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**Fault location in power distribution
networks with distributed generation**

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Laiz de Carvalho Souto

**Fault location in power distribution
networks with distributed generation**

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To all those interested in fault location in electric power systems

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*"There are no unlockable doors
There are no unwinnable wars
There are no unrightable wrongs
or unsingable songs"
(Ozzy Osbourne)*

Abstract

Souto, Laiz **Fault location in power distribution networks with distributed generation.** 114 p. Master Dissertation – Polytechnic School, University of São Paulo, 2016.

This research presents the development and implementation of fault location algorithms in power distribution networks with distributed generation units installed along their feeders. The proposed algorithms are capable of locating the fault based on voltage and current signals recorded by intelligent electronic devices installed at the end of the feeder sections, information to compute the loads connected to these feeders and their electric characteristics, and the operating status of the network. In addition, this work presents the study of analytical models of distributed generation and load technologies that could contribute to the performance of the proposed fault location algorithms. The validation of the algorithms was based on computer simulations using network models implemented in ATP, whereas the algorithms were implemented in MATLAB.

Keywords: power system protection, power system automation, fault location, distributed generation.

Resumo

Souto, Laiz **Localização de faltas em redes elétricas de distribuição com a presença de unidades de geração distribuída.** 114 p. Dissertação de mestrado – Escola Politécnica, Universidade de São Paulo, 2016.

Esta pesquisa apresenta o desenvolvimento e a implementação de algoritmos para localização de faltas em redes primárias de distribuição de energia elétrica que possuem unidades de geração distribuída conectadas ao longo dos seus alimentadores. Esses algoritmos são capazes de efetuar a localização de faltas utilizando registros dos sinais de tensões e correntes realizados por dispositivos eletrônicos inteligentes, instalados nas saídas dos alimentadores de distribuição, além de informações que permitam determinar os valores das cargas conectadas nesses alimentadores, características elétricas, e o estado operativo da rede de distribuição. Ademais, este trabalho apresenta o estudo de modelos analíticos de unidades de geração distribuída e de cargas que poderiam contribuir positivamente com o desempenho dos algoritmos propostos. A validação dos algoritmos foi realizada através de simulações computacionais, utilizando modelos de rede implementados em ATP e os algoritmos foram implementados em MATLAB.

Palavras-chave: proteção de sistemas elétricos, automação de sistemas elétricos, localização de faltas, geração distribuída.

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Acronyms

AC alternate current

A/D analogical/digital

ATP Alternative Transient Program

CT Instrument Current Transformer

DC direct current

DG distributed generation

DFIG Doubly-Fed Induction Generator

DFR digital fault recorder

DKE Deutsche Kommission Elektrotechnik

d-q direct-quadrature

EMF electromotive force

GFRT Grid-Fault Ride-Through

GSC grid-side converter

HV High Voltage

IEC International Electrotechnical Commission

IED Intelligent Electronic Device

IEEE Institute of Electrical and Electronic Engineers

IG Induction Generator

IGBT Insulated-gate bipolar transistor

I-V current-voltage

MATLAB Matrix Laboratory

MCFC Molten carbonate fuel cell

MOV Metal Oxide Varistor

MPPT Maximum Power Point Tracking

MSC machine-side converter

MV Medium Voltage

PEMFC Polymer electrolyte membrane fuel cell

PV Photovoltaic

PMSG Permanent Magnet Synchronous Generator

PMU Phasor Measurement Unit

p.u. per unit

PWM Pulse Width Modulation

RMS Root Mean Square

RSC rotor-side converter

SCIG Squirrel-Cage Induction Generator

SOFC Solid oxide fuel cell

STATCOM Static Converter

VFD variable frequency drive

VSC Voltage Source Converter

VT Instrument Voltage Transformer

WECC Wisconsin Energy Conservation Corporation

WRIG Wound Rotor Induction Generator

WTG Wind Turbine Generator

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Introduction

1.1 General

The presence of distributed generation (DG) in power distribution networks may bring impacts to conventional protection and automation systems, because of irregularity in energy availability and power quality and stability issues, such as momentary variations in voltage levels and increase in harmonic content and short-circuit levels. As a result, traditional fault location algorithms are no longer valid in these conditions (GHORBANI; CHOUDHRY; FELIACHI, 2013; OROZCO-HENAO; MORA-FLOREZ; PEREZ-LONDONO, 2012; HAGH; HOSSEINI; ASGARIFAR, 2012; WU et al., 2011).

Fault location in power distribution networks plays a critical role to reduce supply interruption rates and increase power quality to consumers. Therefore, it is of paramount importance to develop accurate fault location procedures that takes into account these new conditions, and also apply models that properly represent the DG and load technologies so that the fault location procedures present a satisfactory degree of accuracy.

This research project fits into this context and presents fault location algorithms in power distribution networks with the presence of DG. The text is structured as follows: Chapter 2 describes the accuracy issues of the fault location techniques in use, Chapter 3 presents the DG and load technologies commonly used and their behaviour under short-circuits (Section 3.2 to Section 3.6); afterwards, Chapter 4 presents the proposed fault location algorithms, taking into consideration distinct scenarios; to conclude, details of the simulations are presented in Chapter 5, followed by the conclusions and future perspectives.

1.2 Motivations

The analysis of the dynamic behaviour of electric power systems requires equivalent models that represent the phenomena of interest together with accurate parameters to ensure replication of reality. The choice of models relies on knowledge of the actual

system composition and the phenomena in study, whereas the estimation of parameters minimizes the differences between the measured and simulated behaviour. Different model structures may lead to different parameter values, as the estimations tend to compensate for poorly-modelled effects.

The model complexity and the aim of the investigations have to comply with each other. Hence, representation of a given component present in the construction has a purpose with respect to the target of the investigations. On the one hand, over-simplified models may not represent the complexity of a given component accurately; on the other hand, over-detailed models are more difficult to describe, produce slower simulations and unnecessary outputs that may confuse the interpretation of results. Therefore, generic models may be parametrised in such a way that a wide range of components can be represented reasonably well.

Modelling power distribution systems with DG is a difficult task due to their inherent complexity. The technologies in use present different behaviours under abnormal conditions and often require static converters to be connected to the alternate current (AC) grid. As a result, the system behaviour is conditioned by static converters and DG units during grid disturbances. In a recent past, the influence of these technologies on the overall operating conditions was negligible due to their low penetration levels; consequently, simplified models, such as the constant power supply, were adopted without reducing the accuracy of electrical studies. Recently, their increasing penetration level has requested the development of appropriate models to evaluate system performance during short-circuits.

In turn, modelling loads is challenging because most of the utilities have no detailed information about the characteristics of what is connected to the grid, although it is important for various electrical studies and particularly for fault location. Some fault location algorithms apply simplified load models or ignore the load current, which may lead to inaccurate solutions. Correct estimations of the load current contribution may improve the accuracy of fault location, regardless of their non-deterministic behaviour. Some techniques have good precision for load estimation, such as daily load curves and optimization methods.

To conclude, it is necessary to use accurate analytical models that represent the behaviour of the DGs, loads and power converters when the grid is subjected to a fault condition, so that the fault location system can indicate the fault position accurately.

1.3 Objectives and outlines

The main goals of this thesis are summarized as follows:

- Evaluate the state of the art of fault location techniques;
- Evaluate distinct fault location procedures;

- Describe the short-circuit current contribution of distributed generation technologies commonly used, notably wind turbines, photovoltaic cells, fuel cells and gas micro-turbines;
- Describe the impact of loads on the short-circuit currents;
- Describe the influence of power conditioning units on the short-circuit current contribution of distributed energy resources and loads;
- Study and develop fault location algorithms in power distribution networks with distributed energy resources installed along the feeders;
- Validate the proposed fault location algorithms implemented in Matrix Laboratory (MATLAB) through study cases simulated in Alternative Transient Program (ATP).

1.4 Contributions

This thesis aims to contribute for the development and consolidation of fault location algorithms in primary distribution networks with DGs installed along the feeders, as well as to proceed with simulations and tests to validate them. In addition, this project aims at studying analytical models of distributed energy resources and loads during grid disturbances for the same purposes. As a consequence, it is expected that this research provides useful information on the understanding of this subject.

1.5 Publications

- a) Souto L. C., Manassero G. Jr., Di Santo S. G., Fault Location in Distribution Feeders with Distributed Generation, 2016 Clemson University Power Systems Conference, Clemson, 08-11 March 2016.
- b) Souto L. C., Manassero G. Jr., Di Santo S. G., Heuristic Method for Fault Location in Distribution Feeders with the Presence of Distributed Generation, IEEE Transactions on Smart Grid (submitted).

* * *

Review of Fault Location Techniques

2.1 Basic principles

Power transmission and distribution systems are susceptible to short-circuits that can damage them and their connected equipment. Protection schemes are expected to operate in order to clear the fault, by opening the circuit breakers that connect the damaged line to the healthy part of the network. Reclosing schemes are used to bring the line back in operation after the fault is cleared. Temporary faults are cleared in such a way that the power supply continuity is not affected permanently. Conversely, if all the reclosing attempts fail, the fault will be assumed permanent, the circuit breaker associated to the protective relaying equipment will remain open to de-energize the faulted sections.

Faults in power distribution networks are often located through physical indications and field methods such as restoration through switching or recloser operation, indication through fuse and fault-locator operation, downed wires, customer calls and maps, relay targets and direct current (DC) thumping of underground circuits. However, high accuracy is needed in determining the fault location for efficient dispatch of repair crews, often searching in bad weather conditions or at places that are difficult to reach.

The accuracy of a given fault location technique may be affected by several aspects, such as the network elements and the analytical models applied. In turn, the limitations of a given procedure may influence the level of details required to represent adequately such factors. If a particular factor affects fault-location accuracy, then the means of its elimination or minimization have to be considered. Thus, it is important to understand how a particular factor and the accuracy of a given fault location technique may affect each other, so that the means of minimization of errors can be considered.

2.2 Distribution networks

The fault location algorithms developed within this work are intended to power distribution networks. Thereby, a brief explanation about the main characteristics of a typical

Figure 1 – Typical distribution feeder

Source: the author

distribution network is provided in the next paragraphs.

Primary distribution feeders usually have a main line section (line section 10-50) that leaves the substation and is connected to a number of lateral branches (branches 30-90, 40-100, 100-110, 20-60, 60-70, 60-80, 60-120 and 120-130), as illustrated in Figure 1. Intelligent Electronic Device (IED)s installed only at the substation bus (bus 10 in Figure 1) or at the substation bus and connection points of DGs (buses 50, 70, 110 and 130 in Figure 1) are responsible for protecting the main line section of the feeder and providing backup protection to the fuses installed at the lateral branches.

Typical distribution feeders are radial, with different configurations, lines and cables along them; therefore, the relation between the sections' impedances and the fault distance is non-linear. Moreover, faults at different locations may result in the same voltage and current signals recorded at the substation. Furthermore, the current measured at the substation during an overcurrent event may include load currents at each bus and it is virtually impossible to estimate them precisely.

The connection of DGs changes distribution network topology from single-power to multi-power. Consequently, traditional fault location algorithms are no longer applicable under such conditions. High penetration levels of DG will have unfavorable impact on these methods, depending on the number, location and injected current of DG.

For clarification purposes, the differences between radial and network distribution schemes are summarised in Table 1.

Table 1 – Comparison between distribution categories

	Radial distribution	Network distribution
Characteristics	<ul style="list-style-type: none"> – independent feeders branch out radially from a common supply source 	<ul style="list-style-type: none"> – circuits with multiple branches and service taps – areas with high load density and maximum reliability requirements
Parameters	<ul style="list-style-type: none"> – cable length – presence of transformers in a loop – short and open circuits – neutral corrosion 	<ul style="list-style-type: none"> – overall circuit length and number of branches – lumped cable system capacitance – insulation type – fault resistance – transformer primary connection

Source: IEEE-Std.1234-2007 (2007) (adapted)

2.3 Typical approach of an automated fault location system

An automated fault location system requests IEDs installed at the distribution network, as well as communication channels to allow the exchange of information between the IEDs and the system operator.

The IEDs are responsible for recording the voltage and current signals at a few points (usually at the substation bus and sometimes at the connection points of the DG units and other points of common coupling) at a given sample rate. The recorded quantities are sent via communication channels to the system fault location system, which processes the received information and calculates: the pre-fault, fault and post-fault phasor quantities; and the fault type and phases involved. Then it uses these information together with the electrical parameters and topology of the distribution network stored in a database to identify the point of fault. After the system response, the repair crew can be dispatched fast and efficiently.

The operation processes of a typical automated fault location system are schematised in Figure 2, and this work focuses on the development of fault location algorithms that comprise the automated fault location system.

2.4 Errors of fault location

Various factors may impact the accuracy of fault location and must be taken into account (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; GILBERT; MORRISON, 1997; EINARSSON, 2005; IEEE-C37.114-WG, 2015). Overall, accuracy issues may be grouped in three categories, as follows:

Figure 2 – Block diagram of an automated fault location system

Source: the author

- a) Software-related issues: include basic problems in numerical computation, such as rounding, cancellation, recursion, floating-point precision, illegal data and illegal conversion between data types, and errors in software implementation (EINARSSON, 2005). The issues within this category may affect measurement and parameter estimations.
- b) Measurement-related issues: include transient- and steady-state errors of Instrument Voltage Transformer (VT)s and Instrument Current Transformer (CT)s including unfaithful reproduction of the primary signals due to their limited bandwidth and possibility of CT saturation, time and frequency response of voltage and current measurement chains, accuracy of analogical/digital (A/D) conversion in terms of sampling frequency and bit resolution.
- c) Parameter-related issues: comprehends fault resistance, including presence of an arc; inaccuracy in providing impedance data for the overhead line, due to the lack of information about the geometry and total length of its conductors, especially for the zero-sequence impedance, which is affected by the soil resistivity (variable under the whole line route and dependent on the weather conditions), as well as for the source impedances (in case they are involved in the fault location algorithm); strength of equivalent sources behind the line terminals; improper line model, given that long lines on high voltage levels may exhibit considerable capacitance and significant charging current and have to be considered within the algorithm; line imbalance due to lack of transposition, provided that untransposed lines are represented as being transposed; presence and status of series and shunt devices in the line and substation nodes, such as banks of series capacitors equipped with Metal

Oxide Varistor (MOV)s. Such uncertainties may result in inaccurate compensation for the reactance effect in the case of fault location algorithms using one-end measurements, as well as for the mutual effects on the zero-sequence components, if the current required to compensate the mutual coupling is unavailable.

2.5 Fault location in power distribution lines

It is estimated that the majority of power outages originate in distribution systems, which highlights the need for fault location algorithms tailored to distribution feeders. On the one hand, the costs of outages demand investments to reduce outage time; in other words, the faster the fault is cleared, the lower are the economic losses. On the other hand, the cost of undergrounding or instrumenting heavily every feeder at distribution level also becomes very high (JOHNSON, 2006). By and large, an effective fault location system has to be accurate enough to drive maintenance crews directly to the point of fault, and cost effective so that significant investments are unnecessary to operate the system.

Overall, contemporary methods for fault location in power transmission and distribution lines can be categorized as three fundamental types whose main features are summarized in Table 2, based upon (SAHA; IZYKOWSKI; ROSOLOWSKI, 2010; IEEE-C37.114-WG, 2015; TANG et al., 2000):

- a) fundamental-frequency currents and voltages (or impedance-based fault location techniques),
- b) the measurement of travelling waves and high-frequency components, and
- c) knowledge-based approaches.

There has been considerable research effort into the development of impedance-based fault location techniques, since this is the simplest way to determine fault location. These methods use fundamental-frequency voltages and currents at the line terminals together with the line parameters for calculating the faulted line impedance, which is function of the fault distance. Different availability of input signals can be distinguished for multi-terminal lines.

Fault location methods using travelling waves are independent of the network configuration and devices installed in the network, and typically rely on accurate timing information in order to provide accurate results. However, they are inadequate to distribution networks with multiple lateral branches, different conductors, transformers, and other constraints, and also require high sampling rates (SAHA; IZYKOWSKI; ROSOLOWSKI, 2010). Hence, these methods will not be presented in details within this research.

Artificial-Intelligence applications in fault location include artificial neural networks (pattern recognition), expert systems and fuzzy-logic (decision making). These procedures can help to increase the accuracy of estimation because of their flexibility, including

Table 2 – Comparison between fault location techniques with DFRs installed at different locations

	Substation level			Along the feeder
	Fundamental frequency	Travelling wave and high frequency	Knowledge-based approach	
Pros	<ul style="list-style-type: none"> – simple, cheap – low-sample rate 	<ul style="list-style-type: none"> – high accuracy – accuracy does not rely on system condition – good accuracy for high impedance faults 	<ul style="list-style-type: none"> – self adaptive – high accuracy 	<ul style="list-style-type: none"> – self-powered – sensitive
Cons	<ul style="list-style-type: none"> – accuracy relies on system condition – lower accuracy for high impedance faults – lower accuracy for systems with tapped loads – problems with single-phase-to-ground faults 	<ul style="list-style-type: none"> – complex, expensive – high sample rate (above 20 [MHz]) – problem for low fault inception angle – inaccurate with the presence of lateral branches 	<ul style="list-style-type: none"> – rely on external information 	<ul style="list-style-type: none"> – error for high impedance faults and low inception angle – single-phase-to-earth faults may not be detected – installed in all phase lines – complex, expensive
Industry	most applications	few applications	none	few applications

Source: Tang et al. (2000) (adapted)

the possibility of training the network in the case of artificial neural networks (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; TAWFIK; MORCOS, 2001; KORBICZ, 2004; PURUSHOTHAMA et al., 2001; CHEN; MAUN, 2000), but are not commonly applied to power distribution networks due to their inherent complexity.

In this context, the following sections describe the accuracy issues of fault location and a number of techniques in use at the distribution level, notably impedance-based fault location methods.

2.5.1 Accuracy issues

New problems arise for fault location in distribution networks in comparison to the same task in transmission lines. In the latter, each line may be equipped with its own digital fault recorder (DFR) and the fault location algorithm is a numerical procedure that converts voltage and current, given in a digital form, into a single number equals to the distance to fault. In contrast, in the former, DFRs are usually centralized at the substation level, measuring the busbar voltages and transformer currents; as a consequence, accurate fault location becomes more difficult (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; SAHA;

PROVOOST; ROSOŁOWSKI, 2001). Additionally, methods intended to transmission lines are prone to errors when used in distribution networks, because of the non-homogeneity of lines, presence of laterals and tapped loads (SRINIVASAN; ST.-JACQUES, 1989).

Faults in power distribution networks are often located without measurements, through physical indication, field and brute force methods such as restoration through switching or recloser operation, indication through fuse and DFR operation, downed wires, customer calls, maps, relay targets, DC thumping of underground circuits and smelling burnt cables. Nonetheless, data gathering may improve the success of fault location techniques (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010).

The reliability and accuracy of substation-based DFRs is questionable. Some fundamental factors that contribute to this are listed below:

- If the current of a faulted line is not directly available to the DFR, a certain error is introduced when it is supposed to be the transformer current during the fault; moreover, it is not possible to achieve accurate compensation for the pre-fault load current of the faulted line.
- Multi-terminal lines create well-known problems for one-end fault location, as well as the presence of loops, since in general few alternatives are indicated as possible fault points.
- Loads are often located between the fault point and the busbar in Medium Voltage (MV) lines; it is difficult to compensate for them, because they change and are unknown to the DFR (GIRGIS; FALLON; LUBKEMAN, 1993).
- MV lines are mainly overhead lines that present additional problems with adequate representation of the equivalent scheme, including changes in conductor sizes, multiple taps and laterals, inaccurate models and system data, effects of fault impedance and evolution of fault characteristics and magnitudes that can fool the ability of relays to select the correct fault type (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; IEEE-C37.114-WG, 2015).

Furthermore, the fault impedance and type of neutral grounding must be considered within each fault location method. They determine how the power system behaves during ground faults (IEEE-C37.114-WG, 2015):

- Under high-resistance ground faults, the fundamental-frequency fault currents are often small in comparison to the load currents (HANNINEN; LEHTONEN, 1998). Besides, the calculation of zero-sequence impedances can be inaccurate. The best practices assume that the zero-sequence currents and the neutral-to-earth voltage are complex values, so their magnitude and phase angle have to be calculated from the measurements.
- In underground cables, fault location presents additional issues, because the distributed shunt capacitance along the cable changes with the system voltage, stored charge, different zero-sequence return paths and infeed from unpredictable sources. As a con-

sequence, the slightest error in the impedance model may result in large errors in calculating the fault point, as the cable impedance is usually small (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; IEEE-C37.114-WG, 2015).

- In paralleled circuits, the line impedance is not a linear function of the distance to the fault (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010; IEEE-C37.114-WG, 2015).
- The effect of fault resistance can amplify the errors contributed by other factors. For instance, the fault impedance interacts with the tapped load impedance and thereby increases the negative error in the estimation of fault position. Depending on the fault location, the errors vary without consistency (IEEE-C37.114-WG, 2015).

Automatic reclosing can impact the accuracy of fault location, depending on the line configuration (IEEE-C37.114-WG, 2015). The first fault usually provides accurate data, since it usually has valid pre-fault and fault data. If the reclosing takes place in a de-energized line, the absence of load can help to produce more accurate estimations, as long as the DFR selects the correct data, for both one- and two-terminal algorithms. Attempts of automatic reclosing into a permanent fault can increase the DC offset, whose decaying can take several cycles and must be accounted for accurate fault location.

Therefore, while the effects of certain sources of error can be reduced with specific processes, the effectiveness of a process can be diminished.

2.5.2 Conventional methods

Different fault location methods have been proposed to overcome the troubles mentioned above (IEEE-C37.114-WG, 2015; SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010). The conventional procedures compute the equivalent positive- and zero-sequence impedances in a pre-fault steady state for all nodes of the network based on the existing topology. After the fault detection, the fault-loop parameters are calculated in function of the fault type and the place of measurements, whether at the supplying transformer or at the faulty feeder; then, the fault point can be determined. In the case of a few possible points, an adequate procedure shall be applied to select the most likely result.

Overall, fault location techniques can be categorized into terminal and tracer (IEEE-C37.114-WG, 2015; SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010). The former measures electrical quantities at the ends of the circuit to pre-locate the fault, whilst the latter pinpoints the faulty area and usually require a repair crew to walk the cable route in the field. These methods usually take place after the fault is cleared by the protective relaying.

Techniques that apply the lumped-parameter network model are intended for short lines, with all loads modelled as a lumped-parameter impedance (SAHA; IZYKOWSKI; ROSOŁOWSKI, 2010). This approach may compensate for tapped loads, typically much larger than the feeder impedance. Equivalent source and load impedances are calculated with use of pre-fault and fault voltages and currents measured at the substation bus. The

negative sequence network is used for unbalanced faults, in order to minimize inaccuracies caused by differences between pre-fault and fault quantities on the estimation of the source impedance. The accuracy will not be affected if the fault current at a DFR is not in phase with the current at the fault point, but the fault type must be considered so that the adequate voltages and currents can be applied. In addition, the non-homogeneity of the feeder sections has to be taken into account, as well as the accuracy of determining the pre-fault condition.

The use of a two-port network section representation relies on fundamental-frequency voltages and currents measured at a line end before and during the fault. The determination of the faulted section requires information about line parameters, fault type and phasors of the sequence voltages and currents. First, the equivalent radial system is calculated and the effects of the loads are considered by compensating for their currents through static models. Next, the voltages and currents at the fault and remote end are calculated and the fault location is estimated from the voltage-current ratios at the fault, considering the resistive nature of the fault impedance. This procedure can provide multiple solutions in case the line has laterals. Thus, information from the fault indicators is applied so as to obtain a single estimation for the fault point.

The configuration of distribution networks, usually non-homogeneous with branches and loads along the lines, is a concern for impedance-based fault location algorithms (SAHA; IZYKOWSKI; ROSOLOWSKI, 2010; IEEE-C37.114-WG, 2015). The feeders may be multi-ended and/or contain loops that create problems for one-end fault location, as in general there is no indication on a single fault position. Additionally, compensation for loads is complicated, since they are changeable and often located between the fault point and the busbar.

The next subsections presents the main features and concerns related to fault location procedures applied to distribution networks without DG units and with them along the feeders.

2.5.3 Fault location in distribution networks without DG units

Many arrangements for fault location in radial distribution networks have been proposed in literature, as follows.

Fault location and diagnosis schemes based on measurements from DFRs and information from a distribution feeder database are presented in (ZHU; LUBKEMAN; GIRGIS, 1997; SENGER et al., 2005; MARUSIC; GRUHONJIC-FERHATBEGOVIC, 2006). To deal with the uncertainties inherent in the system modelling and the phasor estimation, (ZHU; LUBKEMAN; GIRGIS, 1997) estimates fault regions based on probabilistic modelling and analysis. As multiple solutions could be computed with measurements available only at the substation (since the distribution feeder is a radial network), these algorithms rank the possible fault

locations by integrating the available pieces of evidence in order to identify the actual point of fault.

In order to discriminate the real fault from equivalent faults in fault location methods using one-terminal measurements and the concept of superimposed voltages and currents, (FENGLING et al., 1998) evaluates the changes of contact resistance in function of the phase measuring-errors of voltage to current through theoretical analysis.

(MORA-FLOREZ; MORALES-ESPANA; PEREZ-LONDONO, 2009) presents a learning-based strategy to locate the faulted zone in radial distribution systems that uses fundamental-frequency voltages and currents measured at the substation, support vector machines and information about the nearest neighbours to reduce the multiple estimation of the fault location, considering all fault types, different short-circuit levels, variation of the fault resistance and the system load. Analogously, (SPERANDIO et al., 2011) proposes a combined treatment of information from the monitored protection devices and computer analysis.

(GHADERI; MOHAMMADPOUR; GINN, 2015) presents an active traveling-wave fault location technique, which transmits the Gaussian chirp along the line and applies the cross time-frequency reflectometry to find the point of fault. The proposed method functions in offline post-fault conditions and not only is capable of locating the exact fault distance away from the relay location, but also finds the exact line section in the radial configuration.

2.5.4 Fault location in distribution networks with DG units

Many approaches have been proposed in literature to tackle fault location in power distribution networks with the presence of DG, as follows.

Algorithms with use of voltage and current measurements at the DFRs and based upon the bus impedance matrix, through which the voltage and current quantities can be expressed as a function of the fault location and fault resistance, are presented in (BRAHMA, 2011; ALWASH; RAMACHANDARAMURTHY; MITHULANANTHAN, 2015). (BRAHMA, 2011) presents a general method to locate faults in multi-power, unbalanced distribution systems with significant and arbitrary penetration of DG, where conventional protective devices may not coordinate, and is able to adapt to changes in the topology of the system. The scheme proposed in (ALWASH; RAMACHANDARAMURTHY; MITHULANANTHAN, 2015) identifies the possible fault locations using an alternative formulation of the impedance-based method that overcomes the requirement of fault-type identification by using only one fault-location equation. The proposed scheme is applicable for all DG types without the need for their individual parameters, considering balanced and unbalanced laterals, the capacitive effect of distribution line and all shunt fault types.

The fault location schemes described in (JANSSEN; SEZI; MAUN, 2011; MAJIDI; ARABALI; ETEZADI-AMOLI, 2015) transfers voltage and current from distributed DFRs through the faulted line and calculates the fault distance using a single- or two-end fault

location method. Statistical errors on phasors and networks parameters are considered to obtain an optimal estimation of the fault location in (JANSSEN; SEZI; MAUN, 2011), while (MAJIDI; ARABALI; ETEZADI-AMOLI, 2015) simulates a 13.8 [kV] power distribution network with and without measurement noises and presents a satisfactorily performance for various faults with different resistances.

Extended formulations for general use in distribution systems have been proposed (SALIM et al., 2009; NUNES; BRETAS, 2010), based on calculation of the apparent impedance and fundamental quantities, considering particularities of the distribution systems, such as load-profile variation with local measurements and the presence of distributed generation.

In turn, (GUO-FANG; YU-PING, 2008) proposes an algorithm for urban distribution systems with DGs that relies on information about the differential current ratio, which is used to describe the features of the faulted line segment.

An algorithm based on fault currents that uses fault passage indicators and searches the tree structure of the distribution network with DG to determine the fault channel and identify the point of fault is presented in (WU, 2010). In addition, (CONTRERAS; RAMOS, 2014) explores the design of a versatile and adaptative fault location algorithm for distribution systems with DG that relies on the shortest path optimization problem, applying Dijkstra's Algorithm, to identify nodes with high correlation with faults. Alternatively, (ZHIHAI et al., 2014) proposes a fault location method that uses the signals provided by fault indicators combined with the distribution power grid state at the fault occurrence time and a unified network topology model suitable for different power distribution lines with easy adaptability.

The optimal placement of Phasor Measurement Unit (PMU)s is investigated in (RAJEEV; ANGEL; KHAN, 2015), whereas the optimum number and location of automatic sectionalizing switching devices is analysed in (CELLI; PILO, 1999). Both procedures are valid for both radial and meshed distribution systems. In addition, (HE et al., 2014) presents a fault location method that uses current/voltage sensors sparsely installed in the network and depends on the available sensor locations relative to the fault and the lateral conditions to search all possible paths and calculate the fault distance and fault resistance by reducing the circuit to an equivalent.

Alternatively, (THUKARAM; KHINCHA; VIJAYNARASIMHA, 2005) presents an artificial neural network and support vector machine approach for fault location in radial distribution systems, using measurements available at the substation, circuit breaker and relay statuses. The faults are classified according to the reactances of their path using a combination of support vector classifiers and feedforward neural networks.

* * *

Review of modelling distributed generation and load technologies

The modelling of DG and load technologies are reviewed in this chapter, which introduces the power conditioning units used together with distinct technologies (Section 3.1) and presents the fault behaviour of wind turbines (Section 3.2), photovoltaic cells (Section 3.3), fuel cells (Section 3.4), gas micro-turbines (Section 3.5) and loads (Section 3.6). The analytical models studied in this chapter are not applied to the problem of fault location in this work, since they do not interfere with the proposed fault location algorithms. Nonetheless, the impact of errors in the modelling of DG and load technologies on the accuracy of the fault location algorithms is discussed later in Chapter 5.

3.1 Power Conditioning Units

This section presents the models applied for the AC-DC rectifiers, DC-DC converters and DC-AC inverters required to connect some of the DG and load technologies to the grid. Detailed models for power converters together with the control signals reduce considerably the simulation speed; alternatively, average models are preferred to maintain the desirable accuracy. This work takes the advantages of average models on board during the validation studies.

3.1.1 AC-DC rectifiers

AC-DC rectifiers may be uncontrollable or controllable devices (WANG, 2006). The former is usually referred to diode bridge rectifiers. A diagram of a three-phase full-bridge rectifier is shown in Figure 3. If L_s is so small that can be neglected, the average value of the output DC voltage $\dot{V}_{dc}$ can be calculated as:

$$V_{dc} = \frac{3}{\pi} \cdot \sqrt{2} \cdot \dot{V}_{L-L} \quad (1)$$

Figure 3 – Three-phase full diode bridge rectifier

Source: (WANG, 2006, p. 194) (adapted)

Figure 4 – Three-phase 12-diode bridge rectifier with transformers

Source: (WANG, 2006, p. 195) (adapted)

Where $\dot{V}_{L-L}$ is the AC line-to-line Root Mean Square (RMS) voltage.

Alternatively, a Y-Y and a Y- Δ connection transformer may be applied to form a 12-diode bridge rectifier (WANG, 2006), as illustrated in Figure 4. The phase shift between the two transformer outputs reduces the transition period from 60 degrees to 30 degrees in a period, so the average value of the output DC voltage is obtained through:

$$V_{dc} = \frac{6}{\pi} \cdot \sqrt{2} \cdot \dot{V}_{L-L} \quad (2)$$

In turn, controllable devices can be firing angle controlled thyristor rectifiers or Pulse Width Modulation (PWM) rectifiers. The former replaces the diodes with thyristors, so that the output DC voltage can be regulated by controlling the firing angles of thyristors. The firing angle α is the angular delay between the time when a thyristor is forward biased and the time when a positive current pulse is applied to its gate. For instance, the output DC voltage of a six-pulse thyristor rectifier can be calculated according to:

$$V_{dc} = \frac{3}{\pi} \cdot \sqrt{2} \cdot \dot{V}_{L-L} \cdot \cos(\alpha) \quad (3)$$

3.1.2 DC-DC converters

DC-DC converters are combined to DG units in order to change the output voltage of the generator, when required. Among them, the boost converters and buck converters are typically applied (WANG, 2006). The average value of the output voltage is given by (4) for a boost converter and (5) for a buck converter.

$$\dot{V}_{dd,out} = \frac{\dot{V}_{dd,in}}{1-d} \quad (4)$$

$$\dot{V}_{dd,out} = d \cdot \dot{V}_{dd,in} \quad (5)$$

Where d is the duty ratio of the switching pulse, $0 \leq d < 1$.

3.1.3 DC-AC inverters

A three-phase six-switch DC-AC PWM voltage source inverter is used to convert the power from DC to AC, connected to the grid through LC filters and coupling inductors. The inverter switching functions are given by (6), where $i = 1, 2, 3$ and $k = a, b, c$, while the output phase-to-neutral voltages are calculated through (7):

$$d_i^* = \begin{cases} 1, & S_k^+ ON \\ -1, & S_k^- OFF \end{cases} \quad (6)$$

$$\begin{cases} v_{an} = \frac{d_1^*}{2} \cdot \dot{V}_{dc} \\ v_{bn} = \frac{d_2^*}{2} \cdot \dot{V}_{dc} \\ v_{cn} = \frac{d_3^*}{2} \cdot \dot{V}_{dc} \end{cases} \quad (7)$$

The phase-to-phase output voltages can be found by adding the neutral voltage $v_{nn'}$ to (7):

$$\begin{cases} v_{an'} = v_{an} + v_{nn'} \\ v_{bn'} = v_{bn} + v_{nn'} \\ v_{cn'} = v_{cn} + v_{nn'} \end{cases} \quad (8)$$

3.1.4 Impact of power-converter-interfaced DGs on short-circuit levels

Typical short-circuit levels of power converters connected to the terminals of DG units are presented in table 3, in agreement with the findings from (BARKER; MELLO, 2000). For inverters, the fault contribution depends on the maximum current level and duration for which the current limiter is set to respond; fault contribution may last for less than one cycle in some cases and much longer in other cases. For synchronous generators, the fault contribution depends on the pre-fault voltage, sub-transient and transient reactances

Table 3 – Typical fault levels of power-converter-interfaced DGs

Generator type	Fault current into short-circuited terminals as a percentage of the rated output current
Inverter-connected	100-400% (duration depends on controller settings and current may be less than 100% for some inverters)
Separately excited SG	500-1000% for the first few cycles and decaying to 200-400%
IG or self-excited SG	500-1000% for the first few cycles and decaying to a negligible amount within 10 cycles

of the machine and excitation characteristics. For induction generators, the fault contribution lasts as long as they remain excited by residual voltages on the feeder; for most of them, significant currents only last a few cycles and may be determined by dividing the pre-fault voltage by the transient reactance of the machine; in spite of the short time interval, it is long enough to impact fuse-breaker coordination in some cases.

3.2 Fault Behaviour of Wind Turbines

3.2.1 Wind turbine concepts

Wind turbines can be distinguished in accordance with their operation and control principles (AKHMATOV, 2003; LINDGREN; SVENSSON; GERTMAR, 2012), as follows:

- fixed-speed or variable-speed wind turbines;
- fixed-pitch or variable-pitch wind turbines;
- connected to AC grids directly or through partial- or full-scale power converters.

In spite of the differences above, common features characterize the existing concepts and their interaction with the power grid, which allows the systematization needed to produce generic but sufficiently realistic models of the wind turbines. Based on these similarities, four Wind Turbine Generator (WTG) technologies have been defined (AKHMATOV, 2003; LINDGREN; SVENSSON; GERTMAR, 2012; FOX, 2007; VITTAL; AYYANAR, 2012; SULLA, 2012):

- *type 1*: fixed-speed wind turbines with Squirrel-Cage Induction Generator (SCIG) (with or without blade-angle control);
- *type 2*: wind turbines equipped with Wound Rotor Induction Generator (WRIG) and limited speed variation through an external variable resistor;
- *type 3*: variable-speed, pitch-controlled wind turbines equipped with Doubly-Fed Induction Generator (DFIG) (connected to the grid at the stator terminals and at the rotor windings via partial-scale power converter);

- *type 4*: variable-speed, pitch-controlled wind turbines equipped with Permanent Magnet Synchronous Generator (PMSG) or Induction Generator (IG) (connected to the grid via full-scale power converter).

There is very little standardization in models of wind turbines and wind farms. Many companies and research groups develop their own versions to analyse wind turbines and power plants; consequently, different models are implemented, different time scales are considered and different results are obtained (LINDGREN; SVENSSON; GERTMAR, 2012; SULLA, 2012).

Nonetheless, for any given type, certain key elements that influence the performance of the generator have to be included in the mathematical model, so as to capture its dynamic behaviour and its impact on the system; for instance, aerodynamic characteristics, mechanical controls (pitch and active stall control of the mechanical power delivered to the shaft), shaft dynamics, generator characteristics, converter controls, protection settings and transducers to measure critical variables (VITTAL; AYYANAR, 2012). Although the parameters for the aerodynamics, turbine controls and protection systems may differ for the various types and manufacturers, the model structure is similar and has to take the following features on board (LINDGREN; SVENSSON; GERTMAR, 2012):

- The rotor is a common part in all concepts of wind turbines, but the generator is different. Its representation is more important in type 1 and type 2; in contrast, its dynamic is almost isolated from the grid in type 4 (LINDGREN; SVENSSON; GERTMAR, 2012).
- The shaft system representation is similar to SCIGs, WRIGs and DFIGs (i.e. two-mass shaft system with one mass representing the rotor and turbine blades, the another representing the generator and a gearbox in-between), but not to direct-driven PMSGs.
- Modelling the expected wind speed and variation requires meteorological data of the weather patterns in a given region. Alternatively, measurement series can be used if available.
- The aerodynamics often assumes a stateless static model in which the aerodynamic power is computed in function of the wind speed, swept area, air density and a wind energy extraction coefficient (LINDGREN; SVENSSON; GERTMAR, 2012). Sometimes a constant power or a constant torque model may be assumed.
- The wake effect created by each wind turbine with lower speed behind it depends on the extracted power (GONZÁLEZ-LONGATT; WALL; TERZIJA, 2012).
- Tower oscillations are usually neglected, since their magnitudes are relatively small and the potential energy accumulated in the tower is smaller than the potential energy accumulated in the shaft (AKHMATOV, 2003); hence, possible influences on the generator speed deviation are assumed insignificant.

Figure 5 – Schematic of a fixed-speed wind turbine

Source: (FOX, 2007, p. 71) (adapted)

Different wind turbine concepts deliver different fault currents into the grid during short-circuits (SULLA, 2012; LINDGREN; SVENSSON; GERTMAR, 2012; VITTAL; AYYANAR, 2012). The next topics describe the characteristics of each concept mentioned above, focusing on the fault behaviour.

3.2.1.1 Type 1

Fixed-speed wind turbines comprise an aerodynamic rotor that drives a low-speed shaft, a gearbox, a high-speed shaft and an induction generator. The induction generator is directly connected to the grid and transmits power to a switchboard and a local transformer (FOX, 2007), as illustrated in Figure 5.

The fixed speed is determined by the gearbox and the number of pole pairs of the induction generator. Switched capacitors are used to improve the power factor and an anti-parallel thyristor soft-starter is used to build up the magnetic flux and minimize current transients when the generator is powered up. A pitch-regulated rotor controls the generator speed during the starting period, but the fixed-pitch, stall-regulated wind turbine runs driven by the wind. Due to the steep torque versus slip characteristic of the induction generator, it operates at about constant speed set by the grid frequency with a slip around 2% at rated power (AKHMATOV, 2003).

A torque pulsation is developed at the blade passing frequency due to the rotor aerodynamics, tower shadow and wind shear effects. As such oscillations are usually close to the natural frequency of the synchronous generator, nowadays the fixed-speed wind turbines are equipped with induction machines; some early wind turbines with synchronous

generators include mechanical dampers in the drive train, though.

The theoretical behaviour of the induction machine is well-known in literature (KUNDUR; BALU; LAUBY, 1994; SULLA, 2012). The induction machine consists of the stator and rotor windings. When balanced three-phase currents flow through the stator winding, a magnetic field rotating at synchronous speed n_s is produced and the relative movement between stator and rotor fields induces voltages at the slip frequency f_r in the rotor windings. The electromotive force (EMF) magnitude is proportional to the slip. If the rotor is stationary, then it can be regarded as a transformer. The rotor voltage is proportional to the slip, while the rotor phase current for a given slip is determined by the rotor phase voltage applied across the rotor impedance, which consists of a resistance R_r and an inductance L_r :

$$\dot{I}_r = \frac{s \cdot \dot{V}_r}{R_r + j \cdot s \cdot X_r} \quad (9)$$

The grid determines the voltage when the wind turbine generator and capacitor are connected to the power network. If a fault occurs, the turbine accelerates and draws a large amount of reactive power from the grid. The unbalance between mechanical and electric power may lead the generator to accelerate beyond the critical speed and become unstable. Such behaviour may request disconnection and use of an emergency brake and poses a challenge to voltage recovery, as the amount of reactive power drawn after the fault clearance may result in prolonged voltage sags in the grid (SULLA, 2012). Therefore, generator over-speeding and voltage recovery are the main issues for Grid-Fault Ride-Through (GFRT) of fixed-speed wind turbines. This can be prevented by limiting the capacitor bank sizes and/or adjusting the protection to trip them quickly.

Short-circuits in the grid are usually detected by monitoring fault currents from large synchronous generators. Induction generators cannot be considered a reliable source of fault currents because the time interval (only during the sub-transient period under three-phase short-circuits) is too short for reliable operation of the over-current relays. Thus, it is a common practice to rely on the short-circuit currents from the network in order to operate protection to isolate the wind farm and trip the wind turbines (FOX, 2007); then, the wind turbine is an open circuit. Nonetheless, the magnitude of the machine current is crucial to evaluate the response of the wind turbine protection system.

The usual description of the induction machine is the fifth-order model, whose equations in the per unit (p.u.) system can be written as follows (KUNDUR; BALU; LAUBY, 1994; AKHMATOV, 2003; PETRU; THIRINGER, 2002; MARTINS et al., 2007; MORREN; HAAN,

2007):

$$\begin{cases} \dot{\psi}_{ds} = L_s \cdot \dot{I}_{ds} + L_m \cdot \dot{I}_{dr} \\ \dot{\psi}_{qs} = L_s \cdot \dot{I}_{qs} + L_m \cdot \dot{I}_{qr} \\ \dot{V}_{ds} = R_s \cdot \dot{I}_{ds} - \omega_s \cdot \dot{\psi}_{qs} + \frac{d\dot{\psi}_{ds}}{dt} \\ \dot{V}_{qs} = R_s \cdot \dot{I}_{qs} + \omega_s \cdot \dot{\psi}_{ds} + \frac{d\dot{\psi}_{qs}}{dt} \\ \dot{\psi}_{dr} = L_r \cdot \dot{I}_{dr} + L_m \cdot \dot{I}_{ds} \\ \dot{\psi}_{qr} = L_r \cdot \dot{I}_{qr} + L_m \cdot \dot{I}_{qs} \\ \dot{V}_{dr} = R_r \cdot \dot{I}_{dr} - s \cdot \omega_s \cdot \dot{\psi}_{qr} + \frac{d\dot{\psi}_{dr}}{dt} \\ \dot{V}_{qr} = R_r \cdot \dot{I}_{qr} + s \cdot \omega_s \cdot \dot{\psi}_{dr} + \frac{d\dot{\psi}_{qr}}{dt} \\ T_E = \dot{\psi}_{ds} \cdot \dot{I}_{qs} - \dot{\psi}_{qs} \cdot \dot{I}_{ds} \end{cases} \quad (10)$$

Where R_s , L_s , R_r , L_r and L_m are the stator resistance and inductance, rotor resistance and inductance and mutual inductance, respectively. $\dot{V}_s = (V_{ds}, V_{qs})$ is the terminal voltage, $\dot{I}_s = (I_{ds}, I_{qs})$ is the stator current, $\psi_s = (\psi_{ds}, \psi_{qs})$ is the stator flux. The rotor voltage $\dot{V}_r = (V_{dr}, V_{qr})$ is zero because the rotor circuit is shorted. $\dot{I}_r = (I_{dr}, I_{qr})$ is the rotor current, $\psi_r = (\psi_{dr}, \psi_{qr})$ is the rotor flux in the stator quantities, whilst T_E is the electrical torque. This is the fifth-order model with addition of the movement equation of the generator rotor and representation of the fundamental-frequency transients of the stator current, given by the derivatives of the stator flux.

The currents can be written in function of the fluxes, as in (11):

$$\begin{cases} \dot{I}_s = \frac{1}{L_s - \frac{L_m^2}{L_r}} \cdot \dot{\psi}_s - \frac{L_m}{L_r} \cdot \frac{1}{L_s - \frac{L_m^2}{L_r}} \cdot \dot{\psi}_r \\ \dot{I}_r = -\frac{L_m}{L_s} \cdot \frac{1}{L_r - \frac{L_m^2}{L_s}} \cdot \dot{\psi}_s + \frac{1}{L_r - \frac{L_m^2}{L_s}} \cdot \dot{\psi}_r \end{cases} \quad (11)$$

Alternatively, the short-circuit current can be calculated through the superposition method, as in (SULLA, 2012), comprising a component for the post-fault steady state voltage at the generator terminals and for the natural stator and rotor fluxes. The natural stator and rotor fluxes arise after the fault occurrence to assure the flux continuity before and after the fault inception, then decay exponentially with time constants that depend on the generator parameters. Once known the post-fault transient fluxes, the short-circuit current can be calculated, comprising an AC and a DC component that decay respectively with the rotor and the stator transient time constants and are limited by the transient reactance, usually varying between 5 and 9 times the generator rated current (SULLA, 2012).

The third-order model is derived from the fifth-order one (10) by omitting the fundamental-frequency transients in the stator:

$$\frac{d\psi_s}{dt} = \left(\frac{d\psi_{ds}}{dt}, \frac{d\psi_{qs}}{dt} \right) = (0, 0) \quad (12)$$

Figure 6 – Induction generator third-order model neglecting stator transients

Source: (MARTINS et al., 2007, p. 2) (adapted)

Figure 7 – Equivalent circuit of the induction generator ninth-order model, reactive power compensating capacitor and grid

Source: (PETRU; THIRINGER, 2002, p. 4) (adapted)

It results in a simplified model of the induction machine connected to the grid as a voltage source $\dot{V}_d' + j \cdot \dot{V}_q'$ (referred to the stator) behind a transient impedance $X_d + j \cdot X_q$ (MARTINS et al., 2007), according to (13) and Figure 6.

$$\begin{cases} \frac{d\dot{V}_d'}{dt} = -\frac{1}{\tau} \cdot [\dot{V}_d' - (X_s - X_s') \cdot \dot{I}_{qs}] + j \cdot s \cdot \omega_s \cdot \dot{V}_q' \\ \frac{d\dot{V}_q'}{dt} = -\frac{1}{\tau} \cdot [\dot{V}_q' - (X_s - X_s') \cdot \dot{I}_{ds}] + j \cdot s \cdot \omega_s \cdot \dot{V}_d' \\ T_E = \dot{V}_d' \cdot \dot{I}_{ds} + \dot{V}_q' \cdot \dot{I}_{qs} \end{cases} \quad (13)$$

Where $\tau = \frac{X_r}{R_r}$ and $X_s' = X_s - \frac{X_m^2}{X_r}$. Likewise to the third-order model, the first-order one can be obtained by neglecting the transients in the rotor flux ψ_r .

When the reactive power compensation capacitor is involved in the study, the supply grid also have to be included; as a consequence, the model complexity is increased to the ninth order. The equations in the p.u. system can be written as (14) (PETRU; THIRINGER, 2002) and the equivalent circuit is illustrated in Figure 7:

$$\begin{cases} \dot{V}_g = (R_g + j \cdot \omega_s \cdot L_g) \cdot \dot{I}_g + L_g \cdot \frac{d\dot{I}_g}{dt} + \dot{V}_s \\ \dot{V}_s = (R_s + j \cdot \omega_s \cdot L_s) \cdot \dot{I}_s + j \cdot \omega_s \cdot L_m \cdot \dot{I}_r + L_s \cdot \frac{d\dot{I}_s}{dt} + L_r \cdot \frac{d\dot{I}_r}{dt} \\ 0 = (R_r + j \cdot \omega_r \cdot L_r) \cdot \dot{I}_r + j \cdot \omega_r \cdot L_m \cdot \dot{I}_s + L_m \cdot \frac{d\dot{I}_s}{dt} + L_r \cdot \frac{d\dot{I}_r}{dt} \\ \dot{I}_s - \dot{I}_r = j \cdot \omega_s \cdot C \cdot \dot{V}_s + C \cdot \frac{d\dot{V}_s}{dt} \\ T_E = p \cdot L_m \cdot \text{Imag} \{ \dot{I}_s \cdot \dot{I}_r^* \} \end{cases} \quad (14)$$

Models of lower order than the fifth are usually applied to power system studies, but they may lead to inaccuracies (MARTINS et al., 2007; PETRU; THIRINGER, 2002). For instance, it is shown in (PETRU; THIRINGER, 2002) that the response to shaft torque disturbances is similar above the third order. However, the braking torque versus rotor

speed curve of the induction generator are discrepant: when the fundamental-frequency transients in the stator are neglected in third-order models, their speed increases immediately after the fault occurrence, whereas it decreases in fifth-order models in such a way that a notch is produced in the speed curve (AKHMATOV, 2003). Moreover, the response to voltage dips reveals more differences between the models: the first-order model does not provide any acceptable results; the fifth and ninth-order ones predict surge currents during the first line periods and the latter also predicts a high-frequency oscillation due to the capacitor (PETRU; THIRINGER, 2002). To achieve high accuracy, the evaluation of major grid disturbances requests the representation of the skin effect and saturation of leakage inductances; therefore, models of at least the fifth order are recommended (PETRU; THIRINGER, 2002).

The short-circuit behaviour of fixed-speed wind turbines is determined by the dynamics of the generator (SULLA, 2012; PETRU; THIRINGER, 2002; AKHMATOV, 2003; THIRINGER; PETERSSON; PETRU, 2003). High short-circuit currents are delivered during the fault, decaying with the fluxes in the generator stator and rotor. A method for calculating the short-circuit current of a SCIG is presented in (KANELLOS; KABOURIS, 2009; MORREN; HAAN, 2007; SWEETING, 2011), based upon the assumptions of (SHORT-CIRCUIT..., 2001), and introduced below.

Before the fault, the rotor current $\dot{I}_r$ is zero. The stator current $\dot{I}_s$ is given by (15) and the stator and rotor fluxes can be obtained by (16):

$$\dot{I}_s \cdot e^{j\omega_s t} = \frac{\dot{V}_s \cdot e^{j\omega_s t}}{j \cdot X_s} \quad (15)$$

$$\begin{cases} \dot{\psi}_s \cdot e^{j\omega_s t} = L_s \cdot \dot{I}_s \cdot e^{j\omega_s t} \\ \dot{\psi}_r \cdot e^{j\omega_s t} = L_m \cdot \dot{I}_s \cdot e^{j\omega_s t} \end{cases} \quad (16)$$

When the short-circuit occurs, the rotor and stator fluxes ψ_r and ψ_s have the same angle and approximately the same magnitude. The stator flux is fixed, whilst the rotor flux moves with the rotor (position and angle in movement). After half a period, as they present opposite directions, the machine currents reach their maximum value, which can be very high, but limited by the leakage inductances.

In the frequency domain, it is well-known in literature (KUNDUR; BALU; LAUBY, 1994; CHAPMAN, 2005; KANELLOS; KABOURIS, 2009; SWEETING, 2011; SHORT-CIRCUIT..., 2001) that the induction generator can be modelled as a transient voltage source $\dot{E}'$ behind the stator transient reactance X'_s under the assumption of constant rotor flux during a transient period, according to (17):

$$\begin{cases} \dot{E}'_d = -\omega_s \cdot \frac{X_m}{X_r} \psi_{rq} \\ \dot{E}'_q = \omega_s \cdot \frac{X_m}{X_r} \psi_{rd} \\ X'_s = \omega_s \cdot \left(L_{ls} + \frac{L_{ls} \cdot L_m}{L_{ls} + L_m} \right) \end{cases} \quad (17)$$

The stator short-circuit current can be obtained by substituting (16) at $t = 0$ (reference) in $\dot{I}_s$ from (11). Then, the stator short-circuit current can be obtained according to (18):

$$\dot{I}_s = \frac{\sqrt{2} \cdot \dot{V}_s}{j \cdot X'_s} \cdot \left[e^{\frac{-t}{T'_s}} - (1 - \sigma) \cdot e^{j \cdot \omega_s \cdot t} \cdot e^{\frac{-t}{T'_r}} \right] \quad (18)$$

Where

$$\begin{cases} \sigma = 1 - \frac{L_m^2}{(L_{ls} + L_m)(L_{lr} + L_m)} \\ T'_s = \frac{L'_s}{R_s} \\ T'_r = \frac{L'_r}{R_r} \\ L'_s = L_{ls} + \frac{L_{lr} \cdot L_m}{L_{lr} + L_m} \\ L'_r = L_{lr} + \frac{L_{ls} \cdot L_m}{L_{ls} + L_m} \end{cases} \quad (19)$$

The parameters L_m , L_{ls} and L_{lr} denote the mutual, stator and rotor leakage inductances, respectively. The stator short-circuit current comprises a DC component damped with the stator transient time constant T'_s and an AC component damped with the rotor transient time constant T'_r . Although the current vector does not reach the maximum value exactly at $t = \frac{T}{2}$, the value after half a period provides a good approximation of the maximum current (KANELLOS; KABOURIS, 2009; MORREN; HAAN, 2007), which can be obtained by substituting $t = \frac{T}{2}$ in (18). If the analysis aims to calculate the maximum RMS value of the AC current component, then the stator voltage before the fault occurrence and the stator transient reactance shall be used (KANELLOS; KABOURIS, 2009).

When the voltage $\dot{V}_s$ has a phase displacement of $\alpha + \frac{\pi}{2}$ with respect to the stator at the instant of occurrence of the fault, it shall be replaced with $j \cdot \sqrt{2} \cdot \dot{V}_s \cdot e^{j \cdot \alpha}$. Then, the short-circuit current in a phase is given by the projection of the vector $\dot{I}_s$ (MORREN; HAAN, 2007):

$$\dot{I}_s = \frac{\sqrt{2} \cdot \dot{V}_s}{X'_s} \cdot \left[e^{-\frac{t}{T'_s}} \cdot \cos(\alpha) - (1 - \sigma) \cdot e^{j \cdot \omega_s \cdot t} \cdot e^{-\frac{t}{T'_r}} \cdot \cos(\omega_s \cdot t + \alpha) \right] \quad (20)$$

3.2.1.2 Type 2

These wind turbines are equipped with doubly-outage induction generators and a variable external resistance connected in series with the rotor winding and controlled by the rotor converter, so as to achieve a limited range of speed variation. A schematic is shown in Figure 8. The rotor resistance, mounted on the stator shaft, can be controlled with optical signals (AKHMATOV, 2003; SULLA, 2012; THIRINGER; PETERSSON; PETRU, 2003) to avoid the request for slip rings. The external resistor is pulsed through a DC chopper circuit with variable duty cycle, which results in a variable resistance without moving parts. This arrangement produces a limited variation in the generator speed (around 10%) and a constant power output, albeit the changes in the wind speed, and operation at variable slip above the synchronous speed (AKHMATOV, 2003).

Figure 8 – Schematic of a wind turbine with variable external resistance

Source: author

The total value of the dynamic rotor resistance is the sum of the stationary rotor winding resistance and the dynamic external rotor resistance (SULLA, 2012). In normal operation, a low value of the rotor resistance minimizes power losses. In turn, when a grid fault occurs, the rotor resistance increases, consequently the maximum torque of the torque versus slip characteristic is shifted towards higher slip and higher generator speed (SULLA, 2012); when the voltage is re-established, the rotor resistance is reduced again.

The short-circuit behaviour of a limited-variable speed wind turbine is conditioned by the dynamics of the generator (SULLA, 2012; MARTINEZ et al., 2011; AKHMATOV, 2003), similarly to the type 1 wind turbines. As a result, the models in the frequency domain are the same for types 1 and 2 wind turbines, except for the external resistance added to the rotor resistance in the latter, which causes a rapid decay of the AC component of the stator current (SULLA, 2012; MARTINEZ et al., 2011).

An important constraint of fixed-speed WTGs is that they can over-speed and lose stability in case of voltage depression caused by short-circuits. Besides, the low terminal voltage results in over-speed of the generator and a high drawn of reactive power that decreases the grid voltage further and leads to collapse. An external capacitor bank must be provided for reactive support, since the reactive power consumption cannot be controlled independently of the active power.

Figure 9 – Schematic of a DFIG wind turbine

Source: (FOX, 2007, p. 74) (adapted)

3.2.1.3 Type 3

The DFIG comprises a wound rotor induction generator with the stator directly connected to the grid and the rotor connected to the grid through slip rings and a back-to-back partial-load converter, which takes current into or out of the rotor windings. The rotor converter is controlled by power electronics with Insulated-gate bipolar transistor (IGBT)-switches so as to decouple the network electrical frequency from the desired rotational speed. Variable-speed operation is achieved by controlling the rotor voltage at the slip frequency.

The voltage in the stator is applied from the grid and the voltage in the rotor is induced by the converter. The rotor-side converter (RSC) is coupled through a capacitor to the grid-side converter (GSC), which is connected to the grid through a transformer.

The DFIG supplies electric power to the grid at super-synchronous speed (from the stator and rotor) with high mechanical input power and absorbs power from the grid at sub-synchronous speed (from the rotor through the converters) with low mechanical input power. Therefore, the power flow through the rotor can be bidirectional. At synchronous speed, the net power exchange between rotor and grid is irrelevant, as the DC-link capacitor voltage is controlled by the grid-side converter. The total power delivered to the grid P_g is the sum of the stator power P_s and the rotor power P_r , as presented in (FOX, 2007) and illustrated in Figure 9.

The DFIG is controlled by the converters for frequency/reactive power, voltage/reactive

power and pitch angle/mechanical power (VITTAL; AYYANAR, 2012). It is possible to vary the injected power by acting on the back-to-back converter, particularly by controlling the current through the RSC. Hence, the current-controlled RSC can be seen as a controlled current source in parallel to the DFIG magnetization reactance. In addition, if a Thevenin equivalent impedance is substituted in parallel to these two elements, the DFIG model will match the synchronous generator and the power control will be simple.

A common practice uses the RSC to provide torque and speed control together with voltage or power factor control for the overall system, and the GSC to maintain the DC-link voltage level and provide a path for the rotor power to flow to and from the AC system. As the reactive power injection through the rotor circuit is inversely proportional to the slip, the RSC is preferred to the GSC on voltage-control schemes. Further explanations are given in (FOX, 2007).

The power flow simulation provides the operating condition to set up the time-domain transient stability study of the machine in consideration. The active and reactive power output and the terminal voltage at the WTG bus are used to initialize the model, whereas the outputs provide the current injected by the generator into the network. The electrical power output of the WTG is used to calculate the reference rotor speed according to data provided by the manufacturer (VITTAL; AYYANAR, 2012; AKHMATOV, 2003).

The DFIG can be excited from the rotor circuit by the converter, not necessarily from the power grid (AKHMATOV, 2003). If connected to a strong power system at around rated voltage, the generator will be excited by the RSC, produce active power and not exchange reactive power with the grid; in turn, if connected to a weak power system with fluctuating voltages, the generator will produce active power and also be required to produce or absorb reactive power to control the voltage level at the connection point.

In comparison to conventional asynchronous generators, DFIGs may be advantageous due to the reactive power and voltage control and the decoupling of active and reactive power control with independent control of torque and rotor excitation current (AKHMATOV, 2003). It can be achieved by adjusting the external voltage applied to the rotor so as to control the stator current (SULLA, 2012) and by representing the generator in a direct-quadrature (d-q) axis reference frame rotating at synchronous speed (FOX, 2007). Reactive power support to the grid can be provided by the stator by changing the d-axis rotor excitation current, as well as power factor and torque regulation.

The partial-load converter is usually rated to handle the rotor power and the generator excitation (magnetization from the rotor circuit). Its power capacity is smaller than the full-load converter; on the one hand, it reduces the size and cost of the converter, as it is sized to approximately 30% of the rated power and the power flowing through the rotor is given by the product of the stator power and the slip (TEODORESCU; LISERRE; RODRÍGUEZ, 2010); on the other hand, the power electronics are the most sensitive parts of this wind turbine concept and transient grid disturbances may lead to converter blocking

and disconnection of the wind turbine. Thus, the current flowing through both the RSC and GSC must be limited.

The voltage drop at the WTG terminals during short-circuits results in large oscillatory currents in the stator windings that also flow through the rotor circuit and the power converter due to the magnetic coupling between stator and rotor. Theoretically, the RSC could be oversized to handle the short-circuit current, but it would increase the costs and the main advantage of this turbine concept would disappear. Therefore, the power converter system shall be equipped with a protective system to monitor the converter, generator and grid operation at the generator terminals and order the converter to block when one of the monitored parameters exceeds the relay settings so as to protect the system against electrical and thermal overload (MORREN; HAAN, 2007). Typical blocking times can be of a few milliseconds (AKHMATOV, 2003).

The RSC, GSC, DC-link and converter control also have to be represented. When only the RSC is considered, the transients in the rotor current are higher than when the GSC and the DC-link are also added to the model, because the DC-link capacitor stores energy and thereby interacts with the RSC, exchanging electrical energy during transient events and producing voltage fluctuations at the DC-link. It introduces delays between the RSC and GSC and smooths the active and reactive power profiles.

Therefore, the converter action could well decide the operation of this wind turbine concept during transient events in the grid. As the setting of the overload protection is not well above the rated current, accurate prediction of fault currents is important to obtain accurate results. Thus, modelling of the generator shall be accurate and detailed to represent the converter blocking sequences in short-term analyses. The response to small grid disturbances is mainly determined by the control algorithms, whereas the response to large grid disturbances is also dependent of the system configuration. In case of large grid faults, it may be necessary to short-circuit the rotor in order to protect the converter (THIRINGER; PETERSSON; PETRU, 2003; PETRU; THIRINGER, 2002; AKHMATOV, 2003). The stator disconnection through circuit breakers lasts a few cycles; meanwhile, the DFIG acts as a fixed-speed wind turbine and the induction machine goes from the pre-fault speed value to a nearly synchronous one and farther contributes to the fault current due to the active and reactive power exchange with the grid (THIRINGER; PETERSSON; PETRU, 2003).

For protecting the DFIG wind turbine, the rotor circuit may be short-circuited through a crowbar resistance simultaneously to the blocking of the RSC. Alternatively, a DC chopper may be used to maintain the DC-link capacitor voltage within an acceptable range. For both protection schemes, the current immediately after the fault is determined by the physical system and not by the control strategy in use; Thus, general conclusions on the delivered short-circuit current may be drawn (SULLA, 2012).

The DFIG contributes to the short-circuit power because the stator is directly connected to the grid; consequently, high currents are produced during grid faults (TEODORESCU;

LISERRE; RODRÍGUEZ, 2010; SULLA, 2012; MORREN; HAAN, 2007). The DFIG response can be divided in two stages (KANELLOS; KABOURIS, 2009), as follows:

- Sub-transient period: during the first 2-3 cycles, the DFIG operates as an SCIG;
- Activation of the protection system: when the crowbar protection system or another current limitation function of the RSC is activated, the transients of the rotor flux start decaying and the rotor current is limited.

The maximum short-circuit current of a DFIG can be calculated with good accuracy by using the transient reactance of the induction machine (KANELLOS; KABOURIS, 2009; SULLA, 2012; MORREN; HAAN, 2007). The initial value of the current can be determined under the assumption that stator and rotor resistances can be neglected. When the bypass resistor is connected to protect the converter in case of a fault, the current becomes:

$$\dot{I}_s \cdot e^{j\omega_s t} = \frac{\dot{V}_s \cdot e^{j\omega_s t}}{j \cdot X_s + R_{cb}} \quad (21)$$

And the transient time constant of the rotor becomes:

$$T'_r = \frac{L'_r}{R_r + R_{cb}} \quad (22)$$

The assumption that the stator and rotor fluxes are 180 degrees out of phase after half a cycle is approximately valid for an induction machine, since the slip is small and the stator and rotor are approximately in phase with each other when the fault occurs. Conversely, a DFIG can operate at much larger slip, typically between -0.3 and +0.3 (TEODORESCU; LISERRE; RODRÍGUEZ, 2010; SULLA, 2012; AKHMATOV, 2003), which implies that the fluxes are out of phase at the fault occurrence. When the DFIG is in over-synchronous mode, the rotor flux leads the stator one and it takes less than half a period for them to be 180 degrees out of phase. In turn, when the DFIG is in under-synchronous mode, the opposite happens and it takes more than half a period for the displacement of 180 degrees (KANELLOS; KABOURIS, 2009).

When the voltage at the stator terminals drops to zero, the stator and rotor fluxes rotate slowly, depending on their resistance. It can be neglected for an induction machine because of the small resistance, but it is no longer negligible for a DFIG with bypass resistor. This is another reason why the maximum current can be reached in less than half a period. Considering the differences between an induction machine and a DFIG, the maximum current can be written as in (23):

$$\dot{I}_s = \frac{\sqrt{2} \cdot \dot{V}_s}{\sqrt{X_s'^2 + R_{cb}^2}} \cdot \left[e^{-\frac{\Delta t}{T'_s}} - (1 - \sigma) \cdot e^{-\frac{\Delta t}{T'_r}} \right] \quad (23)$$

The time interval Δt after which the current reaches its first peak depends on the slip and the value of the bypass resistor.

Alternatively, a general method to calculate the short-circuit current of a DFIG, presented in (SULLA, 2012), deals with both symmetrical and unsymmetrical faults, voltage

dips at the WTG terminals and applies a linearised model of the induction machine, neglecting saturation of its reactances. As this effect can increase the short-circuit current, the accuracy of the proposed method is affected. Besides, the step-up transformer and MV line impedances also have to be added to the stator impedance, as they are not negligible.

With crowbar protection, the rotor windings of the DFIG are short-circuited by a set of resistors during a grid fault; then, the current flows through these resistors instead of the power converter. Consequently, the fault behaviour of the DFIG depends on whether or not the crowbar protection is activated.

During the activation period, the DFIG may be assumed as a SCIG with larger rotor resistance (typically up to 20 times the generator resistance) and higher slip, as the control of the current is lost. The high crowbar resistance leads the AC component of the short-circuit current to decay more rapidly in a DFIG than in a SCIG and after some periods it is predominantly a DC component. However, when the RSC is reconnected, it controls the stator current. Then, the DFIG behaves similarly to a full-load converter induction generator and may be treated as a constant current source. On the top of that, it is important to consider that the interval between the fault inception and the insertion of the crowbar resistance may adversely affect the accuracy of the proposed method.

The maximum short-circuit current of a DFIG with crowbar protection can be calculated through (23). This result is strongly dependent of the crowbar resistance, whose value shall be high enough to limit the short-circuit current and low enough to avoid high voltage in the rotor circuit (MORREN; HAAN, 2007). However, the crowbar alone may not be sufficient to achieve GFRT, as the DC-link voltage tends to increase due to the contribution of energy from the rotor and a chopper resistance may be required; in this case, the fault behaviour of the DFIG depends on the equivalent resistance formed by the DC-link capacitor and chopper resistance connected to the rotor through a diode bridge rectifier. The highest fault current occurs when the RSC is blocked. In turn, unsymmetrical faults usually produce high rotor voltages due to the negative sequence in the grid that may be well above the RSC control range. As they do not decay, the crowbar resistance must remain inserted and the RSC blocked for the whole duration of the fault (SULLA, 2012).

The RSC is blocked after the fault occurrence and the rotor circuit is connected to the DC-link capacitor through the diode bridge formed by the anti-parallel diodes of the RSC. The chopper resistance is switched to maintain the capacitor voltage within acceptable values, as the GSC capability is reduced under severe fault conditions. The rotor circuit demagnetizes and feeds current into the DC-link capacitor; high currents are mainly due to the natural stator flux that arises to ensure the continuity of flux before and after the fault. During the decaying period, the rotor circuit can be regarded as a three-phase decaying AC voltage source connected through a diode bridge rectifier (anti-parallel diodes of the blocked rotor converter) to a constant DC voltage source supplied by the DC-link

capacitor plus chopper. This assumption is valid in case the chopper is properly sized and controlled, since the DC-link voltage variations will not exceed a pre-set value. In addition, the DC-link voltage source is seen from the RSC as a variable resistance whose value is the ratio between the DC-link voltage and the rectified decaying rotor current. Therefore, this configuration of the DFIG consists of a short-circuited induction generator with a high equivalent rotor resistance, but for simplification it is assumed to be constant and equal to the ratio between the DC-link voltage and the rectified rotor current at the time of the fault occurrence.

The RSC can be restarted when the rotor current and the DC-link voltage have decayed sufficiently and the fault is still present, for it is able to control the rotor current and thereby the stator current. Much as the DFIG with chopper resistance delivers lower short-circuit currents than the DFIG with crowbar protection does, particularly when the initial loading is low, its anti-parallel diodes must be oversized to handle the short-circuit current.

The value of the equivalent resistance can be applied to calculate the maximum short-circuit current of the DFIG. However, it is complicated to estimate it when the RSC is blocked (SULLA, 2012). Besides, the calculation of the symmetrical and unsymmetrical short-circuit currents is affected adversely when it is assumed that the WTG can be modelled as a linear component without saturation of the leakage and magnetizing reactances (SULLA, 2012).

The equivalence between short-circuit calculations for DFIG with chopper and crowbar protection is proposed in (SULLA, 2012) to avoid detailed representation of the switched chopper resistance with its control logic and RSC diodes. This approach is considered within this research not to include a detailed representation of the switching and non-linearities caused by the diode bridge and chopper action.

When the fifth-order model of the induction generator is applied, the converter can block under voltage drops between 0.8 and 1.0 p.u., which shows that the converter protection is sensitive to transient events in the power network; in turn, when the third-order model is used, the generator and converter maintain uninterrupted operation at the same voltage drops. Hence, it is necessary to apply at least the fifth-order model to predict accurately both the current behaviour and the converter action; the third-order one is oversimplified, as fundamental-frequency transients in the machine current are ignored, and may predict wrong converter actions, whether protection with blocking or uninterrupted operation.

Before starting the dynamical simulations, it is necessary to initialize the DFIG (by means of finding the steady-state operating point) and the power network models. The active and reactive power (independent from each other and dependent of the incoming wind and control strategy, respectively), the terminal voltage and the slip shall be given in the beginning of the initialization; then, the power distribution between stator and rotor,

the stator and rotor current and the rotor voltage induced by the converter shall be found; after that, the frequency converter shall be initialized with information about the rotor power neglecting losses. For simplification purposes, fundamental-frequency components may be assumed so as to neglect higher harmonics and losses in the core, windings and converters, as well as a symmetrical three-phase winding distributed around an uniform air gap.

The stator flux transients are usually neglected for evaluation of dynamic small-signal stability and transient voltage stability, due to the independent power control; consequently, the rotational speed and the terminal voltage are decoupled and the former during the fault does not impact the latter after the fault clearance. Neglecting the stator flux transients may lead to neglecting the fundamental-frequency transients in the machine currents; on the one hand, it does not affect the results under the assumption that the converter maintains uninterrupted operation and the wind turbine does not disconnect during the fault; on the other hand, it may be relevant when the short-circuit results in a significant voltage drop and also be influenced by the converter control system.

Operation of variable-speed wind turbines equipped with converter-controlled DFIGs during grid faults depends mainly on the converter and protective system action. Abnormal operating conditions may lead to converter blocking, generator tripping and consequently wind turbine disconnection and stopping. Moreover, blocked converters lose their controllability and may lead to disconnection of the wind turbine unless a reinitializing routine is applied.

The idea behind the uninterrupted operation is that the wind turbine does not trip when the converter has blocked at a grid fault. The controllability of the RSC is lost when it is blocked; consequently, the generator behaves as an induction generator without independent active and reactive power control. After the fault has been cleared and the voltage and frequency have been re-established in the power network, the RSC synchronizes and restarts on normal operating conditions.

As described in (AKHMATOV, 2003), when the rotor converter blocks, it stops switching and trips; then, the rotor circuit is closed through an external resistor with a current-limiting function. In such case, the generator operates as a conventional induction generator with a short-circuited rotor and an increased rotor resistance, whereas the control system of the RSC continues to monitor the electrical parameters, waiting the order to restart. When the current and the terminal voltage are within the expected ranges, the synchronization starts: the converter starts switching, the external resistance is switched off and the control system resets the controllers by the measured values. After completing this procedure, the control system is shifted and the RSC restarts. There might be the risk of blocking again because of excessive current transients during the control shifting and incomplete synchronization caused by delays in the measured signals applied to reset the controllers.

The external resistance is used to reduce the current magnitude when the RSC is blocked. Another request is to damp properly the transients in the rotor circuit before the restart. Thus, the external resistance has to be neither too large nor too small, in order to minimize the risk of excessive transients when the resistance trips to restart the rotor converter, and to prevent over-speeding of the induction generator and excessive reactive current, respectively. Additionally, the impact of the external resistance on the reactive power demand and the adjustment of the external resistance to the generator electrical data shall be considered.

There is no active power transferred between the rotor and the grid through the converter when the rotor is short-circuited through the external resistor. From the synchronization instant, active power is exchanged via the DC-link, whereas the DFIG absorbs reactive power from the grid for its excitation. Reactive power compensation shall be merged to the grid to cover the demand, reduce voltage drops during faults and perform dynamic reactive power control when the converters are blocked (AKHMATOV, 2003; SULLA, 2012). However, synchronous condensers and/or Static Converter (STATCOM)s must also be applied in order to reduce the voltage drop, since they can produce their own terminal voltage, whilst a static reactive compensator combined with a capacitor bank can be applied to take over the reactive power control. Alternatively, the frequency converters can be used to control reactive power and voltage (AKHMATOV, 2003; MORREN; HAAN, 2007).

3.2.1.4 Type 4

Wide-range variable-speed wind turbines may be based on an induction or synchronous generator. In this concept, the stator is connected to the AC grid through a full-load back-to-back power converter, as illustrated in Figure 10, which decouples the generator speed (variable) from the grid frequency (fixed). Consequently, the electrical frequency of the generator may change with the wind speed, while the grid frequency remains unaltered. The rotor and generator shafts may be coupled directly or through a gearbox in case of low number of poles. Additionally, synchronous generators may be either permanent magnet or electrically, separately excited, whereas induction generators have to be magnetized by the machine-side converter (MSC) and consequently have to be rated to handle the apparent power of the generator.

These generators can extract the maximum power due to the operation in a wide speed range and also present independent active and reactive power control. The MSC controls the generator speed so as to optimize the power extraction from the wind, while the GSC controls the DC-link voltage by feeding active power into the grid and provides reactive power support. In spite of being easier to control during voltage dips, they are more expensive than other concepts because of the two full-load power converters.

The power converter system consists of the GSC and MSC back-to-back connected

Figure 10 – Schematic of a wind turbine with full-load power converter

Source: (GERS; HOLMES, 2011, p. 78) (adapted)

through a DC-link and shall be rated equals to the rated power plus losses of the generator. The GSC is a PWM-Voltage Source Converter (VSC), whereas the MSC can be either a PWM-VSC or a diode-based rectifier. When the MSC uses a diode-based rectifier, the generator output is converted to DC power and then to AC power by the PWM-VSC. A DC-DC converter is applied to control the DC-link voltage, whereas the GSC controls the generator operation and the power flowing to the grid. In turn, when the MSC uses a PWM-VSC, the generator can be directly controlled by its converter and the GSC controls the DC-link voltage level by exporting active power to the grid and the exchange of reactive power with the grid. Both converters can be controlled through the load angle, as described in (GERS; HOLMES, 2011).

The behaviour of the generator and converter determines operation during transient events in the network. Thus, models shall represent the generator, its shaft system and rotor aerodynamics, the frequency converter, its control and protection (SULLA, 2012; AKHMATOV, 2003).

The generator model comprises an initialization routine with steady-state computations and the state equations. For simplification, the generator is usually assumed as symmetrical and three-phase, and the permanent magnets in the rotor establish a sinusoidal flux in the stator so that the electromotive forces are sinusoidal (AKHMATOV, 2003). This work follows these premises; hence, the excitation voltage E_g is given by the EMF produced by the permanent magnets and the generator is modelled through (24).

$$\begin{cases} \frac{d\psi_{ds}}{dt} = -R_s \cdot \dot{I}_d - \omega_e \cdot \psi_{qs} - \dot{V}_{ds} \\ \frac{d\psi_{qs}}{dt} = -R_s \cdot \dot{I}_q - \omega_e \cdot \psi_{ds} - \dot{V}_{qs} \\ \dot{\psi}_{ds} = \psi + L_d \cdot \dot{I}_d \\ \dot{\psi}_{qs} = L_q \cdot \dot{I}_q \end{cases} \quad (24)$$

Where the stator flux is given by $\psi_s = (\psi_{ds}, \psi_{qs})$, the terminal voltage is $\dot{V}_s = (\dot{V}_{ds}, \dot{V}_{qs})$, the machine current is $\dot{I}_s = (\dot{I}_d, \dot{I}_q)$, the stator resistance is R_s and the synchronous reactance is $X_s = (X_d, X_q)$ due to saliency, with $X_d = \omega_e \cdot L_d$ and $X_q = \omega_e \cdot L_q$ (AKHMATOV, 2003). Overall, PMSGs present relatively large p.u. reactances.

The frequency converter system comprises the MSC with its smoothing inductor, the

GSC and the DC-link connection between both sides. The MSC injects the current $I_1 = \frac{P_g}{U_{dc}}$ into the DC-link with voltage U_{dc} . The current from the another side of the DC-link is given by $I_2 = \frac{P_{gc}}{U_{dc}}$, with $P_{gc} = P_s + P_{losses}$, P_s equals to the active power supplied to the power system and P_{losses} equals to the power losses in the GSC. In steady-state operation and under the assumption of no power losses in the DC-link, $P_{gc} = P_g$ and U_{dc} is constant and provides the initial condition of the DC-link, $U_{dc}(0)$. However, when a disturbance occurs, the stationary power equality between P_{gc} and P_g is broken, then a current $I_c = I_1 - I_2$ starts flowing through the capacitor and causes voltage fluctuations on the DC-link voltage, according to (25) (AKHMATOV, 2003)

$$U_{dc}(t) = \sqrt{U_{dc}^2(0) + \frac{2}{C} \cdot \int (P_g(\tau) - P_{gc}(\tau)) \cdot d\tau} \quad (25)$$

The current flowing through the GSC can be calculated through (26):

$$\begin{cases} \frac{d\psi_{ds}}{dt} = -R_s \cdot \dot{I}_d - \omega_e \cdot \psi_{qs} - (\dot{V}_{dc} - \dot{V}_{ds}) \\ \frac{d\psi_{qs}}{dt} = -R_s \cdot \dot{I}_q - \omega_e \cdot \psi_{ds} - (\dot{V}_{qc} - \dot{V}_{qs}) \\ \dot{\psi}_{ds} = X_s \cdot \dot{I}_d \\ \dot{\psi}_{qs} = X_s \cdot \dot{I}_q \end{cases} \quad (26)$$

With $\dot{V}_s = (\dot{V}_{ds}, \dot{V}_{qs})$ equals to the grid voltage and $\dot{V}_c = (\dot{V}_{dc}, \dot{V}_{qc})$ equals to the voltage generated by the GSC. Analogously, the grid voltage $\dot{V}_g = (\dot{V}_d, \dot{V}_q)$ is controlled by the MSC.

The voltage exchanged between the GSC and the grid is given by $S_s = P_s + j \cdot Q_s = \dot{V}_s \cdot \dot{I}_s^*$ and the power losses in the GSC are given by $P_{losses} = R_s \cdot \dot{I}_s^2$.

Since the converter determines the operation of the wind turbine during transients, its protective system has to be evaluated. Overall, the relay settings of the converter are provided by the wind turbine manufacturer; otherwise, they can be evaluated according to the operation principles. The blocking time of the converter controlled by IGBT-switches can be of a few milliseconds. Besides, the generator protection at faults usually focuses on protection against over-current in the stator windings and thermal overload. The PMSG is separated from the fault in the grid by the converter with the DC-link. Hence, grid faults may not damage the PMSG with demagnetization of the magnets. Nonetheless, the converter control has to be designed to reduce stress from the grid on the generator.

In principle, full-load power converters can be disconnected instantaneously during grid disturbances without contributing to fault currents at all (THIRINGER; PETERSSON; PETRU, 2003; PETRU; THIRINGER, 2002); in this case, they behave as an open circuit. Alternatively, they can be controlled so as to produce a certain amount of active and reactive power; in this case, the reactive power can be controlled independently by the GSC, whereas the active power control have to comply with the mechanical parameters of the wind turbine (THIRINGER; PETERSSON; PETRU, 2003).

During a grid fault, the converter shall operate without protective tripping (AKHMATOV, 2003). When the risk of converter blocking at grid faults is indicated, blocking-and-restarting features must be suggested for the frequency converters so that the wind turbine can operate without interruption. Thereby, after the fault clearance, the frequency converter shall restart so that the generator can supply active power to the grid continuously.

In contrast, when the DC-link voltage exceeds the tripping limit, the MSC stops switching, then its IGBT-switches open and the PMSG checks into the DC-link capacitor throughout the diode-bridge, whereas the GSC continues to operate. In this condition, the dynamic behaviour of the generator plus its converter is characterized by two conflicting processes (AKHMATOV, 2003): charge of the DC-link capacitor throughout the diode-bridge from the generator and discharge of the DC-link capacitor by the GSC. The DC-link capacitor discharges due to the active power supply from the GSC to the grid. It can be eliminated by setting the active current reference of the GSC to zero, so that the capacitor charges rapidly and the voltage reaches the generator excitation voltage. Then, the stator-winding current decays to zero and the accumulated magnetizing energy is transferred whilst the DC-link capacitor is charging.

The short-circuit behaviour is mainly determined by the GSC control strategy. Hence, it is specific to each wind turbine and field measurements are the only practical way to get a realistic picture of the fault behaviour of this concept. Overall, the wind turbine does not contribute to the short-circuit power because the full-load converters limit the current fed into the fault to the rated current of the converter or slightly above of it. Thus, the wind turbine can be approximated as a constant current source. For severe fault events, the converter switching may be interrupted during the fault period (KANELLOS; KABOURIS, 2009; SULLA, 2012; MORREN; HAAN, 2007; TEODORESCU; LISERRE; RODRÍGUEZ, 2010).

Voltage dips do not impact directly the generator dynamics because the GSC is able to ride through the fault and supply reactive current. The generator may over-speed within certain limits to store part of the mechanical power as kinetic energy, whilst pitch control is applied to reduce the mechanical power. However, a chopper resistance is requested to dissipate the input power and keep the DC-link voltage within acceptable levels under severe fault conditions. Alternatively, control techniques may be applied to improve the dynamic performance and avoid temporary over-current (SULLA, 2012).

3.2.2 Wind farms

A wind farm typically includes a number of wind turbines. A scheme is illustrated in Figure 11.

Wind turbines are unlikely to produce the same output power in a wind farm due to the shadowing effects among them with respect to the incoming wind; additionally, there may be slight voltage variations throughout the internal cable network of the wind farm.

Figure 11 – Single-line diagram of a detailed wind farm model with 12 wind turbines

Source: (SULLA, 2012, p. 78) (adapted)

Thus, it is important to consider that the wind turbines may be at different operating points with different parameters and relay settings to evaluate the fault behaviour of a wind farm.

Wind farms can be modelled in detail, with representation of each turbine in the farm, their no-load capacitor, the transformer connecting the wind turbine to the internal cable network and sufficient detailed information on the wind farm (AKHMATOV, 2003). Alternatively, reduced models in which the wind farm is represented by a rescaled equivalent may be applied in special conditions, when the differences between the operating points of the wind turbines are not too large (VITTAL; AYYANAR, 2012; LINDGREN; SVENSSON; GERTMAR, 2012). The complete model of wind turbines is required for actual investigation of the control features into individual wind farms, whereas the reduced model may be successfully applied for investigating the collective response of the wind farm under short-circuits (VITTAL; AYYANAR, 2012; LINDGREN; SVENSSON; GERTMAR, 2012). Alternatively, when the wind distribution is irregular over the area where the wind farm is, a multi-machine equivalent approach can be applied to represent the wind farm by a reduced number of re-scaled turbines at the same operating points.

Some simplifying assumptions to calculate the parameters of a typical wind farm present negligible effect on the results, as follows (KANELLOS; KABOURIS, 2009; JAUCH et al., 2007):

- the groups of wind turbines contain the same number of wind turbines;
- adjacent wind turbines and groups of wind turbines are placed at equal distances;

- the wind turbines of the wind farm are connected together;

The first step to calculate the equivalent impedance is to obtain the equivalent impedance of a group of wind turbines through (27), according to (KANELLOS; KABOURIS, 2009):

$$Z_{G,i} = \frac{(Z_G(N) + Z_{GS}) \cdot (Z_P + Z_{GS})}{Z_G(N) + Z_{GS} + Z_P + Z_{GS}} \quad (27)$$

Where $Z_G(N)$ is the equivalent impedance of the group of wind turbines (given by the parallel connection of N wind turbines, according to the recursive (28)), N is the number of wind turbines, Z_{GS} is the impedance of the cable connecting the group of wind turbines to the grid and Z_P is the impedance of the parallel cable used inside the group of wind turbines.

$$Z_G(N) = \frac{Z_G(N-1) \cdot (Z'_N + Z_{TN} + Z_{CN-1,N})}{Z_G(N-1) + Z'_N + Z_{TN} + Z_{CN-1,N}} \quad (28)$$

With

$$Z_G(1) = Z'_1 + Z_{T1} + Z_{C1,2} \quad (29)$$

Where Z'_N is the transient impedance of the generator, Z_{TN} is the impedance of the step-up transformer and $Z_{CN-1,N}$ is the impedance of the cable connecting the wind turbines $N-1$ and N . In case of DFIGs, Z'_N is replaced with the transient reactance X'_s in series with the crowbar resistance R_{cb} ; for induction generators, Z'_N equals $j \cdot X'_s$.

Then, the equivalent impedance of a wind farm with N_G groups is given by (30). In case of identical groups, (30) can be written as (31):

$$Z_{WF} = \frac{Z_{G,1} \cdot Z_{G,2} \cdots Z_{G,N}}{Z_{G,1} + Z_{G,2} + \cdots + Z_{G,N}} \quad (30)$$

$$Z_{WF} = \frac{Z_{G,i}}{N_G} \quad (31)$$

Finally, the equivalent impedance of the system is obtained through (32):

$$Z_{TH} = Z_{WF} + Z_L + Z_{SUB} \quad (32)$$

Where Z_L is the impedance of the overhead line of connection and Z_{SUB} is the equivalent impedance of the substation.

If any input is not available, typical assumptions can be used, as follows (KANELLOS; KABOURIS, 2009):

- if the parameters of the wind turbine generator are not available, then its short-circuit power can be used, as it is always provided by the manufacturer;
- typical short-circuit voltages of the step-up transformer and MV/High Voltage (HV) substation are 5%-7% and 15%-20% respectively;

- a typical MV overhead line can be considered for connection of the wind farm to the substation and the thermal limit of the conductor can be used to determine the number of parallel circuits;
- an average distance of 300 m between adjacent turbines can be considered;
- typical XLPE cables, whose cross section depends on the size of the wind turbine, can be assumed for internal wiring.

When the wind farm is composed of wind turbines equipped with full-load power converters, it can be modelled as a constant current source (KANELLOS; KABOURIS, 2009).

In accordance with (JAUCH et al., 2007), transient faults in weak parts of the system impact locally the system voltage, as local voltage dips are hardly ever noticed in other parts of the system. However, it produces torsional oscillations in the drive trains of the wind turbines, which result in power fluctuations that propagate through the system and may lead synchronous generators to exhibit frequency oscillations. Therefore, a high penetration level of fixed-speed turbines leads to strong power and frequency fluctuations in the grid.

In the case of induction generators, there is no synchronizing torque and almost no interaction between the wind turbine shafts and the generators through the electrical network. Thereby, the wind turbines at the same operating point can be simply added and represented as a reduced equivalent. In particular, the coherent response can be obtained when the wind turbine data are identical, the short-circuit impedances seen from the terminals of the different wind turbines within the wind farm are practically of the same value and mutual interactions are absent (AKHMATOV, 2003).

If a group of wind turbines have different mechanical parameters, their natural frequencies (and shaft torsional modes) will also differ and the risk of mutual oscillations will arise at grid disturbances. The wind turbines start responding to the fault in function of their natural frequencies, but in absence of synchronizing torque, the fluctuations in electrical and mechanical parameters will eliminate each other. The resulting dynamic behaviour is smoother than in case of wind turbines with identical parameters, with reduced voltage oscillations (AKHMATOV, 2003). Thus, it may be preferred to combine wind turbines with different parameters within a large wind farm.

3.2.3 Grid-fault ride-through requirements

Requirements on GFRT capability are related to technology, protection and control of wind turbines, generators and power electronics, as well as design and sizing of auxiliary equipment. Overall, they still represent a challenge for wind turbine manufacturers (TEODORESCU; LISERRE; RODRÍGUEZ, 2010). Essentially, GFRT parts of national grid codes specify the limiting conditions for a wind turbine to remain connected to the grid during a voltage dip by curves of the voltage dip in function of time. Voltage dips that

follow a grid fault and are cleared in normal conditions are expected to be above these curves. The voltage dip duration depends on the speed of fault clearance, which depends on the protection system. Voltage versus time curves from some European national grid codes can be found in (SULLA, 2012; IOV et al., 2007; TEODORESCU; LISERRE; RODRÍGUEZ, 2010).

3.3 Fault Behaviour of Photovoltaic Systems

3.3.1 Basic concepts of photovoltaic systems

Photovoltaic (PV) systems have been deployed at increasing levels in power distribution systems. Consequently, adequate models of panels and inverters are required for different grid impact studies.

A typical grid-connected PV system may be represented by a variable voltage input connected to a DC-DC converter with Maximum Power Point Tracking (MPPT), a regulated DC-link and a DC-AC three- or single-phase inverter.

PV cells are connected in series-parallel arrangements to produce a particular amount of power at a given voltage level, as a typical PV cell produces less than 2 [W] at 0.5 [V] (DC). Single PV cells are connected to build modules that in turn are connected to build arrays. A module may have a power output from a few to hundreds of watts, whereas the power output of an array may vary from hundreds to millions of watts (WANG, 2006).

PV systems can be either stand-alone or grid-connected. In both cases, the DC output generated by the PV cells is converted to AC power through inverters, which results in non-sinusoidal current waveforms. Grid-interfaced inverters are equipped with filters in order to attenuate lower and higher frequency components and smooth the output waveform (APRILIA et al., 2012).

The inverter is the key element of a grid-connected PV system. Its main function is to convert the DC output power of the PV panels to AC grid-synchronized power. Depending on the configuration of the PV system, the inverter can be classified as in (TEODORESCU; LISERRE; RODRÍGUEZ, 2010):

- module-integrated, typically between 50 and 400 [W], for very small PV plants;
- string, typically between 0.4 and 2 [kW], for small roof-top plants with panels connected in one string;
- multi-string, typically between 1.5 and 6 [kW], for medium roof-top plants with panels in one or two strings;
- multi central, typically above 6 [kW] with three-phase topology and modular design for larger roof-top or smaller power plants;

- central, typically between 100 and 1000 [kW] with three-phase topology and modular design for large power plants.

Inverters are more complex in a PV system than in a motor drive with regards to hardware and functionality. Some features of a PV inverter include, the grid connection filter, grid disconnection relay, DC switch and functions such as the MPPT, anti-islanding, grid synchronization and data logger (TEODORESCU; LISERRE; RODRÍGUEZ, 2010).

3.3.2 Grid requirements for response to abnormal conditions

PV systems have to comply with a number of standard requirements in order to ensure safety and seamless transfer of electrical energy to the grid. Local regulations imposed by grid operators apply in most of the countries. Some international bodies have also developed worldwide standards for grid requirements, such as Institute of Electrical and Electronic Engineers (IEEE), International Electrotechnical Commission (IEC), Deutsche Kommission Elektrotechnik (DKE) and so on.

Overall, these regulations stipulate disconnection time limits in function of voltage and frequency variations (TEODORESCU; LISERRE; RODRÍGUEZ, 2010) and conditions for reconnection. The disconnection times refer to the interval between the occurrence of the abnormal condition and the cease to energize the utility line, in order to ride through short-term disturbances to avoid excessive nuisance tripping, particularly in weak-grid situations.

Grid requirements have a significant impact on the design and performance of the inverters. The equipment must be disconnected from the grid in case of abnormal conditions, so as not to be damaged and to ensure safety for the general public, while the inverter controller shall remain connected to the utility to sense the conditions for reconnection.

3.3.3 Modelling photovoltaic systems

There is very little standardization in modelling PV generation in power distribution systems. Most of the efforts have been based on analytical methods that do not reflect their response to variable conditions in irradiation, grid voltage and frequency. Alternatively, the assumption that the PV system behaves as an active load injecting energy into the power system may be convenient, as well as empirical models based on experimental results and field measurements. Although detailed models (for example, including the PV array, MPPT algorithm and power electronics) may be suitable to evaluate a particular PV system, the precision is generally lost when wide aggregation is needed. Hence, a simple, practical and faithful PV system model has to be established together with the aggregate representation of dynamic and static loads within the distribution network model (LESIEUTRE, 2008).

Figure 12 – Equivalent electrical circuit of a single photovoltaic cell

Source: (FARRET; oES, 2006, p. 132) (adapted)

A few decades ago, converter-based generation did not contribute to a significant share of active power generation to the system. They used to be immediately disconnected from the grid after a fault had been detected, because their reactive current contribution to the short circuit was small compared to the traditional synchronous machines. However, due to the increasing penetration levels of converter-based generation, the disconnection may adversely impact the system stability, so this practice is no longer feasible.

New guidelines and regulations pose that converter-based power generation shall be capable to ride through faults, by remaining connected to the grid as long as the fault condition does not exceed certain limits. Whereas they remain connected, their control system has to respond fast to voltage changes by adjusting the reactive current contribution along a given characteristic. Thus, the short-circuit contribution of converters has to be taken on board.

The power converter limits the reactive current magnitude up to the rated current at nominal apparent power. Therefore, the synchronous machine model will not provide accurate results, as its transient short circuit contribution can reach 20 times the nominal value, according to 3. Besides, the fault current contribution with use of power converters is independent of the fault distance and resembles a synchronous machine only within a range of voltage drop values at the converter terminals.

The equivalent electric circuit of a single PV cell is shown in Figure 12. The output current can be calculated by means of (FARRET; oES, 2006; CUK et al., 2011; APRILIA et al., 2012):

$$I_o = I_\lambda - I_d - I_p \quad (33)$$

Where I_λ is the photon current, proportional to the light intensity and dependent on the light wavelength; I_d is the Shockley temperature-dependent diode current; and I_p is the PV cell leakage current.

The parameters of the photon current are related to the cell short-circuit current and to the cell open-circuit voltage, obtained from the current-voltage (I-V) characteristic curve. Moreover, if the photon current is known for certain standard illumination intensity L_s and a prescribed value of $I_{\lambda,o}$, it is possible to obtain the photon current approximately

for another intensity L through:

$$I_\lambda = \frac{L}{L_s} \cdot I_{\lambda,o} \quad (34)$$

The Shockley diode current is given by:

$$I_d = I_s \cdot \left[e^{\frac{q \cdot V_d}{\eta \cdot k \cdot T}} - 1 \right] \quad (35)$$

Where I_s is the reverse saturated current of the diode, k is the Boltzmann constant, q is the electron charge, V_d is the diode voltage, η is an empirical constant and T is the absolute temperature (FARRET; oES, 2006).

In turn, the leakage current is given by:

$$I_p = \frac{V_d}{R_p} \quad (36)$$

The internal losses across the diode can be represented by a parallel resistance (typically between 200 and 800 $[\Omega]$), whereas the manufacturing quality of the PV cell can be reflected by a small series resistance between the photon current source and the load across the terminals (up to 0.1 $[\Omega]$).

Writing the diode voltage in function of the load resistance R_L , as in (37), the output current can be written as in (38):

$$V_d = I_o \cdot (R_s + R_L) = V_o \cdot \left(1 + \frac{R_s}{R_L} \right) \quad (37)$$

$$I_o = \frac{R_p}{R_p + R_s + R_L} \cdot \left[I_\lambda - I_s \cdot \left(e^{\frac{q \cdot V_d}{\eta \cdot k \cdot T}} - 1 \right) \right] \quad (38)$$

When a group of PV cells is integrated, the cells are assumed to be identical. Such practice is reasonable, as the individual cells are manufactured with very similar characteristics to avoid circulation of internal currents among the cells. Hence, the assumptions below are acceptable:

$$\left\{ \begin{array}{l} I_{\lambda,1} = I_{\lambda,2} = \dots = I_{\lambda,n} \\ I_{d,1} = I_{d,2} = \dots = I_{d,n} \\ V_{d,1} = V_{d,2} = \dots = V_{d,n} \\ R_{s,1} = R_{s,2} = \dots = R_{s,n} \\ R_{p,1} = R_{p,2} = \dots = R_{p,n} \end{array} \right. \quad (39)$$

The output voltage and current of a series-connected group are given by (40), where $V_{o,i}$ and $I_{o,i}$ are the average voltage and current in an individual cell.

$$\left\{ \begin{array}{l} V_o = n \cdot V_{o,i} \\ I_o = I_{o,i} \end{array} \right. \quad (40)$$

In turn, the output voltage and current of a parallel-connected group are given by (41):

$$\begin{cases} V_o = V_{o,i} \\ I_o = n \cdot I_{o,i} \end{cases} \quad (41)$$

A PV system at the distribution grid might be considered as a negative power electronic load. However, its principles of control and operation differ from typical power electronic loads that essentially operate near constant power at unity power factor for a wide voltage range (LESIEUTRE, 2008). Moreover, the power converters of a PV system apply a MPPT function in the DC-DC converter module. Therefore, the PV modelling illustrated in 12 is not strictly load modelling.

3.4 Fault Behaviour of Fuel Cells

Fuel cell DG systems have many advantages, such as high efficiency, zero or low of pollutant gases and flexible modular structure. They are invaluable sources to provide reliable power at steady state, but due to their slow internal electrochemical and thermodynamic responses, their response to electrical load transients is not as fast as desired. Hence, their short-circuit behaviour has to be analysed.

This section presents the analytical models of fuel cells related to operation during grid disturbances, including details with respect to the power converter configurations and controllers.

3.4.1 Basic concepts

Fuel cells are static energy conversion devices that convert the chemical energy of the fuel into DC electrical energy (WANG, 2006). These components consist of two electrodes (anode and cathode) and an electrolyte layer in the middle. The electrolyte layer is a good conductor for ions either positive or negative charged and can be either solid or liquid. The type and chemical properties of the electrolyte in use are crucial to the operating characteristics.

Typically, the fuel is fed continuously to the anode, whereas the oxidant is fed continuously to the cathode. The most commonly used fuel is hydrogen, whilst the most common oxidant is oxygen or air. The electrochemical reactions take place at the electrodes.

Among the different types of fuel cells, the most likely to be used for DG applications according to (WANG, 2006) are:

- Solid oxide fuel cell (SOFC): based on a negative-ion conductive electrolyte, it operates at high temperatures (600-1000 Celsius degrees), converts chemical energy into electrical energy at high efficiency (up to 65%) and the solid nature of the fuel eliminates corrosion and management concerns related to the liquid electrolyte;

- Polymer electrolyte membrane fuel cell (PEMFC): with a sandwich-like structure and a Teflon-like membrane that is an excellent conductor of protons and insulator of electrons between the two electrodes, it presents high power density, high efficiency (40-45%) and lower operating temperature (60-80 Celsius degrees) (WANG, 2006); and
- Molten carbonate fuel cell (MCFC): using a mixture of alkali metal carbonate as electrolyte, it operates at high temperatures (600-700 Celsius degrees), when the salt mixture is in liquid phase, and can achieve efficiency in the range of 50-60% before heat recovery and exceed 70% with heat recovery.

3.4.2 Dynamic models for fuel cells

Fuel cells are usually connected to the grid through power electronics. However, the exchange of information between fuel cell manufacturers and power electronic interface designers is often limited. As a consequence, the former model the power electronic interface as an equivalent impedance, whereas the latter represent the fuel cell as a constant voltage source with a series resistance. These approaches may lead to inaccurate results when fuel cells and power electronic converters are connected, so it is important to understand how these components impact each other (WANG, 2006).

Typically, the fuel cell is connected to the power system through a DC-AC converter equipped with voltage- and power-control loops (JAGADURI; RADMAN, 2007). In addition, a battery is necessary to provide voltage support and reactive power compensation. Fuel cells produce DC voltage outputs and present slow transient response and output power ramping, so they cannot follow loads effectively. They serve as a stationary power generator that generates power on its own. Among the types commonly used, the PEMFC has the fastest transient response.

The inverter applies PWM to turn the DC voltage into a controllable AC voltage with fundamental frequency, according to:

$$\dot{V}_{AC} = m \cdot V_{FC} \cdot (1/\delta) \quad (42)$$

Where V_{FC} is the DC voltage at the fuel cell terminals, m is the amplitude modulation index of the converter, and δ represents the firing angle of the power converter with respect to the reference bus voltage (JAGADURI; RADMAN, 2007). The output voltage of the fuel cell stack can be calculated through:

$$V_{FC} = N_{cell} \cdot V_{cell} \quad (43)$$

In turn, the battery added to make up for the slow transients can be modelled as an ideal voltage source, as its internal resistance is very small. The equivalent circuit is

Figure 13 – Equivalent electrical circuit of a fuel cell

Source: (JAGADURI; RADMAN, 2007, p. 5) (adapted)

illustrated in Figure 13:

$$\begin{cases} \dot{I} = Y_{FC} \cdot (E_{FC} - V_{FC}) \\ Y_{FC} = \frac{1}{j \cdot X_{FC}} = j \cdot B_{FC} \end{cases} \quad (44)$$

(44) can be written in terms of real and imaginary components (system reference frame), as:

$$\begin{bmatrix} \dot{I}_{re} \\ \dot{I}_{im} \end{bmatrix} = \begin{bmatrix} 0 & -B_{FC} \\ -B_{FC} & 0 \end{bmatrix} \cdot \begin{bmatrix} \dot{V}_{re} \\ \dot{V}_{im} \end{bmatrix} - \begin{bmatrix} B_{FC} \cdot \dot{E}'_{im} \\ -B_{FC} \cdot \dot{E}'_{re} \end{bmatrix} \quad (45)$$

Although the battery presents an extremely high initial density of current (ZAVALLIS; BEHM; LINDBERGH, 2012), the current over time does not differ considerably from the fully charged case. More current is produced and the temperature rises faster when the electrode area is increased.

3.5 Fault Behaviour of Gas Micro-turbines

Gas micro-turbines used for DG applications have been deployed at increasing levels in power distribution systems. Hence, their impact on the grid has to be represented and evaluated properly. This section presents the concepts of gas micro-turbines commonly used and the analytical models required for operation during grid disturbances, including details with respect to the power converters, as follows.

3.5.1 Basic concepts of gas micro-turbines

The main components of a gas turbine are compressor, combustor and turbine. The air is pressurized in the compressor before entering the combustor, where it is mixed with the fuel injected. Then the mixture is ignited and mechanical power is produced when the hot combustion gases flow and expand through the turbine. The gas turbine drives a synchronous generator, where part of the power produced is converted to electric power (JAGADURI; RADMAN, 2007). Therefore, the electrical characteristics of the gas turbine are determined by the synchronous machine.

Figure 14 – Equivalent electrical circuit of a gas micro turbine

Source: (JAGADURI; RADMAN, 2007, p. 5) (adapted)

3.5.2 Dynamic models for gas micro-turbines

A two-axis model is assumed for the gas turbine (JAGADURI; RADMAN, 2007). According to the phasor diagram, $\dot{E}$ is the voltage induced by the field current $\dot{I}_f$ and $\dot{E}'$ is the net voltage induced by $\dot{I}_f$ and the armature reaction. In the d-q frame of reference, the steady-state characteristics of the gas turbine at its terminals are given by:

$$\begin{cases} \dot{E}' = \dot{V}_q + R \cdot \dot{I}_q - X_d' \cdot \dot{I}_d \\ 0 = \dot{V}_d + R \cdot \dot{I}_d - X_q \cdot \dot{I}_q \end{cases} \quad (46)$$

Ignoring the resistance R , the equations can be written as:

$$\begin{bmatrix} \dot{I}_q \\ \dot{I}_d \end{bmatrix} = \begin{bmatrix} 0 & -\frac{1}{X_q} \\ \frac{1}{X_d} & 0 \end{bmatrix} \cdot \begin{bmatrix} \dot{V}_q \\ \dot{V}_d \end{bmatrix} - \begin{bmatrix} 0 \\ \frac{\dot{E}'}{X_d'} \end{bmatrix} \quad (47)$$

The d-q components of the gas turbine voltage and current are transformed to the system reference frame through the transformation matrix given by (48):

$$[T] = \begin{bmatrix} \cos(\delta) & \sin(\delta) \\ -\sin(\delta) & \cos(\delta) \end{bmatrix} \quad (48)$$

Hence,

$$\begin{bmatrix} \dot{I}_d \\ \dot{I}_q \end{bmatrix} = [T] \cdot \begin{bmatrix} \dot{I}_{re} \\ \dot{I}_{im} \end{bmatrix} \quad \text{and} \quad \begin{bmatrix} \dot{V}_d \\ \dot{V}_q \end{bmatrix} = [T] \cdot \begin{bmatrix} \dot{V}_{re} \\ \dot{V}_{im} \end{bmatrix} \quad (49)$$

Substituting (49) in (47):

$$\begin{bmatrix} \dot{I}_{re} \\ \dot{I}_{im} \end{bmatrix} = [T]^{-1} \cdot \begin{bmatrix} 0 & -\frac{1}{X_q} \\ \frac{1}{X_d} & 0 \end{bmatrix} \cdot [T] \cdot \begin{bmatrix} \dot{V}_{re} \\ \dot{V}_{im} \end{bmatrix} - [T]^{-1} \cdot \begin{bmatrix} 0 \\ \frac{\dot{E}'}{X_d'} \end{bmatrix} \quad (50)$$

The equivalent circuit is shown in Figure 14.

3.6 Fault Behaviour of Loads

Aggregate loads remain the least certain of the modelled elements in power systems. Loads are highly distributed and quite variable, consequently accurate modelling is very

difficult and aggregation is the most practical approach to incorporate them in power system studies. As the load composition continually changes, even if it was possible to obtain an accurate load model for a certain time period, it would be inaccurate a short while later.

Nonetheless, load composition is very important on the analysis of the power system dynamic behaviour, as different load types exhibit distinct responses to disturbances. Despite that, the overall load composition tends to behave fairly predictably. Model structures for large dominant components, such as synchronous generators, are well established, as well as the procedures to determine the associated parameter values. Conversely, models that represent an aggregation of many elements bring uncertainties related to their overall composition. In this context, the next sections describe previous attempts and current practices on load modelling.

3.6.1 Previous attempts on load modelling

Most of the load models currently used in power system studies were developed a few decades ago and not updated adequately after consecutive changes in the load structure. Although the majority of the power system research and industry acknowledges the importance of accurate load modelling, static loads are typically represented by the constant impedance, current and power models, whereas dynamic loads are commonly represented by the induction motor model. Several unsuccessful attempts to rebuild blackouts in the simulations have shown the inadequacy of such models.

Historically, loads have been represented with static characteristics, as constant current for active power and constant impedance for reactive power. Computational limitations used to be the main obstacles to adopt more comprehensive load models. Nowadays, the tools commonly used apply the positive sequence approach in a simplified approach, under the assumptions that only the positive sequence impacts the synchronizing forces between three-phase rotating machines and the behaviour of single-phase loads can be aggregated. However, explicit representation of three-phase and single-phase models may be desirable to study unbalanced faults; for instance, in load centres with many compressor motors for residential air-conditioning and refrigeration, where the response of load-inertia single-phase motors to unbalanced faults is inconsistent with the positive-sequence approach.

Recently, the interest in load modelling has increased due to the appearance of new load types with improvements in efficiency and controllability. Different non-linear power electronic loads are responsible for a significant part of the total demand in the residential sector (MILANOVIC et al., 2013). On the top of that, the complexity of load compositions and their hourly and seasonal changes in the real system pose a challenge to accurate representation.

Figure 15 – WECC Composite Load Model

Source: (BRAVO et al., 2010, p. 8) (adapted)

3.6.1.1 WECC Load Modelling Task Force

Wisconsin Energy Conservation Corporation (WECC) has undertaken significant efforts to improve dynamic load models and deployed an interim load model with static and dynamic parts. The former accounts for 80% and the latter – a default induction motor – for approximately 20% of the total load connected to a HV bus.

However, the interim load model does not reproduce the observed system response of delayed voltage recovery events, since it does not represent accurately the behaviour of small induction motors used in air conditioner compressors. For instance, the wide-spread stalling of residential single-phase air conditioners, which can occur in less than 2 cycles (i.e. faster than the fault clearance) draws a locked rotor current 4-6 times the rated value and results in voltage depression in the distribution and sub-transmission levels (WECC-MVWG, 2012). Hence, stalled air conditioners can be seen as a wide-area high impedance fault.

Afterwards, further advances of computing capability allowed the development of a composite load model with a more realistic structure, which consists of the following (WECC-MVWG, 2012; KOSTEREV; MEKLIN, 2006):

- a) distribution equivalent data: transformer, feeder equivalent and end-use loads placed at the low-voltage bus;
- b) model component data: reactance, time constants, inertia and driven load of motors, voltage and frequency sensitivity of static loads;
- c) load model composition: fractions of the load assigned to each model component.

The composite load model, schematised in Figure 15, takes into account the distance between the transmission bus and the end-users, includes separate impedances of the substation transformer and distribution feeder equivalent and separate capacitors at both feeder ends. The capacitor between transformer and feeder impedances provides the

difference in transformer and feeder reactive flows and a reference point for the transformer voltage regulator. Besides, it includes system and feeder protection and is able to trip part of the equivalent feeder and load (KOSTEREV; MEKLIN, 2006).

The composite load model has a wide range of load dynamics observed in reality. WECC utilities have tested a large variety of end-uses, such as residential and commercial air-conditioners, fans, pumps, residential appliances, lighting, computers, variable frequency drives, non-interruptible power supplies etc. in order to develop dynamic load models (WECC-MVWG, 2012).

Static models represent resistive, lighting, electronic loads and small appliances. Resistive loads, such as space heating, incandescent lighting, water heating and cooking, have been phasing out, whereas electronic loads, such as fluorescent lighting, electronic drives and chargers, light-inertia compressor motors in air conditioners and heat pumps, have been increasing their penetration level. The former are voltage sensitive, while the latter behave mostly as constant power loads with respect to voltage and frequency variations and are susceptible to voltage stability issues and power oscillations. Light-inertia single-phase compressor motors are prone to stall when voltage drops below 60% in 3 cycles or less; in this case, the motor remains stalled even if the fault is cleared and the voltage is recovered and draws a locked rotor current that puts the voltage stability at risk. Electric vehicle chargers are also likely to impact considerably the oscillation damping because of their power sizing and characteristics.

In addition, the load composition presents four motors. Regarding their principle behaviour, the following differences have to be represented:

- a) driven load: application, compressors versus fans and pumps, heavily versus lightly loaded;
- b) electrical parameters: size, large motors versus small motors used in commercial buildings;
- c) inertia: size, speed and application, high motor plus load inertia versus low inertia;
- d) protection: size, application, presence of under-voltage protection.

It is necessary to categorize motors based on their driven load (that is, constant torque versus speed-sensitive loads). Motors driving constant torque loads are more likely to stall and have notable negative impact on damping of power oscillations; also, single-phase and three-phase motors present different control strategies. The motor inertia is also relevant, as the electrical data are usually correlated with the motor size and large motors are designed to be more efficient.

Thereby, the motor models consist of the following:

- single-phase motors driving constant torque load, representative of compressor motors used in residential air-conditioner, refrigerators and heat pumps;

- three-phase motors driving constant torque load, representative of compressor motors in commercial air-conditioning, refrigeration and industrial compressors;
- motors driving load proportional to speed squared and large inertia, such as fan motors;
- three-phase motors driving load proportional to the speed squared and low inertia, such as pump motors.

The above-mentioned models represent only direct-driven motors; others fed via variable frequency drive (VFD)s are considered electronic loads.

Modelling of residential air-conditioners requires attention, as the behaviour of single-phase units cannot be represented with conventional three-phase conventional models. Furthermore, the three-phase motor protection includes two under-voltage relay settings that allow partial motor trip, whereas the single-phase motor protection includes thermal time over-current relay with two trip levels (KOSTEREV; MEKLIN, 2006).

For the load model composition, a load class mix of residential, industrial, commercial and agricultural sectors shall be provided for all substations. Then, it shall be divided in percentages of the power consumption by individual end-users (e.g. chillers, condensers, electronic, lighting) and commercial/residential loads (e.g. fans, TVs, electric cooking), considering different time and ambient conditions, peak and off-peak conditions and assumptions on the human behaviour. Next, the load composition shall be mapped and aggregated into model components (KOSTEREV; MEKLIN, 2006).

Four types of feeders were assumed in (WECC-MVWG, 2012) for each climate zone, as follows:

- a) residential, representative of suburban residential feeders;
- b) commercial, representative of feeders in metropolitan areas;
- c) mixed, combining residential and commercial loads;
- d) rural, representative of rural and agricultural feeders.

Large industrial loads, such as paper mills, steel mills, petrochemical plants, aluminium smelters, semiconductor fabs and computer server farms, are usually fed from dedicated substations and identified explicitly (WECC-MVWG, 2012). The percentages based on energy consumption are presented in (WECC-MVWG, 2012).

WECC utilities tested a large number of electrical end-uses, including residential single-phase air-conditioners, small commercial three-phase air-conditioners, three-phase pumps, three-phase fans, consumer power electronics (TVs and PCs), lighting (fluorescent, halogen etc.) and various residential appliances (dryers, washers etc.). Differences among the various load components and end-uses combinations were found.

Single-phase residential motors apply static functions to represent the relationship between active and reactive power versus voltage and frequency. The compressor model has two states, running and stalled, whose selection is based on the voltage. With respect

to the protection, commercial motors are likely to be equipped with contactors and ice-cube relays, which trip in one cycle and reclose when voltage is restored after the fault clearance, whereas industrial motors are likely to have under-voltage protection, which usually trips and locks-out the motor.

Furthermore, power electronic loads behave as constant power loads with respect to voltage and frequency variations and operate close to unity power factor at the fundamental frequency. They trip for low voltage conditions at higher levels (usually 55-70%), but PCs tend to restart when voltage is restored, whereas VFDs usually lock-out and require manual start (WECC-MVWG, 2012). In turn, static loads can be represented as constant current loads, in case of fluorescent lighting with electronic ballast, and as constant impedance loads, in case of resistive loads such as incandescent lighting, resistive water and space heating and resistive cooking.

The composite load model is the most comprehensive load representation and is taken into consideration by this research, together with the daily load curve profiles, when the information about the load characteristics is available. The composite model presents significant improvements in comparison to the interim model, but it is necessary to populate it with credible parameters so that it can be accurate. Apart from that, some limitations of the composite model have to be taken into consideration. In reality, the distribution systems are single-phase, while loads are connected to individual phases and present different responses during unbalanced disturbances. Additionally, to study single-phase faults with delayed clearing is required to accurately simulate unbalanced faults. In contrast, the transient stability programs are based on positive sequence and do not have each phase modelled, as long as the composite load model assumes balanced response of all phases in agreement with the positive sequence programs.

3.6.1.2 Daily load profiles for low voltage consumers in São Paulo

A study to determine the residential, commercial and industrial daily load curves for low voltage consumers based on field measurements is presented in (JARDINI et al., 2000). It includes a methodology to aggregate these loads, in order to estimate the loading in equipment or in part of the distribution network by using representative daily curves of each activity and the monthly energy consumption of the consumers. A set of load profiles of distribution transformers was also identified. Such information is important for planning and engineering studies and can be applied to transformer rating and to determine the expected load profile in any pre-set point of the distribution network.

The measurements of individual consumers were performed through meters and electronic devices for pulse counting and data storage in intervals of 15 minutes. Then, the mean and standard deviation curves were determined, based on measured daily curves values, and then they were divided by the power base values, in order to make them compatible to possible grouping and determine representative curves for the various consumer

classes.

Load profiles for residential consumers were classified in $[kWh/month]$ ranges from 0-50 and consecutively in intervals of 50 $[kWh/month]$ until 300 $[kWh/month]$, then in intervals of 100 $[kWh/month]$ until 500 $[kWh/month]$, from 500-1000 $[kWh/month]$ and more than 1000 $[kWh/month]$. The towns were grouped according to the $[kWh]$ frequency distribution similarities. The definition of representative curves of a range is complex due to differences in house loads and dwellers habits rising to curves of different shapes, particularly in the peak. Overall, the residential energy consumption in Brazil is mainly due to food preservation, whereas the shower gives the curve peak. The peak characterization is hard to be done, as the electric water heat power is about 3-5 $[kW]$ and the average period is 8 minutes. Besides, the seasonal variation of temperature does not impact significantly the energy consumption, since the variation due to the weather is less than 10% (JARDINI et al., 2000). Other aspects to be analysed include the demand average interval, the power factor profile and consumption comparison of consumers in different accommodations. Also, load profiles for commercial and industrial consumers shall take into account the location, activity classification, the energy consumption during the 12 months of the year and the average energy consumption along the same year.

The daily load measurements include all energy consumption ranges of residential consumers, the most representative commercial and industrial activities in terms of energy consumption and number of consumers, some measurements in distribution transformers and feeders. Representative load curves and equations are shown in (JARDINI et al., 2000).

3.6.2 Validation studies

The load models and data are expected to reasonably represent the principle behaviour of loads during power system disturbances without capturing intricate details of the load dynamics. Additionally, a reasonable estimate of the model composition is required. Thereby, the number of load components has to be large enough to represent the diversity of dynamic behaviours and various end-users, as well as geographic and seasonal characteristics. It is also expected that the models represent the voltage sensitivity of loads for reasonable voltage deviations in the grid, the frequency sensitivity for disturbances involving large generation and load unbalances, the load impact on damping power oscillations and the impact of motor loads on the voltage sags and recovery following faults in the grid.

In order to confirm whether the model structure is adequate to reproduce the observed phenomena and confirm the reasonableness of the model data sets, validation against historic disturbance events is desired. System impact studies shall also be carried out to assess the impact of the load modelling on the power system performance, including a wide range of contingencies such as large generation outages, transmission faults and system separation.

Furthermore, it is important to confirm if the load models together with the data provided by the utilities represents their fault behaviour adequately. The challenges with respect to the model validation comprehend time and seasonal variations, model generalization, disturbances not large enough to extrapolate the load behaviour or too large that may not occur on critical loading conditions and lack of dynamic measurements. Therefore, the ever-changing nature of the loads requires the validation of the model data construction together with the databases, rules and assumptions instead of the validation of a specific data set (KOSTEREV; MEKLIN, 2006).

To conclude, the inclusion of the load models in power system studies shall comply with plausible data sets and numerical stability for the studied conditions, robust performance for reasonable data variations, and not degrade computational efficiency.

* * *

The Proposed Fault Location Algorithms

4.1 General

This chapter presents the features of the fault location algorithms proposed within this research, taking three different procedures into consideration and distinct case studies to address the problem of fault location in power distribution networks with distributed generation, described in Section 4.2, Section 4.3 and Section 4.4. For clarification purposes, the realistic distribution networks illustrated in Figure 16 and Figure 21 are taken as examples.

Figure 16 – Radial distribution feeder - Algorithm 1

Source: the author

4.2 Proposed fault location algorithm 1

The proposed fault location method, applied to the network depicted in Figure 16, is based on the short-circuit calculation in phase components. Input data include, but are not limited to, information about the distribution network operating status, pre-fault and post-fault voltage and current signals recorded at the substation level, the connection points of the distributed generation units, and the electrical parameters of the distribution network. This information is provided by IEDs installed at the substation level and data stored in the utility's database (MANASSERO; TAKEDA; FREITAS, 2014).

The method analyses all the network sections in order to determine the point of fault, given by the fault distance and the fault resistance that produce the post-fault voltages and currents phasor quantities measured at the substation. Since the fault distance and resistances are unknown, the proposed method relies on an optimization process that estimates these quantities in order to minimize the error between the estimated phasor quantities and the measured ones.

Figure 17 presents the block diagram of the proposed fault location method. As illustrated, the algorithm starts calculating the equivalent sources at the substation bus and at the buses where the DGs are connected. Then, the algorithm selects the line section to be investigated and determines the equivalent circuit of that particular line section. After this step it is possible to calculate the fault current, using information about the fault point and the fault resistance, and the post-fault voltages and currents phasor quantities at the substation. The optimization tool is used to provide the fault distance and fault resistances that minimizes the error between the measured and the calculated phasor quantities at the substation.

Therefore, this algorithm may be divided into four main steps presented from Subsection 4.2.1 to Subsection 4.2.4: estimation of the equivalent sources and load impedances; estimation of the equivalent circuit of the investigated line section; estimation of the current at the fault location; and comparison between the post-fault voltages and currents phasor quantities calculated at the substation and the measured ones. The optimization method is described in Subsection 4.2.5.

4.2.1 Estimation of the equivalent sources and load impedances

The algorithm proposed in this paper depends on the correct representation of line sections, loads and distributed generation units. These requirements are met by using the distributed-parameters series-impedance matrix to represent the line sections, by considering that impedances may represent accurately the electric loads connected to the distribution transformers, and by representing the distributed generation units and the substation as equivalent sources and impedances, as presented in Subsection 4.2.1.1 and Subsection 4.2.1.2.

Figure 17 – Block diagram - Scenario 1

Source: the author

4.2.1.1 Estimation of the loads impedances

The proposed fault location method considers that loads connected to distribution feeders behave similar to balanced, delta-connected impedances. In other words, the loads do not contribute to the zero-sequence current. Therefore, the algorithm estimates the loads' impedances by distributing to each load the complex power measured at the substation plus the complex power provided by all distributed generators. This distribution is weighed according to the nominal apparent power of the distribution transformer, as in (SENGER et al., 2005) and (51). However, the load impedances may not be proportional to the nominal load, therefore, a statistical approach was used to estimate its influence, and the results are presented in Subsection 5.3.1.

$$\bar{S}_{l,k} = (P + j \cdot Q) \cdot \frac{S_{l,k}}{\sum_{k=1}^n S_{l,k}} \text{ and } \bar{Z}_{l,k} = \frac{|\dot{V}|^2}{\bar{S}_{l,k}^*} = \bar{Y}_{l,k}^{-1} \quad (51)$$

where

$\bar{S}_{l,k}$ is the k^{th} load complex power;

$\sum_{k=1}^n S_{l,k}$ is the nominal apparent power of the distribution transformer;

$P + j \cdot Q$ is the total complex power provided to the feeder;

$\bar{Z}_{l,k}$ is the k^{th} load impedance; and

$|\dot{V}|$ is the magnitude of the line voltage.

It is important to mention that the proposed fault location method may use any other type of load modelling and connection, representing their behaviour and dynamic characteristics in a different way, without any significant change in the mathematical procedure.

4.2.1.2 Estimation of the distributed generators and substation equivalent voltage sources

Once the pre-fault voltages and currents phasor quantities at the substation are known, as well as the amount of active and reactive power produced by the distributed generation units, the pre-fault voltages and currents phasor quantities can be determined at all network buses using a typical load flow algorithm, assuming the loads as in Subsection 4.2.1.1. The equivalent voltage source at the substation is then calculated using information about the short-circuit levels at the substation bus, which determine the equivalent impedances at that bus, and the voltage and current signals provided by the pre-fault load flow at the substation bus, as in

$$\dot{V}_{eq,ST} = \dot{V}_{S,pre} + \bar{Z}_{eq,ST} \cdot \dot{I}_{S,pre} \quad (52)$$

where

$\dot{V}_{eq,ST}$ is the equivalent source at the substation;

$\bar{Z}_{eq,ST}$ is the equivalent impedance at the substation;

$\dot{V}_{S,pre}$ is the pre-fault voltage phasors measured at bus 10; and

$\dot{I}_{S,pre}$ is the pre-fault current phasors measured at bus 10.

The estimation of the equivalent sources at the distributed generating units is similar to the one presented in (52), however it depends on the equivalent impedances of the respective units. The method to determine these equivalent impedances is discussed later in section Subsection 5.3.1.

It is important to point out that during the first cycles after the fault, the equivalent voltage sources at the substation and at the distributed generation units may not vary significantly, and there may be a change in their equivalent impedances. This is also discussed in Subsection 5.3.1.

4.2.2 Estimation of the equivalent circuit of the investigated line section

In order to better understand the proposed method, consider that section 30-40 of the distribution network depicted in Figure 16 is under investigation. To do so, first it

Figure 18 – Equivalent sources at the investigated line section

Source: the author

is necessary to calculate the equivalent sources and impedances at its both line ends, as depicted in Figure 18.

This is performed by means of the grid nodal admittance matrix, in which the admittance of the section under analysis assumes zero value, which means infinite impedance. This approach allows to break the original network in two parts, one connected to bus 30 and the other connected to bus 40, and then to calculate the equivalent sources and impedances at both sides of the investigated section. The admittance matrix of the network depicted in Figure 16 is presented in (53) referred to the pre-fault interval, focusing on the part that refers to both buses.

$$[\bar{Y}_{bus}] = \begin{bmatrix} \ddots & \vdots & \vdots & \vdots \\ \cdots & \bar{Y}_{30,30} & -\bar{Y}_{30-40} & \cdots \\ \cdots & -\bar{Y}_{30-40} & \bar{Y}_{40,40} & \cdots \\ \cdots & \vdots & \vdots & \ddots \end{bmatrix} \quad (53)$$

where

$$\bar{Y}_{30,30} = \bar{Y}_{20-30} + \bar{Y}_{30-40} + \bar{Y}_{30-90} + \bar{Y}_{l,30}$$

$$\bar{Y}_{40,40} = \bar{Y}_{30-40} + \bar{Y}_{40-50} + \bar{Y}_{40-100} + \bar{Y}_{l,40}$$

Therefore, under the assumption that the admittance of line section 30-40 is equal to zero in (53), i.e. $Y_{30-40} = 0$, it is possible to obtain the equivalent impedances seen by buses 30 and 40, by inverting the modified grid admittance matrix and extracting the impedances corresponding to lines 30 and 40 and columns 30 and 40 from the resulting matrix, for buses 30 and 40. This procedure illustrated in (54).

$$\left\{ [\bar{Y}_{bus}] \Big|_{(\bar{Y}_{30-40}=0)} \right\}^{-1} = \begin{bmatrix} \ddots & \vdots & \vdots & \cdots \\ \cdots & \bar{Z}_{eq,30} & \vdots & \cdots \\ \cdots & \vdots & \bar{Z}_{eq,40} & \cdots \\ \cdots & \vdots & \vdots & \ddots \end{bmatrix} \quad (54)$$

where

$\bar{Z}_{eq,30}$ is the equivalent impedance at bus 30; and

Figure 19 – Fault admittance at the investigated line section

Source: the author

$\bar{Z}_{eq,40}$ is the equivalent impedance at bus 40.

It is important to point out that all quantities presented in this paper refer to a three-phase system. Therefore, parameters such as admittances, impedances, resistances, currents, and voltages are matrices and vectors of order three.

The inverse of the modified grid admittance matrix is also used to determine the equivalent voltage sources. However, in order to obtain these equivalents it is necessary to use the current phasors injected by the distributed generators and substation equivalents. This procedure presented in (55).

$$\begin{bmatrix} \vdots \\ \dot{E}_{eq,30} \\ \dot{E}_{eq,40} \\ \vdots \end{bmatrix} = \left\{ \left[\bar{Y}_{bus} \right] \Big|_{(\bar{Y}_{30-40}=0)} \right\}^{-1} \times \begin{bmatrix} \dot{I}_{eq,ST} \\ \vdots \\ \dot{I}_{eq,GD_n} \\ \vdots \end{bmatrix} \quad (55)$$

where

$\dot{E}_{eq,30}$ is the equivalent voltage source at bus 30;

$\dot{E}_{eq,40}$ is the equivalent voltage source at bus 40;

$\dot{I}_{eq,ST}$ is the equivalent current source at the substation; and

$\dot{I}_{eq,GD_n}$ is the equivalent current source at the “ n^{th} ” DG.

4.2.3 Estimation of the current at the fault location

Considering the line section under investigation, depicted in Figure 19, the proposed fault location method uses an optimization algorithm that varies the fault point and fault admittances and calculates the fault current as in (56).

$$\dot{I}_F = \bar{Y}_F \times (\bar{Y}_{eq,30-F} + \bar{Y}_F + \bar{Y}_{eq,F-40}) \times (\dot{I}_{eq,30} + \dot{I}_{eq,40}) \quad (56)$$

Figure 20 – Fault current injection at the investigated line section

Source: the author

where

$$\begin{cases} \bar{Y}_{eq,30-F} = \left\{ \bar{Z}_{eq,30} + \bar{z}_{30-40} \cdot x \right\}^{-1} \\ \bar{Y}_{eq,F-40} = \left\{ \bar{Z}_{eq,40} + \bar{z}_{30-40} \cdot (l_{30-40} - x) \right\}^{-1} \\ \dot{I}_{eq,30} = \bar{Y}_{eq,30-F} \times \dot{E}_{eq,30} \\ \dot{I}_{eq,40} = \bar{Y}_{eq,F-40} \times \dot{E}_{eq,40} \end{cases} \quad (57)$$

and

$\bar{z}_{30-40}$ is the impedance, per unit length, of line section 30-40;

l_{30-40} is the length of line section 30-40;

x is the fault distance from bus 30; and

$\bar{Y}_F$ is the fault admittance matrix.

Where the fault admittance matrix depends on the fault type and phases involved, as presented in (MANASSERO et al., 2010).

4.2.4 Estimation of the post-fault voltages and currents phasor quantities at the substation

Once calculated the fault current, the algorithm includes again the section under analysis in the admittance matrix. However, this line section is now partitioned at the fault point (without the fault admittances, since the fault current already includes its effect and it is considered as a current source), which means adding a new line and column to represent the fault point as a new bus in the admittance matrix, as in (58).

$$[\bar{Y}_{bus,F}] = \begin{bmatrix} \ddots & \vdots & \vdots & \cdots & 0 \\ \cdots & (\dots + \bar{Y}_{30-F}) & 0 & \cdots & -\bar{Y}_{30-F} \\ \cdots & 0 & (\dots + \bar{Y}_{F-40}) & \cdots & -\bar{Y}_{F-40} \\ \cdots & \vdots & \vdots & \vdots & \vdots \\ \cdots & -\bar{Y}_{30-F} & -\bar{Y}_{F-40} & \vdots & \bar{Y}_{30-F} + \bar{Y}_{F-40} \end{bmatrix} \quad (58)$$

Then, under the assumption that the fault current can be modelled as a current source, the algorithm determines the post-fault voltages and currents at the substation using the modified grid nodal admittance matrix with the equivalent current sources of the substation and DGs, as in (59).

$$\begin{bmatrix} \dot{V}_{10} \\ \dot{V}_{20} \\ \vdots \end{bmatrix} = [\bar{Y}_{bus,F}]^{-1} \times \begin{bmatrix} \dot{I}_{eq,ST} \\ \vdots \\ \dot{I}_{eq,GD_n} \\ \vdots \\ -\dot{I}_F \end{bmatrix} \quad (59)$$

where

$\dot{V}_{10}$ is the calculated post-fault voltage at bus 10; and

$\bar{Y}_{bus,F}$ is the admittance matrix including the fault point F .

The post-fault current leaving the substation (bus 10) is calculated as follows:

$$\dot{I}_{10-20} = \bar{Y}_{10-20} \times \{\dot{V}_{10} - \dot{V}_{20}\} \quad (60)$$

Then, the algorithm compares the actual values to the calculated ones given by (59) and (60), as follows. The p.u. deviations of the voltage and current phasors are added in (61) because both of them affect the identification of the point of fault and these indicators may provide better estimations of the faulted line section when brought together.

$$\epsilon_{30,40} = \frac{|\dot{V}_{10} - \dot{V}_S|}{\max\{|\dot{V}_{10}|, |\dot{V}_S|\}} + \frac{|\dot{I}_{10,20} - \dot{I}_S|}{\max\{|\dot{I}_{10,20}|, |\dot{I}_S|\}} \quad (61)$$

where

$\epsilon_{30,40}$ is the error between calculated and measured phasors;

$\dot{V}_S$ is the post-fault voltage phasors measured at bus 10; and

$\dot{I}_S$ is the post-fault current phasors measured at bus 10.

The investigation of section 30-40 finishes when the optimization method provides the fault distance and fault admittances that minimize the error in (61).

After investigating this section, the proposed fault-location method proceeds with investigating another one, until all line sections are investigated. After finishing the investigations, the proposed method provides the minimum error (ϵ), the fault distance (x) and the fault admittance matrix ($\bar{Y}_F$), associated with all investigated line sections. As presented in Subsection 5.3.1 the lowest minimum error is associated with the most probable fault location in most of the cases.

4.2.5 Optimization tool

Most of the optimization tools in use are iterative methods or heuristics. Heuristics do not use information about the gradient function and, in most cases, are slower than the iterative methods. However, they are less likely to encounter local minimum solutions and thereby are preferred to the problem of fault location.

The heuristics applied to the simulations consists of the pattern search toolbox available in MATLAB, described in (62), which returns the value of the objective function (61) at the solution $(x, \bar{Y}_F)$. It is a deterministic method based on direct search, that minimizes (61) by evaluating it methodically with combinations of input variables around a central initial point. The method starts with selecting the first combination of input variables, then it creates a number of combinations around this one. These combinations create a mesh with a pre-defined size.

The method compares the value of (61) using all combinations, and if there is success in finding a minimum different from the the central combination, the input variables responsible for this result become the new central combination. The process is repeated, but the mesh size is increased to avoid finding a local minimum. However, if there is failure in finding a local minimum different from the initial point, it remains the central combination. The process is repeated, but in this situation the mesh size is decreased to find the minimum. The iterative process ends when the minimum is found.

$$[x, fval] = \text{patternsearch}(fun, x_0, A, b, A_{eq}, b_{eq}, LB, UB, nonlcon, options) \quad (62)$$

where

fun is the function to be optimised (i.e. the fault distance);

x_0 is the starting point of the vector x (i.e. the initial values of the fault distance, fault resistance, and neutral resistance);

A is the matrix of size m-by-n (i.e. the admittance matrix without the fault point);

b is the vector of length m (i.e. the injected currents without the injected fault current);

A_{eq} is the matrix of size r-by-n (i.e. the admittance matrix with the fault point represented as an additional bus);

b_{eq} is the vector of length r (i.e. the injected currents with the injected fault current at the fault point);

$A_{eq} \cdot x = b_{eq}$ represents the linear equality constraints;

$LB = [dist_min, rf_min, rn_min]$ is the lower bound for x ;

$UB = [comprimento - dist_min, rf_max, rn_max]$ is the upper bound for x ;

$options$ is the options structure created with *psoptimset*, which includes the initial mesh size, time limit, and maximum number of iterations.

The lower bound LB and upper bound UB parameters of the optimization process are: $dist_min = 1.00m$: minimum distance value; $rf_min = 1.0\Omega$: minimum fault resistance value; $rn_min = 1.0\Omega$: minimum neutral resistance value; $comprimento - dist_min$: maximum distance value; $rf_max = 500.0\Omega$: maximum fault resistance value; $rn_max = 500.0\Omega$: maximum neutral resistance value;

4.3 Proposed fault location algorithm 2

The new proposed fault location method referred to Figure 21 is based on voltages and currents measurements. It requests information about the post-fault voltage and current phasor quantities at the substation and DG buses, provided by IEDs, as well as the distribution network operating status and electrical parameters, stored in the utility's database.

Figure 22 presents the block diagram of the proposed fault location method. As illustrated, the algorithm starts calculating the equivalent sources at the substation bus and at the buses where the DGs are connected. Then, the algorithm selects the line section to be investigated and determines the equivalent circuit of that particular line section. After this step it is possible to calculate the fault current, using information about the fault point and the fault resistance, and the post-fault voltages and currents phasor quantities at the substation. The optimization tool is used to provide the fault distance and fault resistances that minimizes the error between the measured and the calculated phasor quantities at the substation.

This proposed method locates the fault point by computing the equivalent two-port network representation of the line section under investigation accordingly to Subsection 4.3.1, then calculating the fault current in agreement with Subsection 4.3.2.1 or Subsection 4.3.2.2 and finally comparing the measured and calculated current phasors to determine the error.

Figure 21 – Radial distribution feeder - Algorithm 2

Source: the author

Figure 22 – Block diagram - Scenario 2

Source: the author

4.3.1 Two-port network representation

The algorithm uses synchronized voltage and current phasor quantities recorded at the DGs and substation buses. Then, the proposed algorithm calculates the equivalent circuit of a given line section by means of the two-port network representation, considering the distributed-parameter line model, since it is more precise. The representation of a transmission line whose line length is l is by means of the transmission matrix, considering the equivalent parameters at both line end (i.e. at the sending and receiving ends, denoted by the subscripts S and R, respectively), as in (63)

$$\begin{bmatrix} \dot{V}_S \\ \dot{I}_S \end{bmatrix} = [T(l)] \times \begin{bmatrix} \dot{V}_R \\ \dot{I}_R \end{bmatrix} \quad (63)$$

with

$$[T(l)] = \begin{bmatrix} [A(l)] & [B(l)] \\ [C(l)] & [D(l)] \end{bmatrix} \quad (64)$$

$[A(l)]$, $[B(l)]$, $[C(l)]$, $[D(l)]$ are the transmission line matrix parameters in the two-port representation, given by (65)-(68) in accordance to the procedure presented in (BOWMAN; MCNAMEE, 1964), valid for untransposed transmission lines

$$[A(l)] = \left\{ [U] + \frac{1}{2} \times [Z_\pi] \times [Y_\pi] \right\} \quad (65)$$

$$[B(l)] = [Z_\pi] \quad (66)$$

$$[C(l)] = [Y_\pi] \times \left\{ [U] + \frac{1}{4} \times [Z_\pi] \times [Y_\pi] \right\} \quad (67)$$

$$[D(l)] = \left\{ [U] + \frac{1}{2} \times [Z_\pi] \times [Y_\pi] \right\} \quad (68)$$

where

$[A(l)]$ is the open-circuit voltage rate;

$[B(l)]$ is the negative short-circuit transfer impedance;

$[C(l)]$ is the open-circuit transfer admittance;

$[D(l)]$ is the negative short-circuit current ratio;

$[U]$ is the identity matrix;

$[Z_\pi]$ is the line impedance of the equivalent π line section; and

$[Y_\pi]$ is the line admittance of the equivalent π line section.

Figure 23 – Equivalent admittance in the two-port network model with source at one end

The impedance and length of distinct lateral branches may produce the same voltages and currents at the substation bus and lead to multiple solutions, as the fault distance and resistance are unknown. The algorithm tackles this trouble by investigating all line sections so as to determine the possible fault positions, relying on an optimization method to minimize the errors between the phasor measurements and calculations and sort the most-likely solutions.

Considering the network depicted in Figure 21, the fault may be located along line sections that are quite different. One that is connected to an equivalent source at one end (e.g. line section 30 – 90) and other that is connected to two equivalent sources at both ends (e.g. line section 30 – 40). The presence or absence of sources at the both line ends of the investigated line section may request two procedures, as explained in Subsection 4.3.2.1 and Subsection 4.3.2.2.

4.3.2 Procedures

4.3.2.1 Procedure I

The line section 30-90 illustrated in Figure 21 is used to exemplify the procedure proposed within this section. In this line section, represented by Figure 23, it can be noticed that there are voltages and currents measurements available at only one line end.

The fault point is given by solving (69), taking into consideration the voltages and currents phasor quantities measured at the sending end (bus 30) and the equivalent admittance seen at this bus, as in the equivalent two-port network representation of this line section, depicted in Figure 23.

$$\begin{bmatrix} \begin{bmatrix} \dot{V}_F \\ \dot{I}_{F-90} \end{bmatrix} \end{bmatrix} = \begin{bmatrix} A(l_{30-90} - x) & B(l_{30-90} - x) \\ C(l_{30-90} - x) & D(l_{30-90} - x) \end{bmatrix} \times \begin{bmatrix} \begin{bmatrix} \dot{V}_{90} \\ \dot{I}_{90} \end{bmatrix} \end{bmatrix} \quad (69)$$

where

x is the distance from the sending end to the fault point;

l_{30-90} is the total length of the investigated line section;

The fault point x and the fault admittance $[\bar{Y}_F]$ are unknown and have to be estimated in an iterative process, whereas the voltages and currents phasor quantities at the sending and receiving ends are known.

The current at the receiving end is given by the equivalent admittance $[\bar{Y}_{90,load}]$ multiplied by the voltage, as deduced in (70).

$$[\dot{I}_{90}] = [\bar{Y}_{90,load}] \times [\dot{V}_{90}] \quad (70)$$

Consequently,

$$[\dot{I}_{F-90}] = \{[C(l_{30-90} - x)] + [D(l_{30-90} - x)] \times [\bar{Y}_{90,load}]\} \times [\dot{V}_{90}] \quad (71)$$

and

$$[\dot{V}_F] = \{[A(l_{30-90} - x)] + [B(l_{30-90} - x)] \times [\bar{Y}_{90,load}]\} \times [\dot{V}_{90}] \quad (72)$$

Hence, the fault current seen from the receiving end can be found by substituting (69) in (70), as follows:

$$\begin{aligned} [\dot{I}_{F-90}] &= \{[C(l_{30-90} - x)] + [D(l_{30-90} - x)] \times [\bar{Y}_{90,load}]\} \times \\ &\times \{[A(l_{30-90} - x)] + [B(l_{30-90} - x)] \times [\bar{Y}_{90,load}]\}^{-1} \times [\dot{V}_F] \end{aligned} \quad (73)$$

(73) can be written as (74)

$$[\dot{I}_{F-90}] = [\bar{Y}'_{eq}] \times [\dot{V}_F] \quad (74)$$

where

$$\begin{aligned} [\bar{Y}'_{eq}] &= \{[C(l_{30-90} - x)] + [D(l_{30-90} - x)] \times [\bar{Y}_F]\} \times \\ &\times \{[A(l_{30-90} - x)] + [B(l_{30-90} - x)] \times [\bar{Y}_F]\}^{-1} \end{aligned} \quad (75)$$

In turn, the fault current seen from the sending end can be found by substituting $[\bar{Y}'_{eq}]$ in (69), as follows:

$$[\dot{I}_{F-30}] = [\dot{V}_F] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\} \quad (76)$$

Therefore:

$$\begin{bmatrix} [\dot{V}_{30}] \\ [\dot{I}_{30}] \end{bmatrix} = \begin{bmatrix} [A(x)] & [B(x)] \\ [C(x)] & [D(x)] \end{bmatrix} \times \begin{bmatrix} [\dot{V}_F] \\ [\dot{I}_{F-30}] \end{bmatrix} \quad (77)$$

Figure 24 – Two-port network model with source at two ends - Situation II

The equivalent admittance seen from the sending end $[\bar{Y}_{eq}]$ can be found by substituting (76) in (77) and solving the system as follows:

$$\begin{aligned} [\dot{I}_{30}] &= \{[C(x)] + [D(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\} \times \\ &\times \{[A(x)] + [B(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\}^{-1} \times [\dot{V}_{30}] \end{aligned} \quad (78)$$

Therefore:

$$\begin{aligned} [\bar{Y}_{eq}] &= \{[C(x)] + [D(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\} \times \\ &\times \{[A(x)] + [B(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\}^{-1} \end{aligned} \quad (79)$$

Finally, the objective function f is calculated with use of (81), which calculates the difference between the actual and the calculated current at the sending end. It is noteworthy to point out that its parameters (given by (80)) change in agreement with the fault type. For ABC faults, it is obtained with use of the voltages and currents referred to phases A, B and C; for AN faults, it is obtained with use of the phase-to-ground voltages and currents referred to the phase A; for BC faults, it is given by means of the phase-to-phase voltages and the phase currents referred to the phases B and C; and for BCN faults, it is obtained with use of the voltages and currents referred to the grounded phases B and C.

$$\begin{aligned} f_{min} &= [\dot{I}_{30}] - \{[C(x)] + [D(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\} \times \\ &\times \{[A(x)] + [B(x)] \times \{[\bar{Y}_F] + [\bar{Y}'_{eq}]\}\}^{-1} \times [\dot{V}_{30}] \end{aligned} \quad (80)$$

$$f = \left| \sum_{a,b,c} f_{min} \right| \quad (81)$$

4.3.2.2 Procedure II

The line section 30-40 illustrated in Figure 21 is used to exemplify the procedure proposed within this section. In this line section, represented by Figure 24, it can be noticed that there are voltages and currents measurements available at both line ends.

The fault point is given by solving two equation systems, taking into consideration the voltages and currents phasor quantities measured at the sending end (bus 30) and

the receiving end (bus 40) of the network depicted in Figure 21, and the equivalent two-port network representation of this line section, depicted in Figure 24. According to this representation it is possible to write equations (82) and (83):

$$\begin{bmatrix} \dot{V}_{F-30} \\ \dot{I}_{F-30} \end{bmatrix} = \begin{bmatrix} [A(x)] & -[B(x)] \\ -[C(x)] & [D(x)] \end{bmatrix} \times \begin{bmatrix} \dot{V}_{30} \\ \dot{I}_{30} \end{bmatrix} \quad (82)$$

$$\begin{bmatrix} \dot{V}_{F-40} \\ \dot{I}_{F-40} \end{bmatrix} = \begin{bmatrix} [A(l_{30-40} - x)] & -[B(l_{30-40} - x)] \\ -[C(l_{30-40} - x)] & [D(l_{30-40} - x)] \end{bmatrix} \times \begin{bmatrix} \dot{V}_{40} \\ \dot{I}_{40} \end{bmatrix} \quad (83)$$

The fault current at a given point is given by the fault admittance multiplied by the fault voltage, as deduced in (84).

$$[\bar{Y}_F] \times [\dot{V}_F] = [\dot{I}_{F-40}] + [\dot{I}_{F-30}] \quad (84)$$

Therefore, the objective function f is given by (85). It is noteworthy to point out that its parameters change in agreement with the fault type, analogously to the function (81) described in Subsection 4.3.2.1. For ABC faults, it is obtained with use of the positive-sequence voltages and currents; for AN faults, it is obtained with use of the phase-to-ground voltages and currents referred to the phase A; for BC faults, it is given by means of the phase-to-phase voltages and the phase currents referred to the phases B and C; and for BCN faults, it is obtained with use of the voltages and currents referred to the grounded phases B and C.

$$f = \left| \sum_{a,b,c} f_{min} \right| \quad (85)$$

where f_{min} is the sum of relative variations of the currents calculated at the sending and receiving ends and the voltage at the fault point, as follows:

$$\Delta \dot{I}_{30} = [\bar{Y}_F] \times [\dot{V}_{F-30}] - \{[\dot{I}_{F-30}] + [\dot{I}_{F-40}]\} \quad (86)$$

$$\Delta \dot{I}_{40} = [\bar{Y}_F] \times [\dot{V}_{F-40}] - \{[\dot{I}_{F-30}] + [\dot{I}_{F-40}]\} \quad (87)$$

$$\Delta \dot{V}_F = [\dot{V}_{F-30}] - [\dot{V}_{F-40}] \quad (88)$$

$$f_{min} = \frac{|\Delta \dot{I}_{40}|}{\max \{|\Delta \dot{I}_{40}|\}} + \frac{|\Delta \dot{I}_{30}|}{\max \{|\Delta \dot{I}_{30}|\}} + \frac{|\Delta \dot{V}_F|}{\max \{|\Delta \dot{V}_F|\}} \quad (89)$$

4.3.3 Comparison between measured and calculated current phasors

The errors between measurements and calculations at the hypothetical point of fault are obtained through the objective function f defined for each algorithm and fault type. The investigation finishes when the optimization process provides the fault distance and the fault admittances that minimize the objective function.

Afterwards, the proposed fault location method proceeds with another line section until all of them are investigated. After that, the minimum error (ϵ), the fault distance (x) and the fault admittance matrix ($\bar{Y}_F$) associated with all investigated line sections are provided. The lowest minimum error is associated with the most probable fault location in most cases, as shown in Subsection 5.3.2.

4.3.4 Optimization tool

Analogously to the Section 4.2, the optimization process applied to the simulations consists of the pattern search toolbox available in MATLAB, described in (62), which returns the value of the objective function f at the solution $(x, \bar{Y}_F)$.

4.4 Proposed fault location algorithm 3

The proposed fault location method, also referred to Figure 16, is based on the short-circuit calculation in phase components. This technique combines features present in the fault location methods described in Section 4.2 and Section 4.3; it relies on information about the pre-fault and post-fault voltage and current signals recorded at the substation level, provided by IEDs, and the connection points of the distributed generation units and the operating status and electrical parameters of the distribution network, stored in the utility's database, whereas it locates the point of fault through the equivalent two-port network representation of the line section under investigation, calculating the fault current in agreement with Subsection 4.3.2.1 or Subsection 4.3.2.2 and finally comparing the measured and calculated voltage and current phasors at the substation to determine the error.

The method locates the fault point by analysing all the network sections in order to determine the fault distance and the fault resistance that produce the post-fault voltages and currents phasor quantities measured at the substation. Since the fault distance and resistances are unknown, the proposed method relies on an optimization process that estimates these quantities in order to minimize the error between the estimated phasor quantities and the measured ones.

Figure 25 presents the block diagram of the proposed fault location method. As illustrated, the algorithm starts calculating the equivalent load impedances and the equivalent

Figure 25 – Block diagram - Scenario 3

Source: the author

sources at the substation bus and at the buses where the DGs are connected. Then, it assembles the admittance matrix of a particular line section and calculates the hypothetical point of fault, inserting the estimations about the fault distance and the fault resistance in the admittance matrix. Afterwards, it calculates the post-fault voltages and currents phasor quantities at the substation and the value of the optimization function for that line section and uses the optimization tool to provide the fault distance and fault resistances that minimizes the error between the measured and the calculated phasor quantities at the substation. This procedure is repeated until all line sections are investigated.

Therefore, the fault location method may be divided into four main steps presented in Subsection 4.4.1, Subsection 4.4.2 and Subsection 4.4.3: estimation of the equivalent sources and load impedances; estimation of the equivalent two-port network representation of the investigated line section; estimation of the post-fault voltages and currents phasor quantities and comparison between the measured and calculated values at the substation bus. The optimization method is described in Subsection 4.4.4.

4.4.1 Estimation of the equivalent sources and load impedances

The algorithm proposed in this paper depends on the correct representation of loads and generators. Hence, it assumes that impedances may represent accurately the electric loads connected to the distribution transformers, while equivalent sources and impedances may represent the distributed generation units and the substation, analogously to the

Section 4.2 as presented in Subsection 4.2.1.1 and Subsection 4.2.1.2.

4.4.2 Estimation of the equivalent two-port network representation of the investigated line section

The estimation of the two-port representation of the investigated line section is analogous to the procedure detailed in Subsection 4.3.1 considering the scenarios described in Subsection 4.3.2.1 and Subsection 4.3.2.2 within the equivalent circuit illustrated in Figure 19. However, this fault location method includes the point of fault in the matrix representation, so does the fault admittance, which means representing the fault point as an existent bus in the distribution network. In addition, the fault distance is estimated and applied to the two-port network matrix representation so that the calculations can be performed.

4.4.3 Estimation of the post-fault voltages and currents phasor quantities at the substation

The estimation of the post-fault voltages and currents phasor quantities at the substation bus takes into consideration the equivalent two-port representation described in Subsection 4.4.2. The investigated line section is partitioned at the fault point, as in Subsection 4.2.4, which means adding a new line and column to represent the fault point as a new bus in the admittance matrix. However, this algorithm includes the fault admittances instead of the fault current in the calculations, and (58) is written as (90)

$$[\bar{Y}_{bus,F}] = \begin{bmatrix} \ddots & \vdots & \vdots & \cdots & 0 \\ \cdots & (\dots + \bar{Y}_{30-F}) & 0 & \cdots & -\bar{Y}_{30-F} \\ \cdots & 0 & (\dots + \bar{Y}_{F-40}) & \cdots & -\bar{Y}_{F-40} \\ \cdots & \vdots & \vdots & \vdots & \vdots \\ \cdots & -\bar{Y}_{30-F} & -\bar{Y}_{F-40} & \vdots & \bar{Y}_F + \bar{Y}_{30-F} + \bar{Y}_{F-40} \end{bmatrix} \quad (90)$$

Then, the algorithm determines the post-fault voltages and currents at the substation using the modified grid nodal admittance matrix with the equivalent current sources of the substation and DGs, and (59) is written as (91).

$$\begin{bmatrix} \dot{V}_{10} \\ \dot{V}_{20} \\ \vdots \end{bmatrix} = [\bar{Y}_{bus,F}]^{-1} \times \begin{bmatrix} \dot{I}_{eq,ST} \\ \vdots \\ \dot{I}_{eq,GDn} \end{bmatrix} \quad (91)$$

The post-fault current leaving the substation (bus 10) is calculated through (60). Finally, the algorithm compares the actual values to the calculated ones with use of (61).

After investigating this section, the proposed fault-location method proceeds with investigating another one, until all line sections are investigated. After finishing the

investigations, the proposed method provides the minimum error (ϵ), the fault distance (x) and the fault admittance matrix ($\bar{Y}_F$), associated with all investigated line sections. As presented in Subsection 5.3.1 the lowest minimum error is associated with the most probable fault location in most of the cases.

4.4.4 Optimization tool

The optimization process applied to the simulations consists of the pattern search toolbox available in MATLAB, analogously to the fault location methods presented in Section 4.2 and Section 4.3, which returns the value of the objective function (61) at the solution $(x, \bar{Y}_F)$.

4.5 Evaluation of the fault location algorithms

This section aims at evaluating and discussing the three algorithms presented in this chapter to tackle the problem of fault location in power distribution networks with distributed generation. It is important to point out that the mathematical and computational complexity of the three procedures is the same. The algorithms described in Section 4.2 and Section 4.4 are preferred when the Thévenin equivalents can be estimated with use of the injected power. The former applies the fault current as an injected current in order to compute the point of fault, whereas the latter assembles the admittance matrix considering the investigated line section and including in it the estimated point of fault. In turn, the algorithm described in Section 4.3 is advantageous when the measurements of voltages and currents are known at the substation bus and the buses where the DGs are connected.

* * *

Simulations and Results

5.1 General

This chapter presents the simulations and the results obtained for the scenarios taken into account within the fault location algorithms presented in Section 4.2, Section 4.3 and Section 4.4. Then, the accuracy of the proposed fault location algorithm is evaluated in function of the parameters applied to the simulations.

5.2 Simulation premises

The fault location system was simulated using test data produced by ATP. Short-circuit simulations were performed using a distribution feeder whose topology is depicted in Figure 16. This distribution feeder has a nominal voltage of 13.8 [kV] and is composed of a main branch, where DG1 is connected. Along the main branch there are three tap points where lateral branches are connected and some of these branches end at DG2, DG3 to DG4. The total length of the feeder is 8.7 [km], considering all line sections.

For simplification purposes, the DG units and the substation were modelled as Thévenin equivalents or represented directly by the voltages and currents phasor quantities measured at their connection points, whereas the loads were modelled as constant impedances with a total consumption of 2.2 [MVA] (power factor of 0.92). These assumptions consider that the models applied to these elements do not interfere with the fault location algorithms.

The three-phase short-circuit power (S_{sc}^{3f}), the line-to-ground short-circuit power (S_{sc}^{1f}) and the voltage level at the substation and DG buses are presented in Table 4, whilst the impedances $\bar{z}_p$ and $\bar{z}_m$ are presented in Table 5. The poles and conductors used in the simulation cases are typical of 13.8 [kV] voltage level and are depicted in Figure 26. The line sections were simulated using the ATP Line Constants supporting routine and these sections are composed of 336.4 MCM ACSR phase conductors (mid-span sag of

Figure 26 – Distribution pole

Table 4 – Short-circuit rating

Bus	S_{sc}^{3f} [MVA]	S_{sc}^{1f} [MVA]	$\dot{v}$ [p.u.]
Substation	$1000\angle -80^\circ$	$1200\angle -85^\circ$	$1.05\angle 0^\circ$
DG1	$100\angle -85^\circ$	$110\angle -87^\circ$	$1.00\angle -2^\circ$
DG2	$80\angle -75^\circ$	$75\angle -80^\circ$	$1.01\angle -1^\circ$
DG3	$100\angle -87^\circ$	$130\angle -89^\circ$	$0.99\angle -3^\circ$
DG4	$70\angle -80^\circ$	$85\angle -85^\circ$	$1.03\angle -1.5^\circ$

Table 5 – Short-circuit impedance data

Bus	$\bar{z}_p$ [Ω]	$\bar{z}_m$ [Ω]
Substation	$0.0138 + 0.1581i$	$0.0192 + 0.0295i$
DG1	$0.0906 + 1.7289i$	$0.0754 + 0.1683i$
DG2	$0.4409 + 2.5006i$	$0.1752 + 0.2012i$
DG3	$0.0256 + 1.4647i$	$0.0741 + 0.4371i$
DG4	$0.1953 + 2.2319i$	$0.2772 + 0.4473i$

9.5 [m]) and 1/0 copper ground wires (mid-span sag of 8.5 [m]).

Table 6 presents the fault parameters applied in the ATP simulations. Four fault types, with fault resistances varying from 0 up to 50 [Ω], were simulated in 12 fault points. As a result, 168 simulation cases were produced.

Table 6 – Simulation data

Fault type	Fault instant [ms]	Number of points	R_F [Ω]	Number of simulations
AN	37.50	12	0, 1, 5, 20, and 50	60
BC BCN	37.50	12	0, 1, 5	72
ABC	37.50	12	0, 1, 5	36

5.3 Simulation results

The average error μ [m], the deviation σ [m], the maximum error $\max$ [m], and the minimum error $\min$ [m] of the proposed algorithms are presented in Subsection 5.3.1 to Subsection 5.3.4, considering the first line section indicated by each fault location procedure. The results are based upon the assumptions displayed in Section 5.2.

Even though the indicated line section is the first ranked in most cases, it is noteworthy that the problem of fault location in distribution networks has multiple solutions. As previously mentioned, the proposed methods do not aim at providing a single solution. Thus, the evaluation process takes into account not only the ideal scenario, in which all the parameters are represented exactly, but also scenarios in which there are uncertainties about the loads, the equivalent sources and impedances, the phasor quantities and incorrect line sections parameters, as follows.

5.3.1 Algorithm 1

In this case study, the faults were simulated at the time instant 37.5 [ms] in 12 points coincident with the buses 20-130 comprised by the distribution network illustrated in Figure 16. It is assumed in the simulations that all loads are represented correctly, the network parameters are the same as simulated in ATP and equivalent sources are also correct.

Table 7 indicates that the highest average error occurs for a BCN (phase-to-phase-ground fault), whereas the maximum error occurs for a ABC fault (three-phase fault) and is equal to 8.2% of the feeder's length. The minimum errors, equal to 1 [m], are due to the lower band parameter defined in the optimization process implemented in MATLAB. By and large, the average errors lie between 25 [m] and 110 [m] and indicate a high level of accuracy.

Table 7 – Fault location errors for the algorithm 1

Distance error	Fault type			
	ABC	AN	BC	BCN
$\mu [m]$	101	32	26	108
$\sigma [m]$	181	91	78	102
$\max [m]$	709	399	398	338
$\min [m]$	1	1	1	1

Table 8 – Points of the applied faults

Line section	Distance from	
	first bus [m]	second bus [m]
10-20	1222	278
20-30	362	38
20-60	229	1571
30-40	548	52
30-90	253	147
60-70	98	902
60-80	111	289
60-120	164	136
40-50	575	25
40-100	482	18
120-130	315	168
100-110	971	29

5.3.2 Algorithm 2

In this case study, four fault types were simulated at the time instant 37.5 [ms] in 12 fault points whose locations are given in Table 8, as follows.

The results of the proposed method for the case study without forced errors are presented in Table 9. Considering the correct estimations, the maximum error occurs for a BC fault (phase-to-phase fault), equals to 5.0% of the feeder's length, as well as the highest average error. Except for the BC fault, the errors found in this case study are lower in comparison to the algorithm 1. The average errors lie between 4 [m] and 55 [m] and indicate a high level of accuracy.

5.3.3 Algorithm 3

In this case study, analogously to Subsection 5.3.1, the faults were simulated at the time instant 37.5 [ms] in 12 points coincident with the buses 20-130 comprised by the distribution network illustrated in Figure 16.

The results of the proposed method for the ideal scenario (without forced errors) are presented in Table 10. Considering the correct line sections' estimations, the maximum

Table 9 – Fault location errors for the algorithm 2

Distance error	Fault type			
	ABC	AN	BC	BCN
μ [m]	4	4	55	20
σ [m]	8	8	125	26
max [m]	36	40	438	73
min [m]	0	0	0	0

Table 10 – Fault location errors for the algorithm 3

Distance error	Fault type			
	ABC	AN	BC	BCN
μ [m]	156	156	130	135
σ [m]	198	224	150	155
max [m]	574	916	451	617
min [m]	9	14	3	6

error occurs for a AN fault (phase-to-ground fault) and is equal to 10.5% of the feeder's length, whereas the highest average errors occur for AN and ABC faults. The minimum errors do not reach the lower band parameter defined in the optimization process implemented in MATLAB, since the minimum error, found for a BC fault, is equal to 3 [m]. By and large, the average errors lie between 130 [m] and 160 [m] and indicate a high level of accuracy. Nonetheless, the errors found in this case study are worse than the errors from the algorithms 1 and 2, except for the maximum error calculated for a ABC fault, whose highest value is obtained in the algorithm 1.

5.3.4 Sensitivity analysis

The sensitivity analysis showed in this section aims at verifying the effect of a certain level of error in the estimation of equivalent sources, line parameters, loads and phasors on the proposed methods. The choice of models has taken into consideration the ease of implementation into the fault location algorithms.

5.3.4.1 Errors in the equivalents estimation

The proposed method estimates the equivalent sources and impedances as presented in Section 4.2 and Section 4.4. However, the pre-fault load flow may present a certain level of error. Therefore, a statistical approach was used to determine the influence of these quantities in the fault location results. This approach consisted of multiplying the equivalent sources and impedances quantities by a random number, chosen from a

Table 11 – Fault location errors with errors in the equivalent sources estimations

Distance error	Fault type			
	ABC	AN	BC	BCN
Algorithm 1				
$\mu [m]$	116	109	57	160
$\sigma [m]$	198	220	126	116
max $[m]$	849	999	398	442
min $[m]$	1	1	1	1
Algorithm 3				
$\mu [m]$	166	176	208	182
$\sigma [m]$	128	273	166	166
max $[m]$	482	966	550	580
min $[m]$	32	25	25	11

normal distribution $\mathcal{N}(\mu, \sigma^2)$ with mean μ one and standard deviation σ of 10%, in order to make them different from the ATP simulations, as in

$$\dot{I}_{eq,sc}' = \mathcal{N}(\mu, \sigma^2) \cdot \dot{I}_{eq,sc} \quad \text{and} \quad \bar{Z}_{eq,sc}' = \mathcal{N}(\mu, \sigma^2) \cdot \bar{Z}_{eq,sc} \quad (92)$$

where

$\mathcal{N}(\mu, \sigma^2)$ is a random number;

$\bar{Z}_{eq,sc}$ is the equivalent impedance at the substation or DG; and

$\dot{I}_{eq,sc}$ is the equivalent current source at the substation or DG.

Table 11 indicates that the maximum error referred to the algorithm 1 occurs for a AN fault (phase-to-ground fault). This error is equal to 11.5% of the feeder's length and the average errors lie between 55 [m] and 160 [m]. Meanwhile, it indicates that the maximum error related to the algorithm 3 occurs for a BCN fault and is equal to 11.49% of the feeder's length. The average errors lie between 60 [m] and 160 [m] and suggest a high level of accuracy.

5.3.4.2 Errors in the loads estimation

The proposed method estimates the loads' impedances as presented in Section 4.2, Section 4.3 and Section 4.4. However, this approach may be innacurate since it is impossible to determine correctly the load at each distribution transformer. Therefore, a statistical approach was used to determine the influence of these quantities in the fault location results, as in Subsection 5.3.4.1, with

$$\dot{I}_{eq,load}' = \mathcal{N}(\mu, \sigma^2) \cdot \dot{I}_{eq,load} \quad \text{and} \quad \bar{Z}_{eq,load}' = \mathcal{N}(\mu, \sigma^2) \cdot \bar{Z}_{eq,load} \quad (93)$$

where

Table 12 – Fault location errors with errors in the load estimation

Distance error	Fault type			
	ABC	AN	BC	BCN
Algorithm 1				
μ [m]	107	66	28	120
σ [m]	181	167	80	121
max [m]	703	860	404	406
min [m]	1	1	1	2
Algorithm 2				
μ [m]	5	30	8	17
σ [m]	9	68	17	26
max [m]	36	278	51	79
min [m]	0	0	0	0
Algorithm 3				
μ [m]	117	154	142	134
σ [m]	114	218	162	167
max [m]	362	870	524	702
min [m]	7	14	2	4

$\mathcal{N}(\mu, \sigma^2)$ is a random number;

$\bar{Z}_{eq,load}$ is the equivalent load impedance at a given bus; and

$\dot{I}_{eq,load}$ is the equivalent load current at a given bus.

Table 12 indicates that the maximum error related to the algorithm 1 occurs for a AN fault (phase-to-ground fault). This error is equal to 9.9% of the feeder's length and the average errors lie between 30 [m] and 121 [m]. In addition, the maximum error referred to the algorithm 2 occurs for a AN fault (phase-to-ground fault), equals to 3.2% of the feeder's length. The average errors lie between 5 [m] and 30 [m] and indicate a high level of accuracy. Regarding the algorithm 3, the maximum error occurs for a AN fault (phase-to-ground fault), equals to 10.0% of the feeder's length. The average errors lie between 115 [m] and 165 [m] and indicate a high level of accuracy.

5.3.4.3 Errors in line sections parameters

The proposed method uses information about the line sections electrical parameters that may be stored in a database. However, the actual electrical parameters may be slightly different from the stored ones. Therefore, it is necessary to evaluate the influence of this parameters with regards to the accuracy of the proposed method. The approach used to perform this evaluation consisted of using electrical parameters different from the ones simulated in ATP. The difference is related to the soil resistivity ($400 [\Omega \cdot m]$ instead of $100 [\Omega \cdot m]$) and distribution pole geometry (phase conductors 12 [m] from the ground and neutral conductor 10 [m] from the ground). Table 13 indicates that the maximum

Table 13 – Fault location errors with errors in the line section parameters

Distance error	Fault type			
	ABC	AN	BC	BCN
Algorithm 1				
$\mu [m]$	72	40	90	136
$\sigma [m]$	62	95	68	88
max $[m]$	181	399	280	317
min $[m]$	1	1	1	8
Algorithm 2				
$\mu [m]$	15	14	73	62
$\sigma [m]$	12	14	98	35
max $[m]$	54	44	289	97
min $[m]$	4	0	3	2
Algorithm 3				
$\mu [m]$	138	149	197	177
$\sigma [m]$	103	235	149	174
max $[m]$	357	965	474	667
min $[m]$	9	3	33	20

error referred to the algorithm 1 occurs for a AN fault (phase-to-ground fault). This error is equal to 4.6% of the feeder's length and the average errors lie between 40 [m] and 140 [m]. Regarding the algorithm 2, the maximum error occurs for a BC fault (phase-to-phase fault), equals to 3.3% of the feeder's length. The average errors lie between 15 [m] and 75 [m] and indicate a high level of accuracy. In turn, the maximum error referred to the algorithm 3 occurs for a AN fault (phase-to-ground fault), equals to 11.1% of the feeder's length. The average errors lie between 140 [m] and 200 [m] and indicate a high level of accuracy.

5.3.4.4 Errors in the phasors quantities

The phasor quantities may present a certain level of error because of the acquired measurements. Therefore, a statistical approach was used to determine the influence of these quantities in the fault location results by adding a random phasor error with magnitude equals to 1% of the actual phasor quantity and angle with a random value between 0 and 360 degrees, as in

$$\dot{I}_{eq,SE}' = \dot{I}_{eq,SE} + \Delta \dot{I} \quad (94)$$

where

$\Delta \dot{I}$ is a random phasor error; and

$\dot{I}_{eq,SE}$ is the equivalent current at the substation or DG bus.

Table 14 – Fault location errors with errors in the phasor quantities

Distance error	Fault type			
	ABC	AN	BC	BCN
Algorithm 2				
μ [m]	5	115	50	17
σ [m]	9	359	102	24
max [m]	36	1738	438	67
min [m]	0	0	0	0
Algorithm 3				
μ [m]	156	165	145	136
σ [m]	122	233	165	162
max [m]	362	916	551	663
min [m]	7	14	3	0

Figure 27 – Histogram of correct line sections identification

The results of the proposed method for this scenario are presented in Table 14. Considering the correct estimations, the maximum error related to the algorithm 2 occurs for a AN fault (phase-to-ground fault), equals to 19.9% of the feeder's length. The average errors lie between 5 [m] and 115 [m] and indicate a high level of accuracy. In turn, the maximum error within the algorithm 3 occurs for a AN fault (phase-to-ground fault), equals to 10.5% of the feeder's length. The average errors lie between 136 [m] and 165 [m] and indicate a high level of accuracy.

5.3.5 Histogram

Figure 27 illustrates the percentages of correct identifications of the faulted line section in function of the solutions ranked by the optimization process. It can be noticed that the correct line section is the first ranked in most cases, and that the three most-likely solutions comprehend almost all occurrences; thereby, the first solution provided by the

fault location algorithms is highly likely to be the faulted line section, and the three first solutions are highly likely to indicate the faulted line section in all case studies. Nevertheless, it is noteworthy that the problem of fault location in distribution networks has multiple solutions, as previously mentioned, and the proposed method does not aim to provide a single solution. Figure 27 presents the percentage of correct identifications, considering the case study without forced errors.

The most probable locations of the fault are ranked according to the error computed by the optimization process explained in Section 4.2 to Section 4.4. For evaluation of the accuracy of the proposed method, the result is assumed to be correct when the most probable location indicated by the algorithm matches the network section where the fault occurred.

* * *

Conclusion

Conclusion

This report presented three fault location algorithms capable of identifying the faulted section and locating the fault point. To do so, it was necessary to evaluate the cutting-edge fault location algorithms in power distribution networks with the presence of DG in chapter Chapter 2 and also the fault behaviour of the DG and load technologies currently in use in Chapter 3. Afterwards, Chapter 4 described the proposed fault location algorithms, whereas Chapter 5 showed details of the simulations.

The results indicated that the proposed methods are accurate, regardless of the fault type, but affected by errors in estimating the phasor quantities recorded at the substation and DG buses, the equivalent sources and impedances that represent the analytical models of the distributed generation units and the equivalent load impedances, as well as incorrect line sections parameters. Overall, the algorithm #2 presented the best results in terms of accuracy and correct line section identification, while the algorithm #3 provided the worst ones. On the whole, the results provided by the algorithm #1 are intermediate values between the algorithms #2 and #3, but a few exceptions were found in all case studies.

By and large, all the proposed algorithms show that the impact of the forced errors on the fault location accuracy is relatively low, since the uncertainties did not interfere with the ability to adequately indicate the faulted line section. The average errors saw no significant change within a given scenario, regardless of the error added to the simulations.

Further Perspectives

Further developments and enhancements in this field of study may comprise:

- a) *modelling*: customised solutions for real-world scenarios.
- b) *fault location algorithm*: new software tools and alternative computing methods.

- c) *fault location method*: study of new procedures for fault location in power distribution networks with distributed generation.
- d) *simulations and tests*: more simulations and different study cases performed with use of different analytical models of DG units and loads developed within this research project, in order to validate the proposal in different settings.

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