 5.17. The figure shows starting from the top, the voltage at the substation busbar, the current measured by PMAR-B, the position of the DG units' CBs which are tripped by the DG units' protection, described in Appendix C, before the operation of PMAR-B, which are the last signal at the foot of the figure.

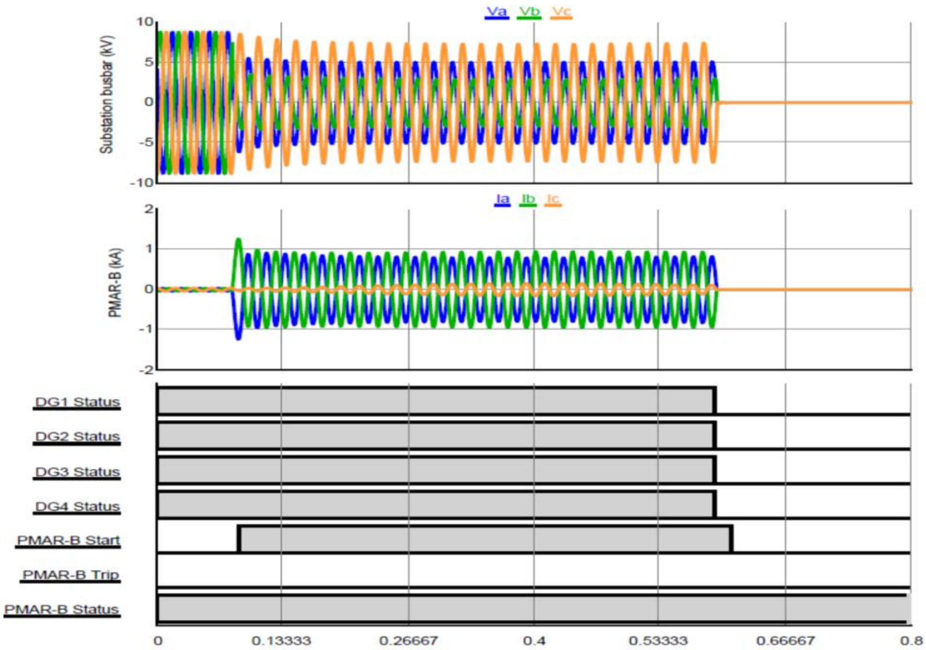

Figure 5.17 Fault 6 in scenario 10 without adaptive over-current protection

Simulating the same fault, but with the developed adaptive overcurrent protection system (which changes the protection settings to the settings reported in Table 5.6 as soon as the network changes configuration), the overcurrent protection operation is faster than the DG interface protection, as shown in Figure 5.18.

Table 5.6 Phase and earth fault protection settings for scenario 9

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	940	0.1	-	-	-	-
OCR-T2	SI	940	0.1	-	-	-	-
OCR-AR-A	SI	400	0.12	1000	0.32	30	0.32
OCR-PMAR-A	SI	250	0.1	625	0.16	30	0.16
OCR-AR-B	SI	350	0.17	875	0.32	30	0.32
OCR-PMAR-B	SI	220	0.1	550	0.16	30	0.16
OCR-AR-C	SI	300	0.21	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

As the overcurrent protection operates faster with the adaptive solution, the voltage sag on the network due to the fault has a shorter duration as shown in Figure 5.18 and DG1, DG2 and DG4 are not unnecessarily disconnected, but continue to supply the loads in islanded mode, as shown in Figure 5.18.

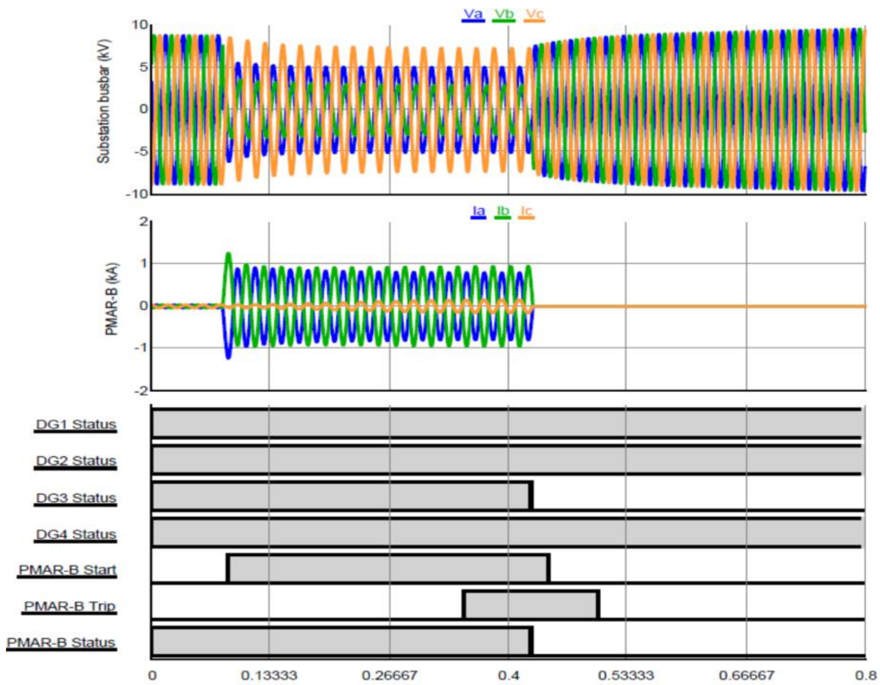

Figure 5.18 Fault 6 in scenario 10 with adaptive over-current protection

5.8 Chapter summary

This chapter has presented an adaptive overcurrent protection system, describing in detail its architecture and the algorithm employed, and has demonstrated the advantages of this solution over a traditional overcurrent protection system.

The novelty of the developed adaptive overcurrent protection system is in its algorithm, which differs from other adaptive protection solutions presented in the literature in terms of its possession of higher flexibility, comprehensive coverage of all events that may influence the protection system and reactive/proactive design.

It is more flexible with respect to other solutions presented in the literature, which are largely based on pre-calculated protection settings and settings groups. The limitations of using setting groups with pre-calculated settings is overcome by calculating the optimum protection settings in real time and then applying them to the OCRs, after verification of their effectiveness using model-based evaluation of performance.

It is more comprehensive with respect to other solutions presented in the literature because it does not consider only the impact of DG connection, which seems to be the only problem addressed by other authors, but it considers also other factors that have an impact that is as important as DG and in some cases even more (e.g. variations in fault level due to grid infeed changes, modifications in network topology due to the actions of ANM).

It is reactive and proactive to changes in the networks while other solutions presented in the literature are designed to be only reactive, which means that the adaptive protection system can also react to changes before they become an issue, for instance when planned disconnection of lines for maintenance.

Examples of the impact of ANM, DG and islanded operation have been used in the laboratory simulations to demonstrate how the adaptive protection system operates and how it can improve the performance of the protection system over traditional systems. The results of a more detailed testing of the presented adaptive protection system are presented in chapter 7, where the results of a detailed testing of the adaptive LOM protection system (presented in chapter 6) are also reported.

5.9 References

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Chapter 6:

Adaptive inter-tripping scheme with back-up passive LOM protection

6.1 Chapter overview

DG penetration is increasing rapidly and it is expected that, in future, a significant proportion of all power consumed will be generated by DG units located relatively close to consumers [6.1, 6.2]. Consequently, several protection issues must be considered, as presented in chapter 3, and one of the main concerns is providing loss of mains (LOM) protection that is both sensitive and stable [6.3]. Current practice is that utilities require DG units to be disconnected from the network as soon as possible in the case of islanding. In the UK, the regulation that governs the connection of such generation, G59/2 [6.4], stipulates that a passive LOM protection relay be fitted to all DG units, and for units with a rating capacity equal to or larger than 5MW, the recommended LOM protection is by means of inter-tripping.

This chapter presents an adaptive inter-tripping scheme protection system that revolutionises the current approaches to LOM, offering significant improvements in terms of sensitivity, stability and flexibility. The adaptive inter-tripping scheme improves the sensitivity of the LOM protection system, overcoming the problem of the non-detection zone (NDZ) associated with all passive LOM protection relays. It also provides flexibility to adapt to any network configuration. The back-up protection is based on passive LOM protection relays with protection settings that are amended online to avoid unnecessary tripping, improving the stability of the LOM protection system. Furthermore, the adaptive LOM protection system allow islanded operation of a section of distribution network, with LOM protection also being provided within the power island using LOM protection relays (with amended protection settings) and by inter-tripping which is adapted to the specific islanded scenario.

The requirement for improved LOM protection will increase in future. The author’s research group is presently working with UK TSOs to investigate system performance during transients and concerns are being expressed over reductions in the levels of system inertia (e.g. due to replacement of thermal plant with wind) leading to higher levels of ROCOF being experienced during non-LOM system transients. ROCOF levels of greater than 1Hz/s are expected in the near future, levels that are much greater than prevailing ROCOF maxima in the UK, and which greatly increase the requirement for stable LOM protection.

The chapter firstly defines the architecture of the proposed solution and explains how it can be implemented in hardware and software, offering guidelines relating to the transition from prevailing approaches to LOM protection to the developed adaptive LOM protection system.

Secondly, it explains the algorithm and provides a detailed description of its operation, itillustrating how the adaptive inter-tripping scheme and the passive LOM protection relays are coordinated and also how communication errors and communication failures are managed.

Finally, it illustrates how the adaptive LOM protection system has been implemented in the laboratory and presents a selection of simulation results to demonstrate how it can improve the sensitivity, stability, and speed of operation of the LOM protection function.

6.2 Methodology

Following up the investigation and demonstration of the problems that traditional LOM protection system will face in future active power distribution networks, an adaptive inter-tripping scheme with passive back-up LOM protection has been developed to improve speed, sensitivity and stability.

The adaptive inter-tripping scheme system has been developed considering commercially available IEC61850-8-1 compliant protection hardware to provide a protection solution that could be implemented using IEC61850-8-1 GOOSE in a trial test in the near future. Furthermore, the passive LOM protection relays presently installed in the UK have been used to implement back-up protection.

Section 6.3 presents the architecture of the developed adaptive overcurrent protection system and section 5.4 gives guidelines on the migration from present LOM protection systems to the developed solution.

The adaptive protection scheme has been implemented in commercially available hardware and demonstrated in a HIL simulation environment explained in section 5.6, to prove the advantages respect to traditional LOM protection schemes.

Finally, the protection solution has been tested through hundreds of true and false LOM events to quantify the improvement in performance. The testing has been reported in chapter 7 together with the testing of the adaptive overcurrent protection system presented in chapter 5.

6.3 LOM protection architecture

The developed adaptive LOM protection system architecture is divided into discrete functional layers, similar to the adaptive overcurrent protection architecture presented in chapter 5. Figure 6.1 illustrates the functional blocks of the adaptive LOM protection system divided into execution, coordination and management functional layers.

The first element at the foot of the diagram consists of the primary system, which includes lines, transformers, DG, CBs, CSs, CTs. VTs, etc. Above, there is the execution layer, which includes all IEDs installed in the network. This includes the AIT IED, which hosts the adaptive inter-tripping algorithm, which is explained in detail in section 6.5.1.

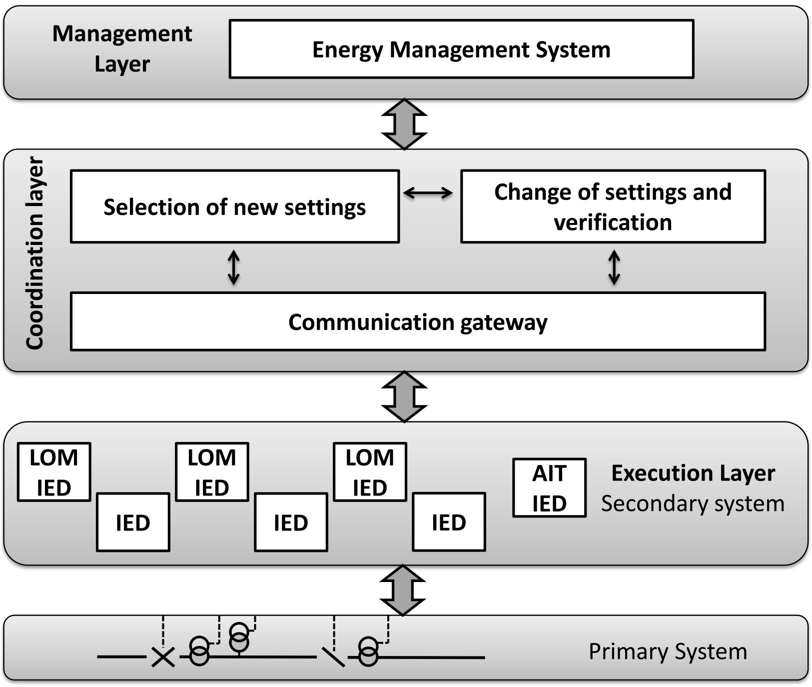


Figure 6.1 Adaptive LOM protection system architecture

Above the execution layer is the coordination layer, which is responsible for amending the settings of the LOM IEDs; this communicates “vertically” with the execution and management layers; in this case IEC61850 and DNP3 communications protocols have been adopted.

The management layer is the uppermost layer within the architecture, and is responsible for monitoring and managing the network. This includes identification of changes in network topology, connection/disconnection of DG, transitions between grid-connected and islanded operation mode, and making this information available via a user interface.

6.3.1 The execution layer

With respect to the developed LOM protection system, the execution layer is composed of protection, control and automation IEDs, passive LOM protection relays (IEDs), and the adaptive inter-tripping (AIT) IED.

The AIT IED communicates horizontally with other IEDs using IEC 61850 GOOSE messaging to monitor the network and to send tripping command to the LOM IEDs in case of LOM when islanded operation is not allowed or not possible. The AIT IED provides the main LOM protection, with faster operation and better selectivity compared with the passive LOM protection relays.

The passive LOM IEDs provide back-up LOM protection to the AIT IED. The protection settings of the LOM IEDs are not fixed as in traditional LOM protection systems; they are instead adapted in real time by the LOM adaptive protection controller (APC). The algorithm of the LOM APC is explained in detail in section 6.5.3.

6.3.2 The coordination layer

The coordination layer contains the functional blocks of the LOM APC. There are three functional blocks and they are responsible for: communication with LOM IEDs and the AIT IED in the execution layer; selection of the protection system settings as the distribution network changes between grid connected and islanded operation; change and verification of protection settings; and blocking operation of the ROCOF function during remote disturbances on the network, which usually results in fluctuations of voltage and frequency that could lead to maloperation of ROCOF.

The three functional blocks are:

- **Gateway**
  This is a network node equipped to interface with IEDs that use different protocols, such as: DNP3[6.5], Modbus[6.6], IEC60870-5-103[6.7] and IEC61850[6.8]. Accordingly, it contains protocol translators to provide system interoperability and uses OLE process control (OPC)[6.9] for communication with other blocks within the coordination layer and with the management layer.
- **Selection of the new settings**
  This functional block communicates vertically with the management layer and with the AIT IED and selects the protection settings for the passive LOM protection relays from a look up table according to whether the section of distribution network is operating in grid-connected or islanded mode, whether the AIT protection scheme is active or not, and whether the network is stable or is experiencing severe disturbances resulting in voltage and frequency fluctuations. Section 6.5.3 explains in detail how the protection settings are selected.
- **Change of settings and verifications**
  This functional block sends new settings to the LOM IEDs through the gateway and then verifies that the settings have been received and applied by the IEDs.

6.3.3 The management layer

Within the developed architecture, shown in Figure 6.1, it is assumed that the management layer monitors the distribution network and makes decisions relating to the operation of the network, e.g. changes of network configuration to address power flow or voltage constraints [6.10, 6.11], or to allow a section of the network to switch from grid-connected to islanded operation mode.

The decision to allow islanded operation can be taken before or after an actual LOM event is experienced. If the decision is made before the LOM condition, it allows automatic switching to islanded operation of a section of the network without power supply to the loads being interrupted. If the decision is made after the LOM condition, the protection system will disconnect all DG units and then the supply will be restored, possibly requiring some form of "black-start" regime if the island is relatively large with multiple DG units.

6.4 Hardware and software implementation

The developed adaptive LOM protection system is composed of the AIT IED, which is one of the IEDs of the execution layer as explained in section 6.3.1, and the LOM APC IED which hosts the functional blocks of the coordination layer presented in section 6.3.2.

Figure 6.2 shows the test case distribution network, with an indication of the hardware (in blue) that should be installed in the network for the implementation of the developed adaptive LOM protection system.

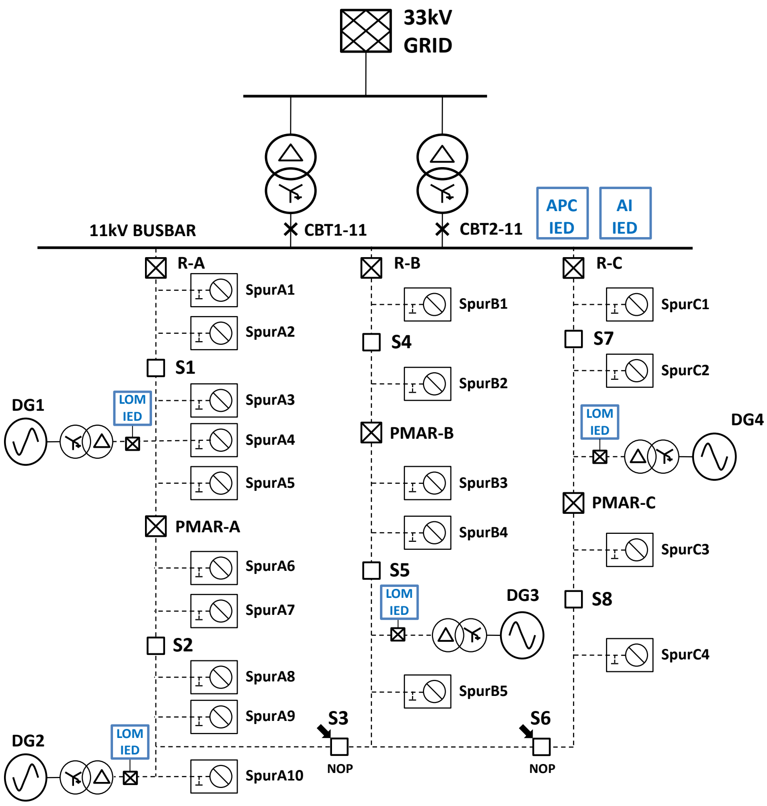


Figure 6.2 Implementation of the adaptive LOM protection system

Considering the test case distribution network, the parameters of which are described in appendix A, the traditional LOM protection system is composed of passive LOM relays with fixed settings. In addition, some DG units might be protected against LOM by hard wired inter-tripping schemes, employing point to point communication links between the DG location and the circuit breaker(s) that, when opened, may cause LOM. Furthermore, a communication infrastructure is available to monitor the network through a SCADA system and to allow remote control of switchgear.

To move from a traditional LOM protection system to the developed adaptive LOM system, it is necessary to change some of the protection devices and improve the communication infrastructure to satisfy the following points:

- All LOM protection relays must be numerical, with communication capabilities to enable IEC 61850 GOOSE messaging and remote reading and amendment of protection settings;
- The communication network must be extended to the LOM relays protecting the main DG units connected to distribution network;
- A new device termed the APC IED must be introduced to host the new functional blocks of the coordination layer.
- A new device AIT IED has to be introduced to host the AIT protection algorithm.

In distribution networks with low DG penetration, it is understandable that these changes are not likely to happen in the near future because of their associated cost. However, in distribution networks with an existing high level of DG penetration, or where there are plans to significantly increase the DG penetration, it is more likely that utilities (or the generation owners) will be required to invest in new IEDs and communications facilities to facilitate the increased penetration levels and to allow the adoption of novel protection, control and automation solutions, which will be required to ensure safe and stable operation of such networks of the future. Furthermore, as previously mentioned, concerns are being expressed over reductions in the levels of system inertia (e.g. due to replacement of thermal plant with wind) leading to higher levels of ROCOF being experienced during non-LOM system transients.

6.4.1 Communications network

The communication infrastructure is an essential element to enable the adoption of the developed adaptive LOM protection system. At present, various types of communication links are used for protection, control and automation signalling, and these can be used to provide the necessary communication infrastructure. Of course, this means developments of the present communication infrastructure to extend to all DG units (above a certain capacity) connected to the distribution network.

The main types of communication media used today are:

- Private pilot wires installed by the DNOs;
- Optical fibres;
- Carrier channels at high frequencies communicating directly over the distribution network lines;
- Radio channels at very high or ultra-high frequencies; and
- Communication link rented from a telecommunication company.

Private pilot wires or communication channels are attractive to DNOs with a very dense distribution network characterised by short distances between IEDs, as for example in the case of urban distribution networks.

Optical fibre communications are the preferred media for communications links, as copper conductors are particularly susceptible to interference from power system faults. Optical fibres can be laid with the conductors themselves by producing composite cables comprising optical fibres embedded within the cable. Therefore in new distribution network or where the lines are being replaced, DNOs might simultaneously invest in communication, aiming to "future proof" distribution networks. There is also growing interest in using non-utility owned independent communications networks and Internet Protocol IP and Multi-Protocol Label Switching (MPLS) for communications functions within utilities [6.12, 6.13].

Power Line Carrier Communications (PLCC) is a robust technique more typically adopted in transmission networks; however it might be a possible option for lower voltages [6.14]. Radio communications is more common in distribution networks, especially in rural areas, for example to allow remote control of network switches [6.15].

Finally, another very attractive option to provide communications with IEDs is to rent facilities from a communications company. This can be a cable, fibre optic, wireless or satellite communication link. Whether or not a particular communication link is used depends on many factors such as its availability in a particular geographic area, the distance between IEDs, the terrain over which the power network is constructed, its reliability, and, of course, its cost.

6.5 Adaptive LOM protection algorithms

Sections 6.5.1 and 6.5.3 provide detailed descriptions of algorithms of each of the two protection schemes. Section 6.5.2 discusses how they can be readily extended to protect new DG installations, and finally, section 6.5.4 explains how communication errors are managed.

6.5.1 AIT algorithm

The developed adaptive inter-tripping scheme does not use any predetermined association of the DG circuit breakers with one (or more) utility network circuit breakers like traditional inter-tripping schemes, but utilises the algorithm shown in Figure 6.3.

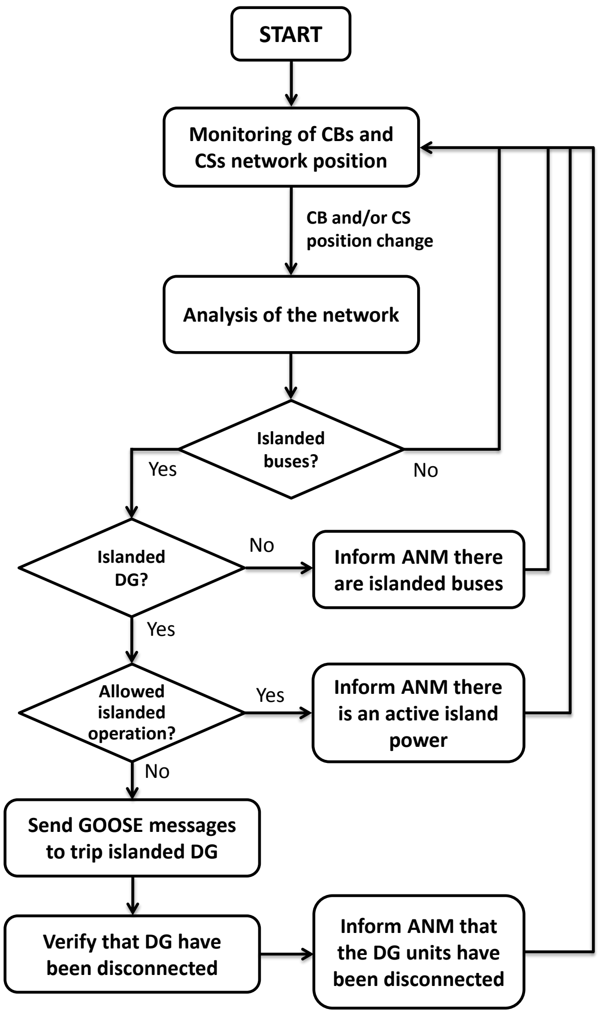
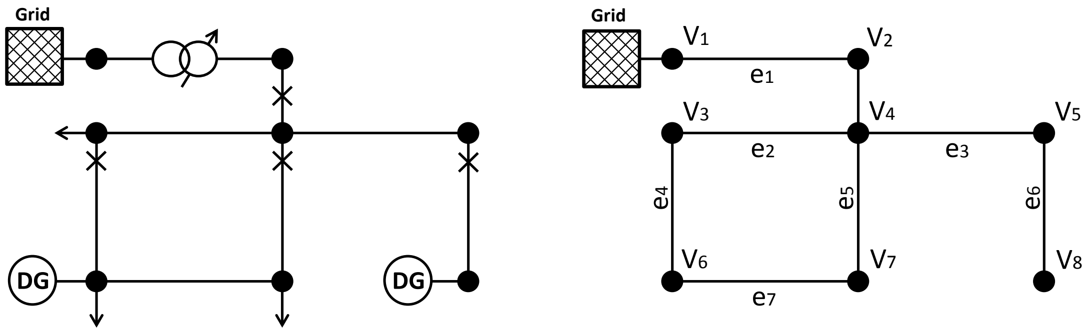


Figure 6.3 Adaptive inter-tripping algorithm

The IEDs that control the CBs and CSs of the network are configured to communicate the position of their associated switches to the AIT IED through IEC-61850 GOOSE messaging. The AIT IED subscribes these GOOSE messages to monitor the position of CBs and CSs. When one or more CBs or CSs change position, the AIT IED detects the network topology change and analyses the network.

Graph theory is used to analyse the network and verify if there are islanded buses. Considering the electrical network shown in Figure 6.4 (a), graph theory is applied to represent the network creating a vertex for each network node and an edge for each network line, as shown in Figure 6.4 (b).



(a) (b)

Figure 6.4 Example of graph theory application

The network topology data, graphically represented in Figure 6.4 (b), can be mathematically presented as a vertex set and an edge set:

- Vertex set V = ; and$V = \{V_1, V_2, V_3, V_4, V_5, V_6, V_7, V_8\}$
- Edge set $E = \{e_1, e_2, e_3, e_4, e_5, e_6, e_7, e_8\}$

When the AIT algorithm detects that one or more CBs or CSs have changed position, it updates the edge set E = by deleting the edge if the CB or CS opening has interrupted the continuity of the edge or by re-adding a edge if the closing of a CB or CS has re-establish the edge.

The updated edge set E is then used to verify if all the vertices are connected to the grid. If one or more vertices results not connected it means that the correspondent buses are islanded.

In cases where there are islanded buses, the AIT IED ascertains if there are DG units connected to those islanded buses that may form a power island. If it is determined that an island, or islands, exist and islanded operation is not permitted, the AIT IED publishes IEC-61850 GOOSE messages to disconnect the DG units, while if islanded operation is permitted it informs the ANM of the existence of an active power island. When islanded operation is permitted, the AIT IED does not disconnect the DG units, however under-over voltage and frequency protection functions remain active to protect the network from fluctuations of voltage and frequency outside of statutory limits.

In an ideal scenario, all DG units connected to a distribution network should have a communication links to the AIT IED. However, this might not be realistic because smaller DG units might not be connected to the communication network or a DG unit which is connected to the communication network might suffer a temporary loss of communication with the AIT IED.

The DG units that are not connected to the AIT IED are protected from LOM by the passive LOM protection relays, which are configured to change active setting group to increase their sensitivity to voltage and frequency fluctuation when communication is lost. The protection settings of the different setting groups should be decided though analysis of multiple simulations of the distribution network. The protection settings applied to the LOM relays of the test case distribution network used in this research work are presented in section 6.5.3.

For those DG units that are connected to the AIT IED, the main LOM protection is the inter-tripping scheme and it is important that the protection settings of the back-up LOM protection system are amended to avoid false tripping during transients in the network and while switching to islanded operation. The APC IED is responsible for amendment of LOM protection settings, its algorithm is presented in section 6.5.3.

6.5.2 Flexibility and extensibility of the AIT scheme

One of the advantages of the developed AIT system is the substitution of all dedicated and individual inter-tripping schemes with one flexible and more easily managed system.

When traditional inter-tripping protection is adopted and a new DG unit is connected to the network, then a new hard wired inter-tripping scheme must be designed and installed in order to extend the protection to the new unit, or one of the inter-tripping schemes used to protect a neighbouring generator must be modified and extended. In both cases, there is a significant cost for extending the protection to the new generator. Moreover, with the increase of DG penetration, there would be an increasing number of inter-tripping schemes in a single section of network, increasing complexity with the potential consequence for incorrect configuration and/or unpredictable behaviour of the protection system.

In networks where islanded operation may be permitted in the future, the presence of several stand-alone inter-tripping schemes may act as an economic barrier, due to the fact that they may become redundant and/or require to be replaced and/or augmented with some other form of control and protection system.

The developed AIT scheme is more flexible compared to direct dedicated inter-tripping schemes because it can protect all generators against LOM for all possible LOM scenarios. It can also allow islanded operation of a sub-network if this is permitted and the DG in the network is/are capable of maintaining voltage and frequency within acceptable limits.

Extending the adaptive inter-tripping system to cater for additional generators is a simple process. There are two main steps within this process: firstly, the new IEDs must be connected to the communication network; secondly, the adaptive inter-tripping data file system is updated to include the new IED. This completes the process and the adaptive inter-tripping software does not require to be fundamentally changed; it inherently monitors and protects the updated network and any new generator(s).

The cost of extending the adaptive inter-tripping scheme system to cater for network extensions and new generators is mainly associated with the connection to the communication network. This communications cost may be shared with other protection, control and automation schemes, as it is not necessary for this scheme to employ a dedicated communication channel, which may be the case for a traditional inter-tripping scheme.

6.5.3 APC Algorithm

Presently, passive LOM protection relays are used to protect DG against LOM as primary protection, or as secondary protection in the case of primary inter-tripping schemes.

The main advantage of using passive LOM protection relays is that their operation is based solely on local measurements and their operation does not rely on communications. However, the main disadvantages are that they might initiate false tripping during non-LOM transients on the network, or they might not trip during a true LOM event if the local DG output and local load are closely matched (NDZ) and DG is capable of supporting an island [6.16].

To benefit from the advantages of passive LOM protection and to overcome their limitations, the APC IED amends the protection settings of each LOM protection relay in real time. Figure 6.5 presents the high level algorithm of the APC IED, with a description of the detailed operation of the APC being presented in the text following the figure.

The APC IED communicates with the network management layer, which hosts the ANM functions, and to the AIT IED in the execution layer to gather information about the network operation mode (grid connected or islanded) and the status of the AIT scheme (active or inactive). The APC IED uses this information to select the correct LOM protection settings for each passive LOM protection relay.

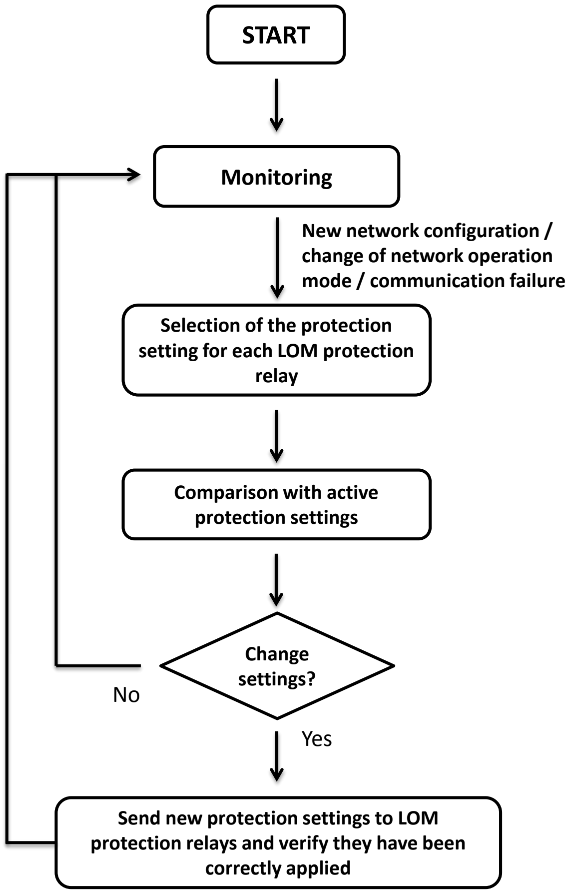


Figure 6.5 APC algorithm

Table 6.1 shows the protection settings for the LOM protection relays when the distribution network is grid connected. The protection settings differ depending on the status of the AIT scheme. If the AIT scheme is inactive, the adopted protection settings reflect the protection settings recommended in the Engineering Recommendation G59/2 [6.17], since this is a traditional scenario where the distribution network is grid connected and the DG units are protected against LOM by passive LOM protection relays without any inter-tripping scheme. If the AIT scheme is active the protection settings are modified to be less sensitive to increase the stability of the LOM protection system avoiding false tripping during transients.

The level of modification of the sensitivity settings has been determined through execution of multiple simulations. In an actual implementation the protection settings should be determined though analysis of the system behaviour. This does not cause problems to the sensitivity of the LOM protection system because the main protection against LOM is provided by the AIT scheme.

Table 6.1 LOM relays protection settings during grid connected operation mode

	AIT scheme active		AIT scheme inactive	
	Setting	Time	Setting	Time
U/V st1	-13%	2.5s	-13%	2.5s
U/V st2	-30%	0.8s	-20%	0.5s
O/V st1	+10%	1.5s	+10%	1.0s
O/V st2	+20%	0.8s	+15%	0.5s
U/F st1	47.5Hz	20s	47.5Hz	20s
U/F st2	47Hz	1s	47Hz	0.5s
O/F st1	51.5Hz	90s	51.5Hz	90s
O/F st2	52Hz	1s	52Hz	0.5s
Vector shift	K1 x 10 degrees		K1 x 6 degrees	
ROCOF	K2 x 0.200Hz		K2 x 0.125Hz	

The constants K1 and K2 used to calculate vector shift and ROCOF protection settings and these values are dependent on the network impedance:

- K1 = 1.0 for low impedance networks or 1.6-2.0 for high impedance networks
- K2 = 1.0 for low impedance networks or 1.6 for high impedance networks

The LOM protection system has been designed also to support islanded operation of the distribution network, which can be initiated during normal operation or after LOM conditions are encountered.

To allow islanded operation, the AIT schemes does not trip the DG units in the power island as explained in section 6.5.1 and the settings of the passive LOM protection relays must be amended to avoid false tripping during fluctuations of voltage and frequency during the switching from grid connected to islanded operation mode and also during transients in the power island which might be more pronounced during islanded conditions (when compared to grid connected operation) due to the reduced network inertia.

Furthermore, during the switching from grid-connected to islanded operation, a blocking signal is sent to the LOM protection relays to temporarily disable the ROCOF protection function.

Table 6.2 shows the protection settings for the LOM protection relays of the DG units connected to a section of the distribution network in islanded operation. The protection settings are different for the cases where the AIT scheme is active or inactive. When the AIT scheme is active, the LOM protection settings are chosen to be less sensitive to avoid false tripping without affecting the sensitivity of the LOM protection system, which is guaranteed by the AIT scheme.

Table 6.2 LOM relays protection settings during islanded operation mode

	AIT scheme active		AIT scheme inactive	
	Setting	Time	Setting	Time
U/V st1	-20%	2.5s	-15%	2.5s
U/V st2	-30%	1.0s	-20%	0.5s
O/V st1	+15%	2.5s	+10%	2.5s
O/V st2	+20%	1.5s	+15%	1.0s
U/F st1	47.5Hz	10s	47.5Hz	10s
U/F st2	46.5Hz	3.0s	47Hz	1.0s
O/F st1	51.5Hz	10s	51.5Hz	10s
O/F st2	52.5Hz	3.0s	52Hz	1.0s
Vector shift	Disabled		12 degrees	
ROCOF	Disabled		0.200Hz	

Another scenario where the protection settings of the LOM protection relays are amended to improve the stability of the LOM protection system is during a severe system disturbance, i.e. to avoid cascades of false tripping of DG units which might compromise the stability of the network.

The APC IED communicates with the network management layer, which hosts the ANM functions, and to the AIT IED in the execution layer to gather information about the network operation mode (grid connected or islanded) and the status of the

AIT scheme (active or inactive). The APC IED uses this information to select the correct LOM protection settings for each passive LOM protection relay.

Assuming that at the management layer a network monitoring system is able to detect that there is a severe system disturbance, a potential solution to avoid false tripping of LOM protection is that the APC is informed of the remote severe system disturbance and amends the protection settings to decrease the frequency and ROCOF protection sensitivity.

Table 6.3 shows the protection settings to be applied during severe system disturbances in the two cases where the AIT scheme is active or inactive.

Table 6.3 LOM relays protection settings during a severe system disturbance

	AIT scheme Active		AIT scheme inactive	
	Setting	Time	Setting	Time
U/V st1	-20%	2.5s	-13%	2.5s
U/V st2	-30%	0.8s	-20%	0.5s
O/V st1	+15%	1.5s	+10%	1.0s
O/V st2	-20%	0.8s	+15%	0.5s
U/F st1	47.5Hz	50s	47.5Hz	20s
U/F st2	46.5Hz	30s	46.5Hz	10s
O/F st1	52.5Hz	90s	52.5Hz	90s
O/F st2	53.5Hz	30s	53Hz	10s
Vector shift	20 degrees		20 degrees	
ROCOF	0.350Hz		0.350Hz	

6.5.4 Application and verification of new protection settings

To apply the new protection settings to the LOM protection relays, there are different possible approaches that may be adopted, depending on the communication capabilities. If the LOM relays are IEC 61850 compliant, then the protection settings can be easily changed by the APC by communicating to the relays using IEC-61850 communication.

To modify the protection settings using IEC-61850, there are two possible approaches:

- fixed protection setting groups;
- variable protection setting groups.

The first approach is based on the use of fixed protection setting groups, i.e. a number of protection setting groups with fixed protection settings are defined to provide up to four levels of LOM protection sensitivity. This approach is easily applicable and might be more acceptable to DNOs which are already familiar with the use of setting groups. However this approach is limited by the maximum number of setting groups available, which is typically four, and therefore it affects the adaptability of the proposed adaptive LOM protection system.

The second approach is based on the use of variable protection setting groups, i.e. setting groups with variable protection settings that can be modified by the APC.

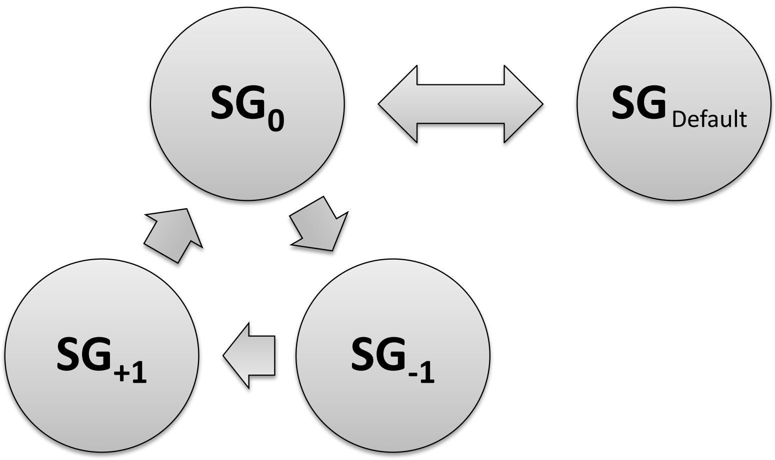


Figure 6.6 Protection setting groups with variable and default protection settings

Figure 6.6 shows four setting groups, SG_0, SG_{+1} and SG_{-1} are the protection settings with variable settings. SG_0 is the active setting group; SG_{-1} is the setting group with the protection settings used before the last protection settings adaptation; and SG_{+1} is an empty setting group.

When the protection settings need to be amended, the APC send the new protection settings to SG_{+1}, then verifies they have been received correctly and finally activates the setting group. When SG_{+1} is activated, it is re-named SG_0, i.e. the active setting group, and the setting group that was SG_0 becomes SG_{-1}.

If the network scenario changes back to the previous scenario before the last protection setting adaptation, the APC activates SG_{-1} inhibits writing and activating the protection settings on SG_{+1}. Then SG_{-1} becomes SG_0 and SG_0 becomes SG_{-1}.

The default setting group has the fixed protection settings shown in Table 6.4, and it is automatically activated in case of loss of communication with the APC.

Table 6.4 LOM relays default protection settings

	Setting	Time
U/V st1	-13%	2.5s
U/V st2	-20%	0.5s
O/V st1	+10%	1.0s
O/V st2	+15%	0.5s
U/F st1	47.5Hz	20s
U/F st2	47Hz	0.5s
O/F st1	51.5Hz	90s
O/F st2	52Hz	0.5s
Vector shift	K1 x 6 degrees	
ROCOF	K2 x 0.125Hz	

6.5.5 Management of communication errors and failures

Both the AIT and the APC are designed to operate in actual systems where there might be temporary or permanent loss of communication with one or more of the IEDs.

Beginning with the AIT IED, the loss of communication with an IED that control a CB or a CS means that its position is unknown to the AIT IED. The AIT IED algorithm treats the status of that CB or CS as uncertain.

As a result of this uncertain condition of the position of the CB or CS, there are three possible scenarios:

- There are no islanded bus(es) in the network, therefore the AIT continues to monitor;

- A number of buses are islanded but this condition would not create a power island as there are no DG units connected to these islanded buses, therefore the AIT communicates this information to the management layer and continues to monitor the network;
- A number of buses are islanded and this could create a power island if the unknown CB/CS status is open; in this case the AIT does not send a tripping signal but communicates to the APC that it is not capable of protecting the DG in that area and therefore the APC amends the protection settings to increase sensitivity as explained in section 6.5.3.

If the AIT loses communication with an LOM protection IED, then it communicates the problem to the APC, which attempts to change the setting group to increase the protection sensitivity.

The APC can lose communication with an LOM protection relay and/or with the AIT:

- If it loses communication with an LOM protection relay, the relay can be configured to changes its setting group to the default protection setting group.
- If it loses communication with the AIT, it assumes that there is a problem with the inter-tripping scheme and it changes the setting groups of all LOM protection IEDs as explained in section 6.5.3.

6.6 Laboratory implementation and demonstration

The developed adaptive inter-tripping scheme with back-up passive LOM protection has been implemented in a HIL simulation environment, where the distribution network model presented in appendix A has been simulated in a RTDS, with commercially available hardware being used for the passive LOM relays, the AIT IED and the APC IED.

Figure 6.7 shows the distribution network test case and the IEDs that have been implemented in the HIL simulation.

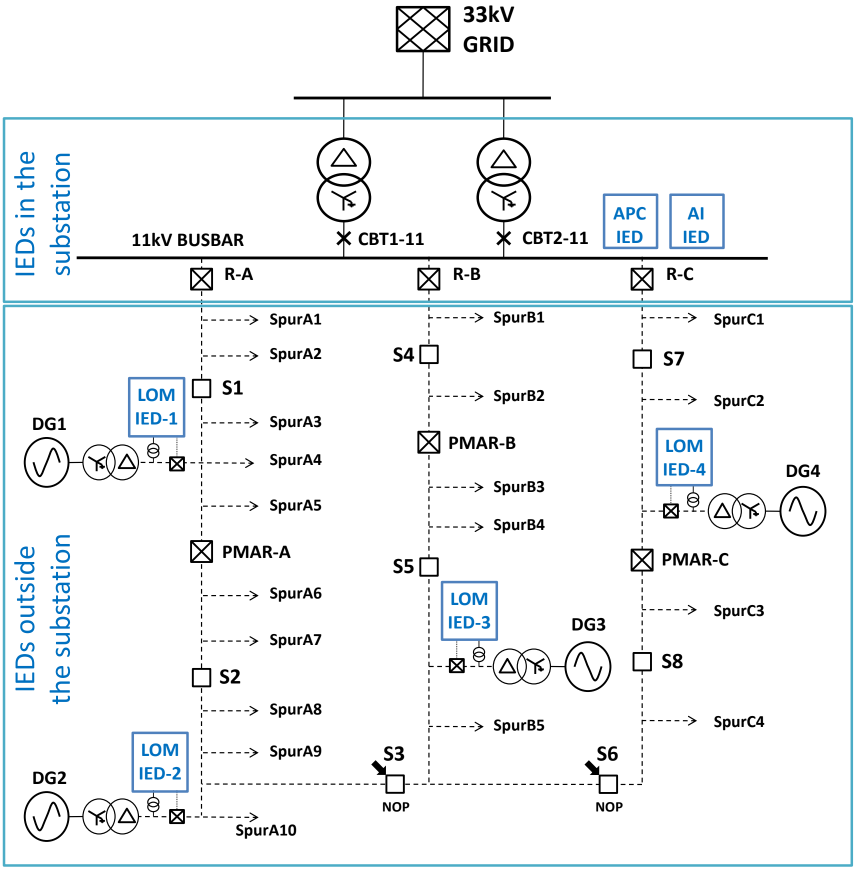


Figure 6.7 LOM IEDs installed in the distribution network test case

The LOM IEDs are Alstom MiCOM P145 protection relays, where the voltage and frequency protection functions have been used to provide LOM protection of the DG units. The APC and AIT IEDs have been implemented in an ABB COM600 substation computer and the COM600’s communication gateway has been used to communicate with the LOM protection relays and the RTDS.

Figure 6.8 depicts the HIL laboratory environment. For the implementation of the LOM IEDs in a HIL simulation, slave amplifiers are used to amplify the voltage signals from the RTDS, so that the LOM IEDs behave as if they were connected to actual VTs. The tripping signal outputs of the LOM IEDs are connected to the digital inputs of the RTDS to close the "passive LOM protection" simulation loop.

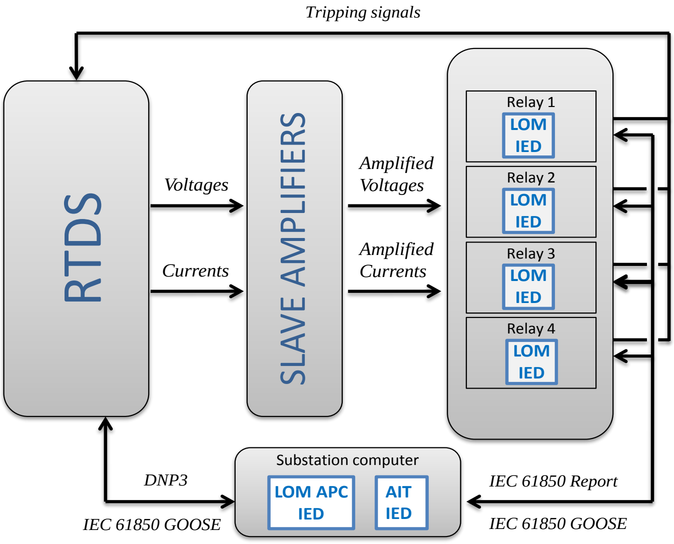


Figure 6.8 HIL simulation of the adaptive LOM protection system

The APC IED implemented in the substation computer uses the communication gateway of the device to communicate to the RTDS GTNET card N.2 and to the LOM IEDs using DNP3 and IEC 61850 respectively.

The AIT IED communicates to both RTDS GTNET card N.1 and LOM IEDs using IEC-61850 GOOSE messaging. The transfer time of GOOSE messages, i.e. the complete transmission time including necessary handling at both ends, as shown in Figure 6.9, has been defined to comply with Performance class P, which defines that the transfer time must be less than or equal to 100ms [6.18].

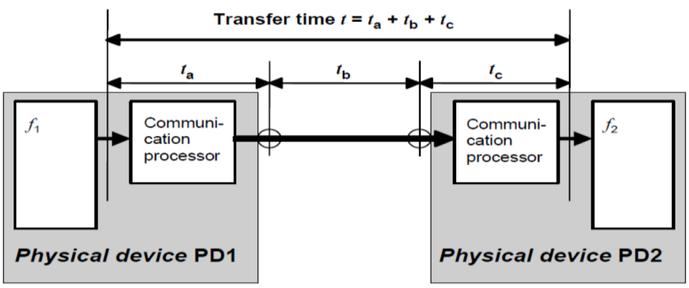


Figure 6.9 Definition of transfer time [6.18]

The transfer time between two IEDs in the same substation, or between IEDs in different geographical locations, is normally different. If the communication between the IED is via metal wires or via an optical fibre based LAN, the transfer time can be in the range of 1ms to 3ms, while if the communication between the IEDs is via radio, microwave, or public Ethernet communication network, the transfer time can be in the order of 50 to 100ms [6.19, 6.20].

The transfer time used in the simulation between the AIT IED and the IEDs shown in Figure 6.8 are summarised in Table 6.5.

Table 6.5 Transfer times between AIT IED and IEDs

IEDs	Transfer time
R-A, R-B, R-C, CBT1-11, CBT2-11	3ms
S1, S2, S3, S4, S5, S6, S7, S8, PMAR-A, PMAR-B, PMAR-C, LOM IED-1, LOM IED-2, LOM IED-3, LOM IED-4	75ms

The transfer time of 75ms is representative of present communication infrastructures that can be readily used to implement the developed solution. However, it is important to note that with the continuous improvement of communication infrastructures, both public or owned by the DNOs, the transfer time can be significantly reduced in the future. For example, IP/MPLS communication networks have been demonstrated to have the capability to provide a communication service that guarantees prioritisation on the communication and therefore can potentially reduce the transfer time to less than 20ms [6.12, 6.13], for critical communications such as that required by LOM protection.

The following sections of this chapter presents a selection of illustrative simulation results to demonstrate the operation of the developed adaptive inter-tripping scheme with back-up passive LOM and to compare it with the operation of a traditional passive LOM protection scheme with the settings presented in appendix C, which have been calculated following engineering recommendation G59/2 [6.17].

6.6.1 Adaptive LOM – demonstration of enhanced sensitivity

Traditional LOM protection exhibits two main problems as explained in section 3.2.6. The first problem is known as the sensitivity problem, i.e. when the passive LOM relay fails to detect a true LOM condition, this is often referred to as the "non-detection zone" (NDZ).

Considering Figure 6.10, where the network switch S3 is open. When R-A changes status from closed to open, feeder 1 becomes a power island disconnected from the grid.

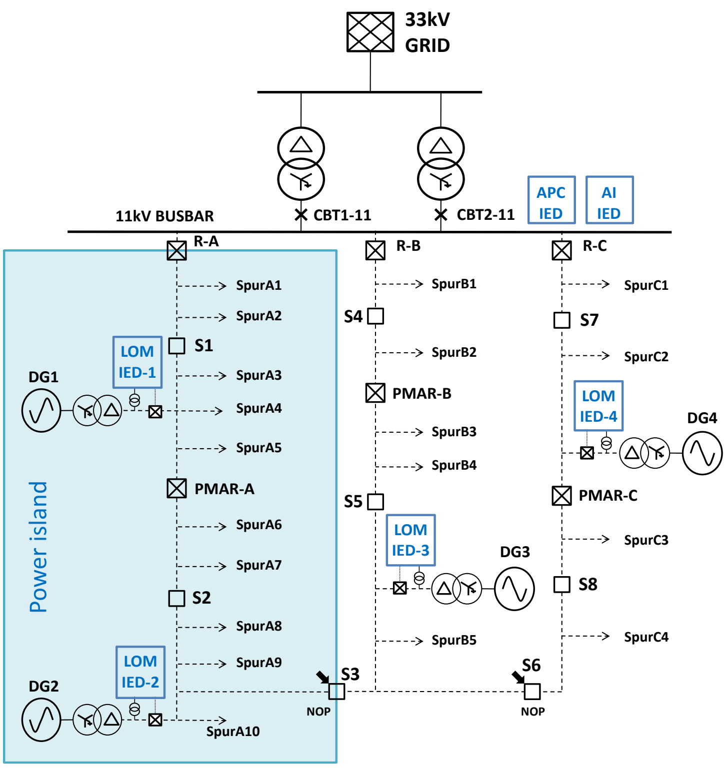


Figure 6.10 LOM of feeder A

At the opening of R-A, the voltage and frequency of the power island will fluctuate. The magnitude of these fluctuations will largely depend on the difference between the levels of generation and load on feeder 1 just before the instant of islanding. These fluctuations will often cause the operation of the passive LOM protection relays, but may not if the local load and generation are very close immediately prior to islanding.

Figure 6.11 presents an example where total generation is 2.6MW + 0.7Mvar, and the total load is 2.72MW + 0.8Mvar prior to islanding. The difference between generation and load is 120kW and 100kVAR and is sufficient to cause a fluctuation in frequency that is detectable by the ROCOF relays at DG1 and DG2, which are set in accordance with G59/2.

The figure illustrates (from the top of the figure down) the active and reactive power generated by DG1 and DG2, the voltage and frequency at the point of connection to the distribution network, DG1 and DG2 protection function operation, and the position of switches AR-A, DG1 CB and DG2 CB.

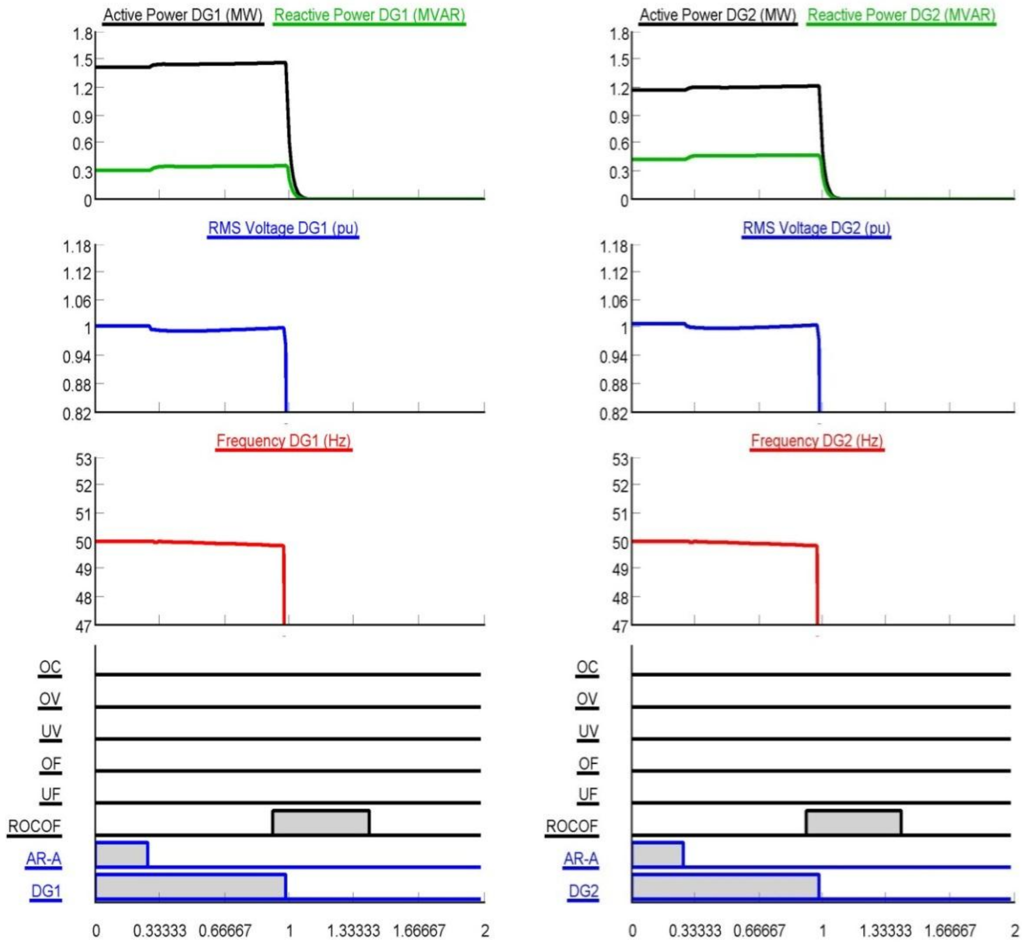


Figure 6.11 Operation of DG1 and DG2 passive LOM protection during LOM of feeder A

While the in the example Figure 6.11, the LOM protection system has operated correctly, if the difference between generation and load is smaller, the LOM protection might fail to detect the LOM event.

For example, if the total load of feeder 1 remains at 2.72MW + 0.8Mvar, but the total generation of DG1 and DG2 is increased to 2.65MW + 0.74Mvar, reducing the difference between generation and load to 70kW and 60kVAR, the LOM protection relays fails to detect the LOM condition as shown in Figure 6.12.

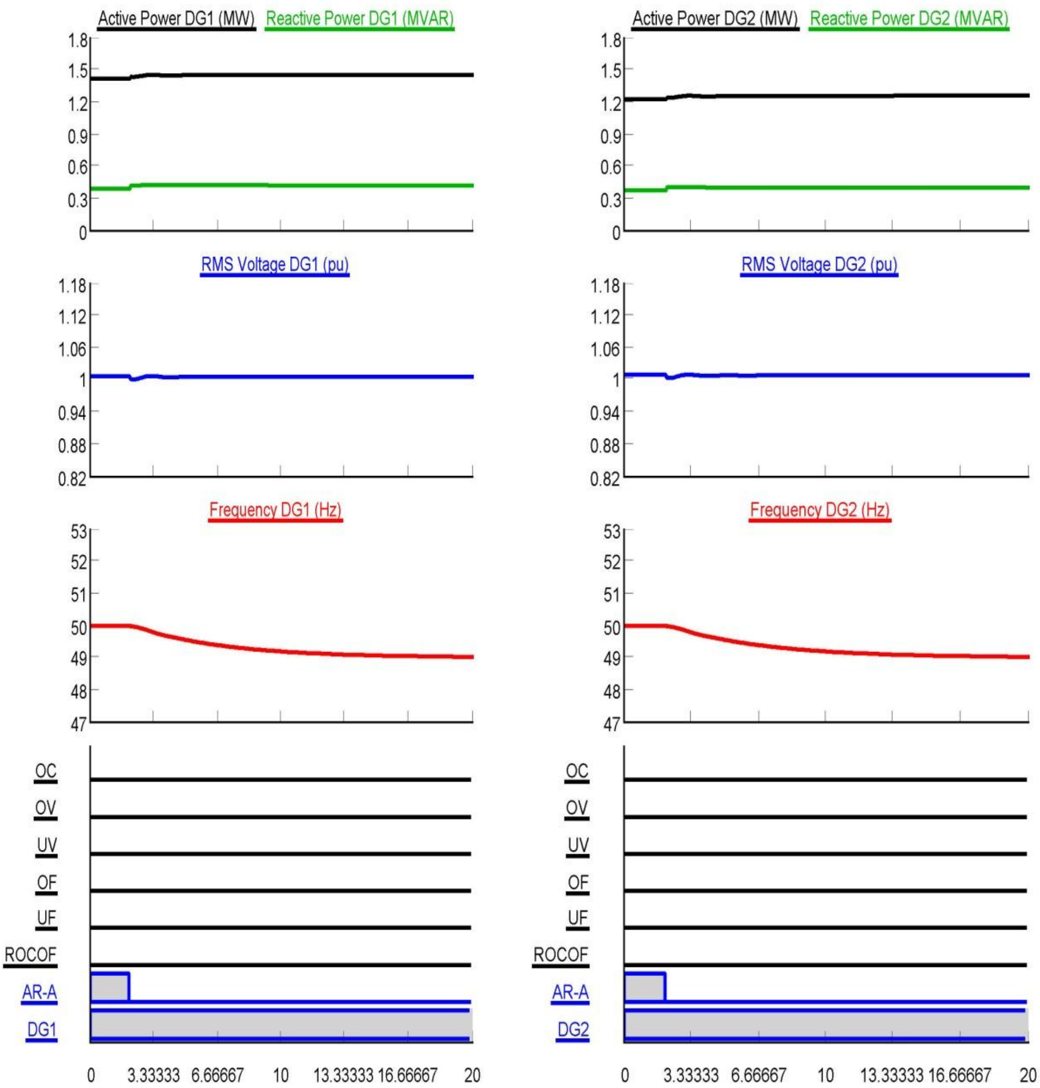


Figure 6.12 Miss-operation of passive LOM protection of DG1 and DG2 during LOM of feeder A

The reason that LOM protection fails to trip DG1 and DG2 in the second example is that the rate of change of frequency is smaller when compared to the first example, with the threshold of 0.2Hz/s (Table 6.1) being exceeded in the first example, but not in the second example.

The adaptive inter-tripping scheme developed as a result of this research overcomes the NDZ problem associated with passive LOM protection, being capable of detecting LOM even when there is a perfect match between load and generation prior to islanding. Figure 6.13 shows the operation of the developed LOM protection system during the LOM event shown previously that was not detectable by passive LOM protection.

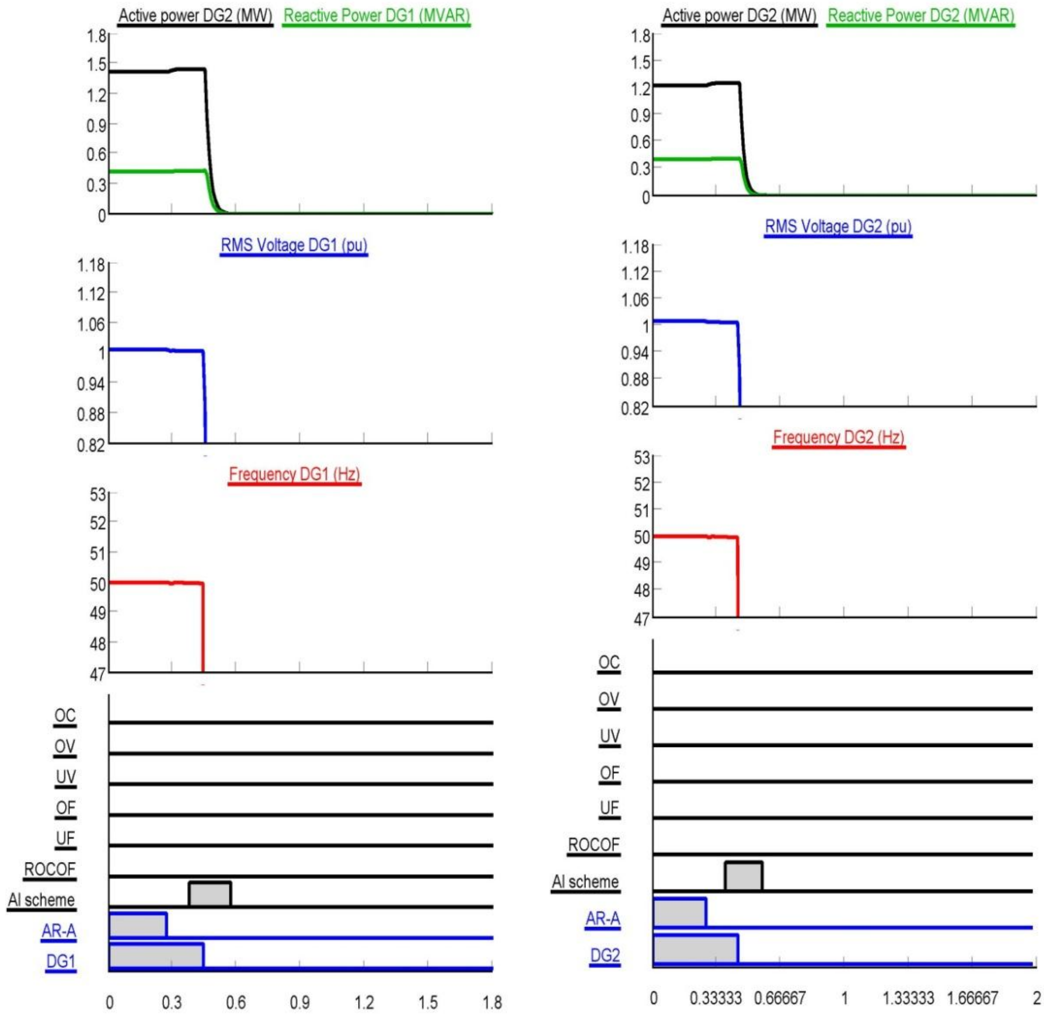


Figure 6.13 Operation of the AIT scheme during LOM of feeder A

The total operation time of the AIT scheme in the simulation presented in Figure 6.13 is 82ms, which is the sum of the communication transfer time between AR-A and AIT IED, the operation time of AIT IED, and the communication transfer time between AIT IED and LOM IEDs 1 and 2, which are 3ms, 4ms and 75ms, respectively.

6.6.2 Adaptive LOM – demonstration of enhanced stability

Stability is another major issue associated with passive LOM protection systems during system disturbances, particularly in power systems with high penetration of DG, as unnecessary operation of LOM and disconnection of large amounts of DG might affect the stability of the entire system. This problem will become more pressing in future.

An example of a (non-LOM) system disturbance is shown in Figure 6.14, where a fault close to the head of feeder A causes a transient in the distribution network with a voltage fluctuation that could cause tripping of LOM IED-3 and LOM IED-4.

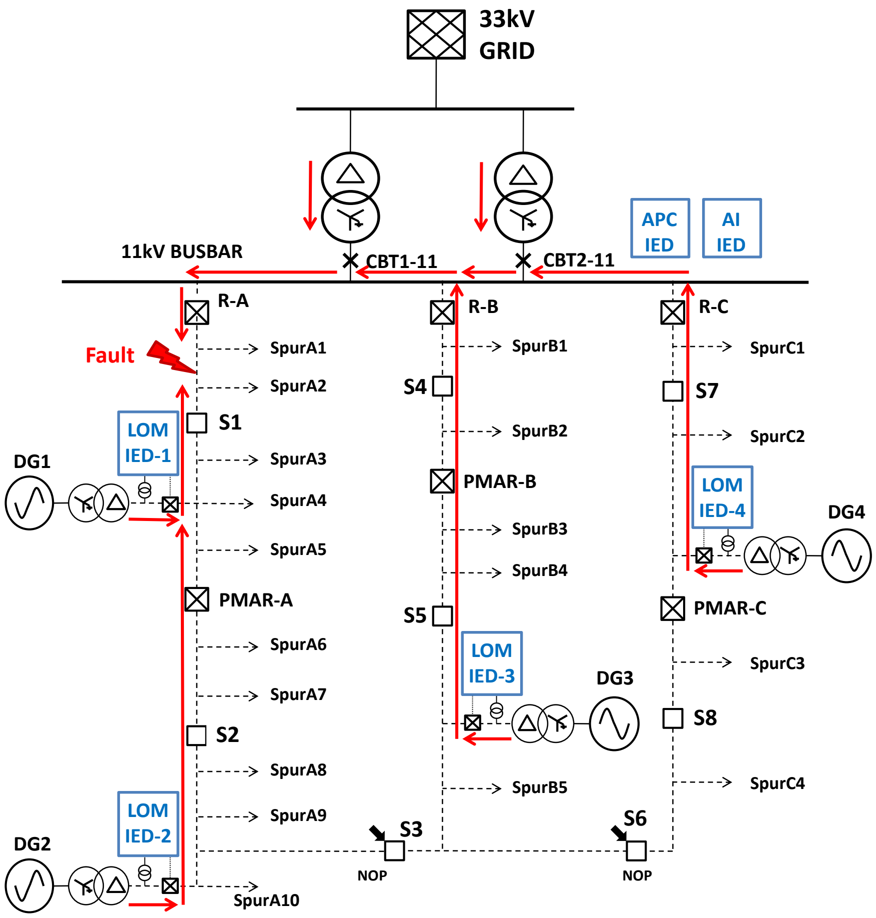


Figure 6.14 Fault on feeder A

In the simulation, the fault level distribution for the network at 33kV has been set to 50MVA, which is a typical value for low fault levels such as those for rural 33kV distribution networks in the UK [6.21], while the fault at feeder A is a three phase fault with a fault resistance of 10Ω, which has been deliberately chosen to be one of the most testing fault scenarios – solid short circuits would be cleared very quickly by the feeder protection and would therefore not be so challenging to the LOM protection stability.

Figure 6.15 shows the fault current measured at OCR AR-A, which is a low fault current due to the low fault level and the resistive nature of the fault. Since the fault current is low, the operating time of the OCR is long, i.e. 1.67s. Figure 6.16 shows the RMS voltage measured by the LOM protection relay of DG3, the G59/2 UV protection characteristic, and the incidence of false tripping after 0.5s.

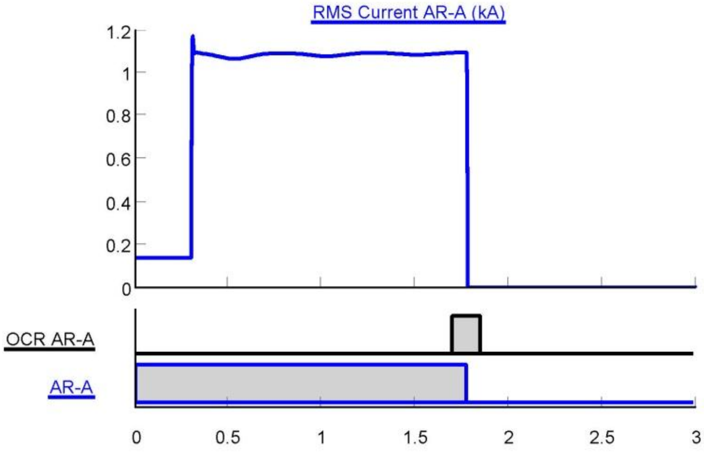


Figure 6.15 Fault current during a three phase fault at feeder A

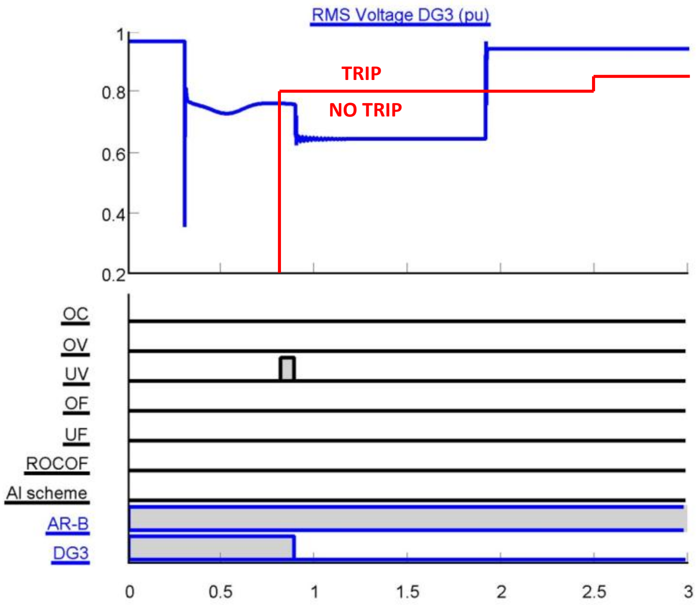


Figure 6.16 False tripping of LOM protection during a three phase fault at feeder A

The developed adaptive LOM protection system improves the stability of the LOM protection when the AIT protection scheme is active, because the LOM protection settings are automatically amended to be less sensitive to network disturbances as shown in Table 6.1.

Figure 6.17 shows the voltage measured by the LOM protection relay at DG3, the G59/2 protection characteristic and the adapted, less sensitive, LV protection characteristic, that is presented in Table 6.1.

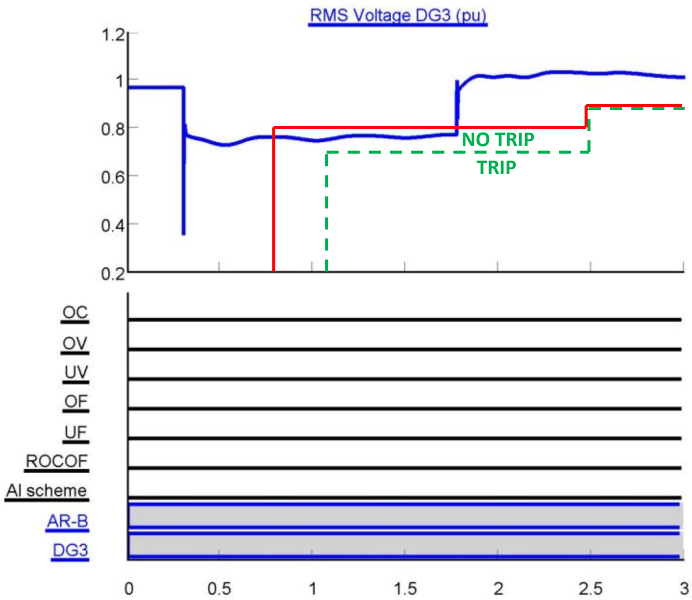


Figure 6.17 Non-operation of LOM protection during a three phase fault at feeder A

Comparing the RMS voltage in Figure 6.16 and Figure 6.17, it is possible to appreciate the importance of avoiding spurious tripping of DG. In Figure 6.16, after DG3 disconnects, the voltage drops from 0.77pu to 0.65pu, aggravating the voltage sag, while in Figure 6.17 the DGs support the voltage.

6.6.3 Adaptive LOM – demonstration of island mode operation

With the increasing penetration of DG, islanded operation is becoming an attractive option to improve the reliability and availability of power supply to the consumers. In the long term future, the reduction in large scale centralised generation, coupled with the increase in DG, may result in islanding becoming a more routine mode of operation. However there are several technical challenges that must be addressed in order for islanded operation to become a viable option, one of which is the challenge associated with LOM protection.

For example, considering the test case distribution network shown in Figure 6.18, and assuming that islanded operation is allowed in the case of disconnection from the 33kV upstream network, there are two main problems. The first is associated with managing the LOM protection system during the switch from grid connected to islanded operation, while the second is associated with how to protect the network against subsequent LOM (i.e. LOM within the island) protection after islanded operation is initiated.

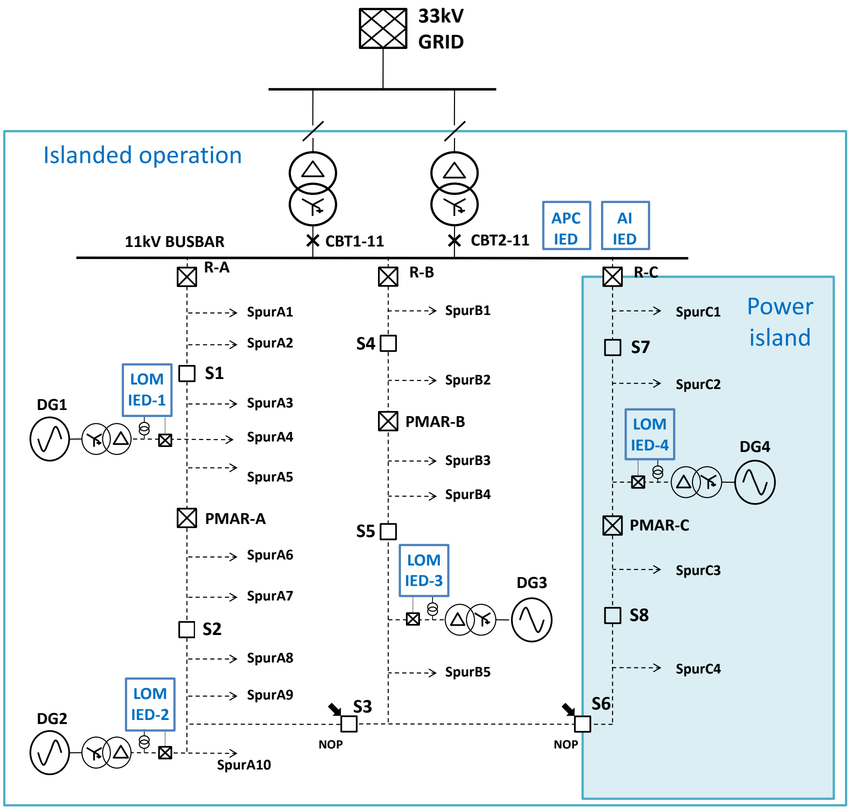


Figure 6.18 LOM protection during islanded operation

With respect to the first challenge, when a distribution network is switched from grid-connected to islanded operation, this results in a disturbance that might cause the tripping of the LOM protection of the DG units. This would compromise the stability of the power island and might lead to cascade tripping of all DG units within the island.

For example, consider a scenario where the total load in the distribution network is 0.6MW+ 0.3Mvar in excess of the power generated by the DG units immediately prior to islanding. When the connection to the grid is lost, the fluctuation in frequency would cause the operation of the ROCOF protection function of all LOM protection relays in the island.

Figure 6.19 shows the frequency measured in the distribution network, the tripping signals from the LOM protection relays, the status of connection to the grid and the connection status of the DG units. As previously stated, the fluctuation of the frequency causes the operation of the ROCOF protection and therefore the unwanted disconnection of all the DG connected to the distribution network.

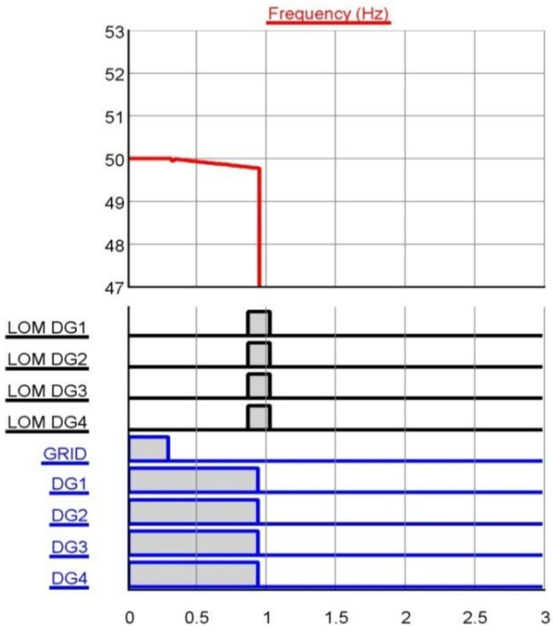


Figure 6.19 Unsuccessful switching from grid connected to islanded operation mode

The developed solution adopts relaxed protection settings and a blocking scheme for the ROCOF protection, as explained in section 6.5.3, which facilitates successful switching from grid connected to islanded operation.

Figure 6.20 illustrates a successful switching operation from grid connected to islanded mode when the developed solution is applied. At the point of islanding of the distribution network, the frequency decreases as in the previous example but in this case, the blocking scheme detects the islanded operation through the fact that the appropriate circuit breaker(s) has opened and blocks the operation of the ROCOF protection and prevents tripping, permitting therefore a temporary fluctuation of the frequency. After 5s, the frequency reaches 49Hz, and it is assumed that some form of load shedding scheme, such as that proposed in [6.22], would disconnect some of the loads to assist the DG units in recovering the island frequency to maintain it within the statutory limits.

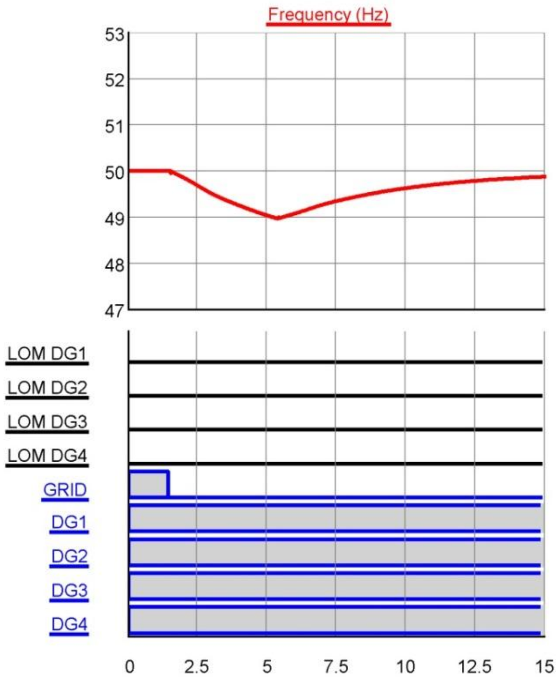


Figure 6.20 Successful switching from grid connected to islanded operation mode

The second problem is associated with protecting the distribution network from LOM during islanded operation. The inertia of the network in islanded mode will be much lower than when operating in grid connected mode. Accordingly, the network is likely to experience voltage and frequency fluctuations with relatively greater magnitudes during any connection or disconnection of loads/DG units, during and after changes to the network topology, etc.

It is highly likely that passive LOM protection relays using G59/2 settings would be overly sensitive in such cases and this would lead to unnecessary tripping which might compromise the stability of the power island. The developed adaptive inter-tripping scheme, with back-up passive LOM protection, is capable of protecting the power island with adequate sensitivity, speed and stability under such scenarios.

Figure 6.21 presents an example of operation of the developed solution during islanded operation. The opening of AR-C causes a “sub-island” to be formed (it is assumed that this is not permitted). The figure (from the top down) shows frequency, the passive LOM and AIT tripping signals to each DG unit, the status of the main island connection, the AR-C status and finally the status of all DG units’ CBs.

The simulated LOM event causes a fluctuation in the frequency that is too small to be detected by the passive LOM protection because the difference between generation and load of feeder C is of only 50kW and 25kVAR. However, this does not affect the developed AIT scheme, which detects the sub-islanding of feeder C and send a tripping command to the CB of DG4.

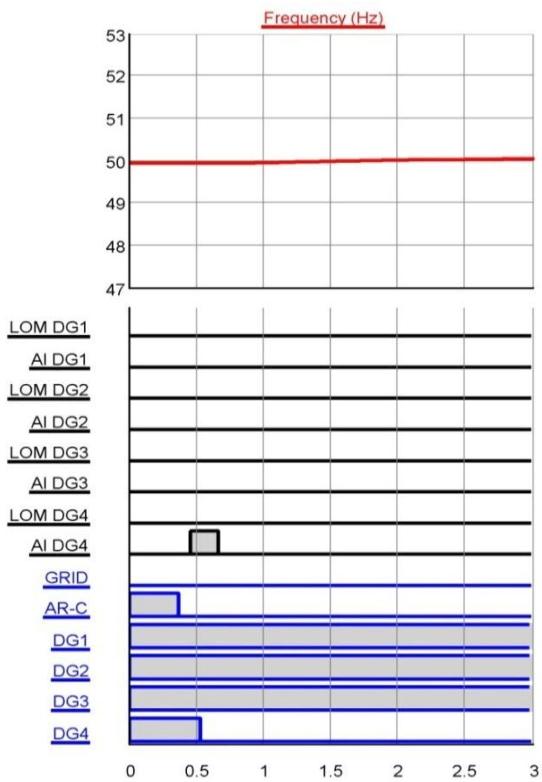


Figure 6.21 Operation of the adaptive inter-tripping scheme during islanded operation

6.7 Chapter summary

This chapter has presented an adaptive inter-tripping scheme with back-up passive LOM protection. It has explained in detail the architecture of the proposed solution, the algorithm, how it has been implemented in commercially available hardware and how it has been simulated in a HIL simulation environment.

The developed adaptive inter-tripping scheme revolutionises the current approach to LOM, offering significant improvements in terms of sensitivity, stability and speed of operation. The novelty of the solution is in its algorithm, which does not use any predetermined association of the DG circuit breakers with one (or more) utility network circuit breakers like traditional inter-tripping schemes, but analyses the network topology using graph theory to identify islanded buses and to disconnect DG units when islanded operation is not allowed.

The developed adaptive inter-tripping scheme has been developed to be easily extendable to protect new DG units. In fact, since there are not predetermined association of the DG circuit breakers with one (or more) utility network circuit breakers, extending the adaptive inter-tripping scheme requires to provide communication to the DG unit and to update the data file of the adaptive inter-tripping scheme.

The developed AIT scheme is also capable to allow islanded operation of a sub-network if this is permitted and protect the sub-network from LOM in case that within the sub-island there was an unwanted islanded section of the sub-island.

Key simulations have been reported to explain the operation of the developed solution and to demonstrate some of the main advantages with respect to traditional LOM protection systems. The developed solution has been proved to have better stability during transients, to not exhibit a NDZ, to have relatively faster operation, to be capable of adapting to any network configuration and capable of protecting against LOM during islanded operation.

A more comprehensive set of simulation results is presented in chapter 7 to validate the developed adaptive inter-tripping scheme with back-up passive LOM protection and to compare its performance against traditional LOM protection systems.

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Chapter 7:

Validation of the developed adaptive protection solutions

7.1 Chapter overview

The developed adaptive protection solutions improve significantly the performance of the overcurrent and LOM protection systems with respect to existing protection schemes as explained in chapters 5 and 6. However, even with a clear technical advantage over conventional protection practices, utilities might be sceptical about adopting such protection solutions because of the lack of a comprehensive validation methodology for such novel adaptive protection systems.

This chapter addresses this concern by initially discussing the difficulties associated with using present validation methodologies to validate adaptive protection solutions. A validation methodology that has been developed for the validation of adaptive protection systems and that has been applied to both the developed adaptive protection solutions described in this thesis is then presented. As explained later in section 7.3, a requirement of the developed validation methodology is to implement all the protection schemes in the simulation and then test the protection response to transients, faulted scenarios, LOM conditions, etc. Therefore the developed adaptive overcurrent protection system and adaptive LOM system have been implemented in the same HIL simulation environment and tested

This chapter presents the results of this simulation comparing the adaptive overcurrent protection system with a traditional overcurrent protection system designed using present DNO protection policies, and comparing the adaptive LOM protection system with a traditional LOM protection system designed in accordance with engineering recommendation G59/2 [7.1].

7.2 Presently used validation methodologies

In modern practice, all protection relays must pass through a certification of conformance process, and in some cases also an application conformance testing process, subject to specific requirements in different countries and utility companies. The certification process is normally performed by a certification organisation or by a testing company under the supervision of a certification organisation, while application conformance exercises are normally performed by a manufacturer or a testing company on the request of a specific end-user [7.2].

The methods by which certifications are performed vary by country. In the UK, the Energy Networks Association (ENA) co-operates with manufacturers in assessing protection relays and, if necessary, in witnessing type tests which include electrical, environmental, software, and dynamic validation. Equipment that meets the specified criteria is given an ENA Notice of Conformity Certificate through the appropriate Protection Assessment Panel (PAP), which is comprised of representatives from Distribution and Transmission Network Operators [7.3].

Certification type tests concern normalised tests using standardised procedures, termed conformance and performance tests, which aim to verify the conformance of the protection relay against its specifications. These tests are generally related to international standards, such as IEC 60255 [7.4] and ANSI C37.90 [7.5]. However compliance may also involve consideration of the electromagnetic compatibility requirements of IEC 61000 [7.6], the environmental testing and enclosure protection (IP codes) requirements defined in IEC 60068 [7.7] and IEC 60529 [7.8], while products intended for use in the EU must also to comply with the requirements of directives 2004/108/EC [7.9] and 2006/95/EC [7.10].

Certification type tests can be divided into categories of technological, functional and application conformance tests. Technological tests consider how the protection relay responds to external disturbances; functional tests verify the functionality of the protection against standard test specifications (these tests are also called static type tests); and application tests are carried out to demonstrate that a protection scheme is capable of protecting particular network configurations under specific fault conditions (these tests are also called dynamic type tests).

Static type testing consists of applying inputs to a protection relay and measuring the performance to determine if it meets the specification or not. These tests are normally extensive and include a high number of tests. For example, considering an overcurrent protection relay, the typical static type tests include: three phase pick-up and drop off accuracy, accuracy of DT timer, accuracy of IDMT curves, accuracy of reset timers, etc. All tests are completed over the complete range of settings. This is normally achieved using a protection test set which generates a series of waveforms and records the response of the protection device.

Dynamic type tests consist of simulating transients, normally using a real time network model, to dynamically demonstrate the satisfactory performance of protection relays. Figure 7.1 shows a typical dynamic type testing hardware environment, where the real time digital simulator simulates the primary system. The protection scheme being tested, which may comprise one or more protection relays, receives voltages and currents from the simulation, amplified to replicate the outputs of actual VTs and CTs.

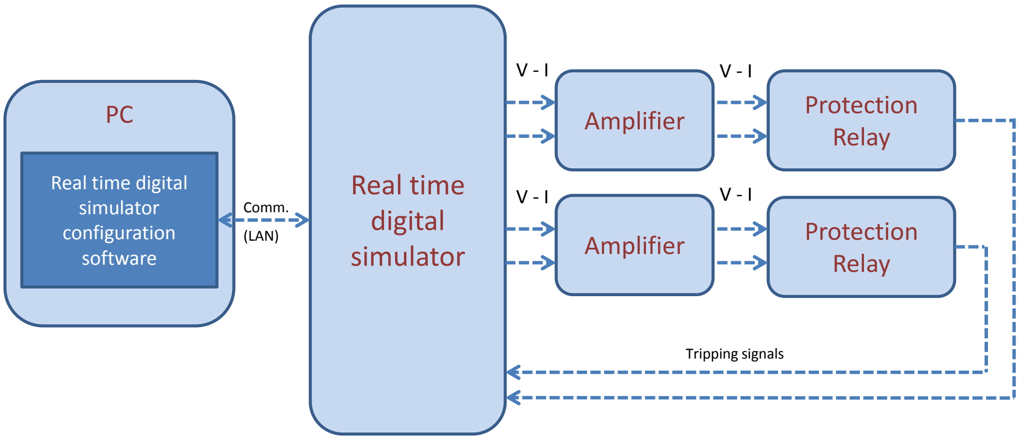

Figure 7.1 Dynamic type testing hardware environment

The protection response to faults, such as trip and reclose signals, is then sent back to the simulator to operate the circuit breakers modelled within the simulation. If the protection provides signals via conventional dry contacts, the signal will be received by the simulator using its digital input card, while if the protection equipment is IEC61850-8-1 compliant the breaker commands can be imported into the simulation using a dedicated IEC61850-8-1 interface card.

With the real time simulation and the protection equipment connected in such a closed-loop regime, the protection can be subjected to a myriad of faults and operating scenarios.

The faults and operating scenarios can be run manually or using automated batch files. The automated batch is often applied to protection system testing where faults are repeatedly applied, with small changes to the fault inception angle, fault type, fault location, etc. In this way the overall time required for testing is significantly reduced.

7.2.1 Limitations of present type testing arrangements

The static and dynamic type testing approaches described previously have been developed to test present-day protection relays and conventional protection schemes; they are well established, understood and applied globally.

With the introduction of adaptability into protection systems, the assessment of the protection schemes becomes more complex. To perform functional conformance tests for adaptive protection systems, static type testing can be adopted in the same way as for conventional protection systems.

However, to perform application conformance tests, the present dynamic type testing technique must be extended and be improved to consider and exhaustively test the adaptability of the protection system.

For dynamic type testing of a conventional protection system it is sufficient to simulate a number of scenarios and verify that the protection system responds to "fault" and "no fault" scenarios in accordance with the protection performance requirements. However, for dynamic type testing of an adaptive protection system, it is necessary to add additional inputs to the simulation to stimulate the adaptability of the protection system and verify that the protection settings are adapted correctly and that the protection system responds correctly to the fault and no fault scenarios.

For example, for an a traditional overcurrent protection system, the dynamic type testing normally consists on simulating a number of earth and phase faults in different locations and with different resistance, and measuring the operating time of the overcurrent protection to verify that it respects the protection performance requirements. When the adaptive overcurrent protection system presented in chapter 5 is considered, it is clear that further variables (e.g. network topology, the connection status of DG, the infeed fault level etc.) must be included to test that the protection settings are adapted correctly and that the protection system response complies with performance requirements. If these additional variables were not considered, the dynamic type testing would not be able to test the adaptability of the system and therefore it would not be possible to know where the adaptive overcurrent protection system would respond correctly to faults and transients under all operational scenarios.

7.3 Adaptive protection systems validation methodology

The developed validation methodology for adaptive protection systems is a dynamic type testing technique where the adaptive protection system is stimulated to adapt to different network scenarios and to protect the network.

To enable the validation of the adaptive protection system, the distribution test case network presented in appendix A is simulated in the RTDS and the developed adaptive protection solutions have been implemented within an HIL simulation.

Figure 7.2 shows the distribution test case network with all the of IEDs involved in executing both the adaptive over-current protection system with automatic settings calculation (as reported in chapter 5) and the adaptive inter-tripping with back up passive LOM protection (as reported in chapter 6).

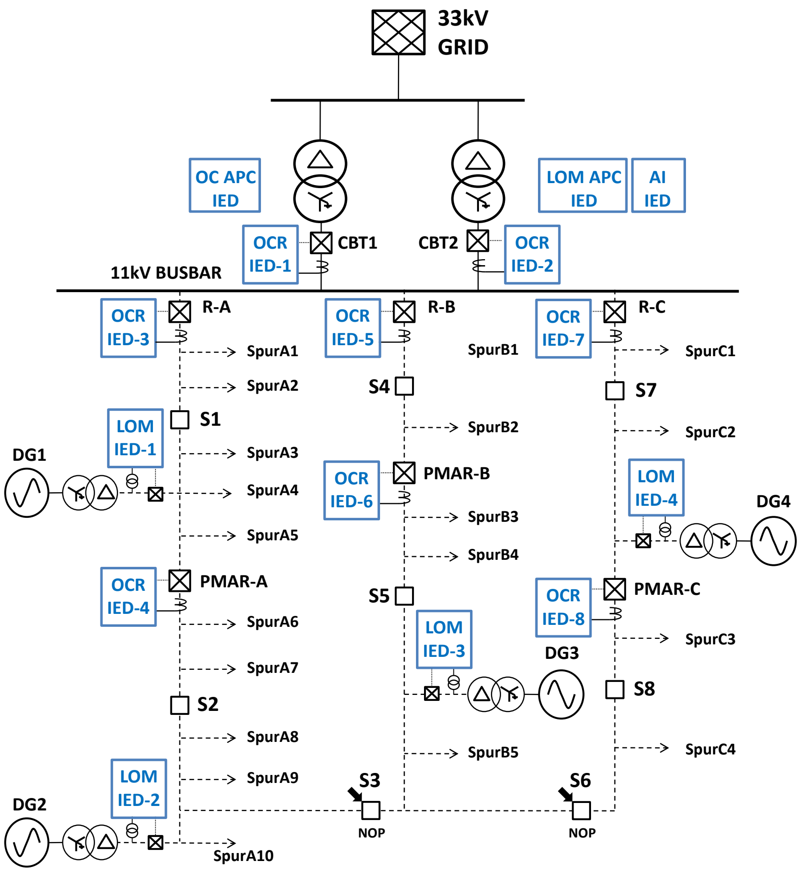

Figure 7.2 Implementation of adaptive protection IEDs in the test case distribution network

It is important that both of the adaptive protection systems are simulated simultaneously to verify that the individual protection schemes are properly coordinated. For example, when there is a fault in the distribution network, it is important to verify that the adaptive overcurrent protection solution clears the fault before the passive LOM protection system unnecessarily trips DG units.

To simulate simultaneously both of the developed adaptive protection systems, there is a practical challenge due to the amount of necessary hardware; the main limitations that applied in the laboratory were the numbers of protection relays and slave amplifiers available.

To overcome these limitations, four of the eight OCR IEDs and three of the four LOM IEDs were simulated in the RTDS, and the OC APC, LOM APC and AI IEDs were all implemented in the ABB COM600 substation computer device.

These arrangements, necessary to implement such a complex system with the available hardware, do not affect the results of the validation. However, in an actual implementation of the proposed adaptive protection solutions, each IED would be an independent hardware device.

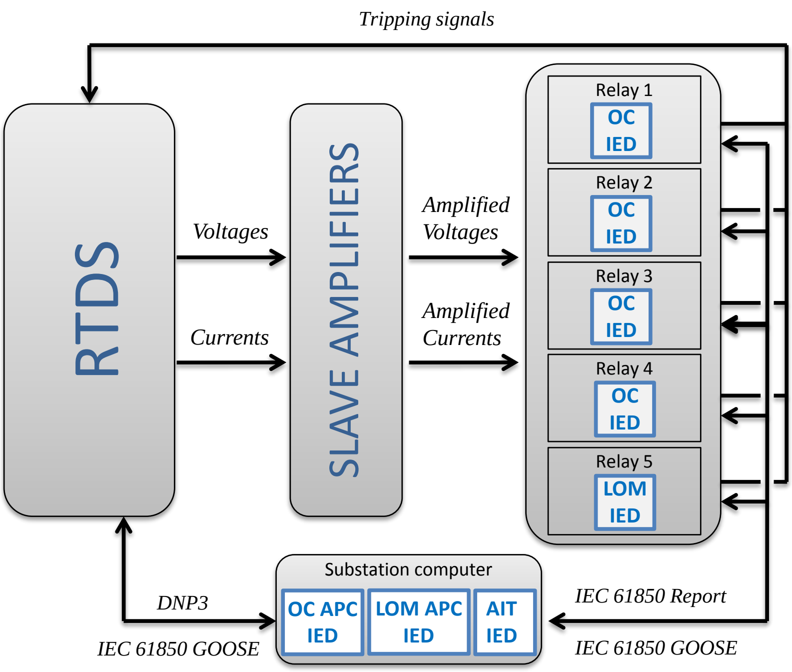

Figure 7.3 HIL simulation for the validation of the developed adaptive protection solutions

7.4 Validation of the adaptive overcurrent protection system with automatic settings calculation

To validate the developed adaptive overcurrent protection system, the simulation scenarios shown in Table 7.1 have been generated to include the following stimuli to the adaptive overcurrent protection system:

- changes of fault level due to change of the fault level at 33kV and the number of in-service transformers at the 33/11kV distribution substation; normally both transformers are in operation, but in some cases one may be not connected (NC);
- islanded operation of the 11kV network, which is permitted if all of the four DG units are in service;
- 11kV distribution network topology, which can be varied by shifting the normally open points (NOP) as necessary, e.g. to restore supply to loads of a parallel feeder that has experienced an upstream permanent fault;
- connection/disconnection of all the four DG units.

Table 7.1 Network scenarios

N.	33kV fault level (MVA)	Substation transformers in service	Normal Open Points	DG units in service
1	300	2	S3, S6	No
2	300	2	S1, S6	No
3	300	2	S4, S6	No
4	300	2	S5, S7	No
5	300	2	S3, S6	Yes
6	300	2	S1, S6	Yes
7	300	2	S4, S6	Yes
8	300	2	S5, S7	Yes
9	100	1	S3, S6	Yes
10	100	1	S1, S6	Yes
11	100	1	S4, S6	Yes
12	100	1	S5, S7	Yes
13	NC	NC	S3, S6	Yes
14	NC	NC	S1, S6	Yes
15	NC	NC	S4, S6	Yes
16	NC	NC	S5, S7	Yes

In order to verify the response of the developed adaptive overcurrent protection system, a series of faults have been simulated for each network scenario, at twelve locations, as shown in Figure 7.4.

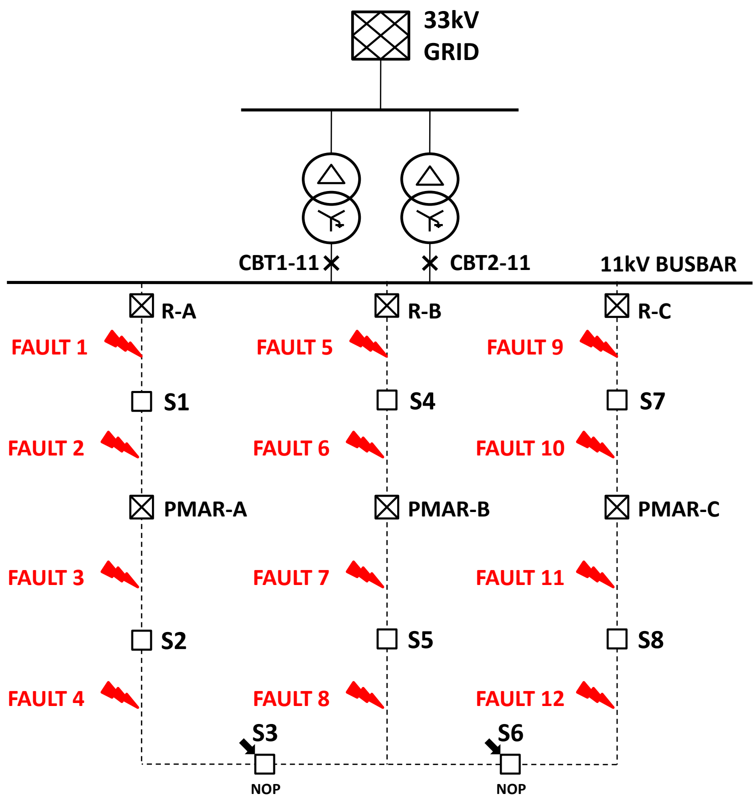

Figure 7.4 Fault locations

The faults simulated at each location include:

- Eleven phase to phase faults with a fault resistance between 0Ω and 10Ω (0Ω, 1Ω, 2Ω, etc.); and
- Eleven phase to earth faults with a fault resistance between 0Ω and 100Ω (0Ω, 10Ω, 20Ω, etc.).

These faults have been simulated twice, once to test the traditional overcurrent protection system and once to test the adaptive overcurrent protection system.

7.4.1 Phase fault overcurrent protection testing results

Figure 7.5 shows the recorded tripping time of the conventional and adaptive overcurrent protection systems for all of the simulated phase faults. As there are 16 network scenarios, 12 fault locations and 11 values of fault resistance, the total number of faults is 2,112.

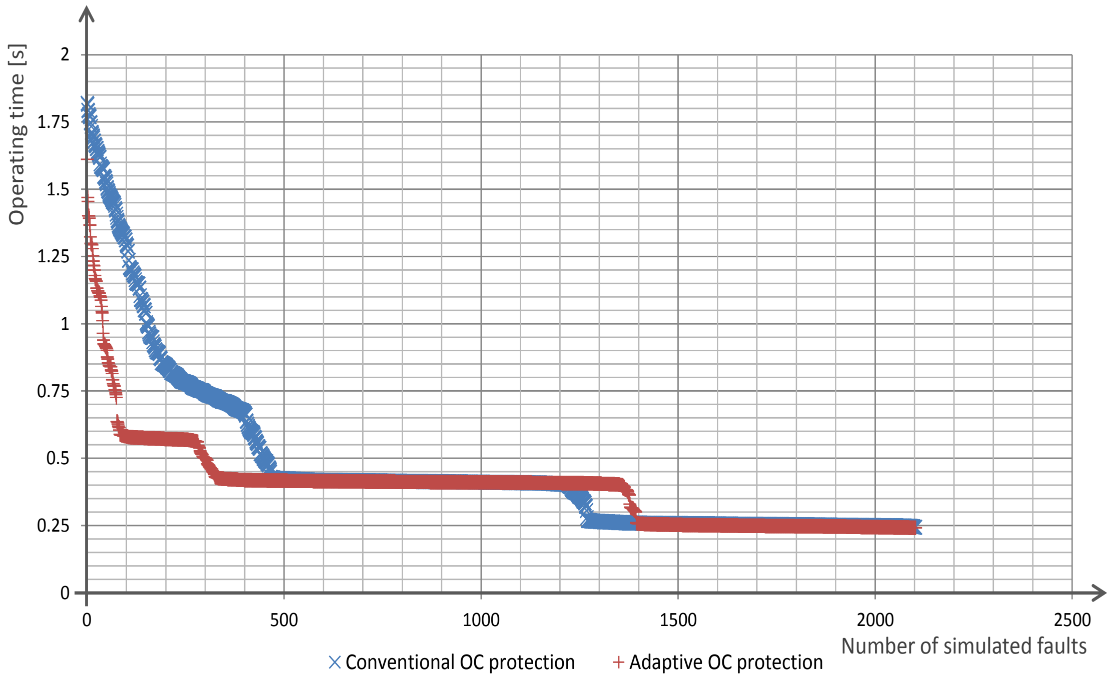

Figure 7.5 Phase fault simulations tripping time

For the first 456 faults, the operation of the adaptive overcurrent protection with amended protection settings is faster than the conventional IDMT overcurrent protection system. For all of the other faults, there is no appreciable difference in tripping time, because the delay time of the DTL characteristics is the same.

The only exception is for the faults between 1214 and 1388, where the adaptive overcurrent protection system has a slower tripping time. This is due to the correction of the DTL overcurrent protection settings to guarantee correct coordination between the OCRs when the network topology changes. Note that the adaptive overcurrent protection system uses three steps of delay for the DTL characteristics, while the conventional protection system uses two steps of delay.

Figure 7.6 shows the tripping time of the conventional overcurrent protection system for different network scenarios. This is longer than 1s in 151 of the simulated faults (i.e. 7.15% of the simulations); these relatively long tripping times are mostly for scenarios with lower fault level and/or islanded operation.

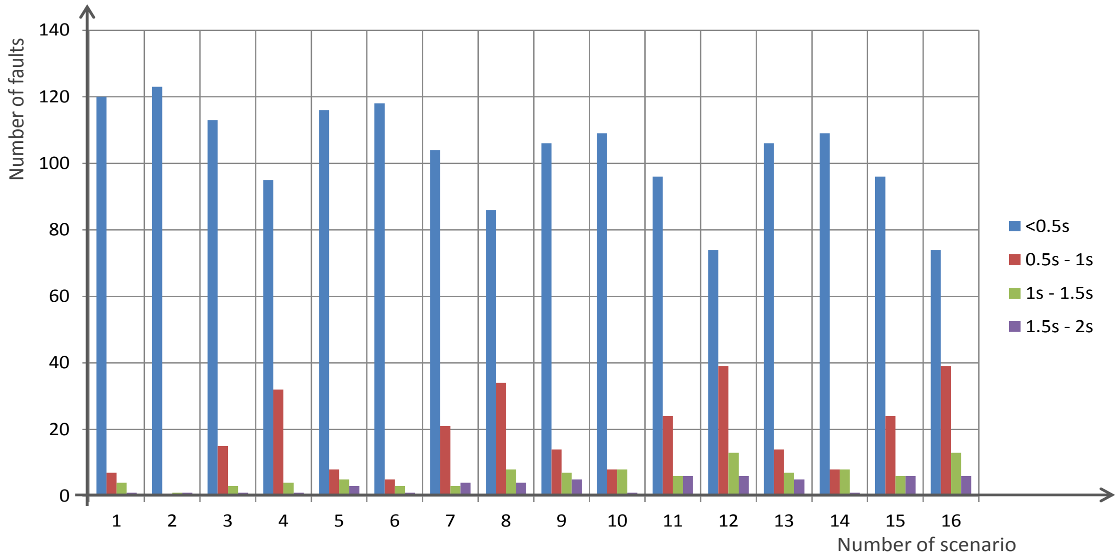

Figure 7.6 Conventional phase over-current protection tripping time for each scenario

Figure 7.7 summaries the tripping time of the adaptive overcurrent protection system showing that the adaptive overcurrent protection system reduces significantly the number of tripping times that are longer than 1s in the conventional scheme, from 7.15% to 1.8%.

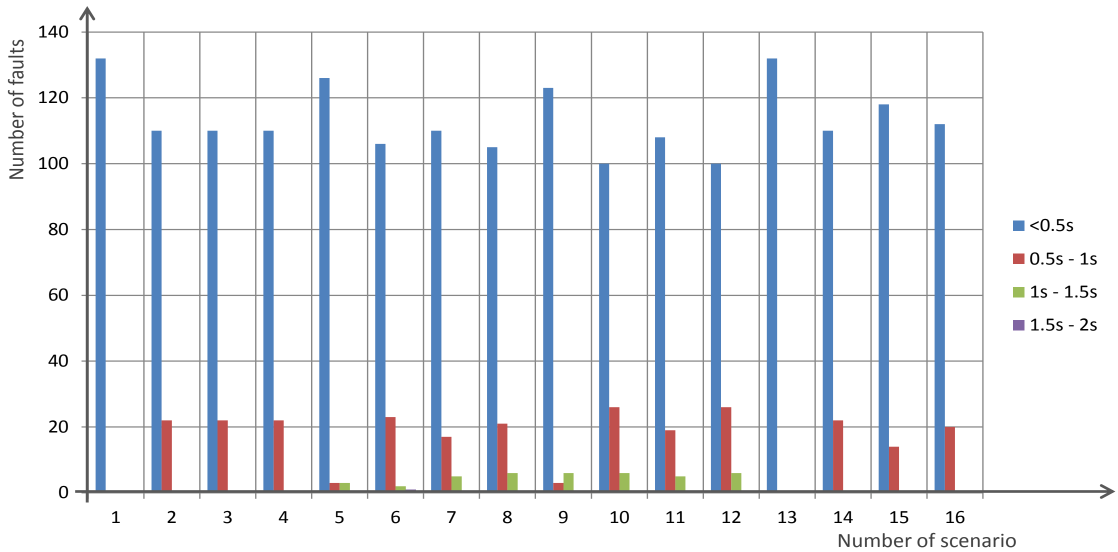

Figure 7.7 Adaptive phase overcurrent protection tripping time for each scenario

Figure 7.8 shows the correct operation, false operation and non-operation of the conventional overcurrent protection. For clarity, correct operation means that the OCR that should clear the fault correctly trips, false tripping means that one of the OCRs that should not trip incorrectly trips (unnecessarily disconnecting an element of load and generation), and non-operation means that the OCR that should clear the fault does not operate.

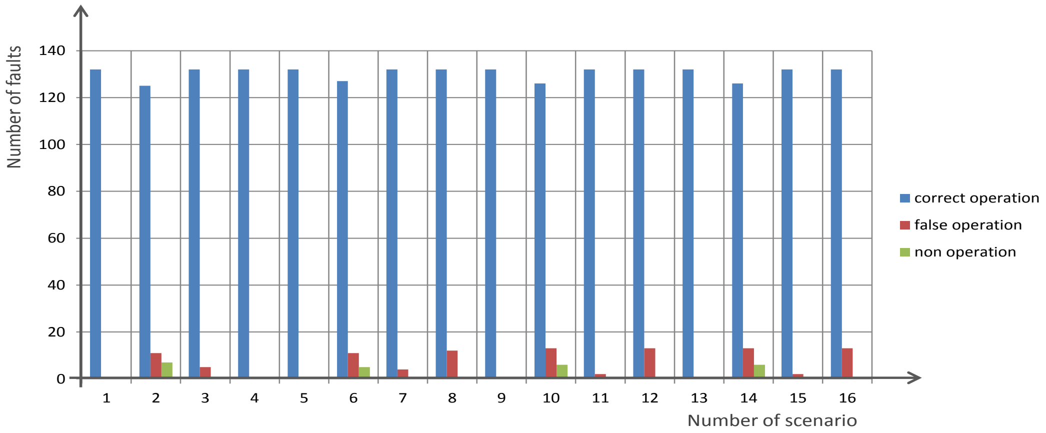

Figure 7.8 Conventional phase overcurrent protection - operational test results

Figure 7.9 shows the correct operation, false operation and non-operation of the adaptive overcurrent protection system. The adaptive overcurrent protection system performs better in all cases: the OCR that should clear the fault always operates correctly, there are no cases of non-operation and the number of false trips is reduced from 4.72% to 1.61% of the total number of simulated faults.

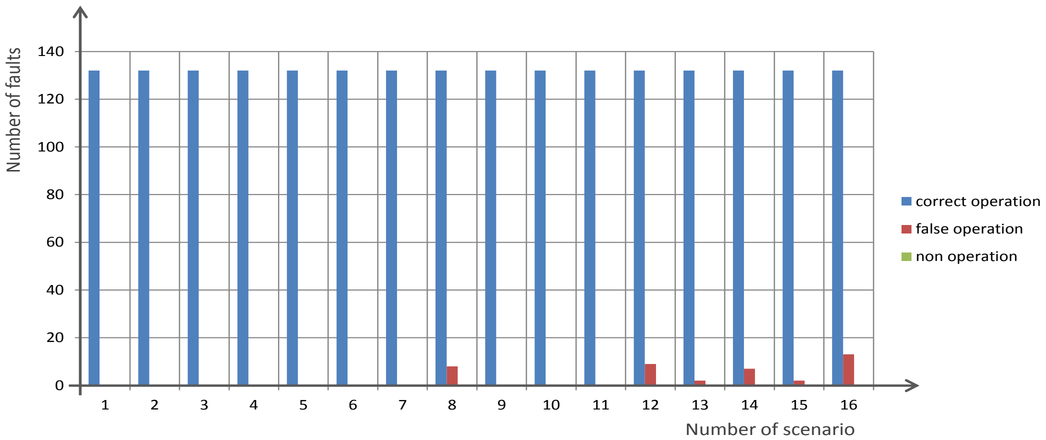

Figure 7.9 Adaptive phase overcurrent protection - operational test results

7.4.2 Phase fault overcurrent protection testing results

Figure 7.10 shows the tripping time of the conventional and adaptive overcurrent protection systems for all of the 2,112 simulated earth faults. The operation of the adaptive protection system is slower for some faults, this is necessary to ensure correct coordination between OCRs as the network topology changes.

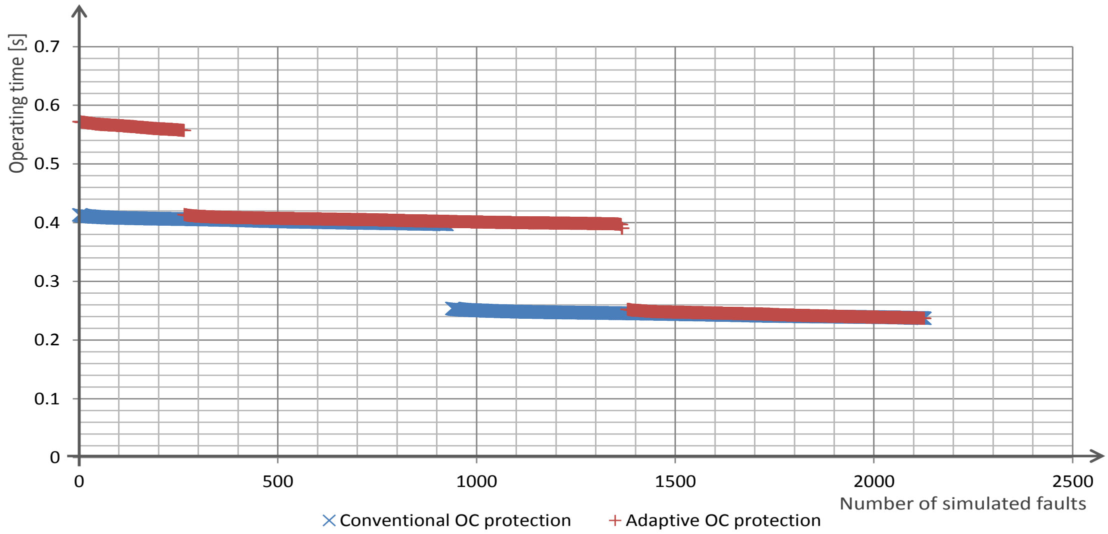

Figure 7.10 Earth fault simulations tripping time

Figure 7.10 reports the mean protection operating time for each network scenario. It is clear that the relatively longer mean operating times are for those scenarios where the NOPs are shifted from the normal position, e.g. scenario 2, scenario 3 and scenario 4.

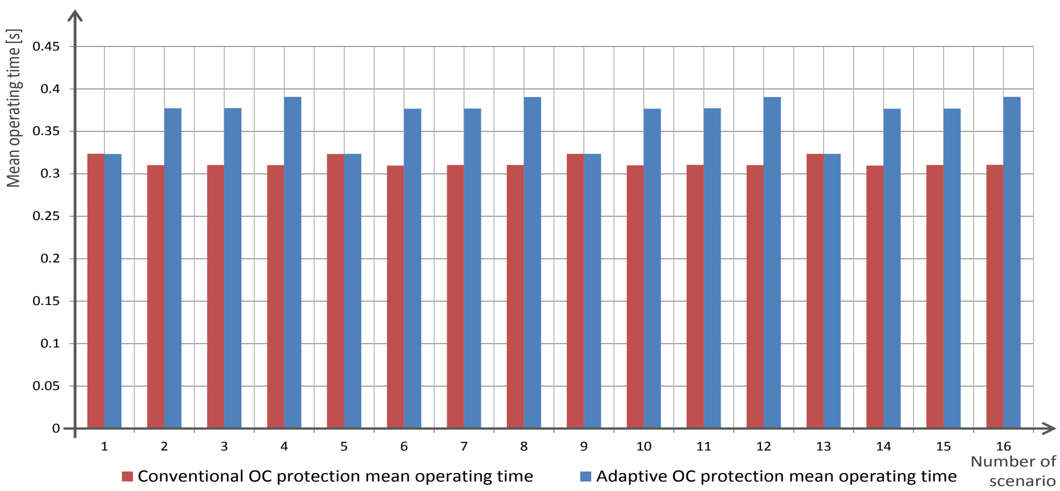

Figure 7.11 Conventional and adaptive earth overcurrent protection mean operating time

Figure 7.12 shows the correct operation, false operation and non-operation of the conventional earth overcurrent protection. It is clear that there are a number of faults that cause false operation, while the problem of non-operation does not appear.

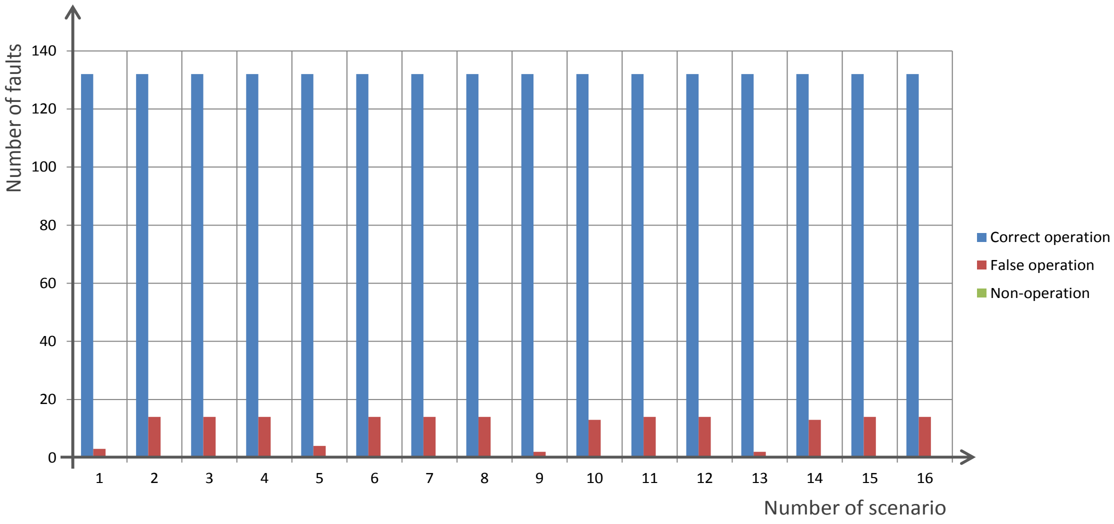

Figure 7.12 Conventional earth overcurrent protection - operational test results

Figure 7.13 show the correct operation, false operation and non-operation of the adaptive earth overcurrent protection. By comparing Figure 7.12 and Figure 7.13, it is clear that the adaptive overcurrent protection system significaltly reduces the number of false operations from 177 to 20, i.e. from 8.38% to 0.95% of the total number of simulated faults.

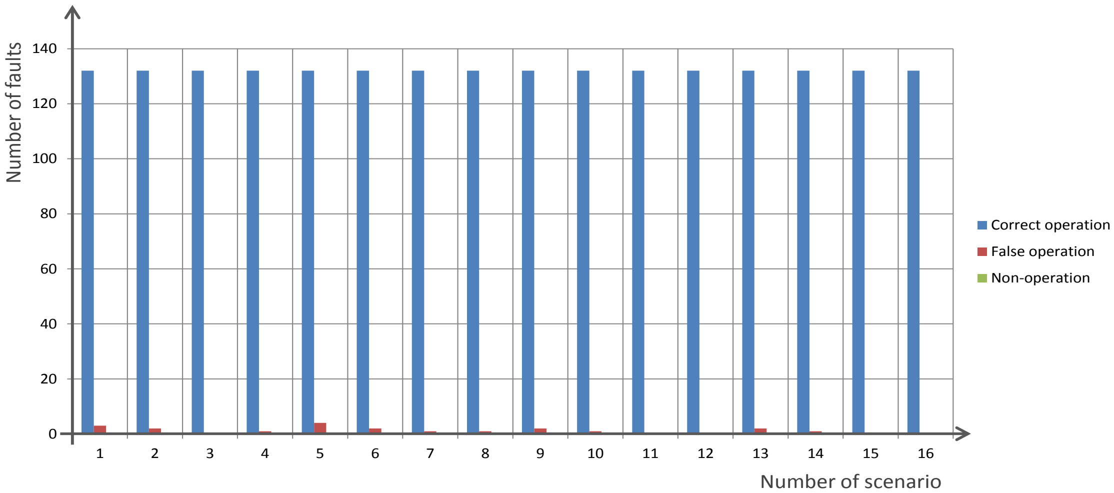

Figure 7.13 Adaptive phase overcurrent protection - operational test results

7.5 Validation of the adaptive inter-tripping scheme with back-up passive LOM

To validate the developed adaptive inter-tripping scheme, an extensive set of simulations have been performed. This set can be subdivided into a subset of simulations to test the protection sensitivity and a subset of simulations to test the protection stability, which are presented in section 7.5.1 and 7.5.2, respectively.

7.5.1 LOM protection sensitivity testing results

To test the protection sensitivity, the islanding of a section of the network has been simulated by the opening of AR-A during three different network topologies where the normally open points are:

A. S3 and S6
B. S4 and S6
C. S5 and S7

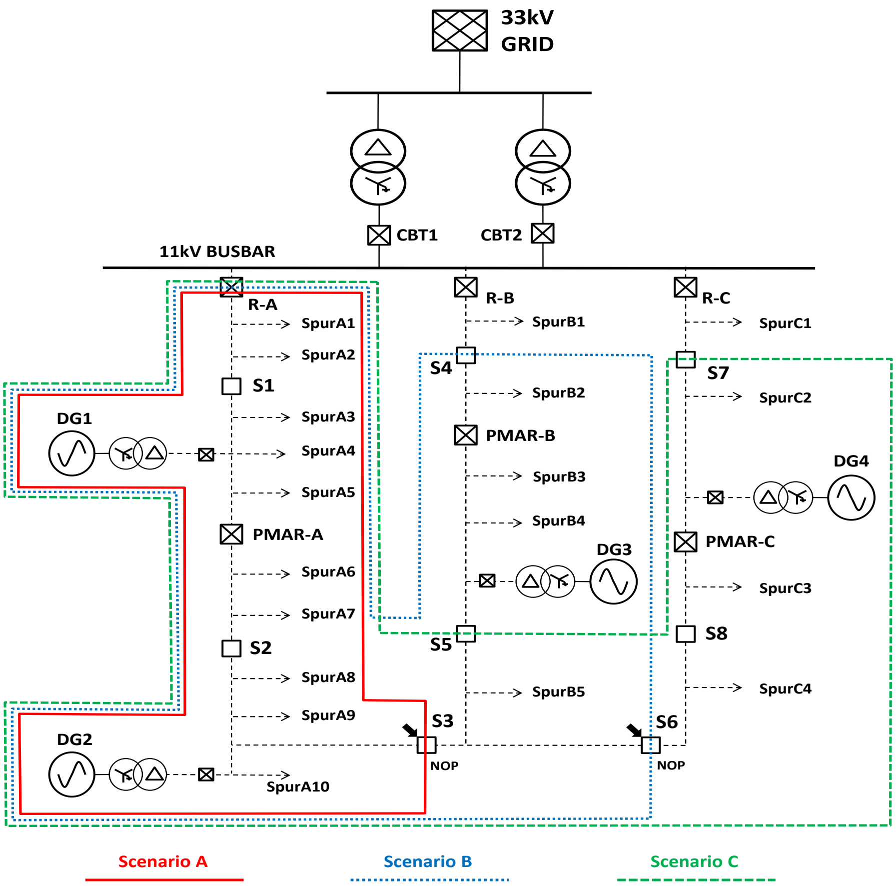

Figure 7.14 LOM sensitivity test network scenarios

The islanding simulation has been repeated for various values of the ratio between power generated and consumed on the feeder. The range of ratios is from 0.9 to 1.1 with a step of 0.05. This method has been used to verify if there is a NDZ associated with the LOM protection, and if an NDZ is found to exist, then its extent is quantified.

Simulations have been carried out for the three scenarios described below:

1. The distribution network is protected against LOM by passive LOM protection relays with fixed protection settings as explained in Appendix C;
2. The distribution network is protected against LOM by the developed adaptive inter-tripping scheme with back-up passive LOM;
3. The distribution network is protected against LOM by the developed adaptive inter-tripping scheme with back-up passive LOM, but with a partial failure of the communication system, i.e. one generator does not receive tripping commands from the AI IED;

The total number of simulated scenarios is nine and they are named A1, A2, A3, B1, B2, B3, C1, C2, and C3.

Figure 7.15 shows the tripping times for each of the passive LOM protections applied at DG1, DG2, DG3, and DG4 (with the protection settings presented in appendix C) for true islanding events with a range of load/generation ratios from 0.9-1.1 prior to islanding.

The results of the simulations show that an NDZ exists when the ratio between the total load and total generation in the three scenarios is between 0.945-0.955 and 1.045. One possible solution to reduce this NDZ could be to reduce the ROCOF protection settings, which are set to 0.2Hz/sec as recommended by G59/2 (see appendix C). This solution would reduce the NDZ, but it would not completely remove it. Furthermore, if the ROCOF protection setting is reduced, it will increase the incidence of unnecessary trips during non-LOM transients in the network, i.e. the LOM protection might become unstable.

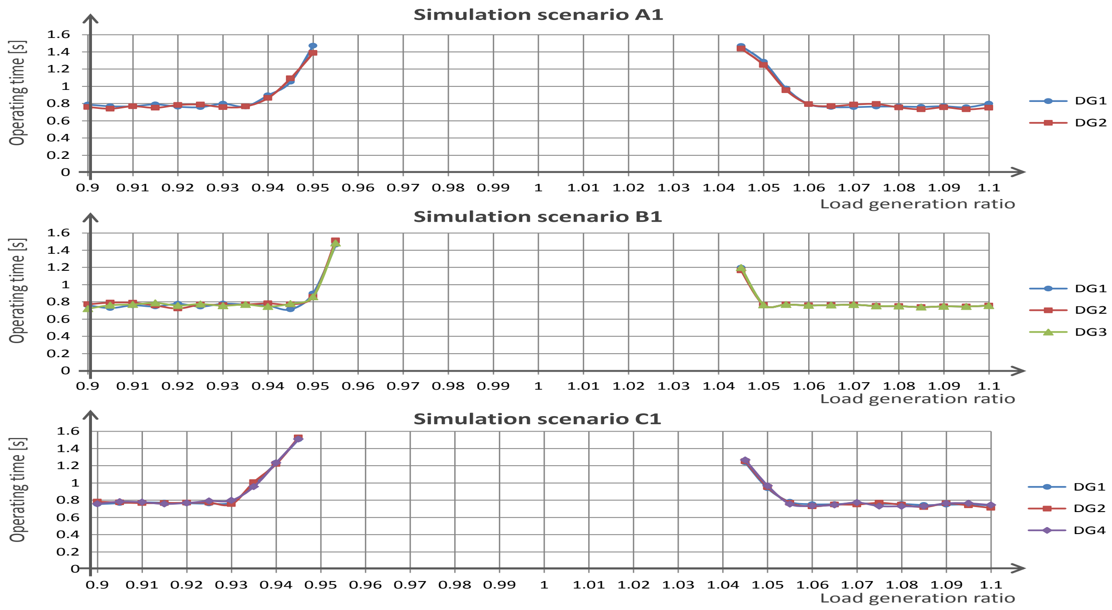

Figure 7.15 Protection sensitivity test results A1, B1 and C1

Figure 7.16 shows the operating time of the proposed adaptive inter-tripping protection system, which provides a faster LOM detection method when compared to the passive LOM protection and, critically, does not have an NDZ or suffer from stability problems.

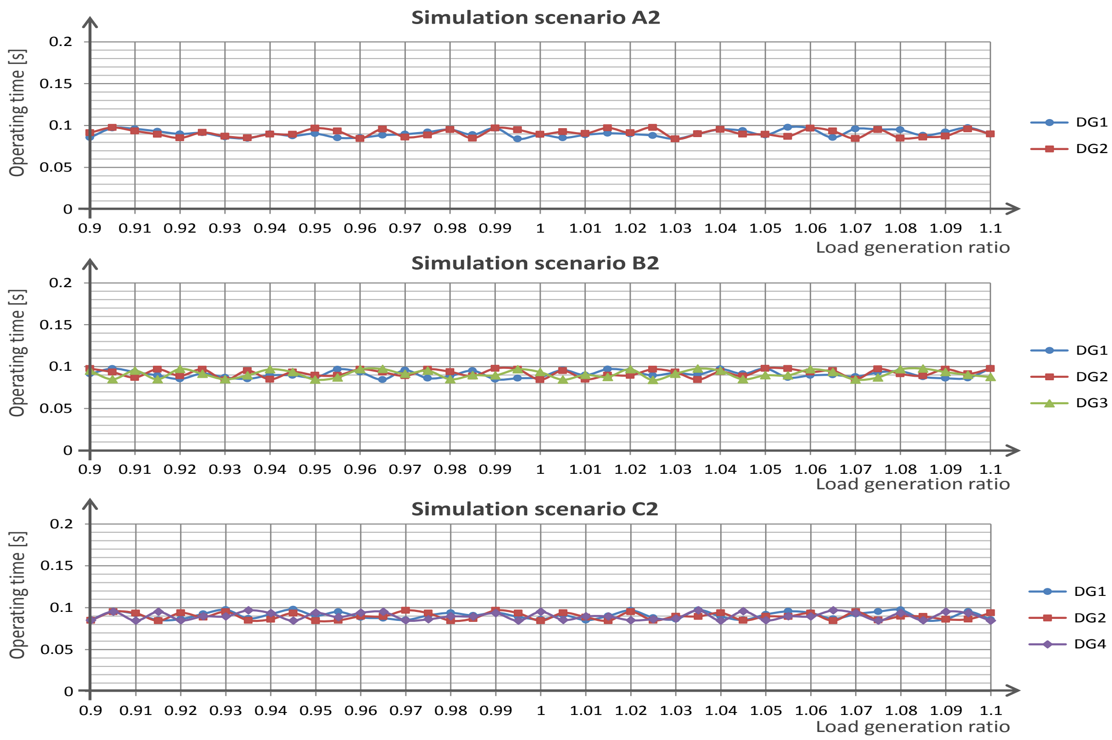

Figure 7.16 Protection sensitivity test results A2, B2 and C2.

The operating time of the adaptive inter-tripping protection system is between 0.08 and 0.1s, which is calculated by summing the communication time between AR-A OCR and AI-IED (which is 3ms, since both IEDs are in the same substation), the computation time of the AI-IED when implemented in a substation computer (5ms-20ms) and the communication time between AI-IED and DG units (75ms).

In the event of a communication failure between the AI-IED and one DG unit, the passive LOM protection provided by the local LOM protection relay guarantees that the DG unit will be disconnected while the rest of the DG units are disconnected by the adaptive inter-tripping scheme, which has a faster operation time.

Figure 7.17 shows the tripping time of the LOM protection system, which is between 0.7s and 0.8s for DG1 and between 0.08 and 0.1s for the other DG units. The passive LOM protection, which protects DG1, does not have an NDZ because even if the load and generation ratio of the power island is close to 1 before islanding, the operation of the adaptive inter-tripping scheme will remove the other DG units, increasing the unbalance between local load and generation from DG1's perspective.

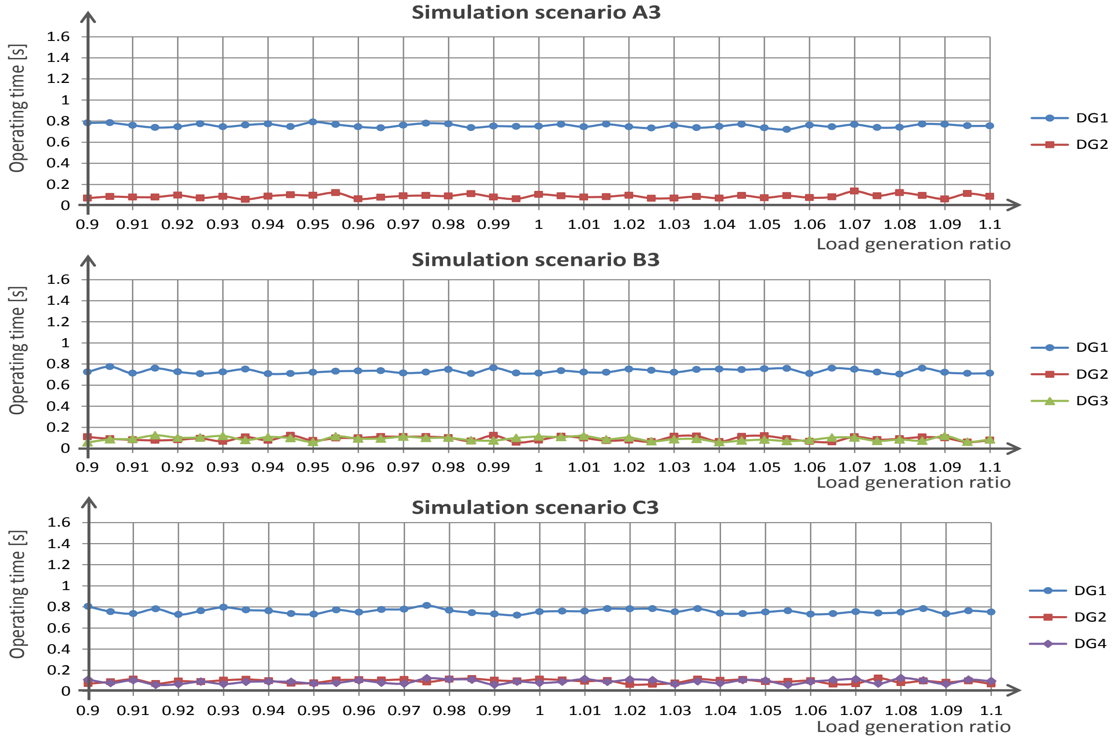

Figure 7.17 Protection sensitivity test results A3, B3 and C3.

7.5.2 LOM protection stability testing results

To test the stability of the LOM protection system, phase to phase faults are simulated in twelve locations as shown in Figure 7.4, which cause voltage and frequency fluctuations that might lead to unnecessary disconnection of the DG units.

The faults are simulated under three different network topologies, where the normally open points are:

A. S3 and S6;
B. S4 and S6;
C. S5 and S7;

For each network scenarios phase to phase faults are applied at twelve locations with a fault resistance between 0Ω and 10Ω (0Ω, 1Ω, 2Ω, etc.).

The fault level has been simulated at 500MVA to represent a network scenario with strong fault contribution from the grid and at 50MVA with one substation transformer not in service to represent a network scenario with weak fault contribution from the grid. These fault level scenarios are numbered 1 and 2, where 1 is the strong fault infeed and 2 is the weak fault infeed.

The total number of scenarios is six, which are named A1, B1, C1, A2, B2 and C2.

Figure 7.18 and Figure 7.19 show the number of correct operation, successful fault ride through and false operation of the conventional passive LOM protection system when there is strong and weak fault infeed, respectively.

The number of correct operation of the LOM, i.e. when the LOM protection disconnects the DG connected to the faulted section of the network is of 33.3% independently to the fault level because, after the over-current protection system isolates the faulted section of the network, voltage and frequency fluctuates causing the operation of the passive LOM protection relays.

The number of false operations of the LOM protection system is 2.6% when the fault infeed is strong (scenarios A1, B1 and C1) and 12.9% when the fault infeed is weak (scenarios A2, B2 and C2).

Successful ride through, i.e. when DG units connected externally to the faulted section remain connected and contribute to the fault, assisting with preserving the stability of the network, is of 64% when the fault infeed is strong and 53.7% when the fault infeed is weak.

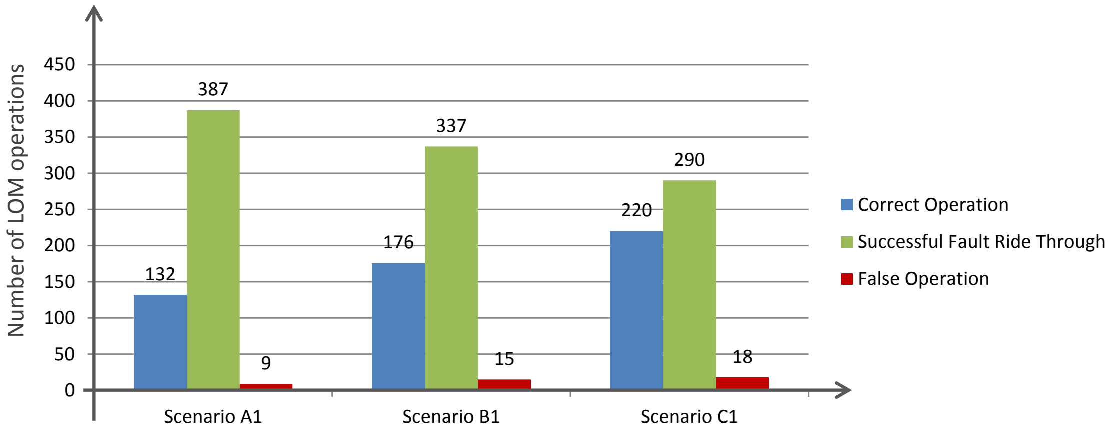

Figure 7.18 Conventional passive LOM protection operation in scenarios A1, B1 and C1

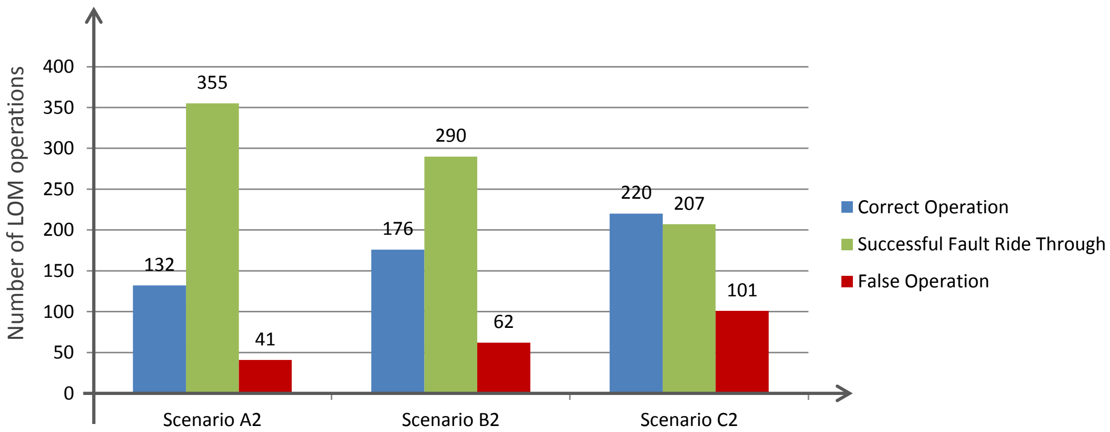

Figure 7.19 Conventional passive LOM protection operation in scenarios A2, B2 and C2

Figure 7.20 and Figure 7.21 shows the number of correct operations, succesful fault ride through and false operation of the adaptive inter-tripping with passive back-up LOM protection.

When the network has a strong fault infeed (scenarios A1, B1 and C1), false operations of the LOM protection are complitely avoided, while when the netwrok has a weak fault infeed (scenarios A2, B2 and C2), there is a significant imprroment, i.e. a reduction of the false operations from 12.9% to 4.7%.

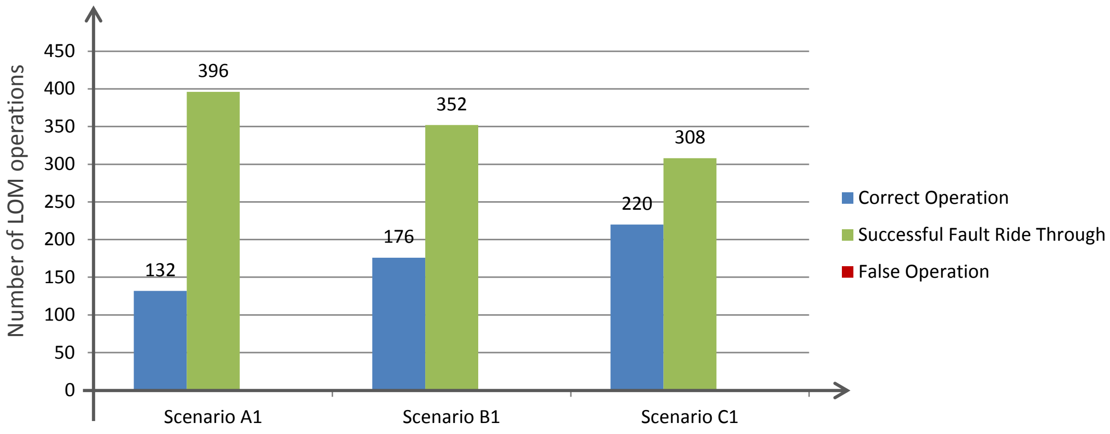

Figure 7.20 Adaptive inter-tripping with back-up passive LOM protection operation in scenarios A1, B1 and C1

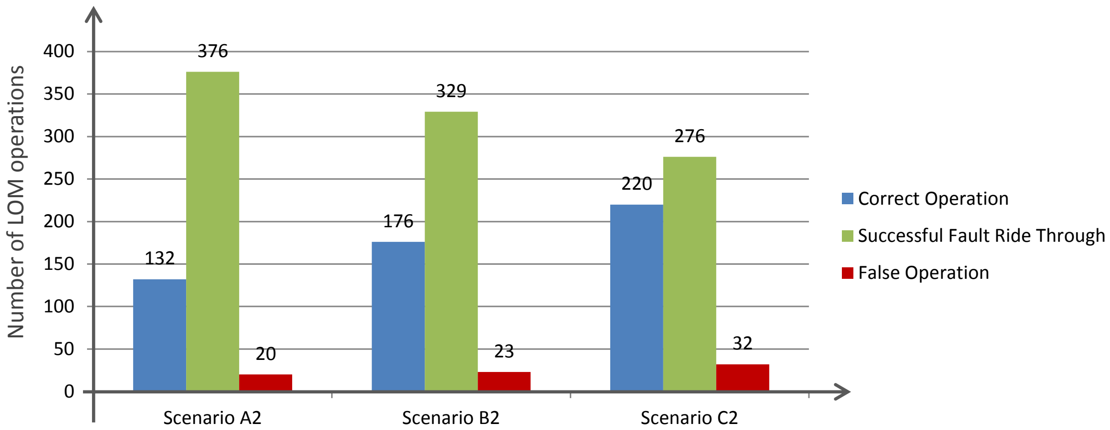

Figure 7.21 Adaptive inter-tripping with back-up passive LOM protection operation in scenarios A2, B2 and C2

7.6 Chapter summary

This chapter has presented the validation results for both the adaptive overcurrent protection system and adaptive inter-tripping scheme, describing in detail how the dynamic type testing of the systems has been performed using an HIL simulation environment.

The results have demonstrated the advantages of both developed adaptive protection solutions. The adaptive overcurrent protection system is faster when compared with a conventional overcurrent protection system and the number of scenarios where tripping times are in excess of 1sis reduced from 7.15% to 1.8% for phase faults, while for earth faults the operation time is less than 0.6s, comparable with conventional earth overcurrent protection. Furthermore, the adaptive overcurrent protection system also significantly reduces the number of false operations from 4.72% to 1.61% for phase faults and from 8.38% to 0.95% for earth faults.

The adaptive inter-tripping scheme has been demonstrated to completely overcome the sensitivity problem associated with all passive LOM protection systems. It is capable of detecting true LOM conditions regardless of the load/generation ratio of the power island. The results also demonstrate that in the case of loss of communications to one DG unit, the back-up passive LOM protection detects the LOM condition and does not exhibit an NDZ. Furthermore, the developed solution possesses enhanced stability when compared with conventional passive LOM protection systems. The results show a reduction of the instances of false tripping from 19.2% to 6.1% of the total number of fault ride through tests.

7.7 References

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Chapter 8:

Conclusions and future work

8.1 Conclusions

This thesis has presented the findings of an extensive analysis of the potential protection problems associated with present and future active distribution networks in the UK. Two of the main protection problems discussed in the literature, namely blinding and false tripping of overcurrent protection, have been effectively disproved, while other protection problems highlighted in the literature have been confirmed and demonstrated. The demonstrated problems include false tripping of directional overcurrent protection applied to primary substation transformers, deterioration of network overcurrent protection grading, and false operation and non-operation of LOM protection. Possible solutions to each protection problem have been analysed and two novel solutions to the demonstrated problems associated with overcurrent and LOM protection have been presented. The first is an adaptive overcurrent protection system with automatic settings calculation, while the second is an adaptive inter-tripping scheme with back-up passive loss of mains protection system. Both of the developed solutions have been validated in an HIL simulation environment and the performance of the protection solutions has been compared to conventional overcurrent and LOM protection systems, which are designed and configured in accordance with UK DNO protection policies.

8.1.1 Analysis of the protection problems

The protection problems associated with present and future distribution networks have been investigated by simulating, in real time, a typical UK rural 11kV distribution network with a protection system designed in accordance with DNO protection policies, implemented in an HIL simulation environment.

The performance of the protection system has been analysed in the presence of DG at different penetration levels and considering the effects of network automation activity that may act to change network topology.

In terms of novelty, the principal contributions of this detailed analysis are:

a) The problem of blinding has been disproved, even under realistic worst case scenario conditions. The simulations have demonstrated that during phase faults the impact is minimal and blinding is very unlikely to happen, while during earth faults, DG actually has the "opposite" effect, i.e. rather than increasing the risk of blinding, DG acts to improve the sensitivity of the overcurrent protection for earth faults. This is due to the fact that DG is normally connected by a star/delta step-up transformer (at 11kV and above) and therefore the fault current contribution increases the zero sequence fault current component measured by the upstream OCR, increasing its protection sensitivity. When IDMT protection characteristics are used for phase fault protection, the operating time slightly increases in the presence of DG. The increases in operating time have been quantified for several scenarios and it can be concluded that these increased times would not cause significant problems.

b) The problem of false tripping of over-current protection relays in feeders adjacent to the faulted feeder has been proved and quantified when DTL overcurrent protection is used. It has been demonstrated that this problem of false tripping can be solved using both IDMT and DTL, where IDMT is used to provide good protection sensitivity and DTL is used to improve the speed of operation for relatively higher fault currents.

c) It has been demonstrated that ANM schemes affect the correct coordination between OCRs when ANM acts to modify the network topology of the network. An example has been used to show how the protection system responds to phase and earth faults when the network topology has been changed.

8.1.2 Adaptive overcurrent protection with automatic protection settings calculation

An adaptive overcurrent protection system has been developed to provide improvements in selectivity and operation speed when compared to a traditional overcurrent protection system. Improved protection selectivity is desirable as it reduces both the total number of Customer Interruptions (CI) and Customer Minutes of Interruptions (CMI), while faster operation is desirable as it reduces the duration of voltage sags, the probability of unnecessary disconnection of DG units and the amount electro-mechanical stress on devices conducting the fault current.

The novelty of the developed adaptive overcurrent protection system is in its algorithm, which differs from other adaptive protection solutions presented in the literature in terms of possession of higher flexibility, comprehensive coverage of all events that may influence the protection system and reactive/proactive design.

It is more flexible with respect to other solutions presented in the literature, which are largely based on pre-calculated protection settings and settings groups. The limitations of using setting groups with pre-calculated settings is overcome by calculating the OCRs' protection settings every time the configuration of the network is changed. If it is deemed that new settings are required, then they are applied to the OCRs, after verification of their effectiveness using a model-based evaluation of performance.

This is achieved by considering the present status of the network and calculating the protection settings using an approach that is different from the normal graph method adopted by utilities.

Utilities normally perform grading from upstream to downstream, considering the worst-case scenario with the graph method; however, the adaptive protection controller (APC) calculates the settings from downstream to upstream, considering the presently prevailing scenarios of network topology, DG connection and fault level, and using an iterative calculation approach. This approach has the advantage of optimising the protection settings for the prevailing status of the network and thereby minimising the operating time of the overcurrent protection with a consequent reduction in the duration of voltage sags, an improvement in the stability of the network and a maximisation of the ability of DG to ride through network faults.

It is more comprehensive with respect to other solutions presented in the literature because it does not consider only the impact of DG connection, which seems to be the only problem addressed by other authors, but it considers also other factors that have an impact that is as important as DG and in some cases even more (e.g. variations in fault level due to grid infeed changes, modifications in network topology due to the actions of ANM).

It is reactive and proactive to changes in the networks while other solutions presented in the literature are designed to be only reactive, which means that the adaptive protection system can also react to changes before they become an issue, for instance when there are planned disconnections of lines for maintenance purposes.

Other solutions presented in the literature are largely based on pre-calculated protection settings and settings groups. The main advantage of the developed adaptive overcurrent protection system with automatic settings calculation compared to an adaptive protection system based on a look-up table are its better flexibility, manageability and updateability. It is more flexible because it does automatically calculate and apply the protection settings without the requirement to identify a defined number of network scenarios and pre-calculate the protection settings for each of them. It is easily manageable and updateable because if the network changes it is sufficient to provide information about the change instead of requiring a complete re-thinking of the adaptive protection scheme as it would be in the case of look-up table. For instance, if new automation schemes are added, then there is no need to update the protection scheme because there are no predefined network scenarios, while if the network is upgraded with new DG units or new lines, then it is sufficient to update the network file without the necessity to re-define the network scenarios and repeat the protection setting exercise for all network scenarios.

The adaptive over-current protection system has been implemented in the laboratory using the RTDS to model the primary system, implementing the protection algorithm in a substation computer and connecting (in an HIL environment) IEC-61850 compliant overcurrent protection relays. The DNP3 communication protocol has been used for communication between the primary system (simulated in the RTDS) and the substation computer, while IEC 61850 reports have been adopted to access and modify the protection settings of the relays.

8.1.3 Adaptive inter-tripping scheme with passive back-up loss of mains protection

The developed adaptive inter-tripping scheme has the potential to offer the most direct and effective method for LOM detection. It is conceptually different from passive techniques in that it can operate without the requirement to measure any electrical system parameters and it is different from presently used inter-tripping schemes in that it does not use fixed logic, but incorporates a flexible algorithm. The flexibility of this solution has the advantage of allowing network topology reconfigurations and the addition of DG units without adding complexity to the scheme, which is a limitation of traditional inter-tripping schemes.

This method increases the reliability of LOM protection by combining the inter-tripping solution with existing traditional passive LOM protection. In the case of communication failure, the local protection relays can be used as backup to provide protection against LOM. False trips from the local relays (using passive methods) may be prevented by blocking their trip outputs and/or using less sensitive settings when the communication system is intact.

The system also allows islanded operation of sub-networks where the generators are capable of supplying the island's loads and can maintain voltage and frequency within permissible operating levels. It is anticipated that islanded operation may be desirable and consequently permissible in future, particularly when the penetration of DG increases to higher levels. The centralised loss of mains protection can also protect islanded sub-networks within its overall zone of supervision against LOM.

The method does obviously require a communication network, which may presently be viewed as prohibitively costly for distribution networks. However, it is believed that this barrier will be overcome in the near future as protection, automation and control increasingly share communication infrastructures, reducing the cost impact. It is also anticipated that communications systems in general will become even more pervasive than is presently the case, and that costs, reliability and robustness of communications networks will all improve, resulting in significant opportunities to improve the operation, control and protection of future power systems.

The passive back-up LOM protection improves the reliability of the presented solution. It guarantees disconnection of islanded DG units even in cases where there is a temporary or permanent communication problem between the AI IED and one or more DG units. The problem of false operation of passive LOM relays is also minimised by relaxing the protection settings of the relays when the inter-tripping scheme is active and there are no detected communications problems.

The adaptive inter-tripping scheme with passive back-up LOM protection has been implemented in the laboratory using the RTDS to model the primary system, implementing the protection algorithm in a substation computer and connecting (in an HIL environment) the passive LOM protection relays. For the communication, IEC 61850 GOOSE has been adopted for its speed of communication and its ability to facilitate interoperability with different manufactures' IEDs. IEC 61850 reports have been adopted to access the protection settings of the relays.

8.1.4 Validation of the solutions

Following the development and demonstration of the proposed adaptive protection systems with simulation examples, both systems have been validated and compared with conventional over-current and LOM protection systems.

The results have demonstrated the advantages of both adaptive solutions. The adaptive overcurrent protection system has two main advantages over conventional overcurrent protection systems, which are shorter mean operating times and reduced incidence of false tripping. Considering the total of 2,112 simulated phase faults, the number of tripping times that are longer than 1s are reduced from 7.15% to 1.8%, while for the 2,112 simulated earth faults, the tripping time is always less than 0.6s for both conventional and adaptive overcurrent protection. Considering the 2,112 simulated phase faults, the number of false operations of protection is reduced from 4.72% for the conventional overcurrent protection system to 1.61% for the adaptive overcurrent protection system, while for the 2,112 simulated earth faults it is reduced from 8.38% to 0.95%.

The adaptive inter-tripping scheme has been demonstrated to completely overcome the sensitivity problem associated with passive LOM protection. It is capable of detecting true LOM conditions regardless of the load/generation ratio within the power island prior to islanding. The results also demonstrate that in cases where communication is lost to one DG unit, the back-up passive LOM protection detects the LOM condition and will not have an NDZ problem due to the disconnection of any other DGs in the island by the inter-tripping scheme causing a large load/generation imbalance form the perspective of the single DG.

The developed solution also possesses higher levels of stability with respect to conventional LOM protection. The results shows a reduction of false operation of the passive LOM protection relays from 19.2% to 6.1% for the total number of fault ride events that the DG units are tested for within the overall set of simulations.

In general, the developed solutions perform significantly better that the conventional protection systems; however further improvements are possible. For example, the implementation of directional overcurrent relays in the adaptive protection system would further reduce the tripping time of the overcurrent protection system and could allow the problem of false tripping to be completely overcome.

8.2 Future research work

Following on from the extensive studies on the potential protection problems that UK 11kV distribution networks will face as DG penetration increases and ANM solutions are adopted, future research is required to extend the studies to include:

- Analyses of the protection problems at LV, where there is a potentially massive DG penetration characterised by PV technologies with very intermittent operation and absence of LOM protection;
- Analyses of the protection problems at 11kV due to unbalanced loads connected at LV, which in some circumstances could lead to power flows on the three phases that are significantly different or even in opposite directions;
- Analyses of the protection problems at higher voltages than 11kV, such as 33kV, where the network is meshed, the rating of the DG units is larger, and the voltage and frequency fluctuations during disturbances might be increasingly significant as the traditional power plants are decommissioned and substituted with lower (or zero) inertia generators, such as inverter-interfaced generators.

Following on from the developed solutions presented in this dissertation, future research is required to focus on:

- The application of the proposed solutions at LV and higher voltages, where different problems and different protection practices are adopted; an evaluation of the performance of the solutions in such different applications is required.
- The validation of the proposed solution in other networks applications using the proposed validation methodology.
- Implementation of the proposed schemes using representative communications hardware (for example switches, routers, traffic emulators) to fully quantify the performance requirements of the communications network for both the adaptive overcurrent and adaptive LOM protection solution and to investigate the impact of communication errors and communication failures between two or more IEDs.
- Implementation in the field to trial the developed adaptive protection solutions. This could be achieved using the new Power Networks Demonstration Centre at the University of Strathclyde, which is opening in January 2013.

Appendices

Appendix A. Test case distribution network

The test case network used in chapter 4 to analyse the impact of DG and ANM on network protection system and in the following chapters 5, 6 and 7 to demonstrate the developed adaptive overcurrent protection and adaptive LOM protection systems is the 11kV overhead rural distribution network shown in Figure A.1.

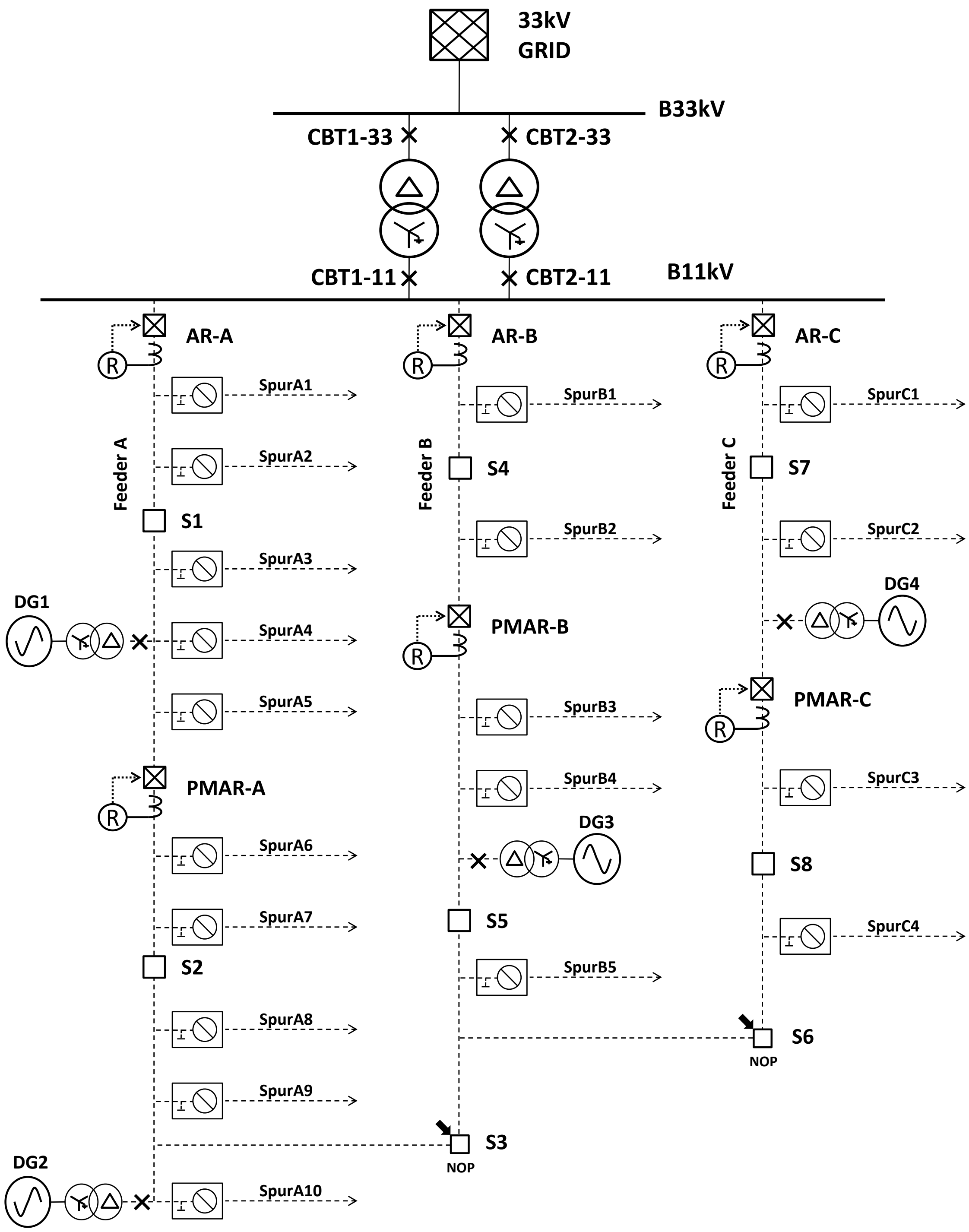

Figure A.1 **UKGDS OHA test case network diagram**

The network model is the “OHA Network”, as specified in the United Kingdom Generic Distribution Network (UKGDS). The model is representative of a typical rural overhead distribution network and the network data is available online at [1].

Table A.1 reports the electrical parameters of the substation transformers and Table A.2 some of the main parameters of the network, such as rating, feeder length and impedance. The per unit values are expressed on the 100MVA base.

Table A.1 Substation transformer data

	Substation transformers
Rating	12MVA
Winding connection	Dy11
Earthing	Solid (0Ω)
Resistance	0.0723pu
Reactance	1.3081pu
Zero Seq Resistance	0.0651pu
Zero Seq Reactance	1.1771pu

Table A.2 presents the main electrical parameters of the three feeders, which have different rating and length, and therefore differ on the total positive, negative and zero sequence impedance. The impedance is in per unit values and are expressed on the 100MVA base.

Table A.2 Feeders data

	Feeder A	Feeder B	Feeder C
Rating	400A	250A	250A
Length	8.6km	3.5km	2.2km
R1	1.13pu	1.59pu	1.01pu
X1	2.31pu	1.08pu	0.68pu
R0	2.19pu	2.02pu	1.27pu
X0	11.15pu	4.65pu	2.93pu

Feeder A, B and C supply 10, 5 and 4 spurs respectively. These are named in Figure A.1 as Spur A1 – Spur A10, Spur B1 – Spur B5, and Spur C1 – Spur C4. The spurs have a tree structure and supply 11/0.4kV transformers and 11/0.23kV single phase transformers. An example of spur is shown in Figure 2.

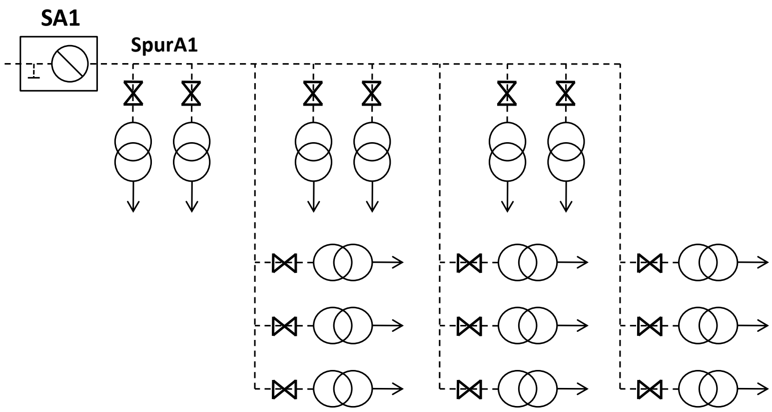

Figure 2 Example of a spur within the UKGDS OHA network

The minimum and maximum length and electrical parameters of the spurs are presented in table 3. The electrical parameters are expressed in per unit on the 100MVA base.

Table A.3 Spurs data

	Minimum	Maximum
Length	2.05km	3.12km
R1	1.15pu	1.75pu
X1	0.65pu	0.99pu
R0	1.41pu	2.13pu
X0	2.75pu	4.19pu

Appendix B. Overcurrent protection system with fixed protection settings

The protection system has been designed to accurately represent present-day UK networks and adheres to a protection policy that has been supplied by a UK DNO. As shown in Figure A.1, each feeder is protected by a multi-shot circuit breaker auto recloser (AR) at the source end of the feeder and by a pole mounted auto recloser (PMAR) situated at approximately 50% along the length of the feeder. Then, spurs are connected to the main feeder through spur sectionalisers rather than via fuses, due to the apparent trend for DNOs to substitute fuses with spur sectionalisers in future distribution networks.

ARs and PMARs can be configured to employ either Inverse Definite Minimum Time or definite time lag characteristics for phase fault protection. This choice is dependent on specific DNO protection policy, while earth fault and sensitive earth fault protection typically utilise DTL characteristics in all cases.

Overcurrent phase fault protection settings have been calculated with both IDMT and DTL protection characteristics using current time logarithmic graphs, to follow the traditional DNO calculation approach. Figure B.1 shows the phase fault IDMT protection characteristics and Figure B.2 shows the phase fault DTL protection characteristics. Finally, Figure B.3 presents the earth fault (EF) and sensitive earth fault (SEF) DTL protection characteristics.

The protection settings are then summarised in Table B.1, where protection settings A represent the protection settings normally applied by DNOs which prefer to use IDMT overcurrent protection characteristics, while protection settings B represent the protection settings that are normally applied by DNO which prefer to use DTL protection characteristics.

Table B.1 Network protection settings

<table>
<tr><th></th><th>Protection Function</th><th>Protection settings A</th><th>Protection settings B</th></tr>
<tr><td rowspan="3">CBT1-11, CBT2-11</td><td>3PH OC 2 STAGES</td><td colspan="2">ST1: IEC SI; I_{pickup} =650A; TMS=0.3
ST2: IEC SI; I_{pickup} =650A; TMS=0.25</td></tr>
<tr><td>DPH OC</td><td colspan="2">IEC SI; I_{pickup} =125A; TMS=0.1</td></tr>
<tr><td>EF OC 2 STAGES</td><td colspan="2">ST1: IEC SI; I_{pickup} =95A; TMS=0.25
ST2: IEC SI; I_{pickup} =125A; TMS=0.3</td></tr>
<tr><td rowspan="4">R-A</td><td>3PH OC</td><td>IEC SI; I_{pickup} =400A; TMS=0.2</td><td>IEC DTL; I_{pickup} =400A; DTL=0.320</td></tr>
<tr><td>3PH OC</td><td colspan="2">I_{pickup} =1200A; DTL=0.320s</td></tr>
<tr><td>EF OC</td><td colspan="2">I_{pickup} =30A DTL=0.320s</td></tr>
<tr><td>SEF OC</td><td colspan="2">I_{pickup} =20A DTL=5s</td></tr>
<tr><td rowspan="4">PMAR-A</td><td>3PH OC</td><td>IEC SI; I_{pickup} =300A; TMS=0.1</td><td>IEC DTL; I_{pickup} =300A; DTL=0.160</td></tr>
<tr><td>3PH OC</td><td colspan="2">I_{pickup} =1000A; DTL=0.160s</td></tr>
<tr><td>EF OC</td><td colspan="2">I_{pickup} =30A DTL=0.160s</td></tr>
<tr><td>SEF OC</td><td colspan="2">I_{pickup} =20A DTL=3s</td></tr>
<tr><td rowspan="4">R-B,
R-C</td><td>3PH OC</td><td>IEC SI; I_{pickup} =250A; TMS=0.2</td><td>IEC DTL; I_{pickup} =250A; DTL=0.320</td></tr>
<tr><td>3PH OC</td><td colspan="2">I_{pickup} =900A; DTL=0.320s</td></tr>
<tr><td>EF OC</td><td colspan="2">I_{pickup} =30A DTL=0.320s</td></tr>
<tr><td>SEF OC</td><td colspan="2">I_{pickup} =20A DTL=5s</td></tr>
<tr><td rowspan="4">PMAR-B, PMAR-C</td><td>3PH OC</td><td>IEC SI; I_{pickup} =150A; TMS=0.1</td><td>IEC DTL; I_{pickup} =150A; DTL=0.160</td></tr>
<tr><td>3PH OC</td><td colspan="2">I_{pickup} =700A; DTL=0.160s</td></tr>
<tr><td>EF OC</td><td colspan="2">I_{pickup} =30A; DTL=0.160s</td></tr>
<tr><td>SEF OC</td><td colspan="2">I_{pickup} =20A; DTL=3s</td></tr>
</table>

Where: 3PH OC = three phase overcurrent, DPH OC = directional phase overcurrent, EF OC = earth fault overcurrent, SEF OC = sensitive earth fault overcurrent, INST = instantaneous, IEC SI = International electrotechnical commission standard inverse characteristic, IEC DTL = International electrotechnical commission definite time lag characteristic, I_{pickup} = Pick up current setting, TMS = time multiplier setting, and DTL = definite time lag.

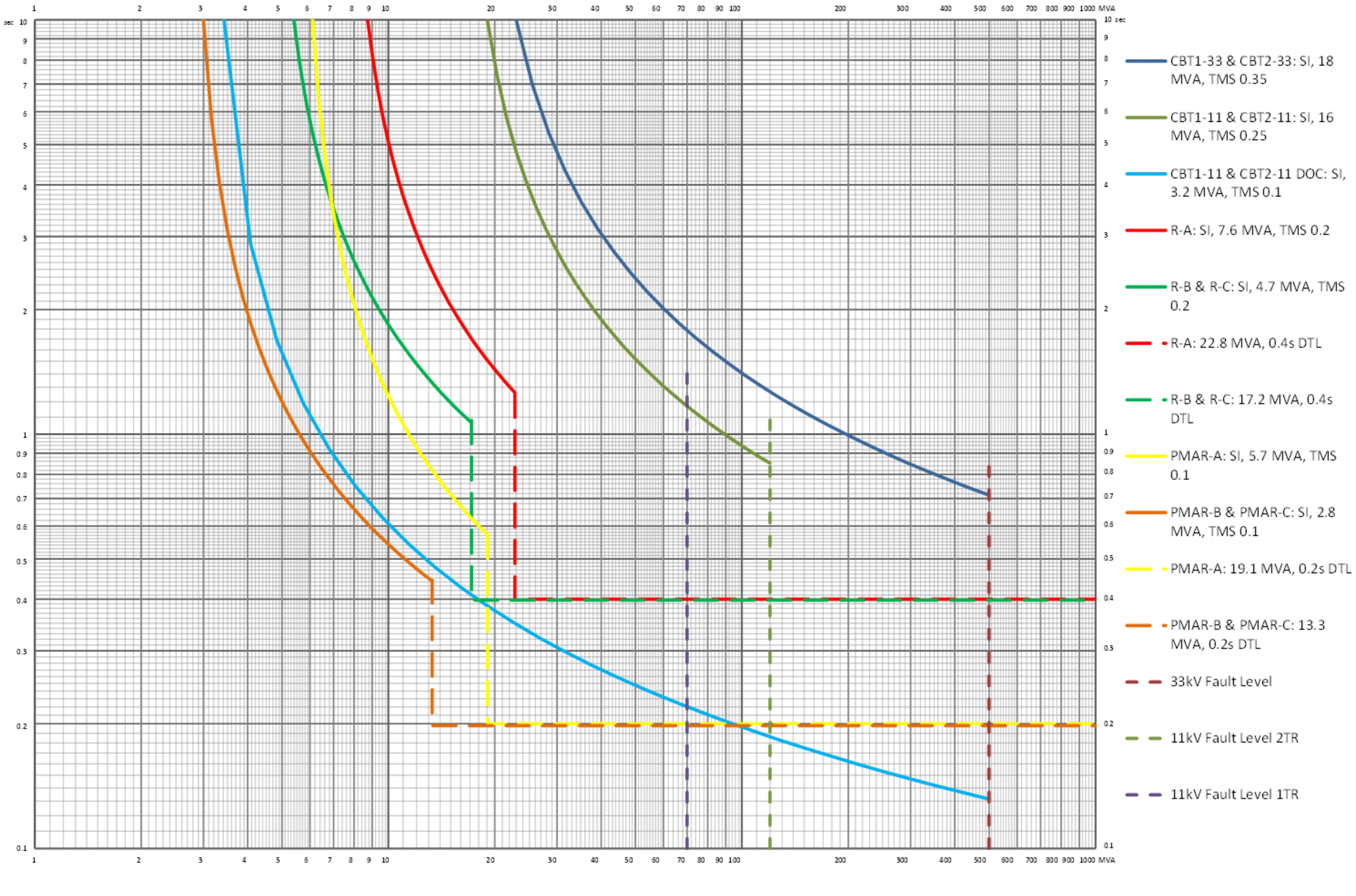

Figure A.1 Phase overcurrent protection IDMT grading

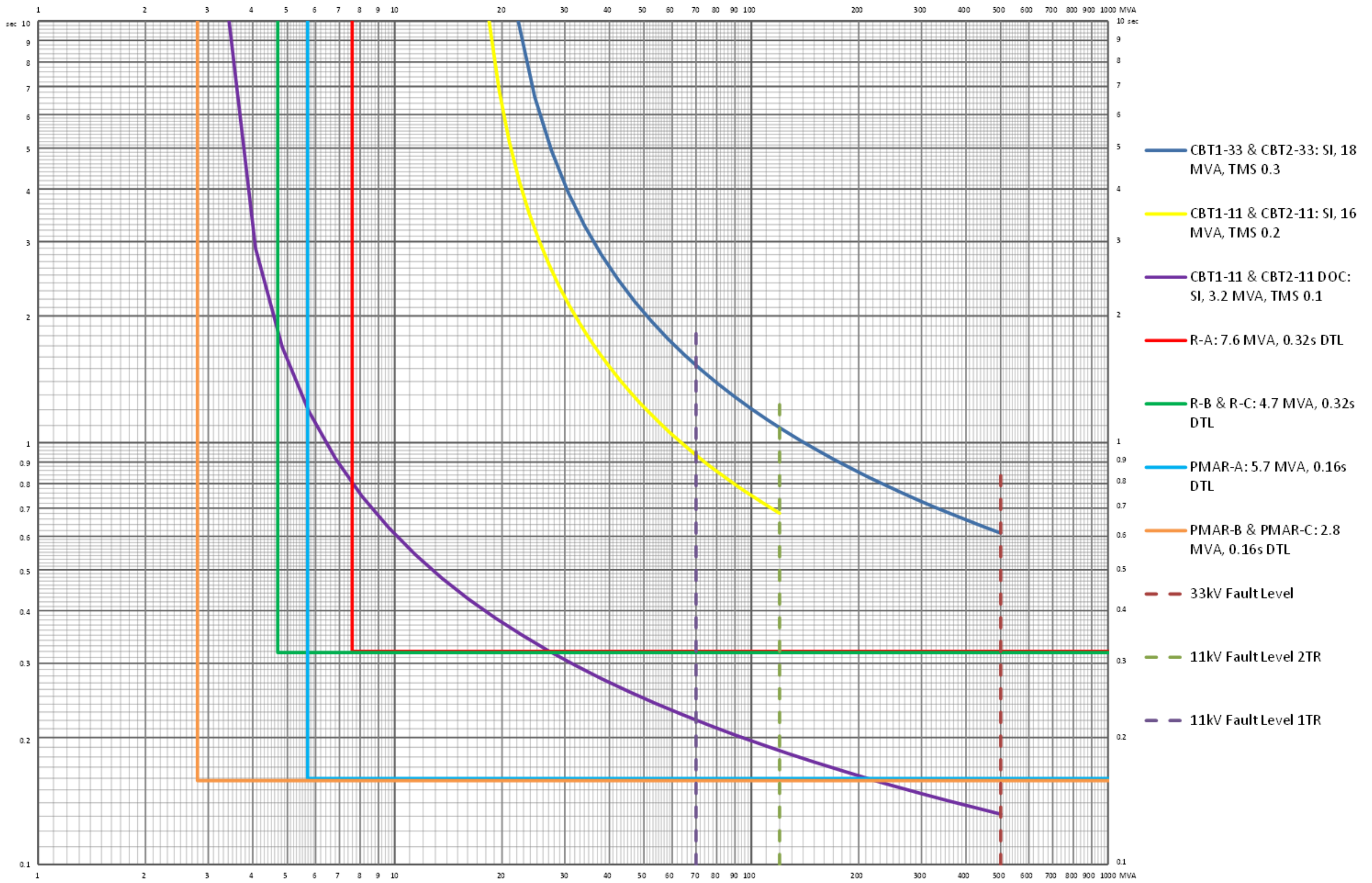

Figure B.2 Phase over current protection DTL grading

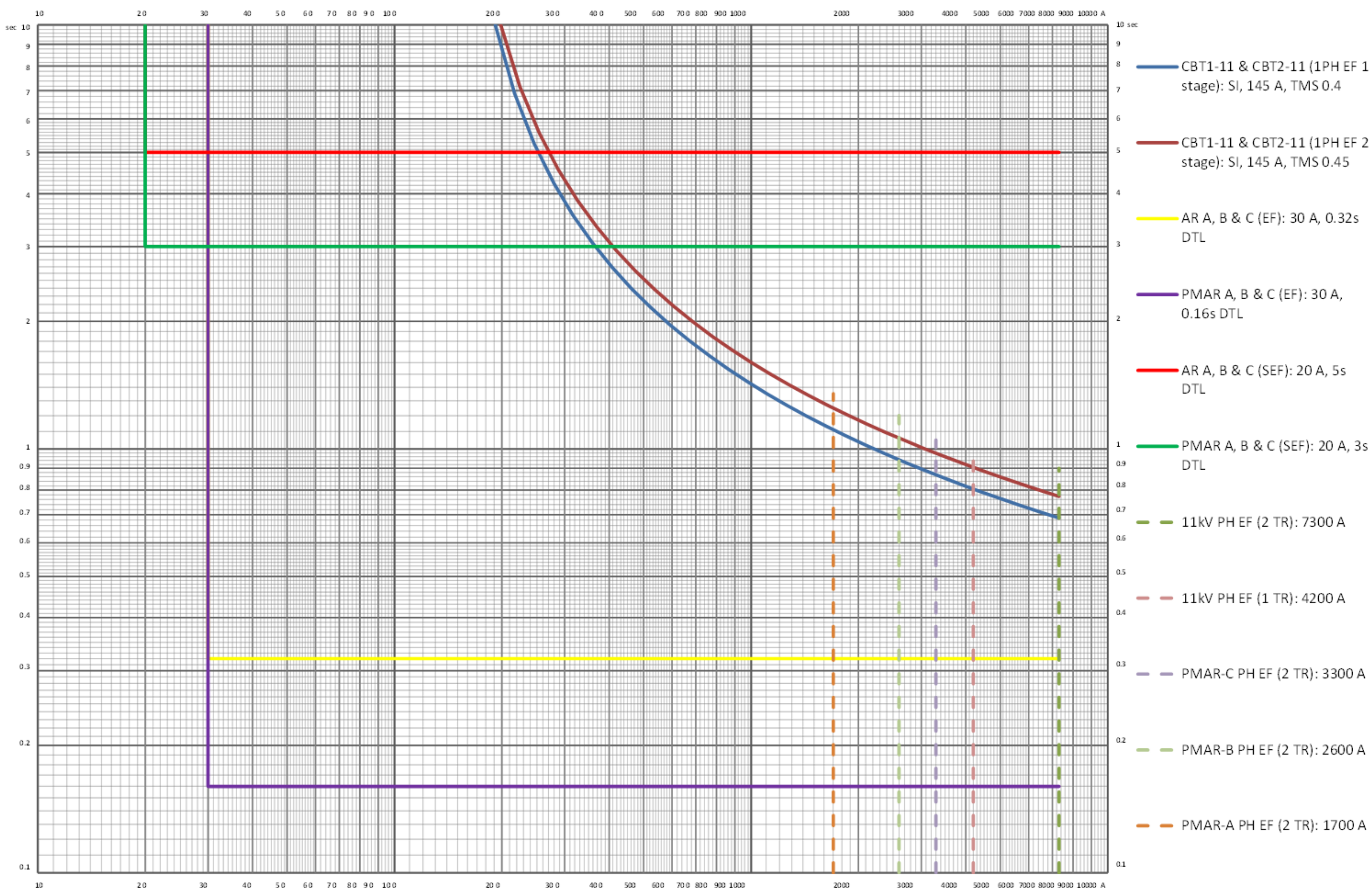

Figure B.3 Earth fault protection DTL grading

Appendix C. Distributed generation interface protection

The DG interface protection has been designed to be representative of present day practice in the UK and conforms with engineering recommendation G59/2 [2]. According to this standard and the distribution code it is the utility's responsibility to protect the network and therefore phase fault protection, earth fault protection and in some cases neutral voltage displacement are installed at the incoming CB. While, when it comes to the DG and its interface protection, it is the DG owner's responsibility. In addition to standard generator protection, the DG owner must ensure that islanding detection is applied as shown in Figure C.1. Table C.1 reports the ANSI device numbers used in Figure C.1.

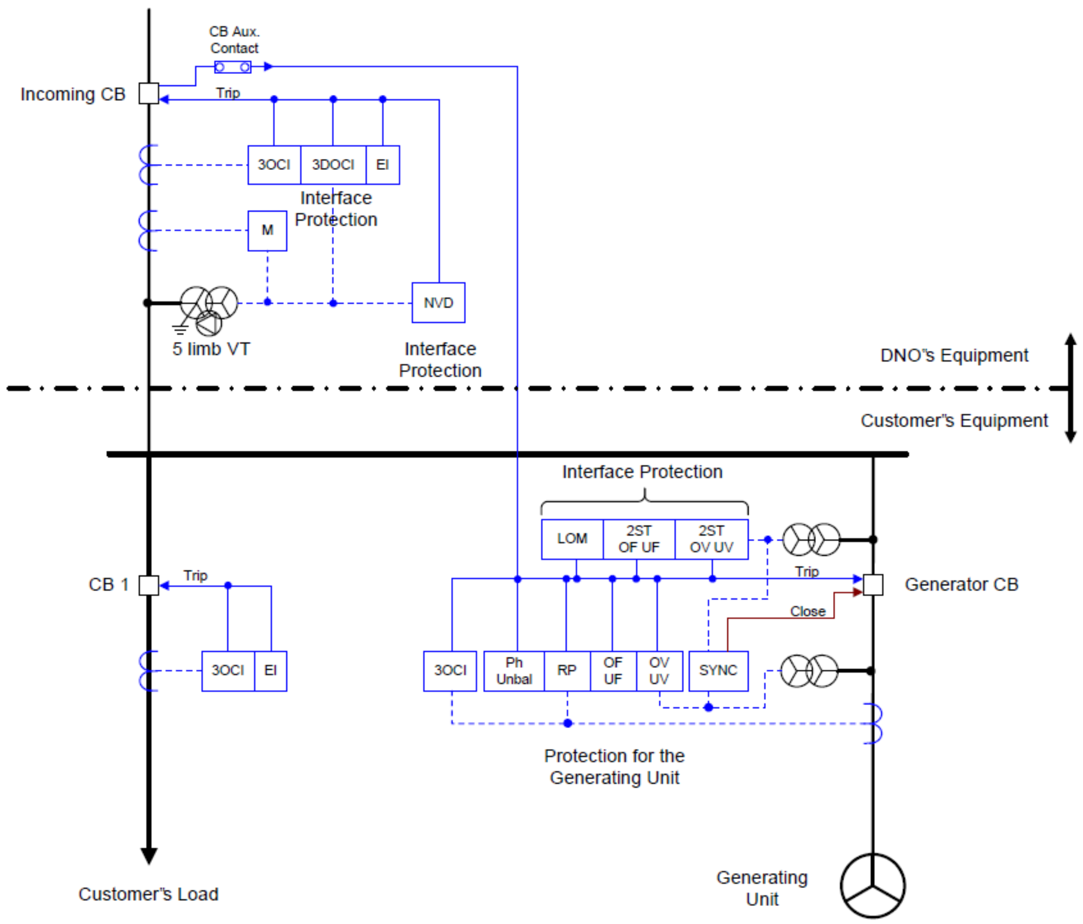

Figure C.1 DG interface protection [2]

Table C.1 ANSI Standard device numbers used in Figure C.1

ANSI	Protection function
25	Synchronizing or Synchronism-Check Device
27	Undervoltage Relay
46	Reverse-phase or Phase-Balance Current Relay
47	Phase-Sequence or Phase-Balance Voltage Relay
50	Instantaneous Overcurrent Relay
51	AC Inverse Time Overcurrent Relay
59	Overvoltage Relay
81	Frequency Relay

The protection functions implemented in the simulations that have been performed for this PhD thesis include both the protection functions that are responsibilities of the utility and the DG owners. Table C.2, which summarise the protection settings suggested in the engineering recommendation G59/2 [2].

Table C.2 DG interface protection settings

Protection function	Protection setting
UV stage1	-13% V_n, delay = 2.5 s
UV stage2	-20% V_n, delay =0.5 s
OV stage1	+10% V_n, delay =1.0 s
OV stage2	+13% V_n, delay =0.5 s
UF stage1	47.5 Hz, delay =20 s
UF stage2	47 Hz, delay =0.5 s
OF stage1	51.5 Hz, delay =90 s
OF stage2	52 Hz, delay =0.5 s
ROCOF	0.125Hz/s – 0.200Hz/s
P OC	120% I_n, IEC EI, TMS=0.1
EF OC	25% I_n, IEC EI, TMS=0.1

Where: UV = under voltage, OV = over voltage, UF = under frequency, OF = over frequency, Vn = nominal voltage, 3PH OC = three phase overcurrent, EF OC = earth fault overcurrent, In = Nominal current, IEC SI = International electrotechnical commission extremely inverse characteristic, and TMS= time multiplier setting.

Appendix D. Adaptive over-current protection settings

This appendix reports phase and earth fault protection settings that have been automatically calculated and applied to the OCRs by the adaptive overcurrent protection system during the simulation of the sixteen scenarios described in chapter 5.

Table D.1. Phase and Earth fault protection settings for scenario 1.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	400	0.16	1000	0.32	30	0.32
OCR-PMAR-A	SI	250	0.1	625	0.16	30	0.16
OCR-AR-B	SI	350	0.2	875	0.32	30	0.32
OCR-PMAR-B	SI	220	0.1	550	0.16	30	0.16
OCR-AR-C	SI	300	0.28	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.2. Phase and Earth fault protection settings for scenario 2.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	200	0.1	500	0.16	30	0.16
OCR-PMAR-A	SI	150	0.1	375	0.16	30	0.16
OCR-AR-B	SI	350	0.23	875	0.48	30	0.48
OCR-PMAR-B	SI	260	0.11	650	0.32	30	0.32
OCR-AR-C	SI	300	0.28	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.3. Phase and Earth fault protection settings for scenario 3.

	IDMT Phase OC			**DTL Phase OC**		**Earth DTL OC**	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	400	0.17	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.12	625	0.32	30	0.32
OCR-AR-B	SI	250	0.1	625	0.16	30	0.16
OCR-PMAR-B	SI	160	0.1	400	0.16	30	0.16
OCR-AR-C	SI	300	0.28	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.4. Phase and Earth fault protection settings for scenario 4.

	IDMT Phase OC			**DTL Phase OC**		**Earth DTL OC**	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.11	-	-	-	-
OCR-T2	SI	630	0.11	-	-	-	-
OCR-AR-A	SI	400	0.17	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.12	625	0.32	30	0.32
OCR-AR-B	SI	300	0.23	750	0.32	30	0.32
OCR-PMAR-B	SI	180	0.1	450	0.16	30	0.16
OCR-AR-C	SI	180	0.1	450	0.16	30	0.16
OCR-PMAR-C	SI	160	0.1	400	0.16	30	0.16

Table D.5. Phase and Earth fault protection settings for scenario 5.

	IDMT Phase OC			**DTL Phase OC**		**Earth DTL OC**	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.11	-	-	-	-
OCR-T2	SI	630	0.11	-	-	-	-
OCR-AR-A	SI	400	0.16	1000	0.32	30	0.32
OCR-PMAR-A	SI	250	0.1	625	0.16	30	0.16
OCR-AR-B	SI	350	0.22	875	0.32	30	0.32
OCR-PMAR-B	SI	220	0.1	550	0.16	30	0.16
OCR-AR-C	SI	300	0.31	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.6. Phase and Earth fault protection settings for scenario 6.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.12	-	-	-	-
OCR-T2	SI	630	0.12	-	-	-	-
OCR-AR-A	SI	200	0.1	500	0.16	30	0.16
OCR-PMAR-A	SI	150	0.1	375	0.16	30	0.16
OCR-AR-B	SI	350	0.23	875	0.48	30	0.48
OCR-PMAR-B	SI	260	0.1	650	0.32	30	0.32
OCR-AR-C	SI	300	0.29	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.7. Phase and Earth fault protection settings for scenario 7.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.11	-	-	-	-
OCR-T2	SI	630	0.11	-	-	-	-
OCR-AR-A	SI	400	0.16	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.1	625	0.32	30	0.32
OCR-AR-B	SI	250	0.1	625	0.16	30	0.16
OCR-PMAR-B	SI	160	0.1	400	0.16	30	0.16
OCR-AR-C	SI	300	0.29	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.8. Phase and Earth fault protection settings for scenario 8.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	630	0.11	-	-	-	-
OCR-T2	SI	630	0.11	-	-	-	-
OCR-AR-A	SI	400	0.16	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.11	625	0.32	30	0.32
OCR-AR-B	SI	300	0.24	750	0.32	30	0.32
OCR-PMAR-B	SI	180	0.1	450	0.16	30	0.16
OCR-AR-C	SI	180	0.1	450	0.16	30	0.16
OCR-PMAR-C	SI	160	0.1	400	0.16	30	0.16

Table D.9. Phase and Earth fault protection settings for scenario 9.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	940	0.1	-	-	-	-
OCR-T2	SI	940	0.1	-	-	-	-
OCR-AR-A	SI	400	0.12	1000	0.32	30	0.32
OCR-PMAR-A	SI	250	0.1	625	0.16	30	0.16
OCR-AR-B	SI	350	0.17	875	0.32	30	0.32
OCR-PMAR-B	SI	220	0.1	550	0.16	30	0.16
OCR-AR-C	SI	300	0.21	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.10. Phase and Earth fault protection settings for scenario 10.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	940	0.1	-	-	-	-
OCR-T2	SI	940	0.1	-	-	-	-
OCR-AR-A	SI	200	0.1	500	0.16	30	0.16
OCR-PMAR-A	SI	150	0.1	375	0.16	30	0.16
OCR-AR-B	SI	350	0.17	875	0.48	30	0.48
OCR-PMAR-B	SI	260	0.1	650	0.32	30	0.32
OCR-AR-C	SI	300	0.18	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.11. Phase and Earth fault protection settings for scenario 11.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	940	0.1	-	-	-	-
OCR-T2	SI	940	0.1	-	-	-	-
OCR-AR-A	SI	400	0.12	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.1	625	0.32	30	0.32
OCR-AR-B	SI	250	0.1	625	0.16	30	0.16
OCR-PMAR-B	SI	160	0.1	400	0.16	30	0.16
OCR-AR-C	SI	300	0.19	750	0.32	30	0.32
OCR-PMAR-C	SI	180	0.1	450	0.16	30	0.16

Table D.12. Phase and Earth fault protection settings for scenario 12.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	940	0.1	-	-	-	-
OCR-T2	SI	940	0.1	-	-	-	-
OCR-AR-A	SI	400	0.12	1000	0.48	30	0.48
OCR-PMAR-A	SI	250	0.11	625	0.32	30	0.32
OCR-AR-B	SI	300	0.17	750	0.32	30	0.32
OCR-PMAR-B	SI	180	0.1	450	0.16	30	0.16
OCR-AR-C	SI	180	0.1	450	0.16	30	0.16
OCR-PMAR-C	SI	160	0.1	400	0.16	30	0.16

Table D.13. Phase and Earth fault protection settings for scenario 13.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	370	0.1	-	-	-	-
OCR-T2	SI	370	0.1	-	-	-	-
OCR-AR-A	SI	240	0.12	600	0.32	30	0.32
OCR-PMAR-A	SI	150	0.1	375	0.16	30	0.16
OCR-AR-B	SI	210	0.18	525	0.32	30	0.32
OCR-PMAR-B	SI	130	0.1	325	0.16	30	0.16
OCR-AR-C	SI	180	0.19	450	0.32	30	0.32
OCR-PMAR-C	SI	100	0.1	250	0.16	30	0.16

Table D.14. Phase and Earth fault protection settings for scenario 14.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	370	0.1	-	-	-	-
OCR-T2	SI	370	0.1	-	-	-	-
OCR-AR-A	SI	120	0.1	300	0.16	30	0.16
OCR-PMAR-A	SI	90	0.1	225	0.16	30	0.16
OCR-AR-B	SI	210	0.15	525	0.48	30	0.48
OCR-PMAR-B	SI	150	0.1	375	0.32	30	0.32
OCR-AR-C	SI	180	0.14	450	0.32	30	0.32
OCR-PMAR-C	SI	100	0.1	250	0.16	30	0.16

Table D.15. Phase and Earth fault protection settings for scenario 15.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	370	0.1	-	-	-	-
OCR-T2	SI	370	0.1	-	-	-	-
OCR-AR-A	SI	240	0.11	600	0.48	30	0.48
OCR-PMAR-A	SI	150	0.11	375	0.32	30	0.32
OCR-AR-B	SI	150	0.1	375	0.16	30	0.16
OCR-PMAR-B	SI	90	0.1	225	0.16	30	0.16
OCR-AR-C	SI	180	0.14	450	0.32	30	0.32
OCR-PMAR-C	SI	100	0.1	250	0.16	30	0.16

Table D.16. Phase and Earth fault protection settings for scenario 16.

	IDMT Phase OC			DTL Phase OC		Earth DTL OC	
	CH	Iset	TMS	Iset	DTL	Iset	DTL
OCR-T1	SI	370	0.1	-	-	-	-
OCR-T2	SI	370	0.1	-	-	-	-
OCR-AR-A	SI	240	0.13	600	0.48	30	0.48
OCR-PMAR-A	SI	150	0.14	375	0.32	30	0.32
OCR-AR-B	SI	180	0.15	450	0.32	30	0.32
OCR-PMAR-B	SI	100	0.1	250	0.16	30	0.16
OCR-AR-C	SI	100	0.1	250	0.16	30	0.16
OCR-PMAR-C	SI	90	0.1	225	0.16	30	0.16

Appendices References

[1] DTI, Ed., *United Kingdom Generic Distribution System (UKGDS)*. DTI (UK), 2005, p.^pp. Pages.

[2] "Engineering Recommendation G59 Issue 2: Recommendations for the connection of generating plant to the distribution systems of licensed distribution network operators," ed: ENA, 2010.