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Industrial Electrical Engineering and Automation

Island Operation with Induction Generators

Fault Analysis and Protection

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We cannot solve problems with the same thinking we used when we created them

A. Einstein

Abstract

Following major blackouts all over the world, in recent years power supply reliability has become a very important issue. Important decisions at political level have pushed many electricity Distribution Network Operators to start major activities striving for improved supply reliability. At the same time, electrical distribution networks are facing a small revolution. Having been mainly passive networks without generation capability for very long time, they are increasingly becoming active networks with considerable amount of local small-scale generation, so called distributed generation. The increasing trend for distributed generation is favored also by environmental policies.

Among other benefits of distributed generation, it also opens new opportunities for improving power supply reliability. Theoretically, distributed generators are suitable to supply electricity to a certain amount of customers located in their vicinity and disconnected from the major grid, that is in island operation. Practically however, technical and safety considerations have prevented so far the general utilization of distributed generators in island operation. Two of the technical issues to be faced when operating a network with distributed generation in island operation are voltage and frequency control and fault clearing.

This thesis focuses on the issue of fault clearing in island operated distribution networks, when the distributed generation supplying the island consists of induction generators. Many hydro-power and wind-power distributed generators are of induction type. The application of induction generators in a stand-alone mode, often referred to as self-excited induction generator, has been known for long time. However, it has mainly been

applied to very small systems and not to supply a larger distribution network.

Fault clearing in power systems is traditionally based on the assumption that the main source of fault current is constituted by synchronous generators. The induction generator behavior during a fault is very different from that of a synchronous generator. Therefore, when a part of the power system, as part of a distribution network, is operated in island with only an induction generator source, it is not clear if its fault clearing system will still perform properly.

In this thesis, a general analysis of the fault behavior of an induction generator connected to a distribution network is carried out. The analysis shows that the induction generator demagnetizes when a short-circuit occurs in the network. The generator is instead capable of sustaining the voltage during single-phase-to-earth faults in the distribution network. Based on this behavior, some considerations on the protection system necessary to assure correct fault clearing are done.

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A special thank goes to all the people at the IEA department for the good and relaxed time I had here. I thank Anna and Johan that have been my room mates during these two years and that have decisively contributed to my improvements in Swedish. I would also like to thank Johan for the precious help he gave me with all the lab work and for having shared with me the writing of chapter 3 of this thesis.

This work has been financed by Svenska Kraftnät. Kenneth Walve, formerly at Svenska Kraftnät, is specially thanked for his ideas and support to the work.

Finally, I would like to sincerely dedicate the thesis to all the people close to me. In particular to my parents, my sister and my girlfriend Ela.

Lund, 12 January 2009
Francesco Sulla

Contents

Chapter 1

Introduction

Traditionally, power system distribution networks have been passive networks with an unidirectional power flow from the high voltage levels to customers at lower voltages. In recent years, distribution networks are undergoing an important change hosting an increasing amount of decentralized generation, i.e. distributed generation. The presence of distributed generation makes the distribution networks active networks, with the possibility of power production at local level.

The increasing diffusion of distributed generation is due to many factors. Society demands environmental-friendly energy and governments often promotes renewable energy sources. By their nature, renewable energy sources are mostly delocalized with limited production capability and therefore their exploitation takes often the form of small to medium scale distributed generation.

Our society has become highly dependent on electricity supply. Recent major blackouts (Italy and USA 2003, Sweden 2003 and 2005) have clearly shown the negative socio-economical consequences power outages may have on almost each sector of modern society. They also pointed out the importance of power supply reliability. Important industrial sectors and infrastructures are equipped with emergency back-up electricity sources to minimize the risks of damages due to power outages. Private customers may also be seriously affected by long power outages. A critical situation may be represented for example by long outages preventing domestic electric heating during cold winter periods. Long outages may take place as a consequence of major damages to the electric power system, as it has been the case following the storm Gudrun that hit southern Sweden in January 2005 (Johansson et al. 2006).

The presence of distributed generation in the distribution networks offers the new opportunity of locally reducing the duration of power outages by island operation. An island is a part of a power system, which has been split from the adjacent power system and is operated autonomously. Although it is an attractive opportunity, island operation of distributed generation is generally not allowed today by electric utilities. At the same time, the interest in island operation of distributed generation is increasing in the last years. Economic considerations may represent a decisive factor toward a different and more positive approach to island operation of distributed generation, which may represent an important means for the utilities to reduce the costs of compensation they are liable to pay to their customers following long outages.

1.1 Motivation

Distributed generation may be divided into different groups depending on the type of network interface: induction generators, synchronous generators or power electronic converters. This research project focuses on the first of these groups. It deals with the fault analysis and protection of an island-operated network with distributed induction generation.

The project has been motivated by different reasons. The fundamental idea is that island operation of distributed generation may help reducing power outages that may prove to be critical for many sectors of society and costly for power utilities. Reliability of power supply and minimization of power outages are today key issues to be addressed by electrical utilities.

From the 1st January 2006, Swedish law (Ellag 1997:857) establishes economic compensation for customers in case of outages longer than twelve hours. Figure 1.1 shows the increasing amount of compensation as a function of outage duration. The maximum compensation amount is set to be 300 % of the customer estimated yearly network tariff. The same law establishes that, starting from 1st January 2011, outages longer than 24 hours are not allowed.

This fact along with the extensive damages to the power system caused by the hurricane Gudrun has induced some utilities to start major investments to secure the power supply reliability in their networks. Typical examples of these investments are the extensive replacement of overhead lines with underground cables in distribution networks and the purchase of small mobile synchronous generation units to energize the network from proper points during outages.

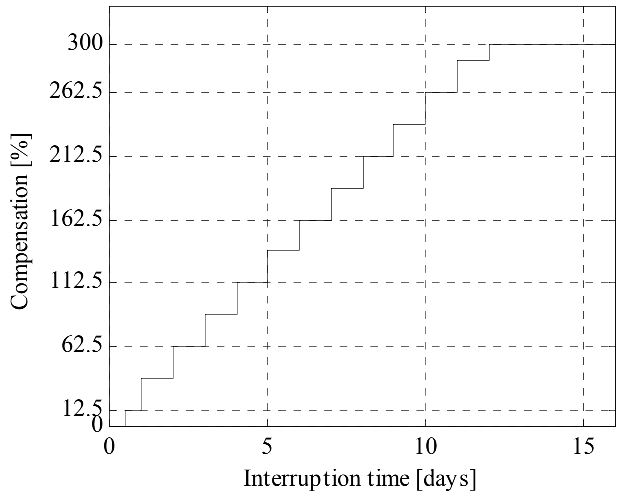

Figure 1.1 Compensation to customers as a function of interruption time. The amount of compensation is expressed in percent of the estimated yearly network tariff.

Distributed generation is another resource that may help in reducing power outages. Conceptually, the energization of an island-network through distributed generation is similar to the use of small mobile generation units. However, distributed generation has seldom been exploited for this purpose. In most cases, distributed generators are not properly equipped to control the voltage and the frequency in an island-network. Additional equipment would be required in this case, but the benefits deriving from island operation of these distributed generators could justify the extra costs. Island operation of distributed generation could also be used to supply, during emergencies, components whose proper functioning is critical in handling crises. One such component may be represented by the batteries in mobile phone base stations.

This project focuses only on distributed induction generation. This is motivated by the fact that induction generators are common among distributed generators, they are a cost effective solution, require little maintenance work and have proven to be reliable. Induction generators are commonly installed in wind farms and in small-scale hydro-power plants. Hence, induction generators may be the only or the dominating type of distributed generation in a local network to be potentially operated in island.

The induction generator is commonly not considered suitable to island operation, because unlike the synchronous generator, it does not have an internal magnetization source and lacks an explicit capability of controlling the voltage. However, induction generators can be used to supply an island. Since the beginning of the nineteen hundreds it is known the ability of an induction generator to self-excite if sufficient capacitors are shunt-connected at its terminals. Once the generator is self-excited, it can supply a load. The voltage can then be controlled using power electronic devices or switched capacitors.

This work is part of a larger project on island operation of induction generation. The other part of the project focuses on voltage and frequency control. This part focuses entirely on fault analysis and protection. Though the expression for the three-phase short-circuit current delivered by an induction generator is common in the literature, its behaviour during unbalanced faults is not widely investigated. This is especially true if the generator is supposed to be operated in island connected to a distribution network.

1.2 Objectives

The main objective of the work presented here is to answer the question whether and how it is possible to assure correct fault clearing during island operation of distributed induction generation in distribution networks. Correct fault clearing is essential to ensure safe operation.

The first step to answer the question is to analyze the behavior of the island-operated induction generator during balanced and unbalanced faults. It is known that an induction generator demagnetizes and loses its voltage when a three-phase short-circuit is applied at its terminals. The next question is about the generator behavior during an unbalanced fault. According to Swedish regulations, it is mandatory to detect and disconnect earth-faults in distribution networks within 5 seconds. The protection principle adopted to disconnect an earth-fault will depend on the behavior of the induction generator during the earth-fault. Is the generator able to sustain the voltage in the network under this condition? The earthing arrangement of the distribution network may change in island operation, because of the loss of the earthing equipment normally located at the point of common coupling. The point of common coupling along with the earthing equipment may not be part of the island-operated network, which will therefore be unearthed.

A secure and dependable protection scheme can be set up only after knowing how the induction generator behaves during faults. Synchronous and induction generators may respond differently to a fault, therefore requiring different protection schemes. During grid-connected operation, the protection scheme in a distribution network is based on the assumption that synchronous generators will deliver the fault current via substation transformers. It is uncertain if the same protection equipment can be used also during island operation with induction generators. This work will investigate to what extent this is possible and it will indicate the need for a different approach, when necessary, for the distribution network protection during island operation with induction generation.

The results from this analysis may be important in assessing the technical and economical feasibility of island operation with induction generation. A need for major changes to the protection system, as compared to grid-connected operation, would represent a further barrier for the utilization of island operation of distributed induction generation. It would prevent a more positive approach on island operation of distributed generation and induction generation in particular. It would represent a further barrier in changing the attitude to island operation of distributed generation from being a problem to avoid toward being a valuable resource.

1.3 Outline of the Thesis

Chapter 2 gives a brief summary on the protection scheme for distributed generators as reported in the Swedish recommendation "*AMP - Anslutning av mindre produktionanläggningar till elnätet*", on which most local connection requirements for distributed generators are based. It also presents briefly some aspects of power quality in distribution networks.

Chapter 3 introduces the principle of self-excitation of an induction generator with both a theoretical and an experimental approach. A recursive algorithm for calculating its steady-state performance is presented. The chapter has been written in collaboration with Johan Björnstedt.

Chapter 4 presents the theory for calculating the three-phase short-circuit current of an induction generator. Some considerations for modeling the induction generator under unbalanced fault conditions are also done.

Chapter 5 presents the models of the various component used in the performed simulations.

Chapter 6 presents the dynamic behavior of the self-excited induction generator during an earth-fault in the distribution network. Different earthing arrangements have been considered. Results from simulations are shown. It also presents a way of modeling the induction generator during earth-faults for carrying out classical symmetrical components calculations.

Chapter 7 presents the results from simulations of short-circuits in the distribution network. The influence of various parameters on the short-circuit current delivered by the generator is analyzed.

Chapter 8 investigates the low-voltage ride-through capability of the self-excited induction generator. Different fault scenarios are considered. A brief comparison with the ride-through capability of a synchronous generator is presented.

Chapter 9 focuses on the protection of the distribution network in island operation with a self-excited induction generator. Both unselective and selective protection systems are analyzed.

Chapter 10 summarizes the main conclusions and contributions of this work, along with some suggestions for future work.

1.4 Contributions

The major contribution of this thesis is showing that safe operation and correct fault clearing in an island-operated distribution network with induction generation is achievable without major changes and with a limited economic investment on the protection system.

The work presents a wide analysis of the fault behaviour of the island-operated induction generator connected to a distribution network. It is hoped that the analysis may help understanding and predicting the short-circuit and earth-fault behaviour of an induction generator.

It is pointed out what kind of protection relays are needed to assure correct fault clearing in case of short-circuits and earth-faults. First, it has been assumed that an unselective protection strategy is adopted, i.e. the generator is disconnected when a fault occurs in the network. Then a selective protection scheme is considered. The requirements on the operating speed of an overcurrent relay to assure selective short-circuit protection in an island-operated network have been highlighted. An analysis on the possibility of adopting selective earth-fault protection schemes in an unearthed or resonant-earthed distribution network in island operation with an induction generator has been carried out.

A new method for estimating the zero sequence voltage in the distribution network to be used for unselective earth-fault protection is proposed. The method permits to use only one voltage transformer on the medium voltage side of a distributed generator step-up transformer, instead of the three voltage transformers needed with the classical broken-delta arrangement.

A recursive algorithm to calculate the steady state performance of a self-excited induction generator supplying a constant impedance load is presented. The algorithm assumes a known constant frequency in the network. The algorithm permits the representation of the generator and load characteristic in the same plane used to represent the no-load voltage-current curve of the induction generator alone. Therefore, it calculates the steady-state points with the same intuitive approach used to determine the no-load operation point of a self-excited induction generator.

A brief investigation on the fault ride-through capability of an island-operated induction generator has been presented.

1.5 Publications

[1] Sulla F., Samuelsson O., (2008). Estimation of the Zero Sequence Voltage on the D-side of a Dy Transformer by Using One Voltage Transformer on the D-side, Presented at: *The 9th International Conference on Developments in Power System Protection (DPSP2008)*, Glasgow, UK, 17-20 March 2008

[2] Sulla F., Samuelsson O., (2008). Analysis of Island-Operated Distribution Networks with Distributed Induction Generation under Fault Conditions, Presented at: *43rd International Universities Power Engineering Conference (UPEC2008)*, Padova, Italy, 1-4 September 2008

[3] Sulla F., Samuelsson O., (2008). Short-Circuit Analysis and Protection of a Medium Voltage Network in Island Operation with Induction Generation, Presented at: *Eight Nordic Distribution and Asset Management Conference (NORDAC2008)*, Bergen, Norway, 8-9 September 2008

Chapter 2

Protection and Power Quality

A distributed generator is generally equipped with a set of protections as required by the owner of the network where the generator is connected. The type of protections and their settings are chosen so that the DNO has the certainty that correct fault clearing in the network is assured also in the presence of distributed generators. In this chapter a standard protection scheme for small-scale distributed generators, following the Swedish recommendation "*AMP - Anslutning av mindre produktionanläggningar till elnätet*", is presented. After the discussion of some power quality issues, it is pointed out that some of the protection settings need to be changed for island operation. Some considerations for choosing acceptable voltage and frequency variations during island operation are also presented.

2.1 Protection scheme for distributed generation

The functions of a protection scheme for a distributed generator are primarily to avoid damage to the equipment at the generator station and to assure a safe fault clearing in the distribution network. Electric utilities do not allow non-intentional islanding of distributed generators. Non-intentional island operation of distributed generators may cause serious concerns about safety and quality of power delivered to the customers. Therefore, the protection scheme for a distributed generator always includes one or more functions aimed at detecting and terminating a non-intentional islanding.

A general protection scheme for a distributed generator will also include some form of protection against abnormal operating conditions that are not directly the cause of a fault in the network, but whose prolonged persistence may cause damages to the equipment at the generator station. This thesis focuses on fault analysis rather than abnormal operating conditions. One example of abnormal operating condition may be represented by a low frequency in the system. The presence of the necessary form of protections against abnormal operating conditions is taken for granted in the remainder of the work.

The protection scheme for small-scale distributed generation recommended by the Swedish AMP is summarized in Table 2.1. It is important to point out that AMP recommendations are thought from the DNO point of view and aim therefore primarily at assuring a correct fault clearing in a distribution network with distributed generation. Additional protection functions could be implemented as well, if necessary to protect the generator station equipment for example.

Table 2.1 Distributed generator protection according to AMP

Type of Protection	**Setting of protection**
Overfrequency	51 Hz, 0.5 s
Underfrequency	48 Hz, 0.5 s
Three-phase overvoltage	1st step: +6 %, 60 s
	2nd step: +20 %, 0.2s
Three-phase undervoltage	1st step: -10 %, 60 s
	2nd step: -20 %, 0.2s
Directional power	-
Unbalance	-
Overcurrent	-
Earth-fault	-
Anti-island	-

The over and underfrequency protection are primarily intended to detect and terminate a non-intentional islanding condition. Together with other forms of protections listed above, as the over and undervoltage ones, they represent also a protection against damages to the generator and turbine.

In general, the settings of the overcurrent protection should be chosen in agreement with the network owner so that network selectivity is achieved.

The earth-fault protection is required by AMP only in some cases. An unselective earth-fault protection sensing the zero-sequence voltage in the DNO network is recommended whenever there is a risk for a stable non-intentional islanding condition. Such a condition may be the result of an earth-fault in the DNO network if there is a probability that the power generated by the distributed generator equals the power consumed by the loads in the islanded network. The network may enter island operation because of the intervention of the DNO earth-fault protection. Figure 2.1 clarifies this concept.

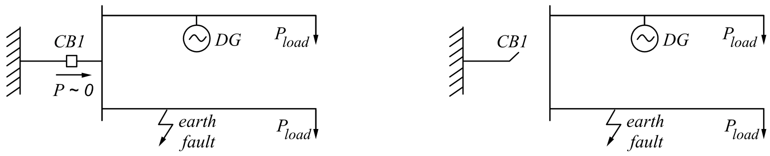

Figure 2.1 Islanding of a distribution network following the intervention of the earth-fault protection at CB1. The DG generates all the power supplied to the load, before and after the fault.

The case depicted in Figure 2.1 represents a typical case in which an additional anti-islanding protection is recommended. If it is possible that the amount of power from the distributed generator equals the power consumed by local loads, standard anti-islanding protections as over or underfrequency may take long time before their intervention in case of a non-intentional islanding. In this case, a more advanced anti-islanding protection as Rate of Change of Frequency (ROCOF) is recommended.

Additional protection may also be needed for protecting the generator itself and it is not included in the protection scheme presented above. An important generator protection, along with the unbalance protection, is the Volt-per-Hertz protection. Since the flux is proportional to the ratio of voltage to frequency, a high ratio of per-unit voltage to per-unit frequency may cause flux saturation and, as a consequence, overheating of the generator and transformers. This protection may be particularly useful in case of island operation. The unbalance protection, along with avoiding the rise of dangerous unbalances in the distribution network, has also the role of protecting the generator against overheating of the rotor iron, which may be a consequence of an excessive negative sequence current in the generator. A negative sequence current causes voltages and currents of double frequency in the rotor iron that may lead to local overheating. In particular, NEMA standards MG1-14.34 and MG1-20.55 state that an induction motor should operate up to 1 percent voltage unbalance without derating and do not recommend operation of the motor with voltage unbalance higher than 5 percent (Bailey 1988). The standard EN 60034-1 states that three-phase motors should be suitable for operation on a three-phase voltage system with a negative sequence component below 1 percent over a long period and below

1.5 percent over a short period of a few minutes. Induction generators may be regarded as structurally identical to induction motors and therefore the same considerations should apply to induction generators.

Summarizing, the typical protection scheme adopted for distributed generators will prevent non-intentional islanding of the generator. To allow intentional island operation it is necessary to change the settings of some protections, particularly the over and underfrequency protections. An island-operated network is a weaker system as compared to a grid-connected network and higher voltage and frequency variations can be expected. The maximum permissible frequency and voltage variations in island operation must be chosen so that no damage is caused to customer and to power generating equipment. Protection relay settings must be changed accordingly. These issues are dealt with in the next paragraph on power quality.

2.2 Power quality in island operation

The IEEE (IEEE 2000) defines an island as "that part of a power system consisting of one or more power sources and load that is, for some period of time, separated from the rest of the system". Since it is separated from the bulk power system, an island-operated network is inherently weaker than the same network in interconnected operation. The term weak underlines here the likelihood of an island-operated network to experience higher and more frequent voltage and frequency excursions from their nominal values. Frequency variations are a consequence of small total system inertia combined with the possibly relatively large generation-load unbalance in the island. The question is now how large frequency and voltage variations can be permitted during island operation. Maintaining the same settings as in grid-connected operation may lead to frequent terminations of the island because of the over and underfrequency protection intervention. On the other side, too large frequency and voltage variations are unacceptable and may result in damage to various equipment and devices.

Two of the most sensitive types of equipment are probably represented by ac motors and electronic devices.

Ac motors may be sensitive to low voltage conditions, drawing large currents and high reactive power. A low voltage condition must be limited in time to not cause damage to motors. A high volt-per-hertz ratio may also be critical for motors, leading to saturation and consequent overheating. High volt-per-hertz ratio may be avoided by using a dedicated protection at the distributed generator station. The standard EN 60034-1 recommends extended operation of ac motors and generators only within specified limits of frequency and voltages. Outside these limits the machine is not expected to have its nominal performance. The same standard states that all low voltage three-phase 50/60 Hz single-speed cage induction motors of frame number up to 315 should be able of continuous safe operation when operated at speeds indicated in Table 2.2, for example when used with adjustable speed drives. The frame number specifies the physical dimensions of the various parts of the motor.

Table 2.2 Maximum safe operating speed (rev/min) for three-phase single-speed cage induction motors for voltages up to 1 kV

Frame Number	**2 pole**
<100	5200
112	5200
132	4500
225	3600
315	3600

EN 60034-1 also states that such motors should be designed to withstand 120 % of their maximum safe operating speed, according to Table 2.2. ANSI C50.41.20 requires that induction motors should be constructed to withstand overspeeds of 20 % in case of two-pole motors and 25 % in case of four-poles (or more) motors (Nilsson 1996). However, such high frequency may entail mechanical damage to the mechanical load of the motor.

Electronic devices are sensitive both to low and high voltages. In absence of further information from the manufacturer, it is customary to assume that an electronic device will not be damaged if the system voltage remains within the limits specified in the curve shown in Figure 2.2. The curve, published by the Information Technology Industry Council, shows the acceptable voltage magnitude as a function of time. The curve applies for a 120 V electronic device at 60 Hz, but it can be considered as a guideline also for other types of devices. Voltage-time points in the prohibited region may cause damage of the electronic equipment, while voltage-time points in the no-damage region should cause termination of the functional state of the electronic device.

Hence, electric utilities are compelled to assure good quality of the power delivered to their customers. A bad power quality may give rise to damages or malfunctioning of customer equipment. This continues to be valid also during island operation and appropriate actions must be taken to assure acceptable power quality also in this case.

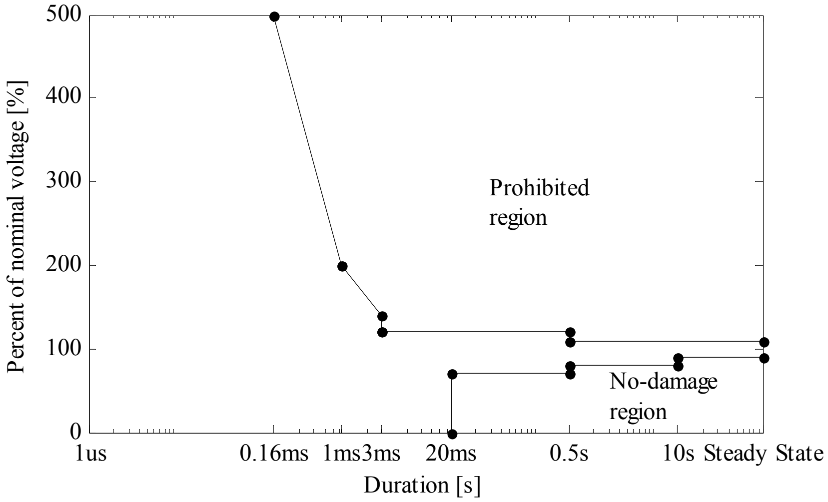

Figure 2.2 Acceptable voltage-time curve for electronic devices. Published by the Information Technology Industry Council

It is interesting to note that, in setting the requirements on frequency variation, the standard EN 50160 distinguishes between systems with and without synchronous connection to a large power system. In case of a system without synchronous connection to a large power system, the frequency average value, measured over a period of 10 s, of the fundamental component of the voltage should be within the following intervals

50 Hz ± 2 % under 95 % of a week

50 Hz ± 15 % under 100 % of the time

An island-operated network may be regarded as a system without a synchronous connection to a large power system and therefore it is reasonable to assume that the above range of frequency variation applies also during island operation. It is worth noting that the requirements the standard sets for frequency variation in a non-interconnected system are much weaker than the requirements set for a system with a synchronous connection to a large power system.

Regarding the voltage magnitude variations, EN 50160 states that the RMS value of the voltage averaged over 10 minutes-periods should be within ± 10 % under 95 % of a week. Moreover, each of the 10 minutes average values should be within + 10 % and – 15 %. This range has been chosen considering that customer equipment and devices are commonly designed to withstand voltage variations of ± 10 %.

2.3 Summary

Summarizing, it has been pointed out that standard protection schemes for distributed generators include functions aiming at detecting and terminating an island condition. In an island-operated network, higher frequency and voltage variations should be expected as compared to grid-connected operation. Some protection relay settings may need to be adjusted during island operation. The new settings must be chosen so that acceptable power quality is guaranteed also during island operation. The standard EN 50160 may be used as a guideline in choosing these new settings.

Chapter 3

Self-Excited Induction Generator

Before proceeding to analyzing specific aspects of island operation with induction generators, it is very important to understand self-excitation. It is this physical process that permits the use of the induction generator in island operation. This chapter has the purpose to introduce this process and to explain how the steady-state operating points can be determined. An algorithm for predicting the steady-state operation of the self-excited induction generator, SEIG, feeding an impedance load is proposed. Experience has shown that after short-circuits, self-excitation may not take place because of the low residual flux in the induction generator. To gain a better understanding of how the residual flux varies with the fault resistance, some laboratory measurements on a small induction generator have been performed and are reported in the last section of this chapter.

3.1 Self-Excitation

Unlike the synchronous generator, an induction generator does not have an internal magnetization source. However, a voltage may build up in an induction generator as the result of a physical process known as self-excitation. This permits the utilization of an induction generator as a stand-alone unit operating in island without connection to any other voltage source.

The process of self-excitation is well known and it has been described mathematically in (Elder et al. 1983). It may take place if a sufficient amount of capacitors is connected at the generator terminals. Self-excitation is initiated by the residual flux in the induction generator rotor iron. When the generator is accelerated to a certain speed, the residual flux will induce a voltage in the stator. Under these conditions, the induction generator behaves much like a synchronous generator with permanent magnet rotor.

If capacitors are connected at the generator terminals, the induced stator voltage will cause the flow of a current into the capacitors. Depending on the generator parameters, the value of the capacitors and the generator speed, a transition from the synchronous operating mode to the asynchronous operating mode may take place at some point leading to the self-excitation of the induction generator.

Once the self-excitation process has started, the induction generator voltage builds up. The voltage build up can be understood by considering the phasor diagram shown in Figure 3.1. The induced stator voltage causes a capacitor current that generates a flux into the generator with the same direction as the residual flux. Therefore, the current circulating in the stator reinforces the residual flux. This in turn causes a higher induced stator voltage leading to a successive increase in current and flux.

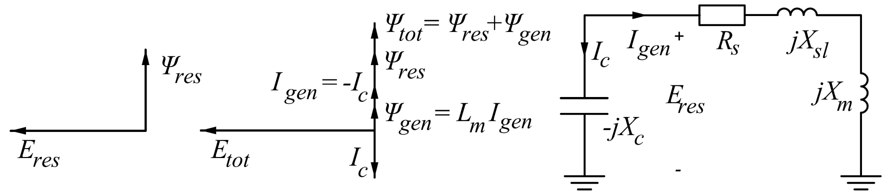

Figure 3.1 Phasor diagrams before and after the capacitor current starts to flow, neglecting stator resistance and leakage reactance. To the right, single line diagram of the induction generator and shunt-connected capacitors

This voltage build up process comes to a halt when the capacitor voltage curve intersects the no-load curve of the induction generator, see Figure 3.2. This point is a stable operating point and it is the steady-state operating point of the self-excited induction generator running at no-load with the shunt-connected capacitors. At this point, the capacitors supply exactly the reactive power needed by the induction generator at no-load.

The no-load steady-state operating point is determined by the no-load curve of the induction generator, by the value of the capacitors and by the generator speed, as illustrated in Figure 3.2. Increasing the value of the capacitors has the effect of shifting the no-load steady-state point towards higher voltages. Increasing the generator speed, i.e. the frequency of the induced voltage, shifts the no-load curve of the generator upwards, while the slope of the capacitor voltage curve decreases. The net result is still an increase in the no-load steady-state voltage.

In reality, there exists another point of intersection with stable operation at very low voltage and current. The existence of this point has been confirmed during this work by laboratory measurements on a small induction generator. To start the self-excitation process, the generator must be "pushed" beyond this point.

From the above considerations, it is deduced that the connection of capacitors supplying a larger reactive power than needed by the induction generator at no-load may cause overvoltage at the generator terminals.

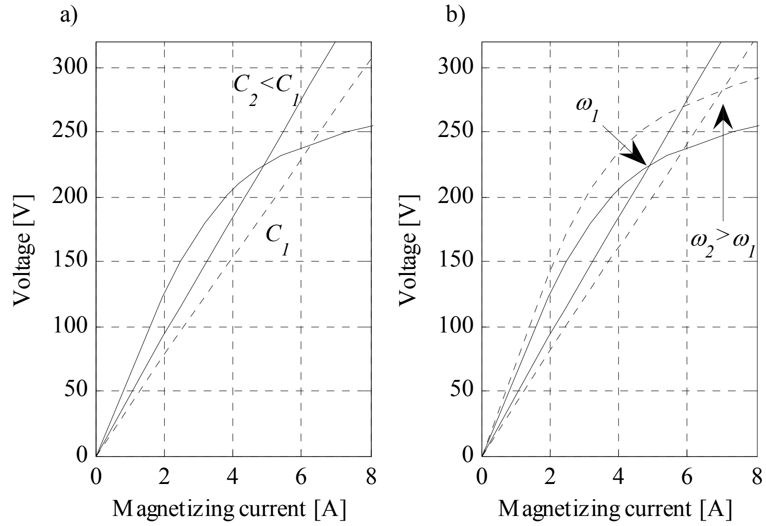

Figure 3.2 Induction generator no-load and capacitor voltage curve. a) Different capacitors. b) Same capacitor, different generator speeds.

3.2 Steady-state Analysis

It is common to plot the induction generator magnetizing curve at no-load as in Figure 3.2 but a similar curve applies for a loaded generator in steady-state as well. To determine steady-state operating points for the self-excited induction generator under different loading conditions, the equivalent circuit in Figure 3.3 is used. The load and capacitors connected to the generator terminals could always be interpreted as one resistive and one capacitive part.

If the load has an inductive part it simply means that the resulting capacitor is smaller. If the load resistor and generator are considered together it is clear that the current flowing into the capacitors is 90° ahead of the terminal voltage and the only way to achieve this is to adjust the slip, *s*, so that the generator and the load together give a corresponding angle of -90°. The slip is the difference between mechanical and electrical speed and in this case the electrical speed is constant and the slip is adjusted by means of varying the mechanical speed. For a given load at a given voltage and frequency it is then possible to calculate this slip, and thus the generator impedance and current.

The advantage of this method is that is uses the same intuitive approach and the same kind of curves as used when determining the no-load steady-state operating point. From the analysis of these curves under loading conditions, it may be easily understood how the various parameters in the analysis will influence the generator steady-state operation.

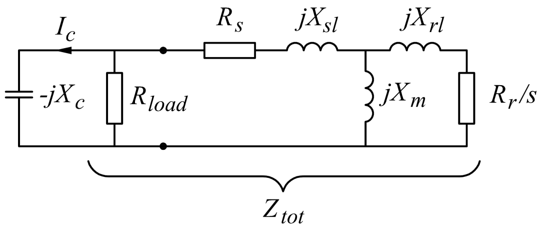

Figure 3.3 Per phase equivalent circuit of self-excited induction generator and resistive load.

Steady-state Laboratory Experiments

The induction generator no-load curve is experimentally determined by connecting the generator to the grid via a variable transformer and reading the current at different voltages. It is then important that the slip is zero when reading the current. The slip is adjusted to zero by means of a DC motor driving the generator.

The experimentally obtained no-load curve of a 230 V 2.2 kW squirrel cage induction machine with parameters according to Table 3.1 is displayed in Figure 3.5 with a dashed line. It shall be noted that the points at low voltage are very difficult to measure accurately. The induction generator parameters have been measured with standard no-load and blocked-rotor tests. A dc measurement of the stator resistance has also been done.

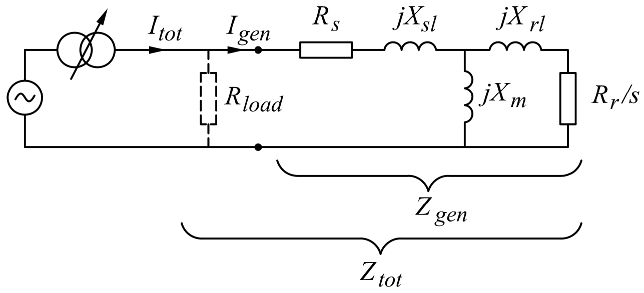

Figure 3.4 Per phase equivalent circuit of grid connected induction generator and resistive load.

Table 3.1 Generator parameters.

V_N (V)	230	X_{sl} (Ω)	1.2
I_N (A)	9	X_{rl} (Ω)	1.2
P_N (kW)	2.2	R_s (Ω)	1
Z_{base} (Ω)	14.8	R_r (Ω)	0.7

A curve similar to the no-load curve could be obtained for the case with a loaded generator. This curve is measured with the 2.2 kW generator, and a parallel load resistor of 25Ω, connected to the grid via a variable transformer. The DC motor driving the generator is now adjusted to achieve a 90° lagging current from the grid meaning that the generator in parallel with the load is purely inductive and may be compensated by a capacitor if operated with self-excitation. The new curve, solid line in Figure 3.5, appears below the no-load curve. The characteristic of 8 steps of a capacitor bank is included in the figure to illustrate the fact that with fixed capacitors the voltage decreases when applying a load. Each capacitor step corresponds to a generated reactive power of 270 var at 230 V.

If we now replace the grid by capacitors it is possible to operate the induction generator with self-excitation. If different numbers of capacitor steps are connected, different operating points are obtained. These points form the very same curve as obtained in the grid connected mode. In Figure 3.6 the experimentally determined results with grid connected generator (solid line) and self-excited generator (+) are presented. As expected the new operating points correspond well with the intersection points between the generator and capacitor curves. For the case with 7 steps it is not possible to achieve a stable operating point and the generator demagnetizes. This could also be deduced from Figure 3.6 by observing that the 7 step curve is almost the tangent to the generator plus resistor curve, meaning that instability is reached.

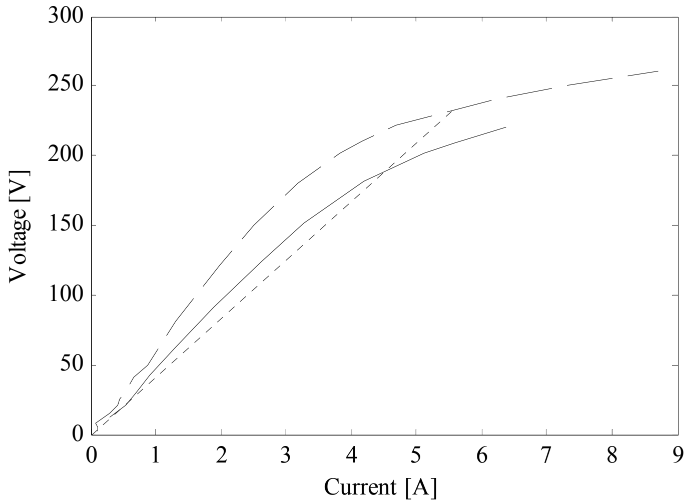

Figure 3.5 No-load curve (dashed), grid connected generator and resistive load (solid) and grid connected capacitors with 8 steps (dotted).

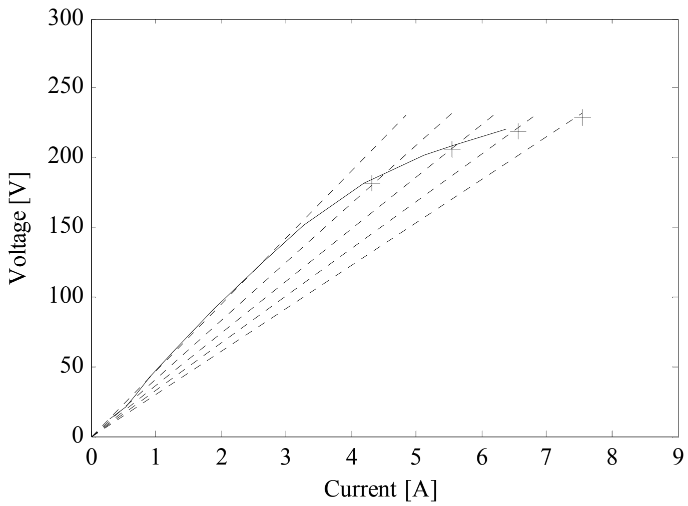

Figure 3.6 Grid connected generator and resistive load (solid), capacitor characteristic with 7-8-9-10-11 steps (dotted) and SEIG with 8-9-10-11 capacitor steps (+).

Algorithm for Steady-state Calculations under Load Conditions

From the previous section it is clear that the induction generator and the load resistor could be considered as one impedance, denoted Z_{tot} in Figure 3.4, when determining steady-state operating points. By means of a simple algorithm it is then possible to calculate all feasible operating points with any loading.

The no-load curve from the laboratory measurements is used and frequency is considered constant when calculating each steady-state point. For different voltages, the generator impedance is calculated by adjusting the slip so that the real part of I_{tot} is zero. A real part of $I_{tot}=0$ implies a possible operating point. The calculations are done under the assumptions that inductive reactances are proportional to the frequency and capacitive reactances are proportional to the inverse of frequency.

```
slip = -0.2
for every voltage V
      while real(I_tot)>0.01
            increase slip by 0.00001
            calculate Z_IG from R_s, X_sl, R_r/s, X_rl, X_m
            calculate I_tot from V, R_load, Z_IG
            calculate I_IG from V, Z_IG
            calculate X_m from no-load curve, V,
                      R_s, X_sl, I_IG
      save I_tot
```

To verify the calculations the results are compared with a SIMULINK SimPowerSystems simulation of a self-excited induction generator and measurements on the laboratory machine. The results are presented in Figure 3.7. The small deviations between calculated, simulated and measured values are mainly due to how the machine no-load curve is implemented in SimPowerSystems and uncertainties in the measured laboratory machine parameters.

The procedure described above could be repeated for different frequencies and results in Figure 3.8. The capacitor characteristic appears as a surface in the figure and the intersection between the capacitor and generator-load surfaces represents all possible operating points with R_{load}=25Ω and 10 capacitor steps.

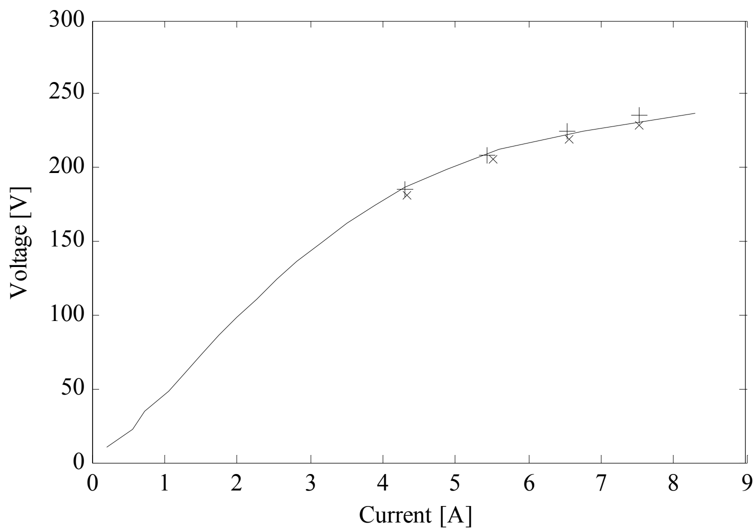

Figure 3.7 SEIG with 25 ohm resistive load. Calculations (solid), simulations (+) and laboratory experiment (x).

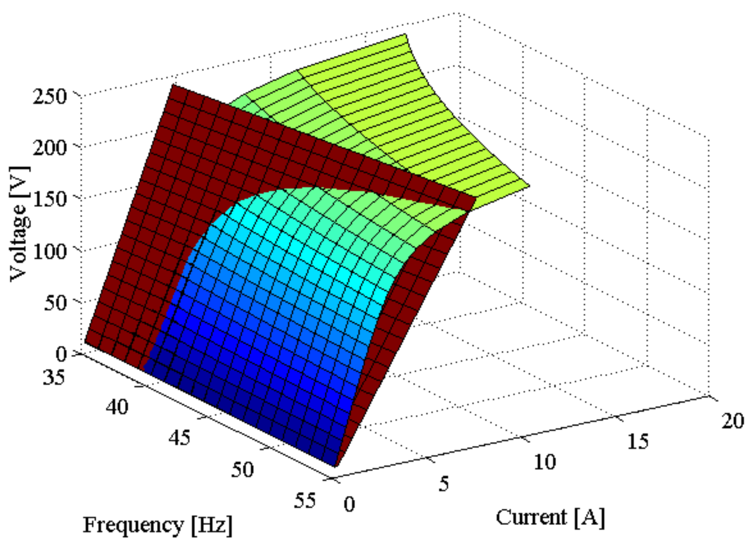

Figure 3.8 Characteristics of a loaded generator (green-blue) and a capacitor (brown). The intersection between the two surfaces represents all the possible steady-state operating points at different frequencies.

When the generator is accelerated, with the capacitors connected, self-excitation is not possible in the beginning. Then at about 40 Hz the self-excitation process starts and the voltage increases. If the generator is further accelerated it moves along the curve formed by the intersection between the two surfaces. If the generator speed decreases below a certain frequency self-excitation is not possible and the generator demagnetizes.

3.3 Residual flux measurements

It is often stated in the literature (Bansal 2005), (Jain et al. 2002) that it may be difficult to self-excite an induction generator after it has been stopped with some load connected or after a short-circuit. The reason is the loss of the residual flux in the rotor iron. More precisely, the residual flux in the rotor iron will decrease to a low value and this value will depend on the way a previously excited generator has been stopped. To get some more insight into the dependence of the residual magnetism on the fault resistance of an applied short-circuit, some measurements have been performed on the small induction generator used above.

The generator has been previously excited and it has been run at nominal speed. Three-phase short-circuits with different fault resistance have been applied at its terminals. The short-circuit causes the demagnetization of the induction generator. After the demagnetization has occurred, the capacitors and the fault resistance have been disconnected while the generator was still running, and the voltage induced by the residual flux has been measured. It is remarked that stopping and reaccelerating the generator proved to have no effects on the reading of the residual voltage. Therefore, during the measurement sequence the generator was never stopped.

The measurements are shown in Figure 3.9. It can be observed that the residual flux magnitude decreases as the fault resistance increases from zero. A further increase in fault resistance does not change much the value of the residual flux. It is interesting to note that above a certain fault resistance, close to twice the generator base impedance, the residual flux increases sharply.

The measurements show that a sudden connection of a resistance close to the generator base impedance results in the demagnetization of the generator and a subsequent very low residual flux in the rotor iron. On the other hand, solid short-circuits and connection of a resistance higher than twice the generator base impedance both cause higher residual fluxes.

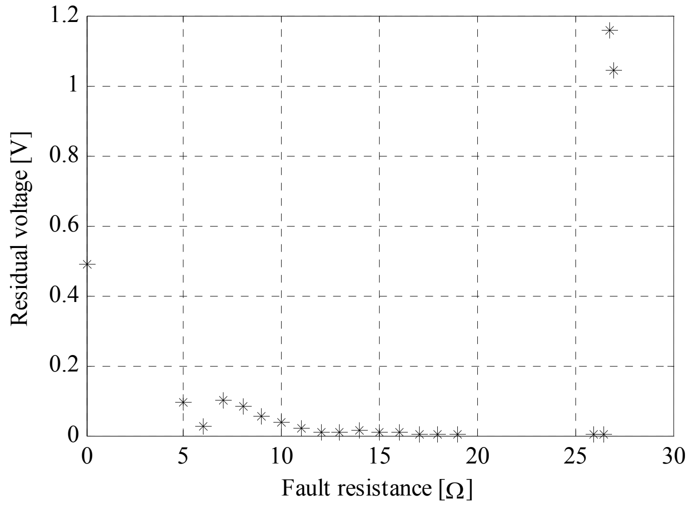

Figure 3.9 Measured residual phase-phase voltage as a function of fault resistance of the applied three-phase short-circuit. The generator base impedance is 15Ω.

Different methods can be used whenever the self-excitation of the induction generator becomes difficult due to low residual flux in the rotor iron (Elder et al. 1983). Among these, connecting a dc voltage source, for example a battery, to the stator seems the most practical one. Other methods, such as using high value capacitors or accelerating the generator above nominal speed, may cause dangerous overvoltages once the self-excitation process has started.

3.4 Summary

The self-excitation process has been described together with an explanation of how to determine steady-state operating points. An algorithm for predicting the steady-state operation of the self-excited induction generator feeding an impedance load was proposed. Laboratory measurements on a small induction generator were performed and it was shown that the residual flux after a short-circuit varies with the fault resistance.

Chapter 4

Short-circuit theory of an induction machine

It is instructive to begin the fault analysis of an induction generator from the simplest case, i.e. a solid three-phase short-circuit at its terminals. A theoretical derivation of the three-phase short-circuit current delivered by an induction generator is presented in this chapter. The mathematical derivation is presented along with an attempt of a simple physical explanation of the process going on inside the generator during a short-circuit. Symmetrical components modeling of the induction generator is also introduced.

4.1 Induction machine space-vector modeling

Space-vectors are a useful tool when dealing with electrical machines. An accurate description of the space-vector concept may be found in (Vas 1992). Here, the space-vector of balanced three-phase quantities is briefly introduced. A space-vector is defined in a reference system and it will have different expressions in different reference systems. Through this entire chapter only a stationary reference frame is considered. This is a reference frame fixed with respect to the machine stator. A balanced three-phase voltage system may be expressed, with obvious meaning of the notation, as in Equation 4.1

$$\begin{aligned} u_a(t) &= \hat{u}\cos(\omega t - \phi) \\ u_b(t) &= \hat{u}\cos\left(\omega t - \phi - \tfrac{2}{3}\pi\right) \\ u_c(t) &= \hat{u}\cos\left(\omega t - \phi + \tfrac{2}{3}\pi\right) \end{aligned} \tag{4.1}$$

The corresponding voltage space-vector in a stationary reference frame is here defined as in Equation 4.2. Notice that the amplitude of the defined voltage space-vector is equal to the peak amplitude of the instantaneous voltage:

$$\overline{u}_s(t) = \frac{2}{3}\left[u_a(t) + a u_b(t) + a^2 u_c(t)\right] = \hat{u} e^{j\phi} e^{j\omega t} \tag{4.2}$$

where

$$a = e^{j\frac{2}{3}\pi},\ a^2 = e^{-j\frac{2}{3}\pi}$$

We will indicate space-vectors with overlined letters. The first part of Equation 4.2 is valid also if the three-phase quantities do not form a balanced system. If no zero-sequence component is present, the instantaneous values in the three phases can be obtained from the corresponding space-vector as

$$\begin{aligned} u_a(t) &= \mathrm{Re}(\overline{u}_s) \\ u_b(t) &= \mathrm{Re}(a^2 \overline{u}_s) \\ u_c(t) &= \mathrm{Re}(a \overline{u}_s) \end{aligned} \tag{4.3}$$

When expressed in the stationary reference frame, the equations describing the electrical dynamics of a squirrel-cage induction machine are given by Equations 4.4 and 4.5.

$$\begin{aligned} \overline{u}_s(t) &= R_s \overline{i}_s + \frac{d\overline{\psi}_s}{dt} \\ 0 &= R_r \overline{i}_r + \frac{d\overline{\psi}_r}{dt} - j\omega_r \overline{\psi}_r \end{aligned} \tag{4.4}$$

$$\begin{aligned} \overline{\psi}_s &= L_s \overline{i}_s + L_m \overline{i}_r \\ \overline{\psi}_r &= L_r \overline{i}_r + L_m \overline{i}_s \end{aligned} \tag{4.5}$$

where

ω_r is the rotor rotational speed

$\overline{\psi}_s$ and $\overline{\psi}_r$ are the stator and rotor fluxes

$\overline{i}_s$ and $\overline{i}_r$ are the stator and rotor currents

R_s and R_r are the stator and rotor resistances

$L_s = L_{sl} + L_m$ is the stator inductance

$L_r = L_{rl} + L_m$ is the rotor inductance

L_{sl} , L_{rl} are the stator and rotor leakage inductances

L_m is the mutual inductance

Equations 4.4 and 4.5 are a general model for an induction machine. Though they are written following the motor convention with the stator current entering the stator as shown in Figure 4.2, they are valid for both an induction motor and an induction generator.

4.2 Short-circuit current - Mathematical derivation

The current delivered by an induction machine during a solid three-phase short-circuit at its terminals can be derived mathematically. However, because of the tedious calculations required, it is common to find in the literature approximate expressions for the short-circuit current. In this paragraph, a rigorous derivation of the induction machine short-circuit current is carried out. The derived formula will be compared with other formulas found in the literature.

The formula for the three-phase short-circuit current is here derived by following the same approach as in (Vas 1992). A stator reference frame is used in the derivation. The idea is to start from Equation 4.4 and to get an expression for the stator current $\overline{i}_s$ during a three-phase short-circuit.

Taking the Laplace transform of Equation 4.4 and considering that the stator voltage must be zero during a solid three-phase short-circuit gives

$$\begin{aligned} 0 &= R_s I_s(S) + S\Psi_s(S) - \psi_{s0} \\ 0 &= R_r I_r(S) + S\Psi_r(S) - \psi_{r0} - j\omega\Psi_r(S) \end{aligned} \tag{4.6}$$

ψ_{s0} and ψ_{r0} are the stator and rotor initial fluxes, i.e. the fluxes at the moment in which the short-circuit has been applied. S is the complex variable. By using Equation 4.5 into 4.6 and eliminating the rotor current from the second equation in 4.6, after some manipulations, gives:

$$\left(R_s + SL_s - \frac{SL_m^2 \left(S - j\omega_r\right)}{R_r + SL_r - j\omega_r L_r} \right) I_s(S) = \psi_{s0} - \frac{SL_m}{R_r + SL_r - j\omega_r L_r}\psi_{r0} \tag{4.7}$$

which can be re-written as

$$I_s(S) = \frac{R_r + SL_r - j\omega_r L_r}{\alpha S^2 + \beta S + \gamma}\psi_{s0} - \frac{SL_m}{\alpha S^2 + \beta S + \gamma}\psi_{r0} \tag{4.8}$$

$$\alpha = L_s L_r - L_m^2$$

$$\beta = R_s L_r + L_s R_r + j\omega_r\left(L_m^2 - L_s L_r\right)$$

$$\gamma = R_s R_r - j\omega_r L_r R_s$$

Taking the Heaviside partial fraction expansion of the two terms in Equation 4.8, leads to

$$I_s(S) = \sum_{k=1}^{2} \frac{r_{sk}}{\left(S - p_k\right)}\psi_{s0} + \sum_{k=1}^{2} \frac{r_{rk}}{\left(S - p_k\right)}\psi_{r0} \tag{4.9}$$

In the previous equation, p_1 and p_2 are the roots of the denominator in Equation 4.8, while r_{sk} and r_{rk} are the four constants defining the numerators after using the Heaviside partial fraction expansion:

$$p_1 = \frac{-\beta + \sqrt{\beta^2 - 4\alpha\gamma}}{2\alpha}$$

$$p_2 = \frac{-\beta - \sqrt{\beta^2 - 4\alpha\gamma}}{2\alpha}$$

$$r_{s1} = \frac{p_1 L_r + R_r - j\omega_r L_r}{\alpha\left(p_1 - p_2\right)}$$

$$r_{s2} = \frac{p_2 L_r + R_r - j\omega_r L_r}{\alpha\left(p_2 - p_1\right)}$$

$$r_{r1} = \frac{-p_1 L_m}{\alpha\left(p_1 - p_2\right)}$$

$$r_{r2} = \frac{-p_1 L_m}{\alpha\left(p_2 - p_1\right)}$$

Equation 4.9 is now expressed in a form that can be easily transformed back from the Laplace into the time domain. The result is the space-vector of the short-circuit current expressed in a stationary reference frame. Inverse transforming Equation 4.9 gives

$$\overline{i_s}\left(t\right) = \left(r_{s1}e^{p_1 t} + r_{s2}e^{p_2 t}\right)\psi_{s0} + \left(r_{r1}e^{p_1 t} + r_{r2}e^{p_2 t}\right)\psi_{r0} \tag{4.10}$$

By applying Equation 4.3 to the current space-vector $\overline{i_s}$ determined above, it is possible to get the instantaneous short-circuit current in all the three phases.

If the rotor speed is assumed constant and equal to the synchronous electrical angular frequency ω_s, i.e. the induction machine slip is assumed equal to zero corresponding to no-load conditions, then the initial conditions can be expressed as

$$\begin{aligned}
&\omega_r = \omega_s \\
&\overline{\psi}_{s0} = L_s \overline{i}_{s0} = L_s \frac{\overline{u}_{s0}}{R_s + j\omega_s L_s} \\
&\overline{\psi}_{r0} = L_m \overline{i}_{s0} = L_m \frac{\overline{u}_{s0}}{R_s + j\omega_s L_s}
\end{aligned} \tag{4.11}$$

The set of equations derived in this paragraph can be easily implemented in software and, given the machine parameters, the short-circuit current in all the three phases can be obtained. This has been done in MATLAB and the results are reported in the next paragraph.

4.3 Short-circuit current expressions comparison

The short-circuit current derived in Equation 4.10 is an accurate expression and takes into account all the parameters of the induction machine. More often, simpler expressions for the short-circuit current of an induction machine are found in the literature. Two are reported here with some changes in the notation, the first from (Vas 1992) and the second from (Jenkins et al. 2000):

$$\overline{i}_s(t) = \frac{\psi_{s0} e^{-t/T_s'} + \left(L_m / L_r \right) \psi_{r0} e^{-t/T_r'} e^{j\omega_s t}}{L_s'} \tag{4.12}$$

$$L_s' = L_s - L_m^2 / L_r$$

$$L_r' = L_r - L_m^2 / L_s$$

$$T_s' = L_s' / R_s$$

$$T_r' = L_r' / R_r$$

$$i_a(t) = \frac{U}{\omega_s L'}\left(\cos(\omega_s t + \phi + \pi/2)e^{-t/T_r} - \cos(\phi + \pi/2)e^{-t/T_s}\right) \tag{4.13}$$

$$L' = L_{sl} + L_{rl}L_m / (L_{rl} + L_m)$$

$$T_s = L'/R_s$$

$$T_r = L'/R_r$$

Both of these equations are derived by first assuming the stator and rotor resistances equal to zero. Their effect is then added by multiplying the dc and ac components by the two exponential terms. However, these two formulas are not so accurate as the one derived in Equation 4.10. A comparison has been made between the results obtained with the three formulas and the short-circuit current obtained by simulation in MATLAB SimPowerSystems. The induction machine speed has been held almost constant during the simulation of the short-circuit by defining a large inertia constant for the machine. The short-circuit occurs when the voltage in phase-a is at its maximum.

The results for the current in phase-a are shown in Figure 4.1. It is noted that the result from Equation 4.10 is practically equal to the simulated current and no errors are appreciable. The results from Equations 4.12 and 4.13 contain both a slight deviation from the simulated current.

It can be concluded that Equation 4.10 gives a more accurate prediction of the three-phase short-circuit current of an induction machine as compared to the simplified Equations 4.12 and 4.13.

4.4 Short-circuit physical explanation

The mathematical expression for the three-phase short-circuit current delivered by an induction machine has been derived in the previous paragraph. An attempt to give a physical explanation of the ongoing short-circuit process inside the machine is made in this paragraph. The approach followed is the same as in (Kimbark 1956) and it is based on the theorem of constant flux linkage. The theorem of constant flux linkage states that "*in any closed electrical circuit the flux linkage cannot change instantaneously*". Simplifying, if no voltage source is present in the closed circuit, the rate of change of the flux is given by

$$\frac{d\psi}{dt} = -Ri \tag{4.14}$$

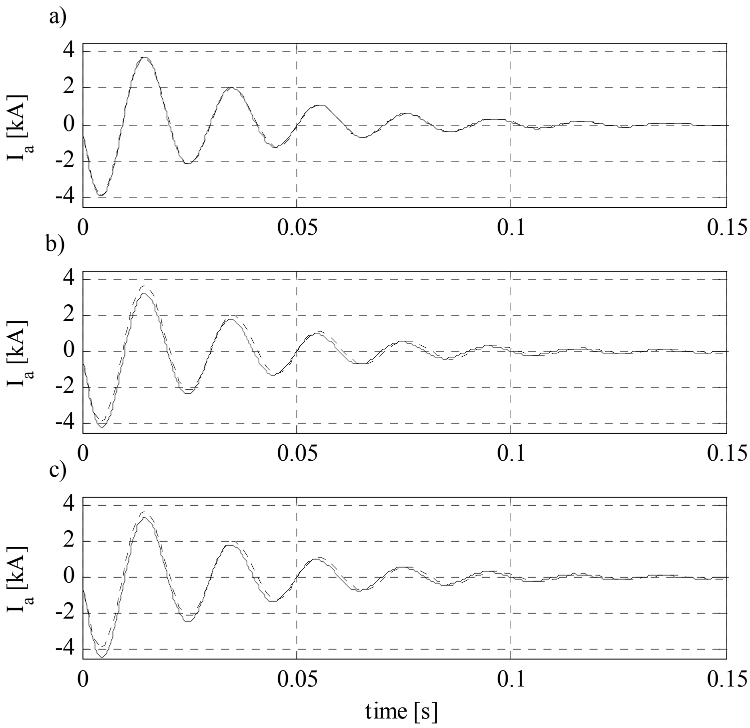

Figure 4.1 Comparison of the phase-a short-circuit current between calculated (solid) and simulated (dashed) current. a) Equation 4.10. b) Equation 4.12. c) Equation 4.13.

When a three-phase short-circuit occurs at the terminals of a squirrel-cage induction machine, there will be two closed circuits, the stator and the rotor ones. Both of them will have a flux linkage at the moment of the short-circuit, ψ_{s0} and ψ_{r0}. These fluxes will be "trapped" and they cannot change instantaneously, therefore immediately after the fault they will remain unaltered.

The stator dc constant flux linkage ψ_{s0} will decay with a time constant, which depends on the transient stator inductance and the stator resistance. The stator transient inductance is practically equal to the sum of the stator and rotor leakage inductance. The decay of the stator flux gives rise to the dc component of the short-circuit current and corresponds to the first term in Equation 4.12.

The rotor dc constant flux linkage ψ_{r0} will decay with a time constant depending on the rotor transient inductance and the rotor resistance. The rotor transient inductance can be assumed equal to the stator transient inductance in the most cases. The decay of the rotor flux gives rise to a dc current in the rotor. Moreover, having assumed that the rotor is rotating with an almost synchronous angular speed, this dc flux links with the stator circuit and it is seen as an ac flux component by the stator. Since the stator flux cannot change instantaneously, an ac stator current must counteract the ac flux induced by the rotor. This current represents the ac component of the short-circuit current corresponding to the second term of Equation 4.12. Its decay will depend therefore on the rotor transient time constant. An ac current component is also induced in the rotor because of the constant stator flux linking with the rotor circuit.

4.5 Symmetrical components modeling

The positive and negative sequence impedances of an induction generator are useful when calculating the steady-state performance of the generator during balanced and unbalanced conditions, if the generator does not demagnetizes. It is possible to express the induction generator positive and negative sequence impedances as a function of the generator parameters and the slip s. During transient conditions, the negative sequence impedance can still be used, but the positive sequence impedance must be replaced by the induction generator transient impedance.

The positive sequence impedance can be derived from the classical equivalent circuit of an induction machine, shown in Figure 4.2. It is the ratio between the stator voltage and the stator current, when balanced three-phase voltages are applied at the generator terminals and it is equal to the total machine impedance seen by the stator, as reported in Equation 4.15.

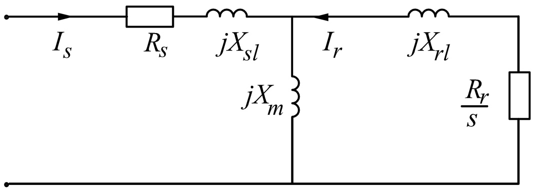

Figure 4.2 Positive sequence equivalent circuit of an induction machine.

$$Z_{pos} = R_s + jX_{sl} + jX_m // \left(\frac{R_r}{s} + jX_{rl} \right) \tag{4.15}$$

The negative sequence equivalent circuit of the induction generator, to be considered when a negative sequence voltage is applied at machine terminals, is derived in (Anderson 1995) and shown in Figure 4.3. It is noted that the only difference, as compared to the positive sequence equivalent circuit, is represented by the negative sequence slip. This is due to the fact that the negative sequence flux in the airgap and the rotor rotate in opposite directions.

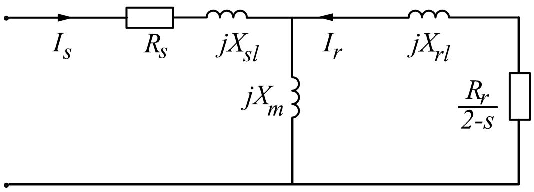

Figure 4.3 Negative sequence equivalent circuit of an induction machine.

The generator negative sequence impedance and slip are expressed as

$$Z_{neg} = R_s + jX_{sl} + jX_m // \left(\frac{R_r}{s_{neg}} + jX_{rl} \right) \tag{4.16}$$

$$s_{neg} = \frac{-\omega_s - \omega_r}{-\omega_s} = \frac{-\omega_s - (1-s)\omega_s}{-\omega_s} = 2 - s \tag{4.17}$$

Since the negative sequence slip is almost constant close to rated operating conditions, we expect the negative sequence impedance not to vary significantly. Moreover, since the rotor resistance R_r is small and its term can be neglected, the value of the negative sequence impedance should be close to the value of the positive sequence impedance with locked rotor, i.e. during start-up with $s = 1$.

Typical positive and negative sequence impedances for an induction generator are shown in Figure 4.4 as a function of slip.

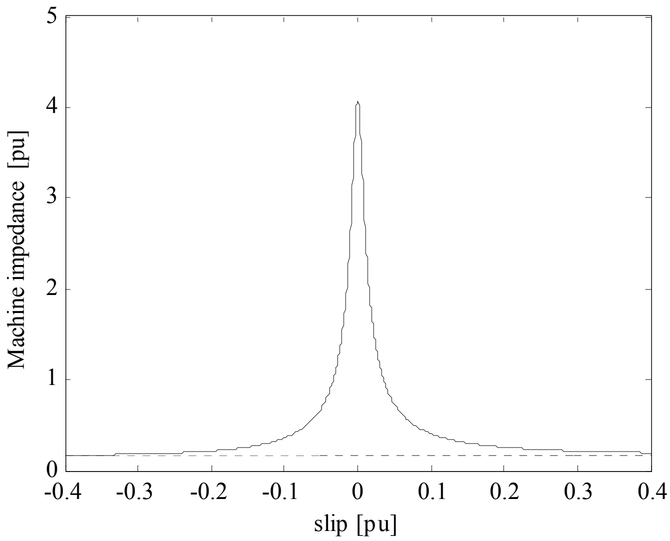

Figure 4.4 Positive (solid) and negative (dashed) sequence impedances of an induction generator.

In (Sarma 1986), it is shown that under transient symmetrical conditions the induction machine can be represented as a voltage behind a transient impedance, as depicted in Figure 4.5.

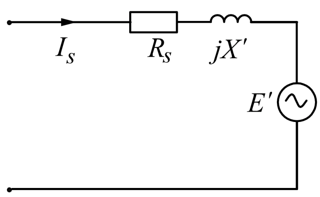

Figure 4.5. Equivalent circuit of an induction machine under transient symmetrical conditions.

The transient impedance is given by the series connection of the stator resistance and the transient inductance. The derivation of the mathematical expression of the transient inductance can be found in the mentioned reference. It is given by:

$$L' = L_s - {L_m^2}/{L_r} \tag{4.18}$$

The transient inductance has been already used in Equations 4.12 and Equation 4.13. The voltage behind the transient impedance can be calculated as:

$$E' = V_{s0} - \left(R_s + jX'\right) I_{s0} \tag{4.19}$$

where V_{s0} and I_{s0} are the pre-fault stator voltage and current.

Chapter 5

Simulation models

This chapter describes the models of the distribution networks used during the simulations performed with MATLAB SimPowerSystems (MATLAB 2006) and reported in the next chapters. Modeling of the various components is briefly introduced.

5.1 Phasor-type and instantaneous-value simulations

SimPowerSystems offers the possibility of computing both phasor-type and instantaneous-value simulations. In the first case, the electrical quantities are represented by phasors and the frequency in the system is assumed constant. The value of the frequency is set before the start of the simulation. All network impedances are therefore constant, as if the frequency would not vary during the simulation. The network quantities may be represented using symmetrical components. Induction machine transient dynamics are included during phasor simulations by separately considering the positive and negative sequence components. This means that dc offsets due to machine transients are taken into consideration. However, a symmetrical short-circuit causes a dc offset which is the same in all the three-phases of an induction machine, since only positive sequence currents flow in this case. The angle of the voltage at the instant of short-circuit occurrence is always considered to be zero for phase-a. Therefore the influence of different voltage angles at short-circuit occurrence on the magnitude of the short-circuit current in the three phases cannot be analyzed with phasor-type simulations.

During instantaneous-value simulations, the electrical quantities are represented by their instantaneous values. Network and machine models are represented by using differential equations. There is no need to set an initial network frequency in this case and the shape of the resulting voltages and currents is determined by the solution of the set of differential equations of the models included in the system.

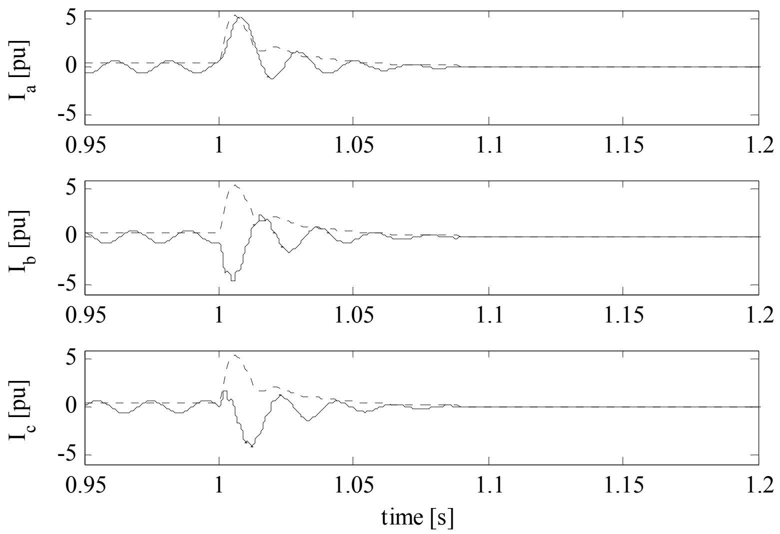

Figure 5.1 Phase currents at a three-phase short-circuit with the same induction generator for instantaneous-value (-) and phasor-type (--) simulations.

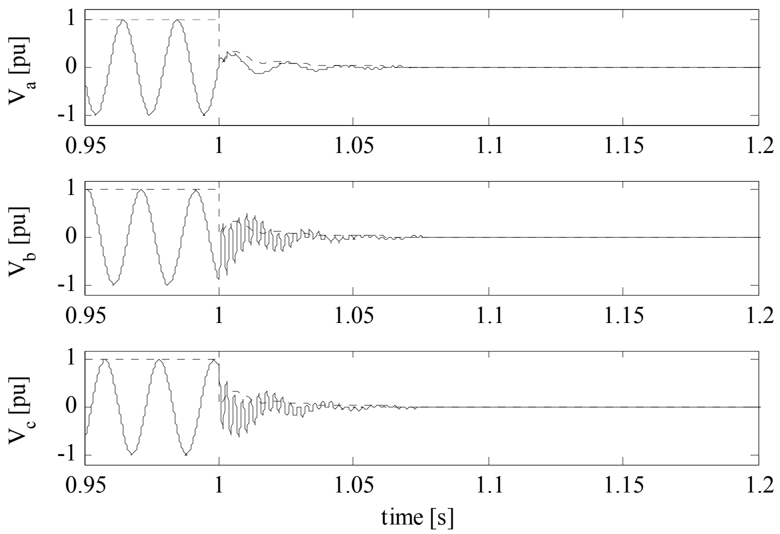

Figure 5.2 Phase voltages at a three-phase short-circuit with the same induction generator for instantaneous-value (-) and phasor-type (--) simulations.

Figure 5.1 and Figure 5.2 give an example of the different results obtained with phasor-type and instantaneous-value simulations. As seen, the phasor current magnitude is almost equal to the magnitude of the instantaneous-value current with the highest dc offset, phase-a current in this case. The phasor current is the same in all three-phases. High order harmonics, clearly present in the instantaneous-value current, are not present in the phasor-current.

Neglecting the frequency variation in the network impedances causes some errors during phasor-type simulations. For example, as said in Chapter 3, the steady-state operating point of a self-excited induction generator with a given amount of capacitors at its terminals will vary with frequency. This is because both the no-load generator curve and the capacitor characteristic change with frequency. When performing phasor-type simulations, the capacitor characteristic is instead fixed and does not change with frequency. The no-load curve of the induction generator is instead adjusted with frequency, or more precisely with its rotor speed.

5.2 Distribution networks models

Two different models of an island-operated distribution network have been used in the simulations in this work. The models are very similar and differ by the number of feeders and the line modeling. One model has been used during phasor-type simulations, the second one during instantaneous-value simulations.

The networks are a simple representation of a distribution network disconnected from its Point of Common Coupling (PCC) and operated as an island. Both the networks are assumed to have a rated voltage of 10 kV. A self-excited induction generator may be connected to feed the island through a step-up transformer.

Figure 5.3 and Figure 5.4 show the single-line diagrams of the two networks. The network earthing method in Figure 5.3 can be chosen by switching the appropriate circuit breakers. It is remarked that the circuit breakers CB2 and CB3 are just used to facilitate the simulations and do not have a direct counterpart in reality.

5.3 Induction machine models

The induction machine is modeled in different ways in SimPowerSystems, depending on which type of simulation is performed.

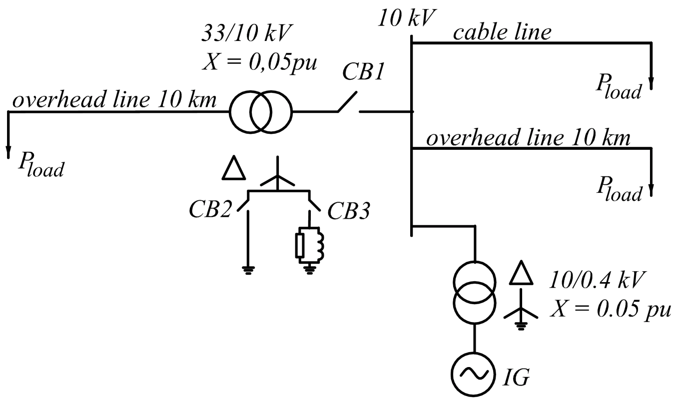

Figure 5.3 Single-line diagram of network model used in phasor-type simulations.

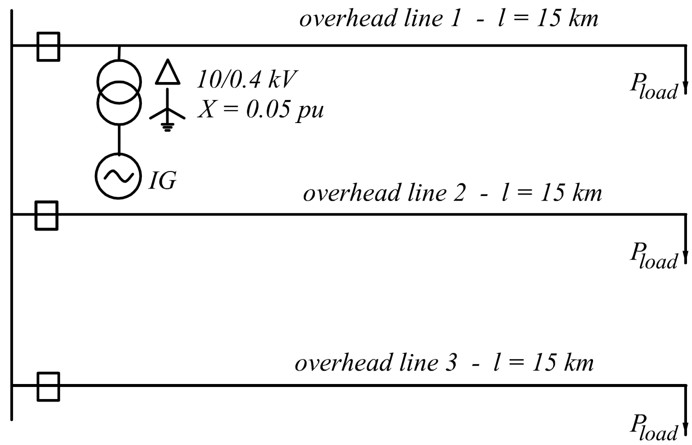

Figure 5.4 Single-line diagram of network model used in instantaneous-value simulations.

When performing phasor-type simulations the induction machine is represented by the classical fourth order electrical model in the positive sequence, see Chapter 4. Both stator and rotor transients are included in the model. In the negative sequence, the induction machine is modeled by its negative sequence impedance, calculated according to Equation 4.16. This results in a first order differential equation. In instantaneous-value simulations, the induction machine is modeled by the classical fourth order electrical model. The equations describing its mechanical dynamics are the same in phasor-type and instantaneous-value simulations.

The machine is assumed unearthed and zero sequence currents cannot flow. Main-flux saturation is included in the simulations, but leakage saturation is not. Iron losses are neglected.

SimPowerSystem allows the simulation of an island-operated induction generator, without any other voltage source or synchronous machine in the network. The voltage dependence on the magnetizing current, defined by the no-load magnetization curve, of the induction generator is changed proportionally with the rotor speed.

Induction generators of three different ratings have been considered and their parameters are reported in Table 5.1, (Anderson 1995).

The induction generator is assumed to be connected to the distribution network through a star-delta connected step-up transformer. The delta is on the high voltage side and the rating of the transformer is always assumed 125 % of the generator rating. The transformer short-circuit impedance is set equal to 5 %.

Table 5.1 Parameters data for the 100, 400 and 1000 kVA Induction Generators

S_N (kVA)	100 / 400 / 1000	L_{sl} (pu)	0.07 / 0.08 / 0.08
V_N (V)	400	L_{rl} (pu)	0.07 / 0.08 / 0.08
R_s (pu)	0.04 / 0.03 / 0.015	L_m (pu)	2.9 / 3.1 / 3.1
R_r (pu)	0.04 / 0.03 / 0.015	H (s)	0.46

5.4 Cable and overhead lines models

In phasor-type simulations, the cable and overhead lines have been modeled as π-links. In instantaneous-value simulations, only overhead lines have been considered and they have been modeled as a resistance in series with an inductance. Cable and overhead line parameters are listed in tables 5.2 and 5.3. Data are taken from (Roeper 1985). The cross-section area of the conductors in the cable and the overhead lines is assumed 95 mm^2. The cable data are for copper conductors, while the overhead line data are for aluminum conductors.

Table 5.2 Data for cable and overhead line in phasor-type simulations

Cable		**Overhead line**	
R_{pos} / R_0 (Ω / km)	0.2 / 1.6	R_{pos} / R_0 (Ω / km)	0.3 / 0.45
X_{pos} / X_0 (Ω / km)	0.13 / 0.3	X_{pos} / X_0 (Ω / km)	0.35 / 1.6
C_{pos} = C_0 (μF / km)	0.3	C_{pos} = C_0 (nF / km)	11/ 6.6

Table 5.3 Data for overhead line in instantaneous-value simulations

Overhead line	
R_{pos} (Ω / km)	0.3
X_{pos} (Ω / km)	0.35

5.5 STATCOM model

A shunt-connected STATCOM may be used to regulate the voltage at the induction generator terminals. A STATCOM has been considered only during some phasor-type simulations and its parameters are reported in Table 5.4.

Table 5.4 STATCOM parameters

S_N (kVA)		100
R_{filt} (pu of STATCOM base impedance)		0.0013/30
L_{filt} (pu of STATCOM base impedance)		0.0013
C_{dc} (mF)		0.35
V_{ac} regulator	K_p	1.5
	K_I	0.8
V_{dc} regulator	K_p	0.0001
	K_I	0.02
Current regulator	K_p	0.14
	K_I	15
	K_f	0.22

The STATCOM is represented as a Voltage Source Converter (VSC) with a capacitor on the dc link and it is connected to the generator terminals via a series RL filter, as shown in Figure 5.5.

In the STATCOM model, it is assumed that only a positive sequence voltage exists in the system. This will lead to a non-optimal performance during unsymmetrical faults causing a negative sequence voltage component. The control part of the STATCOM is implemented in a *dq* reference frame. The ac and dc voltage regulators are PI controllers. The current controller is a proportional-integral vector current controller (VCC), as described for example in (Bongiorno 2007). The series RL filter is directly implemented into the STATCOM model. The filter equations are implemented in the *dq* reference frame, considering the frequency as fixed to its nominal value. The Pulse Width Modulation is not modeled. Instead, the voltage reference V_{dq} calculated by the VCC is transformed directly into the phase voltage phasors that would generate the calculated reference voltage V_{dq}.

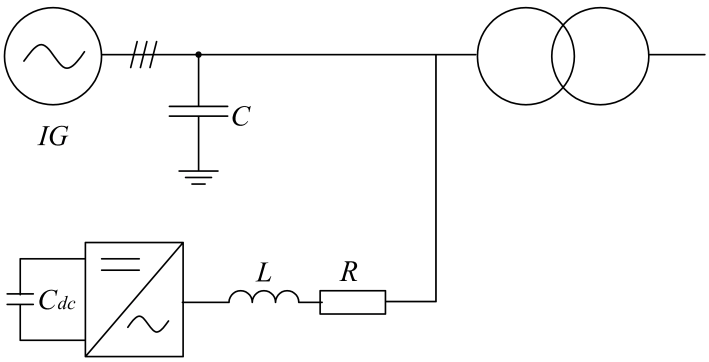

Figure 5.5 Single-line diagram of the induction generator with the shunt-connected capacitors and STATCOM.

5.6 Turbine model

The induction generator is driven by a hydraulic turbine in the simulations. However, the behavior of the generator during short-circuit conditions may be assumed independent on the type of turbine driving the generator, because of the fast short-circuit transients compared to the turbine reaction time.

The hydraulic turbine is modeled by a non-linear system (Kundur 1994), relating the pu output power to the pu water speed and turbine gate. The servomotor is represented by a first order filter and the gate opening or closing speed is limited. The turbine governor uses both a permanent and a transient droop. The turbine parameters are reported below.

Table 5.5 Hydraulic turbine parameters

Servomotor	K_a	5
	T_a (s)	0.2
	Gate position limit g_{min} (pu)	0.01
	Gate position limit g_{max} (pu)	0.97
	Gate speed limit v_{min} (pu/s)	-1/30
	Gate speed limit v_{max} (pu/s)	1/30
Turbine	T_w(s)	2
Governor	Permanent droop	0.005
	Transient droop	2.7
	Reset time (s)	7

Chapter 6

Earth-faults

Detection and disconnection of earth-faults in a distribution network is of great importance for safety reasons. This is true also during island operation. In the case considered during this work, the earth-fault protection will depend upon the behavior of the induction generator during earth-faults in the distribution network. This has not been broadly analyzed in the literature and it is therefore useful to perform a general earth-fault analysis of the island-operated induction generator. Will the generator be capable of sustaining the voltage at an earth-fault or will it demagnetize? In this chapter, it is shown that the induction generator behaves differently depending on the earthing arrangement of the distribution network. Finally, a brief analysis of earth-faults on the low voltage 400 V distribution system is also carried out. Only single-phase-to-earth faults are considered here, while double-phase to earth-faults are considered in the next chapter.

6.1 Introduction

For permanent earth-faults in distribution networks, the Swedish regulation ELSÄK-FS 2004:1 prescribes "*fast and automatic*" disconnection of the faulted part of the system. Earth-faults with a fault resistance up to 5000 ohms must be detected and disconnected. The regulation must be fulfilled also during island operation, leading to a need for an earth-fault protection capable of assuring detection and clearing of earth-faults as prescribed by the law.

Distribution networks in Sweden are mainly operated radially with only one in-feed. The prevalent earthing practice is the resonance earthing with Petersen coil, i.e. to connect at one neutral point in the network a resonance inductance dimensioned to match the total equivalent network capacitance to earth.

The configuration of a distribution network supplied by an induction generator in island operation may vary. It derives from how the island operation is planned, depending in turn on a number of factors. These include possibility of sectionalizing, generator rating and total load on each feeder. Figure 6.1 shows two examples of configurations of an island-operated network with different earthing arrangements. The most important feature that an island-operated network may have, as compared to grid-connected operation, is to be unearthed. This is the case when a single feeder is supplied only from an induction generator and it is disconnected from the common bus at the PCC. In this case, the earth-fault protection at the PCC is not even available and there is a need for a new earth-fault protection during island operation. It is believed that this configuration may be common in case of planned island operation with a distributed generator. If the earthing equipment at the PCC is part of the island-operated distribution network, the latter may continue to be resonant-earthed. The directional earth-fault protection may or may not work properly in island operation and this should be the subject of more detailed studies.

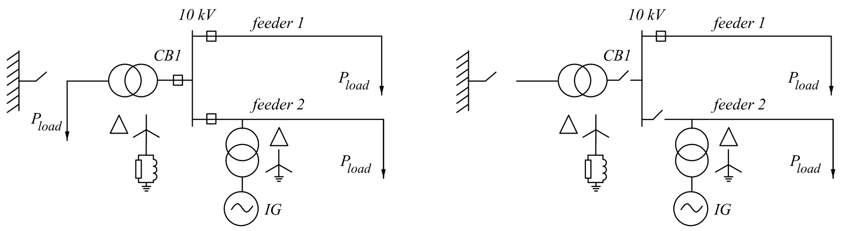

Figure 6.1 Two possible configurations of an island-operated distribution network. Earthed network (left) and unearthed network (right). In the second case, the IG supplies only the load on feeder 2 which is unearthed.

The earth-fault analysis of an induction generator connected to an infinite grid can be found in the literature (Chen 1991), (Wamkewe 2001). In the references, the earth-fault was supposed at the generator terminals and the generator was directly connected to the grid. In this chapter, the earth-fault is applied in the distribution network supplied solely by the induction generator in island operation. This means that the magnetization of the generator is not supplied by an external infinite grid but only by the capacitors through the self-excitation process. Consequently, the case under study is different from the ones considered in the references mentioned above. In the following sections, the earth-fault analysis of an induction generator is carried out through simulations and analytically.

6.2 Description of simulations

As said, the island-operated distribution network may have different earthing arrangements depending on how the island is planned. The case of one or few feeders without a connection to the PCC is believed to be the most concrete possibility in case of planned island operation with a small induction generator. For this reason, the focus in this chapter will be primarily on the network shown in Figure 5.3, when it is operated unearthed with the circuit breaker CB1 open. For sake of completeness, the cases of a resonant-earthed network and a directly earthed network are also considered. The latter may be interesting in countries where the distribution networks are operated solidly earthed. The last two cases are considered by simulating the network in Figure 5.3 with circuit breaker CB1 closed and either of circuit breakers CB2 or CB3 closed.

Single-phase-to-earth faults have been simulated at the end of the 10 km overhead line. Only phasor-type simulations, described in Chapter 5, have been performed. The STATCOM has been neglected and the pre-fault voltage has been regulated through adjusting the value of the fixed capacitors.

In the case of an unearthed distribution network, different cases have been simulated. Three different generator ratings were considered and the fault resistance has been varied from zero to 5000 ohms. Another important parameter varied during the simulations is the total capacitance to earth of the network. This has been done by varying the length of the cable line.

In the case of a resonant-earthed network, the Petersen coil has been chosen to compensate the total network capacitance to earth. A resistance is often used in parallel with the coil and its value has been assumed here equal to 600 ohms (Lindahl et al. 1990). Only the combinations of 400 kVA generator, fault resistances equal to zero and 5000 ohms, cable lengths of 5 and 10 km have been considered in this case.

In the case of a directly earthed network, only the case of a solid earth-fault with the 400 kVA generator has been simulated.

The primary objective with the simulations is to check if the self-excited induction generator demagnetizes or not at an earth-fault in the three above-mentioned cases. A second objective is to gain some insight into how different quantities, that may be used to detect an earth-fault (zero sequence voltage and currents and negative sequence current), depend on various parameters such as generator rating, fault resistance and total network capacitance to earth.

6.3 Simulation results – Unearthed network

The results from the simulations indicate that the induction generator does not demagnetize during single-phase-to-earth faults in an unearthed distribution network. This is true independently of the generator rating, the fault resistance or the total capacitance to earth. The self-excited induction generator is therefore able to sustain the voltage in the network and does not lose its magnetization during an earth-fault. It is remarked that the generator has been assumed to be connected through a ynD transformer to the distribution network. However, what has been said remains true if the transformer is connected ynY. Figure 6.2 shows the positive, negative and zero sequence voltages in the distribution network and the phase voltages at the generator terminals during a solid single-phase-to-earth fault. The positive and negative sequence current from the generator terminals, the fault current and the generator speed for the same earth-fault case are reported in Figure 6.3. Base values in the figures are nominal phase-to-earth RMS voltages, generator nominal RMS current and generator nominal speed.

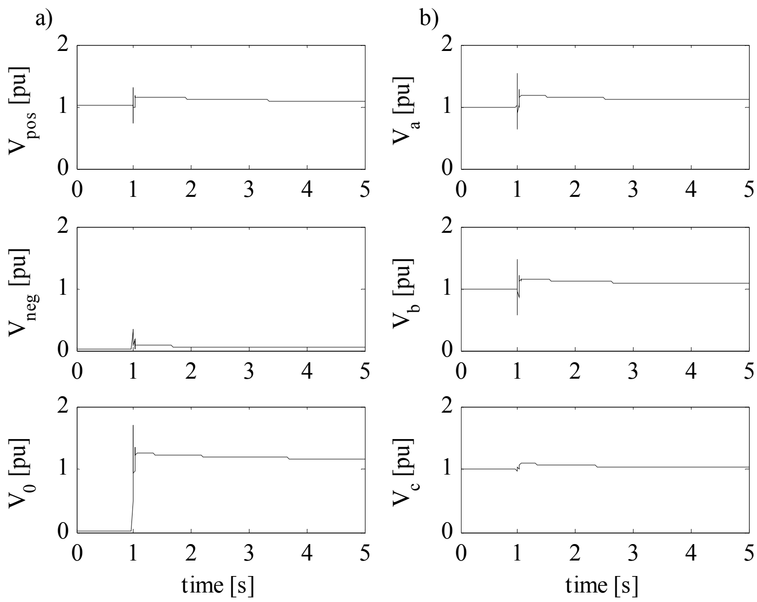

Figure 6.2 Earth-fault with fault resistance Rf = 0 ohm, cable length L = 10 km and unloaded generator. a) Sequence voltages in the distribution network. b) Phase voltages at the generator terminals.

In the case of an earth-fault with zero fault resistance, the voltages in the three phases at the generator terminals do not drop, but instead they may increase above their nominal value.

The same plots are redrawn in Figure 6.4 and Figure 6.5 in case of an earth-fault with fault resistance equal to 5000 ohms. In this case, the phase voltages at the generator terminals decrease slightly. The zero sequence voltage in the distribution network and the negative sequence quantities at the generator terminals are very low and this fact may complicate the earth-fault detection.

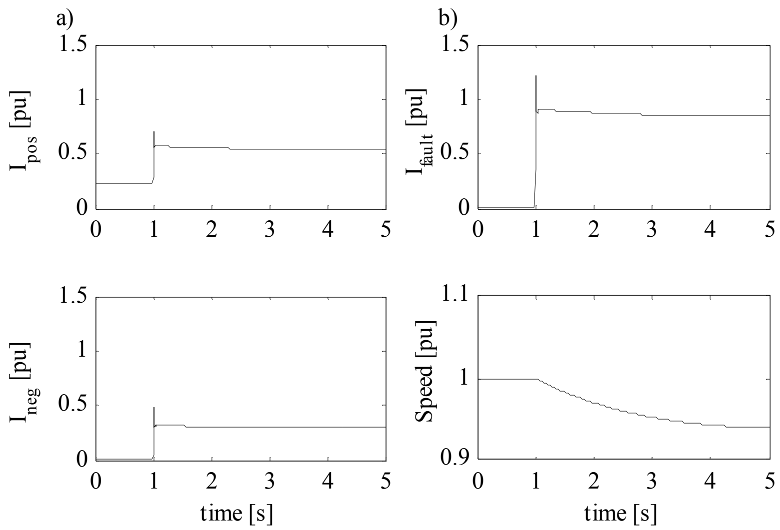

Figure 6.3 Same case as in Figure 6.2. a) Sequence currents at generator terminals. b) Current at fault point and generator speed.

The presence of a STATCOM would not change the results much, but it may help in containing the overvoltages.

Summarizing, it has been found that the induction generator sustains the voltage at an earth-fault in an unearthed distribution network. The value of the positive, negative and zero sequence voltages and currents depend mainly on the fault resistance and the total capacitance to earth. In the next section, it will be shown how the induction generator can be modeled during an earth-fault and how the various quantities can be calculated.

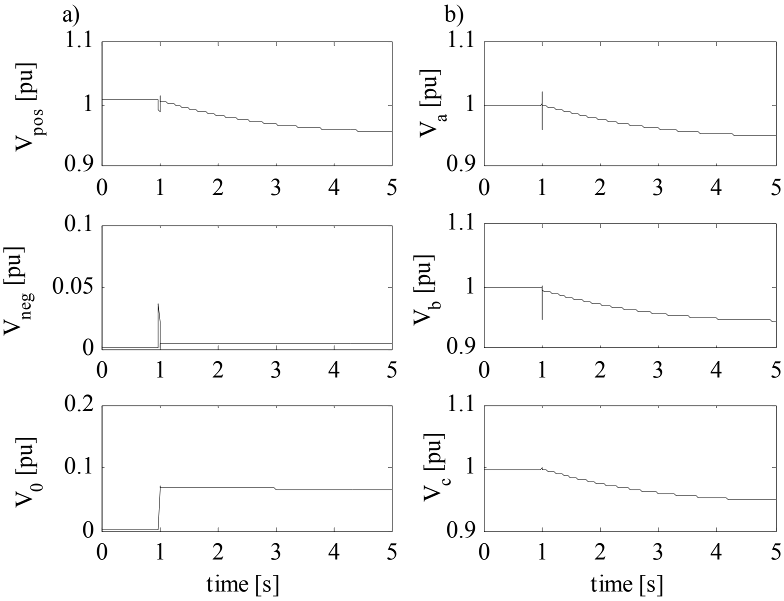

Figure 6.4 Earth-fault with fault resistance Rf = 5000 ohm, cable length L = 10 km and unloaded generator. a) Sequence voltages in the distribution network. b) Phase voltages at the generator terminals.

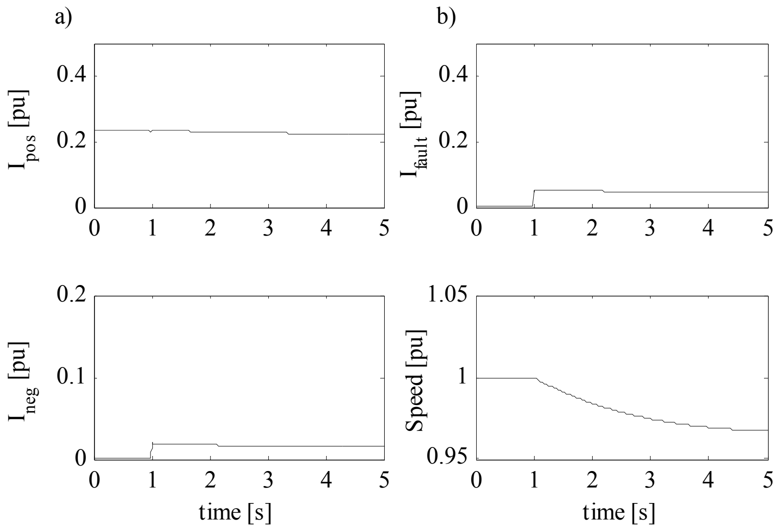

Figure 6.5 Same case as in Figure 6.4. a) Sequence currents at generator terminals. b) Current at fault point and generator speed.

6.4 Symmetrical components analysis

In Chapter 4, it has been shown how an induction generator can be modeled using symmetrical components. During symmetrical transient conditions, the induction generator can be modeled as a voltage behind a transient impedance. The transient reactance and the voltage behind it are given in Equation 4.18 and Equation 4.19. We will assume that the negative sequence impedance in Equation 4.16 is valid also during transient conditions.

The equivalent circuit to be used during a single-phase-to-earth fault in the considered unearthed network is shown in Figure 6.6. It is remarked that the generator transient impedance is used to model the generator at the positive sequence impedance. The negative sequence impedances of the transformer, lines and capacitors are assumed equal to their positive sequence impedances. Line capacitances are neglected at the positive and negative sequence.

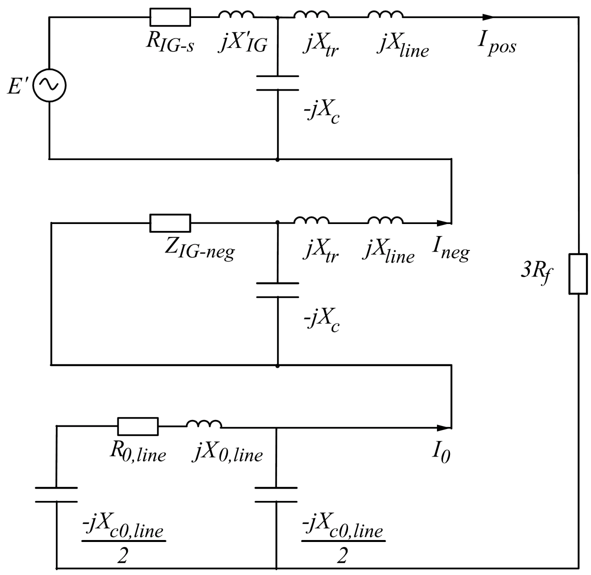

Figure 6.6 Equivalent circuit during an earth-fault in an unearthed network. If more lines are present in the network, their zero sequence impedances, here modeled as π-links, must be added in parallel.

The cable and the overhead lines are represented as π-links in the zero sequence. By using the equivalent circuit with the component values given in Chapter 5, the various post-fault quantities can be calculated. This has been done in the case of a cable length of 5 km for varying values of fault resistance. The results from calculations are compared with those from simulations in Figure 6.7. It can be seen that the calculations are in very good agreement with the simulations. It should be noted that the values from the simulations are taken immediately after the fault has occurred.

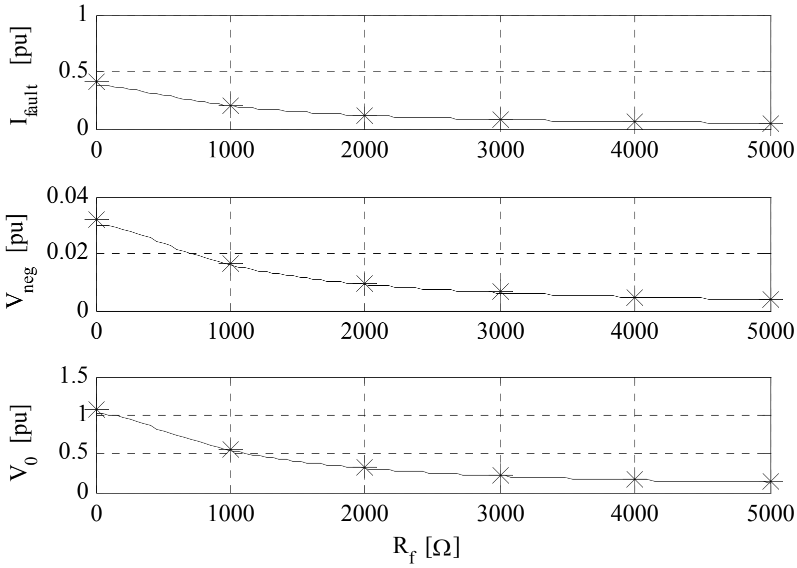

Figure 6.7 Fault current, negative and zero sequence voltage at the fault point at an earth-fault in the unearthed network. Comparison between values calculated using the equivalent circuit in Figure 6.6 (-) and simulated (*). Cable length of 5 km, unloaded generator.

This result shows that, in an unearthed island-operated distribution network with only induction generation, it is possible to use classical methods to calculate the symmetrical component quantities following a single-phase-to-earth fault. The induction generator in this case can be modeled in the same way as a synchronous generator, with the proper values of transient positive and negative sequence impedances. The internal voltage behind the transient impedance does not decay to zero, as in the case of a three-phase short-circuit at the generator terminals, but it will change slowly during the post-fault dynamics.

6.5 Effects of large amount of cables

The presence of large amount of cables in the distribution network has some important effects. It can be assumed that the total positive and zero sequence network capacitances are determined by the amount of cables present in the network, since cable capacitances are much higher than overhead line capacitances. The first effect is that the positive sequence capacitance of the cables, which has been assumed here equal to its capacitance to earth, contributes to the self-excitation of the induction generator supplying reactive power. Consequently, the reactive power generated by the capacitors and the STATCOM at the generator terminals must be decreased by the corresponding amount of power generated by the cables. Therefore, there is a maximum amount of cables that can be present in an isolated network with an induction generator. This amount is determined by the fact that the reactive power generated by the cables must be less than the no-load reactive need of the induction generator. Higher amount of cables may result in overvoltages, for example after load rejection. This amount of cables is dependent on the network nominal voltage, since the amount of reactive power generated by a given capacitance (and hence a given cable length) increases quadratically with the voltage. In the simulations, it has been found that the maximum permissible amount of cables in the network is approximately 3 km in the case of the 100 kVA, 15 km in the case of the 400 kVA and 35 km in the case of the 1000 kVA generator. These amounts generate slightly less reactive power than the no-load reactive need of the connected induction generators. The simulated cable produces about 9.5 kvar per km at a voltage level of 10 kV.

The second effect is that the zero sequence voltage during a high resistive single-phase-to-earth fault in an unearthed distribution network decreases with increasing network capacitance to earth, and hence cable length. This becomes important for the detection of the earth-fault. Large amount of cables may cause the zero sequence voltage at an earth-fault to be lower than the sensitivity limit of the earth-fault protection. A deeper analysis of this issue will be presented in the chapter about protection.

Finally, as it can be seen in Figure 6.2, the positive and zero sequence voltages in the distribution network may increase above voltage nominal value at a solid earth-fault. These fundamental-frequency overvoltages are due to a well-known phenomenon, taking place when the ratio between the total zero and positive sequence impedances is within a certain range (Clarke 1939). The equivalent circuit of Figure 6.6 can help understanding how the overvoltages may arise at a solid earth-fault. As the cable length and hence the network capacitance to earth increases, a serie resonance condition can be approached between the zero sequence impedance and the sum of the positive and the negative sequence impedances in the network. This will cause high fault currents and overvoltages. The magnitude of the overvoltages depends also on the network positive and zero sequence resistances. Because of the induction generator dynamics after the fault, these overvoltages may be higher than one would expect considering a constant voltage behind the transient impedance of the generator. In Figure 6.8, the calculated zero sequence voltage and the 10 kV D-side phase-C voltage arising at a solid earth-fault are plotted as a function of cable length in the network. These quantities have been calculated representing the induction generator as explained in the previous section. The maximum zero sequence and phase-C voltages observed during the simulations are also shown. If the maximum permissible cable length in the network is chosen with regard to the no-load reactive need of the generator, the maximum overvoltages arising with this cable length present in the system are around 2.3 pu of nominal phase-to-earth voltage for all the three considered generators. That is, a voltage equal to 2.3 times the nominal phase-to-earth voltage arises in phase-C at a solid phase-A-to-earth fault with the 100 kVA generator and 3 km cables, with the 400 kVA generator and 15 km cables or with the 1000 kVA generator and 35 km cables. The same overvoltage is experienced with shorter cable length in case of low rating generators, because of their higher positive and negative sequence impedances.

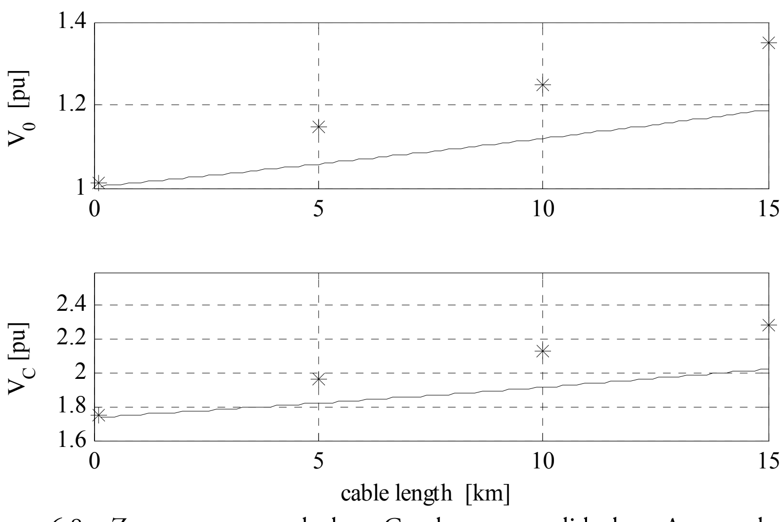

Figure 6.8 Zero-sequence and phase-C voltage at a solid phase-A-to-earth fault in the unearthed network. Values calculated (-) and maximum values from simulations (*). Unloaded 400 kVA generator.

High fundamental frequency overvoltages lasting a few seconds may be dangerous for the Metal Oxide Surge Arresters. It is required that the maximum continuous operating voltage (MCOV) versus time characteristic of the surge arrester should be higher than the fundamental frequency overvoltage versus its duration in the network (IEEE Std C62.22 1997). This fact must be taken into consideration when setting the earth-fault protection in an unearthed network.

Apart from the fundamental-frequency overvoltages, fast post-fault transient overvoltages also arise. These transient overvoltages should be analyzed with instantaneous-value simulations.

6.6 Simulation results – Resonant-earthed network

Also in the case of a resonant-earthed network, the induction generator does not demagnetize but it is instead capable of sustaining the voltage in the system. Figure 6.9 shows the positive, negative and zero sequence voltages at a solid earth-fault in the distribution network with cable length equal to 10 km.

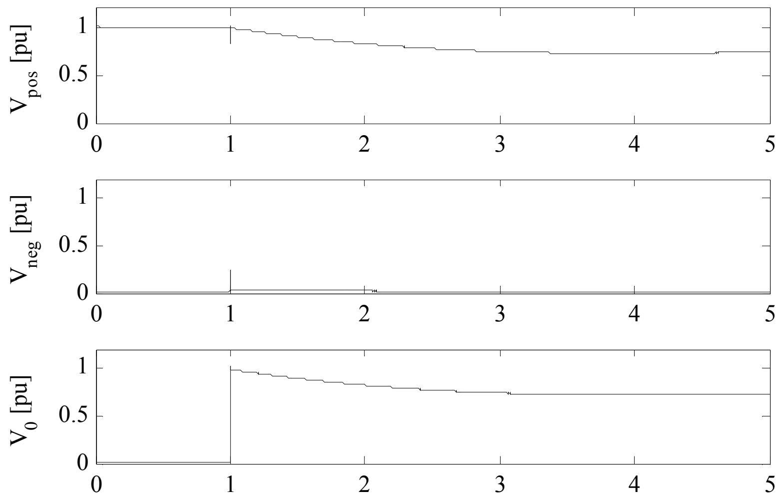

Figure 6.9 Positive, negative and zero sequence voltages at a solid earth-fault in a resonant-earthed network with cable length equal to 10 km. The pre-fault loading of the 400 kVA generator is 10 kW.

From the analysis of the simulations, some differences can be appreciated as compared with the case of the unearthed network. The positive sequence voltage after a solid earth-fault decreases slowly to about 75 % of its nominal value. This is a direct consequence of using a resistance in parallel with the Petersen coil. The resistance will draw an active power during the earth-fault causing the deceleration of the induction generator and the voltage decrease. A higher parallel resistance or fault resistance would cause lower voltage decrease. This means that the results calculated by using the method exposed in Section 6.4 will be valid only immediately after fault occurrence. The overvoltages observed during an earth-fault in an unearthed network do not arise in this case. Moreover, the zero-sequence voltage arising in the distribution network does not vary with the amount of cables present in the network. The last fact is a consequence of the assumed exact compensation of the total network capacitance with the Petersen coil.

6.7 Simulation results – Directly earthed network

The case of an island-operated directly earthed network may arise in some countries, for example Great Britain (Roberts et al. 2001), using direct earthing in their distribution networks.

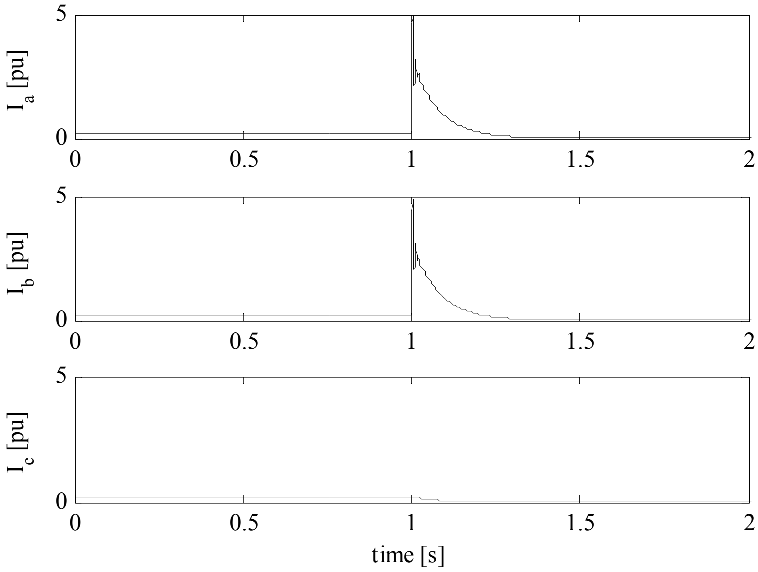

Figure 6.10 Generator currents at a solid earth-fault in a directly earthed network. As seen, the generator demagnetizes. Pre-fault loading of the 400 kVA generator is 10 kW. Cable length is 5 km.

The results from simulations indicate that the induction generator is not capable of sustaining the voltage at a solid earth-fault in a directly earthed network, but instead it demagnetizes quickly. As evident from Figure 6.10 the earth-fault is seen as a phase-phase fault by the generator and its current decays rapidly to zero.

6.8 Laboratory test – Unearthed network

To validate the results from the simulations, a test has been carried out in the lab with a small 2.2 kW induction generator driven by a dc motor. The laboratory set-up is shown in Figure 6.11. The generator has been connected through a Yd transformer to an unearthed network.

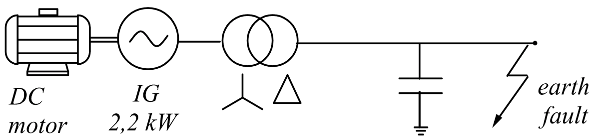

Figure 6.11 Single-phase equivalent circuit of lab set-up.

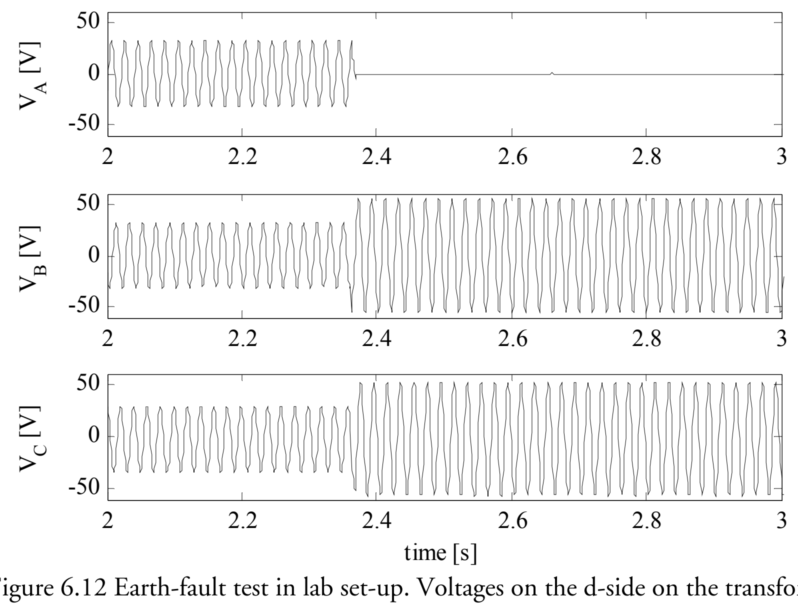

Figure 6.12 Earth-fault test in lab set-up. Voltages on the d-side on the transformer.

The fact that the d-side of the transformer is at a lower voltage should not impact on the conclusions. Series parameters of the network line on the d-side have been neglected. A capacitor is connected between each phase of the network line and a common earth. A phase-a to earth-fault has been applied in the unearthed network by short-circuiting the capacitor between the same phase and the common earth. The measurements of the voltages in the three-phases are shown in Figure 6.12.The results from this lab tests clearly indicate, in accordance with the simulations, that the induction generator is capable of sustaining the voltage at a solid earth-fault in an unearthed network.

6.9 Earth-faults on the low voltage side

During grid-connected operation, faults on the low voltage side of a distribution transformer are normally cleared by means of fuses or other protective devices located downstream the distribution transformer. During island operation with an induction generator, these faults may have a great influence on the behavior of the generator itself and the intervention of the protective devices downstream the distribution transformer cannot be taken for granted. It is therefore important to assess how a fault on the low voltage side impacts on the operation of the induction generator.

The induction generator may supply low voltage loads both at its terminals and via a distribution transformer located somewhere in the distribution network. In countries using TN or TT low voltage distribution systems, the low voltage side of a distribution transformer is normally directly earthed, see for example (Elinstallationreglerna 2003). This has been assumed here. The generator step-up transformer has also been assumed directly earthed on its low voltage y-side, while the induction generator has been assumed unearthed, as shown in Figure 6.13.

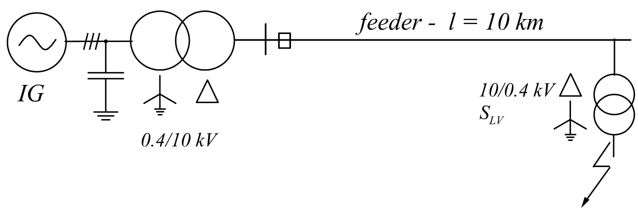

Figure 6.13 Induction generator supplying a low voltage load via a medium voltage line and a distribution transformer.

On the low voltage side of the distribution transformer, an earth-fault may originate from a fault between a phase conductor and the real earth or the PE (protective earth) conductor. In this second case, the fault current is given by (Elinstallationreglerna 2003):

$$I_f = \frac{3U_{ph}}{2Z_{net} + Z_{0LV} + 3\left(Z_{Lph} + Z_{LPE}\right)} \tag{6.1}$$

U_{ph} is the phase-earth nominal voltage

Z_{net} is the positive (and negative) sequence impedance of the medium voltage distribution network, including the distribution transformer

Z_{0LV} is the zero sequence impedance of the distribution transformer

Z_{Lph} is the impedance of the low voltage phase conductor up to the fault location

Z_{LPE} is the impedance of the low voltage PE conductor up to the fault location

During grid-connected operation, the impedance Z_{net} is determined essentially by the impedance of the distribution transformer, since the network impedance is negligible. During island operation, the impedance Z_{net} should include also the impedance of the induction generator and its step-up transformer, since those may not be neglected. Figure 6.14 shows how the sum of $2Z_{net}$ + Z_{0LV} changes as a function of the distribution transformer rating for different network conditions. In the figure, "Net" refers to grid-connected operation. The network has been represented as a Thevenin equivalent with a short-circuit power of 50 MVA in series with a transformer whose rating Str has been varied between 5 and 2 MVA. "IG" refers to island operation with only an induction generator as shown in Figure 6.13. A 10 km line in the medium voltage distribution network has also been considered.

As it can be observed, the total source impedance may be higher during island operation, leading to lower fault currents on the low voltage side of the distribution transformer.

The term $3(Z_{Lph}$ + $Z_{LPE})$ in Equation 6.1 has the greater influence on the induction generator behavior during an earth-fault on the low voltage side of a distribution transformer. This term depends on the distance of the fault from the distribution transformer, the conductor type and cross-section area. However, to not cause unacceptable voltage drops at a utility, this term cannot be very high. If this impedance is considered mainly resistive, a value of 3 Ω can be considered as a higher limit for (Z_{Lph} + Z_{LPE}). This term can be treated as a fault resistance and it accounts for the impedance of the phase conductor and the PE conductor.

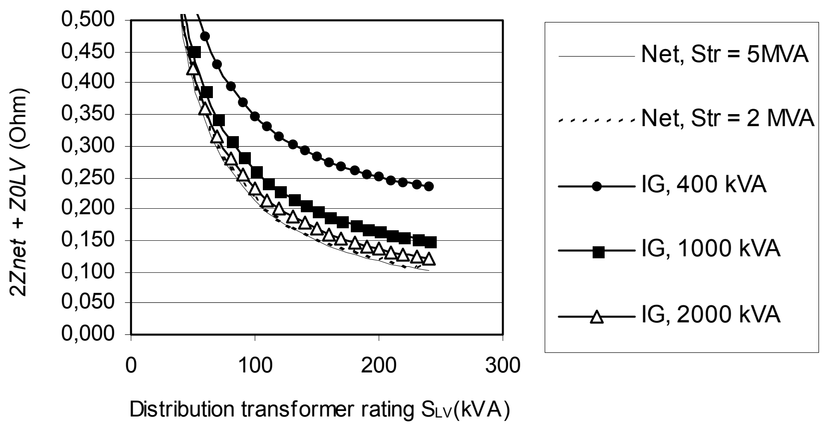

Figure 6.14 Total network and distribution transformer $2Z_{net}$ + Z_{0LV} as a function of the distribution transformer rating S_{LV}.

Some earth-faults have been simulated on the low-voltage side of a 150 kVA distribution transformer varying the term (Z_{Lph} + Z_{LPE}), assumed purely resistive. The earth-faults have been simulated by short-circuiting phase-a conductor with the PE conductor. Also, two different induction generator ratings have been considered, 400 and 1000 kVA. The voltage on the high voltage side of the distribution transformer and the fault current on the low voltage side of the distribution transformer are of interest. These quantities are shown in Figure 6.15 and Figure 6.16, for the case in island operation with the induction generator and also for the grid-connected case. In this last case the network has been modeled as a Thevenin equivalent with a short-circuit power of 50 MVA in series with a transformer of 5 MVA rating. The rated current of the distribution transformer is 216 A. From these figures some considerations can be drawn.

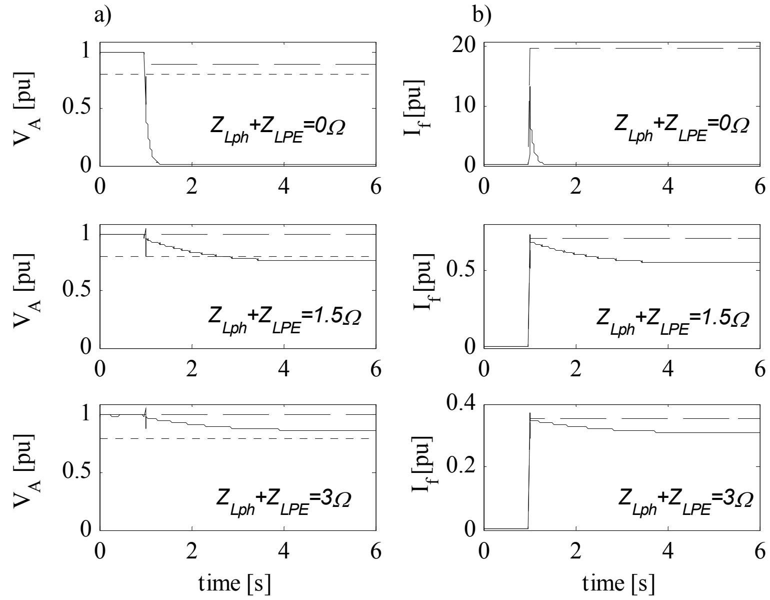

Figure 6.15 Distribution network phase-A voltage (a) and distribution transformer phase-a current (b) at a fault between phase-a and PE conductor on the low voltage side of the distribution transformer. The voltage is in pu of nominal phase-earth voltage. The current is in pu of the distribution transformer rated current. Grid-connected operation (dashed), island operation with a 400 kVA generator (solid). Undervoltage relay setting at 0.8 pu (dotted)

If the earth-fault occurs close to the distribution transformer, i.e. the term (Z_{Lph} + Z_{LPE}) is small, the fault is seen as a low resistive phase-phase fault on the medium voltage distribution network and the induction generator demagnetizes if the transformer fuses do not blow sufficiently fast. If the distance of the fault from the distribution transformer is sufficiently high, i.e. the term (Z_{Lph} + Z_{LPE}) is sufficiently high, the induction generator does not demagnetize, but the generator voltage and speed drop. The magnitude of this voltage drop will determine whether the undervoltage relay located at the generator terminals will trip the generator. As shown in the figures, for a given value of the term (Z_{Lph} + Z_{LPE}), higher rating generators experience lower voltage drops (compare for example the case with (Z_{Lph} + Z_{LPE}) = 1.5 Ω for the 400 kVA generator in Figure 6.15 and for the 1000 kVA generator in Figure 6.16). If the inductance of term (Z_{Lph} + Z_{LPE}) cannot be neglected, then higher voltage drops and lower speed drops may be experienced.

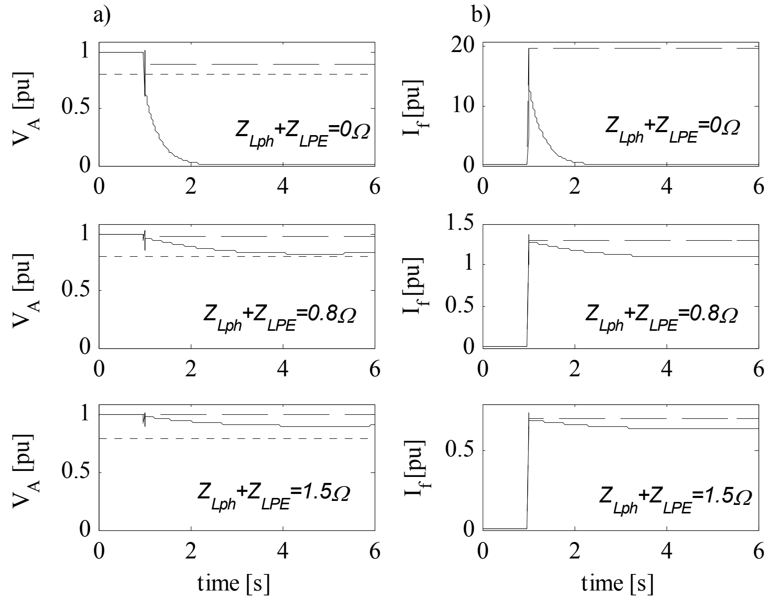

Figure 6.16 Distribution network phase-A voltage (a) and distribution transformer phase-a current (b) at a fault between phase-a and PE conductor on the low voltage side of the distribution transformer. The voltage is in pu of nominal phase-earth voltage. The current is in pu of the distribution transformer rated current. Grid-connected operation (dashed), island operation with a 1000 kVA generator (solid). Undervoltage relay setting at 0.8 pu (dotted)

It must also be noted that the fault current on the low voltage side of the distribution transformer, for a given value of the term (Z_{Lph} + Z_{LPE}), is lower as compared to the case of grid-connected operation for two reasons: the drop in the generator voltage and the higher source impedances. The higher source impedance causes lower fault current only for very small values of the term (Z_{Lph} + Z_{LPE}), because when this increases it predominates over the source impedance term in Equation 6.1. In the chapter about protection, it will be derived a condition under which the transformer fuses may blow. Moreover, some considerations will be made on the proper functioning of overcurrent protective devices downstream the distribution transformer during a fault causing the generator voltage to drop.

6.10 Summary

The self-excited induction generator behavior during an earth-fault depends on the earthing arrangement of the distribution network. The generator sustains the voltage at an earth-fault in an unearthed network. In this case, the generator can be modeled as a constant voltage behind a transient impedance at the positive sequence and classical symmetrical component analysis can be used. Also in the case of an earth-fault in a resonant-earthed network, the generator does not demagnetize. Its voltage however may decrease in this case if a resistance in parallel with the Petersen coil is used. An earth-fault in a directly earthed network is seen as a phase-phase fault by the generator and, in this case, it demagnetizes quickly.

The amount of cables present in an island-operated distribution network with a self-excited induction generator is limited mainly by two reasons. The total reactive power production of the cables must be less than the no-load reactive need of the self-excited induction generator. Moreover, in an unearthed network the zero sequence voltage arising at a high resistive earth-fault decreases with increasing network capacitance to earth, i.e. increasing amount of cables. If the zero sequence voltage decreases below a certain value, it is no longer possible to securely detect all earth-faults as prescribed by low. The first reason is the limiting factor for low rating generators, while the second reason is the limiting factor for high rating generators in unearthed networks.

The fact that the self-excited induction generator does not demagnetize at an earth-fault in non-directly earthed networks implies the need of a dedicated earth-fault protection to be used in island operation. This will be treated in detail in Chapter 9.

An earth-fault on the low voltage side of a distribution transformer is seen as a phase-phase fault in the distribution network, if the distribution transformer is Dyn connected. The behavior of the induction generator for such faults depends on the distance of the fault from the distribution transformer, i.e. on the term (Z_{Lph} + Z_{LPE}). If this term is small compared to the base impedance of the generator, the generator demagnetizes if the fault is not cleared in time. Higher values of the term (Z_{Lph} + Z_{LPE}) may cause the generator voltage to drop, without necessarily demagnetizing the generator. This voltage drop will cause lower fault currents than expected and normally used fuses may not blow.

Chapter 7

Short-circuits

The short-circuit behavior of a self-excited induction generator is presented in this chapter. So far, the behavior of the induction generator at a solid three-phase short-circuit at its terminals and during earth-faults has been analyzed. Next, the behavior of the self-excited induction generator during symmetrical and unsymmetrical short-circuits in the distribution network is considered. The dependence of the short-circuit current on various parameters, as fault resistance, fault location and generator loading, is investigated. The results will be important in assessing the type of relaying necessary for assuring short-circuit protection.

7.1 Introduction

The short-circuit analysis of an island-operated self-excited induction generator has been performed in (Jain et al. 2002). In this reference, the authors investigate the self-excited induction generator behavior for three-phase and phase-phase short-circuits at its terminals, considering only solid faults.

In the case considered in this work, it is particularly important to know the induction generator behavior for short-circuits located in the distribution network. It is not obvious that a short-circuit located at the end of a feeder still causes the same behavior of the generator as solid short-circuits at its terminals. In other words, the dependence of the short-circuit current on the total impedance interposed between the generator and the fault location must be investigated.

Other important factors that could influence the generator short-circuit behavior are its pre-fault loading and the presence of a STATCOM. The latter is used for voltage control and it will be connected at the generator terminals while the generator is supplying some loads. The no-load reactive need of the generator will instead normally be supplied solely by capacitors. It has been found in the literature (Freitas et al. 2005) that a STATCOM should have almost no influence on the three-phase short-circuit behavior of an induction generator. However, in this reference the generator was considered to be grid-connected and the STATCOM was not located directly at the generator terminals. A general description of the STATCOM influence on the short-circuit behavior of an island-operated self-excited induction generator has not been found in the literature. A brief investigation on this issue is performed in this chapter by using phasor-type simulations.

It is possible to connect more than one self-excited induction generator in the same island-operated distribution network. For this reason, a short-circuit analysis with two self-excited induction generators connected on different feeders will be performed here. The case with one induction and one synchronous generator in the same network is also briefly considered. The analysis will highlight if the contemporaneous presence of more than one generator in the network may aid to sustain the voltage at a short-circuit.

In Chapter 4, a theoretical expression for the three-phase short-circuit current of an induction machine running at fixed speed has been proposed. In Section 7.4, it will be investigated if this expression gives accurate results also in the case of a self-excited induction generator by comparing the results from calculations and simulations. The reasons why a self-excited induction generator may deliver a different short-circuit current are the presence of the charged capacitors and STATCOM at the generator terminals and its mechanical dynamics. In the same section it will also be investigated if the short-circuit current formula may be modified to include the case of a three-phase short-circuit with fault resistance in the distribution network, some distance away from the generator.

On the other hand, it is not available a closed formula for the phase-phase short-circuit current of an induction generator and the only way to understand its behavior during such a fault is through simulations.

The results of this chapter will help evaluating the type of relaying necessary for assuring short-circuit protection during island operation with induction generators.

7.2 Description of simulations

Both phasor-type and instantaneous-value simulations have been performed to assess the short-circuit behaviour of an island-operated induction generator. Phasor-type simulations are helpful to get insight into the general behaviour of the generator, to assess if and when it demagnetizes. Instantaneous-value simulations are needed for an accurate prediction of the short-circuit current and to evaluate, for example, if an overcurrent relay would trip in response to that current.

During phasor-type simulations the network shown in Figure 5.3 has been used. Simulations without the STATCOM have been performed first. The major aim with phasor-type simulations is to understand if the generator demagnetizes for short-circuits in the distribution network, in particular for phase-phase short-circuits, and to get some insight into the influence of the STATCOM.

The network shown in Figure 5.4 has instead been used for instantaneous-value simulations. The STATCOM was not included in these simulations. First, only one induction generator has been considered. Then, a second generator has been added at the end of the second feeder, first an induction and then a synchronous generator. The results from instantaneous-value simulations will give a better insight into the decay rate of the short-circuit current delivered by the induction generator. The results from these simulations are therefore important in the choice of the short-circuit protection scheme during island operation and they will be used in Chapter 9, when dealing with overcurrent protection.

Different generator ratings have been considered in the simulations. During the simulations, the induction generator was driven by a hydraulic turbine. However, because of the fast transients involved during short-circuits, the type of turbine should not have a significant influence on the short-circuit current.

7.3 Phasor-type simulation results

In the following are reported the results from phasor-type simulations. First, the influence of various parameters on the three-phase short-circuit behaviour of the self-excited induction generator without STATCOM is showed. The behaviour of the same generator during a phase-phase short-circuit is then reported. Finally the influence of the STATCOM during different types of short-circuits is presented. The generator is in a steady-state condition before applying the short-circuit, with speed and voltage constant and close to their nominal values.

Fault location

The location of the fault changes the total impedance between the generator and the fault. Depending on the line and transformer parameters, this impedance will change the time constants with which the short-circuit current decays. An important result from the simulation is that the self-excited induction generator demagnetizes at a solid three-phase fault at not only its terminals, but also anywhere else in the network. Figure 7.1 shows the generator voltage and current for faults at two different locations, at the generator terminals and at the end of the 10 km overhead line. An increasing distance of the generator from the fault location has the effect of reducing the short-circuit current peak and to slow-down the demagnetization process.

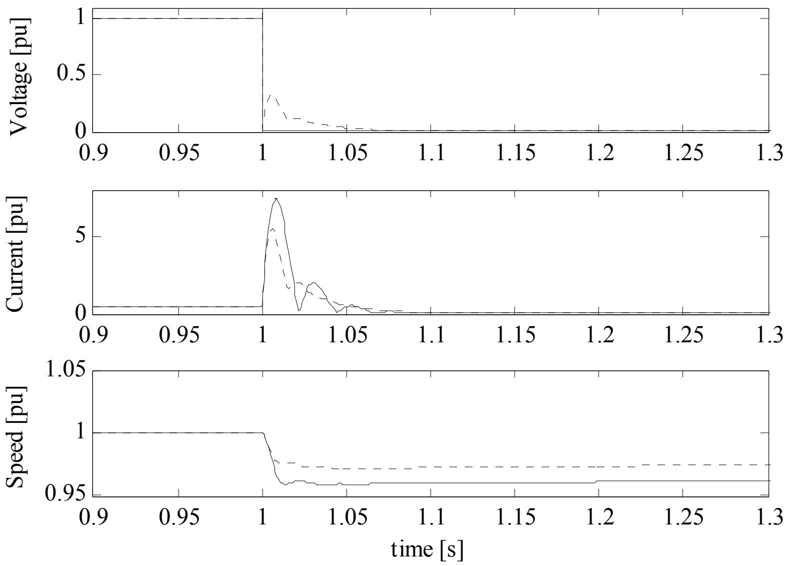

Figure 7.1 Generator voltage, current and speed at a solid three-phase short-circuit at generator terminals (solid) and end of overhead line (dashed). Unloaded 400 kVA generator case.

Fault resistance

Results from simulations with different fault resistances are shown in Figure 7.2. Also in this case, the effect of increasing the fault resistance is to decrease the short-circuit current peak and slow down the demagnetization of the induction generator. It has been found that fault resistances up to 80 % of generator base impedance still cause the demagnetization of the generator. It can be stated that a self-excited induction generator practically demagnetizes for all three-phase short-circuits. In fact, a three-phase short-circuit with fault resistance equal to the generator base impedance would correspond to the nominal loading of the generator and therefore this case cannot really be looked at as a short-circuit. Increasing the fault resistance actually causes higher drops of the rotor speed, in case of an unloaded generator.

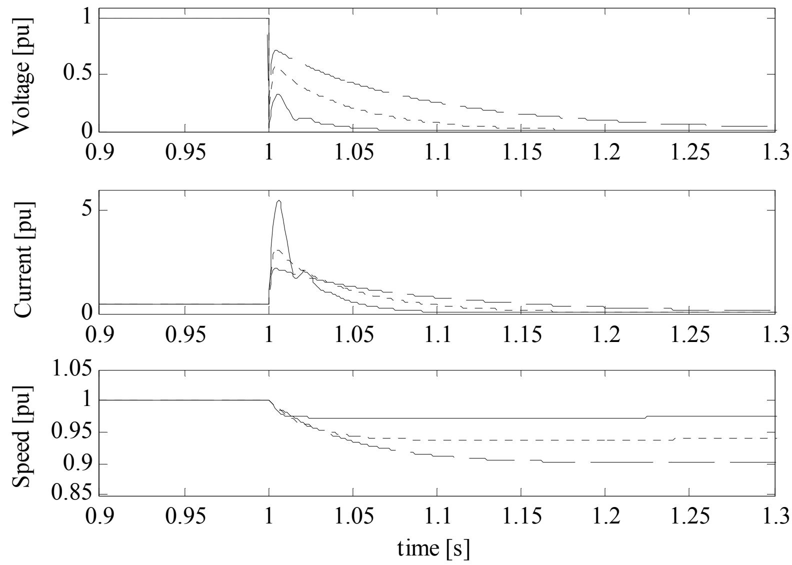

Figure 7.2 Generator voltage, current and speed at a three-phase short-circuit at end of overhead line. Fault resistance equal to zero (solid), 15 % (dotted) and 30 % (dashed) of generator base impedance. Unloaded 400 kVA generator case.

Pre-fault loading of the generator

The pre-fault loading of the generator does not have any appreciable influence on the short-circuit current and voltage of the self-excited induction generator. Results from three-phase short-circuits with three different levels of pre-fault generator loading are shown in Figure 7.3. The pre-fault loading of the generator has significant effects only on the mechanical dynamics of the generator, following the fault. In the simulated cases, the value of the capacitors at the generator terminals have been adjusted for each initial loading to get nominal voltage.

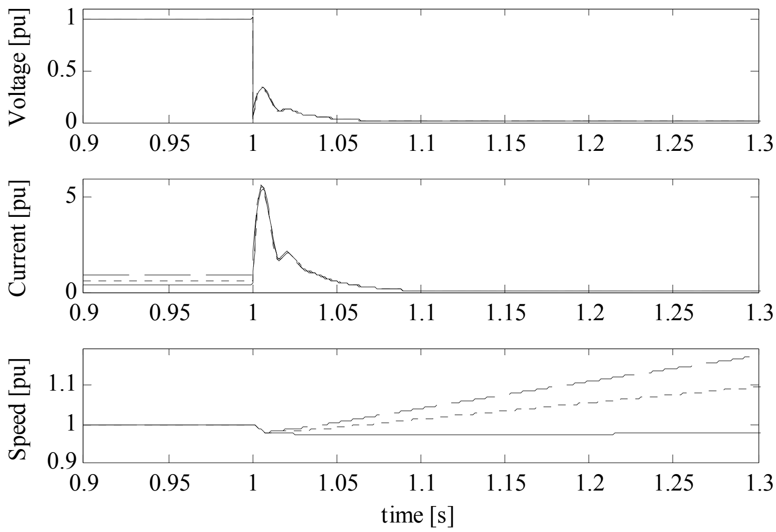

Figure 7.3 Generator voltage, current and speed at a solid three-phase short-circuit at end of overhead line. Generator loading equal to zero (solid), 40 % (dotted) and 67 % (dashed) of generator kVA rating. 400 kVA generator case.

Generator rating

Low rating generators have higher stator and rotor resistances compared to high rating generators, while their leakage reactances do not vary much (Anderson 1995). As a consequence, the stator and rotor transient time constants appearing in Equation 4.12 and 4.13 will be lower for low rating generators, leading to faster demagnetization. This is evident in Figure 7.4, where the results from three-phase short-circuit simulations for three different generator ratings are presented.

Phase-phase short-circuits

Simulation results indicate that phase-phase short-circuits anywhere in the network cause the demagnetization of the island-operated self-excited induction generator. It is remarked that this result is different from what has been found in (Chen et al. 1991). In that reference, it has been shown that if the self-excited generator is connected to an infinite bus, it does not demagnetize at a phase-phase short-circuit but it continues to feed current into the fault.

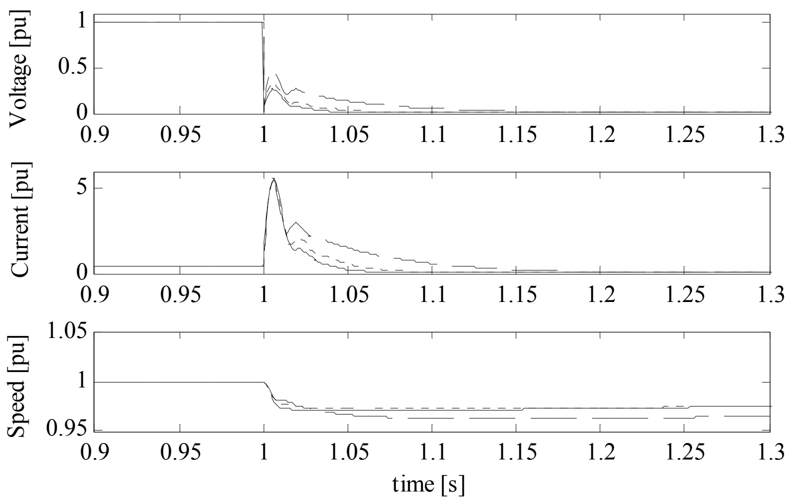

Figure 7.4 Generator voltage, current and speed at a solid three-phase short-circuit at end of overhead line. 100 kVA (solid), 400 kVA (dotted) and 1000 kVA (dashed) unloaded generator.

What has been said previously about the influence of fault resistance, fault location, pre-fault loading and generator rating on the three-phase short-circuit behavior is still valid in the case of phase-phase short-circuits.

During a phase-phase short-circuit in the distribution network, the induction generator current in one phase will be higher than the current in the other two phases, because of the yD connection of the step-up transformer. In the simulated cases of short-circuits between phase-A and phase-B at the end of the 10 km overhead line, the generator current in phase-b is higher than the currents in phase-a and phase-c, which are almost equal.

An important thing to notice about phase-phase short-circuits is that during such a fault, the self-excited induction generator demagnetizes slower as compared to a three-phase short-circuit. This is shown in Figure 7.6, where it is also possible to notice that in case of a phase-phase short-circuit the generator voltage on the phases with lower current decay slower compared to the voltage in phase-b. Phase-c current and voltage are not shown in the figure for sake of clarity, but they are very close to phase-a values, at least for low fault resistances.

Phase-phase-to-earth faults cause the induction generator to demagnetize.

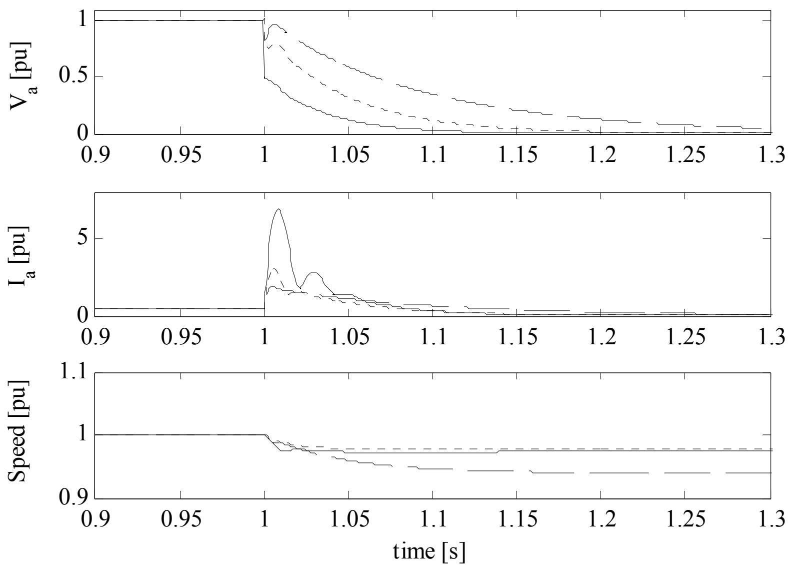

Figure 7.5 Generator voltage, current and speed at a phase-phase short-circuit at generator terminals with zero fault resistance (solid), at end of overhead line with fault resistance equal to zero (dotted) and 15 % of base impedance (dashed). 400 kVA generator case.

STATCOM

A STATCOM with a rated power equal to one fourth of the generator kVA rating has been considered in the simulations. When the STATCOM is connected, the amount of fixed capacitors is chosen to supply solely the no-load reactive need of the generator. The STATCOM supplies the reactive power needed by the generator under load conditions. It uses a voltage control strategy, i.e. it strives to regulate the voltage at the generator terminals to its nominal value by injecting reactive power. During a short-circuit, following the voltage drop, the STATCOM control will try to inject the maximum allowed amount of reactive power it can inject, by increasing the q-axis reference current. The STATCOM control also limits the current it can deliver.

The results from simulations indicate that the STATCOM does not prevent the demagnetization of the self-excited induction generator during a short-circuit. The difference between the short-circuit current with and without the STATCOM is small. The main effect of the STATCOM is to slow down the short-circuit current decay to zero. This fact is appreciable for faults away from the generator or with some fault resistance. In the simulations, it has been assumed that the STATCOM is not tripped during the fault.

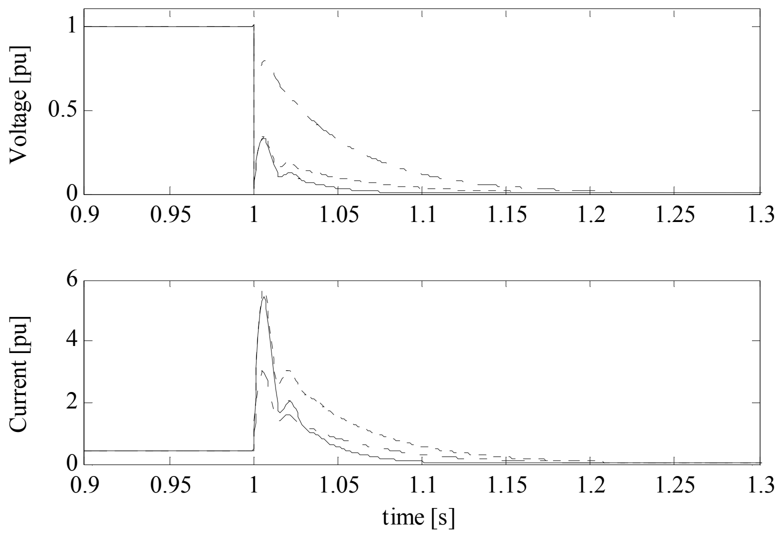

Figure 7.6 Generator voltage and current at faults at end of overhead line. Phase-a at a three-phase short-circuit (solid), phase-b (dotted) and phase-a (dashed) at a phase-phase short-circuit. 400 kVA generator case.

The results from a three-phase and a phase-phase short-circuit at the end of the overhead line are shown in Figure 7.7 and Figure 7.8. The generator and STATCOM currents in the figures are expressed in pu of their corresponding rated values.

It must be noted that the STATCOM does not implement a dual vector current controller (DVCC) (Fainan 2007). The negative sequence voltage arising at a phase-phase short-circuit causes a double-frequency component when transformed inside the controller into dq-coordinates and this causes oscillations in the STATCOM dc-link voltage and output current (Song et al. 1999). A controller taking into account also the unbalances in the voltage, such as a DVCC, could probably give a slightly better performance during unsymmetrical short-circuits.

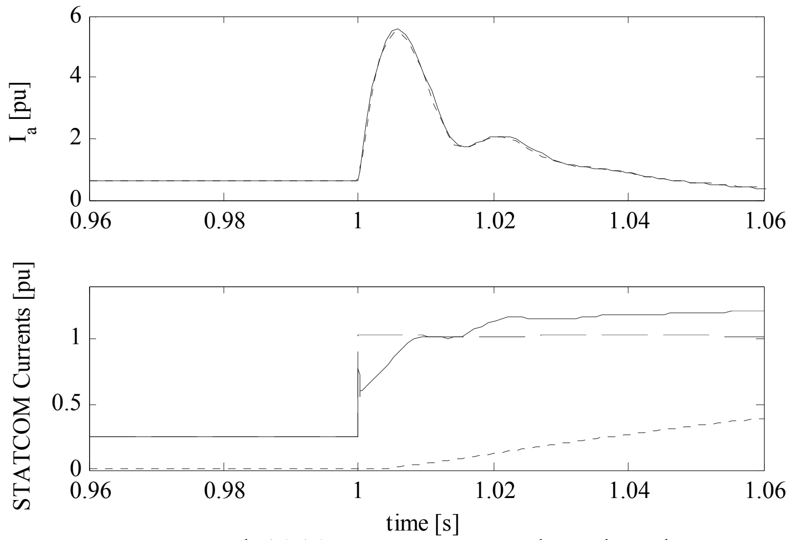

Figure 7.7 Generator and STATCOM currents at a three-phase short-circuit at end of overhead line. Generator current with (solid) and without (dotted) STATCOM (Upper). STATCOM total current (solid), I_q (dashed) and I_d (dotted) reference current (Lower). 400 kVA generator case.

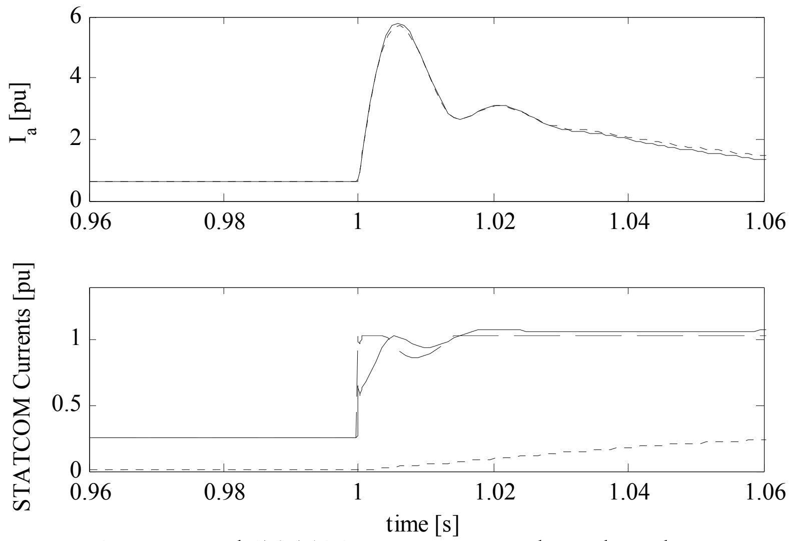

Figure 7.8 Generator and STATCOM currents at a phase-phase short-circuit at end of overhead line. Generator current with (solid) and without (dotted) STATCOM (Upper). STATCOM total current (solid), I_q (dashed) and I_d (dotted) reference current (Lower). 400 kVA generator case.

7.4 Instantaneous-value simulation results

The results from the instantaneous-value simulations confirm the general conclusions drawn in the previous section about the demagnetization of the self-excited induction generator during short-circuits in the network and about the influence of the various parameters on the short-circuit current.

It is interesting to compare the results from the calculations with Equation 4.10 with the results from instantaneous-value simulations for a three-phase short-circuit at the generator terminals. As shown in Figure 7.9 the calculations are in good agreement with the results from simulations. This means that the capacitors at the terminals of the self-excited induction generator and the rotor speed variation do not impact significantly on the current delivered by the generator.

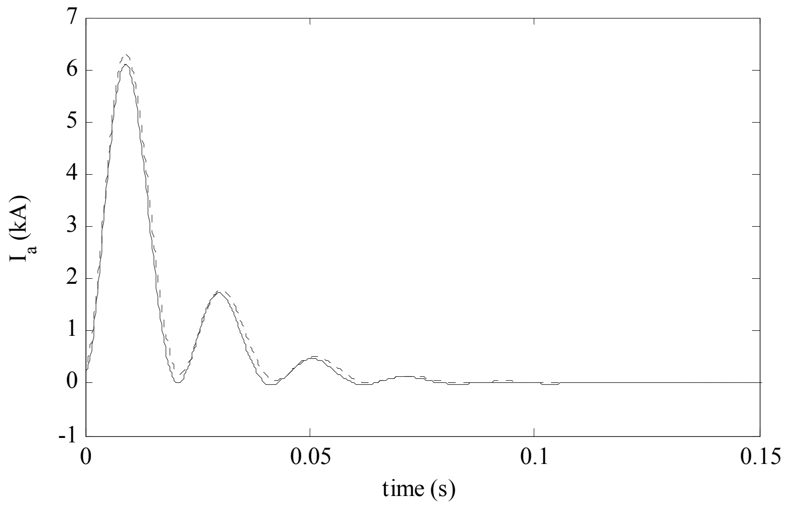

Figure 7.9 Solid three-phase short-circuit at generator terminals. Calculated (solid) and simulated (dotted) generator current. 400 kVA generator case. The pre-fault loading of 45% of nominal generator rating in the simulations has been neglected in the calculations.

In case of a three-phase short-circuit not directly at the terminals of an induction machine, in our case for example at the end of the overhead line in the distribution network, (Sarma 1986) suggests that the impedance between the machine and the fault must be added to the generator transient impedance when calculating the short-circuit current. In case of a three-phase short-circuit away from the generator or with fault resistance, the external impedance between the generator and the fault can be considered as in series with the stator resistance and leakage inductance. Therefore, in the case of a three-phase short-circuit at the end of the overhead line, the transformer and line impedances, along with the fault resistance, may be added to the stator resistance and leakage inductance, when using Equation 4.10. This has been done and the results from calculations and simulations, shown in Figure 7.10 indicate that the method leads to a sufficiently accurate prediction of the short-circuit current for a fault not directly located at generator terminals.

Analyzing the short-circuit current during different types of faults and at different location, it has been noted that the fastest decay rate of the current is obtained during solid three-phase short-circuits close to the generator. This is also the case causing larger short-circuit currents. From Figure 7.9, it can be observed that the short-circuit current decays below the nominal generator current in less than two cycles, for the considered 400 kVA generator case. This time is most likely not sufficient for an overcurrent relay to trip. The consequence of this fact will be analyzed in Chapter 9.

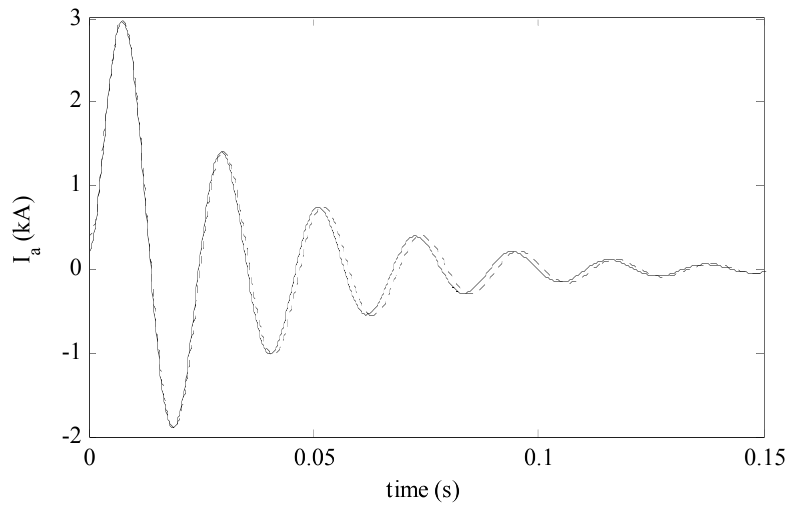

Figure 7.10 Three-phase short-circuit at end of overhead line with fault resistance equal to 10 % of generator base impedance. Calculated (solid) and simulated (dotted) generator current. 400 kVA generator case. The pre-fault loading of 45% of nominal genitor rating in the simulations has been neglected in the calculations.

If two self-excited induction generators are connected to the same island-operated distribution network, they both demagnetize during a three- or phase-phase short-circuit anywhere in the network. Two equal induction generators have been simulated in the same network of Figure 5.4, the second generator being connected at the end of the second feeder. The two generators share initially the same amount of load, i.e. each generator is loaded with 45 % of nominal generator rating. The short-circuit currents of the two generators are shown in Figure 7.11.

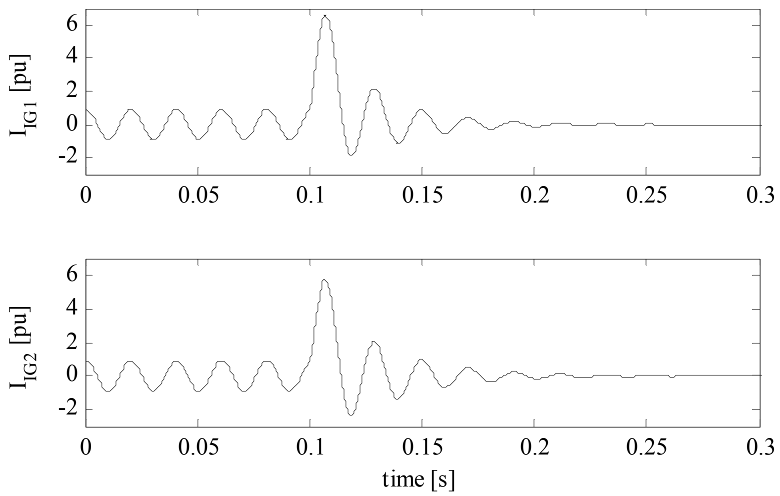

Figure 7.11 Generator current at a solid three-phase short-circuit at end of overhead line with two induction generators connected in the same distribution network. The two induction generators are identical and rated 400 kVA.

If the self-excited induction generator is instead operated connected in the same network with a synchronous generator, its short-circuit behaviour changes. A separately excited synchronous generator of the same rating of the induction generator has been connected in the simulated case at the end of feeder 2. The induction generator does not demagnetize at a phase-phase short-circuit in this case. The presence of the synchronous generator is sufficient to keep the voltage in the unfaulted phase of the induction generator, which will continue to deliver current into the fault, see Figure 7.12. It has been already mentioned that a self-excited induction generator connected to an infinite bus does not demagnetize at a phase-phase short-circuit. Simulations show that this is true also if the induction generator is connected in the same network with only a synchronous generator with the same rating as the induction generator.

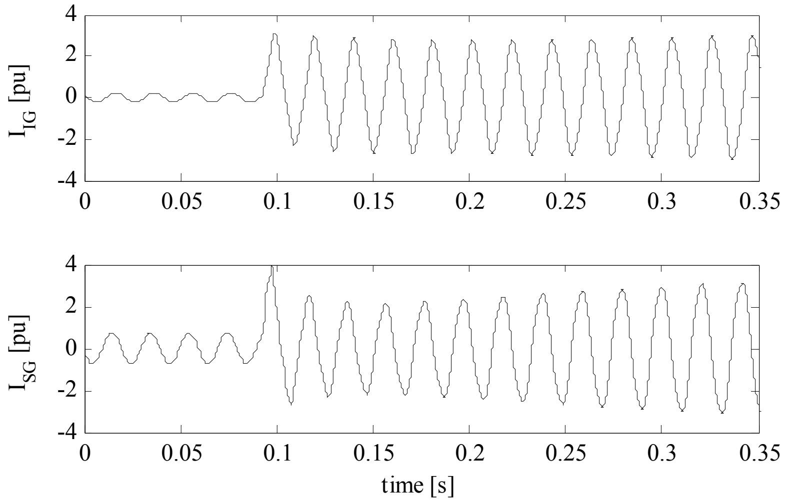

Figure 7.12 Generator current in phase-a at a solid phase-phase short-circuit at end of overhead line with one induction and one synchronous generators connected in the same distribution network.The induction generator in this case does not demagnetize. Both generators are rated 400 kVA.

7.5 Short-circuits on the low voltage side

The behavior of the induction generator for short-circuits at its terminals has been partly analyzed in the previous sections. It is now of interest to understand how the generator behaves for faults on the low voltage side of a distribution transformer. What will be said at this regard is also valid for faults on the low voltage distribution network eventually connected directly at the generator terminals.

As said in the previous chapter, the induction generator in island operation can supply low voltage loads connected at its terminals or on the low voltage side of a distribution transformer located somewhere in the distribution network, see Figure 6.13. The same considerations made in section 6.9 for faults between a phase and the PE conductor remain valid for phase-phase and three-phase faults on the low voltage side, though the magnitude of the generator voltage drop will be higher in case of short-circuits between two or more phase conductors. The induction generator demagnetizes for faults close to the distribution transformer. If the distance of the fault from the distribution transformer, and hence the conductor impedance, increases sufficiently, the generator will not demagnetize but its voltage will drop. For low rating generators, the voltage should drop below the setting of the generator undervoltage relay in any practical case. For high rating generators it may happen that the voltage drop is not below the setting of the generator undervoltage relay. In this last case, the voltage drop causes a decrease of the fault currents as compared to the fault currents for the same fault location during grid-connected operation.

7.6 Summary

It has been shown that an island-operated self-excited induction generator demagnetizes at a short-circuit in the network. The rate of decay of the short-circuit current depends on various factors, as generator parameters, fault resistance and fault location. Phase-phase short-circuits cause slower demagnetization than three-phase short-circuits. Low rating generators demagnetize faster than high rating ones due to lower rotor and stator transient time constants. Solid three-phase short-circuits close to generator terminals cause the larger currents but also the fastest decay rate. Equations 4.10, 4.12 and 4.13 provide acceptable predictions of the short-circuit current of a self-excited induction generator if the fault resistance and the impedance to the fault are added to the stator resistance and leakage inductance.

A shunt-connected STATCOM does not bring any significant change to the short-circuit current delivered by the self-excited induction generator. If two induction generators are connected in the same island-operated network, they both lose their voltage at a short-circuit. If the induction generator is instead operated in island with a synchronous generator, it will not demagnetize for a phase-phase short-circuit.

Finally, it is important to notice that the self-excited induction generator may be able to re-magnetize if the fault, for some reasons, is disconnected while the generator is still running. If not properly controlled, the voltage and the frequency could then attain high values. For this reason it is important to disconnect the induction generator at a short-circuit, once it has demagnetized, even if it does not deliver fault current. A deeper investigation on the self-excited induction generator capability of re-magnetizing, after a fault has been cleared, will be presented in the next chapter.

Chapter 8

Low-Voltage Ride-Through Capability

This chapter investigates the capability of an island-operated induction generator of riding through a fault in the network, when the fault is cleared by proper intervention of a protective device. The ride-through capability of grid-connected induction generators has been widely analyzed in the literature, especially in the context of wind power. But the ride-through capability of an island-operated self-excited induction generator has not been found in the literature. Some lab experiments on a small 2.2 kW induction generator are presented first. The second part of the chapter investigates the ride-through capability of a self-excited induction generator through simulations.

8.1 Introduction

The ride-through capability of a grid-connected induction generator has been the subject of wide analysis in the literature and the benefit of using a STATCOM for improving its ride-through capability has been widely recognized (Qi et al. 2008), (Freitas et al. 2005). An island-operated self-excited induction generator will have a different ride-through capability as compared to a grid-connected induction generator. In the first case, in fact, there is no strong network aiding the voltage restoration and supplying the reactive power needed by the induction generator. The voltage restoration in the network must be instead accomplished only by the self-excited induction generator. This implies that the tripping time of the protection relay clearing the fault must be sufficiently fast to avoid the complete demagnetization of the induction generator. If some voltage is still present at the generator terminals after fault clearing, the process of voltage build-up can take place and the voltage in the healthy network can be restored. It will be shown in this chapter that the STATCOM has an important role in improving the ride-through capability of a self-excited induction generator. However, it is also shown that the self-excited induction generator, even with a STATCOM, has inherently weaker ride-through capability than a synchronous generator.

It is reasonable to assume that the ride-through capability of the self-excited induction generator will improve if the total fault clearing time decreases, since a higher voltage would be present at the generator terminals at the moment of fault clearing. This in turn would aid a faster post-fault voltage build-up. Moreover, if the total clearing time is sufficiently long, the self-excited induction generator may demagnetize and lose the residual internal flux, thus making uncertain its capability of re-excitation. To further investigate the capability of a self-excited induction generator of re-exciting and building-up the voltage after fault clearing, some tests have been performed on the small 2.2 kW induction generator mentioned in Chapter 3. These tests are the subject of the next section.

8.2 Lab tests on re-excitation capability

A self-excited induction generator demagnetizes quickly when a short-circuit occurs in the network and the rate of decay of the voltage and current depends on the generator parameters. If the fault is cleared sufficiently fast, the induction generator will not demagnetize completely and, once the fault is cleared, it may re-excite and recover the voltage. The self-excitation capability of an induction generator may be degraded if some load remains connected at the generator terminals during this process (Elder et al. 1983). However, in the practical case of a fault in a distribution network, the self-excited induction generator would always have some load still connected during the re-excitation process. To assess whether and when the generator is able to recover the voltage after a fault, a set of laboratory tests have been performed on a small 2.2 kW induction machine. The parameters are reported in Table 3.1.

The generator is driven by a dc motor, controlled to act as a hydraulic turbine. The frequency of the voltage before applying the fault is close, but not exactly, 50 Hz. The pre-fault voltage has been regulated to nominal value using switchable capacitances at the generator terminals. A STATCOM has not been used during these tests. A single-line diagram of the lab set-up is shown below.

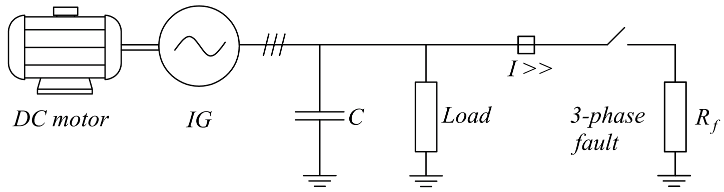

Figure 8.1 Single line diagram of lab set-up for testing the capability of the self-excited induction generator to re-excite after fault clearing.

Three-phase short-circuit tests have been performed with the generator unloaded and with the generator feeding a resistive load of 1.5 kW, i.e. almost 45 % of its nominal VA rating. In all cases, a three-phase short-circuit is applied at the generator terminals and it is cleared by implementing an overcurrent protection with the aid of the real-time software dSPACE. The overcurrent protection sends a trip signal to a contactor after a specified time has elapsed. This time delay has been varied in the tests from 100ms to 1s, varying therefore the fault clearing time.

Short-circuits with unloaded generator

The pre-fault voltage was regulated to nominal value by connecting 9 capacitors steps of 16 μF each at the generator terminals and keeping them connected during the fault. Two short-circuit cases have been considered, the first with no fault resistance and the second with a fault resistance equal to 4 Ω. The short-circuit is cleared with varying time delay in all cases. The results are shown in Figure 8.2 and Figure 8.3.

It was observed that the generator is always able to re-excite after a solid short-circuit even if this is cleared with considerable time delay. This means that there is still sufficient remanent flux in the generator after a solid three-phase short-circuit. This conclusion is in agreement with Figure 3.9, where it has been shown that a solid short-circuit leaves a certain remanent flux in the generator. The voltage build-up after fault clearing must re-start from the remanent flux and it takes about 2 s for the voltage to build up to nominal value after the fault has been cleared. It has been observed that the same qualitative results are obtained with a fault resistance of 3 Ω.

In the case of fault resistance equal to 4 Ω, four different clearing times have been considered. The fault resistance corresponds to almost 30 % of generator base impedance and it is only slightly higher than the 3 Ω fault resistance with which similar results as in the solid short-circuit case have been observed. The generator was able to recover the voltage if the fault clearing time was shorter than 360ms. With longer clearing times, the generator is not capable of re-exciting after fault clearing because of the low remanent flux. From Figure 8.3, it can be noted that the post-fault voltage build-up is faster the shorter the fault clearing time. Because of the fact that the terminal voltage has not completely decayed to zero when the fault is cleared, the voltage build-up in the 4 Ω fault resistance case, when achieved, may be faster compared with the case of a solid-three phase short-circuit.

It is noted that the measured minimum speed of the generator during the transient is almost the same in all cases, around 34 Hz.

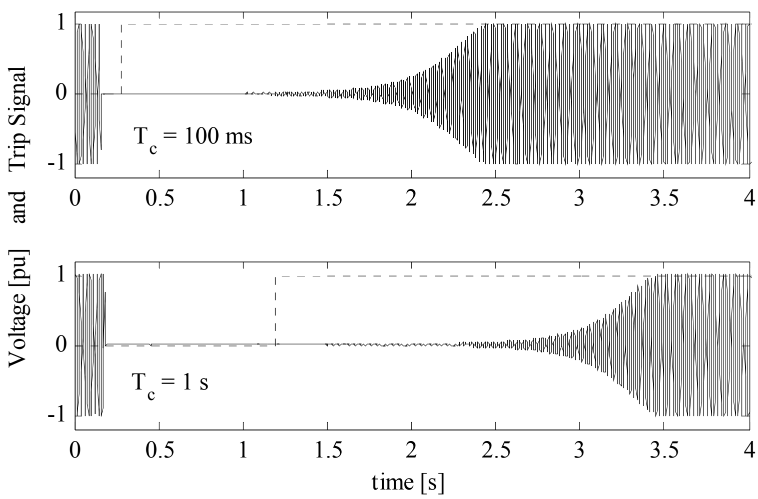

Figure 8.2 Measured generator voltage (solid) and contactor trip signal (dotted) at a three-phase short-circuit at the generator terminals. Fault resistance and pre-fault load are equal to zero. T_c is the time delay after fault detection with which the trip signal is sent to the contactor.

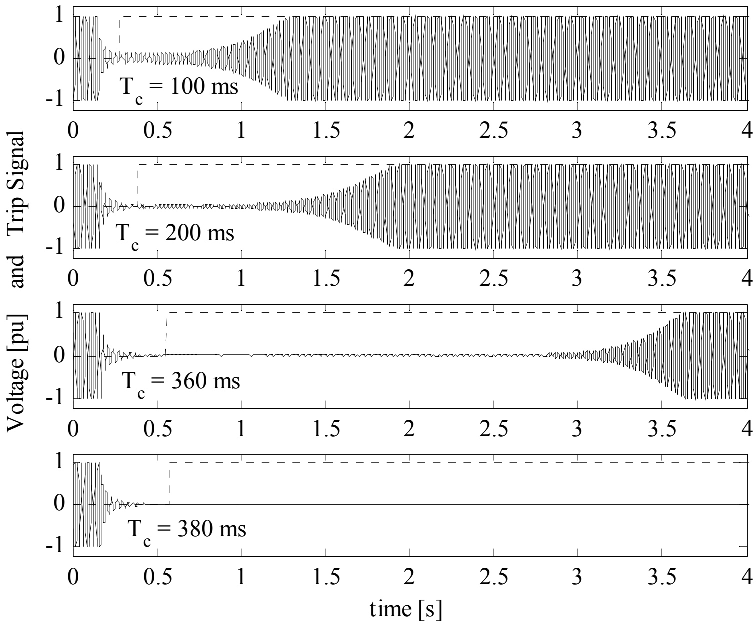

Figure 8.3 Measured generator voltage (solid) and contactor trip signal (dotted) at a three-phase short-circuit at the generator terminals. Fault resistance is equal to 4 Ω. Pre-fault load is equal to zero. T_c is the time delay after fault detection with which the trip signal is sent to the contactor.

Short-circuits with the generator feeding a 1.5 kW load

The pre-fault voltage was regulated to nominal value by connecting 11 capacitors steps of 16 μF each at the generator terminals and keeping them connected during the fault along with the load resistance. The results from short-circuit cases with a fault resistance equal to 4 Ω are shown in Figure 8.4. Surprisingly, it has been observed that it is easier to achieve voltage build-up when the generator is loaded. Moreover, the voltage build-up is achieved faster than in the case with the unloaded generator. A possible explanation for this behaviour is that the increased amount of capacitance at generator terminals and the higher post-fault overspeed make it easier to re-excite the generator, and their effect are more important than the fact that the load remains connected to the generator during the transient.

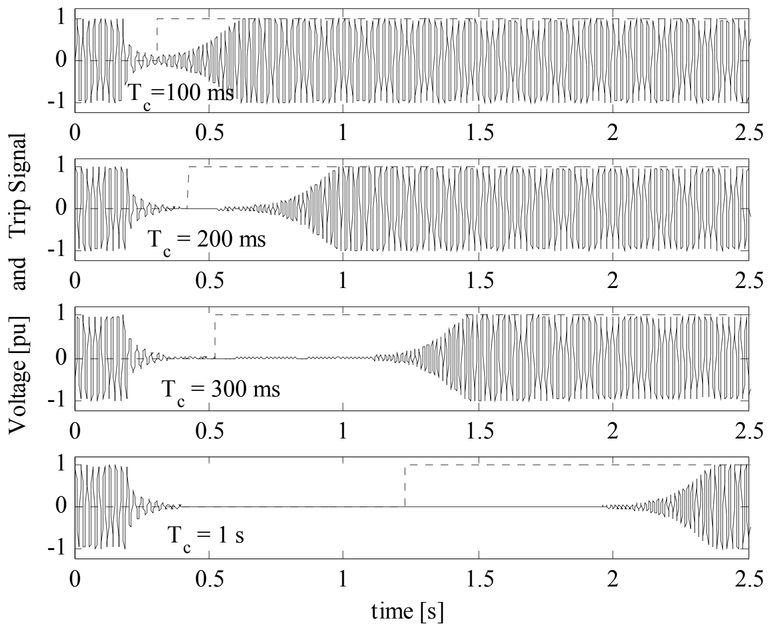

Figure 8.4 Measured generator voltage (solid) and contactor trip signal (dotted) at a three-phase short-circuit at the generator terminals. Fault resistance is equal to 4 Ω. Pre-fault load is equal to 1.5 kW. T_c is the time delay after fault detection with which the trip signal is sent to the contactor.

Considerations on lab tests

The results from the tests carried out on the small 2.2 kW self-excited induction generator indicate that the induction generator is capable to re-excite after a short-circuit at its terminals, if the fault clearing time is sufficiently short. The shortest required critical clearing time, 360 ms, was observed with a fault resistance equal to about 30 % of the generator base impedance. Moreover, in case of solid short-circuits, the induction generator was always able to re-excite, independently on the clearing time.

The tests also showed that the re-excitation of a loaded generator is more likely than in the case of an unloaded generator. This is probably due to the higher capacitances connected at the generator terminals when it is supplying load and to the higher post-fault overspeed. In the case of a loaded generator, the voltage build-up is also faster.

8.3 Low voltage ride-trough capability

In this section, the capability of an island-operated self-excited induction generator of riding through a fault will be investigated by performing phasor-type simulations in SimPowerSystems. As mentioned above, no references have been found in the literature dealing with this topic. The simulated induction generator is the 1000 kVA generator, whose data are reported in Chapter 5. The distribution network is in this case constituted by three overhead 10 km radial lines, whose data are also given in Chapter 5. The generator is initially loaded with about 800 kW, i.e. 80 % of its kVA rating. The load is of constant impedance type, at a first step. At a second step, a varying amount of the total constant impedance load will be replaced by induction motor load. The load is located at the end of the three lines, as shown in Figure 8.5.

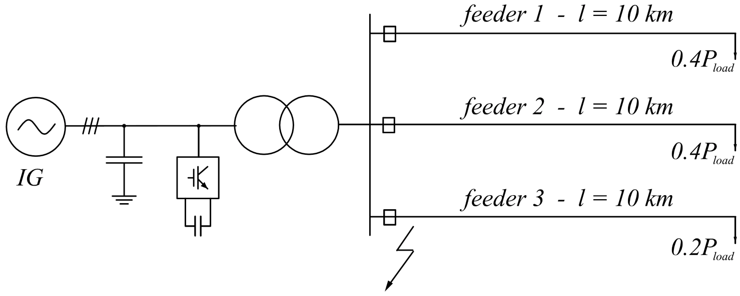

Figure 8.5 Single line diagram of the network simulated to investigate the ride-through capability of the self-excited induction generator.

A solid three-phase short-circuit at the beginning of feeder 3 is simulated first. This is a worst-case scenario, since it causes the highest and fastest drop of the generator voltage. Other fault types and locations will also be considered. The fault is cleared in 100 ms by disconnecting the faulted feeder. The total load lost after fault clearing is equal to 20 % of the total pre-fault load, i.e. 16 % of generator kVA rating. The STATCOM is delivering 55 % of its kvar rating before the fault. The induction generator is driven by the hydraulic turbine model described in Chapter 5. Different cases have been considered and they are reported in the following. Finally, a comparison with the ride-through capability of an island-operated synchronous generator driven by the same turbine is performed.

Constant impedance load

The voltage drop, caused by the demagnetization of the induction generator following the fault, decreases the total power drawn by the constant impedance loads thus causing acceleration of the generator rotor. To contain the overspeed of the generator, the voltage, and hence the load remaining on the healthy feeders, must be reestablished quickly.

Three different scenarios have been considered. In the first case, the STATCOM is disconnected after the fault and it does not participate in the post-fault transient. In the second case, the STATCOM remains connected through the entire transient and it supports the reactive need of the induction generator after fault clearing. In the third case, it has been assumed that braking resistors are available at generator terminals and they are connected to help regulating the speed of the generator after fault clearing. (Freitas et al. 2004) proposes the use of braking resistors as a cost-effective method to improve the transient stability performance of a distributed induction generator connected to a strong grid. If an island-operated network is required to ride-through a fault and a subsequent load disconnection, the use of braking resistors may be a very useful solution, since it replaces the disconnected load after the fault and it "brakes" the acceleration of the generator. The braking resistors have been here assumed to be rated 300 kW, i.e. 30 % of the generator rating. It is here assumed that the resistors are divided into three steps of equal rating. The control strategy for inserting/disconnecting the resistors is as follows. For a step to be connected, the voltage must be higher than 0.2 pu. Each step is then connected or disconnected by a hysteresis regulator with the generator speed as a control variable, as shown in Table 8.1. A time delay of 60ms, for circuit breaker closing, has also been considered in the simulations when connecting the resistors.

Table 8.1 Conditions for the connection/disconnection of the braking resistors

	Connection	**Disconnection**
Step 1	$\omega > 1.07$	$\omega < 0.95$
Step 2	$\omega > 1.09$	$\omega < 1.03$
Step 3	$\omega > 1.12$	$\omega < 1.10$

The results from simulations with constant impedance load in the three cases mentioned above are reported in Figure 8.6. Some important things can be noted. The self-excited induction generator demagnetizes if the STATCOM is disconnected after the fault and its speed increases quickly above 1.5 pu.

The STATCOM increases dramatically the capability of the self-excited induction generator to re-excite and build up the voltage after fault clearing. The braking resistors improve both the post-fault voltage and generator speed, and hence the frequency. However, they do not help decreasing effectively the maximum overspeed of the generator during the transient, which is around 1.3 pu. The maximum voltage is around 1.26 pu without the braking resistors and 1.08 pu in the case with braking resistors.

Hence, the braking resistors help achieving acceptable post-fault voltage and frequency in a shorter time. Some small hydro-power plants with induction generator and semikaplan turbines cannot operate is a stand-alone mode below a certain load, which may be as high as one third of the nominal generator power (Björnsted et al. 2008). Because of this reason, those small hydro-power plants should be equipped with some dump load along with other equipment necessary for their island operation. In these cases, the dump load may be represented by the braking resistors that so would be already available and they would not represent an extra cost.

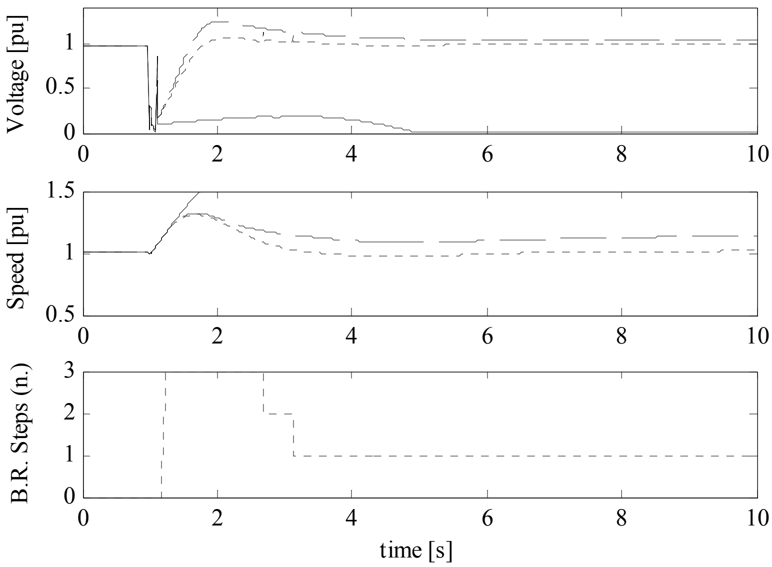

Figure 8.6 Generator voltage, speed and braking resistors (B.R.) steps at a solid three-phase short-circuit on feeder 3 cleared after 100 ms. Without STATCOM and B.R. (solid), with STATCOM (dashed), with STATCOM and B.R. (dotted). The lower plot is from the case with STATCOM and B.R.

Constant impedance and motor load

It is realistic to include an amount of dynamic load in the simulations, to allow for the representation of the part of load constituted by induction motors. This has been done in the case in which both the STATCOM and braking resistors are used. The percentage of motor load on total load has been varied progressively and an equal amount of motor load is present on feeder 1 and feeder 2. The entire motor load remains connected after fault clearing. No motor load was present on feeder 3, which is disconnected after the fault. Motor load on each feeder is represented by a lumped equivalent induction motor model. Power factor correcting capacitors are installed at the terminals of the motor model to get a pre-fault power factor of about 0.94 with nominal motor loading. The inertia constant of motor load has been assumed to be 0.28 s, corresponding to the inertia constant of motors for heat pumps, refrigerators, dishwashers (Taylor 1994).

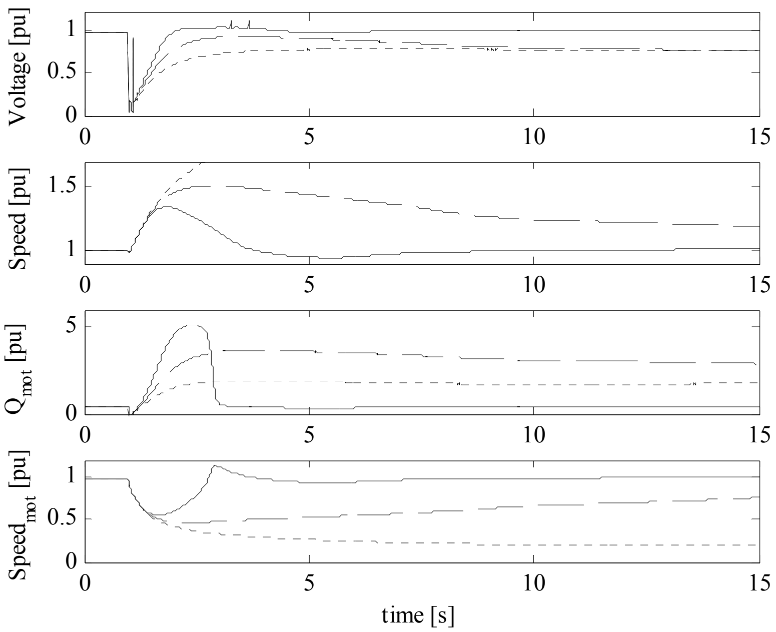

Figure 8.7 Generator voltage, speed and motor reactive power and speed at a solid three-phase short-circuit on feeder 3 cleared after 100 ms. Motor load is 2 % (solid), 6 % (dashed) and 10 % (dotted) of total load.

The mechanical load of the motor has been assumed having a torque proportional to the square of the motor speed. Results from simulations are shown in Figure 8.7. It is seen that the situation gets much worse than with pure resistive load. The post-fault stability is compromised already with 6% of motor load in the network. This is because the motor load decelerates during the voltage dip and starts drawing a considerable amount of reactive power. As a result the self-excited induction generator cannot re-establish nominal voltage. This also causes the generator to accelerate, since the resistive load in the system is kept low. Unacceptable frequencies are obtained a few seconds after the fault in the cases with higher motor load. Eventually the motors will stall and they could be damaged since they draw a large amount of reactive power for a sustained period.

Inertia constant

The considered induction generator and turbine group has an inertia constant equal to 0.46 s. This value has been measured through field measurements on a small hydro-power station with an induction generator rated 315 kW and a semikaplan turbine. Other simulations with an inertia constant value of 2 s have also been performed. Though the maximum post-fault speed, and hence frequency, variations experienced by the generator in this case were obviously lower, no other remarkable differences have been noted compared to the cases exposed above. In particular, the presence of motor load strongly deteriorates the ride-through capability of the induction generator.

Fault clearing time

In the previous sections, it has been assumed that the fault clearing time was equal to 100ms, because this is a realistically attainable value. Two other cases have been considered as well, by setting the fault clearing time to 80 and 120 ms. The short-circuit case with the STATCOM and braking resistors has been simulated with the two new fault clearing times. The only important difference noted in the simulations is that the peak overspeed is slightly lower with a fault clearing time of 80ms and higher with a fault clearing time of 120ms, as compared to the case with a fault clearing time of 100 ms. However, 120ms has been found to be the maximum acceptable fault clearing time, since longer clearing times cause the demagnetization of the generator.

Short-circuit type

Until now, only a solid-three phase short-circuit at the beginning of feeder 3 has been considered. This is regarded as a worst-case scenario, leading to the fastest demagnetization of the generator. Other faults have been simulated as well, a three-phase short-circuit with a fault resistance corresponding to 5 %

of generator base impedance at the end of feeder 3 and a solid phase-phase short-circuit at the beginning of feeder 3. In both cases, the conclusions drawn in the previous sections remain true and no appreciable differences can be observed.

Earth-faults

Since the vast majority of faults in distribution networks are single-phase-to-earth faults, it is relevant to investigate the capability of the self-excited induction generator of riding through such a fault. A solid earth-fault has been considered. The motor load was assumed to be amounting to 10 % of the total load. The fault was assumed to be cleared after 1 s. Figure 8.8 shows the case of a single-phase-to-earth fault in an unearthed network. As seen, the self-excited induction generator is capable of riding through the fault satisfactorily. The voltage and speed deviations are maintained within acceptable limits through the transient. The STATCOM and the braking resistors both contribute to achieve this performance.

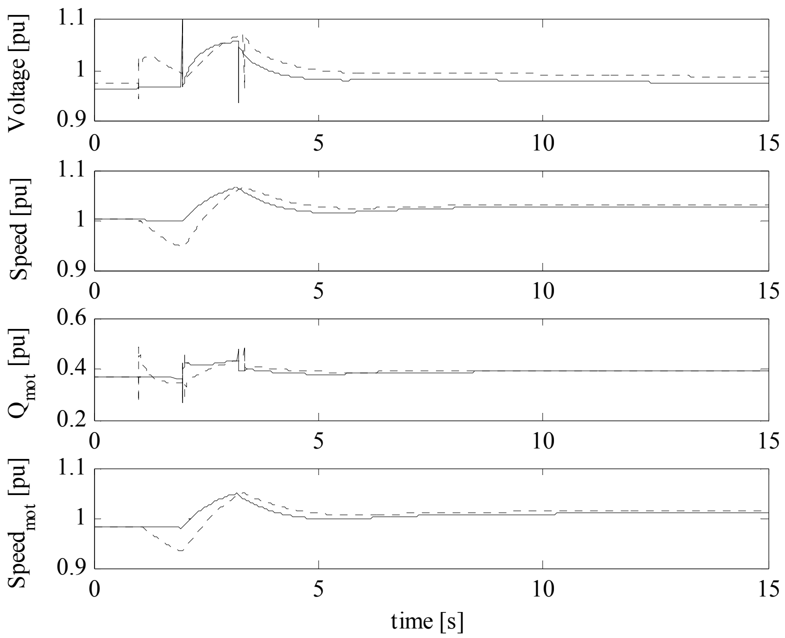

Figure 8.8 Generator phase-a voltage, speed and motor reactive power and speed at a solid earth-fault on feeder 3 cleared after 1 s. Unearthed network. Motor load is 10 % of total load. Cable length is equal to 0.1 km (solid), 10 km (dotted).

The above considerations remain valid in the case of a resonant-earthed network.

Low voltage side faults

The induction generator can supply loads at the 400 V low voltage side through distribution transformers connected to the distribution network, see Figure 6.13. The distribution transformer is normally equipped with fuses on its low voltage side. Here it is investigated how the induction generator rides through a fault on the low voltage terminals of a distribution transformer, when the fault is cleared by fuse melting within 40 ms. The current rating of the distribution transformer is assumed to be 200 A, corresponding to 138 kVA, i.e. 7.2 times less than the generator rating. Only a phase-a to PE conductor fault is considered. The total motor load in the network is assumed to be 10 % of the total load. Before the fault, the distribution transformer was loaded with 90% of its rating, assuming the load as pure resistive. After the fault, only the fuse protecting phase-a melts. Results from simulation are shown in Figure 8.9. The induction generator has good ride-through capability for faults on the low voltage side of a distribution transformer cleared by fuses in a short time.

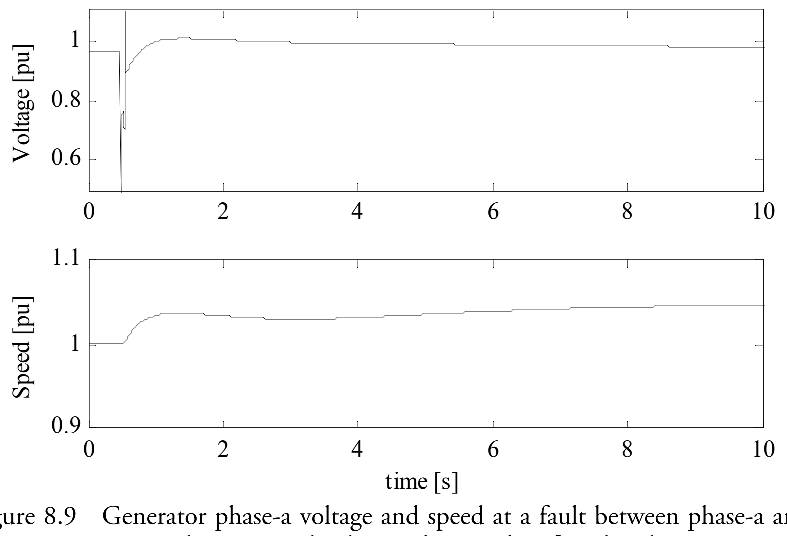

Figure 8.9 Generator phase-a voltage and speed at a fault between phase-a and the PE conductor on the low voltage side of a distribution transformer located at the end of feeder 3. The fault is cleared by fuse melting after 40 ms. Motor load is 10 % of total load. Cable length equal to 0.1 km.

It is also noted, that after the fuse on phase-a of the low voltage side of the distribution transformer has melted, a continuos negative sequence current will be delivered by the induction generator. However, in the considered case, the negative sequence current is as low as 4.5 % of rated generator current and it should not cause particular problems.

STATCOM overloading

Here, it has been assumed that the STATCOM has a short-term overload capability so it can deliver up to 1.5 pu current after fault clearing for some time. The case with motor load of 6 % of total load becomes stable, but the re-acceleration of the motors takes about 7s. The voltage of the IG becomes higher than 0.8 pu already after 0.8s after fault clearing. Therefore, a higher rating of the STATCOM seems to improve the ride-through capability of the self-excited induction generator.

Comparison with Synchronous Generator

To benchmark the ride-through capability of the island-operated self-excited induction generator, a comparison has been done with the ride-through capability of an island-operated synchronous generator. Both a separately excited synchronous generator and a synchronous generator with the excitation derived from the network have been considered. The latter can be black started for island operation by using a field flashing method (Kundur 1993). The same turbine as in the previous cases drives the synchronous generator. The exciter of the separately excited generator has been modeled as IEEE DC1A. This model may be used when a simplified exciter model is required. In the case of the generator deriving its excitation from the network, the exciter has been modeled as a potential source controlled-rectifier, IEEE ST1A type (IEEE 2005). The parameters of the exciters were mainly taken from (IEEE 2005). The braking resistors are connected with the same insertion logic as in the induction generator case, but they are now connected on the high voltage side of the step-up transformer. This should not influence the following analysis, however. It is pointed out that the braking resistors are still important to achieve better post-fault frequencies and voltages. The inertia constant of the turbine-generator group has been assumed equal to 2 s.

The separately excited synchronous generator is able to re-establish the voltage after fault clearing much faster than the self-excited induction generator, see Figure 8.10, even if the amount of motor load in the network is as high as 16 %. The same results are obtained with a synchronous generator whose excitation is derived from the network. In the latter case, the fast voltage recovery is mainly due to the slow decay of the field current. The decay of the field current under short-circuit conditions is governed by the transient d-axis time constant (Anderson 1995), which has been assumed equal to 1.8s. The field current does not change much during the fault and continues to induce an e.m.f. in the stator even if the field voltage is low. After fault clearing, the exciter promptly re-establishes the voltage at the generator terminals.

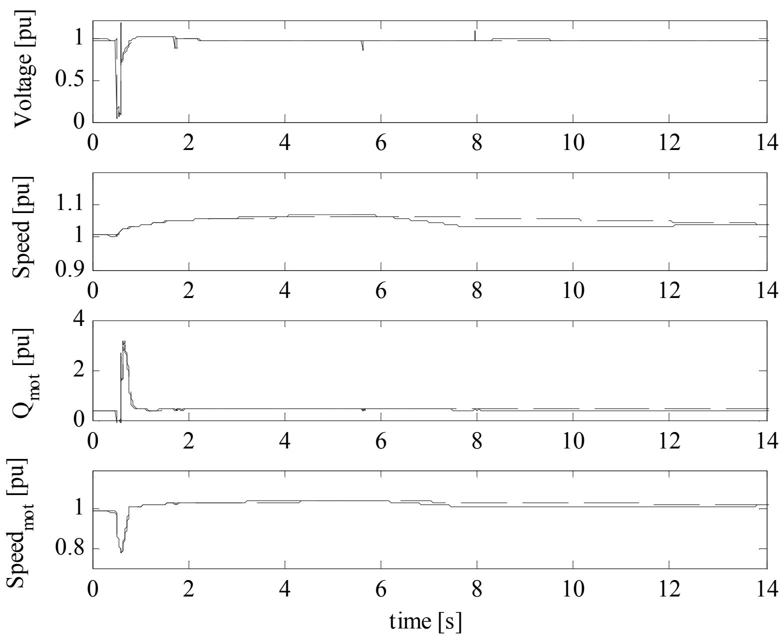

Figure 8.10 Separately excited synchronous generator voltage, speed and motor reactive power and speed at a solid three-phase short-circuit on feeder 3 cleared after 100 ms. Motor load is 6 % (solid), 10 % (dashed) of total load. Synchronous generator inertia constant is equal to 2s.

Summary

The self-excited induction generator demagnetizes when a short-circuit is applied at its terminals. However, it has been experimentally observed that the generator is able to re-excite if the fault is disconnected sufficiently fast. The lab tests indicate that the voltage build-up takes place also if the generator is supplying a load during the transient.

This suggests to further investigate the ride-through capability of the self-excited induction generator. Simulations in SimPowerSystems have been performed. The simulations show that the STATCOM support is essential for the ride-through capability of the self-excited induction generator. The use of braking resistors may improve the post-fault voltage and frequency. However, the ride-through capability is strongly deteriorated by the presence of induction motor loads in the network. In this case, the slow voltage recovery causes a voltage collapse phenomenon and the generator should be disconnected to avoid excessive and long lasting high frequencies and low voltages. Moreover, the motor loads could stall if sufficient load torque remains applied to their shaft. The results have shown that the ride-through performance of the self-excited induction generator improves if the rating of the STATCOM is increased.

The ride-through capability of the self-excited induction generator has been compared to that of a synchronous generator in island operation, through simulations. The induction generator has proved to have inherently poorer ride-through capability as compared to the synchronous generator, independently of the type of excitation system used for the synchronous generator.

Chapter 9

Distribution Network Protection

One of the main objectives of this work is to investigate the requirements on the protection system necessary to assure correct fault clearing in an island-operated distribution network supplied by a self-excited induction generator. Correct fault clearing in the distribution network is a prerequisite for its island operation, since it is essential for complying with law requirements and for terminating hazardous conditions in the network. This chapter deals with these issues, in particular the earth-fault and short-circuit protection of a Swedish distribution network supplied solely by a self-excited induction generator.

9.1 Introduction

Distribution networks are mainly made up of radial feeders with one power infeed from the grid at the so-called Point of Common Coupling (PCC). With some exceptions, the majority of the distribution networks in Sweden are resonant-earthed. The earthing equipment is composed of a Petersen coil, which compensates the total network capacitance to earth, and a resistor in parallel with the coil. The resistor is usually dimensioned to give a resulting earth-fault current of 5-10 A (Lindahl et al. 1990). At a single-phase-to-earth fault, the inductive current in the Petersen coil compensates the capacitive currents flowing into the healthy phases of the faulted feeder and into the healthy parallel feeders. If the inductance of the Petersen coil matches exactly the system capacitance to earth, only a small resistive fault current will flow, due to earthing resistor, line-to-earth conductance and copper losses in the coil. This is a main advantage of compensated networks with overhead lines. The small earth-fault current permits self-extinction of transient arcs at zero-current crossing so that circuit breaker operation and auto-reclosing schemes are not needed. Since loads are connected phase-to-phase and during an earth-fault the voltage triangle is not altered, there is no need for power interruption to customers. This is a great benefit considering that the great majority of system faults are transient earth-faults. With the increased use of vast cables in distribution systems, the benefits deriving from the use of Petersen coil may decrease. An earth-fault in a cable indicates existing damages in the isolation and, if not interrupted, the fault current may restrike cyclically leading to more severe faults between the phases (Winter 1993). However, also with a high penetration of cables in the network, the resonance earthing method has the advantage of reducing the fundamental frequency component of the fault current.

A selective directional earth-fault protection is used for earth-fault protection during grid-connected operation. The earth-fault protection senses the zero sequence current on each outgoing feeder and directionality is achieved by comparing each feeder zero sequence current with a polarizing quantity. The polarizing quantity is normally the zero sequence voltage at the PCC bus. As it will be explained in the following, directional earth-fault relays respond to the in-phase component of the zero sequence current with respect to the zero sequence voltage, permitting to clear the fault by disconnecting only the faulted feeder (Roberts et al. 2001). Zero sequence voltage relays may be used as back-up protection, but they are non-selective.

Each radial feeder is normally protected against short-circuits with an overcurrent device. The short-circuit protection can be achieved with non-directional overcurrent devices, unless the amount of distributed generation installed on the feeders is sufficiently high to cause maloperation of the non-directional overcurrent devices. Commonly used overcurrent devices are fuses and overcurrent relays.

It is worth noting that if the amount of distributed generation installed on a distribution network feeder increases beyond a certain level, the classic non-directional short-circuit protection would not perform properly (Häger et al. 2006). Classical problems that may occur are Mal-trip and Fail-to-trip. Mal-trip refers to the incorrect trip of an overcurrent relay on a healthy feeder, for a fault on another feeder, due to the short-circuit contribution of the distributed generation installed on that healthy feeder. Fail-to-trip refers to a phenomenon, also called blinding, which causes a decrease of the network short-circuit current contribution for a fault downstream on a feeder, if distributed generation is installed upstream on that same feeder. The decreased network short-circuit contribution may cause the overcurrent relay not to trip for a fault on that feeder. Therefore, if the penetration of distributed generation increases beyond a certain level, the network protection system must be changed to assure its correct performance. The introduction of directional relays may be a necessity with a high penetration of distributed generation. These issues, typical of distribution networks with a high penetration of distributed generation, are not dealt with further in this work, which focus instead on island operation of distributed self-excited induction generators.

9.2 Unselective and selective protection schemes

Referring to the island operation of a distribution network with induction generation, two different protection strategies are considered in the next sections. Both an unselective and a selective protection scheme are analyzed. If an unselective protection scheme is adopted, there is no need to identify and disconnect only the faulted part of the system, but instead the entire island will be terminated at a fault occurrence by tripping the induction generator.

Though this approach may sound a bit unreasonable, there are different reasons making it a plausible option for island operation of induction generators. First of all, the short-circuit current levels in island operation are likely to be much lower than in grid-connected operation. A change of the relays settings or fuse rating would be therefore necessary in island operation. This requires time before starting the island and before reconnecting the network to the grid. Also, a risk exists that errors may occur when changing the settings. Second, the self-excited induction generator provides high short-circuit currents only for a short time. It is not certain if the overcurrent devices, even if their settings or rating have been adjusted before starting the island operation, would trip the short-circuit current of induction generators. Third, the short-circuit low voltage ride-through capability of a self-excited induction generator may be compromised because of the induction motor loads present in the network, see Chapter 8. This may nullify part of the advantages of having a selective protection scheme. Finally, only a part of the distribution network may be operated in island and this part may be for example constituted only by one single feeder disconnected from the PCC. In this case, the issue of selectivity does not even arise.

One important concept to notice is that, in the case of an unselective protection scheme, the network protection can be located at the generator station. In this case, in fact, to terminate the island the generator must be tripped. Locating the unselective network protection directly at the generator station has the advantage of not requiring any communication.

On the other hand, a selective protection scheme offers some advantages over an unselective one and it may be particularly desirable when a large part of a distribution network, comprising many feeders, is operated in island. A selective protection scheme disconnects only the smallest possible part of the network in order to clear a fault. As mentioned, the self-excited induction generator may not have the capability of riding through a short-circuit fault. This implies that the island should be terminated even in the case the fault is selectively disconnected. Nevertheless, even in this case a selective scheme maintains an advantage. In fact, a selective tripping of the faulted feeder would accelerate the successive black-start process of the island, avoiding the activity of searching for the faulted feeder, which may be time-consuming. Therefore, a selective protection scheme would at least lead to fastest restoration of the island. Moreover, simulations show that in case of single-phase-to-earth faults, the self-excited induction generator is capable of riding through the fault. Since the vast majority of faults are phase-to-earth faults, a selective earth-fault protection would bring many benefits compared to an unselective protection scheme.

In the remainder of this chapter, the conditions for correct fault clearing in the cases of an unselective and a selective protection schemes are investigated.

9.3 Unselective earth-fault protection

As already mentioned in Chapter 6, it is likely that the part of the distribution network operated in island may be composed by one or more feeders, disconnected from the PCC. This implies that the earthing equipment, normally located at the PCC, may not be part of the island-operated network, which would hence result unearthed. In Chapter 6 it has also been shown that the self-excited induction generator does not demagnetize at a single-phase-to-earth fault, weather the network is unearthed or resonant-earthed. Therefore, it will sustain the voltage in the network. Instead, phase-phase-to-earth faults cause the demagnetization of the induction generator and are not considered further in this section. Both the cases of an unearthed and a resonant-earthed network are dealt with in this section.

At an earth-fault in the distribution network, the Swedish regulation ELSÄK-FS 2004:1 prescribes "*fast and automatic*" disconnection of the faulted part of the system. Earth-faults with a fault resistance up to 5000 ohms must be detected and disconnected. Since these same requirements are still valid during island operation, an earth-fault protection scheme is needed to disconnect the fault. In case an unselective earth-fault protection is chosen, the protection scheme will trip the induction generator when an earth-fault occurs anywhere in the medium voltage side of distribution network. That is, the earth-fault protection scheme will unselectively terminate the island.

Unearthed network

Figure 9.1 shows two possible configurations leading to an unearthed network. The earthing equipment is not part of the network.

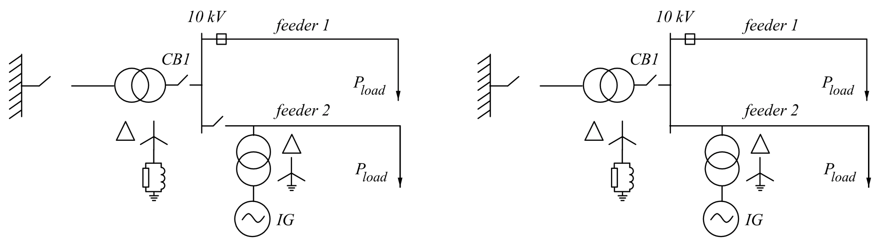

Figure 9.1 Two different network configurations leading to an unearthed network in island operation.

Since the self-excited induction generator sustains the voltage during earth-faults, classical methods can be used to calculate the symmetrical component quantities to be used for earth-fault protection. In principle, the zero sequence voltage and the negative sequence current could be used to detect an earth-fault in the distribution network. Both these quantities are in fact low in absence of an earth-fault. Because of the delta connection of the step-up transformer on its high voltage side, the zero sequence quantities in the distribution network cannot be observed from the low voltage side. Unlike the zero sequence voltage, the negative sequence current would instead permit to detect an earth-fault on the distribution network, by measuring quantities only on the low voltage side of the step-up transformer at the generator station. For this reason, an earth-fault protection based on the negative sequence current measured at the generator terminals could be a cheaper solution compared to a zero sequence voltage protection, that requires the installation of voltage transformers on the high voltage side of the step-up transformer.

A standing zero sequence voltage is always present in the network, also in absence of an earth-fault, due to unbalances in the capacitance to earth of the three phases. To avoid unnecessary tripping, a zero sequence voltage protection for earth-faults must be set so that it does not trip because of the standing zero sequence voltage. Normally, the minimum setting for zero sequence voltage relays is above 3 % of nominal phase-to-earth voltage (Lehtonen et al. 1996).

The negative sequence current in absence of a fault may be due to load unbalances. To get an idea of the magnitude of the negative sequence current supplied by a self-excited induction generator during unbalanced load conditions, a simulation has been performed with a 400 kVA generator supplying a single phase load of 20 kW, 5 % of generator rating, located at the end of a 5 km cable feeder. The resulting negative sequence current has been found to be about 1.7 % of the nominal generator current. Since small load unbalances are to be expected in the network, the setting of an earth-fault protection based on negative sequence current must be high enough to not trip unnecessarily. Recall also from Chapter 2 that the negative sequence voltage of an induction machine must be lower than 5 % of nominal voltage. This implies that too high negative sequence current (above about 25 % of nominal generator current) cannot be tolerated.

Figure 6.6 shows the equivalent circuit of an island-operated unearthed distribution network with a self-excited induction generator during an earth-fault. This equivalent circuit can be however simplified by neglecting the zero sequence series impedance of the line, all the positive and negative sequence impedances and the capacitors at the generator terminals. Figure 9.2 shows the simplified network equivalent circuit for an earth-fault. The capacitance to earth is now equal to the total network capacitance to earth, i.e. it is the sum of the capacitance to earth of all the lines in the network.

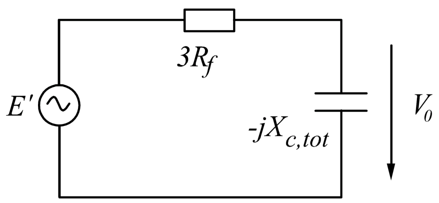

Figure 9.2 Simplified equivalent circuit of an island-operated distribution network with a self-excited induction generator at an earth-fault. *E'* is the pre-fault internal voltage of the induction generator.

The symmetrical component quantities we are interested in can be calculated as

$$V_0 = \frac{E'}{1 + j3\omega R_f C_{tot}} \tag{9.1}$$

$$I_n = I_p = I_0 = \frac{j\omega C_{tot} E'}{1 + j3\omega R_f C_{tot}} = j\omega C_{tot} V_0 \tag{9.2}$$

As said, the zero sequence quantities do not transform to the low voltage side of the step-up transformer because of its delta connection on the high voltage side. The negative sequence current flows instead through the step-up transformer and the generator and it can in principle be measured at the generator terminals. As seen, the zero sequence voltage decreases with increasing fault resistance and network capacitance to earth. Considering constant the source voltage *E'*, the zero sequence voltage can be plotted as a function of network capacitance to earth, see Figure 9.3. The fault resistance has been assumed here equal to the maximum value at which it is still mandatory to detect an earth-fault, i.e. 5000 Ω in the Swedish case. Simulations with an induction generator confirm these results.

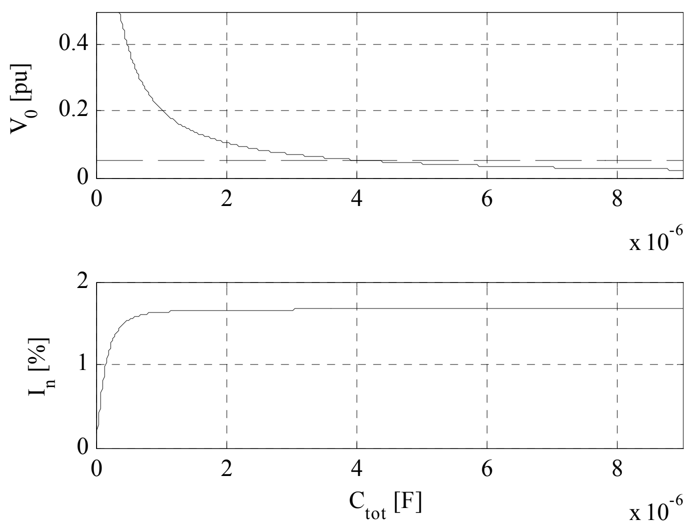

Figure 9.3 Earth-fault with fault resistance equal to 5000 Ω in an unearthed network. Zero sequence voltage in pu of nominal phase-earth voltage (solid) and 5 % setting (dashed) (Upper). Negative sequence current in % of nominal current of a 400 kVA generator (Lower).

When expressed in pu, the above results are valid independently of the network nominal voltage. It can be observed that above a certain value of the network capacitance to earth, the zero sequence voltage decreases below 5 % of nominal value. This value of capacitance is approximately 4.2 μF, As said, it is not possible to set the earth-fault zero sequence voltage protection below 3 – 5 % of nominal voltage. This means that it is impossible to securely detect high resistive earth-faults in an unearthed network if its total capacitance to earth exceeds a certain value. Since the network capacitance to earth is essentially determined by the cable capacitance to earth, it can be said that if more than a certain amount of cables are present in the network, it becomes impossible to detect an earth-fault. This amount can be estimated to about 14 km, based on cable capacitance to earth of 0.3 μF/km, and it does not depend on the rating of the self-excited induction generator. The same capacitance to earth corresponds to about 630 km of overhead lines, assuming their capacitance to earth equal to 6.6 nF/km.

In Chapter 6, it has been mentioned that another reason for limiting the cables extension in the network is that their reactive power production must be lower than the no-load reactive need of the self-excited induction generator. Notice that this limit depends on the voltage rating of the distribution network, because the cable reactive production varies with the square of the voltage. Another limit to the extension of cables present in the network is now posed by the lowest setting that can be used for a zero sequence voltage protection to detect earth-faults. This second limit does not depend on the voltage rating of the distribution network. It is also found out that for lower rating induction generators the factor limiting the possible amount of cables in the network is the reactive need of the induction generator, while for higher rating induction generators the limiting factor is due to the earth-fault detection problematic.

From Figure 9.3 it can be observed that the negative sequence current delivered by the generator during a high resistive earth-fault is below 2 % of the nominal generator current. Since load unbalances in the network may give easily rise to a negative sequence current of the same order of magnitude, it can be concluded that the negative sequence current cannot be used to securely detect earth-faults with a resistance up to 5000 Ω. This is especially true considering that the current transformers used to obtain the negative sequence current signal will also introduce some errors. This confirms what has been found in (Kumpulainen et al. 2005).

Therefore, to detect earth-faults in an unearthed distribution network the zero sequence voltage in the network must be sensed and the extension of cables in the network must be below a certain limit.

Sensing the zero sequence voltage in the distribution network can be achieved by using three broken-delta connected voltage transformers on the high voltage side of the step-up transformer. An alternative method is proposed in the next section. The advantage of the new method for zero sequence voltage sensing is that it requires only one voltage transformer on the high voltage side of the step-up transformer.

Estimation of the zero sequence voltage

In this section, a new algorithm for estimating the zero sequence voltage on the D-side of the step-up transformer is introduced. A more detailed description of the algorithm can be found in [Publication 1]. The estimated zero sequence voltage can be used to detect an earth-fault in the distribution network. The main advantage of the new algorithm is that it requires only one voltage transformer (VT) on the high voltage D-side of the step-up transformer, instead of three VTs required by the classical broken-delta connection. The new algorithm uses the information from three VTs and three current transformers (CT) on the low-voltage y-side of the step-up transformer, which are normally already installed in every generator station. The new algorithm may be therefore cheaper as compared to the classical method to sense the zero sequence voltage. The algorithm is thought to be implemented on a microprocessor relay.

The zero sequence voltage in the distribution network is estimated by measuring one voltage to earth on the D-side of the step-up transformer and the three phase-voltages on the low voltage y-side. The way the estimation is carried out is described below.

Two premises are necessary, (Gajic 2008): 1) a Dy transformer transforms sequence quantities independently, 2) positive and negative sequence voltages are transformed according to

$$
\begin{aligned}
V_{Dpos} &= \frac{N_D}{N_y} V_{ypos} e^{j\vartheta} = \tau V_{ypos} e^{j\vartheta} \\
V_{Dneg} &= \frac{N_D}{N_y} V_{yneg} e^{-j\vartheta} = \tau V_{yneg} e^{-j\vartheta}
\end{aligned}
\qquad (9.3)
$$

where

ϑ is the angle by which the primary-secondary quantities are shifted in the transformation and it is determined by the transformer group number

τ is the transformer ratio

N_D and N_y are the number of turns on the D- and y-side respectively

Zero sequence quantities are not transformed in case of a Dyn transformer. The above equations do not take into account the voltage drop inside the transformer. This can be easily accounted for by modifying the equations as follows:

$$\begin{aligned} V_{Dpos} &= \tau V_{ypos} e^{j\vartheta} - \tau Z_{tr} I_{ypos} e^{j\vartheta} = \tau e^{j\vartheta}\left(V_{ypos} - Z_{tr} I_{ypos}\right) \\ V_{Dneg} &= \tau V_{yneg} e^{-j\vartheta} - \tau Z_{tr} I_{yneg} e^{-j\vartheta} = \tau e^{-j\vartheta}\left(V_{yneg} - Z_{tr} I_{yneg}\right) \end{aligned} \tag{9.4}$$

where

Z_{tr} is the transformer impedance as seen from the low voltage y-side

Expressing the phase voltages on the D-side in terms of their sequence components, leads to

$$\begin{bmatrix} V_{DA} \\ V_{DB} \\ V_{DC} \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix} \begin{bmatrix} V_{Dpos} \\ V_{Dneg} \\ V_{D0} \end{bmatrix} \tag{9.5}$$

In Equation 9.5 the unknown is the zero sequence voltage V_{D0}. V_{Dpos} and V_{Dneg} are obtained from Equation 9.4 through the information collected on the y-side. By inserting Equation 9.4 into Equation 9.5 the following expression is obtained

$$\begin{bmatrix} V_{DA} \\ V_{DB} \\ V_{DC} \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix} \begin{bmatrix} \tau e^{j\vartheta}\left(V_{ypos} - Z_{tr} I_{ypos}\right) \\ \tau e^{-j\vartheta}\left(V_{yneg} - Z_{tr} I_{yneg}\right) \\ V_{D0} \end{bmatrix} \tag{9.6}$$

The previous is a system of three equations. The first of these equations, for example, can be solved for V_{D0},

$$V_{D0} = V_{DA} - \tau e^{j\vartheta}\left(V_{ypos} - Z_{tr} I_{ypos}\right) - \tau e^{-j\vartheta}\left(V_{yneg} - Z_{tr} I_{yneg}\right) \qquad (9.7)$$

This is an estimation of the zero sequence voltage on the D-side of the step-up transformer and the voltage V_{DA} is measured with a VT. Any of the three equations in 9.6 can be used for the estimation, each requiring a different phase voltage to earth to be measured on the D-side.

Therefore, the zero sequence voltage on the D-side of the step-up transformer can be accurately estimated if 1) positive and negative sequence currents and voltages on the low voltage y-side are known, 2) step-up transformer impedance, ratio and angle group are known, 3) one phase to earth voltage on high voltage D-side is measured.

Since distributed generator stations are normally already provided with current and voltage transformers on the low voltage y-side, there are no additional costs to get the positive and negative sequence quantities used in Equation 9.7.

The word “estimation” has been used here instead of “calculation”. The zero sequence voltage can only be estimated because of the uncertainties in transformer parameters and measurement errors from CTs and VTs involved in Equation 9.7. Another source of error in the estimation derives from having neglected the transformer magnetizing current in Equation 9.7 and having assumed that the pu primary current is equal to the pu secondary current. This fact causes errors especially during transformer energization, because the inrush current in this case may be several times the nominal current of the transformer. As a consequence, the estimated zero sequence voltage may be higher than zero until the inrush current has decayed to zero even in absence of an earth-fault. To avoid unnecessary trips in this case it may be necessary to block the operation of the zero sequence voltage relay during transformer magnetization by using for example a second harmonic restrain method (Horowitz et al. 1995). Using microprocessor relaying, the second harmonic component of the current can be obtained with no additional costs. If the transformer has to be energized from the D-side, where no CTs are available, the operation of the zero sequence voltage relay could be blocked if the y-side voltage jumps from zero to a high value in a short time.

However, during normal operating conditions, the estimated zero sequence voltage can be very accurate. The algorithm has been tested in the lab set-up shown in Figure 9.4 by applying an earth-fault on the D-side of the transformer. The transformer data are S = 2 kVA, τ = 220/(√3*133), θ = -30°, Z_{tr}= 1.1+j0.21 Ω, as seen from primary yn-side.

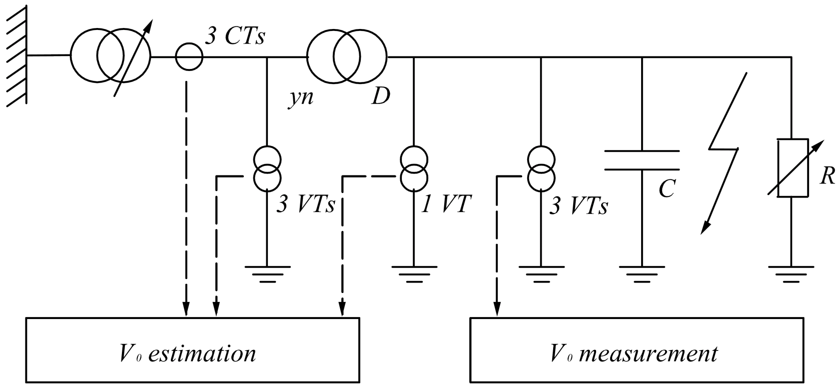

Figure 9.4 Lab set-up for testing the new algorithm. The zero sequence voltage is both measured and estimated. The algorithm allows to use only one VT on the D-side instead of 3 broken-delta connected VTs.

All measurements have been sent to a dSPACE microprocessor, where phasor quantities were calculated by using a Full Cycle Fourier (FCF) algorithm. The new estimation algorithm has also been implemented in dSPACE. The estimated and measured zero sequence voltages are shown in Figure 9.5 under varying loading conditions. As seen, the error does not vary with varying load, indicating that the voltage drop inside the transformer is well compensated. Also, the magnitude of the error is very low in case all the needed parameters are know accurately.

The physical meaning of the method is simple. On the y-side, any information is lost on the neutral point's (which is not a physical point) shift on the D-side. By measuring one phase-to-earth voltage on the D-side this information is regained. All information about positive and negative sequence voltages is identical on both sides of the step-up transformer. Therefore, the zero sequence voltage on the D-side can be estimated.

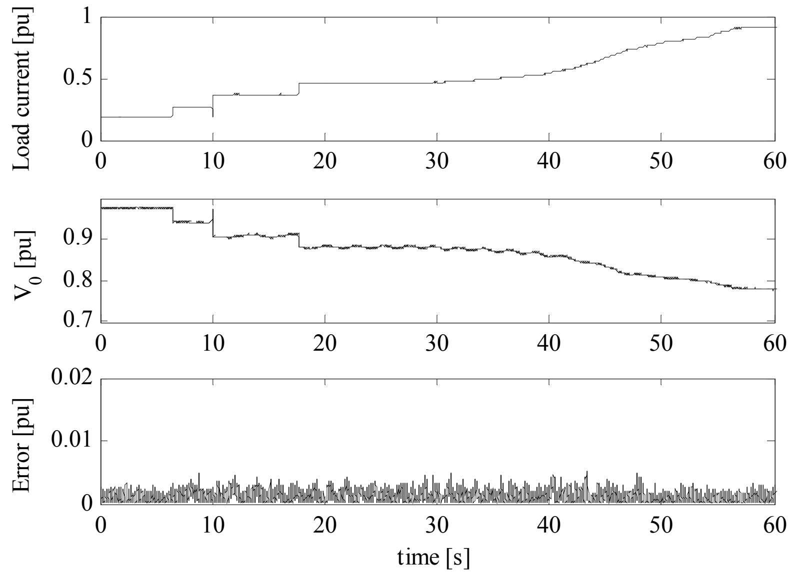

Figure 9.5 Earth-fault on the D-side of the lab set-up. Load current in pu of nominal transformer current (Upper). Estimated (solid) and measured (dotted) zero sequence voltage on the D-side in pu of D-side phase-earth voltage (Central). Error between estimated and measured zero sequence voltage in pu of D-side phase-earth voltage (Lower).

Earth-fault detection in resonant-earthed network

Two different cases in which the distribution network operated in island may result resonant-earthed are shown in Figure 9.6. In the first case, the earthing equipment is located at the neutral of the main transformer, which is now part of the island. In the second case, the earthing equipment is located on a dedicated zig-zag transformer directly connected on the busbar at the PCC, while the main transformer is not part of the island.

As seen in Chapter 6, at a single-phase-to-earth fault in a resonant-earthed network, the self-excited induction generator will sustain the voltage. As in the case of an unearthed network, the only way to detect high resistive earth-faults is to sense the zero sequence voltage in the distribution network. However, an important difference must be noted compared to an unearthed network case. Under the assumption of perfect compensation, i.e. the Petersen coil inductance matching exactly the network capacitance to earth, the zero sequence voltage arising during an earth-fault will not depend on the amount of the network capacitance to earth. Therefore, the only limiting factor for the total amount of cables present in the network will be the no-load reactive need of the self-excited induction generator. Figure 9.7 shows the equivalent circuit valid during an earth-fault in a resonant-earthed network.

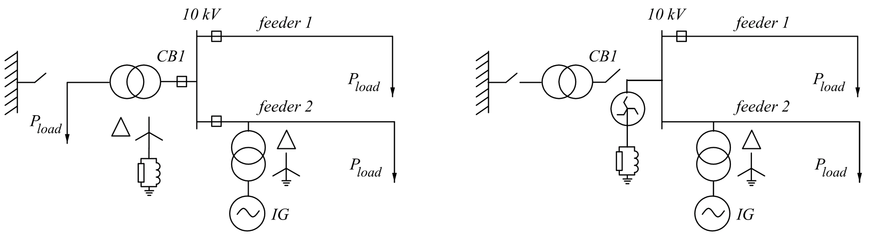

Figure 9.6 Two different network configurations leading to a resonant-earthed network in island operation.

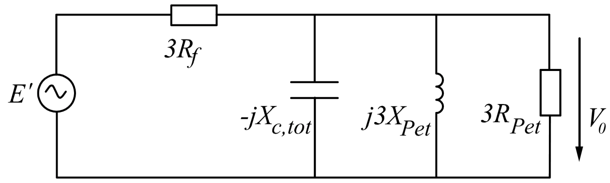

Figure 9.7 Simplified equivalent circuit of an island-operated resonant-earthed distribution network with a self-excited induction generator at an earth-fault. *E'* is the pre-fault internal voltage of the generator.

In reality, a certain amount of mistuning between the Petersen coil inductance and the network capacitance to earth will exist. A mistuning arises also because the induction generator speed, and hence the system frequency, will change slightly during the earth-fault. If the Petersen coil reactance was tuned to match the network capacitive reactance at 50 Hz, following the fault the two reactances will not match exactly. The value of the zero sequence voltage at a high resistive earth-fault will then depend on the compensation level, i.e. the ratio of network capacitive reactance to the coil reactance, and on the total network capacitance to earth, as shown in Figure 9.8. Here, an earthing resistor of 600 Ω has been assumed connected in parallel with the Petersen coil.

As seen, in case of non-perfect compensation, the zero sequence voltage decreases as compared to the perfect compensated case. Increasing network capacitance to earth causes higher zero sequence voltage decrease. Results from simulations confirm what has been said. Therefore, in case of many cables present in the network, higher compensation accuracy would be desired to keep the zero sequence voltage sufficiently high so that a high resistive earth-fault can be safely detected.

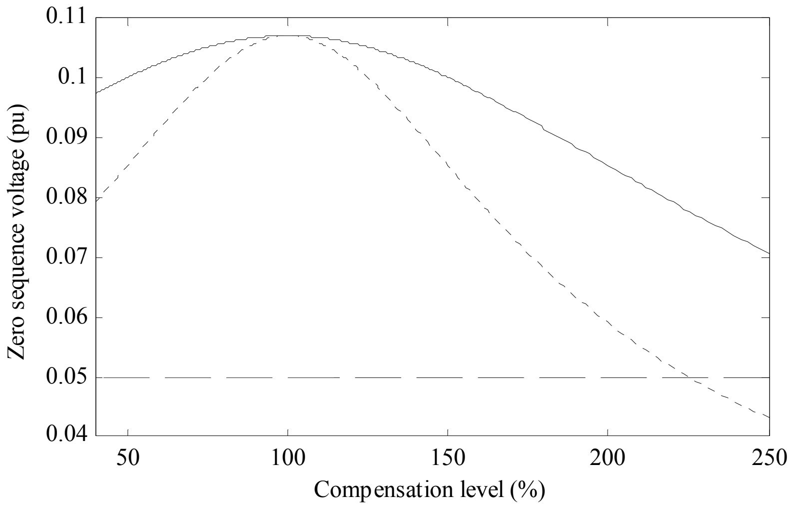

Figure 9.8 Calculated zero sequence voltage at an earth-fault with fault resistance equal to 5000 Ω, with a total cable length of 5 km (solid) and 10 km (dotted). Zero sequence voltage relay setting of 5 % (dashed).

9.4 Unselective short-circuit protection

The unselective short-circuit protection of a distribution network supplied by a self-excited induction generator does not present particular challenges. The self-excited induction generator always demagnetizes for short-circuits not only at its terminals, but also anywhere else in the distribution network. The fast demagnetization of the induction generator following a short-circuit suggests to use undervoltage relays to trip the generator at a short-circuit. The undervoltage relay can be installed at the generator station and the voltages supplied to the relay can be measured directly at the generator terminals. In some cases, depending on the pre-fault loading and fault resistance, over/underspeed relays can be used as back-up of undervoltage relays.

A STATCOM is not able to significantly change the short-circuit behavior of the induction generator and it should not impact on the operation of the undervoltage relay.

The setting of the undervoltage relay must be chosen low enough for not tripping unnecessarily in case of voltage drops due to load insertion. As said in Chapter 2, AMP suggests disconnection of a distributed generator for undervoltages below 80 % in case they last longer than 200 ms. This same setting seems reasonable also for short-circuit protection in the case of island operation of self-excited induction generators. However, in section 9.7, a further factor to consider when chosing the settings for the undervoltage relay protection is discussed, with regard to faults on the 400 V low voltage distribution system.

9.5 Selective earth-fault protection

In this section, it will be investigated under which conditions a selective earth-fault protection can be achieved in an island-operated distribution network. It is supposed that the zero sequence voltage measurement is available on the common bus at the PCC also during island operation. Selective earth-fault protection is achieved in distribution networks with directional earth-fault relays (Roberts et al. 2001), which at an earth-fault compare the direction of the zero sequence currents on each feeder with the direction of the zero sequence voltage. Figure 9.9 shows the current directions in the case of an unearthed and a resonant-earthed network.

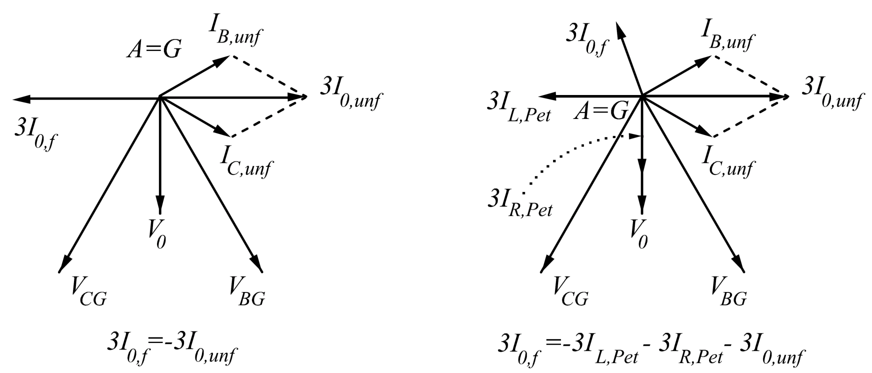

Figure 9.9 Phasor diagrams at a solid earth-fault in an unearthed (left) and resonant-earthed (right) distribution network. In the latter case, the network has been assumed slightly undercompensated (coil reactance higher than network capacitive reactance).

In resonant-earthed distribution networks exactly compensated, the faulted feeder zero sequence current will have only an active component 180 degrees out of phase with the zero sequence voltage. This active component is mainly due to the current of the earthing resistor in parallel with the Petersen coil. The healthy feeders zero sequence current will instead be 90 degrees ahead of the zero sequence voltage. The different direction of the zero sequence current phasors on healthy and faulted feeders permits to selectively detect the faulted feeder.

The same principle to selectively detect the faulted feeder is used for unearthed distribution networks. In this case, the zero sequence current on the faulted feeder will lag 90 degrees the zero sequence voltage, while the healthy feeders zero sequence current will lead the zero sequence voltage.

The sensitivity of modern digital directional earth-fault relays can be high, with lower possible settings of some mA secondary (Hou et al. 2007). For the relay to trip, the zero sequence voltage must also be higher than a threshold, e.g. 3 % of nominal phase-to-earth voltage. The sensitivity of the directional earth-fault protection scheme is also determined by the current transformers (CT) used to sense the zero sequence current on each feeder. Toroidal CTs should always be used when possible. The current setting of the directional earth-fault protection must be chosen also with regard to the errors caused by the CTs. As an example for the magnitude of these errors, in (Lindahl et al. 1990) it is mentioned that the secondary current may be as low as 86% of the primary current for a particular toroidal transformer.

Modern digital directional earth-fault relays can protect both a resonant-earthed and an unearthed network, by setting a different trip characteristic. This is achieved by appropriately rotating the trip characteristic accordingly to the earthing method of the network. The switching between the two characteristics can be sometimes done by means of an external signal (ABB SPAA 348 C User's Manual and Technical Description).

Hence, in principle protection relays used for directional earth-fault detection in a resonant-earthed network can be used also for an unearthed network. Directional detection of high resistive earth-faults may be problematic in unearthed networks. The possibility to detect an earth-fault with a fault resistance up to 5000 Ω depends on the network topology and on the capacitance to earth of each feeder. Some examples in the next sections will clarify better the concept.

It is pointed out that, even in the case a selective earth-fault protection scheme is adopted on each feeder, it is still necessary to have a zero sequence voltage protection at the generator station. In fact, in case the earth-fault occurs on the feeder with the distributed induction generator operating in island, this feeder will be disconnected from the rest of the network by the directional earth-fault protection. However, the induction generator may sustain the voltage on this faulted feeder. Therefore, a zero sequence voltage relay at the generator station is needed to disconnect the generator in this case. The zero sequence voltage relay can be set to trip with a time delay sufficient to avoid unnecessary trips of the generator for earth-faults on adjacent feeders, which should instead be cleared by the feeder directional earth-fault protection.

Unearthed network

The equivalent circuit for an earth-fault in an unearthed network is shown in Figure 9.2. The zero sequence voltage and current at the fault point can be expressed as in Equations 9.1 and 9.2. The zero sequence currents on the faulted feeder and on the healthy ones can be expressed as in (Iliceto 2001), where the sum over *k* is extended over all the healthy feeders:

$$\begin{aligned} I_{0,unf}^{k} &= j\omega C_k V_0 \\ I_{0,f} &= -\sum_k I_{0,unf}^{k} = -j\omega V_0 \sum_k C_k \end{aligned} \qquad (9.8)$$

It is noted that a condition is necessary for a selective earth-fault protection scheme to work properly in an unearthed network. The total network capacitance to earth must be neither too high nor too low. As already mentioned in section 9.3 a too high capacitance to earth would cause too low zero sequence voltage at a high resistive earth-fault. A too low capacitance to earth causes instead too low zero sequence current on the faulted feeder and if the value of this current is below the sensitivity of the directional earth-fault protection scheme, selective protection for high resistive earth-faults is impossible to achieve. However, in this last case a back-up zero sequence voltage protection would still assure compliance with law requirements by tripping unselectively the generator and terminating the island at a high resistive earth-fault.

An example will help clarifying the problem. As a test case, the network with two feeders in Figure 9.1 can be used. Feeder 1 is supposed to be a cable line of 5 km, while feeder 2 an overhead line of 10 km. It is supposed that on both feeders are installed directional earth-fault relays with a minimum possible setting of 5 mA secondary, and toroidal CTs with a ratio 100/1. Considering that the CT senses $3I_0$, the lower zero sequence current that can be detected on the faulted feeder is

$$I_{0,\min} = \frac{0.005 \cdot 100}{1 \cdot 3} = 167mA$$

The cases of a fault on feeder 1 or on feeder 2 are presented in Figure 9.10. Simulations with a self-excited generator confirm the results from the calculations presented in the figure. It can be seen that the zero sequence current is high enough for the directional earth-fault protection to work properly in case the fault occurs on feeder 2. In this case, the healthy part of the network, composed by the cable, generates sufficient current for the directional earth-fault relay on feeder 2 to trip. If the fault occurs instead on feeder 1, the directional earth-fault protection will not work because the current seen by the CT on this feeder is too low, also in case of low resistive earth-faults. However, compliance with law requirements can be satisfied by using an unselective zero sequence voltage relay.

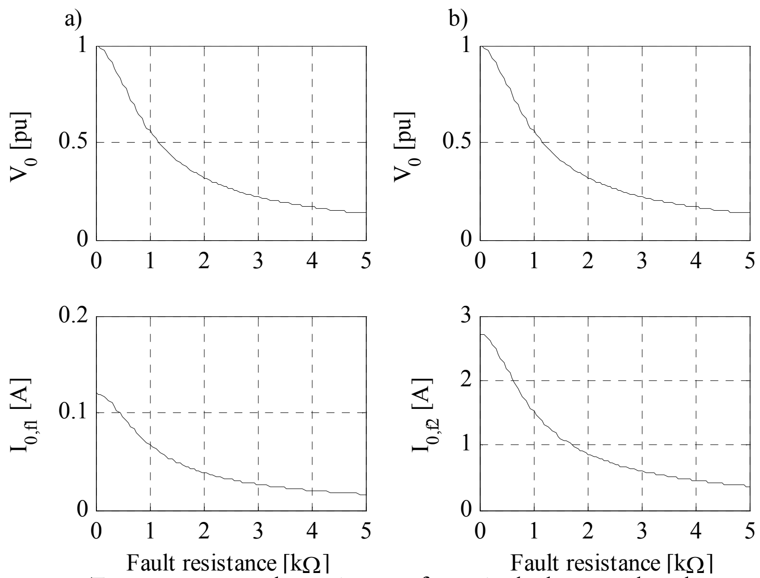

Figure 9.10 Zero sequence voltage, in pu of nominal phase-earth voltage, and zero sequence current on feeder 1 and on feeder 2. a) Earth-fault on feeder 1. b) Earth-fault on feeder 2.

Therefore, it can be concluded that during island operation of an unearthed distribution network with a self-excited induction generator, selective earth-fault protection can be achieved depending on the topology of the network. Moreover, some digital directional earth-fault relays can be used both in resonant-earthed and unearthed networks by properly adjusting their settings. This would imply that no additional equipment would be necessary for selective earth-fault protection when operating the network as an island and unearthed. In case the minimum capacitance to earth required for selective disconnection of each faulted feeder is not present in the network, an unselective zero sequence voltage protection can always be used to comply with law requirements.

Resonant-earthed network

In case the island-operated network is resonant-earthed, a selective earth-fault protection can be used as when the same network is operated connected to the grid. In case the Petersen coil inductance matches exactly the network capacitance to earth, the zero sequence voltage will depend on the ratio between the earthing resistance in parallel with the Petersen coil and the fault resistance. The faulted feeder will always have a zero sequence current with an active component due to the earthing resistance. This component will not change when operating the network as an island with an induction generator. Therefore, the same considerations valid for earth-fault detection when grid-connected remain valid during island operation and the same protection relays can be used. The only difference to note when operating the self-excited induction generator in island in a resonant-earthed network is that at a low resistive earth-fault, the generator voltage and speed will drop slightly with time, see section 6.6. As a consequence, the zero sequence voltage and current sensed on the feeder will also decrease with time. However, simulation results show that this decrease is slight, only some 5 % of the initial value in the first second following the fault, at a high resistive earth-fault. The reason of this speed and consequent voltage decrease is the loading of the earthing resistance in parallel with the Petersen coil.

9.6 Selective short-circuit protection

In this section, it is analyzed under which conditions a feeder overcurrent protective device may trip the short-circuit current contribution of the induction generator. The considered network is shown in Figure 9.11. The fault is supposed to be located on the overhead line 3.

In case of a large island-operated network with a sufficient surplus of generation, it could be advantageous to selectively disconnect only the faulted feeder and to continue the island operation of the remaining network. Because of the fast decaying short-circuit current of the induction generator it is uncertain whether a feeder overcurrent protective device would trip. Feeder overcurrent protective devices may be fuses or overcurrent relays. Since the short-circuit currents during island operation are likely to be much smaller than the corresponding short-circuit currents in grid-connected operation, fuses dimensioned for grid-connected operation are expected not to interrupt the induction generator short-circuit current. Moreover, even assuming that the fuses could be chosen with the same rated current of the induction generator, the short-circuit current would be as high as 5 – 7 times the nominal current of the induction generator only for a short time, less than two cycles, and the corresponding delivered I^2t would not be enough to blow the fuses. Therefore, fuses are believed not to be adapted to selectively disconnect a faulted distribution network feeder during island operation of induction generators. Therefore, only digital relay will be considered in the following.

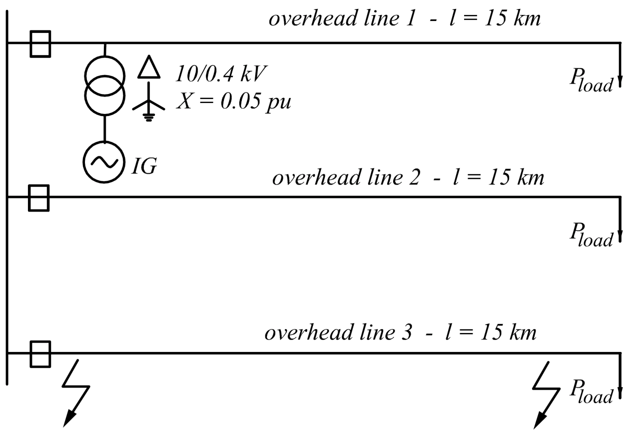

Figure 9.11 Single-line diagram of network model used in instantaneous-value simulations to investigate short-circuit selectivity.

Because of the lower short-circuit currents expected during island operation, it is necessary to change the feeder overcurrent relay settings. The setting of the feeder overcurrent relays must be high enough not to trip for short-time overloading conditions. It is here supposed that the overhead line 3 relay setting is chosen as 150 % of the nominal current of the induction generator connected on the first feeder. No intentional delay is considered for the feeder relay during island operation.

It must be noted that it is not always possible to choose the relay setting as 150 % of the generator rated current. This depends upon the rated current ratio of the used current transformers and the minimum trip current that can be chosen in the relay. It may happen that, given a specified current transformer ratio, the minimum settable operating current in the relay corresponds to much more than 150 % of the generator rated current (this always happens if the generator rating is low enough). However, this is not a problem particular for induction generators. In some relays it is possible to distinguish between rated current of a protected unit and rated current of the used current transformers, through the use of a settable scaling factor. Here, it is assumed that it is possible to set the operating current of the overcurrent relay to 150% of the rated generator current.

The response of a digital relay to the short-circuit current provided by the induction generator in island operation will be calculated. In a digital relay, the current phasor is reconstructed from the current samples by means of an appropriate algorithm, commonly a Fourier algorithm. There exist different versions of Fourier algorithms depending on the length of the data window. Here, it is assumed that the Full Cycle Fourier (FCF) algorithm is implemented in the overcurrent relay for calculating the fundamental frequency phasors. This algorithm is described in detail in (Phadke et al. 1993) and it uses samples during one entire cycle to reproduce the current phasor. If a step is applied to the current, for example, the algorithm requires some time, one cycle, before the calculated result reproduces the new current. A FCF algorithm rejects the dc and harmonic components. It is assumed that the relay uses a sampling frequency of 1 kHz. The overcurrent relay will issue a trip signal if the calculated current phasor exceeds a threshold value for longer than a predetermined time. Commercial normal-speed digital overcurrent relays may require up to 40 – 50 ms before issuing a trip signal, see for example (ABB REJ 523 Technical Reference Manual).

The decaying short-circuit current from the induction generator requires the feeder relay to be sufficiently fast to trip before the short-circuit current has decayed below its pick-up value. How fast the relay needs to be, depends on the type of fault, its distance from the generator, the fault resistance and the induction generator parameters. Particularly important is the rotor transient time constant of the generator, defined in Equation 4.13, which determines the decaying rate of the sinusoidal current component for three-phase close-in faults, as it can be seen from Equation 4.13. High rating induction generators have higher rotor transient time constants, because of their lower rotor resistance (Anderson 1995). As an example, for the considered 400 kVA and 1000 KVA generators the rotor transient time constants are respectively 16.8 and 33.5 ms.

Some instantaneous-value simulations of the system shown in Figure 9.11

have been performed, by applying different short-circuits at different locations on the overhead line 3. Also, two induction generator ratings have been considered separately, a 400 and a 1000 kVA. The current phasors have been calculated from the simulated current by applying a FCF algorithm. The results for three- and phase-phase short-circuits are reported in Figure 9.12.

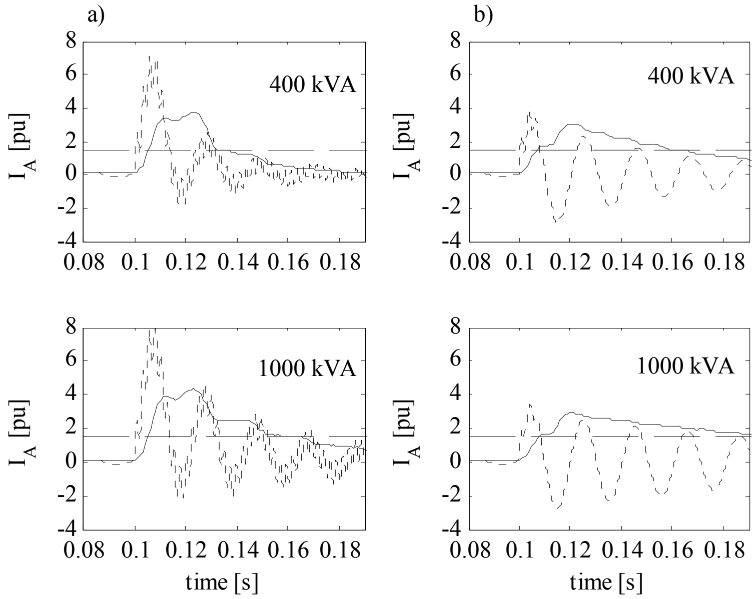

Figure 9.12 Actual (dotted) and calculated phasor (solid) current seen by overhead line 3 feeder relay. a) Three-phase short-circuit at beginning of the feeder, $R_f = 0\ \Omega$. b) Phase-phase short-circuit at end of the feeder 3, R_f = 10 % of generator base impedance referred to the 10 kV side. Currents are in pu of nominal generator current. Relay setting at 1.5 pu (dashed).

It can be concluded that solid three-phase short-circuits close to generator terminals set the higher requirements on relays operating speed. Relays capable of issuing a trip signal within 40 - 50 ms after fault inception could assure selective tripping of the faulted feeder in the 1000 kVA induction generator case. The requirement on the relay operating speed becomes more stringent if the 400 kVA generator is connected. In this last case a relay capable of issuing a trip signal within 25 – 30 ms after fault inception would be needed to trip for solid three-phase short-circuits close to generator terminals. As mentioned above, normal-speed distribution networks feeder digital overcurrent relays may require up to 40 – 50 ms before issuing a trip signal. This means that such relays most likely could assure selectivity in the case of the 1000 kVA induction generator, if their settings were properly adjusted during island operation. From Figure 9.12, it can also be estimated that reducing the pick-up setting from 150 % to 120 % of nominal generator current would permit to use relays with an operating speed almost 10 ms higher than the ones pointed out above.

9.7 Protection issues on the low voltage side

The common practice in Sweden is to use TN systems at the 400 V low voltage distribution level. The PEN conductor of an installation is normally connected to the earthed neutral of the low voltage distribution transformer y-side. The touch voltage is not allowed to be higher than 50 V for a time sufficiently long to be considered dangerous. A fault causing higher touch voltages should be interrupted by a proper device within prescribed times (Elinstallationsreglerna 2003). The protective device must be an overcurrent one; residual current relays (in Swedish, *jordfelbrytare*) may be used as a complement to the overcurrent protection. When operating the induction generator in island operation, the earthing conditions of the low voltage distribution transformers, included the step-up distribution transformer, do not change.

A fault on the low voltage 400 V side of a distribution transformer may happen either between a phase conductor and the PE conductor or between more phase conductors. In sections 6.9 and 7.5 it has been shown that these faults have a strong impact on the behavior of the induction generator, even if the distribution transformer is located some kilometers away from the generator station. As said for the case of a fault between phase and PE conductors, the distance of the fault from the distribution transformer, i.e. the term (Z_{Lph} + Z_{LPE}) in equation 6.1, determines whether the generator voltage will drop below its undervoltage relay setting or not.

At this regard, it is noted that for a given generator rating, there is a value of the term (Z_{Lph} + Z_{LPE}) that causes the generator voltage (and speed) to drop at a value just above the undervoltage relay setting, with delivered generator current lower than its nominal current. Since the generator voltage drops, the overcurrent protective devices on the low voltage side of the distribution transformer, chosen based on the fault current calculated in Equation 6.1 assuming nominal system voltage, may interrupt the fault current with a longer time than expected during grid-connected operation. A similar issue is mentioned in (Elinstallations-Guiden 2003), where it is stated that the short-circuit current in systems supplied solely by generators may be time-dependent and much lower that expected during grid-connected operation.

Therefore attention must be paid so that the overcurrent protective devices still interrupt a phase to PE conductor fault anywhere in the low voltage distribution system within the prescribed times.

Since the drop in fault current is proportional to the voltage drop, a possible approach to avoid longer than allowed interruption times for phase to PE conductor faults is to set the generator undervoltage relay setting sufficiently high, so that the decrease of the fault currents, for faults on the low voltage side, is maintained within acceptable limits. The undervoltage relay setting should be chosen so that if the proper overcurrent protective device does not interrupt the fault within the prescribed time, then the generator should be disconnected. The prescribed time for interrupting a phase to PE conductor fault on the low voltage side depends on where the fault is located.

Lower values of the term (Z_{Lph} + Z_{LPE}) will cause the generator voltage to drop below the setting of the undervoltage relay that will trip the generator if the fault is not disconnected in time by the overcurrent protection device immediately upstream the fault point.

The above considerations are qualitatively valid also for faults between two or three phase conductors.

9.8 Medium and low voltage protection selectivity

In this section, it is investigated if selectivity can be achieved between a distribution network feeder relay and fuses of the low voltage side of a distribution transformer connected downstream the feeder, under island operation of an induction generator. It is noted that not much can be done to improve this selectivity and that the aim of the investigation is just to find out whether there are cases in which selectivity is achieved.

A fault close to the distribution transformer terminals causes short-time high currents and subsequent demagnetization of the induction generator if not interrupted in time, see Chapter 6 and 7. These fault currents are seen also by the overcurrent relay of the medium voltage distribution feeder on which the distribution transformer is connected, if the induction generator is connected on another feeder or at the PCC, see Figure 9.13. It is interesting to investigate if, during island operation with an induction generator, a fault at the low voltage terminals of a distribution transformer may be interrupted by the dedicated transformer fuses before the distribution feeder relay issues a trip signal, in case a selective protection scheme has been chosen. In this case, in fact, selectivity could be achieved between the distribution transformer low voltage fuses and the distribution feeder relay.

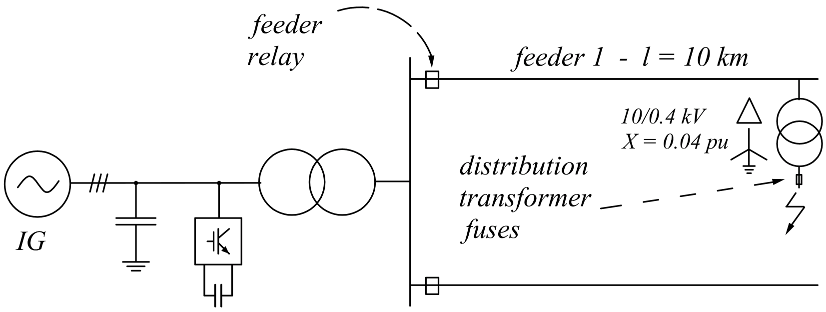

Figure 9.13 Single-line diagram of network model used to investigate short-circuit selectivity between feeder relay and distribution transformer low voltage fuses for faults on the low voltage side.

As described in the previous section, the distribution feeder relay may have a minimum required time of 40 ms to issue a trip signal. Because of the decaying short-circuit current of the induction generator, time coordination between two overcurrent devices in series is not possible. No time delay can be set on the distribution feeder relay, which is therefore supposed here to issue a trip signal after 40 ms if it sees a short-circuit current higher than its setting during all this period. If the fault current is higher than the feeder relay pick-up value, the distribution transformer low voltage fuses must therefore interrupt the fault current before 40 ms, for achieving selectivity with the feeder relay. Analyzing some low voltage fuses technical sheets (IFÖ Electric, Hicap Eco Technical data) the required minimum short-circuit current for different melting times of the fuses can be found. These data can be combined with the results from simulations. A solid fault between phase-a and the PE conductor at the distribution transformer terminals has been considered, with the induction generator rated 1000 kVA.

Figure 9.14 shows the simulated fault currents for different ratings of the distribution transformer along with the minimum current required by the fuses to melt within a specific time, e.g. 40, 80 and 100 ms.

It can be observed that for low rating distribution transformers, their fuses should melt quickly, before 40 ms, interrupting the fault, while the distribution network feeder relay does not pick up in this case. As the rating of the distribution transformer increases above a certain limit, around 200 A in the example in the figure, the fuses will not melt any longer, since the fault current decreases when expressed in pu of the distribution transformer current. A further increase of the distribution transformer rating causes the fault current to be above the pick-up value of the feeder relay for longer than 40 ms. This because the total impedance between the generator and the fault decreases. In the case with a distribution transformer nominal current around 500 A in the example, the feeder relay may issue a trip signal disconnecting all the feeder, while the transformer low voltage fuses will not melt.

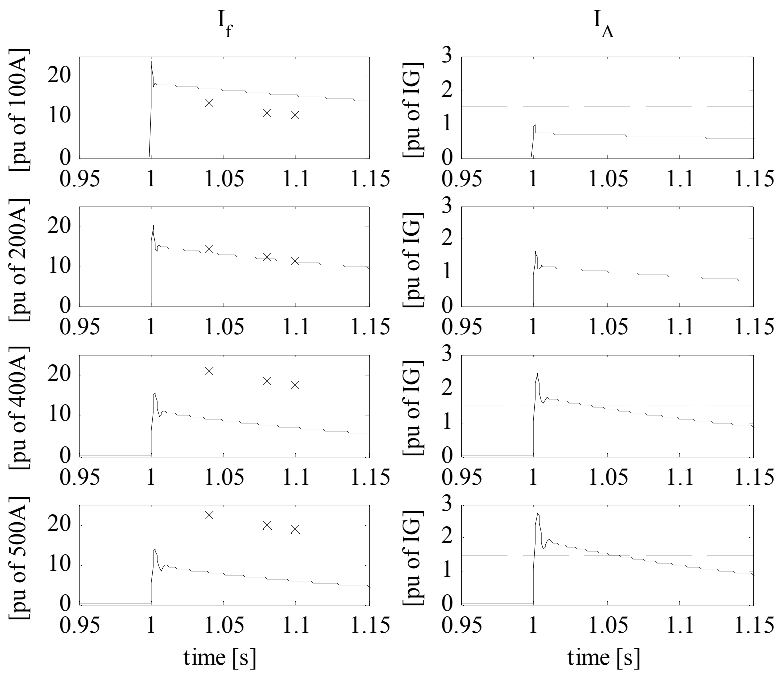

Figure 9.14 Fault current I_f (in pu of the distribution transformer rated current) on the low voltage side and phase-A current (in pu of the 1000 kVA IG rated current) on the medium voltage side during a phase to PE conductor fault at the distribution transformer low voltage terminals. Minimum current for fuse melting at 40, 80 and 100 ms are indicated by “x”. Feeder overcurrent relay setting (dashed). Distribution transformer impedance is considered always equal to 0.04 %.

It can be concluded that selective interruption of a fault at the low voltage terminals of a distribution transformer can be achieved if the ratio between the induction generator rating and the distribution transformer rating exceeds a certain value. In the considered example, this ratio was around 7.5. As the ratio decreases, neither the transformer fuses nor the feeder relay will interrupt the fault current and the generator would be tripped by the undervoltage relay. A further decrease of the rating ratio, causes the distribution network feeder relay to pick-up and eventually to trip the entire feeder on which the distribution transformer is connected. In the example, this lower rating ratio has been found to be around 2.8. It is noted that the quantitative results obtained here are based on the fuses characteristic of a particular manufacturer. Fuses from different manufacturers may have a different characteristic, however the obtained qualitative results remain valid. In the previous chapter, it has been shown that the induction generator exhibits good ride-through capability for a fault on the low voltage side of a distribution transformer cleared by fuse melting within 40 ms.

On the other hand, it has been already mentioned that a fault in the low voltage distribution network some distance away from the distribution transformer may cause the generator voltage to drop. This will cause a drop also in the fault current, see Figure 6.15 and Figure 6.16. In this case, the generator undervoltage protection may trip before the proper overcurrent protective device disconnects the fault. This situation is a bit paradoxical, since faults on the low voltage 400 V distribution system away from the distribution transformer may cause the termination of the entire island, while in many cases faults closer to the generator, e.g. on the medium voltage distribution network or at the low voltage terminals of a distribution transformer, may be disconnected selectively.

9.9 Considerations on selectivity

In the previous sections, it has been investigated under which conditions selective tripping of a faulted feeder or distribution transformer low voltage fuse melting can be achieved.

During earth-faults, the induction generator does not demagnetize and the possibility for selective earth-fault protection depends on the earthing condition of the network. In unearthed networks, selective protection depends upon the total network capacitance to earth and the capacitance to earth of each single feeder. In resonant-earthed networks, the earth-fault currents during island operation do not change appreciably compared to the corresponding earth-fault currents in grid-connected operation, supposing exact compensation. Hence, selective earth-fault protection can be achieved also during island operation with induction generators. Moreover, the self-excited induction generator has good ride-through capability for earth-faults. Therefore, selective earth-fault protection may bring valuable benefits, improving the supply reliability during island operation. Back-up unselective zero sequence voltage protection should always be used.

Selectivity for short-circuit faults is instead more difficult to achieve. Selectivity between different feeders depends on the generator internal parameters and hence on its rating. Fast feeder relays capable of issuing a trip signal within about two cycles are necessary. Selectivity between up- and downstream overcurrent devices cannot be planned based on time delays, because of the fast decaying short-circuit currents. Selectivity with distribution transformers low voltage fuses can be achieved for high ratios of generator to transformer rating. For lower rating ratios, selectivity is not achievable any longer and either the feeder relay (rating ratio below a certain value) or the generator undervoltage relay trips. Also, faults on the low voltage side away from the distribution transformer may cause the intervention of the undervoltage relay. Moreover, the induction generator has a poor ride-through capability for short-circuits on the medium voltage distribution network and it may be necessary to trip the generator also if the fault has been disconnected. This means that selectivity for short-circuits does not bring the same benefits as earth-fault selectivity. One benefit of a selective short-circuit protection, as already mentioned, is that the faulted feeder may be disconnected immediately and the successive black-start of the island may be accomplished quicker, saving the time for searching for the faulted feeder.

9.10 Summary

In this chapter, it has been analyzed the protection of a distribution network in island operation with a self-excited induction generator source.

Unselective protection of the network can be safely achieved both for earth-faults and for short-circuits. Unselective earth-fault protection can be achieved with a zero sequence voltage protection. The zero sequence voltage can be measured directly at the generator station, on the high voltage side of the step-up transformer. A new method, requiring only one voltage transformer on the high voltage side of the step-up transformer, for estimating the zero sequence voltage has been proposed. Unselective zero sequence voltage protection can be used in unearthed and resonant-earthed distribution networks. In unearthed distribution networks, the magnitude of the zero sequence voltage at a high resistive earth-fault decreases with the total network capacitance to earth. Therefore, above a certain value of network capacitance to earth, i.e. if the amount of cables in the network is above a certain value, high resistive earth-fault protection becomes impossible. Short-circuits in the network cause the demagnetization of the induction generator and therefore an undervoltage protection relay at the generator terminals can be used to trip the generator in this case.

Selective earth-fault protection can be achieved in unearthed networks, if the settings of the feeder directional earth-fault protection relays can be changed properly during island operation and depending on the network configuration. That is, the capacitance to earth of all the healthy feeders should be so that it causes the zero sequence current on the faulted feeder to be high enough to be detected. At the same time, the total network capacitance to earth should not be too high to cause the zero sequence voltage to drop below a certain value, e.g. 3 % of nominal phase-earth voltage. Zero sequence voltage and currents in resonant-earthed networks remain very close to the corresponding values during grid-connected operation, at least assuming almost exact compensation of the network capacitance to earth with the Petersen coil inductance. In this case, selective earth-fault protection can be achieved as in the case of grid-connected operation with the same relay settings. Selective earth-fault protection may bring advantageous benefits, given that the induction generator is able to ride through an earth-fault satisfactorily.

Selective short-circuit protection requires fast overcurrent relays on each distribution feeder and changing their settings during island operation. Coordination with protection devices on the 400 V low voltage side of a distribution transformer cannot be planned based on time delays, even though in same cases it may take place. The poor short-circuit ride-through capability of the self-excited induction generator may nullify the benefits deriving from a selective short-circuit protection scheme.

Chapter 10

Conclusions

This chapter briefly summarizes the most important results obtained in the course of this work. Fault analysis of induction generators has been traditionally largely concentrated on faults at the generator terminals. Unbalanced faults in an island-operated distribution network fed by an induction generator have not been systematically investigated in the literature. In this work, a general fault analysis of an induction generator in island operation in a distribution network has been performed through simulations in MATLAB SimPowerSystems.

The results point out that, if an unselective protection strategy is adopted, the protection of a distribution network in island operation with induction generation does not present particular problems. The protection equipment necessary for assuring required fault clearing during island operation is in most cases already installed at the induction generator station or it may be added with a moderate investment.

10.1 Summary of Thesis

A brief introduction to the principle of self-excitation of an induction generator has been given. An algorithm for the calculation of the steady state performance of a self-excited induction generator feeding an impedance load has been introduced, along with laboratory tests supporting the theoretical derivations. This algorithm extends the use of the intuitive voltage-current curves, used for no-load conditions of a self-excited induction generator, to steady-state loading conditions.

A theoretical approach for the calculation of the three-phase short-circuit current of an induction machine has been presented. This approach does not neglect any machine parameter and it results in an accurate prediction of the three-phase short-circuit current of an induction machine. The resulting equation, with some modifications, can be used with satisfactory accuracy also for predicting the current delivered by the self-excited induction generator during a three-phase short-circuit anywhere in the network.

The behaviour of the induction generator at a single-phase-to-earth fault has been shown to depend upon the earthing method of the distribution network. The induction generator will demagnetize if the distribution network is directly earthed, while it will sustain the voltage if the distribution network is unearthed or resonant-earthed.

Short-circuits in the distribution network always cause the demagnetization of the induction generator. The influence of the STATCOM on the short-circuit current of the induction generator has been found to be negligible.

Unselective disconnection of the induction generator at any fault in the network is a protection strategy that is likely to be adopted during island operation. There are different reasons for adopting such an unselective practice. The fast decaying generator short-circuit current may not cause the intervention of feeder overcurrent protective devices. The need of changing the settings of such devices when in island operation is also eliminated. Finally, the island-operated network may be composed of only one medium voltage feeder and it may not contain protective devices other than the ones located at the generator station.

In case an unselective protection strategy is adopted, the protection for earth-faults in an unearthed or resonant-earthed distribution network requires the measurement of the zero-sequence voltage in the network to be performed at the generator station. A new method for the estimation of the zero-sequence voltage on the high-voltage side of the step-up transformer, i.e. in the distribution network, has been proposed. The advantage of this method is the need of only one voltage transformer to be used on the medium voltage side. Alternatively, the zero sequence voltage must be measured with the classical connection of three broken-delta connected voltage transformers at the medium voltage side. Short-circuit protection can be achieved disconnecting the induction generator by means of undervoltage relaying at the generator terminals.

Selective earth-fault protection in unearthed networks can be achieved in some cases, depending on the network configuration. In resonant-earthed networks almost exactly compensated, the directional earth-fault protection used during grid-connected operation can be continued to be used during island operation with a self-excited induction generator.

The requirements on the operating speed of an overcurrent relay to achieve selective tripping of a faulted feeder during short-circuits have also been investigated. Normal-speed feeder overcurrent relays are likely to trip if the island is supplied by large induction generators. However, the settings of the overcurrent relay need to be changed in island operation as compared to the grid-connected operation. Coordination based on time delay between feeder overcurrent relays and overcurrent protection devices on the 400 V low voltage side of a distribution transformer cannot be planned, because of the fast decaying short-circuit current of the induction generator. Depending on their location, faults on the low voltage 400 V distribution system may either be interrupted selectively or cause the intervention of the generator undervoltage relay.

The capability of the island-operated induction generator of riding through a fault has been briefly investigated. Even considering the voltage support offered by the STATCOM during the transient, the island-operated induction generator seems to have inherently poorer capability of riding-through a short-circuit as compared to a synchronous generator. This may nullify the advantages of having a selective short-circuit protection scheme. The induction generator shows instead to have good capability of riding through an earth-fault in the medium voltage network, thus improving the benefits of a selective earth-fault protection scheme.

10.2 Future Work

The work presented in this thesis focuses exclusively on squirrel-cage induction generators. It would be interesting to perform the same kind of analysis on the doubly fed induction generator, which is gaining increasing popularity especially in the wind power sector.

The behaviour of the induction generator has been investigated in laboratory tests in the case of single-phase-to-earth faults in an unearthed network and short-circuits without STATCOM. The measurements confirm the results from simulations. Laboratory tests should be performed also for the cases of earth-faults in a resonant-earthed network and short-circuits with the STATCOM connected to the generator.

The proposed method for the estimation of the zero-sequence voltage has not been tested on the field. It is therefore not known how the measurement errors and noise from current and voltage transformers would impact in reality on the estimation.

The proposed recursive method for the calculation of the steady state performance of a self-excited induction generator feeding a constant load assumes the frequency to be a known constant in the system. Other methods for calculating the SEIG steady-state performance proposed in the literature assume instead a constant turbine mechanical speed, as often the turbine speed is unregulated in many cases leading to an unknown system frequency. The proposed method should be slightly modified to cover the case with constant turbine mechanical speed.

Additional investigation is needed to assess the ride-through capability of an island-operated induction generator. Methods for predicting and quantifying this capability would be helpful also for the island-operation planning. In this work it has not been addressed the question of whether it is possible and how to improve the ride-through capability. The contemporaneous presence of a synchronous generator in the island may help improving the ride-through capability. Laboratory tests using a STATCOM could help to get a deeper understanding into the problem.

Finally, the response of a digital overcurrent relay to the short-circuit current has only been calculated theoretically based on a number of assumptions. Laboratory tests should be performed on commercial feeder overcurrent relays to assess their capacity in issuing a trip in response to the short-circuit current of an induction generator.

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