Improving backup protection using sampled values for generating stations

Presented in Partial Fulfillment of
the Requirements for the Degree of

Master of Science

with a Major in

Electrical Engineering

in the

College of Graduate Studies

University of Idaho

by

Sruthi Chilukuri

Major Professor
Brian K. Johnson, Ph.D.,P.E.

Committee
Herbert Hess, Ph.D.,P.E.
Yacine Chakhchoukh, Ph.D.

Department Administrator
Mohsen Guizani, Ph.D.

August 2017

Authorization to Submit Thesis

This thesis of Sruthi Chilukuri, submitted for the degree of Master of Science with a major in Electrical Engineering and titled "Improving backup protection using sampled values for generating stations", has been reviewed in final form. Permission, as indicated by the signatures and dates below, is now granted to submit final copies to the College of Graduate Studies for approval.

Major Professor:	Brian K. Johnson, Ph.D.,P.E.	Date
Committee Members:	Herbert Hess, Ph.D.,P.E.	Date
	Yacine Chakhchoukh, Ph.D.	Date
Department Administrator:	Mohsen Guizani, Ph.D.	Date

Abstract

Evaluation of relay misoperations provides an opportunity to improve the design of backup protection schemes. Existing generator station backup protection schemes use distance protection (21) or voltage controlled/restrained overcurrent protection (51V) elements for clearing phase faults that are not cleared by either line protection or generator protection. Many schemes also use transformer ground overcurrent protection (51NG) for backup protection for ground faults on the system. Since generator protection can respond to faults accurately only when there is no remote infeed from the other terminals, designing a secure backup protection for a generating station during remote infeed conditions is a challenge. Apart from the remote infeed, fast response of automatic excitation controllers also affects the current seen by the generator protection relay. Considering these effects, different vendors have different approaches for setting the 21 element. In order to analyze these recommendations, this thesis studies the performance of backup protection schemes applied at a thermal power station connected through a breaker and half scheme using Real Time Digital Simulator (RTDS) simulations. To address the challenges appeared in simulations, this thesis proposes a new approach to enhance the performance and coverage of backup protection schemes using the IEC 61850 standard based process bus measurements (sample values) from multiple locations in the same relay. In addition to that, this thesis also address the challenges associated with the existing generator breaker failure protection schemes based on undercurrent elements and proposes a solution using a synchronism check element with sampled values. These two techniques can be used in existing generating station protection schemes to improve the reliability and security of the generator protection.

Acknowledgements

I would like to thank my major professor, Dr. Brian K. Johnson, for his advice and expertise on this research. I would also like to thank my committee, Dr. Herbert Hess and Dr. Yacine Chakhchoukh, whom I have worked closely with throughout this project. I am thankful to my fellow student Matchyaraju Alla of ECE department who supported me and been part of my conference paper on this thesis. Finally, I am grateful and indebted for the support provided by my family who have been behind every life decision I have made. Without them I would not be afforded the immense opportunities in life that I have been fortunate enough to have.

Table of Contents

List of Tables

List of Figures

Acronyms

NERC North American Electric Reliability Corporation
MW Megawatt
PU Per Unit
GEN Generator
GT Generator Transformer
UAT Unit Auxiliary Transformer
ET Excitation Transformer
ST Station Transformer
AC Alternating Current
CT Current Transformer
PT Potential Transformer
VT Voltage Transformer
RTDS Real Time Digital Simulator
DC Direct Current
CB Circuit Breaker
SV Sampled Values
REF Restricted Earth Fault
LV Low Voltage
HV High Voltage

CHAPTER 1

Introduction

1.1 Problem statement

Faults which are not cleared by the main protective relays of transmission lines, transformers, and bus bars affect generators. Hence, these faults need to be cleared by the backup protection of the generator. As per the NERC record of all the generator trips (290 units, about 52,745 MW) during the North American disturbance on August 14, 2003, there were thirteen types of generation-related protection functions that operated to initiate generator tripping [3]. Table 1.1 provides a list of 2003 blackout generation protection trips. It can be seen from the table that there are 8 generator units tripped by the operation of distance element based backup protection and 20 units tripped by the operation of voltage controlled/restrained overcurrent (51V) based protection. The larger number of trips associated with (51V) were due to the implementation of electromechanical relays. The remaining protection functions shown in the Table 1.1 were also operated during the blackout but this thesis will not consider them, However, more details on each protection function were provided in the reference [3].

Table 1.1: Number of Units By Type Tripped in 2003 Blackout

Function Type	21	27	32	40	46	50/27	51V	59	78	87T	Unknown
Units Tripped	8	35	8	13	5	8	20	26	20	59	290

After the analysis of 2003 blackout, the NERC white paper states that it is never appropriate to enable both distance (21) and voltage controlled/restrained overcurrent (51V) protective functions within a generator digital relay. It also states that the 21 distance function is preferred when coordinating with transmission line relays. The coordination between these relay types can be most effectively done because these relays have same operating characteristics and they both measure impedance. The voltage controlled/restrained overcurrent element (51V) is often used as main protection for small generators and also as backup for large generators, and is not recommended when transmission systems use distance line protection functions [3]. Figure 1.1 shows a one line diagram mapping of measurements for the 21 and 51V connected to a generating system. Both 21 and 51V are used for system backup protection, i.e., to operate when the primary protection fails. These relays are set to respond to faults on the transmission system and their trip output is delayed to allow the transmission system protection to operate first. The degree to which the relays can be set to respond to transmission system faults is almost always limited by loading considerations.

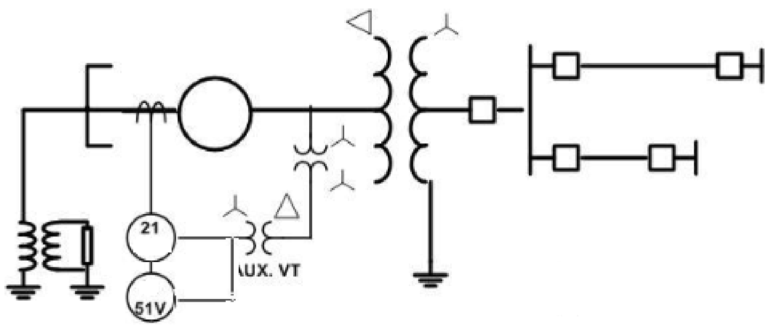


Figure 1.1: Connection Diagram for 21 and 51V Functions

As will be described in Chapter 3, there are protection challenges associated with existing transmission line protection. Hence, there should be an alternate secure and reliable backup protection scheme for generators to protect them from external faults that are not cleared by the line protection. Furthermore, the overall differential protection component that covers the generator and related associated transformers won't be secure during CT open conditions, so there ought to likewise be a backup to the differential component for protection against these conditions.

Relay device 21 measures impedance as the quotient of generator terminal voltage divided by generator stator current. This function can be implemented to provide backup protection for system faults that have not been cleared by transmission system protective functions. Device 51V is a voltage restrained or voltage controlled inverse time overcurrent element which provides sensitive phase fault protection for faults that are not cleared on the system side of the Generating Transformer (GT). During a fault, as the measured phase voltage decreases, the 51V element current pick up also decreases. However, these will be discussed in detail in the Chapter 4.

1.2 PRESENT SOLUTION

A Beckwith Electric white paper [4] analyzed the August 14, 2003 blackout and suggested possible techniques and methods to provide the needed coordination to overcome incorrect protective relay actions that occurred. The authors stated that major power system blackouts at the time the paper was written, were a result of a voltage collapse. This paper addressed generator protection security issues that concerned NERC that resulted from low system voltages, relay settings which restricted generator capability under emergency system conditions, and coordination of generator protection with generator excitation and governor control. The paper also provided practical guidance in implementing NERC-proposed guidelines [3] for setting generator protection to coordinate with transmission protection. Chapter 4 will provide the major relay vendor recommendations that are used in existing systems but it is to be noted that all these recommendations also compromise the sensitivity of detection with remote infeed conditions.

1.3 PROPOSED SOLUTION

Careful considerations have to be taken for choosing protective functions in a generator relay to protect from incorrect trips. Since the generator based backup relay can only measure the effective phase-to-phase fault impedance looking into the system accurately when there is no remote infeed, designing a secure backup for generating stations where there will be remote infeed is a challenge. The proposed idea is to design a scheme using a backup relay for generating stations to protect the generators from external and internal faults. The main objective of this idea is to avoid tripping generator for line faults in the event of transmission relay failure to identify the fault. To do that, this backup relay subscribes to the sampled values from the merging units and is capable of tripping the transmission line breakers.

Since the overall differential protection scheme which covers the generator, generator step-up transformer (GT), Unit Auxiliary Transformer (UAT), and Excitation Transformer (ET) will not be secure during Current Transformer (CT) open conditions, the proposed backup distance element will also cover faults in reverse direction to work as backup to the differential element. The relay reach settings for the generator backup relay must be approved by the transmission owner for fault detection and time coordination. It should be assured that the backup relay will not respond incorrectly due to system loading during extreme system conditions.

The proposed backup relay can also be used to identify the generator circuit breaker failure to open conditions. The challenges associated with the backup relay are addressed in the subsequent chapters.

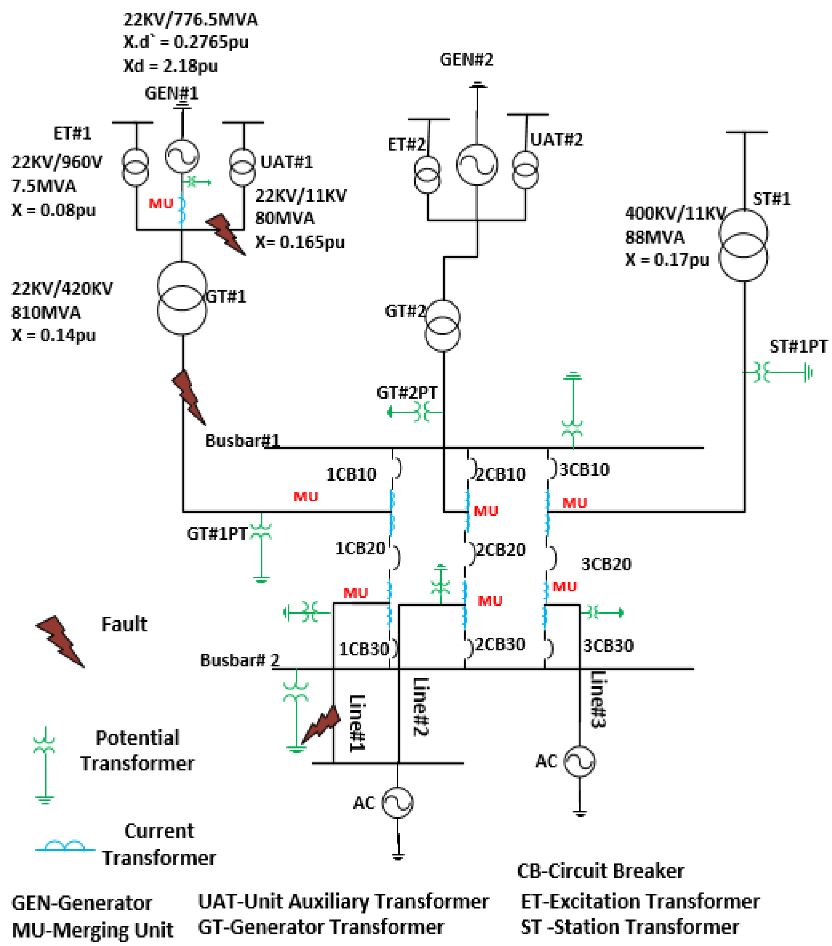


FIGURE 1.2: Single Line Diagram of a Thermal Power Generating Station

1.4 OVERVIEW TO THERMAL POWER PLANT PROTECTION SCHEME

In order to analyze the performance of the distance element, the system shown in Fig 1.2 is considered. This system consists of one Station Transformer (ST) and two generator units where each individual unit includes one UAT and one ET. This system is connected to the transmission system through a breaker and half bus structure. The entire system was modelled in a Real Time Digital Simulator (RTDS).
Each generator has a cylindrical two pole rotor and is connected to a GT which is connected to the 400kV transmission line system. The GT steps-up from 22kV to 420kV, which is a slightly higher voltage than the transmission system voltage of 400kV. This reduces the reactive burden on the generator and the excitation system.

The UAT is used to supply the unit loads for each generator unit. The UAT is connected to the generator terminals Isolated Phase Bus Ducts (IPBD) and steps the voltage from 22kV to 11kV to feed the unit loads, e.g. boiler feed pumps, fans, etc.

The ET is connected to the generator terminals and steps the voltage from 22kV to 960V to feed the excitation AC supply to the Automatic Voltage Regulator (AVR). The AVR takes the AC supply and converts it to DC using a three phase full bridge converter. The DC supply will then be given to the rotors using a slip ring and brush assembly.

The ST is also known as start-up transformer because it steps down the voltage from 400kV to 11kV to initially supply to all the auxiliary loads of the plant when the generators are disconnected from the grid. Once the generators are synchronized to the grid all the unit loads will switch their power from the ST low voltage side to the UAT low voltage winding. The ST will feed the common station loads like coal handling plants and feed water pumps.

The power evacuation system of this plant consists of three transmission lines connected to the generators through a breaker and a half switch-yard. The scheme works on the principle that two lines are always being protected by three circuit breakers, which means that for any fault on the transmission line, circuit breakers in the 20 and 30 series will be tripped. Similarly, for any fault on the generator, ET, UAT and GT system, the circuit breakers 10 and 20 series will be tripped. This scheme facilitates maintenance of any circuit breaker without any outage.

Merging Units (MU) will be located at each set of three phase CT and Potential Transformer (PT) terminals to acquire the analog information for the Sample Values unit (SV). The sampled values will be communicated via a fiber optic network to be available for all relays including the backup relay.

1.5 OBJECTIVES

Overall, the main objective of this project is to design a backup relay to protect a generator from both internal and external faults. This backup relay also plays a major role when breaker failure occurs under fault conditions. Listed below are some additional objectives for this thesis.

1. Implement the proposed model in Real Time Digital Simulator (RTDS) and evaluate the responses to faults that are external to the system and evaluate how the new scheme performs.

2. Discuss equipment vendors recommendations for setting reach values for the generator backup relay and choose the best to implement.

3. Identify the protection benefits if the backup relay voltage measurements are placed on the high voltage side of the generator transformer rather than the low voltage side.

4. Discuss the advantages of using sampled values and merging units for providing the sample values to the backup relay.

5. Implement enhanced distance element based on directional supervision using sampled values.

6. Identify the cases when a breaker failure occurs and how the backup relay can protect against breaker failure faults.

7. Assess how the proposed scheme works if the transmission lines are series compensated.

To fulfill these objectives, the thesis work is organized as follows. Chapter 2 provides a brief introduction to generator protection and discuss the associated faults. Chapter 3 discussed line protection; associated polarizing reference elements and the challenges with line protection. Chapter 4 discuss backup protection for generators, explaining the distance and overcurrent voltage restrained elements and different reach settings proposed by different vendors in setting distance elements for backup protection. Chapter 5 describes the system modelling in RTDS simulations. Chapter 6 explains the different fault cases and discusses the results from RTDS. Chapter 7 describes the proposed protection scheme using sampled values, which includes a directional element, and demonstrates how the proposed backup relay improves performance for the faults cases from previous chapters. Chapter 8 discusses conclusions drawn from this research and provides the future work that can be developed from it.

1.6 SUMMARY

This chapter discussed the protection issues associated with backup protection by distance elements and voltage controlled overcurrent elements. It also described the proposed backup relay to protect the generator from external and internal faults. This backup relay will act as backup to the transmission line protection for external faults and also backup to the overall differential protections for internal faults.

CHAPTER 2

Review on Generator Protection

A generator unit is the most valuable piece of equipment in a power plant, which converts mechanical energy to electrical energy. The generator should be protected from faults occurring within the generator and also from external faults which affect the generator [5]. Before studying faults in a generator system, one should understand the parameters of system that define normal operation. During normal operation, the generator supplies power to the grid through generator step-up transformer and local plant load through a Unit Auxiliary Transformer (UAT), which could be rated at 10% of the unit rating.

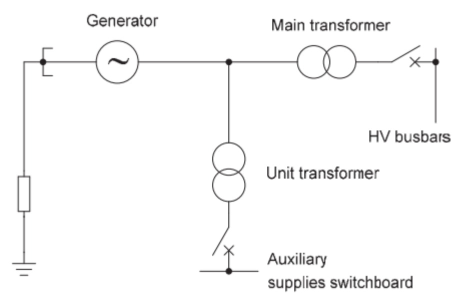


Figure 2.1: Typical Generator System

2.1 Types of Generator Faults

There are two types of generator faults. They are internal and external faults and are classified as follows

2.1.1 *Internal Faults*

1. Stator Phase Faults
   Phase-to-phase faults cause negative sequence currents to flow in the stator which generate double frequency currents in the rotor, which in turn result in increased rotor heating. These faults require fast clearing times because of very high fault current magnitudes and their heating effect on the insulation of the windings. These faults are primarily cleared by the differential protection.

2. Stator Ground Faults
   Usually generators are grounded through high resistance to limit the fault cur-

rent for phase-to-ground to ground faults. Depending on the fault location, the fault clearing time will vary. Faults closer to the neutral require some delay to avoid nuisance trips due to system faults. Faults on the upper 90% of the stator winding are cleared by the zero sequence overvoltage element of the relay and 100% of the winding can be protected against the ground faults using either third harmonic differential or 20Hz injection techniques.

3. Stator Turn-to-turn Faults
   In the event of internal faults in turbo generators large currents flow in the windings due to the unsymmetrical magnetic linkage between the stator windings of the lap-connected generators. This causes severe damage to the windings, shaft and coupling of the machine. The turn-to-turn faults in the stator winding of a synchronous generator will often evolve as a phase fault or ground fault and then cleared by the differential protection or ground fault protection. There are other methods also to detect the turn-to-turn faults but however they are out of scope for this work.

4. Field Winding Faults
   There are two faults associated with rotor field winding. One kind is rotor field winding to ground fault and another is rotor turn-to-turn fault in the winding. The rotor body of the generator is grounded on one side through brushes and the other side is insulated to avoid the flow of circulating currents that could cause bearing damage. If a ground fault occurs in the winding of the rotor, the new ground will provide the return path for the ground fault to flow through. A relay can be connected in the circuit to identify rotor ground faults. Since the DC supply of the field winding always operates as an ungrounded system, the first ground fault in the rotor winding may not cause any major issue to the healthy operation of the generator. So the generator doesn't need to be tripped on the first ground fault on the rotor. But the second fault on the rotor winding will bypass the part of the rotor winding and will disturb the airgap flux in the machine causing vibration that could exceed limits. This condition is dangerous for the generator and needs immediate tripping.

2.1.2 *External Faults*

For faults that occurs external to the generator within the plant, the overall plant differential relay will need to operate as a primary protection or backup based on the system design. The back protection scheme needs to coordinate with the external protection system to trip with a time delay.

2.2 PROTECTION FUNCTIONS IMPLEMENTED IN A GENERATOR RELAY

There are electrical and mechanical protection requirements associated with the Generator, GT, UAT and ET. Though, the complete details will not be given here for each protection scheme, a list of elements typically seen in numerical relays are shown here.

2.2.1 *GT Electrical Protection Functions*

1. GT overall differential protection
2. GT differential protection
3. GT phase-to-phase backup protection
4. GT ground fault backup protection
5. GT overexcitation protection
6. GT restricted earth fault (REF) protection

2.2.2 *Generator Electrical Protection Functions*

1. Generator differential protection
2. Generator split phase differential protection
3. Generator turn-to-turn fault protection
4. Generator phase-to-phase fault backup protection
5. Generator stator ground fault backup protection
6. Generator rotor ground fault protection
7. Generator stator overload protection
8. Generator negative sequence overload protection
9. Generator loss of excitation protection

10. Generator asynchronous protection
11. Generator under voltage protection
12. Generator overexcitation protection
13. Generator reverse power protection
14. Generator over/under frequency protection
15. Generator start-up/stop protection
16. Generator inadvertent energization protection
17. Excitation system failure protection
18. Open phase protection

2.2.3 *Excitation Transformer Electrical Protection Functions*

1. Excitation transformer differential protection
2. Excitation transformer backup protection
3. Excitation transformer winding overload protection

2.2.4 *UAT Electrical Protection Functions*

1. UAT Differential protection
2. UAT HV backup protection
3. UAT LV branch A back up protection
4. UAT LV branch A REF protection
5. UAT LV branch B back up protection
6. UAT LV branch B REF protection

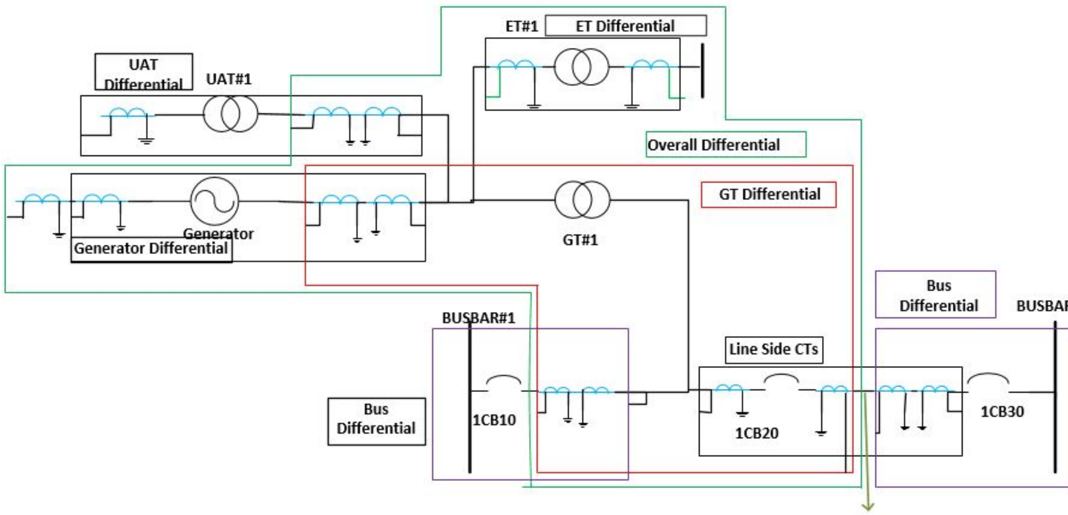


Figure 2.2: Overall Differential Scheme of the System

2.3 GENERATOR DIFFERENTIAL SCHEMES

Since the proposed backup relay works as a backup to the differential protection scheme, the set of differential protection elements applied for a generator will be described here for reference.

Figure 2.2 shows the various differential protection zones applied in a generating station. The overlapping between zones is to avoid blind zones between CTs and breakers. This thesis uses a breaker and a half bus scheme in which two feeders are protected by three breakers. Hence, for each trip, two breakers will be operated. As explained earlier, the primary protection elements for the generator, GT, UAT and ET is differential protection and all are covered by an overall differential protection zone. The overall differential protection works as backup to the individual differential protection. The individual zones of the protection can be identified by the different colors in the Figure 2.2. Based on the vendor, these differential zones will be either provided in one relay or various relays. Note that the polarity grounding of the CT secondaries should be such that they should always be placed towards the object to be protected. It is interesting to note that if one phase of any CT of the overall differential protection is open, then the will be blocked from misoperation so there should be a backup requirement for this element to protect the system from internal faults.

2.4 SUMMARY

This chapter provided the list of protection elements that a generator unit will have in the numerical relay. Since this thesis work concentrates on backup to the differential element, the various differential protection zones applied to the generator are only described in this chapter.

CHAPTER 3

Line Protection and Challenges

3.1 Types of Line Protection

Transmission lines in the bulk power transmission system generally are not protected by simple overcurrent elements because of challenges in setting them due to changes in source impedance as power system configurations vary. The following are the two elements most commonly used in transmission line protection.

1. Line current differential protection

2. Distance protection with communication enhancement

3.2 Line Current Differential Protection

Line current differential protection measures and compares the currents at both ends of the line. Under normal conditions the current enters one end of the line and leaves at the other end, and the difference between the currents at both ends should be equal to the charging current and relatively small. But in a practical system, there are errors associated with the CTs and this plus the charging current requires that the operating quantity be set to a non-zero minimum value. The relay takes an action based on the phasor difference between the currents at each terminal. The line current differential scheme is most often employed for transmission line less than 125km in length. Since both ends of the line are usually connected through fiber optic cable and cost and time alignment challenges increase with length. Line current differential protection typically uses phase currents. But it can be based sequence quantities, for example, negative sequence based differential protection can increase sensitivity for high resistance faults.

3.2.1 *Advantages of Line Current Differential Protection*

1. Immune to power swings

2. Sensitive for high resistance faults

3. Works well on series compensated lines

4. Works well for single pole tripping

3.2.2 *Disadvantages of Line Current Differential*

1. Relatively high communication bandwidth is needed
2. Measurements require time alignment
3. Challenges with communication channel asymmetry for time alignment
4. Requires charging current compensation
5. Can't operate with loss of communication
6. Lack of backup zone.

Even though, line current differential protection normally offers superior performance, as noted above there is a line length limitation for application of this protection. As the demand for bulk transfer over long distances increases, challenges to the line current differential protection application increases so distance protection is the obvious one in these cases.

This thesis work concentrates on providing backup protection using distance element, and does not try to coordinate with the line current differential protection element.

3.3 DISTANCE PROTECTION

Almost all applications of line current differential also set distance elements as a backup. In addition, distance protection, with communication assistance is the primary protection for many lines. The relay measures local voltage and current and calculates an effective impedance looking into the line. Since the impedance of the line can be treated as a constant parameter independent of any contingency, it can be used as the basis of a protection element. Distance relays provide effective transmission line protection. Their tripping characteristics are usually created using comparators and various combinations of voltages and currents [6]. Table 3.1 summarizes the input signals for the phase and ground distance elements most commonly applied in North America. The protection equation is based on $Z_{eff} = V/I$, where V and I are from the Table 3.1. The ground elements use a zero sequence correction factor defined in (3.1) to allow the elements reach setting to be set based on positive sequence line impedance.

Table 3.1: Phase and Ground Distance Elements

Distance Elements		**V**	**I**
phase elements	AB	$V_a - V_b$	$I_a - I_b$
phase elements	BC	$V_b - V_c$	$I_b - I_c$
phase elements	CA	$V_c - V_a$	$I_c - I_a$
Ground elements	A	V_a	$I_a + K_0 I_r$
Ground elements	B	V_b	$I_b + K_0 I_r$
Ground elements	C	V_c	$I_c + K_0 I_r$

$$K_0 = \frac{Z_{0L} - Z_{1L}}{3Z_{1L}} \tag{3.1}$$

There are three distance elements types that carry over from electromechanical relays: impedance, reactance, and mho. Two of these distance elements lack directionality. The impedance-type characteristic is a circle whose center is at the origin of impedance plane coordinates. The reactance-type characteristic is a straight line parallel to the real (resistive) axis. Impedance-type elements need an additional directional element to ensure they only react to faults in the protected line (forwarded relative to the relay). Reactance-type elements need a directional element and a resistance element to limit the reach on both sides of the element characteristic. The mho element has carried over into microprocessor relays and is most commonly applied type in North America.

3.3.1 *Mho Element*

The mho function uses the current and voltage measured at the relay to determine if the apparent impedance falls within the mho characteristic. The mho element is implemented as a comparator. S_{POL} serves as an angular reference for the phase comparison that takes place in the mho element. S_{POL} is the polarizing quantity. S_{op} is the operating quantity that changes most significantly with a fault. Equations (3.2) and (3.3) define those quantities, where V and I are as defined in Table 3.1.

$$S_{op}^{-} = ZI - V \tag{3.2}$$

$$S_{POL}^{-} = V \tag{3.3}$$

$$-90deg \leq arg(S_{op}^{-}/S_{POL}^{-}) \leq 90deg \tag{3.4}$$

Where Z is the reach setting. The relay element will trip when the condition in equation (3.4) is met.

The mho characteristic is a circle that both pass through the origin of the impedance plane and through the line impedance vector at the reach setting. The mho element operates for impedances inside the circle, which is basically oriented toward the first quadrant which is the case for forward faults. For reverse faults, the apparent impedance lies in the third quadrant of the impedance plane and represents a restraining condition for the element. The fact that the circle passes through the origin of the coordinates is an indication of the inherent directionality of the mho elements. However, close-in low impedance faults produce deep voltage sags. Since the voltage is the polarizing angle reference, the mho element may lose the voltage polarizing signal for close-in faults and incorrectly operate for a reverse fault. This fact has been considered by relay designers in selecting the appropriate mho element polarizing reference [7]. They are three commonly used types of polarization.

1. Self Polarized

2. Cross Polarized

3. Memory Polarized

3.3.2 *Self Polarized*

A simple mho distance function, with a reach of Z ohms, is shown in Fig. 3.1. Equation (3.3) represents the self polarized case. The polarizing quantity for this simple mho distance function is simply equal to the measured fault loop voltage V, therefore the function is said to be self-polarized and has the simple characteristic shown in the figure. In practice, a voltage different than the measured fault loop voltage is used to polarize the distance element and this will have an effect on the characteristic.

As noted above a close-in bolted fault is a zero-voltage condition for the relay. A self-polarized mho element loses the polarizing signal and is unable to discriminate between a close-in forward fault and a close-in reverse fault. As a result, this element is very rarely applied in practice.

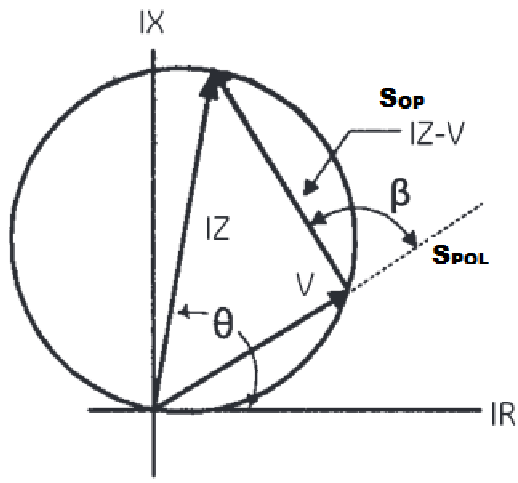


Figure 3.1: Self-Polarized Distance Element in Voltage Plane

3.3.3 *Cross Polarized*

Cross-polarization uses unfaulted phase voltage(s) as the polarizing quantity. The resulting operating characteristic is called a variable-mho characteristic because of its variable shapes for different system and fault conditions as shown in Fig. 3.2. Cross-polarization expands the mho characteristic back by approximately the local source impedance for forward faults. This expansion improves dependability for zero-voltage unbalanced faults and faults that cause voltage inversion and provides greater fault-resistance coverage (especially for systems with a weak local source).

$$S_{POL} = K_p V_p \tag{3.5}$$

In general, the solution to this inability to discriminate between the close-in forward fault and the close-in reverse fault is to provide the mho element with unfaulted phase voltage information. For a close-in bolted fault, only the faulted phase voltage equals zero. There is voltage in the unfaulted phases. We can use only the unfaulted phase voltage for polarizing (cross-polarization), or we can add unfaulted phase voltage information to the faulted phase voltage (combined polarization). The best combined polarization is positive-sequence polarization. Positive-sequence voltage includes both faulted and unfaulted phase voltage information.

For close-in three-phase bolted faults, all voltages collapse to zero and current measured based polarization quantities are not reliable.

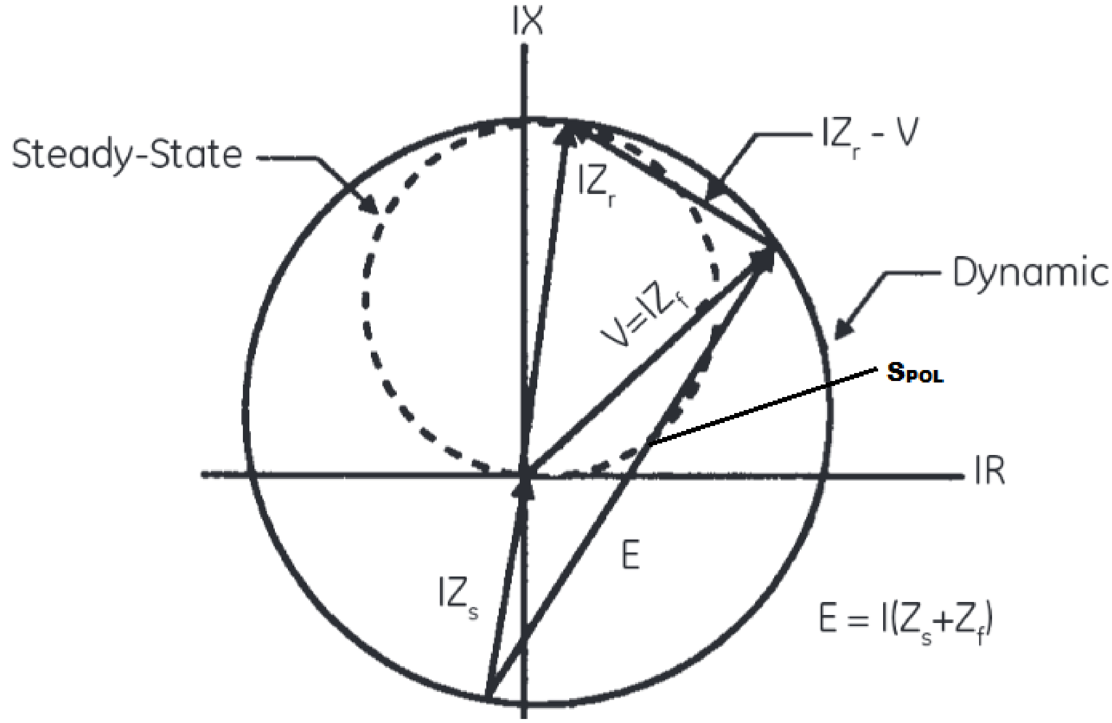


Figure 3.2: Cross-Polarized and Memory Polarized Distance Element in Voltage Plane

3.3.4 *Memory Polarized*

Memory polarization uses recorded faulted phase, unfaulted phase, or positive-sequence voltage(s) as the polarizing quantity. The resulting operating characteristic is also a dynamic mho characteristic as shown in Fig. 3.2 because its shape changes as the memory expires with time. Memory polarization also expands the mho characteristic back to approximately the local source impedance for forward faults. This expansion improves dependability for zero-voltage faults and faults that cause voltage inversion and provides greater fault-resistance coverage. Elements with self-polarization, cross-polarization, and combined polarization do not work for zero-voltage, three-phase faults. Memory polarization solves this problem.

$$S_{POL} = K_p V_{pol} \tag{3.6}$$

V_{pol} is the present memorized positive-sequence voltage value. The polarizing coefficient K_p is generally a complex number. The angle for K_p such that K_p V_p and V are in phase. In this case, the polarizing quantity keeps the same angle even if V = 0. Typical values for the magnitude of kP are 0.1 to 0.2 for combined polarization and -1 for cross-polarization. The length of time applied in memory filter polarization memory is a critical parameter. A longer polarization memory helps to detect faults in difficult system and fault conditions where fault-clearing time or the operating time of capacitor bypass protection is long. However, longer memory may impair distance element security when a power system disturbance causes a frequency excursion or a power swing [8]

3.3.5 *Drawbacks with Distance elements*

Distance elements have challenges under certain types of conditions

1. Infeed effect with non-zero fault resistance on tapped lines

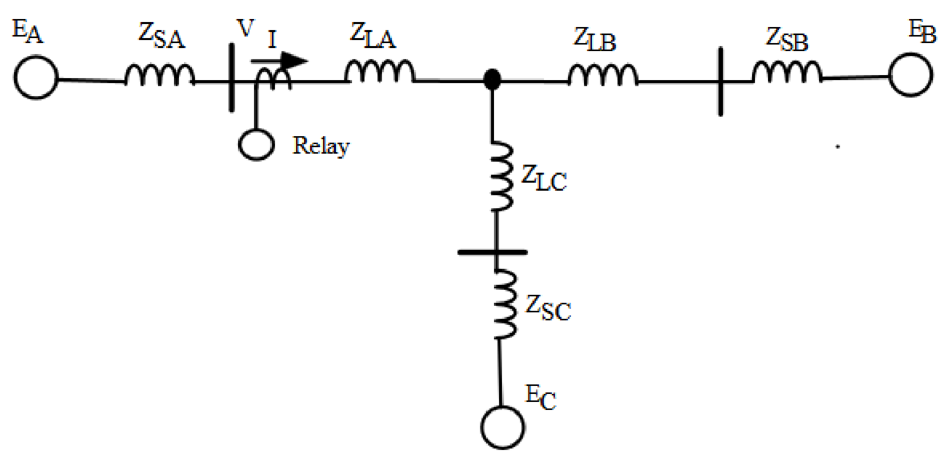


Figure 3.3: Distance Element Performance on Tapped Lines

A short-circuit current source (a generation source or a grounded transformer) connected between a distance relay and the fault location as shown in Fig. 3.3 (called an infeed source) affects the value of the impedance that a distance relay estimates. This is called the infeed effect. The infeed source causes the relay to measure the adjacent line impedance multiplied by a factor. Since the relay sees added voltage due to the infeed, but does not measure the extra current. This factor is the ratio of the current in the adjacent line to the relay current. The infeed effect factor is, in general, a complex number with a magnitude greater than unity. The infeed effect results in the relay estimating an impedance value greater than the actual impedance between the relay and the fault. This impedance measurement error causes distance elements to underreach (see the fault as farther away than it actually is) [8]. The effect of infeed on the distance element will be seen in the next chapter.

2. Mutual coupling
   In cases where there are parallel lines, zero sequence current in one line couples to the other. This causes an added voltage drop that could increase or decrease the calculated effective impedance. The effect of this mutual coupling in this case is that none of the ground distance elements correctly measure the distance to the fault.

3. Load encroachment
   When the system is heavily loaded, the effective impedance at the relay of the system is reduced and may reach into zone of operation, and look like a close-in fault with a high impedance thereby causing a mis-operation. This will be described in detail in Chapter 4.

4. Power Swings
   Power swings refer to oscillations in active and reactive power flows on a transmission system during and following a large disturbance such as a fault in a critical line. Power swings are classified as stable swings and unstable swings. When a stable power swing occur due to events in other parts of the system, the effective impedance varies and may appear to be a fault to the relay. A blocking element is used to prevent this. This element still has to respond correctly if faults occur during power swings.

5. Evolving faults
   An inter-circuit fault on a double-circuit line occurring close to remote station creates fault type identification problems. The fault types, as seen from each line, are different. Distance elements at remote station correctly identify the fault type on both lines. However, both distance elements at local station identify the fault as a BCG fault. This inaccurate identification initiates incorrect three-pole trips at both lines for two single phase-to-ground faults. These are called as evolving faults.
   For evolving faults, it is generally difficult for the relay correctly identify fault inception and fault type changes. Evolving faults present problems for all protection principles. Many faults evolve in some way. The fault resistance (R_F) may vary with time. As a result, the fault current is variable. Another common type of fault evolution is a change of fault type. Many faults initiate as

single-phase-to-ground faults and evolve into phase-to-phase-to-ground faults or three-phase faults.

3.4 SUMMARY

This chapter provided a review on challenges associated with transmission line protection using distance and line differential protection. It briefly discussed the distance element which is the critical element for this thesis. This distance element has problems associated with remote infeed, power swings and evolving faults etc. Overall, this chapter concluded that line protection challenges will sometimes cause the backup element to operate in the event if the line protection fails to operate.

CHAPTER 4

Generator Backup Protection

4.1 BACKUP PROTECTION

The primary protection scheme for generator phase-to-phase fault is the differential protection scheme. Backup protection is recommended to safeguard the generator from the effects of faults that are not cleared due to failures in the normal protection scheme. The backup relaying can be useful to provide protection in the event of a failure of primary protection at the generation station, or on the transmission system, or both. Specific generating station failures include the failure of the generator or generator step-up transformer differential schemes. On the transmission system, failures would include the failure of line protection relay scheme or the failure of a breaker.

4.2 OVERCURRENT ELEMENT FOR BACKUP PROTECTION

Standard overcurrent relays are not recommended for backup protection of a generator [3]. The backup relay must be capable of detecting the minimum generator fault current. This minimum current is the sustained current following a three-phase fault assuming no initial load on the generator and with the manual voltage regulator is in service. If the automatic voltage regulator in service, it would respond to the fault-induced low terminal voltage and boost the field current, thus increasing the fault current. The assumption of no initial load on the generator defines the minimum field current to drive the fault. Typically, a generator's per unit synchronous reactance, which controls the value of the sustained fault current is greater than unity. If the generator is unloaded and is at rated terminal voltage (1.0 pu) prior to the fault, the sustained short-circuit current will be $1/X_d$ which will be less than full load current where X_d is steady state synchronous reactance.

Typically, X_d varies from 1 to 2 pu on the generator base. The subtransient reactance X_d'' can be approximated to 10% X_d and transient reactance X_d' can be around 20% of X_d. If a three phase fault occurs on the line, the initial fault current can be very high since the positive sequence generator impedance is effectively X_d''. As the time constants of subtransient and transient states expire, the generator will reach steady state, and the resulting sustained three phase fault current could be less than the full load rated current as noted above since the effective positive sequence generator impedance is X_d. A standard overcurrent relay must be set above load current and would not detect the minimum sustained fault current. So use of an overcurrent element for back up protection is not a feasible option.

4.3 VOLTAGE DEPENDENT RELAYS FOR BACKUP PROTECTION

The difficulties associated with standard overcurrent protection can be overcome if the fault detection is based on both current and voltage. At full load, the generator terminal voltage will be near the rated voltage. During sustained three-phase fault conditions, the effective internal generator impedance will change from X_d'' to X_d and then causing the terminal voltage to increase (but less than the rated voltage). The type of overcurrent device generally used for system phase fault backup protection is either a voltage-restrained (51VR) or voltage-controlled (51VC) time-overcurrent relay and both are lumped under the designation 51V. Both types of relays are designed to restrain operation under emergency overload conditions and still provide adequate sensitivity for the detection of faults [9]. The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage where to generator should stay online), the 51V relay will not trip. However, during faults, within the protection zone of the relay, the relay will be enabled (51VC), or sensitized (51VR), to trip with the expected fault current level.

Both distance relays and voltage supervised overcurrent relays use the voltage degradation to differentiate between normal load current and a sustained fault current condition. Because of this design, these backup relays are supervised by a loss of potential detection element, device 60. This element blocks tripping in the event of an open phase or a blown fuse in the voltage measurement circuit. Without this blocking feature, these instrument circuit malfunctions would trip a fully loaded unit.

Most large generators, are grounded through a large impedance to limit single line to ground fault current to a few amperes. Generators are also connected to the grid via $\Delta - Y$ grounded transformers. As a result grid side single line to ground faults appear as phase-to-phase faults to the generator. Specialized schemes are incorporated for ground fault detection in the generator itself and consequently, the 51V function is more often required to provide backup phase fault protection and uses a phase-to-phase voltage connection. The generator is normally operated with an automatic voltage regulator in service to boost field current which also boosts fault current. However, fault detection for a voltage-controlled or voltage-restrained relay is a function of both voltage and current. The 51V function must be set to detect the minimum anticipated fault current within its zone of responsibility, in case of a sustained three-phase fault with the manual regulator in service.

Typically, a generator's excitation system is capable of delivering 1.3 to 1.5 times the field current required for the full load operation. The excitation boost is a benefit for the overcurrent element for the 51V function, but if there is impedance between the generator and the fault, the increased field current will also significantly increase the generator terminal voltage. The effect will desensitize the voltage-restrained relay, or possibly prevent the dropout of the under voltage element of the voltage-controlled relay [3]. Consequently, setting calculations are required not only to establish the minimum fault current conditions, but also to define maximum fault voltage conditions.

After the overcurrent tap setting is chosen, a time delay can be chosen. The 51V is a backup function and should not operate unless a primary protection element fails. As such, the time delay chosen should provide ample margin to assure coordination with normal relaying. But the delay must not exceed the generator short time thermal capability or the transformer through fault protection curve. The infeed current effects will vary based on the number of generators connected to the system at the time of fault occurrence requiring further studies. Even though the settings are determined once, it will be difficult to cover all the cases encountered during different operating conditions.

4.4 DISTANCE ELEMENT FOR THE BACKUP PROTECTION

As discussed in the Section 3.3, a distance relay measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. This relay function provides backup protection for system faults that have not been cleared by transmission system protective relays.

As stated earlier, the 21 device is preferred for the protecting generator systems that are connected to a transmission system. If the primary protection for the transmission line is distance protection, using the same element for generator based backup protection can result in better coordination of the relays, as these relays have the same operating characteristics; i.e., they both measure impedance.

The 51V backup relay was designed for applications where the system the generator supplies were protected by time overcurrent relaying [9]. Because of the cost differences in electromechanical technology between 21 and 51V relays, the 51V relays were mostly used to provide backup protection in place of the more expensive 21 relays. This in turn contributed to the number of maloperations that occurred during the 2003 East Coast blackout [3].

4.5 DISADVANTAGES OF ENABLING BOTH 21 AND 51V TOGETHER FOR BACKUP PROTECTION

The decision to enable one of these protective functions should be based on a specific need, either to protect a turbine generator or to provide backup protection functions for the interconnecting power system. If there is no need for applying specific protection, that protection function should not be enabled. However both the 51V and 21 protection functions should not be enabled at the same time. These two protection functions are designed to provide the same protective function for very different applications and purposes, and therefore, should not be enabled together. The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V functions have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V functions are often used effectively on generator connected to distribution system where distribution feeders are protected with time inverse characteristic relays. For these reasons, it is recommended that an impedance function 21 be used rather than a 51V function for generators connected to the transmission system. Since 21 function can clearly define its zone of protection and clearly define its time to operate and therefore coordinate better with transmission system distance protection functions. Therefore, NERC recommends the use of 21 in place of 51V for the generators that are directly connected to the transmission system [3].

4.6 IMPORTANCE OF CT LOCATION FOR DETECTION

The relay can receive measurements from CTs at the neutral end of the generator or from CTs at the generator output terminals. In either case, the PTs are located at the generator terminals. When the neutral CT connection is used, faults on the power system or in the generator stator winding are detected in the first quadrant of the R-X plot. This is because the direction of the relay current and the polarity of the relay voltage are the same for both conditions.

When the relay is connected to CTs at the generator terminals with the generator connected to the power system, a fault in the stator winding will produce relay current in the opposite direction of a system fault. The stator fault impedance will appear in the third quadrant of the R-X plot and will not operate the relay. The impedance for a system fault will remain in the first quadrant and is detected in the forward direction. Reach settings will need to differ in two cases. In addition, there are other settings challenges for the 21 backup element.

4.6.1 *Challenges for setting the 21 Element*

1. The remote infeed effect
   Infeed effect with non-zero fault resistance or with tapped lines was discussed in Section 3.3.5. Here, the effect of remote infeed on the backup distance element will be discussed. As described, infeed during fault conditions increases the voltage drop seen by the relay disproportionate to the current which will make the distance element to underreach. As shown in Fig. 4.1, for a fault on any one of the lines, the unfaulted lines will also feed the fault current. The voltage drop across the faulted line impedance will be increased by the infeed current, causing the distance element measured voltage to be higher than if there are no infeeds. Since, the CT shown in the figure which is used for impedance measurement cannot measure the remote infeed current, it will cause the distance element to underreach.

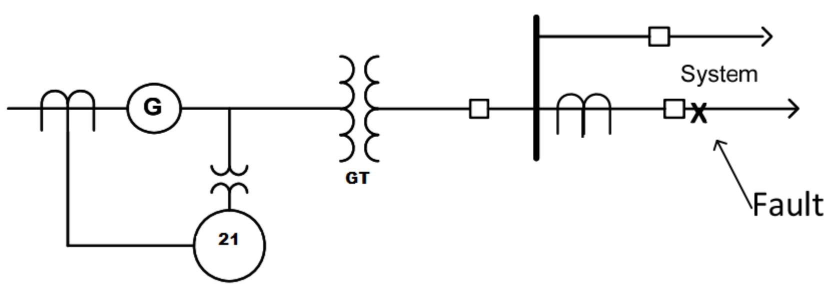


FIGURE 4.1: Remote Infeed Effect on Distance Element

2. Load Encroachment
   The relay uses load encroachment settings to define a region in the impedance plane where operation of the three-phase elements is prevented during heavy load conditions.

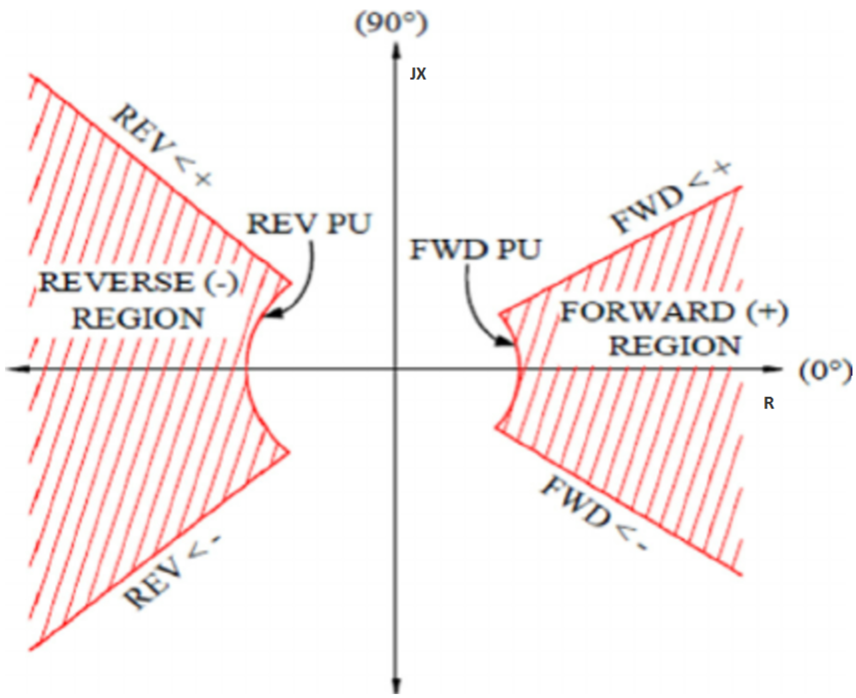


FIGURE 4.2: Load Enchroachment

Typical settings for a load encroachment element are above and below the real axis as shown in Fig. 4.2. The first quadrant is the effective impedance seen by the relay for lagging power factor load entering the line. The fourth quadrant leading power factor export the load. Higher loading conditions may cause the relay to react when the effective impedance enters a set zone, so relay operations can be blocked by the distance relay with load encroachment activated. IEEE C37.102 [9] presents a range of likely acceptable settings for the impedance element at 150 percent to 200 percent of the generator MVA rating at rated power factor so the relay will not operate for normal generator outputs. This setting can be restated in terms of ohms as 0.66- 0.50 per unit ohms on the machine base.

3. Power Swings
   Power swings refer to oscillations in active and reactive power flows on a transmission system during and following a large disturbance such as a fault in a critical line. Power swings are classified as stable swings and unstable swings. The oscillations in complex power and bus voltages are seen by the relay as an impedance swing on the R-X plane that could enter one or more of the set zones. This may cause the distance element to incorrectly trip under stable

swing conditions. The distance element should be able to discriminate between the fault condition and swings conditions, but the element should still trip if a fault condition occurs during a swing and block during a swing condition. The effect of power swings on the distance element in the proposed scheme and on its tripping time will be discussed in the Chapter 6.

4.7 VENDOR RECOMMENDATIONS FOR BACKUP PROTECTION

The following major relay vendors recommendations for setting backup schemes were studied to find out the effectiveness and coverage of the 21 element settings for backup protection for system faults and internal faults.

4.7.1 *Recommendations by Vendor 1*

This vendor recommends setting [10]

1. $Zone_1$ forward and reverse both reach to 75% of the GT impedance
2. $Zone_2$ forward reach to cover 125% of the GT impedance
3. $Zone_3$ forward reach to about 80% of the load impedance considering maximum short time overload on the generator.

This vendor used current and voltage measurements from the generator terminal CT and PT of the generator.

4.7.2 *Recommendations by Vendor 2*

This vendor recommends setting [11]

1. $Zone_1$ forward reach at 120% of impedance of both the GT transformer and the transmission line (in the instance that there are multiple lines and/or multiple generators, the zone1 reach must be increased to compensate for the infeed effect)
2. $Zone_3$ reach at 120% of the generator transient reactance in reverse zone

This vendor also used current and voltage measurements from the terminal CT and PT.

4.7.3 *Recommendations by Vendor 3*

This vendor recommends setting [12]

1. *$Zone_1$* forward reach to 70% to 90% of the GT impedance with a delay setting of 100ms

2. *$Zone_2$* forward reach to cover 200% of the GT impedance when the GT high voltage side breaker is open

This vendor used current and voltage measurements from the neutral CT and terminal PT of the generator as shown in Fig. 4.1.

It can be seen that all the above recommendations are for the impedance element with voltage measurements at the generator terminal. This thesis studied the performance of the two impedance elements one be located at the terminals of generator and Gthe other at the high voltage side of the GT. The following sections will describe the impedances seen by the both the elements and compare performances.

4.8 DISTANCE RELAY 21G ELEMENT

As described earlier in the discussion about CT location, the neutral side CTs are chosen in this work to protect the generator even when it is not synchronized with the grid. The impedances are referred to the secondary for the relays using CT ratios and PT ratios. The rated MVAs of generator and GTs are 776 MVA and 810 MVA respectively. The effective impedances seen by the generator, GT, and UAT when operating at rated MVA and unity pf are 15.58 ohm, 14.93ohm and 151.28 ohm respectively. These impedances will provide the relay setting boundaries for the 21G element (which in this case is using voltage measured at the generator terminals). Beyond these impedance values, the effective impedance load may encroach into the relay zone of operation. This will usually occur during heavy load conditions and tripping will be blocked by the load encroachment function. Appendix B has detailed calculations for referring the impedances to the CT/PT secondary side.

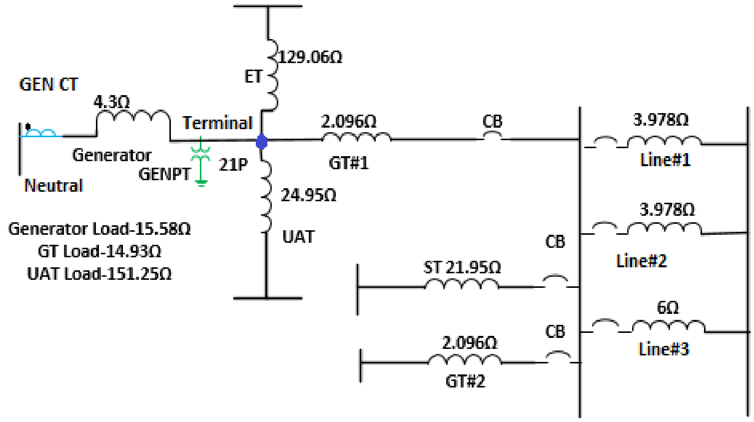


FIGURE 4.3: Relay Impedance Measurements from Generator Terminal Side

4.9 DISTANCE RELAY 21GT ELEMENT

Figure 4.4 shows the impedance when converted to GT HV side relay secondary ohms. The CTs and PTs at the HV side of the GT provide inputs for the distance element. The effective load impedance seen by GT and UAT when operated at rated MVA at unity power factor are 149.72 ohm and 1515 ohm respectively. These impedances will provide the relay boundaries for the 21GT element (which is looking from GT terminals) and beyond these impedance values, the load may encroach into the relay zone of operation. This will usually occur during heavy load conditions and the tripping will be blocked by the load encroachment function. It can be seen that 21 GT appears to have a better margin for the loading conditions than 21G element. Appendix B has detailed calculations for referring the impedances to the secondary side.

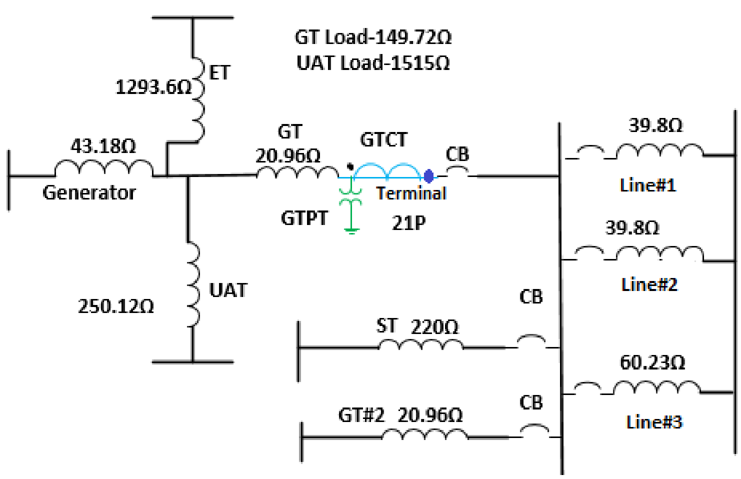


FIGURE 4.4: Relay Impedance Measurements from GT HV Side

Figures 4.3 and 4.4 will be used in Chapter 6 for analyzing the RTDS simulation results and also to help the best distance element measurement location for backup protection.

4.10 SUMMARY

This chapter discussed the protection elements that can be used at the generator for backup protection. The discussion started by discussing the drawbacks of using a simple overcurrent function for the generator backup protection and talked about the use of both voltage and current inputs for the 51V and 21 elements. Since, generators connected to transmission lines are usually protected by distance elements, this chapter recommended using the 21 element for backup protection for phase-to-phase faults. This chapter also reviewed the recommendations from different vendors for setting 21 element in the generator protection relay. Finally the chapter gave an initial comparison of taking distance element measurements at the generator terminal versus at the GT HV terminals.

CHAPTER 5

Modelling in RTDS

5.1 REAL TIME DIGITAL SIMULATOR

The RTDS simulator is one of the two most widely used simulations for real time power system simulation. It consists of custom hardware and software, specially designed to perform real time hardwire in the loop Electromagnetic Transient (EMT) simulation. It operates continuously in real time while providing accurate results over a frequency range from DC to 3 kHz. RTDS uses fully digital parallel processing hardware for simulating complex networks using a typical time step of 50 μs. RTDS has diverse applications in various fields such as protection system testing, control system testing, Phasor Measuring Unit (PMU) studies, IEC61850, smart grid, distributed generation, power electronics, and power hardware in a loop [13]. The following sections describe the modeling of the components used in this research.

5.2 SYNCHRONOUS GENERATOR MODEL

A bulit-in synchronous machine model, as shown in Figure 5.1 and based on generalized machine theory, is connected to the user defined power system network in RSCAD, the graphical interface for RTDS. This model includes an optional Y - Δ generator unit transformer with separately specifiable zero sequence parameters. The model also supports two optional R, RL, or RC shunt load banks which may be placed on the terminals of the machine. This model uses fluxes as state variables rather than currents. Voltage projection techniques are used in order to effectively delay in the closed loop created between machine and main network to ensure numerical stability.

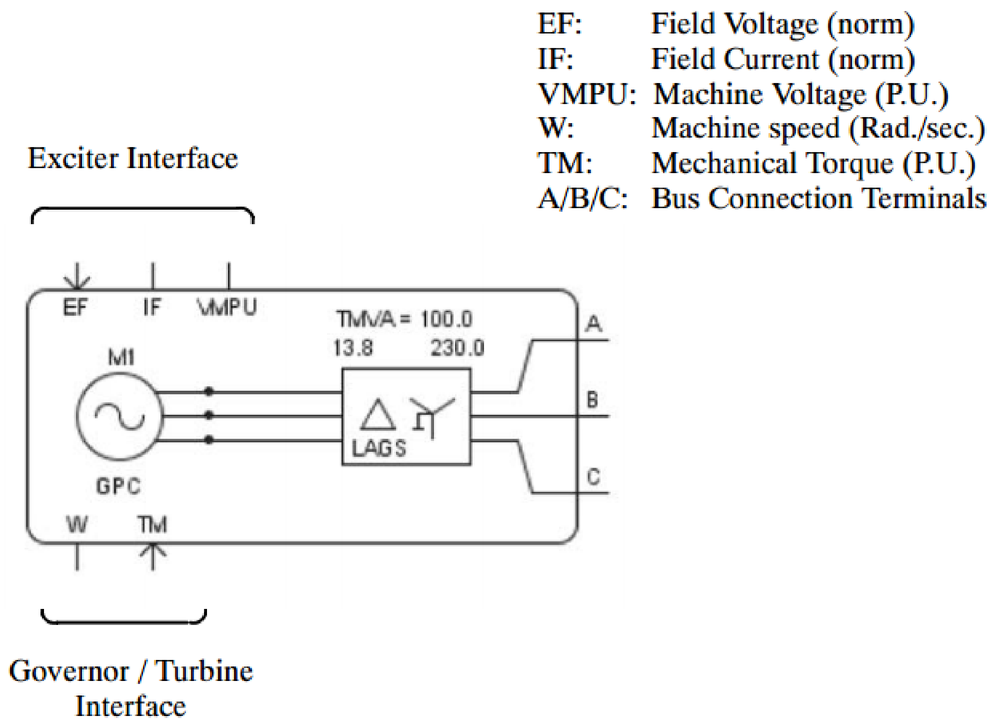


Figure 5.1: Generator Model in RTDS

5.2.1 *Generator Model Parameters for this Project*

In RTDS, a multi-pole synchronous machine (SM) is modeled as an equivalent two pole machine and it is assumed that the machine windings produce a sinusoidal MMF, i.e. space harmonics and slot harmonics are ignored. RTDS transforms all the phase domain equations onto rotating reference frame using Park's transformation to get rid of the inductance dependency on rotor position. Table 5.1 shows the parameters used in RTDS for this study. Both the generators used in the model are identical so they use the same parameters.

Table 5.1: Parameters of Generator Models in the System

Tabs	Parameters	Generator 1
Generator model configuration	Rated MVA	776.5 MVA
	Rated RMS line to line	22kV
	Base Angular frequency	60HZ
	Optional Y-D transformer	No
Machine Electrical Data	Stator Leakage reactance (X_a)	0.1pu
	D-axis Unsaturated Reactance (X_d)	2.1803 pu
	D-axis Unsaturated Transient Reactance ($X_{d'}$)	0.3142 pu
	D-axis Unsaturated Sub-transient Reactance ($X_{d''}$)	0.2134 pu
	Q-axis Unsaturated Reactance (X_q)	2.18 pu
	Q-axis Unsaturated Transient reactance($X_{q'}$)	0.4153 pu
	Q-axis Unsaturated Sub-transient Reactance ($X_{q''}$)	0.2134 pu
	Stator Resistance (R_a)	0.0025 pu
	D: Unsat. Transient Open Time constant (Tdo′)	9.65 sec
	D: Unsat.Subtransient Open Time constant (Tdo″)	0.049 sec
	Q: Unsat. Transient Open Time constant (Tqo′)	1.072 sec
	D: Unsat.Subtransient Open Time constant (Tqo″)	0.065 sec

5.2.2 *Exciter Model*

The bulit-in EXST1 model represents a static excitation system whose source voltage is derived from the generator terminals through a transformer (ET). The exciter maximum output voltage is thus limited by the source voltage. The fixed gain Ka assumes that the rectifier controller of the static excitation system includes an inverse cosine function to linearize the exciter gain.

Transient gain reduction may be implemented using either the forward path lead-lag block (Tb, Tc) or the washout function (Tf, Kf) in the feedback path. Excitation limiter inputs may be provided to the Vs input if required. Table 5.2 lists the exciter parameters used in the model.

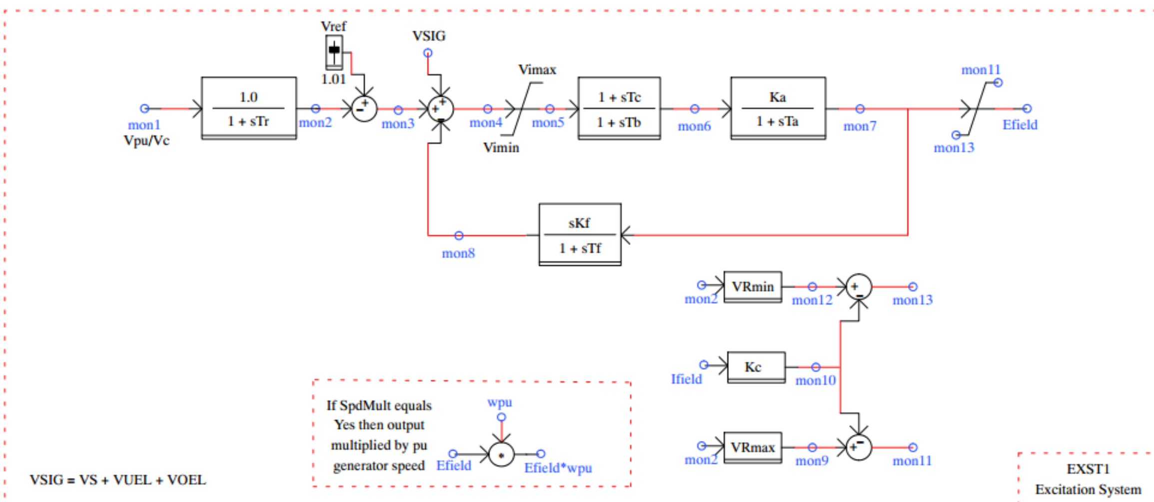


FIGURE 5.2: EXST1 Exciter Model

5.2.3 *Governor Parameters*

The backup element will not have much interaction with the generator governor models, so this thesis used a simplified governor model as shown in Fig. 5.3. The parameters for the governor are in Table 5.3.

Table 5.2: Exciter Parameters

Name	Value
Voltage Transducer Time Constant (T_r)	0.02 sec
Maximum Error Limit (V_{imx})	2 pu
Minimum Error Limit (V_{imn})	-2 pu
AVR Lead Time Constant (T_c)	1.0 sec
AVR Lag Time Constant (T_b)	4.0 sec
Voltage Regulator Gain (K_a)	200
Voltage Regulator Time Constant (T_a)	0.006 sec
Maximum Controller Output	4 pu
Minimum Controller Output	-4.25 pu
Rate Feedback Time Constant	0.56sec

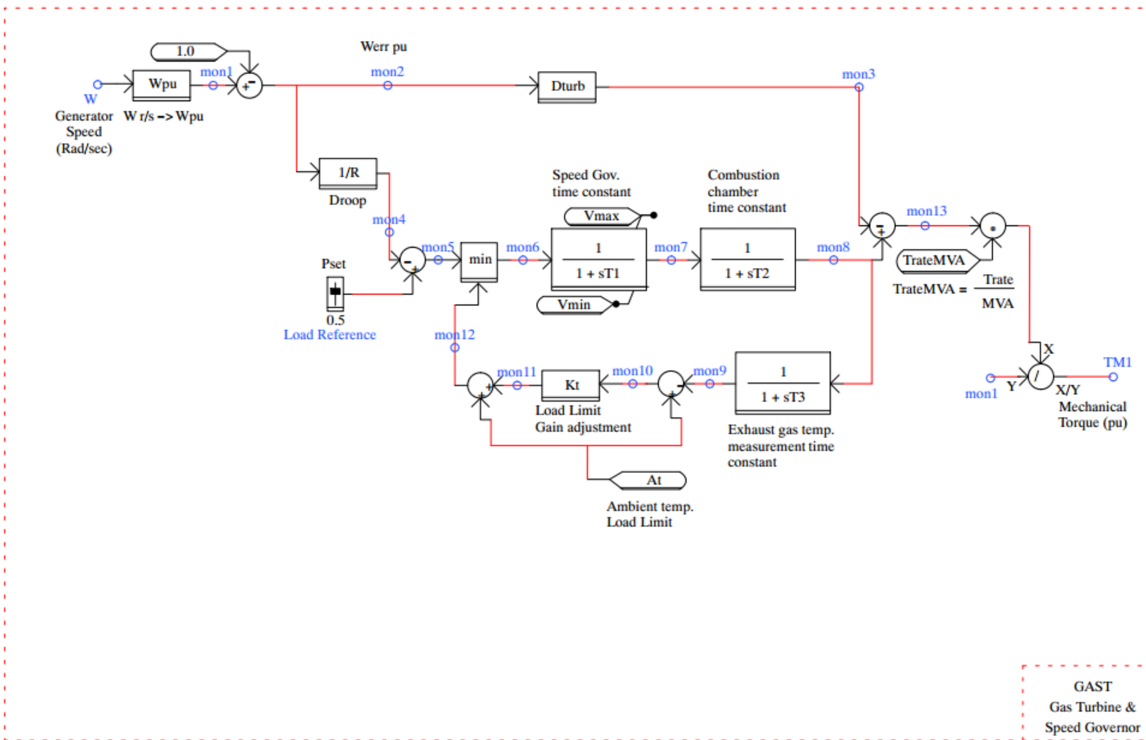


Figure 5.3: Governor model

Table 5.3: Governor Parameters

Name	Value
Permanent droop	0.05 pu
Governor mechanism time constant	0.1 sec
Combustion chamber time constant	0.1 sec
Exhaust temperature measurement time constant	3.00 sec
Ambient temperature load limit	1.0 pu
Temperature limiter gain	2.00
Maximum turbine power	1 pu
Minimum turbine power	0.31 pu
Turbine damping coefficient	0.02

5.2.4 *Transformer Modelling*

RSCAD supports the follow transformer models.

1. Ideal transformer

2. Model representing leakage winding and linear magnetization branch.

3. Saturable magnetizing branch

Depending on the study applications and operating conditions, any of the above modelling options may be chosen where appropriate. The linear transformer model provides a more realistic representation than the ideal transformer and can in fact be considered sufficiently accurate when magnetization winding voltages are maintained below saturation levels. For a better understanding, the linear transformer model may be verified by applying the standard open circuit test. The equivalent representation of the saturating transformer model is shown in Fig. 5.5. An important difference between this model and the non saturating linear model is the placement of the magnetizing branch. In the linear model shown in Fig. 5.4 the magnetizing inductance can be placed between inductance L1 and L2, where the sum of L1 and L2 represent the leakage reactance of the transformer. The relative magnitudes of L1 and L2 are user specified. It can be seen that the magnetizing branch of the saturating transformer is placed at one end of the leakage reactance. This is an approximation which must be made in order to facilitate stable numerical implementation of the non-linear core saturation.

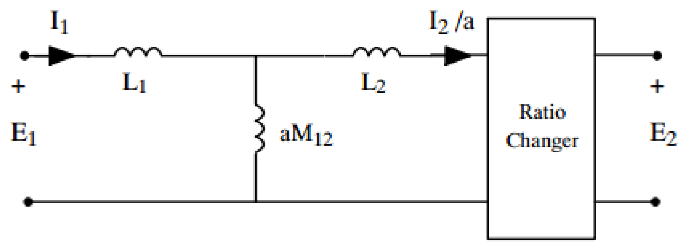


FIGURE 5.4: Transformer Model Displaying the Equivalent Circuit for Two Mutually Coupled Windings

This thesis uses the saturating model for more accurate behavior of the system during faults.

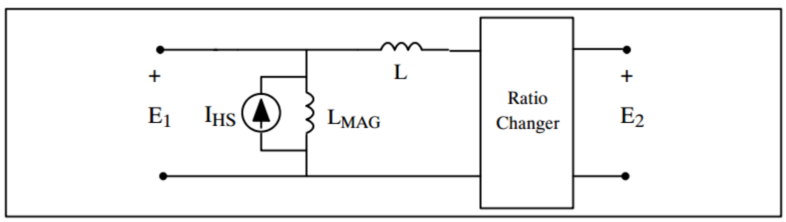


FIGURE 5.5: Saturating Transformer Representation in RTDS

5.3 TRANSMISSION LINE MODELLING

RTDS has several travelling wave transmission line models along with PI section models available for representing overhead lines. However, travelling wave models are generally preferred unless the line is very short, in which case a PI section model must be used. Assuming propagation velocity is equivalent to the speed of light, a 50 μsec time step would see the waveform travel a total distance of approximately 15 km. This means that if the chosen simulation time step Δt is 50 μsec, any line of length less than about 15 km would have to be represented using PI sections. Travelling wave models are preferred for several reasons. Travelling wave models use distributed parameter representations of transmission lines and are much more accurate for modelling long lines than the lumped parameter representation inherent in PI section models. These models are widely used to study the protection performance under transient conditions.

RTDS also has a frequency dependent model available for modelling transient phenomena with more accurate representation of frequency dependent damping. However, this thesis doesn't require the frequency dependency model for analyzing the backup protection performance. As higher frequency components decays with time and only the dominant frequencies of interest left are 60 HZ or lower so backup protection study may not necessarily need frequency dependent models.
In the RTDS, travelling wave transmission line models are solved in the modal domain. That is, a transformation matrix is used to convert the line admittance and impedance matrices from the phase domain into the modal domain and back. Phase domain voltages and currents are converted into the modal domain and back into the phase domain after solving equations at each end of the line.
One of the constraints in using the constant parameter model (Bergeron) and frequency dependent line models relates to the overall length of the line being represented. When the modal propagation time, or travel time, of a line is less than the chosen simulation time-step Δt, the line cannot be represented using these general travelling wave models. This limitation is a result of constraints for maintaining in real time. The travel time of the line is directly related to the line length, and hence it may found that, for short transmission lines, PI section representation will be required to maintain real time. Normally as lines become shorter, the inaccuracies due to approximations resulting from using PI section modelling become less significant. This thesis uses the RSCAD unified transmission line model which uses a travelling wave line model based on a constant parameter Bergeron solution. The sequence components of the transmission line were entered into the RSCAD T-Line program [13].

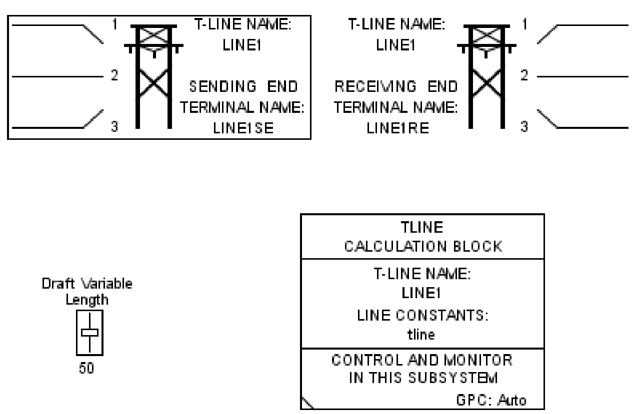


Figure 5.6: Bergeron Constant Parameter Line Model in RTDS

5.4 Distance Element Design

The effective impedances for the different fault scenarios were calculated and analyzed using the distance relay model in the RTDS, a Mathcad distance relay model, and a SEL-421 relay. As part of this work, a 32 samples per cycle digital signal processing distance element was designed and built using the available blocks in the RTDS library. The implemented model created is shown in Appendix C.

5.5 Interface Between RTDS and the Protective Relays

In order to analyze a power system using the RTDS to its full potential, the RTDS was connected to external devices, in this case protective relays. The RTDS uses a Gigabit Transceiver Analog Output Card (GTAO) to interface the analog signals mapped from simulation to the external relays. The GTAO card has twelve, 16 bit analog output channels with an output range of +/-10 volts. These 16 bit channels allow a dynamic range of measurements which the relay can use to analyze steady-state or fault conditions. The GTAO card outputs are oversampled at 1 microsecond and the channels are updated synchronously. The RTDS GTAO cards are physically connected to the protective relays using specially configured low voltage DB-25 cables. Fault testing was carried out using the low-level test interface of the SEL protective relays. The output from the GTAO card is in the low level mV range and is directly fed into the low-level test interface of the relay. For this process, the outputs from RTDS need to be first multiplied by a suitable scaling factor entered in RTDS settings for GTAO to bring the signal to acceptable limits for the relay. Each relay has its own scaling factor and so care was taken that the right value be set into the GTAO card. The scaling factors for the relays used are listed in Fig 5.7. SEL relays have 12 input channels, with W and X as the current channel subset, and Y and Z as the voltage channel subset. These are indicated as a prefix to each input channel quantity. The event record files from the relay were also converted to COMTRADE files for use with a Mathcad relay model.

Channel	Quantity	Scale Factor	Unit
1	IAW	375.375	A
2	IBW	375.375	A
3	ICW	375.375	A
4	IAX	375.375	A
5	IBX	375.375	A
6	ICX	375.375	A
7	VAY	751.121	V
8	VBY	751.121	V
9	VCY	751.121	V
10	VAZ	751.121	V
11	VBZ	751.121	V
12	VCZ	751.121	V

Figure 5.7: Scaling Factor in RTDS for 421 Relay

5.6 SUMMARY

This chapter provided details on the components used in the RTDS model for simulations performed in this thesis. This thesis used dqo based synchronous generator model, saturable transformer model and constant parameter travelling wave line model for simulating the accurate behavior of the power system to produce data for the distance element. This model is also integrated with numerical relay using a GTAO card for getting the COMTRADE files to process in Mathcad relay model.

CHAPTER 6

Cases Studied And Simulation Results

6.1 Simulation results for 21G and 21 GT relays

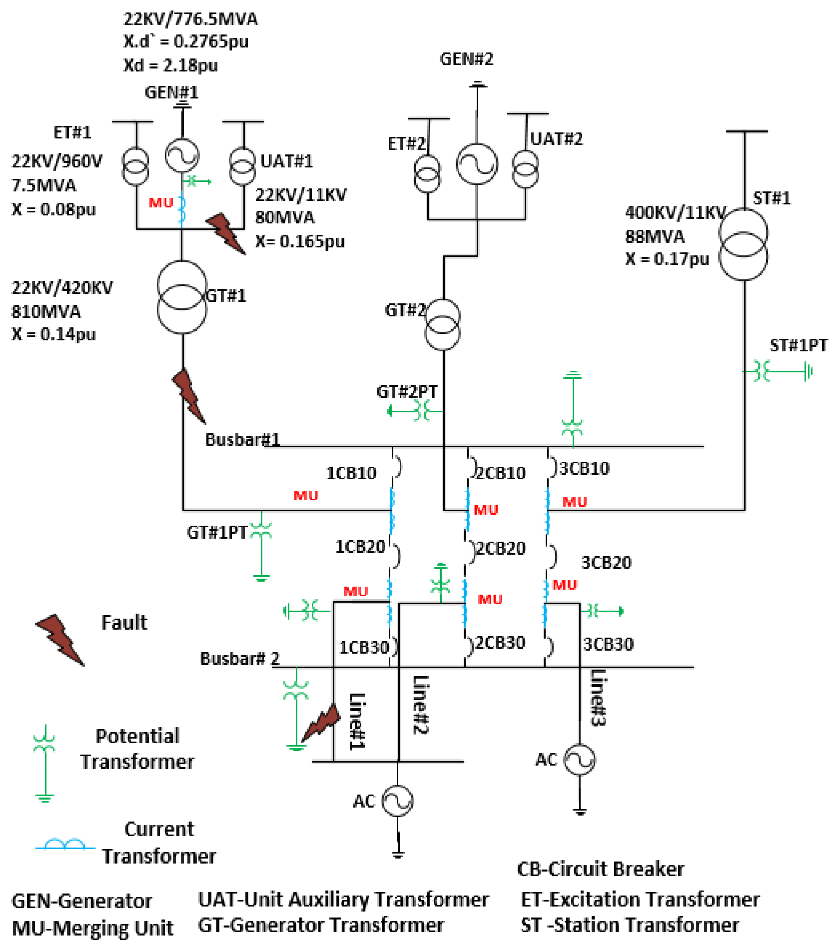


Figure 6.1: Single Line Diagram showing the Fault Locations

The system shown in Fig 6.1 was simulated in the Real Time Digital Simulator (RTDS). The distance relay shown in Appendix C was modelled in the RTDS. The impedance was determined by distance elements taking voltage measurements at both the generator terminals and at the GT HV side for faults of different types at different locations. The measurements were sampled at 32 samples per cycle. It is to be noted that generator distance element 21G uses the neutral side CT hence, it only needs forward zones. For the different simulation cases, the per unit impedance of the GT and UAT were varied from the nominal value to approximate the faults in the windings. This will give a rough estimate on the coverage of the GT and UAT by the distance element for the different phase faults locations. The results may change slightly based on the fault resistance and source contributions in the system.

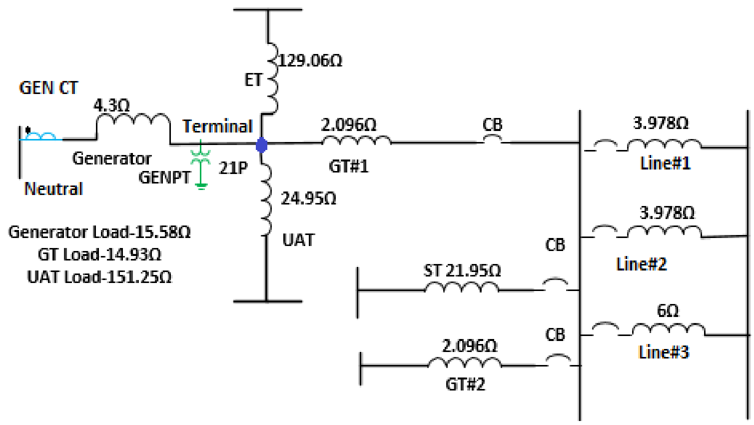


Figure 6.2: Relay Impedance Measurements from Generator Terminal Side

Fig. 6.2 shows the impedances referred to the generator relay base. Usually, the generator terminal Current Transformer (CT) or the neutral CT can be used for the impedance measurement. However, there is an advantage in using the neutral CT as marked in Fig. 6.2 since it can protect the generator when it is not connected to the grid. These transformations for the generator relay were obtained by using a Current Transformer Ratio (CTR) of 5000 and Potential Transformer Ratio (PTR) of 200.
The relay also receives the GT High Voltage (HV) current and voltages as marked

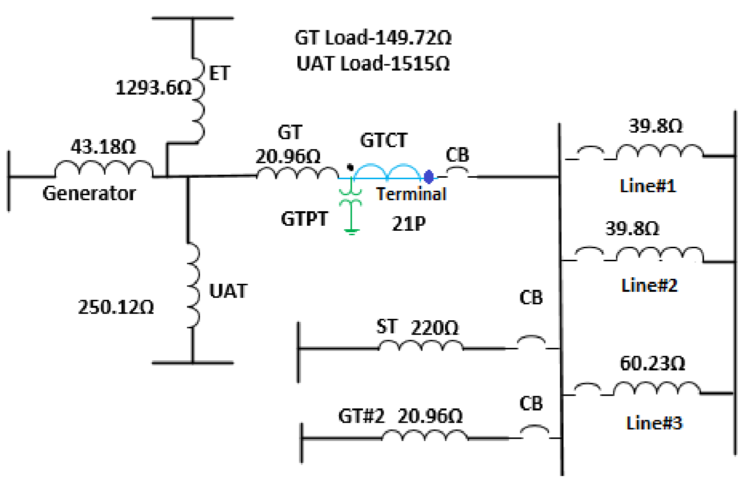


Figure 6.3: Relay Impedance Measurements from GT HV Side

in Fig. 6.3 to measure the effective impedance. Similar to the generator relay, the transformation of impedances for which relay uses a CTR for the GT of 2500 and PTR of 3636. The entire system referred to the GT HV side is also shown in Fig. 6.3. This implied that $Zone_1$ and $Zone_2$ look opposite directions.

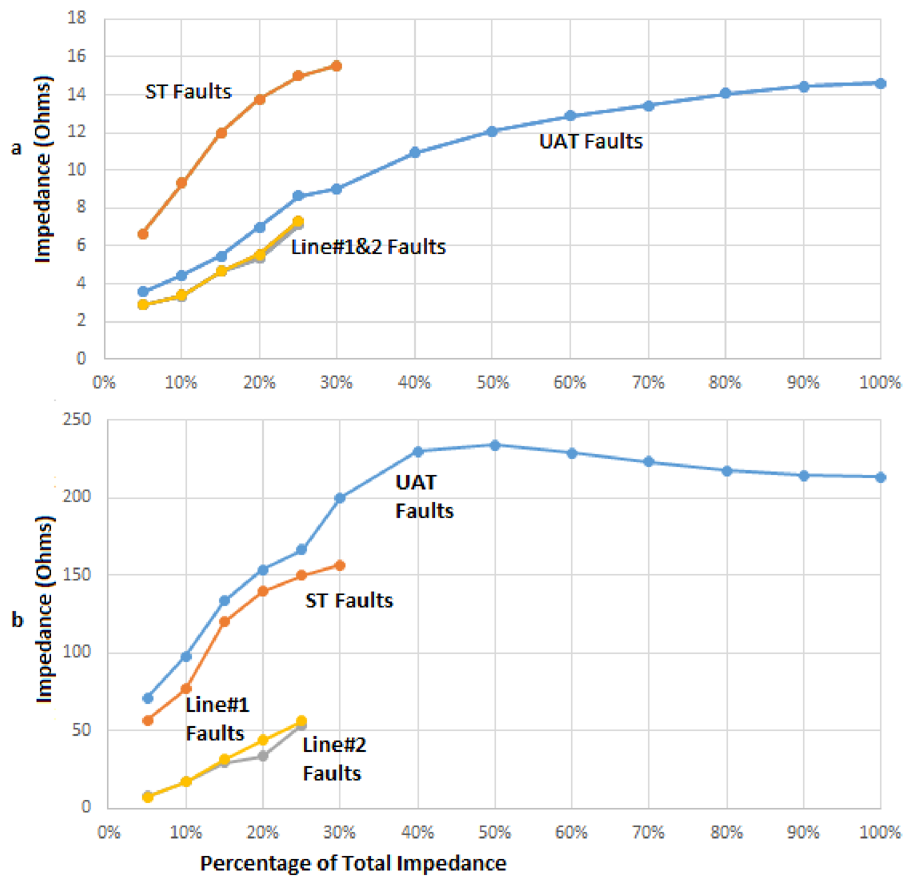


FIGURE 6.4: Impedance Measured for Different Fault Locations: (A). Generator Element, (B). GT HV Side Element

6.1.1 *Distance Element for Forward Faults*

With a zone 1 setting of 80% of the GT load impedance in the forward zone of the 21GT relay, the results in the Fig. 6.4 (B) show that the element is able to detect faults in the GTs of other units, ST, and transmission lines. From the Fig. 6.2, the generator and GT rated load impedances seen by the 21G element are 15.58 ohms and 14.93 ohms respectively whereas from the Fig. 6.3, for GT HV side 21 element (21 GT) the effective rated GT load impedance seen by the relay is 149.72 ohm. Based on the fact that the CT and PT measurement errors cause a problem to the impedance measurement, the 21GT element seems to be a better option for primary and backup protection for forward faults. However, the 21GT element will be supervised by a load encroachment element to prevent it from operating, during heavy loading conditions.

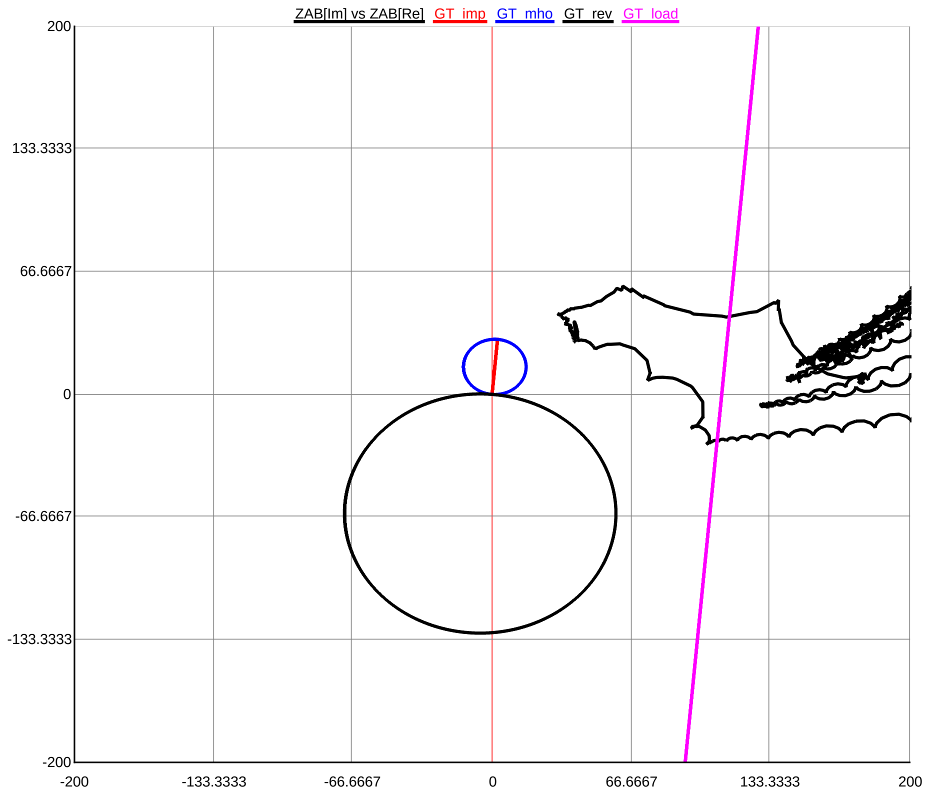


FIGURE 6.5: Effect of Remote Infeed for LL Fault at 40% of Line#2

Fig. 6.5 shows the effect of remote infeed on 21GT element for a phase-to-phase fault at 40% of line length. Here the forward zone is set to 80% of the total line impedance value, 31 ohms. The fault impedance trajectory shows the fault impedance is not in the zone. This is due to the infeed from the other lines during fault conditions. The blinder shown in the figure is the load encroachment setting blinder.

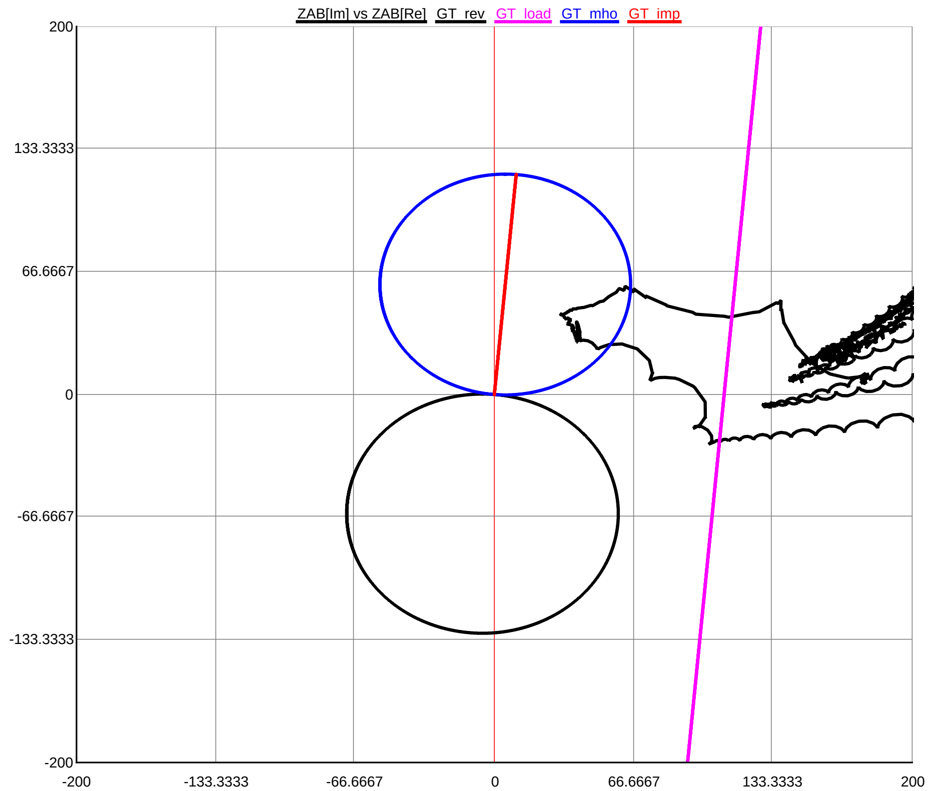


Figure 6.6: Effect of Remote Infeed for LL Fault at 40% of Line#2 with Bigger Impedance Coverage

Fig. 6.6 also shows the effect of remote infeed on 21GT element for a phase-to-phase fault at 40% of line length. But this time, the mho element in the forward zone is set to 80% of the unity power factor rated load impedance value shown in the Fig. 6.3 i.e. 120 ohms. With this setting, the impedance element can see the faults in the lines even with remote infeed. But if the fault location changes or remote infeed increases, this 21GT element may not reach.

6.2 Protection Coordination for External Faults

6.2.1 *Breaker Failure Relay*

Since circuit breakers are mechanically actuated devices, there are cases where the breakers fail to open with the trip command. To improve security, all critical protection tripping schemes initiate the breaker failure protection as well. Conventional breaker failure protection uses the breaker auxiliary contacts or an under current reset based logic to identify the breaker failures. For a fault in the line, both the line distance protection and the generators will see a drop in the impedance measurement. If the line protection detects the fault, it will give trip command the line breakers. If the generator protection detects the fault, it gives a time delayed trip command for the generator, but tripping should be coordinated with the distance relay and breaker failure relay timer as shown in Fig. 6.7.

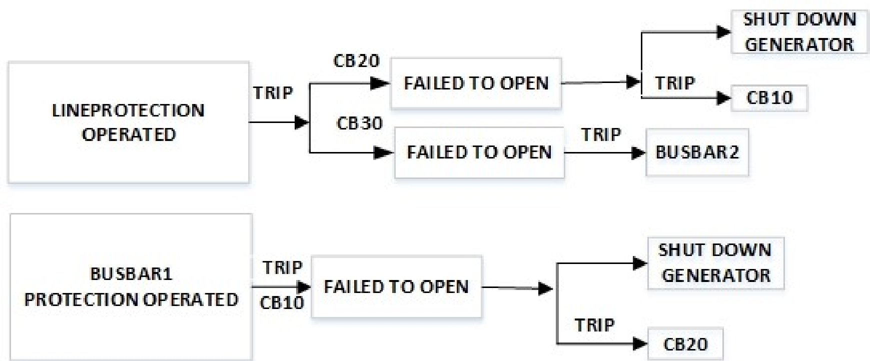


FIGURE 6.7: Breaker Failure Relay Tripping Scheme

For any protective action of transmission line relay, a breaker failure (BF) initiation will also be generated along with the trip command. The breaker timing chart shown in Fig. 6.8 explains the stages of tripping after the BF initiation. This protection can

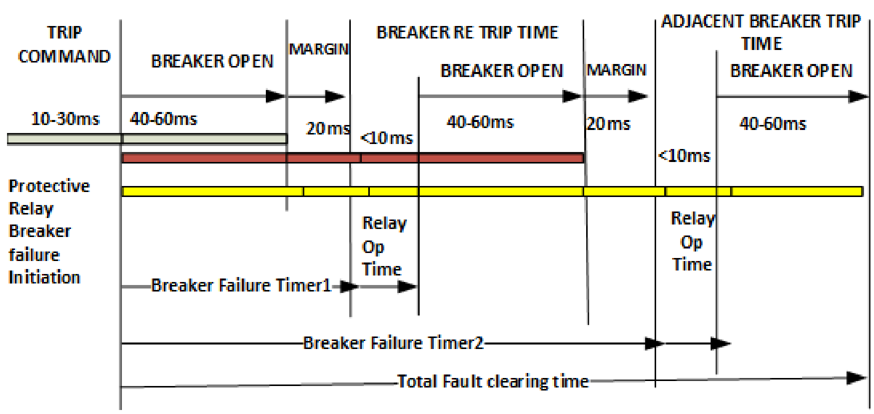


FIGURE 6.8: Breaker Failure Relay Timing Chart

also generate a re-trip. The re-trip function can be used to increase the probability of operation of the breaker, and it can be used to avoid the need for a back-up trip of many breakers in case of mistakes during relay maintenance and test. The typical breaker failure timer 1 delay can be set for 80 to 100 ms and the second timer can be set for 170 to 200 ms [14]. When the GT isolator is open see Fig. 6.9 the generator/unit is out of operation. But if isolator 2 is instead opened then line protection will be disabled and the stub protection will be active. The stub protection operates for faults in the parts of breaker and half bus station configurations which cannot be protected by the distance protection function if the line isolators are opened. The use of the function can be extended for various other purposes, for example when a three phase overcurrent protection element can operate only under special external conditions. In this present system, the CB10 series and CB20 series breakers connected to the generator transformer need to be tripped by the generator group protection relay for any faults on the generator or connected transformers. The relay should also initiate breaker failure. For faults on any one of the lines, breakers CB20 and CB30 will trip. For any of the cases if breaker CB20 does not trip, then either the backup protection needs action or breaker failure is activated after the timer expires if line protection operates. In this case both the breaker failure and the backup protection of the generator work in parallel to isolate the generator by tripping the field breaker, auxiliary breakers and the prime mover. A similar situation also occurs if bus bar protection trips all of the 10 series breakers connected to bus bar 1 and the generator breaker does not open to isolate the fault. Because of the restricted zones of bus bars, those elements will not act as backup protection for the connected transformers in the system.

Fig. 6.9 illustrates the coordination between breaker failure protection and the

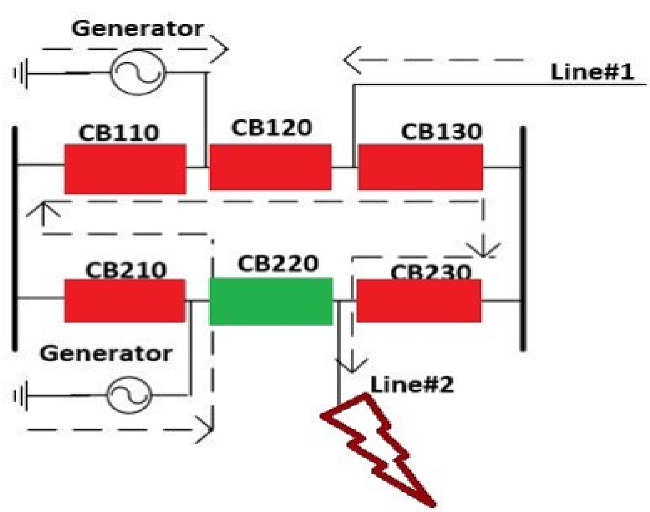


Figure 6.9: Importance of Relay Coordination For External Line#2 Faults

backup protection of the generator to avoid for line faults. For a fault on line#2, if breaker CB230 fails to open, then the breaker failure relay would trip CB130 before the generator protection picks up and trips the unit. Proper coordination will prevent loss of generation. Hence, the 21GT element will typically delayed by 200 to 250 ms to allow external fault clearance based on the elements in the timing chart Fig. 6.8. Note that, since the two generators in the simulated station are same and the protection settings for external faults are also the same, both generators could trip for a line fault because of improper coordination. Chapter 7 discusses options to minimize or prevent this coordination issue.

6.2.2 *Distance Element for Reverse Faults*

The main advantage of using individual differential zones for the generator, GT, UAT, plus the overall generator system differential element is that the differential protection provides reliable main protection for the generator system [9]. However, distance elements can be useful in providing backup protection for the differential elements. By referring the system impedances to the generator relay secondary base, as shown in Fig. 6.2, the CT connected at the neutral of the generator would see the faults on the generator winding even when the generator is energized but disconnected from the system. The total GT impedance seen by the generator distance element (21G) with neutral CTs is 2.096 ohm, but to avoid errors due to CT, PT error, and GT tap changing, the forward impedance of the 21G in $Zone_1$ is set to 75% of the GT impedance i.e. 1.567 ohm. The drawback with this setting is that the impedance element can not cover the major portion of generator winding faults since the impedance seen by the 21G during subtransient state without infeed is 4.3 ohm. The RTDS simulations shown in Fig. 6.4 demonstrated that the Mho element using measurements from GT HV side (21GT) can effectively cover the faults in the GT, generator, UAT, and ET with better coverage than the generator relay whose voltage measurements are from the generator terminals. The CT and PT measuring errors will cause more significant over or under reach of generator distance element than is the case for the GT HV side distance element.

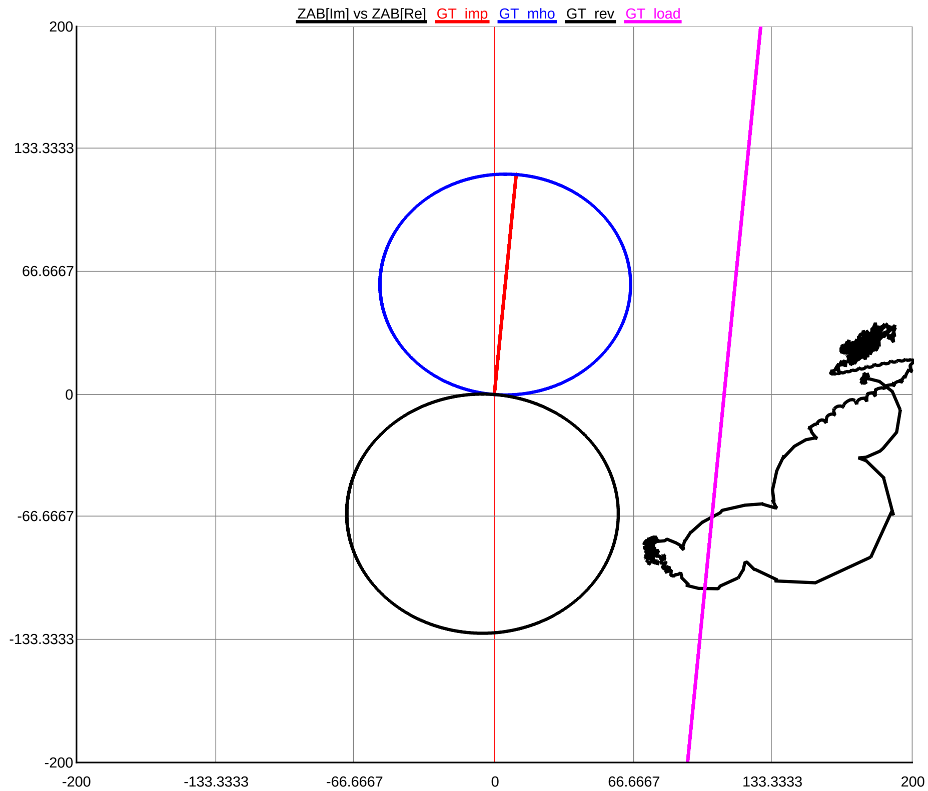


Figure 6.10: Effect of Generator Infeed on 21GT with 50% UAT Impedance Coverage for UAT Phase-to-phase Fault with 30% of Rated Impedance

If the reverse zone of the 21GT setting is set to 50% of UAT impedance value, Fig. 6.10 shows that, 21GT underreaches when there is significant infeed from generator. Whereas increase in reverse zone setting to 80% of UAT impedance value will give better results in covering UAT faults even with infeed from generator as shown in Fig. 6.11.

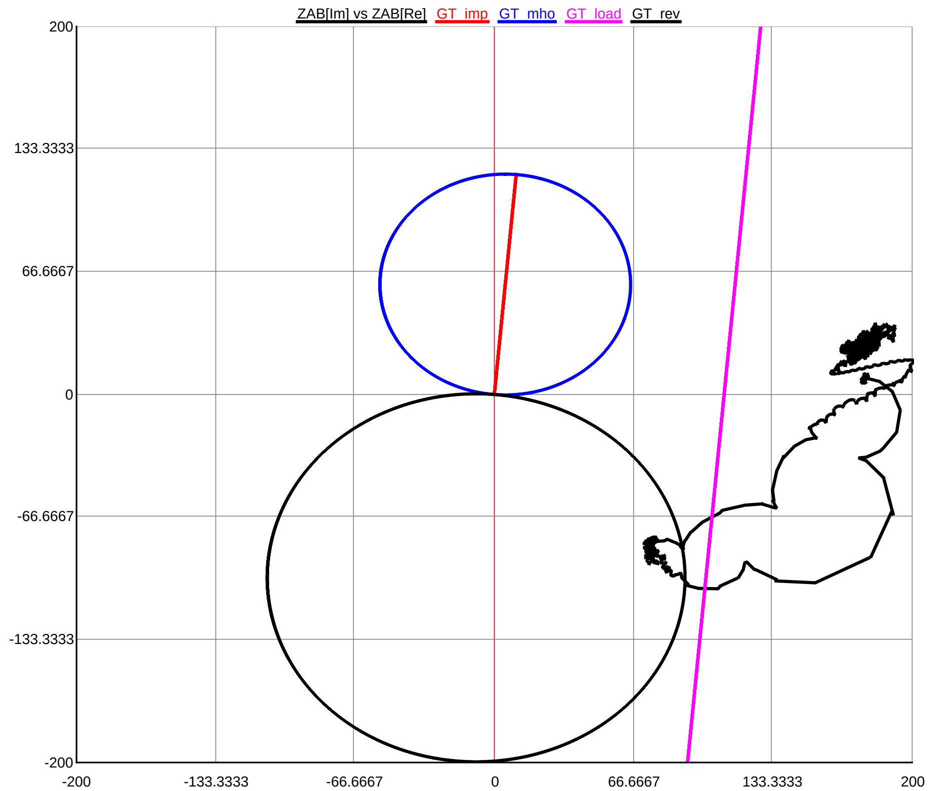


Figure 6.11: Effect of Generator Infeed on 21GT with Bigger Coverage for UAT Phase-to-phase Fault with 30% of Rated Impedance

In addition to this, the distance element can also provide backup protection during CT open circuit conditions of overall differential zone. For instance, if the generator transformer is allowed to energize from the grid during the initial commissioning when generator is disconnected from the Isolated Phase Bus Duct (IPBD), the overall differential protection can not be put into service. However, in this situation the proposed 21GT element in the reverse direction can cover up to 70% of the UAT winding. Additionally, if the UAT LV side breakers are open, the setting can be increased for 150% of the UAT impedance to cover for most of the UAT phase to phase faults.

6.3 Generator Transformer Relay (21GT) Performance During Internal Faults

The settings for the reverse looking zone of the generator transformer relay need to trade off coverage for all fault locations, while not causing nuisance tripping. The reverse zone of the 21GT element can be set as a fast acting element and hence provide a backup element for the differential element. However there are some challenges in determining settings that need to be considered as will be illustrated below.

6.3.1 *Power Swings*

Fig 6.12 shows the generator voltage and current response of the system for a stable power swing. A stable system oscillates in a damped response around a final value. The system reaches a new steady-state operating point. In an unstable system, δ continues growing, and the machine loses synchronism. Unstable operation is undesirable, as it creates high currents and power flows as well as unusual voltages, also system likely to drop loads and trip on damage generators [15]. Unstable operation also causes severe generator torque oscillations. Voltage fluctuations may also affect the power station auxiliaries, which may need to be tripped. Unstable system oscillations need to be detected and the appropriate tripping decisions need to be made in order to divide the system into electrical islands.

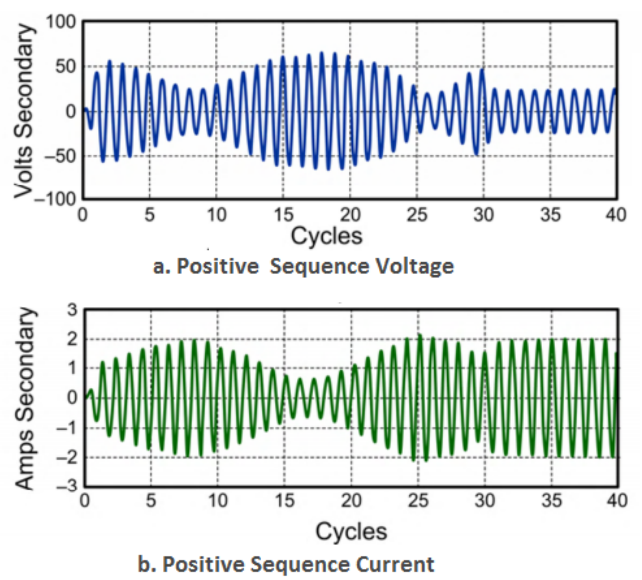


Figure 6.12: Measurements During a Stable Power Swing (a) Relay Measured Voltage (b) Relay Measured Current

Impedance measured by distance elements during power swings tends to oscillate as a result of voltage and current oscillations as shown in Fig 6.12. The apparent impedance may penetrate the element operating characteristic and cause a misoperation.

6.3.1.1 *Impedance Trajectories for Stable and Unstable Power Swings*

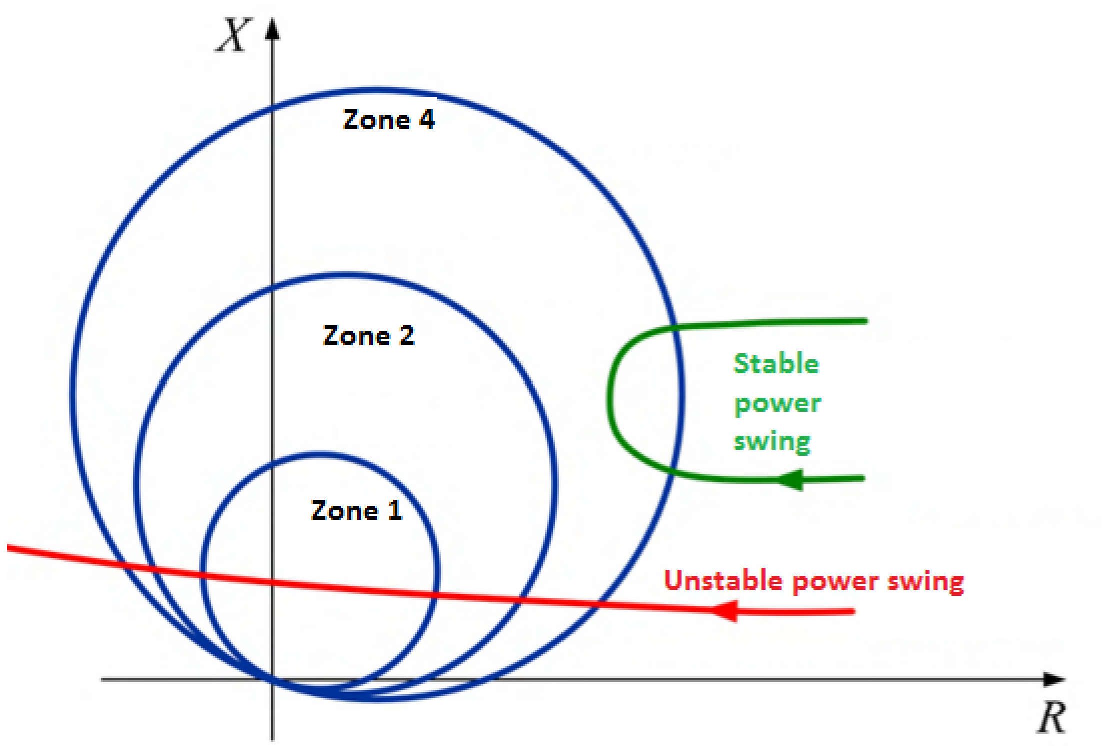


FIGURE 6.13: Swing Characteristic for Stable and Unstable Power Swings

Fig 6.13 shows that the impedance measured by the distance elements during stable and unstable power swings. The element will trip if the measured impedance stays inside the operating characteristic for a time greater than the zone time delay. Fast operating Zone 1 elements and directional comparison tripping schemes are particularly sensitive to power swings. However, Zone 2 and Zone 3 elements may also misoperate for slow power swings.

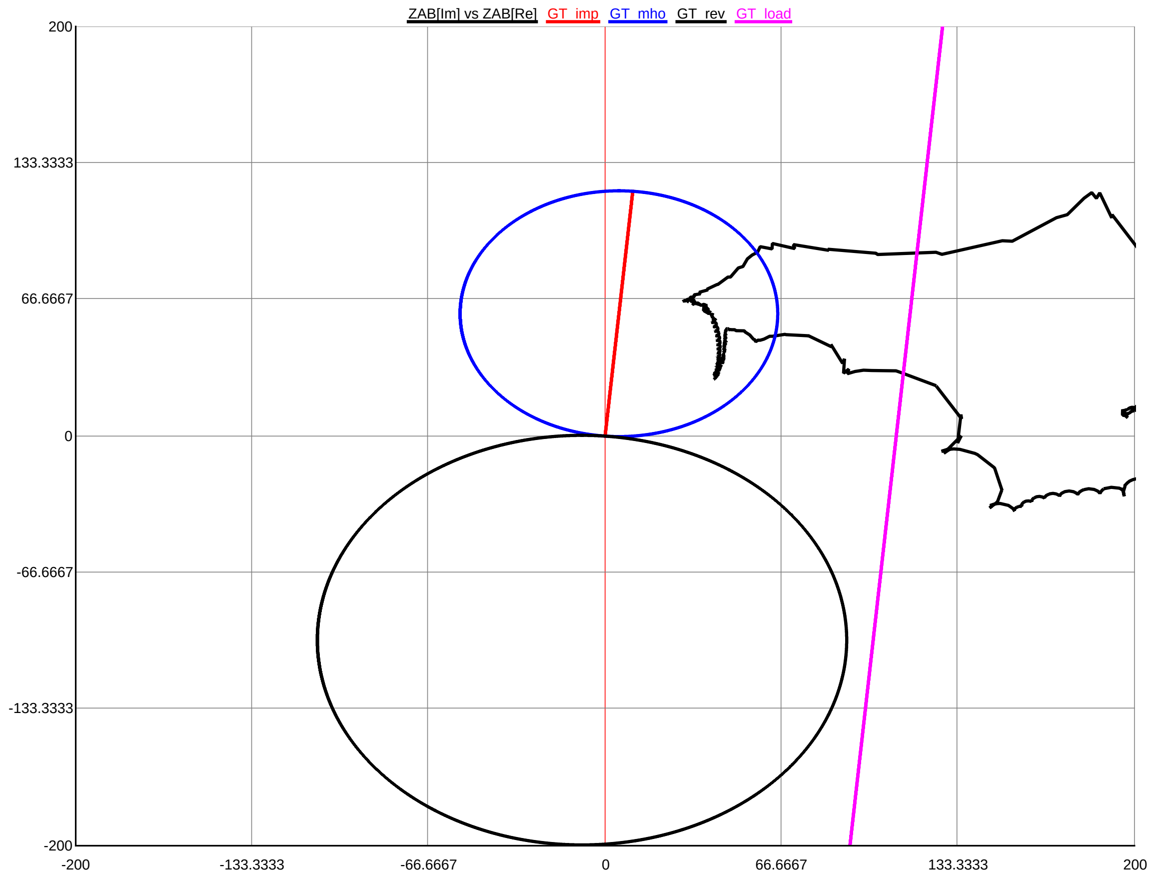


Figure 6.14: 21GT Response for a Stable Power Swing

Fig. 6.14 shows the 21GT impedance trajectory caused by the 3 phase fault on line 3. The fact that the swing trajectory enters the forward zone demonstrates that 21GT will need to be supervised by power swing blocking element. A protection philosophy for power swings is to avoid tripping for stable power swings and to separate the power system into predetermined islands for unstable power swings, to prevent wide area blackouts and equipment damage. Most relays should block during power swings, only selected relays are set to trip. The power swing blocking function (68) discriminates between faults and power swings, and it blocks relay elements prone to operating during power swings.

6.3.2 *Generator Loss-of-field Protection*

The source of field excitation for a generator may be completely or partially removed through such incidents as accidental tripping of a field breaker, a field open circuit, a field short circuit (flashover of the slip rings), a voltage regulation system failure, or the loss of supply to the excitation system. Whatever the cause, a loss of excitation may present serious operating conditions for both the generator and the system. When a generator loses its excitation, it overspeeds and operates as an induction generator. It continues to supply some power to the system and receives its excitation from the system in the form of vars. If the generator is operating at full load, stator currents can be in excess of 2 per unit; and because the generator has lost synchronism, high levels of slip frequency currents can be induced in the rotor damper windings. These current levels can cause overheating of the stator windings and cores of the rotor and stator within a short time [9].

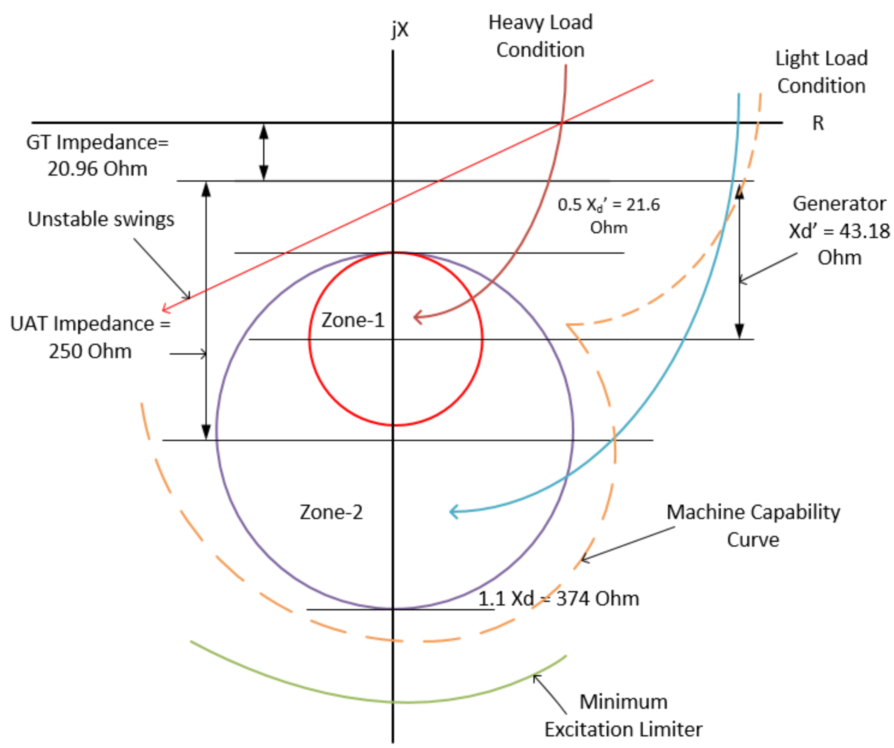


Figure 6.15: Coordination Requirement of 21GT with Loss-of-Field Protection

Protection against loss of field conditions can be implemented with a distance element looking into the machine. The GT distance element for the reverse faults can be tripped quickly but the protection settings will need to be coordinated with power swing blocking and loss- of- field protection to ensure they don't misoperate during stable power swings and loss-of-field conditions.

As shown in Fig. 6.15, if the 21GT reach in the reverse direction is increased beyond GT impedance setting, the 21GT element will respond to both stable power swings and loss-of-field conditions. The locus passing through 50% X_d' represents the safety margin required for the generator loss-of-field element to not to respond for stable power swings [3].

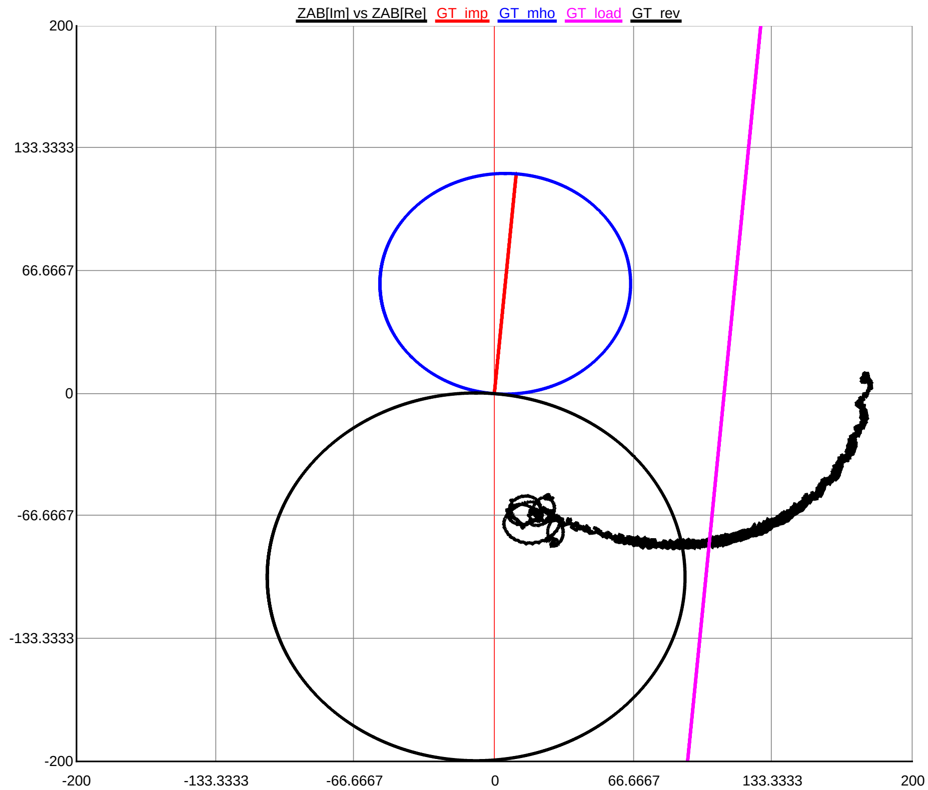


Figure 6.16: Relay Impedance Measurements from GT HV Side for Loss-of-Field Condition When Generator is Operating at Rated Load

There are two zones associated with loss-of-field element shown in Fig. 6.15. Zone-1 in the figure protects the generator from loss-of-field occurring during heavy loaded conditions, whereas Zone2 protects during low load conditions. During loss-of-field, the locus of impedance appears to be same as that of occurs during faults inside the generator or UAT. The reverse 21 GT element will be supervised by these power swings and loss of field element elements to secure it's operation.

Fig. 6.16 and Fig. 6.17 show the 21GT measured impedance trajectories during loss-of-field conditions that occurred when generator was operating at 100% load and 50% load conditions respectively. These figures demonstrate that increasing the 21GT reverse reach to cover UAT faults will cause the 21GT element to respond during loss-of-field conditions of generator. Hence, this 21GT element will need to be supervised by loss-of-field protection element of generator also.

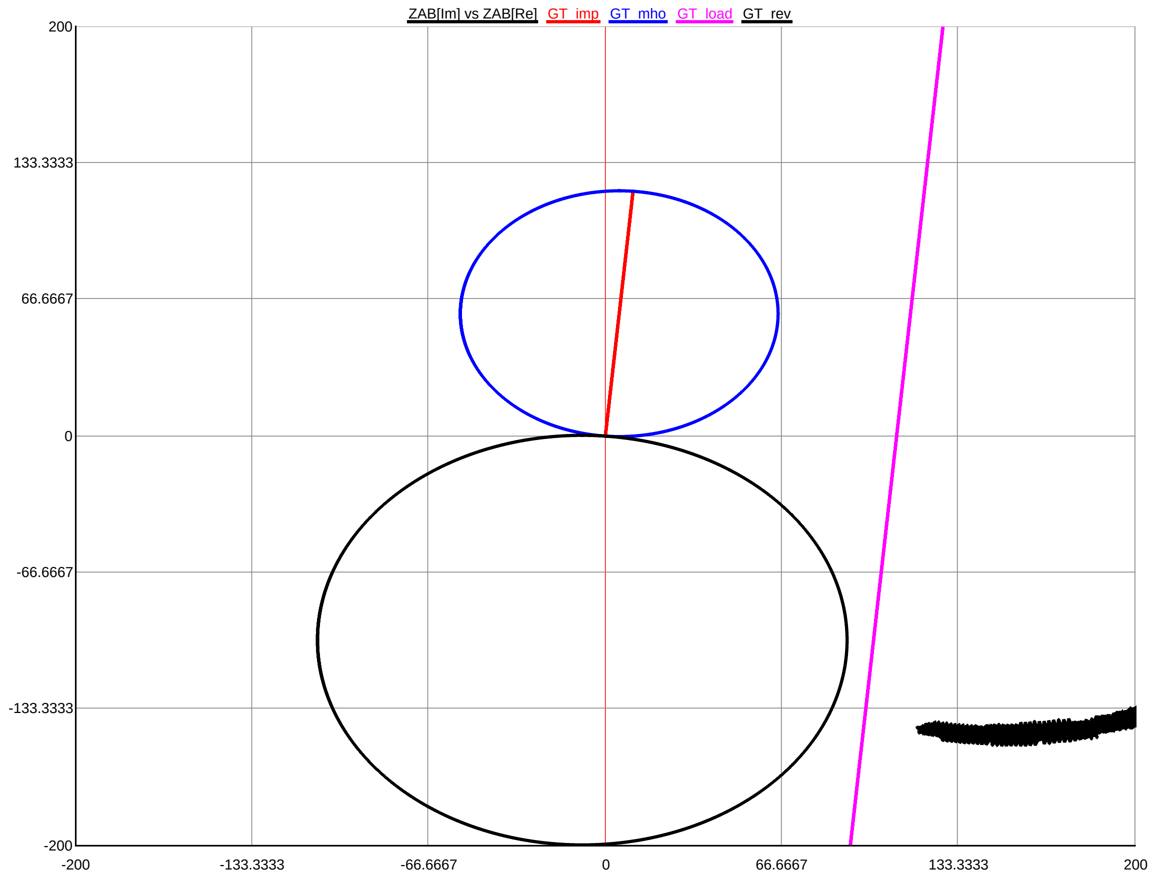


FIGURE 6.17: Relay Impedance Measurements from GT HV Side for Loss-of-Field Condition When Generator is Operating at 50% of Rated Load

6.3.3 *Observations*

Overall, the following observations are drawn about the 21 GT element from these cases.

1. The generator relay backup element (21G element) in the forward zone has less coverage and increasing the coverage may require a load encroachmet element.
2. The generator transformer (21GT element) in the reverse zone can cover most of the faults in the Generator, GT, UAT, and ET.
3. The 21GT can cover up to 80% of the UAT impedance when the UAT secondary breakers are closed and this reach can be increased further if the UAT secondary breakers are open.

4. The 21GT can provide backup protection to overall differential protection with a small time delay to avoid tripping during stable power swings and to coordinate with the loss-of-field protection element.

5. The 21GT can cover for the system faults in forward zone with a delay to coordinate with breaker failure relay. Overall, the simulation results demonstrate that choosing the GT HV side element is better due to better coverage in both forward and reverse zones. However, the forward zone coverage can further be increased adding load encroachment function. The following chapter illustrates the need for breaker failure relay and also the requirement for coordination of the 21GT with the breaker failure relay.

6.4 SERIES COMPENSATED LINES

Modern power systems sometimes operate close to the security limits. Series capacitors are used to reduce overall inductive reactance of a transmission line, thereby increasing the power transfer capability and the power system stability margins. They can provide better load division on parallel transmission paths, can reduce transmission losses, and can improve voltage regulation.

6.4.1 *Series capacitor and the associated protection circuit*

Series compensation also increases the fault current level. Series compensation increases transmission system power transfer capability by reducing the equivalent reactance. During fault conditions, the low equivalent sequence reactance allows very large currents to flow in the transmission line. This current in turn produces high voltages across the terminals of the capacitors. In order to limit these voltages, MOV are often included to protect the capacitors [13].
A MOV is a device which is placed in parallel with the series capacitor compensation to protect it against over voltages. It is a non-linear device which for all practical purposes appears as an open circuit to current when the voltage across it (and hence across the capacitor) is low. At higher voltages, it begins to conduct current, hence limiting the voltage from being developed across the capacitor. The MOV itself is protected by a parallel bypass switch that can be closed when the energy absorbed by the MOV exceeds a predetermined limit. The energy absorbed by the MOV will be a function of the voltage across and the current through the device. During high current fault conditions, the energy build up in the MOV may be very fast. In order

to protect it against permanent damage, it can be removed from the circuit by closing the parallel bypass switch. When this happens, the series capacitor compensation is also effectively removed from the circuit.
Figure 6.18 shows the basic arrangement of an MOV protected series capacitor. The RTDS model is based on this configuration.

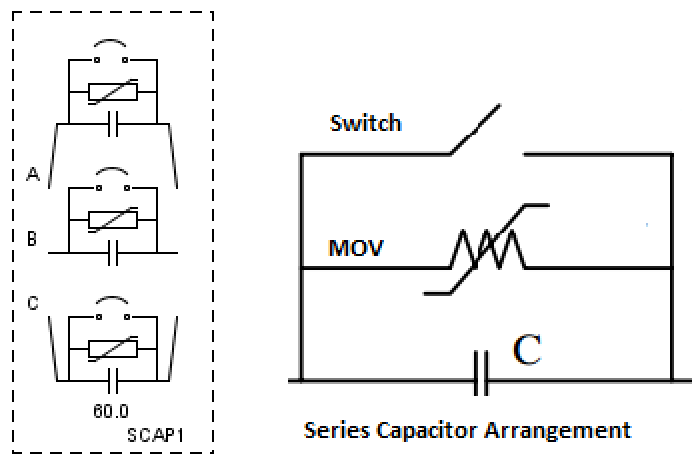


Figure 6.18: Series Compensator Model with Overvoltage Protection in RTDS

Typical MOVs for series capacitor protection are rated to clamp the voltage to a set voltage level, typically about 2 to 2.5 times the normal voltage.
Series compensation also has a number of disadvantages. Besides increasing fault current levels, series compensation affects the power system's dynamic behavior. Series capacitors may also produce subsynchronous resonance of generator units [16]. In addition, series capacitors challenge line protection.

6.4.1.1 *Protection Challenges With Series Compensated Lines*

Series compensated lines present unique challenges for directional, distance, and current differential elements because the transient response of the series capacitor depends on fault location and the source impedance. Transient studies are generally needed to ensure secure and dependable operation of relays in series compensated line applications. The subharmonic frequency oscillations caused by the series capacitors interacting with the line inductance may affect line protective relays as well. Since they are not attenuated completely by the relay filtering elements.

6.4.2 *Voltage Inversion*

A voltage inversion is a significant change (90 to 180 degrees) in the measured line to ground voltage phase angle caused by the voltage drop across the series capacitor during a fault. Voltage inversion may affect directional and distance elements. For elements responding to phase quantities, voltage inversion can occur for a fault near a series capacitor if the net impedance from the relay to the fault is capacitive rather than inductive. To be precise, the relay location in this context refers to the relay voltage measuring point location [16]. Phase elements that take voltage information from the fault side of the series capacitor will correctly declare the fault direction for a forward fault. Elements measuring the voltage from the other side of the capacitor with respect to the fault location may incorrectly declare the fault direction. Voltage inversion may affect not only the compensated line relays, but also the relays of adjacent lines. This also impacts the proposed 21GT element.

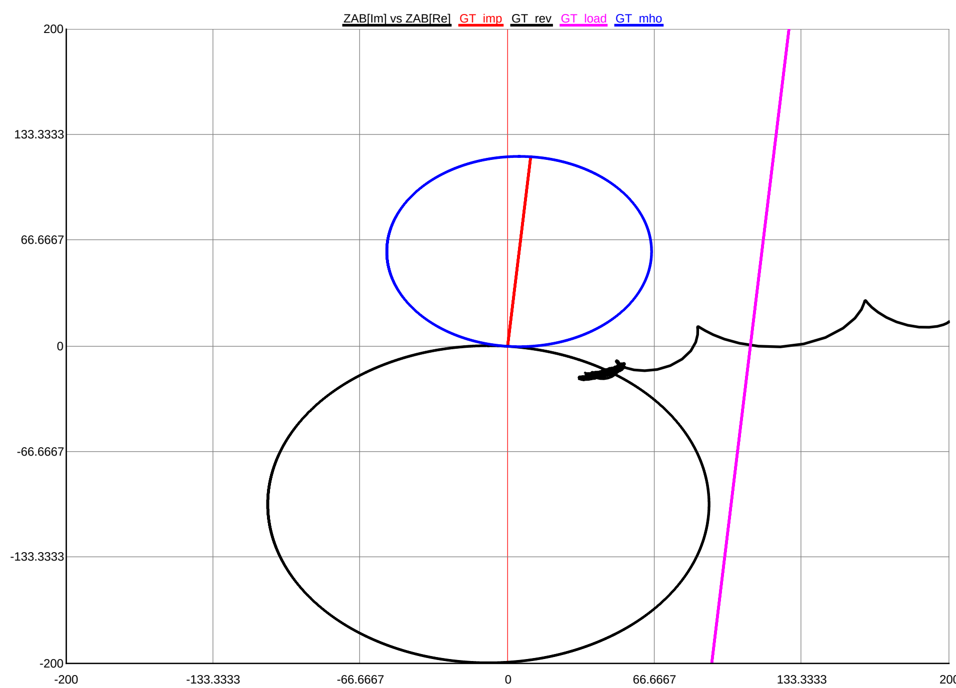


Figure 6.19: Effect of Voltage Inversion on 21GT Element for Phase-to-Phase Fault at 30% of Total Length in a Series Compensated Line

Fig. 6.19 shows the effect of voltage inversion on the 21GT distance element for a phase-to-phase fault at 30% of length of a series compensated line. Because of the voltage inversion, the effective impedance measured by the relay appear to be in reverse zone. Since the reverse zone has short time delay of 5 to 7 cycles, if the 21GT element is not blocked by the voltage inversion logic, this will cause the 21GT element to trip the generator for line faults that are not cleared quickly by line protection.

6.4.2.1 *Current Inversion*

A current inversion is a condition in which the current for an internal fault appears to enter at one end of the line and to leave at the other end. In other words, the current directions resemble those of an external fault. Current inversions occur in series compensated systems when the equivalent system at one side of the fault is capacitive. Current inversions may affect both directional-comparison pilot systems and pilot systems using only current information (phase-comparison and line differential systems). Such a condition is unlikely to be faced by the 21GT element.

6.5 SUMMARY

With the help of RTDS simulations, this chapter proposed the distance element at the GT terminal is better than distance element at the generator terminal. This chapter also described the coordination requirements of 21 GT element for reverse zone with the loss-of-field element and the power swings blocking element. It also explained clearly 21GT coordination requirements with the breaker failure element for external faults. As a result, the 21GT element has to be delayed with a much longer time delay for forward faults than for reverse faults. This chapter also provided an overview on 21GT challenges with series compensated lines.

CHAPTER 7

Proposed Backup Relay

The challenges with applying the 21GT for external faults were discussed in Chapter 6. The 21GT element has to deal with the following for faults in the forward direction.

1. Remote infeed from other lines could cause the 21GT to underreach for forward faults.

2. The fault current decreases over time due to the decaying exponential response of the generator transient response. The transient current response will also be affected by the fast terminal voltage boosting action of the automatic voltage regulator in response to the local voltage collapse during the faults. Hence the effective impedance measured by the relay will be higher.

3. A loss of PT signal will block the GT distance element.

4. The 21GT should only trip the generator if both the line protection and breaker failure protection fails to clear the faulted line. It should be coordinated with breaker failure, so it doesn't trip when line relay fails to pick up.

5. It needs to be secure during power swings.

6. The zone is restricted for close in high resistance faults if the load encroachment is set to block during heavy load conditions.

7. Protection with the 21GT could be compromised if there are any series compensated lines with capacitors at the generator terminals of the lines.

To deal with above challenges, this thesis proposes a backup relay that utilizes sampled values and a directional determination based technique to provide secure and reliable and backup protection.

7.1 SAMPLED VALUES

Although use of the mho element is not a new idea for the backup protection, the proposed solution utilizes a backup relay which subscribes to IEC 61850 sampled values messages from merging units located at all available measurements points of the generator system. This allows the relay to more securely protect for any internal or external faults with a coordinated time interval. The proposed relay will process the currents and voltages received from all of the merging units and use the values for impedance calculation and directional determination to detect if the fault is external or internal. This relay is more immune to PT and CT fuse failure conditions through redundancy not available with a relay hardwired to a single set of CTs and a single set of PTs.

The following sections will illustrate the protection performance of the proposed relay for internal and external faults using RTDS simulations. The relay can also be used to identify generator circuit breaker operation and breaker failure conditions through tracking currents and voltages. The proposed detection technique uses a synchronizing check based detection scheme for identifying the secure opening of the breaker.

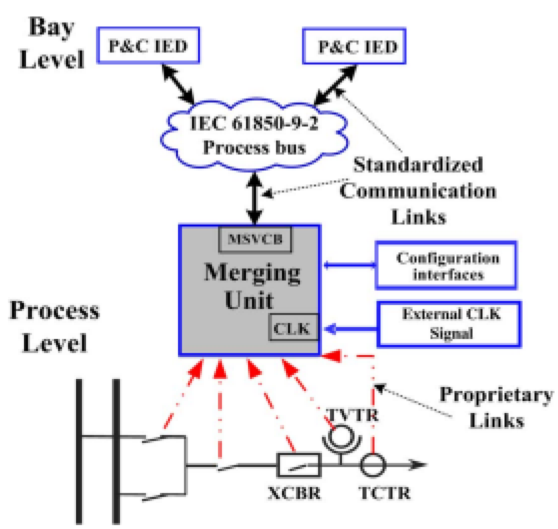


Figure 7.1: IEC 61850 Process Bus Concept [1]

Fig. 7.1 shows the proposed communication bus concept. The process bus idea is relatively simple and can best be explained by looking at this figure. Data gathering starts at the process level with instrument transformers (IT) whose outputs are immediately sampled, converted to digital representation, and formatted for subsequent transmission through the process bus LAN. The process bus is also used to control high voltage equipment such as breakers, breaker control units, disconnect switches, etc. Process level information is then communicated over the LAN to the protection and control devices that are located at the Bay/Unit level. Protective functions are to be performed at the Bay Level, while the overall substation-wide coordination, substation Human Machine Interface (HMI), and the SCADA system interfaces are performed at the station level.

IEC 61850 defines the acceptable maximum communication delay for the time-critical messages to be between 3 to 4 ms [1]. This has to be achieved for all of the time-critical messages (for example, Generic Object Oriented Substation Event (GOOSE) and sampled values), independent from the network traffic load on the process bus communication network. To reduce the additional time delay caused by TCP/IP (Transmission Control Protocol/Internet Protocol) layers, GOOSE and sampled value messages are directly mapped on the Ethernet link layer. However, this elimination of TCP/IP layer reduces the reliability of packet communication. Therefore, to enhance the transmission reliability of GOOSE, the same GOOSE message is repeated several times according to IEC 61850-8-1 [17]. GOOSE is event triggered and messages are generally sent few times per second to the network; whereas, sampled value messages are time triggered and transmitted at the rate of sampling frequency [17]. The same sampled value messages are not repeated, which reduces transmission reliability of sampled value messages over the process bus.

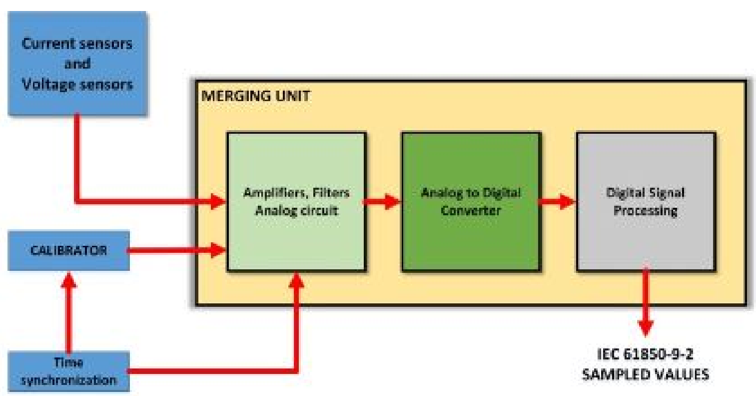


Figure 7.2: Sampled Values and Merging Unit [2]

Fig. 7.2 the merging unit, the key element of the IEC61850-9-2 process bus, is installed in switch yard near to the primary equipment. The merging unit gathers information such as phase voltages and currents from instrument transformers. All the analog quantities are converted to digital signals, digitally filtered, and merged into a sampled value packet, and then synchronized using a time stamp. The information is sent to the relays that are subscribed to merging unit [2].

7.2 DIRECTIONAL DETERMINATION

Directional elements determine the fault direction. They are used to supervise distance elements for increased security and to secure or control overcurrent elements. Directional overcurrent relays can be set more sensitive than the non-directional overcurrent relays [18]. In addition, time-coordination is simplified because the directional element restricts relay response to faults in one direction.

Directional elements determine the effective phase shift between a polarizing reference quantity and an operate quantity. The polarizing quantity is also called a reference quantity and it should be a stable and reliable signal references. The choices of for polarizing references and operate signals vary with application and include voltage or current signals or phase (VA or IA), line voltages or currents, or symmetrical component quantities.

7.2.1 *Directional Element Implementation in a Numerical Relay*

The proposed relay will be using three directional elements. A positive sequence impedance angle element, a negative sequence impedance based directional element and a zero sequence impedance based directional element. Since, the operation of the negative and zero sequence elements depends on unbalanced faults, a positive sequence element is needed for faults with balanced currents. Since the zero sequence element can have issues with the zero sequence mutual coupling with parallel lines, it will not be used for the directional determination faults on the lines. But this proposed relay will use the zero sequence directional element to determine the direction of the neutral current measured by the GT HV side star winding and that will be explained in Section 7.4. The zero sequence element is mainly of value for high impedance and ungrounded system. For unbalanced faults in the system, the negative sequence directional element is preferred because it is immune to both load current and mutual coupling.

7.2.1.1 *Positive Sequence Effective Impedance Angle Based Element*

Equation (7.1) represents the angle comparisons for the phase directional element. This will be mainly used for 3 phase faults where the negative sequence element will not be active.

$$(-90\,\deg + \Phi_{MT1}) < Arg(Z_1) < (90\,\deg + \Phi_{MT1}) \tag{7.1}$$

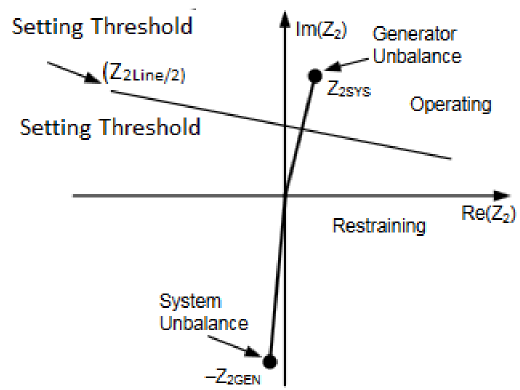


FIGURE 7.3: Negative Sequence Directional Element Characteristics

Where, Φ_{MT1} is maximum torque angle, $Arg(Z_1)$ is $Arg(\frac{V_1}{I_1})$.

Each directional element declares a forward fault condition if the impedance angle is within the range shown in equation 7.1, and a reverse fault condition if the impedance angle is out of this limit. As this method works on positive sequence quantities, it is not as reliable as the negative sequence element for unsymmetrical faults.

7.2.2 *Negative Sequence Impedance Based Directional Determination*

The ratio of negative sequence voltage to negative sequence current measured at the relay location gives an effective negative sequence impedance. The negative sequence voltage developed for either a forward fault or reverse fault is always negative since there is no negative sequence voltage source. The current direction is positive for a forward fault and effective negative for a reverse fault. Therefore, the impedance measured for a forward fault is negative (equal to the effective negative sequence impedance behind the relay) as shown in Fig. 7.3 and the impedance measured is positive (equal to negative sequence impedance in fornt of relay) for a reverse fault. The setting threshold 50 % of the line negative sequence impedance as shown in Fig. 7.3. Overall, if the effective negative sequence impedance measured is above the threshold, it is a reverse fault and vice versa for the forward fault.

A negative sequence impedance based directional element is used for the proposed protection scheme and it is immune to most load flow.

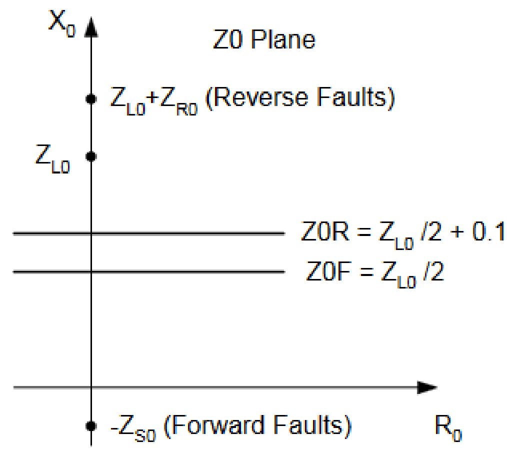


Figure 7.4: Zero Sequence Directional Element Characteristics

7.2.3 *Zero Sequence Impedance Based Directional Determination*

The zero sequence element does a similar comparison to the negative sequence directional element. The zero sequence element characteristic is shown in Fig. 7.4. Similar to the negative sequence directional element, if the measured zero sequence impedance is above the zero sequence positive threshold Z0F, it is reverse fault where as if the measured zero sequence impedance is below Z0R, then it is a forward fault.

As mentioned earlier, this element will be effected by zero sequence mutual coupling so cannot be used for transmission lines with strong zero sequence coupling with neighboring lines.

7.3 BACKUP RELAY MEASURING POINTS

The proposed relays takes the sample values from all of the merging units located as shown in Fig. 7.5. Merging units are located at the generator 1 terminal, GT1 HV side. In this thesis, two protection applications utilizing sample values are described. One application is enhancing the backup protection for generators and another application is a synchrocheck based generator circuit breaker failure detection scheme.

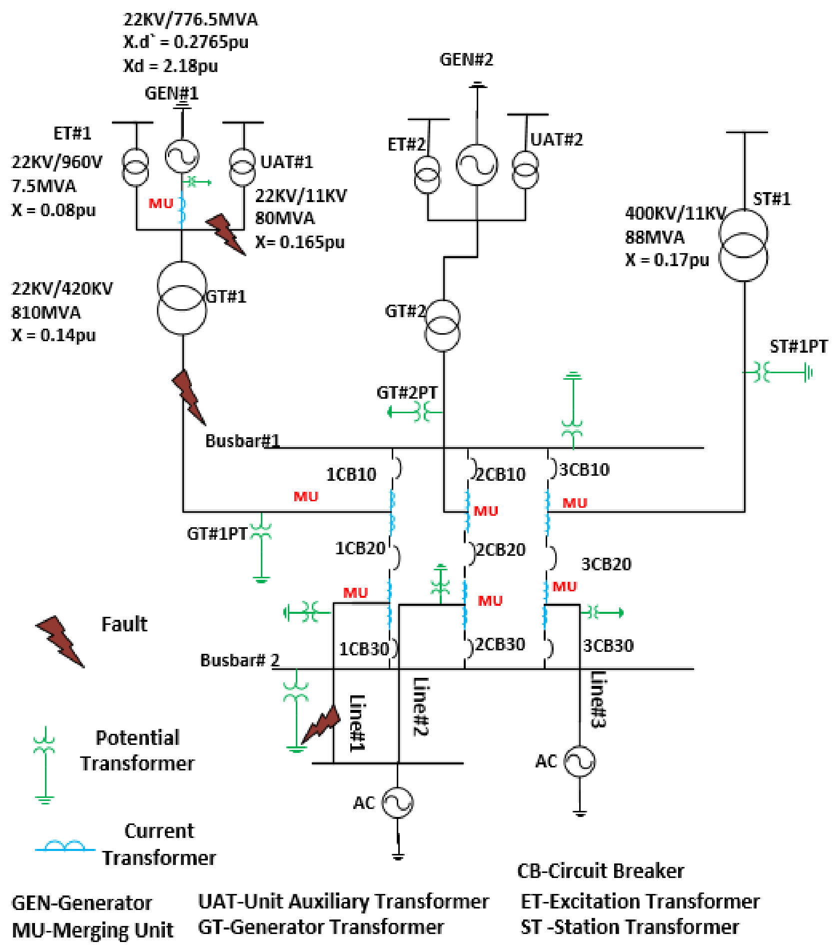


FIGURE 7.5: Single Line Diagram of a Thermal Power Generating Station With Merging Units Locations (MU)

7.4 ENHANCED BACKUP PROTECTION LOGIC

With the use of the sample values from the merging units, this backup relay acts independently for ground faults and phase-to-phase faults. As described earlier, this backup relay uses the inherent directional feature to determine the direction of fault current.

7.4.1 *Enhanced Backup Protection for Ground Faults*

Communication aided directional earth fault elements are used to detect high resistance ground faults in the transmission lines with a minimum time delay. Since the generator neutral is high resistance grounded and the current is limited to few Amps for single phase to ground faults between the generator and the GT, the neutral current measured at the GT HV side neutral can provide protection against transmission ground faults. But time delays are required to coordinate with the differential element for reverse faults and with line protection for all external faults.

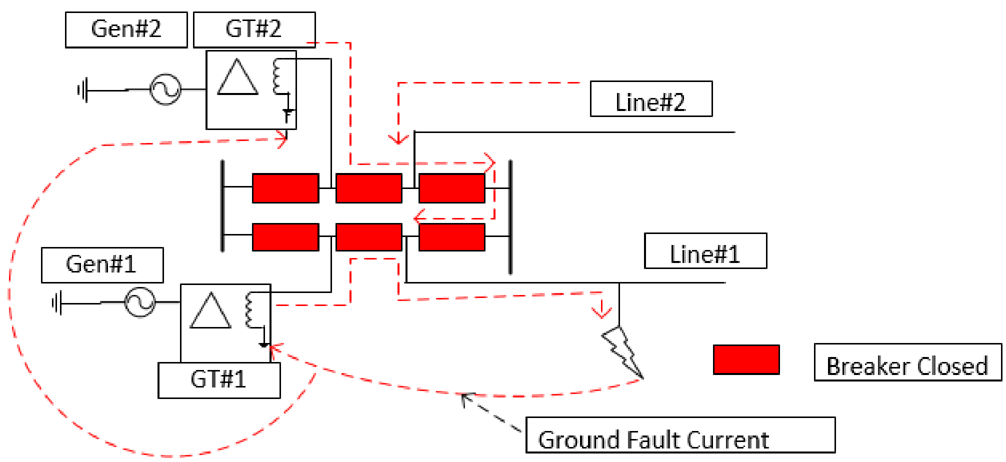


FIGURE 7.6: Backup Relay Scheme for External Ground Faults

Fig. 7.6 shows the approximate fault current paths for a ground fault in line#1. As shown in that figure, if a high resistance ground fault occurs on the transmission line, the fault current completes it's path through the neutral of the GT HV side winding. In this condition, the existing industrial practice is to trip the GT HV side breakers (i.e. generator tripping) in the case of line protection failure to identify the fault. Since both the generator relays have the same setting, the two generators will eventually be tripped for clearing the fault. But the proposed relay in this thesis works in such a way that, it will trip the corresponding faulted line breakers instead of tripping the generator unit.

The proposed backup relay ground fault protection determines if the calculated residual current $(3I_0)$ measured from the GT terminal CT exceeds the set threshold, then the relay will confirm the direction using the residual voltage $(3V_0)$ to decide if the fault is reverse or forward. Once the reverse flag is asserted, the delay can be selectively coordinated with the differential element to issue the trip command. Sometimes faults in terminal bushings and lighting arrestors can be covered when differential protection fails to pickup. If the external flag is asserted, the relay will check for the fault current direction in all the lines prior to the tripping of generator during any system fault and will trip the appropriate line breakers for line faults .

Hence, the relay can selectively isolate the line by opening the corresponding line breaker. Fig. 7.7 shows the logic used for protection against ground faults. If the direction elements in Fig. 7.7 determine the fault is in line#1, the magnitude of the zero and negative sequence currents are checked against the threshold to qualify the response prior to isolating the faulted line.

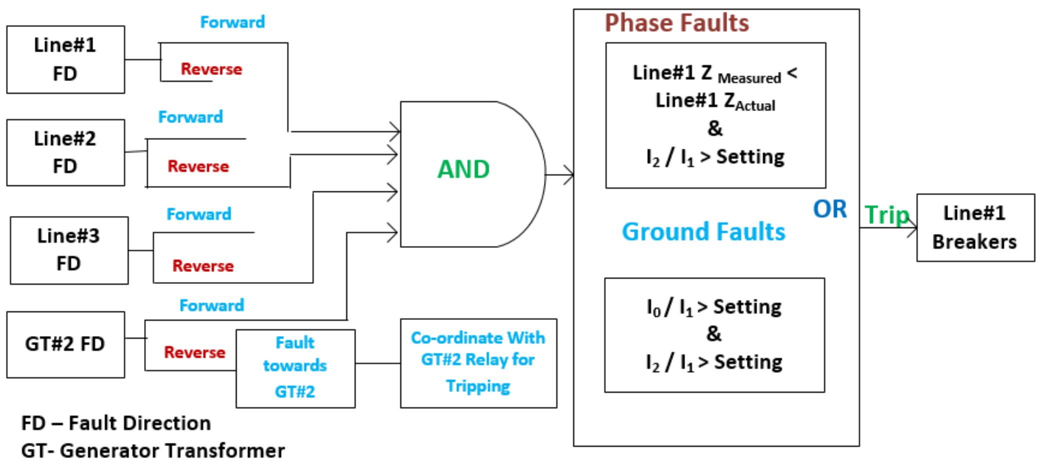


FIGURE 7.7: Enhanced Backup Element with Directional Supervision for Phase Faults and Ground Faults in Line#1

7.4.2 *Enhanced Backup Protection for Phase Faults*

The backup relay is designed such that the 21GT element will respond for any fault impedance that falls inside a mho circle with a diameter of 80% of the the magnitude of the load impedance, excluding angle range of the load region. If the 21GT element picks up, first the proposed relay will check for the direction of the fault current to decide the faulted line or transformer. To illustrate this, Fig. 7.7 explains the proposed logic for a fault in transmission line#1 in Fig. 7.5. If the fault direction detector (FD) identifies that the fault is in line#1 then the backup relay will measure the impedance with the measurements of line#1 sampled values to verify whether the fault is in that zone or not. Based on that, the first priority will be to issue the trip command to the faulted line breaker. Whereas in present situations, if line protection fails to detect for any reason, usually both the 21 elements in the generator relays may pickup to shutdown their units. In any case, if the direction decision is ambiguous or if the generator still experiences the fault even after tripping the lines, the generator will be given a trip command to shut down. This is the last step for ensuring the security of the generator unit. As shown in Fig.7.7, if the backup relay identifies any fault in the nearby GT of another unit, it will coordinate with the generator protection for the other unit for clearing this fault.

The proposed relay was designed in Mathcad to detect transmission line faults, transformer faults and generator faults. To validate this relay model, the RTDS simulation cases generated COMTRADE files for a set of fault conditions. The COMTRADE files were processed through a digital cosine filter to used as inputs for the impedance and directional calculations in Mathcad. The implementations were designed to confirm that the same algorithm can be implemented in numerical relay hardware for processing sample values.

7.4.3 *Security of 21 Element During PT Circuit Failure*

In current applications, the impedance protection will be disabled automatically if a VT circuit failure is detected. But having sampled values measurements available would make the protection secure during VT circuit failure conditions by switching to backup measurements from a different VT. The proposed logic is that in the case of voltage collapse, memory voltage polarization will be used for the fault direction decision. If the direction determined by memory polarization is forward, then the relay would switch to another healthy PT among the available sampled values units to calculate the impedance for forward direction faults.

7.5 ENHANCED GENERATOR CIRCUIT BREAKER FAILURE ELEMENT USING SAMPLED VALUES

The tripping of any of the critical protective elements initiate the breaker failure protection so as to ensure that the fault is isolated before the system reaches the critical clearing time. Conventional breaker failure protection uses the breaker auxiliary contacts or undercurrent based logic, or both to detect the breaker failures. Since, not all generator faults will have sufficient current to maintain the threshold value above the undercurrent element reset threshold, there exists a problem with the undercurrent based detection for mechanical faults [9]. The addition of breaker auxiliary contacts may help in many instances but they are not reliable to judge breaker opening. Since breakers are mechanically actuated devices, there are cases where the breakers are not opened with the trip command. So, all the critical protection tripping should initiate the breaker failure protection.

As described in Section 6.2, when the GT isolator is open that means the generator/unit is out of operation. But if isolator 2 is opened, then line protection will be disabled and the stub protection will be active. In the study, for any faults on the generator or connected transformers, the CB10 series and CB20 series breakers connected to the generator transformer need to be tripped by the generator group protection relay and breaker failure will also need to be initiated. For faults on any one of the transmission lines, the breakers CB20 and CB30 will be given trip command. In any case, if the breaker CB20 does not trip, this requires generate breaker failure initiation and will also cause the generator to feed the fault. In this case both the breaker failure and the backup protection of the generator will work in parallel to isolate the generator by tripping the field breaker, auxiliary breakers, and the prime mover. The similar situation would occur if bus bar protection trips all of the 10 series breakers connected to the bus bar 1 and if the breaker does not open to isolate the fault. Because of the restricted zones of bus bars, those will not act as a backup protection for faults in the connected transformers in the system.

7.5.1 *Generator Circuit Breaker Failure to Open Detection based on Synchronization Element*

Generators, when connected to the grid, will be in synchronism, and the moment the generator circuit breaker opens from the grid, there are appreciable changes of voltage difference, including frequency, slip and angle across the breaker contacts. Measuring these changes, along with the above mentioned undercurrent limiter, would provide a security in identifying the breaker failure case. But as noted earlier, these are sometimes not sufficient to identify a breaker failure. The tripping of any of the generator critical protective elements initiates the breaker failure protection to ensure that the fault is isolated before the system reaches the critical clearing time. The conventional breaker failure protection uses the breaker auxiliary contacts, undercurrent based logic, or both to determine the breaker failures.

The information from the merging units at the backup relay can help in improve the performance of the breaker failure protection for the generating unit. After opening the generator breaker, the angular velocity of the rotating magnetic field and therefore the frequency of the voltage induced in the stator are governed by the rotor speed, which is no longer synchronized with the grid. The proposed relay adds measurement of the voltage difference, frequency, slip, and angle variation across the breaker contacts to complement the undercurrent limiter to provide security for identifying generator breaker failure condition. IEEE standards C50.12 [2] and

C50.13 [19] provide specifications for the construction of cylindrical-rotor and salient-pole synchronous generators, respectively. The limits for both types of generators are angle within +/-10 degrees, voltage difference of 0 to +5 percent and slip within +/-0.067Hz. Although, these are allowable limits for the generator to synchronize with the grid, are not sufficient as settings to decide whether the generator is disconnected from the network or not [19].

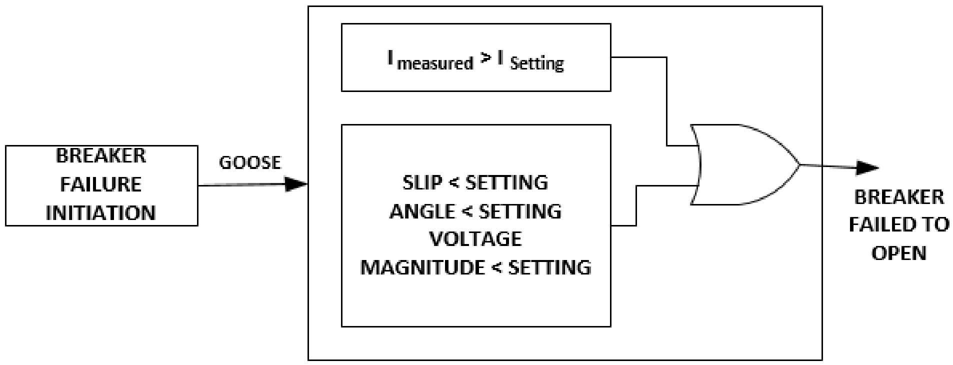


Figure 7.8: Generator Breaker Failure to Open Detection Using Synchronizing Check Logic

The proposed logic shown in Fig. 7.8 can be used to identify a generator circuit breaker failure to open utilizing sample values. According to the logic, if the generator HV side breaker is given the trip command in the event of a fault, the relay will be notified by a GOOSE command to compare the GT HV side phase voltage with a selected grid side voltage to check for deviation of angle, frequency and voltage magnitude along with a check for a decrease in current magnitude and the increase in harmonic content.

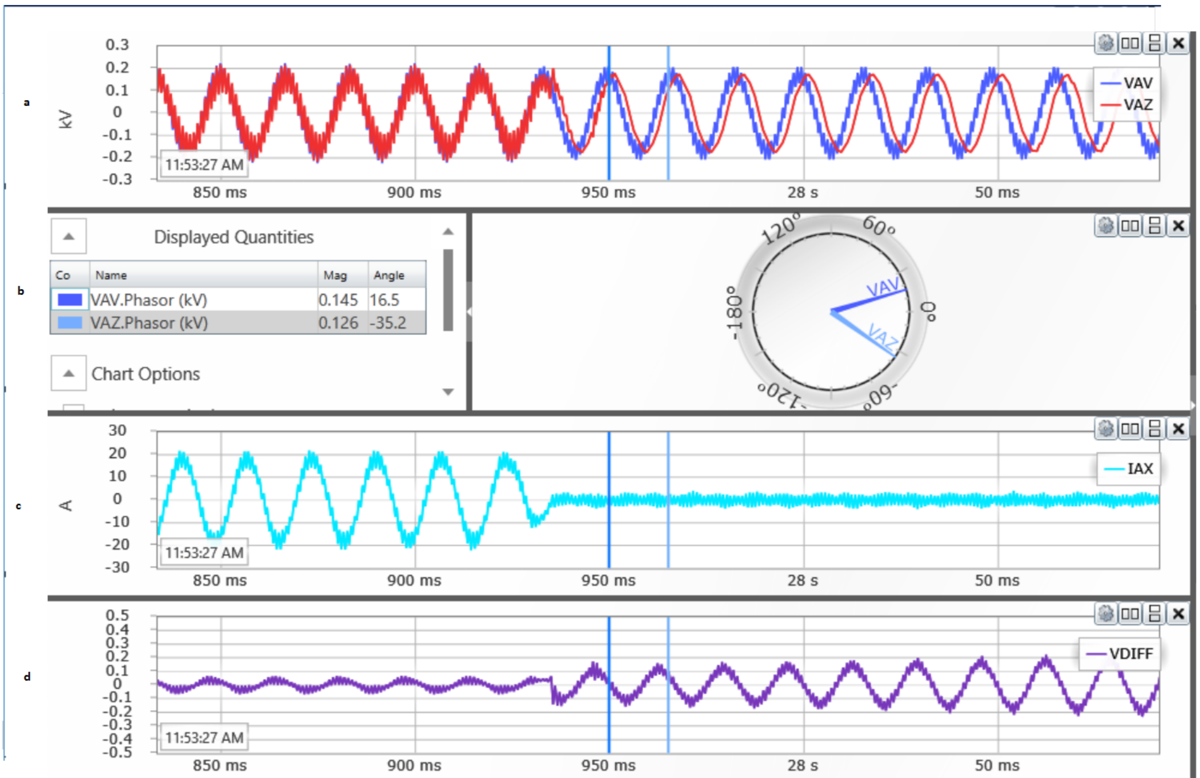


Figure 7.9: Experimental Validation of Synchrocheck Element (a) Voltage Signals of Generator and System; (b) Angular Difference; (c) Generator Current; (d) Voltage Difference

A lab scale 20kw synchronous generator was used to verify the synchrocheck conditions described here as shown in Fig. 7.9. The results in Fig. 7.9 show that at the time of disconnection of the generator circuit breaker, the voltage difference (7.9(d)) and angular difference (7.9(b)) increases between the system and the generator. This figure couldn't show the slip frequency between the generator and the system, but the plot of the voltage magnitudes on either side of breaker in Fig (7.9(a)) shown here shows an indirect effect of increasing slip frequency between the generator and the system.

7.6 Summary

This chapter has described a proposed backup relay with that uses sampled values to improve performance and security. This chapter illustrated the operation of directional element using sequence quantities. This chapter proposed an algorithm for the backup relay to isolate the faulted line without needing to trip the generator for an uncleared phase-to-phase or phase-to-ground fault. This chapter also proposed voltage changeover logic to use in the event of loss of potential for the distance element to measure the impedance. Finally this chapter introduced an enhanced breaker failure detection logic using sampled values.

CHAPTER 8

Conclusions and Future Work

8.1 Conclusions

This thesis demonstrates that system level backup protection can be provided in digital substations using sampled values as defined in the IEC 61850 standard. This thesis demonstrated these principles using a generator station as an example. The sampled values data from merging units can be sent to different relays, which can use the information to enhance backup protection for the generating station. The advantage of using these values in the backup relay is that the relay can be secured against loss of potential. The backup relay can access data for a wider variety of CTs and PTs without needing physical conductors to each phase of each transformer.

Faults that are not cleared by the transmission line protection can be cleared by a backup relay using distance elements (21). This thesis studied the sensitivity of distance elements using measurements from either the generator terminals (21G) or the generator transformer (GT) HV side terminals (21GT) for the backup to see which was more effective.

Through use of RTDS simulations this thesis demonstrates that the Mho element using measurements from GT HV side can effectively cover the faults in the GT, generator, UAT, and ET with a better coverage than having the generator relay taking measurements from the generator terminals. This work concluded that the 21GT reverse zone can be used as a backup to the overall differential element. But the protection settings will need be coordinated to prevent misoperation during stable power swings.

The sensitivity and security of the 21GT for the external faults was enhanced by using sampled values. In the event of an external fault, if the impedance measured by the GT HV side relay is lower than the 80% of the rated load impedance, the backup relay will determine the direction of the fault current and determine the approximate fault location by calculating the effective fault impedance. This element is secured against the loss of PT signal due to the proposed switchover logic enabled by use of sampled values.

This work also proposed a backup ground element based on the measured zero sequence current at the HV side of the GT neutral winding. This will be used to clear high resistance faults that are not cleared by the line protection.

The proposed protection scheme emphasized the importance of coordination between the distance element and breaker failure relay to ensure that the backup relay does not operate before the breaker failure protection can operate to clear the fault to prevent nuisance trips of the generators.

In addition, the new scheme also utilized the sample values measurements to perform synchronization check across the breaker to detect breaker failure conditions in challenging situations to supplement traditional breaker failure elements. Although traditional current-based breaker failure protection schemes remain a critical component to the generator system protection, current schemes are potentially deficient when there is little or no current prior to the breaker trip. The backup relay can also have an additional synchronism-check based breaker open detection along with the traditional current-based scheme.

Overall, the proposed protection scheme can protect the generator unit from the phase and ground faults by providing backup protection for transformer, bus and line faults and also effectively determine the generator circuit breaker failure conditions.

This thesis has also performed basic study on the challenges associated with the series compensated lines for this backup relay. The mis-operation of the backup relay for the voltage inversion can be avoided by PT change over logic and delay for the bypass breaker to operate.

8.2 FUTURE WORK

The results presented in this thesis suggest additional avenues for future work.

1. Enhancing the security of the proposed element for series compensated lines
   The work demonstrated in this thesis can be extended to enhance the logic for a system with series compensated lines. As explained earlier, voltage inversion causes distance and directional elements to fail and current inversion causes both line current differential and distance elements to misoperate. For a fault on a line#1 shown in Fig. 7.5, the designated relay on line#1 sees the fault in reverse direction and the other parallel lines see the fault in the forward direction. A protection scheme can be implement in the backup relay to provide secure protection during these fault conditions.

2. The proposed 21GT element will have issues with the starting current of large motors with high interia on the UAT LV side bus. The large motor starting current can cause severe voltage stress which may cause the 21GT element to

overreach so this effect can be studied using RTDS to recommend a potential blocking function.

3. Though the 21GT has better reverse fault coverage than 21G, but it's performance is limited by the infeed from the generator during UAT faults. Whereas for the 21G, the infeed from the system will limit the performance during UAT faults and this infeed from the system will vary based on the system strength. Hence, the performance of these two elements can also be studied for various source impedance conditions.

4. This thesis provides a backup solution to thermal power generating stations only. The system configuration changes for a hydro station. Hence, a similar relay approach can even be devised for hydro stations. For most of the hydro stations, there will not be any connecting auxiliary transformer. Hence, this station may not require reverse zone protection. Overall system configuration can be modelled in RTDS and verify the performance of backup relay.

5. The network traffic due to the additional of the merging units will affect the performance of backup relay in subscribing the sample values. This can be studied further to address the performance of backup relay during network failures. There are likely to be publications on this topic from other researchers in the near future.

6. Existing numerical relays may have computational limitations in processing. So this work can be extended to determine the computational limitation of numerical relay for increase in the number of merging units connected to them.

Bibliography

[1] "IEC 61850-9-2, part 9-2: Specific communication service mapping (scsm) - sampled values over ISO/IEC 8802-3."

[2] "IEEE standard for cylindrical-rotor 50 Hz and 60 Hz synchronous generators rated 10 MVA and above," *IEEE Std C50.13-2014 (Revision of IEEE Std C50.13-2005)*, pp. 1–63, May 2014.

[3] D. Tziouvaras, J. Quintin Verzosa, and T. E. Wiedman, "Power plant and transmission system protection coordination," *NERC System Protection and Control Subcommittee Report*, 2009.

[4] C. J. Mozina, "Implementing NERC guidelines for coordinating generator and transmission protection," in *65th Annual Conference for Protective Relay Engineers*, 2012, pp. 491–504.

[5] J. L. Blackburn and T. J. Domin, *Protective relaying: principles and applications, Fourth Edition*. CRC press, 2014.

[6] A. Guzman, E. Schweitzer, and J. Roberts, "Z = v/i does not make a distance relay," in *20th Annual Western Protective Relay Conference*, 1993.

[7] H. J. A. Ferrer and E. O. Schweitzer, *Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems*. Schweitzer Engineering Laboratories, 2010.

[8] E. Schweitzer and J. Roberts, "Distance relay element design," in *proceedings of the 46th Annual Conference for Protective Relay Engineers, College Station, TX*, 1993.

[9] IEEE Power System Relaying Committee, "IEEE guide for ac generator protection," *IEEE Std. C*, vol. 37, pp. 1–177, 2007.

[10] *SEL-700G Generator and Inter-tie Protection relays Instruction Manual*. Schweitzer Engineering Laboratories, May 2015.

[11] A. Siemens, "SIPROTEC multifunction machine protection 7UM62 v4. 6 manual," *Order No. "C53000-G1176-C149-5"*, 2014.

[12] *G60 Generator Protection System Instruction Manual product version: 7.3X*. GE, 2014.

[13] RTDS Technology Inc., Winnipeg, MB, Canada. (2014). Accessed on 16-Jan-2017. [Online]. Available: http://www.rtds.com

[14] "IEEE guide for breaker failure protection of power circuit breakers," *IEEE Std C37.119-2016 (Revision of IEEE Std C37.119-2005)*, pp. 1–73, July 2016.

[15] D. A. Tziouvaras and D. Hou, "Out-of-step protection fundamentals and advancements," in *Protective Relay Engineers, 2004 57th Annual Conference for*, 2004, pp. 282–307.

[16] H. J. Altuve, J. B. Mooney, and G. E. Alexander, "Advances in series-compensated line protection," in *2009 62nd Annual Conference for Protective Relay Engineers*, March 2009, pp. 263–275.

[17] V. Skendzic, I. Ender, and G. Zweigle, "IEC 61850-9-2 process bus and its impact on power system protection and control reliability," in *Proceedings of the 9th Annual Western Power Delivery Automation Conference, Spokane, WA*, 2007.

[18] J. Roberts and A. Guzman, "Directional element design and evaluation," in *Proceedings of the 21st Annual Western Protective Relay Conference*, 1994.

[19] "IEEE standard for salient-pole 50 Hz and 60 Hz synchronous generators and generator/motors for hydraulic turbine applications rated 5 MVA and above," *IEEE Std C50.12-2005 (Previously designated as ANSI C50.12-1982)*, pp. 1–45, Feb 2006.

APPENDIX A

RTDS MODEL

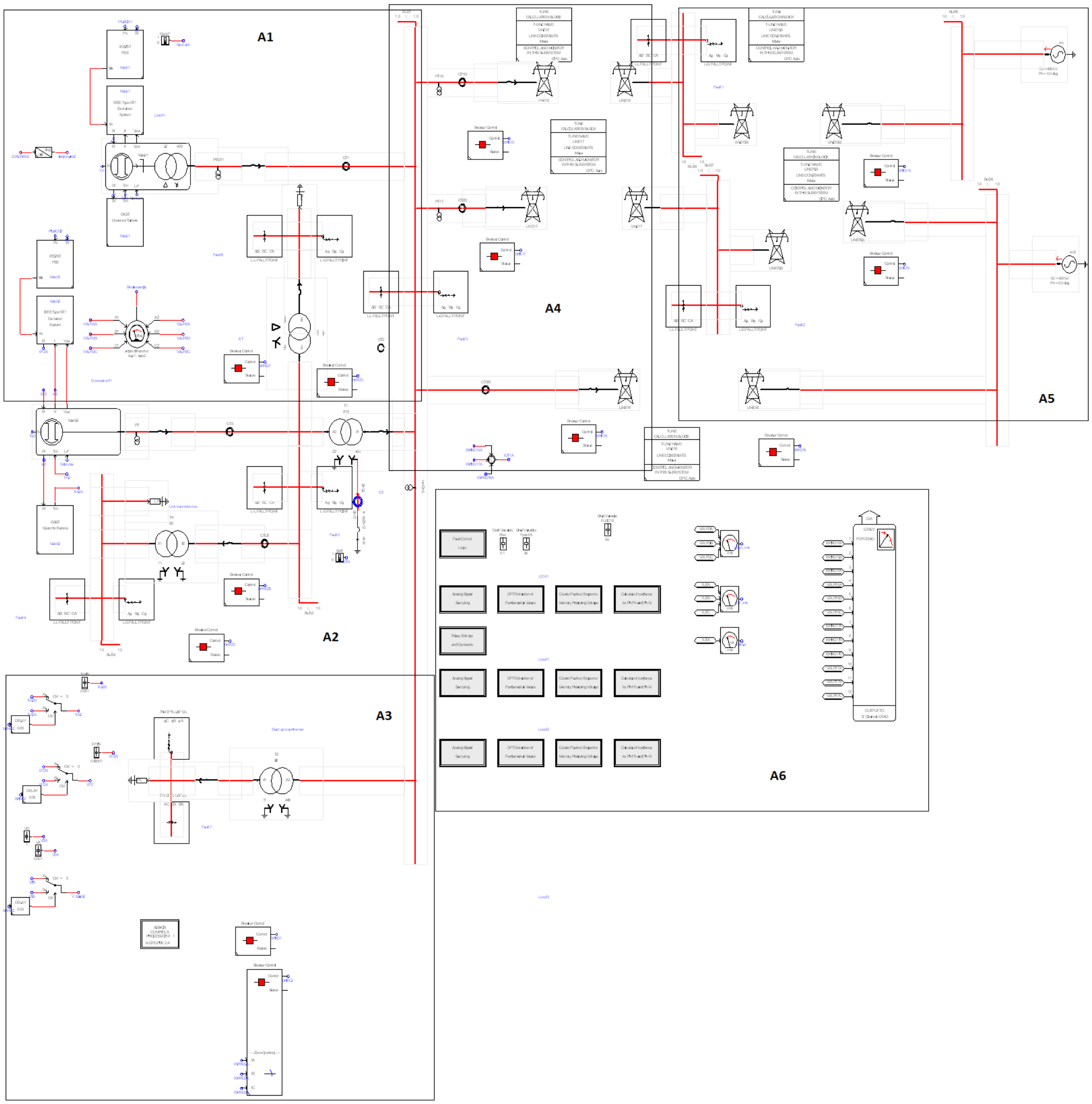


Figure A.1: RTDS Simulation Model

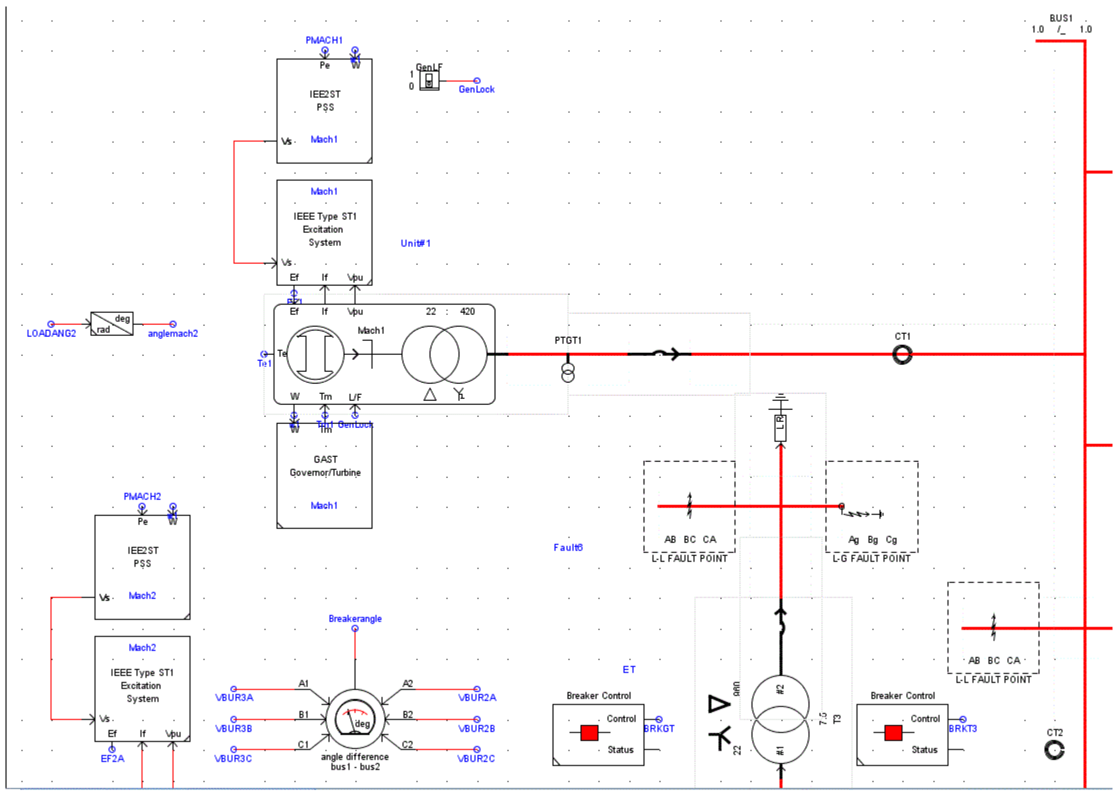


Figure A.2: RTDS Simulation Model

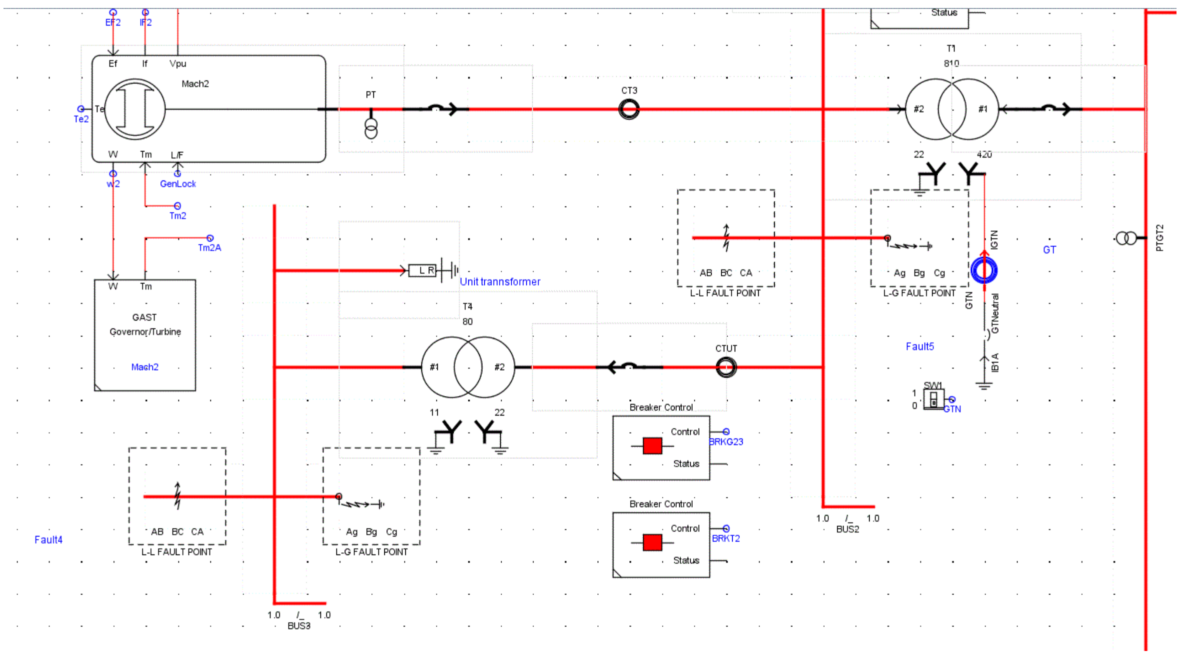


Figure A.3: RTDS Simulation Model

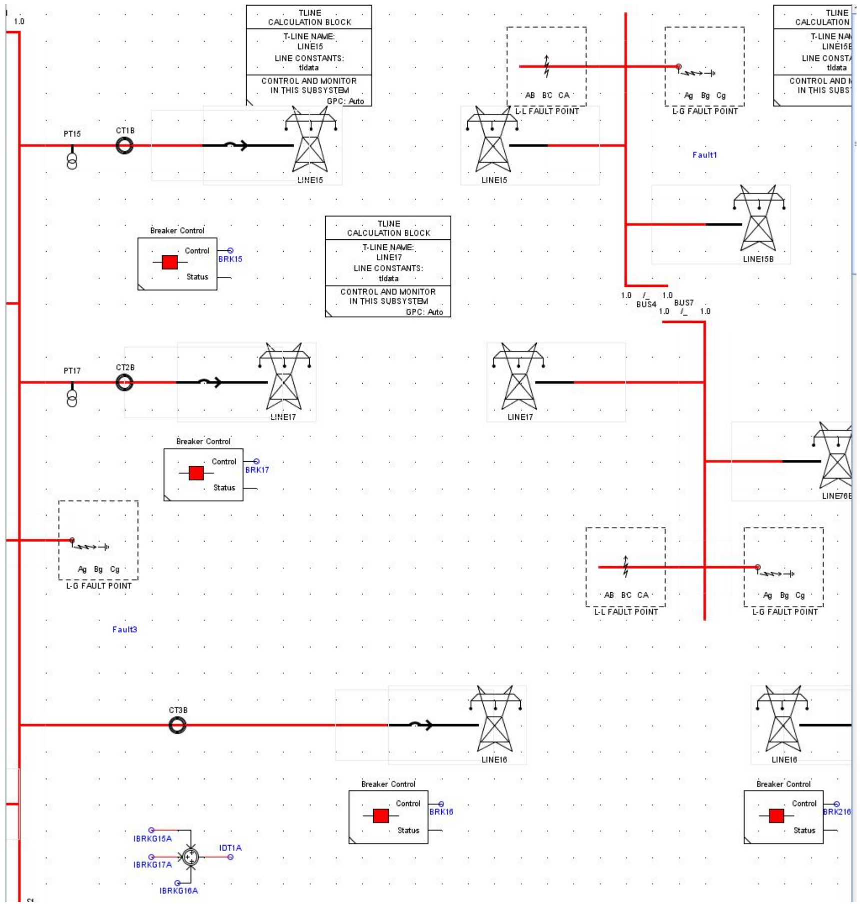


Figure A.4: RTDS Simulation Model

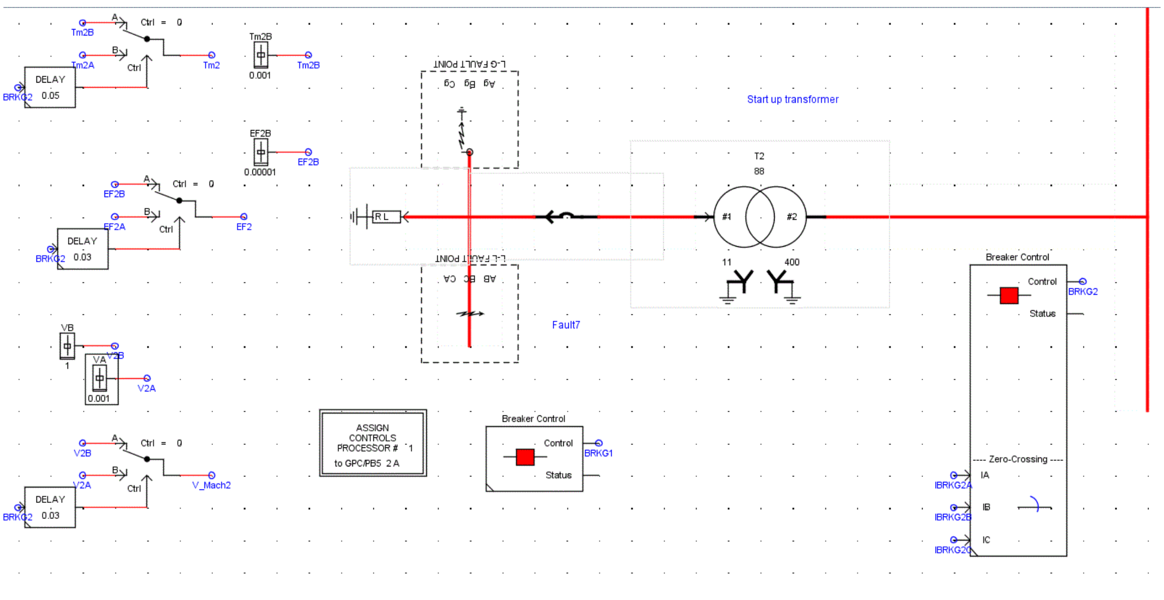


Figure A.5: RTDS Simulation Model

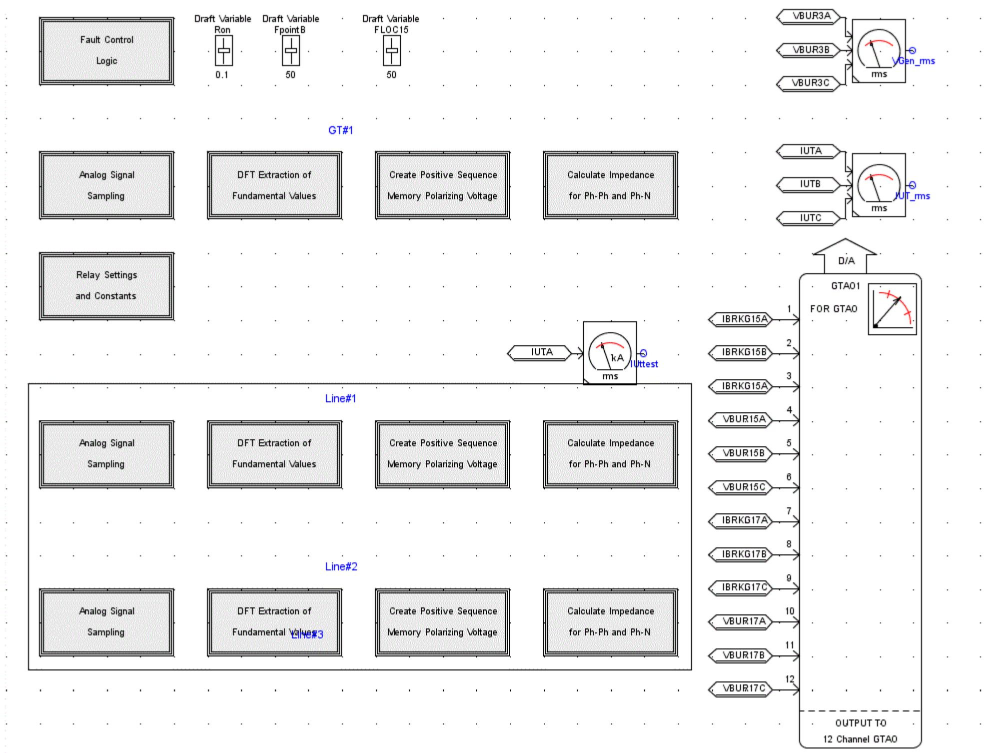


Figure A.6: RTDS Simulation Model

APPENDIX B

System Model

Generator Parameters

$MVA := MW \qquad pu := 1$

$V_{gen} := 22KV \qquad S_{gen} := 776.5MVA \qquad CTR := \frac{25000}{5} \qquad PTR := \frac{22000}{110}$

$Z_{gen\_base} := \frac{V_{gen}^{2}}{S_{gen}} \qquad Z_{gen\_base} = 0.62331\,\Omega$

$s_{gen} = \sqrt{P^2 + q^2}$

$R\_gen\_load := \frac{V_{gen}^{2}}{S_{gen}} \cdot 0.85 \cdot \frac{CTR}{PTR} = 13.24533\,\Omega$ this corresponds to 660MW

$acos(0.85) = 31.78833 \cdot deg$

$X\_gen\_load := \sin(31.78deg) \cdot Z_{gen\_base} \cdot \frac{CTR}{PTR} = 8.20679\,\Omega$

$Z\_gen\_load\_relay := Z_{gen\_base} \cdot \frac{CTR}{PTR} = 15.58274\,\Omega$ Generator Load impedance

$X_{d\_gen} := 2.1803pu$

$X_{d\_ohm} := Z_{gen\_base} \cdot X_{d\_gen} \qquad X_{d\_ohm} = 1.359\,\Omega$

$X_{d\_ohm\_relay} := X_{d\_ohm} \cdot \frac{CTR}{PTR} \qquad X_{d\_ohm\_relay} = 33.97505\,\Omega$

$X_{d'\_gen} := 0.2765pu$

$X_{d'\_ohm} := Z_{gen\_base} \cdot X_{d'\_gen} \qquad X_{d'\_ohm} = 0.17235\,\Omega$

$X_{d'\_ohm\_relay} := X_{d'\_ohm} \cdot \frac{CTR}{PTR} \qquad X_{d'\_ohm\_relay} = 4.30863\,\Omega$

$X_{d''\_gen} := 0.1963pu$

$X_{d''\_ohm} := Z_{gen\_base} \cdot X_{d''\_gen} \qquad X_{d''\_ohm} = 0.12236\,\Omega$

$X_{d''\_ohm\_relay} := X_{d''\_ohm} \cdot \frac{CTR}{PTR} \qquad X_{d''\_ohm\_relay} = 3.05889\,\Omega$

Excitation Transformer Data

$Z_{ET} := 0.08pu \qquad S_{ET} := 7.5MVA$

$Z_{ET\_base} := \frac{V_{gen}^{2}}{S_{ET}} \qquad Z_{ET\_base} = 64.53333\,\Omega$

$Z_{ET\_ohm} := Z_{ET} \cdot Z_{ET\_base} \qquad Z_{ET\_ohm} = 5.16267\,\Omega$

$Z_{ET\_ohm\_gen\_relay} := Z_{ET\_ohm} \cdot \frac{CTR}{PTR}$ $\quad Z_{ET\_ohm\_gen\_relay} = 129.06667\,\Omega$

Unit Auxillary Transformer Data

$Z_{UAT} := 0.165pu$ $\quad S_{UAT} := 80MVA$

$Z_{UAT\_base} := \frac{V_{gen}^{2}}{S_{UAT}}$ $\quad Z_{UAT\_base} = 6.05\,\Omega$

$Z\_gen\_UAT\_load := Z_{UAT\_base} \cdot \frac{CTR}{PTR} = 151.25\,\Omega$ $\quad PTR = 200$

$Z_{UAT\_ohm} := Z_{UAT} \cdot Z_{UAT\_base}$ $\quad Z_{UAT\_ohm} = 0.99825\,\Omega$ $\quad CTR_{UT} := 1000$

$Z_{UAT\_ohm\_gen\_relay} := Z_{UAT\_ohm} \cdot \frac{CTR_{UT}}{PTR}$

$Z_{UAT\_ohm\_gen\_relay} = 4.99125\,\Omega$

$Z_{UAT\_ohm\_UT\_relay} := Z_{UAT\_ohm} \cdot \frac{CTR_{UT}}{PTR}$

$Z_{UAT\_ohm\_UT\_relay} = 4.99125\,\Omega$

$Z\_UT\_load := Z_{UAT\_base} \cdot \frac{CTR_{UT}}{PTR}$ $\quad Z\_UT\_load = 30.25\,\Omega$

Generator Transformer data

$V_{GT} := 420KV$ $\quad S_{GT} := 810MVA$ $\quad Z_{GT\_pu} := 0.14pu$

$Z_{GT\_gen} := \frac{V_{gen}^{2}}{S_{GT}}$ $\quad Z_{GT\_gen} = 0.59753\,\Omega$

$Z\_gen\_GT\_load := \frac{CTR}{PTR} \cdot \frac{V_{gen}^{2}}{S_{GT}}$ $\quad Z\_gen\_GT\_load = 14.93827\,\Omega$

$Z_{GT\_gen\_ohm} := Z_{GT\_gen} \cdot Z_{GT\_pu}$ $\quad Z_{GT\_gen\_ohm} = 0.08365\,\Omega$ $\quad$ On Generator side

$Z_{GT\_gen\_ohm\_relay} := Z_{GT\_gen\_ohm} \cdot \frac{CTR}{PTR}$ $\quad Z_{GT\_gen\_ohm\_relay} = 2.09136\,\Omega$

Setting Recommandations from Different Vendors (See Section 4.7)

Vendor 1 recommends to have 21G

Zone #1 covers 70% of GT impedance with 0.4 sec delay

Zone #2 covers 100% of GT impedance with 1 sec delay

To compensate tap changings

Forward zone impedance

Zone_1 forward impedance

$$0.7 \cdot Z_{GT\_gen\_ohm\_relay} = 1.46395\,\Omega$$

Zone_1 reverse impedance

$$0.7 \cdot Z_{GT\_gen\_ohm\_relay} = 1.46395\,\Omega$$

Zone -2 forward impedance

$$0.125 \cdot Z_{GT\_gen\_ohm\_relay} = 0.26142\,\Omega$$

Vendor 2 recommends to have 21G

one #1 covers 70% of GT impendance with 0.6 sec

Vendor 3 recommends to have

$$Z_{B.SET} = K_{rel}\, Z_{A1} = 0.8 \times 0.8 \times 30 \times 0.001 \times \frac{420^2}{1000} \times \frac{2500}{400KV/110V} = 2.33\ (\Omega)$$

Going for 1.5 sec delay

$$2.33 \cdot \frac{400000}{110} \cdot \frac{1}{2500} = 3.38909$$

It can only look into the faults on the system.

The thevenin equivallent impednace of the system from the generator bus is realy less

Vendor 4 preferrence

$$Z_{line\_ohm} := 58.49 \cdot e^{j \cdot 85deg} \cdot ohm \qquad Z_{line\_ohm} = (5.09774 + 58.26743i)\,\Omega$$

$$Z_{line\_gen\_ohm} := Z_{line\_ohm} \cdot \frac{22^2}{420^2} = (0.01399 + 0.15987i)\,\Omega \qquad CTR = 5 \times 10^3$$

$Z_{line\_gen\_ohm\_relay} := Z_{line\_gen\_ohm} \cdot \frac{CTR}{PTR}$ $\left|Z_{line\_gen\_ohm\_relay}\right| = 4.0120$ PTR = 200

$Zone\_1reach := 1.2\left(Z_{line\_gen\_ohm} + Z_{GT\_gen\_ohm}\right) \cdot \frac{CTR}{PTR}$

$\left|Zone\_1reach\right| = 5.61993\,\Omega$

Reverse Impedance

$Zone\_3reach := 1.2 \cdot X_{d'\_ohm\_relay}$ $Zone\_3reach = 5.17035\,\Omega$

Vendor 5 relay recommendations

$Zone\_1$

$0.7 \cdot Z_{GT\_gen\_ohm\_relay} = 1.46395\,\Omega$ time delay of 100ms

When the GT hV side scircuit breaker is switched off then there would be

$2 \cdot Z_{GT\_gen\_ohm\_relay} = 4.18272\,\Omega$

Zone_2 time delay is 0.4sec $\left|(0.0288 + j \cdot 0.307) \cdot 150\right| = 46.25219$

NERC

$Z\_gen\_load\_relay = 15.58274\,\Omega$

0.66 pu to 0.5 pu

$0.66 \cdot Z\_gen\_load\_relay = 10.28461\,\Omega$

$0.4 \cdot Z\_gen\_load\_relay = 6.2331\,\Omega$

Forward Impednaces on Generator Side

$Z\_gen\_load\_relay = 15.58274\,\Omega$ Load blinder should be desired to find out the powerfactor angle

$X_{d'\_ohm\_relay} = 4.30863\,\Omega$

$Z_{GT\_gen\_ohm\_relay} = 2.09136\,\Omega$

$$Z_{UAT\_ohm\_gen\_relay} = 4.99125\,\Omega$$

$$Z_{ET\_ohm\_gen\_relay} = 129.06667\,\Omega$$

$$Z_{ST\_ohm\_gen\_relay} := 21.95ohm$$

$$\left|Z_{line\_gen\_ohm\_relay}\right| = 4.01207\,\Omega$$

$$Z_{GT\_HV\_ohm} := 30.49ohm$$

$$Z_{GT2\_gen\_ohm\_relay} := Z_{GT\_HV\_ohm}\cdot\left(\frac{22^2}{420^2}\cdot\frac{5000}{200}\right)$$

$$Z_{GT2\_gen\_ohm\_relay} = 2.09143\,\Omega$$

Line #1 relay

$$Z_{line1\_ohms} := 58ohm \qquad Z_{line3\_ohms} := 87.62ohm$$

$$Z\_line1\_gen\_relay := Z_{line1\_ohms}\cdot\frac{22^2}{420^2}\cdot\frac{5000}{200} \qquad Z\_line1\_gen\_relay = 3.97846\,\Omega$$

$$Z\_line2\_gen\_relay := Z\_line1\_gen\_relay \qquad Z\_line2\_gen\_relay = 3.97846\,\Omega$$

$$Z\_line3\_gen\_relay := Z_{line3\_ohms}\cdot\frac{22^2}{420^2}\cdot\frac{5000}{200} \qquad Z\_line3\_gen\_relay = 6.01022\,\Omega$$

When the system is connected to the grid for a fault on UAT or ET, there will be in feed from the generator transformer. So it will not be covered in overall differential protection because of high knee point requirements. The faults in the UAT are not covered by the overall differential protection. UAT differential will act as main protection to the UAT.

Generator reverse faults

$$X_{d\_ohm\_relay} = 33.97505\,\Omega$$

$$X_{d'\_ohm\_relay} = 4.30863\,\Omega$$

$$X_{d''\_ohm\_relay} = 3.05889\,\Omega$$

Station Transformer data

$Z_{ST} := 0.176pu$ $\qquad S_{ST} := 88MVA$

$Z_{HV\_ST} := \frac{(400kV)^2}{S_{ST}}$ $\qquad Z_{HV\_ST} = 1.81818 \times 10^3\,\Omega$

$Z_{HV\_ST\_ohm} := Z_{HV\_ST} \cdot Z_{ST}$ $\qquad Z_{HV\_ST\_ohm} = 320\,\Omega$

$Z\_gen\_ST\_relay := Z_{HV\_ST\_ohm} \cdot \frac{22^2}{420^2} \cdot \frac{5000}{200}$ $\qquad Z\_gen\_ST\_relay = 21.95011\,\Omega$

GT Impedances

$CTR_1 := 2500$ $\qquad PTR_1 := \frac{400000}{110}$

$Z_{GT\_HV\_base} := \frac{V_{GT}^{\,2}}{S_{GT}}$

$Z_{GT\_HV\_base} = 217.77778\,\Omega$

The GT effective impedance

$Z_{GT\_HV\_load} := Z_{GT\_HV\_base} \cdot \frac{CTR}{PTR}$

$Z_{GT\_HV\_load} = 5.44444 \times 10^3\,\Omega$

$Z_{GT\_HV\_ohm1} := Z_{GT\_HV\_base} \cdot Z_{GT\_pu}$ $\qquad Z_{GT\_HV\_ohm1} = 30.48889\,\Omega$

$Z_{GT\_HV\_ohm\_relay} := Z_{GT\_HV\_ohm} \cdot \frac{CTR_1}{PTR_1}$ $\qquad Z_{GT\_HV\_ohm\_relay} = 20.96187\,\Omega$

The impedance look into the transformer from HV side relay of the GT is $20.961ohm$

The UT impedance referred to the HV side of the GT is

$Z_{UAT\_base1} := \frac{(22KV)^2}{80MVA}$ $\qquad Z_{UAT\_base} = 6.05\,\Omega$

$Z\_UAT\_base\_GT := Z_{UAT\_base} \cdot \frac{(420KV)^2}{(22KV)^2}$ $\qquad Z\_UAT\_base\_GT = 2.205 \times 10^3\,\Omega$

$Z\_UAT\_load\_GTref := Z\_UAT\_base\_GT \cdot \frac{CTR}{PTR}$ $\qquad Z\_UAT\_load\_GTref = 55125\,\Omega$

$Z_{UAT\_ohm} = 0.99825\,\Omega$

$Z\_UAT\_GT\_HV\_relay := Z_{UAT\_ohm} \cdot \frac{420^2}{22^2} \cdot \frac{CTR}{PTR} = 9.09563 \times 10^3\,\Omega$

$Z\_ET\_GT\_HV\_relay := Z_{ET\_ohm} \cdot \frac{420^2}{22^2} \cdot \frac{CTR}{PTR} = 4.704 \times 10^4\,\Omega$

$X_{d\_ohm} = 1.359\,\Omega$

$Z\_Gen\_X_{d\_GT\_HV\_relay} := X_{d\_ohm} \cdot \frac{420^2}{22^2} \cdot \frac{CTR}{PTR} = 1.23826 \times 10^4\,\Omega$

$Z\_Gen\_X_{d'\_GT\_HV\_relay} := X_{d'\_ohm} \cdot \frac{420^2}{22^2} \cdot \frac{CTR}{PTR} = 1.57033 \times 10^3\,\Omega$

$Z\_Gen\_X_{d''\_GT\_HV\_relay} := X_{d''\_ohm} \cdot \frac{420^2}{22^2} \cdot \frac{CTR}{PTR} = 1.11485 \times 10^3\,\Omega$

Reverse Direction faults

$CTR = 5 \times 10^3$ $\quad$ $PTR = 200$

$Z_{GT\_HV\_base} \cdot \frac{CTR}{PTR} = 5.44444 \times 10^3\,\Omega$ $\quad$ Load point of the generator transformer

$Z_{GT\_HV\_base} \cdot \frac{CTR}{PTR} = 5.44444 \times 10^3\,\Omega$

$Z_{GT\_HV\_ohm\_relay} + 0.5Z\_UAT\_GT\_HV\_relay = 4.56877 \times 10^3\,\Omega$

$Z_{GT\_HV\_ohm\_relay} = 20.96187\,\Omega$ $\quad$ $Z\_UAT\_GT\_HV\_relay = 9.09563 \times 10^3\,\Omega$

$Z_{GT\_HV\_ohm\_relay} + Z\_ET\_GT\_HV\_relay = 4.7061 \times 10^4\,\Omega$

$Z\_ET\_GT\_HV\_relay = 4.704 \times 10^4\,\Omega$

$Z_{GT\_HV\_ohm\_relay} + Z\_Gen\_X_{d'\_GT\_HV\_relay} = 1.5913 \times 10^3\,\Omega$

$Z\_Line1\_GT\_HV\_relay := Z_{line1\_ohms} \cdot \frac{CTR}{PTR}$

$Z\_Line1\_GT\_HV\_relay = 1.45 \times 10^3\,\Omega$

$$Z\_Line2\_GT\_HV\_relay := Z\_Line1\_GT\_HV\_relay = 1.45 \times 10^{3}\,\Omega$$

$$Z\_Line3\_GT\_HV\_relay := Z_{line3\_ohms} \cdot \frac{CTR}{PTR}$$

$$Z\_Line3\_GT\_HV\_relay = 2.1905 \times 10^{3}\,\Omega$$

$$Z\_ST\_GT\_HV\_relay := Z_{HV\_ST\_ohm} \cdot \frac{CTR}{PTR}$$

$$Z\_ST\_GT\_HV\_relay = 8 \times 10^{3}\,\Omega$$

$$Z\_GT2\_GT\_HV\_relay := Z_{GT\_HV\_ohm} \cdot \frac{CTR}{PTR}$$

$$Z\_GT2\_GT\_HV\_relay = 762.25\,\Omega$$

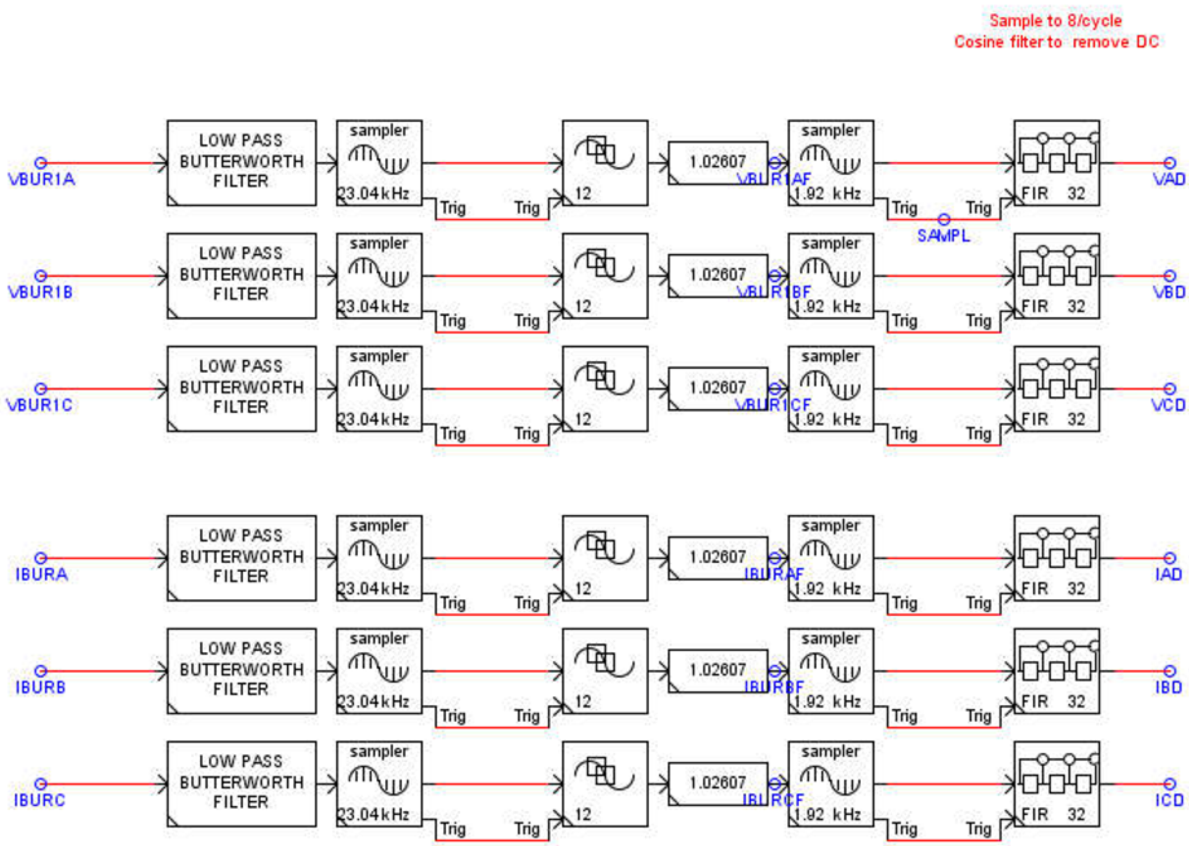
$$Z_{GT\_HV\_Set} := 1.5 \cdot Z_{GT\_HV\_ohm\_relay} \qquad Z_{GT\_HV\_Set} = 31.44281\,\Omega$$

With this setting, the GT HV side relay in reverse zone would cover the phase to phase faults of GT and some portion of faults in UAT, ET and Generator.

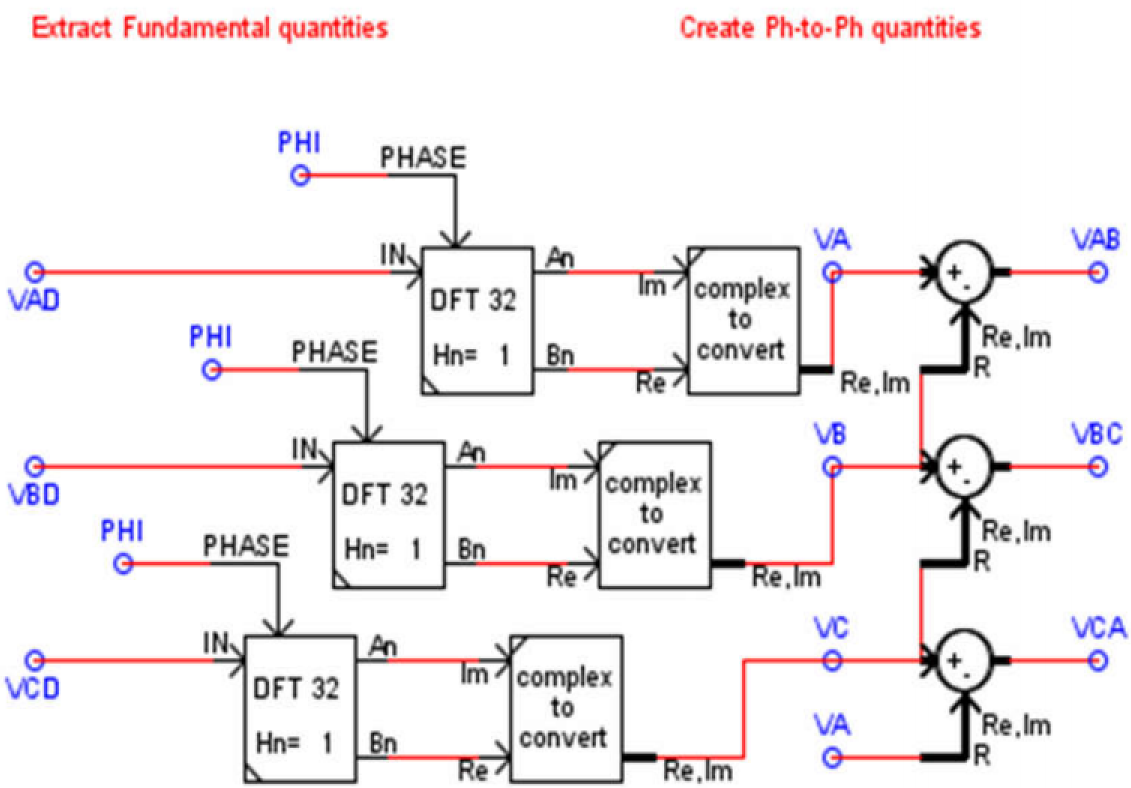
APPENDIX C

FILTER

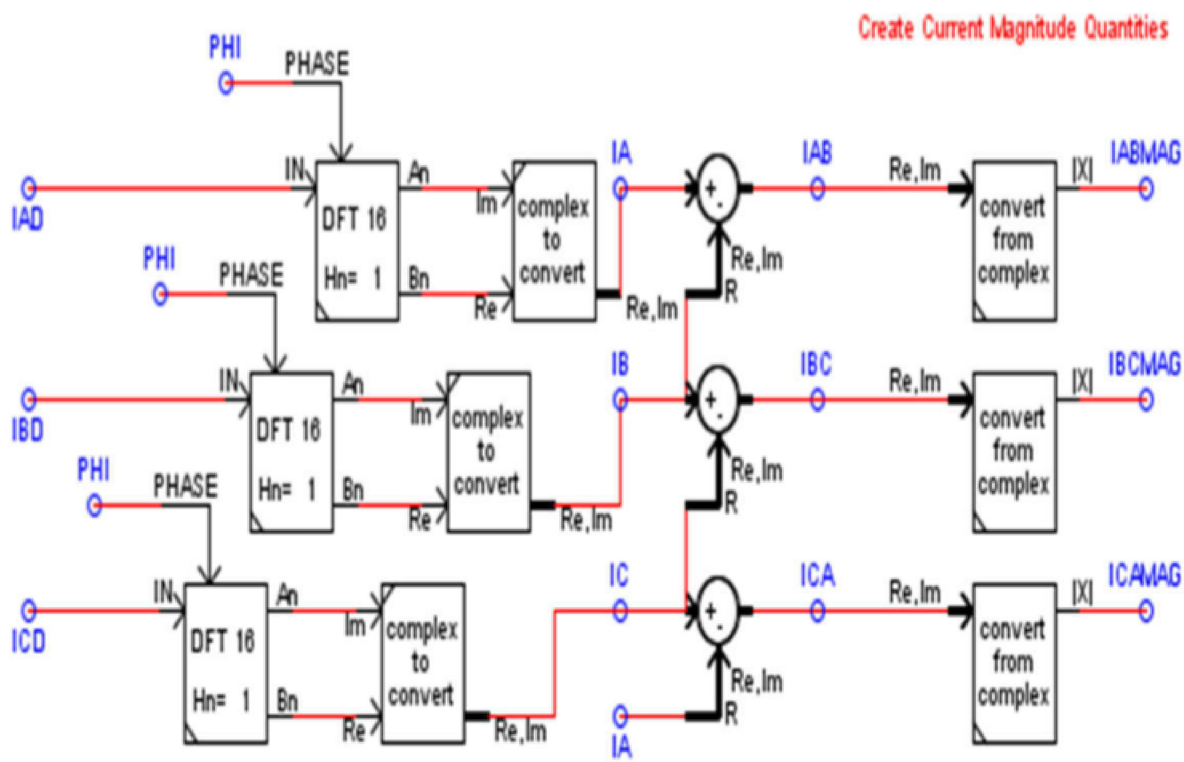
Analog Signal Sampling



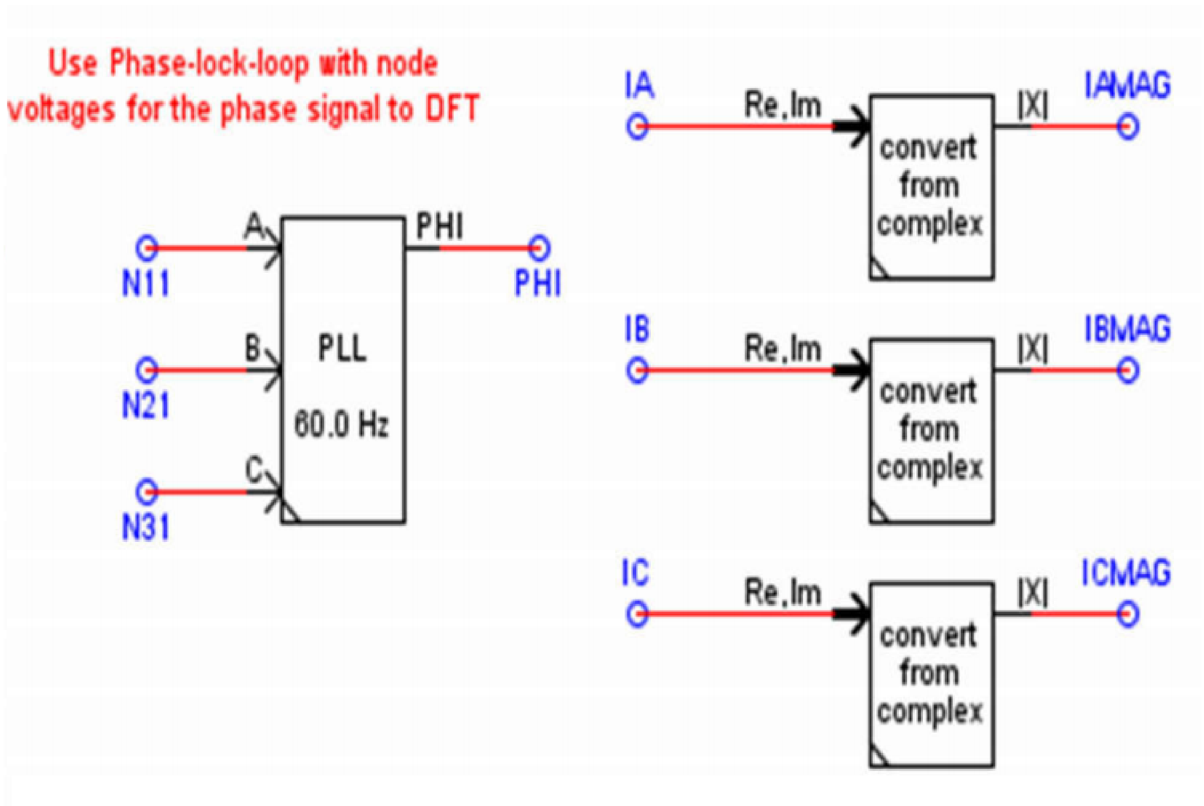
Discrete Fourier Transform of Fundamental Values



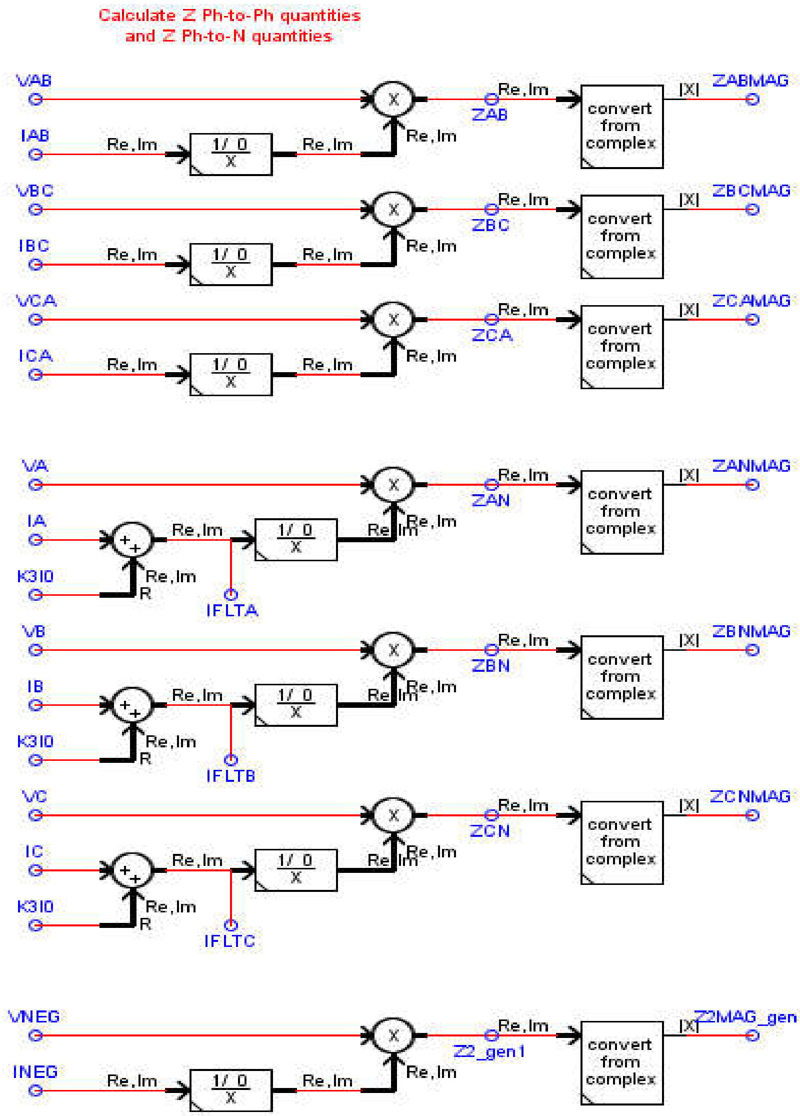
Discrete Fourier Transforms For Currents



Phase Current Magnitudes



Calculating Impedance for phase to phase and phase to neutral



Sequence Currents and Voltages