REAL TIME DIGITAL SIMULATION AND TESTING OF GENERATOR PROTECTION ELEMENTS

By

Gwala Amanda Xoliswa

This thesis is submitted in partial fulfilment of the requirements of the degree in Masters in Electrical Engineering at the College of Agriculture , Engineering and Science, University of KwaZulu-Natal for a research Masters.

May 2018

Supervisor: Dr Akshay Kumar Saha

DECLARATION 1 – PLAGIARISM

I Amanda Xoliswa Gwala declare that

1. The research reported in this thesis, except where otherwise indicated, and is my original research.
2. This thesis has not been submitted for any degree or examination at any other university.
3. This thesis does not contain other person's data, pictures, graphs or other information, unless specifically acknowledged as being sourced from other persons.
4. This thesis does not contain other person's writing, unless specifically acknowledged as being sourced from other researchers. Where other written sources have been quoted, then:
    a. Their words have been re-written but the general information attributed to them has been referenced.
    b. Where their exact words have been used, than their writing has been placed in italics and inside quotation marks, and referenced
5. This thesis does not contain text, graphics or tables copied and pasted from the Internet, unless specifically acknowledged, and the source being detailed in the thesis and in the Reference sections.

Student Name: A.X. Gwala (209500175)

Signature: …………………….

Date: …………………….

As the Candidate's supervisor I agree to the submission of this thesis.

Supervisor Name: Dr. A. K. Saha

Signature: ……………………..

Date: ……………………..

DECLARATION 2 – PUBLICATIONS

DETAILS OF CONTRIBUTION TO PUBLICATIONS that form part and/or include research presented in this thesis (include publications in preparation, submitted, *in press* and published and give details of the contributions of each other to the experimental work and writing of each publication).

Publication 1:

Gwala A, Saha A.K.: "Real time simulation and testing of loss of field excitation events in RTDS", Southern African Universities Power Engineering Conference (SAUPEC), 2015

Publication 2:

Gwala A, Saha A.K.: "Simulation of 100 % stator winding internal ground fault protection in RTDS", Southern African Universities Power Engineering Conference (SAUPEC), 2015

Student Name: Miss Amanda Xoliswa Gwala

Signature: ……………………………….

ACKNOWLEDGEMENTS

To God the Almighty, I thank you for blessing me with wisdom and strength to carry out this work till the end.

To my supervisor for this project Dr. A. K. Saha, thank you for your valuable advice and guidance throughout this project. Your words of encouragement and your patience are what made it possible.

To my family and closest friends, I am overwhelmed by the support that you have shown me throughout my academic career. A special thanks goes to my mother Nomusa Gwala, I do not know how I would have made it this far without you, you have been a mother to my son and for that I thank you and I appreciate you.

To my late grandmother MaNdlovu Gwala, I will forever treasure your teachings and the love you showed me.

Thank you to everyone who has made this project a success.

ABSTRACT

Power system protection is designed to identify and isolate the system from any type of fault or abnormal condition which may endanger the equipment and operation of the system as a whole. Ground faults are the most common types of faults in generators and can damage the stator winding severely. Stator winding protection therefore becomes one of the crucial protection functions in generator protection. The grounding method used plays an imperative role in determining which protection functions are to be employed on the generator. This thesis reviews different types of stator winding faults that occur for a generator and how the generator is protected against these faults using different types of protection system. It also presents how the different types of generator grounding affect generator protection schemes, focusing on high and low impedance grounding. The development of real time digital simulators has greatly improved the simulation and testing of protection studies. In the past, mathematical models were not fully compatible for the representation of the complete synchronous generator stator. The Real Time Digital Simulator (RTDS) has developed a synchronous generator phase domain model which allows for simulation of generator stator internal faults. This thesis illustrates the suitability of the third harmonic voltage protection scheme against stator internal faults. An overview of abnormal conditions that occur on a generator was also reviewed, how they affect the generator and their protection systems. The thesis focused on reverse power, over-excitation, and differential and current unbalance protection. The loss of field excitation in synchronous generators also largely contributes to voltage instability. The large consumption of reactive power and rapid changes in the system components leads to severe damage of the generator and jeopardizes system stability. This thesis looks into loss of field excitation events and how their impacts can be reduced by using the R-X protection scheme. It also illustrates results based on closed loop testing conducted using hardware generator protection relay and the models developed on the RTDS. The simulation and testing of generator protection functions were proved to be theoretically and practically correct which could be used as a guideline for improvements in protection studies.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF VARIABLES

A	Amps
E_g	Machine terminal voltage
E_s	System voltage
E_{RMS}	output voltage (RMS)
f	Frequency in Hertz
N	Number of turns in the winding
n_s	Synchronous speed [rpm]
P	Number of poles
P_e	Active power
X_T	Transfomer impedance
V	Volts
δ	Load angle between E_g and E_s
φ_{max}	Maximum core flux needed to produce E_{RMS}

CHAPTER I

1. INTRODUCTION

1.1 General Overview

A power system is prone to different types of failures. This is due to transient disturbance that occurs as a result faults and interchanging loads. The power system therefore has to be protected against unwanted disturbances or abnormal conditions. Synchronous generator protection becomes critical as these machines produce high voltages and are also connected to other equipment which may be prone to damage during abnormal events. As a result the protection of generators must also consider these equipment as well. Generators are also very expensive and a vital factor in the power system. These entire factors make the design of a protection scheme for the generator very much complex [1].

Synchronous generators are designed to allow for occurrences of abnormal working conditions. Just like any system, generators are monitored by use of protection relays to detect faults and abnormal conditions. These systems ensure that the machine is completely isolated from the system during fault events. There are various faults that can occur on a synchronous and some can be imposed by power system operations. As a result, the generator is equipped with different protection elements for detecting faults and certain unwanted conditions. Following is a descriptive list of internal faults and abnormal operating conditions. There are various faults and abnormal conditions that can occur for synchronous generators as listed below:

Stator and rotor winding internal faults

- Primary and back-up protection of phase or ground faults in the stator and associated areas
- Rotor earth faults

Generator abnormal conditions

- Reverse Power (32)
- Loss of field excitation (40)
- Over excitation (24)
- Inadvertent energization (67)
- Negative sequence current protection (46)
- Stator thermal protection (49)

- Over and under frequency (81O and 81U)
- System and generator zone faults protection (21)
- Phase over-current voltage controlled time overcurrent (51V)
- Over voltage (59) and Under voltage (27)
- Loss of synchronism (78)
- Loss of voltage transformer signal to relaying or voltage regulator

The arrangement of generating systems has developed over the years including the synchronizing technology involved in linking them to the power grid. Though technology has improved the basic requirements of a power system relaying protection to offer selectivity and reliability remains the same. The technology advancements of protection relays has moved from electromechanical and static relays to digital multifunction relays which ensure the same requirements are achieved in not only a simple but reliable manner. The availability, additional performance, economic advantages, and reliability of digital multifunction protection systems, this technology is being incorporated into most new protection schemes [3].

1.2 Background

Generators do not have the same level of protection. As the generating capacity of the machine increases, the basic protection requirements are maintained and depending on the requirements of the utility the protection elements maybe added for larger machines. From the cost management perspective, damage on bigger units is very costly, both in terms of repair as well as the profits lost due to the unavailability of the machine. The generator is the most capital intensive and significant equipment in the power system and its protection becomes critical both to the faulted generator as well as the power system fed by it. Normally, the larger the machine is, the more expensive its protection scheme is. The employment of multifunction relays is cost effective which allows protection engineers to design more reliable protection systems at a lower cost with additional protection schemes [3, 4].

Previously, analogue simulators were used for generator protection studies but the digital simulators (such as the one that will be used for this research) which are being used currently have shown to have better performance and capability in providing the most accurate results because of improved frequency response (bandwidths) and thresholds (pickup settings) [3].

1.3 Research Questions

The focus for this study will be guided by the following research questions:

- Analysis of different protection schemes for generator abnormal conditions, focusing on:-
    - Loss of field excitation
    - Loss of prime mover
    - Over-excitation
- The use of voltage controlled phase over current elements for protection of
- Suitable protection for hundred percent stator winding against internal faults in low and high resistance grounded generators, concentrating on:-
    - Differential protection
    - Third harmonic voltage differential element 64 G

1.4 Thesis Objectives

There are several abnormal conditions that can result in damage to the generator and various faults that the generator may be exposed to which results in various different types of protection being applied as specified in section 1.1. The aim of this thesis is to model and simulate generator protection under various conditions using the RSCAD software. There are numerous methods that have been used for such studies however; the simulation of stator winding ground faults could not be fully examined as these methods were limited in terms of the mathematical approach generally used for dynamic modelling of synchronous machines in simulation programs.

The phase domain synchronous generator model obtained in the Real Time Digital Simulator allows for the simulation stator internal faults across the stator winding. This thesis serves to illustrate how 100 percent stator ground protection can be achieved on a high impedance grounded generator. Furthermore, the generator field circuit can be represented in detail with the use of power system components also allowing more realistic contingencies and fault scenarios which could enhance the results obtained from protection studies.

The generator is also connected to generator controllers and due to the effect of generator protection on system disturbances and vice versa, the simulation also made use of the power stabilizer and excitation control systems. Therefore, the generator has inputs for governor/turbine and exciter interfaces. This thesis looks into loss of field excitation events and how their impacts can be reduced by using the R-X protection scheme. It also illustrates results based on closed loop testing conducted using hardware generator protection relay and the models developed on the RTDS. This study also focuses on the simulation and testing of generator protection functions such loss of prime mover, over-excitation and phase overcurrent with voltage control.

1.5 Thesis Layout

This thesis consists of six chapters. Chapter one presents the introduction of the study, a general background as well as the objectives of the study. Chapter two provides a theoretical background to power system protection and generator protection relaying principles. The literature reviews focuses on stator winding protection as well as protection against generator abnormal conditions. Generator excitation and grounding systems are also discussed and furthermore, improvements in generator system modeling and testing.

Chapter three offers a detailed description of the methodology to be used for each protection function. The study system at which the simulation of the protective functions will be based on is also presented in this chapter. The Real Time Digital Simulator, and hardware closed loop testing was discussed. This chapter also focuses on the settings of each protection function as based on the SEL 300G generator relay.

Chapter four presents the simulation results for all the abnormal protection functions investigated. These include over-excitation (24), loss of prime mover (32), and loss of field excitation (40). It also consists of the phase over-current with voltage control (51C/V).

Chapters five illustrates the implementation of stator ground protection on synchronous generators on different types of generator grounding methods and their impacts on the reliability of protection system. The compatibility of the stator differential method (87P) is investigated for a low resistance grounded system and how 100 % stator ground protection can be achieved on a high impedance grounded generator using the third harmonic voltage differential method

Chapter 6 gives conclusion on work done and results obtained as well as recommendations for future work.

1.6 Conclusion

This chapter presented a general overview of the importance of generator protection in an electrical system. It also focused on the thesis objectives and layout which will be used to achieve the study objectives.

CHAPTER II

2. LITERATURE SURVEY

2.1 Introduction

Electrical rotating machinery falls under a class of equipment which is very complex and more prone to several types of failures [1]. These machines have a significant role that they play in the power system and therefore, their protection is a vital factor which helps preserve the system integrity as well as reduce the damage to the equipment due to different types of failures. There are numerous kinds of faults that can occur on synchronous generators and, hence several types of protection functions. The level of protection for generators differs from one to the next, largely depending on the size of the machine. All generator units consists of standard basic protection functions against stator short circuits but other protection schemes may differ depending on the generators operating conditions [2, 3].

The objectives of this thesis have been discussed in the previous chapter. This chapter presents the theory of generator protection elements which are employed in synchronous generators. The causes and impacts of each disturbance or fault are discussed. It also covers the history of generator modeling approaches as well as the one used in this study.

2.2 Generator Protection Relaying Principles

The principal function of protective relaying is to cause the rapid removal from service of any element of a power system when it suffers a short circuit, or when it starts to operate in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system [3]. The second function of any protective relaying system is to provide indication of the location and type of failure [3, 4]. Figure 2.1 illustrates a distinctive power system one line diagram.

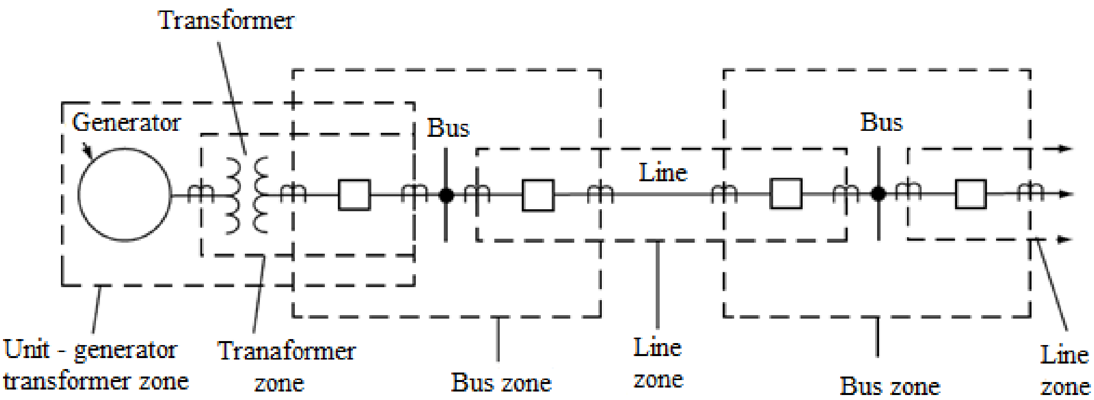

Figure 2.1: Typical electric power system one-line diagram [1]

To ensure stability and security of the entire power system, protection engineers develop wide protection and control mechanisms, complementary to the conventional local and zonal protection strategies as seen in Figure 2-1.

Any protective relaying system has functional characteristics which include:-

- Reliability: This feature has two factors: - dependability which relates to the degree of certainty that a relay will operate accurately and security which associates with the level of confidence that the relay system will not operate incorrectly. The ability of the relay to prevent unnecessary operation for faults or abnormal condition outside its designated zone of operation [3, 4].
- Selectivity: the ability of the protective relay to discriminate between a faulted and non-faulted section. Selectivity or relay coordination is important to assure maximum service continuity with minimum system disconnection.
- Sensitivity: the ability of protective relays to operate as fast as possible within their primary protection zone and have delayed operation in their back-up protection zone [4, 5, 6].

2.3 Generator Protection Elements

As discussed in chapter one, generator protection consists of several protection elements which protect the system against abnormal conditions and faults. The degree of monitoring functions for such systems is determined by the severity of the protection system, however any protection system should be able to provide adequate protection and initiate a complete shutdown should a fault be detected. [5].

2.3.1 Stator Winding Protection

The most common faults reported on generators are ground faults. Stator internal faults are generated by insulation breakdown caused by the contamination of windings from factors such as dust and oil. Contaminants collect outside the stator slots on the coil surfaces [5, 6]. The deterioration of the insulation may be due to overvoltage, overheating of the windings or mechanical damage due to the occurrence of faults. In the case of overvoltage. These situations are usually triggered by lighting or switching surges and unbalanced loading or loss of cooling which results in over-heating [7]. The protection methods for stator faults include the following:-

- **Percentage Phase Different Protection (87)**

Phase faults occur rarely in generators but the generator must still be protected against these faults should they occur. These types of faults develop in the winding end turns where all the three-phases are in close proximity. The danger to these faults is that they often change to ground faults which make their detection a high priority [8, 9]. This relay is mostly popular for such cases. This protection relay operates for internal faults where there is sufficient fault current detected by the relay. For faults near the neutral, this relay is not adequate for this application and therefore a more effective scheme should be used. The basic operation of differential protection functions is that they compare the phase currents on both sides of the object to be protected. Should the differential current of the phase currents in one of the phases exceed the set start value of the stabilized operation characteristic or the instantaneous protection stage, the relay generates an operate signal [9, 10, 11].

In figure 2-2, the current in the restraint coil produces contact opening torque and current in the operating coil produces contact closing torque. Relay contacts will close when the operating current exceeds the restraining value by a given percentage. The percentage is referred to as the slope of the relay. This configuration provides an automatic increase in the operating coil current necessary to tripping as fault current and the resulting CT error increase [3].

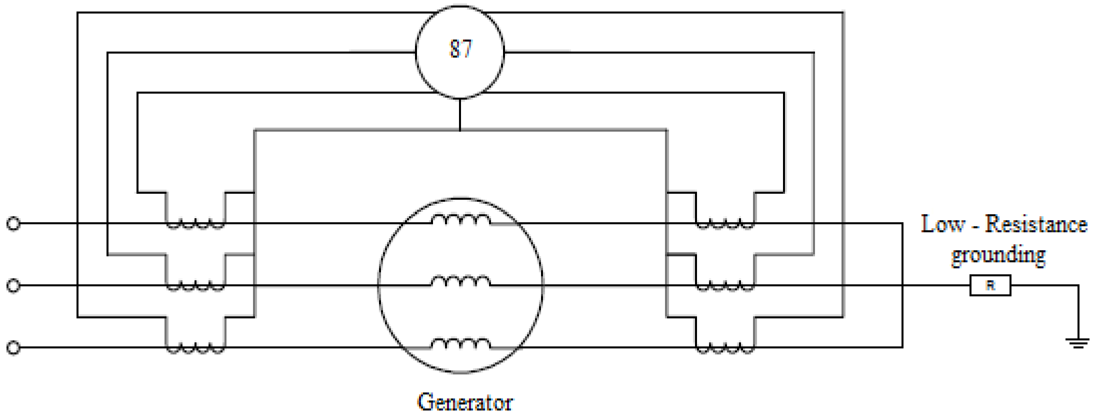

Figure 2-2: Percentage phase differential protection [3]

The disadvantage of this relay is that it fails to operate for stator winding faults if the generator is grounded through a high impedance method. On high impedance grounded generators, the fault current is reduced to a point that the relay will become insensitive towards the fault. Another drawback of this relay is that it will not sense a turn to turn fault that occurs on the same phase due current difference [12].

- **Ground differential protection (87GN)**

This element is utilized for protecting the generator against internal ground faults. It can detect faults only up to 10 percent of the generator neutral. This scheme must be properly set to prevent unwanted tripping for external faults [13, 14]. A schematic showing the basic operation of the 87GN relay is shown on figure 2-3.

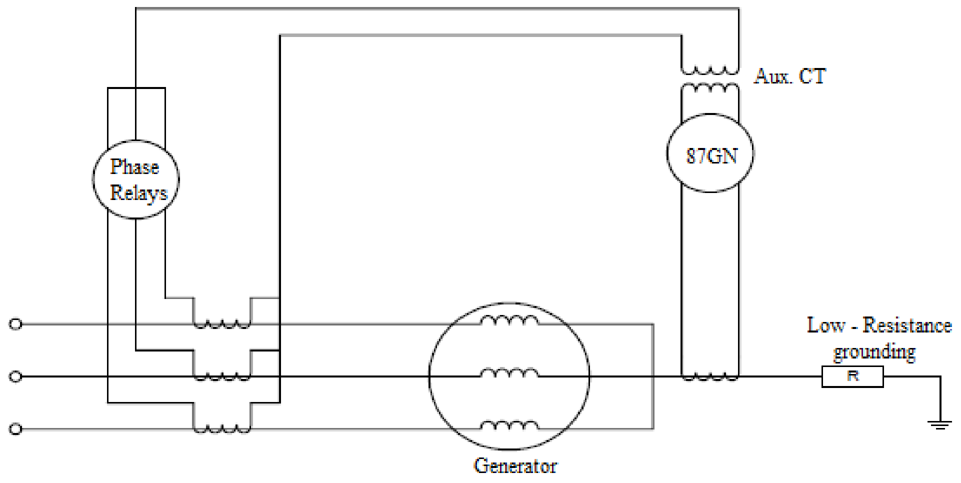

Figure 2-3: Ground differential protection [13]

As mentioned previously low resistance grounded system experience high fault currents and therefore require sensitive and high speed differential protection for generators which make this scheme more suitable compared to the phase differential relays [14].

- **Instantaneous ground overcurrent protection (50G)**

Also referred to as self-balancing differential ground relay scheme, this protection scheme senses faults close to the generator neutral. This relay offers protection for low magnitude internal ground faults. Its operation relies on the toroidal current transformer connected to the generator phase and neutral terminals as shown in figure 2-4. The transformer allows for measuring of ground current raised from the generator. If the output of the current transformer exceeds the set threshold an instantaneous over-current trip will shut down the generator. For an external ground faults, the output of the current transformer will remain zero. Hence, this configuration makes it possible to safely set the relay to a low value for maximum protection of the generator [8].

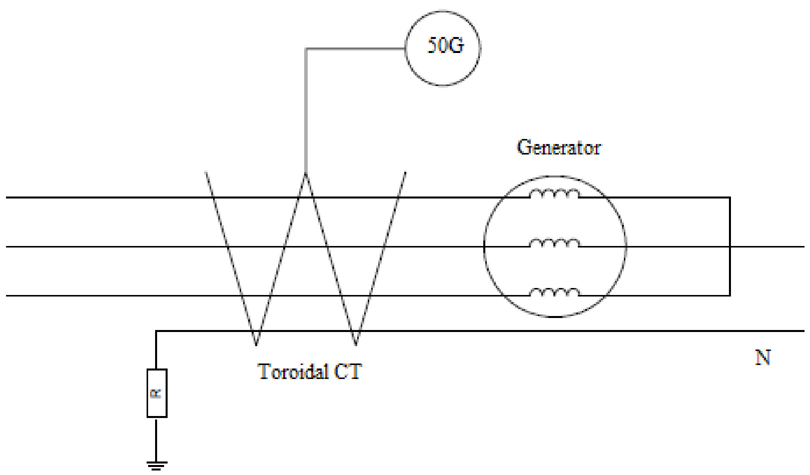

Figure 2-4: Instantaneous ground overcurrent protection [13]

- **Ground time-overcurrent protection (51G)**

This scheme provides back-up protection for un-cleared feeder fault that the instantaneous ground overcurrent relay may fail to detect. These relays offer reliable sensitive protection for ground faults [15, 16]. Faults occurring at next to the generator terminals may cause high damaged due to high fault currents.

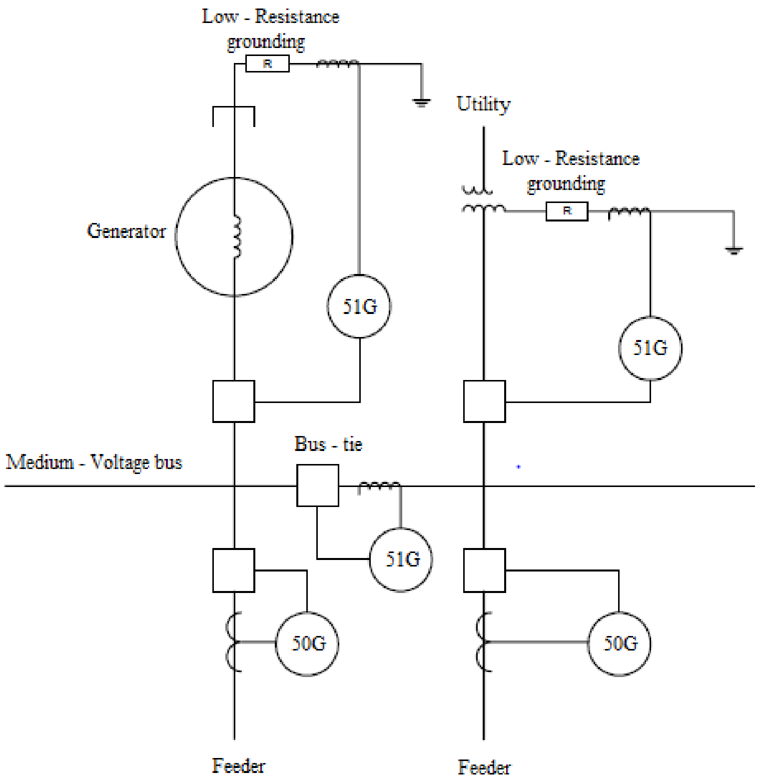

Figure 2-5: Ground time-overcurrent protection [3]

This condition can be prevented by using the instantaneous ground overcurrent protection relay with a time-overcurrent relay [13]. Figure 2-5 illustrates how 50G backs up the ground time overcurrent relay (51G).

- **Wye-broken-delta voltage transformer ground overvoltage protection (59G)**

This scheme is mostly used on high impedance grounded generators. It is utilized to detect both ground faults and the zero sequence neutral over-voltage components. This is achieved by monitoring the voltage across the across the broken delta secondary winding of the voltage transformer [13].

- **Zero-sequence neutral overvoltage protection (59GN)**

This element is also employed on high resistance grounded machines. The over voltage relay is tuned to the system fundamental frequency and does not operate for third harmonic voltages obtained at the generator neutral [13].

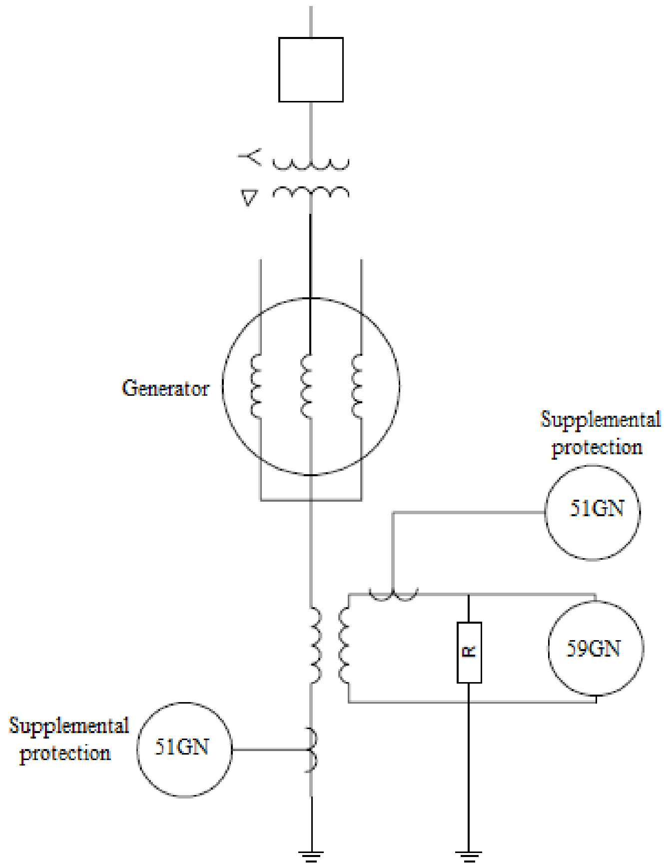

Figure 2-6: Zero-sequence voltage protection in high impedance grounded generators [13]

Figure 2-6 demonstrates the assembly of the zero sequence voltage protection for unit connected generator.

2.3.2 100 % Stator Winding Ground Fault Protection - 64

For high impedance grounded generators, the protection schemes mentioned above cannot achieve 100 percent stator winding protection. 100 percent stator winding ground protection and generator neutral breaker offer complete protection of the stator winding. The schemes mentioned above can only protect 5 to 95 percent of the stator winding. The other 5 percent remains unprotected, though a fault that occur at this point may not cause significant damage however reoccurrence of the fault on the same winding may result in a turn to turn faults. The fault current at generator neutral points may not be sufficient to operate the relay [11, 13, and 14].

2.3.2.1 100% Stator Ground Fault Protection for High Impedance Generators – 64G

The 100% stator ground element is suitable for providing the ground fault function on generators that are high impedance grounded with a high resistance or reactance to the system ground. Harmonic voltages are generated by generators, with the third order being the largest. These harmonic are in phase and also obtained at the generator neutral as zero sequence quantities. When a fault occurs at the neutral, the third harmonic voltage at neutral is reduced to zero, while the third harmonic at the terminal of the generator is increased to the total third harmonic voltage produced by the machine as shown in figure 2-7. These features are then used to identify ground internal faults throughout the stator winding [8, 9, and 14].

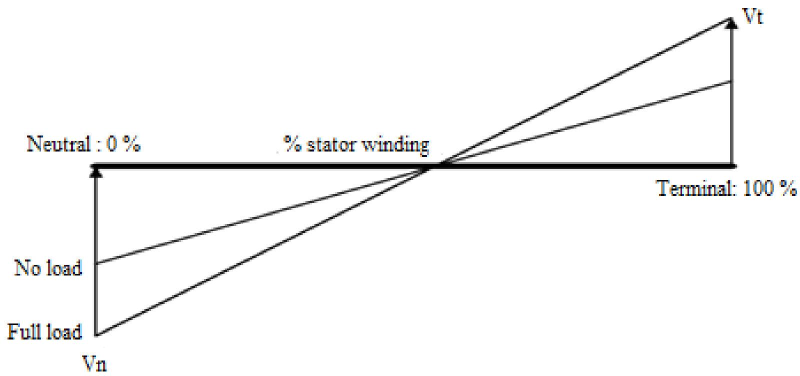

Figure 2-7: Third-harmonic voltages under normal operations [14]

Third harmonic under voltage scheme: This scheme consist of an under voltage relay adapted to sense third harmonic voltage using a zero sequence neutral over-voltage protection relay which is regulated by the fundamental frequency. The overlapping overvoltage/under voltage scheme provides 100% protection for generator stator ground faults by using two measuring functions that cover different portions of the machine winding [1]. The zero sequence relay can detect internal faults that occur up to 95 percent of the stator winding. Faults occurring at the neutral can be detected by the under voltage relay [16, 17, and 18].

However, setting the relay characteristics requires operational characteristics of the machine obtained during operation. The relay must be set such that it does not operate during normal operation when the harmonic voltages at their lowest, it should be set to ensure that it can operate for faults that could not be detected by the zero-sequence neutral overvoltage protection [8].

Third harmonic overvoltage scheme: This protection function will operate when there is an increase in the generator terminal third harmonic voltage and the relaying threshold is exceeded. This increase is obtained or allied with generator neutral stator ground faults. For this function to operate successfully, it must be set above the maximum third harmonic voltage that can be obtained during normal operation conditions. It must also be coordinated with the zero sequence neutral over voltage protection relay to prevent operation for blind spots resulting in low voltages which occurs when faults occur [8, 19].

Differential third harmonic ratio voltage scheme: In this scheme, the voltage is measured both on the neutral and terminals of the generator. This function operates like a differential element; during normal operation the third harmonic terminal and neutral voltage ratio remain fixed due to the zero sequence components. When an internal stator ground fault occurs, the ratio is altered except in dead zone areas. The change in ratio is used as a measure for detecting faults either at the neutral or generator terminals. A zero sequence overvoltage relay is used sense faults near the dead band areas. It is critical that before this method can be used, the third harmonic voltages should be measured in order to verify that they are sufficient for this method to be used especially when the machine is running at low speeds [20, 21].

2.3.2.2 Sub-harmonic Injection - 64S

This method uses the injected voltage to detect ground faults along the stator. The voltage is injected with the use of a transformer between the grounding element and ground. The grounding element may be a distribution transformer, reactor or resistor [22]. The injected voltage has a relatively low sub-harmonic frequency, usually a quarterly of the system frequency is chosen. The currents that are caused by the injected voltage are continuously measured. During normal conditions, this current will flow through the stator winding shunt capacitances to ground, once a ground fault occurs, the shunt capacitances are short-circuited and as result the magnitude of the current rises. From this principle, the relay can detect occurrence of ground fault by the change in current magnitude [23].

The benefit of this function is that the impedance of the stator capacitance reactance is increased by the low injected frequency which surges the reliability and sensitiveness of this element [23, 24]. Furthermore, the current is measured for the full quarter of the system frequency (12.5 or 20 Hz cycles) that is used, and this method also uses a coupling filter to block the fundamental frequency component of the signal [8]. The drawback from using this method is that it is expensive due to the additional equipment it requires for the injection of voltage. Figure 2-8 illustrates principle of operation of this protection method.

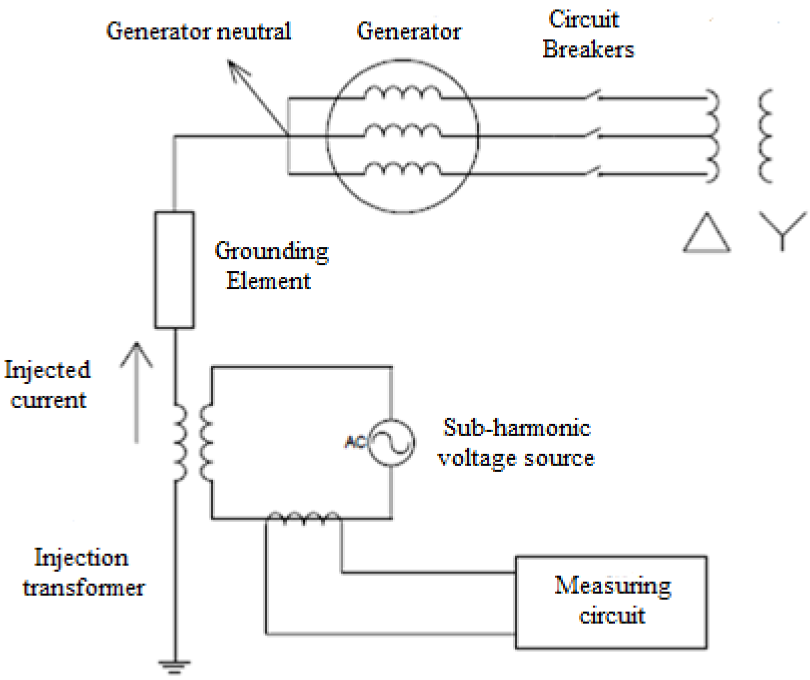

Figure 2-8: Sub-harmonic injection method [8]

2.3.3 Loss of Field Excitation

The loss of excitation on a generators can be initiated by numerous factors comprising of human error, generator excitation system failure, a short or open circuit in the field leads, unintentional tripping of the field breakers, or flashover of the exciter commutator. When there is a reduced or loss of excitation of the synchronous generator, conventionally it will start functioning like an induction generator. Thus, the unit pulls inductive reactive power from the system instead of supplying it to the system. If the system that the unit is connected cannot provide sufficient reactive power required for the generator to remain in induction generation mode, the generator will lose synchronism [25].

2.3.3.1 Concept of Loss of Field Excitation

In a synchronous generator, the rotor is driven by a mechanical prime mover; however DC current is required to energize the rotor magnetic field to create flux. The flux produces an internal voltage which is synchronism with the voltage of the system connected to it. During loss of field excitation, the decaying of the rotor current and internal generator voltage is determined by the field time constant. The reactive power output is directly proportional to the internal machine voltage. To replace the excitation previously provided by the field circuit, the machine will draw the reactive power from the system. The rated reactive power the generator is allowed to operate at may be exceeded resulting in instability of the machine and the system connected to it [3, 26].

The internal voltage to produce by the machine cannot be met and results in weakening of the magnetic coupling between rotor and stator leading to loss of synchronism.

To analyze the effects of the loss of field excitation event, the power angle equation is used. Figure 2-9 shows the decaying of the machine internal voltage associated with the power angle curve

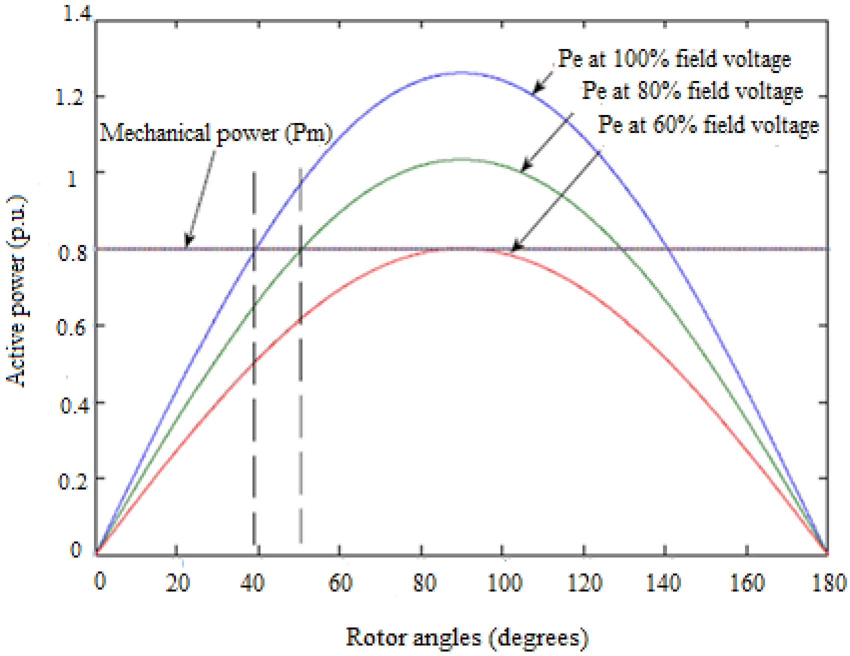

Figure 2-9: Generator active power versus load angle

The active power produced by the machine has a direct relationship with the internal voltage, current and the sinδ. The internal voltage and active power are a function of field voltage. The above figure shows the relationship active and mechanical power with respect to the operating angle of the machine and system voltage. The active power reaches its maximum at an operating angle of 90^0. Above this point, the generator cannot produce any active power; excess mechanical power in the system is dissipated by the increase in machine speed. However, an increased in speed leads to an increase in frequency putting the machine at a risk of losing synchronism. This unwanted operation also results in the machine running as an induction generator drawing reactive power from the system connected to it [4, 8, and 9].

2.3.3.2 Generator Damage Due LOFE

The damage that may occur on generator following a loss of field excitation relies on the design and conditions such as final slip during that scenario. Some of the factors that result are high stator currents and heating up of the stator and rotor cores. The reactive power drawn by the machine increases stator currents. The velocities of stator and rotor magnetic fields vary with the slip frequency. For a short circuit in the field winding, induced currents will flow through the rotor as well as on the field winding. Whereas an open field fault will cause excessive heating on the rotor and also create damaging over voltage transients in the field circuit [8, 9, and 27].

2.3.4 Over-excitation 24

A generator stator core is designed with a maximum magnetic flux density that it can operate at. If the generator is operated above this density, eddy currents and other conductive components will heat up the stator core causing significant damage over a short a period of time. The magnetic flux in the core is proportional to the voltage applied to the winding divided by the impedance of the winding. The flux in the core increases with either increasing voltage or decreasing frequency [8, 9]. Equation 2.1 expresses that the generator voltage is determined by the number of turns present in the output winding and the rate of flux in the magnetic core.

$$e = N\,\frac{d\varphi}{dt} \qquad (2.1)$$

Under normal operating conditions, the generator voltage the rate of change of flux is defined by the unit frequency which is also as a result of the speed the machine is running at. The association between the magnetic core flux and output voltage can be expressed in equation 2.2:-

$$\varphi_{max} = \frac{\sqrt{2}\,E_{RMS}}{N*2\pi f} \qquad (2.2)$$

Therefore, the core flux is directly proportional to voltage and inversely proportional to frequency as seen in equation 2.3.

$$\varphi \propto \frac{V}{f} \qquad (2.3)$$

It is difficult to measure the magnitude of flux in the generator stator core or transformer core. As a result, it is normally worked out as volts per hertz. Under normal operating conditions, a generator under no load with rated frequency and voltage would have one unit flux and hence at one per unit excitation. However, if the generator is operated at 105 percent above the normal rated voltage and frequency, it would have 1.05 per unit excitation. Hence an over-excitation condition results from increased voltage at normal rated frequency or from reduced frequency at rated voltage. This condition leads to dielectric breakdown of the insulation [8].

Generators and transformers can be exposed to recurring over-excitation by inappropriate operating practices or operator error without distracting other operations or the power system. Due to over-excitation being a function of voltage and frequency, it can occur without any warning. The thermal degradation of the insulation occurs progressively and the stator core failure may result in a catastrophic failure [28].

2.3.4.1 Causes of Over-excitation

The automatic voltage regulator primary role is to maintain the rated output voltage by controlling field current which creates field flux. As mentioned in section 2.3.4, the machine output voltage is a product of flux and speed. If the speed is reduced, the flux in the machine is increased to levels above the allowable limits leading to an over-excitation condition. This can be caused by the loss of the generator feedback voltage signal to the automatic voltage regulator. The regulator would increase the field current to excite the machine in an effort to rectify the condition. This could further result in the regulator maintaining maximum field forcing current which may lead to field overcurrent thereby tripping the related protection or the regulator itself. Nevertheless, the produced generator terminal voltage will exceed the rated voltage causing severe damage due to over-excitation [29].

Load rejection has been found to be other additional cause to over-excitation when it occurs with an automatic voltage regulator with a capacitive load in the system that the generator is connected to. Capacitive loads are normally added to the system to improve the reactive power supply. Regulators have a reactive power limiting function which reduces reactive power flow to the generator. The capacitive load must be rated such that it does not activate the regulator limit when it is in operation as it will increase the field current and hence the generator output voltage as well [8, 29].

2.3.4.2 Damage instilled by Over-excitation

Under normal generator operating conditions, the produced flux in the core will be within the range of the allowable saturation flux density. The produced flux will be restricted to the core due to the adequate core permeability. If the flux produced exceeds the allowable limit, the core will saturate and the excess flux produced will enter the non-laminated metallic materials around the core. This will produce eddy currents which cannot be handled by these materials resulting in component failure [8, 9].

The damage usually appears at the ends of the stator core. The high currents induced within the stator laminations by excess alternating flux can cause severe heating and create voltage gradients adequate to breakdown the inter-laminar insulation. This can damage the core permanently, making it unable of handling flux even under normal conditions due to arcing and over-heating. Repairing of the affected equipment is a very expensive procedure which includes restacking the stator core [8, 9, and 16].

2.3.5 Unbalanced Currents (Negative Sequence) – 46

Unbalanced currents are caused by various conditions. Some of the most common causes are unbalanced loads, unbalanced faults and open phases in the system. All these conditions produce negative phase sequence components which create double frequency currents in the slot wedges coil retaining rings in cylindrical rotors and in pole shoes in salient pole rotors. The excessive induced rotor currents can cause destructive temperatures in a short period of time [8, 30].

The design of any generator should allow it to be able to withstand negative sequence currents without damage for a specified time provided the apparent power rating of the machine is not exceeded and the allowable maximum current does not go above 105 percent of rated current in each phase. The concept of unbalanced currents also referred to negative sequence engrained to the theory of symmetrical components. Symmetrical components in a three phase system can be differentiated into negative, positive and zero sequence components. Positive sequence components of currents and voltages represent a balanced load as they follow the same rotation as the power system. Unbalanced loads create negative and zero sequence components which create issues in the system they operate in [24, 28].

2.3.5.1 Effects of Negative Sequence Rotor Heating

The magnetic field formed in the air gap rotates at synchronous speed with the same rotation as the generator rotor at the same velocity. This allows the field to uphold a fixed position and hence no current will be induced in the rotor windings. During a negative sequence condition, unbalanced currents exist in the system, new magnetic field are generated which oppose the magnetic field formed in the air gap. The newly formed magnetic fields also rotate at synchronous speed in an opposing direction. Due to this phenomenon, the field seems to be rotating at double the frequency. This causes double frequency currents to be induced in the rotor windings. The creation of these current results in over heating which may result in insulation failure, vibration and thermal expansion issues [8, 16].

Failures associated with this type of condition are overheating and coil retaining ring failures. The increase in temperature usually occurs along slot wedges which results in shear failure due to the force acting on the slot material. One of the critical aspects in cylindrical rotors is the shrink fit on coil retaining rings on the rotor body. The excessive heating can loosen the shrink fit causing the rings to lift from the rotor body. This leads to vibration and loss of electrical contact as well as arcing reducing the life of the retaining rings. Old design of coil retaining rings will tend to also suffer from stress crack corrosion due to localized high temperatures making the material brittle [1, 8].

2.3.5.2 Generator Negative Sequence Capability

A negative sequence protection element relies in two factors, the generator’s ability to withstand high rotor currents for an allowable time and the magnitude of I_2 the generator can tolerate continuously as shown in table 2-1. The impacts of negative sequence currents in any rotor are temperature dependent. The longer the time, the higher the damage. Therefore the settings are based on continuous unbalanced currents limitations depending on the machine equipment. The time at which this relay is expected to trip is also defined in a similar manner. The heat generated during this condition should not reach the thermal time constant of the materials used in the machine; in such situations the I^2t representation becomes overly conservative due to heat transfer [1, 8, and 9].

Table 2-1: Continuous Negative Sequence Capabilities [9]

Type of Generator	Permissible I_2 (%)
Salient Pole	
With connected armotisseur windings	10
With non-connected armotisseur windings	10
Cylindrical rotor	
In-directly cooled	10
Directly cooled	Up to 350 MVA – 8
	351 MVA to 1250 MVA – 8
	1251 MVA to 1600 MVA - 5

The IEEE Standards C37.102 – 2006 specifies the allowable short time and continuous negative sequence capabilities. It also states that any generator should be able to endure unbalanced currents that result in I_2^2t duties as listed in table 2-2.

Table 2-2: Short Time Unbalanced Current Limit [9]

Type of Generator	Permissible I_2^2t
Salient Pole	40
Synchronous Condenser	30
Cylindrical Rotor	
Indirectly cooled	30
Directly cooled	(0 MVA to 800 MVA) -10
	(801 MVA to 1600 MVA) – 5

The recommended limitations do not take heat dissipation into consideration for complex rotors designs. The standard also specifies that for any generator, faults should be limited at the generator terminals to prevent impacts of DC component of fault current.

2.3.6 Prime Mover Failure – 32

Loss of prime mover occurs when the synchronous generator loses its mechanical input while it is still in operation. If the generator field is still excited, the generator goes into reverse power mode and start acting like a synchronous motor. Prime mover failure can be very damaging to the generator if left undetected, the loss of steam in steam turbines can lead to lead distortion and softening of the blades. The damage caused by this condition also reduces the turbine's efficiency and ability to equalize heating resulting in hot spots which causes stress on the turbine [8, 9].

2.3.6.1 Impacts of Motoring

During the motoring condition there is inadequate steam flow in the turbine. The flow of steam is not only used for turning the turbines blades but it also cools them. Once the steam flow is lost, a temperature build-up occurs causing the blades to heat up resulting in distortion. Other impacts such as creation of hot spots have been discussed in the previous section [31].

In hydro turbines, when the water supply is lost, cavitation is one of the critical resulting aspects. This occurs mostly on hydro turbines with a low pressure. The low pressure towards the back of the turbine can produce low temperature steam bubbles resulting in blade surface fragmentation.

Engine driven generators are equipped with mechanical protection systems that shutdown the drive if mechanical failure occurs. In these types of units, motoring can be caused by the operation of mechanical protection systems causing further damage if the mechanical fault has not been cleared from the system. Another disadvantage is that motoring can further lead to explosion and fire because of unburned fuel [1, 8, and 31].

2.3.7 Abnormal Frequency Protection (81)

Abnormal frequency results from occurrences on the connected power system. The system frequency depends on the operating synchronous speed of the generator. Any divergence between the generated active power and the load in the system can result either acceleration or deceleration of the generation [1, 32]. Over-frequency which results operation occurs due to generation excess. It normally occurs subsequently to loss of major load or loss of a major tie on the transmission side. When this occurs the prime mover continues to supply mechanical input to the generator disturbing the equilibrium between the mechanical input and electrical power in the generator. The mechanical input exceeds the electrical power output resulting in the increase of generator synchronous speed. According to equation 2.4 synchronous speed is directly proportional to the system frequency and therefore in the case of increase of synchronous generator speed over-frequency results [8].

$$n_s = \frac{120 * f}{p} \tag{2.4}$$

Where:

n_s = synchronous speed [rpm]

F = Frequency [Hz]

P = Number of poles

The impacts of over-frequency on the generator do not have severe consequences. The situation can be amended rapidly by reducing the electrical power output using the governor or manual controls. The problem that raises concern with over-frequency is the increase in terminal voltage. The terminal voltage of a generator which is operating under the control of the manual regulator will increase proportional to frequency and the possibility of reaching the 105 % limit of terminal voltages arises [32]. Conversely, when the load on the system exceeds the generated active power the synchronous generator speed decreases and as a result under-frequency occurs. This condition can be caused by the loss of a large generator. The reduction in speed limits generator ventilation and hence, loads carrying capability [3].

2.3.8 Out of Step Protection - 78

Generators connected in parallel with each other or parallel to the grid operate at the same frequency and voltage of the network they connected to. The generators are given an allowance and tuned so that they can be able to handle system disturbances [9]. If one of the generator’s bonding forces becomes insufficient to have the generators linked with the rest of the generators, it loses synchronism and is said to be out of step with the other generators. Loss of synchronism can be caused by a variety of factors including network faults, loss of generation, load increase etc. This phenomenon is also known as pole slipping as the affected generated operates at a lower frequency then the normal operating frequency resulting in slip frequency. The other remaining generators in the system continue to operate with this slip frequency presence resulting in a production of pulsating current with peak magnitudes which could be higher than a three phase faults occurring at generator terminals [8, 33].

To prevent operational issues with the rest of the network, out of step protection should be applied as soon as it is detected and the affected generator must be isolated from the system. Previously, electrical centers were located on the transmission system and as a result out of step protection was provided by transmission line disregarding the need to trip generators. With increasing demand for electrical power the transmission system has expanded and continues to become stronger, the generator impedances have increased due to improved generator cooling methods which allow greater MVA capacity. Consequently, these improvements have allowed for electrical centers to be moved into the generator step transformer units and generator itself which has been found to be increasing stresses on both components. Therefore, a need for out of step protection to be employed at the generator was recognized due to electrical centers of swings which affect the generator and cannot be detected by network protection. The overcurrent relays employed for generator protection fail to reliably detect this condition. The produced pulsating currents are adequate to trigger the overcurrent relay but tripping of the relay relies on the duration of the excess which is determined by the slip frequency [8]. The following are the several schemes employed for out of step protection:-

1. Single MHO Scheme
2. Single Blinder Scheme
3. Double Blinder
4. Double Lens and Concentric Circle Schemes

Out of all these schemes, the single blinder is the most common. The tripping characteristic of the various types of out-of-step protection schemes is a two-dimensional area defined on an R-X impedance plane [1, 8, 9 and 33].

2.4 Generator Excitation Systems

The function of generator excitation systems is to provide direct current (DC) to the synchronous generator field winding, and to perform control and protective functions crucial to the satisfactory operation of the power system. The excitation system's performance necessities are determined by generator and power system considerations. The generator consideration include supplying and adjusting the field current as the generator output varies within its continuous capability as well as responding to transient disturbances with field forcing consistent with the generator short term capabilities. The electrical system utilizes different types of excitation systems depending on the application used which have different individual response times as they are classified into static and rotating excitation systems. Rotating exciters respond slower than static exciters. From these two categories results four basic types of excitation systems that are employed to control the output of ac machines:-

- DC generator commutator exciter
- Alternator rectifier exciter with stationery rectifier system
- Alternator exciter with rotating rectifier system
- Static excitation systems [7,8, 9]

2.5 Generator Grounding Systems

There are several grounding schemes used in practice. The type of grounding protection used is determined by the type of grounding method used. The grounding assists to reduce the mechanical stresses and fault current level which reduces the voltage transients and allows for suitable ground fault detection. Different methods used include the following:-

- Solidly grounded
- High impedance
- Low impedance
- Hybrid grounding and ungrounded grounding schemes [9].

Solidly grounded generators are directly connected to ground through the neutral point. With this method, the phase to ground fault currents tend to exceeds the fault currents obtained during three phase fault currents. The design of generators does not allow for a grounding system which cannot reduce the fault current level less than a three phase fault current. Therefore, this method is therefore only utilized if the zero sequence reactance can reduce the ground fault to below three phase fault current and the generator design can withstand high currents [8, 9, and 34].

High impedance grounded systems have a ground to neutral impedance that reduces the phase to ground fault current to a value between 10A or less. Low impedance grounded systems utilize low resistance concerning the generator terminal and the ground. The resistance should be designed in such a way that it can reduce the fault current to 200 Amps or less. This grounding scheme is further divided to three schemes which are the distribution transformer, high resistance and ground fault neutralizers [34, 35].

For an ungrounded system, there is no direct connection between the generator neutral and ground. A small ground fault current can flow due to the shunt capacitance in the system. Stator ground faults are a huge concern in an ungrounded system. The occurrence of arcing grounds can result in the damage of the welding in nearby laminations and harm the insulation between the laminations. In the times of faults in an ungrounded system, the fault current will cause overheating at the location where the fault has occurred which will cause additional deterioration of the stator insulation [12].

The type of protection used depends on the grounding arrangement used. For high impedance grounded system, stator ground faults do not cause mechanical stress on the generator stator. As a result, protection elements employed to detect faults in this system is more attentive to sensitivity when compared to the speed at which the element relay operates at. For grounded systems where the fault current level is not reduced to levels that will cause harm to the generator, the operating speed of relaying element is more critical [8, 12, 19].

2.6 Improvement in Generator Modeling and Testing

The size of the power has increased enormously over the years. This new large electric power network system contains of an enormous number of non-linear and linear elements which leads to a complicated dynamic behaviour by the system equipment. Synchronous generators are the principal source of electricity generation and therefore the analysis, design, and operation of such machines requires advanced tools and techniques to be used. Power system simulation software has tools that permit engineers to design as well as analyse power networks including the performance of individual machines or equipment [36, 37]. With the use of these tools, mathematical equations of the system can be formed and solved using numerical methods, providing a clearer understanding of the behaviour of the system without the field experiments or disastrous laboratory.

Prevailing methods of synchronous machines in electromagnetic transients programs employ the *dq0* theory to express the physical behavior of the machine in terms of mathematical equations. These equations are then normally executed in electromagnetic transients programs using the interfaced approach by solving machine equations in *dq0* frame and injecting machine currents into the network as current sources. Though these particular models are commonly used because of their fast algorithm and also that electric utilities usually have access to the *dq0* parameters of their synchronous generators, these model still fail to accurately foresee the transient performance of the synchronous machines in irregular conditions such as during the presence of internal faults or rotor eccentricity. They also do not take into consideration the effects of non-sinusoidal distribution of the windings and permeance in synchronous machines due to the fact that some essential assumptions of the *dq0* theory not being applied in such scenarios [36].

The RTDS now consist of a newly designed and developed phase domain synchronous machine model. The embedded phase domain approach [37] is used to implement this model in the environment of RTDS. The term phase domain means that the values of machine inductances change with respect to the rotor position and level of saturation. The term embedded means that the network solution is incorporated in solving the differential equations of the machine. This approach shows superior numerical performance in comparison with the conventional interfaced approach [36]. The phase domain synchronous machine model can use two methods to compute the inductance matrix of the machine which is the *dq-* based method and MWFA method:-

DQ−Based Method: In this approach, it is assumed that not only the healthy windings create a perfect sinusoidal distributed magneto−motive force (MMF), but also the MMF due to the faulted windings will be sinusoidal. The advantage of this method is that the users do not need to know the information about the distribution of the windings and rotor geometry. This method however does not show the phase−belt harmonics (3rd, 5th, and 7th harmonics due to the non−sinusoidal distribution of the windings [38].

MWFA-Based Method: This method is based on the Modified Winding Function Approach in which the actual distributions of the windings are considered in computing the inductances of the windings. The minimal data required to use this model is the number of poles, number of stator slot, actual distribution of the windings, and the geometry of rotor poles. In contrast to the dq-based approach, this method correctly represents the phase−belt harmonics [37, 38]. However, this method is not available to user so the d-q based method was used for this project.

Electromagnetic transient simulation programs also known as the EMTP programmes are simulations tools employed to accurately analyse the behaviour of power systems in the time domain. These simulation programmes are used in a wide range of applications such as harmonic analysis, power stability studies, power system controls etc. The drawback with these simulators is that they do not permit for dynamic testing as they cannot allow for internal faults to be applied directly to the stator winding in synchronous generators [39]. For a complete generator study to be examined, the control of its electrical parameters must be made possible. For a prime mover, the system should be able to control or achieve constant speed, real power and be able to match gains and time constants. The excitation system must also be capable of achieving constant voltage and/or constant reactive power together with its gain and time constants. The system must be able to adjust all these parameters to meet up with the current generation parameters.

However, running an electromagnetic transient simulation program in real time allows for simulation results to be synchronized with the real world phenomenon [37] making it possible to interface the actual hardware equipment and analyse its behaviour under real world conditions. The use of the real time digital simulators have made it possible to conduct Hardware-in-Loop (HIL) tests, which have been proved to be the key platform for power devices [38]. Closed-loop testing is characterized by taking output signals from the simulation, and using them as input signals to a device under test. The output from the device under test is then fed back into the simulation, thereby affecting the simulation. This type of testing most closely resembles the actual performance of the device in service. More on closed-loop or HIL test will be discussed in the following chapter.

2.7 Conclusion

This chapter has presented a literature survey to emphasize the integral objective and significance of power system protection. The fundamental principles that govern the operation of the protection relaying systems as well as their functional characteristics have been discussed. A brief theory of synchronous generators, excitation and grounding systems have been presented. Furthermore, the chapter focuses on the generator protection elements, going into detail about their impacts on the generator operation and how the different abnormal conditions affect the power system. It also looked at the different protection methods used for ground protection.

The chapter concluded with the improvements in generator modelling and testing. The drawbacks of analogue or EMTP- type simulators in the modelling as well testing of generator protection elements were discussed. The phase domain synchronous machines obtained in RSCAD software was discussed, with the focus on its different types of models and it success in making generator protection studies more efficient and accurate.

CHAPTER III

METHODOLOGY

3. Introduction

This chapter serves to present the methods used in achieving the objectives of this research as stated in chapter 1. The theory of the different generator protection methods to be simulated and tested has been reviewed in the previous chapter as well as their impact on the generator and power system connected to affected generator. This research was conducted on a study system that has served as a benchmark for power system stability studies. The model was constructed on the RSCAD software which is a simulation package for the Real Time Digital Simulator. This arrangement permits for hardware in-loop testing of protection relays. Therefore, using generator protection relays generator protection elements can be tested more realistically.

There are different types of generator protection relays and those used in this research are reviewed individually. Communication channels between the hardware relays and the simulator allows for sending and receiving of signals such as tripping of the hardware relay as well as operation of the circuit breaker to isolate the faulted section or equipment.

3.1 Study System Model

The model of the system used in this study is a well-known model used mostly in stability studies. It consists of a 555 MVA generator connected to a step-up transformer which is also coupled to an infinite bus through two parallel transmission lines as shown in figure 3-1. This model is generated from [15] where there are four 555 MVA generators, but for the purposes of this study only one generator was used. The generator is also connected to generator controllers and due to the effect of generator protection on system disturbances and vice versa, the simulation also made use of the power stabilizer and excitation control systems. Therefore, the generator has inputs for governor/turbine and exciter interfaces.

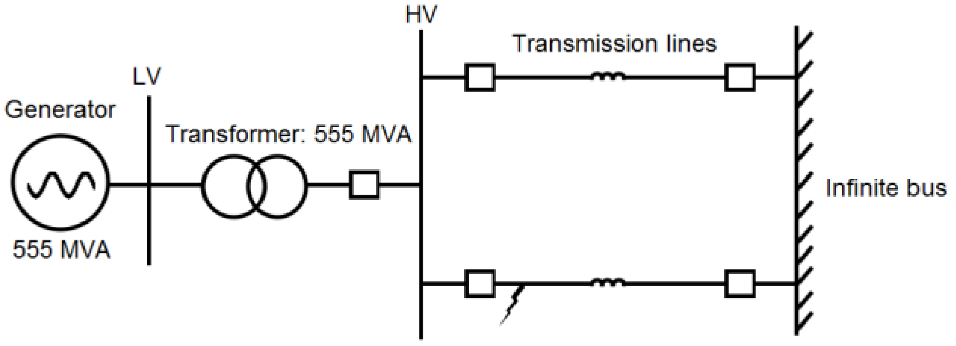

Figure 3-1: Test system model [15]

3.2 Real Time Digital Simulator - RTDS

The simulator used in this thesis is the RTDS Simulator from RTDS Technologies Inc. [6]. It uses a custom parallel processing hardware architecture assembled in modular units known as racks. The racks contain slots and rail mounted cards. There is a common communications backplane which links all rack-mounted cards enabling sharing of information. Communication of data is done in parallel by having individual backplane functions for each rack. The RTDS hardware uses a GPC (Giga Processor Card) [26] to execute the network solution. The computations required to model the user's power system components are performed on Triple Processor Cards (3PC) [26] or other GPC cards. The computed history terms and admittance values are then transferred through the backplane communication channels to the GPC card, which runs the network solver.

The simulator consists of a graphical user interface known as the RSCAD Software Suite. The software is the user's main interface with the RTDS software and contains modules designed to allow the user to perform all the necessary steps to compile, run the simulation (done on a draft module) and analyze the simulation results (runtime module) [6], [26]. Models are implemented with a limited number of instructions in the range of the computational capacity of 3PC and GPC cards to ensure a real time simulation [26]. Figure 3-2 shows the designed model used for this which is a resemblance to that shown in figure 3-1.

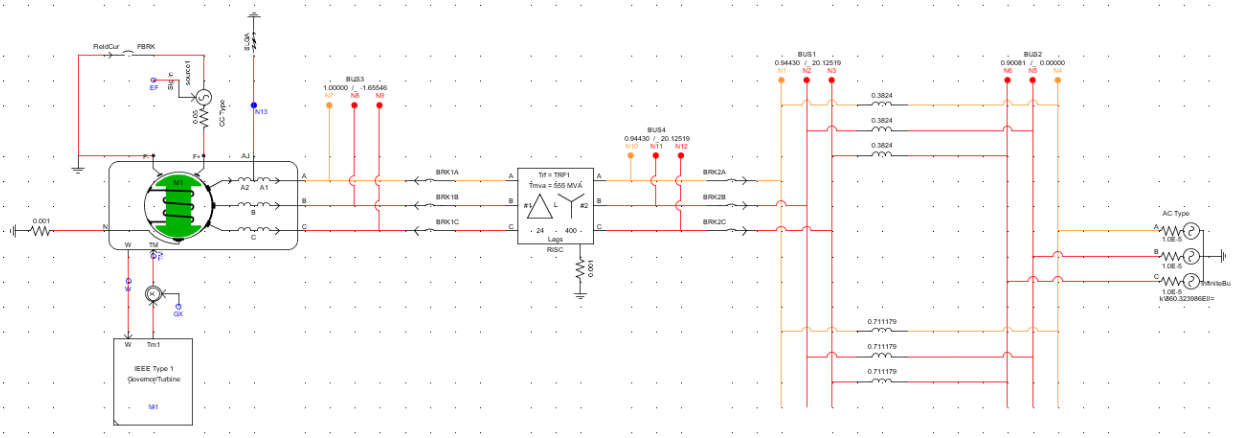

Figure 3-2: Test system model in RSCAD

The phase domain feature of this model makes it capable of simulating synchronous machines internal faults. To be able to simulate generator internal stator winding faults, the self and mutual inductances of machine stator windings including faulted windings must be computed as functions of rotor location and saturation. The phase domain synchronous machine model can use two methods to compute the inductance matrix of the machine which are the DQ- based method and MWFA method.

DQ−Based Method: In this approach, it is assumed that not only the healthy windings create a perfect sinusoidal distributed magneto−motive force (MMF), but also the MMF due to the faulted windings will be sinusoidal. The advantage of this method is that the users do not need to know the information about the distribution of the windings and rotor geometry. This method however does not show the phase–belt harmonics (3rd, 5th, and 7th harmonics due to the non–sinusoidal distribution of the windings) [14].

MWFA-Based Method: This method is based on the Modified Winding Function Approach in which the actual distributions of the windings are considered in computing the inductances of the windings. The minimal data required to use this model is the number of poles, number of stator slot, actual distribution of the windings, and the geometry of rotor poles. In contrast to the do-based approach, this method correctly represents the phase–belt harmonics [14]. However, this method is not available to user so the d-q based method was used for this project.

This system uses the same parameters for the generator as well as for the transmission line used in the previous model. The only difference is that, a step up transformer is added since this model does not have an option of including the step up transformer.

3.2.1 Closed-Loop Testing Method

Closed loop testing has made it possible for protection engineers to determine how the relay operates for a given fault condition. It allows one to analyze the behavior of the relay succeeding to initial operation (for reclosing strategies). With this arrangement, protection engineers can analyze the effect of the relay operation on the power system and its stability.

Closed loop testing has made it possible for protection engineers to determine how the relay operates for a given fault condition. It allows one to analyse the behaviour of the relay succeeding to initial operation (for reclosing strategies). With this arrangement, protection engineers can analyse the effect of the relay operation on the power system and its stability. The interaction between the individual protection relays in a full protection scheme during the response to fault conditions and also consider the effect of inaccuracies, non-ideal characteristics or errors in measurement. Investigations and troubleshooting of field events where relays are found to operate differently in practice than expected can also be conducted using this arrangement [11]. Figure 3-3 shows the equipment and method of testing used in this study.

Instrument transformers are included in the simulation model of the protected plant for the purpose of measurement and their secondary quantities are exported to analogue output cards that form part of the real-time simulator hardware. Analogue amplifiers then amplify the analogue signals at the output of the simulator to the magnitudes which correspond to the secondary output variables of the instrument transformers within the real-time model. The outputs of these amplifiers, representing the secondary voltages from voltage transformers and secondary currents from current transformers within the real-time model, are injected into the normal measurement inputs of the SEL 300G generator protection relay that is under study.

Various protection elements are implemented inside the SEL 300G generator protection relay in order to respond to different system contingencies and fault scenarios. When the protection relay makes a decision to trip the generator in response to a fault on the generator or some other stability issue, the relay's trip signal is sent back to the real-time model via a digital input panel on the simulator in order to open the corresponding circuit breakers to clear the fault. For example, in the event of a stator ground fault on the stator winding, the relay will sense the internal stator winding fault and issue a signal to open the main's circuit breaker as required.

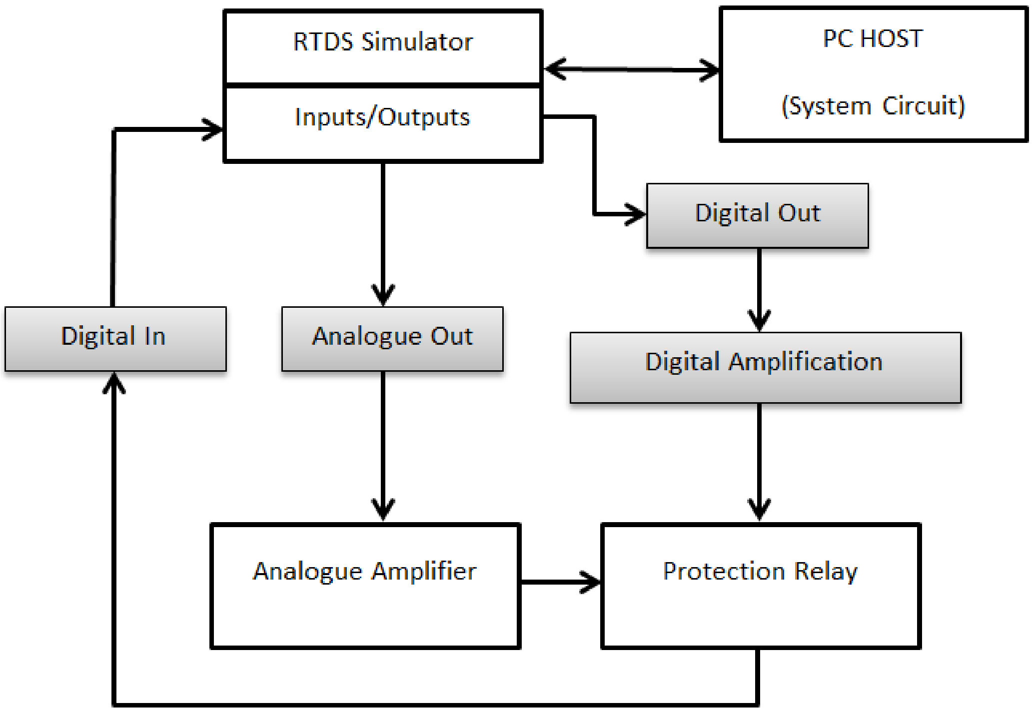

Figure 3-3: Closed loop testing of the SEL 300G generator protection relay using the RTDS system

3.3 Generator Protection Abnormal Element Settings

3.3.1 Over-Excitation (24) Settings

According to the [IEEE gen protection standard guide] over excitation of a synchronous generator or transformer will occur if the voltage to frequency exceeds 105 percent for a generator operating at full load or 110 percent at no load. Over-excitation of generators or transformers leads to saturation of the stator magnetic core which results in the induction of stray flux in non-laminated components. As discussed in chapter 2.3.4 generator voltage is directly linked to frequency and flux, thus the use of voltage per frequency to detect over excitation is adequate for this function.

The protection relay detects over excitation by using the ratio of voltage and frequency to estimate the flux in the magnetic path. If the voltage to frequency increases above threshold settings, the protection relay will detect this scenario and will operate the main breaker. The time delay curves can be set either as definite-time or inverse time.

This protection element uses two level volts per hertz units. The first element level setting is set to operate at 105 percent of rated voltage acting as an alarm activated after 30 seconds. In practice this allows for time to rectify the issue of for the system disturbances to ride through. The trip is set at 110% of rated generator voltage to trip at a time delay of 6 seconds. The trip signal opens up the main breaker, field breaker and other auxiliaries if the need arises. The settings description for the SEL 300G protections were tabulated as follows:-

Table 3-1: Settings description for the volts/hertz protection element for the SEL 300G relay.

Function	Setting
Volts/Hertz Alarm set point	1.05 p.u.
Alarm Definite-Time Delay	30 seconds
Volts/Hertz Trip Pickup	1.1 p.u.
Trip Definite-Time Delay	6 seconds

3.3.2 Reverse Power (32) Settings

Generator protection relays are able to measure the real-power flow from the generator terminals. For reverse power, the manufacturer gives the amount of power consumed by the unit during motoring. The real power is given in kW. This power differs from turbine to turbine with steam turbines requiring from 0.5 to 3.0 percent kW and hydro turbines with their blades above the tail-race water level needing only 0.2 to 2 percent kW of their name plating rating.

The theory of operation of this protection element is similar to other element, when the measured real-power is below the element setting then the protection relay detects loss of prime mover condition, a definite timer is started and eventually a trip signal is issued. The SEL 300G provides two reverse-power thresholds. This function offers two set points, it is up to the user to use both or one which can be used as a tripping interlock for generator controls.

To accurately set this element, the prime mover's manufacturer rated motoring power, generator rated power and the motoring withstands time limit are needed. For this research a steam turbine was used, and according to the [IEEE standard], the reverse power during loss of prime mover is about 1 % of nameplate. Therefore a typical setting would be 0.5 % of nameplate and the motoring value can be calculated as follows:-

$$Motoring\ value\ (rated\ motoring\ power) = 2.39\ MW \quad (3.1)$$

The prime mover rated motoring power can also be calculated as follows:-

$$Per\ unit\ motoring\ power = -\frac{Rated\ motoring\ power}{Generator\ rated\ power} \quad (3.2)$$

In a motoring condition, the flow of current changes direction. It is therefore critical that this condition be detected. To ensure protection system reliability, a safety factor is added to account for errors in protection and instrument measuring equipment. A multiplier of 0.5 to 0.7 assures secure detection of low power levels such as 0.01 per unit. Therefore a multiplier of 0.7 was chosen for this study which gave us the following level setting:-

$$Pick - up\ (level\ 1\ power\ threshold) = -0.00355\ per\ unit$$

$$Time\ delay = 20\ seconds$$

This time delay can be set between 20 and 30 seconds to prevent relay from operating for power swings. The relay trip signal can be used to detect low forward power or overload conditions or used for sequential tripping which was not investigated for this study. If the trip signal is used for consecutive tripping of other breakers or inputs controls to the prime mover, the relay trip set point must be set on a positive (forward) power value. The power range can be set between 5 to 10 percent of the active power rating of the machine. Table 3-2 shows the settings description for the SEL 300G protection relay used for the loss of prime mover element. For this condition, only the main breaker and the field breaker are tripped.

Table 3-2: The settings description for the SEL 300G protection relay used for the loss of prime mover element

Function Description	Setting
Level 1 Reverse Power set point	-0.00355 per unit
Level 1 Reverse Power Definite-Time Delay	20 seconds
Level 2 Reverse Power set point	-0.00507 per unit
Level 2 Reverse With Definite-Time Delay	2 seconds

3.3.3 Loss of Field Excitation

As mentioned in chapter 2, the performance of the generator in terms of the active and reactive power it delivers is largely related to the generator capability which in turn is limited by the Generator

Capability Curve (GCC) which is given by the manufacture of the generator, the Under Excitation Limit (UEL) and System Steady-State Stability Limit (SSSL). During loss of field excitation conditions, the generator operates below the UEL which can harm not only the generator but the unit as whole threatening voltage and long-term stability of the system. The fall of internal voltage results in no intersection point between mechanical power and electrical power resulting in loss of synchronism.

There are two standard distance relaying protection schemes used at the generator terminals to detect loss of field excitation: negative offset mho and positive offset mho. The operating principle of these two schemes relies on the fact that during loss of excitation, the impedance locus as seen from the generator terminals moves to the impedance cycle of the R-X plane recommended by the IEEE for positive and negative offset MHO operation.

The standard settings for this scheme in the R-X plane is a circle with mho diameter and negative offset which is shown in figure 3-4 below followed by the calculations for both zone 1 and zone 2.

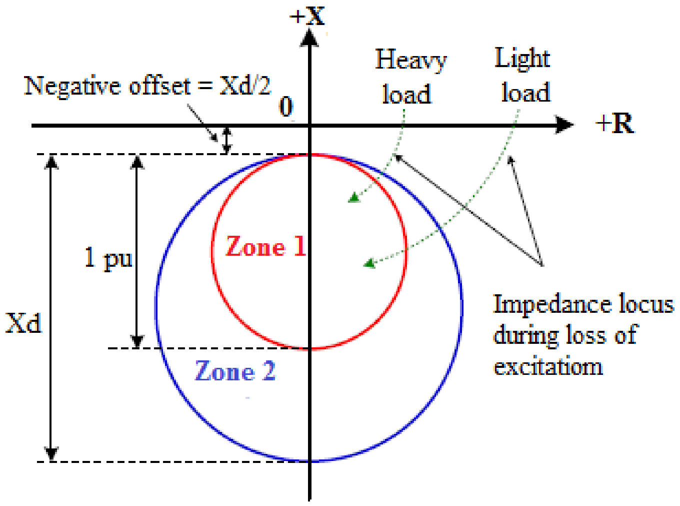

Figure 3-4: Loss of excitation protection scheme using a negative-offset mho element

If the measured impedance at the generator terminals falls into the operating region (inside zone 1 or zone 2), the relay will detect the scenario as loss of field excitation and operate after an intended time delay and a trip signal will be sent to the generator main breaker and field breaker. The relay settings are based on CT and VT secondary quantities, the impedances were calculated on the CT and VT secondary basis.

Generator ratings (primary):

$Ibase = \ 13.35\ kA \qquad Vbase = 13.86\ kV$

Secondary relay quantities:

$VT\ Ratio = 218.18 \quad CT\ Ratio = 5000{:}1$

$$Nominal\ VT\ secondary{:} V_{NOM} = \frac{Vbase}{VT\ Ratio} = 63.51\ V \tag{3.3}$$

$Nominal\ CT\ secondary{:}\ I_{NOM} = 2.67\ A$

$Nominal\ (1.0\ per\ unit)\ impedance{:}\ Z = 23.78\ \Omega$

From generator parameters:

$x_d = 1.81 \quad x_d{}' = 0.3$

Zone 1 settings:

$Diameter(for\ 1.0\ per\ unit) = 23.78\ \Omega$

$$Offset\ reactance = -\frac{x_d{}'}{2} = -3.57\ \Omega \tag{3.4}$$

$Operate\ time\ delay = 0.1\ seconds$

A short time delay of approximately 0.1 s is suggested to prevent unnecessary operation during switching transients.

Zone 2 settings:

$Diameter{:}\ x_d = 43.04\ \Omega$

$$Offset\ reactance = -\frac{x_d{}'}{2} = -3.57\Omega \tag{3.5}$$

$Operate\ time\ delay = 0.5\ seconds$

The minimum time delay of 0.5 s is typically used to prevent relay disoperation during power swing conditions. Table 3-3 shows the settings of this element as configured on the SEL 300G generator protection relay.

SEL 300G Generator Protection Relay

The SEL-300G uses the same principle used by the multifunction generator relay in RSCAD to detect loss of field excitation condition. This principle was discussed in section 2.3.3. Generally zone 1 time settings are set with a smaller time delay in order to react quickly in the case of loss of field excitation occurring under full load conditions. Zone 2 is set to have a longer time delay to ensure the relay trips even under light load conditions.

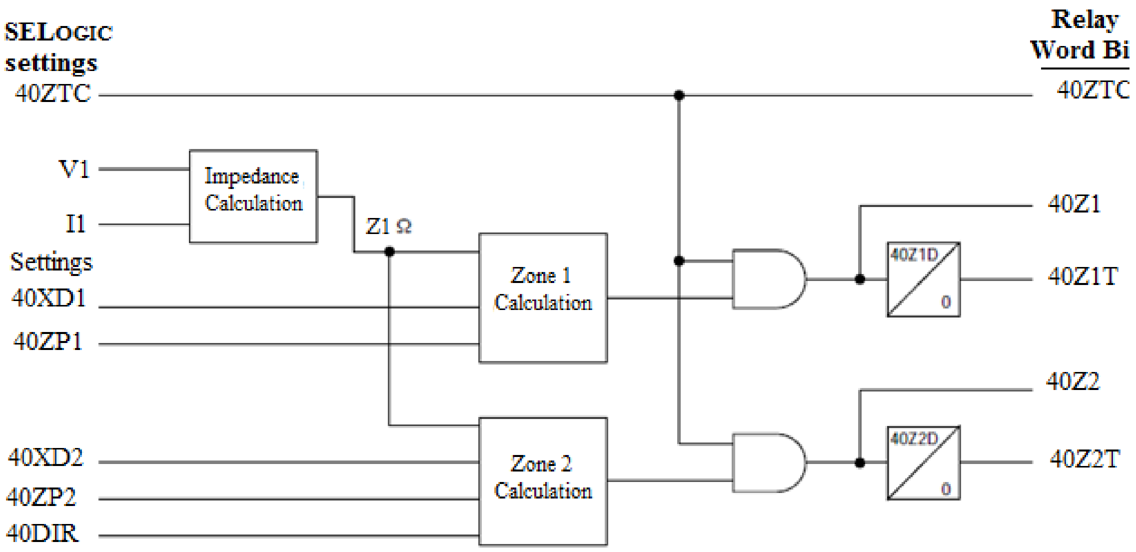

Figure 3-5: Loss-of-field excitation logic diagram

Table 3-3: Loss of Field Excitation settings using negative MHO element

Relay Word Bit	Function Description	Settings
Zone 1 Settings		
40Z1P	Zone 1 MHO Diameter (Ohms)	23.78
40XD1	Zone 1 Offset reactance (Ohms)	-3.57
40Z1D	Zone 1 Delay time (Seconds)	0.1
Zone 2 Settings		
40Z2P	Zone 2 MHO Diameter (Ohms)	43.04
40XD2	Zone 2 Offset reactance (Ohms)	-3.57
40Z2D	Zone 2 Delay time (Seconds)	0.5

3.4 Phase Over-current Fault Protection Over-current (51P)

3.4.1 Phase Over-current Voltage Restraint (51V)

These relays are used as back up protection in low resistance grounded generators for differential protection. This element causes the pick-up current to decrease with reduction in voltage. The pick-up setting was set to 150 % of the full load current. The voltage was set according to the bus voltage of the system. The operating time can be set according to the inverse curves. When the generator nominal voltage is at 100 percent the relay operates at 100 percent of its pickup setting. When a fault occurs the system voltage is reduced, the relay trip set points is also reduced as the generator phase to phase decreases.

$$51V\ Pickup\ Setting = \frac{Maximum\ load\ current}{Current\ Transformer\ Ratio} \times 1.5\ \ Amps \tag{3.6}$$

The curve shape selected for this study was instantaneous; however in practice the curve shape and dial must be chosen to allow the element to coordinate with the differential protection settings as it would normally be the primary protection for this application. This element is also torque controlled by a loss of potential additional element which prevents operation of the 51V to prevent operation of the relay if a potential transformer fuse blown condition occurs. Figure 3-6 illustrates the relay operational characteristics showing the direct proportionality between the phase-to-phase voltage and the pickup setting. At 25 percent of the nominal phase-phase voltage, the relay uses pickup setting obtained at 25 percent of the relay setting.

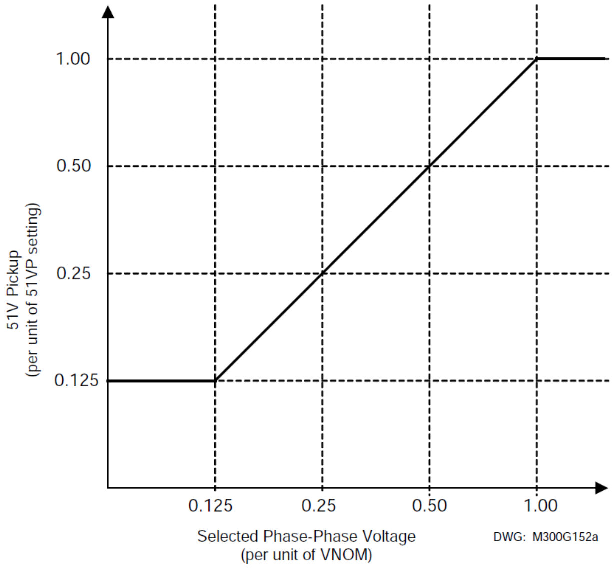

Figure 3-6: 51V element voltage restraint characteristic

3.4.2 Phase Over-current Voltage Controlled (51C)

For this function, the current pickup is set below the rated current and the operation of the relay is blocked until the voltage drops to a pre-set nominal voltage. The function is normally set at 80 percent of rated voltage with a current pickup of 50 percent of generator rated current.

$$51C\ Current\ Pickup\ Setting = \frac{Maximum\ load\ current}{Current\ Transformer\ Ratio} \times 0.5\ \ Amps \tag{3.7}$$

$$51C\ Voltage\ Pickup\ Setting = Nominal\ Voltage \times 0.8\ \ Volts \tag{3.8}$$

Similar to the voltage restraint, this element also needs to torque controlled by the loss of potential function. Additional to that function, the voltage controlled element is also torque controlled by an under-voltage element. For the purposes of this study the curves and operational times chosen were similar used for the voltage restraint element.

Table 3-4: Voltage-controlled and voltage-restrained time-overcurrent settings

Relay Word Bit	Function Description	Setting
51V	Voltage-Restrained Over-current Pickup	4.005 Amps
51VT	Voltage- Restrained Time-O/C Trip	0.2 seconds
51C	Voltage-Controlled Current Pickup	1.335 Amps
51CT	Voltage- Controlled Time-O/C Trip	0.2 seconds
27PP1	Phase-to-Phase Under-voltage Pickup	88 volts

3.5 Stator Ground Fault Protections

3.5.1 Differential Protection

Differential protection is based on the fact that it is only in the case of faults internal to the zone that the differential current will be high (the differential current is the difference between the output and input currents of the protected zone). The relay must first be set up according to calculations and standard setting points of the power system. This is to ensure maximum protection of the equipment to be protected. One of the most important settings is the minimum operating and restraining currents. The operating current is calculated as follows.

This current would be flowing through the relay operation coil under normal conditions.

$I_{OPMIN} = 0.25\ Amps$

This is the minimum relay setting of I_{OPMIN} in the relay therefore, this setting is used. In practical, slope 1 is normally set at 25%. Therefore, to set the minimum restraining current (I_{RSTMIN}), the following formula is used:

$$I_{RSTMIN} = \frac{I_{OPMIN} \times 1}{Slope\ 1} \qquad (3.9)$$

The slope1/ slope2 break point is given by the following.

$$I_{RS} = I_{RSTMIN} \times I_{R_S} \qquad (3.10)$$

Where IRs is a multiplying factor and the minimum is 2 for the RTDS relay. The slope 2 is normally set from 50% to 100%. For this practical, 80% is used. The relay must have an upper limit of the operating current. This is to prevent excessive through fault by initiating tripping if this value is exceeded. Normally transformers are equipped with the overcurrent relay for this purpose. This acts as a backup to the overcurrent protection. The restraining current at the maximum operating current if found using the following formula.

$$I_{ORS} = \frac{I_{RS}}{Slope\ 2} \tag{3.11}$$

The amount of operating current necessary to make the relay operate does not increase beyond this breakpoint value times the HI Set PU setting parameter. The high set value is selected as 3. The diagram below shows the curve used to set up the differential protection relay.

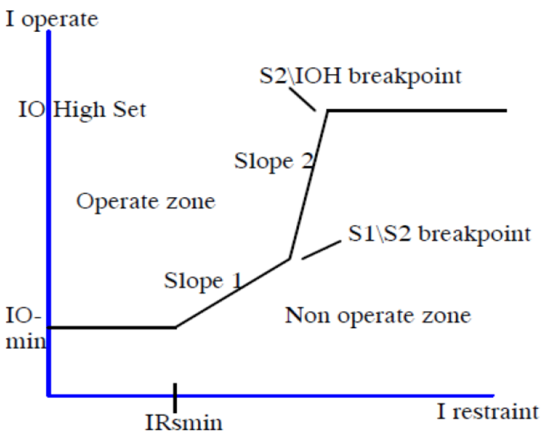

Figure 3-7: Dual slope differential curve

The purpose of the dual slope differential protection shown in figure 3-7 on the generator is to prevent the relay mal-operation during heavy out of zone faults. The relay setup is similar to the transformer relay settings; except that there are no harmonic settings and the differential operating minimum current setting could be very low.

Table 3-5: 64G Relay settings

Relay Word Bit	Function Description	Setting
LoSetB1	Minimum Operating Current	0.25 Amps
IRsB1	Slope1/ Slope2 Break Point	2 Amps
HiSetB1	Maximum Operating Current	2.5 Amps
Slope1B1	Slope 1	30 %
Slope2B1	Slope 2	80 %

3.5.2 100% Stator Ground Fault Protection for High Impedance Grounded Generator

The generator relay offers two elements (64G1 and 64G2) that offer full protection against stator to ground faults. The 64G1 element uses the voltage produced across the neutral impedance which is proportional to the location of the fault in the winding. As a result, faults from 100 % down to 5-10 % of the winding can be detected by measuring the fundamental neutral voltage. The 64G1 element is effective in detecting stator faults in the neutral dead band. The neutral voltage is calculated and compared to the setting threshold. If the voltage is greater than the threshold a timer is started and if the threshold is exceeded longer than the time delay the element operates. The 64G2 uses the third-harmonic voltage differential element which measures the third-harmonic voltage magnitudes at the generator terminals and neutral point. If the difference between the measured third-harmonic voltage magnitudes is greater than the setting, the relay operates. To set this element, the 3rd harmonic voltages from the neutral and terminal points of the generator were monitored using the relay and measured in runtime using a vector display.

As mentioned in section 3.3, the dq-based faulted generator model does not produce the winding- and permeance-related harmonics. Some of these harmonics such as the required third harmonic of the neutral and terminals are used for protecting the stator of synchronous machine against the ground faults. These harmonics however can be generated and added to the terminal and neutral voltage and passed to the relay as shown in the following figures. The third harmonic voltage across the windings is proportional to the active power of the machine [11], [14]. The grounding method was incorporated into the artificial third harmonic voltage generation method that was used. The generated third harmonic voltages both at the terminals and neutral of the generator also depend on the capacitances and earthing resistances and therefore the stray capacitances were included to ensure that the model is as representative as possible.

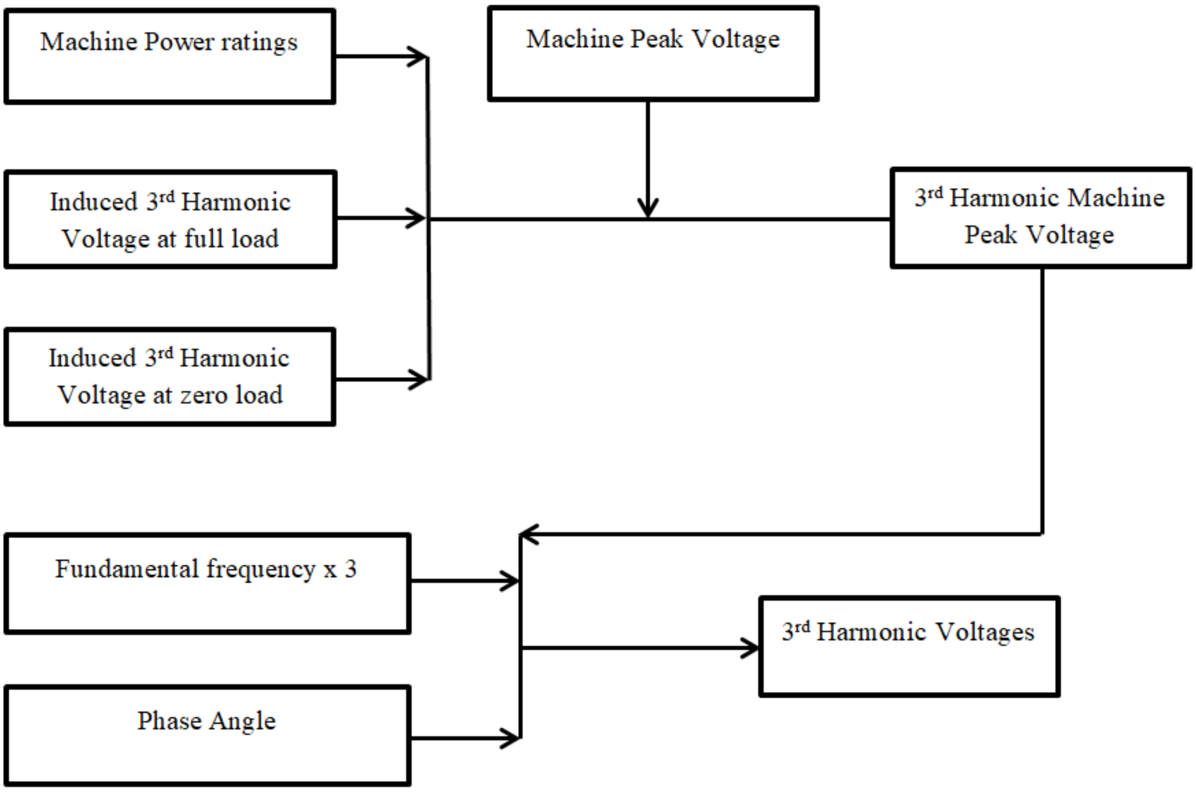

Figure 3-8: Generation of the 3rd harmonic voltage

The circuit in Figure 3-8 shows the generation of the 3rd harmonic voltage across a synchronous machine winding. Figure 3-9 shows the equivalent circuit for the sources of the 3rd harmonic and the neutral impedance and stray capacitances that these sources see. The required input for this circuit is the percentage of the 3rd harmonic in full load and no load of the machine. A grounding transformer was used which reduces the fault current to a range of 3 – 25 A [5]. The IEEE standard C37.101 [18] was used to calculate the size of the secondary resistor which limits the fault currents. The secondary resistor of the grounding transformer was calculated to be 0.271 Ω. finding the exact value of this resistance is not critical since the equipment capacitive tolerances and resistances change due to temperature rise. The maximum stator-ground fault current that flows through the primary winding of the grounding transformer was found to be 5.11 A

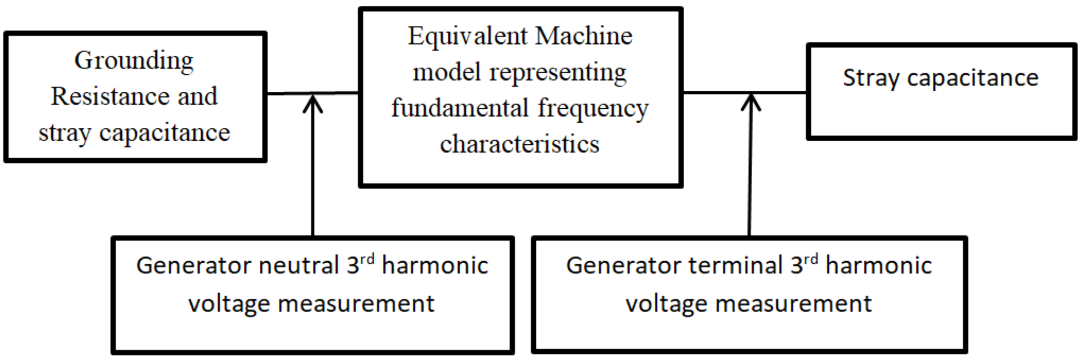

Figure 3-9: Simulation of the 3rd harmonic voltages during faults

The setting for the 64G1 element is calculated as follows, assuming 95 percent coverage across the stator winding. Table 3-6 illustrates the final settings used for this element

$$64G1P = \left(1 - \frac{95\ \%}{100\ \%}\right) * \left(\frac{kV \times 1000}{1.73 * PTRN}\right) = \left(1 - \frac{95\ \%}{100\ \%}\right) * \left(\frac{24\ 000}{1.73 * 100}\right) = 6.94\ Volts \qquad (3.12)$$

Where:

kV = Rated generator line-to-line voltage

PTRN = Ngt • Nat,

N_{gt} = Ratio of the grounding transformer

N_{at} = Ratio of auxiliary transformer

Table 3-6: Measured neutral and terminal voltages at no load and full load

Measured 3rd Harmonic Voltages – 0 % Load	
Generator terminal (VP3_NL)	2.3
Generator neutral (VN3_NL)	6.4
Measured 3rd Harmonic Voltages – 100 % Load	
Generator terminal (VP3_FL)	7.3
Generator neutral (VN3_FL)	14.5

$$64G2RAT = \frac{(\mathrm{VN3_{NL}})+(\mathrm{VN3_{FL}})}{(\mathrm{VP3_{NL}})+(\mathrm{VP3_{FL}})} = 2.18 \qquad (3.13)$$

$$\text{64G2P: StrVal642} = 1.1 * (0.1 + |64G2RAT * (VP3x - VN3x)| \qquad (3.14)$$

$$\text{64G2P: StrVal642} = 17.378$$

Where:

VP3x = third harmonic terminal voltage, VP3, for the given load point

VN3x = third harmonic neutral voltage, VN3, for the given load point

Higher values for 64G2P will generally increase the security of the element [17].

It is also important to note how the two elements complement each other, the failure of the overvoltage relay to operate for faults near the neutral and at this section the overvoltage relay is complemented by the third harmonic voltage ratio protection element. Together these elements are referred to as 64G from generator protection elements list. Figure 3-10 shows the relationship between the 64G1 and 64G2.

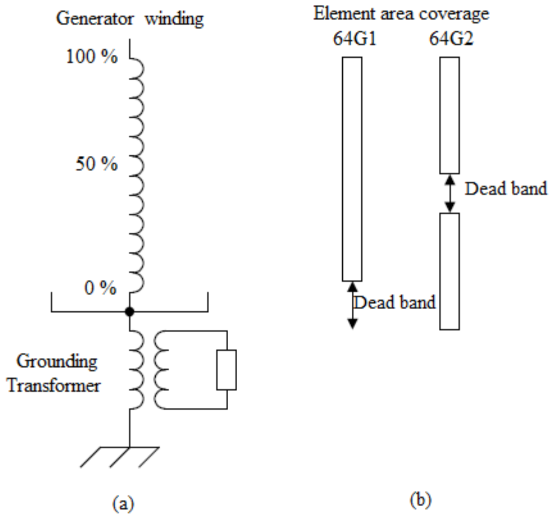

Figure 3-10: 64G element operating characteristics [12]

3.6 Conclusion

In this chapter the settings of each protection element has been discussed in detail to provide understanding during fault event analysis. The study system of which all the protective functions are based has been discussed taking into consideration all the necessary calculations for each element, where assumption were made it was clearly stated. The Real Time Digital Simulator to be used in this study was also discussed, together with the hardware close-loop testing method.

CHAPTER IV

BASIC GENERATOR PROTECTION ELEMETS

4. Introduction

This chapter aims to illustrate the impact of basic generator protection abnormal conditions. The study system was modeled and simulated under various abnormal conditions using the RSCAD software. There are several abnormal conditions that can result in generator damage and numerous natures of faults that the generator may be exposed to which the generator must be protected against. For this study, the focus was only on over-excitation (24), loss of prime mover (32) also referred to reverse power protection, loss of field excitation (40) and phase-overcurrent with voltage restraint/control function (51VC).

The previous chapter focussed on the settings of the individual protection elements and the relay logics used. For this chapter the study was based on the low resistance grounded generator in the study system used for this thesis.

4.1 Normal Generator Operating Conditions

Active power load is one of the critical generator operating parameters. It gives an indication of the generator performance. It represents energy flow. An excess increase in active power indicates overloading of the generator. This means that the generator is operating at or above its stator current limit. Active power is dissipated on resistance as heat, high stator currents causes' thermal stress on the insulation winding.

High excessive generator voltage can lead to an overload scenario which can heat up the core. For this research, under normal conditions the generator at full load was found to be operating at 500 MW and 242 MVAR as shown in figure 4-1 and figure 4-2.

Reactive power in synchronous generators is determined by the amount of field current used to excite the rotor field. It is a function of the generator stator terminal voltage and current. Reactive power has a direct impact on the generator loading. If active power is kept constant, the fluctuating field current will change the reactive power. Exceeding the maximum reactive power loading on the generator will result in excitation field current limit on the rotor to be exceeded in the lagging power factor range.

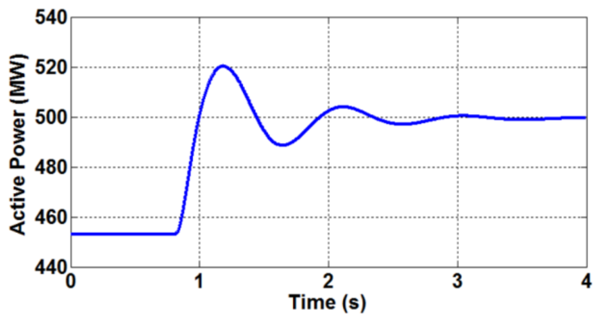

Figure 4-1: Generator active power under normal conditions

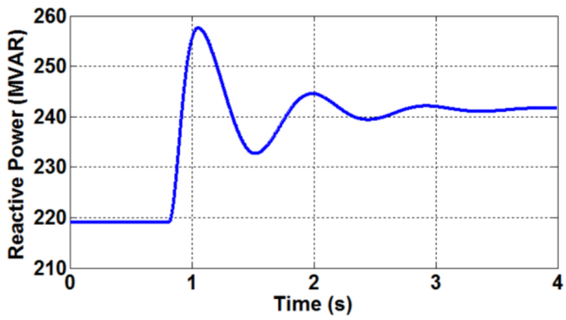

Figure 4-10: Reactive power delivered by generator to the system under normal conditions

This can cause the rotor winding to heat up leading to insulation failure. Reducing the reactive power loading below the minimum limit causes the generator to operate at a leading power factor causing the stator core to overheat. Under this condition the minimum terminal voltage limit can be exceeded and the generator can lose stability from slipped poles. Active and reactive powers are a measure of the generator performance capability.

There are other various parameters that are monitored in generators to indicate performance of the machine. These include stator currents, stator terminal voltage, field current and voltage and speed. Throughout this research, these parameters will be used as a measure of how the generator operates under different types of fault failures. For protection measures, breaker and relay signals will be used as a measure of the protection functions put in place through the calculations of thresholds put in place. Generator stator currents and voltage are measured using voltage and current transformers. In practice, different accuracy classes may be used for monitoring and relaying requirements. Depending on relaying requirements, an analog output of 5 Amps or 1 Amps is used at a rated generator output current.

The generator stator currents are monitored and form as basis for protection relaying equipment for current elements such as phase current unbalance and calculation of the negative sequence currents flowing in the rotor.

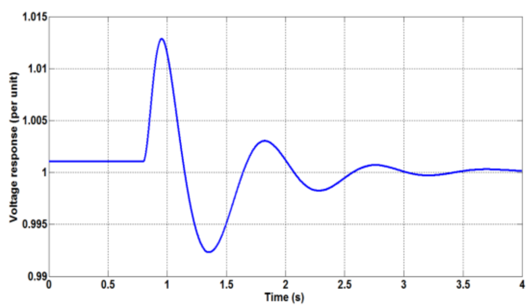

Figure 4-3: Generator terminal voltage

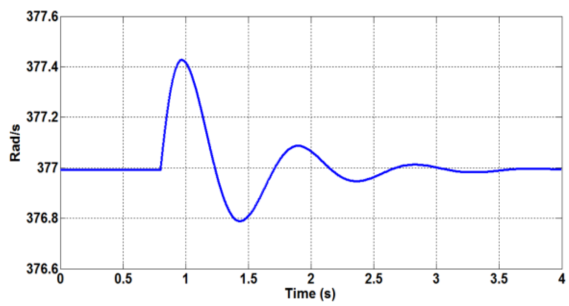

Figure 4-4: Speed

Figure 4-3 illustrates the terminal voltage induced by the generator. Monitoring the generator terminal voltage becomes vital during synchronization of generators to the system; it must be matched with the system voltage before the main generator breaker can be allowed to close. This ensures smooth and safe closure of the breakers and linking to the system, this also prevents cases of over-fluxing that might occur during this stage. Figure 4-4 shows the speed at which the machine is running at. In industry the monitoring of the speed plays a very critical role as it indicates generator shut down. Over-speed protection is also very vital and ensures that a fail-safe function is maintained. Though this is used in industry, it will not be investigated in this study.

Figure 4-5 show that the main breaker connecting generator to the load was closed (binary signal 1) indicating a healthy operation. Under abnormal conditions the circuit breaker would be open to isolate generator from the load. The breaker prevents the high fault current from damaging equipment downstream which cannot withstand currents of high magnitude.

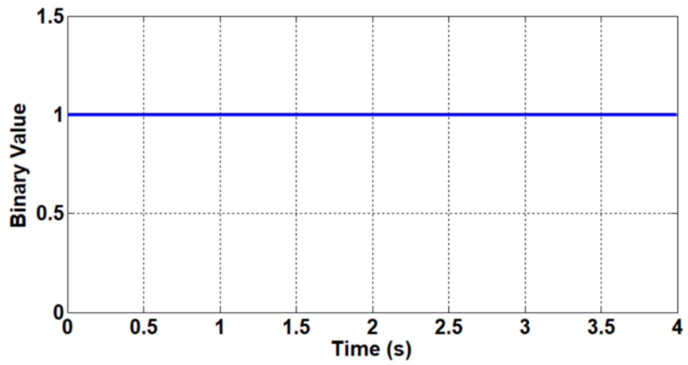

Figure 4-5: Binary control signal for main circuit breaker

4.2 Over-excitation (24)

As discussed in chapter three, the generator relay uses the maximum phase voltages and calculates the ratio of volts per hertz and compares this to the setting threshold. For this study, the field current was increased beyond the generator over excitation limit. The relay detected the fault and a trip signal was issued as shown in figure 4-6 and the breaker opened in figure 4-7.

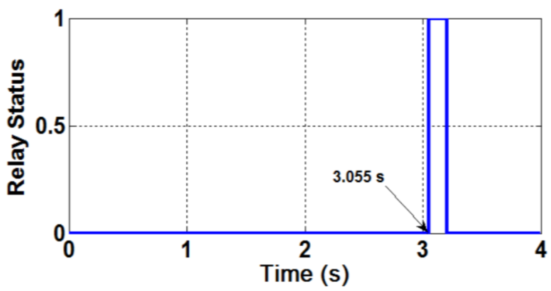

Figure 4-6: Relay response

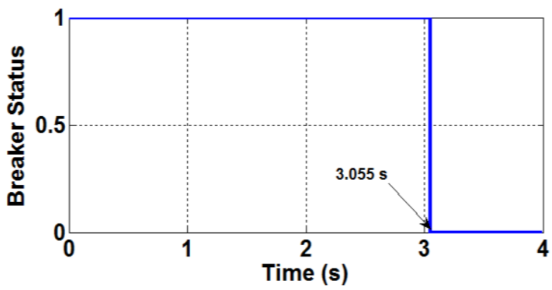

Figure 4-7: Breaker status

Figure 4-8 shows the excessive increase in terminal voltage which could result in the over fluxing of the generator stator core. Under normal circumstances, the automatic voltage regulator will work to ensure that the generator output voltage is kept constant to prevent a transient basis during network disturbances. Generators are usually equipped with inverse-time over voltage protection relays to prevent over voltage.

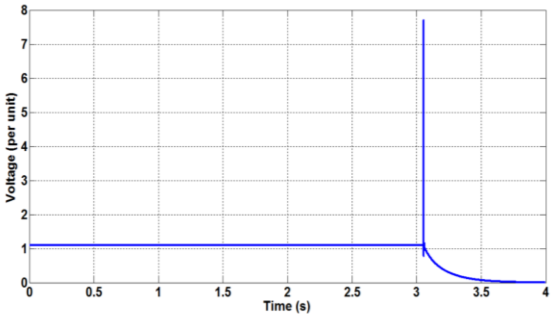

Figure 4-8: Terminal voltage under over excitation conditions of the generator

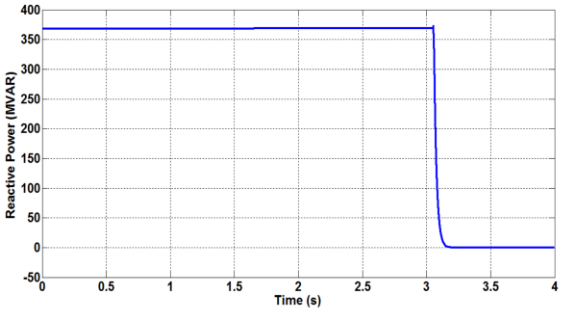

Figure 4-9: Reactive power

Figure 4-9 shows a significant increase in reactive power when compared to figure 4-2 under normal conditions. This proves the relationship between the field current and the reactive power. By increasing the field current in the lagging power factor range, the reactive power loading on the machine can be exceeded. Active power remains constant as illustrated in figure 4-10. Figure 4-11 presents the increase in generator stator currents due to the over excitation the stator magnetic core is heated and your currents increase to indicate this phenomenon.

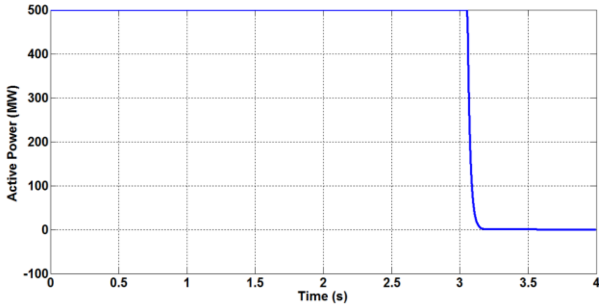

Figure 4-10: Active power under generator over excitation condition

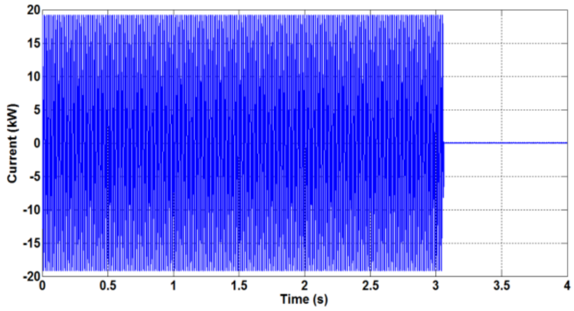

Figure 4-11: Generator stator currents

4.3 Reverse Power (32)

RSCAD software allows user to control mechanical input manually. This way the user can simulate a scenario for loss of prime mover by reducing the mechanical torque. The torque is reduced till there is inadequate torque to keep the generator rotor running at the same frequency as the grid connected to it.

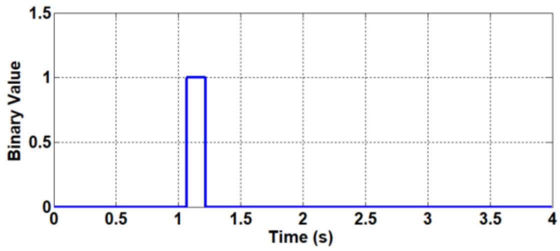

Figure 4-12: Detection and issuing of trip signal

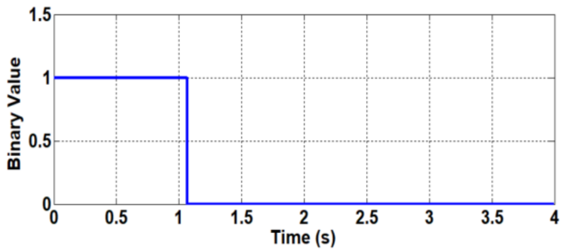

Figure 4-13: Correct clearing of reverse power fault

Figure 4-12 and 4-13 shows that the relay detects and issues a trip signal to the breaker for isolation. The fault was cleared within the expected time of 20 seconds put in place. The relay resets itself after 50 milliseconds.

Figure 4-14 shows how active power was reduced from 500 MW to its tripping point for reverse protection. At that point the system behaves like a synchronous motor. The sensitivity and setting of the reverse power protection function lies on the type of prime mover used. The power required to motor is a function of the load and mechanical losses of the idling prime mover and generator.

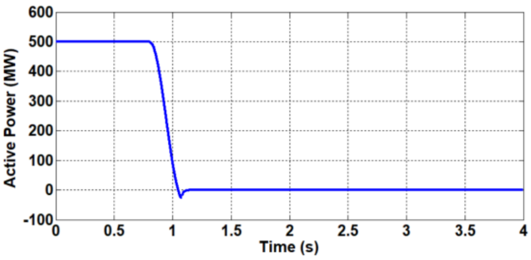

Figure 4-14: Active power delivered by generator

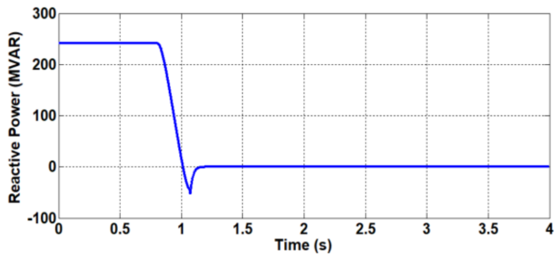

Figure 4-115: Generator reactive power under motoring conditions

From figure 4-15 to 4-19, it can be observed that the reactive power varies with the changes in field current. When the loss of prime mover occurs, the excitation system continues to maintain constant reactive power levels causing the power factor to drop excessively due reversing of active power to motoring levels. During motoring the speed at which the prime mover runs at cannot be controlled. Under normal conditions the prime mover is controlled by controlling fuel into it but in reverse power the alternator is driving the prime mover from the grid and the grid is uncontrollable.

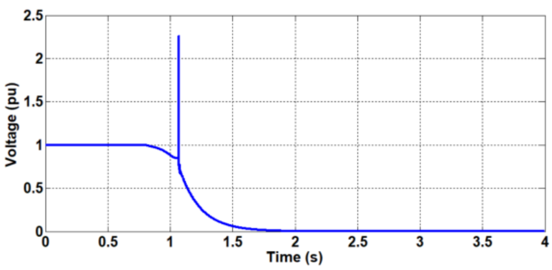

Figure 4-16: Terminal voltage

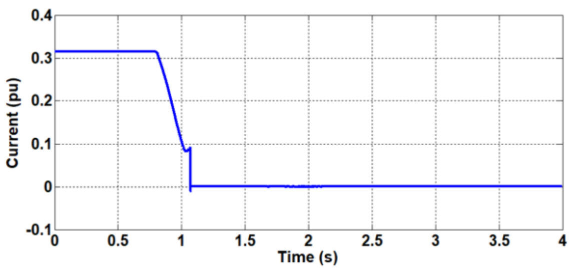

Figure 4-17: Field current

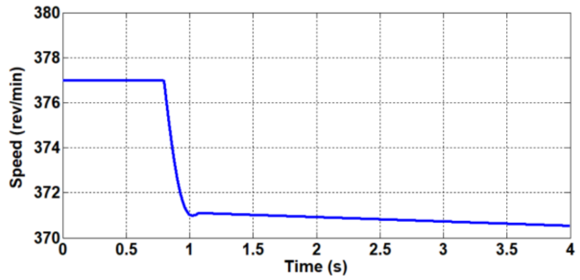

Figure 4-18: Generator speed

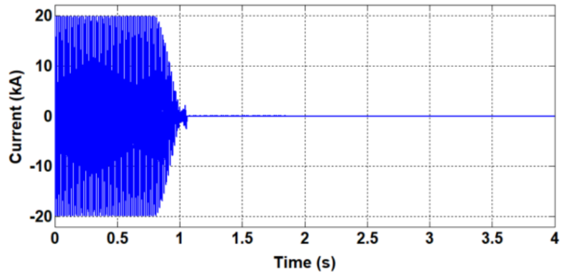

Figure 4-19: Stator currents

4.4 Loss of Field Excitation (40)

This is a two-offset element which is applied at the generator terminals with the protection relay facing the machine. When a generator loses excitation, it consumes a large amount of reactive power from the external power system in order to support its terminal voltage. The excessive reactive power drawn by the generator can harm the generator and cause instability of the whole system. To lower the damage that may be caused by this condition, loss of field excitation protection detects scenarios when the excitation is below the minimum excitation limit. For the purposes of this study, this condition will be tested for both an open circuit and short circuit on the generator field circuit.

4.4.1 Short Circuit Fault in the Field Winding

The results presented in this section illustrate the impact of a short circuit occurring in the excitation circuit. A short circuit on the slip rings will reduce the excitation voltage down to zero. This will cause a gradual reduction of the excitation current and eventually a loss of excitation. A short circuit fault was in the generator field to ground and the following findings were found. Figure 4-20 to 4-21 shows the detection and clearing of LOFE by relay and breaker.

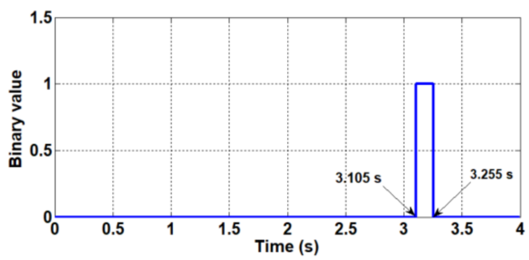

Figure 4-20: Relay trip signal

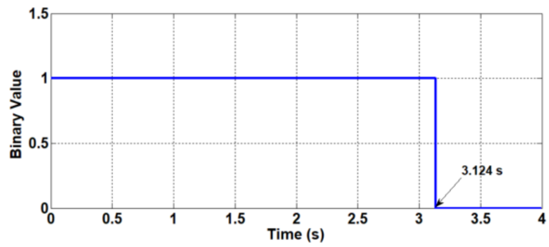

Figure 4-21: Main breaker status

Figures 4-22 to 4-25 illustrate that with the removal of the field supply, the generator continues to supply constant real power to the system for a couple of seconds till the excitation voltage as well as the generator output levels reach their minimum levels. Figure 4-25 show that the field current continues to increase in an attempt to reimburse the drop in voltage.

Reactive power output has a direct proportionality to the internal generator voltage. Therefore, generator voltage is reduced at the same degree as the produced reactive power as illustrated in figure

4-23. The generator then becomes under-excited and absorbs increasingly negative reactive power and if the fault is not detected results in a pole slip scenario causing generator to loose synchronism.

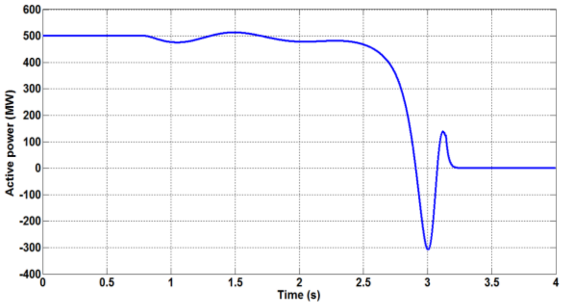

Figure 4-22: Active power

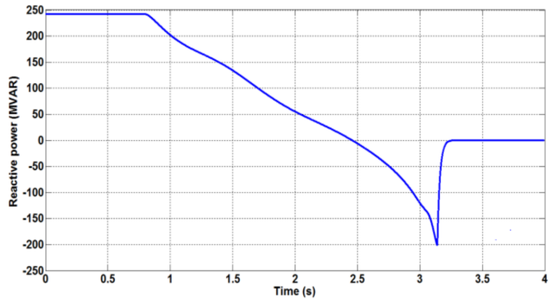

Figure 4-23: Reactive power

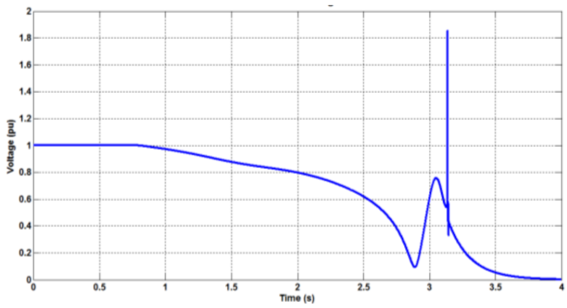

Figure 4-24: Terminal voltage

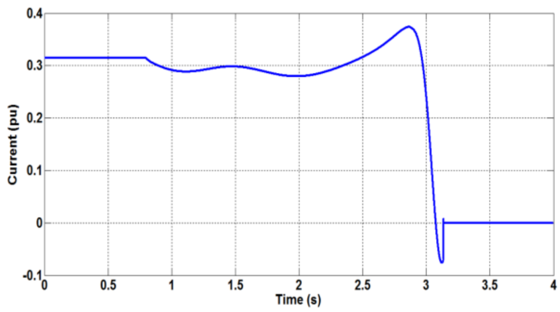

Figure 4-25: Field current during LOFE

Referring to section 2.3.3.1, the impacts of the drop in generator voltage during loss of field excitation results in an undesired change in the power angle curve. The power output of the machine is defined by the operating angle at that time with respect to the system voltage. If the power curve is reduced, the machine tries to keep the operating angle at 90 degrees so as to not lose synchronism by sustaining stability with its mechanical inputs and electrical outputs. At 90 degrees, the generator operates at its maximum rated electrical power output capacity. Any excess mechanical input power at this point is used to increase the speed of the machine. As the speed of the machine increases, the machine loses synchronism. Figure 4-26 illustrates increase in speed.

Figure 4-27 illustrates the LOFE operating characteristics being overlaid by the impedance. The impedance locus enters zone 1 at 3.105 seconds giving a difference of 0.046 seconds which is approximately equal to the set time delay of zone 1. During this condition, the phase stator currents lead the phase voltages which as a result enter the impedance plane in the second quadrant.

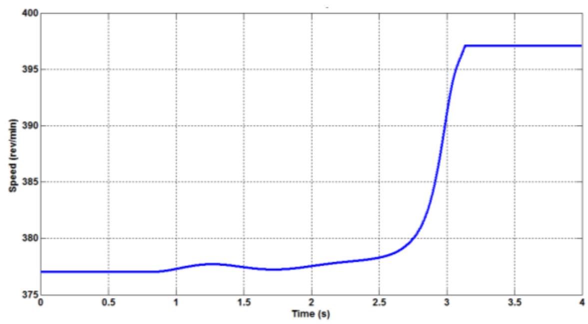

Figure 4-26: Speed of the generator

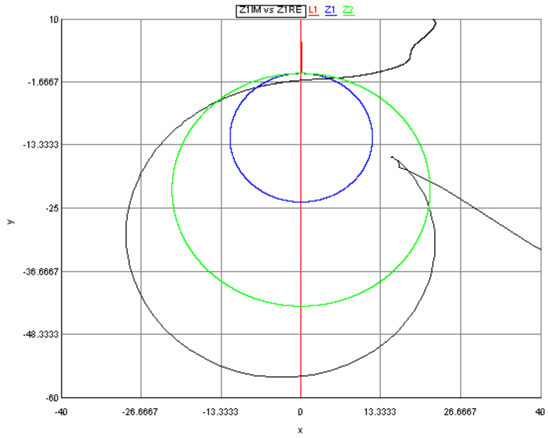

Figure 4-27: R-X diagram showing impedance locus during LOFE (from runtime interface in RSCAD), all units in resistance (Ohms)

4.4.2 Open Field Circuit

As discussed in chapter two, an open circuit in the field circuit will cause a total loss of excitation. When the field breaker is open, a high voltage is induced in field winding and there is a risk for damages to the discharge resistor [12]. The next results show simulation of LOFE in the case of an open field breaker. The breaker is intentionally opened at 0.8003 seconds and the field current drops drastically as shown figure 4-28. The relay picks up the fault as impedance locus falls on zone 2 of the 40 element characteristics. The generator main breaker was opened at 1.02 seconds giving a difference of 0.2197 seconds which can be accounted for time delay of 0.200 seconds in zone 2.

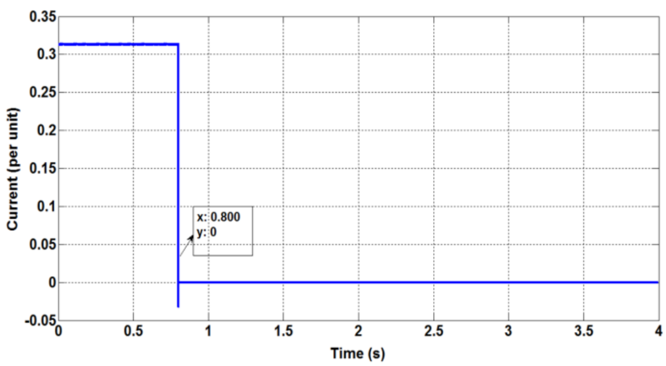

Figure 4-28: Field current

The study showed that for open field the effect on the generator's parameters is more severe due to the impulsive change in the field current which in turn causes extreme fluctuations in the terminal voltage. Figure 4-29 to 4-30 show the response from the relay and generator main breaker response.

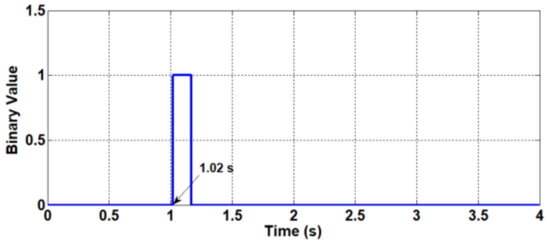

Figure 4-29: Response from relay

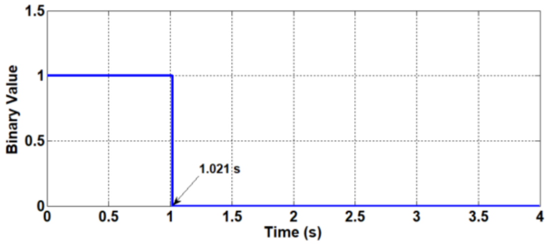

Figure 4-30: Breaker response

Figure 4-31 to 4-33 illustrates the drastic changes in the generator parameters during open field circuit. The decaying of terminal voltage in both these conditions is due to the field current decaying at the field time constant rate.

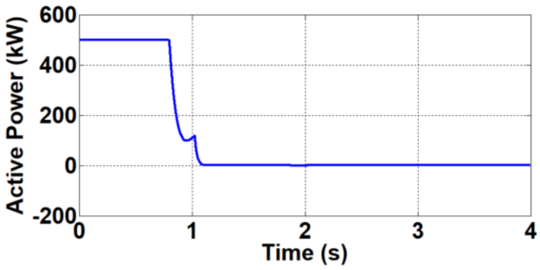

Figure 4-31: Active power during an open field circuit in the excitation system

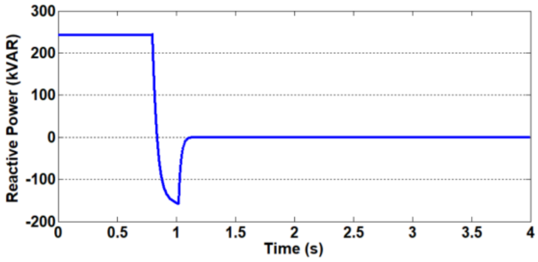

Figure 4-32: Reactive power

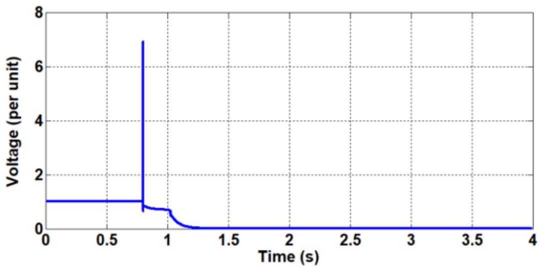

Figure 4-33: Terminal voltage induced by the generator

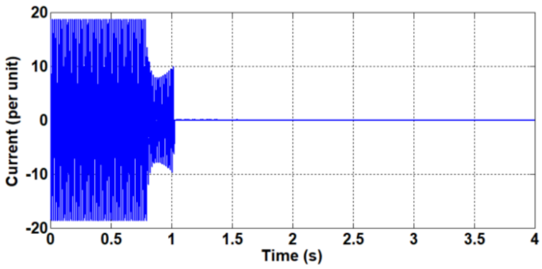

Figure 4-34: Stator currents

Figure 4-34 shows the impact in stator currents at the generator terminals. The impedance locus in figure 4-35 was more rapid compared to the short circuit fault condition making it challenging to prove that the relay had tripped at the appropriate time.

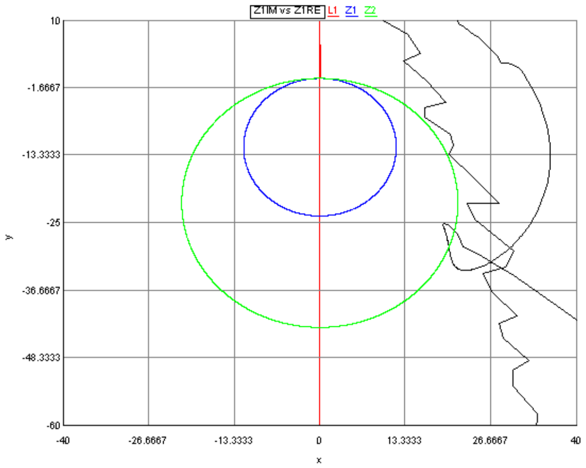

Figure 4-35: Impedance locus

4.5 Phase Over-Current Protection

4.5.1 Voltage Restraint

There are two types of over current relays with voltage control. These relays are used to locate faults close to the generator terminals which may result in voltage drop and fault current reduction in cases where the generator might be off line while the field is still energized or if the fault is too severe. For generator protection, it is critical that the over current relays are equipped with voltage control for such cases. The next results are based on phase over current with voltage restrained element. This element causes the pick-up current to decrease with reduction in voltage. The pick-up setting was set to 150 % of the full load current. The voltage was set according to the bus voltage of the system. A fault was applied near the generator terminals and the figure 4-36 to 4-37 show the breaker and relay response.

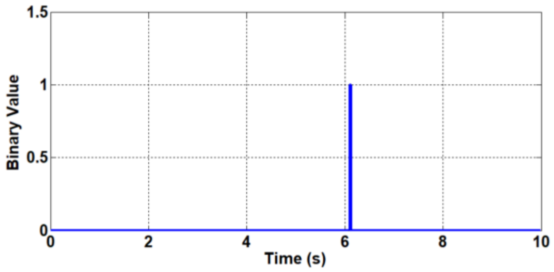

Figure 4-36: Relay response

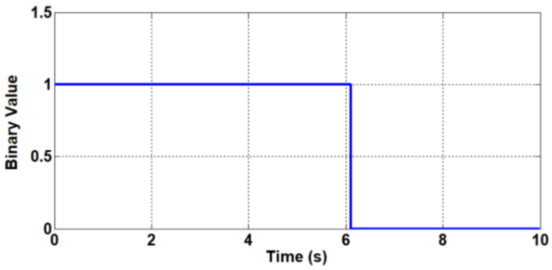

Figure 4-37: Breaker response

Figure 4-36 shows the fast detection of the fault by the relay due to the relay characteristics. The breaker in figure 4-37 shows the operation of the breaker and the isolation of the faulted system. Figure 4-38 shows fluctuations in stator currents increase going above 60 kA which is four times greater than the full load current. The currents produce I^2R losses which increases winding temperatures. The high currents results in high temperatures which can gradually lead to vibration issues due to thermal expansion and mechanical stresses. The integrity of the insulation deteriorates much faster due this condition.

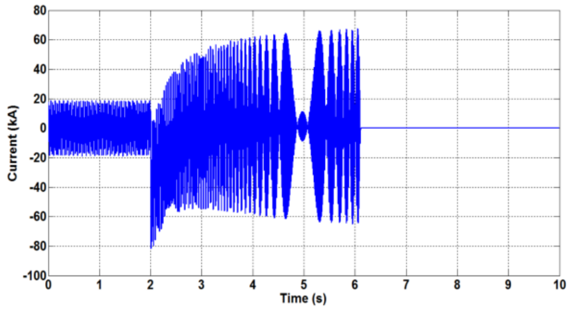

Figure 4-38: Stator current during a system fault

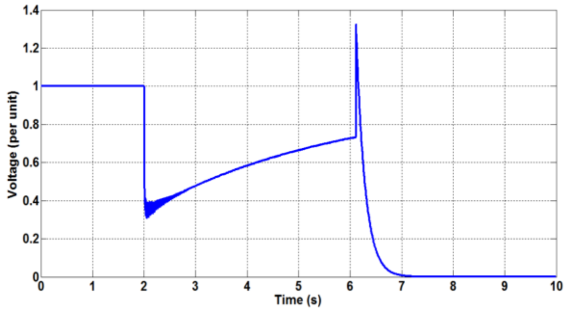

Figure 4-39: Generator terminal voltage

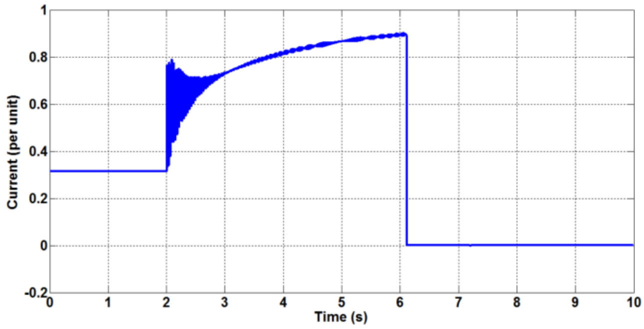

Figure 4-40: Generator field current

4.5.2 Voltage Controlled 51GC

The over-current setting in this element is set below the generator fault current and the voltage is set to ensure that the over current element will not be triggered for extreme system incidents. An external fault was applied at the generator terminals. Figure 4-41 shows the reduction in voltage due to the fault. The rated voltage dropped below 80 percent and the current pick-up setting was reached triggering the relay as seen in figure 4-42.

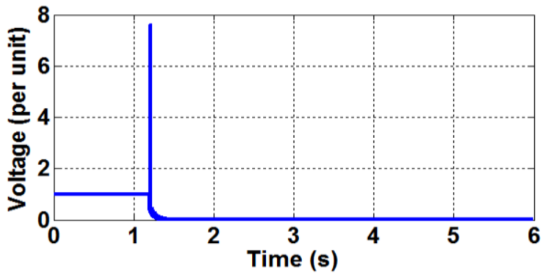

Figure 4-41: Breaker status

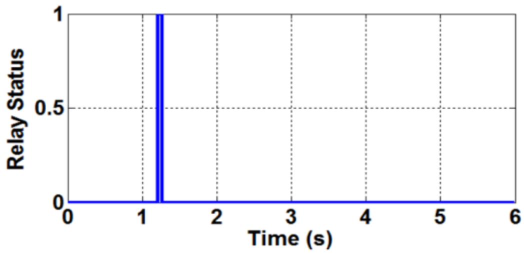

Figure 4-42: Relay trip Signal

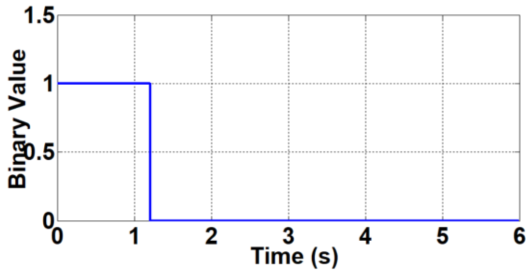

Figure 4-43: Breaker status

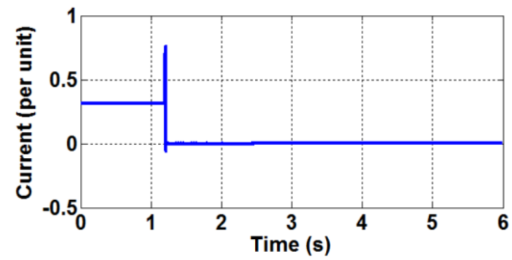

Figure 4-44: Generator field current

Figure 4-43 illustrates opening up of the breaker to isolate the faulted section. The field current as shown in figure 4-44 is increased as the automatic voltage regulator attempts to excite more due to drop in voltage.

4.6 Conclusion

In this chapter, various abnormal generator conditions were investigated. The performance of the over-excitation protection scheme was studied by increasing the field current, a function available in the phase-domain synchronous machine. This scheme was successfully implemented, as expected an increase in reactive power was observed validating the relationship between the generator field current and reactive power. The loss of prime mover protection scheme was simulated by reducing the mechanical torque. The generator protection relay detected the motoring condition and issued a trip signal at the expected time providing the reliability required from a protection system.

Two loss of field excitation events were presented as well as the protection function used to protect the generator during these events. The R-X protection scheme used for the protection of LOFE in generators showed to be competent in protecting the generator during LOFE events and doing so at an appropriate time of operation. The voltage-restrained and voltage-controlled time overcurrent protection schemes were successfully implemented for the protection of the generator against external phase faults. These schemes proved that the fault can be detected before generator current becomes too low.

CHAPTER V

100% STATOR GROUND PROTECTION

5.1 Introduction

The most common faults reported on generators are ground faults. Synchronous generator internal stator ground faults are initiated by the breakdown of insulation winding. The deterioration of the insulation is caused by various factors including moisture and accumulation of dirt on stator surfaces [3]. This chapter presents the implementation of 100 % stator winding ground fault protection can be achieved for high impedance grounded generators. The use of phase differential protection was also investigated as to prove its limitations on high impedance grounded generators as compared to low impedance grounded generators. This chapter presents results obtained for a high resistance grounded generator stator faults protection for both phase differential and the third harmonic voltage (differential) elements.

5.2 Phase Differential Protection

Differential protection schemes are the primary protection used for asymmetrical faults in generators [7]. Overcurrent or over-voltage relays are also the fundamental protection relays used due to their reliability and simplicity. The drawback with these relays is that they cannot detect faults near the generator neutral in high impedance grounded generators. In this study, the generator was grounded with 0.5 Ohms resistance for low impedance grounding. An internal solid line to ground fault on phase A of the stator winding was first applied at 50 %. The transformer was not included as part of the study. The figures below shows the results obtained during this scenario.

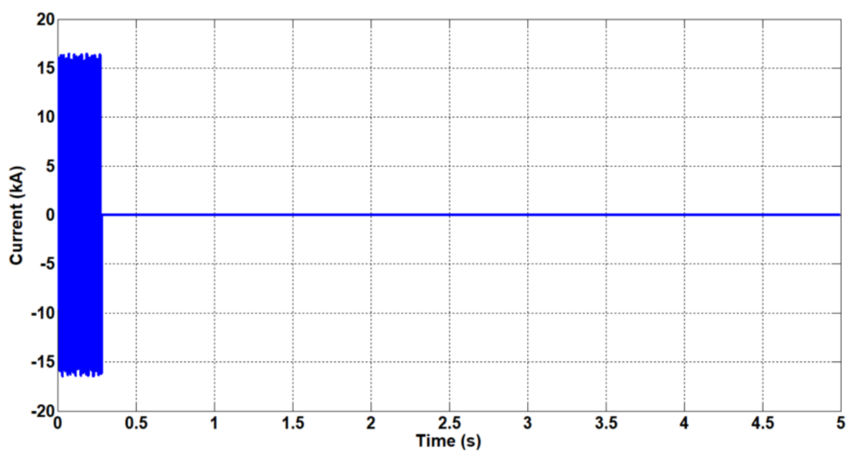

Figure 5-1: Stator currents

Figure 5-1 shows the increase in current during the implementation of the fault on the stator. Figure 5-2 to 5-3 illustrates the generator voltage and the differential operating characteristics which fall under the operating region and hence the relay issues a signal to open up the breaker as shown in figure 5-4 and 5-5.

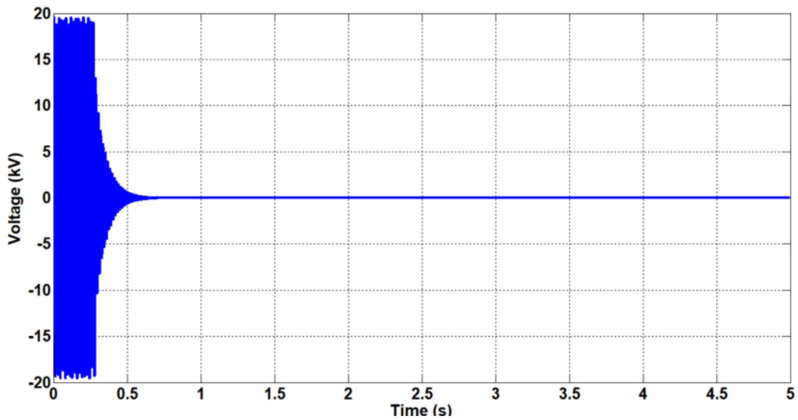

Figure 5-2: Generator voltage

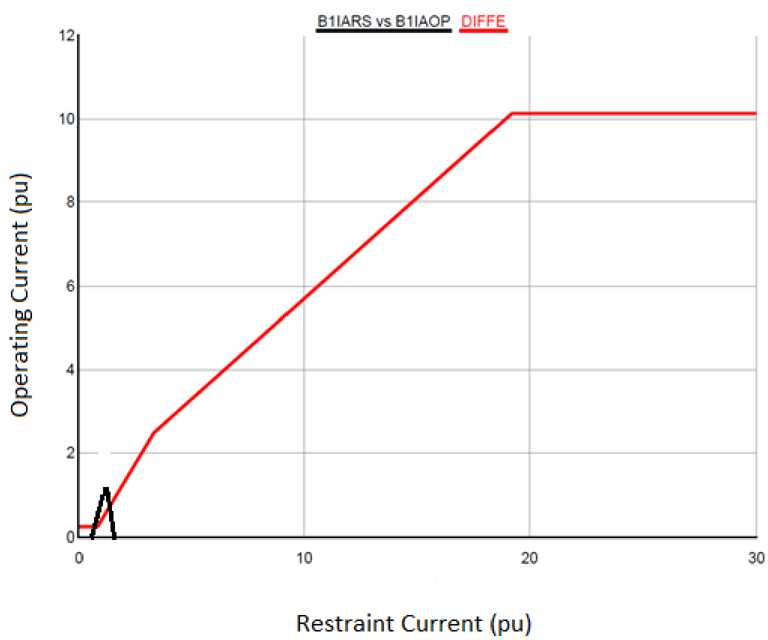

Figure 5-3: Differential operating characteristics

The above figure presents the relaying characteristics for phase A only. The difference between the operating current versus the restraint current covered on the differential characteristics of the relay is illustrated.

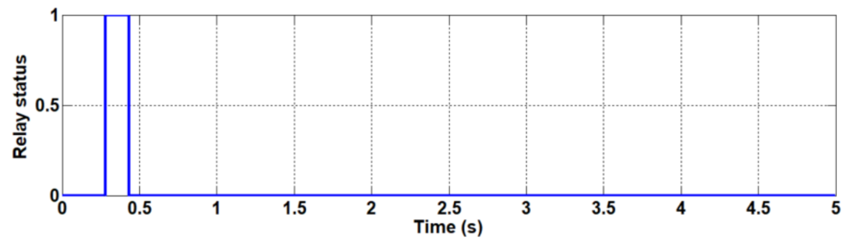

Figure 5-4: Relay status

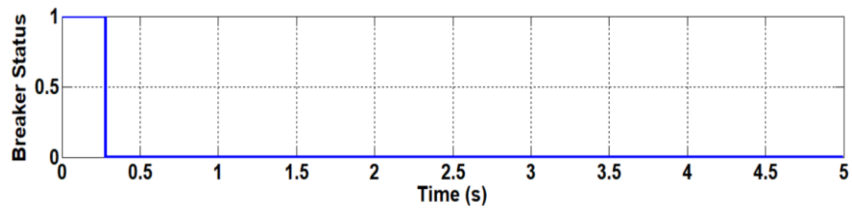

Figure 5-5: Breaker status

A line to ground fault was also applied at 5 % of the stator winding. The differential element was not activated when the fault was applied. This is due to the reduced induced voltage close to the neutral point which limits the fault current. Figure 5-6 shows differential characteristics of the relay between the operating and restraining currents, as seen the operating current is too small and is restricted in the restraining region.

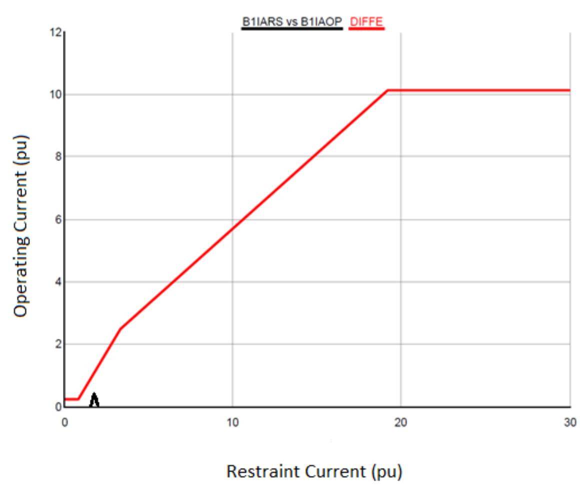

Figure 5-6: Relay differential characteristics

The grounding resistance was increased to 100 Ohms to simulate a high impedance grounding system. The solid ground fault was applied at 50 % of the stator winding. Figure 5-7 illustrates that for this type of system, differential protection is not adequate for this application.

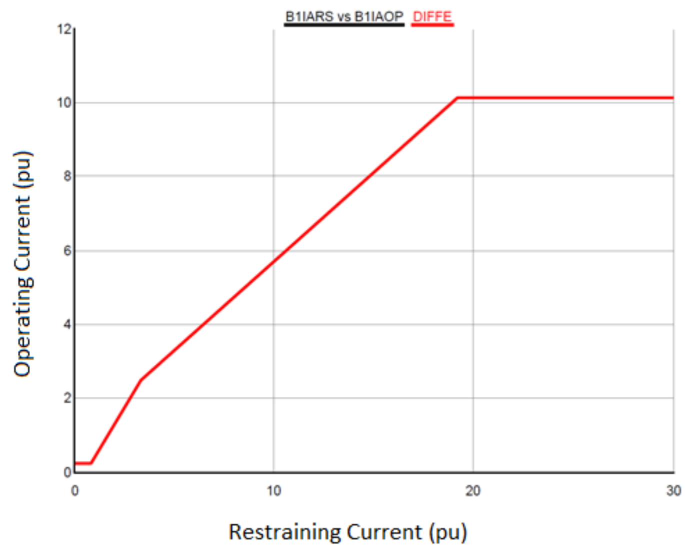

Figure 5-7: Relay differential characteristics for a high impedance grounded generator

5.3 Third Harmonic Voltage (Differential) – 64 G

As discussed in chapter three, differential protection schemes are the primary protection used for asymmetrical faults in generators [7]. Overcurrent or over-voltage relays are also the fundamental protection relays used due to their reliability and simplicity. The drawback with these relays is that they cannot detect faults near the generator neutral in high impedance grounded generators. With this type of grounding system, the stator-ground faults currents are limited to as low as 10 A which makes the Phase differential protection in capable of detecting these faults.

This scheme is dependent on the availability of third harmonics in the generator. As mentioned in the previous section that the phase domain synchronous generator fault d-q based model used in this study does not generate the odd number harmonics, hence the first step was to artificially generate the third harmonics and add them to the neutral and terminal of the generator and pass them on to the multifunction generator relay. To realistically generate the third harmonic voltages, a logic which included all the factors that impact their production was created. The harmonic voltages obtained from the generator depend on the construction, excitation system used and loading on the generator.

The grounding method was incorporated into the artificial third harmonic voltage generation method that was used. The generated third harmonic voltages both at the terminals and neutral of the generator also depend on the capacitances and earthing resistances and therefore the stray capacitances were included to ensure that the model is as representative as possible.

5.3.1 Simulations Results

A grounding transformer was used which reduces the fault current to a range of 3 – 25 A [5]. The IEEE standard C37.101 [18] was used to calculate the size of the secondary resistor which limits the fault currents. The secondary resistor of the grounding transformer was calculated to be 0.271 Ohms. The exact value of this resistance is not critical since the equipment capacitive tolerances and resistances change due to temperature rise. The maximum stator-ground fault current that flows through the primary winding of the grounding transformer was found to be 5.11 A. The following results shows simulations where a ground faults were applied at different locations along the stator. Figure 5-8 presents a ground fault which was applied at 95 percent of the stator winding.

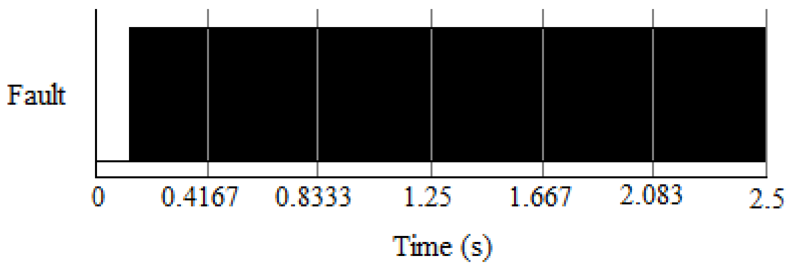

Figure 5-8: Fault logic

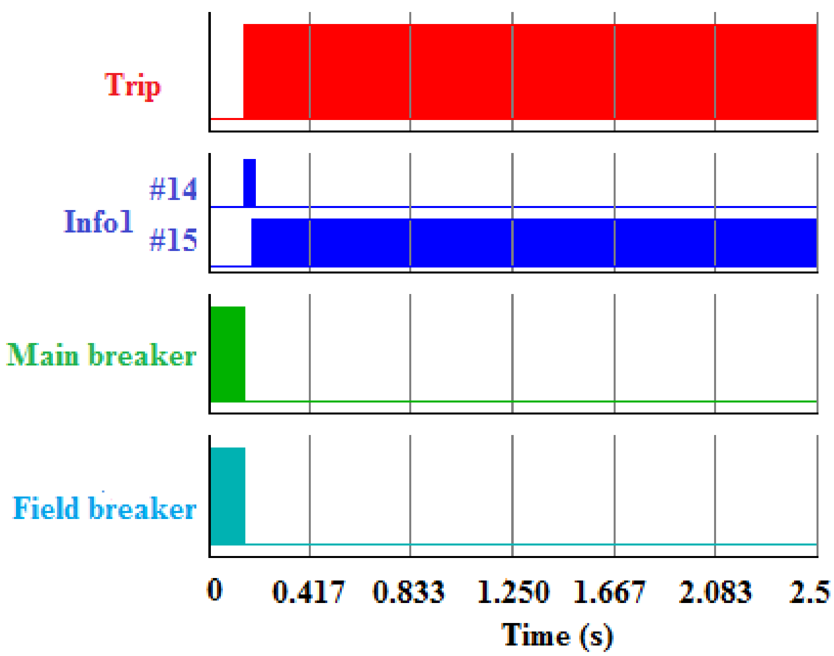

Figure 5-9: Relay and breaker signals

This fault is detected by the relay and both the 64G1 and 64G2 pick up the fault and issue a trip signal as seen in figure 5-9. The main generator breaker and the field breaker are opened to shut down the generator. As discussed in chapter three, when a fault is applied at the terminal, the third harmonic voltage at that point is reduced to zero and increased to maximum at the neutral. The info1 signal represents the generator protection elements signals and in this case bit 14 and 15 represents 64G1 and 64G2 respectively.

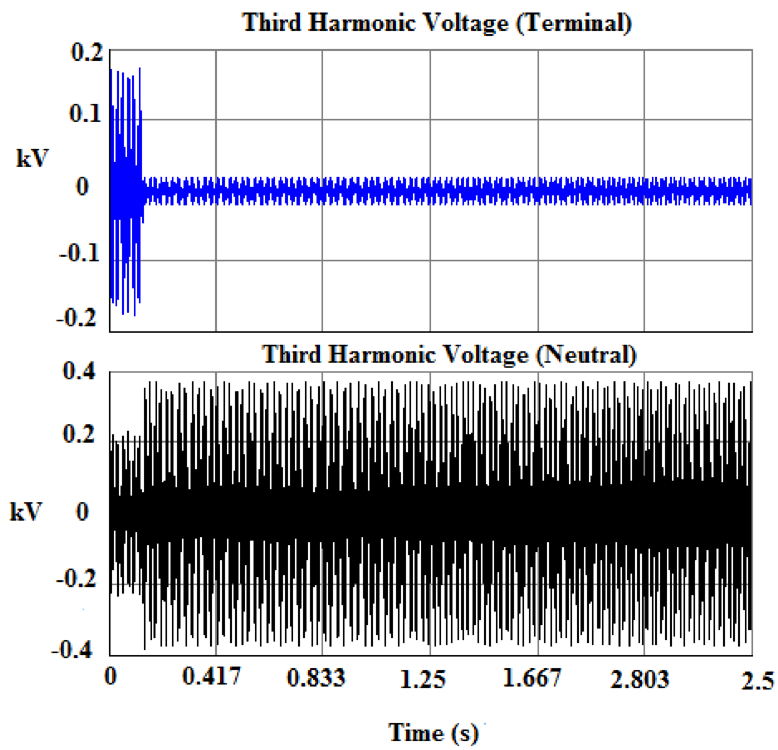

Figure 5-10: Measured terminal and neutral third harmonic voltages (95 percent)

Figure 5-10 shows this phenomenon for a fault which occurs at 95 percent. The same fault at figure 5-8 was also applied at 50 percent of the stator winding. At this point, the reliability of the 64G2 element in detecting ground faults is dissatisfactory. Looking at the info1 signal in figure 5-11, one can clearly see the inadequate operation of 64G2 which is represented by bit 15. Since the two elements complement each other, overvoltage element 64G1 is more reliable and therefore operates to ensure the respective breakers are opened and the generator is shut down.

As shown in figure 3-10, 64G2 element has a null point at the middle of the stator winding (around 50 percent) which prevents this element from being effective. However, the operation of the 64G1 element at this point is exceptional due to the large neutral over-voltage which causes this element to trip. 64G1 detects the ground fault first. Figure 5-12 shows that there is not much change in the third harmonic voltage; therefore the operation of 64G which relies on the operation of the 64G1 element.

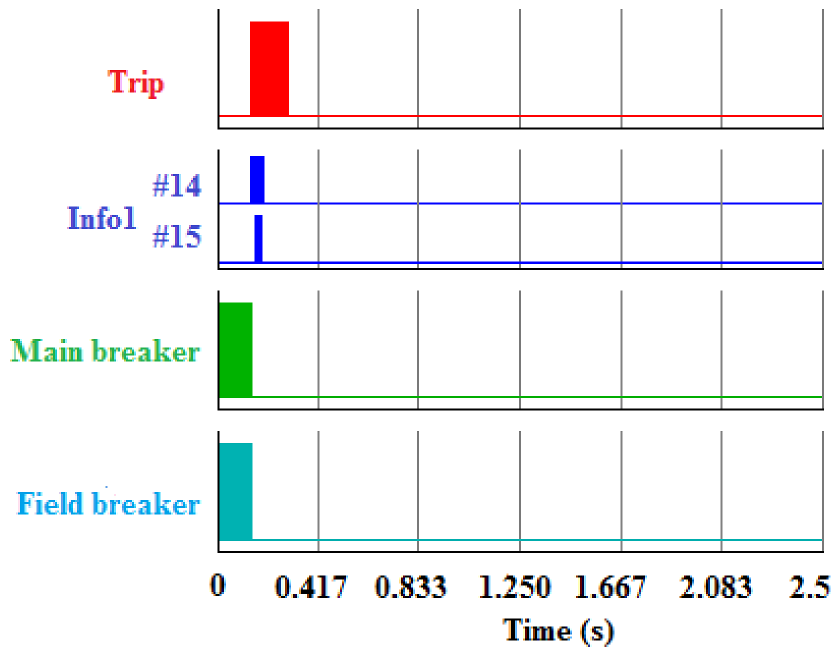

Figure 5-11: Relay and breaker response (fault at 50 %)

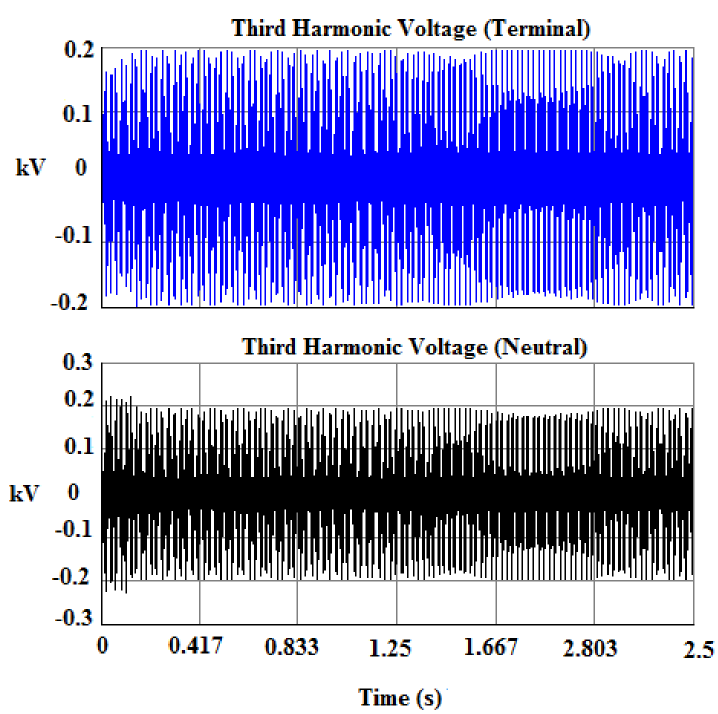

Figure 5-12: Neutral and terminal third harmonic voltage at 50%

To fully understand the 64G elements operating characteristics, an internal ground fault was also applied at zero percent of the stator winding. Again, faults that arise near the neutral results in an increase in the third harmonic voltage at the terminal side of the generator. Near the neutral there is insufficient neutral over-voltage available to trip the 64G1 element during fault conditions.

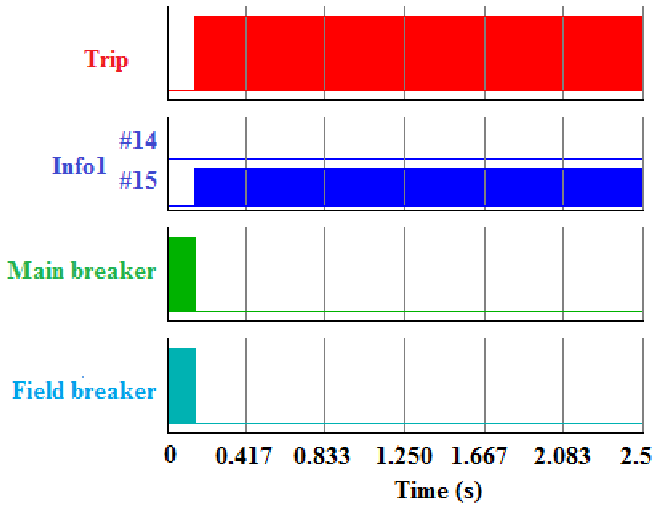

Figure 5-12: Breaker and relay signals during a ground a fault at 0 % of the stator winding

Figure 5-13 serves to show the operations of breaker and relay signals for a fault applied at 0 % of the stator winding. The 64G2 elements play an efficient role in ensuring that faults at this point are detected and the generator stator winding remains protected.

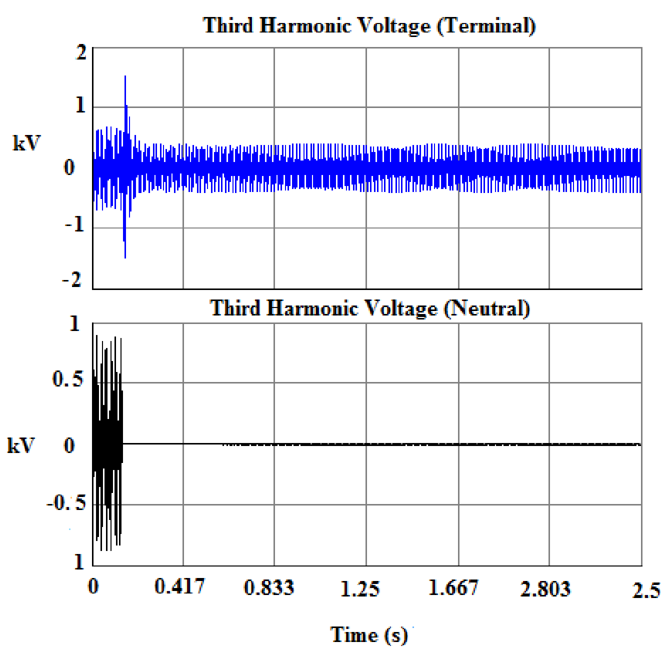

Figure 5-13: Variation of the neutral and terminal third harmonic voltage

Figure 5-14 illustrates the reduction of third harmonic voltage at the neutral of the generator. This shows that 100 % of the stator winding is fully protected at all locations against solid ground faults. The operation of the 64G2 elements also depends on the loading of the generator. The magnitude of the third harmonic voltages is highly affected by the loading of the generator. For this reason, the settings of this element require the protection engineer to know the magnitude of these harmonic voltages at zero and full load conditions on the generator.

Therefore, it was also investigated if the generator remains protected at 0 % and 100 % loading from 0% to 100 % of the stator winding. Solid ground faults were applied through the entire length of the stator, analysing the behaviour of both the 64G1 and 64G2 elements. The results obtained from these two cases were tabulated and recorded.

Table 5-7: Results obtained for 64G operating characteristics for different fault locations full load

Percentage of the stator winding	64G1	64G2
95	Tripped	Tripped
85	Tripped	Tripped
75	Tripped	Tripped
65	Tripped	Tripped
55	Tripped	Tripped
54	Tripped	Unreliable Tripping
52	Tripped	Unreliable Tripping
50	Tripped	Unreliable Tripping
45	Tripped	Tripped
35	Tripped	Tripped
25	Tripped	Tripped
15	Tripped	Tripped
10	Tripped	Tripped
5	No Trip	Tripped

Table 5-8: Tabulated results obtained for 64G operating characteristics for different fault locations at zero loading on the machine

Percentage of the stator winding	64G1	64G2
95	Tripped	Tripped
85	Tripped	Tripped
75	Tripped	Tripped
65	Tripped	Tripped
55	Tripped	Unreliable Tripping
54	Tripped	Unreliable Tripping
52	Tripped	Unreliable Tripping
50	Tripped	Unreliable Tripping
45	Tripped	Unreliable Tripping
40	Tripped	Unreliable Tripping
35	Tripped	Tripped
25	Tripped	Tripped
15	Tripped	Tripped
10	Tripped	Tripped
5	No Trip	Tripped

5.4 Conclusion

The occurrence of stator ground faults requires that the implemented methods provide 100 % stator ground protection at all times. This paper presented a new phase domain synchronous machine model which allows for internal faults to be applied along the stator winding. Differential protection is not adequate for the protection of the stator winding in high impedance grounded generators; however, it can be used for low resistance grounded generators. The multifunction generator model and the phase domain generator model demonstrated how the 100 % stator winding protection is achieved with the use of the 64G generator protection element which uses the third harmonic voltage ratio and overvoltage schemes.

CHAPTER VI

CONCLUSION AND RECOMMENDATIONS

6.1 Introduction

This thesis evaluated the operation of over-excitation, reverse power and loss of field excitation. The phase over current was tested both for voltage controlled and voltage restrained elements. The stator ground fault protection elements were also evaluated. The background information on the objectives of the thesis and relevancy to the practical design was demonstrated. Project specifications were met and the applicable evidence is provided in the thesis. The study model was modeled in the RSCAD simulation package and the simulated results correspond to theoretical predictions. The objective of this project was to implement generator protection, model and simulate different generator protection elements by applying real life scenarios that might affect or damage the generator.

A hardware closed-in loop relay testing was also conducted using the 300G generator relay with the use of the real time simulator. With this arrangement, the hardware relay was tested and results as to how it operates for a given condition were obtained as well as the behavior of the system after the occurrence of a certain abnormal condition or fault. The achieved results from the hardware relay proved the simulation results with the software relay to be accurate.

The thesis showed the significance of designing suitable protection function schemes. Protection of large synchronous generators is a complex discipline that is of critical importance and vital factor in the power system.

6.2 Conclusion

In chapter 4.3 a 70.1 percent increase in field current was obtained during the over-excitation abnormal event. The over-excitation of generators leads to the thermal damage in the cores because of extremely high flux. This can also results in the saturation of the magnetic core, causing high inter-laminar voltages between the laminations ends of the core which also lead to a high field. It was concluded that relay operated within the set threshold which proved the reliability of the protection function against over-excitation condition

In chapter 4.3 the loss of prime mover function was investigated. The results illustrated that the relay function can detect the motoring condition and operated within the allowable time delays. In chapter 4.4, two LOFE events were presented as well as the protection function used to protect the generator during these events. The R-X protection scheme used for the protection of LOFE in generators showed to be competent in protecting the generator during LOFE events and doing so at an appropriate time of operation. An undetected loss of field condition can lead to the decaying of voltage if the affected generator remains connected to the system. The system was tested both for an open circuit and short circuit in the field winding. Chapter 4.5 investigated the operation of phase over-current elements and showed how these elements were successfully implemented for protection again phase to phase faults.

The occurrence of stator ground faults requires that the implemented methods provide 100 % stator ground protection at all times. This paper presented a new phase domain synchronous machine model which allows for internal faults to be applied along the stator winding. Chapter 5.2 proved that differential protection is not adequate for the protection of the stator winding in high impedance grounded generators.

In chapter 5.3, the multifunction generator model and the phase domain generator model demonstrated how the 100 % stator winding protection is achieved with the use of the 64G generator protection element which uses the third harmonic voltage ratio and overvoltage schemes. These scheme complement each ensuring that the stator winding is protected at all points. The dead bands of 64G1 and 64G2 were shown, with the 64G1 scheme failing to operate at lower percentages of the stator winding and the unreliability of the 64G2 schemes around the middle of the winding. Even with such catastrophes, both these schemes show to be a more reliable method.

6.3 Recommendations

For future purposes, it is recommended that the evaluation of the loss of field element include the use of the positive offset MHO element. This method improves relay reliability by achieved accelerated tripping during periods where this condition concurrently with an under voltage condition. With the Real Time Digital Simulator, the presentation of the field circuit as well generator controls can allow for more studies to be carried out.

Through improved technologies, methods for achieving 100 percent stator ground fault protection are increasing. Another method that can be investigated is the sub-harmonic injection method. This method uses the injected voltage to detect ground faults along the stator. The voltage is injected with the use of a transformer between the grounding element and ground. The grounding element may be a distribution transformer, reactor or resistor. The injected voltage has a relatively low sub-harmonic frequency, usually a quarterly of the system frequency is chosen. The currents that are caused by the injected voltage are continuously measured. During normal conditions, this current will flow through the stator winding shunt capacitances to ground, once a ground fault occurs, the shunt capacitances are short-circuited and as result the magnitude of the current rises. From this principle, the relay can detect occurrence of ground fault by the change in current magnitude. The advantages of this method are that the frequency increases the impedance of the stator capacitance reactance thereby increasing the sensitivity of the protection scheme [13]. Furthermore, the current is measured for the full quarter of the system frequency (12.5 or 20 Hz cycles) that is used. A coupling filter is utilised to block the fundamental frequency component of the signal [5] to prevent unnecessary tripping occurrences. However, the drawback from using this method is that it is expensive due to the additional equipment it requires for the injection of voltage.

APPENDIX A

1. Additional Models Used

- **Multifunction Generator Relay**

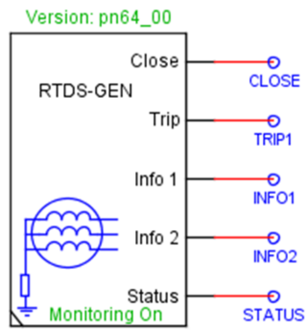

Figure7-1: Generator relay

The multi−function generator relay is suitable for providing the protection function on synchronous machines. The relay provide protection elements such as loss of field protection, 100% stator protection, volts per hertz, differential elements for phase and neutral currents and other additional relay elements which offer complete protection for the generator. It also has additional plot signals which allow sufficient information to assist in verifying theoretical calculations with the simulation result. The relay consists of internal current transformer, voltage transformer. The phase voltages and currents and neutral voltage and current are connected to the 14 inputs of the GENERATOR function. Additional inputs are also available for an external frequency tracking signal and synchronization voltage signal. A 16 point DFT is used to calculate the RMS values and the instantaneous impedance is calculated for the phase−to−phase, phase−to−ground, positive sequence, negative sequence, and zero sequence.

- **Circuit Breaker**

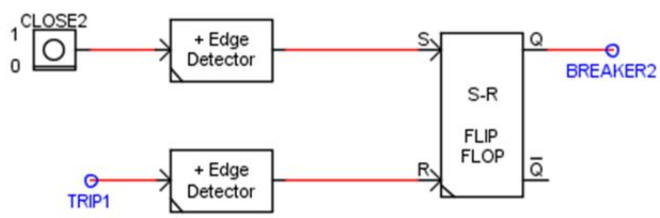

Figure 7-2: Circuit breaker logic control

The circuit breaker is a three phase circuit breaker. In practice a protection relay issues command to open and close the circuit breaker under its control to separate trip and close coils on the circuit breaker. By contrast, the model of a circuit breaker in the real-time simulator is controlled (i.e. opened and closed) by means of a single logic input. Once the relay has issued a trip command, one requires that the real-time model of the circuit breaker remains open until a human operator manually recloses the breaker.

Figure 7-2 shown above illustrates the circuit breaker model which is designed to respond to separate open and close commands by means of an SR flip-flop component. A trip command from the generator relay shown in figure 7-1 will be used to open the circuit breaker, and a push button component (activated by a human operator from the runtime interface) to close the breaker. Initially the breaker is closed, once the relay issues the trip command the circuit is opened and can later be closed by the human operator. The main purpose of the breaker in this case is to provide isolation of the generator from the grid in occurrences of faults or abnormal conditions.

- **Fault Logic**

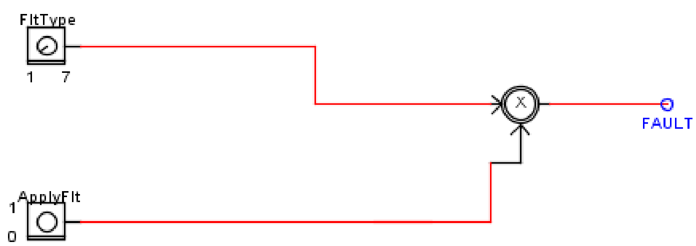

Figure 7-3: Fault logic control

A fault logic circuit needed to be implemented in the draft model that enables the user to change the fault type, fault selectivity and apply the fault in the run time interface. The purpose of doing so provided a more efficient way of testing as opposed to switching between the draft and runtime interface to implement changes to the faults on the system. The following logic circuitry allows the user to activate the fault using a push button, switch between the different combinations of line to ground faults and select the numerous fault combinations via a dial switch.

- **Hardware Closed Loop Testing**

The system was simulated in RSCAD software in PC. The hardware relay input was connected to the required RTDS analog/digital output and the RTDS analog/digital output was connected to the to a power amplifier since a physical relay was being used. The analog/digital output of the relay (where trip signal is sent- out contact) was connected with the analog digital input of the RTDS. Protective relays are designed to be fed from the secondary windings of current and/or voltage transformers present in the system.

For testing purposes using the real time simulator, the simulated values of the instrument transformers secondary variables must be converted to signal-level voltages using the GTAO card. The signal level analogue output voltages sent from the rack in real time must be converted to correctly-scaled currents and voltages for input to amplifier. In this way, the real time simulation can be used to drive the relay with the same power level currents and voltages it would experience in the field. For this project an OMICRON CMS 156 power amplifier was used. It has six signal level inputs, three of which feed a voltage-to-current power amplifier with a gain of 5 A per signal-level volt, and three of which feed a voltage-to-voltage power amplifier with a gain of 50 Volts per signal-level volt.

- GTAO Scaling – Voltage

Each channel of the GTAO has a scaling factor which scales the analogue signals to the levels desired by the interfaced hardware

V secondary = 110 Volts (calculation in the appendix A)

$$GTAO\ Scale = Vsecondary * \frac{5}{250} * 50 = 110\,V$$

- GTAO Scaling – Current

I secondary = 2.67 A

$$GTAO\ Scale = Isecondary * \frac{5}{25} * 5 = 2.63\,V$$

- **300G Generator Relay**

The SEL-300G can be applied in primary or backup applications for complete generator or unit protection. It provides protection over the operating frequency range of 20–70 Hz. The relay using the instrument transformers measures system operating voltages and currents. The relay processes and evaluates the each set protection elements according to the system current operating parameters. It also an internal analog to digital converter which sample voltage and current obtained values in order for them to be used by the microprocessor [18].

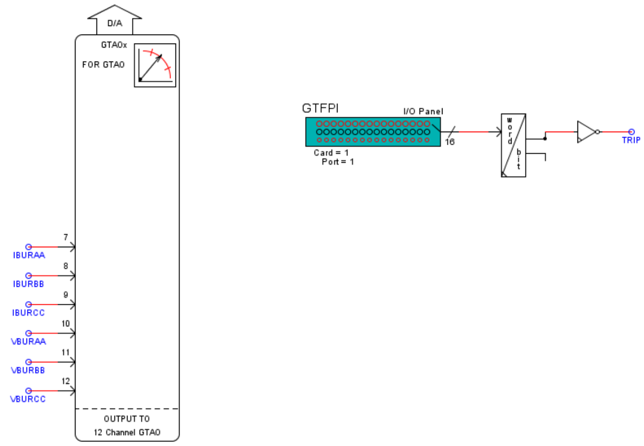

Figure 7-4: GTAO and GTFPI cards

The input signals to the GTAO cards are secondary stator voltages and currents.

- **Communicating with a 300G Relay Using the AcSELerator Quickset Software**

QuickSet is an easy-to-use yet powerful tool with template design capabilities for easy, consistent settings and applications to help you get the most out of your SEL device. It is used to configure and set the relays settings. The communication of the relay and the PC was achieved through the use of serial cable. The determined CT and PT settings were set on the CT and PT models in the model and the quickset menu for setting relay. The communication parameters were as followed. The CT and PT Ratios for the relay were also set to be: -

2. Hardware Testing of Protection Elements

2.1 Volts/Hertz (Overexcitation-24) Element Testing

The 300-G generator protection was also tested for over-excitation. The same settings used in the simulation of the over-excitation element were used. The hardware relay also has similar settings to the software multifunction relay. The settings are also according to nominal generator voltage and frequency [17]. Using the same procedure used to implement over-excitation with the software relay. The voltage was increased to until the V/Hz ratio exceeded the level 2 pick-up (110 %). Level 1 was used as an alarm signal. The following results were obtained from RSCAD when the hardware detected over-excitation. The time of operation was calculated as follows when the voltage is 110% [17].

$$top = \frac{24ITD}{\left(\frac{\frac{V_{PP}}{50} * \frac{FNOM}{VNOM}}{\frac{24IP}{100\%}} - 1\right)^{0.5}} = 0.316\, s$$

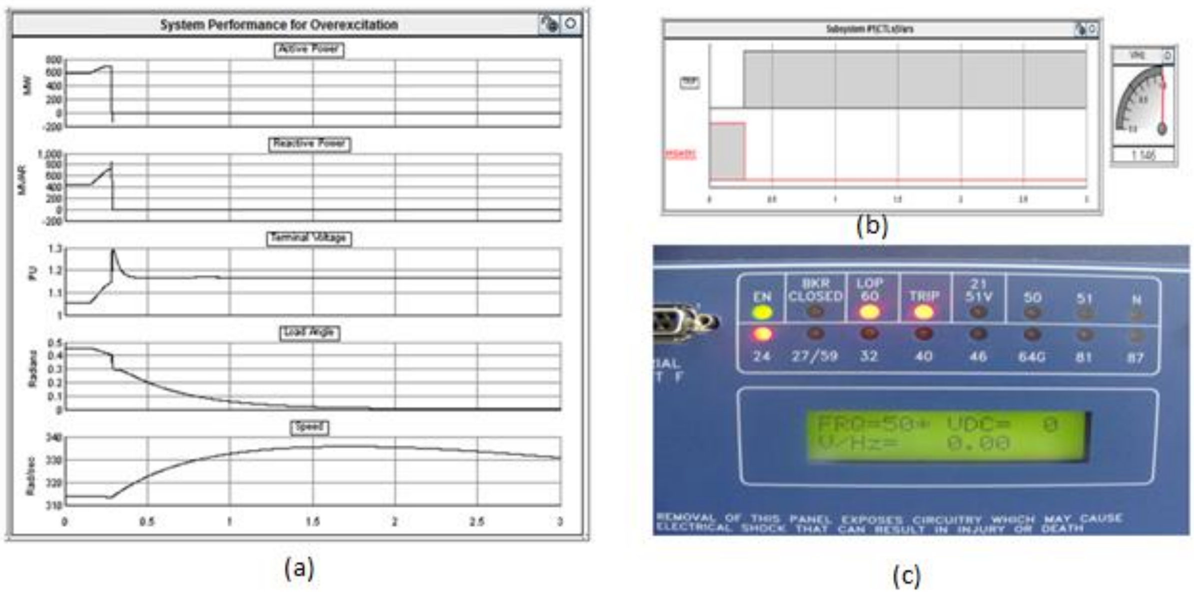

Figure 7-6: (a) System performance after over-excitation, (b) Picture showing that the hardware tripped with the volts/hertz (24), (c) trip signal from hardware relay and breaker operation in RSCAD software runtime interface

Results show that the hardware relay tripped at about 0.3 seconds and therefore it can be concluded that it operated as expected.

2.2 Loss of Prime Mover (32) Element Testing

Anti-motoring protection in the SEL-300G is provided by a reverse/low-forward power element. This element measures the real-power flow from the generator. If the generator real-power output drops below the element threshold, the relay operates. Two reverse-power thresholds are provided but only level 1 was used. Level 2 is for sequential tripping which was not required in this project. The settings used are similar to those calculated for the simulation with the software relay [17].

To implement failure of prime mover, a switch is used to control the mechanical torque manually and reduced to less than the level 1 settings and the following results were obtained from hardware relay and runtime interface in RSCAD software.

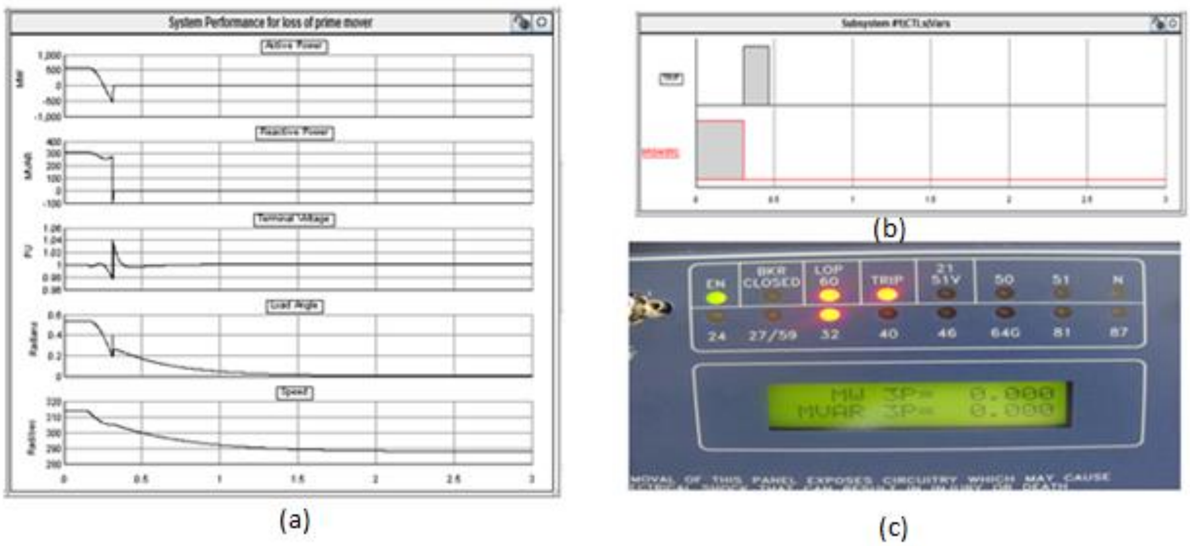

Figure 7-7: (a) System performance after failure of prime mover, (b) hardware tripped with the volts/hertz (24), (c) trip signal from hardware relay and breaker operation in RSCAD software runtime interface

2.3 Loss of Field Excitation

The results shown here were obtained during a short circuit fault in the field winding.

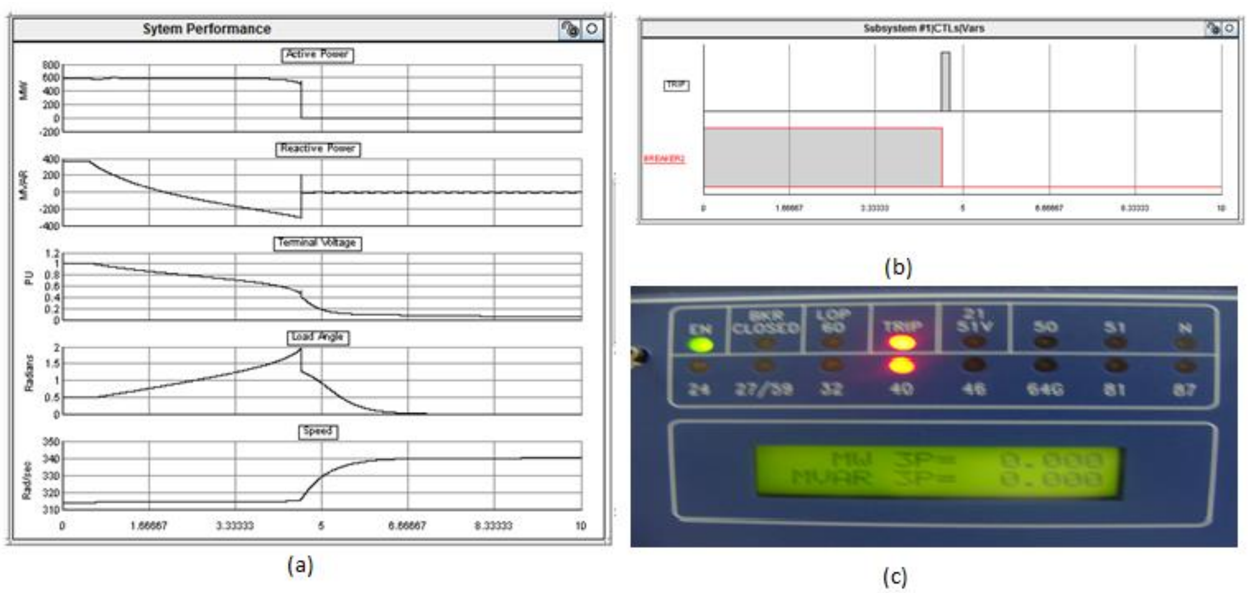

Figure 7-8: (a) System performance after loss of field excitation, (b) Trip signal from hardware relay for loss of excitation and (c) operation of breaker

Obtained results show that hardware relay detected and issued trip signal for loss of field excitation. The system shows to have been drawing a lot of reactive power before the generator was shut down while the active power remained constant. The terminal voltage falls at the same rate as reactive power because of the relation they possess. The load angle increases trying to maintain equilibrium between mechanical output and electrical output.

3. Test system data

Table A1: Generator Data

Machine rated MVA	555
Rated voltage	24 kV
Frequency	50 Hz
Stator leakage reactance	0.15 p.u.
D-axis: Unsaturated reactance	1.81 p.u.
D: Unsaturated transient reactance	0.3 p.u.
D: Unsaturated sub-transient reactance	0.23 p.u.
Q-axis: Unsaturated reactance	1.76 p.u.
Q: Unsaturated sub-transient reactance	0.25 p.u.
Stator Resistance	0.003 p.u.
D: Unsaturated Transent open Time constant	8 sec
D: Unsaturated Sub-Transent open Time constant	0.03 sec
Q: Unsaturated Sub-Transent open Time constant	0.07 sec

Table A2: Governor data

Governor gain	20
Lead time constant	0.001 sec
Lag time constant	0.001 sec
Maximum valve opening	0.95 p.u.
Minimum valve opening	0.00 p.u.

Table A3: Transformer data

Transformer rating (three phase)	555 MVA
Base Frequency	50 Hz
Leakage inductance	0.15 p.u.
Winding 1 connection	Delta
Winding 2 connection	Star
Transformer model type	Linear

Table A4: Bus data

Bus 1	24 kV
Bus 2	400 kV
Bus 3	400 kV
Bus 4	400 kV
Infinite Bus	400 kV

REFERENCES

1. J. Lewis Blackburn Thomas J. Domin (2006). Protective Relaying Principles and Applications. 3rd ed. Boca Raton, USA: CRC Press, Taylor & Francis Group, LLC. Page 229-240 ISBN 1-57444-716-5.

2. M.V. Bakshi, U.A. Bakshi (2006). Protection & Switchgear Engineering Protection & Switchgear Engineering. 4th ed. India: Technical Publications. Page 114-120 ISBN 8189411551.

3. Stanley H. Horowitz, Arun G. Phadke: Power System Relaying, Third Edition, John Wiley & Sons, Ltd., England, 2008

4. Y.G. Paithankar, S.R. Bhide (15 Aug 2004). Fundamentals of Power System Protection. Prentice-Hall of India Pvt.Ltd. pages 168-183, ISBN 8120341236.

5. A. E. Fitzgerald and C. Kingsley, *Electric Machinery*. McGraw-Hill, 1971.

6. T. Wildi, *Electrical Machines, Drives and Power Systems*. Prentice Hall

7. Working Group J-5 of the Rotating Machinery Subcommittee, Power System Relay Committee, "Coordination of Generator Protection with Generator Excitation Control and Generator Capability," 1-4244-1298-6/07 (C) 2007 IEEE.

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

9. IEEE Std C37.102™-2006: IEEE Guide for AC Generator Protection, IEEE Power Engineering Society

10. *IEEE Guide for Generator Ground Protection*, IEEE Standard C37.101, 1993.

11. P.M. Anderson: Power System Protection, John Wiley & Sons, Inc., New York, 1999

12. Wu, A. et al. (2004), MV generator low-resistance grounding and stator ground fault damage, IEEE Transactions on Industry Applications, Vol. 40, No.2, March/April 2004, pp. 672-679

13. Pillai, P. et al. (2004), Grounding and ground fault protection of multiple generator installations on medium-voltage industrial and commercial power systems – Part 3: Protection Methods – Working group report, IEEE Transactions on Industry Applications, Vol.40, No.1, January/February 2004, pp 11-16

14. ABB.Oy, Differential Protection of RET54_ Reference Manual, 1st ed. Vaasa, Finland: ABB Oy, 2005.

15. Prabha Kundur: Power System Stability and Control, McGraw-Hill Inc., New York, 1994

16. R. P. Mehta, B. Oza, "Laboratory Simulation of Generator Protection", Fifteenth National Power Systems Conference (NPSC), IIT Bombay, December 2008 pp.131-136

17. Fulczyk M, Influence of Generator Load Conditions on Third-Harmonic Voltages in Generator Stator Winding, IEEE Transactions On Energy Conversion, Vol.20, 1, 2005

18. 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.

19. 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

20. J. Pilleteri and J. R. Clemson, "Generator Stator Ground Protection,"Proceedings of the May 7-8, 1981 Protective Relaying Conference, Georgia Institute of Technology, Atlanta, GA.

21. M. Stein and J. R. Linders, "Ground Fault Protection of the Complete Generator Winding," Proceedings of the Pennsylvania Electric Association Relay Committee, October 6-7, 1977.

22. Charles J. Mozina, 15 Years of Experience with 100% Generator Stator Ground Fault Protection (What Works, What Doesn't and Why), 62nd Annual Conference for Protective Relay Engineer, 2009

23. Daquiang, Bi et al. (2001), Analysis and improvement on stator earth-fault protection by injecting 20 Hz signal, Tsinghua University, Beijing, China.

24. Xiangjun, Zeng et al. (2002), Improvement of subharmonic injection schemes for huge hydro-generator stator ground fault protection, 2002 IEEE, pp.707-710

25. J. Berdy; Loss-of excitation protection for modern synchronous generators; General Electric Co. Document GER-3183, 1975

26. ABB Generator Protection Application Guide, 1MRK 502 003-AEN, 1997 G. R. Berube and L.M. Hajagos, "Coordination of Under Excitation limiters and Loss of Excitation Relays with Generator Capability," in 2009 IEEE Power & Energy Society General Meeting, pp.1-8.

27. H.G. Darron, J.L. Koepfinger, J.R. Mather, P.A. Rusch, “The influence of generator loss of excitation on bulk power system stability”, IEEE Trans. on PAS, Vol. 96, No.5, pp. 1473-1483, 1975.

28. IEEE PES Generator Protection Tutorial Task Force, “IEEE Tutorial on the Protection of Synchronous Generators,” 1995.

29. R. Sandoval, A. Guzman, H.J. Altuve, “Dynamic Simulations Help Improve Generator Protection”, SEL 2006.

30. A. F. Elneweihi, et al., "Negative-sequence overcurrent element application and coordination in distribution protection," Power Delivery, IEEE Transactions on, vol. 8, pp. 915-924, 1993.

31. Muhammad Mohsin Aman1, et al., “Modeling and Simulation of Reverse Power Relay for Generator Protection,” 2012 IEEE International Power and Optimization Conference (PEOCO2012), Melaka, Malaysia: 6-7 June 2012

32. D. Finney, M. Adamiak, B. Kasztenny, “Dynamic testing of generator protection using a model generator platform,” 56th Georgia Tech Protective Relaying Conference, May 2002.

33. Rotating Machinery Protection Subcommittee: “Out of Step Relaying for Generators”, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-96, No. 5, September/October 1977.

34. Pillai, P. et al. (2004), Grounding and ground fault protection of multiple generator installations on medium-voltage industrial and commercial power systems – Part 2: Grounding Methods – Working group report, IEEE Transactions on Industry Applications, Vol.40, No.1, January/February 2004, pp 17-23

35. Powell, L.J., (1998), The impact of system grounding practices on generator fault damage, IEEE Transactions on Industry Applications, Vol.34, No.5, September/October 1998, pp. 923-927

36. A. B. Dehkordi, P. Neti, A.M Gole, and T.L. Maguire, Development and Validation of a Comprehensive Synchronous Machine Model for a Real−Time Environment,” IEEE Trans. Energy Conversion, Vol. 25, No. 1, March 2010.

37. A.B. Dehkordi, A.M Gole, and T.L. Maguire,” Permanent magnet synchronous machine model for real− time simulation”, International Conference on Power System Transients (IPST 2005), Montreal, June, 2005.

38. “Real-Time Digital Simulator Power System Users Manual”, RTDS Technologies, Winnipeg, Manitoba, Canada, November 2006.

39. J. Wu and N. N. Schulz, “Experimental Design for Remote Hardware-In-The-Loop testing”, Proceedings of ASNE Reconfiguration and Survivability Symposium, Jacksonville, Florida, Feb. 2005