"POWER SYSTEM PROTECTION: INVESTIGATION OF SYSTEM PROTECTION SCHEMES IN THE 330KV OF NIGERIA TRANSMISSION NETWORK".

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A THESIS WRITTEN IN THE DEPARTMENT OF ELECTRICAL/ELECTRONIC ENGINEERING AND SUBMITTED TO THE SCHOOL OF POSTGRADUATE STUDIES IN PARTIAL FULFILLMENT OF THE REQUIREMENT FOR THE AWARD OF THE DEGREE OF DOCTOR OF PHILOSOPHY IN ELECTRICAL AND ELECTRONIC ENGINEERING, UNIVERSITY OF BENIN,

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2006

CERTIFICATION

We certify that this work was carried out by TSADO JACOB in the Department of Electrical/Electronic Engineering, University of Benin, Benin City, Edo State of Nigeria.

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PROF. P.A. KUALE	ENGR. S.O.ONOHAEBI
(CHIFE SUPERVISOR)	(HEAD OF DEPARTMENT)
…………………..	………………………
DATE	DATE

DEDICATION

This thesis is dedicated to God Almighty

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ABSTRACT

The protection system in the 330kV of Nigeria Transmission Network is investigated in this study. The study has reviewed the existing protection system as practiced and discovered common factors that often lead to power outages and blackouts to include; lack of co-ordination of system protection scheme control strategies and low power generation. The present status of the 330kV Transmission network is presented and new transmission lines to strengthen the existing network against system instability are proposed. The thesis also discussed the causes of system collapses, provides an overview of the existing system protection schemes and proposed wide area monitoring, protection and control scheme.

This thesis has modelled the Nigerian 330kV grid system transmission network using NEPLAN power software programme which has been used for the calculation of three-phase and single-phase to earth short-circuit fault currents at each of the substations, and apparent impedance of the network. The results obtained from these studies are used for the co-ordination of distance relays and settings of inverse definite minimum time overcurrent relays, and earthfault relays. The results also form the basis for the selection of circuit breakers from the manufacturer's tables.

Various types of relay characteristics used in transmission line protection with specific emphasis on distance protection schemes are also analyzed. An algorithm and flowchart for setting, testing and commissioning of numerical (microprocessor) distance relays have been developed. Results obtained from the tests carried out on the setting of microprocessor based on distance relays on Benin-Oshogbo transmission line are presented. Additionally, the philosophies of differential and restricted earth fault protection schemes, guidelines for proper selection of current transformers and setting of relays, testing and commissioning of differential and restricted earth fault protection schemes with practical examples are also presented. This thesis has therefore achieved the characterization of the protection schemes of the Nigerian electrical supply power industry at 330kV level and also provides for the improvement of additional protection schemes whenever there is a need to expand the network.

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LIST OF ABBREVIATIONS

SPS	System Protection Scheme
CS	Control Strategies
WAMP&C	Wide Area Monitoring Protection and Control
PMU	Phasor Measurement Unit
GPA	Global Position System
EPNES	Electrical Power Network Efficiency and Security
NEPSI	Nation's Electrical Power Supply industry
IDMT	Inverse Definite Minimum Time
CT	Current Transformer
CVT	Capacity Voltage transformer
NEPA	National Electrical Power Authority
PHCN	Power Holding Company of Nigeria
EPSI	Electrical Power Supply Industry
TC	Tripping Coil
CB	Circuit Breaker
S	Switch
ISO	Independent System Operator
IPP	Independent Power Producers
NCC	National Control Centre
SNCC	Supplementary Nation Control Centre
RLC	Related Line Constraint
SSC	System Synchronous Constraint
PBC	Power Balance Constraint
SSS	Successful System Splitting
FACTS	Flexibility AC Transmission System
LTC	Load Tap Control
AGC	Automatic Generator Control
EMS	Energy management System
PC&M	Protection, Control and Metering

CHAPTER ONE

GENERAL INTRODUCTION.

The economic well being of any nation and quality of lives of its citizenry have become dependent on reliable electricity and continuity of its supply. Therefore as a matter of paramount importance, even momentary interruption is looked upon with disfavour

Energy in the form of electricity is one of the nature's formidable and most productive energy discovered by man. Some of the inherent advantages of electricity energy include the following; it is amenable to sophisticated control, it can easily be converted to other forms of energy at typically high efficiencies, and it is inherently pollution free.

The basic objective of power system is to generate electricity in sufficient quantity, at the most suitable generating location, transmit it in bulk to load centres in a safe and efficient manner. Furthermore, it should be distributed to various customers, as and when required in a proper form, quality and at lowest possible ecological impact and economic price.

1.1 Background to the Study

The flow of electrical energy from generating stations via transmission network and over to the borders of consumers demand on accurate and up-to date knowledge of the operational status of the transmission network. Corporate restructuring within EPSI is going on in Nigeria. There will be increasing interest to utilize the transmission network in the most efficient and economical manner and thereby reducing stability margins as deregulation and privatisation take effect. System protection schemes using classical relay technique are not sufficient in the future where the operational conditions in the transmission network will come closer to the limits of safe operation. The increased level of system constraints require evaluation of the existing criteria for safe network operation and optimal planning in the power system.

1.2 Motivation and Objectives of the Research.

Many researchers had focused on the possible ways of improving power system stability and security in Nigeria. Little appears to be done on the protection system and control, which are the insurances behind power system operation. Without practical experience in the field, it is difficult to keep up-to-date knowledge particularly with respect to new relay hardware.

Power system protection study is one subject area that practicing engineers and graduate students need to understand more thoroughly. The nation's electrical power supply industry (EPSI) therefore needs to be investigated in all necessary ramifications and in this way it can be more easily operated, hence this research work therefore addresses the technical problems associated with the practice of power system protection and control at the 330kV transmission network of Nigeria with the following aims and objectives: -

a) To acquire an in-dept understanding with practical experience of power system protection and control as a subject.
b) In-dept study of the Nigeria transmission system to identify its weaknesses and deficiencies, hence make suggestions for improvement.
c) Establish the present status of protection schemes in use and their performances in relation to system disturbances.
d) Investigate the causes of system failures, behaviours of protection schemes during disturbance and study the means available to enhance better system management and operation.
e) Review new power system protection and control schemes being used in large networks and the possibility of adopting some into the Nigeria system to improve on the existing situation.
f) To develop a computer model of the 330kV transmission network of Nigeria for easy calculation of short circuit fault currents required for the setting of protective relays at each substation.

1.3 Methodology

This study, in terms of the objectives, can be described as an applied research involving fieldwork. It is necessary therefore to review the current systems and processes in order to identify improvement opportunities. The starting point for this improvement process is the awareness of the current situation with regard to the reliability of the protection system as practiced and the causes of protection system failures.

The summary of how the investigation was carried out to address the problem statement and hence achieve the objectives of the research is as follows:

a. Seven months attachment programme as a research student to protection, control & metering (PC&M) department, Benin transmission substation. Sapele road.
b. Six months of another attachment programme as a research student to Jiyoda Engineering LTD, a protection and control-consulting firm, Lagos.

The whole transmission network is investigated with respect to its protection and its future expansion. Accordingly necessary literature review and thorough study of the 330kV transmission network protection schemes as it is on ground were embarked upon. The approach followed included components and transducers used for protection in all its ramifications.

A most important methodology in protection work is the study of faults and fault analysis of a power system. Hence, simulation studies of three phase, single phase to earth short-circuit fault current, and distance relay evaluation have been carried out on the Nigeria grid system using NEPLAN software. A pre-requisite for this, is, data collection for; the setting of every relay and choice of current transformers requires the knowledge of fault currents. All these were investigated in the research work and presented.

The data used for the network short circuit study and distance relay evaluation were collected during the period of the attachments. Some of the data used were collected directly from site equipment, meeting with the utility staff, consultant and existing site records. The following gives the list of the equipment and data collected.

(a) Overhead Line Parameter of the Entire Network.

(i) Length of each of transmission line between substations (ii) MVA rating

(iii) Positive and zero sequence impedance (iv) Number of circuits.

a) Transformer Parameters (at each substation)

(i) Vector grouping (ii) MVA rating (iii) Impedances values (iv) Winding configuration.

b) Generator-Transformer Parameters (at each Generation Station)

(i) MVA rating (ii) Transformation ratio (iii) Impedances values

c)Generator Parameters (at each generation station)

(i) MVA rating (ii) Impedances values.

1.4 Outline of the Thesis

The rest of thesis is organized as follows: chapter two covers the literature review related to power system protection to include the fundamentals, basic objectives and principle of power system protection and control.

Chapter three gives an overview of the present status of the Nigeria power system. It presents the existing transmission network system and proposed future grid expansion indicating the proposed transmission lines and some of the planned generating stations.

Chapter four investigates the causes and cures to power system collapse with special reference to Nigeria power system. The chapter contains the proposed wide–area monitoring and protection & control (WAMP&C). This scheme is proposed to improve electric power network efficiency and security (EPNES) of the nation's electrical power supply industry (NEPSI).

Chapter five presents' short circuit studies on a model transmission network of 330kV,using NEPLAN power software programme. The chapter gives details of some the data collected on the transmission network, which was used for the studies.

Transmission line protection schemes were examined in chapter six. Various types of relay characteristics used in transmission line protection with specific emphasis on distance protection schemes are presented. The chapter also presents state of the art of the transmission line protection in Nigeria, an algorithm and flowchart for setting, testing and commissioning of numerical (microprocessor) distance relays.

Chapter seven presents the philosophy of power transformers differential and restricted earthfault protection schemes. Guideline for selection of current transformers, constraints associated with transformer protection schemes particularly differential and restricted earthfault protection schemes and options to ensure correct design and implementation of the schemes are also presented in chapter seven.

The conclusions and recommendations are presented in chapter eight. References and Appendices are the last part of this thesis.

CHAPTER TWO

CONCEPTS OF POWER SYSTEM PROTECTION

2.0 Introduction

Power system protection and control play a significant part in reliable electric power supply, progress in design and development in these fields necessarily had to keep pace with advances in the design of primary plant, such as generators, transformer, switch gear, over head lines and underground cables. Indeed, progress in the fields of protection and control is a vital pre-requisite for the efficient operation and continuing development of electricity supply system as a whole.

However, the issue has become even more important in a deregulation system. No actor wants to be temporarily removed from the system due to incorrect protection behaviours as this may lead to (unnecessary) loss of income, penalty fees and advantages for competitors. Construction of generating plants, transmission and distribution of electrical energy system is a costly business. At different stages of energy processing i.e. generation, transmission, distribution and utilization (Figure2.1) protection of personnel and equipment is of prime importance.

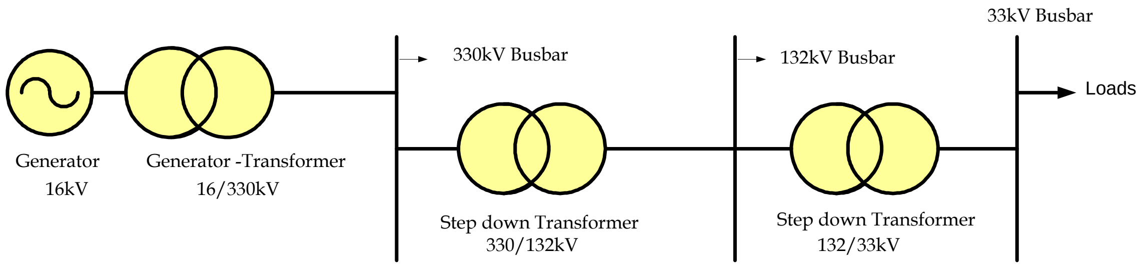


Figure 2.1: Typical power system arrangement.

2.1 The Fundamental Objective of System Protection

The fundamental objective of system protection is to maintain a very high level of continuity of electrical supply, and to detect fault occurrence and isolate the faulted equipment and section, so that damage to the faulted equipment is limited, disruption of supplies to adjacent unfaulted equipment is minimized and hazard to personnel prevented. However, it is impossible as well as impractical to avoid power outage, because of consequences of natural events such as wind, earthquake that cause faults and faults caused by equipment failures or misoperations due to human error. Hence, protection is effectively an insurance policy and investment against damage from system faults.

It should be noted however that the term “protection” does not indicate or imply that the protection equipment can prevent faults or failures of equipment. It cannot anticipate faults either. The protective relays act only after an abnormal or intolerable condition has occurred with sufficient indication to permit their operation thus “protection” does not mean “prevention” but rather minimizing the duration of the trouble and limiting the damage, and indeed isolating faulty section and equipment of a power system.

When a protection system is designed a compromise must be made among the following basic facets:

1. Reliability: assurance that the protection will perform correctly
2. Selectivity: maximum continuity of service with minimum system disconnection.
3. Speed of operation: minimum fault duration and consequent equipment damage
4. Simplicity: minimum protective equipment and associated circuitry to achieve the protection objectives
5. Economics: maximum protection at minimum total cost
6. Personnel: Protection system performance reflects the “Personality” of the protection engineers.

Correct relay performance is of great importance in any power system throughout the world. Correct performance indicates that:

i. At least one of the primary relays operated correctly.
ii. The faulted area is properly isolated in the time expected.

The generic view arrangement of power system protection is depicted graphically in figure2.2.

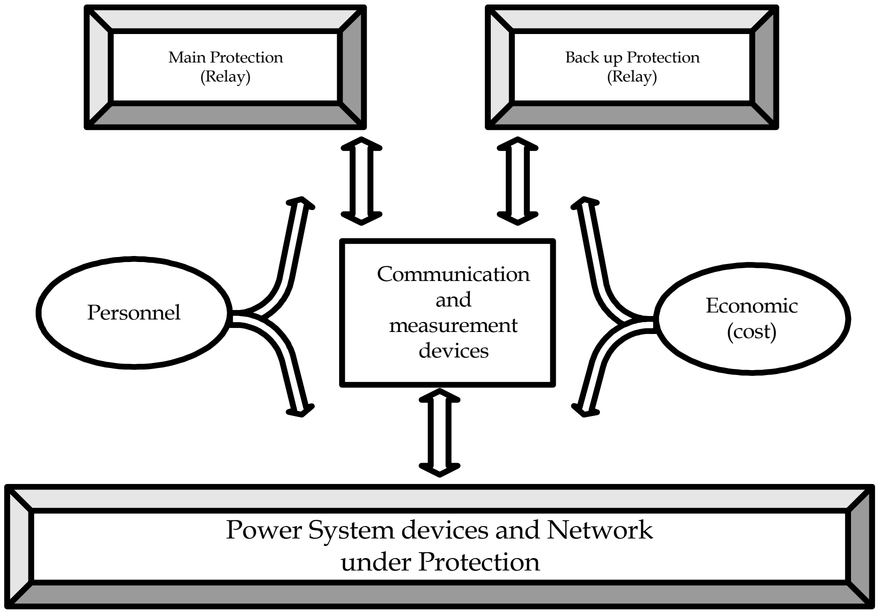


Figure 2.2 Block diagram of the generic view of power system protection

The arrangement shows a close loop system, this implies that for efficient and reliable performance of protection each of units as shown need proper co-ordination.

2.2 Basic Definitions Used in System Protection.

Protection is the science, skill, and art of applying and setting protective relays and/or fuses to provide maximum sensitivity to fault and undesirable condition

Protective gear is the apparatus, including protective relays, transformers and ancillary equipment, for use in a protective system.

Protective relay is a relay designed to initiate disconnection of a part of an electrical installation or to operate a warning signal in the case of a fault or other abnormal condition in the installation. A protective relay may include more than one unit electrical relay and accessories.

Protective scheme is the co-ordinated arrangements for the protection of one or more elements of a power system; it may comprise several protective systems.

Protective system is the combination of protective gear designed to secure, under predetermined conditions usually abnormal, the disconnection of an element of a power system, or to give an alarm signal, or both.

Primary relays are relays within a given protection Zone that should operate for prescribed abnormalities within that zone.

Backup relays are relays located adjacent to primary relays which are set to operate when the primary relays fail to operate within the given *Primary* relays' zone of protection.

2.3 Basic Principle of Power System Protection.

The figure 2.3 shows the basic illustration for fuse arrangement.

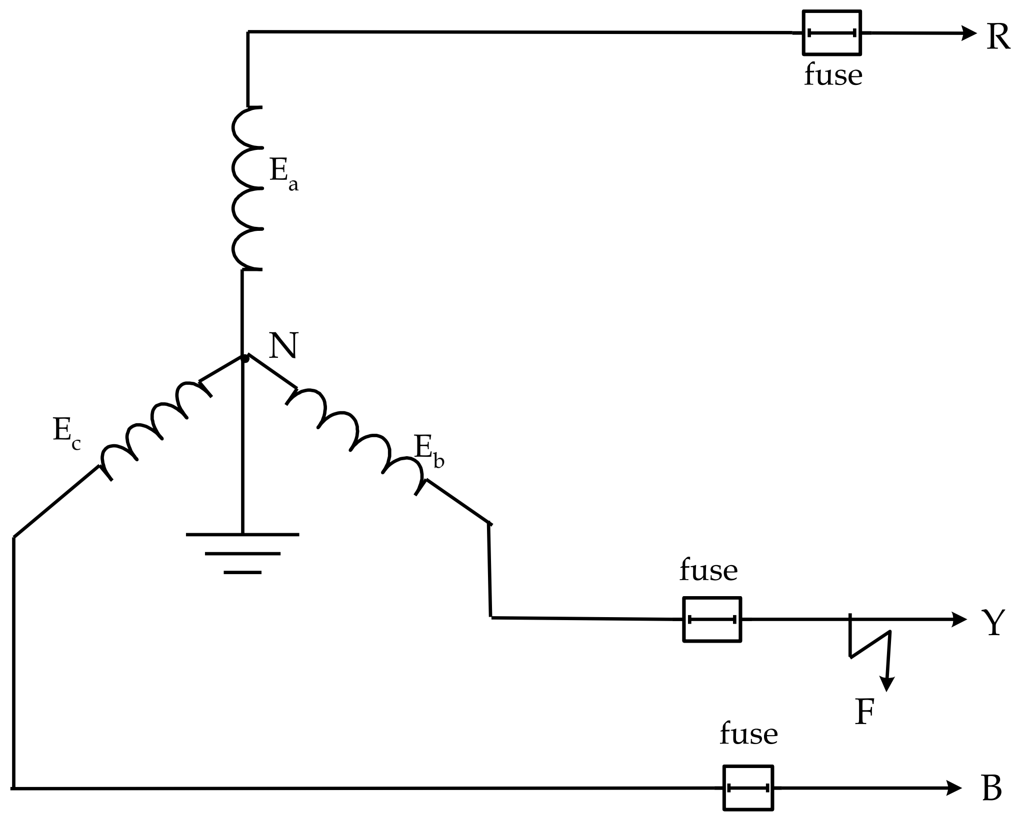


Figure 2.3 Fuse protection scheme for a three phase generator

For an earthfault F on the yellow phase, the current through the yellow phase will increase. The fuse wire thereby detects the fault current, when the current through the fuse exceeds it rated valve, the wire melts thereby opening the circuit to the load.

In the case of the relay/current transformer protection, figure 2.4 shows the basic arrangement for a single-phase feeder, which can easily be extended to cover three-phase protection arrangement.

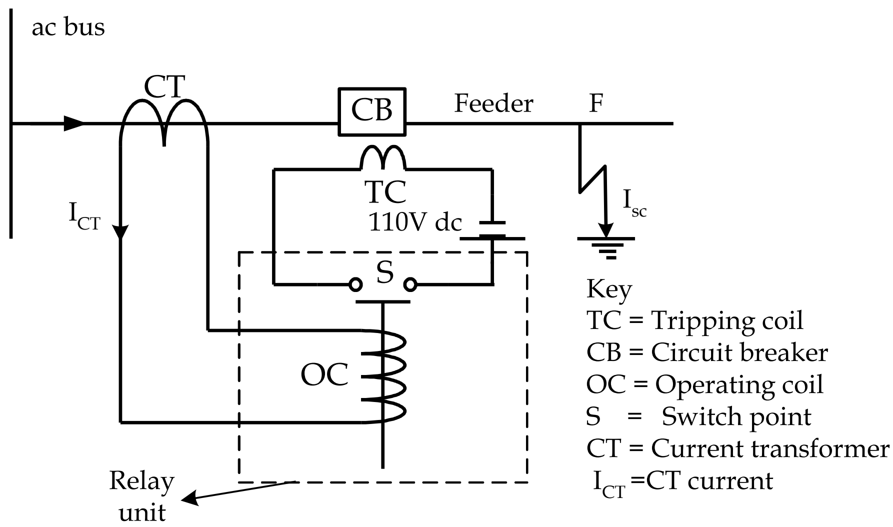


Figure 2.4 Typical protection system for a single phase feeder.

The relay / CT connection remains in a balanced state as normal current flows. When there is a fault at F the relay/CT arrangement detects the fault current I_{sc}. This increases the CT current, hence that of the relay. That is; the CT current increases from I_n to I_{sc} thereby increasing the corresponding flux density from B_n to B_{sc} and so we have the relation.

$$\frac{1}{2}\left(B_{sc}^2 A \big/ \mu_o \right) \geq\geq \frac{1}{2}\left(B_n^2 A \big/ \mu_o \right) \text{......................} (2.1)$$

and

$$F_{sc} \geq\geq F_n \text{...} (2.2)$$

where,

$$F_n = \frac{1}{2}\left(B_n^2 A \big/ \mu_o \right) \text{.......................................} (2.3)$$

and

$$F_{sc} = \frac{1}{2}\left(B_{sc}^2 A \big/ \mu_o \right) \text{.....................................} (2.4)$$

so that,

F_n & F_{sc} are the forces due to the changes in the balancing forces of the relay.

B_n = normal flux density in the relay (wb/m^2)

B_{sc} = flux density due to the short circuit fault current.

μ_o = Permeability of the free space,

A_n = cross- section of the relay iron (m^2)

The closing of the switch thereby energizes the tripping coil of the circuit breaker (CB) through the battery. The CB now opens the circuit, isolating the faulty part from healthy part of the system.

Figure 2.5 shows a decision flow chart that explains operation of a general protection process that might be implemented in a computer control system. Usually the system is in the normal state, and the protective device is set to assume that the normal state prevails at start up. As time is incremented, the protective device checks the observed system variable, represented by X in the flow chart, to determine if any variable exceeds its threshold value. If not, time is incremented to observe the next measured value. If the threshold is exceeded, the time threshold is checked and tripping action is withheld until the time threshold expires, when both the quantity and time thresholds are exceeded, then the circuit is tripped.

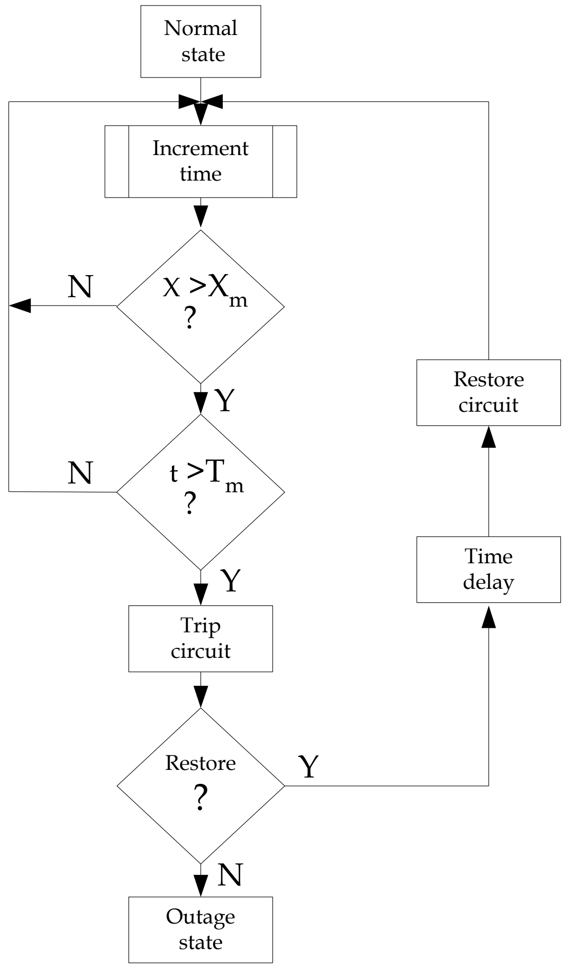


Figure 2.5 Flow chart of protective device functional diagram

This type of logic is designed to prevent tripping for short, temporary disturbances that might be observed. Such disturbances are often a part of the normal operating condition of the network, and tripping should not be initiated for such events. In some protective systems, automatic restoration is begun following a preset time delay. This concept has proven valuable since most power system disturbances are temporary [1].

2.4 Principles of relay application

The power system is divided into protection zones defined by the equipment and the available circuit breakers. Six categories of protection zones are possible in each power system: (i) generators and generator-transformer units, (ii) transformers, (iii) buses, (iv) Lines (transmission, sub transmission, distribution), (v) utilization equipment (motors, static loads, etc.), and (vi) capacitor and / or reactor banks (when separately protected).

Most of these zones are illustrated in Figure 2.6. Although the fundamentals of protection are quite similar, each of these six categories has protective relays specifically designed for the primary protection, which are based on the characteristics of the equipment being protected. The protection of each zone normally includes relays that can provide backup for the relays protecting the adjacent equipment.

The protection in each zone should overlap that in the adjacent zone; otherwise, a primary protection void would occur between the protection zones. This overlap is accomplished by the location of the current transformers, the key sources of power system information for the relays. This is shown in Fig. 2.6, and more specifically in Fig. 2.7. Faults between the two current transformers (Fig. 2.7) result in both zone X and zone Y relays operating and both tripping the associated circuit breaker.

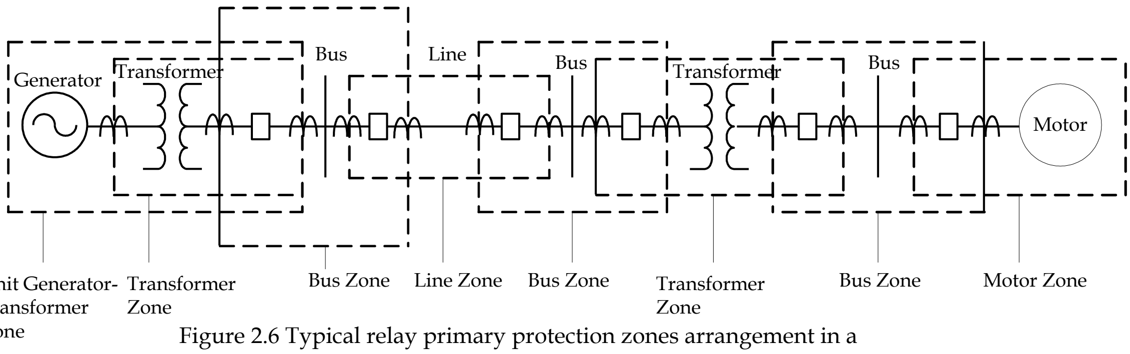


Figure 2.6 Typical relay primary protection zones arrangement in a power system

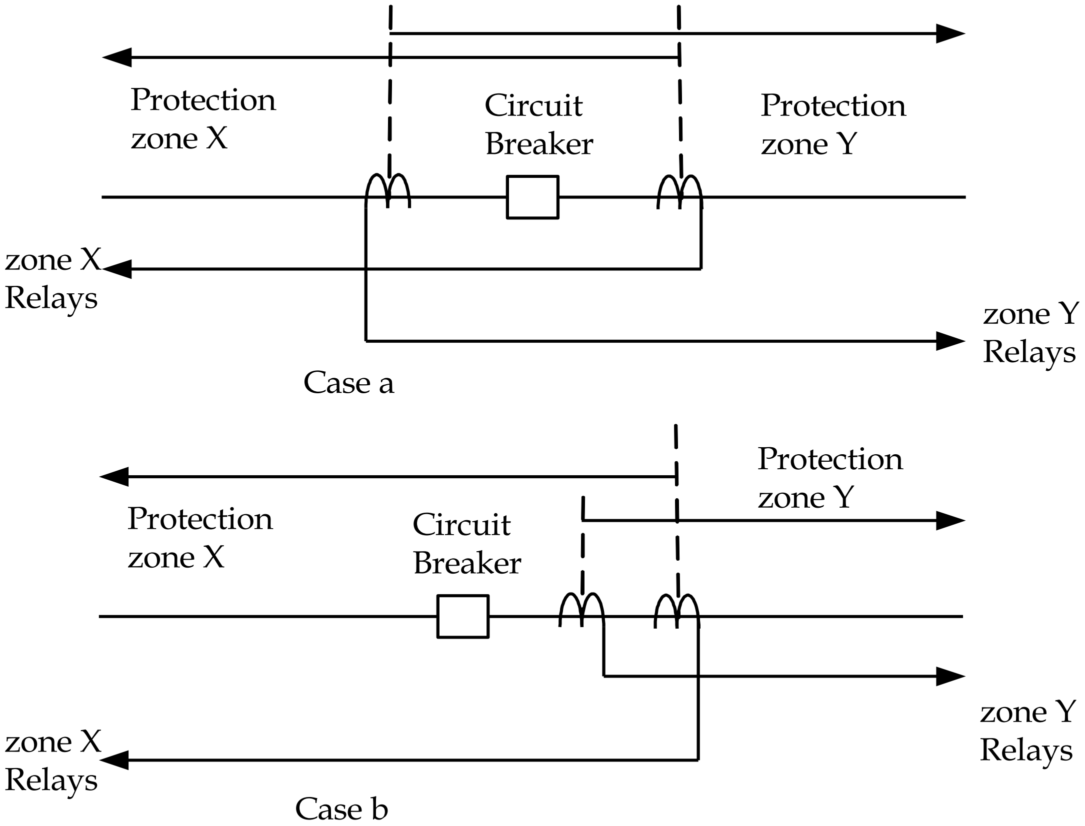


Figure 2.7 Overlapping protection zones with their associated current transformer

For case (a) this fault probably involves the circuit breaker itself and so may not be cleared until the remote breakers at either end are opened. For case (b) zone Y relays alone opening the circuit breaker would clear faults between the two current transformers from the left fault source. The relays at the remote right source must also be opened for these faults. The operation of the zone X relays are not required but cannot be prevented. Fortunately, the area of exposure is quite small and the possibility of faults low. Without this overlap, primary protection for the area between the current transformers would not exist, so this overlap is standard practice in all applications.

2.5 **Required Information for Protection Application**

One of the most difficult aspects of applying protection is often an accurate statement of the protection requirements or problem. This is valuable as an aid to a practical efficient solution, and is particularly important when assistance is desired from others who might be involved or might assist in the solution, such as consultants, manufacturers, and other engineers. The following are some of the basic information required to assist protection engineers with their protection practice.

2.5.1 *System Configuration*

This is the physical arrangement of the network system by a single-line or three-line diagram showing the location of the circuit breakers, current and voltage transformers, generators, buses, transformer and taps on lines. System grounding is necessary when considering ground-fault protection.

2.5.2 *Impedance, MVA Rating and Connection of the Power Equipment, System Frequency, System Voltage, and System Phase Sequence*

Most of this information is usually included on the single-line diagram, but often omitted are the connections and grounding of the power transformer banks, and the circuit impedances. Phase sequence is necessary when a three-line connection diagram is required.

2.5.3 *Existing Protection and Problems*

If it is a new installation, this does not apply, but should be indicated. Otherwise, information about the existing protection such as diagram, equipment parameters and any problems permitting its up dating or integration with the changes desired should be readily available.

2.5.4 *Operating Procedures and Practices*

Additions or changes should conform to the existing practices, procedures, and desires. Where these affect the protection, they should be indicated clearly.

2.5.5 *Importance of the System Equipment Being Protected*

This is often apparent from the system voltage level and size. For example, differential and restricted earthfault protections are usually used to protect high rating transformers and lower rating ones by over current protection. However, this should be clarified as to the desires of the protection engineers or the requirements of the system. In general, the more important the equipment to be protected is to the power system and its ability to maintain service, the more important it becomes to provide full and adequate high-speed protection for it.

2.5.6 *System Fault Study*

A fault study is important for most protection applications. For phase fault protection a three-phase fault study is required, while for ground-fault protection a single-line-to-ground fault study is required. These latter should include the zero-sequence voltages and the negative-sequence currents and voltages, which can be useful where directional sensing of ground faults is involved.

On lines, information regarding a fault on the line side at an open breaker (known as a "line-end" fault) is important in many cases. The currents recorded should be those, which will flow through the relays or fuses rather than the total fault current.

The fault study should indicate the units (i.e., in volts or amperes at a specified voltage base, or in per unit with the base clearly specified. Experience has shown that quite often the base of the quantities is not shown or clearly indicated.

2.5.7 *Maximum Loads and System Swing Limits*

The maximum load that will be permitted to pass through the equipment during short time or emergency operation for which the protection must not operate should be specified. Where known, the maximum system swing from which the power system can recover after a transient disturbance is important in some applications and should be specified.

2.5.8 *Future Expansion*

The system growth or changes that are likely to occur within a reasonable time and are known or planned should be indicated.

Not all of the items listed above necessarily apply to a specific problem or system requirement, but this checklist should assist in providing a better understanding of the protection problems and requirements. Usually, the fault study, together with related information, will provide information on the measurable quantities to which the protective relays can respond. Where this is not apparent, the first priority for any application is to search for the signal that can be utilized to distinguish between tolerable and intolerable conditions.

CHAPTER THREE

OVERVIEW OF THE PRESENT STATUS OF THE NIGERIA POWER SYSTEM

3.0 Introduction

Nigeria's electricity sector is mainly dominated by (NEPA) which was established in 1972 as a vertically integrated utility responsible for generation, transmission, distribution and supply of electricity. At its establishment NEPA was a complete monopolistic power industry to which there is often no-economically viable alternative, but the 1998 NEPA Amendment Act and the 1998 Electricity Amendment Act, which was recently passed by the national assembly and signed into law on 11- 03-2005 by the Federal Government of Nigeria. The new Power Holding Company of Nigeria (PHCN) is now in place to facilitate the process of privatization, deregulation and unbundling of NEPA.

To initiate the process, NEPA is divided into private generating companies, which could be called GENCOS; Transmission Company called TRANSYSCO and distribution companies called DISCOS (figure 3.1) in line with the ongoing privatization and deregulation to improve the reliability of electricity supply.

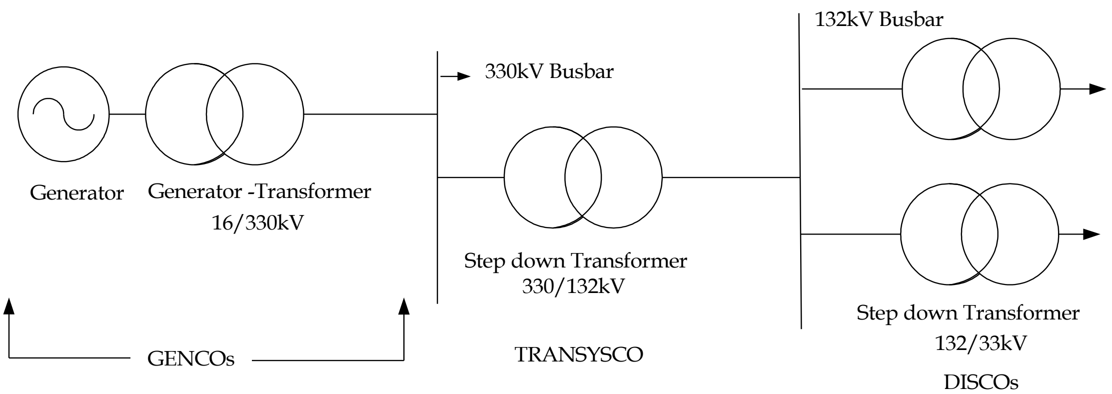


Figure 3.1. The electrical power supply structure

There shall be a regulatory body, which will be equivalent to an independent system operator (ISO). This new organization structure is mandatory, thereby laying the foundation for the Nigerian Electric Power Supply Industry (EPSI) in the direction of becoming a commercial enterprise.

However, in practice the sector is still to a large extent closed, the exception to this being the active encouragement of the involvement of Independent Power Producers (IPP). Already a number of proposals for IPP are on the way, while some are almost at the stage of completion. For example, Nigeria Agip Oil Company, Philips Oil Company and NNPC have 20%, 20%, and 60% stake in the independent power project located at Kwale in Delta state, Lagos state IPP has added 90MW into National Grid system and Akwa Ibom state IPP has in progress the construction of the gas generation station of 450MW.

However, the situations that lead to these changes and suggestions on how this new development can effectively work are discussed in [2-4]. Nigeria's existing electricity transmission system together with NEPA's principal generating stations are shown in figure 3.2

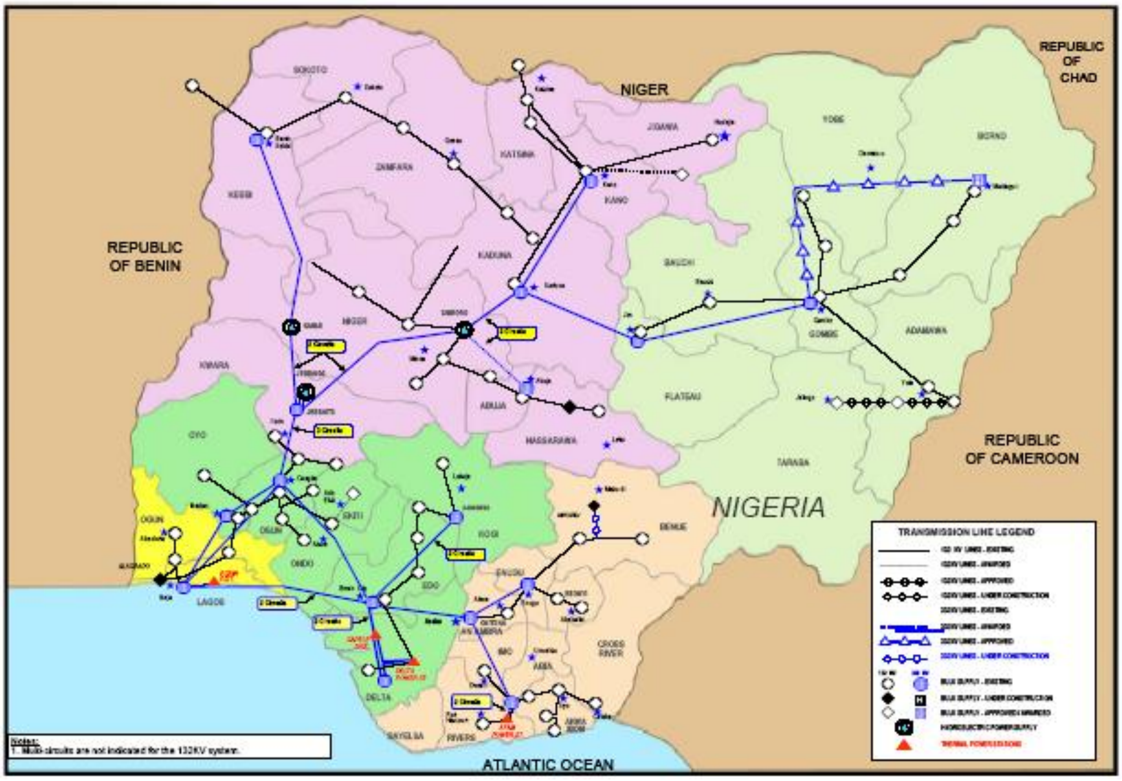


Figure 3.2 Schematic of Nigeria's Electricity system.

3. 1 Generation and Supply Condition

NEPA's generating plant sum to some 6200MW of installed capacity, of which 1920MW is hydro and 4280MW thermal- mainly gas-fired. The thermal stations are mainly in the southern part of the country located at Afam, Ijora, Delta, Egbin and Sapele. The hydroelectric power stations which are in the country's middle belt are located at Kainji, Jebba and Shiroro. They are highly dependent on the inflow of water into their reservoirs for the generation of electricity. Hydropower generation is normally more environmentally friendlier than thermal power stations. Nigeria has abundant undeveloped hydropower resources. Development of Zungeru, Mambilla, Makurdi, Ikom, Lokoja, Katsina-Ala projects have been delayed for financial reasons. There are several sites for mini hydro powers stations to enhance the spread of generating stations. For example a study has been carried out at Ikpoba River in Edo state for the development of micro-hydro Electric power generation [5] and Ogbonmwan River in Evboro village two, Edo state [6]. It is worth mentioning that in comparison with the advanced countries the hydro generating potential of Nigeria has been under utilized. If proper investigations are carried out, distributed wind-generating and solar power stations could be sited in some parts of the country to reduce shortage of power generation.

NEPA's history is one of being unable to supply the nation's demand for electricity. In August 2004, only 4460MW of the present 6470MW total installed capacity was then available and, of this, only some 3000MW of the demand was satisfied on a daily basis due to the condition of NEPA's generating plants. This suppressed demand is estimated to be between 5000MW and 12 000MW. As a practical indication of the latent demand for electricity, it was reported that the 330kV overhead lines from Shiroro to Abuja that was commissioned in early 2004 to reinforce supplies to Abuja was fully loaded within weeks of the line being energized. Figure 3.3 illustrates the historical maximum power demand and generation of electricity on the NEPA system.

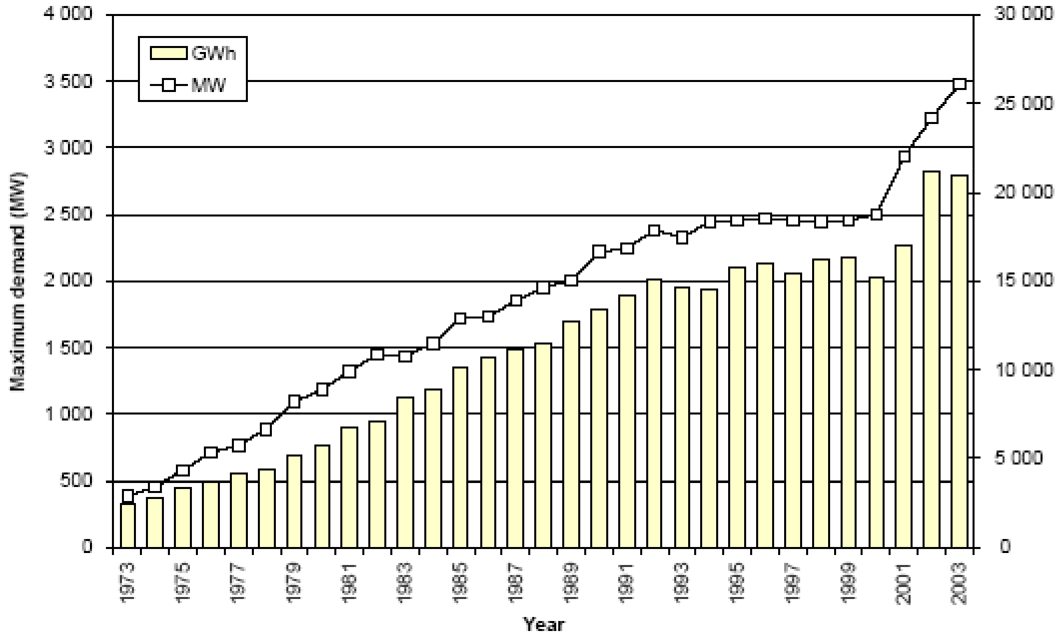


Figure 3.3: Historical growth in NEPA Electricity generation and maximum demand.

Table 3.1 summarizes the output from NEPA's respective power plants over the past five years.

Table 3.1 Energy Generated by NEPA Stations, GWh [68].

	1999	2000	2001	2002	2003
Kainji	2377	1995	1587	2104	2643
Jebba	2907	2514	1931	2087	2571
Shiroro	2435	2274	2675	2199	2539
Sub-total	7719	6783	6193	6390	7753
Egbin	5923	5603	6941	6877	6810
Sapele	1271	1339	1329	1167	905
Afam	5	67	340	1734	2091
Delta	1473	1434	2142	3429	3452
Ijora	0	0	7	1594	0
Sub-total	8672	8443	10759	14801	13258
Total	16391	15226	16952	21191	21011

It can be seen that, on average, the annual energy generated by the hydroelectric plant is about 8900 GWh (1920 MW of installed capacity at 53 per cent capacity factor) while the thermal plant provides the remaining system energy requirement.

Tables 3.2 and 3.3 summarize the status of NEPA's hydroelectric and thermal plant portfolio.

Table 3.2 Status of NEPA Hydroelectric generating Plant [68].

Name	Type	Co. DT	Unit No.	Installed	Operable (MW)	Available (MW)	Status	Comments
Kainji	Hydro	1978	1G5	120.0	-	-	Unavailable	Rotor problems with 1G5 being investigated
Kainji	Hydro	1978	1G6	120.0	120.0	120.0	Available	
Kainji	Hydro	1968	1G7	80.0	80.0	80.0	Available	Sets 5&6 are fixed blade and output is limited at low water levels
Kainji	Hydro	1968	1G8	80.0	80.0	80.0	Available	
Kainji	Hydro	1968	1G9	80.0	-	-	Unavailable	Stator earth fault on 1GB
Kainji	Hydro	1968	1G10	80.0	80.0	80.0	Available	
Kainji	Hydro	1976	1G11	100.00	100.00	100.0	Available	
Kainji	Hydro	1976	1G12	100.00	90.00	90.0	90MW available	Water leakage around seals
Jebba	Hydro	1986	2G1	93.3	93.3	93.3	Available	Significant water leakage into Jebba power station being investigated
Jebba	Hydro	1986	2G2	93.3	93.3	93.3	Available	
Jebba	Hydro	1986	2G3	93.3	93.3	93.3	Available	
Jebba	Hydro	1986	2G4	93.3	93.3	93.3	Available	
Jebba	Hydro	1986	2G5	93.3	93.3	93.3	Available	
Jebba	Hydro	1986	2G6	93.3	93.3	93.3	Available	
Shiroro	Hydro	1989	3G1	150.0	150.0	150.0	Available	All units available. Low water level in dry season restricts 24 hour running.
Shiroro	Hydro	1990	3G2	150.0	150.0	150.0	Available	
Shiroro	Hydro	1990	3G3	150.0	150.0	150.0	Available	
Shiroro	Hydro	1990	3G4	150.0	150.0	150.0	Available	
Sub-total				**1,920.0**	**1,710.0**	**1,710.0**		

Table 3.3 Status of NEPA Thermal generating Plant

Name	Type	Comm. Date	Unit No.	Installed Capacity (MW)	Operable (MW)	Available (MW)	Status	Comments
Sapele	Steam	1978	ST1	120.0	120.0	120.0	Available	Discussion currently with AES on ROT
Sapele	Steam	1978	ST2	120.0	-	-	Unavailable	
Sapele	Steam	1978	ST3	120.0	-	-	Unavailable	
Sapele	Steam	1978	ST4	120.0	-	-	Unavailable	
Sapele	Steam	1978	ST5	120.0	-	-	Unavailable	
Sapele	Steam	1978	ST6	120.0	120.0	-	Under repair	
Egbin	Steam	1985	ST1	220.0	110.0	110.0	Available	All units' dual fuel with oil firing capable. Units 1 &6 currently restricted to 50% output
Egbin	Steam	1985	ST2	220.0	220.0	220.0	Available	
Egbin	Steam	1986	ST3	220.0	220.0	220.0	Available	
Egbin	Steam	1986	ST4	220.0	220.0	220.0	Available	
Egbin	Steam	1987	ST5	220.0	220.0	220.0	Available	
Egbin	Steam	1987	ST6	220.0	110.0	110.0	Available	
Sapele	GT	1981	GT 1	75.0	-	-	Unavailable	Discussion currently with AES on ROT
Sapele	GT	1981	GT 2	75.0	-	-	Unavailable	
Sapele	GT	1981	GT 3	75.0	-	-	Unavailable	
Sapele	GT	1981	GT 4	75.0	-	-	Under repair	
Afam 1	GT	1959	GT 1	10.3	-	-	Unavailable	Afam 1 station no longer in use. Station will be scrapped after SPDC commissions the Afam 6 power station.
Afam 1	GT	1965	GT 3	17.5	-	-	Unavailable	
Afam 1	GT	1965	GT 4	17.5	-	-	Unavailable	
Afam 2	GT	1976	GT 5	23.9	-	-	Unavailable	Only GT6 serviceable station will be scrapped after SPDC commissions the Afam 6 power station
Afam 2	GT	1976	GT 6	23.9	23.9	23.9	Available	
Afam 2	GT	1976	GT 7	23.9	-	-	Unavailable	
Afam 2	GT	1976	GT 8	27.5	-	-	Unavailable	15 MW is available from the station station will be scrapped after SPDC commissions the Afam 6 power station.
Afam 3	GT	1978	GT 9	27.5	-	-	Unavailable	
Afam 3	GT	1978	GT10	27.5	-	-	Unavailable	
Afam 3	GT	1978	GT11	27.5	-	-	Unavailable	
Afam 3	GT	1978	GT12	75.0	-	-	Unavailable	Station will be scrapped after SPDC commission the Afam 6 power station.
Afam 4	GT	1982	GT13	75.0	-	-	Unavailable	
Afam 4	GT	1982	GT14	75.0	-	-	Unavailable	
Afam 4	GT	1982	GT15	75.0	-	-	Unavailable	Recent repair
Afam 4	GT	1982	GT16	75.0	-	-	Unavailable	NEPA repair of blade failure being carried out.
Afam 4	GT	1982	GT17	75.0	70.0	70.0	70 MW available	
Afam 4	GT	1982	GT18	75.0	-	-	Unavailable	
Afam 5	GT	2001	GT19	138.0	138.0	-	Under repair	Currently under overhaul by Siemens
Afam 5	GT	2001	GT20	138.0	138.0	138.0	Available	
Delta 2	GT	2003	GT 3	25.0	25.0	25.0	Available	Station recently rehabilitated by Marubeni/Hitachi by replacing existing units
Delta 2	GT	2003	GT 4	25.0	25.0	25.0	Available	
Delta 2	GT	2003	GT 5	25.0	25.0	-	Under repair	
Delta 2	GT	2004	GT 6	25.0	25.0	25.0	Available	
Delta 2	GT	2004	GT 7	25.0	25.0	25.0	Available	
Delta 2	GT	2004	GT 8	25.0	25.0	25.0	Available	
Delta 3	GT	2004	GT 9	25.0	-	-	Imminent	Existing units being replaced by new 25 MW Marubeni/Hitachi units
Delta 3	GT	2004	GT10	25.0	-	-	Imminent	
Delta 3	GT	2004	GT11	25.0	-	-	Imminent	
Delta 3	GT	2004	GT12	25.0	-	-	Imminent	
Delta 3	GT	2004	GT13	25.0	-	-	Imminent	
Delta 3	GT	2004	GT14	25.0	-	-	Imminent	
Delta 4	GT	1989	GT15	100.0	100.0	100.0	Available	
Delta 4	GT	1990	GT16	100.0	100.0	100.0	Available	
Delta 4	GT	1990	GT17	100.0	100.0	100.0	Available	
Delta 4	GT	1990	GT18	100.0	100.0	100.0	Available	
Delta 4	GT	1990	GT19	100.0	100.0	-	Under repair	GT19 being repaired by approved GE agent
Delta 4	GT	1990	GT20	100.0	100.0	-	Under repair	GT20 being repaired by approved GE agent
Lijora	GT	1978	GT4	20.0	-	-	Unavailable	Unit fired on distillate fuel
Lijora	GT	1978	GT5	20.0	20.0	20.0	Available	
Lijora	GT	1978	GT6	20.0	-	-	Unavailable	

In these Tables [68], where units are being maintained and hope to be returned to service in the near future, the plant status is referred to as available.

3.1.1 Other Supply Arrangements and Future Generation.

In addition to NEPA's own generating plants, there is currently only one IPP in operation in Nigeria- Ebute Power Barge – 9 x 30MW Open Cycle Gas Turbine (OCGT) plant located near Lagos. This was originally developed by Enron, but completed by AES in October 2002. The Ebute power plant is adjacent to NEPA's Egbin power station plot and is supplied with gas from the same pipeline that supplies the Egbin power station.

As part of the Government's reform programme, a new management partnership has been introduced: the Private Public Partnership (PPP) sector. The PPP is aimed at allocating the risks and functions of an infrastructure project, such as a power station, between the Government and the private sector in such a way so as to minimize risk for the private sector and thereby encourage investment. The PPP models currently being explored under the PPP for application to the power sector include Build-Own-Operate (BOO), Rehabilitate -Operate-Transfer (ROT) and Lease-Own-Transfer (LOT). The reform has encouraged the development of gas-fired generating plants as illustrated by Agip and Shell. These are:

(i) Okpai Power Project (Agip) (ii) Afam VI (Shell).

The Agip plant is currently under construction, with 300 MW of OCGT plant is now commissioned. In the near future the plant will to be converted to combined cycle operation by adding a 150 MW steam turbine giving a total of 450MW.

Shell Petroleum Development Company (SPDC) has gone out to tender for the construction of Afam VI. The final configuration of this plant is not defined yet. However, it is likely to be a 600-700MW CCGT plant located near Port Harcourt. Though a Power Purchase Agreement (PPA) has yet to be agreed, it is hoped to be commissioned in 2007. Further investment in generating plant is expected in the short-term (Table 3.4), which NEPA expects to come to fruition before the end of 2007. If all the projects outlined in Table 3.4 proceed and succeed, then by 2007 some 8486 MW will be connected to Transysco's network. This capacity still falls short of the Government's target of 10 000 MW by 2005. Of this all-only 1920 MW of hydro plant will be involved although large hydroelectric projects have been identified [7]. Looking further forward, Table 3.5 summarizes some of the power projects that are currently under discussion.

Table 3.4 NEPA's view of future generation connected to Transysco's

	Jan 2004	June 2004	Jan 2005	June 2004	Jan 2006	June 2006	Jan 2007	June 2007
Existing Plant (MW)								
Delta (1,3&4)	525	750	750	900	900	900	900	900
Egbin (ST1-ST6)	1,100	1,100	1,320	1,320	1,320	1,320	1,320	1,320
Afam 4&5	232	370	370	370	370	370	370	370
Sapele ST1-ST6	120	240	240	240	240	240	240	-
Ijora	20	20	20	20	20	20	20	20
Kainji 1G5-1G12	550	550	550	550	550	550	550	550
Jebba 2G1-2G6	560	560	560	560	560	560	560	560
Shiroro 4G1-4G4	600	600	600	600	600	600	600	600
AES Egbin	270	270	270	270	270	270	270	270
Existing Plant	3,977	4,460	4,680	4,830	4,830	4,830	4,830	4,590
Committed Plant (MW)								
Agip Okpai IPP OCGT	-	-	300	-	-	-	-	-
Agip Okpai IPP CCGT	-	-	-	450	450	450	450	450
Ibom Power	-	-	-	-	-	142	142	142
Committed Plant	-	-	300	450	450	592	592	592
Financed Plant (MW)								
Geregu[3] Siemens Units 1,2&3	-	-	-	-	-	-	276	414
Papalanto units 1-8	-	-	-	-	-	126	251	335
Omotosho Units 1-8	-	-	-	-	-	126	251	335
Alaoji Power Station	-	-	-	-	-	-	400	400
Shell PDC Afam	-	-	-	-	-	-	-	700
Financed plant	-	-	-	-	-	252	1,178	2,184
Planned, no finance or PPA (MW)								
Sapele ROT								
Geometrics ring-fenced IPP	-	-	-	-	-	-	-	1,020
	-	-	-	-	100	100	100	100
Planned, no finance or PPA	-	-	-	-	100	100	100	1,120
Total Connected to Transys Co	3,977	4,460	4,980	5,280	5,380	5,774	6,700	8,486

Table 3. 5 Generator Proposed for 2010-2020

	Area	Unit size (MW)	2010 (MW)	2015 (MW)	2020 (MW)	Comments
Sapele i3m	Benin	100	300	300	300	
SOL gas CCGT ASCL,	Benin	138	1,242	2,300	2,300	ASCL will use 800 MW.
Ajaokuta	Benin	138	828	828	828	Gas is source of concern
Geregu (6x138MWGT unit)	Benin	42	670	670	670	Gas is source of concern
Okitupupa	Benin	138	900	1,200	1,200	
Rockson Engineering (Delta) +	Enugu	39	156	156	156	Gas is source of concern
Ibom phase 1	Enugu	138	552	552	552	
Ibom phase 11	Enugu	100	-	390	390	Gas is source of concern
Bonny	Enugu	100	500	500	500	Gas is source of concern
Eagle Energy	Enugu	100	500	500	500	
ICS Power	Enugu	100	300	600	600	
Oji (coal)	Enugu	500	500	1,500	1,500	Retrofit 3 GT Units by 2015
Enugu (coal)	Enugu	138	690	1,242	1,242	
Afam VI- to replace Afaml-	Enugu	150	450	900	1,800	
IV*	Enugu	150	450	450	450	
Onne (4 CCGT)	Enugu	138	900	1,200	1,200	Gas is source of concern
Total	Lagos	100	408	816	1,632	Gas is source of concern
Rockson Engineering (Afam) +						
(New Lagos) Tacobel Waste to	Lagos	42	670	670	670	
gas at Ayobo	Lagos	125	500	500	500	
Papalanto	Shiroro	138	1,000	1,000	1,000	
Eagle Gas (Agbara, Lagos)						
Abuja power (SPDC)						
Proposed New Capacity			11,516	16,274	17,990	
Total Capacity Connected to TransysCo's (2007)			8,486	8,486	8,486	
TOTAL INSTALLED CAPACITY			20,002	24,760	26,476	

3.2. Transmission Network System

The electricity network comprises 11,000km Transmission lines (330kV and 132kV), 24000km of Sub-transmission line (33kV), 19000km of distribution lines (11kV) and 22,500 Substations.

The transmission network is subdivided into five regional areas with national control centre (NCC) and supplementary national control centre (SNCC) located at Oshogbo and Shiroro respectively. These are the coordinating and supervising centres. The regional control centres are located at Lagos, Benin, Jebba, Kaduna and Oshogbo. For effective and efficient operations, district control centres were established to take control of the distribution of the electricity. But, the power system suffers from low plant availability on transmission and distribution network as a consequence persistent and frequent blackouts are the norm. Failure to invest in the electricity sector is the result of economic mismanagement and Nigeria's dependence on oil that has served to divert investment into the oil sector at the expense of developing, or even maintaining the existing electricity infrastructure. An unreliable and / or unobtainable electricity supply has led to about 97% of firms owning generators [8] to satisfy their electricity demand.

The transmission network is characterized by high-energy losses. Total losses have always been a significant factor on NEPA's system and peaked at 44 per cent of 'sent out' generation in 1991 [8]. Losses have improved, but still account for some 30 per cent of sent out generation. Losses comprise 'technical' losses in the transmission and distribution system, and 'non-technical' losses associated with illegal connections, other unbilled consumers and the manipulation of meter readings.

The transmission network (TRANSYSCO) remains a single utility company under the new arrangement. The situation we hope will change; however there will be increasing interest to utilize the transmission network in the most efficient and economical manner. Under this new arrangement the electricity industry will be profit driven, that is, maximum profit with minimum investment. Protection requirements are bound to change. Figure 3.4 shows the present transmission network.

3.2.1 Proposed Additional Lines to the Existing Transmission Network.

Investigation revealed that grid system is predominately characterized with radial network and very long transmission lines. Some of these lines risks total or partial system collapse when major fault occurred in then. The lines that link the hydro generating stations in the Northern part of the country with those of thermal generating stations in the Southern part of the country are Oshogbo – Benin, Benin – Ikeja west, Oshogbo – Ikeja west, Jebba – Oshogbo.

To ensure the stability of the system and limit the risks of system collapse it will be necessary to consider Flexible Grid Configuration Strategy (FGCS). This calls for the installation of the following lines.

1. Second circuit on Benin-Oshogbo, Ikeja west-Oshogbo, Benin-Onitsha, kaduna-Kano and Jos-Gombe.
2. Completion of the country's 330KV loop through Alaoji-Enugu (New haven)-Makurdi-Jos, Abuja-Ajaokuta lines and Calabar-Jalingo. These lines will provide alternative link between generation in the Northern and Southern parts of the country.
3. Installation of another line to evacuate power from Egbin to other areas apart from the double line to Ikeja west and Aja. Hence, Egbin to Benin line is suggested.

The suggested lines will strengthen the existing network thereby reducing transmission congestion. Figure 3.5 shows the suggested future grid system indicating the proposed lines and some of the planned generation stations.

CHAPTER FOUR

CAUSES AND CURES TO POWER SYSTEM COLLAPSE: A CASE REFERENCE TO NIGERIA POWER SYSTEM

4.1 Introduction

Power system collapses, when the net flow of electrical energy in the network is zero. Global review of examples of system collapse is shown in table 4.1[9] whilst table 4.2 shows the Nigeria case. Power system collapse has serious consequences, the most recent famous example is that of August 14, 2004 where large portions of the Midwest and Northeast United States and Ontario, Canada experienced huge electric power blackout. The outage affected an area with an estimated 50 million people and 61 800MW of electric Load. Before full power was restored it was estimated that the total costs to the Unites State economy ranged between $4 billion and $10 billion US dollars. In Canada gross domestic product was down by 0.7% in August. There was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down by 2.3 billion (Canadian dollars) [10]. The August 10, 1996 outage in California alone is reported to cost $1 billion us dollars [11].

Table 4.1: Some Famous System Collapses Globally [9, 10, 11]

DATE	LOCATION	LOAD INTERRUPTED	TIME
November 9, 1965	Northeast	20,000MW	
August 22, 1970	Japan	-----	30 min.
November 10,1972	Bretagne, France	-----	Minutes
July 13, 1977	New York	6,000MW	
December 22, 1982	West Coast	12,350MW	
September 02, 1982	Florida, USA	------	1 –3min
June 5,1986	England	------	5 minutes
July, 1986	California	7, 500 MW	------
January 17, 1994	Wyoming, Idaho	9, 336 MW	------
December 14, 1994	Western Interconnection	30, 489MW	------
August 10, 1996	Czechoslovakia	------	Days
1998	Auck – Land	------	39 days
September 28, 2003	Italy	------	30 minuses
1999	Kuwait	------	Days
2003	Denmark	------	Unknown

Before the beginning of this research work a number of system collapses had occurred in the country. In the year 2002 alone there were 24 numbers of system collapse, 13 in 2003, and 12 in the year 2004 and from January to May 2005 a total of 7 collapses were recorded.

Table 4.2: The number of system collapses in Nigeria [67]

Year	No
2002	24
2003	13
2004	12
Jan-may (2005)	7

Evaluation of the Nigerian system collapses showed that protection system failures have been involved to about 70% of the blackout events. A study of major outages in North America over past decades also reveals that in most recorded cases, some undesirable action by one or more protective devices contributed factors to the cascading of events and outages, which finally led to the blackout [12,13]. Incorrect and unwanted relay operations were involved in the Northeast Blackout, the New York City Blackout, and the Western System Coordination Council (WSCC) event of 1996. Out of the last five major WSCC events (the North Ridge earthquake, December 14th 1994 caused a blackout. The blackouts on July 2nd & 3rd 1996, and August 10th 1996) where caused by false tripping of line and generator protection relays [14].

It is of course not possible to completely eliminate the possibility of system collapse in power system any where in the world. The goal of a rational engineering approach should be to reduce the frequency of such events. The concern of this research is how to improve and modify the practice of protection system to achieve this goal.

4.2 Causes and Anatomy of System Collapses

There is a tendency to point at a "single" event triggering cascading outages that might lead to system collapse. Major blackouts are typically caused by multiple contingencies with complex interactions requiring sequence of low probability events to occur.

4.2.1 The Case of December 25th 2003 Nigeria System Collapse

The investigation of December 25th 2003 Nigeria system collapse lead to further insight into the cause and cures for such event. At about 12.49hour, Egbin-Ikeja west 330kV line II (N8W) tripped at both ends of the line. Prior to the fault, there were six units on barge at Egbin with a total generation capacity of 1090MW. Eight units at AES barge station with a total generation capacity of 242MW were added. With a load of 100MW to Ikorodu and 128MW to Aja the net load on the two Ikeja west lines were about 1104MW.

At about 10 minutes later, the second Ikeja west line I (N7W) tripped separating Egbin power station plus its associated network of Aja and Ikorodu from the rest of the system. The entire system could not survive this outages and that lead to complete system collapse.

The summary of the tripping events and the analysis are as follows.

(a) Sequence of tripping event at Egbin power station on line N8W; Main 1 SIPROTEC relay (numerical distance relay) at Egbin tripped on Zone 1 earthfault at a distance of 41.6km on Blue phase. Back up relay (main II) YTG distance relay on the same line did not trip.

(b) Sequence of tripping event at Ikeja west substation on line N8W; both main 1 relay (SIPROTEC relay) and main 11 relay (OPTIMHO relay) on this circuit tripped on zone 1 earthfault on the blue phase at the distance of 19.2 km

The faults were single phase to earth faults of transient in nature or else the lines would have not stayed on re-energization. Various studies have also shown that about 70% to 90% of fault on most overhead lines are transient [1]. Transient fault could be caused by flashover from the high transient voltage induced by lightning to the tower, swinging wires and temporary contact with foreign objects.

This type of fault is cleared by immediate tripping of circuit breakers to isolate the faulted phase, and does not re-occur when the line is re-energized. The process of re-energization is by single pole auto reclosing (SPAR) scheme, which is a relay application. Auto reclosure is a practice in power system protection all over the world. Unfortunately these schemes were deactivated in all the circuit in the system for some reasons. One of the reasons given was that the breakers were shattering on reclosure. If the SPAR were activated in the system the events that lead to the system collapse would have been averted, because at the time of the second line tripping the first line would have been successfully restored automatically minimizing the chance of losing the two lines at the same time.

The circuit breakers (CB) used on 330kV lines are designed for rapid auto reclosing each with a duty cycle of 0-0.3 sec, this means that the breakers are capable of opening and closing back almost immediately. There are numbers of factors that could cause a circuit breaker to shatter even during normal operation and not only during auto-reclosing. Such factors include:

(a) Loss of interrupting medium (i.e. arc quenching medium such as SF_6)

(b) Slow operation mechanism

(c) Wrong choice of timing.

4.2.1.1Reasons for Using Auto-reclosure Scheme

Some of the reasons for SPAR are summarized as follows.

1. Minimizing the interruption of the supply to the customers.
2 Maintenance of system stability and synchronization.
3 Restoration of system capacity and reliability with minimum outage and least expenditure of manpower.

Application of auto-reclosing requires evaluation of the following fundamental factors:

i. The benefits and possible problems associated with reclosing.
ii. The choice of dead time.
iii. The choice of reset time.
iv. The decision to use single – or multiple –shot reclosing

[15, 16] Describe in detail the philosophy and application of auto-reclosing in power system.

4.2.2 Other Causes of System Collapses in Nigeria.

Power swing phenomenon is another peculiar problem identified in Nigeria's transmission system that often poses trait to the network security. The swings are commonly identified along Benin, Oshogbo, and Ikeja-west lines. Power swing is a phenomenon that causes fluctuation in power flow, this occurs due to contingency events such as equipment failure, human error, thunderstorms, over grown vegetation and power system dynamics such as short circuits, line switching, or fluctuation due to significant variations in the load causing the generators in the system to slip relative to each other. ***Frequency instability, voltage instability and transient angular instability*** usually accompany these adjustments. Thereby leading to cascading events (tripping of relays) and if proper control measures are not taken to restore the system to stability, the situation leads to undesirable separation of network into islands, followed by system collapse. This type of disturbance cannot normally be correctly identified by an ordinary distance protection. It is often necessary to prevent distance protection schemes from operating during stable or unstable power swings, in order to avoid cascade tripping. The best option to this problem is to have a dedicated power swing or out-of-step relay located where swinging sources are identified (Benin, Ikeja-West, Oshogbo) to strategically split the system into Islands such that the plant capacity and connected loads on either side of the Islands are matched. [17] Further described in detail the power swing theory and how to monitor and analysis swing with advanced monitoring/recording devices and benefits it yields to utility.

The following factors are generally the causes of blackout.

i. Congested grid (Lack of flexibility grid strategy).
ii. Lack of reactive power support close to the load centers.
iii. Aging equipment that is prone to failure.
iv. Maintenance practices.
v. Lack of proper generation scheduling during stressed conditions.
vi. Low level of investment in the power system is a major contributing factor (the challenge here being identifying who is to invest and the recovery of such investment).
vii. Human error.
viii. Lack of coordinated response among control area
ix. Lack of proper application of protective relaying control schemes and remedial actions.
x. Deficiencies in industry policies that will enhance strong reliability standards, and their enforcement.

4.3. The Existing System Protection Scheme (SPS) used to Mitigate Against System Collapse in Nigeria Power System.

The present system protection scheme being used to maintain system stability at the grid level when the system is under disturbances depends on the reading of frequency meter. The control policy of $50(\pm 2.2)\%Hz$ being used to monitor the system stability does not give satisfactory information about the stability limit to system collapse. Hence, the under frequency relay used for load shedding and generator protection against wide spread blackout is not effective. The practice is that, when the system frequency value gets between 48.8Hz to 47.8Hz commands are given through phone call from control center (NCC Oshogbo) to operators at different sub transmission stations to shed certain about of load by opening circuit breaker in order to restore the system frenquency. The effort to control system instability in this case is limited to substations, which makes the process local. This is a contributing factor to large-scale blackouts.

4.4. The Proposed Wide-area Monitoring and Protection & Control System (WAMP&CS)

In view of the global deregulation process in the electric power industry, utilities are examining the application of information technology (IT) as an option to support corporate business strategies that focus on improving service and power quality as well as reducing cost of operation and maintenance. In response to these new needs, Wide-area monitoring, protection & control system (WAMP&CS) is being proposed to complement existing protection and control systems to provide state of the art solutions for counteracting system instabilities. The scheme is to detect abnormal system conditions early enough to initiate and predetermine counter actions to ensure reliable system performance.

The diagram shown in Figure 4.1 and 4.2 explain the basic principles of operation.

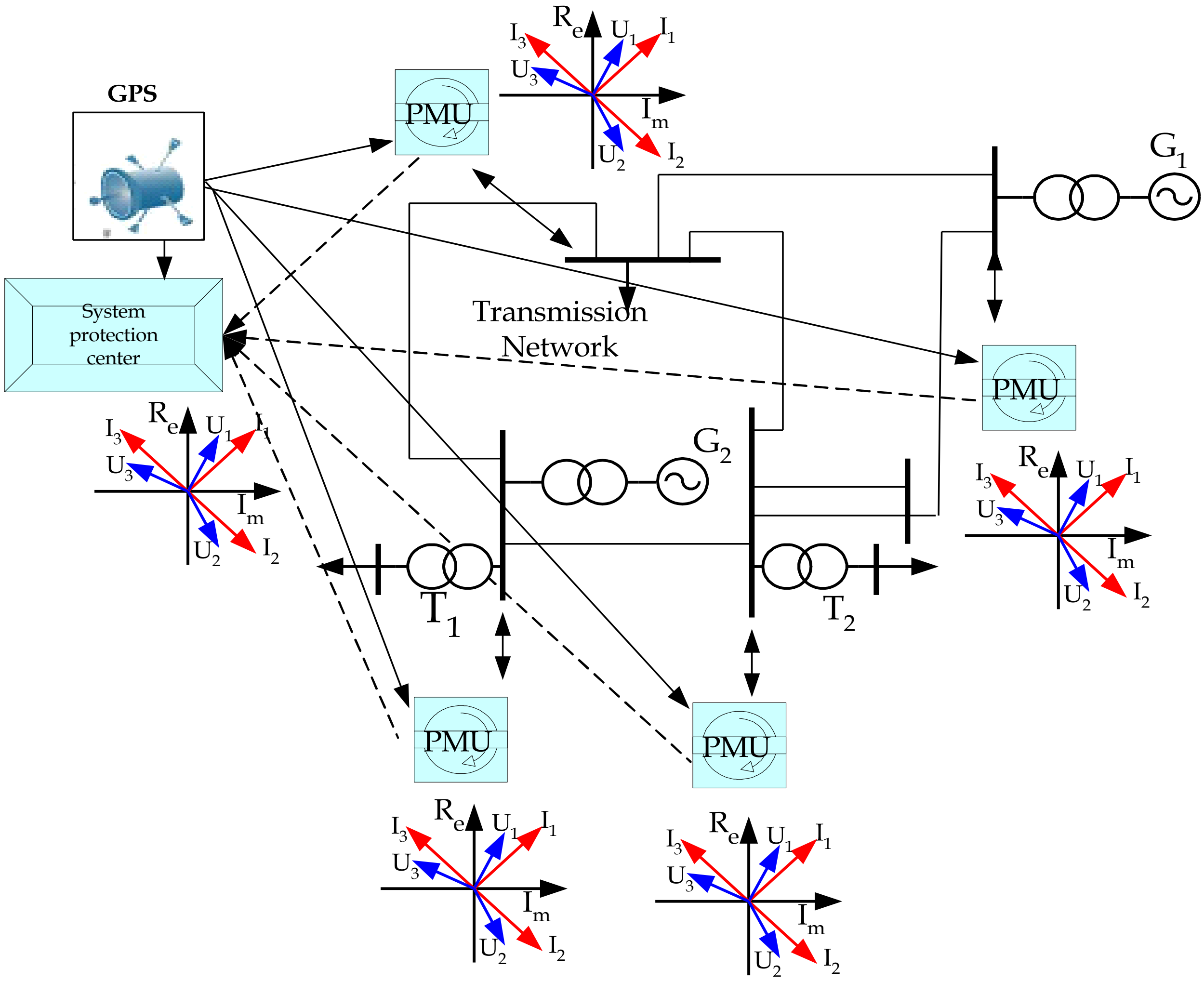


Figure 4.1 Wide-area monitoring and protection & control scheme

The basis for WAMP&CS is the Phasor Measurement Unit (PMU), which fulfill the requirement of a on-line (dynamic) system view [18, 19]. Accurate and actual real time information from the system stability conditions could be obtained from phasor measurement units [PMU], which are suggested to be installed at critical points (such as Benin, Oshogbo and Ikeja west) of the transmission network for sampling voltages and currents Phasors i.e. instantaneous values of both magnitudes and relative rotor angles, these values are synchronized by global positioning system (GPS) satellites, by taking simultaneously snapshots of the PMU [20]. Further processing of these data delivers accurate values of the stability limit ΔS to voltage instability at the various locations as well as for the entire network in the system protection center. The objective is to detect incipient problems early enough and to initiate preventive actions.

In the first stage of implementation, WAMP&CS should be used as a monitoring system only in order to assess the dynamic behaviors of the power system. In the second stage, analytical system studies need to be conducted to establish a defence plan that defines the actions, which are required for maintaining the power system integrity.

In the final stage, WAMP&C will be used to prevent instabilities by initiating the most appropriate action according to the defence plan.

The extensive system wide PMU measurements can further be used to investigate which locations in the network the installation of flexible AC transmission system (FACTS) would be feasible to optimize the power flow.

Figure 4.2 shows typical sequence of actions that could be initiated by WAMP&CS if the system approached instabilities.

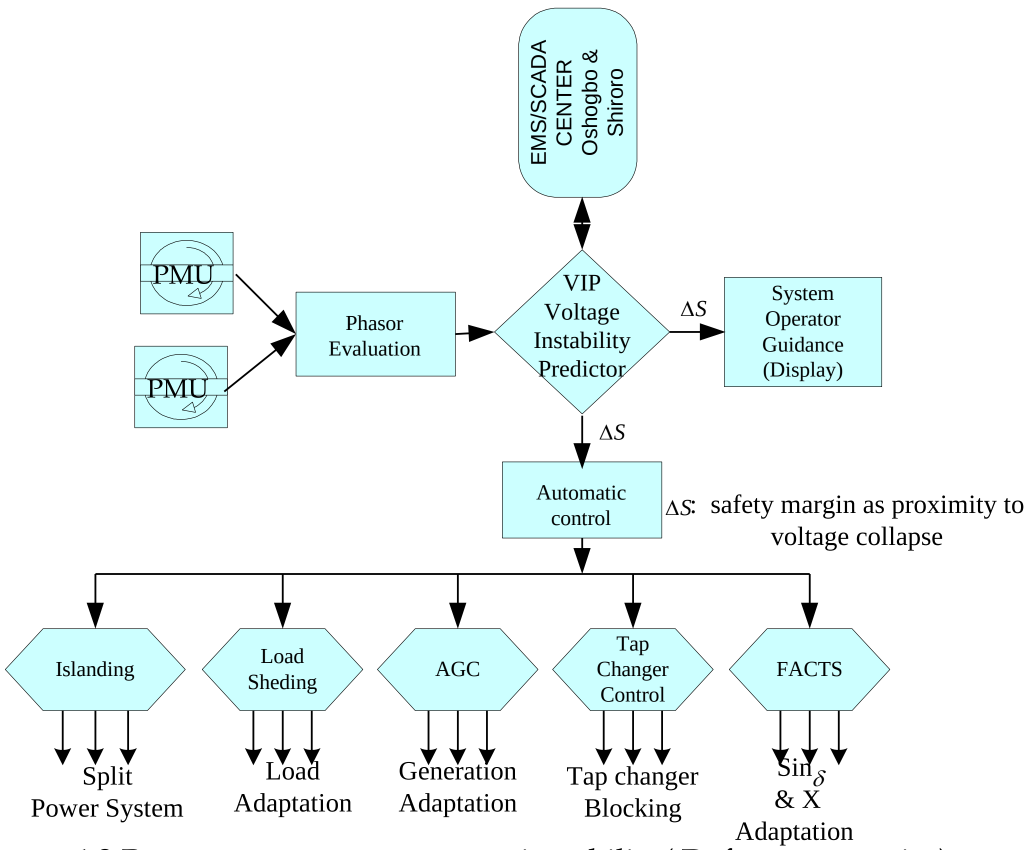


Figure 4.2 Responses to power system instability(Defence strategies)

a) Alerting the system operator by indication of the remaining stability limit ΔS and by providing on line guidance to counteract a critical situation. In addition, corresponding information is produced for the Energy Management System (EMS).

b) Control actions are initiated if the stability limit ΔS reaches a preset critical level to prevent voltage instabilities. The following gives the highlights of control strategies; however, [21, 22] contain further information.

(1) Flexible AC Transmission System (FACTS)

a. Raising dynamic stability limit.

b. Provide better power flow control.

c. It can counteract voltage instability following loss of several transmission lines.

(2) Load Tap Changer Control (LTC)

- If the load current increases LTC is supposed to raise the tap position (of the transformer) to compensate for the voltage drop. Therefore, WAMP&C blocks LTC or changes the set point of tap changer to preserve system stability.

(3) Automatic Generator Control (AGC)

- Objective of AGC is to regulate frequency and to maintain balance of power between generator and load.

(4) Load Shedding

a. Under frequency relay are used to initiate and minimize the risk of system collapse.

b. Under voltage initiated to preserve system stability.

c. Select only feeder that will be open to regain the frequency stability.

4.4.1 Islanding a Strategy in Improving Nigeria Power System Stability.

Islanding in power system implies separating the power system network into sectional area called islands. Serious disturbance in power system may trigger growing oscillations or instability that may lead to loss of synchronization between groups of generators and possibly blackouts.

Normally, system islanding may automatically happen after some transmission lines are tripped by normal distance relays, but unbalanced electrical islands are often produced. In this case some islands are mainly made up of generators and by contrast, the other parts will almost have no generator but Loads. Then blackout of the entire system is almost inevitable.

But when the islanding, also known as controlled system separation (CSS) is planned, it becomes defence strategy against blackout. In this case the splitting of the whole transmission network into islands is properly done when necessary by special relays. After system splitting, the whole power system is under intentional islanding operation and each island generation theoretically remains in a balance state. Thus, although the power system is operating in an abnormal degraded state, however, customers are continuing to be served until eventually the whole network is linked together after the situation that lead to separation is attended to.

If proper system spitting (islanding) strategy had been put in place, many blackouts would have been avoided. Active and viable system splitting can efficiently avoid blackout of the entire power system [23] and is ordinarily better than a passive system islanding which is being experienced in the Nigeria transmission system presently.

The problem with system splitting is to determine proper splitting strategies that will ensure synchronization of generators and satisfaction of "equality" and "inequality" constraints in each island. That is, balance between generator and Load.

Successful islanding comes about by satisfying the following conditions

1. Generators in each island are synchronized approximately , that is, System Synchronous Constraint (SSC)
2. In each island, generation and load are balanced approximately (Equality constraints), that is Power Balance Constraint (PBC)
3. Transmission lines and other transmission services must not be loaded above their transmission capacity limit (e.g. thermal capacity limits and

steady state stability limits)(inequality constraints), that is Related Line Constraint (RLC)

System Synchronous Constraint (SSC) is a function of Frequency (F) Phase angle (θ) and Time (T). Power Balance Constraint (PBC) is a function of power generated (P_G) and power loss (P_L). Related Line Constraint (RLC) is a function of thermal capacity (θ^0) and line length (L).

These constraints can be formulated mathematically for gaining better insight to the concept as follows:

Successful System Splitting $(SSS) = \left(\left|\sum S\,S\right| + \left|\sum PB\right| + \left|\sum RL\right|\right)$...........(4.1)

Where,

$$SSC = f\left(f, \theta, T\right) \qquad (4.2)$$

$$PSC = f\left(P_G, P_L\right) \qquad (4.3)$$

$$RLC = f\left(L_P, \theta^o\right) \qquad (4.4)$$

It also follows that for PS constraint is to be satisfied than

$$S_G^i = S_L^i + S_d \qquad (4.5)$$

Where

S_G^i is the injected complex generator power into an island i

S_L^i is the complex load power at in island i

S_d is allowable power balance error limit within an island.

After considering these conditions and the present structure of the transmission network, three islands of the network are being proposed to strategically split the network at Benin, Oshogbo and Ikeja west (Figure 4.3).

4.4.2 Condition Required for the Application of Islanding

Islanding should be considered as the last defence strategy towards saving power system from total collapsing. FACTS which is the first defence plan can produce or consume reactive power instantaneously incase of voltage collapses. Hence it can counteract voltage instability following loss of several transmission lines. After the applications of LTC, AGC and Load shedding fails to restore system stability. Islanding should be conducted after load shedding is conducted to establish generation spinning reserve.

CHAPTER FIVE

SHORT CIRCUIT STUDIES ON THE MODEL TRANSMISSION NETWORK (AT 330KV)

5. Introduction

Short circuit protection is necessary to protect personnel and apparatus from the destructive effects of the resulting excessive current flow, which is caused by relatively low impedance of the short circuit fault occurrence. To provide the required protection, there is need to determine the magnitudes of short circuit currents at various selected points in the electrical network. This determination requires that the calculation of the current valves and because it is a life-safety related it is recommended by the NEC, that: "*Equipment intended to interrupt current at fault levels shall have an interrupting rating sufficient for the nominal circuit voltage and the current that is available at the line terminals of the equipment. Equipment intended to interrupt current at other than fault levels shall have an interrupting rating at nominal circuit voltage for the current that must be interrupted*" [24].

Results of short circuit and distance relay evaluation studies provide the following summarized necessary information to protection system engineers.

I. For setting of overcurrent and earthfault protective relays.

II. The fault current is used as a basis for selection of switchgear from the manufacturers' table.

III. As means of determining whether or not the bus sections of the switchgear are supported adequately to withstand the forces generated from the fault currents.

V. To know the maximum current available to operate an electrical protective device, such as relays and fuses.

VI. For the distance relay co-ordination studies.

A protective device co-ordination study is made to enable proper selection and setting of electrical protective devices. Ideally in any power system network, when a fault occur it is desirable to interrupt and remove only the faulted part of the electrical system, leaving the remaining system in operation. When this is accomplished the system is said to be co-ordinated.

The co-ordination study evaluates current transformer ratios; protective relay characteristics and settings, fuse ratings, circuit breaker ratings, and trip settings. The study provides the information needed to design a system with the optimum level of protection.

In every power system loads are added and removed, transformers are added and replaced and utility companies are adding generation and transmission facilities. As these changes takes place, the impedance of the overall electrical system changes, as do the protection requirements. With the added capacity on utility systems, the system is subjected to higher values of short circuit currents and greater forces than when the system was first designed and installed. Thus, the adequacy or in adequacy in protection system can duly be determined through short circuit and co-ordination studies or when the electrical protective device fails to interrupt a fault and explodes. This might be one reason why explosions occur in the system and sometimes-associated to sabotage. Hence, it is necessary to carry out this study periodically as to review and re-design protective system. However, with this research effort these studies can now be carried out if the opportunity will be given with necessary support by the concerned authority.

5.1 Types of Short Circuit Faults

There are five main types of faults figure 5.1 in power transmission system. These include the following.

I. Three phase short circuit fault
II. Two phase to earth short circuit fault
III. Phase to Phase short circuit fault
IV. Single phase to earth short circuit fault
V. Three phase to earth short circuit fault

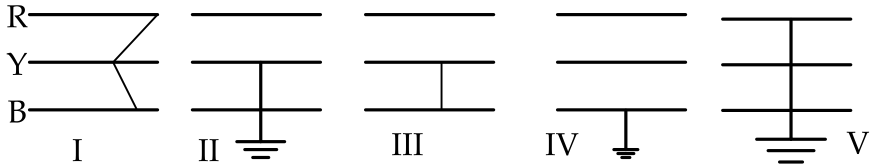


Figure 5.1 Types of short circuit faults

The frequency of occurrence of these faults in power system is given as 5%, 10%, 15% and 70%for three phase faults, two phase-to-phase fault, Phase to Phase fault, and single phase to earth fault respectively [25]. Three phase and single phase to ground fault are however considered in this study being the most severe and therefore the requirement for the setting of overcurrent and earthfault protective relays [26].

(a) Single Line to Ground Fault

In general, the single line to ground (SLG) fault on transmission system occurs when one conductor falls to ground or comes in contacts with the neutral line. Figure 5.2a shows the general representation of a SLG fault at a fault point F with impedance Z_F (This impedance $Z_{F,}$ may be thought of as the impedances in the arc in the event of having a flashover between the line and a tower). Usually, Z_F is ignored in fault studies [43]. Figure 5.2a shows the single line-to-ground fault while figure 5.2b shows the interconnection of the resulting sequence networks. From the figure 5.2b it can be observed that the zero, positive and negative currents are equal to one another. Therefore,

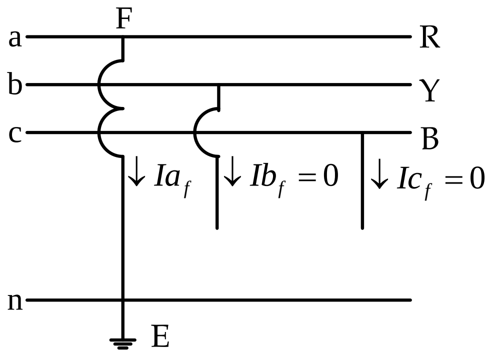


Figure 5.2a Single line-to-ground (SLG) fault

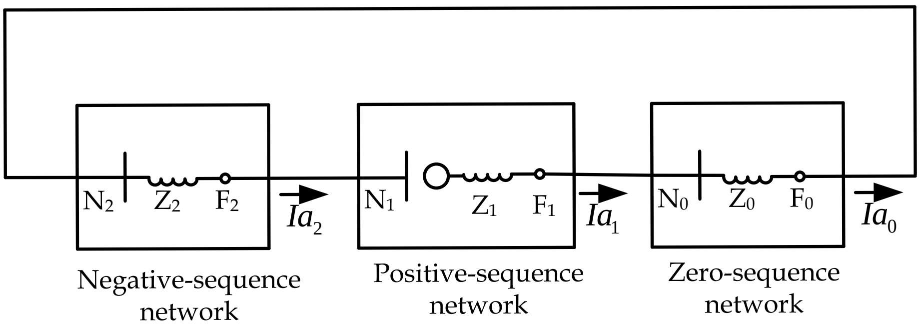


Figure 5.2b interconnection of sequence networks for SLG fault

$$Ia_0 = Ia_1 = Ia_2 = \frac{Va_0}{Z_0 + Z_1 + Z_2} \text{....................(5.1)}$$

Since

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} Ia_0 \\ Ia_1 \\ Ia_2 \end{bmatrix} \text{.....................(5.2)}$$

and the fault current for the phase a can be found as

$$Ia_f = Ia_0 + Ia_1 + Ia_2$$

or

$$Ia_f = 3Ia_0 = 3Ia_1 = 3Ia_2 \text{........................(5.3)}$$

Detail analysis for the development of other faults equations types are further explained in [26, 64, 65]. However, the following summarized the short circuit current equations for the various types of faults considered.

(b) Line to line short circuit current equation.

$$Ia_1 = \frac{Vo_1}{Z_1 + Z_1} \text{..(5.4)}$$

$$Ia_1 = -Ia_2 \text{...(5.5)}$$

$$Ia_0 = 0 \text{...(5.6)}$$

(c) Two line to ground short circuit current equation.

$$Ia_1 = \frac{V0_1.(Za_2 + Za_0)}{Za_1.(Za_2 + Za_0) + Za_2.Za_0} \text{.....................(5.7)}$$

$$Ia_2 = -\frac{Ia_1.Za_0}{Za_2 + Za_0} \text{...(5.8)}$$

$$Ia_0 = -\frac{Ia_1.Za_2}{Za_2 + Za_0} \text{...(5.9)}$$

(d) Three line short circuit fault current equation.

$$Ia_1 = \frac{Vo_1}{Za_1} \text{...(5.10)}$$

$$Ia_2 = Ia_0 = 0 \text{...(5.11)}$$

and

$$Za_2 = Za_0 = 0 \text{..(5.12)}$$

Where,

Vo_i = operating voltage or pre fault voltage at faulted node i

Za_i = network impedance at faulted node of positive (i = 1), negative (i = 2) and zero (i = 0) sequence system.

Ia_i = initial short circuit current at faulted node of positive (i = 1), negative (i = 2) and zero (i = 0) sequence system.

5.2 Computer Model of the Transmission Network for Short Circuit Studies and Distance Relay Evaluation.

When calculating short circuit fault currents for a large network the computer model of the electrical system becomes necessary for the following reasons.

1. Eliminates the rigors of modifying the bus matrices in the calculation involving symmetrical component.
2. Modification can easily be made to network as it changes.
3. Parameters for the calculation can easily be updated.
4. Save a lot of time.
5. Results obtained from the study can easily be presented.

Presently, power system software programs are being used world wide for power system studies and analysis, such studies as <u>Short circuit study</u>, <u>Optimum Power Flow</u>, <u>Load Flow</u>, <u>Transient Stability</u>, and <u>Locational</u>

Maginal Pricing. Some of these programs include MATH LAB, NEPLAN, ETAP, and PSS.

NEPLAN educational Version 4.2 of 50 nodes made for researcher was used for this study. Busarello + cott + partner Inc developed the program driver module in 2001.

From the experience, the fault currents obtained from simulation using this program are normally higher by 5% than actual values but this is acceptable. The figure 5.3 shows a flowchart methodology use in the application of the program.

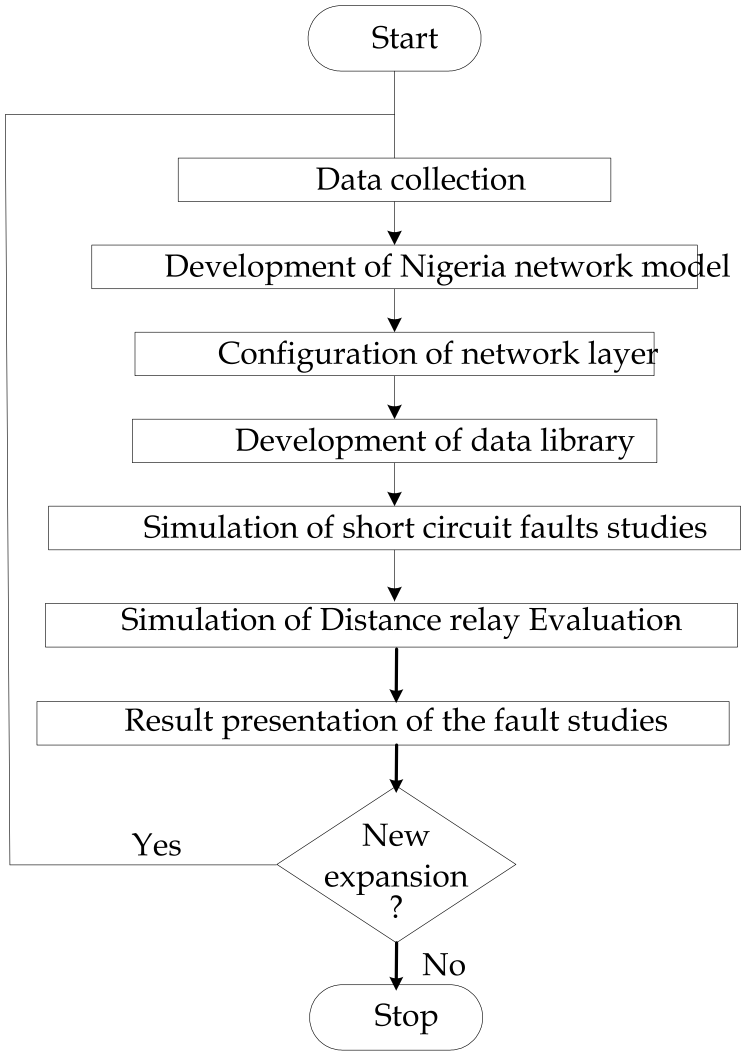


Figure 5.3 Flowchart showing methodology to the programme application

5.2.1 Data collected and used for short circuit study.

A most important methodology in protection work is the study of faults and fault analysis of a power system. A pre-requisite for this is data collection; the data used for the network short circuit study and distance relay evaluation were collected during the period of the field experience. Some of the data used were collected directly from the site equipment, some through meetings with the utility staff, consultant and existing site records [7, 27]. The following gives the list of the equipments and data collected.

a) Overhead Line Parameter of the Entire Network.

(i) Length of each of transmission line between substations

(ii) MVA rating of the lines

(iii) Positive and zero sequence impedance

(iv) Number of circuits

These parameters are listed in Appendix A Table 5.1 while the positive sequence and zero sequence impedances of the existing lines are listed in Appendix A Table 5.2.

b) Transformer Parameters (at each of the substations)

(i) Vector grouping

(ii) MVA rating of each transformer

(iii) Impedance values of transformers

(iv)Winding configuration.

These parameters are listed in Appendix A Table 5.3

c) Generator parameters (at each of the generation station)

(i) MVA rating of each generator

(ii) Impedances values of generators

These parameters are listed in Appendix A Table 5.4

d) Generator-Transformer parameters (at each of the generation station)

(i) MVA rating

(ii) Transformation ratio

(iii) Impedances values

These parameters are listed in Appendix A Table 5.5

This data collection and documentation in the afore mentioned tables is a necessary and vital experience during this investigation and much work in the future in almost all aspects of EPNES will most likely depend on this data and perhaps those collected by others who may have worked in load flow [66].

5.2.2. Network Configuration

The detail 330kV one-line diagram of the transmission network is shown in figures 5.4a, 5.4b, 5.4c and 5.4d respectively. In the programme the network is being sectionalized into three-network layers. This is done to accommodate the entire transmission network: -

Section A: This section has all the power station and transmission lines in the North with Jebba transmission station as the coupling point.

Section B: This section has all the power station and transmission lines in the South West with Oshogbo and Benin as the coupling points.

Section C: This section has all the power station and transmission lines in the south East with Onitsha Substation as the coupling point.

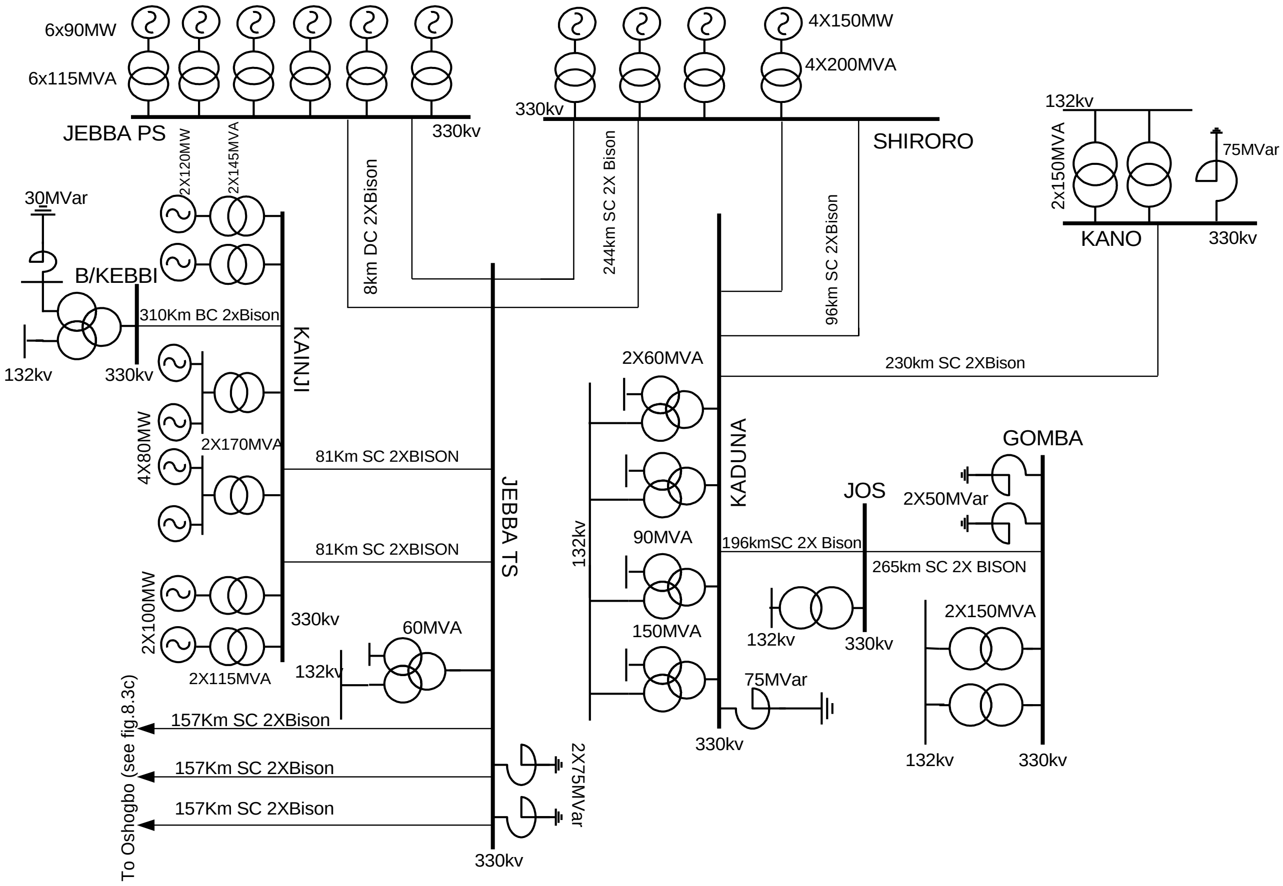


FIGURE 8.3a : 33OkV NIGERIA TRANSMISSION NETWORK MODEL FOR SHORT-CIRCUIT STUDY

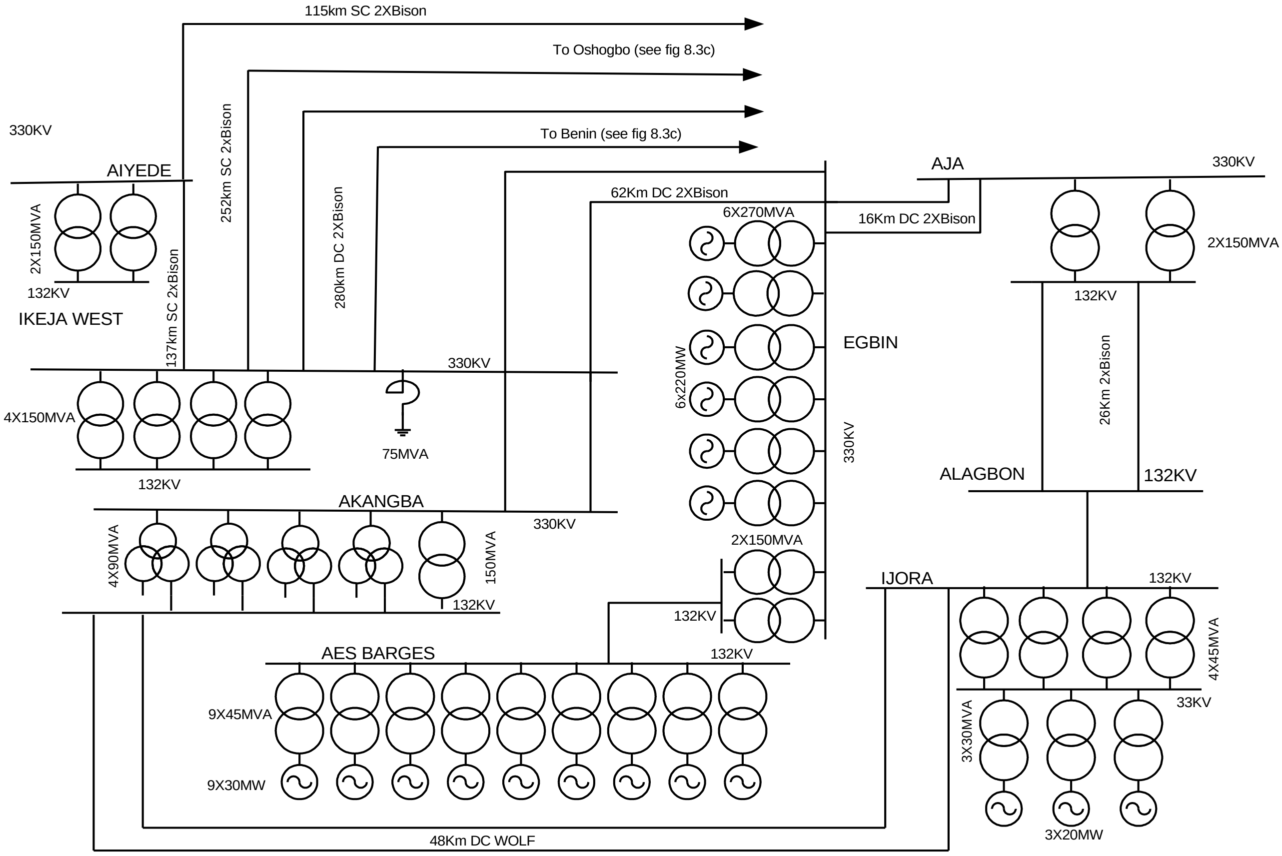


FIGURE 8.3b : 330kV NIGERIAN TRANSMISSION NETWORK MODEL FOR SHORT - CIRCUIT STUDY

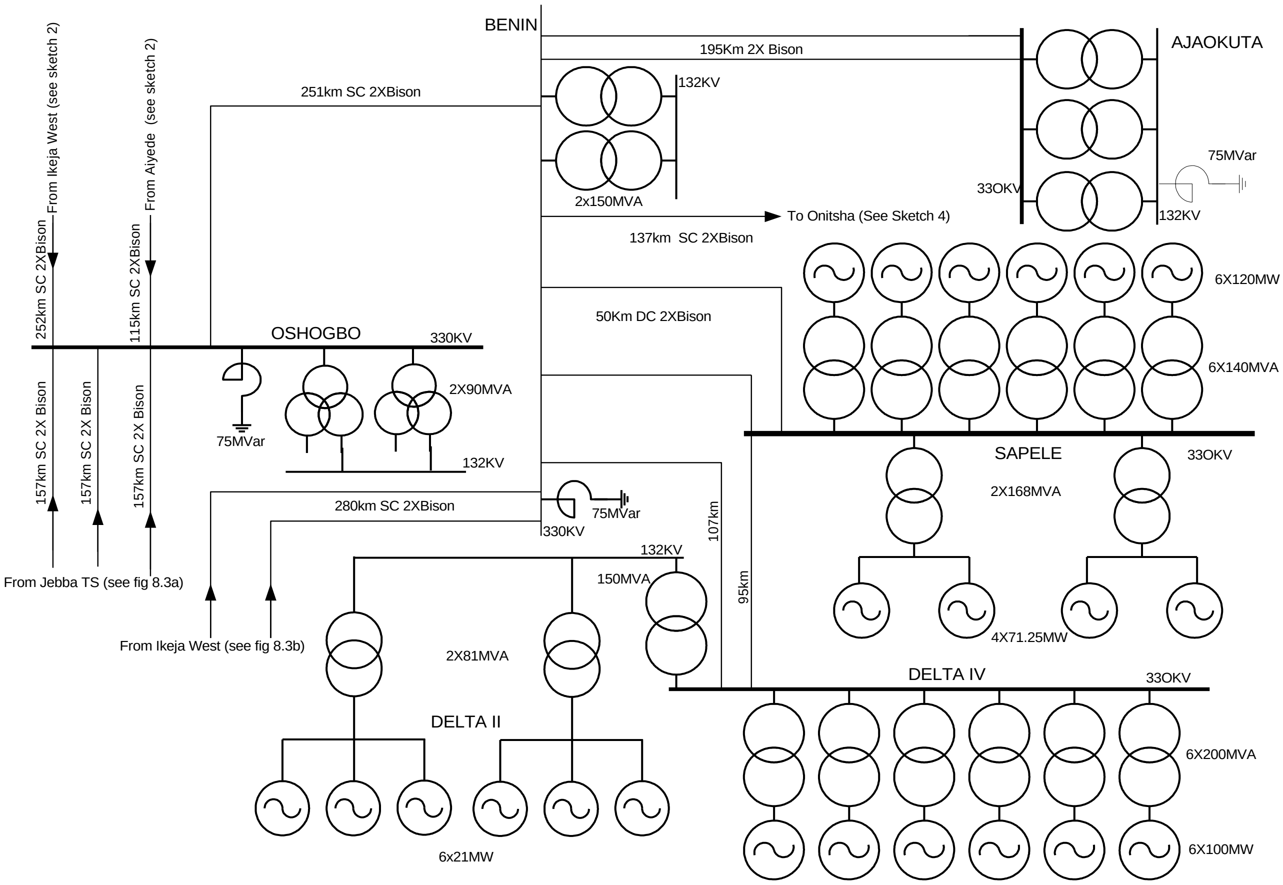


FIGURE 8.3c: 330KV NIGERIA TRANSMISSION NETWORK MODEL FOR SHORT-CIRCUIT STUDY

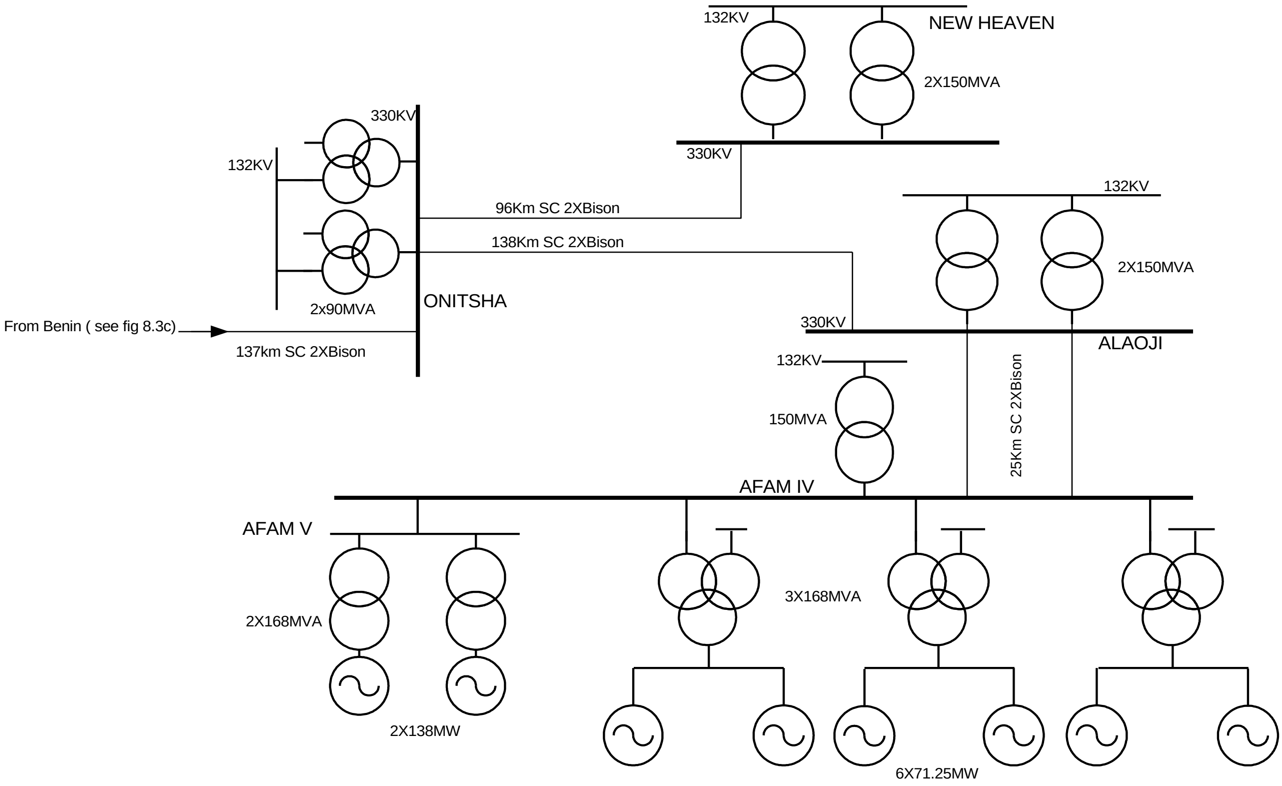


FIGURE 8.3d : 33OkV NIGERIA TRANSMISSION NETWORK MODEL FOR SHORT-CIRCUIT STUDY

5.2.3 Results from the Computer Simulation.

The results obtained form the computer simulation studies can be presented in two forms.

1. Plate form: this gives the summary of the results at all the stations for example Sketch A1.1 shows the computer simulation result of three phase short circuit maximum fault current of the network layer section A. While Sketch A2.1 show the computer simulation result of single phase short circuit maximum current of the network layer section A.
2. Table form: this gives the detail information about the fault currents obtained from the computer simulation studies at each substation of the transmission network.

Detail results from the simulation studies for three phase, single phase to earth short circuit studies and distance relay evaluation are presented in Table 5.1, 5.2 and 5.4 respectively.

5.2.4 Discussion of Results from the Simulation Studies.

The results from the computer simulation of the network short-circuit and distance relay evaluation studies show that.

I. Egbin power station has the maximum values of single phase to earth and three-phase short-circuit fault currents of 17.464kA and 13.437kA respectively.

II. The minimum values of single phase to earth and three-phase short circuit fault currents are 1.272ka at Birnin Kebbi and 1.057ka at Gombe substation respectively.

III. The fault currents obtained from simulation using this program are normally higher by 5% than actual values but this is acceptable.

IV. The values of short-circuit current obtained exceeded interrupting capacities of some Circuit Breakers and Current Transformers thereby causing the explosion of some of the equipments in the grid network.

V. The values of impedance obtained for the remote end of the adjacent line are exactly equal to the standard values of the lines. This show that the model is reliable and can be used for real practical setting of distance relay.

CHAPTER SIX
TRANSMISSION LINE PROTECTION

6.0 Introduction

Transmission line is the major link between generation, distribution and utilization of electrical power system and should be the last device to be tripped even under stressed condition [28]. The possibilities to utilize other equipment for restorative actions will be severely limited after lines' outages. When for example generators are used to their maximum capacity after a grid weakening the result may be cascading of lines' outages on one hand, but on the other hand, it may be advisable to serve the system in case of transient instability to attain stable subsystems. However, in that case tripping should be performed in a planned, controlled and predictive manner.

6.1 Types of Transmission Line Protection Schemes

There are two types of protection schemes used in transmission lines, namely, main and backup protection.

(a) Main Protection

The type of protection provided for a transmission line as the main protection depends to a large extent on its length based on the following:

1. Very short lines: Unit type of protection: Overcurrent and differential Protection.
2. Medium length lines: Distance Protection
3. Long and very long lines: Distance Protection.

(b) Back up Protection

The back up protection for transmission line is generally provided by combination of the overcurrent and earthfault protective relays. These relays are generally used to provide back up protection for transmission lines in case the main protection fails to operate due to one problem or the other.

6.2 Distance Protection

The problem of combining fast fault clearance with selective tripping of plant is a key aim for the protection of power systems. To meet these requirements, high–speed protection systems for transmission and primary distribution circuits that are suitable for use with the automatic reclosure of circuit breakers are under continuous development and are being very widely applied [29,30].

Distance protection scheme is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral over current protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations. Therefore the settings of the distance protection do not need to be re-calculated due to the prevailing operating condition, as the case with overcurrent protection scheme.

A distance relay is comparatively expensive but simple to apply and more reliable incase of meshed system configurations. Additionally, it can provide both primary and remote back-up functions in a single scheme. It can easily be adapted to create a unit protection scheme when applied with a signaling channel [31]. In this form it is eminently suitable for application with high-speed auto-reclosing, for the protection of critical transmission lines.

6.2.1 Principle of Distance Protection.

The basic principle of distance protection involves the division of the voltage at the relaying point to the measured current. The apparent impedance thus calculated is compared with the predetermined impedance (normally the impedance of the circuit being protected multiplied by some factor), known as the reach point factor. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point, and then the relay operates.

The reach point of a relay is the point along the line impedance locus that is intersected by the boundary characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied.

The principle of operation of distance protection as explained above is based on the simple Ohm's law equation:

$$Z = \frac{V}{I} \angle \theta^{o} \text{..................}(6.1)$$

Where: - Z is the system impedance

V is the system voltage

I is the system current

θ^{o} is the angle between voltage and current

Under normal system condition impedance is high but drops very rapidly during abnormal system condition. This is so because current increase drastically while the voltage drops to zero and thereby resulting to low impedance. The basic arrangement of distance relay showing CT and (CVT) connections is shown in figure 6.6.

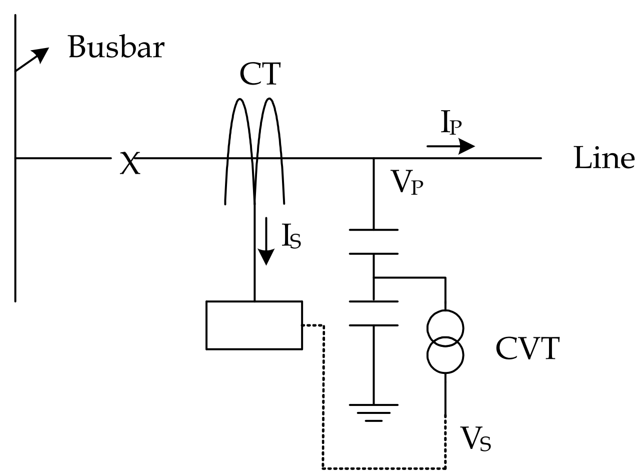


Figure 6.1 Sketch diagram of Distance \Impedance relay Showing CT and CVT connection

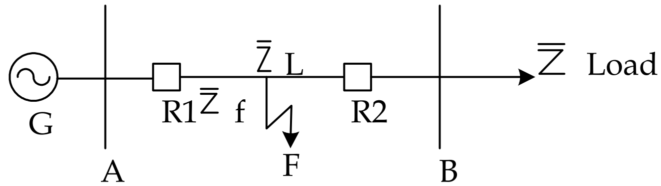


Figure 6.2 A line diagram illustrating protection of Transmission line by distance relay R1 and R2

In figure 6.2 a transmission line under the protection of two distance relays R1 and R2 connects the generator and the load. Figure 6.3 shows the operating principle for distance protection. During normal conditions the apparent impedance as seen by R1 is approximately the load impedance Z load. Hence the apparent impedance as seen by R1 is located far outside the zone of operation; in this case indicated as 1. When the short circuit fault occurs at F the apparent impedance "jumps" into the zone of operation and the relay operates. The new apparent impedance as seen by R1 is the impedance Z_f between terminal A and the fault location F, that is, less than the pre-set impedance value of the zone of operation.

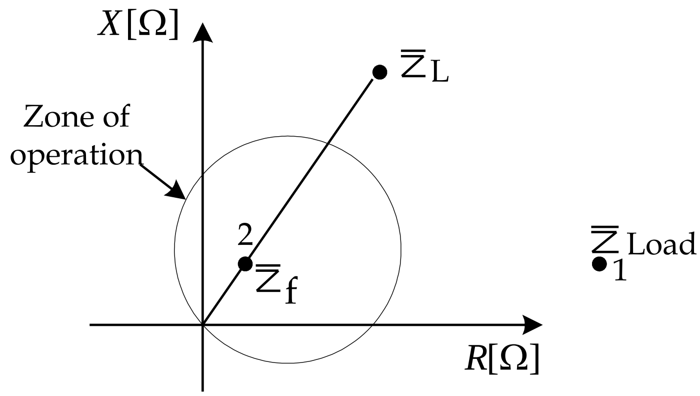


Figure 6.3 RX diagram for distance relay R1 in figure 6.2 , indication 1 refers to normal operation where as 2 indicates the fault situation.

There is always an uncertainty in the parameter involved in a protection system. For example, the line impedance may vary due to temperature and / or the polarization voltage may be distorted. Because of these uncertainties, the entire line in figure 6. 2 is not covered by R1's zone of operation as this may lead to undesirable relay operations for faults immediately behind terminal B. Usually 80 – 85% of the line is covered.

However, to assure fault clearing throughout the entire line an additional zone is used. Figure 6.4 shows three subsequent lines. The zone 1 associated to R1 operates instantaneously for faults located between terminal A and the point, which refers to 80% of the line length between terminals A and B. To cover the remaining 20% of the line zone 2 is used. Thus to assure fault clearing for the entire length zone 2 is typically set to cover 120% of the length. However for a fault close to terminal B on the line between B and C both zone 1 of R3 and zone 2 of R1 will see the fault. To avoid unnecessary line tripping and achieve selectivity, the zone 2 is given a single time delay. Further, a third zone is used to give remote back-up protection in case of failure of the primary protection. Zone 3 is typically set to cover about 120% of the longest adjacent line [32]. Hence when a fault occurs in the middle of the line between B and C zone 1 and zone 2 of R3 will see the fault. Additionally, zone 3 of R1 will see the fault. Thus, if R3 fails to operate then R1 will operate as remote back-up protection. To achieve time selectivity between the different relays and zones of operation, zone 3 is given a doubt delay time. The time delays for zones 2 and 3 are typically in the range of 0.4 s and 1–2 s respectively. The same performance and interaction will take place for relays R2, R4 and R6 as for R1, R3 and R5. However R2, R4 and R6's directional reach is of course reversed as compared to R1, R3 and R5.

In case of series compensated lines some complexity is added to the setting process of the distance protection. These complicating features related to series compensated lines are further described in [33,34].

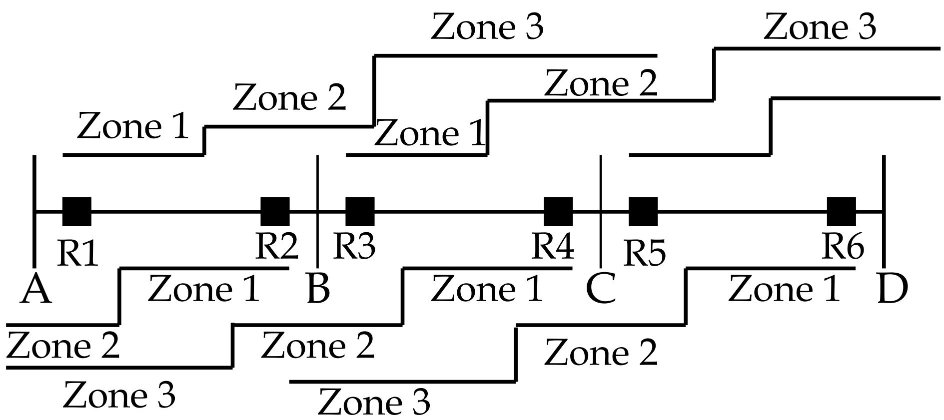


Figure 6.4 The reach of the different zones of operation

Zones 1 and 2 are mainly used to clear local faults on the primary protected line. However zone 3 is used in a number of different applications and the main usages are listed below:

I. To provide remote back up for phase to ground and/or phase-to-phase faults on adjacent sections of transmission circuits in case of failure of the primary protection at remote substations when local back-up protection is not available. For example, in figure 6.4 zones 3 of R3 composes the remote back up for the line between terminals C and D.

II. To provide a remote breaker failure protection for phase faults on adjacent circuits beyond the remote terminal, coincident with failure of a circuit breaker to operate, on application as shown in the right part of figure 6.5 where zone 3 of R4 provides remote breaker failure protection in case the circuit breaker associated to R2 fails to operate.

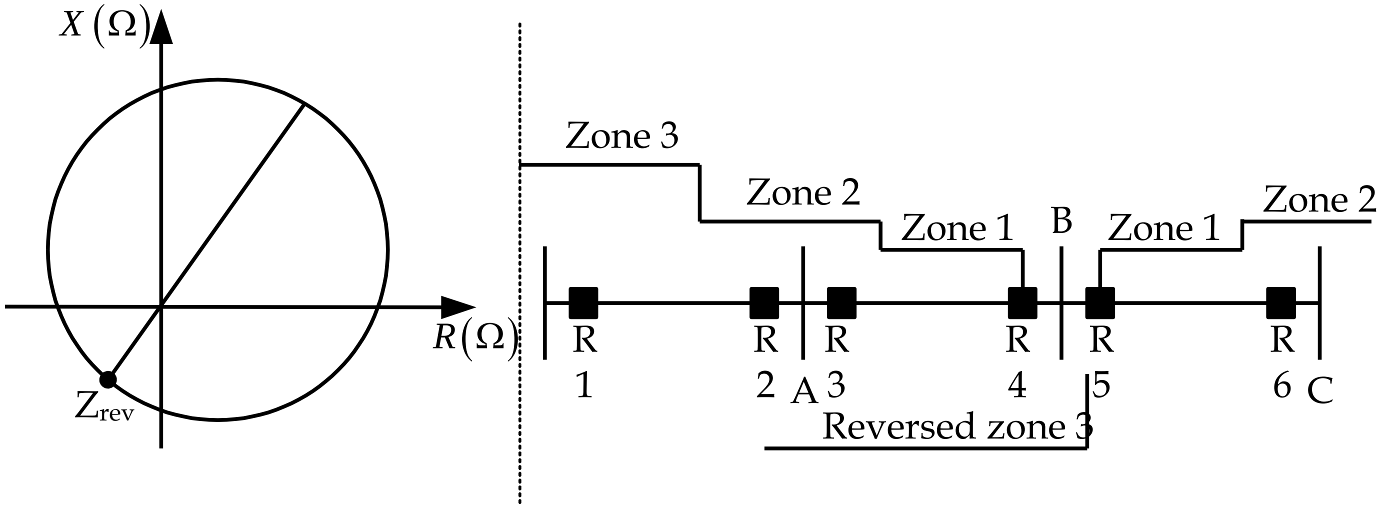


Figure 6.5 Reversed tripping characteristic and illustration of local and remote breaker failure protection

III. Reversed zone 3 elements may provide local breaker failure protection if the impedance characteristic includes the origin; figure 6.5. An example is given in the right part of the figure 6.5 where the reversed zone 3 element of R5 operates as local breaker failure protection in case the circuit breaker associated to R4 fails to operate.

IV. As a starting function for zone 1 and/or zone 2 relays.

V. In some pilot relaying a reverse-looking impedance relay is used to detect faults behind the terminal of the protected line and send a blocking signal to the remote terminal.

VI. In permissive under reach protection schemes [34] the zone 3 may be used as the permissive criteria.

VII. In accelerated overreach protection schemes [31] the zone 3 may be used as the extended zone.

VIII. As reverse-looking impedance relay in some pilot relaying schemes used for weak infeed system configurations [32, 34]. If the reversed zone 3 relay located at the weak infeed terminal, does not see the fault at the time the relay at the remote strong infeed terminal announces the fault. Then the relay at the weak infeed terminal operates or returns the acceleration signal.

IX. As local back up to achieve selectivity in case of infeed from T-lines.

However, the fundamental idea of zone 3 distance relaying is to provide 100% remote back up protection to all adjacent circuits and also to be discriminative in time with zone 2 of all adjacent circuits. [34,35]. Unfortunately, this is not always easy to accomplish due to long lines, infeed and load encroachment. In some cases more than three zones are used. Usually this is to support more than one of the zone3 functions listed above.

In fact, certain utilities have taken their remote backup zone 3 relays out of operation [28]. The main reason is that they are not needed when local back up protection is provided. Local back up may include redundant relay sets that are largely independent, local breaker failure protection and /or busbar protection. Also when reliable pilot relaying scheme and separate directional earth fault overcurrent protection are used, the likelihood for remote back up operation is very small. Zone 3 relays cost money, are added complexity, are taking up rack space and may potentially operate in an undesirable manner during overload. In case of digital relays the space argument is not longer valid. Additionally the hardware cost will not increase much when zone 3 is used in digital applications. However due to the setting complexity the cost for zone 3 is still large.

National Electricity Reliability Council (NERC) Planning Standards Guide III.A.G17 states: *"application of zone 3 relays with setting overly sensitive to overload or depressed voltage conditions should be avoided where possible."* [36]. However, to point out the complexity of the issue related to applying zone 3 as remote back-up the following sentence is quoted from [36]: *"This led to a suggestion for removing line zone 3 protection, on an approach which tackles the symptoms but not the cause of the system voltage instability and should not even be considered".*

6.2.2 Distance Relay Performance

Distance relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual Ohmic reach of the relay under practical conditions with the relay setting value in 0hms. Reach accuracy particularly depends on the level of voltage presented to the relay under fault conditions. The impedance measuring techniques employed in particular relay designs also have an impact.

Operating times can vary with fault current, with fault position relative to the relay setting and with the point on the voltage wave at which the fault occurs. Depending on the measuring techniques employed in a particular relay design, measuring signal transient errors, such as those produced by capacitor voltage transformers or saturating. CT's can also adversely delay relay operating for faults close to the reach point. It is usual for electromechanical and static distance relays to claim both maximum and minimum operating times. However, for modern digital or numerical distance relays, the variation between these is small over a wide range of system operating conditions and fault positions.

6.2.3Distance Relay Characteristic

Some numerical relays measure the absolute fault impedance and then determine whether operation is required according to impedance boundaries defined on the R/X diagram. Traditional distance relays and numerical relays that emulate the impedance elements of traditional relays do not measure absolute impedance. They compare the measured fault voltage with a replica voltage derived form the fault current and the zone impedance setting to determine whether the fault is within zone or out-of zone of protection. Distance relay impedance comparators or algorithms that emulate traditional comparators are classified according to their polar characteristics; the number of signal inputs they have, and the method by which signal comparisons are made. The common types compare either the relative amplitude or phase of two input quantities to obtain operating characteristic that are either straight lines or circles when plotted on an R/X diagram. At each stage of distance relay design evolution the development of impedance operating characteristic shapes (figure 6.6) and sophistication has been governed by the technology available and the acceptable cost.

Since many traditional relays are still in service and since some numerical relays emulate the techniques of the traditional relays, a brief review of impedance comparators is justified.

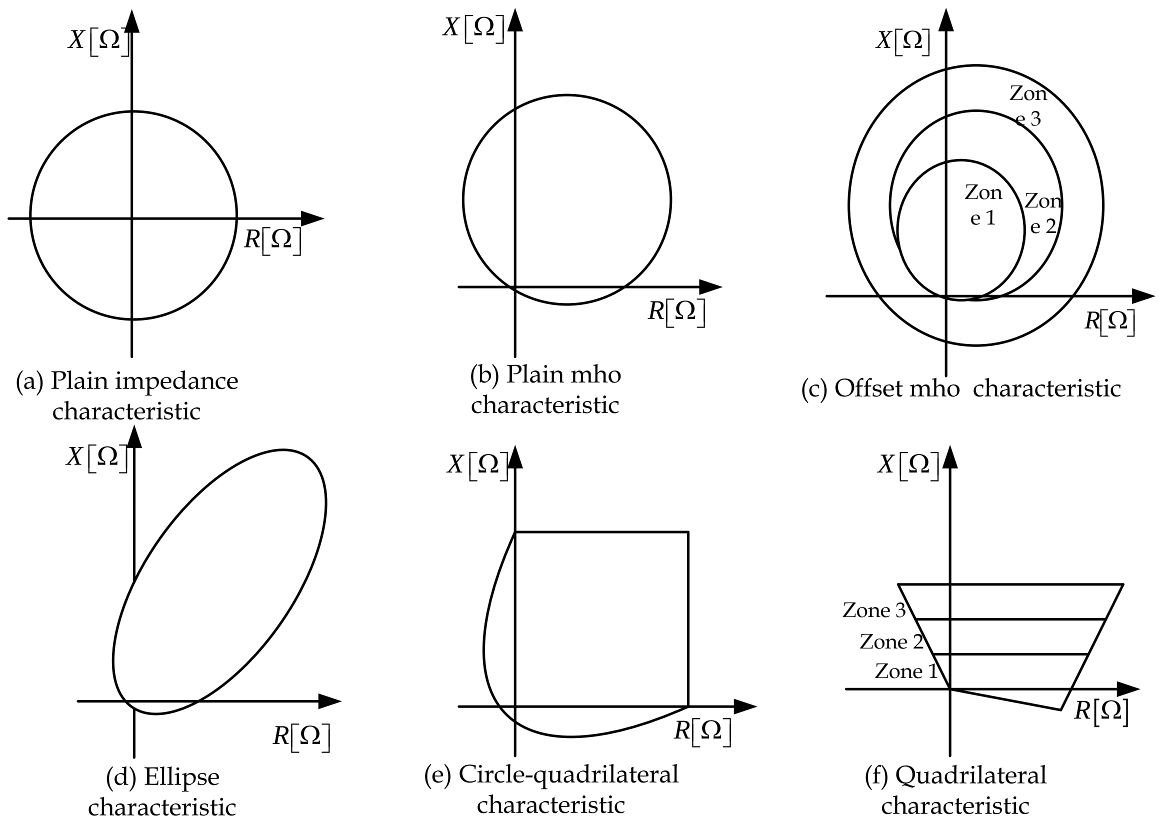


Figure 6.6 The development of the distance relay protection and performance characteristics.

6.2.3.1 Amplitude and Phase Comparison

Relay measuring elements whose functionality is based on the comparison of two independent quantities are essentially either amplitude or phase comparators. For the impedance elements of a distance relay, there are numerous techniques available for performing the comparison, depending on the technology used. They vary from balanced beam (amplitude comparison) and induction cup (phase comparison) electromagnetic relays, through diode and operational amplifier comparators in static-type distance relays, to digital sequence comparators in digital relays and to algorithms used in numerical relays.

Any type of impedance characteristic obtainable with one comparator is also obtainable with the other. The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic center at the origin of the R/X diagram figure 6.6a. If the sum and difference of V and I are applied to the phase comparator the results is a similar characteristic.

6.2.3.2 Plain Impedance Characteristic

This characteristic takes no account of the phase angle between the current and the voltage applied to it; for this reason its impedance characteristic when plotted on an R/X diagram is a circle figure 6.6a with its center at the origin of the co-ordinates and of radius equal to it's setting in ohms. Operation occurs for all impedance values less than the setting, that is, for all points within the circle. The relay characteristic, shown in figure 6.7 is therefore non-directional, and in this form would operate for all faults along the vector AL and also for all faults behind the busbar up to impedance AM. It is to be noted that A is the relaying point and RAB is the angle by which the fault current lags the relay voltage for a fault on the line AB and RAC is the equivalent leading angle for a fault on line AC. Vector AB represents the impedance in font of the relay between the relaying point A and the end of line AB Vector AC represents the impedance of line AC behind the relaying point. AL represents the reach of instantaneous Zone 1 protection, set to cover 80% to 85% of the protected line.

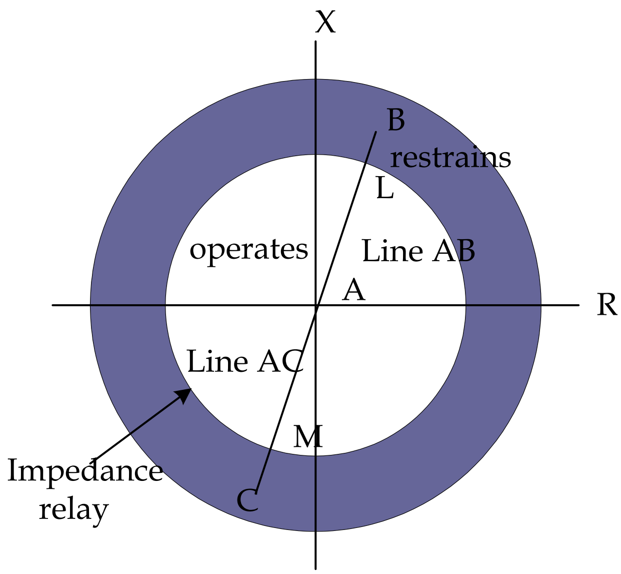
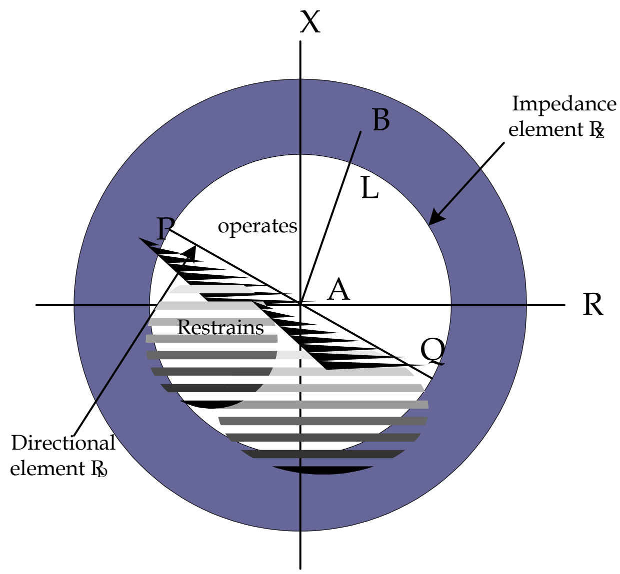
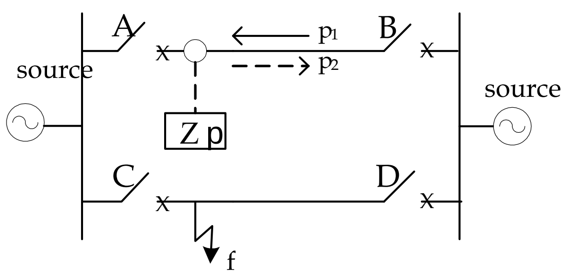


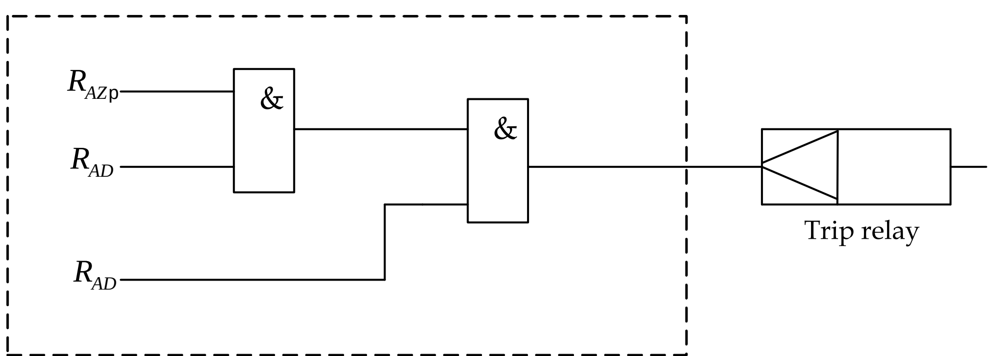
Figure 6.7 Plain impedance relay characteristic



(a) Characteristic of combined directional/ impedance relay characteristic



(b) Illustration of use of directional/ impedance relay circuit diagram



$R_{AZ\,p}$: Distance element at A

R_{AD}: Direction element at A

(c) Logic for directional and impedance elements at A

Figure 6.8 Combined directional and impedance relay

A relay using this characteristic has three important disadvantages:

i. It is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination

ii. It has non-uniform fault resistance coverage

iii. It is susceptible to power swings and heavy loading of a long line, because of the large area covered by the impedance circle.

Directional control is an essential discrimination quality for a distance relay, to make the relay non-responsive to faults outside the protected line. This can be obtained by the addition of a separate directional control element. The impedance characteristic of a directional control element is a straight line on the R/X diagram, so the combined characteristic of the directional and impedance relays is the semi- circle APLQ shown in Figure 6.8.

If a fault occurs at F close to C on the parallel line CD, the directional unit R_D at A will restrain due to current I_{F1}. At the same time, the impedance unit is prevented from operating by the inhibiting output of unit R_D. if this control is not provided, the under impedance element could operate prior to circuit breaker C opening. Reversal of current through the relay from I_{F1} to I_{F2} when C opens could then result in incorrect tripping of the healthy line if the directional unit RD operates before the impedance unit resets. This is an example of the need to consider the proper co-ordination of multiple relay elements to attain reliable relay performance during evolving fault conditions. In older relay designs, the type of problem to be addressed was commonly referred to as one of 'contact race'.

6.2.3.3 General Mho Characteristics

The mho impedance element is generally known as such because its characteristic is a straight line on an admittance diagram. It cleverly combines the discriminating quantities of both reach control and directional control, thereby eliminating the "contract Race" problems that may be encountered with separate reach and directional control elements. This is achieved by the addition of a polarizing signal.

6.2.3.3.1 Plain Mho Characteristic

This type of mho characteristic has circular shape but its center does not pass through the origin. The result of this is that the reach i.e. the limit of operation is not uniform for all the angles and that the impedance element is inherently directional in such a way that it will operate only for faults in the forward direction along line AB. Figure 6.14 shows the diagram.

The impedance characteristic is adjusted by setting Zn, the impedance reach, along the diameter and φ, the angle of displacement of the diameter from the R axis. Angle φ is known as the Relay Characteristic Angle (RCA). The relay operates for values of fault impedance Z_F within its characteristic.

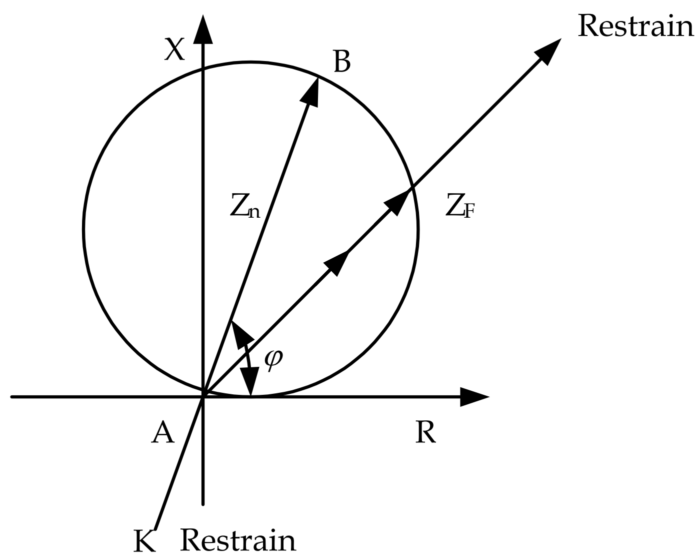


Figure 6.9 Plain mho characteristic

.

6.2.3.3.2 Offset Mho Characteristic

This has special advantage in that the relay can be arranged to provide protection under close up fault conditions, i.e. permits the operation for faults in the forward direction and limited back up in the reverse direction. Typical application is third zone and busbar backup zone. Figure 6.10 shows the offset Mho characteristic.

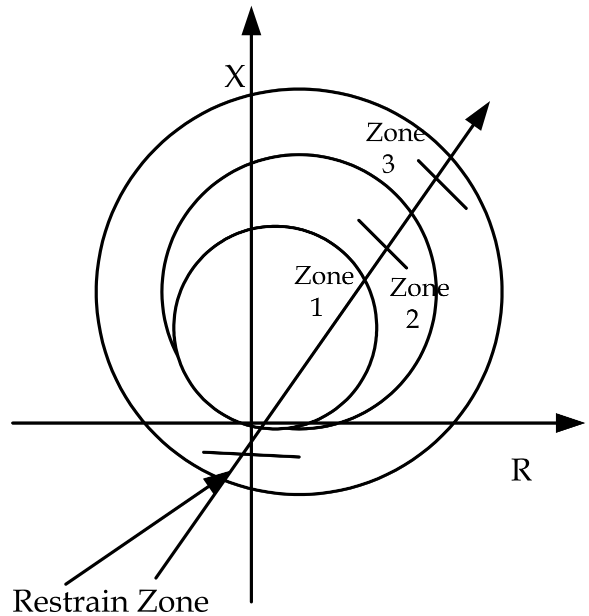


Figure 6.10 Offset mho characteristic

6.2.3.3.3 Lecticular Characteristics

Ellispsetics shape is another mho characteristic. The shape is compressed longitudinally and it is used where more discriminative operation is required in the direction of the line than in the direction of the Load. It tolerates much higher degrees of line loading than offset mho and plain impedance characteristics; figure 6.11 shows the characteristic diagram.

A general categorization can be made between the different shapes of the zone of operation and the different relay types. Electromechanical relays usually have a circular shape. For example the YTG relay shape is based on the mho characteristic.

Solid-state relays have a combination of circular and quadrilateral characteristic or a simple quadrilateral characteristic. Examples are the ASEA RAZOA relay, which has the circle–quadrilateral shape or the SIEMENS 7SL24 relay with the quadrilateral Constant resistive reach characteristic. Numerical relays generally have a quadrilateral characteristic where the reach can be set independently in resistive and reactive directions. An example is the Siprotec and Ohmega relays.

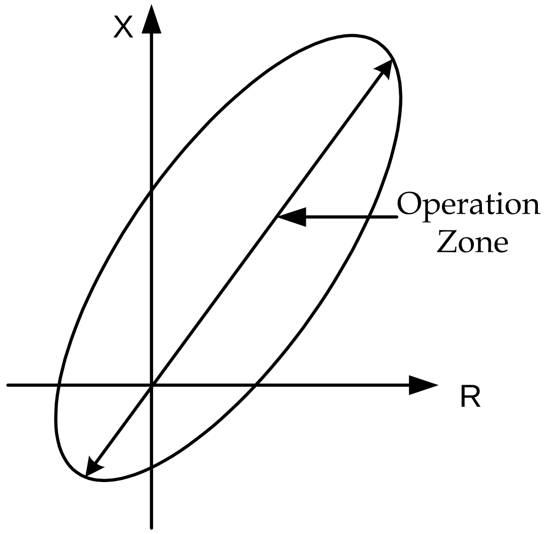
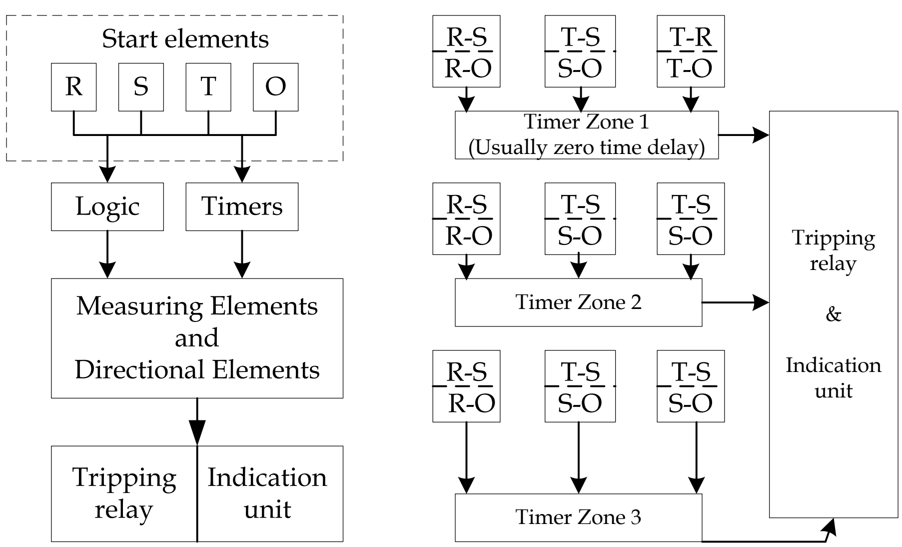


Figure 6.11 Lecticular characteristic

6.2.4 Distance Relay Types.

Distance protection are usually divided into two groups; switched and unswitched (full scheme) schemes. Different arrangements exist depending on the manufacture of the relay. Figure 6.12 illustrates the block diagram of switched and unswitched distance protection.



(a) switched distance relay (b) full scheme switched distance relay

Figure 6.12 Block diagram of Distance relay

In the switched distance protection scheme, there is only one measuring unit. The fault is detected by the start elements and the start elements and mathematical logic blocks determine the correct input signals with respect to the fault type for the measuring elements. Additionally, timers are used to decide which zone of operation (reach) has to be applied. When the apparent impedance as seen by the measuring element is within the (pre-set threshold for the) active tripping zone, and the directional element sees the fault, the tripping signal is sent. Examples of switched distance relay are the Siemens 7SL24 relay and the ASEA RAZOA relay.

In the unswitched type of relays, there are separate measuring element for each type of fault and each zone per phase. Hence the start elements are not required. During operation no switching occurs and the operation is faster than for switched relays. However there are four generations of relays:

(a) Electromechanical relay;

These mechanically driven electrical (disk or cylinder) relays are single phase only and are dedicated to a single protection function. The probability of failure increases dramatically as they approach the end of their useful life (20years or more) [37-39]. Electromechanical relays provide only a single curve choice and feature very limited adjustment settings. Also, different types of these relays are required to meet the coordination requirements. To this effect large space is required for installation making it economically disadvantaged as compared to other types of relays.

(b) Solid state relay;

Solid-state (static) relays are in most cases single phase and significantly smaller and lighter than electromechanical relays. They are less sensitive to dusty conditions and are not subject to wear. However, electronic component drifts can occur with age or in extreme ambient temperatures and the related voltage surges may be problems.

(c) Integrated relay

Integrated relays are similar in design and function to solid state relays but uses mostly integrated circuit rather than discrete components. Integrated circuit allows these relays to combine three-phase ground and current protection, metering, communication, control and monitoring capabilities. Although these relays do not perform as well as digital ones, they are comparably priced.

(d) Digital /numerical relays

These microprocessor-and software – based relays feature advanced programmable functions which maximize flexibility and monitoring capabilities, and offer a wide choice of trip curves and self–test capabilities. The microprocessor replaces most of the electronic circuitry; thereby maximizing integration of advanced protection functions, control/monitoring alarms and annunciation, metering and communication into a single device. Use of digital technology significantly reduces the risk of drift. The unit has a high immunity to electromagnetic fields and transients, and is designed for harsh environments and a wide range of operating temperatures. Fundamentally, the microprocessor relays are superlative to any pervious methodology. The system usually operates on a single power supply. If the supply is down, the whole system is down. Similarly, nonintegrated electro–mechanical units may also trip upon the failure of one of the other components. Yet, the drawback to the relay can be overlooked because:

1. There is a back up, an electromechanical or other microprocessor relay.
2. The microprocessor's intrinsic self–diagnosis reporting alerts the utility that a malfunction must be resolved.
3. Reduced engineering and drafting requirements. Space saving (switch board and control building).

Figure 6.13 illustrates a block scheme of a typical numerical relay [39].

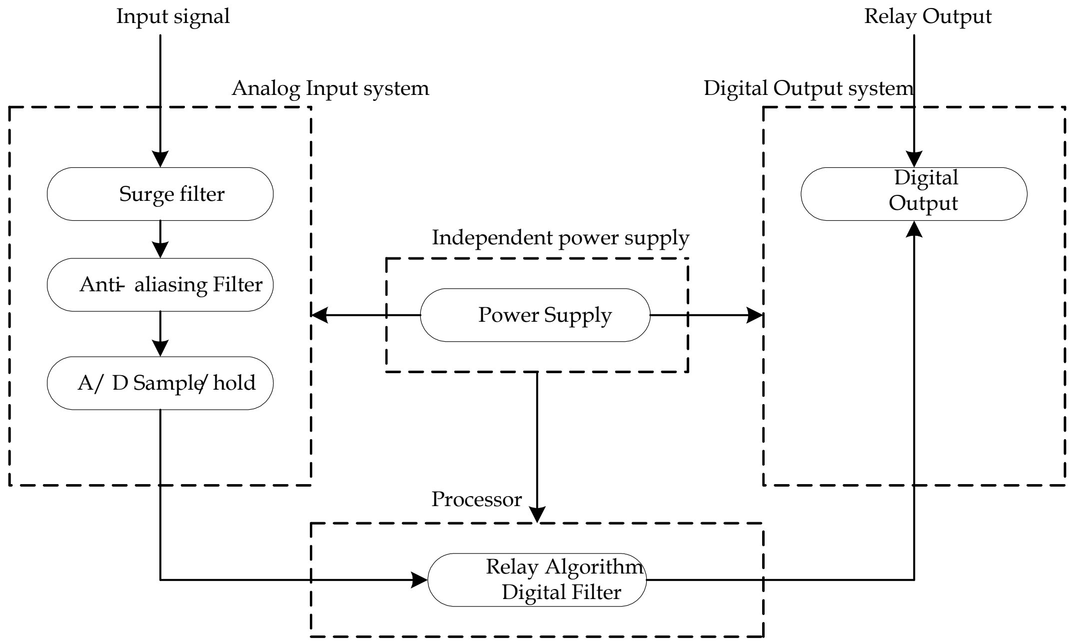


Figure 6.13 Block diagram of a numerical relay

6.2.5 Evaluation of Distance Protection

Distance protection is intended to clear all types of phase-to-phase faults and phase to ground faults. Using symmetrical components and the system in figure 6.14, the inputs required for the distance relay to distinguish all possible fault conditions may be determined.

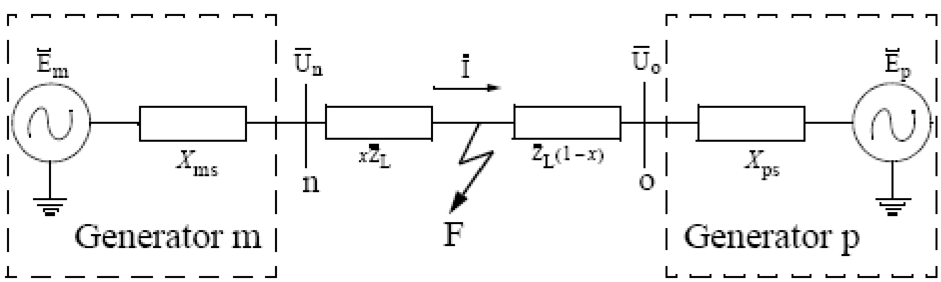


Figure 6.14 a two-machine arrangement.

In figure 6.14 two generators at terminals n and o are connected through a transmission line. Different fault types at the location F are studied where F is located at the point referring to x % of the total line length as seen from terminal n. The impedances included in the system are indicated in figure 6.14 where the line impedance is divided into two sections with respect to the fault location. The positive and negative sequence impedances are considered to be the same for the line. This is a common assumption made during these types of studies. For the symmetrical component circuits in figures 6.15 and 6.16 the same notation is used where subscript 1 relates to the positive sequence component and the subscripts 2 and 0 to the negative and zero sequence components respectively.

A detailed introduction to symmetrical components can be found in [40]. However, the main equations for the voltages are repeated below where the a-operator is defined. Equations (6.9) to (6.17) may also be used for currents. In that case the corresponding currents replace the voltages.

Now consider an unbalanced three-phase system

$$\overline{U}a = \overline{U}a1 + \overline{U}a2 + \overline{U}a3 \quad (6.2)$$
$$\overline{U}b = \overline{U}b1 + \overline{U}b2 + \overline{U}b3 \quad (6.3)$$
$$\overline{U}c = \overline{U}c1 + \overline{U}c2 + \overline{U}c3 \quad (6.4)$$

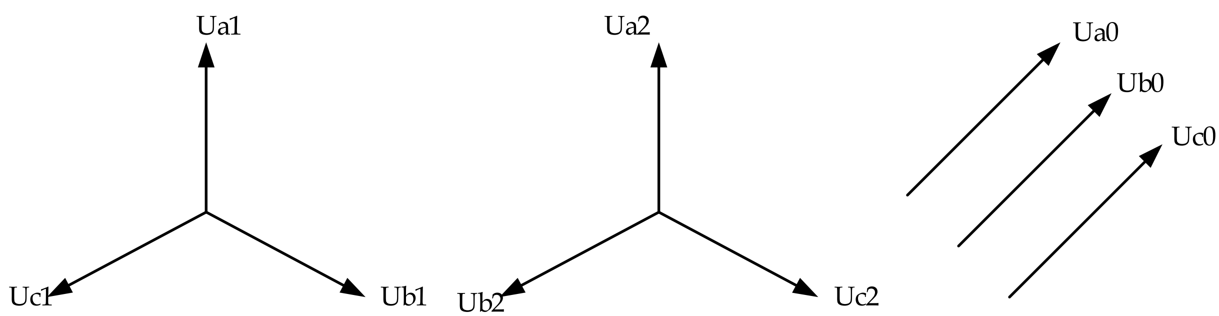


Figure 6.15 symmetrical components

Choose "a" phase as the reference phase and replace Ua3 by Uao

$$\overline{U}a = \overline{U}a1 + \overline{U}a2 + \overline{U}a0 \quad (6.5)$$
$$\overline{U}b = a^2\overline{U}a1 + a\overline{U}a2 + \overline{U}a0 \quad (6.6)$$
$$\overline{U}c = a\overline{U}a1 + a^2\overline{U}a2 + \overline{U}a0 \quad (6.7)$$

$$\text{Where } a = e^{j\frac{2\pi}{3}} = 1.0\angle 120^0 \quad (6.8)$$

It is convenient to delete subscript "a" for the symmetrical components, so that equations, 6.5 to 6.7 become;

$$\overline{U}a = \overline{U}1 + \overline{U}2 + \overline{U}0 \text{.............................}(6.9)$$

$$\overline{U}b = a^2\overline{U}1 + a\overline{U}2 + \overline{U}0 \text{........................}(6.10)$$

$$\overline{U}c = a\overline{U}a1 + a^2\overline{U}2 + \overline{U}0 \text{......................}(6.11)$$

Add equation 6.9, 6.10 and 6.11

$$\overline{U}a + \overline{U}b + \overline{U}c = 0$$

$$\overline{U}0 = \frac{1}{3}\left(\overline{U}a + \overline{U}b + \overline{U}c\right) \text{...................}(6.12)$$

Multiply equation 6.10 by "a" and equation 6.11 by a^2 and add the resulting equations to equation 6.9,

$$\overline{U}a + a\overline{U}b + a^2\overline{U}c = 3\overline{U}1$$

$$\therefore \overline{U}1 = \frac{1}{3}\left(\overline{U}a + a\overline{U}b + a^2\overline{U}c\right) \text{..............}(6.13)$$

Multiply equation 6.10 by a^2 and equation 6.11 by a and add the resulting equations to equation 6.9,

$$\overline{U}a + a^2\overline{U}b + a\overline{U}c = 3\overline{U}2$$

$$\therefore \overline{U}2 = \frac{1}{3}\left(\overline{U}a + a^2\overline{U}b + a\overline{U}c\right) \text{..............}(6.14)$$

Equation 6.9 to 6.14 can be re-written in matrix form.

$$\begin{bmatrix} Ua \\ Ub \\ Uc \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} U0 \\ U1 \\ U2 \end{bmatrix} \text{................}(6.15)$$

$$\begin{bmatrix} U0 \\ U1 \\ U2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} Ua \\ Ub \\ Uc \end{bmatrix} \text{.............}(6.16)$$

In case of a phase-to-phase fault between phase's b and c at F to earth the corresponding symmetrical component network is shown in figure 6.16. Hence U1 and U2 are equal which gives the relation in (6.17).

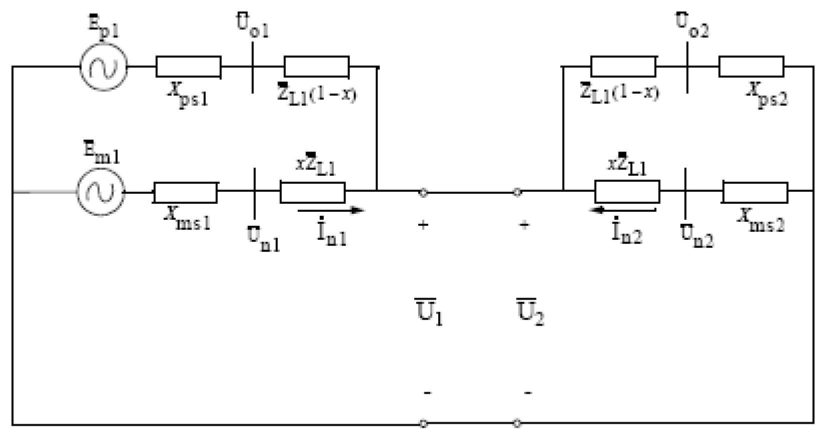


Figure 6.16 Symmetrical component circuit for a phase- to-phase fault Between phases b and c.

$$\overline{U}n1-\overline{Z}L1.\overline{I}n1=\overline{U}n2-\overline{Z}L1.\overline{I}n2 \text{...........(6.17)}$$

After some rearrangement (6.17) is given as in (6.18)

$$x\overline{Z}L1=\frac{\overline{U}n1-\overline{U}n2}{\overline{I}n1-\overline{I}n2} \text{.......................(6.18)}$$

When (6.13), (6.14) and the corresponding equations for the currents are inserted into (6.18) the following expression is given for the impedance between terminal n and the fault location.

$$x\overline{Z}L1=\frac{\overline{U}nb-\overline{U}nc}{\overline{I}nb-\overline{I}nc}=x\overline{Z}L \text{..............(6.19)}$$

In other words to detect the correct fault location for phase to phase faults between phases b and c the input signals for the distance relay should be the phase currents and voltages for these phases. If a similar investigation is made for all the remaining combinations of possible phase to phase faults it is found that equation (6.19) is also applicable in these cases though the input signals must be changed to the affected phases.

Equation (6.19) is also applicable for three phase faults or double phase to earth faults. This can easily be verified by performing a similar analysis based on symmetrical components for these specific fault cases [41].

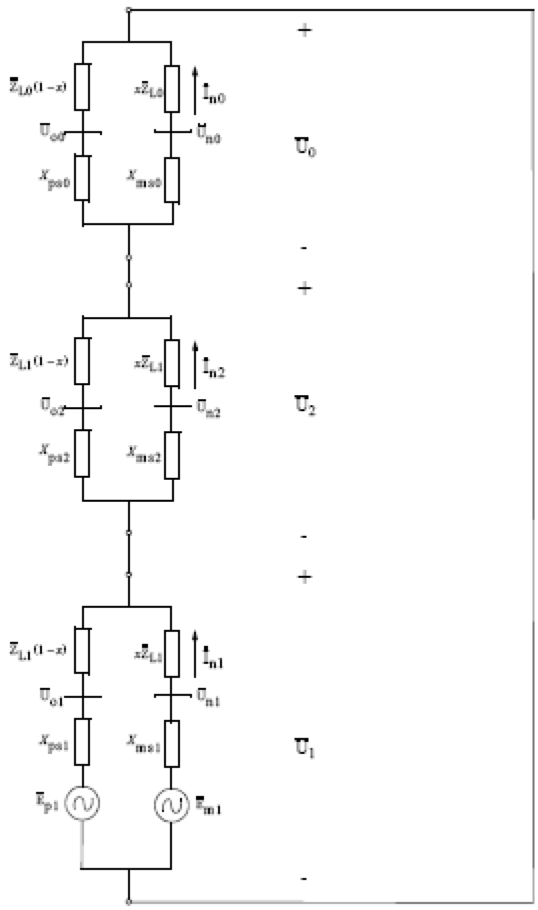


Figure 6.17 systematical circuit for phase a to ground fault.

When a short circuit is applied between the phases "a" and ground at F in figure 6.19 the corresponding symmetrical component network is given as in figure 6.22. Relations (6.20) to (6.23) can be determined from figure 6.17. As indicated above the positive and negative sequence impedances for the transmission line are identical. However, the zero sequence impedance is typically three times larger in case of transmission lines.

$$\overline{U}n1 = \overline{U}1 + x\overline{Z}L1.\overline{I}n1 \ldots\ldots\ldots\ldots(6.20)$$

$$\overline{U}n2 = \overline{U}2 + x\overline{Z}L2.\overline{I}n2 \ldots\ldots\ldots\ldots(6.21)$$

$$\overline{U}n0 = \overline{U}0 + x\overline{Z}L0.\overline{I}n0 \ldots\ldots\ldots\ldots(6.22)$$

$$\overline{U}1 + \overline{U}2 + \overline{U}0 = 0 \ldots\ldots\ldots\ldots\ldots\ldots(6.23)$$

When (6.20), (6.21) and (6.22) are inserted into (6.23) and equation (6.18) and the corresponding current equation are applied, the impedance between terminal n and the fault is given as in (6.24).

$$x\overline{Z}L1 = \frac{\overline{U}na}{\overline{I}na + In0.\dfrac{\overline{Z}L0 - \overline{Z}L1}{\overline{Z}L1}} = x\overline{Z}L.............(6.24)$$

Where xZL: apparent impedance as seen by the distance relay

Una: phase a voltage at the relay location.

Ino: Residual (zero-sequence) current at the relay Location.

ZLO, ZLI: Sequence impedance for the primary protection circuit.

Ina: phase current at the relay location.

In order to decide the correct fault distance for a single short circuit fault between phases “a” and ground the phase voltage and phase current at the relay location should be used as inputs to the distance relay. Additionally, the residual current as seen by the relay must be included. The same equation is applicable for all combinations of single phase to ground faults, though the associated voltages and currents must be applied as relay inputs. Equations (6.18) and (6.24) explain that distance relays use the phase voltages and currents to determine the apparent impedance for fault localization. Zone2 and zone3 setting in distance relay required the apparent impedance between adjacent terminals in the network. Determination of apparent impedance for a large network is very complicated. However a computer software programme can be used. The Nigeria’s transmission network model in chapter four was further used to calculate the apparent impedance (distance relay evaluation) of the network.

6.3 Line Protection in the Nigeria Transmission System.

The line protection in Nigeria transmission system consists of the two independent (redundant) protection scheme for each line called main 1 and main 2 .The main reasons for this is to provide back up protection in case main 1 fails to operate. Additionally, to allow maintenance work to be carried out on one relay, while the line is loaded but it is still satisfactorily protected by the second relay or second protection scheme, main 2.

6.6.1 Outline of the Protection Scheme at the Line Terminal.

Figure 6.18 shows an outline of the standard line protection system in the Nigerian transmission system. Most line terminals in the network, apart from limited numbers of 132kv terminals, are equipped with a system identical or similar to the one in figure 6.18.

Most devices are duplicated though the two main groups share a few components. The same voltage and current transformers are used. None of the circuit breaker is duplicated. However independent fuses protect the voltage signals from the VT into the two main groups and same CT coils are use for the current signals. The DC supply for the two main groups are separated and are not allowed to share any fuse. Below gives the description of the abbreviations in figure 6.18.

DP = Distance Protection

JS1-JS23 = Zone 1 to 3 of the directional definite time over current elements.

JS3 1NV= the non – directional inverse time over current element.

UO= Zero voltage protection

COM = Pilot Relaying Equipment

AR=Auto Reclosing

BFP= Breaker Failure Protection

SS= Busbar Protection

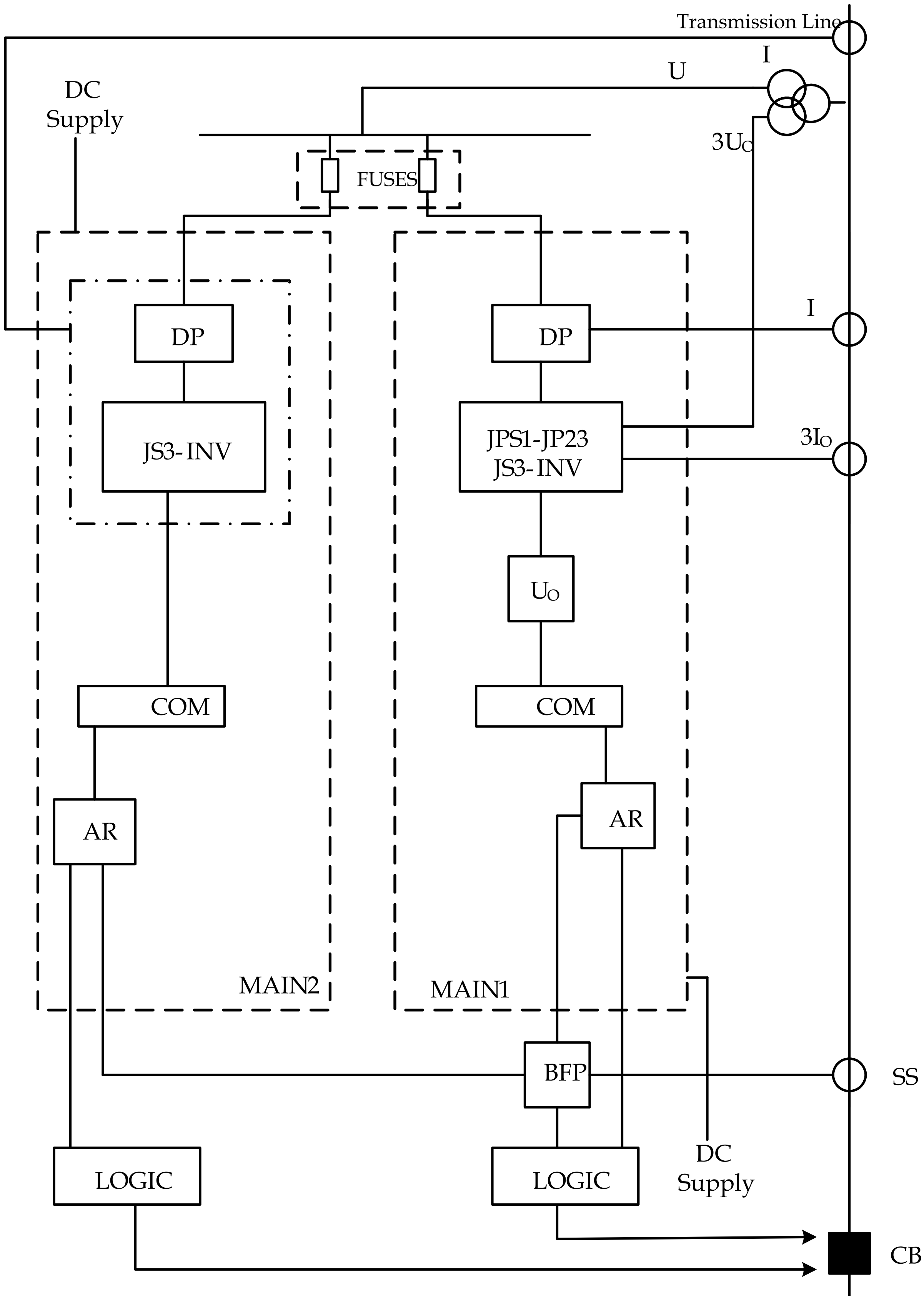


Figure 6.18 Line protection system

Both main 1 and main 2 contain a distance relay, which is intended to clear short circuit faults. Additionally, main 1 includes earthfault overcurrent relay. However to assure clearing of small residual currents in case of maintenance work on main 1 an inverse time earth –fault over current relay is required in main 2. Generally the earth fault overcurrent protection performs better than distance protection in case of a large fault resistance and gives a higher number of successful auto-reclosure.

Also, earthfault is about 80% of the faults in power systems and these types of faults are mainly cleared best by earthfault overcurrent protection [32]. This is why the local backup is very important in the system. There are few cases where local back up (earthfault) overcurrent relay trip on earthfault without the main 1 and main 2 tripping in event of the fault. The disadvantage of this type of overcurrent protection is that their reach is dependent of the prevailing network configuration. Hence when extensive network reconfigurations are made the relays must be given new settings to operate as intended. Another drawback with the earthfault overcurrent protection scheme is that a good knowledge of the positive, negative and zero sequence impedances of the system are required to give the relay proper settings. Additionally, the calculation process is complicated. However, computer software can be used for this process and this was one of the achievements of this work.

Breaker failure protection and busbar protection are included in the scheme although they are classified as substation protection. Pilot relaying is widely used to decrease the fault clearing time, pilot-relaying schemes mainly "accelerated under reach" and "intertripping under reach".

At a few substations phase comparison relays are being used as main1 line protection. Example of such line is Jebba TS (B8J and B9J). Very important Transmission lines particularly those emanating from power stations are generally provided with two main protections schemes. The type of distance protection provided also depends on the operating voltage level of the line. For 132kv and below, switched types of distance protection are used whereas non-switched types are used for higher voltage level. Where two distance relays are used to provide main 1 and main 2 protection schemes, the normal practice is to use either two different types of relays or same, but different manufactures. For example, an electro-mechanical relay may be combined with a solid-state relay or numerical relay or two numerical relays of different manufacturers such like Ohmega and Siprotect (Siemens) numerical distance relays. This is widely practiced in Nigeria transmission Network. The background for the decision was to increase reliability, as two different relays probably will not suffer from the same inadequacies. Today this philosophy is slowly changing because (almost) all relays manufactured are numerical and largely based on the same algorithms. However, still different designs of relays are required in the two main groups although they must not necessarily be of different brands. The main reason for this requirement is to safeguard against software inadequacies. Another reason may be that it is harder to give two different relay types incorrect settings as compared to identical relays as the "copy and paste" technique may be avoided.

6.3.2 Mixture of Distance Relays

Three-relay technologies are presently used in the power system protection in Nigeria: 1 Electromechanical relays, 2. Solid–State relays and 3. Numerical/ Microprocessor relays. Today, there are distance relays that are more than 15years old in the Nigerian transmission system. However, these relays might be soon replaced as the industry is undergoing reform. About 152 distance protection devices are installed and these are made of different technologies, Table 6.1 and Table 6.2 show the statistics.

Table 6.1 Mixture of different types of distance relays

	Electromechanical	Solid -State	Numerical
Main 1	24	2	63
Main 2	34	-	22
Total	58	2	87

Table 6.2 Mixture of different types of numerical distance relay

	Optimho	Siprotec	Ohmega
Main 1	37	20	6
Main 2	4	--	18
Total	41	20	24

The electromechanical relays (Table 6.1) still comprise of large fraction of the lines protection relays, which are being slowly changed. Use of the microprocessor relay in the network is gradually progressing from experimental to frontline protection schemes. Although the industry is changing, the potential selectors of the microprocessor relays remain fairly constant. Utility managers, Engineers, consultants, operations personnel and technical staff: these people are affected by the change from electromechanical to microprocessor relay. While implementation of this new technology appear to be over whelming to many of these people. Most personnel have not readily the grasp new concepts and advantages of the new technology and its expanded features.

The resistance to change is understandable, but to meet the needs of the protective – relay applications, individuals must adjust to the new methodology. It is often stated that there is no single correct way to design a protection system. Achieving the balance between security and dependability is a highly subjective process, one that is often described by the phrase that "*relaying is an art and not a science*". Therefore, the protection engineer must hold Murphy's Law at the same stature as Ohm's Law when plying his trade. The design and setting of the protective relaying system must account for what will happen for any type of fault that can occur in the power system and any type of failure that can occur in the operation of the protection system. Many people involved in power system design and operation understand how these protective relaying systems operate when everything is working, as it should. The real key to being a good protection engineer is to know how the protection system operates when everything is not working, as it should. To this end, a thorough understanding of each part of the protective system and the power system it protects and how each interacts and overlaps is required. This depth of understanding only comes with determination and practical experience, which then brings the knowledge.

6.4 Algorithms for Distance Relay Setting

Careful selection of the reach setting for the various zones enables correct co-ordination between distance relays in a power system. Numerical distance relays have up to five zones; some are set to operate in reverse direction. However, the basic zone of protection as practiced comprises of instantaneous directional zone 1 and two more time delayed zones. Figure 6.19 illustrates the zones of protection of a line JK under the protection of relay RI and R2.

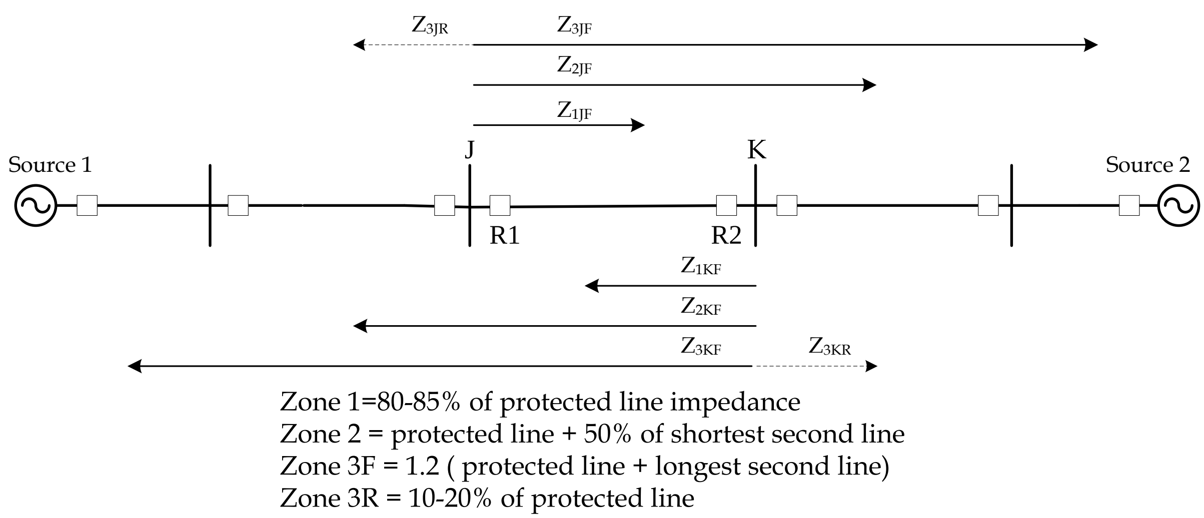


Figure 6.19 Typical diagram illustrating three zone distance protection co-ordination

STEP 1 Data Required for the Setting Calculation

The line parameter:

1) Positive and zero sequence impedance of the line (Z_1, Z_O)
2) Length of line under protection.
3) Current & Voltage Transformer Ratios (CTR & VTR).

STEP 2 Distance Protection Settings.

<u>2.1 The following first settings are common for the three zones.</u>

1. The CT secondary current is set to 1A or 5A depending on the CT rating.

2 Set the line angle on the relay; the line angle is the angle of the positive impedance of the line.

3 Residual compensation settings:

The zone reach setting for each zone of protection is made in terms of the positive sequence impedance of the transmission line. To allow the earth fault comparators to correctly take account of the fault Loop impedance, the ratio of voltage to current is multiplied by a compensation factor, which may be determined from the following equation:

$$K_N = \frac{1}{3}\left[\frac{Z_0}{Z_1} - 1\right] \text{.............................(6.25)}$$

Settings made on the relay are:

EF. Compensation $\frac{Z_0}{Z_1}$ ratio (the ratio between the zero and positive sequence impedances)

EF. Compensation Z_o angle (angle of the zero sequence impedances).

<u>2.2 Zone 1 impedance setting</u>

The normal practice is to make the zone 1 setting equal to 80% of the positive sequence impedance of the protected line to allow for the inherent errors in estimating line impedance and possible errors in voltage and current transformers. The tripping is instantaneous in the case [32, 33].

Zone 1 = 80% of protected line impedance

The zone 1 resistance setting for earth fault quad characteristics is set to give an adequate. Resistance coverage to allow for tower footing resistance and arc resistance. This setting is required in secondary ohms.

<u>2.3 Zone2 impedance setting</u>

Zone 2 impedance setting: is set to cover 50% of the shortest second line taking into account the effect of infeed at the remote end. Zone 2 ensures complete protection coverage of the line under protection. To achieve selectivity zone 2 is given single time delay before tripping.

Zone 2 = Zone 1 setting + 50% of shortest second line apparent impedance.

The Zone 2 resistance setting for earth fault quad characteristics is set to give an adequate resistance cover to allow for tower footing resistance and arc resistance. This setting is required in secondary ohms and is often set to the same value as Zone 1 resistance.

Zone2 and Zone3 times are normally set to give a grading merging between the Zones and ensure that fault clearance times are achieved.

2.4 Zone3 impedance setting

The zone 3 impedance setting will depend upon the system adjacent to the protected feeder and the amount of back up protection required. To give back–up protection on the protected feeder, the Zone 3 should be at least equal to but not less than the Zone 2 settings.

The zone 2 and zone 3 timers are normally set to give a grading margin between the zones and ensure that fault clearance times are achieved [32].

Zone 3 forward reach is obtained are follows.

Zone 3 forward Z3F = 1.2 (Zone1setting + longest second line)

Zone 3 reverse Z3R = 10% of Zone 1 setting.

STEP 3. Power Swing Blocking

Power swing blocking (Z6) is generally set concentric with Zone 3 characteristic. The settings expression depends on the type of relay to be used

With Zone 3 set looking in forward direction:

Z6 [Inner] = Zone 3 Forward

Z6 [Outer] = 1.5 X Zone 3 Forward

With Zone 3 set looking in reverse direction:

$Z6^1$ [Inner] = Zone 3 Reverse

$Z6^1$ [Outer] = 1.5 X Zone 3 Reverse

STEP 4 Determination of Expected Distance (km)

Expected Distance (km) =

$$\frac{Injected \quad Voltage}{Expected\ Zone1\ \mathrm{Re}ach\ (Volt)} \times 0.8 \times Length\ of\ \ Line\ (Km) \ldots\ldots\ldots\ (6.26)$$

The injected current is kept constant, while varying injected voltage to check the accuracy of the fault location measurement. This method is only applicable to alternative method; other test equipment may require different approach.

Expected Zone 1 Voltage Reach is calculated as follows:

For Phase to Phase Fault:

$V_1 = 2 \times Z_1 \times I_{Inj}$ ……………. (6.27),

where Z_1 is Zone 1 setting and I_{Inj} = Injected Current.

For Phase to Earth Fault:

$V_1 = (1+K_N) \times Z_1 \times I_{Inj}$… … …. (6.28),

where K_N is Residual Compensation factor.

The idea behind equations (6.27) and (6.29) is that during a phase to phase fault, the fault loop impedance is the impedance between two phases i.e. current circulate from source to fault point in the two phases involved and since the impedances of the two phases are the same hence 2 x Z_1 is considered. But for a phase to earth fault, current circulation is in the faulted phase through the earth back to the source from the fault point. Hence the impedance of one phase and residual comp factor (K_N) are considered.

The constant 0.8 in (6.26) is to take care of the 80% of Zone 1 setting since Zone 1 reach is used as the reference Zone. It is easy to use Zone 1 as the setting is just a fixed % of the total length of the line and more so, most manufacturers do not guarantee accuracy of fault location for fault beyond Zone 1 or 100% of the total length of the line.

STEP 5 Commissioning Flow-chart for Protective Relay:

The figure 6.20 shows the procedure for commissioning a protective relay, this is to ensure that the overall protective system function correctly as designed.

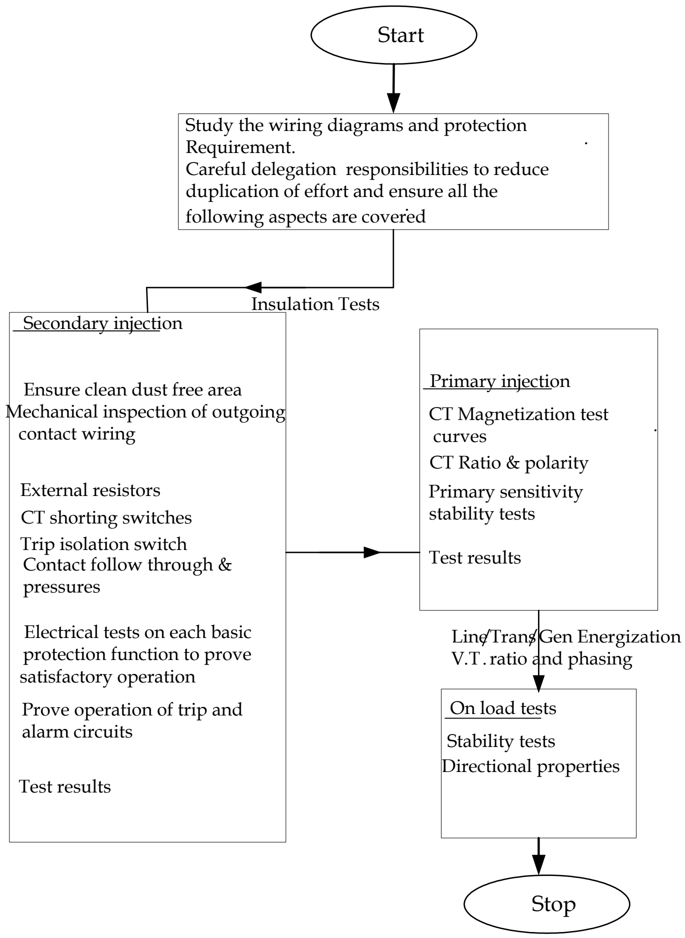


Figure 6.20 Commissioning chart for protective relay flow

At the end of each stage it is necessary to ask oneself "is there any thing that may be wrong, wiring or otherwise, that I have not checked that may prevent correct operation?" – If so, CHECK IT OUT!

6.5 Practical application example to distance relay settings

The following details give the setting calculations of distance setting for the protection of the line between Benin and Oshogbo (H7B**).** Figure 6.27 shows the line under protection and adjacent lines.

1.1 Relay location (substation): Benin

Circuit (Line): Oshogbo [H7B]

Type of Relay: Ohmega.

1.2 Line parameters (System Data)

Line Length: 251km

$$CTR:\frac{1500}{1} \text{ and } VTR:\frac{3000}{1}$$

Per unit impedance values are;

$$Z_1 = 0.0089 + j0.0763pu$$

$$Z_0 = 0.0636 + j0.225pu$$

Actual impedance values

$$Z_1 = 9.69 + j83.1 = 83.67\angle 83.3^0\,\Omega pry$$

$$Z_0 = 69.26 + j247.2 = 256.72\angle 74.35^0\,\Omega pry$$

The corresponding secondary actual positive impedances value:

$$Z_1 = (9.69 + j83.1)\frac{CTR}{VTR} = 4.98 + j41.55 = 41.8\angle 83.3^0$$

1.3 EF compensation ratio:

$$\frac{Z_0}{Z_1} = \frac{256.72\angle 74.35^0}{83.67\angle 83.3^0} = 3.07\angle -8.95^0$$

1.4 Residual compensation factor KN:

$$KN = \frac{1}{3}\left[\frac{Z_0}{Z_1} - 1\right] = \frac{1}{3}\left[3.07\angle -8.95^0 - 1\right] = 0.697\angle -13.3^0$$

1.5 <u>Zone 1 setting</u>

Required Zone 1 reach = 0.8 x Positive impedance of the protected line.

$$= 0.8x41.8\angle 83.3^0 = 3.9 + j33.21 = 33.44\angle 83.3^0\,\Omega\sec$$

1.6 <u>Zone 1 resistance</u> setting for earth fault quad characteristic:

$$X\left[Zone1\right] = 33.21\Omega\sec$$

$$R\left[Zone1\right] = 3.9x2 = 7.8\Omega\sec$$

$$R_{1E}\left[Zone1\right]pry = R_{1Line} + \frac{1}{2}R_{arc} + R_{Tower}$$

Taking arc resistance and tower footing resistance to be 6 ohms and 10 ohms respectively.

$$R_{1E}\left[Zone1\right]pry = 7.8 + 3 + 10 = 20.8\Omega pry$$

The secondary corresponding value is 10.4 ohms sec.

1.7 Zone 2 Setting

The apparent impedances of the remote ends to Oshogbo substation seen by the relay located at Benin (figure 6.22) are listed below: These values were obtained from computer simulation studies of the apparent impedance (distance relay evaluation) on the Nigeria transmission network modelled in chapter five.

JEBBA TS = $138.39\angle 83.1^0 \Omega pry$

AYEDE = $292.38\angle 87.5^0 \Omega pry$

IKEJA WEST = $931.38\angle 231.9^0 \Omega pry$

The shortest second line is Jebba TS with apparent impedance of $138.39\angle 83.1^0 \Omega pry$

Required Zone 2 Reach = Protected line impedance + 50% [shortest second line apparent impedance].

$$= 83.67\angle 83.3^0 + 50\%\left[138.39\angle 83.3^0 - 83.67\angle 83.3^0\right]$$

$$= 111.05\angle 83.3^0 \Omega pry$$

$$= 55.53\angle 83.3^0 \Omega \sec$$

1.8. Zone 3 Setting

Required Reverse Zone 3 Reach [Z3R]=10% Of Zone 1 Setting

$$= 0.1x41.8x0.8\angle 83.3^0 = 3.34\angle 83.3^0 \Omega \sec$$

Maximum Reverse Zone 3 Reach [Z3R]′

$$\left[Z3R\right]' = Z3Rx\left[1+KN\right] = 3.34X\left[1+0.697\right] = 5.67\Omega \sec$$

Required Zone 3 Forward Reach [Z3F] =120% [Protected line + Longest Second line (apparent impedance)]

$$= 1.2\left[[83.67\angle 83.3^0 + \left[931.04\angle 231.9^0 - 83.67\angle 83.3^0\right]\right]$$

$$= 931.049\angle 231.9\Omega pry$$

$$= 465.52\angle 231.9\Omega \sec$$

The value obtained from the calculation for Zone 3 Forward Reach in not practicable, the option is to plot the polar characteristic for Z3F Benin- Oshogbo line (H7B) giving 20% consideration for load encroachment have consider the important of the line.

Figure 6.23 shows the plot for the determination of Zone 3 forward reach.

The maximum impedance reach [Z3G max] from the plot is 92Ω.

Then:

$$Z3F = \frac{Z3G\max}{1+KN} = \frac{92}{1.697} = 54.2\angle 83.3^0\,\Omega\sec$$

We therefore then set Zone 2 to be equal to Zone 3, that is:

$$Zone2 = Zone3 = 54.2\angle 83.3^0\,\Omega\sec$$

1.9 Zone 2 and Zone 3 resistance setting for earth fault quad characteristic:

Resistance part of the Zone 2 and Zone 3 = 54.2cos83.3^0 = 6.32

R2E [Zone 2] = R2E [Zone 3]

$$R2E\left[Zone2\right] = R_{2line} + \frac{1}{2}R_{arc} + R_{Tower} = 12.64 + 3 + 10$$

$$= 28.64\Omega pry$$

$$= 14.32\Omega\sec$$

Reactive part of the Zone 2 and Zone 3 = 54.2sin83.3^0 $= 53.8\Omega\sec$

2.0 Power Swing Blocking is set as Zone 6 (Z6).

Inner Forward Reach:

Z6 [Inner] = Zone 3 Forward = 54.2Ω sec

Outer forward Reach:

Z6 [Outer] = 1.5 x Zone 3 Forward.

= 1.5 x 54.2 = 81.30 Ωsec

Inner Reverse Reach:

Z6′ [Inner] = Zone 3 Reverse = 3.34Ω sec.

Outer Reverse Reach:

Z6′ [Outer] = 1.5 x Zone 3 Reverse.

= 1.5 x 3.34 = 5.01Ω sec.

The expected reach values for 60^0, 30^0 and 0^0angle are obtained from the relay characteristic plot as shown in figure 6.28.

The values obtained from the calculations for the setting of each of zones are inputted (entered) into the Ohmega distance. Reach test for various fault type were carried out to determine the actual zone of operation of the relay compare to the calculated values and operational time of the relay. The results obtained from various tests carried out are shown in table. 6.4 to 6.8.

Table 6.4 Reach test result on the Ohmega distance relay at an angle 0f 90^0

Relay Angle	Required Reach ZΩ	Fault Type	Relay Volts	Relay Amps	Measured Reach ZΩ	% Error
75^0	Zone 1 33.4	A-G B-G C-G	27.9 27.8 28.9	0.5 0.5 0.5	32.8 32.7 34	1.8 2.1 -1.8
75^0	Zone 2 54.2	A-G B-G C-G	42.9 42.0 43.2	0.5 0.5 0.5	50.5 49.4 50.8	6.8 8.9 6.3
75^0	Zone 3 54.2	A-G B-G C-G	42.9 42.0 43.2	0.5 0.5 0.5	50.5 49.4 50.8	6.8 8.7 6.3
75^0	Zone 3 Rev 3.3	A-G B-G C-G	2.4 2.5 2.5	0.5 0.5 0.5	2.8 2.9 2.9	15.2 12.1 12.1
85^0	Zone 1 33.4	A-B B-C C-A	34.2 34.7 34.7	0.5 0.5 0.5	34.2 34.7 34.7	-2.4 -3.9 -3.9
85^0	Zone 2 54.2	A-B B-C C-A	52.4 52.8 53.6	0.5 0.5 0.5	52.4 52.8 53.6	3.3 2.6 1.1
85^0	Zone 3 54.3	A-B B-C C-A	52.4 52.8 53.6	0.5 0.5 0.5	42.4 52.8 53.6	3.3 2.6 1.1
85^0	Zone 3 Rev 3.3	A-B B-C C-A	2.8 3.4 3.2	0.5 0.5 0.5	2.8 3.4 3.2	15.2 -3.0 +3.0

Table 6.5Reach test result on the Ohmega distance relay at an angle of 60^0

Relay Angle	Required Reach ZΩ	Fault Type	Relay Volts	Relay Amps	Measured Reach ZΩ	% Error
75^0	Zone 1 28.8	A-G B-G C-G	26.1 26.0 27.0	0.5 0.5 0.5	30.8 30.6 31.8	-6.9 -6.3 -10.4
75^0	Zone 2 49.2	A-G B-G C-G	41.8 41.3 41.5	0.5 0.5 0.5	49.3 48.7 48.9	-0.2 1.0 1.6
75^0	Zone 3 49.7	A-G B-G C-G	42.0 42.4 42.2	0.5 0.5 0.5	49.5 50.0 49.7	0.4 -0.6 0
75^0	Zone 3 Rev 3.9	A-G B-G C-G	2.7 2.6 2.7	0.5 0.5 0.5	3.2 3.1 3.2	-17.9 20.5 17.9
85^0	Zone 1 28.8	A-B B-C C-A	30.8 30.6 30.5	0.5 0.5 0.5	30.8 30.6 30.5	-6.9 -6.3 -6.0
85^0	Zone 2 49.2	A-B B-C C-A	46.9 46.6 46.6	0.5 0.5 0.5	46.9 46.6 46.6	4.7 5.3 5.3
85^0	Zone 3 49.7	A-B B-C C-A	50.0 50.4 50.3	0.5 0.5 0.5	50.0 50.4 50.3	-0.6 -1.4 -1.2
85^0	Zone 3 Rev 3.9	A-B B-C C-A	3.3 3.3 3.3	0.5 0.5 0.5	3.3 3.3 3.3	15.4 15.4 15.4

Table 6.6 Operational times obtained form reach test for the 90^0 angle

Phase	Zone 1 (ms)	Zone 2 (ms)	Zone 3 (ms)
A-B	40	391	1040
B-C	42	391	1042
C-A	41	392	1040
A-G	38	390	1042
B-G	37	387	1044
C-G	40	390	1042

Table 6.7 Power Swing Test Result

Three phase current and voltage applied to the relay

Phase current	Current Setting (A)
I_A	0.5A
I_B	0.5A
I_C	0.5A

Voltage for operation = 75.2V
Impedance Reach = 75.2 ohms
Table 6.8 High Set Overcurrent (HSOC) Test Result.

Phase	Current Setting (A)	Current Operated (A)	Time Setting (Sec)	Time Operated (Sec)
A-B	4	4.04	1	1.043
B-C	4	4.03	1	1.039
C-A	4	4.04	1	1.040

CHAPTER SEVEN
POWER TRANSFORMER PROTECTION

7.0 Introduction

Power transformers belong to a class of very expensive and vital components of in the alternate current electrical power system. If a large capacity power transformer experiences a fault, it can cause system instability. It is necessary to take the transformer out of service as soon as possible so that damage is minimized. The cost associated with repairing a damaged transformer may be very high. The unplanned outage of a power transformer can cause electric utilities millions of naira. Consequently, it is of great importance to minimize the frequency and duration of unwanted outages.

Protective system applied to transformers, thus play a vital role in the economic operation of a power system. Protection of large power transformers is perhaps the most challenging problem in the power system relaying [42]. In common with other electrical plants, choice of suitable protection is governed by economic considerations. For transformers of the lower ratings, only the simplest protection scheme such as fuses can be justified, but for large rating transformers comprehensive protection scheme should be applied.

Advanced digital signal processing techniques and recently introduced Artificial Intelligence (AI) [42] approaches to power transformer provide the means to enhance the classical protection principles and facilitate faster, more secure and dependable protection for power transformer. Also it is anticipated that in the near future more measurements will be available to transformer relays owing to both substation in integration and novel sensors installed on power transformers. All this will change for power transformer protection.

This chapter briefly reviews the state of the art, but it is primary devoted to the discussion of the problems associated with classical protection of power transformer using differential and restricted earth fault protection schemes.

7.1 Transformer Fault Categories

Transformer fault are generally classified into:

(a) **External faults**: The external faults are those faults or hazards that occur outside the transformer. These faults included: over Loads, over voltage, under frequency and external system short-circuits [43].

(i) *Internal Faults***:** Internal faults are fault that develop slowly, often in the form of a gradual deterioration of insulation. This deterioration may eventually become serious enough to cause a major arcing fault and if the cause not detected and corrected promptly may lead to serious damages. Incipient faults are caused as a result of the following:

a. Poor internal connections in either the magnetic circuit.
b. Loss of coolant due to leakage.
c. Blockage of coolant flow.
d. Loss of fans or pumps that are designed to provide cooling

(ii) Active faults are faults that occur suddenly and that usually require fast action by protective relays to disconnect the transformer from the power system and limit the damage to the unit. These faults include:

a. Solid circuits in start –connected windings
b. Short circuits in delta – connected windings
c. Phase to phase short circuit
d. Turn to turn short circuit.
e. Core faults.

7.2 Types of Power Transformer Protection Schemes

There are two general categories of protective arrangement to protect power transformers [44-46].

1. Main protection schemes are:

a) Buchholz gas relay
b) Differential relay
c) Restricted earth fault relay and,

2. Backup protection schemes are:

a) IDMTL over current relay

b) IDMTL earth fault relay

c) Standby earth fault relay

d) Surge arrester/ diverter

e) Oil Temperature monitor

f) Winding temperature monitor

Over current protection with fuses or relays provided a first type of transformer fault protection [47]; it continues to be applied in small capacity transformers. Connecting an inverse time over current relay in the paralleled secondary of the current transformers introduced the differential principle to transformer protection [47]. The percentage differential principle [48] that was immediately applied to transformer protection [49] provided excellent results in improving the security of differential protection for external fault with CT saturation.

7.3 Differential Protection Scheme for the Protection of Power Transformer

Transformer differential protection scheme provides fast tripping when fault occurs, before severe damage spread out. Differential Protective relays have been in service for many years [48, 49]. The scheme is being used in Nigeria for the protection of power transformer.

7.3.1 Working Principle of Differential Protection Scheme.

The fundamental operating principle of transformer differential protection is based on comparison of the transformer primary and secondary windings current. For an ideal transformer having a 1:1 ratio and neglecting magnetizing current, the current entering and leaving the transformer must be equal. Figure 7.1 below shows a typical differential relay connection diagram.

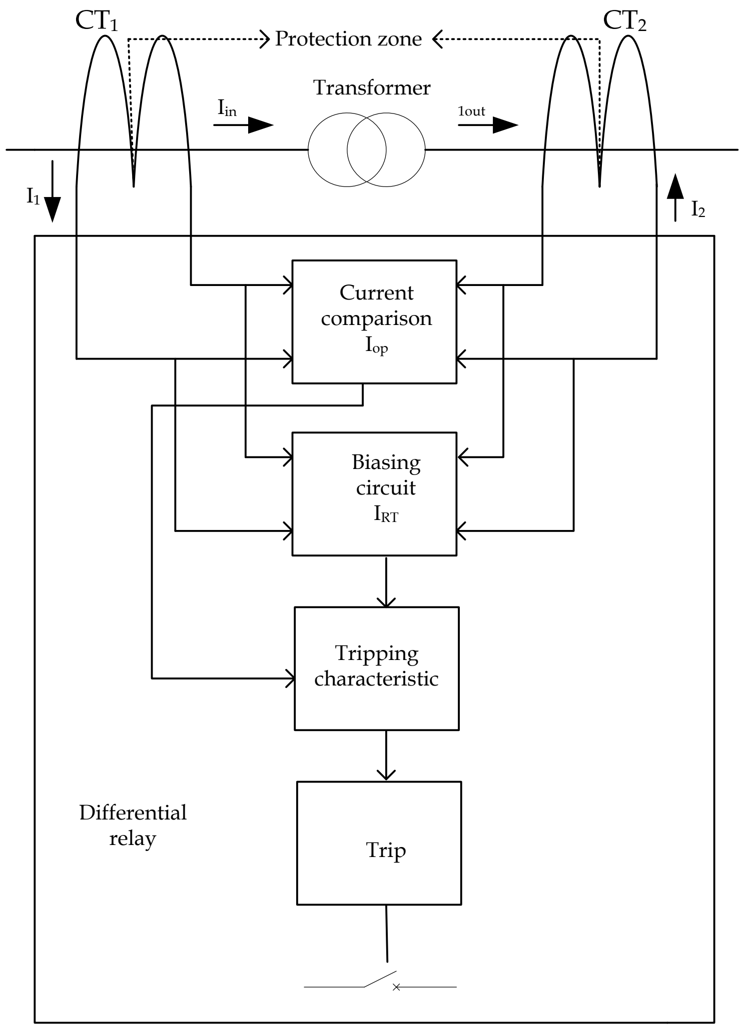


FIGURE 7.1 Typical differential Relay connection

The operating current, 1_{op}, can be obtained as the pharos sum of the currents entering the protection element:

$I_{OP} = K\left|I_1 + I_2\right|$................(7.1)

I_{op} is proportional to the fault current for internal faults and approaches zero for any other operating (Ideal) conditions. Restraining current is determined as follows:

$$I_{RT} = K\left|I_1 - I_2\right|..................(7.2)$$

$$I_{RT} = K\left(\left|I_1\right| + \left\|I_2\right|\right)............(7.3)$$

$$I_{RT} = \max\left(\left|I_1\right|, \left|I_2\right|\right)...........(7.4)$$

Where K is a compensation factor, usually taken as 1 or 0.5. [50]

Equation 7.3 and 7.4 offer the advantage of being applicable to differential relays with more than two restraint elements.

The differential relay generates a tripping signal if the operating current, 1_{op}, is greater than a percentage of the restraining current, 1_{RT}:

$$I_{OP} \geq SLP.I_{RT}............(7.5)$$

Figure 7.2 below shows a typical differential relay operation characteristic. This characteristic consists of a straight line having a slope equal to SLP and a horizontal straight line defining the relay minimum pickup current, 1pu. The relay-operating region is located above the slope characteristic (equation 7.5), and the restraining region is below the slope characteristic.

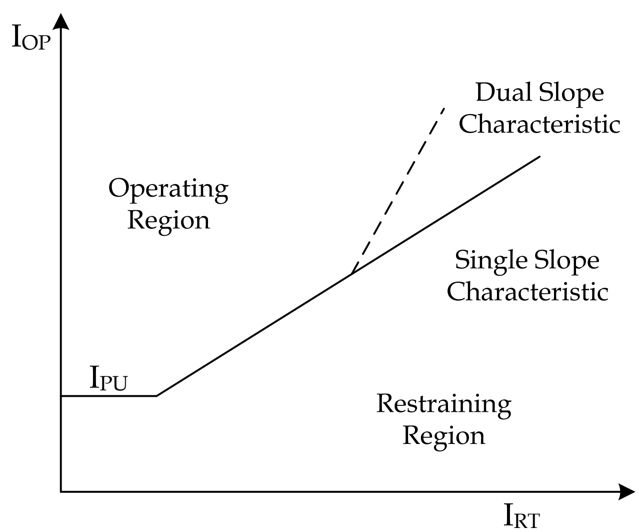


Figure 7.2 Differential relay with Dual slop characteristic

Differential relays perform well for external faults, as long as the CTs reproduce the primary currents correctly. When one of the CTs saturates, or if both CTs saturate at different levels, false operating current appears in the different relay and may cause relay mal operations. Some differential relays use the harmonics caused by CT saturation for added restraint and to avoid mal operations [52, 61, 62]. In addition, the slope characteristic of the percentage differential relay provides further security for external faults with CT saturation. A variable – percentage or dual – slope characteristic, originally proposed [53] further increases relay security for heavy CT saturation. Figure 7.2 shows this characteristic as dotted line. CT saturation is only one of the causes of false operating current in differential relays. The Figure 7.3 presents general hardware configuration of a digital differential relays. The differential relaying principle is used for protection of medium and large power transformers. This superior approach compares the currents at all terminals of the protected transformer by computing and monitoring a differential (unbalance) current.

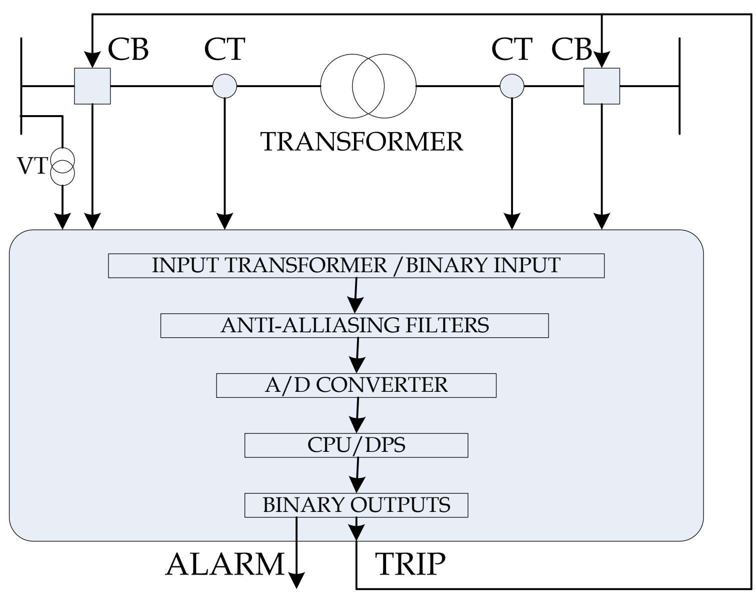


Figure 7.3 Hardware Structure of a Digital Relay for Power Transformers

The Figure 7.4 presents a simplified flow chart of the logic of a digital differential relay for power transformers. Within this frame, the second or higher harmonic is commonly used to restrain the differential relay during stationary overexcitation conditions: while the biased percentage characteristic is used to prevent false tripping during external faults.

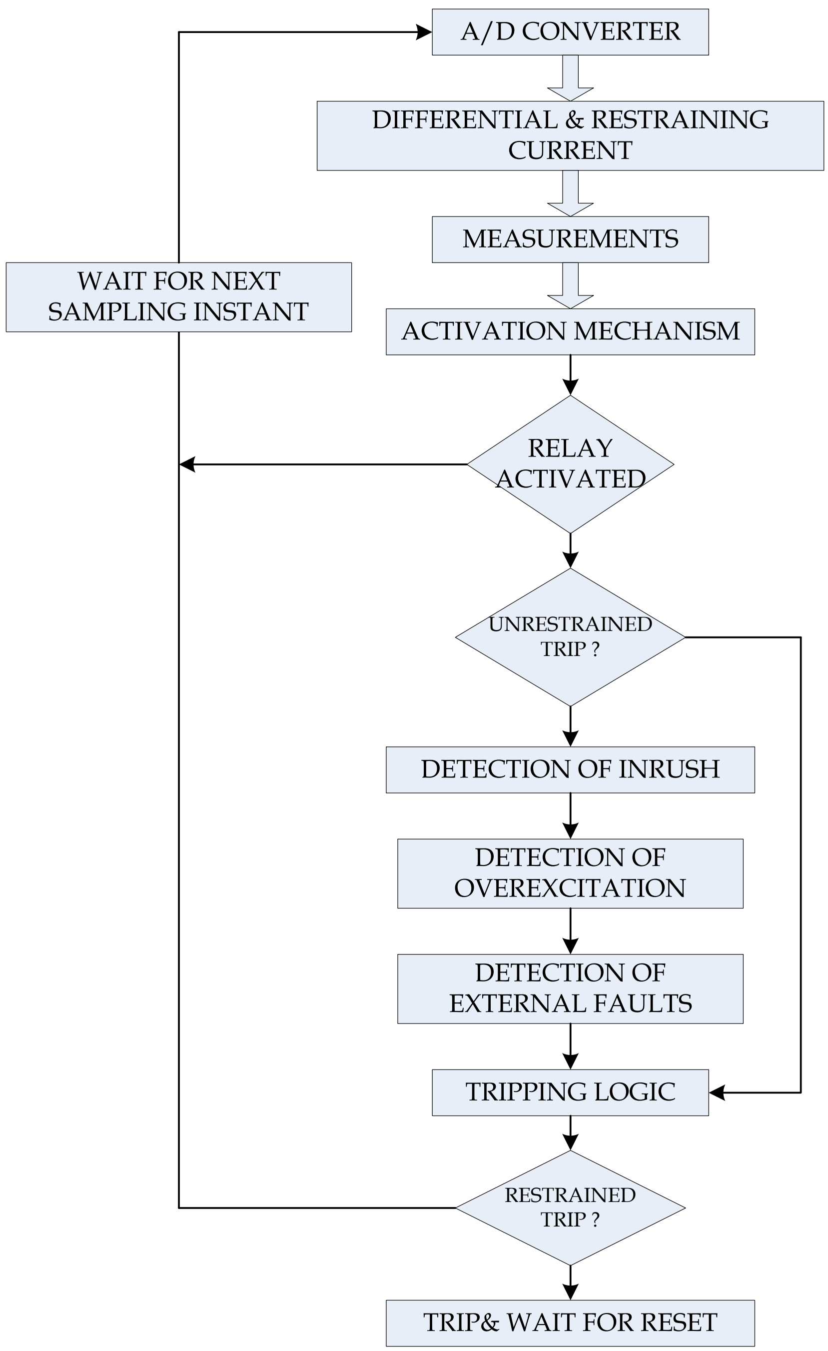


FIGURE 7.4 Simplified Flow Chart of the Logic for Digital Differential Relay for Power Transformers

7.3.2 Problems in Differential Relaying for Power Transformer.

In the application of differential protection scheme for the protection of power transformers other possible errors are:

i. Mismatch between the CT ratio and the power transformer ratio
ii. Phase shift in currents between the primary and secondary winding of the transformer.
iii. Magnetizing inrush currents created by transformer transients because of energization, voltage recovery after the clearance of an external fault, or energization of a parallel transformer.
iv. High exciting current caused by transformer over excitation.

The first two problems are discussed in this work; the discussion is based on the survey of scientific literature and partly on the author's personal experience gained from meetings with utility staff and the consultant in this area during the course of this work. However Table 7.1 presents the summary of the problems related to protective relaying of power transformers while Table 7.2 presents improvements area resulting from the protection techniques for power transformers [42].

7.3.2.1 Determination of Phase Shift in Transformer Winding

In a single phase transformer (Figure 7.5) the output current is either 0^o or 180^o out of phase with the corresponding input current. But for three-phase transformer phase shift between input current and output current are in multiples of 30^o. Figure 7.6 shows phase shift representation related to the minute hand of a clock.

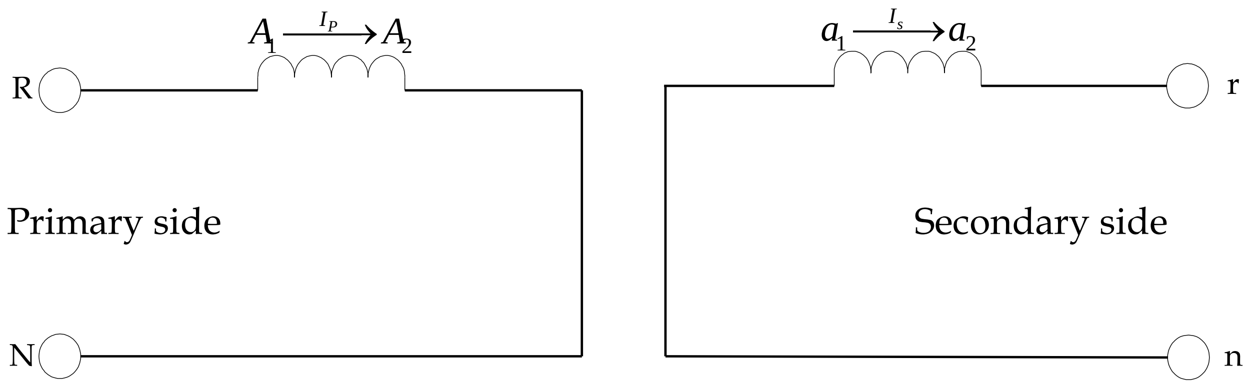


Figure 7.5 Single Phase Current flow in Power Transformer

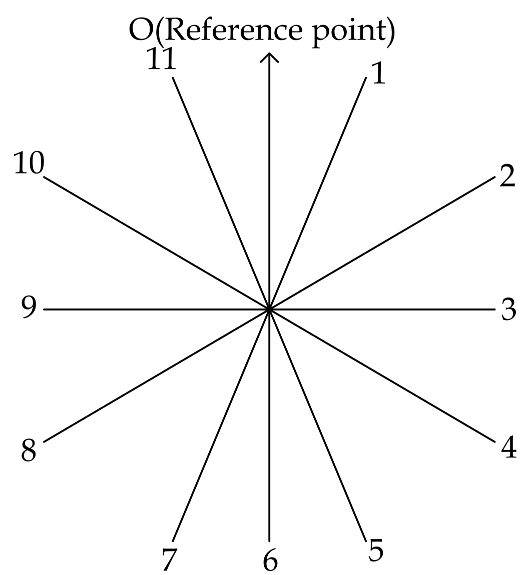


Figure 7.6 Phase Shift Representation Related to Hand of a Clock

In the design of differential protection scheme for power transformer, it is important to note that phase shift exist between input current and output current of most power transformers. And such phase shift must be compensated for when designing a differential protection scheme; if not there will be erroneous operation for external faults.

This work has made an effort to develop a simple phasor analytical technique using the principle of symmetrical components and “a” operator to determine the phase shift in current between primary and secondary windings of a power transformer. Operator “**a**” is a complex vector or number of unit magnitude with an angle of 120^0 and is defined by [26, 51].

$$a = 1\angle 120^0 = 1e^{j(2\Pi/3)} = 1(\cos 120^0 + j\sin 120^0) = -\frac{1}{2} + j\sqrt{3}\Big/2$$

It also follows that $a^2 = \angle 240^0 = 1\angle -120^0 = -\frac{1}{2} - j\sqrt{3}\Big/2$

Where j= $\sqrt{-1}$

In the application of the symmetrical component in this case, ABC positive sequence of the rotation Figure 7.7 is adopted and phase a is considered to be the reference phase. Using “a” operator and a balance three-phase positive symmetrical component (Figure 7.7), we have the following equations,

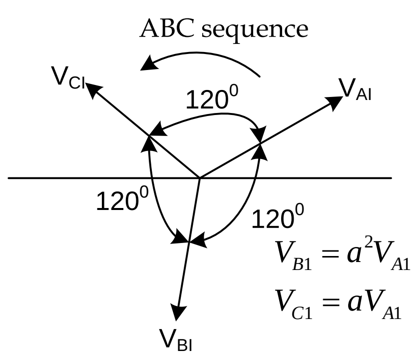


Figure 7.7 Positive Sequence Component Phasor

$$V_{b1} = a^2V_{a1}.....................(7.6)$$
$$V_{C1} = aV_{a1}......................(7.7)$$

Writing equation 7.6 and 7.7 in terms of current and removing subscribe 1; we now have equations 7.8 and 7.9 as;

$$I_b = a^2 I_a \text{.....................}(7.8)$$
$$I_C = aI_a \text{......................}(7.9)$$

The phase shift between transformer windings can be determined using equation 7.8 and 7.9 with "a" operator. Bearing in mind that phase a of the secondary side the transformer is the reference phase, it than follows that current l_a is the reference current. To determine the phase shift, we calculate the angle between the resultant current of the reference phase. We now convert the angle to the hand of the clock (Figure 7.6) to determine the vector group of the transformer. We first write in capital letters the connection of the primary winging follow by the connection of the secondary winding in small letters and then the phase shift. Form an example; Figure 7.8 shows a star/ delta transformer with the circulating currents in primary and secondary windings. The phase shift and the vector group of the transformer are determined as follows;

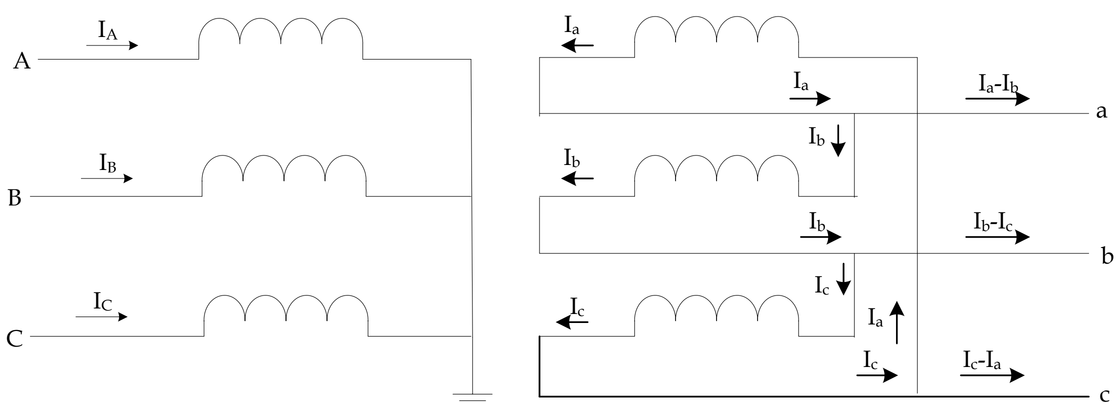


Figure 7. 8 Star-Delta Transformer

The resulting current flowing out of phase a, i.e. the secondary winding of the transformer is I_a-I_b, substituting I_b in equation 7.8 we now have

I_a-a^2I_a. That is $I'\left(1-a^2\right) = I'[1[-\frac{1}{2} - j\sqrt{3}\big/2\,]\,] = I'\left[1.5 + j\sqrt{3}\big/2\right]$

The phase angle is than determine by the expression, θ= $\tan^{-1} y/x = +30^0$

The phase shift angle is 30^0 and the corresponding clock hand (Figure 7.6) is 11. This means that the seconding is leading the primary by 30^0. The primary side of the transformer (Figure 7.8) is star winding while the secondary side is delta winding: - the vector group of the transformer is therefore **Yd11** since the secondary vector corresponds to position **11** on the clock hand with the primary vector at 12 (10) the reference point.

If the secondary is lagging the primary by 30^0, the corresponding angle on the clock hand will be 1. Then the vector group will be **Yd1.** Following the steps above, phase shift and vector group of other transformer types can be determined.

In figure 7. 8 above, the primary side is star winding and secondary side is Delta winding: - the vector group of the transformer is therefore Yd11 since the secondary vector corresponds to position 11 on the clock hand with the primary vector at 12 (0) the reference point.

If the secondary is lagging the primary by 30^0, the corresponding angle on the clock hand will be 1. Than the Vector group will be **Yd1**. Following the steps above, phase shirt and vector group of other transformer types can be determined.

7.3.2.2 Phase Shift Compensation and Removal of Zero Sequence Current.

Phase shift and zero – sequence current are introduced in some types of power transformers as earlier discussed. To avoid mal operation of transformer differential relay, phase shift compensation and removal of zero-sequence current becomes necessary. There area two approaches to these issues, the first method depends on how CTs are connected and the second is the introduction of interposing current transformer (ICT). Delta-star power transformer figure 7.9 illustrates a CT connection to compensate for phase shift and remove of zero sequence current. The current in the primary side of the transformer leads the current in the secondary side by 30^0. The normal way to compensate the phase shift between the primary and secondary side of the transformer is to connect the CTs in star side of the transformer in delta and the CTs in the delta of transformer connected in star to achieve the balance, which is a mirror image of the delta side of power transformer winding. This mirror image of delta connection will provide the correct phase shift of the phase current to the relay differential element so that the current in the differential element will have the same angular relationships and current component as the current in the phases entering and leaving the power transformer windings. The CT delta connection filters out the zero sequence component of current that does not appear in the incoming current on the delta side of the power transformer. CTs in delta side of transformer will have to be star connected to achieve the balance.

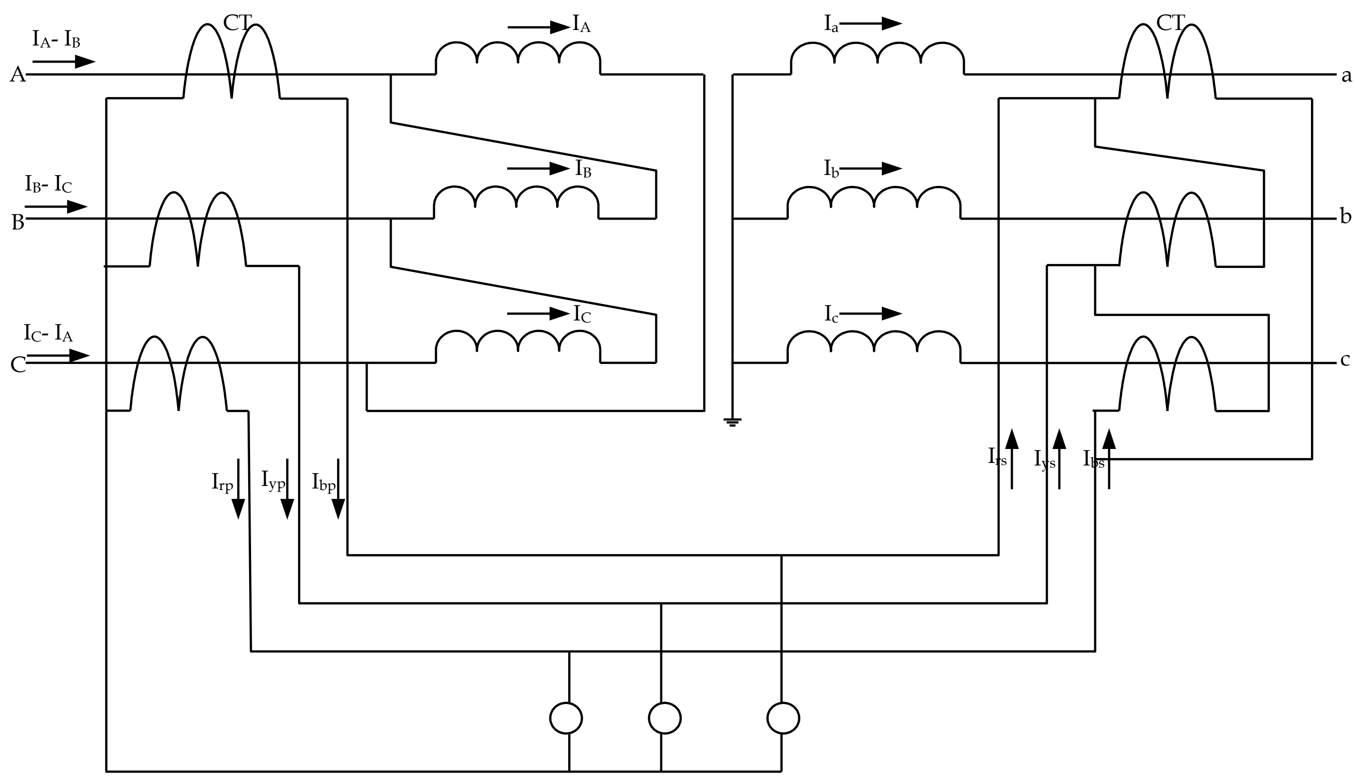


Figure 7.9 Delta-Star Transformer with Traditional Connections for Phase Shift Compensation

Consider the currents distributions as shown (Figure7.9), it is usual to say that CTs current entering the relay on the delta side of the power transformer are: -

$$I_{rp} = \frac{I_A - I_B}{CTR1} \text{.........................(7.10)}$$

$$I_{yp} = \frac{I_B - I_C}{CTR1} \text{........................(7.11)}$$

$$Ibp = \frac{I_C - I_A}{CTR1} \text{......................(7.12)}$$

The turn ratio of the power transformer is:

$$n = \frac{V_P}{V_S}.\sqrt{3} \text{.........................(7.13)}$$

Where

CTR1= Current transformer ratio of the primary side

V_P = Primary side phase voltage

V_S = Secondary side phase voltage

I_{rp} = Red phase primary line current flowing into relay

I_{yp} = Yellow phase primary line current flowing into relay

I_{bp} = Blue phase primary line current flowing into relay

I_A, I_B & I_C are red, yellow and blue phases current respectively.

We can express the current entering the relay on the delta side of the transformer with respect to star side of the transformer, equations 7.10, 7.11 and 7.12 than becomes:-

$$I_{rp} = \frac{V_S}{V_p}.\frac{1}{CTR1}.\frac{I_a - I_b}{\sqrt{3}} = K_1\frac{[I_a - I_b]}{\sqrt{3}} \text{................(7.14)}$$

$$I_{yp} = \frac{V_S}{V_p}.\frac{1}{CTR1}.\frac{I_b - I_c}{\sqrt{3}} = K_1\frac{[I_b - I_c]}{\sqrt{3}} \text{................(7.15)}$$

$$I_{bp} = \frac{V_S}{V_p}.\frac{1}{CTR1}.\frac{I_c - I_a}{\sqrt{3}} = K_1\frac{[I_c - I_a]}{\sqrt{3}} \text{................(7.16)}$$

where;

$$k_1 = \frac{V_S}{V_p}.\frac{1}{CTR1\sqrt{3}}$$

The CTs currents leaving the relay on the star side of the main transformer are:-

$$I_{rs} = -\frac{1}{CTR2}.\left[I_a - I_b\right] = -K_1\left[I_a - I_b\right] \text{.............}(7.17)$$

$$I_{ys} = -\frac{1}{CTR2}.\left[I_b - I_c\right] = -K_1\left[I_b - I_c\right] \text{.............}(7.18)$$

$$I_{bs} = -\frac{1}{CTR2}.\left[I_c - I_a\right] = -K_1\left[I_c - I_a\right] \text{..............}(7.19)$$

Where: CTR2 = Current Transformer ratio of secondary side

I_{rs} = Red phase secondary current flowing into/out relay

I_{ys} = Yellow phase secondary current flowing into/ out relay

I_{bs} = Blue phase secondary current flowing into/ out relay

The CT delta connection in secondary side of the main transformer compensates the phase shift in the power transformer and filters out the zero-sequence current component. One phase current minus the adjacent phase current (I_a-I_b) filters out zero- sequence currents. In applications where the CTs are star connected at the low side of the power transformer, the following current combinations compensate the power transformer phase shift and remove zero-sequence currents.

$$I_{rs} = -K_2\frac{\left[I_a - I_b\right]}{\sqrt{3}} \text{.....................}(7.20)$$

$$I_{ys} = -K_2\frac{\left[I_b - I_c\right]}{\sqrt{3}} \text{.....................}(7.21)$$

$$I_{bs} = -K_2\frac{\left[I_c - I_a\right]}{\sqrt{3}} \text{.....................}(7.22)$$

The currents I_{rp}, I_{yp}, I_{bp} , I_{ys} I_{bs} and I_{rs} are the input current into the differential element and do not have zero-sequence component. From the analysis so far, it can be say that, *Rules for phase shift compensation is to connect CT opposite to main transformer. That is*

Star CTs on the delta side of the main transformer

Delta CTs on the star side of the main transformer

However, there are alternatives to the rules above by using interposing current transformer (ICT) as can be seen shortly.

7.3.2.3 Correction of Mismatch of Ratios using Interposing Current Transformer (ICT)

Interposing current transformer (ICT) connection is another alternative solution to the problem of CT ratio mismatch and removal of zero-sequence current encountered by the engineers in differential protection of power transformers. ICT are primarily used in conjunction which differential relays in protection of transformer to perform the following duties.

a. To correct CT ratio mismatch which may exist between primary and secondary CTs.
b. Restoration of the phase shift between the current on the primary and secondary side of a power transformer caused by the connection of the windings.
c. Filtering out zero-sequence current when the transformer neutral is earthed or in an autotransformer.

It is important to note the following for proper application of ICT.

a. ICT should be mounted as close as possible to the relay.
b. ICT should carry as much as possible light burden.
c. More number of turns (i.e. high ratio) should be used for stability purpose.

ICT are unenclosed single-phase shielded transmission. The insulation consists of synthetic resin varnish and is suitable for use under adverse climatic conditions. The ICT generally consists of eight windings which are pair-wise equal in the number of winding turns and in the cross-sectional area of the wire. The winding ends are each connected to a separate terminal. The terminals are being consecutively marked with the alphabetic letters from A, B, C to Q as shown in figure 7.10, the design and the technical details [54, 55].

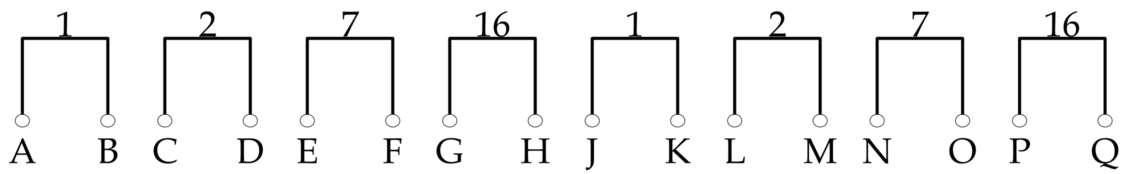


Figure 7.10 Winding and Terminal Designation of Interposing Current Transformer(ICT)

Figure 7. 11 illustrate the configuration of an ICT; as well shows alternative ways of connection that gives same current ratio result but have different reliability during through fault current. The configuration with 18:24 ratio is more stable because higher number of turns is used as against those of 12:16 and 3:4. The terminals that are not used for the configuration are short-circuited.

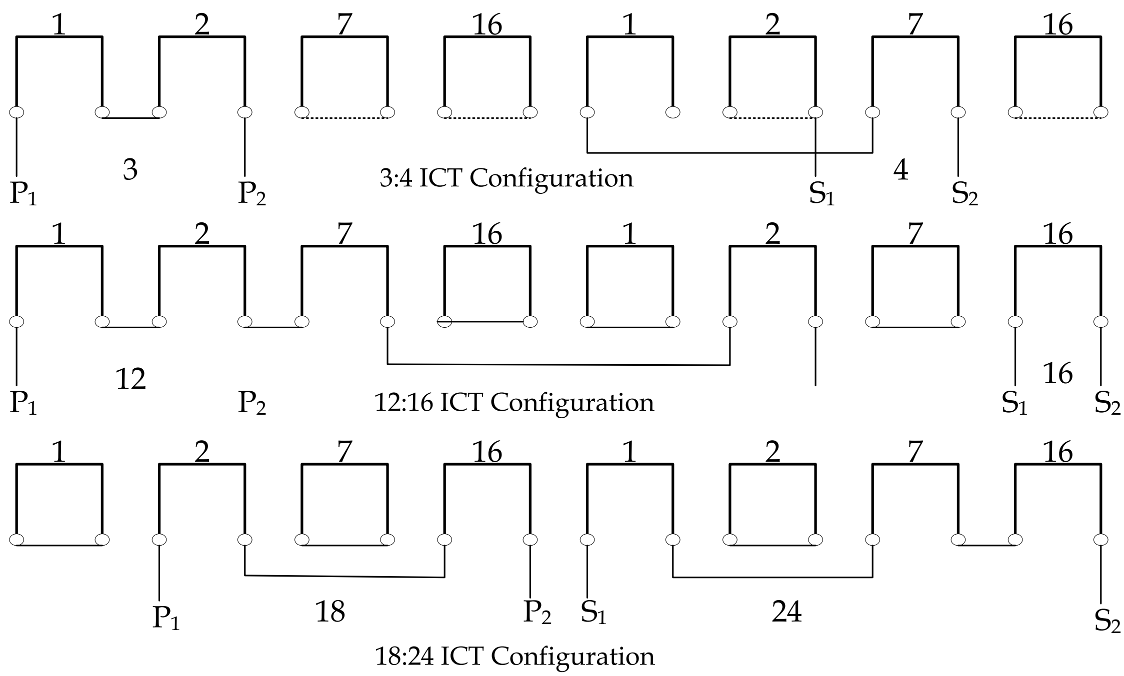


Figure 7.11 Showing Different Ratio Configuration with same Current Ratio

Most transmission differential relays used in the national grid required the application of ICT. However, the modern numerical differential protection relays now available have ICT integrated in them and so extra ICTs are not required. This account for ratio mismatch error, phase shift and zero sequence currents, thereby making design and installation of transformer differential very easy.

7.4 Current Transformer Requirements for Protection.

Current transformers are among the most commonly used items of electrical apparatus and yet surprisingly, there seems to be a general lack of even the most elementary knowledge concerning their performance characteristics and limitations among engineers who are continually using them [55]. However, detail information concerning CT&VT performance characteristics and limitations are further [56, 57]. Figure 7.12 shows a simple arrangement of current transformer with bar primary.

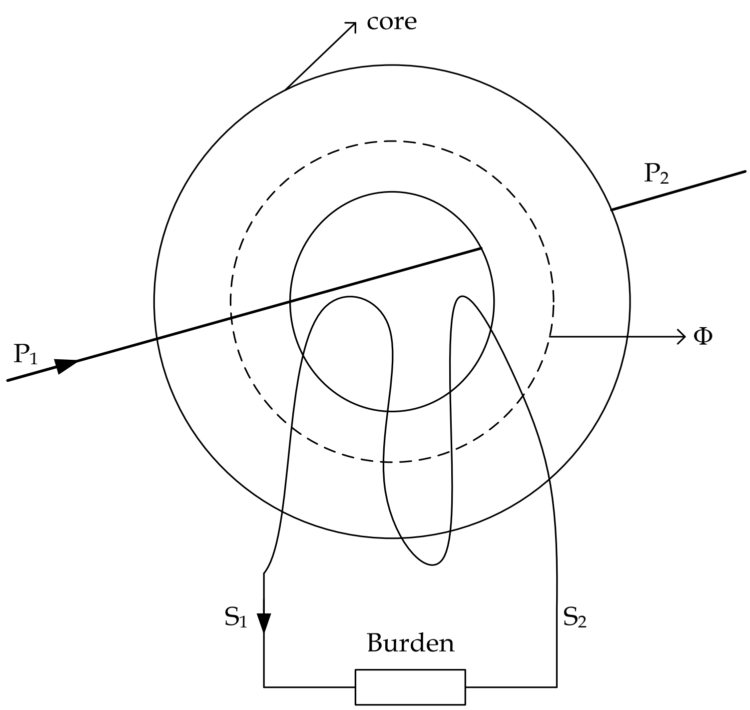


Figure 7.12 Current Transformer with Bar Primary

The importance of current transformers in the transmission and distribution of electrical energy cannot be over emphasized because upon the efficiency of current transformers and the associated voltage transformers that the accurate metering and effective protection of those distributions circuits and plants depend.

Current transformers isolate the secondary (relay, instrument and meter) circuits from primary (power) circuit and provide quantities in the secondary, which are proportional to those in the primary. The role of a current transformer in protective relaying is not as readily defined as that for metering and instrumentation. Whereas the essential role of a measuring instrument transformer is to deliver from its secondary winding a quantity accurately representative of the primary side, a protective transformer varies in its role according to the type of protective gear it serves.

Failure of a protective system to perform its function correctly is often due to incorrect selection of the associated current transformer [58-60, 63]. Hence, current and voltage transformers must be regarded as constituting part of the protective system and must be carefully matched with the relays to fulfill the essential requirements of the protection system.

There are two basic groups of current transformers, namely; measurement CT's and protective CT's the requirements of which are often radically different. It is true in some cases that same current transformer may serve both purposes of metering and protection in modern practice. This is the exception rather than the rule:

1. Measurement CT's: The measuring current transformer is required to retain a specified accuracy with respect to the lord currents being measured.

2. Protection CT's: The protective current transformer must be capable of providing an adequate output over a wide range of fault conditions, from a fraction of full load to many times full load current.

7.4.5 Current Transformer Ratings

1. Current Transformer Burden; All C.T accuracy considerations require knowledge of the C.T burden, which is the load applied to the secondary of the C.T and should preferably be expressed in terms of the impedance of the load and its resistance and reactance components. In practical it is usual to quote the

relay burdens, in the first place, in terms of VA (Volt – amperes) and power factor. CT burdens are usually given in preferred values, such as 5, 10, 15, 30VA

2. Continuous Rated Current: - This is the maximum current the current transformer can carry continuously. It is usually the rated primary current.

3. Short Time Rated Current: - This is the amount of current that can flow for a given time period with out any harmful effects. This is usually specified for 0.5, 1, 2, or 3 seconds and with the secondary short-circuited.

4. Rated Secondary Current: - This is the maximum continuously rated current the secondary can carry. It is usually 1 or 5A.

5. Accuracy Limit Factor (ALF). A current transformer is designed to maintain its ratio within specified limits up to a certain value of primary current. This multiple is termed its rated accuracy limit factor.

In determining the accuracy limit factor it is necessary to consider the maximum value of primary current up to which the current transformer is required to maintain its ration.

7.4.2 Current Transformer Designation

Current transformer are usually designed as either class ‘P’ or class ‘X’

Class P is usually specified in terms of

- Rated Burden
- Class (5Por 10P)
- Accuracy Limit Factor

Consider the following example of a class ‘p’ CT

15VA 10P20

This means that the CT has an external secondary burden of 15VA the composite error will be 10% or less for primary current up to 20 times rated current.

To convert from VA and accuracy limit factor (ALF) into volts, we can use the expression

$$V_K = \frac{VA}{I_N}.ALF \text{.........................}(7.23)$$

or when the internal voltage drop in the C.T needs to be taken into account and we now have

$$V_K = ALF\left(I_N R_{CT} - \frac{VA}{I_N}\right)\text{.........................}(7.24)$$

Class P type of CT are general used for instantaneous over current protection and Relays with inverse & Definite Minimum time lag characteristics.

Class X – The performance of class X current transformer of the low reactance type shall is specified in terms of each of the following characteristics: -

i. Rated primary current

ii. Turns ration (The error in turns ration shall not exceed

iii. Knee – point voltage

iv. Exciting current at the knee point voltage and/ or + 0.25%) at a stated percentage thereof.

v. Resistance of secondary winding

Class 'X' specifications is general used in application of differential relay unit systems where balancing of outputs from each end and of the protected plant is vital.

7.4.3 Current Transformer Selection for Transformer Differential Relays.

In transformer differential applications, CT are selected to accommodate a maximum fault current and at the same time, to preserve the low current sensitivity. As a minimum standard, CT saturation should be a voided for the maximum symmetrical external fault current. The CT ratio and burden capability should also permit operation of the differential instantaneous element for maximum internal fault.

Procedure for the Selection of CT.

A CT selection procedure guide is given below for differential protection application, proper current transformer selection lead us to improved transformer protection

Primary Side of the Transformer CT Selection Procedure

Step 1

Choice the high side CT ratio by considering the maximum high side continuous current. The selection of the CT ratio should ensure that at maximum load the continuous thermal rating of the CT, leads and connected relay burden is not exceeded. For delta connected CTs. The relay current is $\sqrt{3}$ times the CT current. Let this ratio be the nearest standard ratio higher than high side continuous current/ relay nominal current (1_N), which is 5A or lower value determined by the relay tap setting.

Step 2.

Determine the burden on the high side CTs

Step 3

For the primary side CT ration select the CT accuracy class voltage that will exceed twice the product of the total primary side CT secondary burden and the maximum symmetrical CT secondary current, which could be experienced due to an external fault. If necessary, select a higher ratio than that indicated in step 1 to meet this requirement. For the maximum internal fault, the CT ratio and burden capability should permit operation of the differential relay instantaneous unit.

Secondary of the Transformer side CT Selection Consideration.

Step1. Select CT ratio that will provides an adequate current at full load and that will avoid CT saturation for maximum asymmetrical fault.

Step 2. Select a CT that will provide adequate low current sensitivity, prevent saturation on external faults, and assure operation on the extremely large internal fault currents.

7.4.4 Precondition Test on Current Transformer Before Commissioning: -

1. Insulation resistance checks.
2. DC Resistance/continuity check
3. Magnetising characteristic
4. Primary injection Test
5. Polarity check.

The following where carried out during the course of this work on the five cores GET oil impregnated current transformer for the purpose of understanding the CT characteristic and suitability for protection co-ordination. Magnetizing characteristic, Insulation resistance check and primary injection. To achieve accurate result from the Magnetic characteristic test, it is advisable to get rid of any residual flux that may exist in the CT from the factory test and this can be achieved by first gradually raising the voltage applied to the CT till the CT saturates or the maximum allowable voltage value is reached. The voltage is then progressively reduced to zero after which the actual test can be carried out. It is very important to note that error will be introduced and therefore the result obtained will not be accurate if residual flux is not removed.

Figures 7.13 and 7.14 shows the schematic circuit diagrams for magnetizing characteristic test and primary current injection test. To carry out the test, voltage is being applied in steps of 10V to each of the core of the CTs and the corresponding magnetizing current readings from the ammeter are recorded. The readings/result obtained from the various tests carried out is recorded in tables 7.3 to 7.11. Figure 7.15 shows the magnetizing characteristic curves for the cores numbers 1 to 5 tested.

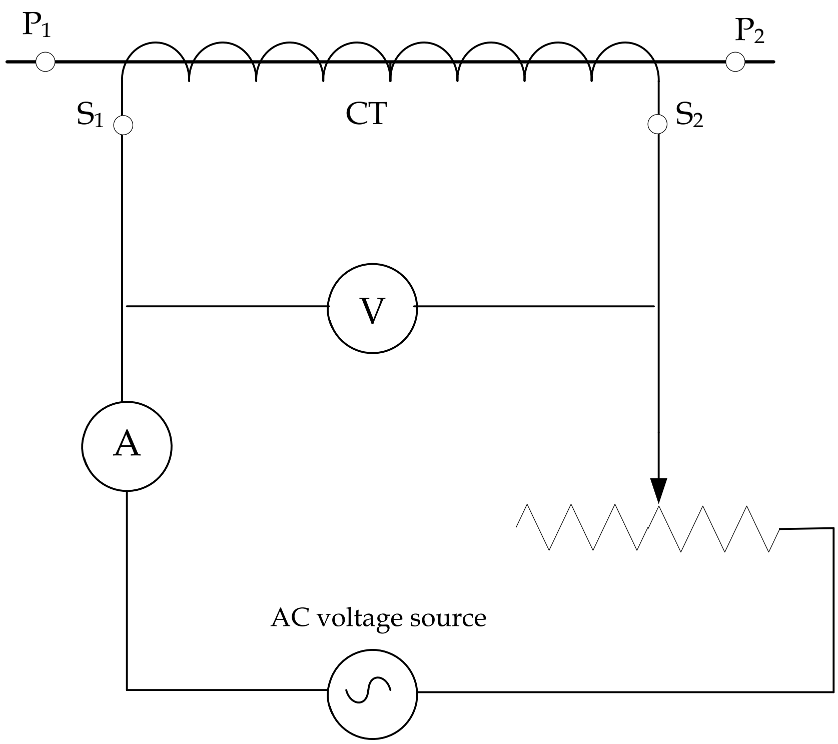


Figure 7.13 Sketch of CT Magnetizing
Characteristic Test Arrangement

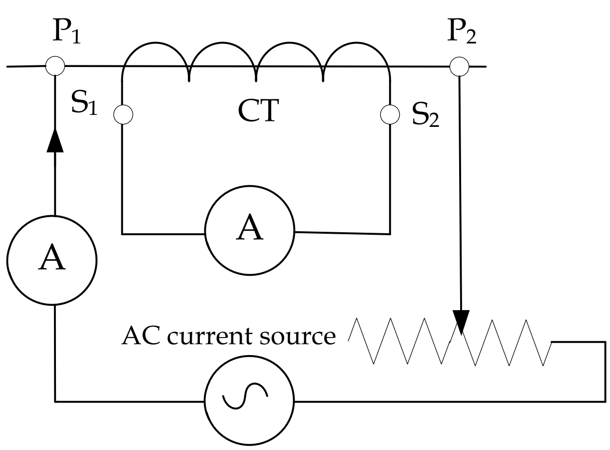


Figure 7.14 Sketch of CT Primary Injection Test

Table 7.3: Magnetization Test Result

I/P Voltage (V)	Current I (mA) Core 1	I (mA) Core 2	I (mA) Core 3	I (mA) Core 4	I (mA) Core 5
0	0	0	0	0	0
10	0.7	3.5	2.2	0.6	0.5
20	1.1	5.2	3.3	0.9	0.8
30	1.4	6.1	4.2	1.2	1.2
40	1.8	6.8	4.9	1.5	1.4
50	2.1	7.4	5.6	1.8	1.7
60	2.3	7.9	6.2	2.0	1.9
70	2.6	8.3	6.8	2.2	2.2
80	2.8	8.4	7.3	2.4	2.4
90	3.1	8.7	7.8	2.6	2.5
100	3.3	9.1	8.3	2.8	2.8
110	3.4	9.4	8.7	3.0	2.9
120	3.7	9.8	9.2	3.2	3.1
130	3.8	10.0	9.6	3.3	3.3
140	4.1	10.0	10.0	3.5	3.5
150	4.2	10.7	10.4	3.6	3.7
160	4.4	11.0	10.8	3.8	3.8
170	4.6	11.4	11.1	4.0	4.0
180	4.8	11.7	11.6	4.1	4.1
190	4.9	12.0	12.0	4.2	4.2
200	5.1	12.3	12.3	4.3	4.4
210	5.3	12.7	12.7	4.4	4.5
220	5.5	13.4	13.1	4.6	4.6
230	5.6	13.6	13.4	4.8	4.9
240	5.8	14.0	13.9	4.9	5.0

Table 7.4 Primary Current Injection Tests on GEC Impregnated CT (Core1)

Primary Injected Current (A)	Measured Sec. Current (A)	Calculated Ratio	Expected Ratio
10	0.007	1428.5	1500
15	0.010	1500.0	1500
20	0.014	1428.0	1500
25	0.017	1470.5	1500
30	0.020	1500.0	1500

Table 7.5 Core 2

Primary Injected Current (A)	Measured Sec. Current (A)	Calculated Ratio	Expected Ratio
10	0.007	1428.57	1500
15	0.0105	1428.57	1500
20	0.014	1428.57	1500
25	0.017	1470.59	1500
30	0.020	1500.00	1500

Table 7.6 Core 3

Primary Injected Current (A)	Measured Sec. Current (A)	Calculated Ratio	Expected Ratio
10	0.0068	1470.59	1500
15	0.010	1500.00	1500
20	0.0138	1449.28	1500
25	0.017	1470.59	1500
30	0.020	1500.00	1500

Table 7.7 Core 4

Primary Injected Current (A)	Measured Sec. Current (A)	Calculated Ratio	Expected Ratio
10	0.0065	1538.45	1600
15	0.0094	1595.74	1600
20	0.0130	1538.46	1600
25	0.0158	1582.28	1600
30	0.019	1578.95	1600

Table 7.8 Core 5

Primary Injected Current (A)	Measured Sec. Current (A)	Calculated Ratio	Expected Ratio
10	0.0065	1538.46	1600
15	0.0094	1595.74	1600
20	0.0128	1562.50	1600
25	0.016	1562.50	1600
30	0.0192	1562.50	1600

Results obtained on Resistance/Insulation Test carried out on the CTs.

Table 7.9 Primary to Ground Test

I/P Voltage (KV)	O/P Resistance (MΩ)
2.5	1
5	400

Table 7.10: Primary to Secondary of CT

I/P Volts	O/P Resistance				
2.5KV	1S1 – 1S2 2KΩ	2S1 – 2S2 2KΩ	3S1 – 3S2 2KΩ	4S1 – 4S2 2KΩ	5S1 – 5S2 2KΩ

Table 7.11 Secondary to Ground of CT

I/P Volts	O/P Resistance				
2.5KV	1S1 – 1S2 1KΩ	2S1 – 2S2 1KΩ	3S1 – 3S2 1KΩ	4S1 – 4S2 1KΩ	5S1 – 5S2 1KΩ

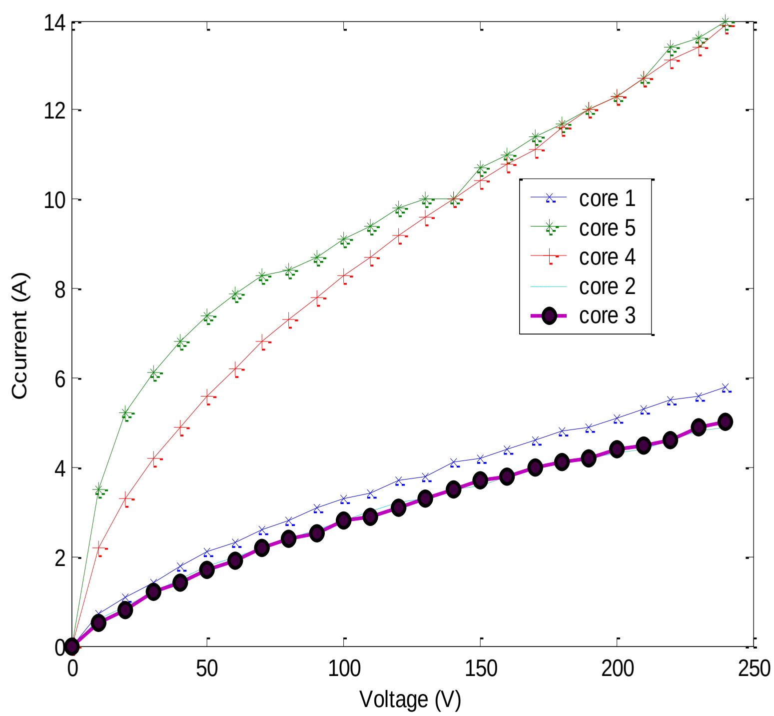


Figure 7.15 Magnetization Curves of the Five Core GEC Impregnation CTs

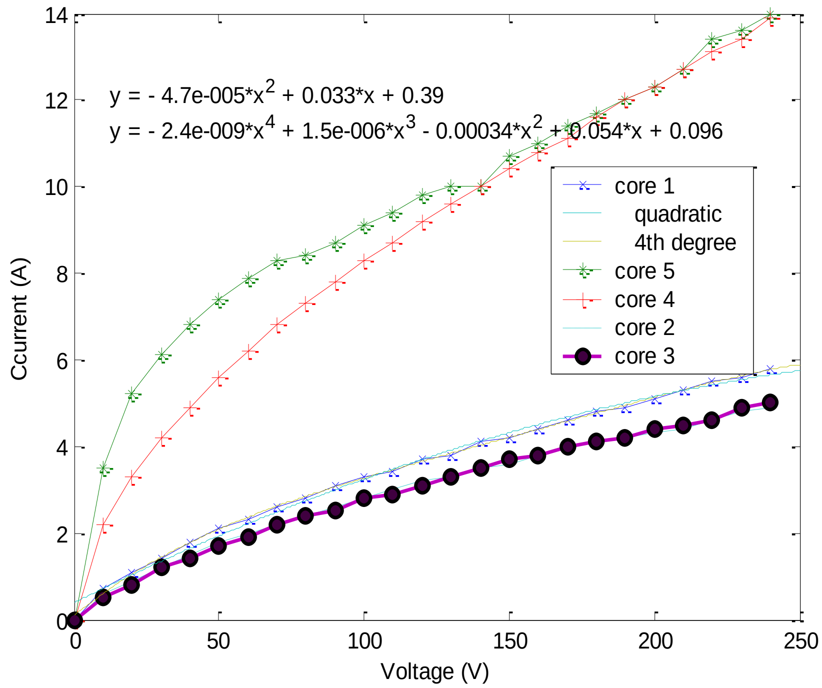


Figure 7.16 Quadratic and 4th degree polynomial curve fitting technique applied on core 1 of the CT.

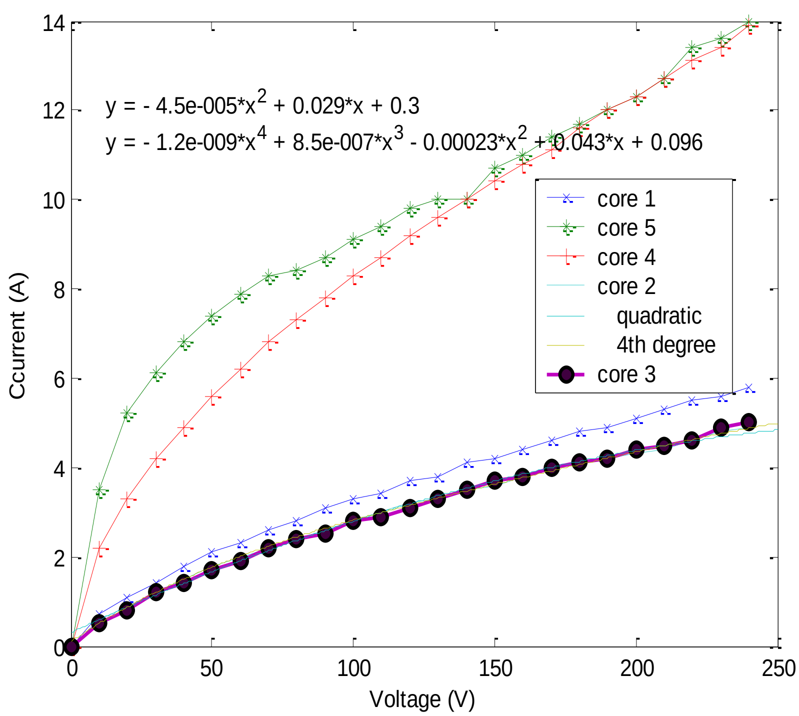


Figure 7.17 Quadratic and 4th degree polynomial curve fitting technique applied on core 2 of the CT.

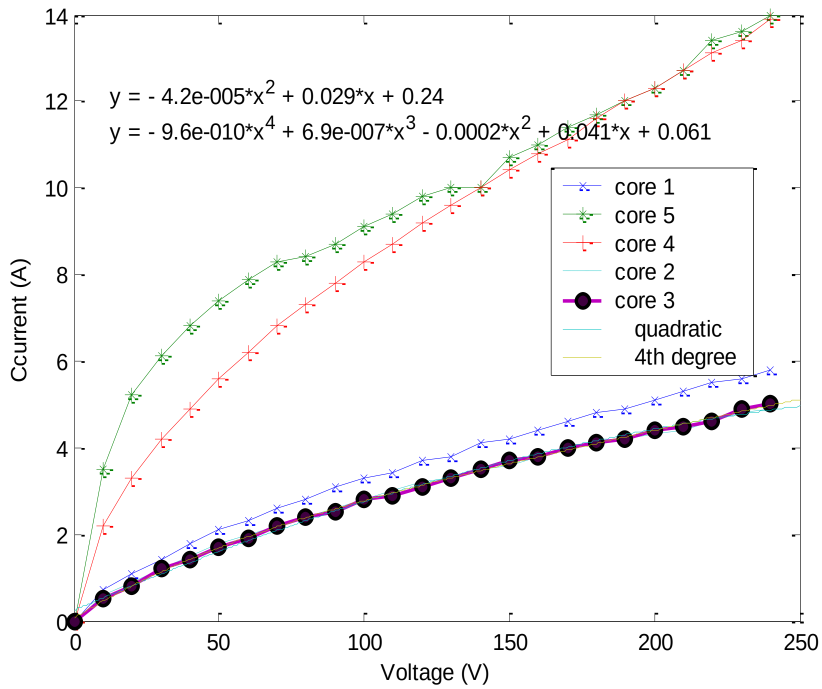


Figure 7.18 Quadratic and 4th degree polynomial curve fitting technique applied on core 3 of the CT.

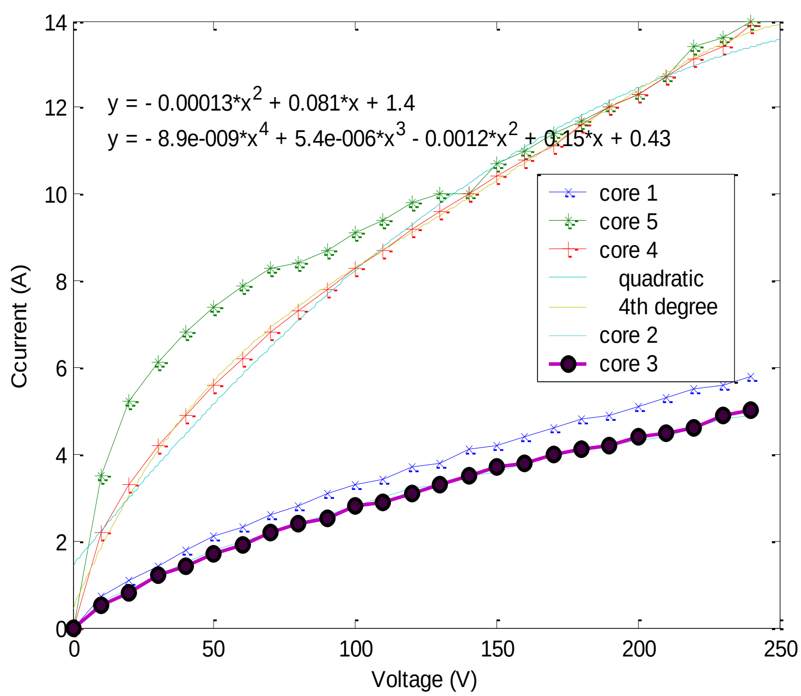


Figure 7.19 Quadratic and 4th degree polynomial curve fitting technique applied on core 4 of the CT.

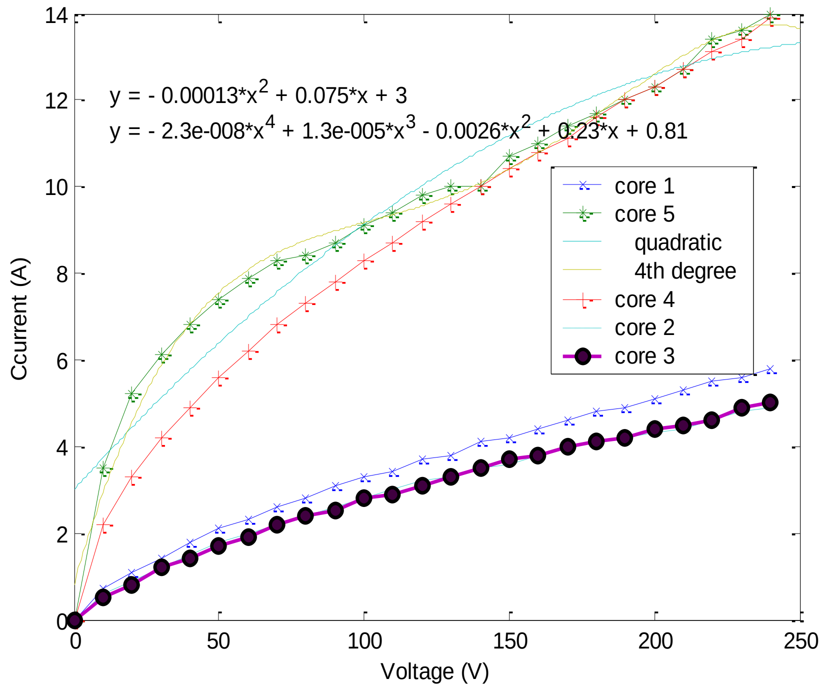


Figure 7.20 Quadratic and 4th degree polynomial curve fitting technique applied on core 5 of the CT

7.4.4.1 Curve Fitting and Development of Model for the CT

When the graph of magnetization curve of the curve of the current transformer were plotted as shown in figure 7.15, it is observed that some few point were out of the range. Thus there is the need to curve fit the data and obtain a standard relationship between the applied voltage and magnetizing current for each of the core.

Applying curve fitting technique on figure 7.15 (a) obtained from the original data using MATLAP gives the following equations taken from curve in figures 7.16 to 7.20.

1. For core 1 of the CT, the quadratic results into the expression given as

   $I = -4.7e - 005V^2 + 0.033V + 0.39$..(7.25)

   While, fourth order polynomial results into the expression given as

   $I = -2.4e - 009V^4 + 1.5e006V^3 - 0.00034V^2 + 0.054V + 0.096$............(7.26)

2. For core 2 of the CT, the quadratic results into the expression given as

   $I = -4.5e-005V^2 + 0.029V + 0.30$..(7.27)

   While, fourth order polynomial results into the expression given as

   $I = -1.2e-009V^4 + 8.5e-007V^3 - 0.00023V^2 + 0.043V + 0.096$.........(7.28)

3. For core 3 of the CT, the quadratic results into the expression given as

   $I = -4.2e-005V^2 + 0.029V + 0.24$..(7.29)

   While, fourth order polynomial results into the expression given as

   $I = -9.6e-010V^4 + 6.9e-007V^3 - 0.0002V^2 + 0.041V + 0.061$.............(7.30)

4. For core 4 of the CT, the quadratic results into the expression given as

   $I = -0.00013V^2 + 0.081V + 1.4$...(7.31)

   While, fourth order polynomial results into the expression given as

   $I = -8.9e-009V^4 + 5.4e-006V^3 - 0.0012V^2 + 0.15V + 0.43$...............(7.32)

5. For core 5 of the CT, the quadratic results into the expression given as

   $I = -0.00013V^2 + 0.075V + 3$..(7.33)

   While, fourth order polynomial results into the expression given as

   $I = -2.3e-008V^4 + 1.3e-005V^3 - 0.0026V^2 + 0.23V + 0.81$...............(7.33)

From the characteristic of the curves the following conclusions can be made.

- **i.** Core 4 and 5 are classified as **Class X** cores because they have and these cores are suitable for differential protection scheme.
- **ii.** Core 1 is a **Class P** core suitable for overcurrent protection scheme.
- **iii.** Core 2 and 3 are **metering CT** cores and these cores are suitable for the measurement.
- **iv.** Having known the CT characteristic and the model, we can design and construct a similar CT in Nigeria through copy technology, which is a step forward.

7.5 Fault Current Distribution in Transformer Windings

Under fault conditions, currents are distributed in different ways according to winding connections. Understanding of the various fault current distributions is essential to the design of differential protection scheme, performances of directional relays and settings of over-current relays.

According current distribution on delta-star transformers and star-delta transformer with earth fault and phase to phase fault within and outside the zones of protection are considered as follows:-

7.5.1 External Phase-to-Phase Fault

Delta-star transformer in figure 7.21; shows a yellow phase to blue phase fault outside the zone of protection in the secondary side of the transformer. The fault will result to current flowing in the blue phase and yellow phase on the primary of the transformer as shown in the figure 7.21. The single current in secondary circuit of the primary CTs will produce two currents flowing into the differential relay. These currents are counter balanced by the currents produce in the secondary CTs of the transformer, in this condition there will not be tripping of differential relay, because the operating condition is not satisfied, as earlier explained.

If the fault is on red phase to yellow phase, the current will only be flowing in the primary side of the yellow and red phases of transformer. We would have same result as the case earlier explained. Similarly, a red phase to blue phase fault on the secondary side of the transformer outside zone of protection will result to current flowing in the blue phases.

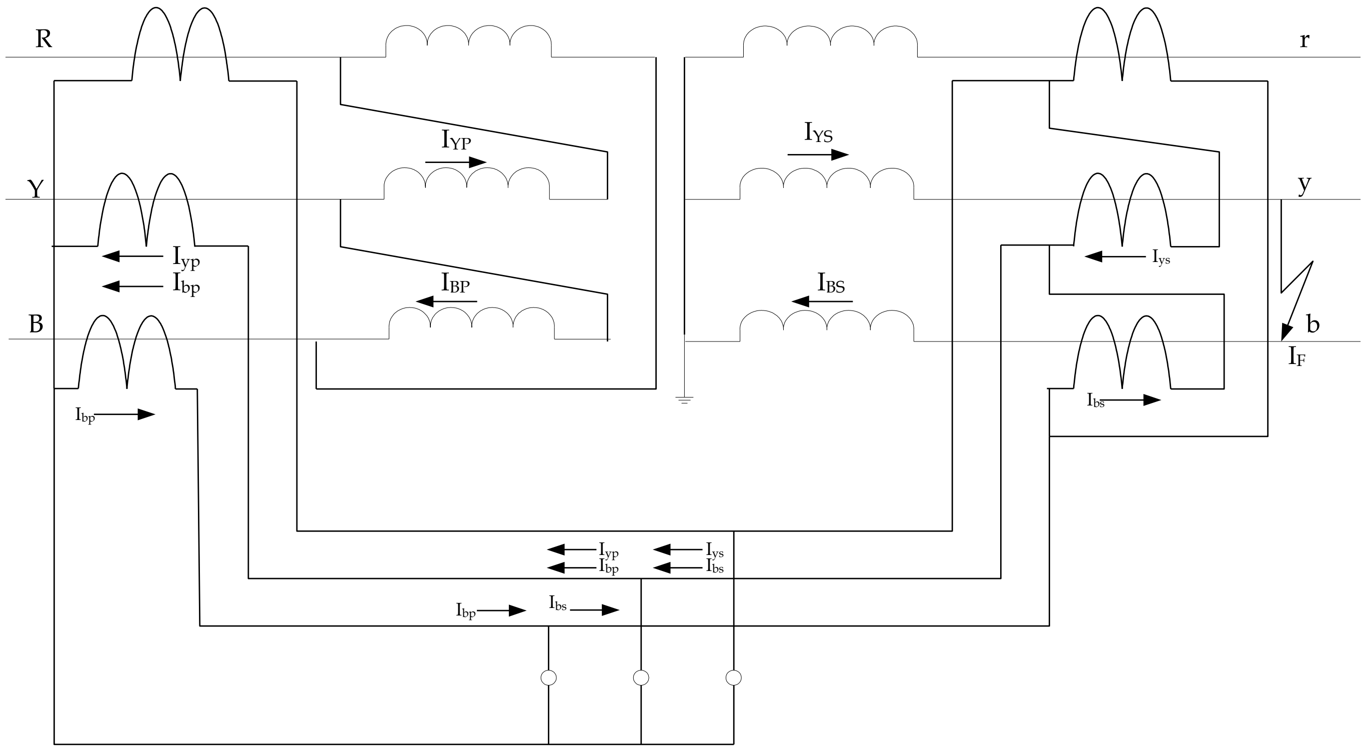


Figure 7. 21 Fault Current Distribution of Delta-Star Transformer with Yellow-Blue (Phase to Phase) Fault out Side the Zone of Protection

7.5.2 External Phase to Earth Fault

In the scheme shown in figure 7.22, an earth fault on secondary side of main transformer in blue phase outside zone of protection will result to a current in the blue phase of the primary side of the main transformer. The single current in the secondary circuit of primary side CTs will produce two currents flowing into the differential relay. These currents are counter balanced by the currents produce in the secondary side CTs of the main transformer as shown in the figure 7.22. This condition does not satisfied tripping of differential relay.

We will have similarly situation if the earth fault had occurred on the yellow or red phase.

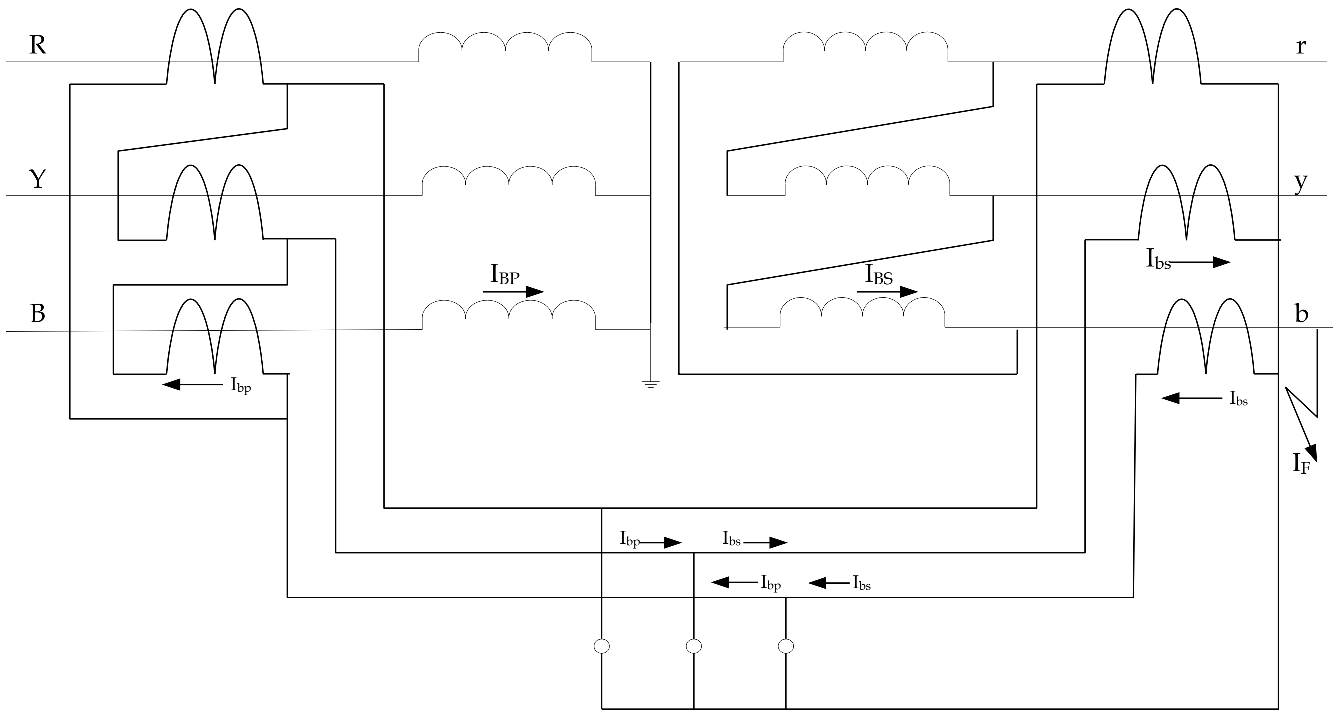


Figure 7. 22 Fault Current Distribution of Star-Delta Transformer with Blue Phase to Earth Fault out Side the Zone of Protection

7.5.3 Internal Phase to Earth Fault

In the scheme shown in figure 7. 23 an earth fault on the blue phase of the secondary side of main transformer within the zone of protection will result to current in the blue phase primary side of the main transformer the single current in the secondary circuit of the primary side CTs will produce two currents flowing into the differential relay. The current on the blue phase produce in the secondary side CTs sum up with that of the primary CTs and these situations satisfied tripping of differential relay of blue phase which may result to tripping of other phases as these will cause on balance in the system.

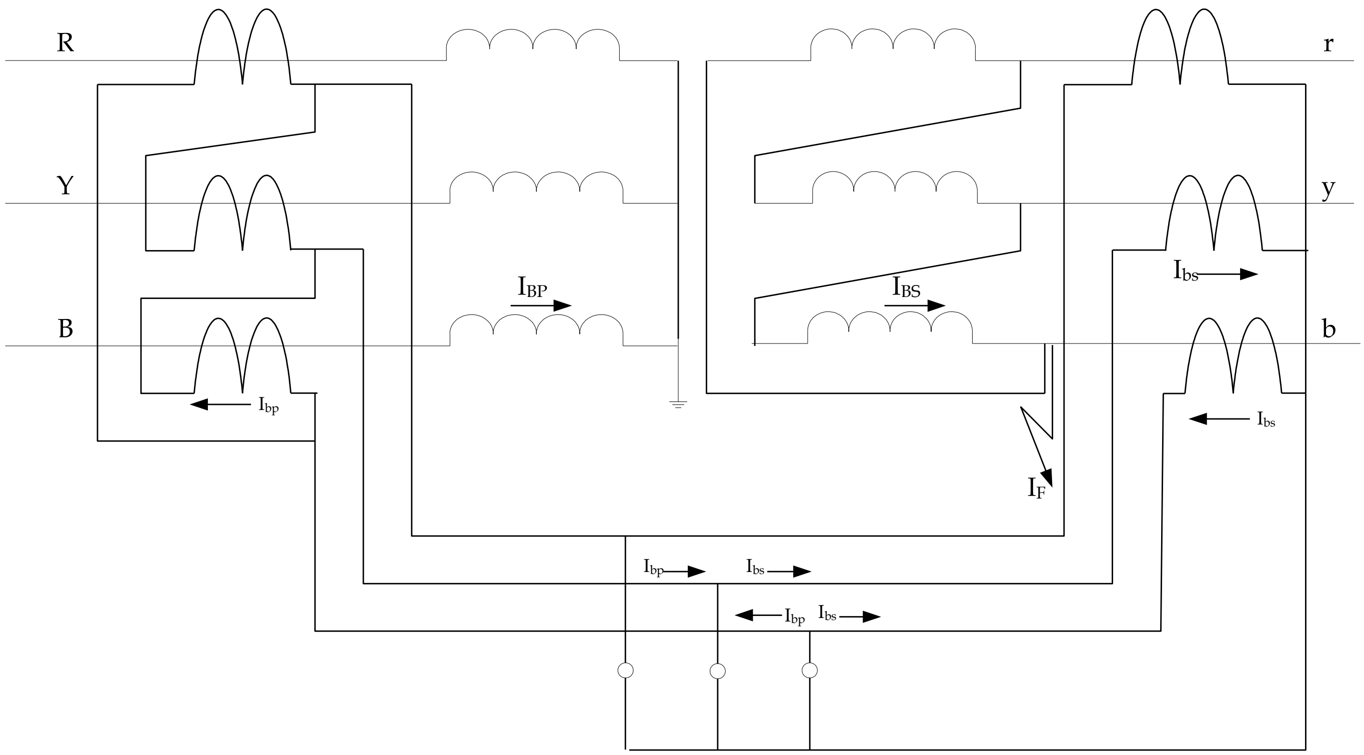


Figure 7. 23 Fault current distribution of the Star- Delta Transformer with phase to earth fault within the zone of protection

7.5 4. A typical Illustration of Differential Protection Scheme

7.5.4.1 Consider a simple differential scheme for Yd11, 15MVA, 132/33KV Start-Delta Transformer shown in figure 7.24.

Full load current is determine as follows

Say red phase:

$$I = \frac{RatedMVA}{\sqrt{3} \times RatedVoltage}$$

For the primary side of the transformer

$$I = \frac{15 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 66A$$

For the secondary side of the transformer

$$I = \frac{15 \times 10^6}{\sqrt{3} \times 33 \times 10^3} = 263A$$

The current flowing in primary CTs at full load current will be

I = Full load current/CTs Ratio.

If CT ratio of 130/1 for the primary CTs is selected than

I = 66/130 = 0.51A

To obtain the actual current flowing into relay form the CTs, we multiply 0.51 by $\sqrt{3}$ (star- delta transformation factor) to obtained 0.88A.

Note, there is a phase shift introduced as earlier discussed. For the scheme to balance vectorially the CTs on the 132kV side must be connected in delta while those of the 33kV side must be connected in star.

The current flowing in secondary CTs at full load current choosing CT ratio of 300/1 will be; I = 263/300 = 0.88A

The Two CTs currents flowing into the differential relay are balanced both in magnitude and phase as shown in figure 7. 24. The problem with this design is that the CTR of 130/1A is not conventional. Hence, this type CT has to be specifically manufactured for this particular transformer, which will make replacement difficult in the event of damage. To provide solution to this problem consider the differential scheme shown in figure 7. 25.

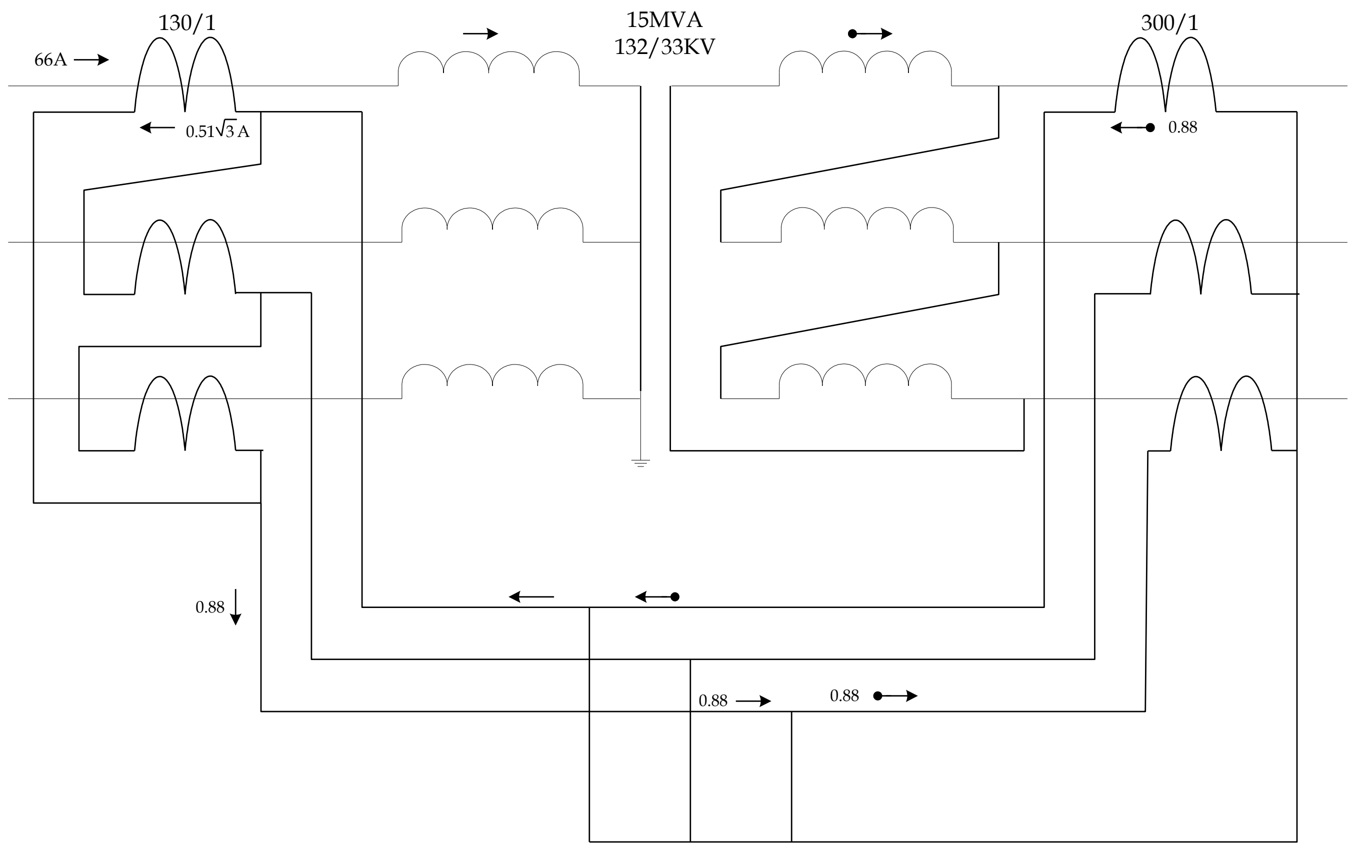


Figure 7. 24 Differential scheme for Yd11 15MVA ,132/33KV star-delta transformer using main CTs

7.5.4.3 Differential scheme for Yd11 15MVA, 132/33KV Start –Delta Transformer using ICTs,

ICTs can be used to correct ratio mismatch or vector mismatch or both at the same time as discussed in section 7.3.2.2 the application is now applied here to solve the problem with the scheme shown in figure 7. 24.

The scheme in Figures 7.24 and 7.25 are same scheme, but the later have both conventional CT in each side of the transformer. The problem is solved by the introduction of one set of ICTs which is used to correct both ratio mismatch as well as the vector mismatch. This ICT is located on the primary side. It would be more difficult if the ICTs were to be placed on the secondary side because of delta connection of the main transformer winding.

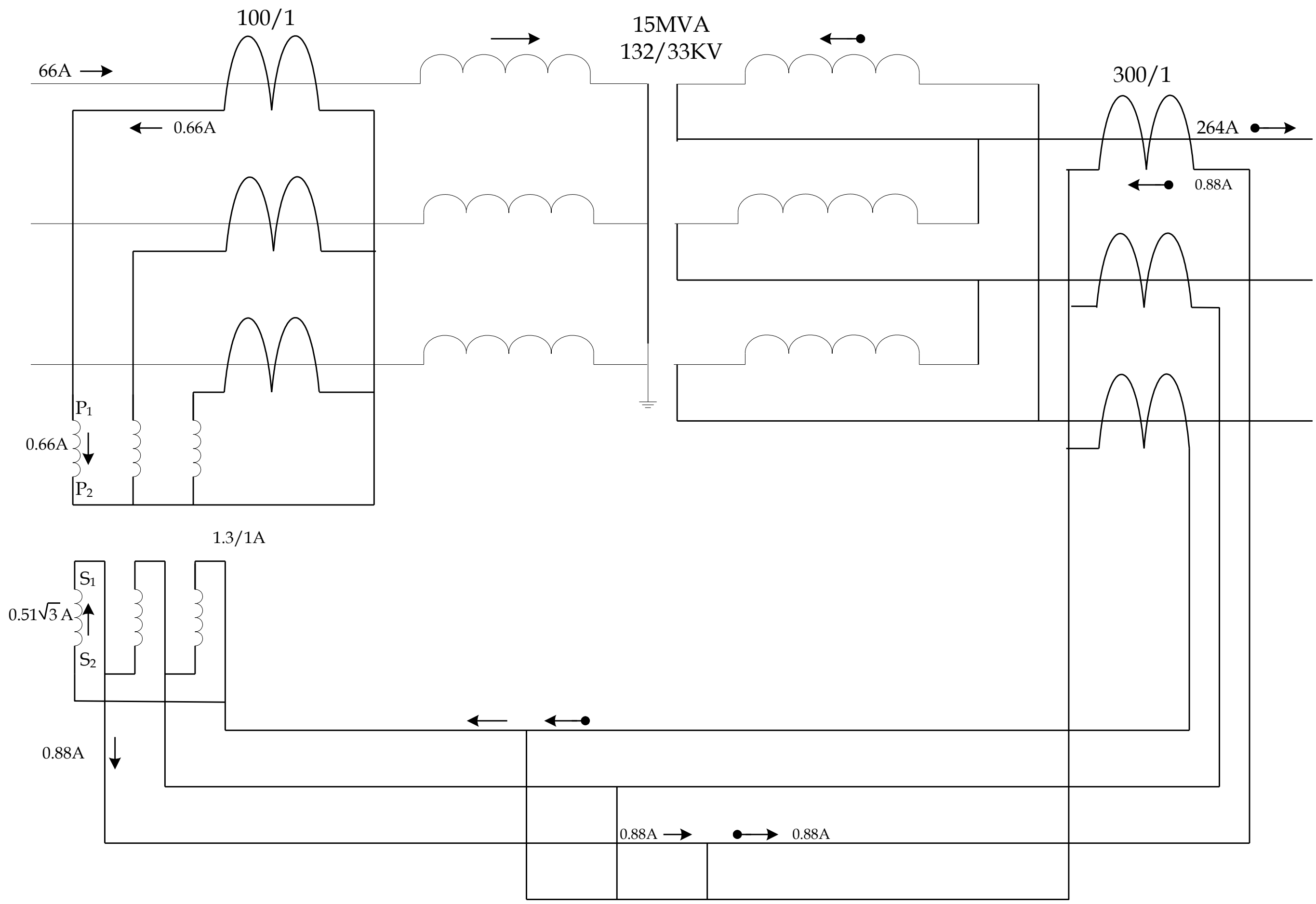


Figure 7.25 Differential scheme for Yd11 15MVA ,132/33KV star-delta transformer using ICT

7.5.4.3 Differential Scheme for a Typical Star-Delta Transformer Using Two Sets Of ICT

Another set of ICTs can be introduced in the secondary side as shown in figure 6.26. The ICTs on the primary side can be used for vector mismatch while the set on the secondary side can be used for ratio mismatch. Both schemes in figure 7.25 and figure 7.26 are same. The best option to be used in application will depend on the cost of the design and reliability of the scheme.

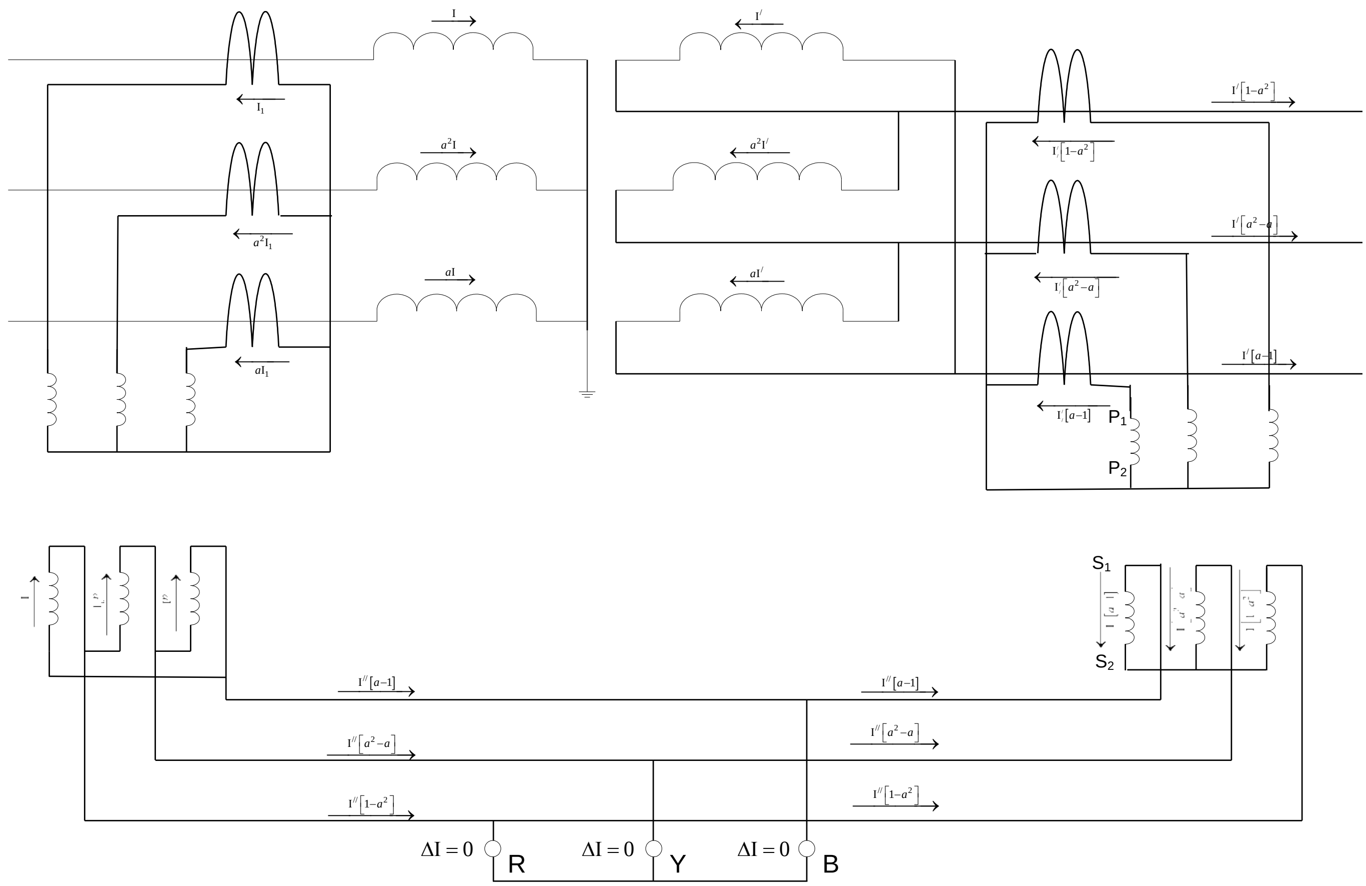


Figure 7.26 Differential scheme for a typical star-delta transformer with two set of ICT

7.5 .4.4 Differential Scheme for a Typical Star-Star Transformer with One Winding Grounded

Elimination of zero sequence current earlier discussed is applied in figure 7. 27, which shows a typical star-star transformer with secondary winding grounded. Earth faults on the secondary side will reflect as a phase faults on the primary side. For the differential scheme for this type of transformer to function properly, a closed delta connection must be introduced in the ICT connection as shown in the diagram. This is to eliminate the zero sequence current that would be present in the secondary side but not reflected on the primary side.

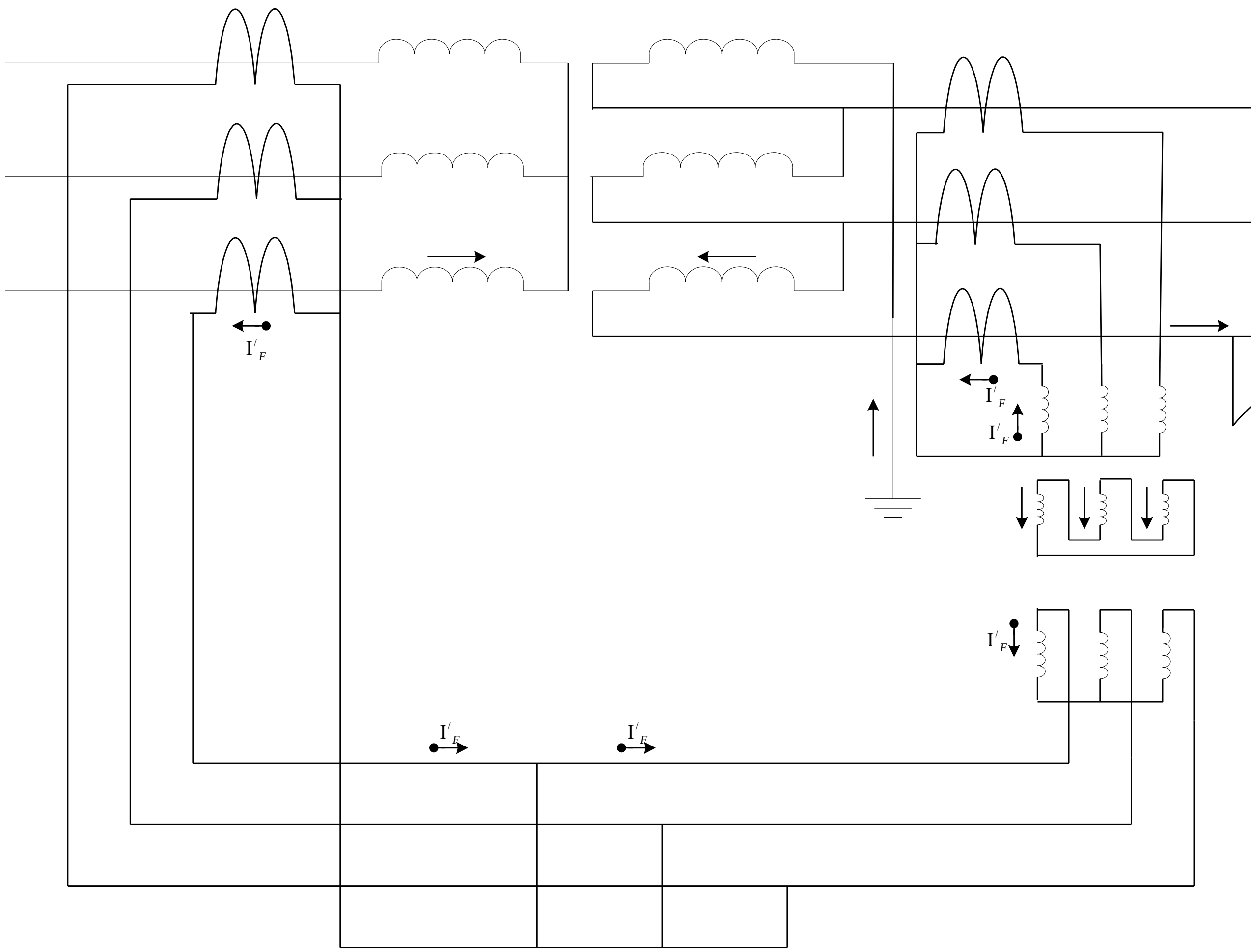


Figure 7.27 Differential scheme for a typical star-star transformer with one winding grounded

7.5.4.5 Differential scheme for a typical star-star transformer with both winding grounded.

Under normal condition, earth faults on one side will reflect as earth faults on the other winding. Similarly, phase faults on one side will reflect as phase faults on the other. But the normal practice is to connect the CTs in the delta form. The advantage of this is that any zero sequence current that may exist on one side is eliminated and not reflected into secondary circuit and cannot therefore cause any un balance. Figure 7.28 shows the scheme.

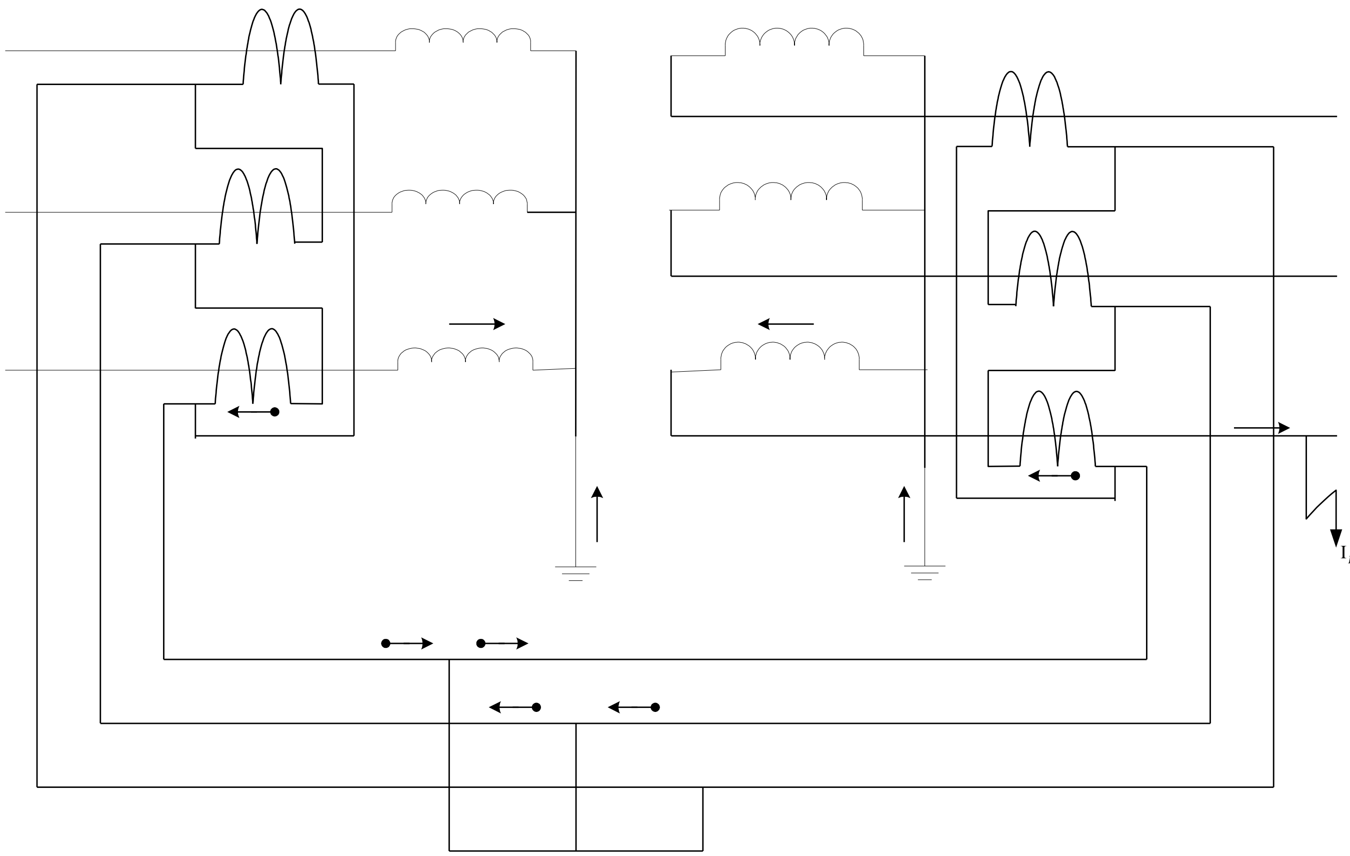


Figure 7.28 Differential scheme for a typical star-star transformer with both windings grounded

7.5.4.6 Differential scheme for a typical Autotransformer.

An autotransformer is a form of star-star transformer except that both the primary and secondary winding share a common winding. In other words, the secondary winding is common to the two sides. The principle of operation is exactly same as that of star-star transformer with both its windings grounded, through one neutral point figure 7.29 shows typical scheme.

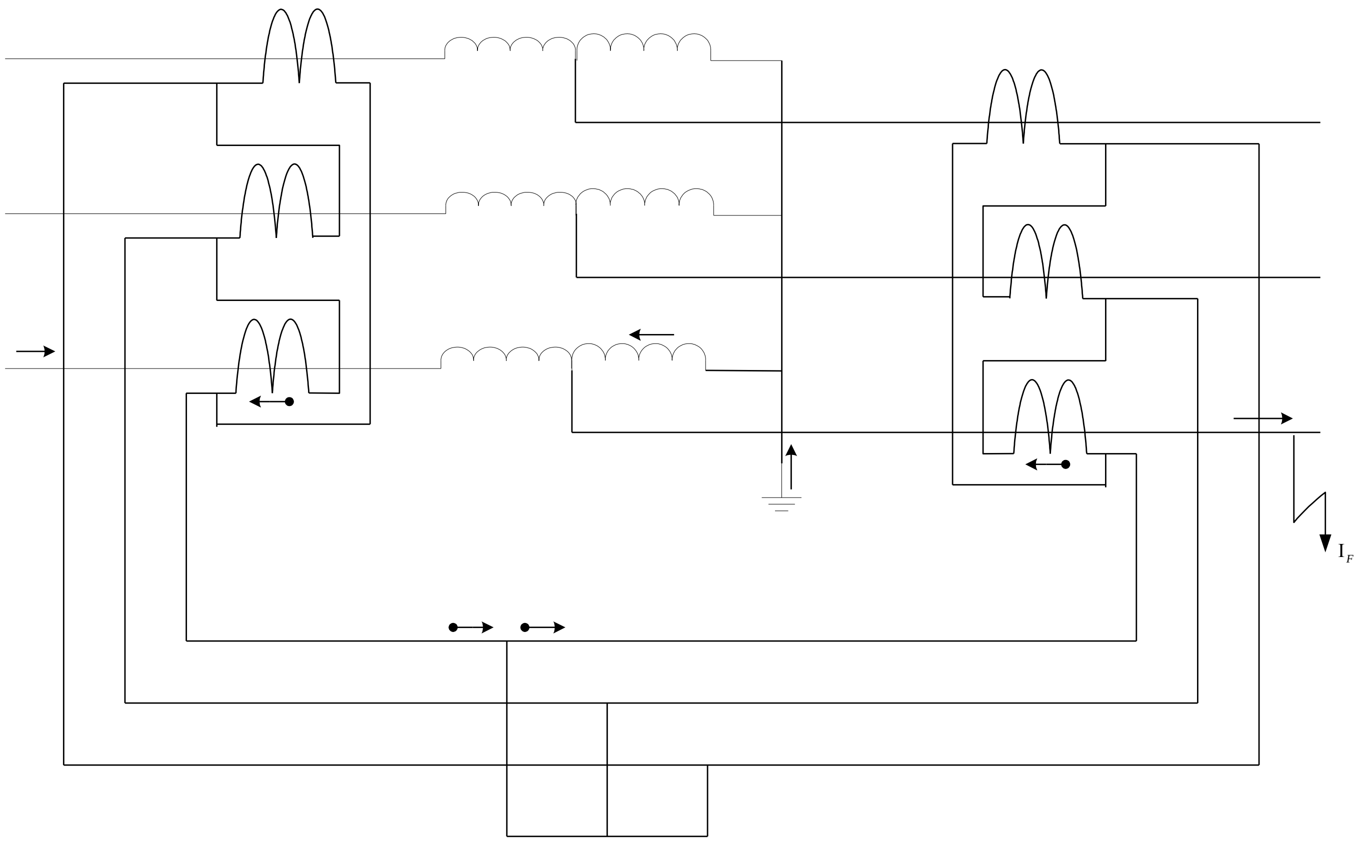


Figure 7.29 Differential scheme for a typical Auto-transformer with one winding grounded

7.5.4.7 Differential scheme for a Three winding Transformer.

Differential protection of three winding transformer is essentially similar to that of two winding transformers. The same rules regarding CT connections still apply. The total load on the secondary side and tertiary windings must be balanced against the load in the primary.

In situation where the tertiary winding is not connected to load, then the load current in primary is balanced against that of the secondary. A typical differential scheme for a three windings transformer is shown in figure 7.30.

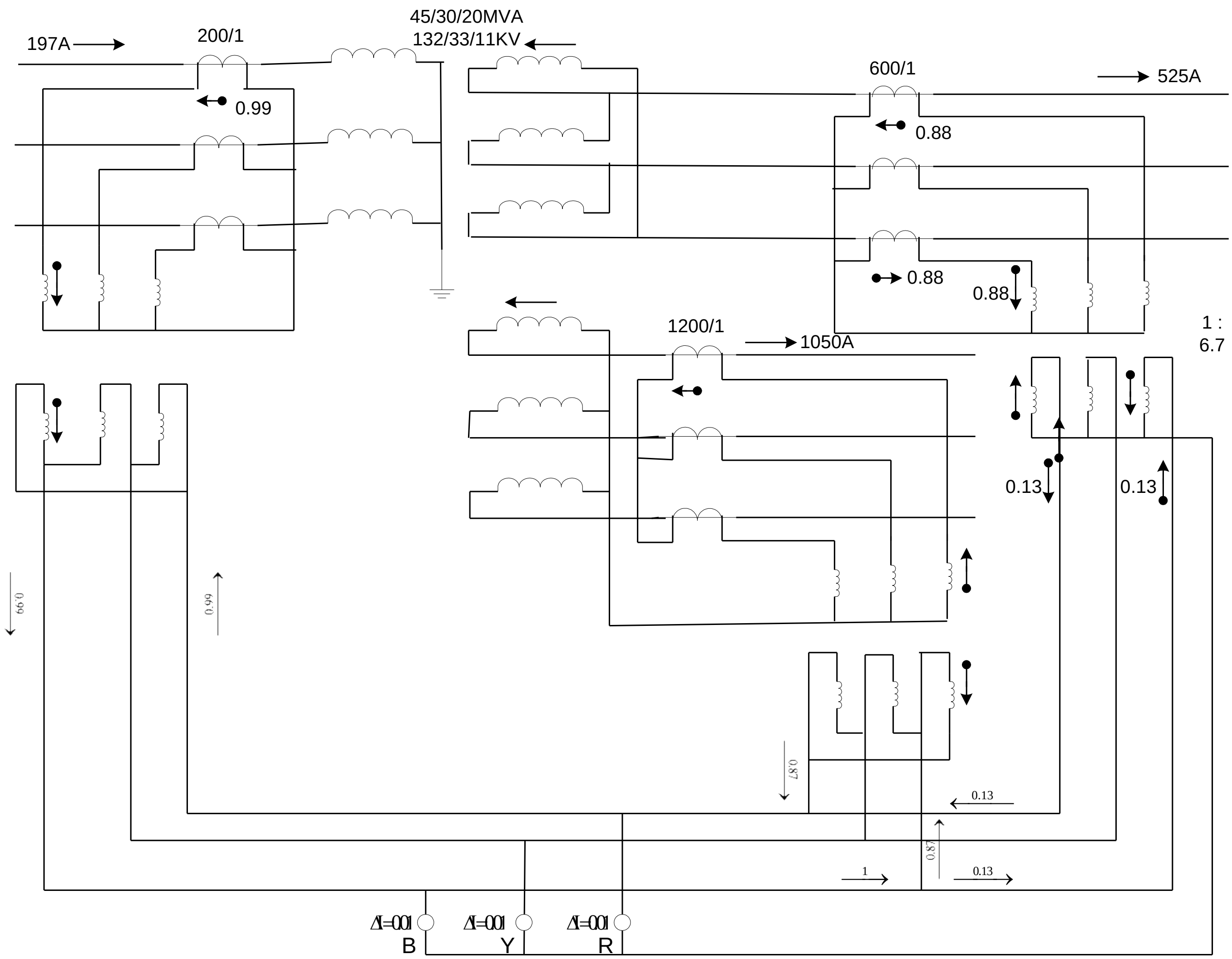


Figure 7.30 A Typical illustration of three winding transformer differential scheme

7.6 Confirmatory Test for Transformer Differential Scheme.

The stability checks; provide means of confirming the correctness of the designed scheme. The scheme will be unstable and will be trip for external faults or even normal load conditions. If there is an error in the implementation of the scheme. The following methods can be can be used to check the stability of the scheme before commissioning the transformer:

a. Visual Inspection
b. Secondary Injection Method

7.6.1Visual Inspection

This involves physical inspection of the wiring from point to point. Errors in the designed scheme based on this method cannot be easily detected since the designers will that the scheme is right. The way out of this disadvantage is either to invite a different engineer to cross check or conduct a further test such as secondary injection test.

7.6.2 Secondary Injection Method

This method is based on the proper understanding of the current distribution in both the primary and secondary circuits during various fault conditions and these are then simulated using only one secondary injection Kit. The main CT incoming connections are isolated at the protection panel and currents are injected to the input of both the primary side and secondary side of the protection simultaneously. This can be achieved by connecting the two inputs in series. Figure 7.31 shows the basic arrangement for carrying out the test It is quite likely that there are ICTs on both sides and since these ICTs may not be of the same ratio, the current into the relay would not be the same of both sides. This means that, there would be differential current even the 'Through Fault' condition (STABLE CONDITION) and not just for the 'In-Zone fault condition' (OPERATE CONDITION).

The most important point to note is that the difference of the currents should be measured in the operating coil for stable condition and the sum for the operate condition. However, proper understanding of fault current distribution under various conditions considered in section 7.5 is very necessary in carrying out the secondary injection test.

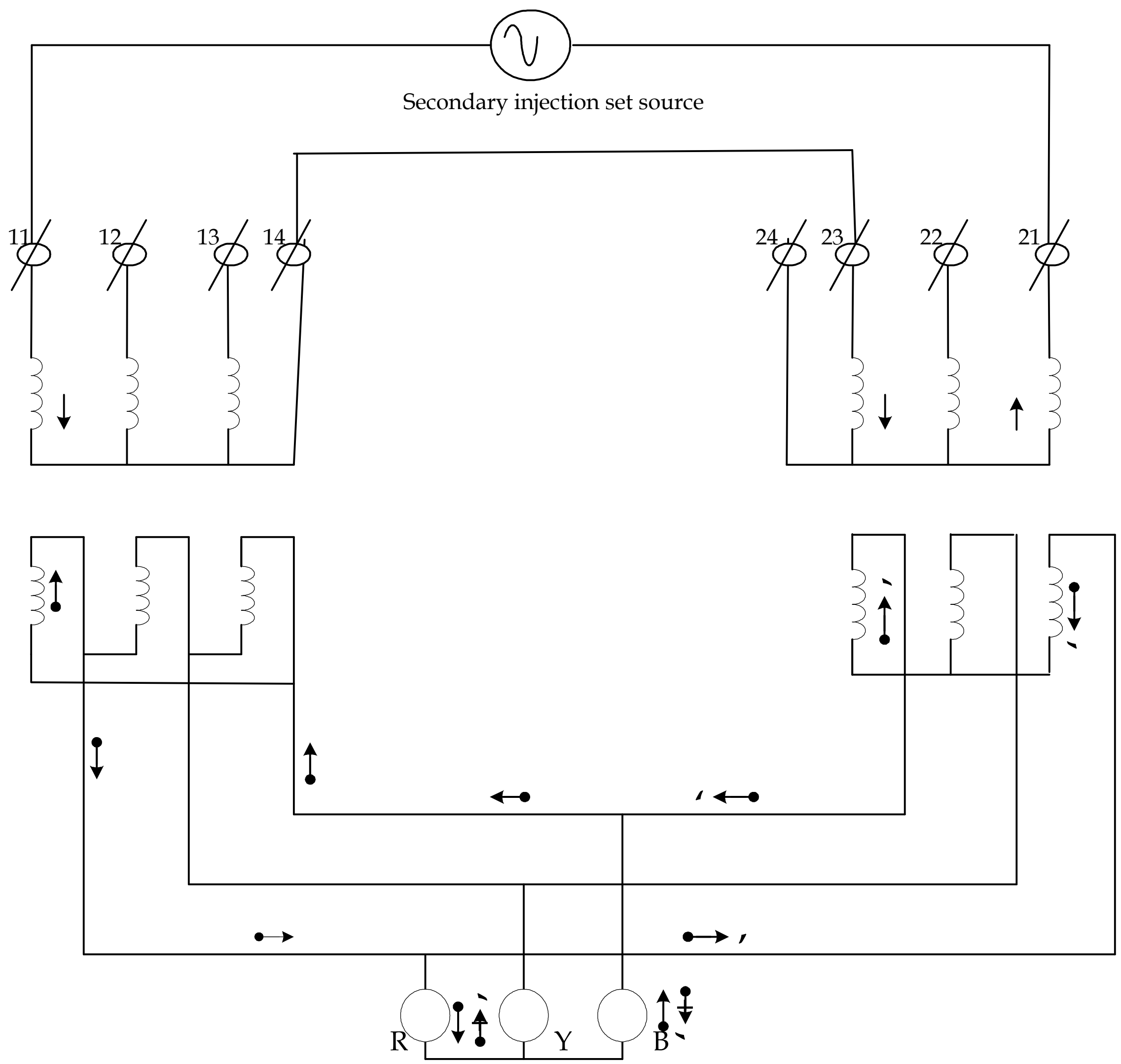


Figure7. 31 Typical connection for secondary injection test method

The terminals 11, 12, 13 and 14 on primary side and 21, 22,23 24 on secondary side should be opened, thus isolating the main CTs. The remaining wiring is mainly in the panel and includes the relay itself. This wiring can be checked completely using the secondary injection test set. Table 7.12 gives the possible ways of connection for the stability check.

Table 7.12: Stable [Through Fault] Condition Connection.

HV	LV	Connection	Injection	Different current
1/ Red	Red Blue	Link 14 and 23	11 and 21	$\Delta I_R = I' - I''$ $\Delta I_Y = 0$ $\Delta I_B = I' - I'$
2/ Yellow	Yellow Red	Link 14 and 21	12 and 22	$\Delta I_R = I' - I''$ $\Delta I_Y = I' - I''$ $\Delta I_B = 0$
3/ Blue	Blue Yellow	Link 14 to 22	13 and 23	$\Delta I_R = 0$ $\Delta I_Y = I' - I''$ $\Delta I_B = I' - I'$

Table 7.13: Operate [In zone Fault] Condition Connection.

HV	LV	Connections	Injection	Different current
1/ Red	Red Blue	Link 14 and 21	11 and 23	$\Delta I_R = I' - I''$ $\Delta I_Y = 0$ $\Delta I_B = I' - I''$
2/ Yellow	Yellow Red	Link 14 and 22	12 and 21	$\Delta I_R = I' - I''$ $\Delta I_Y = I' - I''$ $\Delta I_B = 0$
3/ Blue	Blue Yellow	Link 14 to 23	13 and 22	$\Delta I_R = 0$ $\Delta I_Y = I' - I''$ $\Delta I_B = I' - I''$

7.6.3 Precaution to be taken when carrying the Testing.

1. Depending on ICT ratio and the level of the current injected, the relay many operate for both stable and operate conditions, in either case the relay must not be allowed to be energized for too long otherwise it could be damaged.

ii. The injected current I should not exceed 50% of the current rating of the relay. (25% is acceptable), this current may be low but will be sufficient to confirm the status of the wirings.

7.6.4 Live Tests

After the panel wiring and the relays have been tested and found satisfactory, the CT terminal should be reconnected and final checks can than be carried out with the main transformer energized form the power source. The problem that might be encountered can then be easily traced to the main CT connections.

7.7 Restricted Earthfault (REF) Protection or Balance Earthfault (BEFf) Protection Scheme for Power Transformer.

Restricted earthfault (REF) is a high-speed protection scheme, which is used to protect transformer windings against internal faults such as; Short circuits between phases or/and any earth fault on the transformer within its protected zone. REF is similar to the differential protection scheme; their principle of operation is based on balanced scheme, where the residual currents flowing in one winding or a group of windings is compared with the currents through the associated neutral of the same windings. The relay should remain in–operative during external faults but very sensitive for internal faults.

For a delta (or unearthed star) transformer, balanced earthfault protection scheme can be used to provided the protection. This can be achieved by connecting three line CTs in parallel (residual connection). In this case the relay will operate for internal earth faults, since the transformer itself cannot supply zero sequence current to the system it should be connected to an earth source.

Figure 7.32 and 7.33 shows a typical balanced earth fault for delta winding transformer and typical restricted earth fault for star winding transformer.

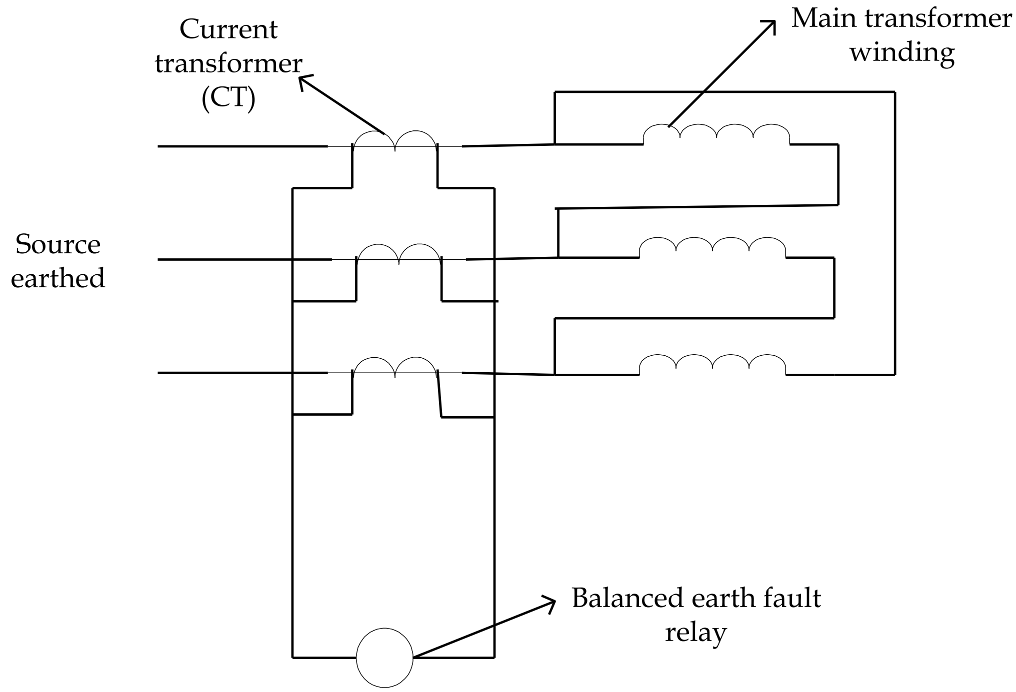


Figure 7.32 Typical Balanced earth fault circuit connection for delta winding with source earthed

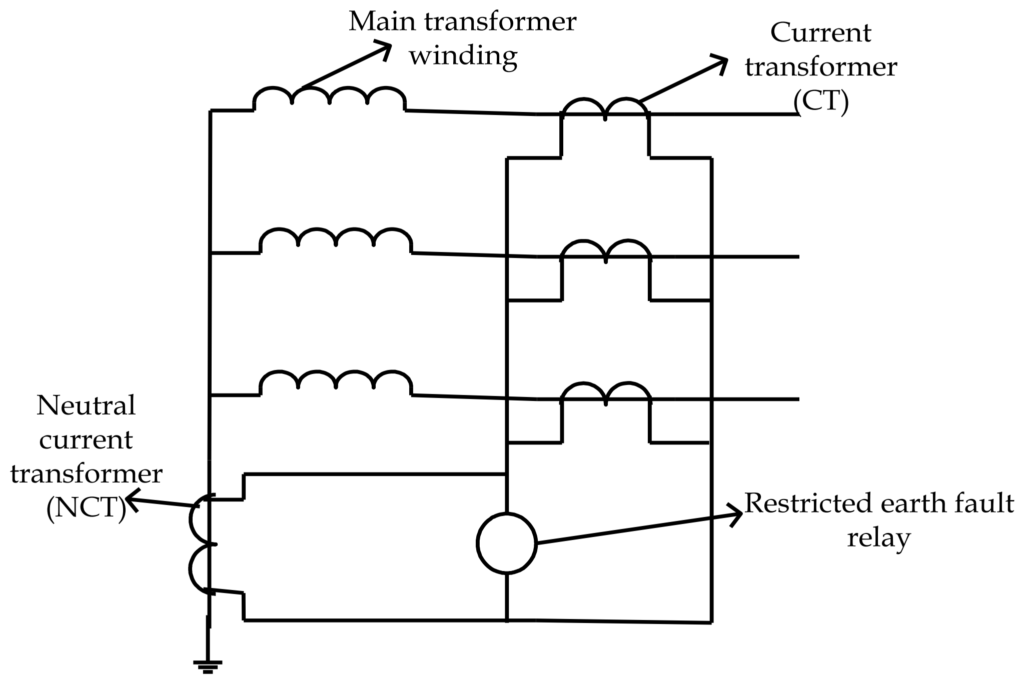


Figure 7.33 Typical Restricted Earth fault Circuit Connection for Star Winding Earthed

For an earthed star winding, the residual connections of line CTs are further connected in parallel with a CT located in the transformer neutral. Under external fault conditions the current in the line CTs is balanced by the current in the neutral CT. under internal fault conditions, current only flows in the neutral ct and since there is no balancing current form the line CTs, the relay will operate.

7.8.1Basic Factors that can Causes Incorrect of REF Protection Scheme

There are a number of factors that can cause in-balance in the REF schemes and these are related to the current transformers used for the scheme.

a. Ratio Mismatch.
b. Accuracy mismatch.
c. CT polarities
d. Wiring error

7.7.1.1 Ratio Mismatch

REF protection scheme should have the same CTs ratio. Difference in ratio will cause an in-balance in the currents during normal loading or external faults and this in-balance can cause relay operation depending on its magnitude.

7.7.1.2 Accuracy mismatch

The accuracy of the CTs for REF should be as close as possible if not the same or else the relay can operate particularly during external faults. CTs of different accuracy can cause occasional operation of REF either during line / transformer energization or during external faults.

7.7.1.3 CT Polarities

The CT polarities should be arranged such that the current distribution in the scheme is balanced i.e. the differential current should be approximately zero during normal loading condition or external faults see figures 7.34 & 7.35 for illustration.

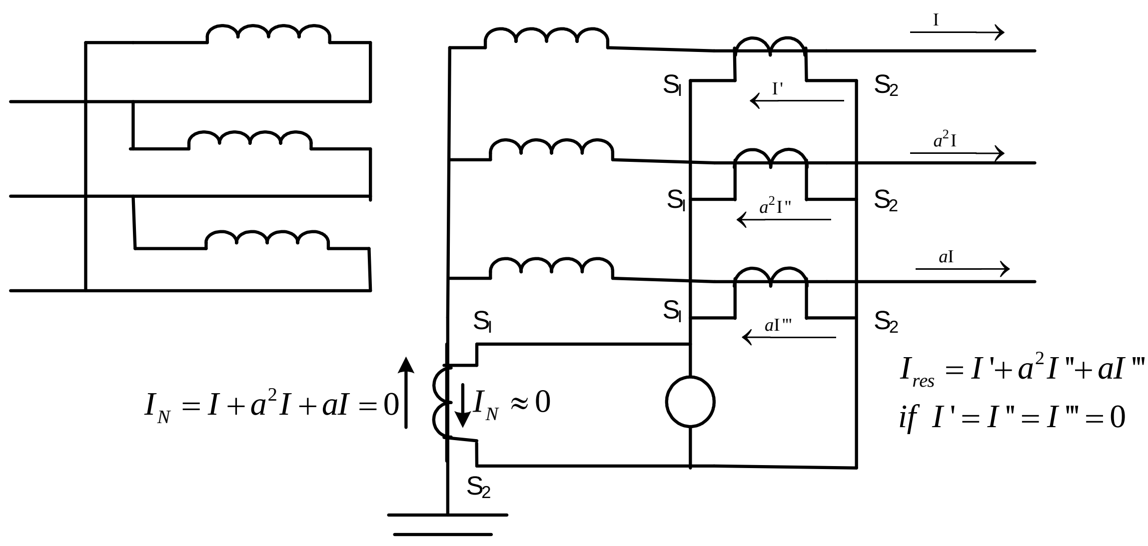


Figure 7.33 Current Distribution in Delta-Star Transformer REF Protection Scheme Under Normal Loading Condition.

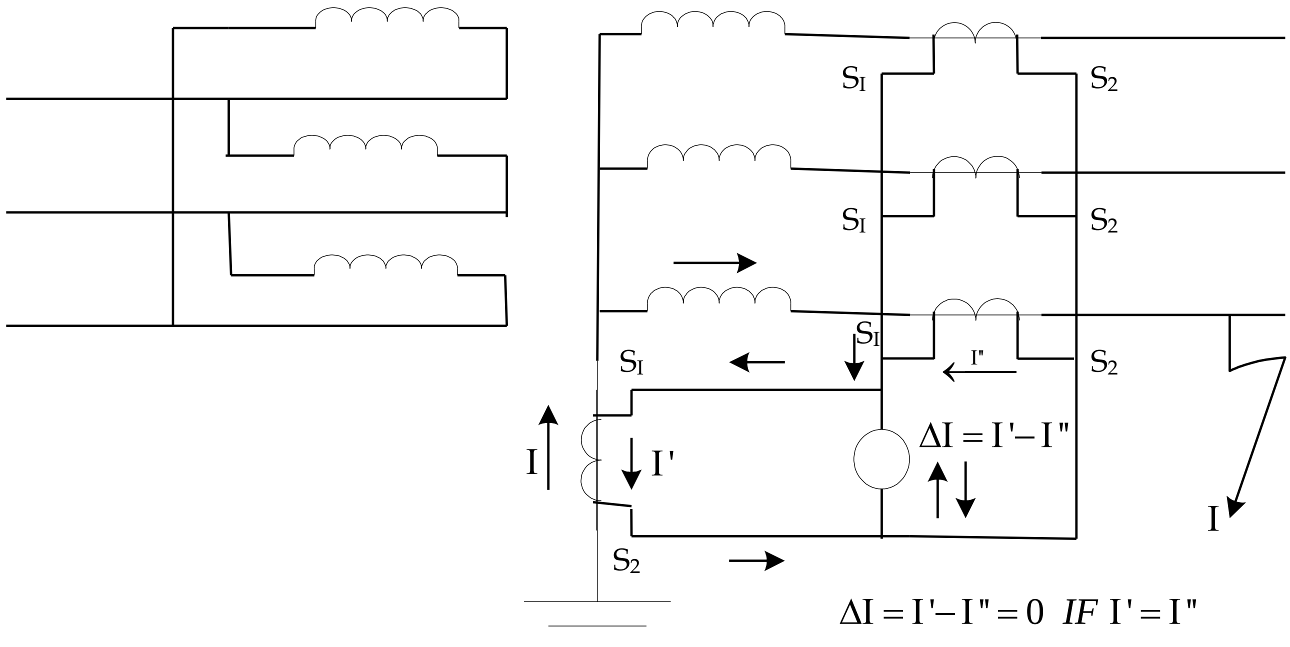


Figure 7.35 Current distribution in a Delta-Star transformer REF protection scheme under external condition

The two figures 7.34 and 7.35 show typical REF schemes for the star winding of a delta-star transformer. The residual current in the phase CTs during normal loading will be high if any of the phase CT polarities are reversed see figure 7.36, it is not easy to detect fault during normal loading if the neutral CT polarities are reversed. The only way of detecting such situation is when the scheme persistently operates for known a external fault; that is when it can be concluded that neutral CT has reversed polarities, See figure7.37.

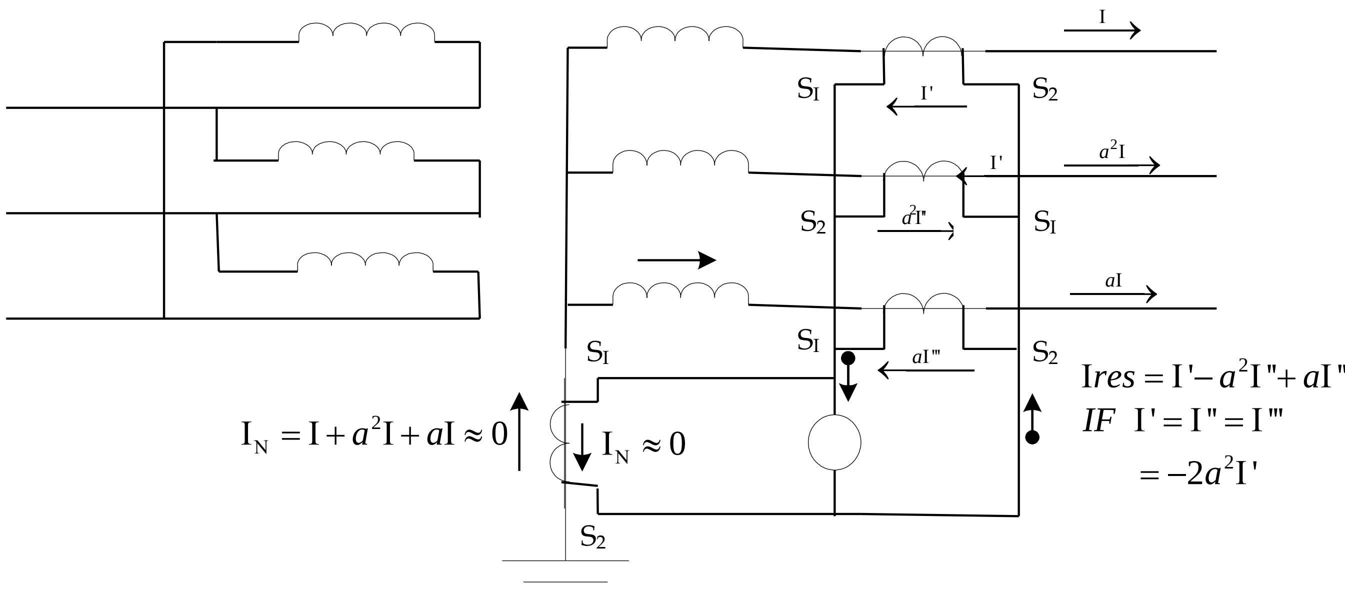


Figure 7.36 Current distribution in a Delta-Star transformer REF protection scheme when a phase CT polarity is reversed

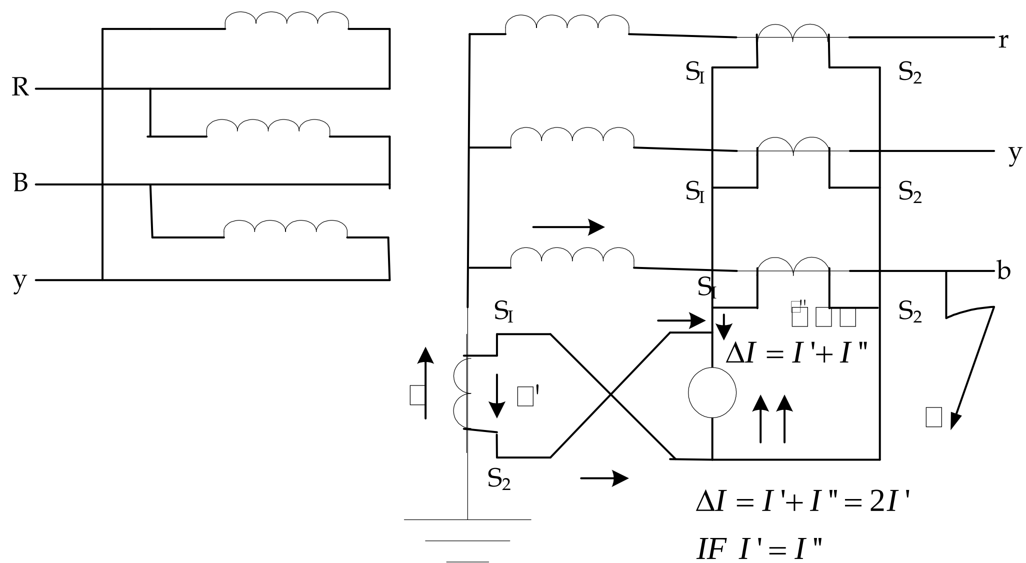


Figure 7.37 Current Distribution in a Delta-Star Transformer REF protection scheme when neutral CT polarity is reversed

7.7. 1.4 Wiring Errors

Errors in wiring can lead to mal operation of the relay either during normal loading or external fault conditions. The effect of error in wiring can be similar to that of CT polarities problem.

7.7.2 Output Relay

The output relay in REF scheme is similar to the output relay in differential scheme in that it is a simple over current relay that is sensitive and of high-speed operation. It operates instantaneously once the operating condition is satisfied.

7.7.3 REF Scheme Using ICTs in conjunction with Main CTs to Correct Ratio Mismatch

One major requirement for the REF scheme is that the ratio of the phase CTs must be the same as the ratio of the neutral CT; sometime this is not possible leading to a ratio mismatch. This situation cause the relay to operate incorrectly for external faults, however because the situation can be corrected using ICTs; the only problem is that the ICTs must be of the same class as the main CTs.

7.7.4 REF Scheme using common CTs with differential scheme.

The cost of REF protection would be too high if separate CTs are used for the protection scheme. To reduce the cost, the general practice is to use the same sets of phase CTs used for differential scheme for the REF scheme.

A typical example of such arrangement is shown in figure 7.38.

Say red phase:

$$1 = \frac{RatedMVA}{\sqrt{3 \times RatedVoltage}}$$

For the primary side of the transformer

$$1 = \frac{45 \times 10^6}{\sqrt{3 \times 132 \times 10^3}} = 197A$$

For the secondary side of the transformer

$$1=\frac{45\times10^{6}}{\sqrt{3\times33\times10^{3}}}=788A$$

The current flowing in CTs on the primary side of main transformer (I_{CTP}) at full load current will be;

I_{CTP} = Full load current/ CTs Ratio.

If CT ratio of 200/1 for the primary side of the transformer is selected than

I_{CTP} = 197/200 = 0.99A

The current flowing in CTs on the secondary side of main transformer (I_{CT}s) at full load current will be;

I_{CTS} = Full load current/ CTs Ratio.

If CT ratio of 800/1 for the primary side of the transformer is selected than

I_{CTP} = 788/800 = 0.99A

I_{CTP} = I_{CTS}, however, because of the phase shift introduced in the main transformer Star–Delta, the scheme is not balance. To balance the scheme, the following steps are taken,

a. ICT of ratio $\sqrt{3}:1$ connected in Star – Delta is introduced into the scheme at the primary side of the main transformer. This arrangement takes care of the phase shift by the connection of the main transformer.

b. ICT of ratio 1:1 connected between the CTs and the relay on the secondary side of the main transformer is to take care of the zero sequence current that might circulate as a result of any earth fault on the secondary side of the main transformer. With these measures the current in the differential relay are balanced.

c. The REF relay on the primary side of the main transformer is mainly to protect the primary side of the main transformer against earth fault. Since the working principle of REF is based on the balance scheme, neutral current transformer (NCT) of ratio 200:1 is chosen to balance the scheme.

d. Standby earth fault (SBEF) relay on the secondary side of the main transformer is mainly to protect the earthing transformer against earth fault. Since the working principle of SBEF is based on the balance scheme, the neutral current transformer (NCT) of ratio 800:1 is chosen to balance the scheme (figure 7.38).

CHAPTER EIGHT

CONCLUSION AND RECOMMENDATIONS

8.1 Conclusion

The protection system in the 330kV of the Nigeria Transmission Network has been investigated. Some possible causes of system collapse have been identified. However, the recent advances in the fields of protective relaying, primarily due to the impact of computer and information technology (IT) will allow changes in protection practices as required by the new operation regime of deregulation and privatization. Where strong market forces appear to utilize transmission capacity closer to their stability margin and at the same time ensure reliable supply of electric power to customers, all these will be achieved with minimum investment. Hence, the new approach to approval of moving away from evaluation of single protection devices towards wide area monitoring and controls system becomes a necessity. WAMP&C is however a proposal and the strategies for the implementation are also suggested.

The transmission network at 330kV voltage level was modelled and used for the calculations of apparent impedances of the network, three phase and single phase to earth short circuit fault currents, using NEPLAN power software. The results from the studies are the basis for the review of settings of earthfault and overcurrent relays, distance relay coordination and for the selection of switchgear from the manufacturer's tables. Algorithm and flowchart for the setting, testing and commissioning of numerical distance relays were presented. Hence, practical settings and testing of Ohmega distance relay was carried out on Benin-Oshogbo transmission line. The results obtained were found satisfactory and were also presented.

Additionally, some of the constraints associated with transformer protection, particularly differential and restricted protection schemes have been discussed. Options to ensure correct design and implementation of differential and restricted earthfault protection schemes for power transformers with typical examples were also presented.

Results of these studies should be used to improve operating procedures in power system protection practices, to minimize the probability of system collapse and improve electric power network efficiency and security. Studies show that operation procedures alone are not sufficient to ensure electric power network efficiency and stability (EPNES). Special controls and protection scheme strategies are also necessary to be put in place so as to mitigate against the conditions leading to blackout. Some of the schemes proposed include intelligent load shedding, islanding, flexible AC transmission system (FACTS) application, load tap changer control (LTC) and automatic generator controls (AGC) system.

8.2 RECOMMENDATIONS

From the findings, recommendations are made as follows: -

- Special attention should continue to be paid to the training of protection engineers and to encourage research work, with a view to ensuring that better designs and performances may be obtained in the future from protection schemes.
- The protection engineers should improve on the present traditional time-based maintenance policy to reliability centered maintenance (RCM) policy. They should also direct much more effort towards protection system design criteria, efficient and reliable implementation of power system protection.
- Opportunity should be given by the utilities companies to faculty members (relevant academic staff of University) to carryout some of the system studies often contracted out with large sum of money to foreign contractors without transfer of local knowledge, thereby weakening local capacity building.
- The following measures should be taken to prevent blackouts and improve electrical power network efficiency and stability (EPNES).
    1. Implement special protection schemes and control strategies as proposed in this work;

2. Perform protection coordination studies on a regular basis as system conditions change;
3. Secure real-time operating limits of the network on daily basis;
4. Test not only individual relays but also other system protection components and condition assessment of aging infrastructure;
5. Regulatory actions to ensure coordination and enable efficient system planning;
6. Strengthen transmission network, through building new lines, distributed generation and use of FACTS.
7. Single pole auto-reclosing schemes in all the 330kV transmission lines in the network should be reactivated. The scheme should be extended to 132kV transmission lines in the future.

8.2.1 Recommendations for Further Studies;

1. Load shedding schemes is a means of improving power system stability by providing smooth load relief in situations where the power system would have gone unstable. There is a need to improve upon the present practice of load shedding scheme in Nigeria power industry. In the present situation, operators manually shed loads when a certain level of under frequency is reached to maintain system stability regardless of the actual load conditions. Hence, making the process rough and insensitive. An intelligent (automatic) load shedding scheme, which we are proposing for further studies will be in position to know the actual load to be shed and to dynamically select only those feeders to be opened that are needed to regain the frequency stability. Implementation of automatic load shedding schemes requires intensive network analysis in line with recent understanding of the system collapse phenomenon. This proposal has much to do with academic work and is therefore recommended for further research work.

2. Harmonic effects on distance protection and arc-resistance modeling are other areas of power system protection studies recommended for further studies.

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APPENDIX A

Table A5.1: Existing 330kV transmission network circuits

From	To	Circuits	Construction	Length (km)
Birnin Kebbi	Kainji	1	SC 2 x Bison	310
Kainji	Jebba	2	SC 2 x Bison	81
Jebba	Jebba Power Station	2	DC 2 x Bison	8
Jebba	Oshogbo	3	SC 2 x Bison	157
Jebba	Shiroro	2	SC 2 x Bison	244
Shiroro	Kaduna	2	SC 2 x Bison	96
Kaduna	Kano	1	SC 2 x Bison	230
Kaduna	Jos	1	SC 2 x Bison	196
Jos	Gombe	1	SC 2 x Bison	264
Oshogbo	Aiyede (Ibadan)	1	SC 2 x Bison	115
Aiyede (Ibadan)	Ikeja West	1	SC 2 x Bison	137
Oshogbo	Benin	1	SC 2 x Bison	251
Oshogbo	Ikeja West	1	SC 2 x Bison	252
Ikeja West	Akangba	2	SC 2 x Bison	17
Ikeja West	Benin	2	DC 2 x Bison	280
Ikeja West	Egbin	2	DC 2 x Bison	62
Egbin	Aja	2	DC 2 x Bison	16
Benin	Ajaokuta	2	SC 2 x Bison	195
Benin	Sapele	3-1	DC 2 x Bison	50
Benin	Onitsha	1	SC 2 x Bison	137
Onitsha	New Haven (Enugu)	1	SC 2 x Bison	96
Onitsha	Alaoji	1	SC 2 x Bison	138
Alaoji	Afam	2	DC 2 x Bison	25
Delta	Sapele[1]	1	SC 2 x Bison	95
Delta	Benin[2]	1	DC 2 x Bison	107
Aladja	Sapele/Aladja Tee	1	SC 2 x Bison	19
Sapele/Aladja Tee	Delta	2	DC 2 x Bison	13

1 Delta to Sapele = 13km DC (Delta to Sapele/Aladja Tee) +19km SC (Sapele/Aladja Tee to Aladja) + 63km SC (Aladja to Sapele)

2 Sapele to Benin = 13km DC (Delta to Sapele/Aladja Tee) + 44km SC (Sapele/Aladja Tee to Sapele) + 50km DC (Sapele to Benin)

DC =Double conductor

SC=Single conductor

Table A5.2: Transmission lines Impedances per unit length (km)

S/N	Line Type	Impedance			
		R_1 Ohms/km	X_1 Ohms/km	R_0 Ohms/km	X_0 Ohms/km
1	SC 2xBison, 330Kv	0.039	0.331	0.276	0.985
2	DC 2xBison, 330Kv	0.0394	0.303	0.274	0.997
3	SC 2xBison, 132kV	0.207	0.413	0.429	1.552
4	DC 2xBison, 132kV	0.207	0.408	0.399	1.365

Bison = 2x350mm^2

Wolf = 150 mm^2

SC=Single Conductor

DC= Double Conductor

Table A5.3: List of 330/132KV Power Transformers and parameters

S/N	Sub-Station	330/132Kv TX	Type of TX	MVA Rating	Vector Group	Impedance value at nominal tap position
1.	Kainji	Nil				
2.	Jebba TS	T1	3Winding	80	$Y_N$yod1	X_{H-L} =12.05% on 60 MVA X_{H-T}=19.80% on 60 MVA X_{L-T} =6.87% on 60 MVA
3	Oshogbo	T1	3Winding	90	Yyod1	X_{H-L} =11.24% on 90 MVA X_{H-T}=6.78% on 30 MVA X_{L-T} =2.26% on 30 MVA
		T2	3Winding	90	Yyod1	X_{H-L} =11.40% on 90 MVA X_{H-T}=5.92% on 30 MVA X_{L-T} =2.21% on 30 MVA
4	Akangba	T1	Auto + Tert	162	Yyod11	X_{H-L} =1.24% on 150 MVA X_{H-T}=9.26% on 50 MVA X_{L-T} =4.42% on 50 MVA
		T2	3 Winding	109	Yyod1	X_{H-L} =11.15% on 90 MVA X_{H-T}=5.84% on 30 MVA X_{L-T} =2.18% on 30 MVA
		T3	3 Winding	109	Yyod1	X_{H-L} =11.5% on 90 MVA X_{H-T}=6.75% on 30 MVA X_{L-T} =2.23% on 30 MVA
		T4	3 Winding	109	Yyod1	X_{H-L} =11.15% on 90 MVA X_{H-T}=5.84% on 30 MVA X_{L-T} =2.18% on 30 MVA
		T5	3 Winding	109	Yyod1	X_{H-L} =11.15% on 90 MVA X_{H-T}=5.84% on 30 MVA X_{L-T} =2.18% on 30 MVA
5	Benin	T1	Auto + Tert	150	Yyod11	X_{H-L} =11.86% on 150 MVA X_{H-T}=6.42% on 30 MVA X_{L-T} =3.32% on 30 MVA
		T2	Auto + Tert	150	Yyod11	X_{H-L} =11.68% on 150 MVA X_{H-T}=6.37% on 30 MVA X_{L-T} =3.31% on 30 MVA

T1=Transformer number one, Auto+Tert= Autotransformer with tertiary Winding
TX =Transformer

TableA 5.3 (Cont)

S/N	Sub-Station	330/132kV TX	Type of TX	MVA Rating	Vector Group	Impedance value at nominal tap position
6.	Kaduna	T1	Auto+tert	150	Yd 11	X_{H-L} =11.22% on 150 MVA X_{H-T}=9.34% on 50 MVA X_{LT} =4.44% on 50 MVA
		T2	3 Winding	108	$Y_N y_n$d1	X_{H-L} =11.44% on 90 MVA X_{H-T}=5.90% on 30 MVA X_{L-T} =2.90% on 30 MVA
		T3	3 Winding	80	$Y_N y_n$d1	X_{H-L} =12.05% on 60 MVA X_{H-T}=19.80% on 60 MVA X_{L-T} =6.87% on 60 MVA
		T4	3 Winding	80	$Y_N y_n$d1	X_{H-L} =12.05% on 60 MVA
7	Onitsha	T1	3Winding	90	Yyod11	X_{H-L} =12.2% on 90 MVA X_{H-T}=6.7% on 30 MVA X_{L-T} =2.26% on 30 MVA
		T2	3Winding	90	Yyod1	X_{H-L} =11.35% on 90 MVA X_{H-T}=5.92% on 30 MVA X_{L-T} =2.2% on 30 MVA
8	Shiroro	T1	Auto	162	$Y_N$yod11	X_{H-L} =11.24% on 150 MVA X_{H-T}=9.38% on 50 MVA X_{L-T} =4.45% on 50 MVA
		T2	Auto	162	$Y_N$yod11	X_{H-L} =11.34% on 150 MVA X_{H-T}=9.32% on 50 MVA X_{L-T} =4.41% on 50 MVA
9	Ikeja West	T1	Auto +Tert	150	Yyod11	X_{H-L} =11.84% on 150 MVA X_{H-T}=6.51% on 30 MVA X_{L-T} =3.35% on 30 MVA
		T2	Auto + Tert	150	Yyod11	X_{H-L} =11.91% on 150 MVA X_{H-T}=6.50% on 30 MVA X_{L-T} =3.37% on 30 MVA
		T3	Auto + Tert	150	Yyod11	X_{H-L} =11.78% on 150 MVA X_{H-T}=6.40% on 30 MVA X_{L-T} =3.32% on 30 MVA
		T4	Auto + Tert	150	Yyod11	X_{H-L} =11.80% on 150 MVA X_{H-T}=6.42% on 30 MVA X_{L-T} =3.30% on 30 MVA

Table A5.3 (Cont)

S/N	Sub-Station	330/132kV TX	Type of TX	MVA Rating	Vector Group	Impedance value at nominal tap position
10	Kano	TI T2	Auto +Tert Auto +Tert	150 150	Yyod11 Yyod11	X_{H-L} =11.69% on 150 MVA X_{H-T} =6.34% on 30 MVA X_{L-T} =3.29% on 30 MVA X_{H-L} =11.80% on 150 MVA X_{H-T} =6.64% on 30 MVA X_{L-T} =3.33% on 30 MVA
11	Aiyede	T1 T2	Auto Auto	150 150	Yyod11 Yyod1	X_{H-L} =11.73% on 150 MVA X_{H-T} = 6.38% on 30 MVA X_{L-T} =3.32 %on30 MVA X_{H-L} =11.71% on 150 MVA X_{H-T} =6.38% on 30 MVA X_{L-T} =3.31%on30 MVA
12	Jos	TI	Auto	150	Yyod11	X_{H-L} =11.51% on 150 MVA X_{H-T}=10.19 % on 50 MVA X_{L-T} =5.17 %on50% MVA
13	Gombe	TI T2	Auto Auto	150 150	Yd11 Yd11	X_{H-L} =11.53% on 150 MVA X_{H-T}=10.18% on 50 MVA X_{L-T} =5.17% on 50 MVA X_{H-L} =11.53% on 150 MVA X_{H-T}=10.18% on 50 MVA X_{L-T} =5.17% on 50 MVA
14	New Heaven	TI T2	Auto +Tert Auto +Tert	150 150	Yyod11 Yyod11	X_{H-L} =11.45% on 150 MVA X_{H-T}=10.32% on 50 MVA X_{L-T} =5.22% on 50 MVA X_{H-L} =11.45% on 150 MVA X_{H-T}=10.16% on 50 MVA X_{L-T} =5.16% on 50 MVA

Table5.3A (Cont)

S/N	Sub-Station	330/132kV TX	Type of TX	MVA Rating	Vector Group	Impedance value at nominal tap position
15	Afam	T1	Auto + Tert.	162	Yyod11	X_{H-L} =11.3% on 150 MVA X_{H-T}=9.35% on 50 MVA X_{L-T} =4.46% on 50 MVA
16	B/Kebbi	T1	3Winding	109	Yyd1	X_{H-L} =11.77% on 90 MVA X_{H-T} =19.65% on 30 MVA X_{L-T} =7.18% on 30 MVA
17	Ajaokuta	T1 T2 T4	Auto Auto Auto	162 162 162	YNyod 11 YNyod 11 YNyod 11	X_{H-L} =11.13% on 150 MVA X_{H-T}=9.5% on 50 MVA X_{L-T} =4.35% on 50 MVA X_{H-L} =11.10%on 150 MVA X_{H-T}=9.5% on 50 MVA X_{L-T} =4.29% on 50 MVA X_{H-L} =11.11%on 150 MVA X_{H-T}=9.17% on 50 MVA X_{L-T} =4.28% on 50 MVA
18	Jebba PS	Nil				
19	Egbin	T1 T2	Auto +Tert Auto + Tert	150 150	Yyod11 Yyod11	X_{H-L} =12.0%on 150 MVA X_{H-T}=10.3% on 30 MVA X_{L-T} =5.0% on 30 MVA X_{H-L} =12.0%on 150 MVA X_{H-T}=10.3% on 30 MVA X_{L-T} =5.0% on 30 MVA

20	Aja	TR3 TR4	Auto (Tert. Not brought out) Auto (Tert. Not brought out)	150 150	Yyod1 Yyod1	X_{H-L} =6.8%on 150 MVA X_{H-T}=(5.84% on 30 MVA)* X_{L-T} =(2.5% on 30 MVA)* X_{H-L} =6.8%on 150 MVA X_{H-T}=(5.84% on 30 MVA)* X_{L-T} =(2.5% on 30 MVA)*
21	Delta	Inter Bus	Auto +Tert	150		X_{H-L} =10.84 % on 150 MVA X_{H-T}=22.23% on 90 MVA X_{L-T} =12.22% on 90 MVA

Table A 5.4: Generator Parameters

Station	Units	Rated Capacity(MVA)	Impedances			
			X_d%	X_O%	X_D%	X_2%
Afam IV Afam V	Unit 13- 18 Unit 19&20	83.8 165	13.3 22.6*	8.8 9,6*	217 190.5*	13.2 21.4*
Delta IV Delta II	Unit 1-6 Unit 3-8	133.8 29.725	22.6 10.5	9.6 7	190.5 159	21.4 11
Egbin	Unit 1-6	245.8	23	16.5	187	23
Jebba	Unit 1-6	103.5	26	15	65	24
Kainji	Unit 5&6 Unit 7-10 Unit 11-12	126 85 115	22 17.2 20	19 17.2 15	90 75 72	22 18 21
Sapele	GT (unit 1-4) ST (unit 1-6)	83.3 133.97	17 15.4	10.1 17.6	216 217	16.4 13.2
Shiroro	Unit 1-4	176.5	20	15*	50	23
Ijora	Unit 4-6	32	14.2		210	29.1
AESBarges	Unit 202-205 Unit 207-209 Unit 210&211	38.6 40 50	15* " "	9.5*	150* " "	20* " "

*Assumed data
Note: All impedances are on machines rating MVA base

Figure A5.5: Existing generator transformer parameters

Station	**Units**	**Transformer MVA**	**Transformer kV**	**Transformer XH-L**
Afam IV	G13-G14	3 x 168.5	10.5 / 345	13.3%
Afam V	G19, G20	2 x 163	15.75 / 330	10.0%
Delta IV	G1-G6	6 X 200	11.5 / 330	7.84%
Delta II	G3-G8	2 x 81	11 / 132	9.33%
Sapele GT	G1-G4	2 x 168	10.5 / 330	13.0%
Sapele ST	G1-G6	6 x 140	16 / 330	14.5%
Egbin	G1-G6	4X270	16 / 330	10.22%
Lagos AES	G1-G4	4X40	10.5 / 132	15.0%
Lagos AES	G5-G6	3X48	11.5/132	12.0%
Lagos AES	G8, G9	2X60	11.5/132	15.0%
Jebba	G1-G6	6 x 115	16 / 330	10.62%
Kainji	G5-, G6	2 x 145	16 / 330	12.7%
Kainji	G7 - G10	2 x 170	16 / 330	12.3%
Kainji	G11 - G12	2 x 115	16 / 330	12.0%
Shiroro	G1-G4	4 x 200	15.2 / 330	13.0%
Ijora	G4-G6	3X30	11/33	10.0%

APPENDIX B

. Basic Nomenclature, Connection and Representation of Transformer.

A brief review of few points on transformer design connection and nomenclature in so far as they affect differential schemes is highlighted herein. Basically, there are four types of winding connection for a large three phase transformer, although the types commonly found in NEPA grid are: delta, start and auto-transformer, the fourth type is interconnected star (zigzag). Positive sequence phase rotation is assumed and the diagrams are accordingly drawn. The diagrams are mainly attempting to analysis the internal connection of the transformer, i.e. what occur behind the bushings and it unchangeable by the end use. However, the diagrams also can be seen as representation of some forms of external phase connection shifts. For instance, in Nigerian practice, the phases, R, Y, and B are connected to bushings A, B, and C respectively. For clarity, the three windings are named W_1 W_2 and W_3 and a neutral point as N. Figure B1 and B2 show three different ways of star and delta winding connection, while figures B3 and B4 shows four ways of zigzag and single way of auto-transformer winding connections respectively. The latter has no flexibility in how it's wired; the only way to obtain a phase shift is to rename the phases from one side to another, which is quite uncommon.

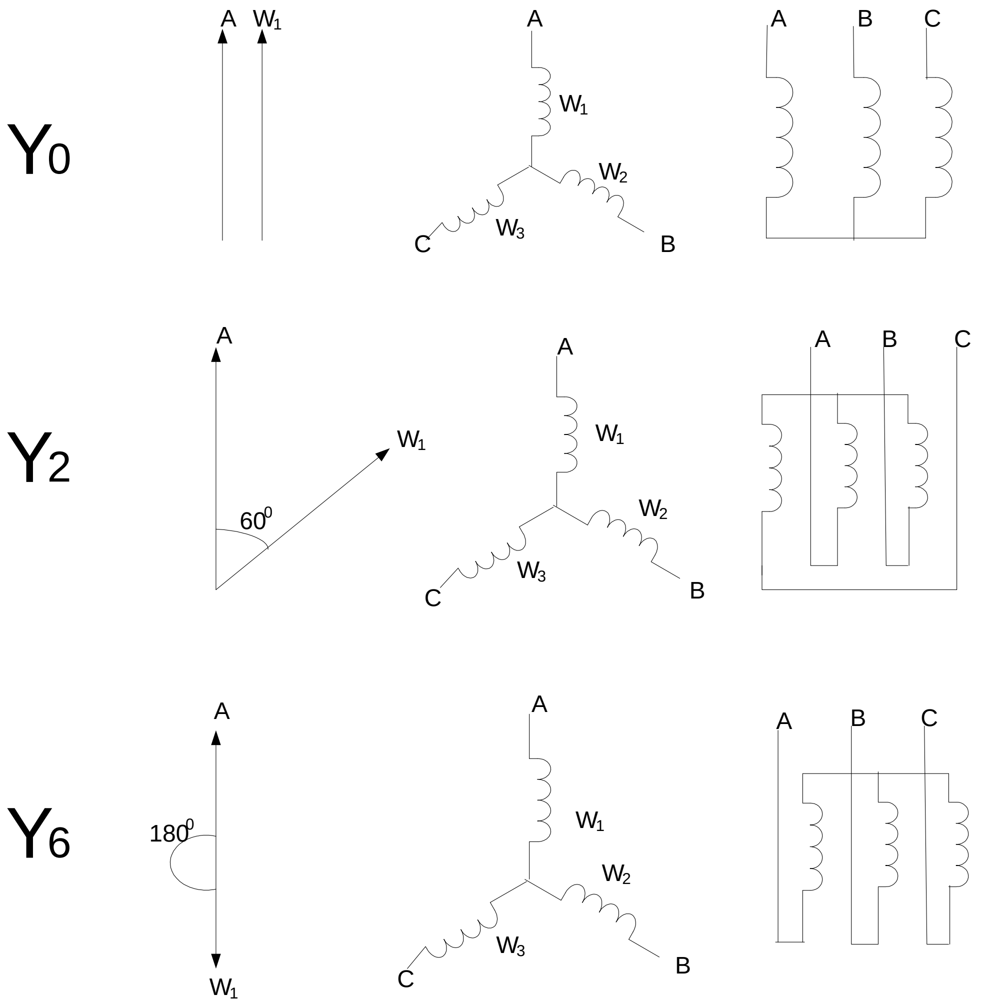

FIGURE B1 Three ways of Star Winding Connection Transformer

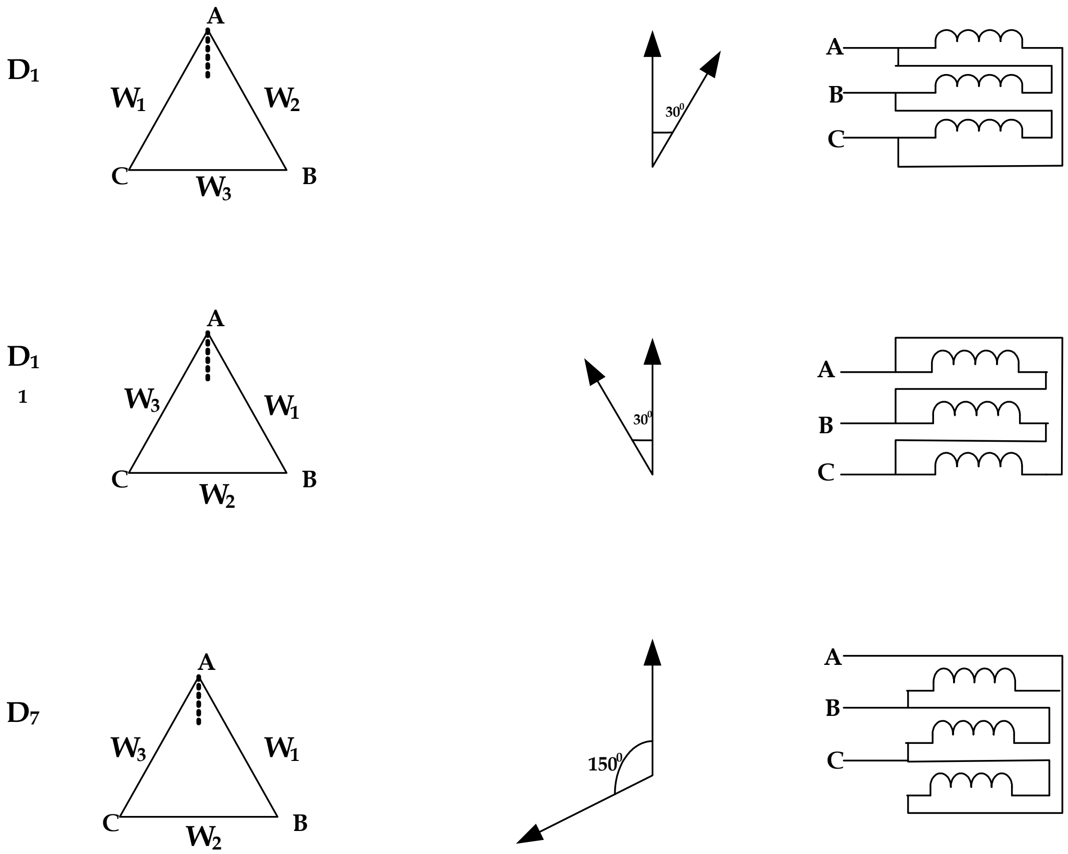

Figure B2 Three ways of Delta Winding Connection of Transformer

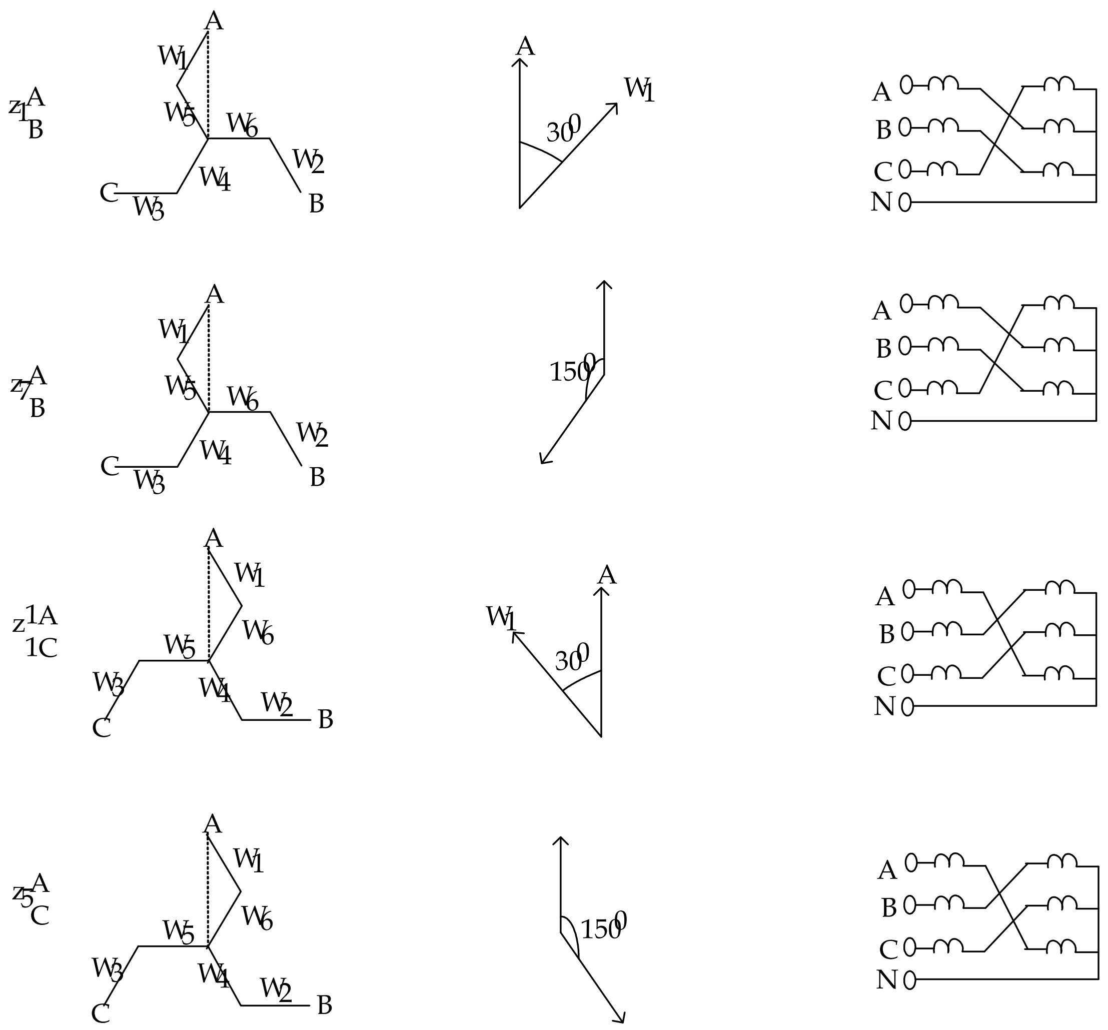

Figure B3 Four ways of Connecting Zigzag Winding Transformer

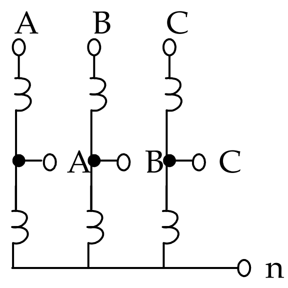

Figure B4 Auto Transformer Winding

Zigzag winding is series connections of two windings whose voltages are 60^0 out of phase but have same voltage magnitude. There are two basic ways to create a zigzag winding: - Connection of A leg in series with B leg (called a ZAB) and connection of A leg in series with C leg (called a ZAC). More of possible winding connections are possible, but only four different winding connections are considered in figure B4

Most engineers have some familiarity with two commonly known delta connection that give either a + 30^0 phase shift of positive sequence voltages and currents, there are actually many other ways to configure a star or delta that give other phase shits, and to further complicate matters, there is the occasional Zigzag winding connection and the additional confusion over what occurs when CTs are connected in delta. These alternate transformer winding configurations are sometimes referred to by terms such as Dy# or Yy#, Yd#, D2#, Yz#, where high voltage windings are indicated by capital letters and low voltage windings by small letters (reference to high and low is relative). # refers to positions on a clock face and indicates the phase displacement of the low voltage phase to neutral vector with respect to the high voltage phase to neutral vector.

This presentation analyses the variety of possible winding configuration and with examples. It additionally show how phase shifts in angle in power transformers are determine mathematically. Many papers and instruction manuals refer to compensation in terms of phase shifting. This leads engineers to have a vague and misleading understanding that the relay is some how phase shifting current to compensate for the transformer phases shift [50]. While a “sequence component differential” relay might be able to work this way, most transformer differential relays work outside of the sequence component domain and do some form of current balance calculation in the ABC domain.