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Industrial Electrical Engineering and Automation

100% stator ground fault protection

- a comparison of two protection methods

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100% STATOR GROUND FAULT PROTECTION

A comparison of two protection methods

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Abstract

This master thesis studies two methods that can protect the stator winding of unit-connected generators against stator ground faults: the subharmonic injection method and third harmonic voltage method.

Stator ground faults can seriously damage the generator and therefore, the entire stator winding must be protected against these faults. Since conventional protection schemes can not detect stator ground faults that occur close to the neutral of the generator, other methods such as the two ones presented in this master thesis are needed to provide the 100% coverage of the stator winding.

In order to study the principles of operation of the subharmonic injection method and the third harmonic voltage method, an explanation is provided achieved through critically reviewing of previous literature research and simulations are performed with MATLAB SIMULINK.

The results obtained in the simulations and the information taken from the literature research permit to compare the two protection methods and draw on strengths and weaknesses of both. Some setting values for the two protection methods are also proposed according to the study performed.

To conclude, the subharmonic injection scheme is technically superior in terms of sensitivity, coverage of the stator winding, independence of the generator design and of the load conditions and can be applied to all the generator turning states (running, standstill and turning on gear). The third harmonic voltage scheme is not as capable as the subharmonic injection scheme but it is cheaper since it doesn’t require additional equipment. Moreover, along with conventional protection relays it can provide 100% coverage of the stator winding.

Acknowledgements

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Chapter 1: Introduction

Synchronous generators are very important elements in power systems since they are in charge of providing an uninterrupted power supply to the consumers. Therefore their reliability and good functioning are crucial. The construction as well as maintenance costs are high depending on the complexity and the size of the generators. Moreover, damaged generators usually have to be returned to the manufacturer to restack and rewind because it is not common that companies using generators have the skills to repair them.

The important role of generators in the power system and the cost of fixing them in case of damage require a protection system against faults, which means, they must be protected against the damage caused by irregular situations in the electrical network or in the generator itself.

As stated in Gilany et al. (2002), “Protection system used for generator protection should be robust to extent that it will not interrupt the system for non-serious faults and on the other hand should be sensitive enough to detect all kinds of faults in the generator windings with different degrees of seriousness”. Therefore, if the generator protection system is robust and sensitive, the generator will not be unnecessarily shut down but it would in case the generator is damaged.

Thus, generators have to be protected against external faults and internal faults. Generators are protected against external faults by several circuit breakers that isolate all faults that could occur in the network (i.e. transformers, buses, lines…).

At the same time, synchronous machines must be protected against faults that could occur inside the machine. There are several ways to detect these faults and avoid the damage caused by them.

This work will focus on stator ground faults and will look into different schemes currently being used to provide 100% stator ground fault protection in synchronous machines.

1.1 References

Gilany, M., Malik, O.P., Megahed, A.I. (2002), Generator stator winding protection with 100% enhanced sensitivity, Electrical power & energy systems 24 (2002), pp 167-172.

Chapter 2: Stator ground faults

A stator ground fault is the most common type of fault to which generators are subjected. “Stator ground faults could be caused by the insulation degradation in the windings as well as environmental influences such us moisture or oil in combination with dirt which settles on the coil surfaces outside the stator slots. This often leads to electrical tracking discharges in the end winding which eventually punctures the groundwall” (Finney et al. 2002).

Why must generators be protected against stator ground faults?

A stator ground fault is a single-phase to ground fault. Generators must be protected against them for two reasons:

- The first and obvious one, they are faults and that means they are irregular situations in the work of the machine causing non-desirable voltages, currents, oscillations or damage.
- The second reason, an undetected and non-cleared ground fault could develop into a phase-to-phase fault or into an inter-winding fault if another single-phase to ground fault occurs. Since these faults are short-circuits they are associated with immediate damage to the generator since the resulting short-circuit current would be of devastating magnitude.

Therefore, one can distinguish two scenarios in the generator functioning:

- **Scenario I:** a single-phase to ground fault occurs in the stator.
- **Scenario II:** after the first single-phase to ground fault, another one occurs in another phase or at the same phase, creating a short-circuit between two points of the stator.

In sections 2.1 and 2.3, the damage inflicted to the generator in each scenario will be discussed.

2.1 Scenario I: one single-phase to ground fault occurs

In order to explain the magnitude of the damage suffered by a generator during a single-phase ground fault in the stator, Pillai et al. (2004a) presented the following stator ground fault scenario: imagine one has a generator with the neutral point grounded by a resistor and this generator is connected to a network bus through a circuit breaker. If a stator ground fault occurs at the terminals of the generator, there will be two fault currents: one flowing into the generator from external sources and one generated in the generator itself. The current in the fault is the superposition of the two fault current and the damage in the generator associated with this fault is determined by the total fault current.

One could say that the damage inside the generator could be proportional to the energy released in the arc at the fault point which is,

$$Damage = \alpha \cdot \int_0^{T_f} u_{arc}(t) \cdot i(t)dt \qquad [1]$$

T_f is the time during which the faulted current persists.

2.1.1 Damage inflicted by the current flowing into the generator from the external sources.

One could argue that the fault in the stator is detected by the stator protective system with no time delay, which means one cycle of delay. If one considers that the circuit breaker of the generator has an operating time of five cycles, then this current will persist for six cycles (in 60 Hz systems would be 0.1 seconds approximately). Evaluating the expression [1] with six cycle delay, we would have an idea about the damage caused by the current flowing into the generator.

2.1.2 Damage inflicted by the current from the generator

When the generator breaker is tripped, the current inside the generator is not interrupted because the generator field remains excited. The excitation will decrease after the circuit breaker is tripped due to the single-line to ground short-circuit time constant τ. This constant is different in each generator but usually has the values in the range 0.8-1.1 s as Powell (1998) estimated.

Then, the expression [1] over the period of time necessary to extinguish the current will be,

$$Damage = \alpha \cdot \int \left[I \cdot \varepsilon^{\frac{-t}{\tau}} \right]^k dt \qquad [2]$$

In this case, the integration time will be considerably longer. Consequently, the damage (energy) will be bigger than in the case above because the fault current continues to flow until the generator field demagnetizes. Now, there is no circuit breaker that can clear the fault current.

Thus, most of the damage in a faulted generator is caused by the generator itself and the only way to avoid the damage is reducing the fault current. How can the single-phase to ground fault current be reduced?

There are several practices to reduce the fault current. For example, large generators are not usually connected directly to the distribution bus. A step-up transformer is connected at the terminals of the generator and this transformer is grounded so that the stator fault current is small (usually not higher than 10 A to 20 A). This generator and step-up transformer is known as unit-connected generator.
Another way to reduce the fault current is grounding the neutral point of the generator.

Before going through the Scenario II, groundings will be discussed in the following section in terms of how they can avoid the damage to the generator when a stator ground fault occurs.

2.2 Grounding methods

There are different methods in power systems to ground the elements. One can ground the system and/or the sources (generators and/or transformers) by using methods such as low-resistance grounding (LRG), reactance grounded, high-resistance grounded (HRG) and ungrounded.

As stated in Fulczyk and Bertsch (2002), “the elements connected between the generator neutral and the ground determines the zero sequence currents during its normal operation and during ground faults in the stator winding […]” .
There are lots of methods to ground the neutral of the generators in order to reduce the single-phase to ground fault current. Some of these methods discussed by Fulczyk and Bertsch (2002), by Pillai et al. (2004b) and by Ilar et al. (1979) are presented.

2.2.1 Low-resistance grounded system

The generator neutral is connected to ground through a resistor that limits the ground fault current to several hundred amperes (200-600 A). This fault current is really high and can damage the stator but, at the same time, allow sufficient current for sensitive and selective tripping of the protective devices.
Nowadays, it is rarely used in large generators because there is a high risk of burning the generator stator iron. One doesn’t use it neither in unit-connected generators. However, it is the most common grounding method used in the medium-voltage industrial power distribution system. As presented in Wu et al. (2004), sometimes low-resistance grounding method is combined with a high-resistance grounding that is switched on when the ground fault occurs.

2.2.2 High-resistance grounded system

The high resistance is connected between the neutral point of the generator and the ground. Sometimes, a low resistor is connected at the secondary winding of a single-phase transformer called the distribution transformer or the neutral grounding transformer. This method of grounding limits the ground fault currents to the order of 5 to 10 A, and then there is no danger of damage in case one ground fault occurs.

2.2.3 Ungrounded neutral

There is no connection between the neutral of the generator and the ground. As Ilar et al. (1979) says, very few generators are operated ungrounded due to the need for limiting surge voltages in the windings.

2.2.4 Low-reactance grounding

A reactor is connected between the generator neutral and the ground. Since it is a low-reactance reactor, the current that flows substantially in case of a stator ground fault occurs. Therefore, this method is rarely used in large generators but it is used in medium-voltage ones.

2.2.5 Neutral grounded through neutralizer

A neutralizer consists of a resistor in parallel with a reactance that connects the neutral point with the ground. This method can also decrease the ground-fault current to magnitudes that do not damage the generator.

To conclude this section, one has to consider that grounding methods are strongly related to the protection system of the generator. Each protection system, especially those that guarantee 100 % stator ground fault protection, need to adapt to the grounding method so that they together provide the necessary protection for the generator.

The discussion in the Scenario I, where just one single-phase to ground fault occurs, one must say that the grounding methods currently being used permit not to consider one ground fault in the stator as a critical situation in terms of the damage inflicted to the generator. Thus, it is recommended that the generator be immediately tripped off to prevent the short-circuit Scenario II due to a second single-phase to ground fault occurs. This fatal Scenario II will be discussed in the following section.

Grounding methods can influence de damage when a single-phase to ground fault occurs. One of the most frequently used method is the high-resistance groundings, especially in unit-connected generators.

2.3 Scenario II: more than one single-phase to ground fault occurs

The Scenario II describes the following situation: one has a generator high resistance grounded (through a resistor or through a distribution transformer) and a single-phase to ground fault occurs. As the generator is high resistance grounded, the ground fault current will not be high enough to damage the core steal.

Then, as stated in Pope (1984) having one phase grounded, the possibility exists for a phase-to-phase fault occurring if a second phase goes to ground and this would result in a very high fault current. The same would happen if the first single-phase to ground fault was near the neutral of the generator and this was followed by a second ground fault higher up in any phase.

In both cases the faulted current would be high enough to inflict serious damage to the generator. Once again, the faulted current will not be interrupted when the generator will be tripped off because the generator field will remain excited. One can evaluate the damage that this faulted current could inflict using the expression [2] presented in previous section 2.2. In this case, the damage (energy) will be higher because the faulted current will be higher too.

The generator should never be subjected to this Scenario II because the consequences are fatal. Therefore, when the first single-phase to ground fault occurs, the stator ground fault protection system must detect it and must start the generator tripping off procedure.

2.4 Stator ground fault protection methods

When a ground fault occurs inside a generator, its protection system must be able to detect it and shut down the generator. This protection system has to be coordinated with the nearby fault clearing system in order to allow the external generator ground faults to be isolated by the circuit breakers.

As it was said above, the generator ground fault protection system method is directly related with the grounding of the neutral. So, one must be aware that the schemes of the protection systems change depending on the grounding used, and some of the grounding methods can not be used with some protection systems and vice versa.

In Pillai et al. (2004c) some of the typical methods to protect the generator against ground faults are presented:

2.4.1 Percentage phase differential protection (device 87)

This device is able to detect most internal ground faults in the generator but if the maximum ground fault current is below the phase differential pick-up, the device will not be able to detect it. In these cases, a ground differential scheme may be needed. The figure shows the scheme of this protection scheme.

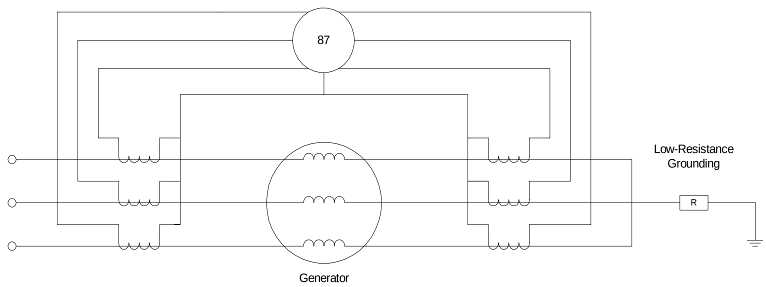

Figure. Percentage phase differential protection

2.4.2 Ground differential protection (device 87 GN)

In Pillai et al. (2002c), this device is defined as the one “that provides excellent security against misoperation for external faults while providing sensitive detection of internal ground faults”. This device is able to detect ground faults to within 10% of the generator’s neutral.

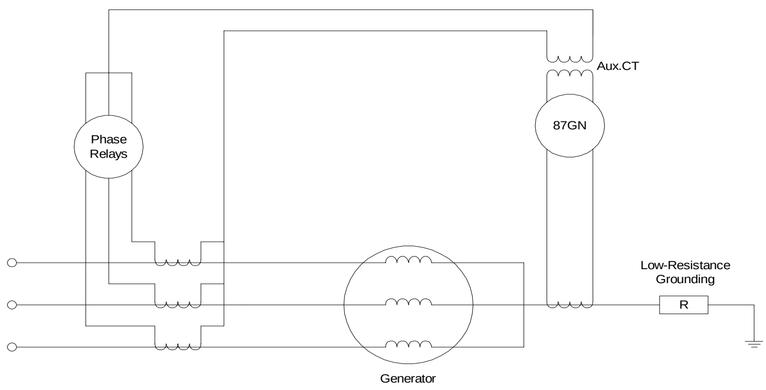

Figure. Ground differential protection

2.4.3 Ground time-overcurrent protection (device 51G)

These elements are responsible to provide a back-up protection against external faults, which means, when the circuit breakers (device 50G) have not isolated the external fault, ground time-overcurrent relays (51G) will isolate it.

When the fault occurs near the terminals of the generator, there is a possibility of damage from the prolonged high fault currents. This damage can be reduced using an instantaneous ground overcurrent protection (device 50G) combined with the time-overcurrent relay.

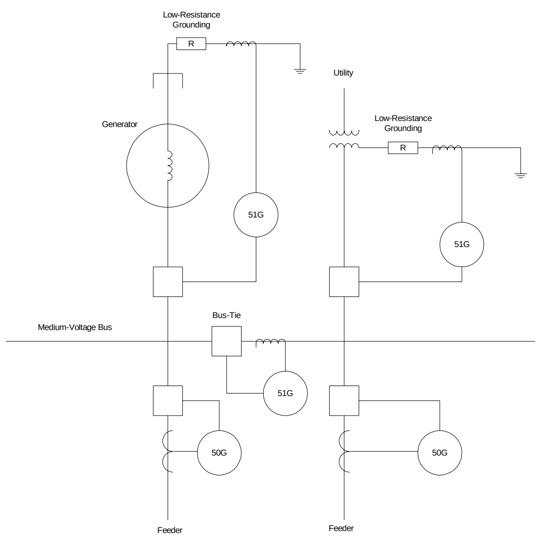

Figure. Ground time-overcurrent protection

2.4.4 Instantaneous ground overcurrent protection (device 50G)

It detects faults near the generator neutral and provides back-up protection for low-magnitude external ground faults.

This device is based in a toroidal current transformer that surrounds the generator phases and the neutral. This configuration permits to measure the ground current coming from the generator and the system and in this way, ground faults are detected.

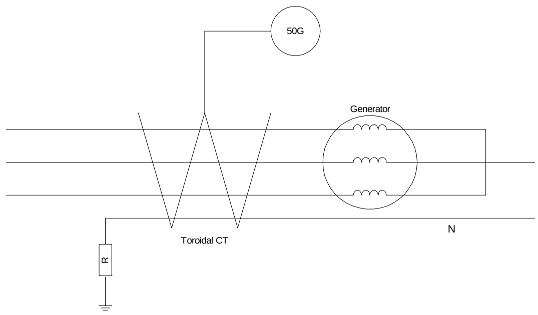

Figure. Instantaneous ground overcurrent protection

2.4.5 Wye-broken-delta VT, ground overvoltage protection (device 59 GN)

This device is mainly used in high-resistance grounded generators. A ground fault in the generator stator winding can be detected because this device consists in a voltage transformer whose secondary (wye-broken-delta configured) measures the phase ground voltage. This protection scheme is a variation of the stator winding zero-sequence neutral overvoltage protection described below.

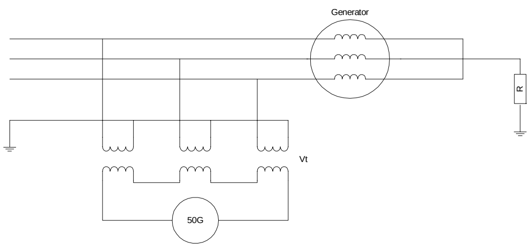

Figure. Wye-broken-delta Vt, ground overcurrent protection

2.4.6 Stator winding zero-sequence neutral overvoltage protection

This is the most conventional and common used protection for high-resistance grounded systems and it is a time-delayed overvoltage relay tuned to the fundamental frequency and insensitive to third-harmonic voltages that are present at the generator neutral. This device is able to detect faults to within 2-5%. A time-overcurrent ground relay (51 GN) can be used as a back-up protection.

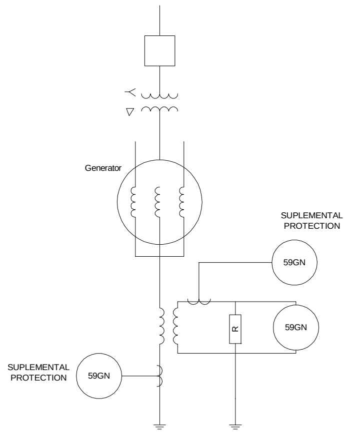

Figure. High-resistance grounded and unit-connected generator with zero-sequence voltage protection

2.4.7 Protection schemes that can provide 100% coverage of the stator winding

These methods described above can detect ground faults for only about 95% of the stator winding since there is not enough voltage to drive current when the fault occurs near the neutral. Thus, in the remaining 5% of the stator winding (the closest part to the neutral), the relays can not operate. Therefore additional protection methods are used to provide a 100% stator ground fault protection.

Special protection systems based on the third harmonic analysis and on the subharmonic voltage injection can detect stator ground faults close to the neutral. These protection methods are strongly recommended for large generators since the entire stator winding must be protected.

The objective of this Master Thesis is studying these two methods in order to have a fully protected stator of unit-connected generators.

2.5 References

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Chapter 3: Subharmonic injection method

This chapter studies the subharmonic injection method used to protect the stator winding of unit-connected generators against stator ground faults. The chapter starts with the principle of operation and afterwards two models of the injection scheme are built in order to simulate them with MATLAB SIMULINK. The analysis of the obtained results permits to know the strengths and weaknesses of this method. At the same time, this analysis permits to suggest some setting values for the protection scheme.

3.1 Principle of operation

A subharmonic voltage (usually one fourth of the system frequency) is injected through an injection transformer between the grounding element of the generator (i.e. resistor, distribution transformer or reactor) and ground. The operation theory of this principle is based on measuring the change of the subharmonic current resulting from the injected voltage when a stator ground fault occurs. Since the impedance of the stator to ground varies when the fault occurs, the subharmonic protection scheme can detect this change of the injected current and initiate the tripping-off of the generator.
During normal operation, the resulting subharmonic current is limited by the grounding impedance (resistor, reactor or distribution transformer with resistor loaded at the secondary), by the internal impedance of the injection circuit and by the shunt leakage capacitance to ground of the stator winding, bus, step-up transformers, etc. The reader might realize that the inductance of the stator winding has not been mentioned as an element the limiting current. As it will be shown later, the inductances of the stator windings can be neglected when compared to the impedances of the grounding element and the shunt capacitances to ground.

When the ground fault occurs, the fault resistance appears in parallel with the shunt capacitances to ground. Thus, the impedance that limits the subharmonic current changes and this also makes the current change.

The subharmonic injection principle of operation is based on this change in the subharmonic current. Therefore, detecting and measuring this change and operating if it

is necessary will be the function of the subharmonic injection scheme in order to protect the stator winding.
Figure 1 shows the principle of operation of this method.

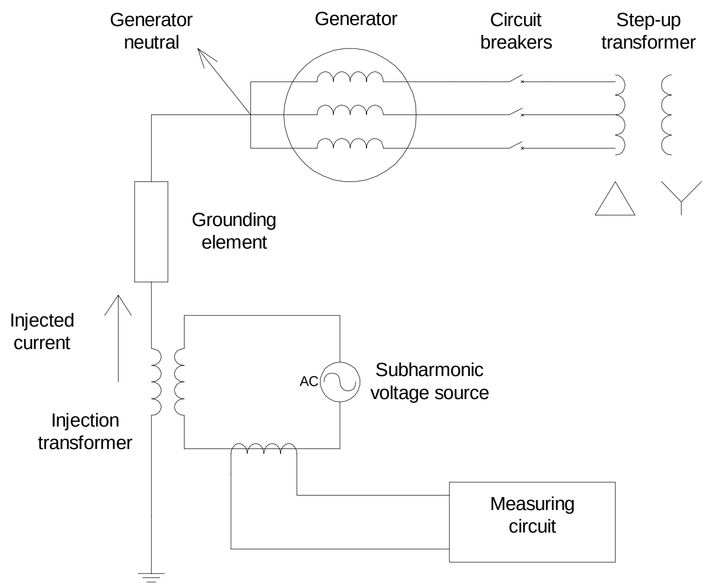

Figure 1. Principle of operation

The subharmonic voltage could also be injected at the terminals of the generator but as stated in Tai et al. (2000) the injection voltage scheme injected from the generator neutral is more flexible to be carried out and presents better results than injected from the terminals.

The study of the subharmonic injection method will be done in the European power frequency 50 Hz. Thus, the frequency of the subharmonic injected voltage, that is one fourth of 50 Hz, will be 12.5 Hz.

As discussed in Reimert (2005), the scheme uses a subharmonic signal for two reasons. First the lower frequency increases the impedance of the stator capacitive reactance. This improves scheme sensitivity. Secondly, by measuring the current as an integrated value over full 12.5 Hz cycles, all other harmonics of 50 Hz are eliminated, allowing more sensitive determination of the injected current.
Both reasons will be explained with more detail in subsequent sections.

As it was said in the introduction of this work, large unit-connected generators must be high-resistance grounded in order to avoid the damage caused by a stator ground fault.

The method used to ground the generator determinates the configuration of the subharmonic scheme. In the next section, different configurations for the subharmonic injection scheme are presented according to the method used to ground the generator.

3.1.1 Subharmonic injection schemes depending on the method of grounding

There are four main configurations currently being used to inject the subharmonic voltage in the generator. Their schemes will be presented in the next paragraphs. These schemes do not contain all the elements needed to build the protection system (i.e. filters, signal processing devices, etc.) however the sketch of the main elements will be presented.

3.1.1.1 Injection transformer and a grounding resistor

In this configuration, the method used to ground the generator is a resistor. The subharmonic voltage is injected through the injection transformer between the grounding resistor and the ground. The injected current is measured at the secondary of the injection transformer by the measuring circuit whose elements will be described later. Figure 2 shows this configuration.

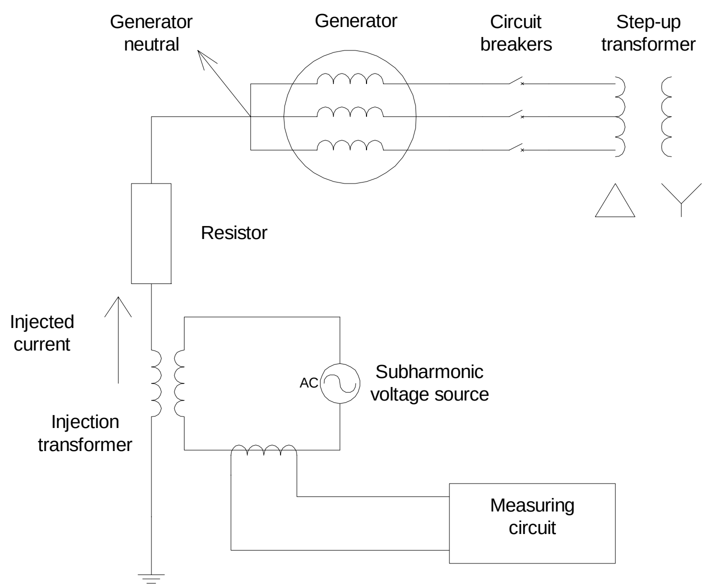

Figure 2. Injection transformer and a grounding resistor

3.1.1.2 Injection transformer and distribution transformer as a grounding (separated)

This configuration is almost equal than the previous one and the only difference is the substitution of the grounding resistor for the distribution transformer with a resistor loaded at its secondary winding. The distribution transformer has the turn ratio high enough to permit that a very small resistance at the secondary winding is very high when reflected to the primary. For example, in Pope (1984) an example is presented using the distribution transformer as grounding. The loaded resistor at the secondary has a value of 0.4316 Ω and reflected to the primary 1553 Ω since the distribution transformer has a turn ratio of 14400/240. Figure 3 shows the scheme.

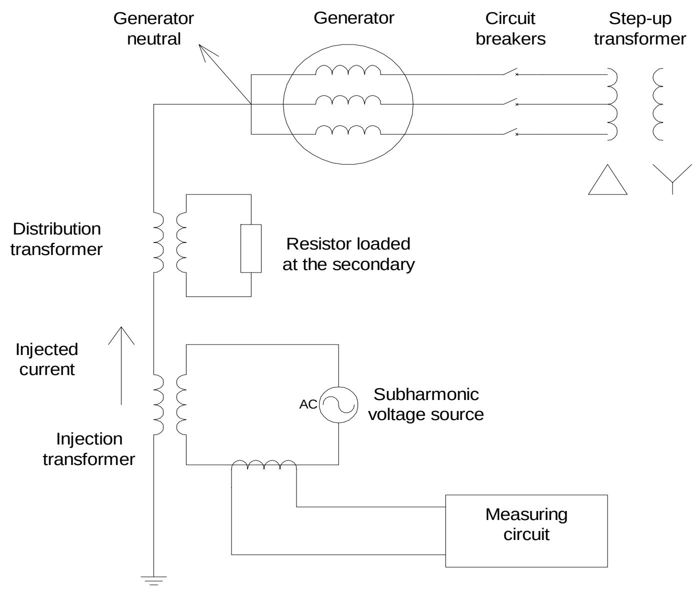

Figure 3. Injection transformer and distribution transformer as a grounding (separated)

3.1.1.3 Voltage injection through the grounding distribution transformer

The subharmonic voltage source is connected to the secondary side of the distribution transformer. Concretely, the subharmonic source injects the voltage across the loaded resistor. The measuring circuit is placed at the secondary of the distribution transformer. Figure 4 shows this scheme.

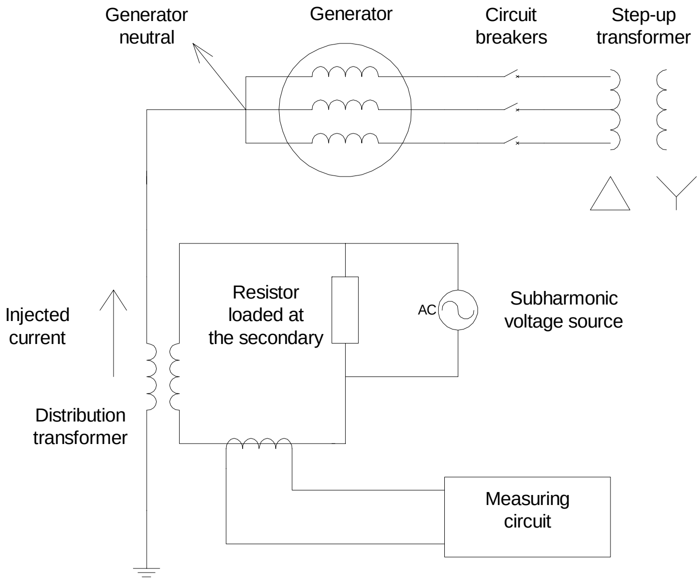

Figure 4. Voltage injection through the grounding distribution transformer

3.1.1.4 Neutral reactor grounded generators

The grounding reactor acts not only as grounding element but also one can assume that acts as primary winding of a transformer. Thus, the subharmonic voltage source is connected across another reactor that acts as secondary winding and the measuring circuit measures the current flowing through it.

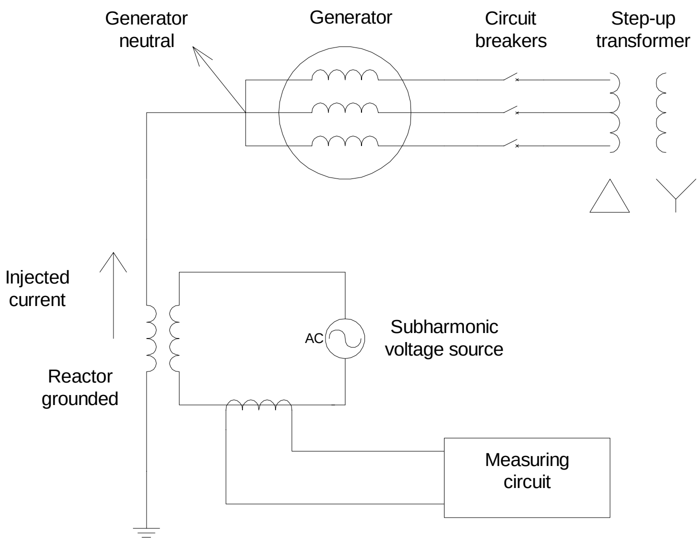

Figure 5. Scheme for neutral reactor grounded generators

The four configurations described above are currently being used. In the United States, distribution transformers with the resistor loaded at the secondary are quite used since single-phase transformers are not as expensive as in Europe. On the other hand, in Europe they tend to use more the high resistor to ground the generator.
These configurations are described in several papers, i.e. Pope (1984), Tai et al. (2000), Daquiang (2001), etc. and all of them accomplish their function and detect stator ground faults along the entire stator winding.

The configuration used to study the subharmonic injection method is the first one, with the grounding resistor and the injection transformer.
The following sections present the equivalent scheme of this configuration along with the unit-connected generator.

3.1.2 Equivalent scheme of the unit-connected generator with the injection scheme

As mentioned in the chapter 2, the generators studied in this work are unit-connected generators. This means that a step-up transformer will be connected in between the terminals of the generator and the electrical network. Moreover, circuit breakers are placed in between the generator and the bus in order to isolate the generator from external faults. At this point, it is necessary make some assumptions in order to obtain a simple model, which means, substitute some elements of the scheme but taking into account their effect on the circuit.

First of all, the measuring circuit will be taken out. The injection transformer and all the elements of the injection circuit (signal controllers, test circuits, etc) will be substituted for injection impedance ($Z_{inj} = R_{inj}+j\cdot X_{inj}$). Therefore, the 12.5 Hz voltage source will have to be reflected (E'_{inj}) to the generator side of the transformer using the turns ratio (r_t). The internal resistance of the subharmonic source will be reflected as well to the generator side of the transformer and will be also included in the injection impedance (Z_{inj}).

The generator will be modelled as follows:

- One reactor per phase whose value is X_d or X_d' or X_d'' which are the synchronous, transient and subtransient reactance respectively.
- The stator winding capacitance to ground will be modelled as one capacitor per phase placed after the reactance. This is just a provisional way of modelling this capacitance to ground since afterwards it will be done in another way.
- In order to model the 50 Hz power generation of the synchronous machine, one 50 Hz AC source will be placed in each phase. Their amplitude will be the nominal voltage of the generator divide by square root of 3 ($U_n/\sqrt{3}$) and their phase will be 0º, -120º and 120º depending on the phase (A,B and C respectively).

Finally, the capacitor between the circuit breaker and the step-up transformer, the bus and the step-up up transformer can be modelled just taking into account their capacitances to ground. Thus, three capacitors per phase will be placed to model these elements.

Figure 6 shows the equivalent of the unit-connected generator with the injection scheme.

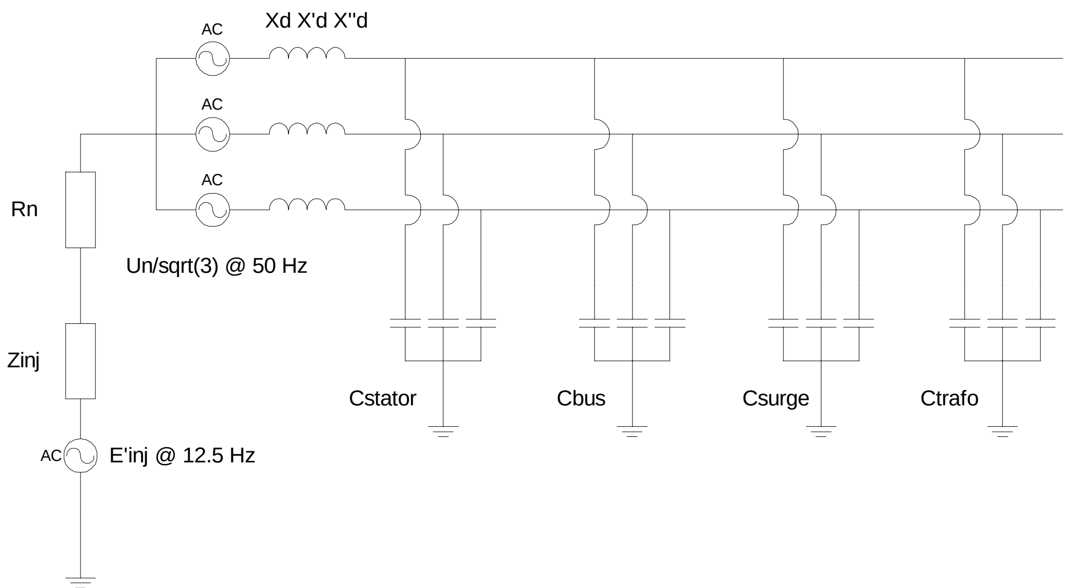

Figure 6. Equivalent of the unit-connected generator with the injection scheme

This is the first simplified scheme one can obtain. In order to explain even easily the way in which this protection scheme works, more simplifications can be done.

However, one must know the values of the elements of the unit-connected generator and the protection scheme so that the simplifications can be done.
The following section presents the values for the unit-connected generator and the subharmonic injection scheme that will be used in all the calculations and simulations of this chapter.

3.2 Typical values for a unit-connected generator and a subharmonic injection scheme

3.2.1 Typical values for a unit-connected generator

Table 1 shows values and characteristics of the unit-connected generator used in the calculations and simulations of this chapter.

Table 1. Typical values for a unit-connected generator

Rated power (S_N)	850 MVA
Rated rotational speed	3000 rpm
Rated frequency (f_0)	50 Hz
Rotor type	Round rotor
Nominal voltage (U_n)	21 kV
Synchronous reactance (X_d)	2.44 p.u.
Transient reactance (X_d')	0.43 p.u.
Subtransient reactance (X_d'')	0.25
Zero sequence reactance (X_0)	0.13
Negative sequence reactance (X_2)	0.24
Zero sequence resistance (R_0)	0.0025
Positive sequence resistance (R_1)	0.0034
Negative sequence resistance (R_2)	0.04
Capacitance to ground of the stator winding (C_{gnd})	0.385 µF
Power factor	0.882
Grounding resistor (R_n)	Rated 10 A 21/√3 → R_n=1212 Ω
Bus capacitance (C_{bus})	0.1 µF/phase
Surge capacitor between step-up transformer and circuit breakers capacitance (C_{surge})	0.25 µF/phase
Step-up transformer capacitance (C_{trafo})	0.2 µF/phase

3.2.2 Typical values for a subharmonic injection scheme

According to the figure 6, there are two values of the subharmonic injection scheme that must be defined: E_{inj}' and Z_{inj}. These values will be taken from an example presented in Pope (1984).

E_{inj}' is the subharmonic voltage source reflected to the generator side of the injection transformer. In Pope (1984), the injection transformer has a turns ratio of

$$r_t = \frac{V_{generator\_side}}{V_{source\_side}} = \frac{1}{2.5}$$

and the voltage source has a magnitude of 140 V (source_side), which means that the reflected voltage to the generator side is

$$V_{gen.\_side} = V_{source\_side} \cdot \frac{1}{2.5} = 56\text{V}$$

Therefore, E_{inj}'= 56 V.

Z_{inj} is the equivalent impedance of the injection circuit. It also includes the internal resistance of the subharmonic voltage source. In Pope (1984), the leakage impedance of the injection transformer is $\underline{Z}_{inj} = 36 + j\cdot 125$ in a 60 Hz system frequency. This means that,

$$\underline{Z}_{inj} = 36 + j\cdot 125 \begin{cases} R = 36\Omega \\ L = \dfrac{125}{2\cdot\pi\cdot 60} = 0.331\text{H} \end{cases}$$

Thus, it will be assumed that $\underline{Z}_{inj}$ (impedance of the injection circuit) will be calculated with R=36 Ω and L=0.331 H. One must realize that depending on the system frequency this impedance will vary since $X=j\cdot 2\pi\cdot f\cdot L$.

3.3 Simplified equivalent scheme and equations

3.3.1 Simplifications

As it was said above, if one has an idea about the typical values of a unit-connected generator and its subharmonic protection system one can simplify even more its equivalent scheme. Concretely, the inductance of the stator winding can be neglected when compared to other impedances, i.e. the stator winding capacitance, the grounding resistor or the other capacitances (bus, surge capacitor between circuit breakers and step-up transformer and the step-up transformer capacitance to ground). In order to show it, per unit values of the elements of the generator will be presented.

<u>Base values for the generator</u>

$S_{base}=S_N= 850$ MVA

$U_{base}=U_n= 21$ kV

$$I_{base} = \frac{S_{base}}{\sqrt{3}\cdot U_{base}} = \frac{850\cdot 10^6}{\sqrt{3}\cdot 21\cdot 10^3} = 23369 \text{ A}$$

$$Z_{base} = \frac{U_{base}}{\sqrt{3}\cdot I_{base}} = \frac{21\cdot 10^3}{\sqrt{3}\cdot 23369} = 0.5188 \ \Omega$$

Let's see per unit values of the stator winding inductance, of the stator winding capacitance, of the grounding resistor and of the other capacitances. The impedance of the inductance (Z_{ind}) and capacitance (Z_{cap}) of the stator winding and the impedance of the other capacitances (Z_{other}) are calculated for the subharmonic frequency 12.5 Hz. The p.u. value for the stator winding inductance is calculated using the highest reactance, which means, the synchronous reactance X_d=2.44.

$$\underline{Z}_{ind}^{pu} = \frac{j\cdot X_d(50Hz)}{\frac{50Hz}{12.5Hz}} = \frac{j\cdot 2.44}{4} = j\cdot 0.61$$

$$\underline{Z}_{cap}^{pu} = \frac{-j\cdot\frac{1}{C_{gnd}\cdot w}}{Z_{base}} = \frac{-j\cdot\frac{1}{0.385\cdot 10^{-6}\cdot 2\pi\cdot 12.5}}{0.5188} = -j\cdot 63745$$

$$R_n^{pu} = \frac{R_n}{Z_{base}} = \frac{1212}{0.5188} = 2336$$

$$\underline{Z}_{other}^{pu} = \frac{-j\cdot\frac{1}{3\cdot(C_{bus}+C_{surge}+C_{trafo})\cdot w}}{Z_{base}} = \frac{-j\cdot\frac{1}{3\cdot(0.1+0.25+0.2)\cdot 10^{-6}\cdot 2\pi\cdot 12.5}}{0.5188} = -j\cdot 14873$$

As one can see, the stator winding inductance can be neglected in front the stator winding capacitance, grounding resistor and other capacitances since its impedance is extremely lower. From this point onwards the stator winding inductances will not be considered any more.

Before presenting the simplified equivalent scheme, there is another simplification one can apply to the equivalent circuit. Initially, the 50 Hz AC sources will be removed from the equivalent diagram since the main goal of this first equivalent is explaining the principle of operation of the subharmonic injection method and this can be done easily without considering the 50 Hz power generation of the synchronous machine. In further sections, the 50 Hz generation will be included.

3.3.2 Simplified equivalent scheme

Applying the presented simplifications on the figure 6 and putting together all the capacitances, one has the simplified equivalent scheme of the subharmonic injection method and the unit-connected generator.

In order to represent the ground fault in the scheme, a resistor is placed in parallel with the total capacitance and there is a switch that permits to simulate the stator ground fault scenario.

Figure 7 shows the simplified equivalent scheme.

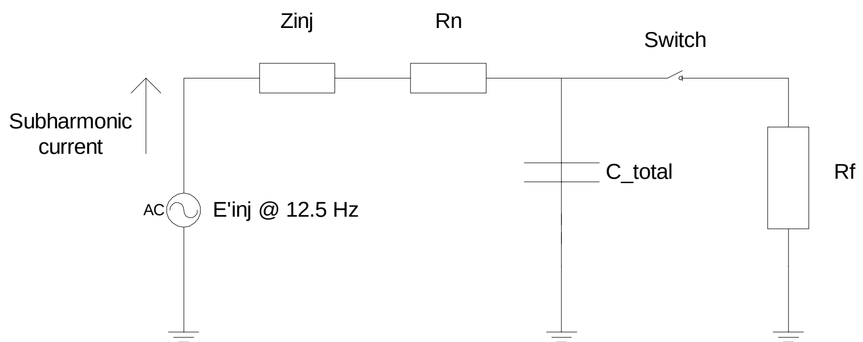

Figure 7. Simplified equivalent scheme

$C_{total}= C_{gnd} + 3\cdot(C_{bus}+C_{surge}+C_{trafo}) = 0.385\mu F + 3\cdot(0.1\ \mu F/phase + 0.25\ \mu F/phase + 0.2\ \mu F/phase) = 2.035\ \mu F$

As one can see, this scheme is very simple but at the same time is completely valid to perform the analysis of the subharmonic injection method.

Since there is no stator winding inductance and the stator winding capacitance has been added with the other capacitances, it is not possible to place the fault in any particular position of the stator winding. This fact will be discussed later when the effect of the 50 Hz power generation will be included.

3.3.3 Mathematical equations

In this section, the mathematical equations for the subharmonic current will be presented. First of all, the subharmonic current in a non-fault scenario is presented.

$$\underline{I} = \frac{\underline{E}'_{inj}}{\underline{Z}_{inj} + R_n + \underline{Z}_{C\,total}} \qquad [1]$$

As one knows the values of the injection circuit impedance, the grounding resistor and the total capacitance to ground, it is possible to calculate the non-fault current.

$$\underline{I}_{non\_fault} = \frac{56}{36 + j \cdot 0.331 \cdot 2\pi \cdot 12.5 + 1212 - j \cdot \frac{1}{2.035 \cdot 10^{-6} \cdot 2\pi \cdot 12.5}} = \mathbf{0.0088\ A\ |\ 78.67^{o}}$$

The magnitude of the non-fault current is very small since the impedance of the capacitances to ground is very large. The angle of the non-fault current is close 90 º due to the influence of this large capacitance.
This non-fault value for the subharmonic current will be very important from this point onwards so the reader should have it in mind.

When the ground fault occurs, the impedance that limits the subharmonic current changes. Consequently, the subharmonic current is divided in two currents: one that flows through the capacitor and the other one through the fault resistance. The equation [2] shows the total subharmonic current in a fault scenario.

$$\underline{I}_{fault} = \underline{I}_C + \underline{I}_{Rf} = \frac{\underline{E}'_{inj}}{\underline{Z}_{inj} + R_n + \underline{Z}_{C\,total} // R_f} = \frac{\underline{E}'_{inj}}{\underline{Z}_{inj} + R_n + \dfrac{\underline{Z}_{Ctotal} \cdot R_f}{\underline{Z}_{Ctotal} + R_f}} \qquad [2]$$

One can substitute the known values and apply some mathematics.

$$\underline{I}_{fault} = \frac{56}{36 + j\cdot 26 + 1212 + \dfrac{-j\cdot 6257\cdot R_f}{-j\cdot 6257 + R_f}} = \frac{56}{1248 + j\cdot 26 - \dfrac{j\cdot 6257\cdot R_f \cdot (R_f + j\cdot 6257)}{(R_f - j\cdot 6257)\cdot(R_f + j\cdot 6257)}} =$$

$$= \frac{56}{1248 + \dfrac{39150049\cdot R_f}{R_f^2 + 39150049} + j\cdot\left(26 - \dfrac{6257\cdot R_f^2}{R_f^2 + 39150049}\right)} \qquad [3]$$

The fault current depends on the fault resistance. It is not easy to imagine the curve that represents the fault current when varying the fault resistance. Therefore, MATLAB-SIMULINK software is employed in order to obtain and analyse the values of the subharmonic current.

3.4 Simulation 1: the simplified equivalent scheme

The Simulation 1 uses the simplified equivalent scheme of the figure 7 in order to study the behaviour of the subharmonic current in fault and non-fault conditions. All the elements of the circuit have a defined value except for the fault resistance (R_f). Thus, the main goal of this simulation will be checking how the 12.5 Hz current changes when the stator ground fault occurs and study the influence of the fault resistance R_f.

The model has been built using SIMULINK and it is exactly the same circuit as in figure 7. The simulation time is two seconds and the stator ground fault occurs at t = 1s. The solver used is “ode23s (stiff/ Mod. Rosenbrock)” and the relative tolerance is 1e-03. The simulation is performed with variable-step that the computer decides.
In Appendix A one can see the SIMULINK model.

3.4.1 Example with R_f=1000 Ω

First of all, let's take R_f= 1000 Ω and see what happens with the subharmonic current.

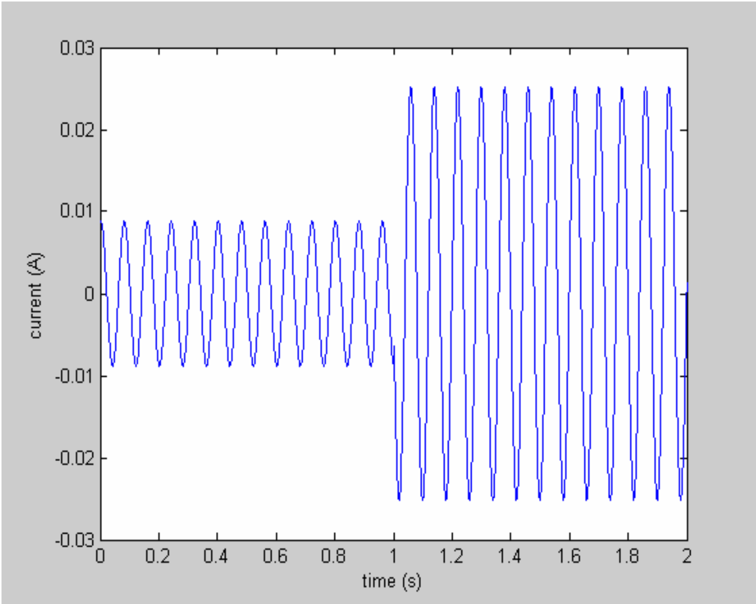

Figure 8. Subharmonic current when R=1000 Ω

The first thing one can see is that at t = 1s, the subharmonic current suddenly changes. During the first second, the current has a magnitude close to 9 mA but after t = 1s its magnitude increases until 25 mA approximately. One has realized that the current changes its magnitude when the stator ground fault occurs.

Moreover, if one looks carefully the curve of the current around t = 1 s, one will see that the angle of the current also changes when the stator ground fault occurs.

Thus, one concludes that the subharmonic current changes in terms of magnitude and phase when the stator ground fault occurs. Figures 9 and 10 show the magnitude and the angle of the current in order to quantify the change of the current. They have been obtained using phasor simulation in SIMULINK.

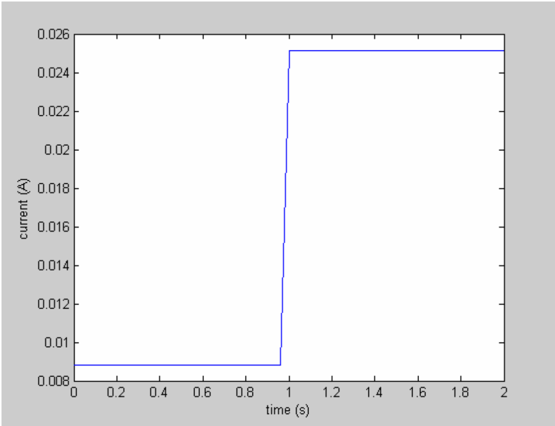

Figure 9. Magnitude of the current

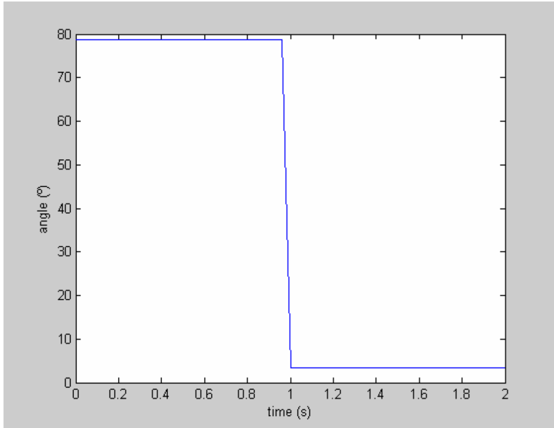

Figure 10. Angle of the current

First of all, one can see that the non-fault current has a magnitude of 8.8 mA and its angle is equal to 78.67º. These values are the same than the ones obtained using the equation of the non-fault current. When the ground fault occurs, the magnitude increases until 25.1 mA and the angle decreases until 3.34º.

Before extracting wrong conclusions, let's see what happens for other values of the fault resistance.

3.4.2 Varying the fault resistance R_f

The fault resistance will be varied firstly from 0 to 12 kΩ, with a 100Ω step. Both magnitude and the angle of the fault current will be checked per each fault resistance. Figure 11 shows the magnitude of the subharmonic current when varying the fault resistance.

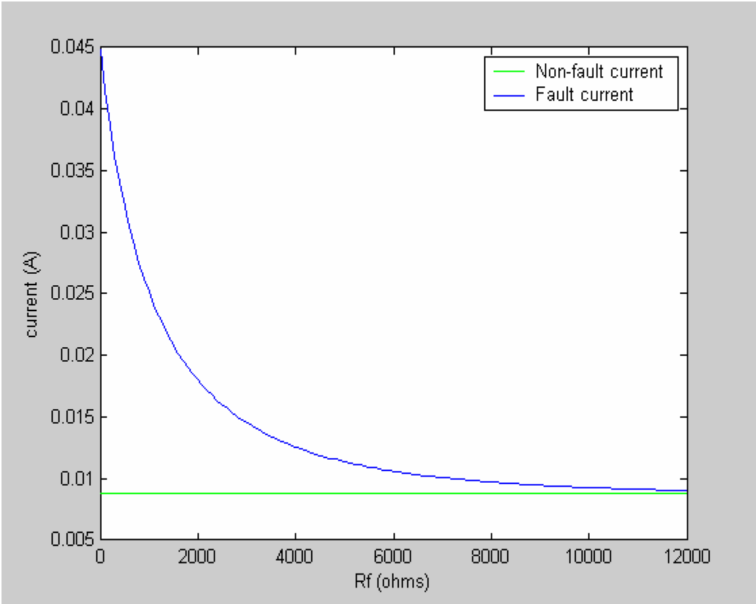

Figure 11. Magnitude of the subharmonic current VS. fault resistance

First of all, one can see that the magnitude of the fault current is always higher (from 0 to 12 kΩ) than the non-fault magnitude. One can also see that the fault magnitude decreases when the fault resistance increases. When R_f is bigger than 8 kΩ, the difference between the fault and the non-fault current magnitude is very small. For instance, the subharmonic current is 9.7 mA when R_f = 8 kΩ and this means the difference between the fault and non-fault magnitude is 0.9 mA.

Thus, one can make the following reflection: imagine a subharmonic injection scheme that pretends to detect the stator ground fault using change of the current magnitude when the fault occurs. The scheme would be able to detect stator ground faults when the fault resistance was not very high but the scheme could have problems to detect high-resistance faults due to the high sensitivity required. As it was said above, the difference between the fault and non-fault current when R_f = 8 kΩ is less than 1 mA and this is difficult to detect by relays.

Even relays were sensitive enough to detect this difference, if the fault resistance is increased more the curve of the magnitude current continues decreasing until it crosses the non-fault level of current.

The fault resistance that makes the fault current be equal to the non-fault current can be found using equation (3).

$$I_{fault} = 0.0088 \text{ A} \rightarrow R_f = 15.9 \text{ k}\Omega$$

For higher fault resistances than 15.9 kΩ, the fault current magnitude is lower than the non-fault current.

Therefore, one must look for another method that will be able to detect high-resistance faults. Figure 12 shows the behaviour of the angle of the current when varying the fault resistance from 0 to 12 kΩ.

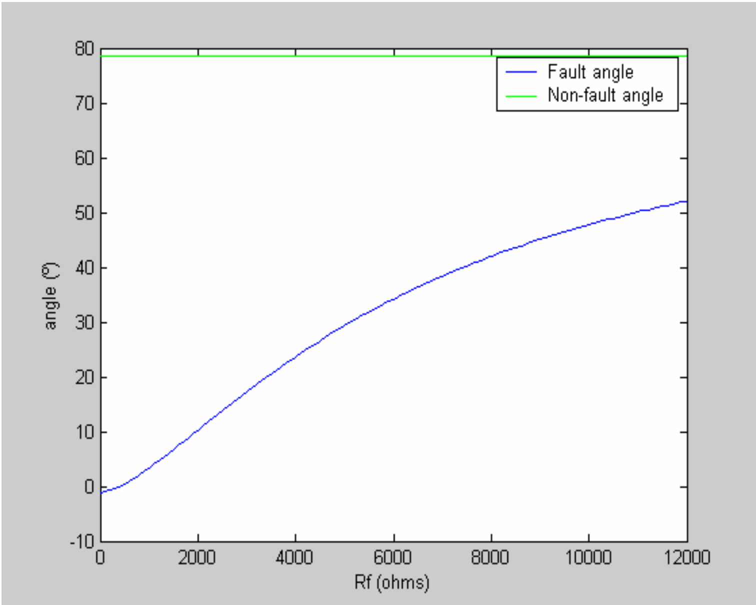

Figure 12. Angle of the subharmonic current VS. fault resistance

As one can see, the angle of the subharmonic fault current is always lower than the non-fault current one. One can also see that the angle of the fault current increases when the fault resistance increases. The angle of the fault current when R_f = 12 kΩ is 52.07º and this means that the difference between the fault and the non-fault angle is 78.67-52.07 = 26.6º. This angle difference can be perfectly detected by a signal processing unit and this means that checking the angle of the subharmonic current provides more sensitivity than checking the magnitude.

Since the fault of 12 kΩ can be easily detected, let's run the simulation with higher fault resistances. The angle of the fault current is shown in table 2.

Table 2. Angles of the subharmonic current per different fault resistances

Fault resistance (Ω)	Angle (º)
≈ 0	-1.1933
2000	10.254
4000	23.642
6000	34.192
8000	41.99
10000	47.746
12000	52.074
14000	55.408
16000	58.036
18000	60.151
20000	61.886
22000	63.332
24000	64.554
26000	65.598
28000	66.502
30000	67.29

As one can see, in case the fault resistance was 30 kΩ the angle of the subharmonic current would be 67.29º which means that the difference with the non-fault current would be 11.38º. This value could also be detected without any problems by the protection scheme.

To conclude, the subharmonic protection scheme can detect stator ground faults measuring the change of the current resulting from the subharmonic injected voltage.
On one hand, if the scheme focuses on the magnitude change, stator ground faults can be detected until certain resistance fault. For high-resistance faults, the difference between the non-fault and the fault magnitude of the current is not big enough, therefore it becomes a problem in terms of sensitivity of the scheme.
On the other hand, if the scheme focuses on the change of angle of the current, stator ground faults can be detected even though the fault resistance is very high. Simulations have shown that fault resistances of 30 kΩ could be detected.

The subharmonic injection scheme can use several criterias to decide whether the generator must be tripped off or not. All of them are based on the mentioned change of

the magnitude and angle of the subharmonic current. In section 3.6, these criterias will be discussed.
In the following section, the effect of the 50 Hz power generation will be included in the subharmonic protection scheme. The measuring circuit will be also described.

3.5 Simulation 2: equivalent scheme with the 50 Hz power generation

In this section, the 50 Hz power generation is included in the model of the subharmonic injection scheme. As it was said in section 3.1.2, the 50 Hz generation could be modelled by one AC source per phase but a modification will be introduced as it will be explained in section 3.5.1. The rms value of the voltage generated in each phase will be the nominal voltage of the generator divided by square root of 3 and the angle will be 0, -120º and 120º for phases A, B and C respectively.
Once more, the inductance of the stator winding can be neglected due to the same reason explained in 3.3.1.

When considering the effect of the 50 Hz generation, the measured current will not have only the 12.5 Hz but also it will contain the 50 Hz. Therefore, the equations for the current will not be calculated and the whole study will be based on the data obtained in the simulation in MATLAB SIMULINK.

3.5.1 The model

As it was said above, a modification can be done when modelling the 50 Hz power generation. In the faulted phase, instead of having just one AC 50 Hz source one can introduce two sources whose amplitudes are $\alpha \cdot U_n/\sqrt{3}$ and $(1- \alpha) \cdot U_n/\sqrt{3}$. The fault resistance R_f is placed between these two sources. Moreover, the capacitance to ground of the stator winding is divided in two capacitors: one placed at the neutral whose value is $\alpha \cdot C_{stator}$ and the other is placed with the rest of capacitances to ground and its value is $(1-\alpha) \cdot C_{stator}$. The aim of splitting the stator ground capacitance and the power generation in the faulted phase is modelling the fault location as follows:

- $\alpha=1$ means that the fault is placed at the terminals of the generator since all the capacitance of the stator winding comes before the fault resistance.

- α=0 means that the fault is placed at the neutral since all the capacitance of the stator winding is placed after the fault resistance.

Figure 13 shows the subharmonic protection scheme with the 50 Hz power generation.

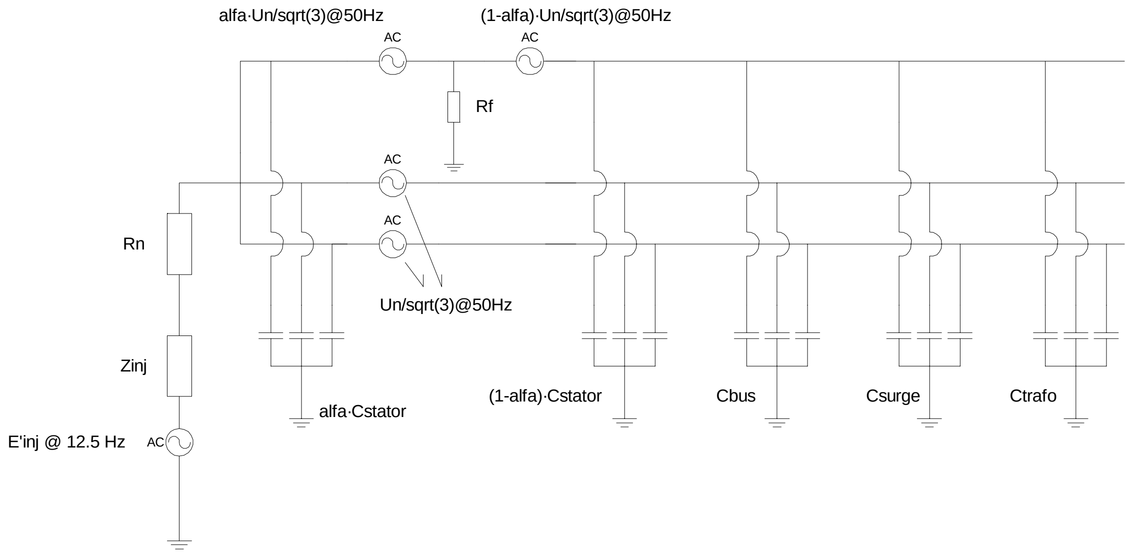

Figure 13. Subharmonic protection scheme with the 50 Hz power generation

In Appendix B, the model built with SIMULINK is shown. It has some extra resistors that don't appear in figure 13 due to SIMULINK requirements.

The simulation time is 0.8 seconds and the stator ground fault occurs at t = 0.4s. The solver used is "ode23t (mod. stiff /Trapezoidal)" and the relative tolerance is 1e-10. The simulation is performed with variable-step decided by the computer.

3.5.2 Example with R_f = 1000 Ω and α = 1

First of all, an example with the fault resistance equal to 1000Ω and the fault placed at the terminals will be studied. The injected current is shown in figure 14.

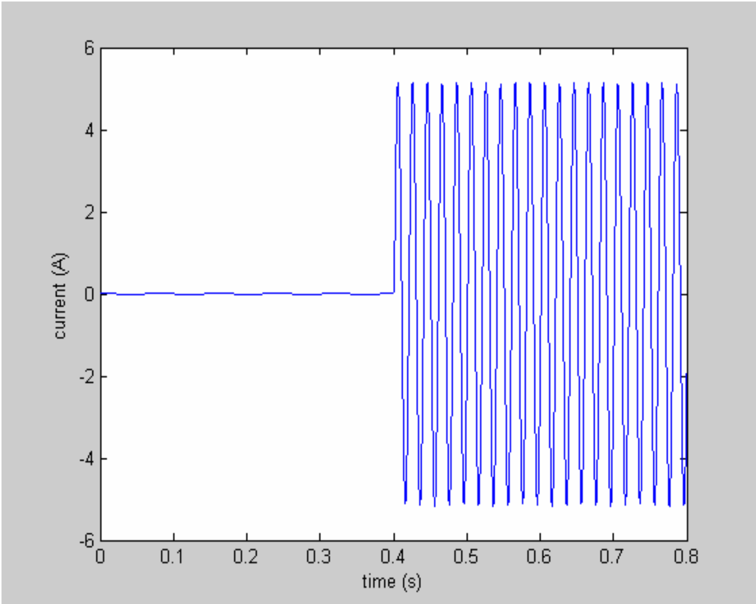

Figure 14. Injected current per R_f = 1000 Ω and α =1

Once again, one can perfectly see that there are to well-differentiated parts in the current curve. In the first 0.4 seconds, the current has a small magnitude but in the second 0.4 seconds, after the ground fault occurs, the current magnitude increases a lot. Moreover, the frequencies of the fault and non-fault currents are different. The non-fault part is a 12.5 Hz sinusoid while the fault part is a 50 Hz curve. Let's zoom in the two parts.

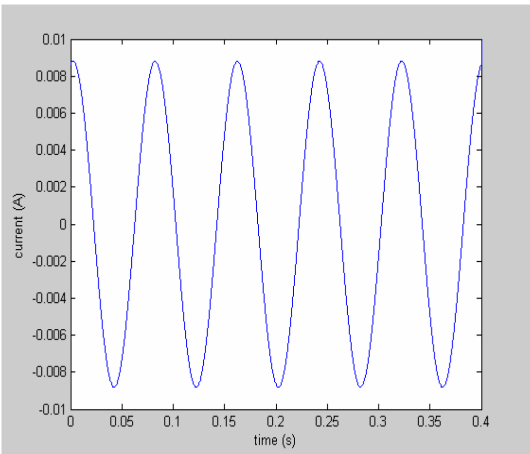

Figure 15. Non-fault current

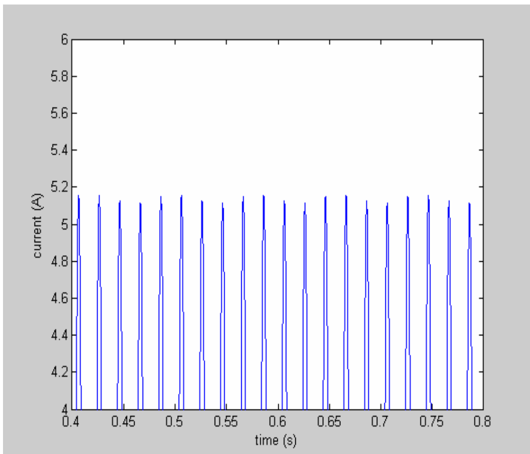

Figure 16. Upper part of the fault current

In figure 15, one can now see the 12.5 Hz sine wave. Once again, the amplitude of the non-fault subharmonic current is 8.8 mA.

In figure 16, one can see that the curve is not exactly a sine wave. The peaks of the curve have different height and they are equal one to each other every four peaks. Thus, in the fault part, the 50 Hz current due to the power generation is mixed with the 12.5 Hz current resulting from the injected subharmonic voltage. Therefore, the amplitude of this part of the current is very high due to the influence of the 50 Hz generated current.

Thus, there is the need to extract the 50 Hz effect from the injected current in order to measure the 12.5 Hz current and compare it with the non-fault subharmonic current. In other words, one needs to filter the measured current in order to get just 12.5 Hz frequency.

At this point, it is necessary to talk about the measuring circuit that was excluded of the equivalent scheme.

3.5.3 Measuring circuit

The measuring circuit is placed at the secondary of the injection transformer. The current that flows through it is taken by a current transformer. As it was said above, this current must be filtered in order to get the 12.5 Hz frequency. Once the current is filtered, it must be measured and compared to a reference value in order to send the tripping signal if it is necessary. In the next section, the way of filtering will be discussed.

3.5.4 Filtering

The function of the filter is permitting to pass the 12.5 Hz frequency and attenuating (or reducing) not only the 50 Hz frequency but also other harmonics. One might know that the windings of the generator create harmonics of the 50 Hz frequency during its normal operation. There are several ways to do this filtering but this work will not go deeply through them.

There are a great amount of low-pass filters that could be used. Some of them use just resistors, capacitors and reactors and others use other filter technologies. One can find as well digital filters that convert the analogue signal to a digital signal, then an algorithm process it and it is converted again to analogue.

In this work, a digital filter that uses Fourier analysis is proposed. The idea would be that a signal processing unit has as input the current resulting from the injected voltage. This unit converts from analogue to digital the magnitude of the current of each fixed step time. Then, these values are filtered using a sine and cosines filter. After this filter, one knows which are the magnitude and the angle of the 12.5 Hz current and the signal processing unit compares them with the reference values and send a signal to trip off the generator if it is necessary. Figure 17 shows an overview of the filtering process.

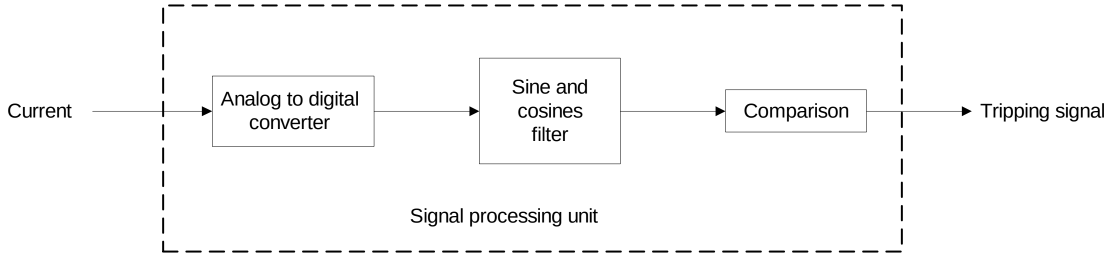

Figure 17. Overview of the filtering process

3.5.4.1 Sine and cosines filter

One can apply Fourier analysis in order to get the magnitude and the phase of the 12.5 Hz current. The following equations will show the principle of operation of sine and cosines filters. The mathematics presented refers to continuous signals but in section 3.5.4.2 discrete analysis will be done.

Imagine that the input current of the sine and cosines filter is:

$$f(t) = \sin(4wt) + \sin(wt + \varphi) \qquad [4]$$

where w is the subharmonic angular frequency w=2π·12.5 [rad/s] and φ is the phase of the 12.5 Hz current. Thus, the function *f(t)* is the sum of the 12.5 Hz and 50 Hz current.

One can easily find the Fourier coefficients of the Fourier series

$$f(t) = a_0 + \sum_{1}^{N} a_n \cdot \sin(n \cdot wt) + \sum_{1}^{N} b_n \cdot \cos(n \cdot wt) = \sin(4wt) + \sin(wt) \cdot \cos\varphi + \cos(wt) \cdot \sin\varphi$$

[5]

$$a_1 = cos\varphi$$

$$b_1 = sin\varphi$$

$$a_4 = 1$$

Thus, one can find the magnitude and the phase of the first harmonic (in this case f=12.5 Hz) with the following expressions:

$$magnitude = \sqrt{(a_1^2 + b_1^2)}$$

$$phase = \tan^{-1}\left(\frac{b_1}{a_1}\right)$$

[6] and [7]

And the coefficients a_1 and b_1 can be calculated using the Fourier expressions for the coefficients:

$$a_1 = \frac{2}{T}\int_0^T f(t)\cdot\sin(wt)$$

$$b_1 = \frac{2}{T}\int_0^T f(t)\cdot\cos(wt)$$

[8] and [9]

where T is the period of the subharmonic current T=1/12.5 =0.08 s.

Thanks to the Fourier analysis, the magnitude and the phase of the 12.5 Hz are known after the sine and cosines filter.

There is a problem usually common in this type of filters. One needs to know all the values of a T period before knowing the magnitude and the phase. This means that the filter output (magnitude and phase) is delayed 0.08 s approximately.

There is another issue to comment about this way of filtering. One must consider that synchronous machines could have small variations in the frequency of the power generation. For instance, the frequency of the generator could be in the range from 47 Hz to 53 Hz for a brief period of time. In equation [5], Fourier coefficients would be different if the frequency of the power generation varied. Thus, one must find a solution to avoid that the subharmonic injection scheme is affected by the variations of the 50 Hz frequency.

The following section discusses how this filter is applied to the Simulation 2.

3.5.4.2 Filtering in Simulation 2

In Simulation 2, the way of filtering is closer to the reality since one uses the data of the vector *current* instead of having a continuous signal. The principle of operation is the same described above but Fourier analysis must be performed in a discrete domain.

First of all, let's talk for while about data one gets from MATLAB SIMULINK. Once the simulation is run, one obtains the vector *current*. As it was said, this vector contains the a lot of data taken every X time but one doesn't know X since the simulations are run with variable step (the computer decides the step time).
Therefore, the first thing to do is obtain the vector *fixstepvect* which is a vector that contains the magnitudes of the current for a known step time. This vector would be the one obtained after the analogue to digital converter.

In Simulation 2, *fixstepvect* has 70001 data with a step time of 0.8 s/70000 data, which is 7000 data per each 12.5 Hz cycle. The vector *fixstepvect* is obtained interpolating the vector *current* per each step time from 0 to 0.8 seconds.

Thus, the Fourier analysis must be applied but in discrete way. This means that the coefficients a_1 and b_1 can be found as follows:

$$a_1 = \frac{2}{N}\sum_{1}^{N} fixstepvect(n)\cdot\sin(w\cdot(n-1)\cdot\frac{0.08}{N}) = \cos\varphi$$
$$b_1 = \frac{2}{N}\sum_{1}^{N} fixstepvect(n)\cdot\cos(w\cdot(n-1)\cdot\frac{0.08}{N}) = \sin\varphi \qquad \text{[10] and [11]}$$

where w is the subharmonic angular frequency and N is the number of data per each 12.5 Hz cycle. According to the number of data per simulation, N was chosen arbitrarily N=7000. Thus, the magnitude and the phase can be found using the equations [6] and [7].

As it was said above, the signal processing unit must be wait the first 7000 data (one 12.5 Hz period) to have the first magnitude and phase output. Then, when the analogue to digital converter has a new data (*fixstepvect*(7001)), the same must be done to calculate the Fourier coefficients but now the sum must be from n=2 to n=7001.

In this way, each new data permits to recalculate the magnitude and the phase of the current. In Appendix C, the algorithm used in MATLAB to do the filtering in Simulation 2 is presented. If the reader checks this algorithm, he/she might realize that the calculation of the magnitude and phase of the current is done each 10 data instead of each one data. The reason is that the simulations were faster and the evolution of the magnitude and the phase can perfectly be seen.

3.5.5 Results of the simulation 2

3.5.5.1 Example R=1000 Ω and α=1

Figures 17 and 18 show the magnitude and the phase of the injected current after it has been filtered in the sine and cosines filter.

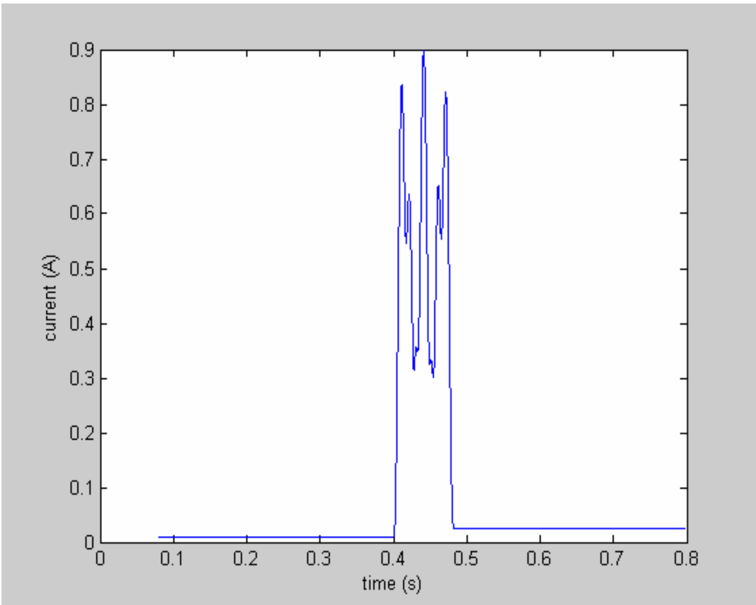

Figure 17. Magnitude of the filtered current

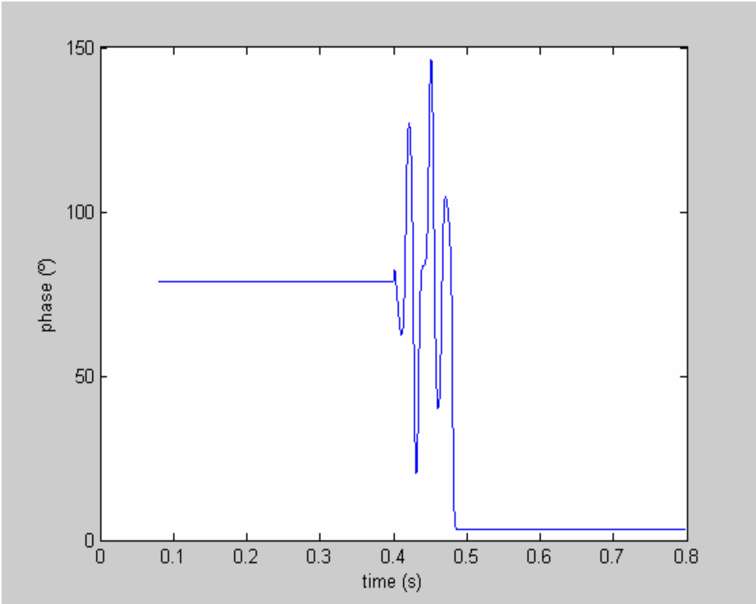

Figure 18. Phase of the filtered current

There are several things to comment about these two figures:

1.- In both figures, lines are plot from t = 0.08 s. As it was mentioned above, the first filtered magnitude and phase can be obtained after one 12.5 Hz period, which is 0.08 s.

2.- When the ground fault occurs, the filter has a non-stable period where both magnitude and phase take strange values. This period lasts a little bit more than 0.08s (from 0.08 to 0.085 s) which is more or less a 12.5 Hz period. Thus, the signal processing unit must wait before having the real fault magnitude and the real fault phase.

3.- The filtered magnitude and phase have both in non-fault and fault conditions the same values than in simulation 1, which means, the filter works properly and has totally eliminated the 50 Hz effect. Thus, the non-fault current is 0.0088 A | 78.76º and the fault current is 0.0251 A | 3.34º.

3.5.5.2 Varying R_f and α

Table 3 shows the magnitude and the phase of the filtered fault current obtained from the simulations. The fault is placed at the terminals (α =1), at the neutral (α =0) and in the middle (α =0.5) of the stator winding. The fault resistance R_f takes the following values: 1000, 3000, 5000, 8000, 20000 and 30000 Ω.

Table 3. Magnitude and phase of the filtered current

R_f (Ω)		α =1 (terminals)	α =0.5 (middle)	α =0 (neutral)
1000	I_f	0.0251 A	0.0251 A	0.0251 A
	φ_f	3.34º	3.34º	3.34º
3000	I_f	0.0145 A	0.0145 A	0.0145 A
	φ_f	17.23º	17.23º	17.23º
5000	I_f	0.0114 A	0.0114 A	0.0114 A
	φ_f	29.30º	29.30º	29.30º
8000	I_f	0.0097 A	0.0097 A	0.0097 A
	φ_f	41.99º	41.99º	41.99º
20000	I_f	0.0087 A	0.0087 A	0.0087 A
	φ_f	61.89º	61.89º	61.89º
30000	I_f	0.0086 A	0.0086 A	0.0086 A
	φ_f	67.29º	67.29º	67.29º

As one can see, the values for each fault resistance are the same for any alfa. Since the 50 Hz AC sources don't have internal impedance and the stator winding inductances have been neglected, all the capacitors are connected in parallel which means that splitting the stator winding capacitance had no sense. In any case, this shows that the subharmonic injection scheme can protect all the stator winding because the fault position does not affect.

Moreover, all the values for each fault resistance are exactly the same than in Simulation 1 and once again this means that the sine and cosines filter works properly.

Once the behaviour of the subharmonic injection scheme has been explained, it is time to discuss different criterias to trip the generator.

3.6 Different criteria to trip the generator

Within the subharmonic injection method, there are several criterias one can use to decide whether trip or not the generator when the stator ground fault occurs. In the following paragraphs, different criterias will be discussed based on the magnitude and phase change when the fault occurs. The implementation of them will not be explained here but the working principle will be discussed.

3.6.1 Criteria based on the magnitude of the current

As one have seen in Simulation 1, the magnitude of the 12.5 Hz current increases when the stator ground fault occurs as long as the fault resistance is lower than 15.9 kΩ. Concretely, its value depends on the fault resistance being the magnitude of the fault current lower when the fault resistance increases.

As it was shown above, the sensitivity of this criteria can be critical when the fault resistance takes high values since the difference between the non-fault and the fault magnitudes is very small (i.e. R_f = 8000 Ω → difference = 0.9 mA)

If one considers that the minimum acceptable difference between the non-fault and the fault magnitude is 1 mA, the maximum R_f that would be protected is R_f = 7700 Ω (I=9.8 mA).

Therefore, if one wants to apply this criteria, it is necessary to set the value I_{set}. If the magnitude of the 12.5 Hz current is higher than I_{set}, the stator ground fault has occurred and the generator should be tripped off.

Mathematically, the generator should be tripped off if:

$$|\mathbf{I}|>\mathbf{I_{set}}$$

As it was said above, this is just the principle of this criteria. Actually, Pope (1984) proposes that the 12.5 Hz can be encoded to provide security against misoperation and the scheme doesn't act when the magnitude of the current exceeds I_{set} for the first time but it waits some cycles to make sure that a stator ground fault has occurred.

3.6.2 Criteria based on the angle of the current

As it was shown above, the phase of the 12.5 Hz injected current also varies when a stator ground fault occurs. In a non-fault scenario, the 12.5 Hz current has a phase close to 90º (78.67º) due to the capacitance to ground of the stator winding, the bus, the step-up transformer and the surge between the circuit breaker and the transformer.

When the fault occurs, the phase of the injected current decreases to a value that depends on the fault resistance. Then, one can set a phase value φ_{set} and the generator should be tripped of when the phase becomes lower than this φ_{set}. Mathematically, the protection system should act when:

$$|\varphi| < \varphi_{set}$$

This criteria has more sensitivity since the difference between the phase of the non-fault current and phase of the fault one is considerable even though the fault resistance is high. For instance, if the fault resistance was 30 kΩ, the phase of the injected current would be 67.29º, which means that the difference between the non-fault and the fault phase would be more than 10º.

3.6.3 Criteria based on the mutation principle

As discussed in Daqiang et al. (2001), the change of the phase of the injected current due to stator ground faults can also be detected using the mutation principle. In normal state, the angle of the current keeps constantly close to 90º (78.67º) and its variance rate is almost zero. When the stator ground fault occurs, it results in a great variance.

Therefore, the generator should be tripped off when

$$|\Delta\varphi| = |\varphi(n) - \varphi(n-1)| > \Delta\varphi_{set}$$

where $\varphi(n)$ and $\varphi(n-1)$ are the phases in two continuous calculation periods and $\Delta\varphi_{set}$ is the maximum variance allowed (usually set to a small value like 5º).

Comparing the angles of two different measures, one can not only obtain high sensitivity but also insulation deterioration can be detected. Insulation deterioration can be monitored by gradual variance of the phase.

3.6.4 Criteria based on the real part of the admittance

If one knows the magnitude and the phase of the current and the injected voltage, one can calculate the admittance of the circuit as follows:

$$\underline{Y} = \frac{\underline{I}}{\underline{V}}$$

Table 4 shows the real part of the admittance depending on the fault resistance and shows also the non-fault admittance.

Table 4. Admittance vs. fault resistance

Fault resistance (Ω)	Admittance (Ω^{-1})
≈ 0	0.8009
2000	0.3162
4000	0.2053
6000	0.1564
8000	0.1289
10000	0.1113
12000	0.0991
14000	0.0901
16000	0.0832
18000	0.0777
20000	0.0733
22000	0.0696
24000	0.0665
26000	0.0639
28000	0.0616
30000	0.0597
Non-fault	0.00003

As one can see, the real part of the admittance is almost zero when the generator is working properly. When the ground fault occurs, the real part of the admittance grows considerably.

Thus, a reference value Y_{set} could be set and if the admittance is higher than this value the generator should be tripped off. Mathematically, the generator is tripped off if:

$$\mathbf{Y_{real}>Y_{set}}$$

3.6.5 Δ-Current relays

As described in Tai et al. (2000), this criteria calculates the increment of the fault component of the current that flows through the fault resistance. When the generator is running under normal conditions, the increment of this current ΔI_{fR} is zero since there is not current flowing through any fault resistance. When a stator ground fault occurs, then the fault component appears and therefore there is an increment ΔI_{fR}. Then, the generator should be tripped off when:

$$|\Delta \mathbf{I_{fR}}|>\varepsilon$$

where ε is set to a small value in order to have enough sensitivity (in the paper, it is said that ε =0,15 is a good value to reach the 8 kΩ).

3.7 Settings for the protection scheme

Once the different criterias have been presented, it is time to set the values for the protection scheme. These values will be introduced into the signal processing unit. In this section, just two of the five criterias will be discussed: the criteria based on the angle of the current and the one based on the real part of the admittance. The magnitude criteria and the Δ-Current criteria will not be dealt due to the fact that they can not protect high-resistance faults. Furthermore, the mutation principle criteria will also not be discussed in order not to go into further detail in the explanation of the monitoring process.

3.7.1 Setting the values for the angle criteria

As it was shown it table 2, the fault phase of the current is 67.29º when R_f = 30 kΩ and lower when the fault resistance is lower. Considering that the non-fault phase is 78.67º and that the maximum fault resistance to protect is R_f = 30 kΩ, thus the φ_{set} could be 70º.

Then, the subharmonic protection unit should send the tripping off signal when

$$|\varphi|<70^{\circ}$$

Moreover, the signal processing unit should be programmed in order to avoid a false trip due to the transient values when the ground fault occurs (see figure 18). The waiting time should be about 0.085 s. If one adds the waiting time to the time of operation of the relay in charge to trip the generator (0.03 s), the subharmonic injection scheme can trip off the generator 0.105 seconds after the ground fault has occurred. This time can be considered quite fast.

3.7.2 Setting the values for the real admittance criteria

As one has seen in section 3.6, the admittance seen by the subharmonic injected current changes considerably when the ground fault occurs. When the generator is working under normal conditions, the admittance is almost zero and it increases when the ground fault occurs. The admittance depends on the fault resistance: the higher the fault resistance, the lower the admittance.

Thus, if one wants to protect until R_f = 30 kΩ (Y_{real} = 0.0597 Ω), Y_{set} could be set at 0.0500 Ω^{-1}.

Then, the subharmonic protection unit should send the tripping off signal when

$$|Y_{real}|>0.0500\ \Omega^{-1}$$

Once more, the signal processing unit should be programmed in order to avoid a false trip due to the transient values when the ground fault occurs. The admittance is calculated using the magnitude and the phase of the current and both have transient values when the ground fault occurs. Therefore, the waiting time should be again about

0.085 s and thus, the subharmonic injection scheme can trip off the generator 0.105 seconds after the ground fault has occurred.

3.8 Other schemes

The subharmonic injection scheme discussed in this work is one of the simplest (but perfectly valid) currently being used nowadays. There are several versions of this scheme that add some modifications in order to improve certain aspects. Two of them will be mentioned.

3.8.1 Compensated injection scheme

As described in Xiangjun et al. (2002), this scheme can be applied to generators grounded through a distribution transformer. A reactor L is connected in parallel with the loaded resistance at the secondary of the distribution transformer in order to eliminate the influence of generator windings' capacitance to ground. This scheme can detect ground faults using the magnitude criteria with fault resistance higher than 8000 Ω. Figure 19 shows the injection scheme of this method.

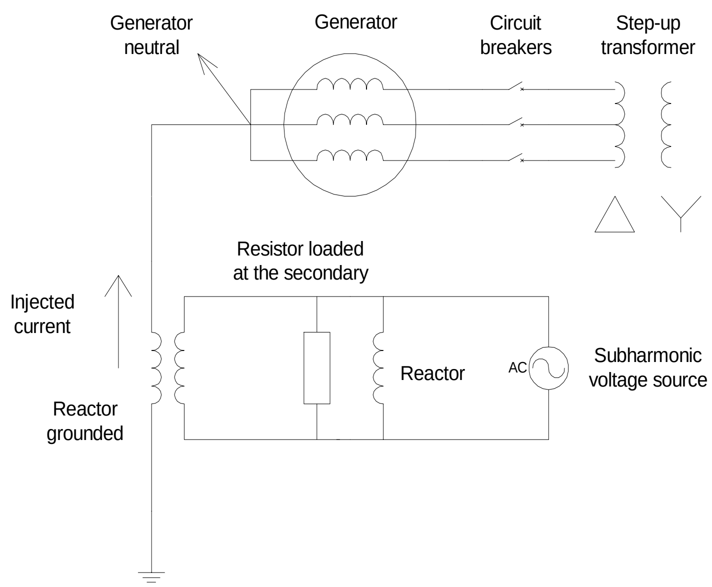

Figure 19. Compensated injection scheme

3.8.2 Subharmonic injection scheme based on the equilibrium principle

As described in Wu, Wan and Lu (2002), this method is also applied to generators grounded through a distribution transformer with loaded resistance at the secondary. This scheme is very similar to the one described above but the difference is that instead of adding a reactor in parallel with the grounding resistor, there is an impedance. The arm with this impedance is called the balanced arm. The aim of this method is setting the impedance to a certain value in order to have the same current flowing through the balance arm than through the rest (I_1=I_2) before the protection scheme is connected to the generator. Then, the scheme is connected to the generator and these currents are a little bit different due to the capacitance to ground of the generator stator winding.
When the ground fault occurs, the difference between these currents increases much more and thus, the stator ground fault can be detected. Figure 20 shows this scheme.

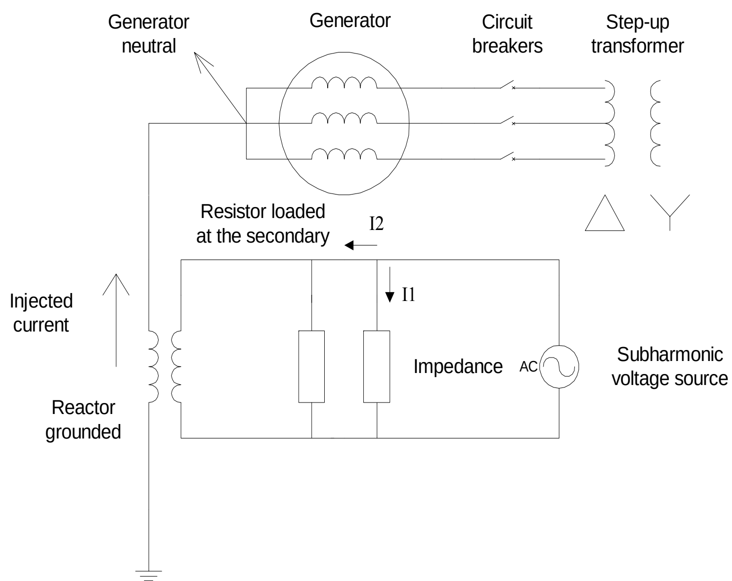

Figure 20. Subharmonic scheme based on the equilibrium principle

3.9 Discussion

In this chapter, the subharmonic injection scheme has been presented as a method to provide 100% coverage of the stator winding against stator ground faults.

Its principle of operation is based on measuring the change of the subharmonic current resulting from the subharmonic injected voltage when the stator ground fault occurs. This change is produced both in the magnitude and the phase of the current.

The configuration of the injection scheme depends on the type of grounding of the generator. Moreover, there are several types of schemes depending on the elements that they have, i.e. filters, added reactors, balanced arms, etc.

Different criteria can be applied in order to compare the subharmonic current with a reference. It has been shown that the magnitude criteria can have problems in terms of sensitivity of the scheme when the fault resistance is high. Criteria that directly or indirectly use the phase of the subharmonic current provide more sensitivity even though the fault resistance takes high values. For instance, the criteria based on the angle of the current and the one based on the real part of the admittance can detect faults until 30 kΩ.

Moreover, if one monitors the angle of the current, one can detect the deterioration of the insulation in the stator winding. This can be done with the criteria based on the mutation principle.

As discussed in Ilar et al. (1979), the injection voltage is an independent quantity which can be derived from the machine voltage or from the station battery. Thus, the subharmonic protection scheme can detect stator ground faults when the generator is running, when it is on standstill and on turning gear. Since this 100% protection scheme is operable before start-up, it is possible to detect a fault before it actually causes any damage.

To conclude, the subharmonic injection method can provide 100% stator ground fault protection for unit-connected generators.

3.10 Further work on subharmonic injection scheme

Although the analysis presented of the subharmonic injection method has been done accurately, one can go into further detail in some issues. The following paragraphs sum up the further work that could be done.

- The models used in the simulations are very simple. More complex models, i.e. finite elements models could be developed in order to have results closer to the reality. Moreover, the simplifications performed to obtain the equivalent schemes could differ a little bit from the reality. For instance, the injection transformer has been modelled as an impedance and this could make the results differ from the reality.
Thus, improving the model could become further work.

- The filtering of the current and the comparison with the reference value have been explained from a theoretical point of view. The implementation of the signal processing unit in charge of these operations would be another issue to develop in future studies.
It is also necessary to think about the way the variations of the 50 Hz frequency will be taken into account in order to have a protection scheme that can work in the range of frequencies from 47 to 53 Hz.

- In this chapter, the response of the injection scheme in different operation conditions has not been dealt with. Ilar et al. (1979) concludes that the behaviour of the subharmonic injection scheme is independent of the operation conditions. This could be corroborated in further studies.

- After all these studies will be carried out, the final issue to do is testing the method in a real generator in order to adjust certain parameters and look for certain details that had not been taken into account.

3.11 References

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Chapter 4: Third harmonic voltage method

This chapter studies the third harmonic voltage method used to protect the stator winding of unit-connected generators against stator ground faults. The chapter starts with the principle of operation and the explanation of the different conventional protection schemes using the third harmonic voltage. Afterwards two models are built in order to simulate them with MATLAB SIMULINK. The analysis of the obtained results permits to know the strengths and weaknesses of this method. At the same time, this analysis permits to suggest some setting values for the protection scheme.

4.1 Principle of operation

The third harmonic method takes advantage of the harmonic voltages produced by all the generators. The output voltage of one generator is not a perfect sinusoidal wave, has harmonics voltages in it, it means, all the generators produce harmonic voltages. In all these group of harmonics we can find ones called triplen harmonics 3^{rd}, 9^{th}, 15^{th}, and so on. They appear in each phase and have the same magnitude and phase. The same phase make that they do not sum to zero. They therefore appear in the neutral terminal of the generator as a zero-sequence quantity. The third harmonic voltage is usually the largest one of all these harmonic voltages.

The operation theory of this principle is based on measuring the third harmonic voltage in the neutral, in the terminal, or in both of them, to protect the generator. This voltage is measured between these points and ground.
The third harmonic voltages produced by the generator are present in the two ends of the stator winding in all the generators but are different depending of the design and the loading of the machine.

Before talking about the different ways to protect using the third harmonic voltage and their principles of operation, it is interesting to see the characteristics of the third harmonic voltage. Figure 21 shows the theoretical third harmonic voltages distribution a long the stator winding in normal operations. The figure also shows the variation of the third harmonic voltage with load. At some point within the stator winding we will find the null point, where the third harmonic voltage is equal to zero.

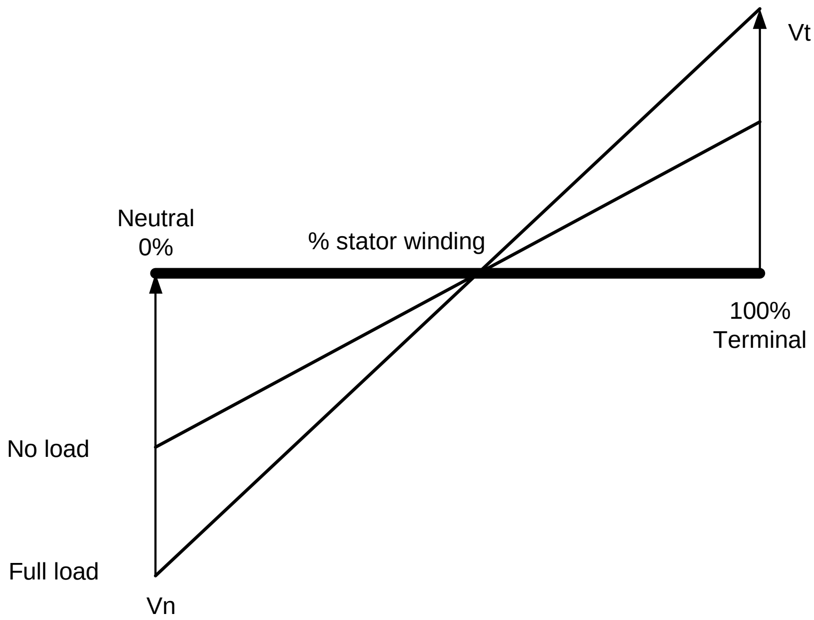

Figure 21. Third-harmonic voltages under normal operations

When a ground fault occurs near the generator neutral, the third harmonic voltage at the neutral decrease to zero, while the third harmonic voltage at the generator terminal increases to equal the total third harmonic voltage produced by the generator as we can see in figure 22.

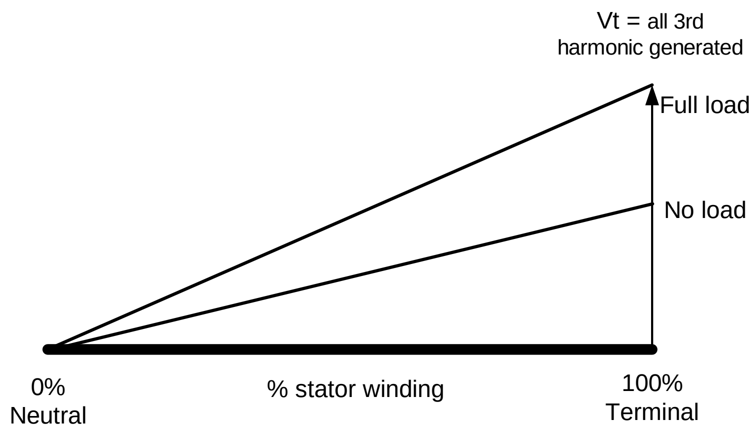

Figure 22. Third-harmonic voltages under fault conditions at the neutral

The opposite occurs for a ground fault at the generator terminals. Here the terminal third harmonic voltage decrease to zero, while the neutral third harmonic voltage increase to the total third harmonic voltage produced by the generator. That is shown in figure 23.

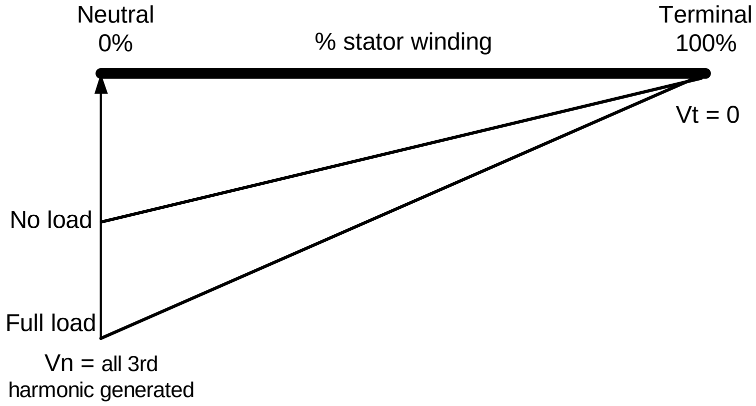

Figure 23. Third-harmonic voltages under fault conditions at the terminal

We have just seen what happens when the fault occurs at the neutral or at the terminal, but the third harmonic voltage is also function of where in the stator winding the fault occurs. If we have a fault close to the neutral, the third harmonic voltage at the neutral will decrease and will increase at the terminal. The decrement or increment will depend on where the fault occurs. The opposite situation occurs when the fault is close to the terminal.

As discussed in Schlake et al (1981), the third harmonic voltage is hard depending on the excitation level, the load and power factor.

Now that we know the behaviour of the third harmonic voltage in the different conditions, we will describe a typical unit connected system and after the different protection schemes and their principles of operation, depending on where we measure the third harmonic voltage. In following sections, the equivalent scheme for the third harmonic voltage with the unit-connected generator will also be presented.

4.1.1 Typical scheme for a unit-connected generator

As mentioned in the introduction, the generators studied in this work are unit-connected generators. This means that a step-up transformer will be connected in between the terminals of the generator and the electrical network. Moreover, a circuit breaker is placed in between the generator and the step-up transformer in order to isolate the generator from external faults.

The generator used to be grounded by a grounding transformer with a load resistor. Normally the potential transformer neutral is directly grounded. We can see in figure 24 one relay in parallel with the load resistor. It is a standard overvoltage relay for the fundamental frequency, and with a appropiate setting use to protect the upper 90% to 95% of the stator winding as explained at the beginning of the chapter.
The lower 10% of the winding (neutral), should be protected by a third harmonic relay. Then the next step should be explaining the different protection schemes using the third harmonic voltage produced by the generator.

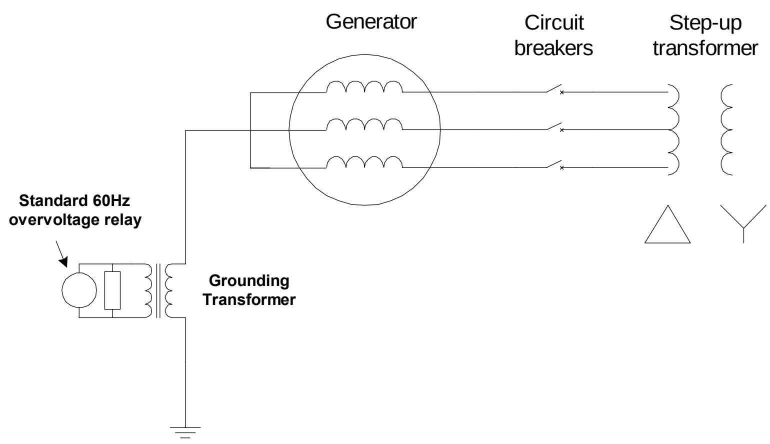

Figure 24. Typical unit connected generator

4.1.2 Three main protection schemes for a unit-connected generator using the third harmonic voltage

Now is time to introduce the different protection schemes depending where we measure the third harmonic voltage. We can measure it at the neutral, at the terminal, or in both.

4.1.2.1 Third harmonic undervoltage scheme

In this method we will measure the third harmonic voltage at the neutral. As we can see in figure 25, there is a 27H undervoltage relay turned to detect third harmonic voltage (150 Hz) and a 59GN overvoltage relay turned to the fundamental frequency (50 Hz).

As is said in Pope (1984), the overlapping overvoltage/undervoltage scheme provides 100% protection for generator stator ground faults by using two measuring functions that cover different portions of the machine winding.

Also as explained in Reimert (2005) that it may be difficult to get the setting. The relay 27H relay must be set sufficiently low to avoid dropout during periods of normal operation when third harmonic voltage is at a minimum. At the same time, the setting must be high enough to detect all the faults not seen by 59GN relay with the generated third-harmonic voltages at a maximum.

Probably, it is not possible to put together the above conditions if the third harmonic voltage produced by the generator is minimal under certain operating conditions. As is stated also in Reimert (2005), overvoltage relays may be required to supervise the 27H relay during start-up and shutdown. If the machine does not generate enough third harmonic voltage at light load, an overcurrent supervision may be required. A blocking relay may also be required to prevent operation of the 27H relay when the excitation is removed from the generator.

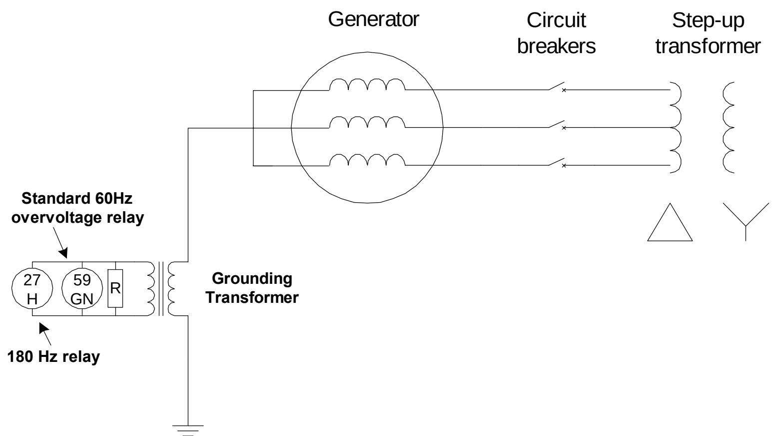

Figure 25. Third harmonic undervoltage scheme

4.1.2.2 Third harmonic overvoltage scheme

In this scheme, the third harmonic voltage is measured at the terminal of the generator. This time we will detect a fault close to the neutral because the third harmonic voltage at the terminal increases.

The third harmonic overvoltage scheme use the same principles used in the undervoltage scheme. As is described in Reimert (2005), the 59T overvoltage relay is tuned to the third harmonic voltage and operates on the third harmonic voltage rise at the generator terminals associated with a ground fault near the generator neutral. The criteria for setting the 59T relay is the opposite from the setting described for the third harmonic undervoltage relay. The 59T must be set above the maximum third harmonic voltage during normal operations and below the minimum voltage for a fault in the 59GN blind spot.

In Reimert (2005), it is also said that the third harmonic undervoltage scheme is generally preferred over the overvoltage scheme because it will detect shorted and open circuits on the primary and secondary winding of the grounding transformer. In both schemes will not detect an open grounding resistor, but the 59GN relay will operate if a ground fault develops with the resistor open.
Figure 26, shows the explained.

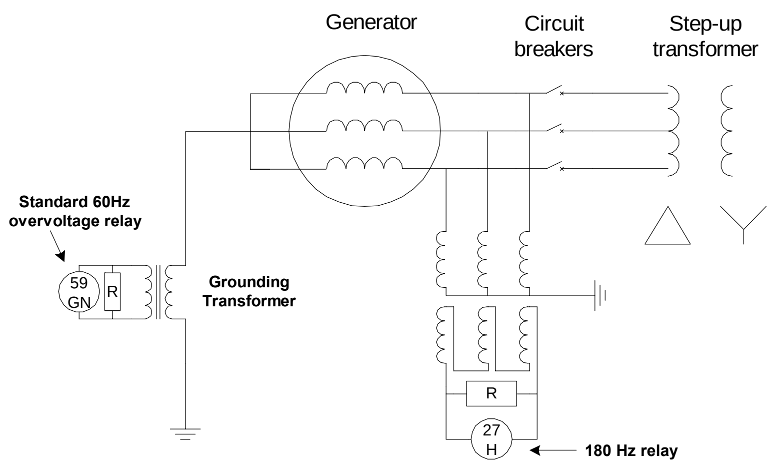

Figure 26. Third harmonic overvoltage scheme

4.1.2.3 Third harmonic ratio voltage scheme

Now the third harmonic voltage will be measured at both sides, at the neutral and at the terminals of the generator. In this case the impedances of the zero-sequence circuit theoretically fixes a ratio between the third harmonic voltage at the terminal and the third harmonic voltage at the neutral during normal operation.

This ratio will be modified when a ground fault occurs, except near the null point, where will not be detected. The voltage ratio scheme is shown in the Figure 27, and uses this change in the ratio to detect ground faults at the neutral and at the terminal end of the stator winding. As is said in Reimert (2005), the balance scheme again requires inclusion of a 50 Hz 59GN overvoltage relay to provide fault detection near the null point in the winding. Also explains, when we apply the third harmonic undervoltage and overvoltage schemes are often complicated because the wide variations of the third harmonic voltage at different modes of operation or by the insufficient third harmonic voltage at light load. This last scheme tries to avoid these problems being not sensitive to the variations in third harmonic voltage produced by the generator.

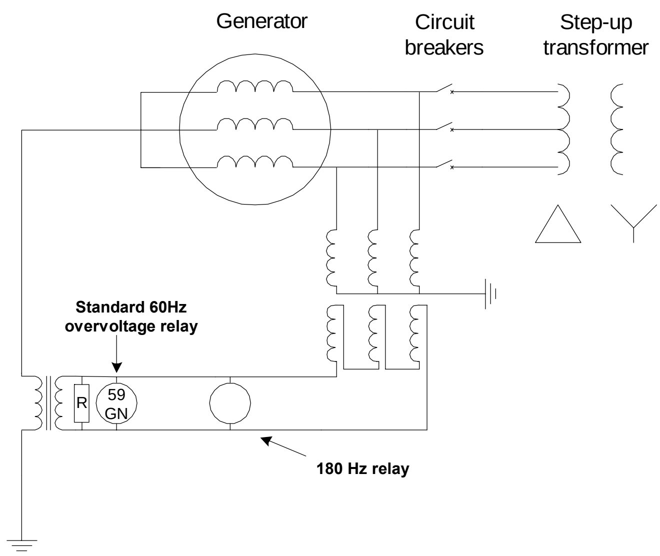

Figure 27. Third harmonic ratio scheme

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4.1.3 Equivalent scheme of the unit-connected generator for third harmonic voltages

In figure 24, we could see the diagram. Now is time to get an equivalent scheme of the unit-connected generator considering the third harmonic voltage produced by the generator. At this point, it is necessary make some assumptions in order to obtain a simple model to work with.

The generator will be modelled as follows to represent the third harmonic voltage:

- One reactance per phase whose value is X_d or X_d' or X_d'' which are the synchronous, transient and subtransient reactance respectively.
- The stator winding capacitance to ground will be modelled as one capacitor per phase placed after the reactance. This is just a provisional way of modelling this capacitance to ground since afterwards it will be done in another way.
- The third harmonic voltage per phase is represented as E_3, which is the result of a third harmonic produced in the stator windings. They will be equal in magnitude and phase in each of the three phases. It will be represented as the winding of the generator.

In the same way as in chapter 3, the bus that connects the generator with the step-up transformer, the surge between the circuit breaker and the step-up transformer can be modelled just taking into account their capacitances to ground. Thus, three capacitors per phase will be placed to model these elements.

Finally, the grounding transformer will be represented as one equivalent resistor R_N in the generator neutral. Figure 28 shows all the above simplifying assumptions.

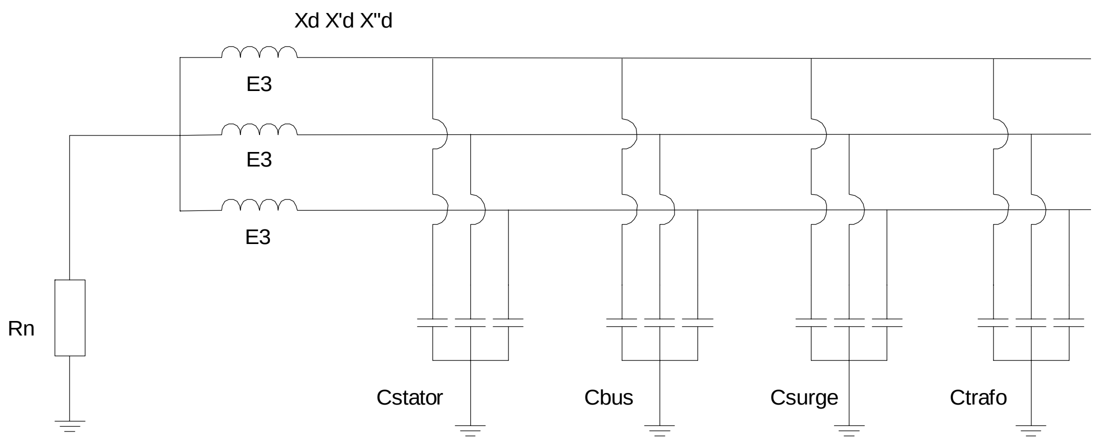

Figure 28. Equivalent of the unit-connected generator for third harmonic voltages

Now we got a first sketch of the equivalent circuit, the following step is selecting the values and characteristics for a typical unit-connected generator and its third harmonic voltages. This along with a simplified scheme that will be presented in the section 4.3, will allow us to start the simulations.

4.2 Typical values for a unit-connected generator and for third harmonic voltages.

4.2.1 Typical values for a unit-connected generator

The following table shows values and characteristics of the unit-connected generator used in the calculations and simulations of this chapter. The values are the same as the values used for the injection method.

Table 5. Typical values for a unit-connected generator

Rated power	850 MVA
Rated rotational speed	3000 rpm
Rated frequency	50 Hz
Rotor type	Round rotor
Nominal voltage (U_n)	21 kV
Synchronous reactance (X_d)	2.44 p.u.
Transient reactance (X_d')	0.43 p.u.
Subtransient reactance (X_d'')	0.25
Zero sequence inductance (X_0)	0.13
Negative sequence inductance (X_2)	0.24
Zero sequence resistance (R_0)	0.0025
Positive sequence resistance (R_1)	0.0034
Negative sequence resistance (R_2)	0.04
Capacitance to ground of the stator winding	0.385 µF
Power factor	0.882
Grounding resistor (R_n)	Rated 10 A 21/√3 → R_n=1212 Ω
Bus capacitance (per phase)	0.1 µF/phase
Surge capacitor between step-up transformer and circuit breakers capacitance (per phase)	0.25 µF/phase
Step-up transformer capacitance (per phase)	0.2 µF/phase

4.2.2 Typical values for third harmonic voltages.

As is mentioned earlier, the third harmonic voltage produced by one generator is function of the design of the machine and the values can change a lot from machine to machine. The strategy to get the best third harmonic voltages values for the simulations will be following the data from the different papers are used as a references.

Reimert (2005) explains that the minimum third harmonic voltage produced by the protected generator should be about 1% through all the levels and operation modes. This is necessary to differentiate between normal and fault conditions. It is also mentioned that most of the machines will produce a third harmonic voltage between 1 and 10% of the phase-to-neutral voltage.

It is attached in the Appendix D, a figure where it is represented the different amount of third harmonic voltage in function of the load conditions.

The following situation will be analysed:

- Third harmonic voltage under no-load conditions
- Third harmonic voltage under full load conditions, which will be the maximum third harmonic voltage produced by the generator.
- Third harmonic voltage under light load conditions, which will be the minimum third harmonic voltage produced by the generator.

So the third harmonic voltages E_3 that we suppose to study the protection of ours schemes are in the following table 6.

Table 6. Third harmonic voltage values

	E_3 (V)	% Phase-to-neutral fundamental voltage	% E_3 no-load
No-load	210	1.73	100
Full load	420	3.46	200
Light load	121	1	57

From this moment, the values of the table 6 will be assumed as our third harmonics voltages produced by the generator.

The following section presents more simplifying assumptions, just to find an easier way to model how the third harmonic works and use that model for our simulations.

4.3 Simplified equivalent scheme for third harmonic voltages

Now the goal is to find the simplest and best scheme to simulate the third harmonic behaviour. As we will see some extra assumptions will be done to represent when a fault occurs in the stator winding of the generator. According to that, we will get two different schemes, one under non-fault conditions and the others under fault conditions.

4.3.1 Simplifications and simplified scheme for non-fault conditions

The equivalent circuit developed for non fault conditions is based on the following simplifying assumptions:

- The third harmonic voltage is uniformly distributed along the surface of the armature and will be represented as AC voltage source. The magnitude of them will depend on the conditions we will be working (no load, full load, light load) as is explained in Section 4.2.2, but they will be in phase and their frequency is 150 Hz.
- The generator capacitance is distributed uniformly and constant along the stator winding and will be modelled with two capacitors grounded, half one before the AC source and the other half after it.
- The series inductance of the windings is neglected. In Appendix E, we can find the measurements made in ABB in Västerås (Sweden), where it is demonstrated that the inductance for a third harmonic model can be neglected.

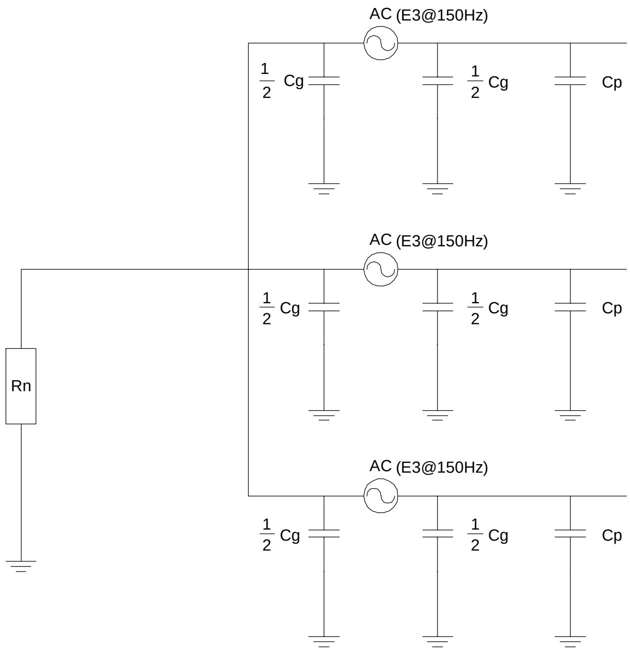

Figure 29. Equivalent scheme under non fault conditions

All these assumptions are reflected in figure 29, where:

E_3	is the third harmonic voltage generated
Cg	is the phase capacitance to ground of the generator stator winding
Cp	is the sum in parallel of the external capacitance of the system seen from the generator
Rn	is the ground resistor

4.3.1 Simplifications and simplified scheme for fault conditions

When we figure out the faulted scheme, we should make the same assumptions as before for the two non faulted phase and we should add the following assumptions for the faulted phase:

- The third harmonic produced by the generator in this phase is modelled as two AC sources, one between the neutral point and the fault place (E_{3n}) and the other between the fault place and the terminal of the generator (E_{3t}).

-The generator capacitance to ground is represented with two capacitors for each AC source, two before the fault place in each side of the AC source. And two capacitors after the fault placed in the same way.
-The AC sources and its capacitances are function of the distance from the neutral the fault occurs.

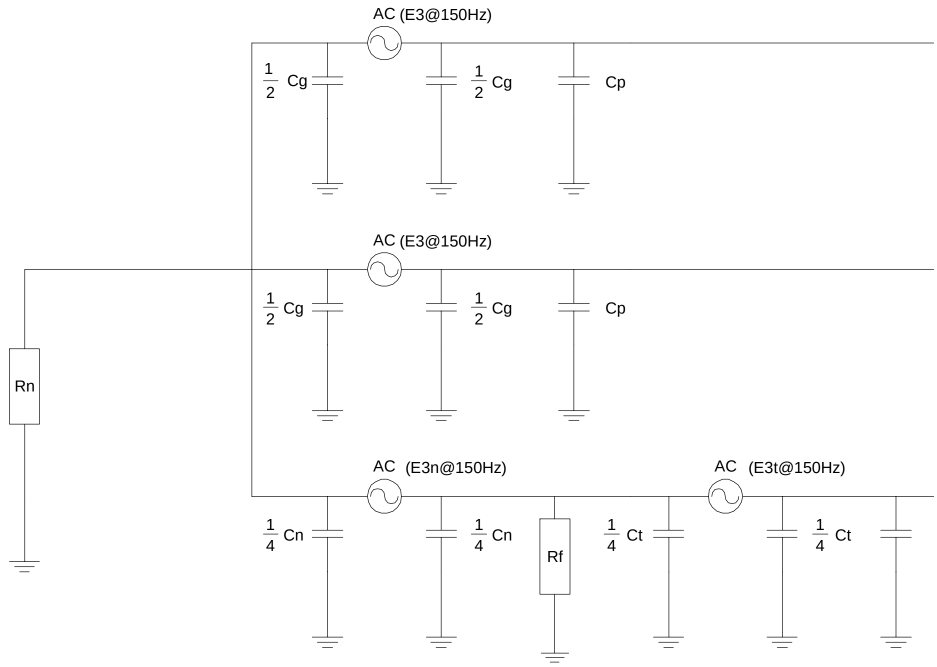

Figure 30. Equivalent scheme under faulted conditions

The equivalent circuit for the third harmonic voltage under faulted conditions is shown in figure 30, where:

E_{3n}, E_{3t}	are the third harmonic voltages produced by the stator winding between the generator neutral and the ground-fault location K, and between the generator terminal and the ground fault location K, respectively.
Cg	is the phase capacitance to ground of the generator stator winding
Cp	is the sum in parallel of the external phase capacitance of the system seen from the generator
Cn,Ct	are the phase capacitance to ground of the generator stator winding between the ground-fault location K and the generator neutral, and between the generator terminal and the ground-fault location K, respectively.
Rn	is the ground resistor

Finally, the parameters E_{3n} and E_{3t} in figure 30 are:

$$E_{3n} = K * E_3$$
$$E_{3t} = (1-K) * E_3$$
[1] and [2]

And also Ct and Cn are function of the location of the fault, and are:

$$C_n = K * C_{stator}$$
$$C_t = (1-K) * C_{stator}$$
[3] and [4]

where K is the distance of ground-fault location from the neutral point of the generator K= 0,..,1.

Once we have the values and the schemes, is time to have a look to the mathematical equations.

4.3.3 Mathematical equations

As is mentioned at the beginning of this chapter, the third harmonic voltage appears as zero-sequence quantities. Then the third harmonic voltage produced by the generator is distributed between the terminal and the neutral shunt impedances governing the zero-sequence. In figure 31 we can see this zero-sequence circuit, where Z_g is equivalent to the grounding resistor R_N and we got its value 1212 Ω from table 5. The neutral end capacitance (C_{0n}) is equal to half the stator winding capacitance to ground of the generator. The terminal shunt capacitance (C_{0t}) is equal to the other half the stator winding capacitance plus the sum in parallel of external capacitances.

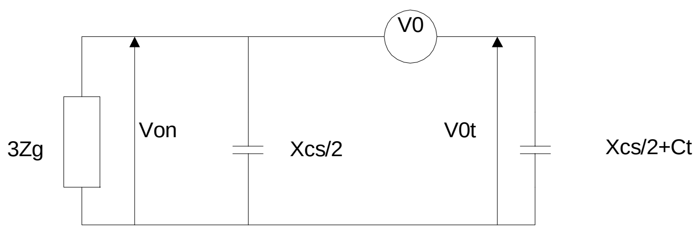

Figure 31. Zero-sequence circuit

From table 5 we can get the values and solve:

$$C_{0n} = \frac{1}{2} * C_{generator} = 0.5 * 0.128 * 10^{-6} = 0.642 * 10^{-7} F$$
$$C_{0t} = \frac{1}{2} * C_{generator} + C_{bus} + C_{CB} + C_{trafo} = 0.642 * 10^{-7} + 0.55 * 10^{-6} = 0.614 * 10^{-6} F$$

Now we can find the capacitive reactance, being:

$$X_{0n} = -j \frac{1}{2 * \pi * f_3 * C_{0n}} = -j16526\Omega$$
$$X_{0t} = -j \frac{1}{2 * \pi * f_3 * C_{0t}} = -j1728\Omega$$

where f_3 is the third harmonic frequency, in our case is equal to 150 Hz.

Then to solve the circuit, we should find the neutral end impedance. It will be a parallel combination of X_{0n} and $3 * R_N$:

$$Z_{0n} = \frac{-jX_{0n} * 3 * R_N}{3 * R_N - jX_{0n}} = \frac{-j16526 * 3636}{3636 - j16526} = 3469.18 - j763.48$$

When the third harmonic produced by the generator is 210 V (no-load conditions), the third harmonic voltage across the neutral will be:

$$V_{0n} = V_0 * \frac{Z_{0n}}{Z_{0n} - jX_{0t}} = 210 * \frac{3469.18 - j763.48}{(3469.18 - j763.48) - j1728} = 174.65\angle 23.27^{\circ} V$$

and at the terminal of the generator will be:

$$V_{0t} = V_0 * \frac{X_{0t}}{Z_{0n} - jX_{0t}} = 210 * \frac{-j1728}{(3469.18 - j763.48) - j1728} = 84.96\angle -54.32^{\circ} V$$

It could be interesting checking the third harmonic voltages at the neutral and at the terminal, when the generator is producing the maximum (full load) and the minimum (light load) third harmonic voltage. The way to calculate them is the same, just changing the value of V_0. The following table 7 shows the results.

Table 7. Third harmonic voltages

	V_0 (V)	V_{0n} (V)	V_{0t} (V)
Full load	420	349.30	169.92
Light load	121	100.63	48.95

If one calculates the ratios,

$$\frac{|V_{3n}|}{|V_{3n}|+|V_{3t}|}$$

$$\frac{|V_{3t}|}{|V_{3n}|}$$

one can realize that this ratio is equal for the three generator load conditions. Since this ratio just depends on the distribution of the capacitances along the stator winding, this ratios is equal to 0.67 (the first one) and to 0.48 (the second one) in the three load conditions.

From this moment onwards, it will be assumed that the ratio does not depend on the load. However, as it is reported in Yin et al. (1990) and in Marttila (1986), in some generators this ratio is also quite constant and in other generators the ratios varies substantially. Thus, the simulations will be performed under our ideal situation where the ratio keeps constant all the time.

The levels of third harmonic at each end of the stator winding from table 7, are the third harmonic voltages that we should get when we simulate the non-fault scheme in the next section. Those results are important to have a reference to prove the simulations.

Next step is check what happens when a fault occurs. Figure 32 represents the faulted phase of the system. Now we split the stator winding capacitance in two capacitors, one in neutral side and the other one in the terminal side, just to get easier equations.

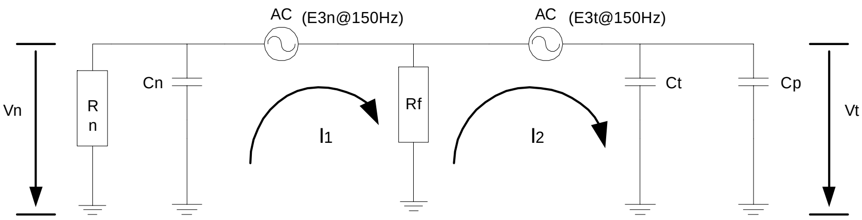

Figure 32. Faulted line equivalent scheme

When we analyze the faulted scheme of figure 32, we can get some equations to find which will be the third harmonic voltage at the neutral at the terminal. Actually, it is not exactly the same scheme that we figure out for faulted conditions, but they are completely equivalents. We use the scheme from the figure 32, just because is easier to get and understand the equations, which are the following :

$$V_n + E_{3n} = (I_1 - I_2) * R_F$$
$$(I_2 - I_1) * R_F + E_{3t} = V_t$$
[5] and [6]

where,

$$I_1 = -\frac{V_n}{Z_n}$$
$$Z_N = R_N // C_n$$
[7] and [8]

and combining those equations with the equations [1],[2],[3] and [4], finally we get:

$$V_n = K * E_3 * (1 - \frac{R_F}{Z_N}) = K * E_3 * (1 - \frac{R_F}{\frac{R_N * -j\frac{1}{2*\pi*f_3*K*C_{generator}}}{R_N - j\frac{1}{2*\pi*f_3*K*C_{generator}}}})$$ [9] and [10]

$$V_t = ((1-K)*E_3) - (V_n * \frac{R_F}{Z_N})$$

The data E_3 is the third harmonic voltage produced by the generator and f_3 is its frequency (150 Hz).

The third harmonic voltage when a fault occurs depends on the location of the fault (*K)* and on the fault resistor (R_F*)*. The following section we will use the software MATLAB-SIMULINK to make the simulations, where we will study the behaviour of the third harmonic voltage at the two ends of the stator winding in function of *K* and R_F.

4.4 Simulation

The software employed for the simulations was MATLAB-SIMULINK.

When we find the model for the simulations, we found the problem that we could not build just one scheme to simulate the non-fault and fault conditions, because when the fault occurs the distribution of the capacitance a long the stator winding should change in function of the fault location (distance from the neutral). Then we should figure out two different schemes, one for the non-fault condition and another for the fault condition.

First we will see the simulation for the non-fault condition and after the fault condition, where is simulated the three different methods (undervoltage, overvoltage and ratio voltage). Others protection schemes using the third harmonic voltage are proposed and they will be simulated too.

4.4.1 Simulation under non-fault conditions

In this simulation we use the simplified equivalent scheme of the figure 31 in order to study the behaviour of the third harmonic voltage non-fault conditions. The main goal is find how the third harmonic voltage is distributed between the neutral and terminal end of the stator winding.

The model has been built using SIMULINK and it is exactly the same circuit than in figure 31. We simulated for the different level of third harmonic voltages produced by the generator in function of it is working with no load, light load or full load.

The following table 8 shows the results from the simulations:

Table 8. Different levels of third harmonic voltage depending of the loading conditions

	E_3 (V)	V_n (V)	V_t (V)
Full load	420	349.18	179.80
Light load	121	100.60	48.92
No load	210	174.59	84.90

Those values will be our reference to check the behaviour of the third harmonic voltage when a ground fault occurs in all the later simulations. That is the main reason because we should prove if they are equal to the result got studying the zero-sequence.

If we remember the results that we got in the Section 4.3.3 and we compare them with the results gotten from the simulation, we realize that are almost the same. That is the evidence that the simulation was done in the right way.

Also is important remind that the ratio between the third harmonic voltage at the neutral and the third harmonic at the terminal and the ratio between the third harmonic voltage and the total third harmonic voltage, are equal for all the load conditions.

4.4.2 Simulation under fault conditions

In following simulations, we will use the fault scheme represented in figure 32 but some changes in the schemes are made just to implement the simulation in the SIMULINK to study how change the third harmonic voltage of the generator in function of the position of the fault and the value of the fault resistance.

The difference between the following simulations is where we will measure the third harmonic voltage (neutral, terminal or both) and we will use always the same scheme. The model used is included in the Appendix F with all the changes from figure 32.

4.4.2.1 Undervoltage protection method

We will study how change the third harmonic voltage in the neutral end of the generator in function of the position of the fault and the value of the fault resistance.

Also the third harmonic voltage is function of the load, so we will get different results depending of the loading conditions. This method is based in the fact that the third harmonic voltage at the neutral end of the generator decrease when a fault occurs near the neutral point. So our worst situation will be when the generator produces the minimum third harmonic voltage, it means, when it is working at light load. In our case, as is mentioned in section 4.2.2, the third harmonic produced under this condition is 121 V.

The simulation consisted in get the third harmonic voltage along all the stator winding (from 0% to 100%) and for the next values of fault resistors: 1Ω, 100Ω, 1kΩ, 3kΩ, 8kΩ, 15kΩ, 25kΩ, 1MΩ.

In the following figure 33, we will see the different voltages along all the stator winding for some of these fault resistors.

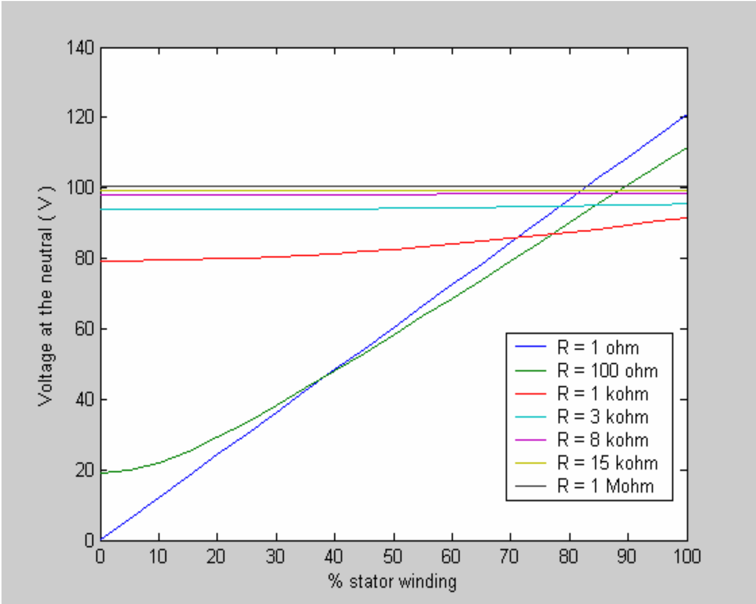

Figure 33. Third harmonic voltages at the neutral (light load)

When the fault resistor is really low we can see if the fault occurs in the neutral the voltage falls down almost until 0 V, but if it occurs at the terminal of the generator then all the third harmonic voltage produced by the generator is in the neutral 121 V. We can also point out that during low resistance fault the third harmonic voltage at the neutral depends almost linearly on the fault location.

We can find the null point, where the third harmonic voltage is equal to the third harmonic voltage under non-fault conditions, around the 83% of the stator winding from the neutral point.

Every time we increase the ground fault resistor the third harmonic voltage along the stator winding is getting more constant (every time is less dependent of the position of the fault) and closer to the non-fault voltage. It means, when we simulated the fault with a fault resistor equal to 1 MΩ, we should get more or less same the third harmonic voltage than in non-fault conditions. The value of the fault resistor is so high that we can think as the line is isolated from the ground.

The same two observations as above we can find when we simulate the generator working under full load or non-load conditions. The difference is that the generated third harmonic voltage and the non fault voltage are higher, but the curves have the same shape. We can see the graphs in the Appendix G.

4.4.2.2 Overvoltage protection method

We will study how change the third harmonic voltage at the terminal end of the generator changes as function of the position of the fault and the value of the fault resistance.

This method is based in the fact that the third harmonic voltage in the terminal end of the generator increase when a fault occurs near the neutral point. So we should check what happens when the generator produces the maximum third harmonic voltage. The maximum third harmonic assumed in the section 4.2.2 is 420 V when it is working full loaded.

The fault resistor values used are the same as in the section above. Figure 34 shows third harmonic voltage along all the stator winding for some of the fault resistors.

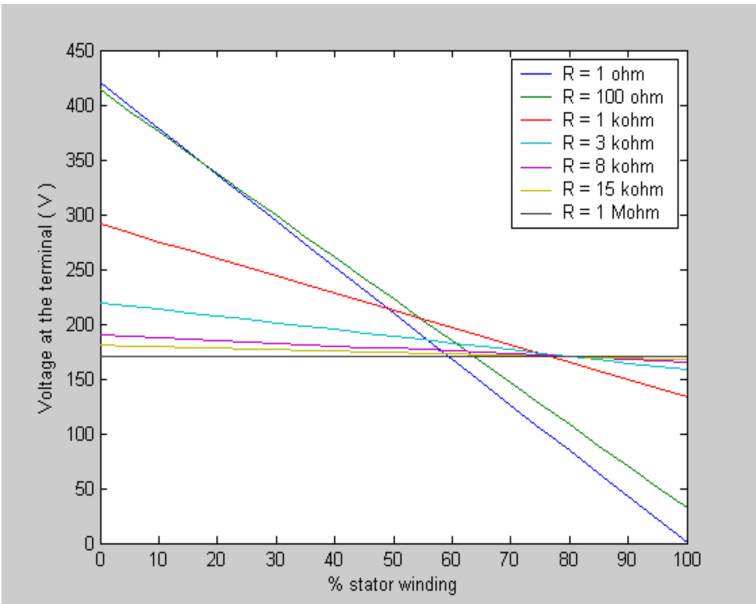

Figure 34. Third harmonic voltages at the terminal (full load)

Studying the overvoltage method we can realize that works in the opposite way than the undervoltage. When the fault resistor is really low, if the fault occurs at the terminal the voltage drop almost till 0 V, but if it occurs at the neutral of the generator then all the third harmonic voltage produced by the generator is at the terminal. Watching the figure 34, we can see that the third harmonic voltage at the terminal is linearly depending on the fault position for all the fault resistances, and the null point is moving futher from the neutral everytime that we increase the fault resistance.

We can find the null point of the third harmonic voltage around the 58% from the neutral point.

Everytime we increase the ground fault resistor the third harmonic voltage along the stator winding is getting more constant (every time is less dependent of the position of the fault) and closer to the non-fault voltage. When we simulate 1 MΩ fault resistor, the same situation and explanation as we explained studying the undervoltage method is valid.

The observations above are the same when we simulate the generator working under light loaded or non-loaded conditions. The difference is that the generated third harmonic voltage and the non fault voltage are lower. We can see the graphs in the Appendix G.

4.4.2.3 Ratio voltage protection method

This method uses the third harmonic measured at the neutral and at the terminal and compares them. Studying the undervoltage and the overvoltage, we have already seen the behaviour of the third harmonic at the two ends of the stator winding, so we just have to use the results gotten from the two simulations above.

We will simulate the ratio voltage protection scheme, where it uses the ratio between the third harmonic voltage at the terminal and at the neutral. Afterward we will simulate two more protection schemes, which relate in a different way the third harmonic voltages at the two ends of the stator winding.

The ratio voltage scheme is: $\frac{|V_{3t}|}{|V_{3n}|}$

When we calculate this ratio for the non-fault situation for all the load conditions, is always equal to 0.486. As we assumed in the section 4.3.3. the ratio is equal for all the load conditions because is just depending on the capacitance distribution of the generator. Thus, once we know our reference ratio, we look for the different ratios in function of the fault location and the value of the fault resistor. It is shown in figure 35.

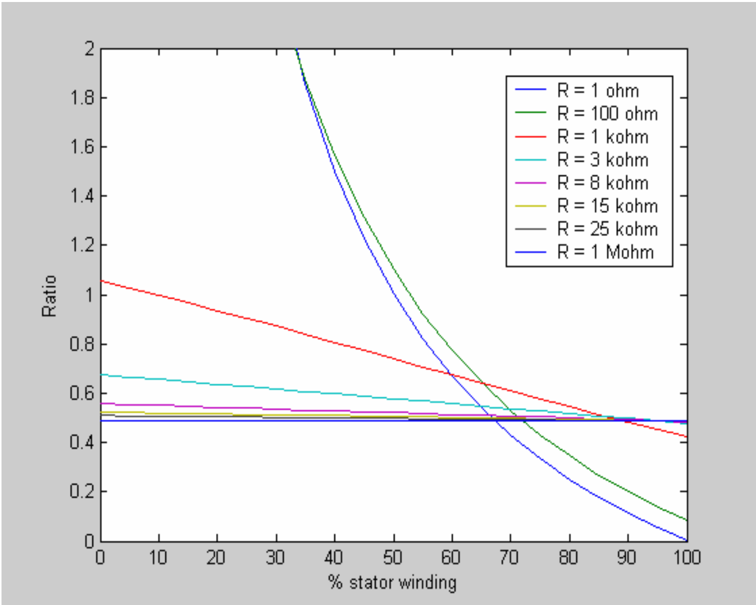

Figure 35. ($|V_{3t}|$ / $|V_{3n}|$) ratio

The figure above is when the generator is working light loaded, but we check the values of the ratio when the generator works in the other two conditions, we find exactly the same values (Appendix G) for the same reason as was explained above. It means, do not mind under which load conditions is working.

In the section 4.3.3 was already introduced that some papers reported different ratios for different load conditions during normal operation, where they get the maximum ratio under light load conditions and the minimum ratio under full load conditions. We will talk about how to set the setting values in this case in the section 4.5.

Once we studied the ratio between the two third harmonic voltages, we will simulate two different protection criteria more, trying to get a better sensitivity and coverage of the stator winding.

4.4.2.4 Others protection methods

The goal is try different relations between the two voltages (V_{3t} and V_{3n}) to find a better protection, it means, to protect as much as possible of the stator winding and also a higher fault resistance.

The first criteria (criteria 1) is: $$\frac{|V_{3n}|}{|V_{3n}|+|V_{3t}|}$$

Here the non-fault ratio is equal to 0.67, and is also equal for all load conditions, so is not function of the third harmonic generated by the generator. As the ratio scheme, that criteria is just depending on the capacitance distribution in the generator. Thus, when we simulate under fault conditions in function of the fault location and the fault resistance, we should get the same values for all the load conditions.

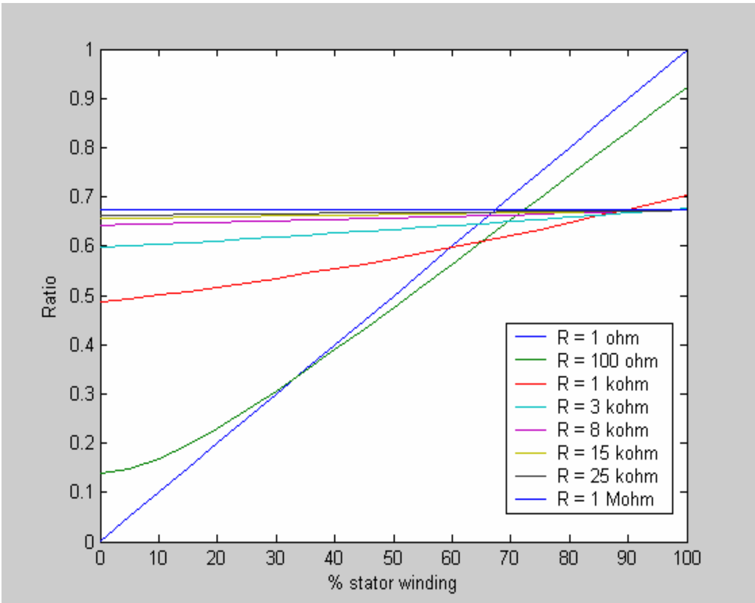

Figure 36. ($|V_{3n}|$ / $|V_{3n}|$+$|V_{3t}|$) ratio

The figure 36 is the ratio in function of the fault resistance and the location of the fault, under full load conditions. Simulating under light load and no load, we will get exactly the same values as we predicted (Appendix G).

In the section 4.3.3 was already introduced that some papers reported different ratios for different load conditions during normal operation, where they get the maximum ratio under light load conditions and the minimum ratio under full load conditions. We will talk about how to set the setting values in this case in the section 4.5.

The second criteria (criteria 2) tried is: $|\beta * V_{3t} - V_{3n}|$

Now we can see the new data β, and can be found its value using the following equation:

$$|\beta * 169.8 - 349.18| = |\beta * 48.92 - 100.6|$$

where the left side of the equation are the full load values and the right side are the light load values, which are the minimum and the maximum third harmonic voltages generated respectively. Then β will be equal to 2.06, which is the inverted value of the first ratio protection scheme studied before. Our reference value for this scheme 2 will be equal to 0.61 V.

In figure 37 is represented the ratio in function of the fault location and the fault resistor value, when the generator is working full loaded.

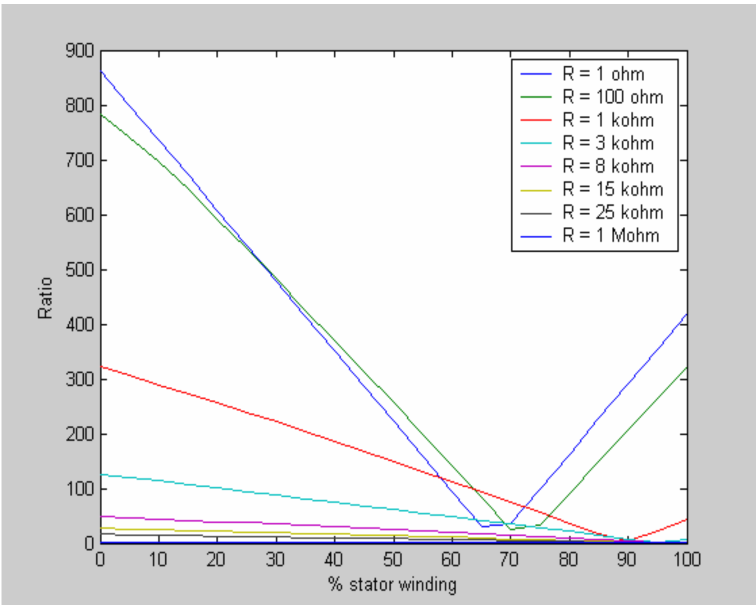

Figure 37. (| X * V_{3t} - V_{3n}|) ratio (full load)

Working with this ratio we can realize that will change depending on the load. The shape of the graphs are the same for different load conditions, but the values for non-load and light load conditions are lower than the full load values. As we said the reference value is equal to 0.61 and when a ground fault occurs close to the neutral, the ratio increase. So, our critical situation is when the generator is working light loaded and generates the minimum third harmonic voltage. Figure 38 shows that situation.

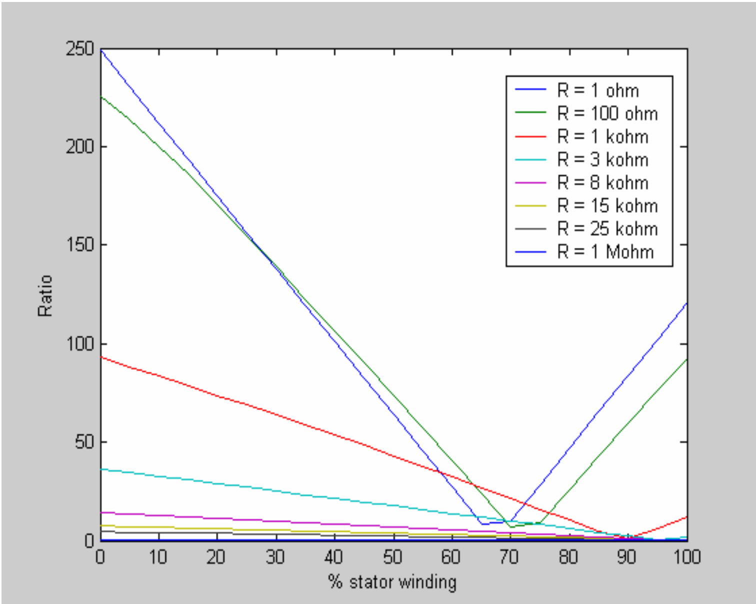

Figure 38. **($|X * V_{3t} - V_{3n}|$) ratio (light load)**

The next step will be set the setting values for all the protections schemes simulated above, where our main principle of setting will be guarantee that the relay never misoperates under all normal operating conditions of the generator. Knowing the behaviour of the third harmonic for each protection method, should be easy set those values.

Also in he following Section we will study the sensitivity and the distance from the neutral protected by each method, after set their setting values.

4.5 Setting the values for the protection scheme

4.5.1 Undervoltage protection method

The third harmonic voltage relay in this case, should be set above the third harmonic voltage when a ground fault occurs but also below the minimum third harmonic produced by the generator under non-fault conditions in order to avoid false operation.

Our minimum third harmonic voltage at the neutral is 100.6 V (light load). As is mentioned in Engelhart (1973), the third harmonic relay is adjustable to pick up range of 5 – 10 V. So, our undervoltage relay should be set between 90 – 95 V.

The critical situation for the sensitivity is when the generator is working full loaded and produces the maximum third harmonic voltage. We should study that critical situation.

As is explained in Yin et al (1990), is very useful and practical find the "maximum resistance", so called critical resistance, is used to describe the characteristic of the stator ground fault protection scheme. When this critical resistance is combined with the part of the winding covered by the protection scheme, one can further get a Protection Coverage-Critical Resistance (PCCR) curve. Figure 39 is the PCCR curve for the undervoltage protection scheme.

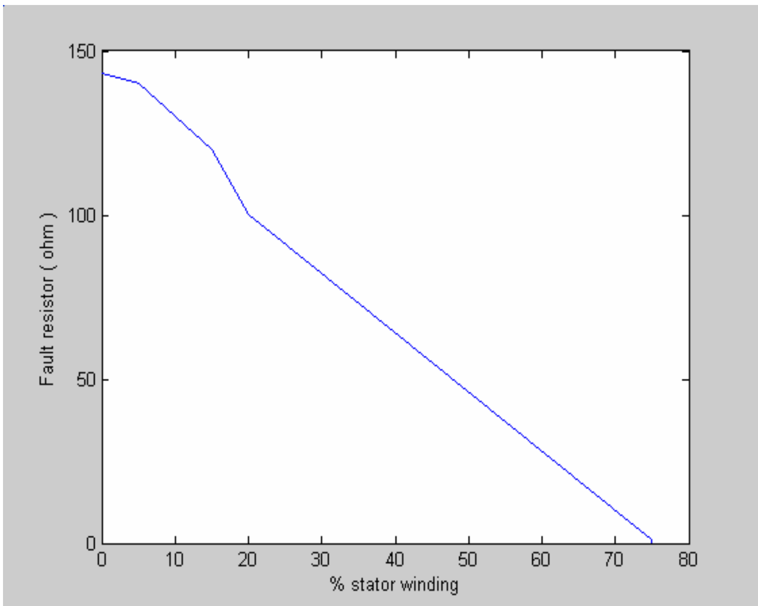

Figure 39. PCCR curve

This is a convenient measure to draw a comparison and will be applied to analyze the characteristic of the following protection schemes.

4.5.2 Overvoltage protection method

The third harmonic voltage relay in this case, should be set below the third harmonic voltage when a ground fault occurs but also above the maximum third harmonic produced by the generator under non-fault conditions in order to avoid false operation.

Following this criteria, we have as a maximum non-fault third harmonic at the terminal 169.8 V (full load). So the overvoltage relay should be set above this value, but when we check when the generator is working not full-loaded, we realize that all the third harmonic fault values are lower. It means, the protection scheme cannot realize when a stator ground fault occurs close to the neutral working not full-loaded because third harmonic at the neutral never will higher than 169.8 V.

We can see that is no way to protect the stator winding by this method if the relay does not know under which load conditions the generator is working.

4.5.3 Ratio voltage protection method

In this method, we have a different setting depending of the protection scheme used. We will develop the setting for each scheme according to Yin et al (1990).

The first ratio was: $\frac{|V_{3t}|}{|V_{3n}|}$

and its operating equation will be,

$$\frac{|V_{3t}|}{|V_{3n}|} > V_{set} * k_s$$

where V_{set} is the setting value and k_s is the safety value, which has to be higher than one. We will use $k_s = 1.2$, so 20% of safety.

The ratio for non-fault conditions is 0.486, then solving the equation above we get:

$$\frac{|V_{3t}|}{|V_{3n}|} > 0.58$$

Now, knowing our limit value together with the results from the simulations we can create the PCCR curve.

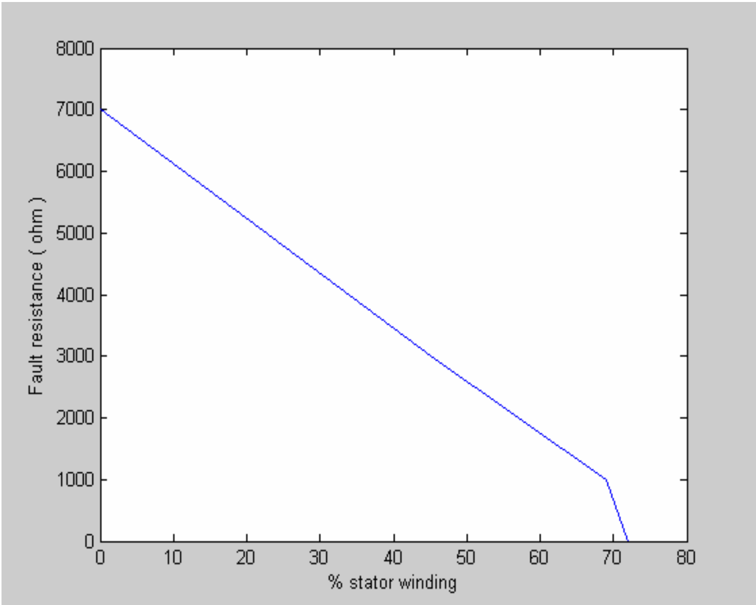

Figure 40. PCCR curve

We can see in figure 40 that we can protect the first 10% from the neutral, when the fault resistor is not higher than 6 kΩ. The zone of the stator winding covered by the scheme is around the 70% from the stator winding. The sensitivity decreases when the fault location moves from the neutral towards the terminal. Also we can point out that the sensitivity is linearly depending on the distance of the stator winding protected until almost the 70% of the stator winding from the neutral.

We get the sensitivity and the coverage of the ratio protection scheme and if we compare it with the undervoltage protection method (do not make sense compare with the overvoltage method because it can not provide any protection), we can realize that it gives a better protection. Working with the ratio voltage method we got a 50 times better sensitivity for more or less the same % stator winding protected.

As we explained in the simulation of this scheme, some papers reported different ratios for different load conditions during normal operation, where they get the maximum ratio under light load conditions and the minimum ratio under full load conditions.
In this case we should the maximum ratio (light load) as V_{set} and multiplied by the safety value we will get the setting value to trip off the relay. Once we set the setting

value we should check our critical situation that will be under light conditions, where the ratios will be lower and restrict our sensitivity.

Is fair to say that working with our model where the ratios are equal under all the load conditions is the best situation in terms of coverage and sensitivity, it means we are setting the ideal situation. All the others cases should be worse.

4.5.4 Other protection methods

Calculating the setting values for the other two schemes proposed (scheme 1 and 2), we will see if we can improve the results that we have already got.

The scheme 1 is:

$$\frac{|V_{3n}|}{|V_{3n}|+|V_{3t}|}$$

And its operating equation is,

$$\frac{|V_{3n}|}{|V_{3n}|+|V_{3t}|} < \frac{V_{set}}{k_s}$$

now V_{set} will be equal to the reference value 0.67 and $k_s = 1.2$, so we find:

$$\frac{|V_{3n}|}{|V_{3n}|+|V_{3t}|} < 0.56$$

Figure 41 shows its PCCR curve, where the sensitivity is lower than the ratio studied before. If we want protect the 10% of the stator winding from the neutral, the highest fault resistance that is able to protect is around 2.2 kΩ.

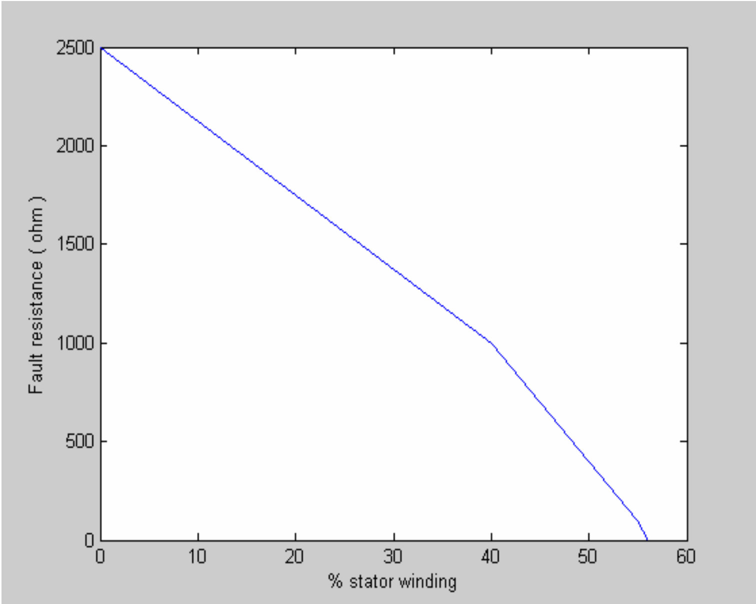

Figure 41. PCCR curve

The portion of the stator winding protected by the scheme is around the 55% from the neutral point of the generator. Watching the results we can conclude that this new criteria 1 is not better than the ratio voltage one, in terms of sensitivity and coverage. Let is see what happens with the criteria 2.

The criteria 2 is: $\left|\beta * V_{3t} - V_{3n}\right|$

Where our reference value was equal to 0.61 and again k_s = 1.2. Then, the operating equation is:

$$\left|\beta * V_{3t} - V_{3n}\right| > V_{set} * k_s$$

the scheme should operate when the following condition is not accomplish:

$$\left|\beta * V_{3t} - V_{3n}\right| > 0.73$$

Now we should check the values of this equation when the generator produces the minimum third harmonic voltage what is our critical situation because the equation result values will be the lowest ones. Analyzing the critical situation we can make the PCCR curve represented in the figure 42, where shows that we can protect all the stator winding for fault resistors lowers than 1 kΩ. Is important point out that we can protect until the 75% of the stator winding from the neutral for a fault resistance equal to 25 kΩ.

Actually, using this criteria 2, we get between 3 or 4 times better sensitivity than using the ratio voltage method and the coverage is also higher.

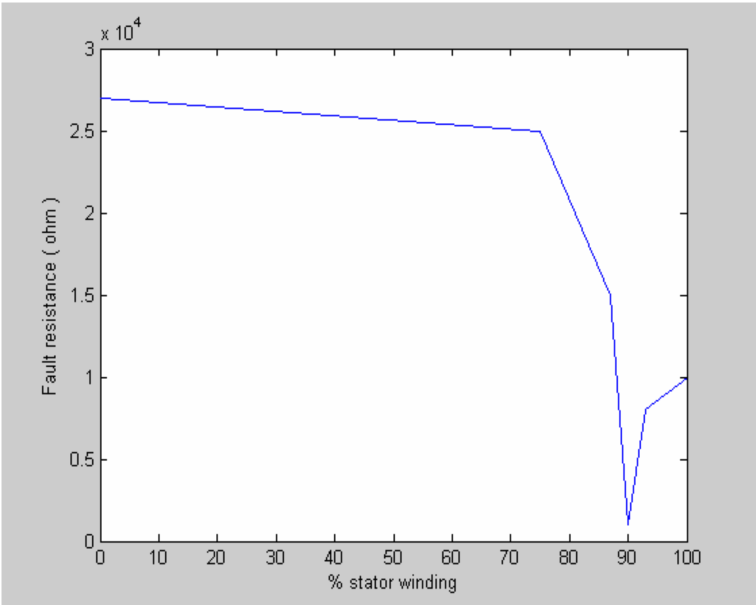

Figure 42. PCCR curve

Finally, we can put all the PCCR curves in the same graph to have a better view to compare them. It is showed in figure 43, where: (1) ($|V_{3t}| / |V_{3n}|$), (2) ($|V_{3n}| / |V_{3n}|+|V_{3t}|$) and (3) ($| X * V_{3t} - V_{3n}|$).

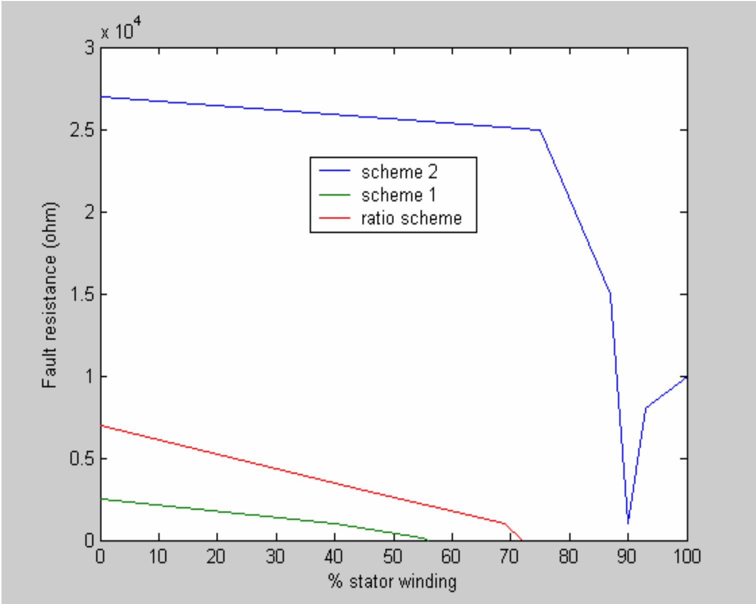

Figure 43. PCCR curves

The sensitivity of the ratio scheme and criteria 1 are much lower than the last one (criteria 2). It is interesting to see that the protective zone of the third scheme can cover all the stator winding.

4.6 Discussion

In this chapter, the third harmonic method has been presented as a method to provide 100% coverage of the stator winding against stator ground faults.

Its principle of operation is based on measuring the change of the third harmonic voltage at the neutral and at the terminal when the stator ground fault occurs. This change is produced in the magnitude of those third harmonic voltages.

The operating principle of the protection scheme depends on where we want to measure the changes of the third harmonic voltage. It can be detect it at the neutral end of the generator, at the terminal end and in both setting a relation between them.

We proved that we can not protect the stator winding of the generator using the overvoltage protection scheme.

The undervoltage protection scheme has 50 times lower sensitivity than the ratio voltage scheme for more or less the same coverage, because the ratio voltage scheme has lower dependence of the load conditions.

Different criteria can be applied in order to relate the two third harmonic voltages at the two ends of the generator, getting other two criteria (criteria 1 and 2). Comparing the criteria 1 and 2 with the ratio scheme, it has been shown that the criteria 2 improve the sensitivity of the ratio scheme (between 3 and 4 times more sensitivity) and the protection provided for the scheme 2 is worse.

So the scheme 2 proposed has the best sensitivity and coverage even though the fault resistance takes high values. It can detect faults around 25 kΩ for a 75% of the stator winding protected and provide a 100% of coverage for lower than 1 25 kΩ fault resistances.

As explained in Reimert (2005), the third harmonic voltage produced by the generator is a function of generator design and loading. The third harmonic produced is critical to the successful application of these schemes. The minimum third harmonic voltage produced by the protected generator should be about the 1% of the phase-to neutral voltage to differentiate between normal and fault conditions.

As mentioned Pope (1984), the third harmonic voltage protection schemes can detect stator ground faults when the generator is running, but not when it is on standstill and on turning gear.

The simulations of the third harmonic method have been done considering the ideal situation in which the ratios V_{3t}/V_{3n} and $V_{3n}/(V_{3n}+V_{3t})$ are constant for all the load conditions in the non fault scenario. The literature research says that these ratios might not be constant and this reduces the fault resistance that can be detected with the third harmonic method. We should analyse the third harmonic voltages behaviour in each generator in other to know if this method can be applied.

To conclude, the third harmonic voltage method is suitable to protect large unit-connected generators against stator ground faults.

4.7 Further work

Although the analysis presented of the third harmonic voltage method has been done accurately and is totally valid, one can go into further detail in some issues. The following paragraphs sum up the further work that could be done.

- The models used in the simulations are very simple. More complex models, i.e. finite elements models could be developed in order to have results closer to the reality. Moreover, the simplifications performed to obtain the equivalent schemes could different a little bit from the reality.
In this chapter, the response of the third harmonic voltage schemes in different operation conditions has been dealt. The way to simulate the different operation condition (generator load) has been done increasing or decreasing the third harmonic voltage produced by the generator. Thus, improving the model could become further work.

-Study the influence of methods of grounding of the stator winding as reported Mieczyslaw, Zielichowski and Fulczyk (2003). Also study and build a model where multiple generators are connected to the same bus, and analyze the behaviour of the third harmonic protection schemes.

-Study new ground fault protection schemes based on fault components. As reported Tai, Yin, Chen (2000), these schemes can provide a higher sensitivity.

- After all these studies will be carried out, the final issue to do is testing the method in a real generator in order to adjust certain parameters and look for certain details that had not been taken into account.

4.8 References

Tai, NengLing et al. (2000), Analysis of the stator ground protection schemes for hydro-generator of three-gorges power plant based on zero sequence voltages, Department of

Electrical Engineering, Huazhong University of Science and Technology, China, IEEE (2000), pp.1888-1893.

Pope, J.W. (1984), A comparison of 100% stator ground fault protection schemes for generator stator windings, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No.4, April 1984, pp. 832-840

Mieczyslaw, Zielichowski and Fulczyk (2003), Analysis of operating conditions of ground-fault protection schemes for generator stator winding, IEEE Transactions on Energy Conversion, Vol. 18, No.1, March 2003, pp. 57-62

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Schlake, R.L., Buckley, G.W, McPherson, G (1981), Performance of third harmonic ground fault protection schemes for generator stator windings, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No.7, July 1981, pp. 3195-3202

Yin, X.G. et al (1990), Adaptive ground fault protection schemes for turbo-generator based on third harmonic voltages, IEEE Transaction on Power Delivery, Vol. 5, No. 2, April 1990, pp. 595-603

Marttila, R.J. (1986), Design principles of a new generator stator ground relay for 100% coverage of the stator winding. IEEE Transactions on power delivery. Vol. PWRD-1, No. 4, October 1986, pp. 41-51

Chapter 5: Comparison of the two protection methods

5.1 Strengths and weaknesses of the protection methods

In this work, the subharmonic injection method and the third harmonic voltage method have been studied. It has been shown that both methods can provide protection in the 10 % of the stator winding close to the neutral where conventional protection schemes can not detect stator ground faults.

Tables 9 and 10 present the strengths and weaknesses of the subharmonic injection method and the third harmonic method respectively. Table 9 presents the strengths and weaknesses that have been shown in the simulations. Table 10 presents those that have been taken from the literature research. Their reference is numbered from 1 to 4.
The simulation comparison between the two methods has been done using the criterias and the schemes that have provided the best results in each method. One has to take into account the different assumptions and simplifications of chapters 3 and 4 made to build the models of the two methods.

Table 9. Strengths and weaknesses shown in the simulations

	Subharmonic injection method		Third harmonic voltage method	
	Strengths	**Weaknesses**	**Strengths**	**Weaknesses**
Coverage of the stator winding	100 % coverage of the stator winding. Conventional protection relays not required.		Along with overvoltage 50 Hz relay, can provide 100% coverage of the stator winding.	
Power supply required		Power supply is required in order to inject the subharmonic voltage.	There is not need of power supply.	
Maximum fault resistance that can be detected and dependence of the fault location	The maximum fault resistance that can be detected is 30 kΩ. It can be detected along the entire stator winding.		The maximum fault resistance that can be detected is 25 kΩ and protects the 80% of the stator winding from the neutral.	The maximum fault resistance decreases when the fault occurs further than the 10 % from the neutral.

Table 10. Strengths and weaknesses taken from the literature research

	Subharmonic injection method		Third harmonic voltage method	
	Strengths	**Weaknesses**	**Strengths**	**Weaknesses**
Influence of the generator design	Completely independent of the generator design. (1)			The design of some generators makes application of any third-harmonic voltage schemes difficult. (1)
Protection for different generator states	It can provide complete ground fault protection during start-up, shutdown, running and even on standstill. (1)		It can provide ground fault protection when the generator is running. (1)	It can not provide ground fault protection during start-up and standstill. (1)
Sensitivity affected by load conditions	Not affected by the load conditions. (2)			Affected by load conditions. (1)
The protection scheme must be disconnected when the generator is not running		The scheme must be disconnected for personnel safety since the injected voltage is typically over 100 V. (1)	The scheme does not have to be disconnected.	
Cost of the scheme		Higher than the one of the third harmonic voltage scheme. (1)	Lower than the one of the subharmonic injection scheme.(1)	
Detection of open circuits in the grounding transformer or its secondary circuit.		NO (2)	YES (2)	
Testing features provided	YES (2)			NO (2)
Detection of the stator insulation deterioration	YES (3)			
Easiness to retrofit on existing installations			YES (4)	

5.2 References

(1) Reimert, D. (2005), Protective relaying for power generation systems, Taylor & Francis Group.

(2) Pope, J.W. (1984), A comparison of 100% stator ground fault protection schemes for generator stator windings, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No.4, April 1984, pp. 832-840.

(3) Tai, NengLing et al. (2000), Research subharmonic injection schemes for hydro-generator stator ground protection, 2000 IEEE, pp.1928-1932.

(4) Schalke, R.L., Buckley, G.W. and McPherson, G. (1981), Performance of third harmonic ground fault protection schemes for generator stator windings, IEEE Power Engineering Society, pp. 3195-3202.

Chapter 6: Conclusions

Neutral point overvoltage relays used to protect the generator stator winding can not detect stator ground faults that could occur close to the neutral of the generator. The study performed in this master thesis concludes that the subharmonic injection method and the third harmonic voltage method can provide this protection.

Several criteria and schemes have been studied in each method. In the third harmonic method, the criteria 2 (see section 4.5.4) is the one that has the best results. This criteria trips off the generator when $|\beta \cdot V_{3t} - V_{3n}| > V_{set} \cdot k_s$, where β is set-up constant that depends on the generator, $V_{set} \cdot k_s$ is the reference voltage to trip off the relay.
In the subharmonic injection scheme, the criteria of the subharmonic current angle and the criteria of the real part of the admittance provide the best protection (see section 3.6). The generator is trip off when the angle of the current is lower than the reference value ($\varphi < \varphi_{set}$) or when the admittance of the current is higher than the reference value ($Y_{real} > Y_{set}$).

The tables 9 and 10 in chapter 5 present the comparison of the two protection schemes using, in each method, the criteria that has better results. The setting values have been suggested in sections 3.7 and 4.5.

If one wants to protect a generator against stator ground fault that could occur close to the neutral, one has to take into account several aspects. The third harmonic voltage scheme can not be installed in those generators that do not produce third harmonic or produce less than 1% of the nominal voltage. In this situation, the only suitable scheme is the injection one.

The sensitivity of these two methods is measured in terms of the maximum fault resistance that they can detect. The simulations have shown that injection scheme can protect the entire stator winding against a 30 kΩ fault resistance. The third harmonic method can detect fault resistances of 25 kΩ in the 75% of the stator winding close to the neutral. The rest of the stator winding is protected but the fault resistance very small

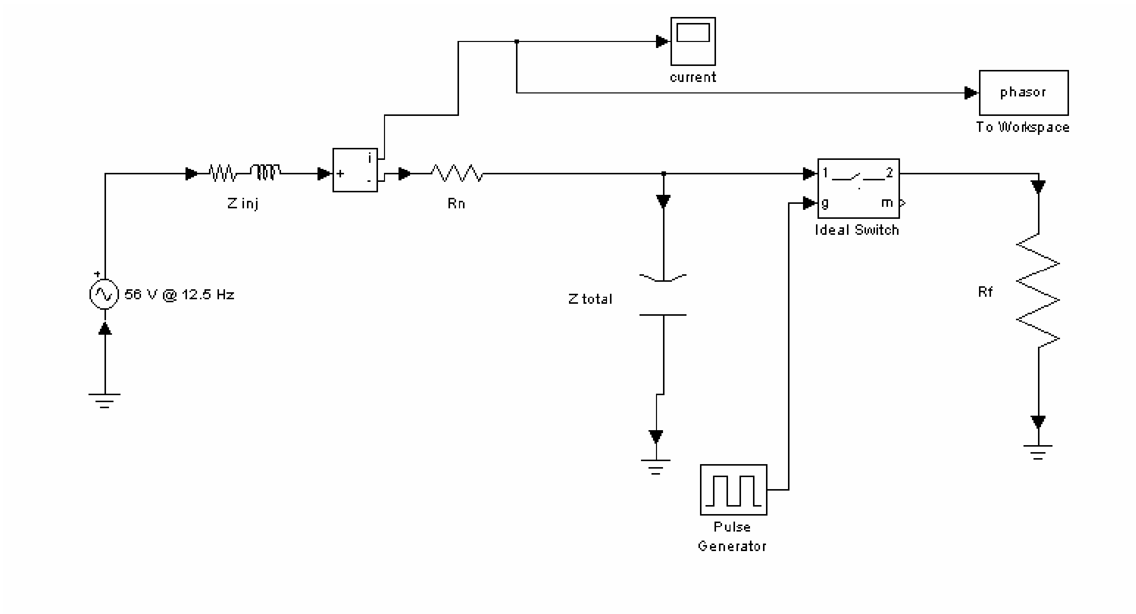
and therefore, the third harmonic voltage method must have additional protection relays such us the overvoltage relay (59).
Moreover, the simulations of the third harmonic method have been done considering the ideal situation in which the ratios V_{3t}/V_{3n} and $V_{3n}/(V_{3n}+V_{3t})$ are constant for all the load conditions in the non fault scenario. The literature research says that these ratios might not be constant and this reduces the fault resistance that can be detected with the third harmonic method.
Thus, the sensitivity of the third harmonic method is affected by load conditions and the sensitivity of the injection method is not affected by them.

In terms of the state of generator, the injection scheme can detect faults when it is running, on start-up or shutdown or even when it is in standstill. Since the third harmonic scheme is based on the generation of the third harmonic, it just can detect ground faults when there is enough third harmonic, which occurs when the machine is running.

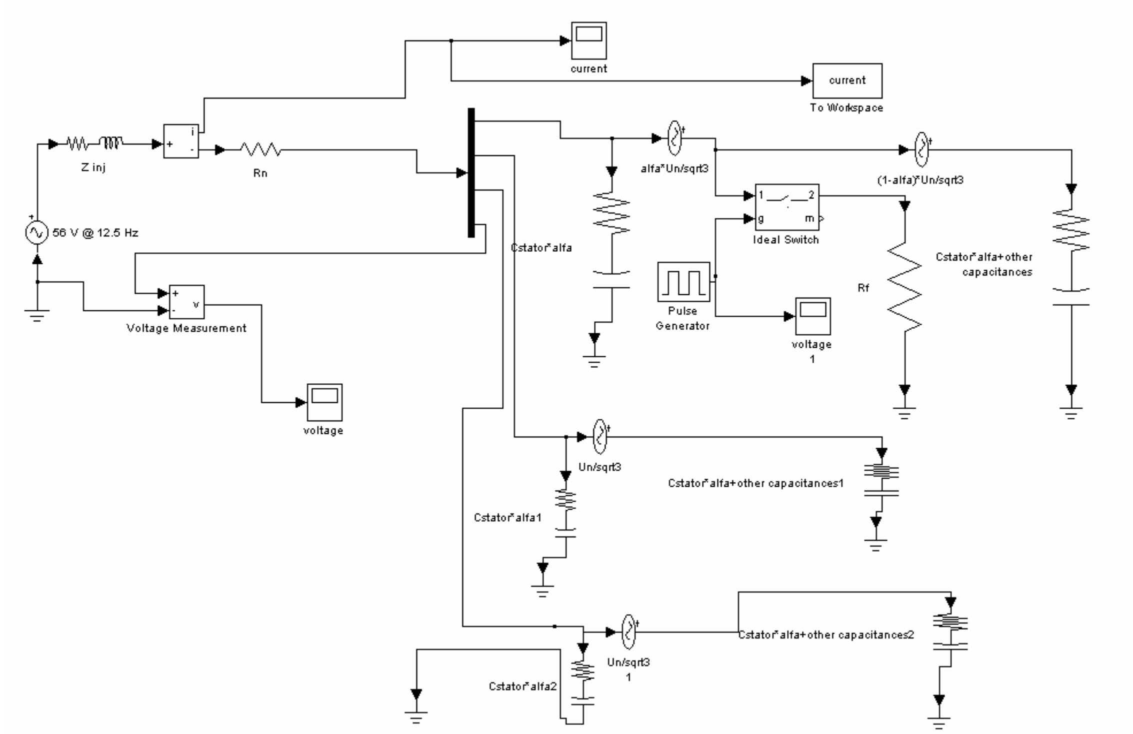
In terms of cost, the third harmonic scheme is less expensive since it does not need the subharmonic injection device. Therefore, all the generators that have conventional relays that protect the range from the 10% until the terminal of the stator winding can install in a cheaper way the third harmonic scheme in order to have 100% coverage.

To conclude, the injection scheme has better figures in terms of sensitivity, coverage of the stator winding and is not affected by load conditions neither by the generator turning state. Moreover, the injection scheme does work with all kind of generator designs. However, the third harmonic voltage method is cheaper and along with other conventional protection relays can also provide the 100% protection of the stator winding.

Appendix A: Scheme of the Simulation 1



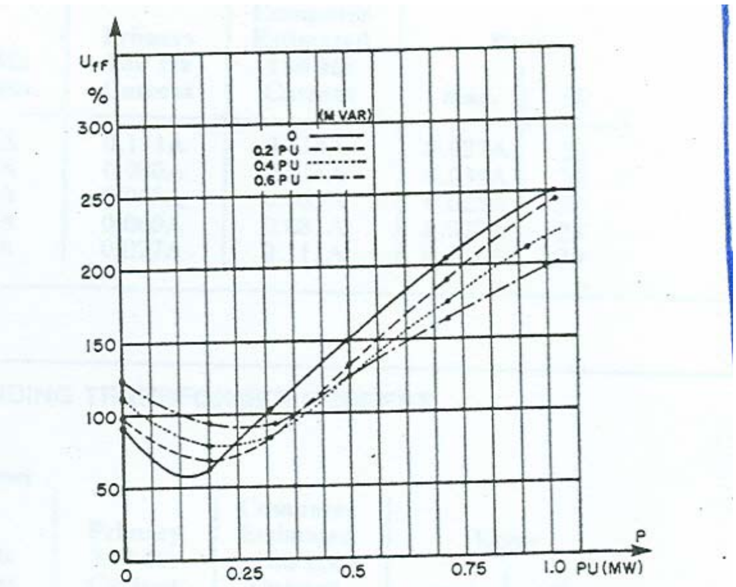
Appendix B: Scheme of the Simulation 2



Appendix C: Filtering M-file

```
% commands to get the vector with fix step time
j=1
t=0
while j<70002
   fixstepvect(j)=interp1(tout,current,t);
   t=t+0.08/7000;
   j=j+1;
end

% getting sin (wn) and cos (wn)
x=(0:0.08/7000:0.8);
s=sin(2*pi*12.5*x);
c=cos(2*pi*12.5*x);

%multiply fixstepvect per sine and cosines waves
i=1
while(i<70002)
Vsin(i)=fixstepvect(i)*s(i);
Vcos(i)=fixstepvect(i)*c(i);
i=i+1;
end

%get the phase (fi) and the magnitude (Ifault) after filtering
i=1
k=0
while k<63000
C=0;
S=0;
    while i<7001
    C=C+Vsin(i+k);
    S=S+Vcos(i+k);
    i=i+1;
    end

Ifault(k/10+1)=sqrt((C/3500*C/3500+S/3500*S/3500)/2)*sqrt(2);
theta=atan2(S/3500,C/3500);
theta=theta*180/pi;
fi(k/10+1)=theta;
time(k/10+1)=x(k+7000);
k=k+10;
i=1;
end
```

Appendix D: Third harmonic vs. load condition



U_{fF} = THIRD HARMONIC VOLTAGE EXPRESSED AS A PERCENTAGE OF NO LOAD VALUE.

PU = PER UNIT POWER OUTPUT.

FIGURE 7 VARIATION OF THIRD HARMONIC VOLTAGE WITH REAL AND REACTIVE POWER. (REF. 2)

Appendix E: Measurements

The main goal of our visit to Vasterås was get the third harmonic series inductance of the windings, just to be able to demonstrate if we could neglect this inductance when we build the model. The way to get our goal was having the generator in standstill operation.

We injected a third harmonic voltage (150Hz) with a magnitude equal to 2% of the nominal voltage of the generator (8 V).

This first measurement was done with the terminal grounded (R=1kΩ) and with the neutral ungrounded as we can see in the figure 1. A resistor of 4.78 Ω was placed in series with the grounding resistor to measure the current across it.
The generator capacitance was so low that we could neglect them.

Calculating,

$$V_{inj} = 8V$$
$$R = 4.78\Omega$$

then the current at the terminal is,

$$I = \frac{V_R}{R}$$

where the voltage was measured and was equal to 0.03 V. So the current was equal to 6.28e-3 A.
Then if we calculate,

$$I = \frac{V_{inj}}{\sqrt{(R + R_G)^2 + (L * \pi * 2 * 150)^2}}$$

.

where L is the only data unknown. Calculating we get $L = 0.64$ H , and its inductance in front of the resistor can be neglected.

Later we did the same measurement but we grounded the neutral and left ungrounded the terminal and we injected the voltage from the terminal. Now, we measure the current at the neutral. The figure 2 shows the set up. We got exactly the same results.

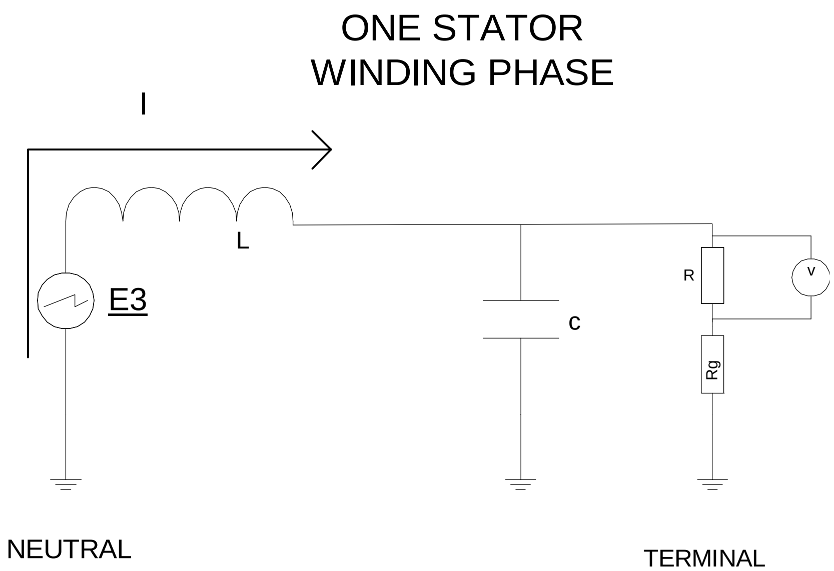


Figure 1

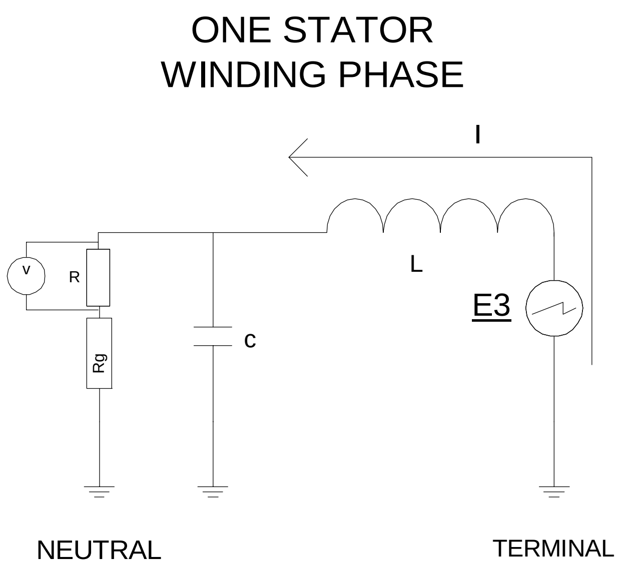
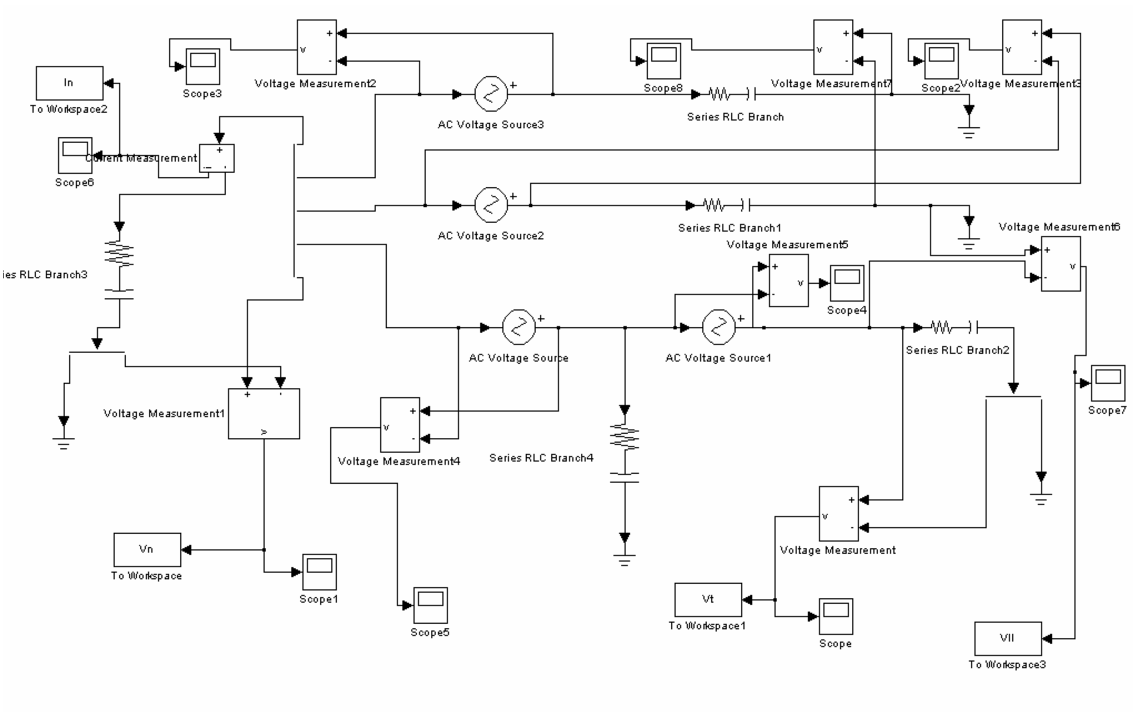


Figure 2

Appendix F: Faulted scheme



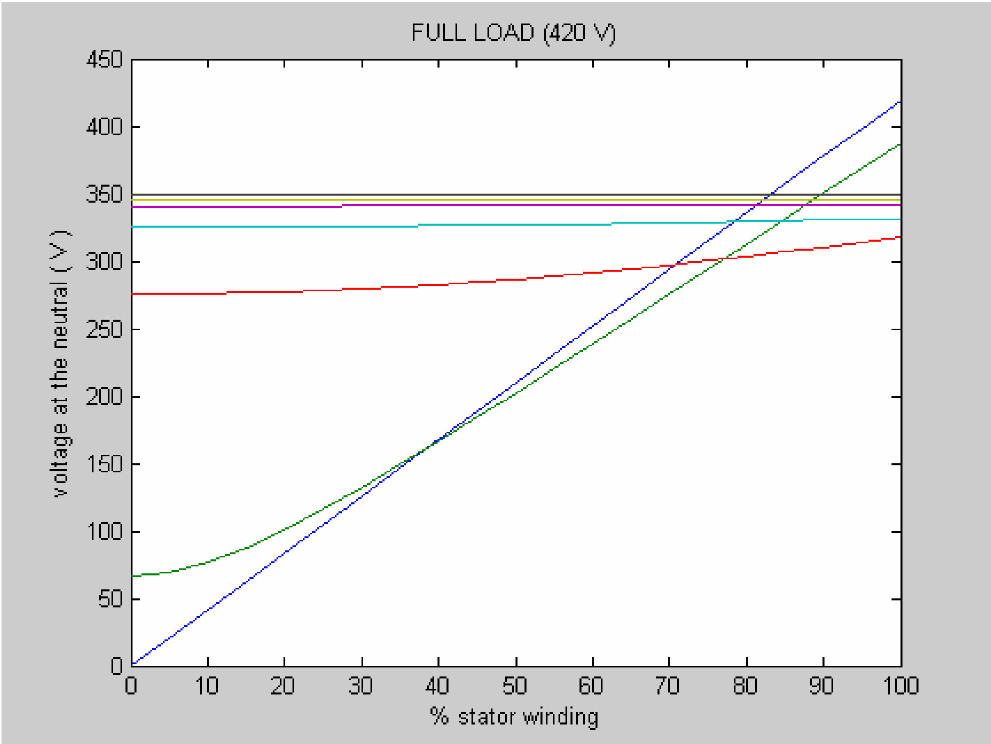
The changes are:

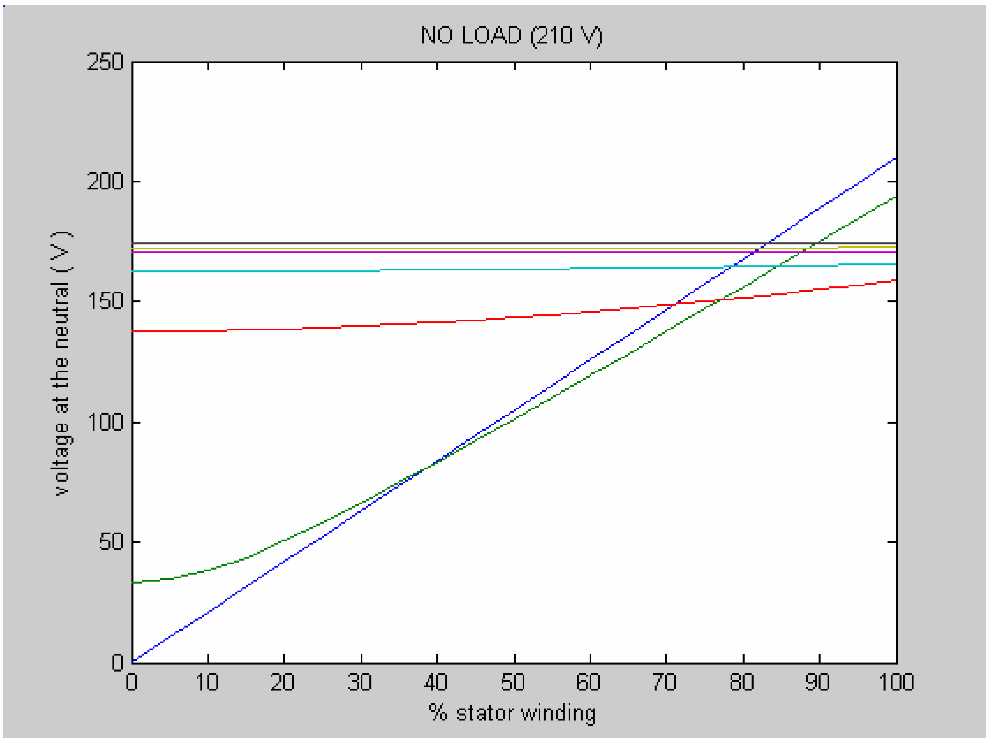
- We have had to put a 1Ω resistor between the AC source and the capacitor at the terminal because the SIMULINK does not allow you to put a capacitor next to the AC source.

- The capacitors in parallel with the fault resistor and the ground resistor we have to transform in series because SIMULINK does not allow you to put a parallel branch with a inductance equal to zero.

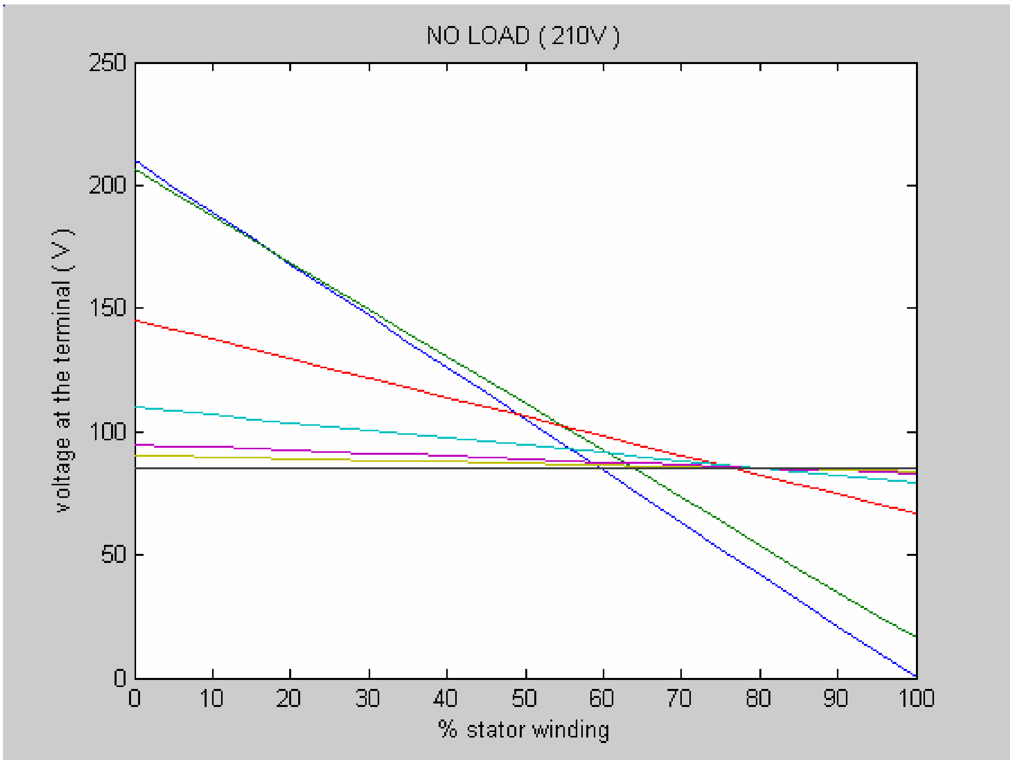
Appendix G: Figures

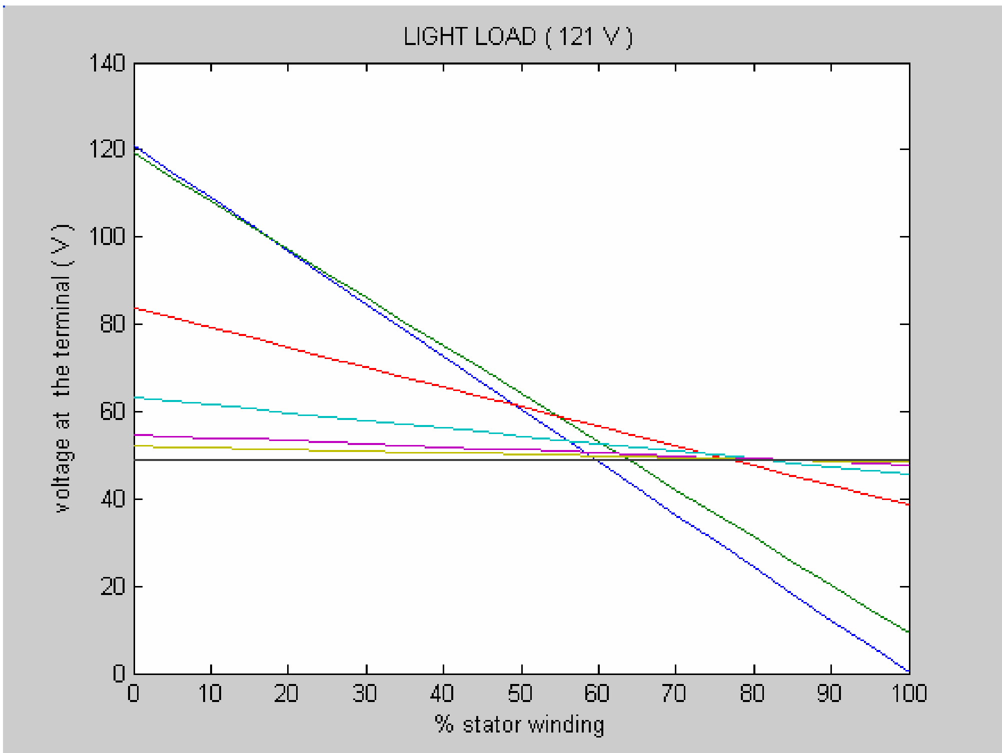
Third harmonic voltage at the neutral



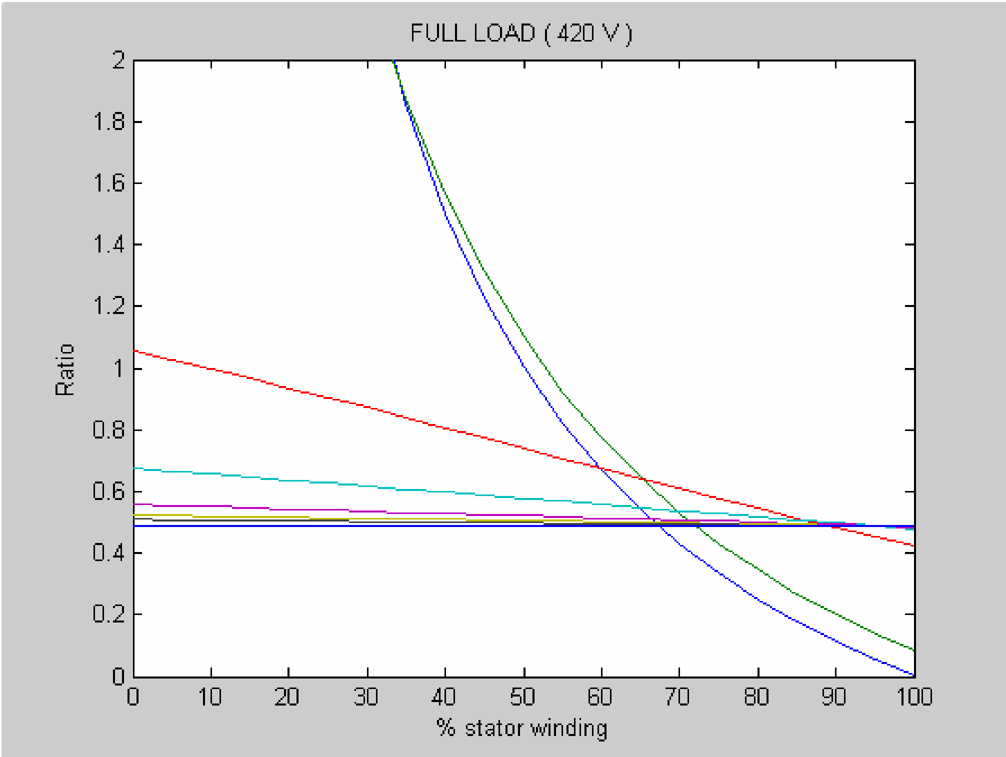


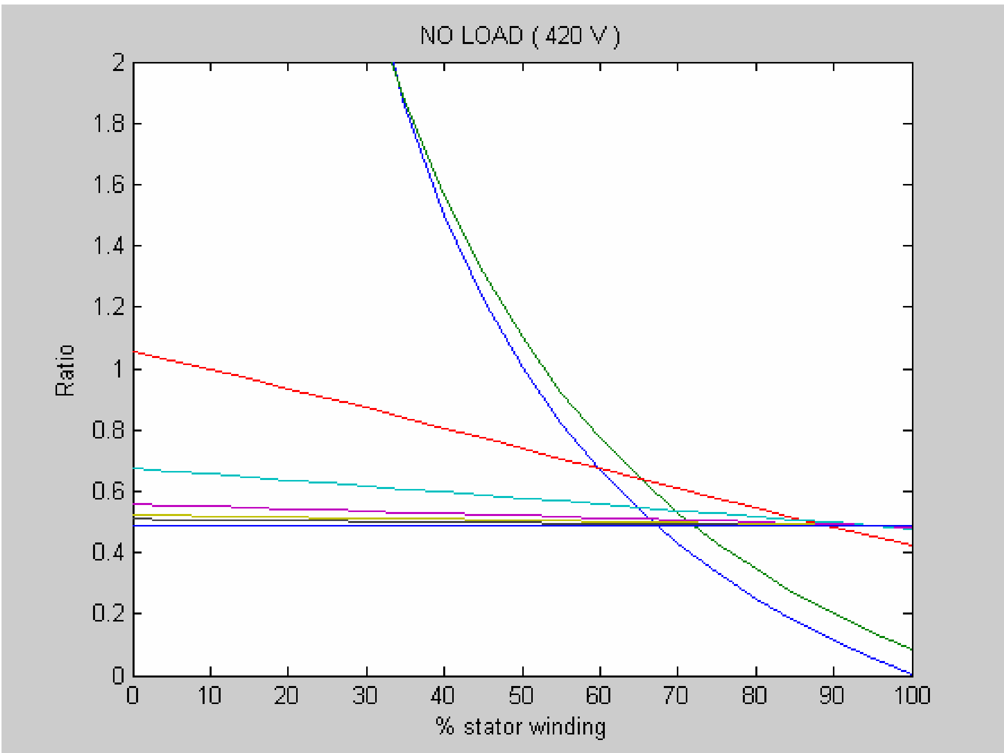
Third harmonic at the terminal



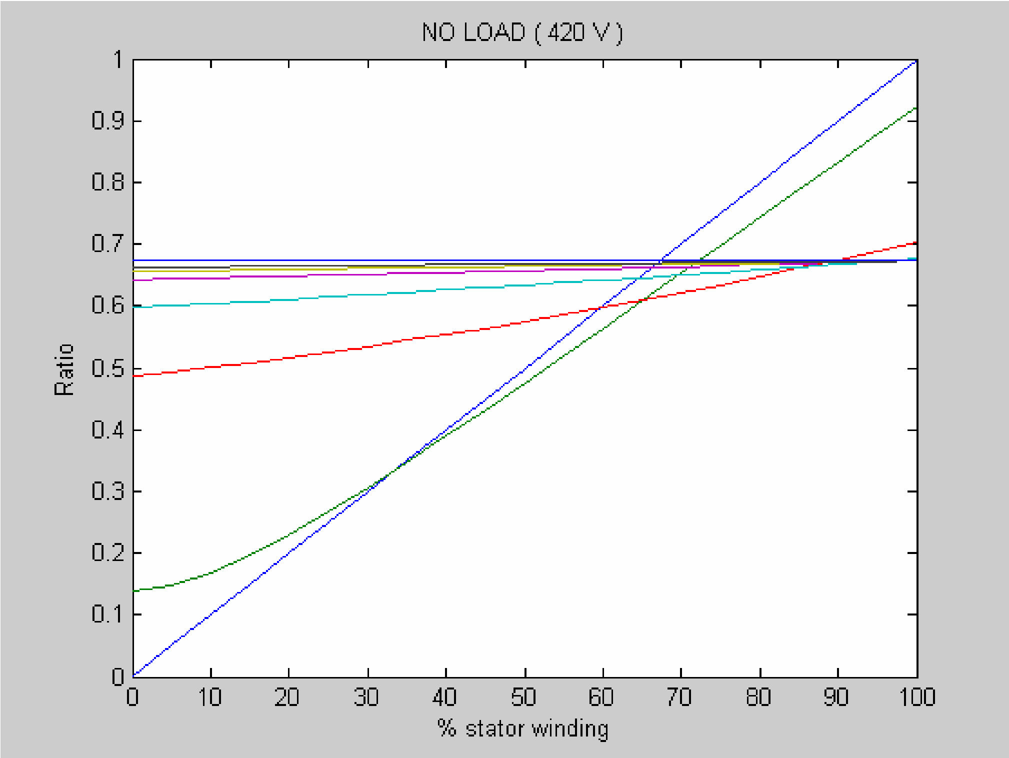


Ratio voltage protection scheme





Criteria 1


NO LOAD (420 V)
Ratio
% stator winding
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
10
20
30
40
50
60
70
80
90
100