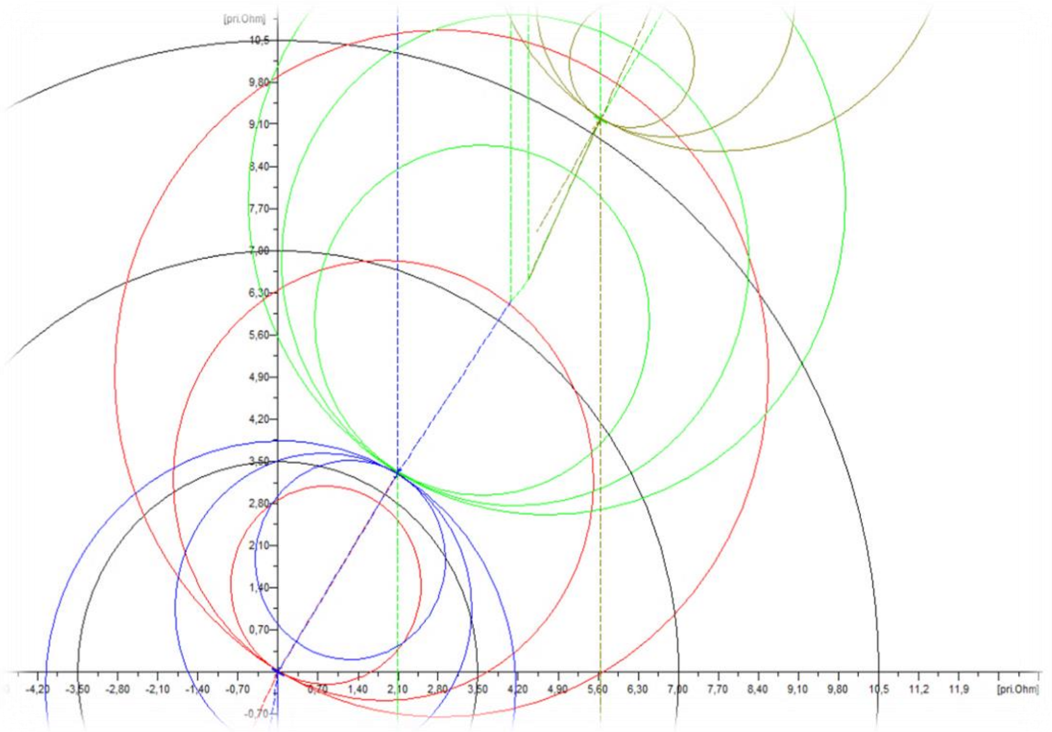
INVESTIGATION OF RELAY PROTECTION SYSTEMS IN MV NETWORKS WITH LARGE IN-FEED OF DISTRIBUTED GENERATION

DEPARTMENT OF ENERGY TECHNOLOGY

M. SC. IN ELECTRICAL POWER SYSTEMS AND HIGH VOLTAGE ENGINEERING



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MASTER'S THESIS

AALBORG UNIVERSITY
STUDENT REPORT

June 2014

Aalborg, Denmark

Title:	**Investigations of relay protection systems in MV networks with large in-feed of distributed generation**

Semester:	10^{th} semester, 2014
Project period:	3. February – 3. June 2014
Semester theme:	Master's thesis
ECTS:	30
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Copies: 3

Pages total: 96

Appendix: 12

Supplements: 3 CD-ROM

SYNOPSIS: In a power system, the goal of the protection system is to identify and clear fault conditions to minimise damage and disruption to the network and equipment, while maintaining reliability, security, sensitivity and selectivity. The ever increasing penetration of DG sources threatens to negatively impact the operation of the protection system, and affect each of the four aims of the protection system.

Tests are carried out on a 60 kV ring network, based on a real Danish system, with a 26 MW CHP plant and a 60 MW wind farm of full-rated VSC-connected wind turbine generators. A model is developed in DIgSILENT PowerFactory and tested according to the IEC 60909 standard for short-circuit currents, to determine the extent of the effect of DG sources on the protection system

The results find that the largest effect seen is the reduction in reach of the distance relays, particularly the back-up 3^{rd} zone. Each of the reliability, security, sensitivity and selectivity are affected, through the direct effect of a reduced reach and through corrective measures that can be taken to attempt to restore the protection to its desired level. Problems encountered include: increased fault clearance time; loss of back-up protection for portions of circuit; reduced loadability.

ACKNOWLEDGEMENTS / RINGRAZIAMENTI

Nicola

Questa tesi rappresenta per me uno dei traguardi finali, e importante della mia carriera universitaria; la fine di un percorso accademico caratterizzato da tante difficoltà ma ancor di più da tantissime soddisfazioni. Non avrei mai potuto raggiungere questo traguardo senza il contributo di altre persone che vorrei qui ringraziare.

Per primi i miei genitori che mi hanno dato tutto, senza il loro sostegno e il loro affetto sarebbe stato impossibile raggiungere questo traguardo, che dedico a loro. Spero di aver dato loro tante soddisfazioni. Un grande grazie va a mia sorella e mio fratello per il loro supporto, per non avermi mai fatto sentire solo e distante da casa e per aver sempre creduto in me, anche in questa bella avventura.

Infine vorrei ringraziare tutte le persone, parenti e amici, contenti per i risultati da me ottenuti e che sono state orgogliose di me.

I would like to say thank you to Alice, who has been by my side during these two years, giving me moral support, emotions and with whom I have spent many happy days.

Finally I want to thank Cormac, a great friend with whom I have worked on this master’s thesis, and say thanks to all the friends who have shared with me this wonderful adventure.

Cormac

For me, this thesis represents the final step in my education process, through which I have been supported all the way, by my wonderful parents Anne-Marie and Henry. They have made it possible for me to get the most out of my education, while still being able to enjoy all the plus sides of life. I dedicate this work to them, and hope I have made them proud and will continue to do so throughout my engineering career. I would also like to give a special thanks to my brother Eoin who has been a motivation for me to always do my best, even if it's just to make it as tough as possible for him to follow behind me.

I would like to thank my girlfriend Kathrine who has been by my side throughout my time in Denmark, all my friends at home in Ireland, who were always there whenever needed and those in Denmark who have had to step in and have done an excellent job of always keeping my mood up when far from home. I hope I have been as good to them as they have been to me.

I would also like to thank those who I have worked alongside in projects up to now, and to Nicola, who I worked together with on this thesis, I give a big thank you for everything throughout the long, tough final semester.

Both authors would like to give their thanks to those who have helped throughout the course of this thesis, including our supervisors Florin Iov and Sanjay Chaudhary for their continued support and guidance, and to Michael Rangård at Energimidt who provided all the data necessary and was there to answer any questions we had.

PREFACE

The present Master's Thesis entitled *Investigation of relay protection systems in MV networks with large in-feed of distributed generation* is documented by group EPSH -1034 in the 10th semester at the Institute of Energy Technology, Aalborg University for partial fulfillment of requirements for completion of the Master's degree in Electrical Power Systems and High Voltage Engineering.

The project period was from 3rd February to 3rd June 2014. The project is carried out in collaboration with Energimidt, who have provided the data for the 60kV distribution network and support throughout the project period.

Literature references are mentioned in square brackets by numbers. Detailed information for the literature is presented in the Bibliography. Appendices are assigned with letters and are arranged in alphabetical order. Equations are numbered in format (X-Y), figures are numbered in format Figure X-Y, appearing below the figure and tables are numbered Table X-Y, appearing above the table, where X is the chapter number and Y is the number of the item. The enclosed CD-ROM contains the material used throughout the project time; details regarding the CD-ROM content are provided in the Appendix.

Nomenclature

AC	Alternating Current
CHP	Combined Heat and Power
CIGRE	International Council on Large Electric Systems
DG	Distributed Generation
DH	District Heating
DN	Distribution Network
DNO	Distribution Network Operation
DSO	Distribution System Operator
HV	High Voltage
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
LV	Low Voltage
MV	Medium Voltage
OHL	Overhead lines
OLTC	On-Load Tap Changer
p.u.	Per-Unit Value
PV	Photovoltaic
TSO	Transmission system operator
WTG	Wind Turbine Generator

CONTENTS

1. INTRODUCTION

1.1 Background

Amid rising cost of fossil fuel, environmental concerns, and a need to secure future energy supply, directives from national and international organisations, on renewable energy generation, are being implemented. Among these is the EU Directive 2009/28/EC "*Promotion of the use of energy from renewable sources*" which has set targets for the year 2020, for individual countries for energy consumption supplied by renewable sources. This directive set targets for Denmark to have a 20% share of renewable energy in gross final energy consumption by 2020. By 2011 Denmark had already reached 23.1% share of renewable energy and the Danish government renewed ambitious targets of 30% energy supplied by renewable sources [1].

The vast majority of renewable energy systems in Denmark use wind as the primary energy source. This is reflected in the latest stats held by The European Wind Energy Association (EWEA), which shows Denmark had installed 4,162 MW capacity of wind generation, with 3,241MW provided by onshore wind turbines [2], which often are connected as distributed generation. Overall in Europe the trend in new installed power capacity is moving more and more towards renewable systems, as is clear from Figure 1-1 which shows the new power capacity installed in 2012 [2]. Many of these new renewable generators are being connected to the distribution system as distributed generation.

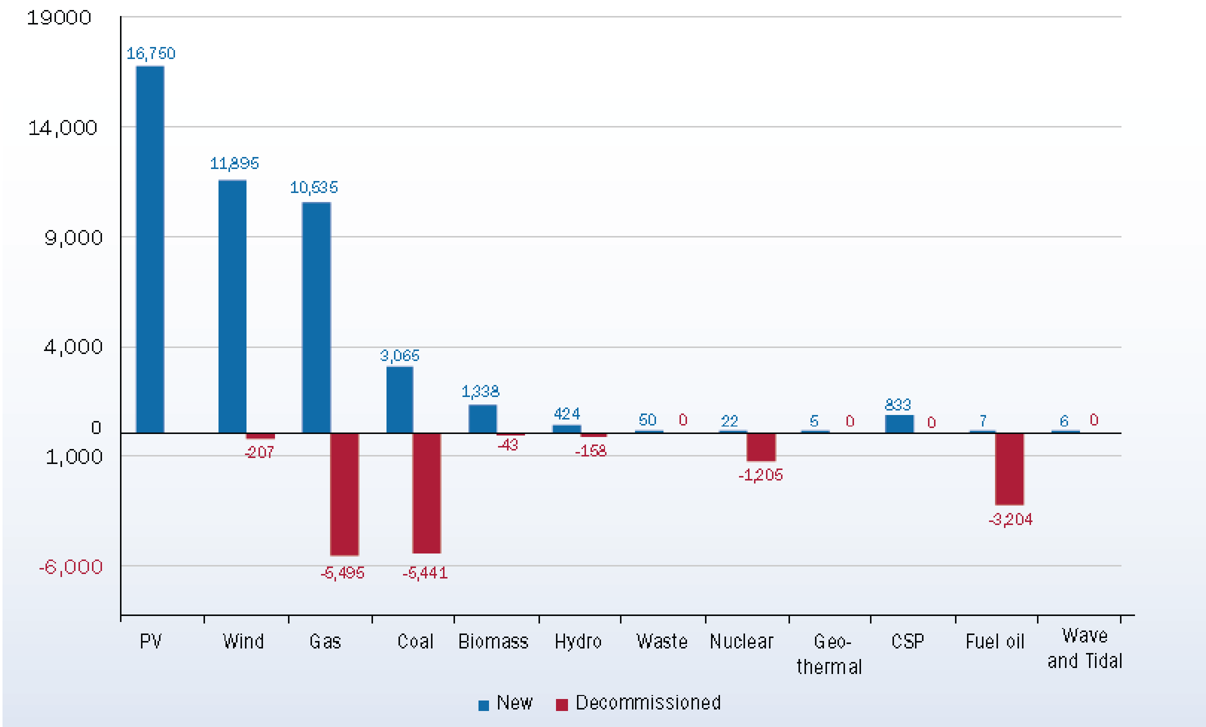
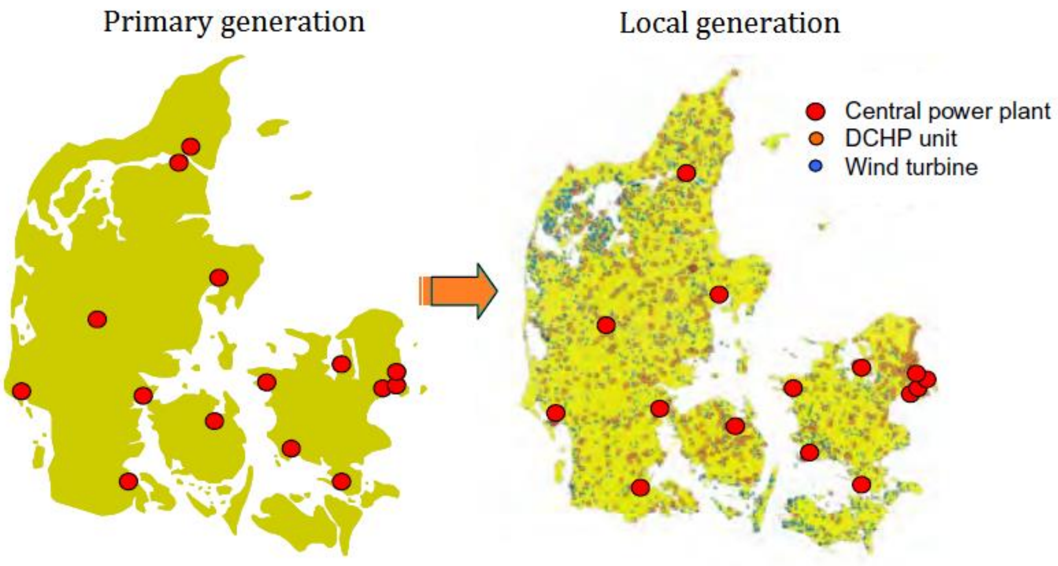


Figure 1-1 New installed Power Capacity in MW in Europe in 2012 [2]

Denmark also has an increasingly high number of combined heat and power (CHP) plants. Cogeneration of electricity and heat is one of the most energy-efficient and environmentally friendly ways in which to produce electricity and heat and can save around 30% of fuel compared with separate generation of heat and power [3]. These major advantages of CHP have seen development of an extensive CHP network in Denmark, with the result that more than 80% of Danish district heating is cogenerated with electricity.

These factors mean that over the last two decades, Denmark has registered a vast growth in distributed generation (DG). Figure 1-2 shows the extent of the decentralised generation system, which has seen a significant increase in wind power as well as dispersed CHP plants.



(a) (b)

Figure 1-2: The development of centralized to decentralized generation system in Denmark [4]

These DG sources are mostly connected at the 60 kV and 20-10 kV voltage level, with a combined capacity from CHP and Wind turbines of 3200 MW connected at these voltage levels. The spread of generation across the various voltage levels of the Danish power system is shown in Figure 1-3.

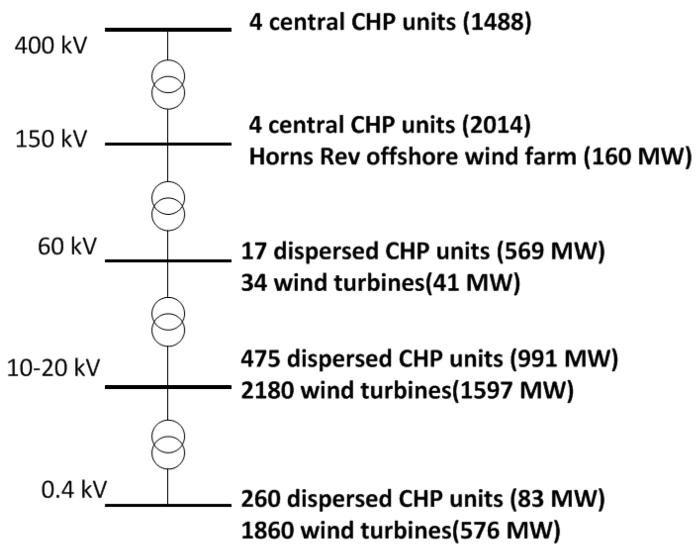


Figure 1-3: Power System of Western Denmark Production Capacity per Voltage Level in 2009 [4]

Traditionally, the power system was characterised by a unidirectional flow of power from large generators in remote locations through a transmission system at high voltage, to sub-transmission systems, and distribution systems at medium and lower voltage levels, and ultimately to electricity customers as in Figure 1-5 (a). However, one of the consequences of the massive shift in generation towards high penetration of DG is that this is no longer true. In fact, as highlighted in Figure 1-4, the capacity of wind power and CHP, has exceeded the consumption in Denmark since 2003, and several 60 kV distribution networks, especially those situated along the North Sea coast line, with prevailing wind regimes, have become net power producers, transmitting their excess power up to the 150 kV transmission grid. These changes mean that a modern power system has a power flow as in Figure 1-5 (b).

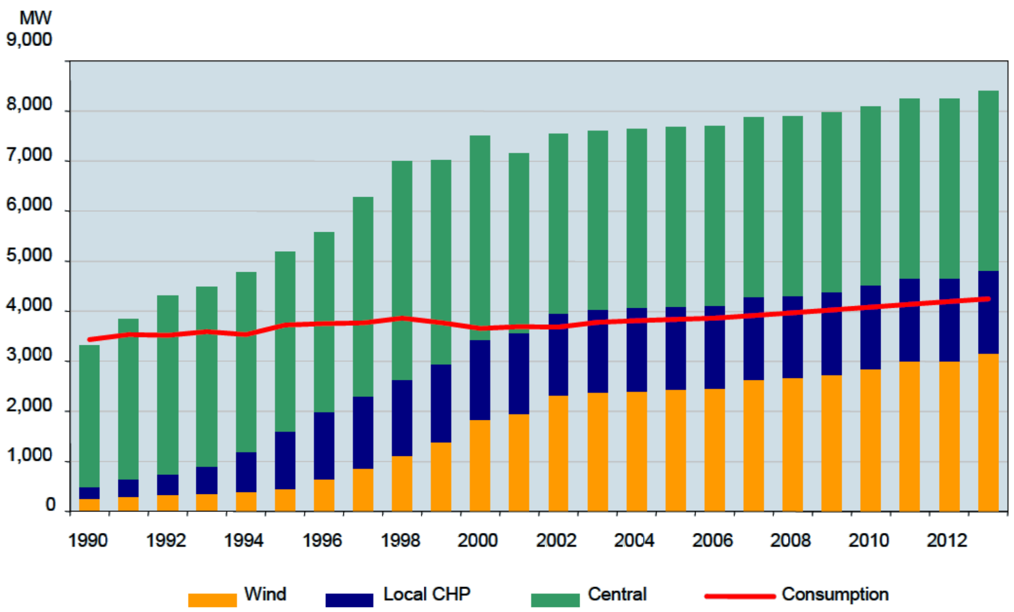
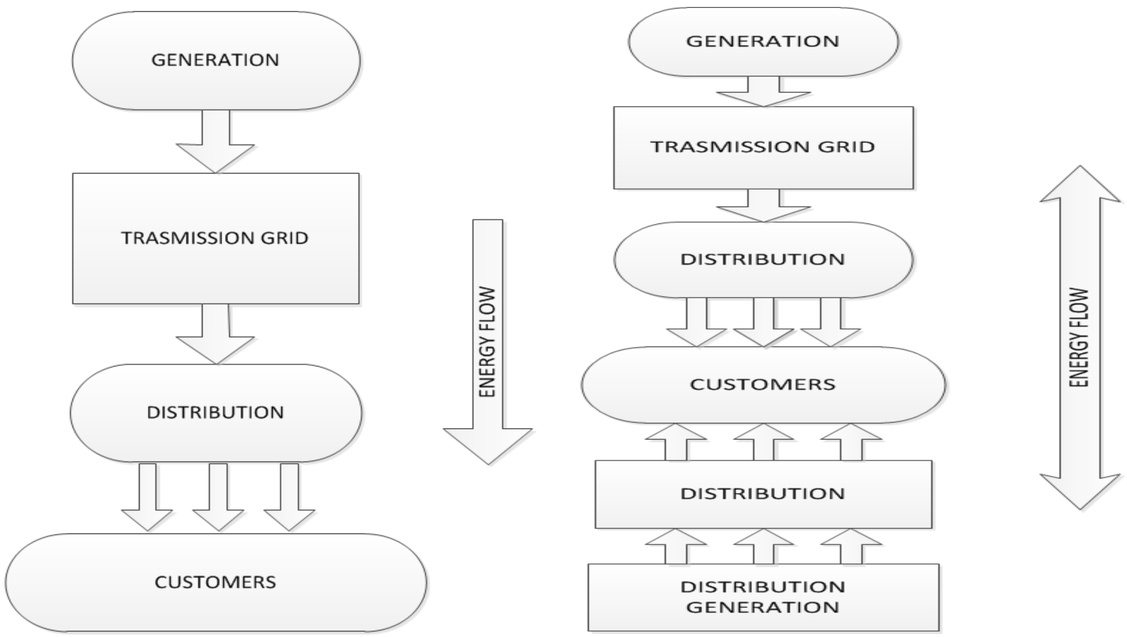


Figure 1-4: Installed generation capacity and consumption in Denmark [5]



(a) **(b)**

Figure 1-5: (a) Traditional power flow, (b) Modern/future power flow [4] [6]

It is not only the direction of power flow that is affected. The increasing penetration of DG also has a big effect on the system fault level. Without DG, the only source of short circuit current was the grid, and protection systems were designed accordingly. However, DG represents an additional source of short circuit current, having an effect on many of the elements of a power system, most notably on protection elements including distance and over-current relays. Protection systems are often still operated according to old and outdated schemes that were developed before the advent of DG and must be redesigned in order to continue to operate as planned.

Distributed Generation

There are 4 main types of DG, based on the machine type and the grid connection. They are

- Type I: Synchronous generators, (e.g. CHP)
- Type II: Asynchronous generator directly connected to grid (e.g. Constant speed WTs)
- Type III: *D*oubly fed asynchronous generators, with power converters in the rotor circuit, (e.g. Variable speed WTs)
- Type IV: Full scale power electronic connected generators (e.g. Variable speed WTs, PV)

As mentioned, in Denmark, the vast majority of DG systems consist of CHP plants and WTGs.

CHP

From a power systems point of view, CHP plants are seen as Type I, synchronous generators connected directly to the power system.

WTG

Wind turbines can be divided into four main categories, as listed below and shown in Figure 1-6 [6] [7]:

- Fixed speed WTs (FSWTs), operating in a narrow range of rotor speed;
- Partial variable speed WTs with variable rotor resistance (PVSWTs);
- Variable speed WTs with partial-rating frequency converter, known as doubly-fed induction generator-based concept (DFIGWTs);
- Variable speed WTs with full-rating power converter, also known as Voltage Source Converter (VSC)-based WTs (VSCWTs).

For the sake of this project, only the VSC WTs will be considered, which are characterised by the generator connected to the grid by means of a full-rating converter, which performs the reactive power compensation and a smooth grid connection [8]. The focus is on the contribution of the VSC WT to the short circuit current.

Further details regarding wind turbine operation and control schemes can be found in [6] [7] [8].

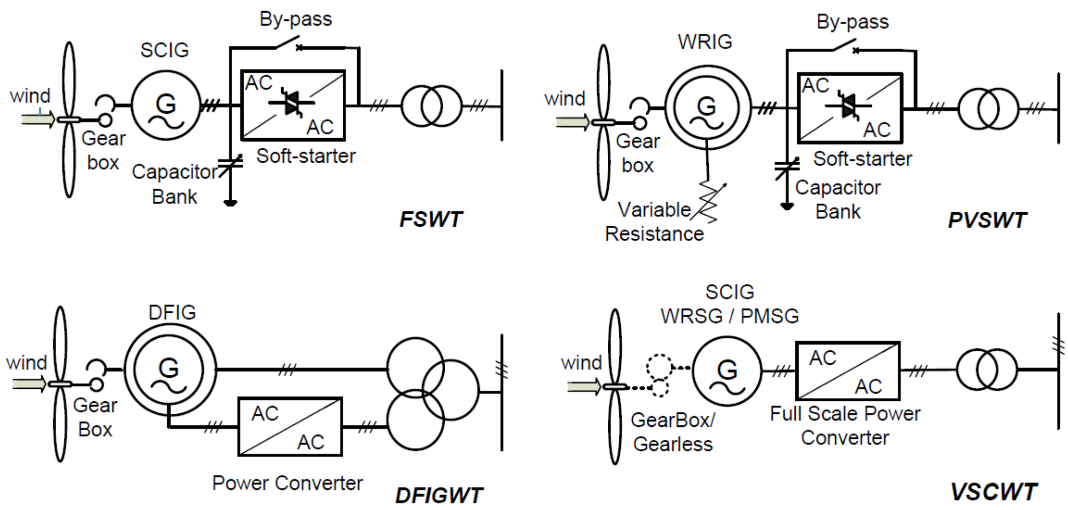


Figure 1-6: Wind turbine concepts [9]

Protection definitions

Some definitions are declared here to define some general concepts in protection systems [9] [10]. These are used throughout the report.

- **Reliability** of a protection system: The ability of the protective system to operate as expected.
- **Security** of a protection system: The ability of a system or device to avoid operating unnecessarily.
- **Sensitivity** of a protection system: The ability of the system to identify an abnormal operating condition, exceeding a defined threshold value.
- **Selectivity** of a protection system: The ability of the system to maintain greatest possible supply level by disconnecting the minimum section of the network necessary to isolate the fault.

The increase in DG affects each of these, which is investigated throughout this report.

1.2 Problem Statement and Analysis

When a short-circuit fault occurs in a power system, abnormal fault conditions are introduced, which are characterised by high currents in the circuit and low bus voltages, especially close to the fault location, all of which can damage equipment attached to the network or introduce instability in the network.

Protection in a power system is designed to protect against this scenario by recognising potentially damaging fault conditions and taking action to limit the damage they can cause, by isolating the faulted area in the system and ultimately bringing the system back to normal operating conditions. In this way the protection system is a reactionary system, with devices which react to changing conditions and take corrective actions

Relay devices are used to detect fault conditions and to send a tripping signal to their associated circuit breaker to isolate the fault. The detection and tripping criteria are most commonly based on overcurrent or distance methods which both can detect the severity of the fault to a particular relay, by measuring the increased current level in the case of overcurrent relays, or by detecting the location of the fault in the case of distance protection. The relays can then be designed with protection zones which are time graded, and respond more quickly to more severe faults. It is this procedure that ensures that the minimum interruption is experienced following detection of a fault.

Traditionally the only source of short-circuit current in a network was the external grid however with the introduction of distributed generation, another source of fault current is also introduced which changes the total system fault level, while protection systems are often still operated according to old and outdated schemes that were developed before the advent of DG. This change in fault level can cause problems in the form of: reduced selectivity performance by loss of coordination between devices; reduced sensitivity, causing devices to fail to recognise fault conditions or to incorrectly recognise normal operations as fault conditions; longer fault clearance times, by underestimating the severity of a fault.

This reduces the reliability and security of the network, which ultimately increases the cost of operating the distribution system by having a greater amount of the network out of use or by damaging equipment connected to the network

Relays are typically placed at busbars and should firstly protect the line to which they are connected, however in some cases substations use circuit breakers alone and are only protected by the distance relays placed at the neighbouring busbars. As more distributed generation units, including wind turbines and small combined heat and power plants, are connected to feeders from these "un-protected" substations, the problems mentioned are accentuated.

1.3 Objectives and Methodology

The issues detailed above will be investigated through this report. To achieve this a number of tasks need to performed, including performing a state-of-art of faults and relays; modelling of a realistic network in a power system simulation tool, including protection system and short-circuit current sources; assessment through simulation studies of existing relay settings in different scenarios involving distributed generation; investigation and presentation of new protection schemes to deal with changing fault levels, based in assessment results.

State-of-Art

- Power system overview, including grid configurations;
- Distributed Generation, including the most common technologies and how their implementation effects protection systems;
- Faults, including fault types, occurrence, and how they are realised in a real system;
- Calculation methods and standards for short-circuit current calculations;
- Relay devices, including, how they operate; coordination schemes; potential distance relaying problems.

Modelling

- Modelling and implementation of a realistic 60kV network including 60/10 kV substations
- Modelling and implementation of distributed generation units.
- Modelling and implementation of protection relays.

Assessment Studies

- Definition of test case scenarios and success criteria
- Assessment through simulation studies of existing relay settings in different scenarios involving distributed generation and grid events
- Assessment of new relay schemes

Outcome

- Clear outline of effect of DG on protection system
- Proposal of changes for existing relay settings based on simulation studies

1.4 Limitations and assumptions

1.4.1 Network and DG modelling

The modelled network is based on real network data from a portion of the 60 kV distribution network in Denmark, which can be taken to accurately represent a typical Danish system.

For the purpose of this project, the DG is assumed to consist of *Type I* synchronous generators, in the form of CHP plants, and *Type IV* generators, in the form of VSC connected wind turbines. These are reasonable assumptions when considering the penetration of DG in the Danish power system.

1.4.2 Short-circuit calculation and analysis

The IEC 60909 standard is used for calculation of short-circuit current from a short-circuit fault. It is an approximate method which uses a number of correction factors to justify assumptions made. This standard is chosen as it is widely used across Europe and the EU, including in Denmark.

The investigations carried out are conducted for balanced three-phase short-circuit faults, with the assumption that they can occur at any point on the line. In Denmark the 60kV network consists of mostly cables, with statistics showing that a three-phase short-circuit is not the most frequent grid faults, especially along the cable. However as this fault type is often the most severe, and is often listed in grid codes for fault behaviour, these studies represent a generalised study of faults in power systems.

The simulation tool DIgSILENT PowerFactory is used for this work as it is can perform the desired tasks and is used by Energimidt, who collaborated on this work.

1.5 Report Outline

The remainder of the report is intended to give the reader a clear understanding of:

- Faults occurring in power systems and how they should be calculated and considered by system planners and operators
- The negative effects of faults within power systems;
- The goal of a protection system to identify and clear fault conditions to minimise damage and disruption to the network and equipment
- The changes occurring in the modern power system, how they affect the system fault level and the detrimental effect that can occur if they are not considered in protection design;
- How these issues manifest themselves in a real network;

This is followed by an in-depth investigation, utilising network models and simulation studies, of the effect on protection devices, of increasing levels of distributed generation, and finally end with the presentation of solutions which aim to restore the intended operation of the protection system.

Chapter 2 gives a clear insight into power system faults, short-circuit currents, calculation methods and contribution to system fault level of the grid and DG sources.

Chapter 3 covers the theoretical background related to protection devices, with a focus on distance relays. It includes coordination schemes and potential relaying problems.

Chapter 4 introduces the system definition, the simulation tool PowerFactory, the model of the network and DG sources, the setting and implementation of the relays in PowerFactory.

Chapter 5 focuses on the analysis of the system under various scenarios, and presents the test cases, methodology and results.

Chapter 6 concludes with a set of overall conclusions and some tasks that have been identified as future work.

2. FAULTS

2.1 Introduction

Protection systems are designed to protect the power system against undesirable operating conditions that result from faults in the network. Faults can occur as a result of lightning, tree flashover, deterioration of insulation, or human error, amongst others [10], and the most common characteristic of fault conditions is a rapid increase of the current to levels above normal operating values, often as a result of the fault creating a short circuit between lines or from lines to ground. Faults can also result in changes in voltage or frequency in the network [11].

Many studies are performed by system planners and operators to ensure that the power system is designed and operated correctly and to assess the performance, reliability and security of the system under fault conditions. These studies include short-circuit, load flow, stability and reliability analyses [11], [12], [13], [14].

Short circuit analysis is one of the most widely used studies especially when considering protection systems, for which a short circuit analysis can provide the values necessary for determining relay settings and for coordination of protection devices. For the purpose of this project the focus will be on short circuit analysis for fault level calculations.

2.2 Fault types

A short-circuit fault can be represented by adding a fault impedance Z_f at the location of the fault. The fault can effect all three phases equally, in the case of a symmetric fault where the fault conditions resulting from the fault are the same on each of the phases and can be treated on a per-phase basis; or the fault can result in unbalanced conditions in the case of asymmetric faults such as a single phase to ground fault or a phase to phase fault on two of the phases. This type of fault results in unbalanced conditions in the network.

The main short circuit fault types can be seen in Figure 2-1 and have been defined in [16], [10], [17], [18], [15], [19].

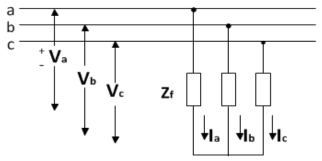
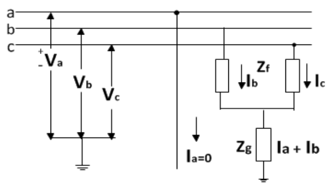
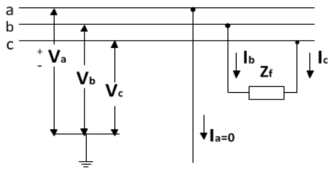
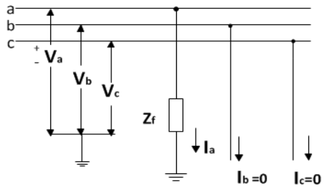
Fault	Circuit diagram of the fault point	Boundary conditions	Descriptions
Three-phase SC		$I_a + I_b + I_c = 0$ $V_a = Z_f \cdot I_a$ $V_b = Z_f \cdot I_b$ $V_c = Z_f \cdot I_c$	• Connection or all conductors with or without simultaneous contact to ground • Symmetrical loading of the three external conductors • Calculation on a single-phase basis
Double line-to-ground SC		$I_a = 0$ $V_b = (Z_f + Z_g)\cdot I_b + Z_g \cdot I_c$ $V_c = (Z_f + Z_g)\cdot I_c + Z_g \cdot I_b$	• Unsymmetrical loading • All voltage non-zero • SC current high than in a three-phase SC near-to-generator
Line-to-line SC		$I_a = 0$ $I_b = -I_c$ $V_b - V_c = Z_f \cdot I_b$	• The leakage current flowing to ground a capacitive ground fault current
Single line-to-ground SC		$I_b = I_c = 0$ $V_a = Z_f \cdot I_a$	• Very frequent occurrence in low voltage networks

Figure 2-1 Symmetric and asymmetric faults [15]

In [20], data was gathered on the causes of failures in a sub-transmission and distribution system. The network under observation consisted of 90% cables with roughly 62% of interruptions come from the cable system. The majority of these occur on the cable itself, with a smaller number occurring at joints and terminals. From this data, statistics on the occurrence of each of the different types of faults, can be inferred and is shown in Table 2-1.

Table 2-1 Statistics on fault types [20]

Fault Type	Occurrence
Three-Phase to ground	30%
Single Phase to ground	60%
Double Phase to ground	5%
Phase to Phase	5%

2.3 Short Circuit Current

As mentioned, short-circuit currents are vital for analysing outages and faults and for the design of equipment and installations needed for the reliable operation of power systems [16]. Short circuit currents occur when a fault, such as breakdown of insulation, results in a short circuit between lines or to ground as discussed in section 2.2. It is this current which can damage equipment on the system and which needs to be detected and prevented by the protection equipment.

The variation in the magnitude of the short-circuit current is due to two main components. They are, the equivalent system impedance at the fault point, which produces a decaying DC component, and the performance of the rotating machinery, which result in a decaying AC component. The rate of decay depends on the instantaneous value of the voltage at the time that the fault occurs, and also on the power factor of the system at the fault point [10]. The fault characteristics can be divided into three time divisions:

- Sub-transient, which is immediately following the fault occurrence, and is associated with the largest currents;
- Transient, this is associated with the DC and AC decay of the fault current.
- Steady-state, which occurs after all the transients have had time to settle and the characteristics are not changing.

The time behaviour of the short-circuit current depends on the fault location relative to the generation, and therefore in the IEC 60909 standard on short circuit current faults, where far-from-generator and near-to-generator current waveforms are distinguished [12], [17]. The time behaviour of the SC current in both cases is shown in Figure 2-2 and Figure 2-3. They differ most significantly in the time behaviour of the AC component. In the far-from-generator case, the AC component has a constant RMS value while the near-to-generator waveform has a varying RMS AC component.

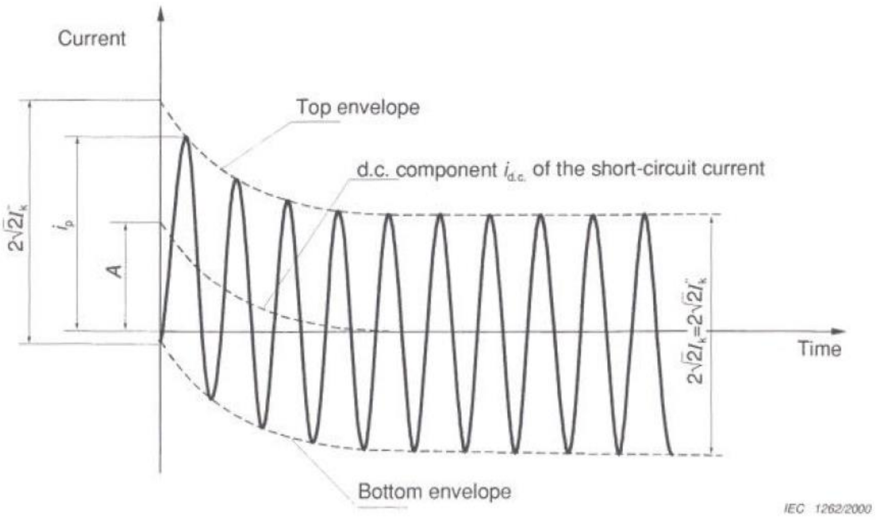


Figure 2-2 Time behaviour of the short-circuit current far-from-generator [12], [17]

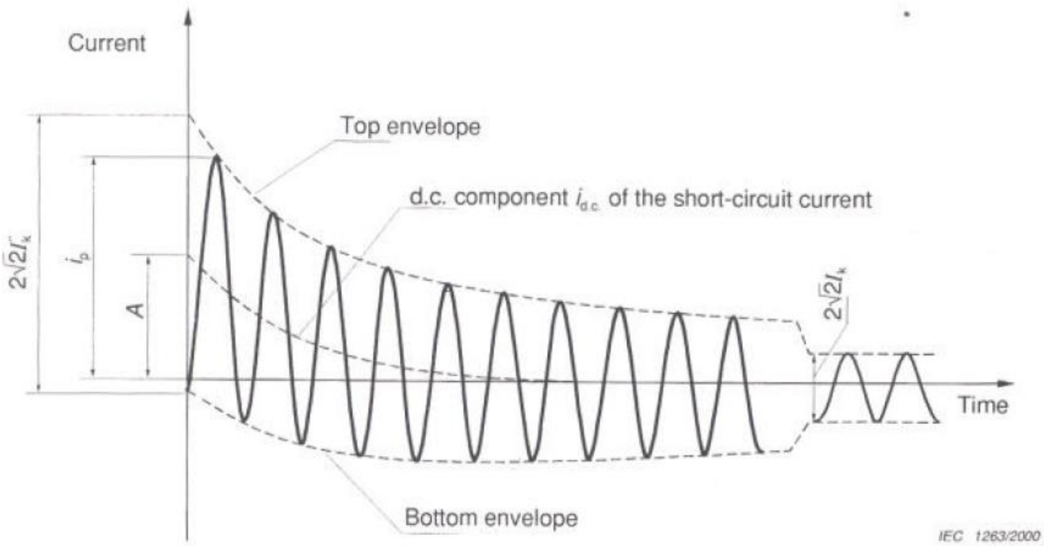


Figure 2-3 Time behaviour of the short-circuit current near-to-generator [12], [17]

Where I''k is the initial symmetrical SC current, i_p is the peak SC current, idc is the decaying DC aperiodic component and A is the initial value of the DC aperiodic component.

The three following parameters of short-circuit current have also been identified as being important by [16]:

- **Total time duration**, which is the total operating time of protective equipment and the breaking time of switchgear triggered by the protection device;
- The **R.M.S. value of the short-circuit current**. This parameter, combined with the total time duration, gives a measure for the thermal effects of the short-circuit;
- The **short-circuit breaking current**, which is the r.m.s.-value of the short-circuit current at the time of operating the circuit-breaker;

2.4 Standards for fault calculation

2.4.1 Short-circuit calculation methods

There are 4 main calculation methods for short circuit studies [16], [15]. They are:

- Nodal method;
- Symmetrical component method;
- Complete method;
- Dynamic time method.

The choice of method depends on the final application, level of detail required and fault type. However, the symmetrical component and superposition methods, or approximate methods based on these methods are the most widely used, both for hand calculations and in power system simulation tools such as DIgSILENT PowerFactory. Information on the method and application of the different calculation methods can be found in [16], [12], [17], [18], [15], [19], [21].

The calculation methods become relevant when examining the standards that have been defined by the IEC and ANSI/IEEE such as IEC 60909-2001; [18] and ANSI C37.5, which are used by system planners when designing protection systems. The IEC 60909 standard, as is used in Europe will be discussed in detail in section 2.4.3.

2.4.2 Overview of standards

A number of standards are available for calculation of short circuit currents. The most important are:

- **IEC 60909-2001** - Short-circuit currents in three-phase a.c. systems. Part 0: Calculation of currents [18];
- **VDE 0102:2002-07** - Short-circuit currents in three-phase a.c. systems - Part 0: Calculation of currents (IEC 60909-0:2001); German version EN 60909-0:2001 [17];
- **IEEE 141-1993 -** IEEE recommended practice for electric power distribution for industrial plants;
- **ANSI C37.010.1999** - IEEE application guide for a.c. high-voltage circuit breakers rated on a symmetrical current basis;
- **ANSI C37.5** Methods for determining the rms value of a sinusoidal current wave and normal frequency recovery voltage, and for simplified calculation of fault currents;

The IEC 60909 was adopted as the European Standard EN 60909 in 2001, and is based on the earlier German VDE 0102. These standards are the same in requirements, methods and in practice, and can be referred to as the **IEC method**. This is the most widely used standard in all EU and European countries.

Similarly, the IEEE 141 and the ANSI C37 have been adopted as the North American ANSI C37.5 standard, and can be referred to as the **ANSI method**. This is the most widely used standard in North American

For the purpose of this project, focus will be put on the IEC 60909 standard, while comparisons to the ANSI standards can be found in [13], [22]

2.4.3 IEC 60909

The simulation tool, DIgSILENT PowerFactory, provides options for performing short circuit analysis according to the IEC method, which is used for this project. This section highlights the key features of this standard. These are essential for understanding of short-circuit analyses for protective systems.

The IEC method is based on the superposition method, mentioned in section 0, providing an equivalent voltage source at the fault location. It makes a number of simplifying steps when compared to the superposition method, and does not require pre-fault values or operating conditions. The simplifications are as follows [18], [15]:

- nominal conditions are assumed for the whole network, with bus voltage taken to equal the rated voltage;
- load currents are neglected, i.e. $I_{op} = 0$;
- loads are not considered in the positive and negative sequence network.

Considering these simplifications and the following:

- currents in normal operation (pre-fault condition) are, in magnitude, much smaller than the corresponding SC currents;
- power systems are basically inductive especially at high voltage; in normal operation, currents lag bus voltages with inductive power factor around 0.9, whereas SC currents lag bus voltages with a much lower power factor (i.e. phase shift close to 90°),

the steps of the superposition method can be simplified and Figure 0-2c can be approximated as Figure 0-2b. The operating current and short circuit current in steady-state can be represented by their corresponding phasors.

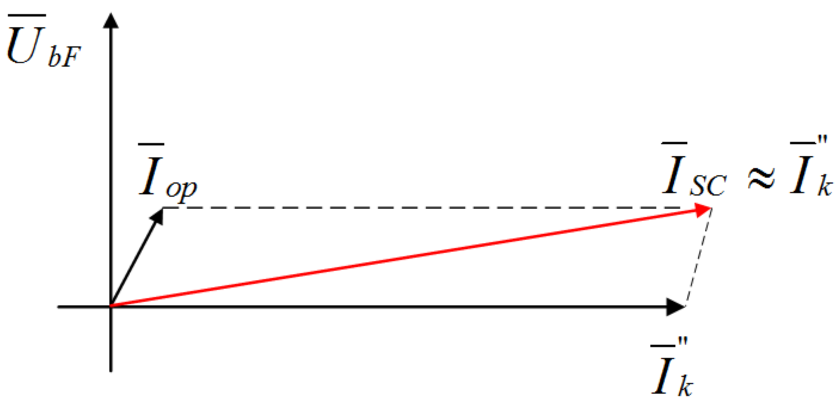


Figure 2-4 Steady-state operating current and short-circuit current [19].

$\boldsymbol{U_{bF}}$ is the pre-fault bus voltage; $\boldsymbol{I_{op}}$ is the pre-fault operating current; $\boldsymbol{I''_k}$ is the steady state SC current; $\boldsymbol{I_{sc}}$ is the total short-circuit current obtained by superposition.

As mentioned, the pre-fault voltage at the faulted bus is assumed to be equal to the rated value U_n. To ensure that the results are estimated on the safe side, a correction factor c is applied to the voltage at the faulted busbar so that $U_{bF} = cU_n$. The correction factor c is found in the IEC 60038 standard, shown in Table 2-2 for voltages above 35kV. Two c factors are given, c_{max} for calculating the maximum short circuit current, and c_{min} for calculating the minimum short circuit current.

The c factor can be user-defined within PowerFactory, or can automatically be set depending on the voltage level at the fault location.

Table 2-2 Voltage Factor c [18]

Nominal voltage U_n	Voltage factor c_{max} for max SC current calculations	Voltage factor c_{min} for min SC current calculations
High voltage > 35kV (IEC 60038, table IV)	1.10	1.00

The following values of short-circuit current are considered [18], [23], [24], [25]:

- Initial symmetrical short-circuit current I_k'';
- Symmetrical short-circuit current I_k;
- Peak short-circuit current i_p;
- DC component of the short-circuit current i_{dc};
- Symmetrical short-circuit breaking current I_b;
- Thermal equivalent short-circuit current I_{th}.

How the IEC 60909 deals with these values is detailed in the following.

Initial symmetrical short-circuit current I_k''

I_k'' is the RMS value of the AC symmetrical component of the short circuit current at the time the fault occurs. It is calculated by inserting an equivalent ideal voltage source in the positive sequence network, at the fault location, with value $cU_n/\sqrt{3}$. The remaining sources in the network are not considered, with voltage sources being replaced by short circuits, and current sources replaced by open circuits. All network feeders, synchronous and asynchronous machines are replaced by their internal impedances. All line capacitances shunt admittances and non-rotating loads, except those of the zero-sequence system, are neglected.

This method is illustrated in Figure 2-5

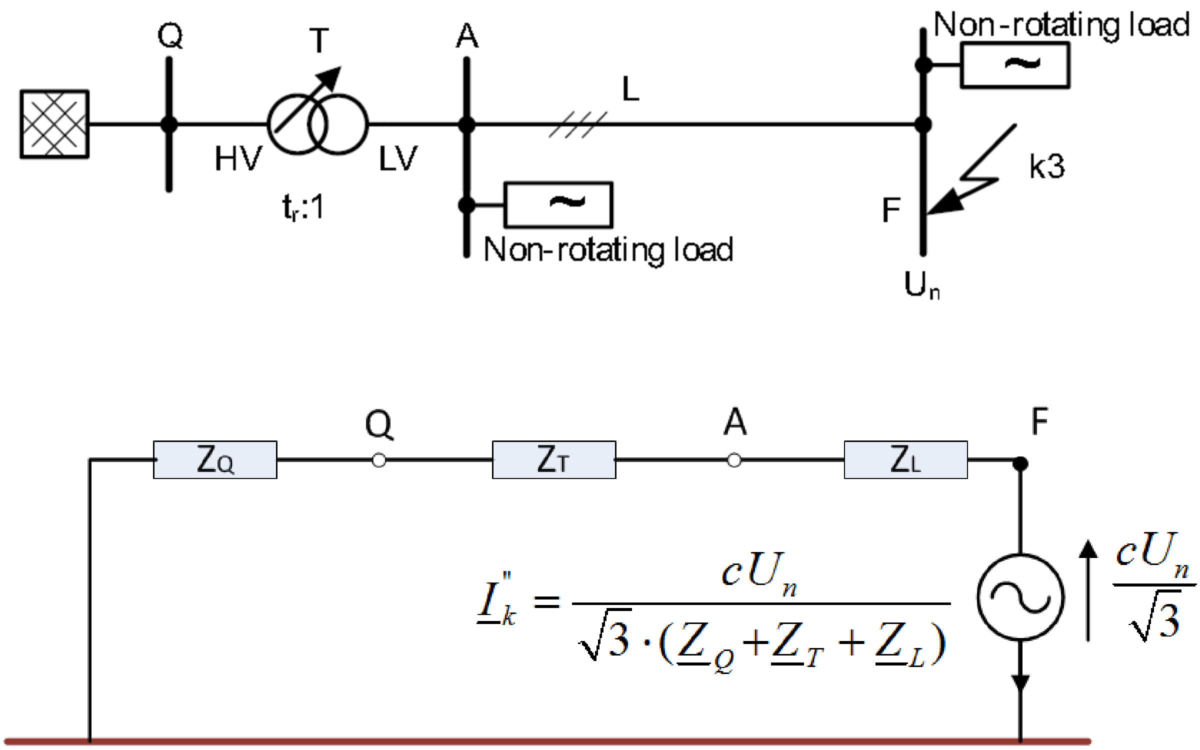


Figure 2-5 Equivalent voltage source illustration [18]

Symmetrical short-circuit current I_k

Far-from generator, I_k is assumed to be equal to the initial value I_k'' , whereas near-to generators, the values of I_k varies, with the calculation taking many effects into account, including magnetic circuit saturation, excitation type, automatic voltage regulator, type of machine [18].

Peak short-circuit current i_p

The peak short circuit current is the maximum value of SC current and occurs just following the fault, and for meshed networks can be calculated as:

$$i_p = k\sqrt{2}I_k'' \tag{0.1}$$

Where k is given by:

$$k = 1.02 + 0.98e^{-R_e/X_e} \tag{0.2}$$

There are three methods for approximating the R/X ratio.

- Method A: The R_e/X_e ratio is chosen as the smallest ratio from all the network branches in the network.

- Method B: The R_e/X_e ratio is the ratio of the positive sequence impedance at the fault location, with a correction factor of 1.5 applied.

- Method C: This method uses an equivalent frequency f_c to calculate the R_e/X_e ratio, given by:

$$\frac{R_e}{X_e} = \frac{f_c}{f}\frac{R_c}{X_c} \tag{0.3}$$

Where R_c and X_c are the resitance and reactance determined using the equivalent frequency f_c as follows:

$$X_{ci} = \frac{f_c}{f} X_i \tag{0.4}$$

The ratio $\frac{f_c}{f} = 0.4$ is assumed. Method c is recommended for meshed or ring networks.

These methods are available options within PowerFactory.

DC component of the short-circuit current i_{dc}

The d.c. component of the SC current can be calculated as:

$$i_{dc} = \sqrt{2} I_k^{"} e^{-2\pi f t R_e / X_e} \tag{0.5}$$

where f is the nominal frequency, t is the time and Re/Xe is the exact ratio for a radial network or an equivalent ratio for a meshed network. The following methods are used to determine R_e/X_e.

- Method B: equivalent to method B from peak short-circuit current i_p
- Method C: equivalent to method B from peak short-circuit current i_p
- Method C': equivalent to method C from peak short-circuit current i_p but with with the following values for $\frac{f_c}{f}$, depending on $f.t$

Table 2-3 f_c/f ratio for various values of f.t [18]

$f.t$	<1	<2.5	<5	<12.5
f_c/f	0.27	0.15	0.092	0.05

Symmetrical short-circuit breaking current I_b

The symmetrical short-circuit breaking current I_b is the value of the AC symmetrical component at the time of operation of the circuit breaker.

For a far from generator fault it can be assumed

$$I_b = I_k = I_k''$$

For a near to generator fault the following is used:

$$I_b = \mu q I_k'' \tag{0.6}$$

Factor μ is a function of the ratio I_k'' / I_{rG}, where I_{rG} is the rated current of the generator. Factor q is a function of the ratio P_{rM}/p where P_{rM} is the rated active power and p the number of pole-pairs of an asynchronous machine. For synchronous generators $q = 1$ is used so that $I_b = \mu I_k''$.

Both factors depend on the considered minimum breaking time, t_{min}, and specific relations and diagrams are provided in the standard. A safe, but conservative approximation would be μ=1, μq=1 [25].

Thermal equivalent short-circuit current I_{th}

The thermal equivalent short-circuit current, I_{th}, is defined as the rms value of a non-decaying current, having the same thermal effect and duration as the actual current [25]:

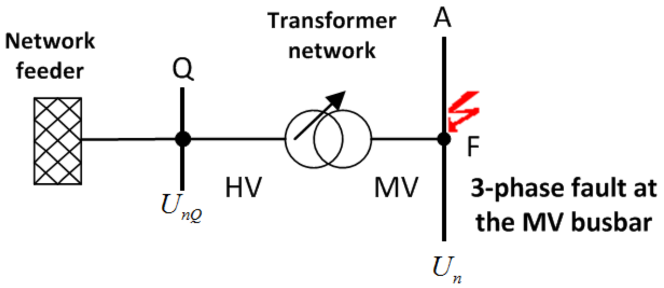
$$\int_0^{T_k} i^2 dt = I_k''(m+n) = I_{th}^2 T_k \tag{0.7}$$

T_k is the duration of the short-circuit current. Factors m and n, are used for the thermal effect of the dc and the ac component, respectively, and are provided by the standard [18].

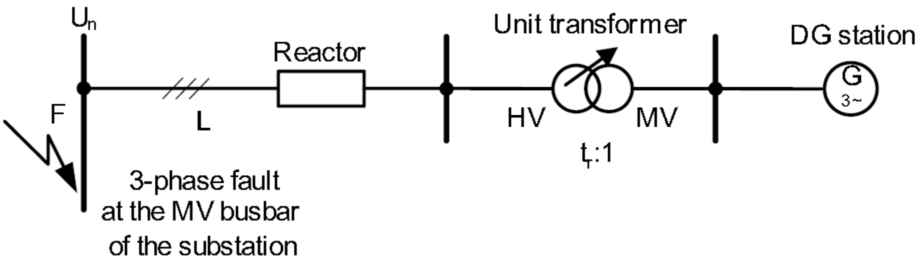
2.5 Contribution to system fault level

In distribution systems with DG, the total fault level is the phasor sum of the maximum currents from [25]:

- the upstream grid, including the network transformer, as in Figure 2-6 (a);
- the generators connected at the distribution level, including unit transformer, reactor and line, as in Figure 2-6 (b).



(a)



(b)

Figure 2-6 Contribution to fault level from (a) upstream grid and (b) generator [25]

While the contribution of the upstream grid is dealt with in the IEC 60909 standard, the standard was developed without consideration of distributed generation. The following will look at the contribution of the upstream grid according to the standard and detail the method for calculating the contribution from DG, following the IEC 60909 methodology.

2.5.1 Contribution from upstream grid

The short circuit current contribution from the grid is given by the following [25]:

$$I_k'' = \frac{cU_n}{\sqrt{3}(Z_Q + Z_T)} \tag{0.8}$$

Where, Z_Q is the impedance of the network feeder at the point Q as in Figure 2-6 (a) and Z_T is the impedance of network transformer.

IEC 60909 contains correction factors that can be applied under certain conditions [18].

2.5.2 Contribution from distributed generation

There are 4 main types of DG, based on the machine type and the grid connection. For the purpose of this project, the DG is assumed to consist of *Type I* synchronous generators, in the form of CHP plants, and *Type IV* full scale power electronic connected generators, in the form of VSC wind turbines. These are reasonable assumptions when considering the penetration of DG in the Danish power system.

The contribution of these types of generation to fault level is examined below, while the contribution of *Type II* asynchronous generators directly coupled to the grid and *Type III* doubly fed asynchronous generators can be found in [25].

CHP - Type I synchronous generator

The IEC 60909 deals with synchronous generator, with their initial symmetrical short circuit current calculated using the following:

$$I_k'' = \frac{cU_n}{\sqrt{3}(Z_G + Z_T + Z_L + Z_R)} \tag{0.9}$$

Where Z_G, Z_T, Z_L and Z_R are the impedances of the generator, transformer, line and reactor, as in Figure 2-6 (b).

VSC WTG - Type IV: full scale power electronic connected

For type IV generators, connected via power electronic converters, the initial symmetrical short circuit current can be calculated using the following:

$$I_k'' = kI_{rG}, 0 \leq t \leq \Delta t \tag{0.10}$$

Where I_{rG} is the rated generator current. The time Δt depends on the protection and fault ride through capability of the DG unit.

However, this method of current approximation predicts only the magnitude of the fault current, but not the phase shift, which can lead to inaccurate results [15], [25].

Instead, relevant grid codes should be considered when calculating the contribution from a VSC connected wind turbine.

2.6 Undesirable effect of faults

Fault conditions can cause severe damage to circuit components, including lines, transformers and switching devices [26]. They, produce very high peak currents, which can immediately damage equipment; produce a sustained current many times above the rated level of many devices and equipment, which has a detrimental thermal effect; produce high breaking currents for switching devices. DG can increase the detrimental effect of fault currents in circuits by both increasing the system fault level and by negatively impacting the protection systems ability to detect and clear faults in as short a time as possible. It is for this reason that it is so important to analyse and understand the impact of DG on the protection system.

2.7 Summary

This chapter has covered all aspects of power system faults that should be considered when investigating relay protection systems, including fault types, calculation methods and standards for short-circuit currents, the negative effects of faults on circuit elements, and the contribution of various sources to the fault level.

The most common fault types have been presented, along with how often they are expected to occur in the power system, and when they should be considered. A deeper look is taken at the calculation methods and standards for evaluating the effect of faults. The widely used European fault calculation standard, the IEC 60909 standard for short-circuit calculation is then given an in-depth presentation, as it is the calculation method used for the assessment of relays under high DG penetration conditions. The current values, such as the initial short-circuit current, thermal current, peak current and breaking current are shown, along with the calculation method to give a clear understanding of the results available from the IEC 60909 standard. It also details the options which must be considered within the simulation tool, PowerFactory, for short circuit analyses.

3. PROTECTION

3.1 Introduction

As mentioned, protection in a power system is designed to protect against damage that can be caused by faults in the system. Typically a fault in a network can result in high fault current or changes in voltage, which can damage equipment attached to the network. The job of protection is to recognise potential damaging fault conditions and take action to limit the damage they can cause, and ultimately bring the system back to normal operating conditions. In this way the protection system is a reactionary system, with devices which react to changing conditions and take corrective actions.

The most common devices in modern power systems are relays, which operate by opening or closing electrical contacts on meeting a given set of contents. Other devices include: thermo-magnetic switches, fuses, and moulded case circuit breakers (MCCBs). This report will focus on relays as a protection device. Relays are generally organised according to their input parameter, voltage, current or frequency, and their method of operation such as overcurrent, overvoltage, distance, or differential protection [27].

3.1.1 Protection process

A number of states have been defined by [9] to describe the operation of a protection system. These are:

- normal state, when the network is operating as intended;
- abnormal state, when an event results in the network not operating under normal operating conditions;
- action state, when the system does not leave the abnormal state by itself and corrective action must be taken;
- outage stage, when the faulted component is taken out of service;
- restorative state, when the removed component, and the operating state of the network are inspected and the system is brought back into normal state.

The steps taken are shown in Figure 3-1. To reach the abnormal state, action state or the outage state both inequality constraint on a certain parameter of the system, such as the current, and a time constraint must be met. X_m is the check that the observed parameter exceeds predefined limits, while T_m is a time constraint which potentially allows the system to return to the normal state without the faulted device being taken out of service. The time constraint also allows for time-coordination of a number of devices in the same system.

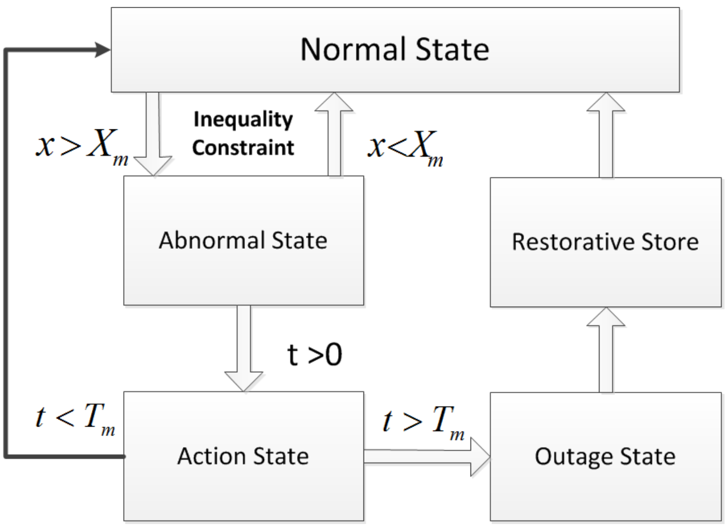


Figure 3-1 Operating process of protection system [9]

3.1.2 Operation of devices

The steps outlined in the previous section are implemented in protection devices as in Figure 3-2. Using the notation from Figure 3-1, x is a metered quantity, such as current, voltage or frequency; X_m is the threshold quantity; the comparison element performs the inequality check and triggers the decision element if outside the threshold; the decision element performs the time check against T_m; finally, the action element sends an action signal, such as a trip signal to a circuit breaker to remove the disturbance.

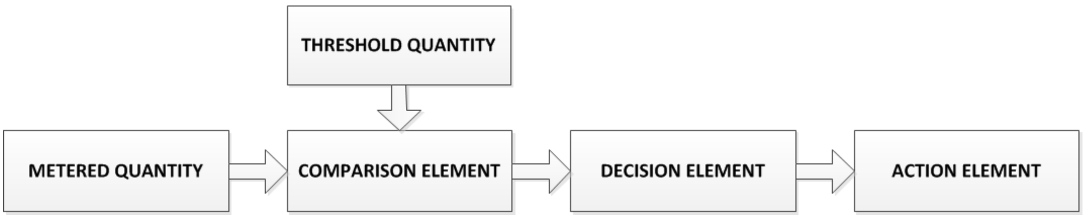


Figure 3-2 Protection Device Elements [27]

The total time for a given device to clear a fault is called the clearing time (T_c) and depends on the comparison time (T_p), decision time (T_d), and the action time (T_a) of the device. This is shown in the following equation and is used to time-coordinate multiple protection devices in a single network.

$$T_c = T_p + T_d + T_a \tag{0.11}$$

3.2 Relays

There are a number of different relays commonly used for power system protection, the most common being overcurrent, overvoltage/undervoltage, distance, and differential relays [27]. This report will focus on distance relays as the main relay device for protection of a 60 kV grid. The operation, setting and coordination schemes of distance relays is explained here, along with an outline of known potential distance relay problems.

Information regarding the remaining relay types and other protection elements can be found in [27], [10], [9], [11].

3.2.1 Distance Protection

Distance relays are typically used for long lines, such as those in the transmission network and sub transmission network, or at the higher voltage distribution system. In low voltage distribution networks they are not very common due to the short line lengths. They work on the principle of maintaining selectivity by setting a number of protection zones and detecting the fault location, by measuring the voltage and current at the relay location and from this calculating the impedance of the line to the fault, according to Ohm’s law [28]. As the impedance of the line is linearly proportional to the length, the fault location can be determined from the impedance. If a short circuit occurs close to the protection device, the impedance is lower than for a fault occurring far from the device [10].

The impedance relay has a circular operating characteristic in the complex Z plane, with centre at the origin and a radius equal to the threshold setting, in ohms. The relay operates for all values of impedance less than the setting, i.e. for all the points inside the circle [10]. A directional unit is combined with an impedance relay to ensure that the relay detects on faults in front of the distance unit, reducing the operating characteristics to a semi-circle. Figure 3-3 (a) below shows the impedance relay characteristics in the X-R plane, including the directional unit. In Figure 3-3 (b) three relay characteristics are shown, corresponding to three zones of protection. The circle with the smallest radius is for faults closest to the relay and has the shortest operating time.

More commonly, a mho relay characteristic is used which combines the properties of impedance and directional relays. Its characteristic is inherently directional and the relay only operates for faults in front of the relay location; in addition it has the advantage that the reach of the relay varies with the fault angle, so that a mho relay can have a greater reach in the X or R direction. The characteristic, drawn in the complex Z plane, is a circle with a circumference that passes through the origin, as shown in Figure 3-4.

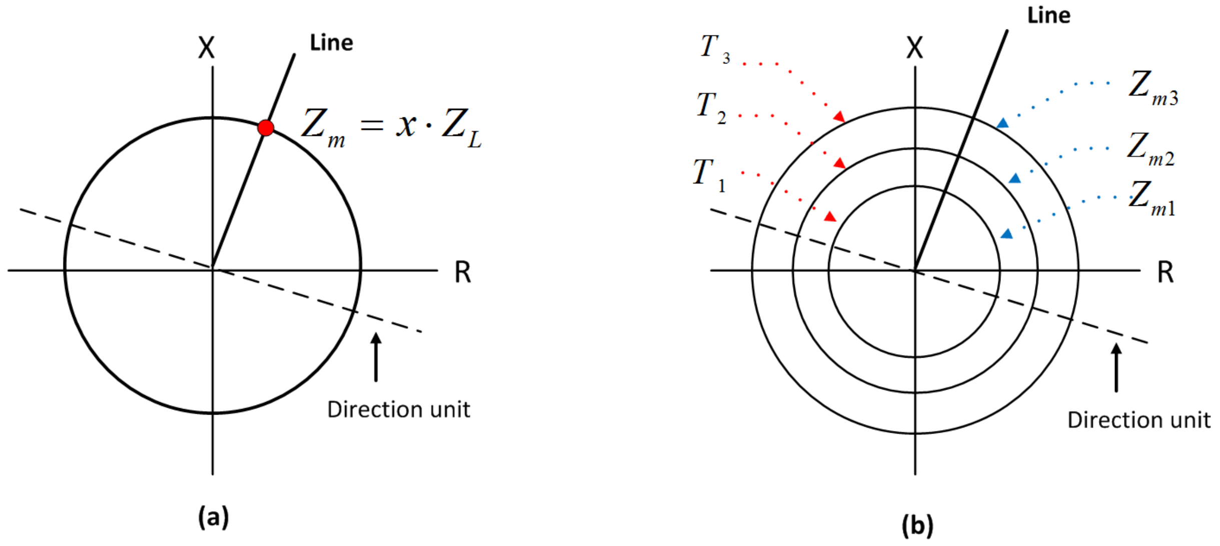


Figure 3-3 Impedance relay characteristics and directional unit [27]

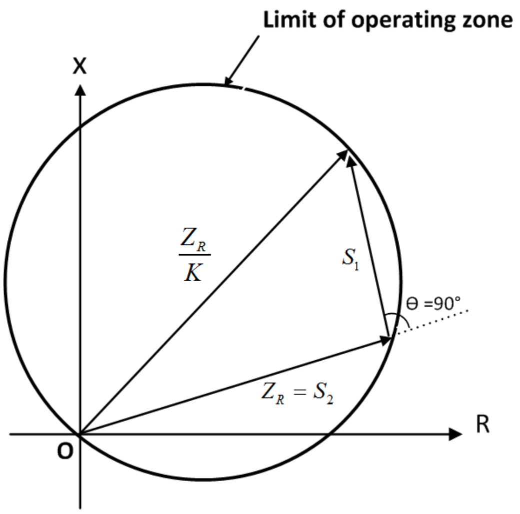


Figure 3-4 mho relay characteristic [10]

Normally, three protection zones in the direction of the fault are used in order to cover a section of line and to provide back-up protection for further feeders. However, some relays have one or two additional zones in the direction of the fault plus another in the opposite direction which acts as a back-up to protect the busbars [10].

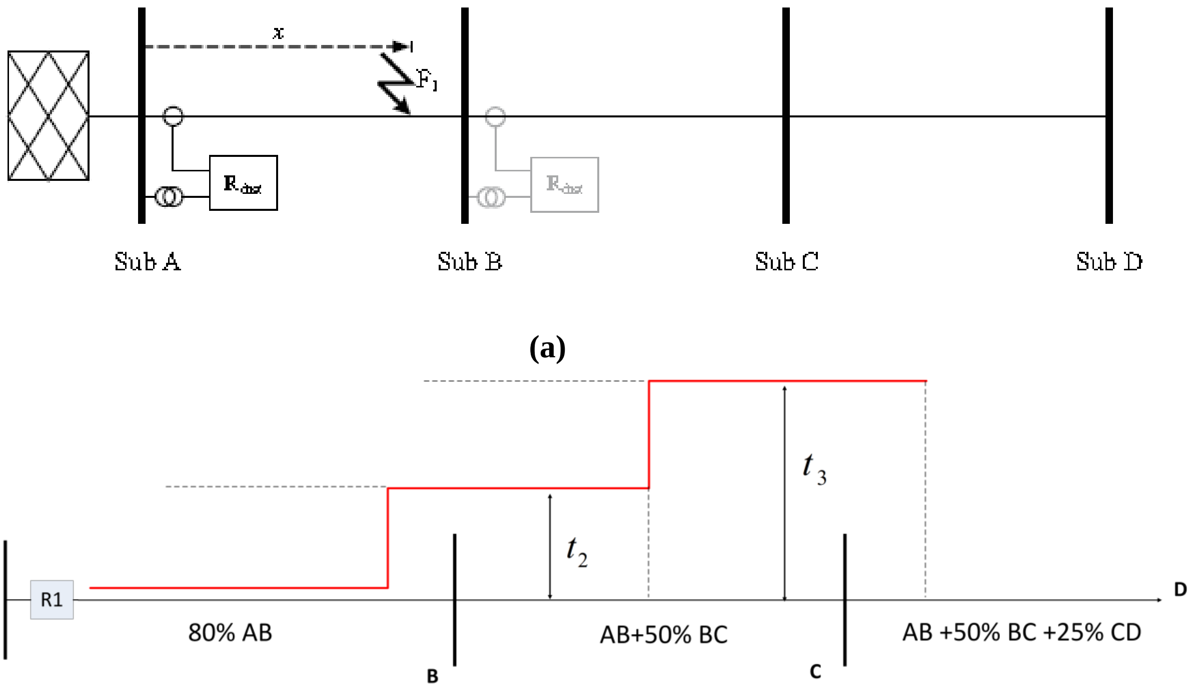
In the majority of cases the setting of the reach of the three main protection zones is made in accordance with the following criteria [10]:

The first zone is set to cover between 80 and 85% of the length of the main protected line; the second zone is set to cover all the main line plus 50% of the next line as a safety margin; the 3rd zone is a back-up zone for the remote line and is set to cover all the main line plus 100 per cent of the second line, plus 25 per cent of the subsequent line.

If we consider the network in Figure 3-5 (a), the above rules mean that zone 1 should include 80% of AB, zone 2 should cover AB + 50% BC, while zone 3 should cover AB + BC + 25% CD. This can be seen in Figure 3-5 (b), which also includes the time setting for the protection zones. In practice this means that the threshold settings are:

$$
\begin{aligned}
Z_{t1} &= 0.8Z_{AB} \\
Z_{t2} &= 0.8Z_{AB} + 0.5Z_{\mathrm{BC}} \\
Z_{t3} &= 0.8Z_{AB} + 0.5Z_{\mathrm{BC}} + 0.25Z_{CD}
\end{aligned}
\tag{0.12}
$$

These rules allow for some margin of error in the impedance measurement, as well as good coordination between protective devices.



(a)

(b)

Figure 3-5 Setting protections zones for distance relays [27], [10]

Other relays include numerical and electronic relays with polygonal characteristics. A typical characteristic diagram is shown in Figure 3-6. In this case, zones 1 to 4 provide cover in the forward direction and zone 5 in the backward direction. Electronic relays can provide greater versatility for characteristic setting, including shaping the characteristics to avoid load tripping, or to provide cover for a transformer.

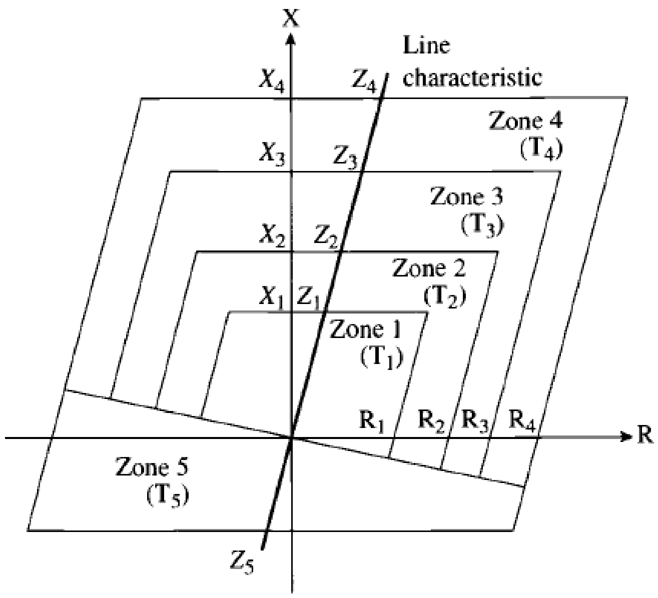


Figure 3-6 Numerical relay with polygonal characteristic [10]

3.3 Selectivity Conditions and Coordination of relay devices

A protection system detects the presence of an abnormal operating condition and intervenes in order to prevent damaging consequences. Selectivity of a protection system is the ability of the system to maintain the greatest possible supply level by disconnecting the minimum section of the network necessary to isolate the fault. In other words the protection system should take out of service the component or part of a plant in which abnormal conditions occur, thus permitting the remaining parts of the electrical system to remain in service.

3.3.1 Distribution System Configurations

Distribution systems have a number of configurations. The most common configuration is the radial system, as in Figure 3-7 (a). Lines begin at a common bus, which is the only point at which the parallel lines are connected. A loop or ring structure, as in Figure 3-7 (b), adds additional security to the system, at an increase of cost and complexity. The meshed system again adds further security but complexity. Ring and meshed networks add additional security by allowing most loads in a local distribution network to connect to the greater power system from more than one point. If a fault occurs on one line, the loads can be fed from a second line in the system. These systems are often operated as radial networks with coupling switches normally operated in the open position. This allows for the protection system to be kept as simple as in a radial network, with the added ability to switch in a second line when there is a fault.

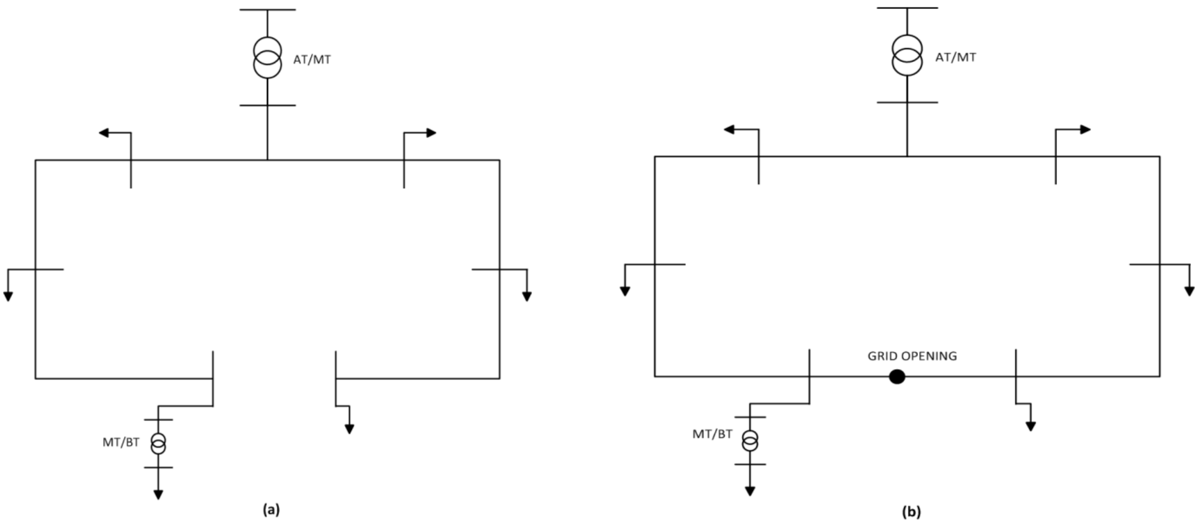


Figure 3-7: Distribution System Configurations: (a) Radial grid structure, (b) Ring grid structure

The 60 kV distribution systems in Western Denmark has been built as a meshed or ring network with at least two supply possibilities to each 60 kV station and with interconnections between neighbouring distribution companies [4].

Due to the effect of the network configuration on the fault current flow in the network, the coordination of relay devices depends highly on the configuration of the network. In the following, an analysis is conducted on possible protection coordination schemes of protection devices, employed in typical MV network structures.

3.3.2 Coordination in radial lines

The most straightforward configuration of an MV line is a simple radial structure as in Figure 3-8, with a single feed at the source bus. In this case, it is sufficient to install one relay on each line, at the top of the feeder. If a short circuit occurs on the line, the relay connected to that line should detect it and send the tripping signal to remove the faulted line. For example, for a fault at the point P, in Figure 3-8, the distance relay R2 detects the presence of abnormal operating conditions, and measures the fault to be in the second protection zone. Relay R1 also detects the presence of abnormal operating conditions and measures the fault to be in the third protection zone. The relays have steps in operating time for each of the zones. Zone 2 has a shorter operating time than zone 3 so that R2 sends a tripping signal to its circuit breaker, and removes the faulted line (Line 2), while keeping Line 1 energised, ensuring the selectivity of the circuit.

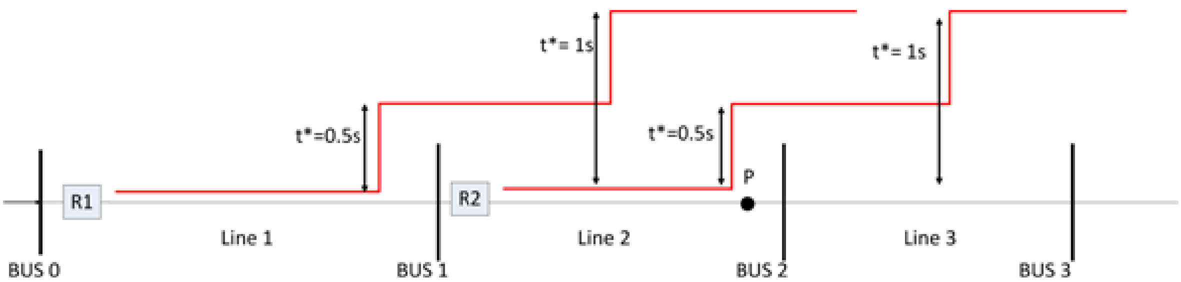


Figure 3-8: System protection with distance relays in a MV network

3.3.3 Coordination in ring networks

In a ring network, the current and power flow is not unidirectional but bi-directional as can be seen in Figure 3-7, where there is a source at both ends of the circuit. It is necessary therefore to install distance relays, both upstream and downstream of each busbar to ensure full selectivity. If there is a short circuit at any point on the line the two relays at each end of the line will detect the fault and send a tripping signal to the circuit breakers to d-energise just the faulted line, ensuring selectivity.

For example, if there is a short circuit at point P, in Figure 3-9, R2 in the first zone in the forward direction and R2b in the first zone in the opposite direction will detect the fault and remove the faulted line. R1 acts as back up to R2 in case of malfunction of the relay or circuit breaker. A relay facing the opposite direction, behind R2b should provide back-up to R2b.

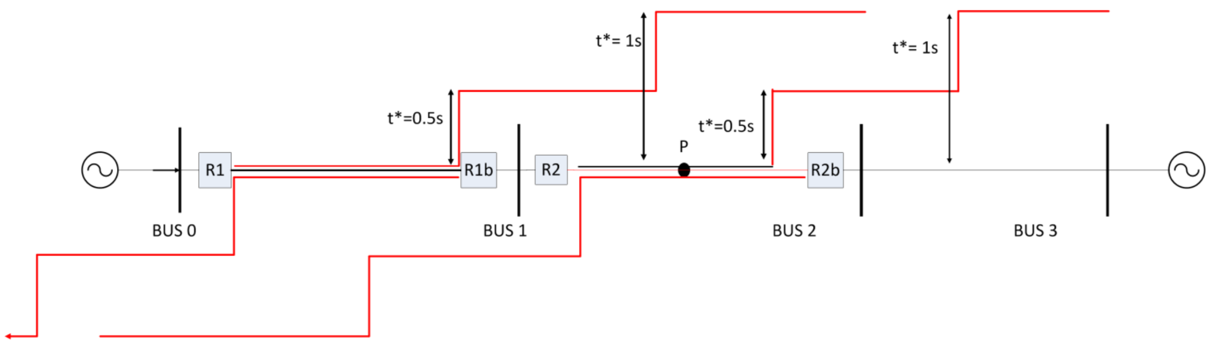


Figure 3-9: Protection in a ring network

3.4 Potential distance protection relaying problems

A number of sources [28] [29] [30] have identified some key areas where distance relay protection system problems can occur. This section will highlight some of these key issues, while the investigation of the possible impact and contribution of DG to these problems is the main aim of this report.

3.4.1 Under-reach

Reach issues have been identified by [29] as an area of concern in circuits with the presence of a number of in-feed feeders. As mentioned previously, distance protection operates under a zonal system, with the first zone protecting up to 80-85% of the protected line, the second zone protecting the remaining section of the line with a safety margin into the remote line, and a third zone providing back-up protection to the remote line. With the presence of in-feed feeders, such as in Figure 3-10, the reach of the second and third zones is reduced. This can introduce security and selectivity issues. To counteract these problems the second and third zone setting needs to be increased which can lead to loadability reduction [29].

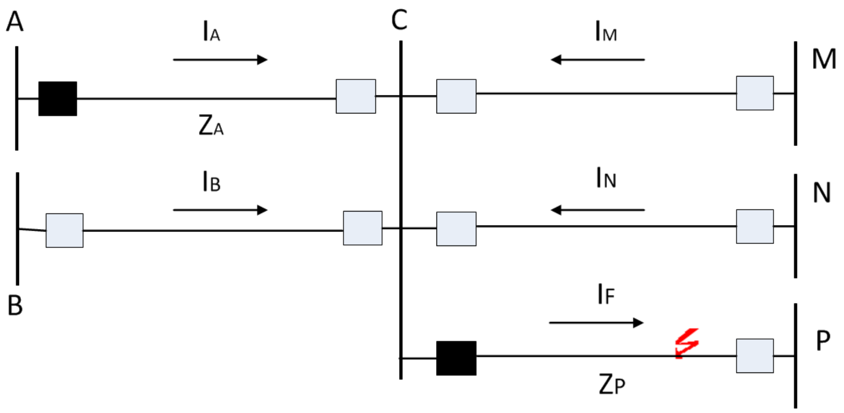


Figure 3-10 Protection of bus with a number of in-feed feeders [29]

3.4.2 Loadability reduction

Following from the previous reach issues, loadability problems for over-reaching protection zones have been recognised. Figure 3-11, gives an example of the loadability reduction, following an increase in the over-reaching protection zones. This issue is most prevalent for the far reaching third zone, especially if the remote line is longer than the protected line. It is a problem for the three phase fault zone characteristics, as high loading conditions will typically effect all phases. The reduction of the loadability can lead to cascade tripping.

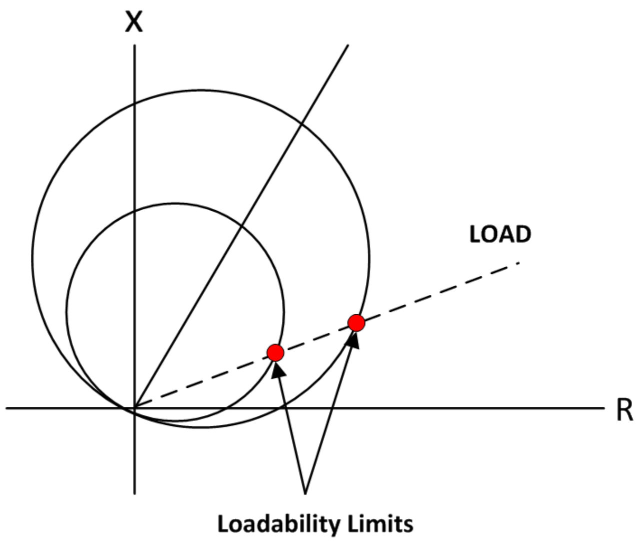


Figure 3-11 Loadability reduction for increased 3rd zone setting [29]

3.4.3 Cascade tripping

It has been observed that undesired third zone operations caused by unexpected loading conditions following line tripping have often contributed to cascade tripping, as was the case for the wide scale blackout in North America in 2003 [30]. Following the tripping of a line, loading conditions can increase on the still connected lines, which can lead to the load coming within the reach of the 3rd zone of relays. An example of this occurring is shown in Figure 3-12. The operating point before and after the initial tripping incident of the Sammis-Star line is shown. This effect is further accentuated if the initial tripping occurs on an in-feed feeder.

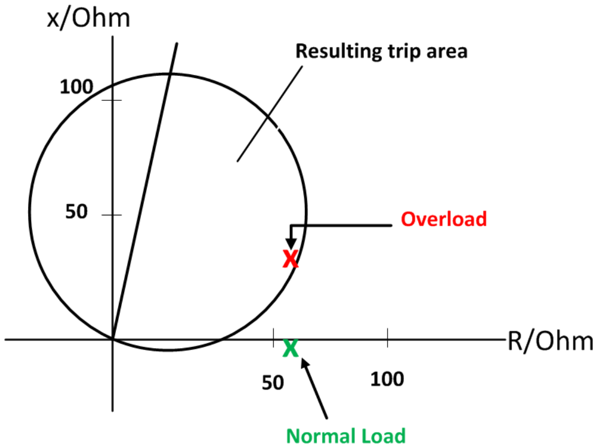


Figure 3-12 Cascade tripping example from USA blackout in 2003 [30]

The problems described here are investigated for a system under high DG penetration in chapter 5.

3.5 Summary

This chapter describes protection systems to give the reader a clear understanding of the operation and desired function of a protection system in a network. Focus is on distance relays as the relay device for detecting fault in the 60kV Danish network, and method of operation, characteristics and coordination of devices in a network is discussed.

Finally a number of distance relaying issues which have been identified by a number of sources are outlined, which serves as an indication of the potential problems that may be faced in a system using this type of relay, and as a lead in to the investigation of the effect of high DG penetration on the selectivity and security of distance relays, which comes in chapter 5

4. SYSTEM DEFINITION AND MODELLING

4.1 System Definition

A high interest section of the 60 kV network in the Danish power system has been considered as the test network for the purpose of this project, and a realistic model has been developed using the relevant data from it. This section of the network is of high interest due to the large penetration of DG, along with a relatively small number of protection devices, which have not been updated since the installation of a large portion of the DG.

Busbars and feeders

The system consists of 5 busbars connected via 5 60 kV cables in a ring configuration, along with a connected CHP plant and Wind farm. The layout can be seen in Figure 4-2. Bus 1 has both a 150/60 kV substation connecting to the external grid, and a 60/10 kV substation connected to a load feeder. It provides connection to the external grid, and is the main source of short-circuit current. The remaining busses consist of 60/10 kV substations each with a connected 10 kV load feeder and a connection via 60 kV cables to the adjacent busbars.

Distributed Generation

The chosen section of the network has 89 MW of installed capacity, consisting of a 26 MW CHP plant and a 63 MW wind farm. The CHP generator, shown as CHP in Figure 4-2, is connected to one of the 60/10 kV busses, to which a load feeder is also connected, while the wind farm, shown at Bus 7 in the figure, is connected to a dedicated 60/10 kV bus, and directly to the main busbar Bus 1.

There are a total of 30 VSC connected WTGs, twenty 2 MW WTGs and ten 2.3 MW WTGs. They are connected to a common bus via 3 transformers of 31.5 MW, 31.5 MW and 25 MW. The individual turbines in the wind farm are connected to each of the respective transformers in parallel, and therefore can be combined to three single turbine/transformer equivalents as shown in Figure 4-1. Some details are lost in this assumption, specifically the geographic spread of the wind turbines, and subsequent smoothing effect, however as the short-circuit analysis is performed at steady-state, this loss of detail does not have an effect on the results.

Details regarding the modelling of the DG in the network can be found in section 4.4.

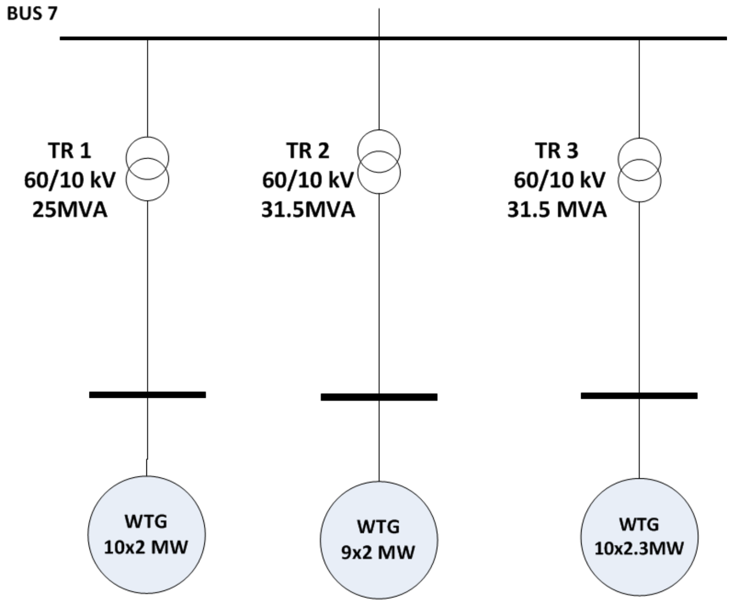


Figure 4-1 Wind farm equivalent layout

Relays

The protection devices, numbered P1-P8 in Figure 4-2, are a mix of older mho and newer numerical polygonal distance relays. Each of the relays has associated current and voltage transformers which measure the current and voltage at the relay location. Three of the busses have protection connected on each of the feeder cubicles while the remaining busses do not have their own relays and instead come within the protection zones of the remote relays.

All the relays follow the scheme outlined in section 3.2.1 and Figure 3-5. Three protection zones have been set: the first zone is designed to protect 85% of the line to which it is connected; the second zone is designed to protect up to 50% of the remote line; the third zone protects the last 50% of the remote line and 25% of the next line. These values provide a margin of error in measurement from the current and voltage transformers of the relays.

The protection system has been implemented and operated on the real network, which will provide the base case scenario. It has been operated according to schemes implemented before the addition of the DG. Various protection schemes will be discussed in the assessment studies chapter (chapter 5), as well as an investigation of the validity of this scheme when there is in-feed from DG sources and an examination of the effect on these relays and relay settings of the addition of the DG.

Details regarding the implementation of the relays in the system model can be found in section 4.5.

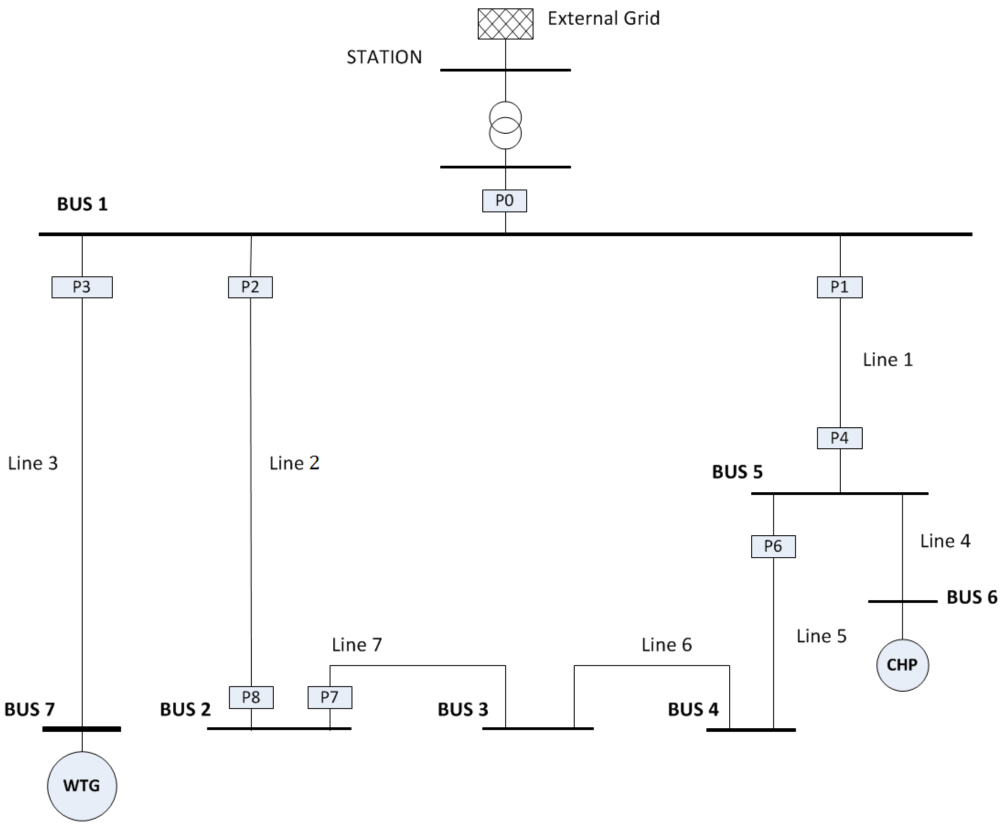


Figure 4-2: Test section of 60 kV distribution grid with CHP plant (synchronous generator), Wind farm (VSC connected), busbars and relays indicated.

4.2 Power System Simulation tool – DIgSILENT PowerFactory

To allow for a detailed analysis of protection systems in a realistic setting, a detailed model of the 60 kV ring network has been built in the power system simulation software DIgSILENT PowerFactory. Data was provided by Energimidt, representing a real grid in Denmark where a high penetration of DG was present. This network can be used to accurately represent a typical ring network with DG.

All elements necessary for performing short circuit studies were included. These include network elements such as transformers and lines/cables, and more importantly the sources which contribute to the short circuit level, such as the grid, synchronous generators like CHP plants and power electronic connected generators like VSC wind turbines. The protection system itself was also implemented in the model, allowing for direct assessment of various protection schemes and an analysis of the sensitivity and selectivity of the system.

DIgSILENT PowerFactory is used as it provides all of the necessary tools for performing this type of analysis. The details of the software are discussed in the following section. It is an interactive software package dedicated to electrical power system and control analysis in order to complete the main objectives of planning and operation optimisation.

It makes use of a single database, with the required data for all equipment within a power system (e.g. line data, generator data, protection data, harmonic data, controller data), along with an intuitive graphical design interface, meaning that PowerFactory can easily execute all power simulation functions within a single program environment, including the following [31]:

- Load flow analysis
- **Short-Circuit Analysis**
- **Protection Analysis**
- Harmonic Analysis
- RMS Simulation
- EMT Simulation
- Contingency Analysis
- Reliability Analysis
- Optimal Power Flow

This report will focus on the most important functions used for this project, the short-circuit and protection analysis tools.

4.2.1 General Network Design

PowerFactory provides an interactive single-line diagram drawing function, which allows for systems to be built from an extensive library of electrical components, including: lines/cables, loads, generators, transformers, busses, switches, relays, DC interconnectors, etc. This method of constructing a system is intuitive and provides a clear overview of the operation of the system, with all functions being performed within the graphic window. An example of a single line diagram is shown in Figure 4-3. The system shown contains a DG source, synchronous generator connected to external grid connected via two lines and a transformer, with busses at each of the connection points. The same system will be used further in the chapter, as a test system to highlight the short-circuit analysis function and modelling of various elements.

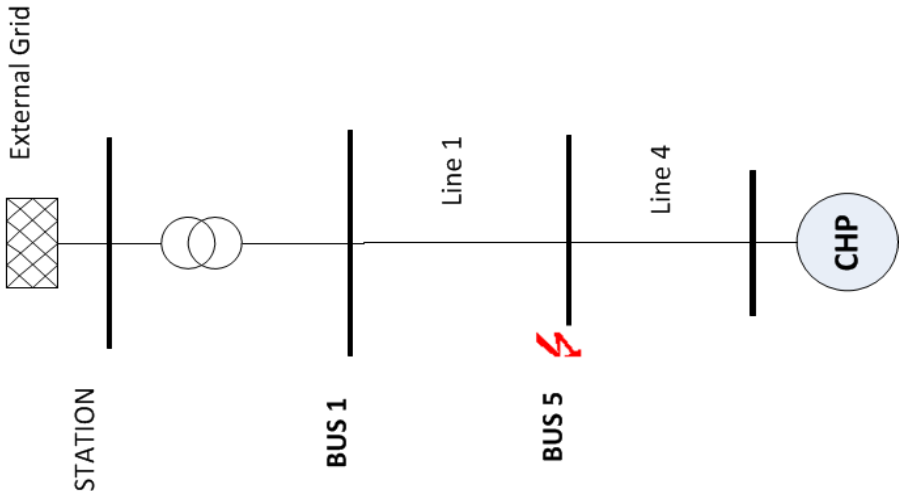


Figure 4-3 Power Factory Single Line diagram

As mentioned, PowerFactory provides an extensive library of electrical component. Within each element the options listed below are available. The most important options for short circuit analysis are highlighted in bold below. These options tell Power Factory the characteristics of each element when performing specific functions.

- **Basic Data**
- **Load Flow**

- **VDE/IEC short-circuit**
- **Complete short-circuit**
- **ANSI short-circuit**
- IEC 61363
- RMS-simulation
- EMT-Simulation
- Harmonics/Power Quality
- Optimal Power Flow
- Reliability
- Generation Adequacy
- Tie Open Point Opt.

4.2.2 Short Circuit Analysis

PowerFactory has a built in Short Circuit function which allows for calculation of short circuit levels at state condition as a result of a short circuit fault at a selected point in the network. A number of calculation methods can be chosen, such as the approximate IEC 60909/VDE 0102 and IEEE 141/ANSI C37, as well as the complete/superposition method. These methods have been discussed in section 2.4.3, where details on the methods can be found.

Here a focus will be put on the options and methods PowerFactory provides for performing an analysis according to the European standard IEC 60909 methods [21].

Fault options

- Short Circuit level can be calculated for the following fault types:
  - 3-phase SC;
  - 2-phase SC;
  - 1-phase to ground SC;
  - 2-phase to ground SC;
  - 1-phase to neutral SC;
  - 1-phase neutral to ground SC;
  - 2-phase to neutral SC;
  - 2-phase neutral to ground SC;
  - 3-phase to neutral SC;
  - 3-phase neutral to ground SC;

- Fault Location: The faults can be placed at busses, terminals or on the lines. For a fault on the line the specific position on the line can also be chosen. This option is essential for testing of distance protection devices as it allows for testing of the selectivity and sensitivity of fault detection in all zones of the relays. It is also extremely useful for calculating the effect of in-feed currents from DG sources.
- Fault impedance: The impedance of the fault can be set, both the resistance and reactance.
- Multiple faults: The IEC 60909 takes a single fault location while the complete method can be used for multiple faults.

Other basic options

- Maximum/minimum short circuit currents
- Max voltage tolerance: either 6% or 10% depending on the voltage correction factor, as discussed in section 2.4.3.

- Breaker time: used to calculate the symmetrical breaking current I_b
- Fault Clearing time: used in the calculation of the thermal equivalent SC current I_{th}

Advanced options

- Grid identification
- c-Voltage Factor: whether specified by user or calculated by Power Factory;
- Asynchronous motors: if their contribution is considered;
- Conductor temperature: pre-fault conductor temperature;
- Decaying Aperiodic Component: Options correspond to the B, C and C' methods discussed in section 2.4.3;
- Peak-SC Current: corresponds to methods A, B and C methods discussed in section 2.4.3;
- Calculate I_k: how to deal with asynchronous motors when calculating I_k, whether they are connected, disconnected;
- Consider Protection Devices: choose to calculate measured current and tripping times for protection devices;
- Automatic Power Station detection: automatic detection or user selection of power stations in order to apply the impedance correction factor.

4.3 Network Model

4.3.1 Terminals

Terminals are used as connectors in the single line diagram window of PowerFactory, connecting the various electrical elements in the diagram. They can be used as a busbar, a junction node or an internal node. They take no specific data in relation to the IEC 60909 method, aside from the voltage level.

4.3.2 Lines

Lines are modelled in Power Factory using the lumped parameters for impedance and reactance. Aside from the impedance value which is essential for any calculations in the network they require no further information specifically for the IEC 60909.

4.3.3 Loads

Loads are specified by their specific operating point. They are not considered for the IEC 60909 method; however for the complete method a pre-fault load flow is calculated in which the loads are considered.

4.3.4 Transformers

Transformers are described by their rated power level and turns ratio. For short-circuit studies the positive and zero sequence impedance is of great importance, and is defined by the short-circuit voltage u_k, in the positive sequence and u_{k0} in the zero sequence.

Further settings are available, specific to the IEC 60909, where it must be specified if the transformer has an on-load tap changer (OLTC), and the settings of the tap changer. For the purpose of this study, the transformers are taken to have no OLTC.

The network studied contains 4 transformers, one connecting to the external grid, and three within the wind farm. Each of the transformers is taken to have a positive sequence short-circuit voltage (Uk) of 7%, a zero sequence short-circuit voltage (Uk_0) of 3% and copper losses equal to 1% of the rating. These values are typical values for transformers of these sizes. The full list of parameters relevant to the short-circuit study can be found in Table 4-1, while the calculation of the transformer impedance according to the IEC 60909 method is shown in detail in section 4.4.1.1.

Table 4-1 Transformer parameters relevant to short-circuit studies

Transformer	Rating (MVA)	Positive sequence short-circuit voltage (Uk)	Zero sequence short-circuit voltage (Uk0)	Copper Losses (kW)	On-Load Tap Changer
Grid Trafo	125	7%	3%	12.5	No
WF Trafo 1	31.5	7%	3%	3.15	No
WF Trafo 2	31.5	7%	3%	3.15	No
WF Trafo 3	25	7%	3%	2.5	No

4.4 Short-circuit sources

4.4.1 External Grid

The external grid is the main source of short-circuit current in the network. Power Factory provides an external grid element where IEC 60909 relevant parameters can be assigned. The parameters relevant to IEC 60909 short-circuit studies are:

- Short-Circuit Power S_k'';
- Short-Circuit Current I_k'';
- X/R ratio;
- Impedance ratio (Z2/Z1, X0/X1, R0/X0);

The values for each of these parameters are set to calculate either the maximum or minimum short-circuit current.

The parameters used in this study are given in Table 4-2, while the calculation of the transformer impedance according to the IEC 60909 method is shown in detail in section 4.4.1.1.

Table 4-2 Parameters for external grid

Parameter	Maximum	Minimum
Short-Circuit Power S_k'' (MVA)	10000	8000
Short-Circuit Current I_k''(kA)	38.49	30.79202
X/R ratio	10	10
Z_2/Z_1	1	1
X_0/X_1	1	1
X_0/R_0	10	10

4.4.1.1 Grid Contribution

The full calculation of the short-circuit contribution from the grid according to the IEC 60909 can be found in the appendix.

I_k'' for three-phase fault

$$I_{kgrid}'' = \frac{cU_n}{\sqrt{3}Z_L} = 7.764\angle -73^\circ kA \qquad (0.13)$$

Where:

- I_k''= initial symmetrical short circuit current (kA)
- c = Voltage factor that accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)
- Z_L = Equivalent positive sequence short circuit impedance (pu)
- U_n = Nominal system voltage at the fault location (kV)

Figure 4-4, shows the Power Factory values of the short-circuit contribution from the grid. The short circuit current value given by Power factory has a magnitude of 7.72 kA, which is as calculated analytically, validating both the model and the method.

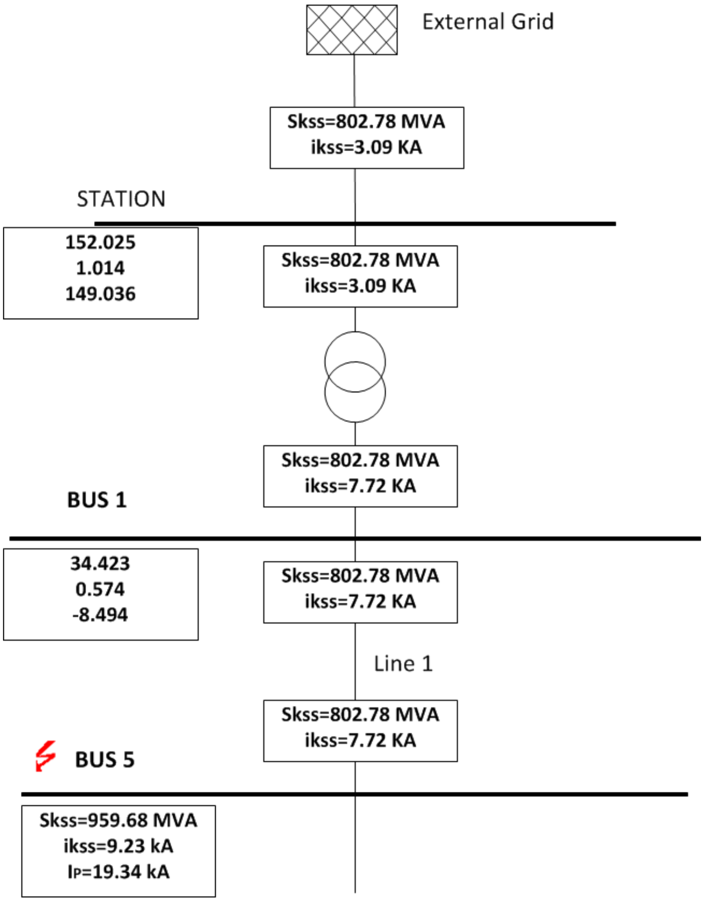


Figure 4-4: Short-circuit from grid

4.4.2 Combined Heat and Power (CHP)

From a power systems point of view, CHP plants are seen as synchronous generators connected directly to the power system. Provisions have been made for this type of system in the IEC 60909 standard. The standard uses an equivalent voltage source and short-circuit impedance to determine the short-circuit contribution. The most important of these values are the saturated sub-transient reactance Xd''_{sat}, and the stator resistance. Power Factory also allows for definition of IEC60909-specific variables for synchronous generators. The following variables are available:

- Sub-transient Reactance (Xd''_{sat});
- Stator Resistance (R_{str});
- Zero sequence Reactance (X_0);
- Zero sequence Resistance (R_0);
- Negative sequence Reactance (X_2);
- Negative sequence Resistance (R_2);
- Saturated synchronous reactance (Xd_{sat});
- Machine Type: Salient pole series/Turbo Series.

The power rating and nominal voltage of the generator are also required.

The following values are chosen for the CHP according to actual values and typical values for synchronous generators of this type.

Table 4-3 CHP parameters for short-circuit analysis

Parameter	Value
Power Rating	26MW
Sub-transient Reactance ($\boldsymbol{Xd''_{sat}}$)	0.17 pu
Stator Resistance ($\boldsymbol{R_{str}}$)	0.025 pu
Zero sequence Reactance ($\boldsymbol{X_0}$)	0.1 pu
Zero sequence Resistance ($\boldsymbol{R_0}$)	0.01 pu
Negative sequence Reactance ($\boldsymbol{X_2}$)	0.17 pu
Negative sequence Resistance ($\boldsymbol{R_2}$)	0.02 pu
Saturated synchronous reactance ($\boldsymbol{Xd_{sat}}$)	2 pu
Machine Type	Salient pole series

4.4.2.1 Short circuit contribution from CHP synchronous generator

The full calculation of the short-circuit contribution from the CHP according to the IEC 60909 can be found in the appendix.

$I_k^{"}$ **for three-phase fault**

$$I_{kG}^{"} = 1.360\angle -88^{\circ} kA \tag{0.14}$$

Figure 4-5 shows the Power Factory values. It can be seen that again the value is very to the SC current calculated by hand.

Total SC current from calculations

$$I_{kTotal}^{"} = I_{kG}^{"} + I_{kgrid}^{"} = 9.124kA \tag{0.15}$$

Where:

- $I_{kG}^{"}$ = Initial symmetrical short circuit current of the Generator (kA)
- $I_{kgrid}^{"}$ = Initial symmetrical short circuit current of the Grid (kA)

Total SC current from PowerFactory

$$I_{kTotal}^{"} = 9.23kA \tag{0.16}$$

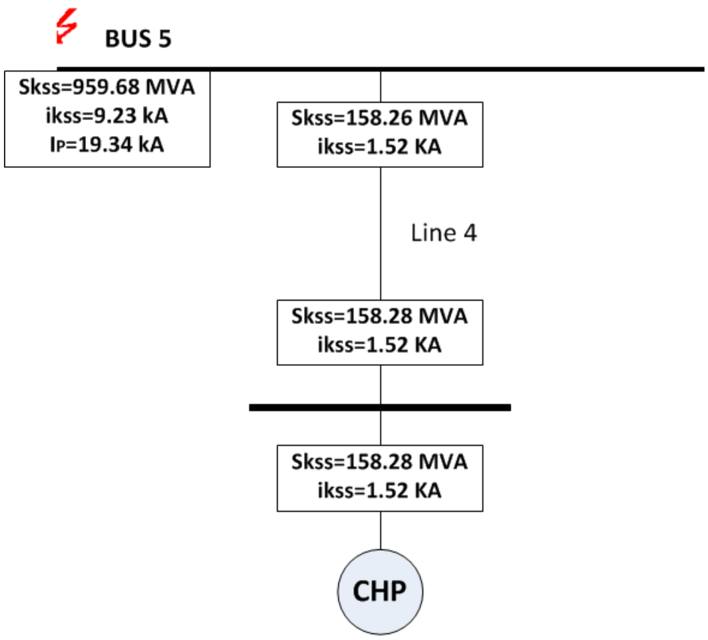


Figure 4-5: Short-circuit contribution from synchronous generator

4.4.3 Wind Turbine Generator

There is a wind farm present in the system under test. The wind turbines are Type IV: fully rated converter connected machines, with a total combined rated active power output of 60 MW.

Type IV, converted connected machines are not considered in IEC 60909, instead the short-circuit current contribution from VSC connected wind turbines in Denmark is dependent on *"Technical regulation 3.2.5 for wind power plants with a power output greater than 11 kW"* defined by Energinet [32], which specifies the reactive power requirements of wind turbines above 1.5 MW during a voltage drop, as occurs during a short-circuit fault.

As the WTG is connected via a fully rated converter, the operating point can be set according to a given control scheme. The regulation from Energimidt sets the current requirements for WTGs for voltage control, essentially making the wind turbine a voltage controlled current source. The characteristic curve can be seen in Figure 4-6.

The requirement defines the ratio of reactive current to nominal currentI_Q/I_N, with I_Q equal to the short-circuit current. Power Factory provides a VSC WTG model which can adhere to this characteristic curve, which is used within the model of the network.

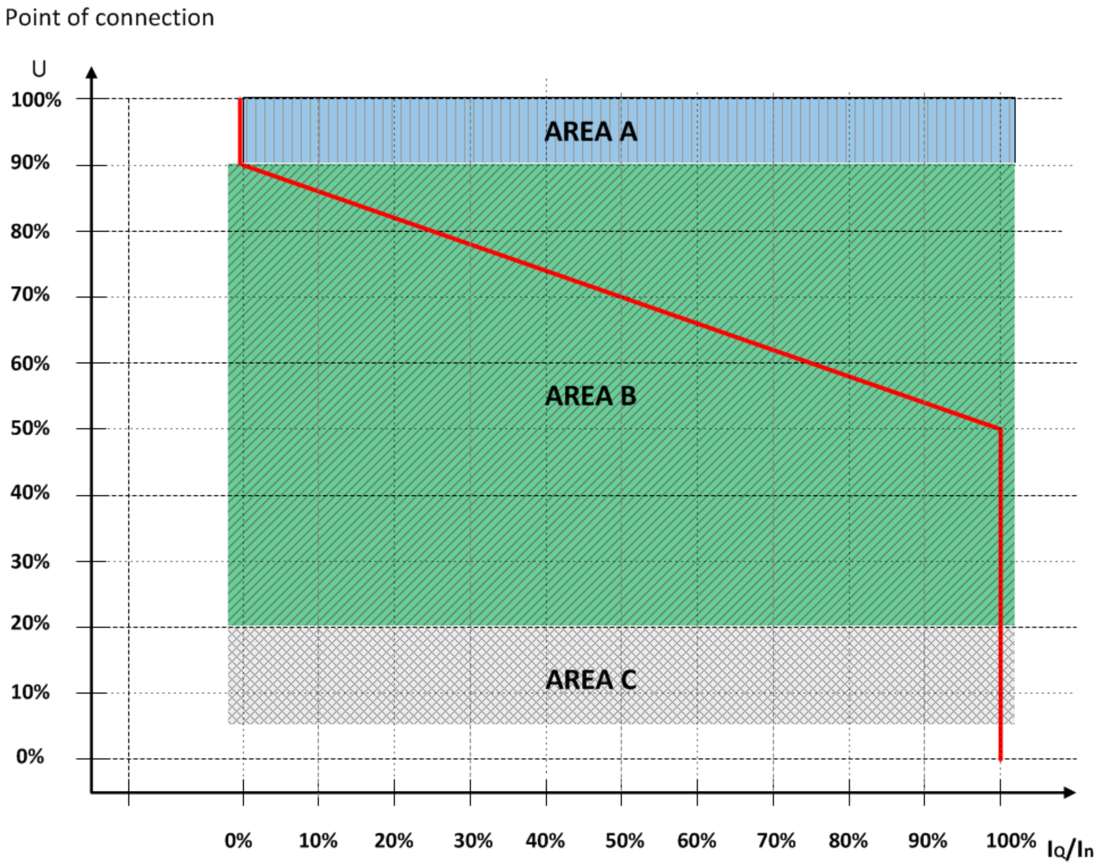


Figure 4-6 Reactive current requirements for voltage support according to Energinet [32]

4.5 Relays

4.5.1 Introduction

On top of the standard electrical circuit elements already discussed in this section, PowerFactory also provides a library of relay devices. This library contains a number of real relays from major manufacturers such as ABB, Siemens and General Electric, along with generic models of mho and polygonal distance relays, overcurrent relays and under-voltage relays, for which settings can be set by the user.

The relays can be connected at terminals in the circuit, with an associated circuit breaker, as shown in Figure 4-7. With the addition of relays in the network, they can be used to run tests and see how the protection system reacts to changing conditions. Tripping times for faults at all locations in the circuit can be tested under a wide range of conditions, which also allows further testing of possible solutions in specific networks to any problems that may be introduced with the addition of DG in the network.

An extensive guide to relays in PowerFactory has been included in the Appendix, while the specific type and setting for the relays in this network can be found the next section.

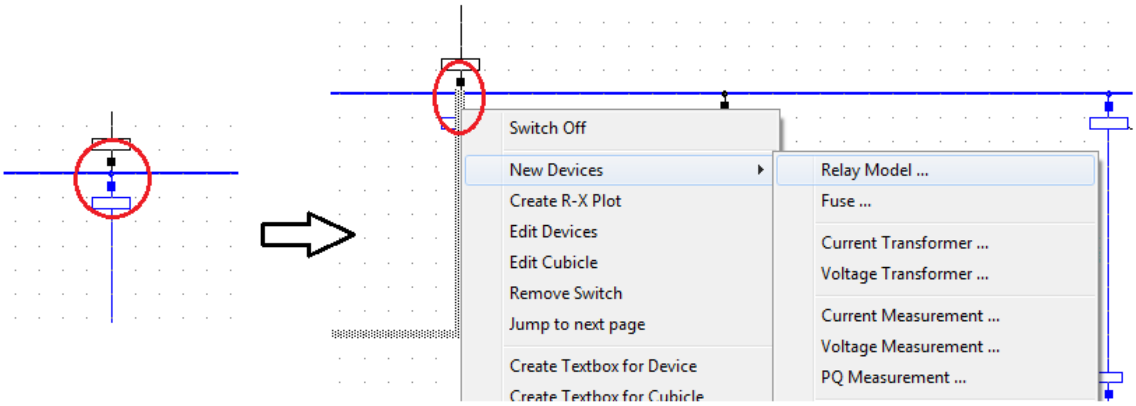


Figure 4-7 Addition of Relay in PowerFactory

4.5.2 Relay implementation

The relays are as in Figure 4-2 able below gives a list of the relay information relevant for implementing the model within PowerFactory. The zones are set using an impedance magnitude and zonal values shown represent the base case of relay settings as are installed in the real network, and are given in secondary ohms.

Table 4-4 Base Case Relay Values

Name	VTR	CTR	Uz	In[A]	Z'1 [Ω]	Z'2 [Ω]	Z'3 [Ω]
P1	60000/100	800/5	3,75	5	0,5832	1,6050	2,7846
P2	60000/110	400/5	6,818	5	0,4876	1,0791	1,6788
P4	60000/110	400/5	6,818	5	0,3208	0,6642	1,2038
P6	60000/110	300/5	9,091	5	0,6443	0,9732	1,2591
P7	60000/110	400/5	6,818	5	0,8592	1,1995	1,5316
P8	60000/110	400/5	6,818	5	0,4876	0,7624	1,2038

4.6 DIgSILENT Programming Language (DPL)

PowerFactory also provides a programming language (DPL) which can be used to interact with the network model in a systematic way. Through the use of the DPL, elements in the circuit can be accessed and both the properties of the elements can be altered and values can be read from them. A DPL script is written in a text editor and is based on the object-oriented C++ programming language. It provides a large number of functions specific to the circuit element in question. Extensive guides can be found in the Power Factory user manual [21] on the specific functions and object names.

The DPL scripts used in this project can be found in the Appendix.

5. Assessment Studies

5.1 Methodology

5.1.1 Introduction

An analysis was conducted to examine the effect of distributed generation on relay sensitivity and selectivity in MV ring networks. This chapter will detail the analysis and present a number of key results for evaluating the ability of the protection system to perform to an acceptable level under high DG penetration situations.

Tests are performed using Power Factory for a number of different test cases, which are detailed in section 5.1.2. The tests performed are short-circuit sweeps which perform a short-circuit analysis at a number of points throughout the circuit, and output all necessary circuit values such as instantaneous short-circuit current (I_k''), which are later processed in processing and plotting tools such as MS Excel and Visio.

Time-distance diagrams are provided which show the operating times of all the relays, against the line length or impedance. This gives a clear overview of the protection zones and operating times of the different relays in both directions around the ring.

The reach of the relays are also portrayed on schematics of the grid, highlighting clearly the reach of the relays under various test conditions. They give an insight into the exact areas where under-reach or overreach issues are experienced, related to the location of the sources of short-circuit current in the grid.

5.1.2 Test Cases

A number of test cases have been defined which will give an extensive set of results for analysing the effect of DG on the selectivity and sensitivity of the protection device in a MV ring network. The Danish 60 kV network discussed in section 4.1 is used as the test circuit with a number of variable parameters. The following elements are used as variables:

- CHP
  - Size
  - Connection Point
- WTG
  - Size
  - Connection Point
- Relay settings
  - Calculated considering DG
  - Calculated without considering DG
- Fault Type
  - 3-phase
- Grid configuration
  - Single external grid connection

The table below shows the possible test combinations, with the numbering used to show which setting is being used for each parameter, and to name and identify the individual cases. For example a test case numbered 15_12_03 has; one 26 MW CHP connected at bus 5; a wind farm of 60 MW connected at bus 2; relay settings calculated without considering the DG; 3-phase fault.

Table 5-1 Test case matrix

CHP		Wind farm		Relay Settings	Fault Type
Size (#*26MW)	In-feed Point (Bus)	Size (#*60MW)	In-feed Point (Bus)	DG considered	#-ϕ
0	1	0	1	0	3
1	2	1	2	1	1
2	3	-	3	-	-
-	4	-	4	-	-
-	5	-	5	-	-

The reasoning behind these choices is explained below:

CHP

CHP plants are a common DG element in Danish grids, with a 26MW plant being present in the ring circuit analysed for this report. The variables given will allow an analysis of the effect that increasing the size of the CHP will have, representing a possible future situation, as well as testing the effect of the location of the in-feed of the CHP into the ring, relative to the relay and external grid locations.

Wind farm

Similar to the CHP plants, wind farms are a common DG element in Danish grids, again also being present in the ring network analysed for this report. Again, the variables given will allow an analysis of the effect that the presence of a wind farm will have, as well as testing the effect of the location of the in-feed of the wind farm into the ring, relative to the relay and external grid locations.

Relay settings

The test cases provide consideration to two different situations under which the relay settings can be calculated: with and without considering the effect of the in-feed of the DG sources. Relay settings are commonly calculated without considering the effect of the in-feed from DG. This test case allows for examining possible problems when DG is present and has not been considered, or on the other hand, possible problems when DG sources have been considered but are not connected due to malfunction or maintenance, or are operating below rated values in the case of low wind speeds, for example.

Fault type

Test can be conducted for both 3-phase and single phase faults. 3-phase faults are examined because this fault type is often the most severe, and is often listed in grid codes for fault behaviour. Single phase faults are the most common faults experienced in cabled systems.

5.1.3 Success Criteria

Tests will be evaluated against a base case; that for which the actual installed relay settings were calculated. The analysis will look at a number of parameters, with the most important being the reach/sensitivity of the relays, and the ability of the relays to detect and clear fault conditions. The ability of the protection to operate as designed under various conditions will be considered as a success criteria.

5.2 Base case – without DG

The ring network, with no DG sources connected, is used as a base case, as it represents the case for which the relay settings were designed.

This scenario is shown in Figure 5-1.

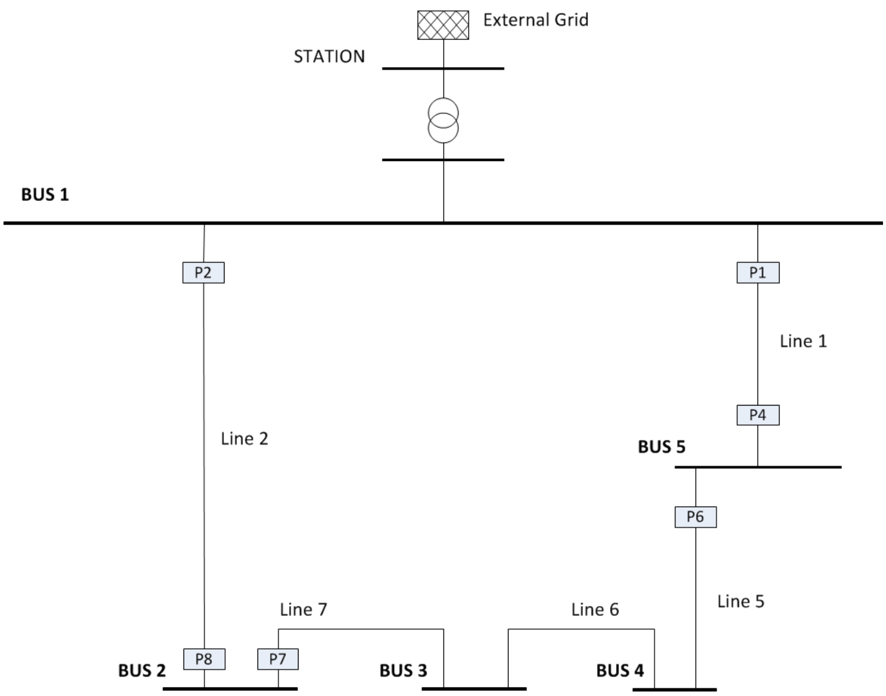


Figure 5-1: Ring Network without DG sources

A short circuit sweep was performed, which calculates the tripping times of all the relays for short circuit fault locations across the entire ring, including both lines and terminals. A time-distance diagram (Figure 5-2) was then compiled from this data which shows the tripping times of the relays, and therefore the relay zones, for all locations in the ring. The upper half shows the operating times in the clockwise direction around the ring and the lower half shows the operating times in the anti-clockwise direction. The x-axis shows the impedance of the lines, with the bus bars labelled. The y-axis shows the operating time.

The time-distance diagram in Figure 5-3, is constructed using the kilometrical method which determines the tripping time at each position by overlaying the impedance characteristic of the relays on the impedance characteristics of the path, giving a clear outline of the expected zones. Comparison of the two time-distance diagrams shows that the relays perform as expected, with the actual zones matching with the expected zones.

It is important to note that , in the kilometric time-distance diagram the location of the source of the short circuit current is not taken into account, so the relays with zones that extend past BUS 1 in the forward or reverse direction are shown to overlap the bus and provide back-up protection to Relay 1 and Relay 2. In reality this will not occur, as the external grid, in this case the only source of short circuit current is connected to bus 1 and therefore the current will always flow away from this point. The relays will not protect faults that occur past BUS 1 in their forward direction. Protection systems in the external grid should be designed to detect faults within the ring, close to BUS 1, to provide back-up protection in case of malfunction of Relay 1 or Relay 2.

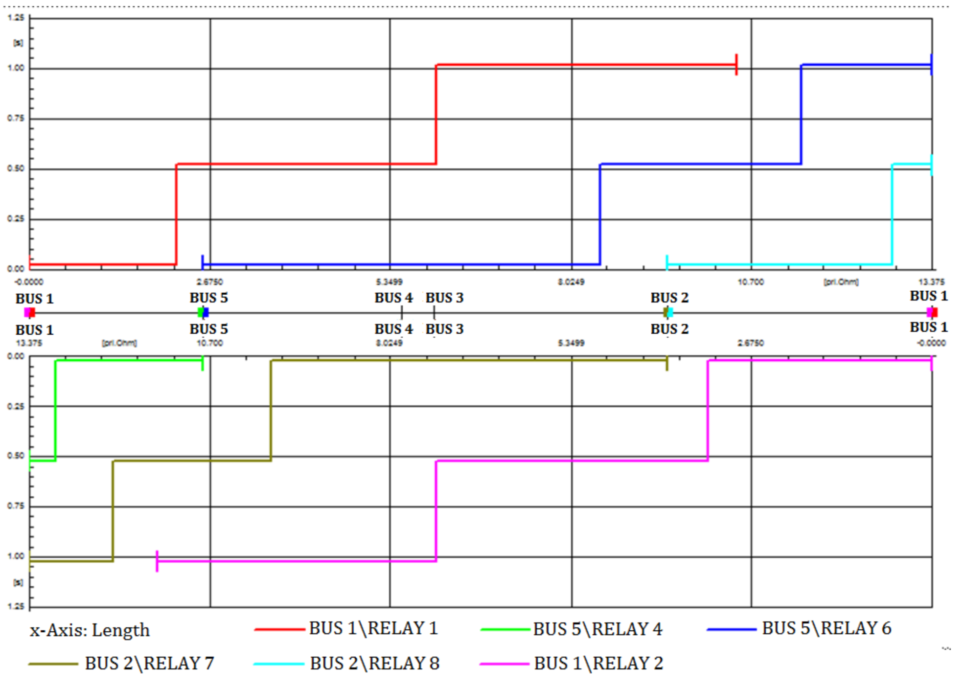


Figure 5-2 Base case short circuit sweep time-distance diagram

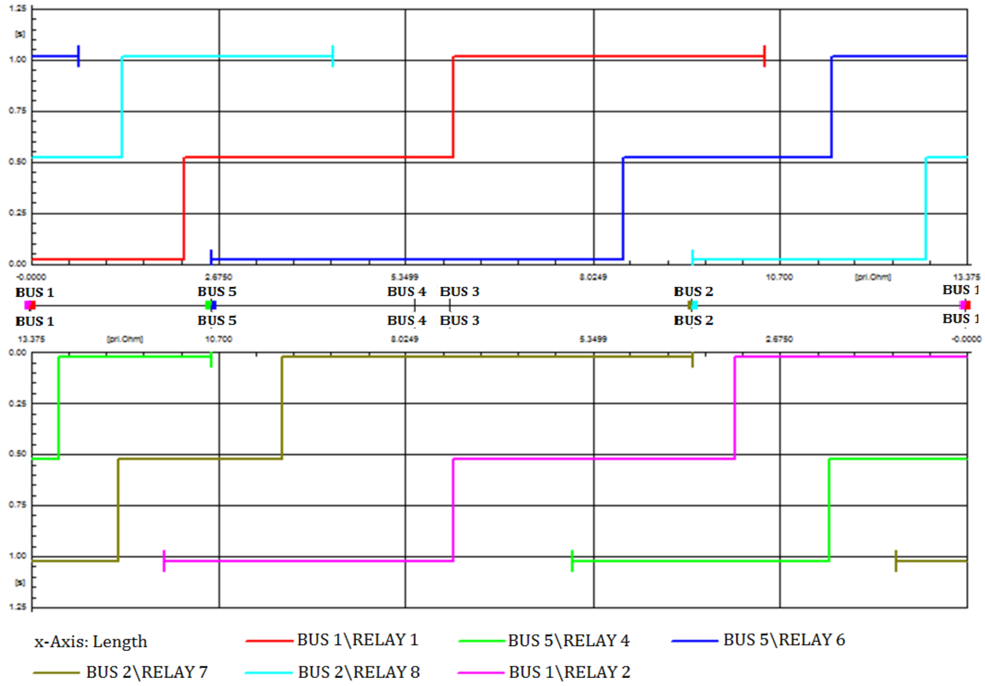


Figure 5-3 Base case kilometrical time-distance diagram

5.3 DG in original network

Three initial tests were performed on the 60 kV ring network. The 3 tests were conducted for various DG scenarios: with just the CHP connected; with just the wind farm connected; with both CHP and wind farm connected. A detailed analysis of the results can be found in the following sections.

5.3.1 60 MW Wind Farm in-feed at BUS1 (00_11_03)

To test the effect of DG sources on the sensitivity and selectivity of the relays, the 60 MW wind farm was connected to BUS 1, via line 3, as shown in Figure 5-4. The same tests were performed as for the base case, calculating the tripping times for all relays at all points in the circuit.

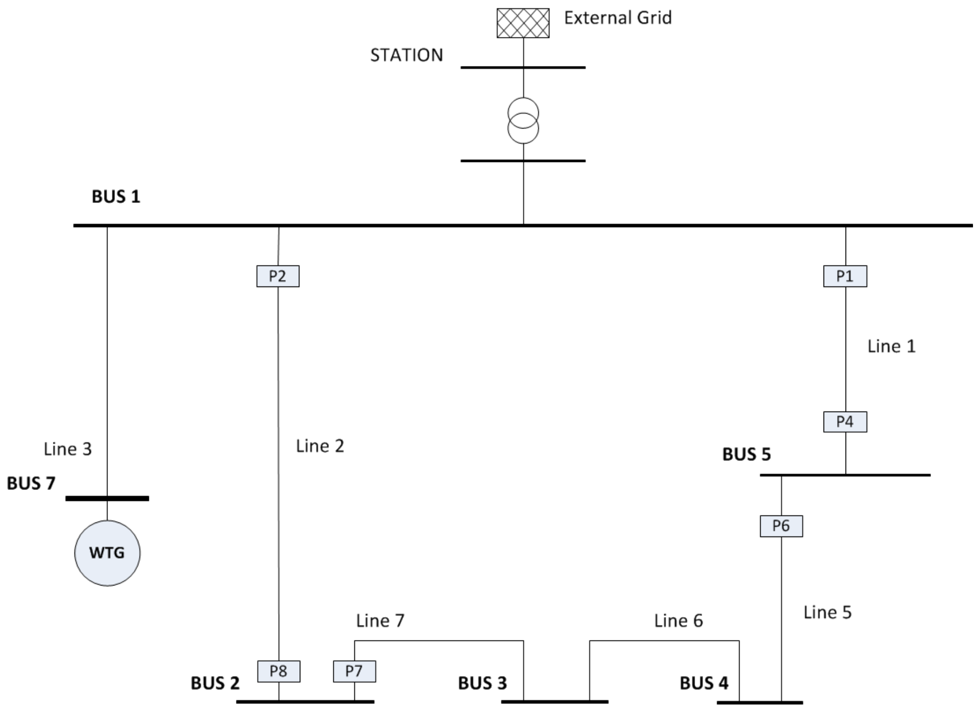


Figure 5-4 Ring network with wind farm

The short-circuit sweep time-distance diagram is shown in Figure 5-5, from which it can be seen that the reach of the relays is unchanged when compared to the base case. The wind farm has no effect on the relay cover, due to the location of the connection point of the wind farm. The wind farm is connected at the same bus as the external grid; so that this bus remains the only source of short-circuit current into the ring.

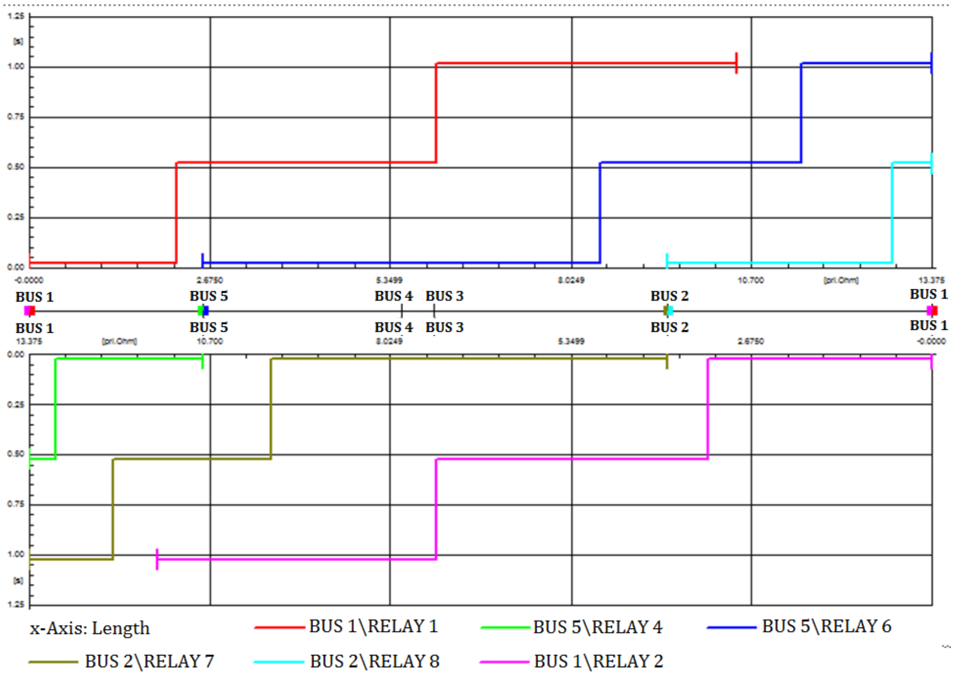


Figure 5-5 Test (00_11_03) time-distance diagram

5.3.2 CHP in-feed at BUS 5 (15_00_03)

To again test the effect of DG sources on the selectivity of the relays, the 26 MW CHP plant was connected to BUS 5, via line 4, as shown in Figure 5-6. The same tests were performed as for the previous tests.

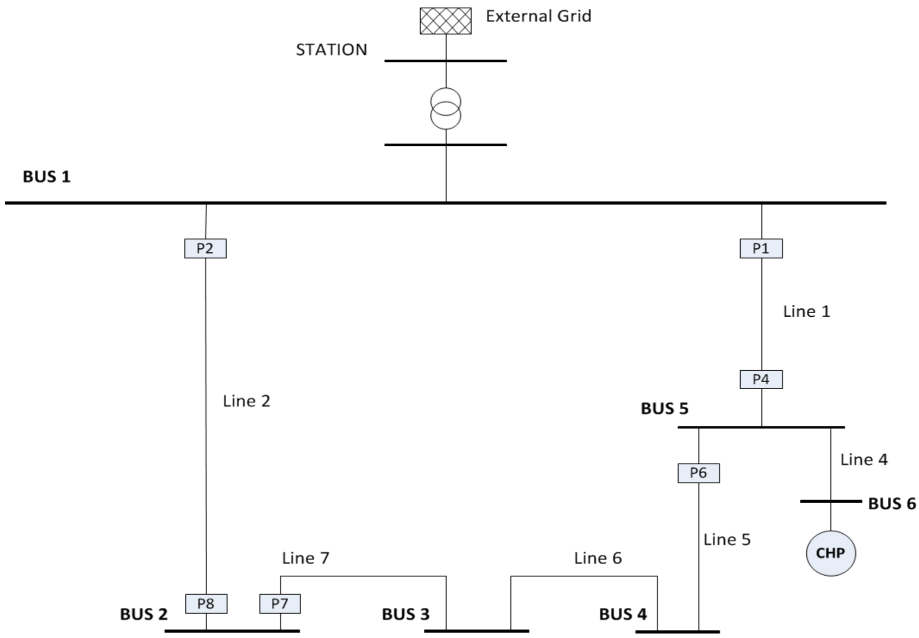


Figure 5-6: Ring network with CHP connected

The short-circuit sweep time-distance diagram for test 15_00_03 is shown in Figure 5-7. It is immediately evident that the connection of the DG source has an effect on the cover of the relays, when compared to the base case. From Figure 5-7, it can be seen that the zones of relays 1, 7 and 2 are reduced with the addition of the CHP, resulting in under-reach. The black lines in the diagram indicate the extent of the under-reach.

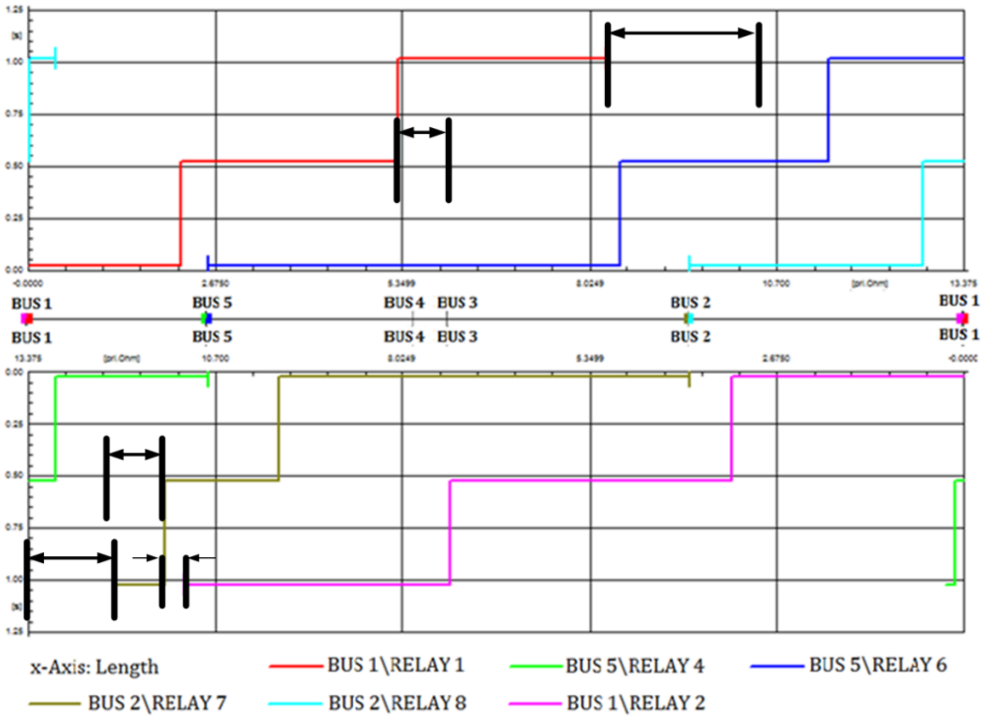


Figure 5-7 Time-Distance Diagram with CHP 15_00_03

The grid schematics in Figure 5-8, Figure 5-9 and Figure 5-10 show how this under-reach looks in the network, and shows the areas which are most affected, relative to the location of the in-feed of the DG.

The diagrams indicate the zonal reach of a particular relay. The thickest area is for the first zone, reducing in thickness for the subsequent zones. The green area represents the part of the circuit where the relay detects the fault in the same protection zone for both the case with and without the DG overlap and the operating time of the relay is unchanged. The red area in each of the diagrams indicates the area that was covered by the relays without DG which is no longer covered by the same zone with the addition of the CHP. If a fault occurs in these areas the fault clearing time is reduced or the fault is no longer detected.

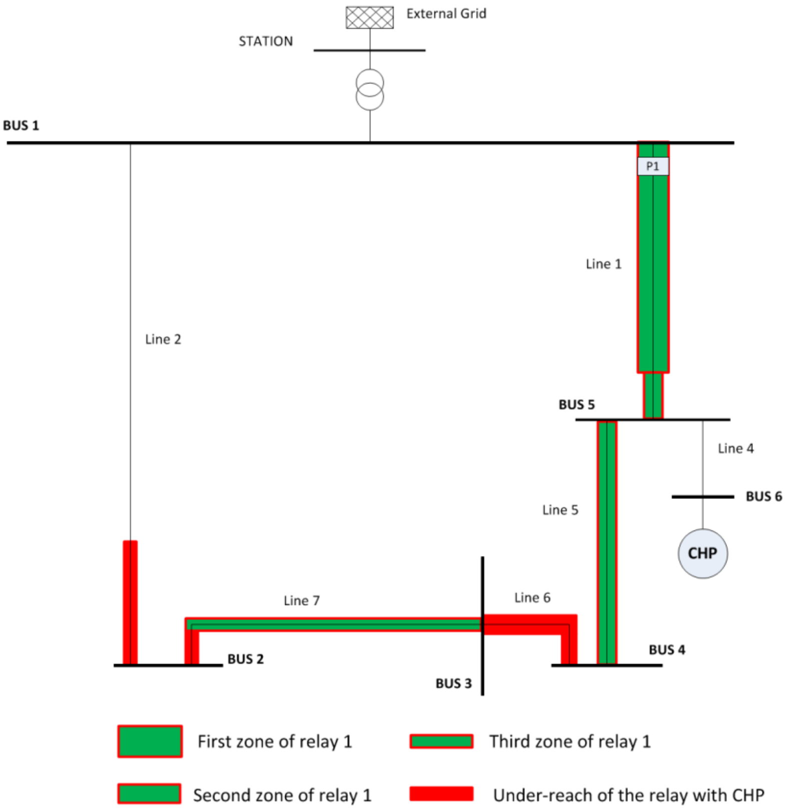


Figure 5-8:Under-reach of relay 1 with CHP

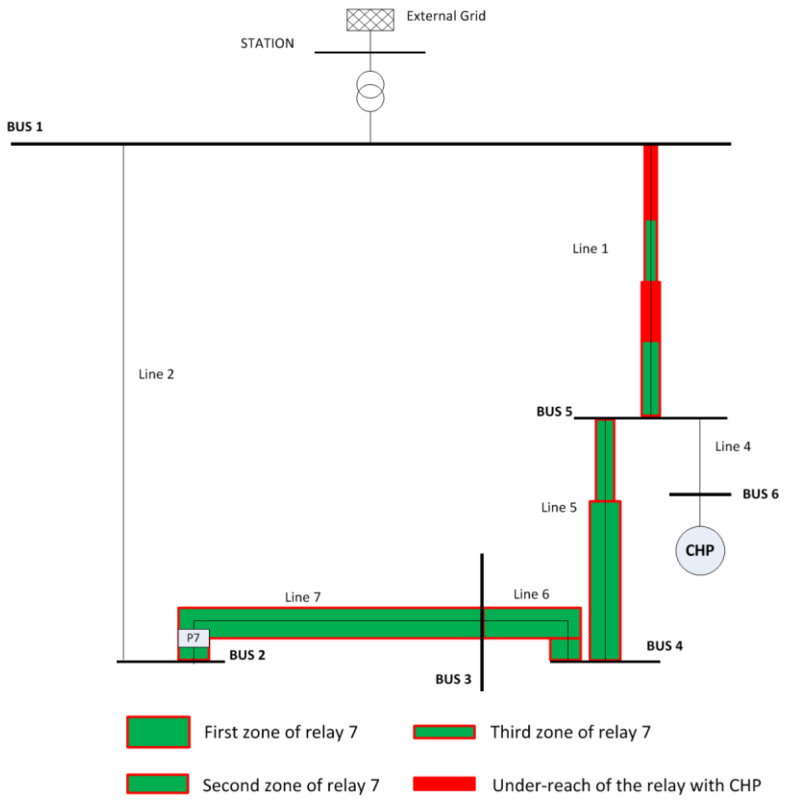


Figure 5-9: Under-reach of relay 7 with CHP

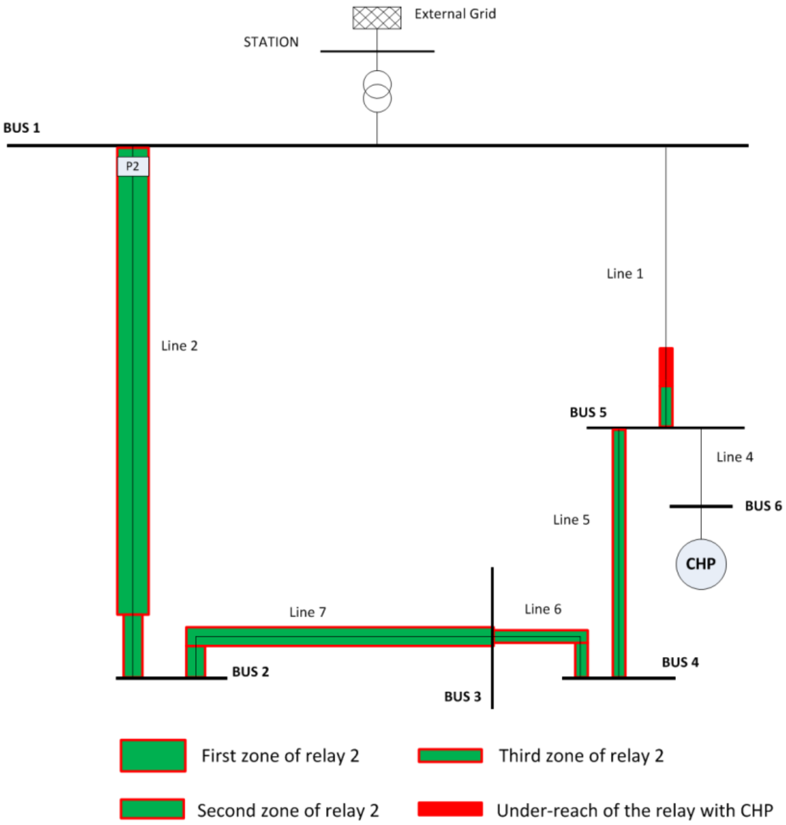


Figure 5-10: Under-reach of relay 2 with CHP

It can be noted that this under-reach only has an effect when there is an intermediate in-feed of the CHP between the protected zone and the relay location. As none of the first protection zones of the relays reach across BUS 5, no under-reach is experienced for these zones. The under-reach is a result of the current flowing from the CHP to the grid effectively increasing the impedance seen by the relay, making a fault appear further away, which ultimately reduces the reach of the relay. The reduction in reach means that the required fault clearance time for the backup protection is no longer provided as it should be.

The effective cover of the zones of the distance relays can be calculated by considering the ratio of the DG in-feed current to the current measured by the relay, known as the in-feed constant K. The calculation of this cover is shown below.

Effective cover of relays

When calculating the desired reach of the relay zones, a reach constant X is used to define the percentage reach on the protected or remote line. In accordance with the zone setting grading scheme explained in 3.2.1, X_1, X_2 and, X_3 the reach constants for the three protection zones are 85%, 50% and 25% respectively, into the respective lines. When an intermediate in-feed is present, as the results show, the reach is decreased. The reach for the zones of relay 1, 2 and 7 are shown here with the presence of DG, using test 15_00_03 for the short-circuit current values.

Zone 1 of each of the relays is not affected by the in-feed so that the reach $X_1 = 85\%$ both with and without the presence of DG.

Relay 1

In relay 1, the reach of both zone 2 and zone 3 is reduced as a result of the DG in-feed. The expression for calculating the effective cover of zone 2 over line L_{567} for relay 1 is:

$$X_2 = \frac{Z_2 - Z_{L1}}{Z_{L5-6-7}(1+K_2)} \tag{0.17}$$

Where,

Z_2 = setting for zone 2 (Ω)

$Z_{L5\text{-}6\text{-}7}$ = impedance of adjacent line, L_{567} (Ω)

Z_{L1} = impedance of the line associated with relay, L_1 (Ω)

K_2= in-feed constant for zone 2

The in-feed constant K_2 at bus 5 is given by:

$$K_2 = \frac{I_{Line4CHP}}{I_{Line1Relay}} = \frac{2.91\angle 98°}{6.8\angle 105°} = 0.427\angle -7° \tag{0.18}$$

So that $1 + |K_1|$= 1.42

$$X_2 = \frac{Z_2 - Z_{L1}}{Z_{L5-6-7}(1+K_1)} = \frac{6.0186 - 2.5729}{(6.8914 \cdot 1.42)} = 0.352 = 35.2\% \tag{0.19}$$

As expected, the reach of zone 2 is less than 50% of the line from bus 5 to bus 3.

For zone 3, the reach is shown below:

$$X_3 = \frac{Z_3 - Z_{L1} - (1+K_2)Z_{L5-6-7}}{Z_{L2}(1+K_3)} \tag{0.20}$$

$$X_3 = \frac{Z_3 - Z_{L1} - (1+K_2)Z_{L5-6-7}}{Z_{L2}(1+K_3)} = \frac{10.4422 - 2.5729 - (1.42 \cdot 6.8914)}{(3.9114 \cdot 1.42)} = -0.345 = -34.5\%$$

Z_3 = setting for zone 3 (Ω)

Z_{L2} = impedance of the line associated with relay (Ω)

K_2= in-feed constant for the adjacent line

K_3= in-feed constant for the adjacent line

As can be seen from the result, the effective reach of the zone 3 is now -34.5% of the Z . This means that the relay no longer provides coverage over the entire adjacent line with an extra safety margin of 25%, instead it covers only up to 65.5% of the line, drastically reducing the back-up it provides for further relays. No back-up is provided for the final 34.5% of the remote line.

Relay 7

$$K = \frac{I_{Line4}}{I_{Line5-6-7}} = 1.73\angle -13 \tag{0.21}$$

So that 1+K = 2.71

$$X_2 = 18.6\% \tag{0.22}$$

$$X_3 = -31.8\% \tag{0.23}$$

Again relay 7 does not completely cover the adjacent line, covering faults only up to 68% of the line.

Relay 2

For **relay 2** an under-reach is only experienced for zone 3. This has been calculated below:

$$X_3 = 14.4\% \tag{0.24}$$

The in-feed constant K is the same for relay 2 as for relay 7.

It is possible to see, that the calculations matches with the simulated graphical results shown in Figure 5-7 and shows the biggest under-reach of the zone 3 and zone 2 for relay 1 and relay 7,and show a small under-reach in the third zone for relay 2.

Results

The table below summarises the results:

Table 5-2 Overview of reach reduction due to presence of DG

Relay	Zone	Desired reach	Effective reach
1	2	50%	35.2%
	3	25%	-34.5%
7	2	50%	18.6%
	3	25%	-31.8%
2	3	25%	14.4%

In the case of relay 1, zone 2, relay 7, zone 2 and relay 2, zone 3 the reduction due to the DG is actually acceptable as they will still serve their duty as intended, with zone 2 still covering the final section of the protected line not covered by zone 1. The margin of safety is however reduced.

The 3rd zone reduction for relay 1 and 7 is not acceptable, as they will no longer provide the level of back-up protection that is required of them. The 3rd zone should provide back-up to all of the remote line, however the remaining 34.5% and 31.8% of the remote lines of Relay 1, and 7 respectively has no back-up protection.

To provide the necessary back-up protection, the relay settings need to be recalculated to take account of the in-feed. This is done in section 5.5.

5.3.3 CHP at BUS 5 and WTG at BUS 1 (15_11_03)

Finally, both the wind farm and CHP were connected, as shown in Figure 5-11. The results in this case were the same as in test 1, with the CHP alone. This is because, similar to test (15_11_03) with just the wind farm connected, the wind farm has no effect on the relays due to the location of the connection point on the same bus as the external grid.

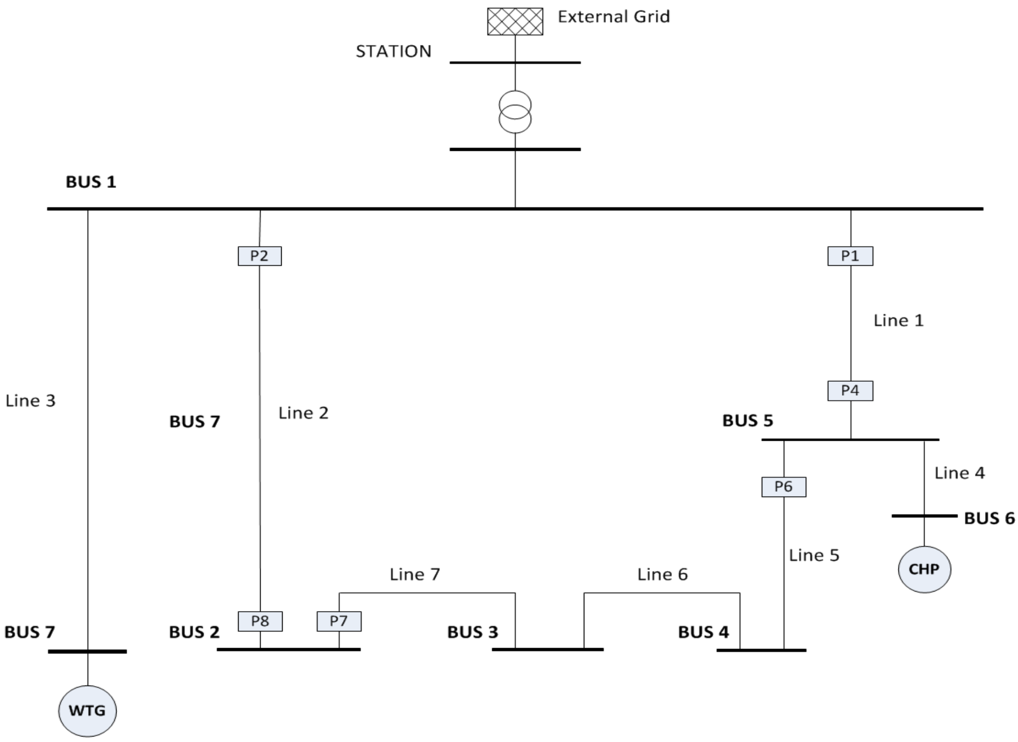


Figure 5-11 Ring network with wind farm and CHP

5.4 Ring network under various DG scenarios

To further test the effect of DG in the ring network, a number of further DG scenarios were implemented in the network and analysed. A total of 5 further tests were conducted, one involved increasing the size of the CHP to represent a possible future scenario of a growing population or load demand in the surrounding area being met by installation of a second CHP plant. The remaining tests were concerned with testing the effect of having the wind farm connected to a bus situated within the ring. An in-feed to each of the individual busbars, BUS 2, BUS 3, BUS 4 and BUS 5, in turn, was connected and analysed. Of most interest were the 'unprotected' busbars BUS 3 and BUS 4, as they provided an in-feed point within the first protection zone of relays 6 and 7.

Each test case will first show the grid where the CHP and WTG have been connected and the resulting short-circuit sweep time-distance diagram of the relays, which show the operating times of all the relays, against the line length or impedance. This gives a clear overview of the protection zones and operating times of the different relays in both directions around the ring with under the various DG scenarios. The results are then discussed together to give a clearer overview of the results.

5.4.1 Two parallel CHPs at BUS 5

Figure 5-12 show the effect on the cover of the relays, when two CHP are connected in parallel at BUS 5. It’s possible to see in this case, that the zones of relay 1 and relay 7 are further reduced with more CHP connected in parallel, resulting in an additional under reach, and the back-up is no longer provided for the relay 6.

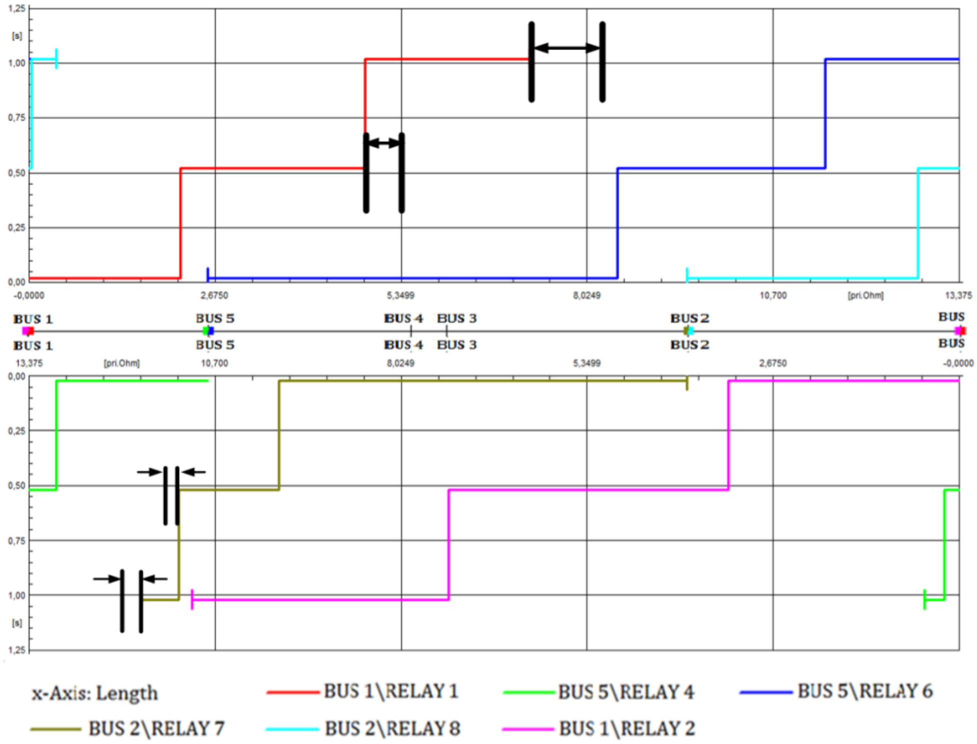


Figure 5-12 Test 1 Time-Distance Diagram with two parallel CHP

5.4.2 Wind farm on Bus 2 (15_12_03)

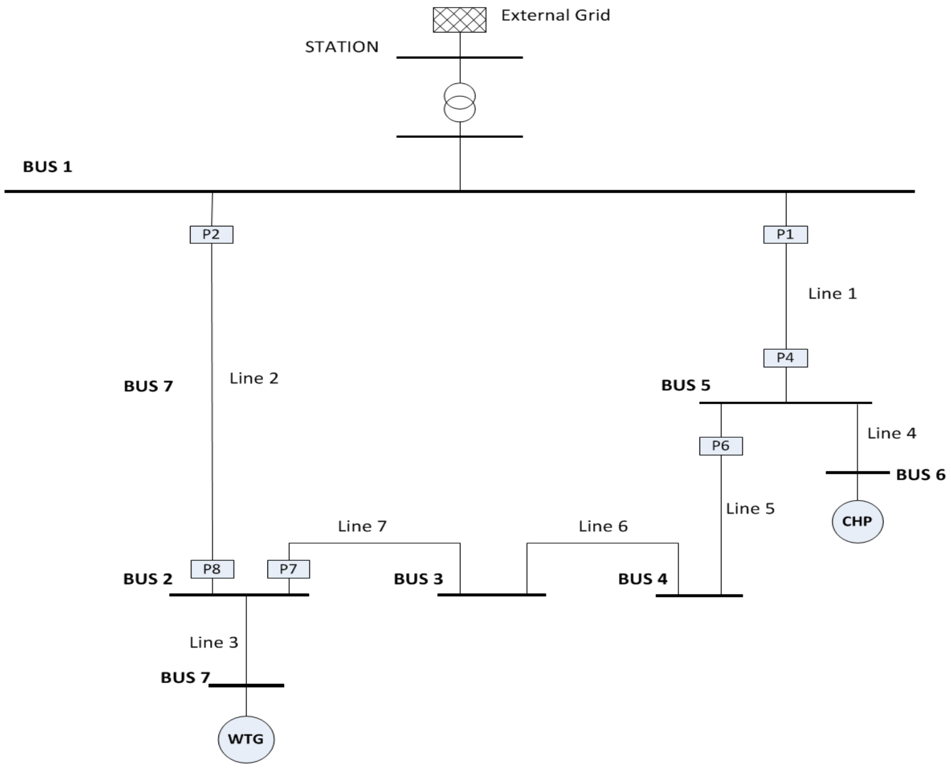


Figure 5-13: Ring network with WTG at BUS 2

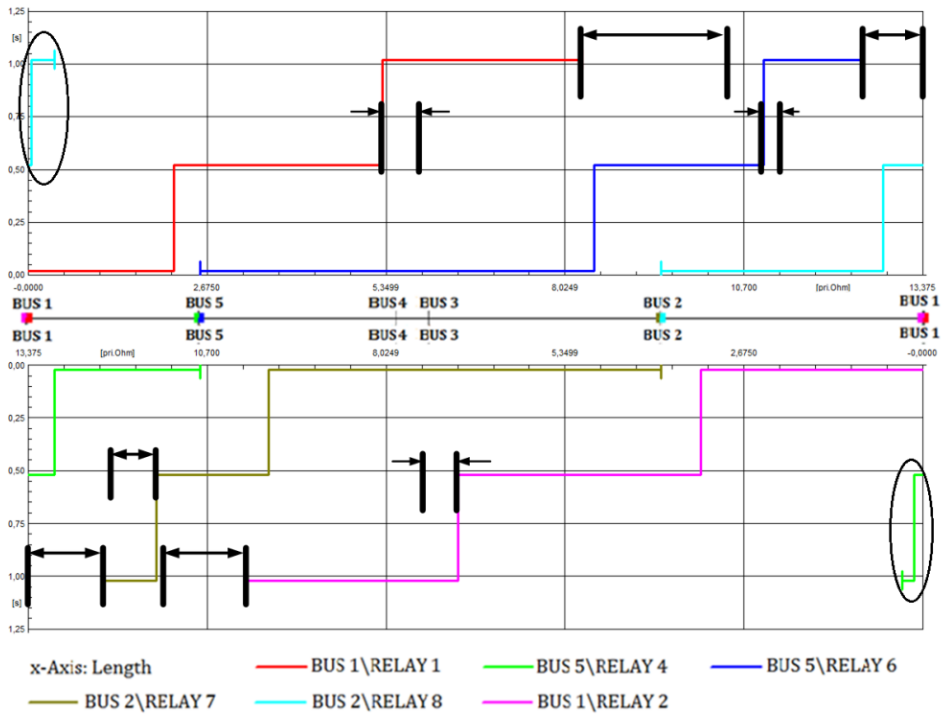


Figure 5-14: Test (15_12_03) time-distance diagram

5.4.3 Wind farm on Bus 3 (15_13_03)

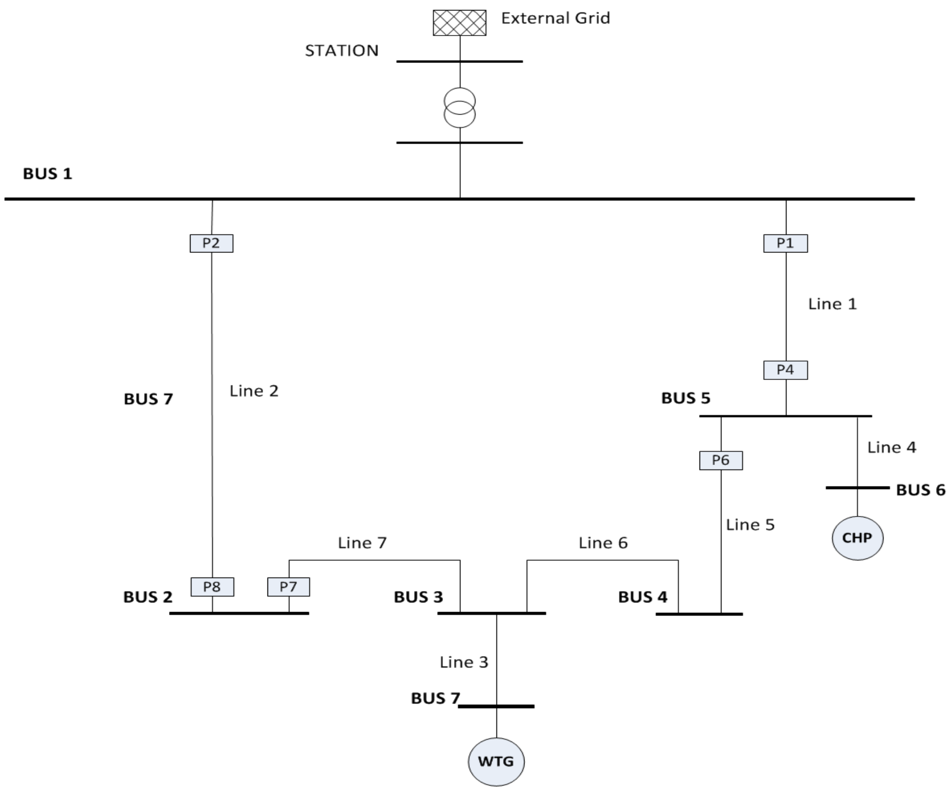


Figure 5-15: Ring network with WTG at BUS 3

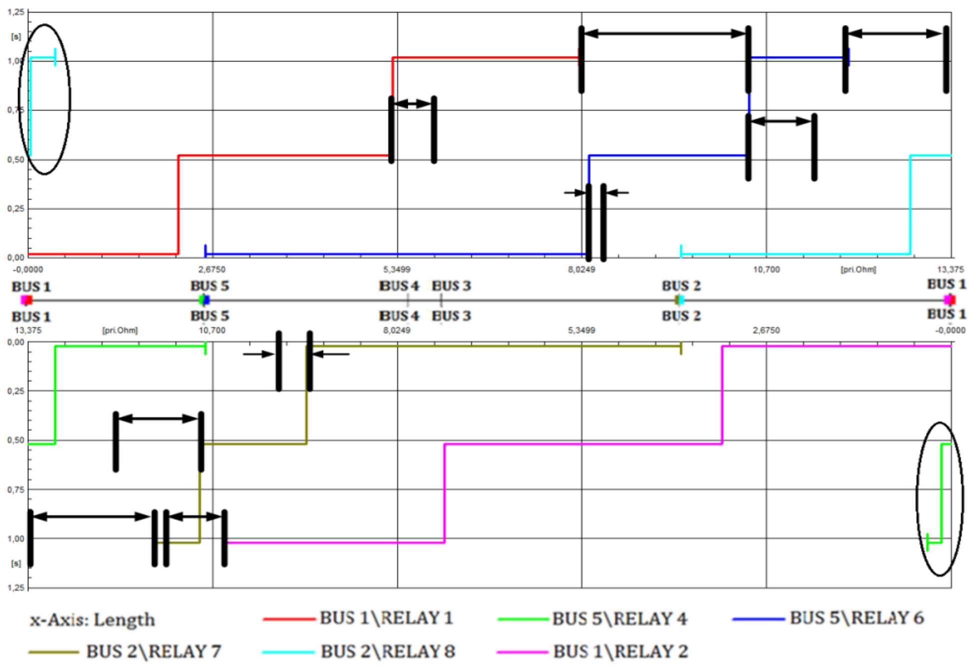


Figure 5-16: Test (15_13_03) time-distance diagram

5.4.4 Wind farm on Bus 4 (15_14_03)

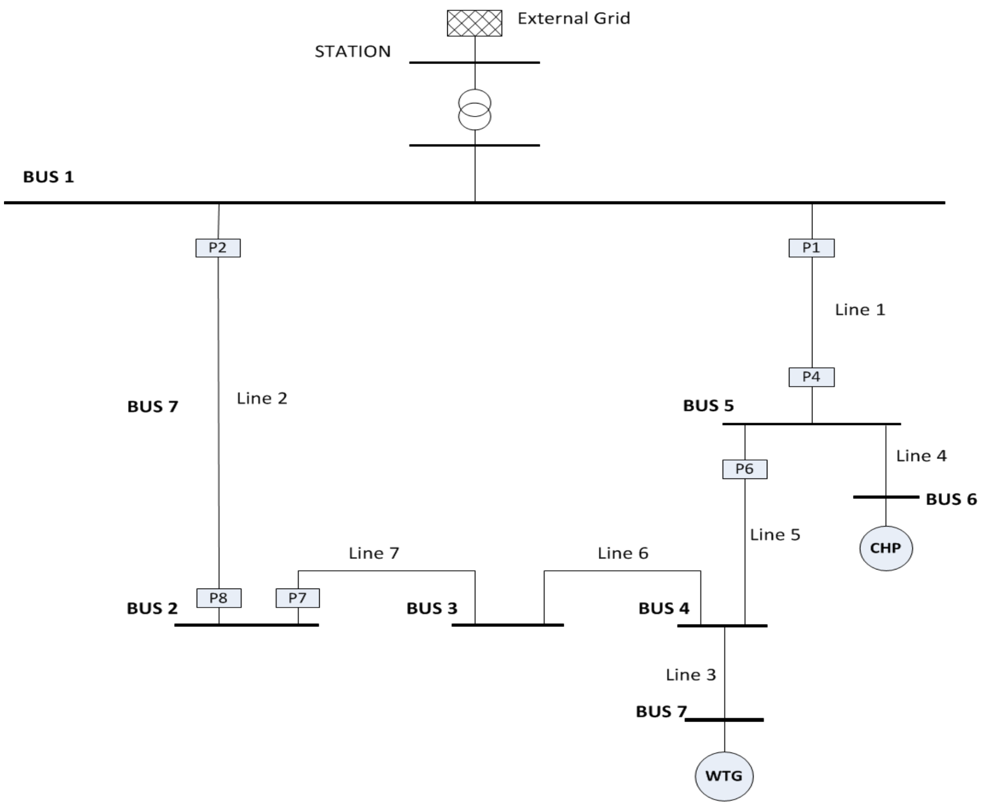


Figure 5-17: Ring network with WTG at BUS 4

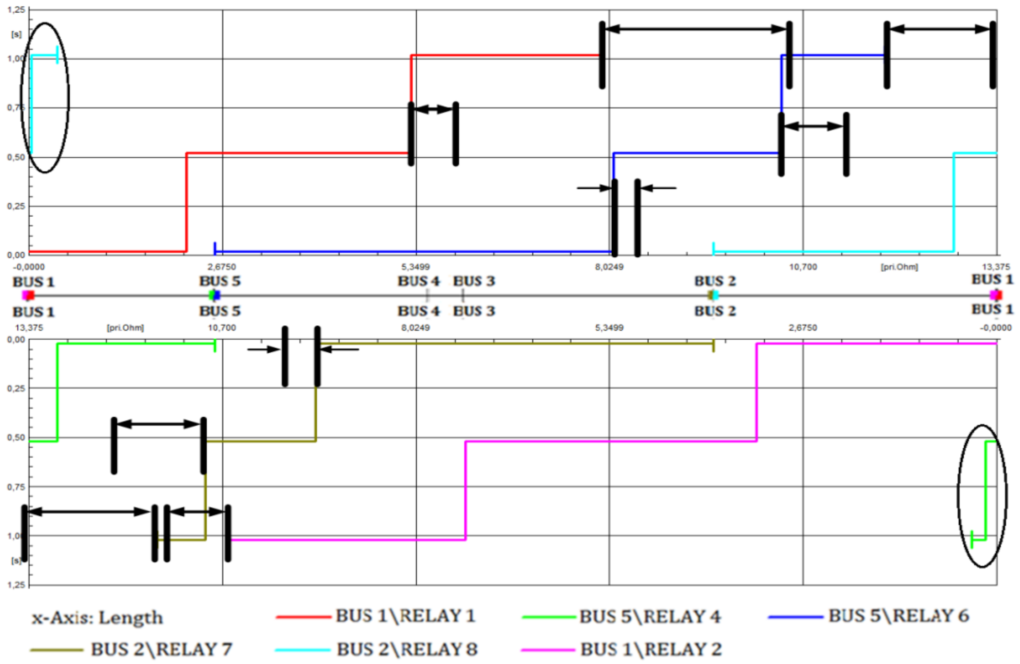


Figure 5-18: Test (15_14_03) time-distance diagram

5.4.5 Wind farm on Bus 5 (15_15_03)

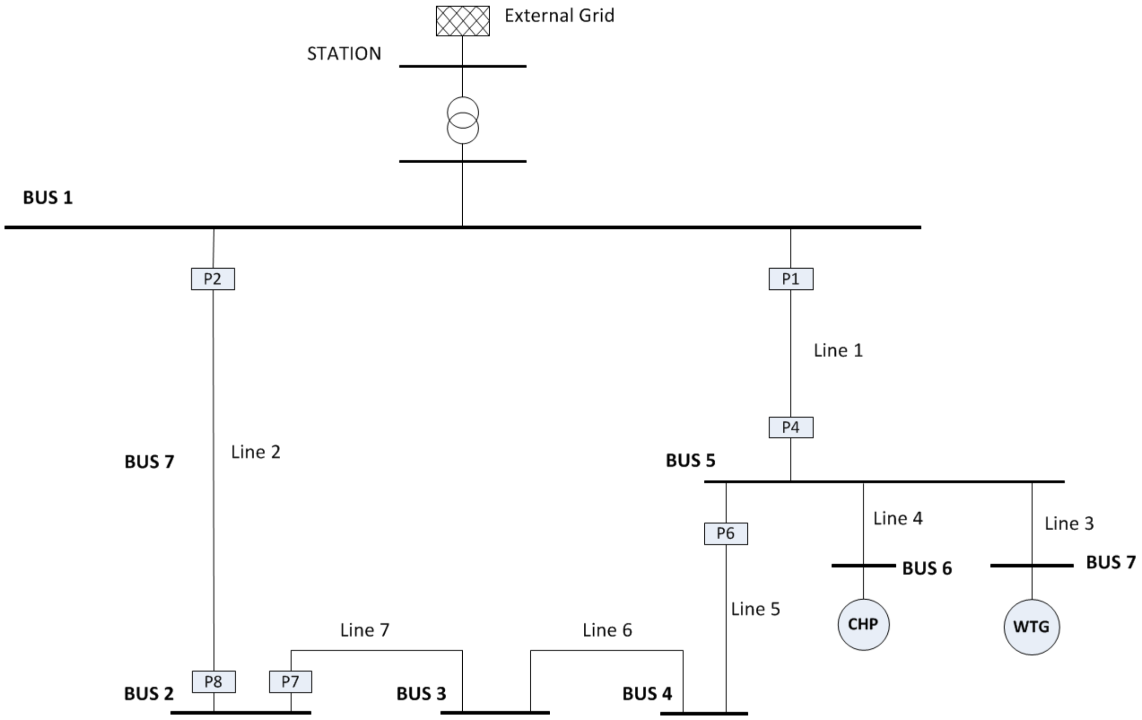


Figure 5-19: Ring network with WTG at BUS 5

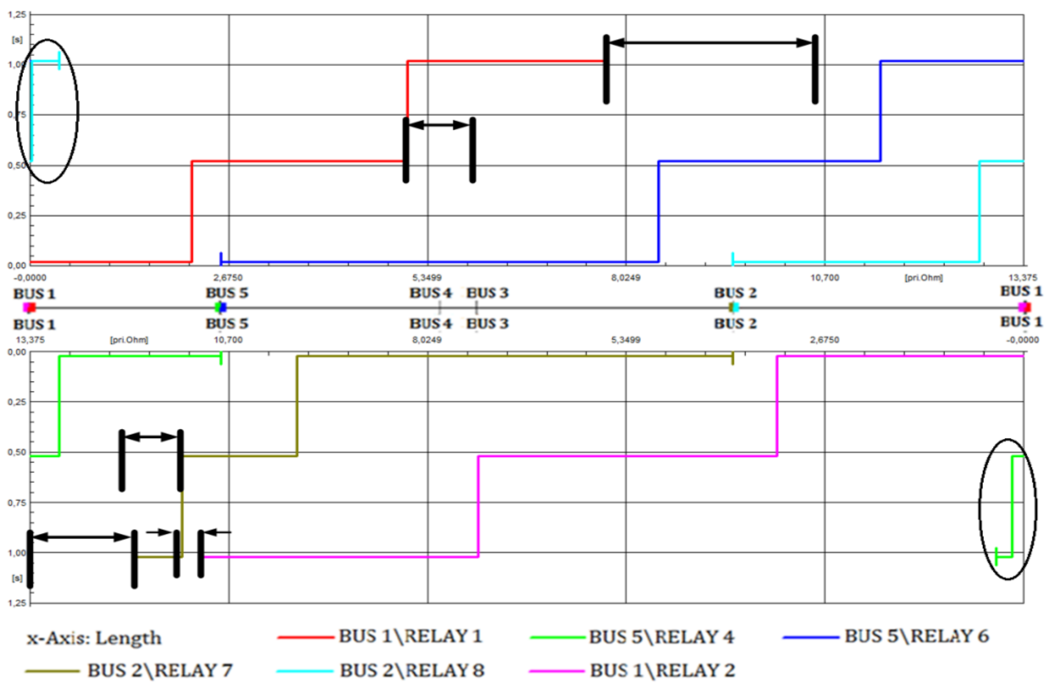


Figure 5-20: Test (15_15_03) time-distance diagram

5.4.6 Results

On analysis of the various DG scenarios it is evident that when the wind farm is connected within the ring or the CHP capacity is increased, under-reach problems experienced earlier are accentuated. The same issues are present, but to a greater extent.

Of most interest is when the in-feed of the wind farm is at BUS 3 or BUS 4. In these cases (15_13_03 & 15_14_03), a reduction is seen in the reach of even the first protection zone of relays 6 and 7, and the 2nd and 3rd zone under-reach is worsened.

BUS 3 and BUS 4 do not have their own relay devices so that they come within the first protection zone of relays 6 and 7. This means that a connection point for a short-circuit current source is now available within the first zone of these relays. The first zone under these scenarios covers only up to 70-75% of the line so that the area covered with an instantaneous fault clearing time is reduced to only a 50% portion of the line. Faults occurring outside of this will have a clearing time at least equal to the 2nd zone clearing time. This increases the time that faults are sustained on the line, which can have many detrimental effects for the devices and equipment.

5.5 Recalculating relay settings with in-feed constant considered

For many of the cases above, the worst effect seen is the reduction of the reach of zone 2 and zone 3. The zone 2 reduction results in a much lower margin of error for covering the end of the protected line, but in many of the cases studied the zone 2 still provided the adequate level of protection. The zone 3 reduction however is much more serious as it greatly reduces the back-up provided to the remote line. In many of the cases up to one third of the remote line was missing a back-up protection system. In the case of failure of a relay or circuit breaker, this can lead to sustained fault conditions with detrimental effects to all elements connected.

To restore adequate back up, consideration must be given to the effect of the DG in-feed when calculating the setting values for the protection zones. This is done by taking account of the in-feed constant for the various relays and protection sections, which gives the ratio of the in-feed current to the measured relay current for each of the protection sections, as was discussed in section 5.3.

Two of the cases have been chosen to recalculate the relay settings and show what effect this has on each of the zones. The side effects of recalculating the relay settings are then considered in section 5.5.3.

5.5.1 CHP in-feed at BUS 5 (15_00_03)

An analysis was carried out in section 5.3.2, showing the effect of the connection of the in-feed of a CHP at Bus 5, within the ring network, detailing the reduction in the reach of the various zones of each of the relays, as well as calculating the effective cover.

Here, the settings for restoring the reach to the desired value are shown. For the first zone settings, none of the relays are affected by the in-feed. The second and third zones on the other hand require a readjustment. The values are shown in Table 1-1 and Table 5-4, and illustrated in Figure 5-21 and Figure 5-22.

Table 5-3: Zone 2 setting with and without in-feed and % increase (15_00_03)

Relay	In-feed not considered	In-feed considered	Increase %
R1	6,02	8,03	33,34
R2	7,36	7,36	0,00
R4	4,53	4,53	0,00
R6	8,85	8,85	0,00
R7	8,18	13,02	59,24
R8	5,20	5,20	0,00

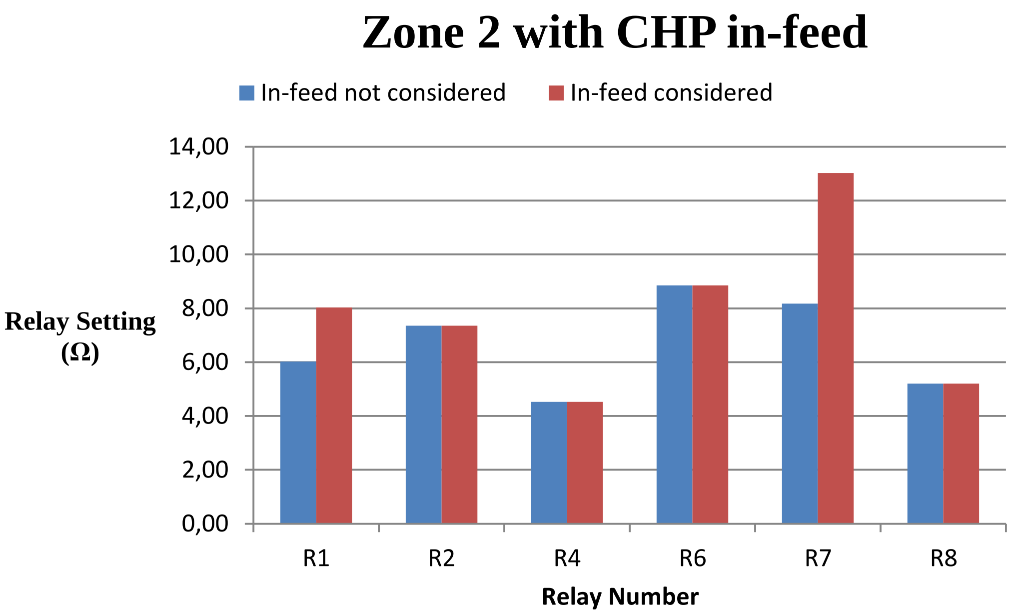


Figure 5-21 Zone 2 setting with and without in-feed (15_00_03)

Table 5-4: Zone 3 setting with and without in-feed and % increase (15_00_03)

Relay	In-feed not considered	In-feed considered	Increase %
R1	10,44	16,46	57,65
R2	11,45	13,09	14,37
R4	8,21	8,21	0,00
R6	11,45	11,45	0,00
R7	10,44	27,14	159,87
R8	8,21	8,21	0,00

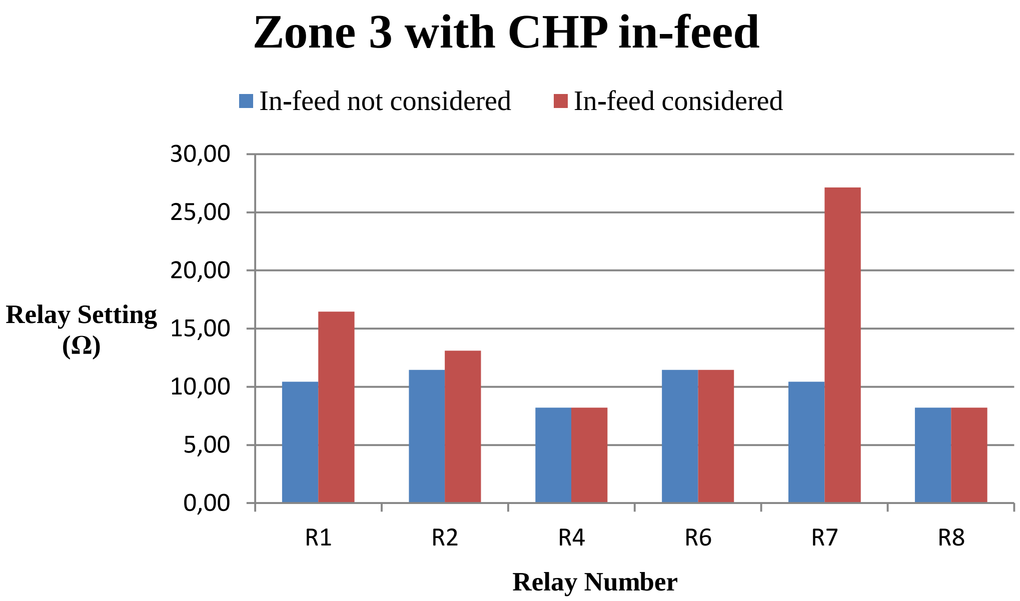


Figure 5-22 Zone 3 setting with and without in-feed (15_00_03)

5.5.2 CHP at BUS 5 and WTG at BUS 3 (15_13_03)

An analysis was carried out in section 5.4.3, showing the effect of the connection of the in-feed of a CHP at Bus 5, and the wind farm at Bus 1, within the ring network and detailing the reduction in the reach.

Here again, the settings for restoring the reach to the desired value are shown. For the first zone settings, only relay 6 and 7 note any changes, and then only a 1,34% and 2% increase respectively. The second and third zones on the other hand require a large readjustment. The values are shown in Table 5-5 and Table 5-6, and illustrated in Figure 5-23 and Figure 5-24.

Table 5-5: Zone 2 setting with and without in-feed and % increase (15_13_03)

Relay	In-feed not considered	In-feed considered	Increase %
R1	6,02	7,41	23,12
R2	7,36	7,36	0,00
R4	4,53	4,53	0,00
R6	8,85	10,24	15,75
R7	8,18	16,47	101,45
R8	5,20	5,20	0,00

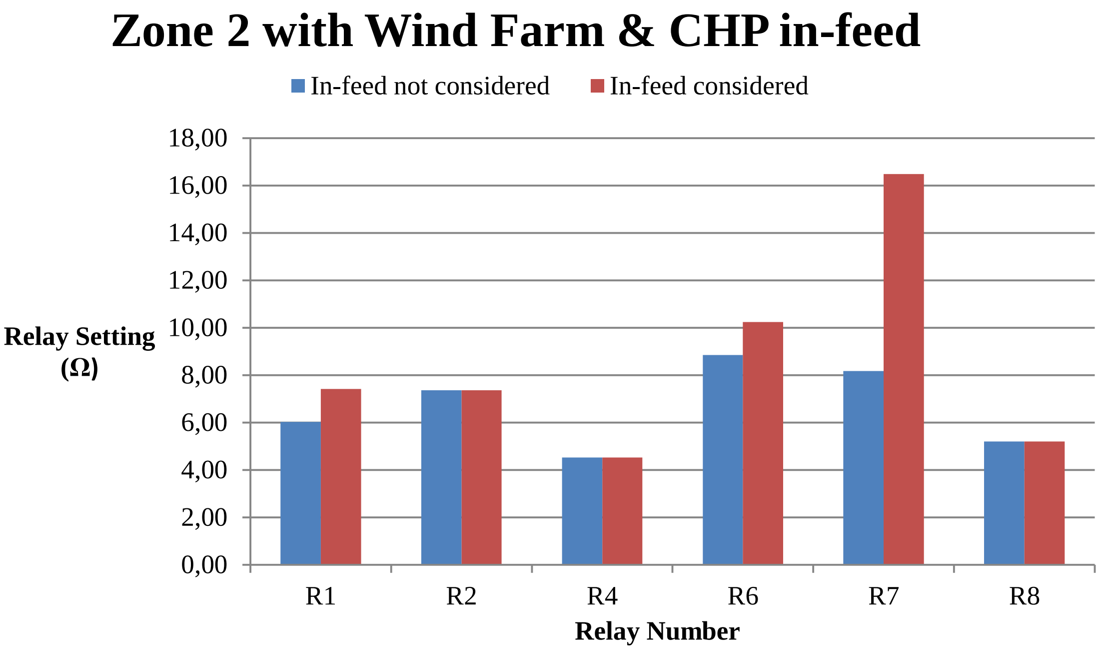


Figure 5-23 Zone 2 setting with and without in-feed (15_13_03)

Table 5-6: Zone 3 setting with and without in-feed and % increase (15_13_03)

Relay	In-feed not considered	In-feed considered	Increase %
R1	10,44	21,15	102,51
R2	11,45	13,40	17,03
R4	8,21	8,21	0,00
R6	11,45	21,44	87,35
R7	10,44	30,86	195,50
R8	8,21	8,21	0,00

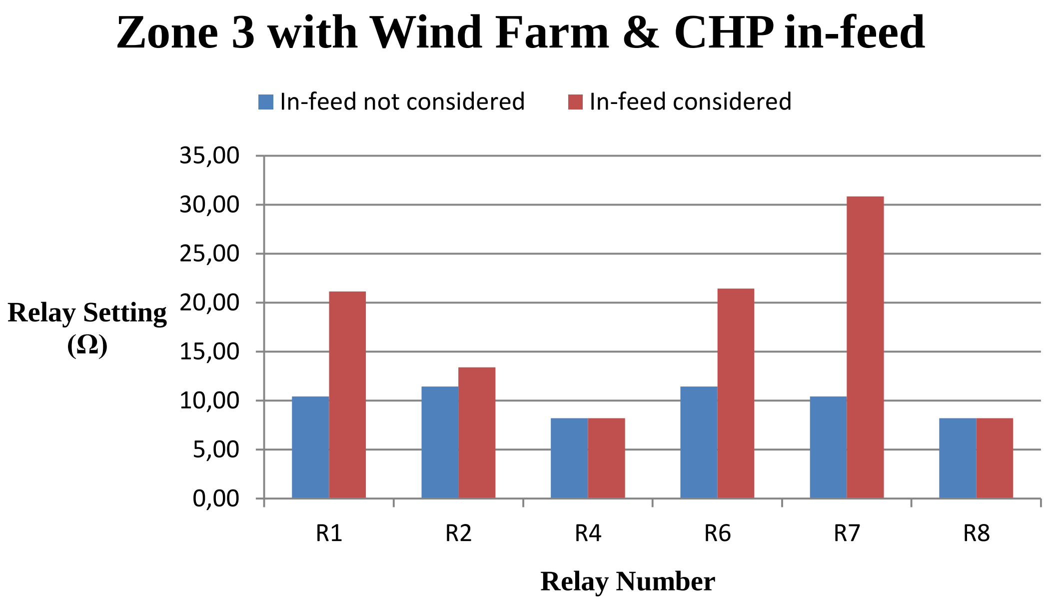


Figure 5-24 Zone 3 setting with and without in-feed (15_13_03)

5.5.3 Side effects of increasing relay impedance setting

The increased zone settings can have a number of side effects for the system.

Loadability

The case shown in Figure 5-24 for the third zone setting with both CHP and wind farm connected in the ring shows the largest increase in settings. Relay 6 3rd zone impedance setting increases by 87%, while relay 1 increases by over 100% and relay 7 increases by close to 200%. Figure 5-25 shows these increases for the relay locations in the grid.

It is clear that the relays which 'face towards' the DG connection points have need for the biggest increase in zone 3, particularly Relay 1 and 7 which can see two DG sources. The large increase is to restore the back-up protection for the entire line but it also has a negative effect of greatly reducing the loadability of the circuit. The large increase of the 3rd zone of relay 1 and relay 2 greatly reduces the loadability of Bus 3, Bus 4 and Bus 5.

The reduction in loadability can result in unnecessary tripping of the relays, reducing the security of the system. It can also lead to a problem of cascade tripping. If, for example, a fault occurs on line 1, relay 1 and 4 should detect and clear the fault, removing just the faulted line, and supply should remain to Bus 2, 3, 4 and 5 through the other path. However, following the tripping of line 1, an increased loading in the remaining line can push the operating point of the loads to within the 3rd zone of relay 7, which will then send an incorrect tripping signal to Relay 7. This process may also continue then to relay 2, until the entire ring circuit is disconnected.

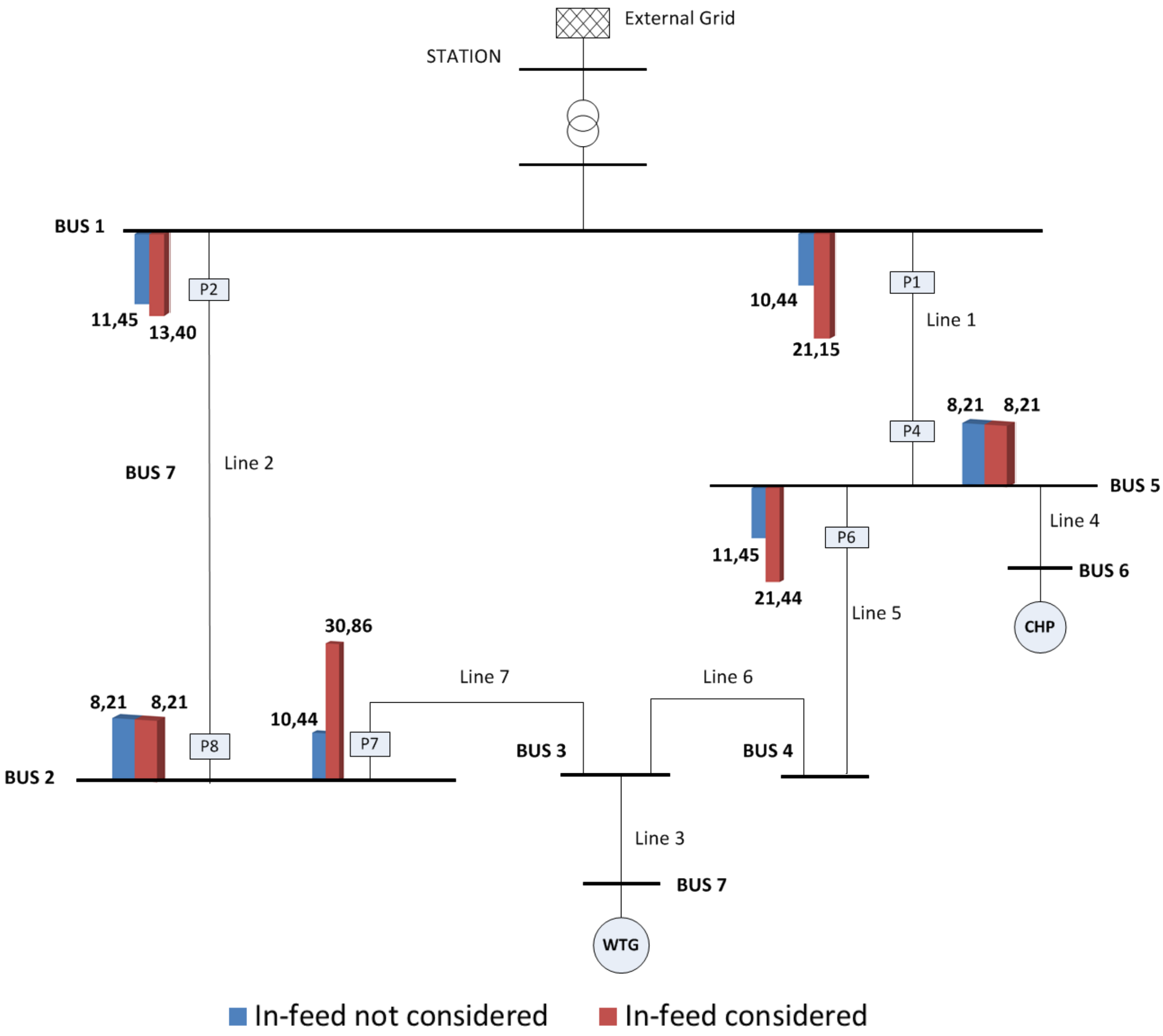


Figure 5-25 Zone 3 impedance settings increase as a result of in-feed and relay location

Selectivity

Another problem which can occur with the increased impedance setting of the 2nd and 3rd zone is a loss of selectivity if the DG sources have been disconnected due to malfunction or maintenance, or are operating below rated values in the case of low wind speeds. If this is the case a resulting over-reach occurs, causing overlap of the second and third protection zones and a loss of selectivity. This phenomenon can be seen in Figure 5-26. In this case the effect does not have a large effect as the system is quite small, with the source bus being reached before a large effect is seen. However in a larger circuit this problem can greatly reduce the selectivity.

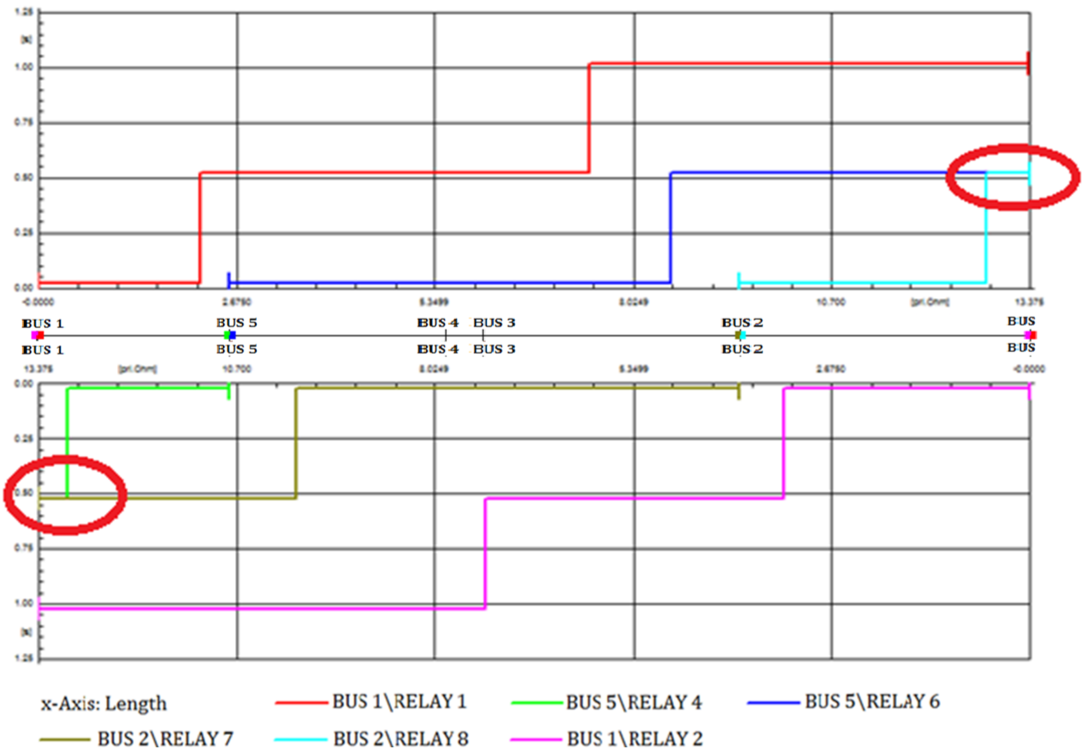


Figure 5-26 Overreach of relays following disconnection of DG sources (15_13_13)

5.6 Suggested method for improving relay operation

In this section, strategies are considered in order to improve the operation of the relays and their selectivity and security. Two strategies will be discussed here based on two different approaches:

- Distance protection with signalling channels
- Layered time grading

The two methods are explained referring to the problems found in the simulation studies, detailing how each method may help to alleviate the problem. In each case it can be specified whether the priority is to guarantee the best possible selectivity or to clear the fault in the shortest time possible, with less concern on the number of elements taken out of service.

As mentioned in section 5.1.1, it is assumed that the fault can occur everywhere on the 60 kV ring network.

5.6.1 Overreaching transfer trip

Standard distance relay zonal protection schemes with normal time-stepped zone grading enable fast fault clearing only up 85% of the line length under normal conditions, as was shown in Figure 3-5. A fault occurring in the remaining 15% of the line will always have a given time-delay before being cleared. Under high DG penetration scenarios, such as for Wind farm on Bus 4, this reach is further reduced, increasing the fault clearance time for a greater portion of the protected line.

Using a communication channel for the exchange of information between relays facing each other, the capability of selectively clearing all faults on the protected feeder without time-delay is possible. To achieve this, this method employs an over-reaching zone to supplement the standard first protection zone. The over-reaching zone extends to 120% of the protected line, for both relays on the line. If a fault is detected in this zone a signal is sent to the second relay. When the relays at both ends of the feeder detect a fault in the over-reaching zone and send each other signal, an instantaneous tripping signal is sent to both associated circuit breakers, de-energising the line. Figure 5-27 [28], demonstrates this principle. If Z_{1B} both sends and receives a fault detection signal then a tripping signal is sent to the breaker.

This method can be only used for ring networks as relays facing each other are required. This method provides the great advantage of clearing the fault as quickly as possible, while maintaining selectivity in the system. The main disadvantage of this method is in regards to the additional cost of installing the telecommunication system.

To highlight the effectiveness of this method, it is explained in application for the case Wind farm on Bus 4 for relay 7 and 6, where all the three zones are affected from a big under-reach. In this case the reach of the first zone of both Relay 7 and Relay 6 is reduced to 75% due to the in-feed of the wind farm, meaning that only 50% of the line is covered under the first relay operating time of both relays. Applying the overreaching transfer trip for relay 6 and 7, will guarantee an instantaneous operation time for the entire line, vastly improving the fault clearing time and reducing the detrimental effect of a sustained fault current.

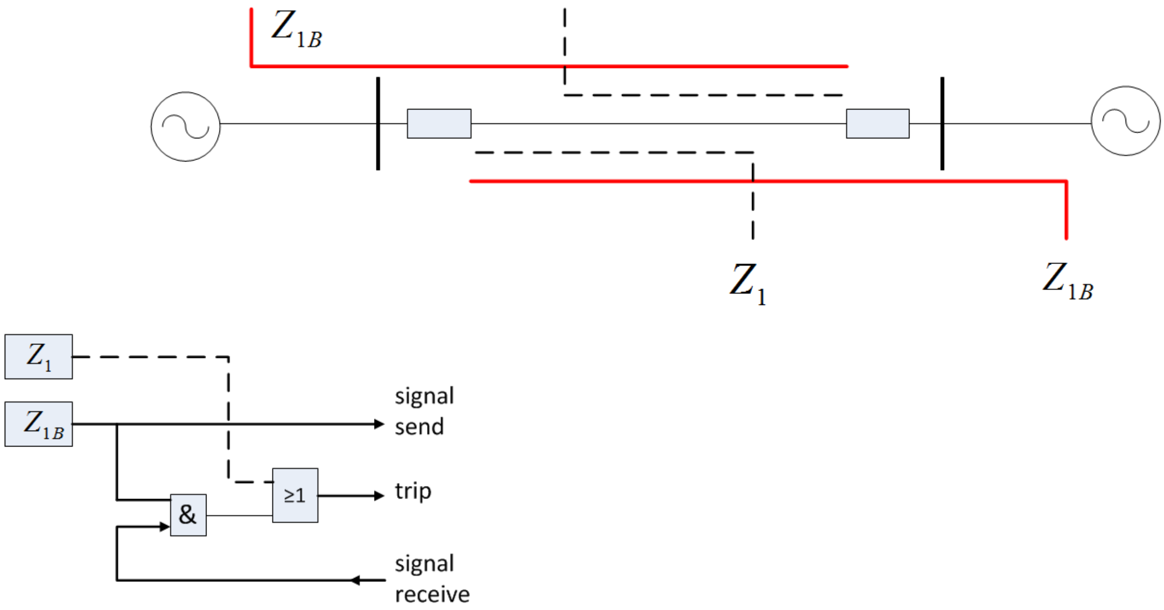


Figure 5-27 Distance protection with communication [28]

5.6.2 Layered time

When the WTG or CHP are connected, the under-reaching of the relay can be improved by considering the in-feed constant K in the calculation of the impedance zones of the relays, as in section 5.5. However, if the DG sources have been disconnected due to malfunction or maintenance, or are operating below rated values in the case of low wind speeds, a resulting over-reach occurs, as was discussed in section 5.5.3. This will cause overlap of the second and third protection zones, resulting in a loss of selectivity. This effect can be seen in tests 15_13_13 & 15_14_13.

The layered time strategy illustrated in Figure 5-28 can be used to alleviate this problem. The strategy involves an slight increasing of the tripping time for the second and third zones of the relay further away from the DG in-feed bus, for which over-reaching is present.

In this case, this increasing of the operating time returns the selectivity on the second relays protected line, as it will operate first even though the zones still overlap. This method therefore improves the selectivity but at the cost of increasing the fault clearing time for the first relay, making it more attractive if selectivity is a priority in the network.

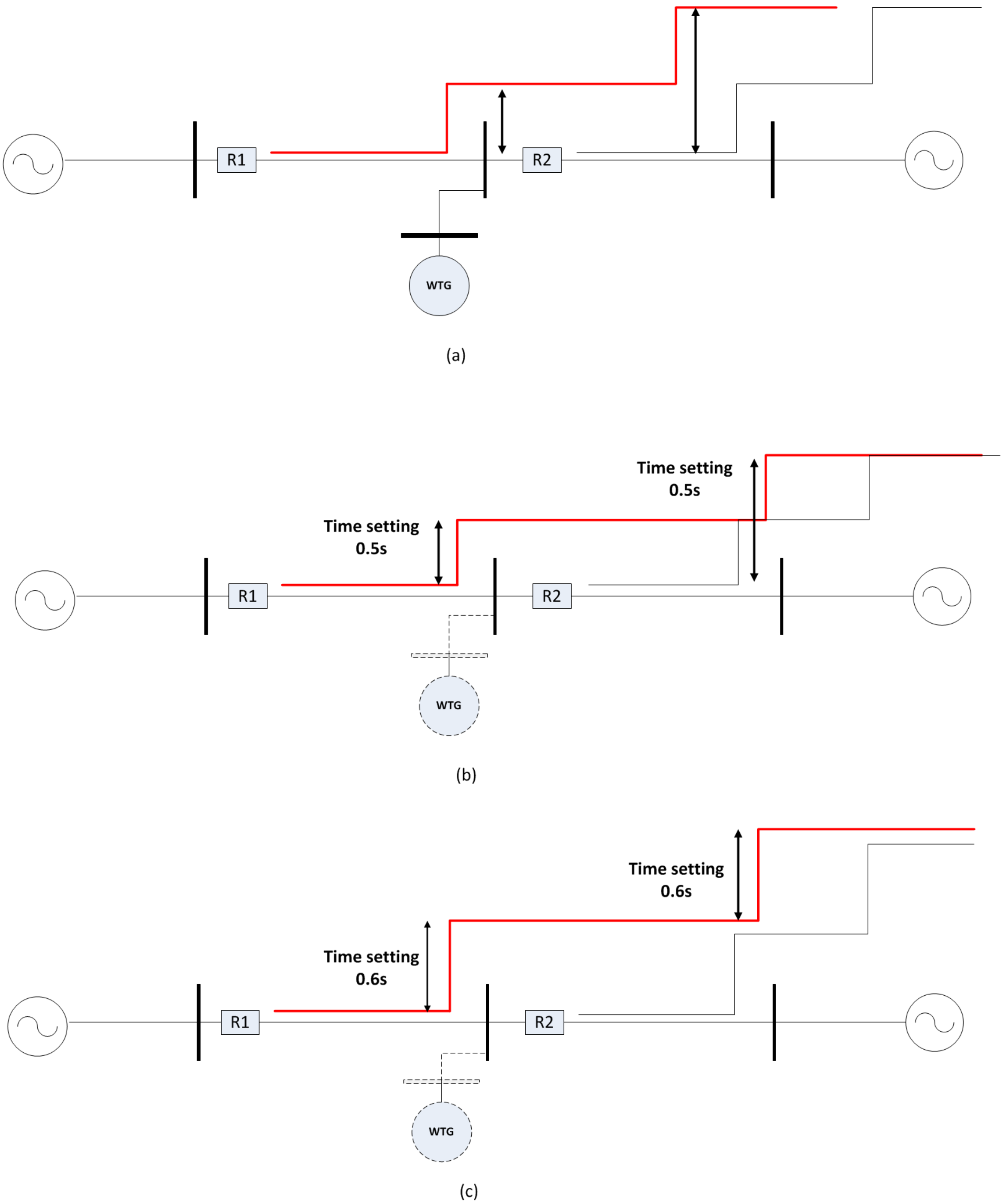


Figure 5-28 Layered time strategy (a) Zone settings with in-feed factor K (b) overlapped zones of the relay when the WTG is disconnected (c) Applied layered time strategy

5.6.3 Relay characteristic shaping

Another option is the use of modern electronic relays. These relays provide the ability to shape the relay characteristic. The zone can be shaped so as to decrease the setting in the direction of the load while maintaining adequate cover in the expected fault area. An example is shown in Figure 5-29.

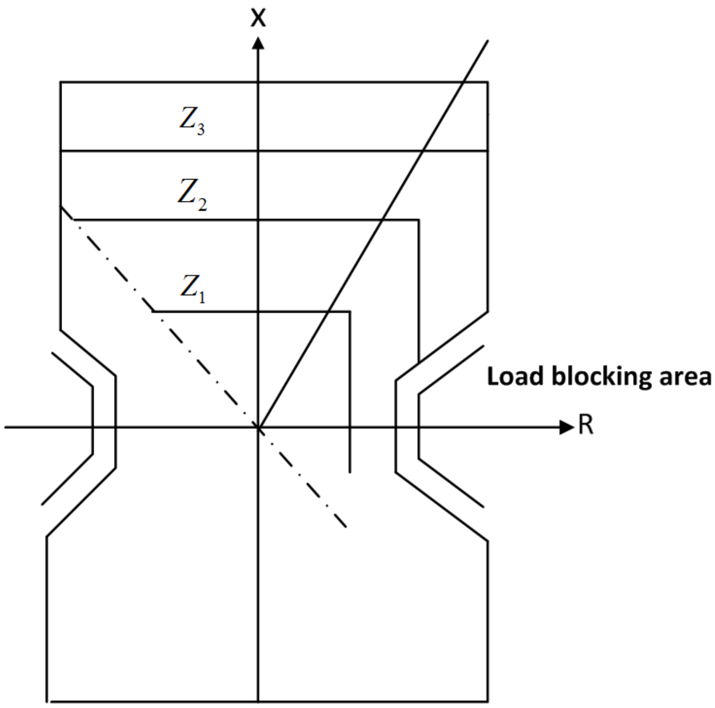


Figure 5-29 Electronic relay setting with shaping for load

6. CONCLUSIONS AND FUTURE WORK

6.1 Conclusion

In a power system, the goal of the protection system is to identify and clear fault conditions to minimise damage and disruption to the network and equipment, while maintaining reliability, security, sensitivity and selectivity. The ever increasing penetration of DG sources threatens to negatively impact the operation of the protection system, and effect each of the four aims of the protection system. This work has investigated and shown the cause and severity of the effect of DG on distance protection under various operating scenarios, with the following findings.

The CHP plant present in the circuit had the biggest effect, despite having a smaller rated power capacity than the wind farm, due to the connection method and location in the circuit. The wind farm is connected through voltage step-up transformers, which step down the current they supply by the same ratio, resulting in the maximum short-circuit current of 0.56 kA supplied by the wind farm being lower than the 2.58kA maximum short-circuit current from the CHP plant. The wind farm is originally connected to the same bus as the external grid, which already represents the biggest source of short-circuit current and therefore while perhaps increasing the total fault level in the circuit, does not have an effect on the reach or coordination of any of the relays within the ring circuit.

Protection relays facing the in-feed connection are affected, the biggest effect being a reduction in reach, leading to a number of issues with maintaining the expected level of reliability, security, sensitivity and selectivity. Firstly, the reduction in reach, results in many of the cases in an inadequate level of back-up protection, with consequences for the sensitivity and reliability by potentially leaving the system vulnerable to damaging, sustained fault conditions. To restore the back-up, the effect of the in-feed current must be taken into account when calculating the relay settings. This results in an increasing of the impedance settings, particularly for the 3rd zone, where increases of up to 200% are necessary depending on the relay location and operating scenario. Again, this results in a number of detrimental side-effects, this time with consequences for the selectivity and security.

The security of the system is reduced by the reduction in loadability that results from the increased impedance setting and may lead to incorrect tripping in high load conditions, or cascade tripping following a contingency. A loss of selectivity can also be expected if the DG is disconnected due to malfunction or maintenance, or operating below rated values, for example due to low wind speeds in the case of a wind farm.

All of these factors mean that a balance must be found when evaluating the solution method to cope with high penetrations of DG, depending on the specific grid, and ultimately on the priority and needs of the grid operator.

It should be noted that although the tests were carried out on a ring network, the results are also relevant when considering a radial circuit with DG connected, however additional consideration must be given to the power flow direction, which is not necessarily an extra factor in ring networks where two relays are required per line.

The findings throughout the report are in line with and satisfy the goals of this thesis.

6.2 Future work

In this work an analysis was conducted on the effect of high DG penetration on protection systems in MV ring networks. The analysis has resulted in a number of key findings. However some areas have been identified here for further research and analysis, which, due to time constraints were not capable of being completed under the present work.

- Testing using complete method for short-circuit calculations to take account of loading conditions of the network. This can include extensive testing of the loadability of the relays, including N-1 contingency analysis for conditions following a fault

- Further analysis of the thermal effect of increased fault clearance times, as well as the effect on the breaking current.

- Analysis under a wider set of scenarios, including for various fault types, more complex circuit configurations and wider range of DG scenarios

.

- Laboratory testing of distance relays, to further test the effects discussed throughout this thesis. Laboratory testing could also include design and testing of setting characteristic shaping.

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Appendices

APPENDIX A FAULT STATISTICS

Table 0-1 Faulted components – move to appendix?

Component	# of failures	# of interruptions
Bus bar	16	10
Circuit breaker	79	21
Disconnector	263	53
Earthing switch	7	7
Power transformer	174	69
Reactor	2	0
Power Capacitor	60	52
Measuring transformer	3	0
Fuse	12	10
Overhead line	20	19
Cable system	435 « 31%	417 « 62%
- Cable	359	350
- Joint	54	51
- Terminations	22	16
Surge diverter	1	1
Rectifier	299	0
Control equipment	13	9
Other	8	1
Total:	1392	669

Table 0-2 Cause of cable failures – move to appendix?

Cause of failure	Number	% of Total
Damage	3	5.2%
Digging	5	8.6%
Sabotage	1	1.7%
Personnel	_	_
Improper control	3	5.2%
Improper construction	3	5.2%
Other	1	1.7%
Material/Method	9	15.5%
Manufacture/material	8	13.8%
Lack of maintenance	3	5.2%
Other equipment	14	24.1%
Unknown	8	13.8%
Total	58	100%

APPENDIX B SHORT-CIRCUIT CURRENT CALCULATIONS

Symmetrical faults, that is three-line and three-line-to-ground faults, with symmetrical impedances to the fault, can utilise single phase representations when calculating resulting fault conditions as they leave the electrical system balanced. This symmetry is lost during asymmetric faults and in these cases in order to calculate short circuit currents resulting from an asymmetric fault, a system of symmetrical components is set up, which are designated as:

- **Positive-sequence**, consisting of three phasors of equal magnitude, spaced 120 ° apart and rotating in the same direction as the phasors in the power system under consideration, i.e. the positive direction. Positive sequence quantities are specified as Z_1, I_1, U_1
- **Negative-sequence**, consisting of three phasors of equal magnitude, spaced 120 ° apart, rotating in the same direction as the positive-sequence phasors but in the reverse sequence. Positive sequence quantities are specified as Z_2, I_2, U_2
- **Zero-sequence**, consisting of three phasors equal in magnitude and in phase with each other, rotating in the same direction as the positive sequence phasors. Zero sequence quantities are specified as Z_0, I_0, U_0

The positive, negative and zero sequence impedances Z_1, Z_2, Z_0 are determined and from this, sequence networks are set up. The three sequence networks are then connected in a given arrangement depending on whether the fault is a single line to ground, double line to ground, or line to line fault. From these, the fault currents can be found for each of the sequences I_1, I_2, I_0 which can then be converted back to the 3 phase system I_a, I_b, I_c using the following equation [10]:

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & \underline{a}^2 & \underline{a} \\ 1 & \underline{a} & \underline{a}^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix}$$

Where $\underline{a} = -\frac{1}{2} + j\frac{\sqrt{3}}{2}$ and $\underline{a}^2 = -\frac{1}{2} - j\frac{\sqrt{3}}{2}$.

This can be rewritten as:

$$I_{abc} = AI_{012}\ , \qquad (0.25)$$

Where A is the symmetrical component transformation matrix, transforming between symmetrical sequence current I_{012} and phasor currents I_{abc}.

Figure 0-1 shows the equivalent sequence networks and how they are connected for three phase, double phase and single phase faults. The dashed lines represent whether a connection to ground is made. If there is no connection to ground, the zero sequence network is open circuited.

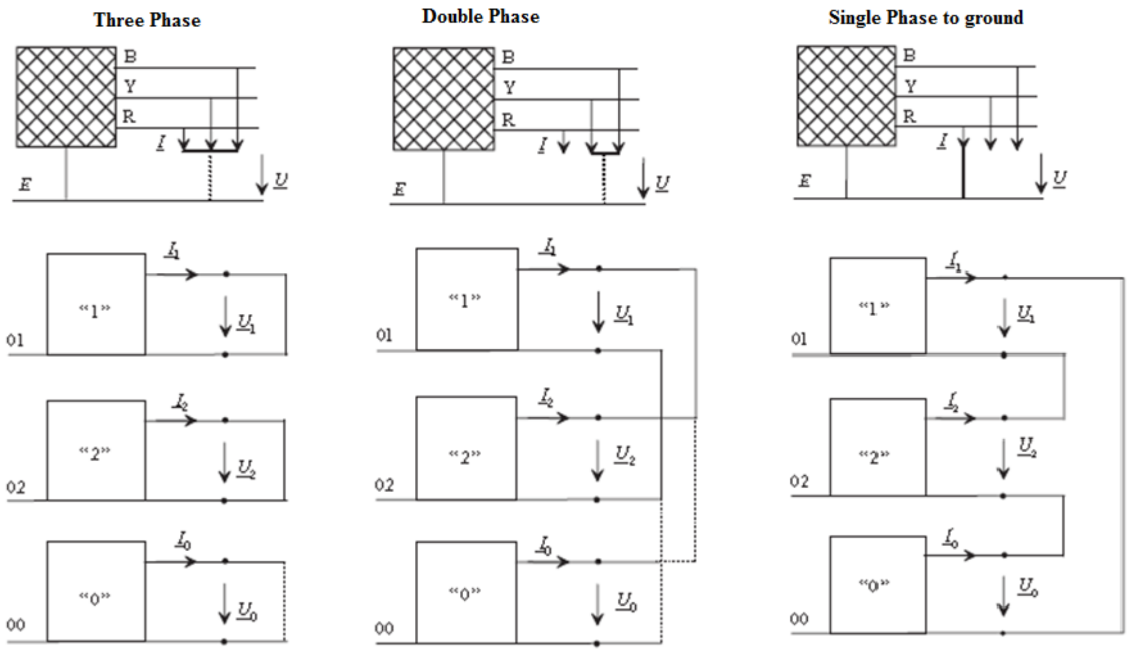

Figure 0-1 Symmetrical components for three phase, double phase single-phase to ground fault [16]

Complete method

The complete, or superposition, method is a method for calculating the short circuit current that is so-called as it uses a superposition of pre-fault values in two steady state operating conditions to find the fault conditions.

The initial step of this method is to calculate the pre-fault currents and voltages by performing a load flow calculation of the network for a given operation scenario.

Next, a negative voltage, equal in magnitude to the voltage at the fault location from the first step, is applied at the fault location. Other voltage sources and short-circuited and again a load flow calculation is performed.

The final step is to superpose both of these scenarios, which results in zero voltage (short-circuit) at the fault location, and provides the remaining current and voltage values under the fault conditions. This principle is illustrated in Figure 0-2.

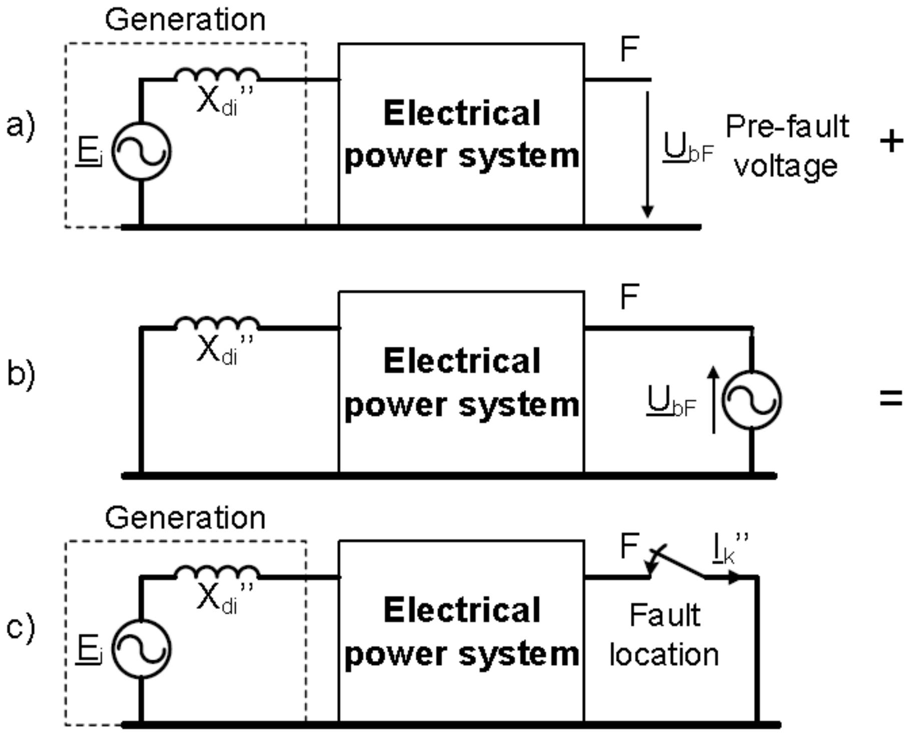

Figure 0-2 Principle of the superposition method. a) Pre-fault operating condition; b) negative pre-fault voltage at the SC location; c) Superposition of a) and b) to get SC conditions [15]

Grid Contribution

An example of the short-circuit contribution from the grid is given here. Figure 1-4 shows the 150 kV external grid supplying a radial line through a transformer connected to a BUS 1, cable $L_{(1)}$ connected to the BUS 5 and cable $L_{(2)}$ connected at the end with a synchronous generator G. The procedure for calculating the contribution of the grid to a 3 phase fault at BUS 5 is shown, and compared to the result retrieved from Power Factory.

The network data is shown to the left of Figure 1-4.

$$U_{nQ} = 150kV$$
$$I_k^{"} = 38.49kA$$
$$U_n = 60kV$$
$$S_{rT} = 125MVA$$
$$U_{rTHV} = 150kV$$
$$U_{rTMV} = 60kV$$
$$U_{kr} = 7\%$$
$$P_{kRT} = 1.25MW$$
$$L_{(1)} = 5.78Km$$
$$L_{(2)} = 1.21Km$$
$$Z_{L(1)} = 1.1017 + j2.325\Omega$$
$$Z_{L(2)} = 0.13068 + j0.15246\Omega$$

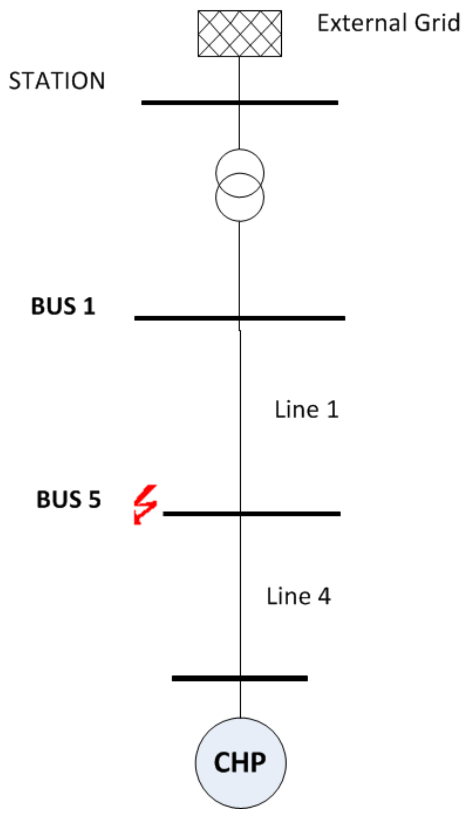

Figure 0-3 Network showing location of grid and fault

The IEC 60909 uses the equivalent voltage method which was described in detail in section 2.4.3, where the impedances of each of the elements in the path from the source to the fault location are calculated and the short-circuit current then calculated using an equivalent voltage source.

- **Impedance of the supply network**

$$Z_{GridHV} = \frac{c_Q \cdot U_{nG}}{\sqrt{3} \cdot I_{kG}^{"}} = \frac{1.1 \cdot 150}{\sqrt{3} \cdot 38.49} = 13.7 \cdot 10^{-3}\, pu \tag{0.26}$$

$$\text{If} \quad V > 35kV \Longrightarrow \quad R = 0 \tag{0.27}$$

$$X_G = 13.7 \cdot 10^{-3}\, pu \tag{0.28}$$

Where:

- Z_{GHV} is impedance of the network feeder (pu);
- X_G is the reactance of the network feeder (pu);
- Un_G is the nominal voltage at the connection point (Vac);

- I_k'' = Short-Circuit current of the network feeder (kA).

- **Impendence of the Transformer**

$$Z_{THV} = \frac{U_{rTHV}^{\;2}}{S_{rT}} = \frac{150^2}{125} = 180\Omega \tag{0.29}$$

$$Z_{TMV} = \frac{U_{rTMV}^{\;2}}{S_{rT}} \frac{60^2}{125} = 28.8\Omega \tag{0.30}$$

$$Z_T = 0.07 pu \tag{0.31}$$

$$R_T = 00.1 pu \tag{0.32}$$

$$X_T = \sqrt{0.07^2 - 0.01^2 =} 0.069 pu \tag{0.33}$$

Where:

- Z_{THV} = Positive sequence impendence of the transformer high voltage side (Ω)
- Z_{TMV} = Positive sequence impendence of the transformer medium voltage side (Ω)
- Ur_{THV} = Nominal voltage of the transformer at the high voltage side (Vac)
- Ur_{TMV} = Nominal voltage of the transformer at the medium voltage side (Vac)
- Sr_T = Rated capacity of the transformer (VA)
- R_T = Resistance of the transformer

- **The impedance correction factor can be calculated as:**

$$K_T = 0.95 \cdot \frac{c_{\max}}{1 + 0.6 \cdot x_T} = 1.003 \tag{0.34}$$

Where:

- X_T = Relative reactance of the transformer (pu)
- K_T = Impendence correction factor (pu)
- c = is a voltage factor which accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)

- **Total Impedance**

$$Z_L = Z_{Grid} + Z_T + Z_{L(1)} = 0.038 + j0.087 pu \tag{0.35}$$

Where:

- Z_L = Equivalent positive sequence short circuit impedance (pu)
- Z_T = Impedance of the transformer
- $Z_{L(1)}$ = Impedance of the line L(1)

- **Calculation of $I_k^{"}$ for three-phase fault**

$$I_{kgrid}^{"} = \frac{cU_n}{\sqrt{3}Z_L} = 7.764\angle -73^{\circ} kA \qquad (0.36)$$

Where:

- I_k'' = initial symmetrical short circuit current (kA)
- c = Voltage factor that accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)
- Z_L = Equivalent positive sequence short circuit impedance (pu)
- U_n = Nominal system voltage at the fault location (kV)

Figure 4-4, shows the Power Factory values of the short-circuit contribution from the grid. The short circuit current value given by Power factory has a magnitude of 7.72 kA,

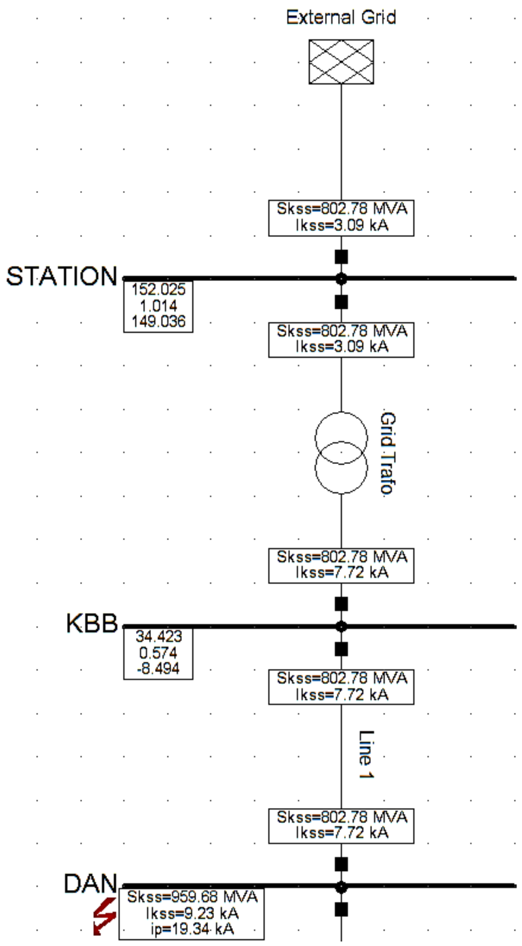

Figure 0-4: Short-circuit from grid

CHP contribution

Figure 0-5 shows the system modelled as a simple radial network with a voltage level of 150/60kV, and supplied by a single distributed generator. The equipment and cable parameters are shown to the left of Figure 0-5 .

$$S_{rG} = 26MVA$$
$$U_{nG} = 60kV$$
$$x_d^{''} = 17\% = 0.17$$
$$\varphi = 18.10^{\circ}$$
$$\cos\varphi = 0.95$$
$$Z_{L(2)} = 0.13068 + j0.15246\Omega$$

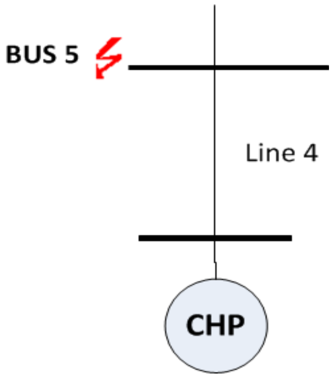

Figure 0-5: Network showing location of CHP, lines, and fault

- **Impedance of the generator**

$$Z_{Gen} = 3.616 + j24.587\Omega \qquad (0.37)$$

$$K_G = \frac{c_{\max}}{1 + \chi_d^{''} \cdot \sin\varphi_G} = \frac{1.1}{1 + 0.17 \cdot (0.312)} = 1.045 \qquad (0.38)$$

$$I_{kG}^{''} = \frac{cU_n}{\sqrt{3} \cdot (Z_G + Z_{L(2)})} = \frac{1.1 \cdot (60 \cdot 10^3)}{\sqrt{3} \cdot (1.045 * (0.13068 + j0.15246) + (3.616 + j24.587))}$$

$$I_{kG}^{''} = 1.360\angle -88^{\circ} kA \qquad (0.39)$$

Where:

- Z_{Gen} is the impedance of the generator;
- K_G = Voltage correction factor;
- c = Voltage factor that accounts for the maximum system voltage (1.05 for voltages <1kV, 1.1 for voltages >1kV)
- $\chi_d^{''}$ = Per-unit sub-transient reactance of the generator (pu)
- cos φ_g = Power factor of the generator (pu)
- U_n = Nominal system voltage at the fault location (kV)
- $I_k^{''}$ = Initial symmetrical short circuit current (kA)

Figure 4-5 shows the Power Factory values. It can be seen that the value result close enough to the SC calculated by hand.

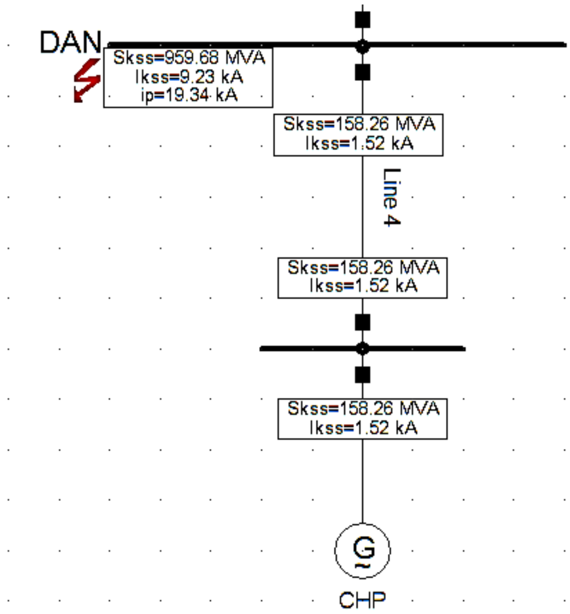

Figure 0-6: Short-circuit contribution from synchronous generator

- **Total SC current**

$$I''_{kTotal} = I''_{kG} + I''_{kgrid} = 9.124kA \tag{0.40}$$

Where:

- I''_{kG} = Initial symmetrical short circuit current of the Generator (kA)
- I''_{kgrid} = Initial symmetrical short circuit current of the Grid (kA)

APPENDIX C: DPL

```
! DPL Short Circuit script
! Define Variables
int i_NumLines, i_NumLoads, i_NumTerms, i_NumFaultLocs, i_NumRelays, i_NumPaths;
int i, j, i_Length_Str, i_strcmp, i_RelPos;
int i_LdfChk, i_LdfErr, i_ShcErr;
double d_LineLength, d_TestInput;
double Xf,Rf; !Fault values
string s_TestInput, s_Temp, s_fname, s_fpath;
object o_ActCase, o_Shc, o_Ldf;
object o_Line, o_LineSCC, o_Load, o_Term, o_Relay, o_Bar, o_Trafo;
set set_Lines, set_LinesSCC, set_Loads, set_Terms, set_FaultLocs, set_Relays, set_Paths, set_Bars,
set_Trafos;

!Clear output window
!ClearOutput();
!****************************************************
! Active study case
EchoOff();
o_ActCase = ActiveCase();
if(.not.o_ActCase) {
  output('No active case - exited.');
  exit();
}
!****************************************************
! Discover all Lines
set_Lines = SEL.GetAll('ElmLne');
i_NumLines = set_Lines.Count();
set_LinesSCC= SEL.GetAll('ElmLne');
set_LinesSCC.SortToVar(0, 'loc_name');

! discover trafo
set_Trafos = SEL.GetAll('ElmTr2');
set_Trafos.SortToVar(0, 'loc_name');
o_Trafo=set_Trafos.First();

! Discover all Terminals
set_Terms = SEL.GetAll('ElmTerm');
set_Terms.SortToVar(0, 'loc_name');
i_NumTerms = set_Terms.Count();

set_Bars = SEL.AllBars();
set_Bars.SortToVar(0, 'loc_name');

for(o_Term=set_Terms.First(); o_Term; o_Term=set_Terms.Next()) {
!  printf('%s',o_Term:loc_name);
}
! Discover Relays
set_Relays = AllRelevant('*.ElmRelay',0);
set_Relays.SortToVar(0, 'loc_name');
i_NumRelays = set_Relays.Count();

for(o_Relay=set_Relays.First(); o_Relay; o_Relay=set_Relays.Next()){
!  printf('%s',o_Relay:loc_name);
}

! end of discovering elements
!****************************************************
```

```
! Short-circuit
o_Shc = GetCaseCommand('ComShc'); !set short circuit object
if(.not.o_Shc) {
  output('No Short-Circuit Calculation - exited.');
  exit();
}
! Short-circuit calculation method
o_Shc:iopt_mde = 1; ! 1=IEC, 3 = Complete method
o_Shc:iopt_asc = 0; ! print results
!o_Shc:iopt_shc = 1; ! fault type
! o_Shc:iopt_min = 1; ! min currents

! Location, impedance and execution of SC
i=1;
!\Test2withoutWTG.txt
fopen('..\Results.txt','w',0);

for(o_LineSCC=set_LinesSCC.First(); o_LineSCC; o_LineSCC=set_LinesSCC.Next()){
  fprintf(0,'\nIkss in %s\n',o_LineSCC:loc_name);

  for(o_Line=set_Lines.First(); o_Line; o_Line=set_Lines.Next()){
    for (i_RelPos=5;i_RelPos<=95;i_RelPos+=10){
      o_Shc:shcobj = o_Line;   !set faulted line
      o_Shc:ppro=i_RelPos;          ! relative position of fault on line

      ResetCalculation();
      i_ShcErr=o_Shc.Execute(); ! Execute Short Circuit
      if(i_ShcErr) exit();

      fprintf(0,'%s; %d percent; Ikss =;%.2f',o_Line:loc_name,o_Shc:ppro,o_LineSCC:m:Ikss:1);
    }
    fprintf(0,'\n');
  }
!  fprintf(0,'%s; Ikss =; %.2f',o_Trafo:loc_name,o_Trafo:m:Ikss:1);
}
  fprintf(0,'\nIkss in %s\n',o_Trafo:loc_name);
  for(o_Line=set_Lines.First(); o_Line; o_Line=set_Lines.Next()){
    for (i_RelPos=5;i_RelPos<=95;i_RelPos+=10){
      o_Shc:shcobj = o_Line;   !set faulted line
      o_Shc:ppro=i_RelPos;          ! relative position of fault on line

      ResetCalculation();
      i_ShcErr=o_Shc.Execute(); ! Execute Short Circuit
      if(i_ShcErr) exit();

      fprintf(0,'%s; %d percent; Ikss =;%.2f',o_Line:loc_name,o_Shc:ppro,o_Trafo:m:Ikss:1);     !   Ikss2 =
%.2f;, o_Line:m:Ikss:2

      }
      fprintf(0,'\n');
    }

fclose(0);
! End of Short-Circuit
!*************************************************
o_Shc.GetContents();
```

APPENDIX D: CD-ROM CONTENTS

The enclosed CD-ROM contains the following material used throughout the project period:

- Report: folder containing project report in MS Word and Adobe PDF format;
- References: folder containing all public references used throughout the report and listed in the bibliography;
- PowerFactory: folder containing all DIgSILENT PowerFactory projects in .pfd format and the DPL code used;