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An improvement in protection coordination and criteria settings for Bhutanese power system

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AN IMPROVEMENT IN PROTECTION COORDINATION AND CRITERIA SETTINGS FOR BHUTANESE POWER SYSTEM

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การปรับปรุงการประสานสัมพันธ์การป้องกันและข้อกำหนดการตั้งค่าสำหรับระบบไฟฟ้าของภูฏาน

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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เชเต็น เชอร์ริ่ง :
การปรับปรุงการประสานสัมพันธ์การป้องกันและข้อกำหนดการตั้งค่าสำหรับระบบไฟฟ้าของภูฏาน. (AN IMPROVEMENT IN PROTECTION COORDINATION AND CRITERIA SETTINGS FOR BHUTANESE POWER SYSTEM) อ.ที่ปรึกษาหลัก : ชาญณรงค์ บาลมงคล

งานวิจัยนี้เป็นโครงการนำร่องเพื่อศึกษาการประสานสัมพันธ์รีเลย์กระแสเกินเฟสและรีเลย์กระแสเกินกราวด์ที่สถานไฟฟ้า 132/33/11 kV ของภูฏาน ด้วยการจำลองการทำงานของรีเลย์ตามการตั้งค่าที่ใช้อยู่ในปัจจุบันกับการตั้งค่าที่คำนวณขึ้นใหม่เปรียบเทียบกัน เพื่อให้ข้อแนะนำในการปรับปรุงเกณฑ์การตั้งค่ารีเลย์ทั้งสอง

เกณ์การตั้งค่ารีเลย์ผลต่างได้รับการตรวจสอบและปรับปรุงเช่นกัน โดยคำนึงถึงอัตราทดกระแสของหม้อแปลงวัดกระแส การชดเชยกลุ่มเวกเตอร์ กระแสพุ่งเข้าและการกรององค์ประกอบลำดับศูนย์ เพื่อเสนอแนะการตั้งค่าการเริ่มทำงานเป็นความชันที่ 1 และ 2

นอกจากนี้มีการวิเคราะห์การตั้งค่ารีเลย์ระยะทางที่ใช้ป้องกันการลัดวงจรระหว่างเฟสและระหว่างเฟสกับกราวด์ ด้วยการจำลองการทำงานของรีเลย์ตามการตั้งค่าที่ใช้อยู่ในปัจจุบันกับการตั้งค่าที่คำนวณขึ้นใหม่เปรียบเทียบกันเพื่อยืนยันผล และได้พัฒนาโปรแกรม EXCEL สำหรับช่วยคำนวณการตั้งค่ารีเลย์ MiCOM P44x พร้อมผังงานของการคำนวณ

สาขาวิชา วิศวกรรมไฟฟ้า ลายมือชื่อนิสิต ....
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Overcurrent and ground fault relay coordination have been studied for a pilot 132/33/11 kV Substation in Bhutan. The calculated settings as well as the existing settings have been simulated and the critical findings and recommendations are made. The methodology of overcurrent and ground fault relay coordination are also proposed.

Similarly, the criteria settings for differential relay have been discussed along with the compensation in respect of CT ratio, vector correction, magnetic inrush and zero sequence filtering. The pickup setting followed by 1st and 2nd slope biasing has been discussed.

Further, the distance relay setting has been analysed whereby the parameters and methodology for phase to phase and phase to ground resistive reach setting are elaborated. The field settings are compared with the calculated settings and simulations have been carried out for verifying the results. The distance relay setting calculations are developed through excel template taking into consideration the MiCOM P44x relays. Accordingly, the flow chart has been made in conformity with the guidelines.

Field of Study: Electrical Engineering Student's Signature ....
Academic Year: 2022 Advisor's Signature ....

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1 INTRODUCTION

1.1 Introduction to Power system in Bhutan: Challenges and Opportunities

Bhutan is a carbon negative country, and its major source of revenue is from hydroelectricity generation. The power system development in Bhutan began with the commissioning of 360 kW hydro power plant at Thimphu in 1967 [1]. Since then, several other hydropower plants were added to the Bhutanese Power System and today we have an installed capacity of 2,326 MW of Hydro Power for a population of about 700,000. Three hydro power plants are on the verge of completion which will add 2,338 MW of hydropower to the Bhutanese Grid, thereby forming a 4,664 MW grid.

Druk Green Power Corporation (DGPC) caters to the generation while Bhutan Power Corporation Ltd. (BPC) looks after the transmission and distribution of electricity. After the domestic consumption, surplus energy is being exported to India through a bilateral contract model agreed between the Government of Bhutan and India. In 2018 Bhutan achieved 100% electrification.

The highest national coincident load of 492.25 MW occurred on 1st of January 2022 at 18:00 hrs. The total generation for 2021 was 11,366.71 MU (Million Unit). A sum of 2,128.58 MU was consumed domestically and the surplus of 9,156.71 MU [2] was exported to India.

Around 80% of the hydro energy generated is being exported to India which forms the major revenue source of Bhutan. Therefore, the hydro power resources play an important role in the socio-economic development of Bhutan.

Along with the hydropower development, several transmission and distribution lines along with substations were constructed. As of 2021, BPC has 1713.64 km of transmission lines (ranging from 66 kV to 400 kV) with a transformation capacity of 1900.5 MVA. While the distribution lines are 16,957.14 km (ranging from 415 V to 33 kV) with transformation capacity of 959.187 MVA [2].

As of 2021, BPC has a total of 33 substations (400 kV, 220 kV, 132 kV and 66 kV) and 5,162 distribution substations of 33 kV and 11 kV voltage levels. Most of the 11 kV substations are indoor substation while 33 kV substations are a mix of outdoor as well as indoor substation. Few of the 33 kV, 66 kV, 220 kV and 400 kV of the substation are Gas Insulated Substation (GIS).

Bhutanese Power System (2,326 MW) forms a tiny portion of gigantic Indian grid (407,797 MW) [3]. The geographical and climatic conditions of Bhutan exert numerous threats to its power system. The protection systems are well designed and relays from reputed manufacturers such as ABB, GE, Siemens, etc., are installed to ensure maximum protection.

1.2 Protection Coordination : Art or Science?

All the transmission and distribution lines along with the substations requires substantial protection against the overload and short circuit events. Even after half a century of power system development we still faces protection settings problems resulting in warranted blackouts. Coming up with the extensive understanding of the protection system will lead to optimum use of plants and equipment thereby preventing lots of unwanted upgradations and utilizing the equipment to its optimum capacity without any damage to the equipment itself.

Protection requires qualities such as selectivity or discrimination, reliability, sensitivity, stability and fast operation [4]. For seamless operation of protection functions, skillful means of protection coordination is necessary otherwise frequent failure of equipment are common. The relay coordination is done for a new substation prior to its execution however most of the existing substation needs to be protected too with all the limitation of the equipment ratings it has inherited.

While for the new substation, the protection engineers have all the required parameters as per the will of the protection setting criteria and is relatively comfortable however to implement a protection setting criteria on an existing substation with its inherent limitation and the increased loads and system fault

levels, requires an extensive works. The results of the initial calculations need to iterate until such point that the required grading margin is met, or often certain layer of protection hierarchy are compromised. Thus, it is often said that protection coordination is more of an art than science.

The IEEE Standard 242 “Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems” [5] also known as the Buff Book provides the recommendation while applying the protection setting in industrial system. However, when the substations and loads are so dynamic such that the substations owned by different utility which has its own standards of upgradation, then the deficiency in relay coordination occurs due to the system constraints.

Hence this research focuses on revisiting the standard of protection criteria settings in relation to the different scenarios existing in Bhutan. The protection system in Bhutanese power system consists of conventional electromechanical relays to latest state of art technology numerical relays hence working in this research would be fascinating.

1.3 Existing issues and Problem Statement

In reference to the 62nd Operation Coordination Committee (OCC) Meeting of Bhutan [6], major grid disturbances were observed on 26th and 28th of August followed by 1st September, 2020. Entire country went under blackout except the eastern region. OCC meeting is an official forum amongst the power system stakeholders of Bhutan which discusses various protection related issues.

Frequent tripping of 132 kV lines is observed along with lack of fault discriminations. Tripping of 400/220 kV, 200 MVA Interconnecting Transformer for a fault in the feeders often desynchronizes the 1020 MW Tala Hydropower Plant and 336 MW Chhukha Hydropower Plant. In another instance, generators at 60 MW Kurichhu Hydropower Plant tripped for faults in downstream feeders. In all the above cases, OCC members requested relevant stakeholders to verify the relay settings and its coordination.

However, due to the lack of proper relay setting criteria and guidelines and further due to the lack of technical expertise, the problems couldn't be solved. The field engineers often resort to the trial-and-error methods of relay setting and coordination. Of late, Bhutan Power Corporation (BPC) released the first edition of the relay setting guidelines, but it lacks clarity and is void of many technical guidelines on relay setting and coordination.

In absence of the expertise in computer software for protection coordination studies, the visibility of relay setting, and coordination of the network is poor. Protection coordination studies have never been done through simulation software. Sometime in 2020, BPC procured Computer Aided Protection Engineering (CAPE) software however no one has used it due to lack of training and knowledge on protection setting criteria.

All the above issues indicate the poor human resource in protection coordination and thus lacks the proper relay setting criteria and guidelines. As a result, the power system equipment is exposed to unwanted faults and damages but somehow the system is running with lots of nuisance tripping. With every such incidences, the revenue loss from the power generation is immense.

With the existing practice, the threats to the substation equipment and the stability of the power system are massive. The price of relay miscoordination would be grave as the generation doubles in few years.

Thus, Bhutanese Power System urgently requires the 'Review of the Existing Setting' and develop 'Standard Protection Criteria Setting'. This study will set a benchmark for the protection coordination at par with the international level of practice.

Therefore, the problem statement is ***'Review the overcurrent, earthfault, differential and distance protection system of Bhutan Power System by application of Computer Aided Protection Software (DIgSILENT) and define the Protection Setting Criteria to strengthen the grid stability, reliability and security thereby preventing Power System Catastrophe'.***

1.4 Scope of the study

The scope of the study to fulfill the objectives of the problem statement are as follows:

a) Modelling of entire Bhutanese Power System Transmission Network in DIgSILENT (66 kV to 400 kV).
b) Load Flow Analysis.
c) Short Circuit Studies on all Buses.
d) Formulation of Relay Setting and Coordination Criteria.
e) Modelling the Relays in Bhutanese Power System Network in DIgSILENT.
f) Validation of Relay Setting through DIgSILENT Simulation.
g) Review the Existing Relay Setting in a pilot Substation under study.
h) Review of 1st Edition of BPC Relay Setting guidelines.

1.5 Objectives of the Study

Bhutan faces a series of haphazard tripping both at distribution and transmission level, despite having the numerical relays installed in the system. Often a substation goes under total shutdown due to a fault on the feeders and sometimes a fault on remote transmission lines gets tripped by Zone 3 instead of the Zone 1 of the protected line. These are an indication of improper relay setting and coordination and it seems the existing relay setting, and coordination practice doesn't suffice the requirement of power system protection.

Therefore, the main objectives of the stud are:

1. To review the existing relay setting and coordination of overcurrent, earthfault, differential and distance protection in reference to the IEEE recommended practice for transmission and distribution system of Bhutan. The pilot study is being carried out on a 132/33/11 kV Substation and the criteria settings are recommended accordingly.
2. The inherent defects of the existing protection system by virtue of its construction will be analyzed. After finding the root causes of the failure

of existing relay coordination which leads to nuisance tripping, the relay setting and coordination criteria for Bhutan Power System will be developed. The calculated relay settings will be simulated through DIgSILENT software to ascertain the accuracy of the relay setting and criteria.

3. Develop a standard relay setting and coordination criteria for Bhutan Power Transmission and Distribution System.

1.6 Expected outcome of the Study

At the end of the study, the main anticipated outcome would be the standard relay setting and coordination criteria for overcurrent, earthfault, differential and distance protection. The settings will be calculated based on the relay setting and coordination criteria in an excel template. The calculated values will be conformed to its criteria settings through DIgSILENT Simulations. The implementation of the settings will contribute to reduced nuisance tripping in Bhutan Power System.

Thus, this study will set a benchmark for relay setting and coordination for Bhutan Power System.

1.7 Introduction to Protection

The electrical power produced from the generation system is being evacuated to the substation via the transmission line for distribution. Several feeders run from the distribution substation to the load centers. In the normal conditions, the power is being delivered with certain voltage and frequency. Any deviations are being closely monitored and is being adjusted accordingly.

However, during the faults such as Line to Ground (LG), Double Line to Ground (LLG), Line to Line (LL) or three phase (LLL) faults, the response from the protection system should be fast enough to isolate the faulty section and minimize the outage. The prolonged fault on the system damages the system equipment.

The efficient and safer use of electricity requires the protection system, which will be able to provide uninterrupted power while isolating the faulty section as fast as

possible. Fault discrimination along with sensitivity and reliability are vital in maintaining the stability of the power system.

Unit and non-unit protection forms the major classification whereby, the former is confined to its limited zone such as the differential zone and the latter performs the protection functions for feeders. The commonly used principle for protection coordination is the time grading, current grading, or combination of both.

The selection of protection system and its coordination must begin with the design of the substation. The system fault level and the anticipated load plays a major role in deciding the protection system elements such as the Current Transformers (CT) and Voltage Transformers (VT).

The protection system equipment must withstand the maximum anticipated fault current while also delivering the power at normal load without losing its accuracy and integrity. The protection system starts with fuses in distribution system followed by Auto Reclosers (AR), Sectionalizer, etc. As the hierarchy increases the fault current increases, hence relays with certain time current characteristics are required.

Feeder protections comprises of overcurrent and earthfault protections, while the transformers, generators and busbars are protected by differential protection. The high voltage transmission lines utilize the distance protections and often line differentials are used for short lines.

Protection systems are also classified as Primary (main) and Backup protections. For instance, differential protection forms the primary protection in transformer while overcurrent and earth fault relay provide the backup protection. In high voltage transmission line protection, Main I and Main II distance protections are followed.

Depending on the technology, the protection devices are classified as Electromechanical, Static and Numerical Relays. Electromechanical relays work based on electromagnetic attractions while static relays contain certain electronic circuits. Numerical relays are the digital relays which acquires the sequential samples of alternating current (ac) quantities and process it through microprocessor using certain algorithms.

2 LOAD FLOW AND SHORT CIRCUIT STUDIES IN RELATION TO THE INDIAN GRID

It is of utmost importance for any utility company to have a desktop model of the entire powers system network. The modelling may be done in any software such as DIgSILENT, PSSE, ETAP, etc. Bhutan Power System is interconnected to Indian grid through five tie lines as shown in Figure 1. In this case, the desktop model of Bhutanese Power System has been developed in DIgSILENT Power Factory (Research License) Ver 2022 as given in Figure 2.

The following elements of Bhutanese Power System are modelled.

a) All Hydropower Plants-60 MW Kurichhu, 336 MW Chhukha, 1020 MW Tala, 126 MW Dagachhu, 24 MW Basochhu (Upper Stage), 40 MW Basochhu (Upper Stage), 720 MW Mangdechhu.
b) Transmission Lines-400 kV (Twin Moose and Quad Moose ACSR Conductors), 220 kV (ACSR Zebra), 132 kV (ACSR Panther) and 66 kV (ACSR Panther, Wolf and Dog). The lines below 66 kV are not included as it is distribution lines, and the total load of the substation has been modelled.
c) The parameters of the conductors are taken from 'Manual on Transmission Planning Criteria', a document of Central Electricity Authority, India [7].
d) The GPS coordinates of entire transmission line has been added to view it on geographic diagram through the "WMS/WMTS service" as shown in Figure 3.
e) Peak load of all substations is considered.
f) Since Bhutan is a small part of gigantic Indian grid, hence the five interconnection points between India and Bhutan has been modelled as external grid source with the existing fault level and Thevenin impedance.

Details of the parameters available on request.

2.1 Load Flow and Short Circuit Simulations

The short circuit fault current of Bhutanese substation will be determined by associated Indian grid as they are interconnected. The interconnection occurs with

400 kV, 220 kV, and 132 kV system in India. Siliguri and Alipurduar are the 400 kV substations while Birpara Substation is at 220 kV and 132 kV system with Salakati and Rangia substations.

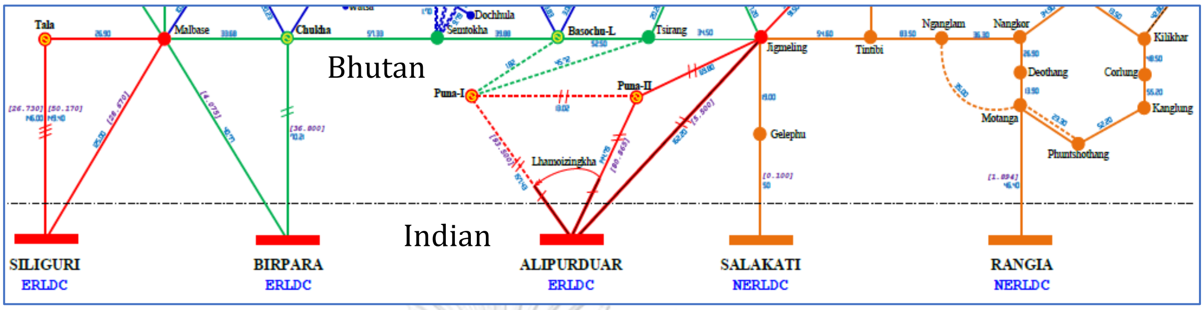


Figure 1 Bhutan-India power corridors

(Image taken from BPSO website)

It will be difficult to carry out the short-circuit studies along with entire Indian grid of 410,339 MW as of 31.12.2022 [8] while it is 2,326 MW on Bhutan's grid. Therefore, the tie line substations needs to be modelled as external grid.

'External Grid' represents an overlaying equivalent transmission network of Indian grid. Modelling external grid requires:

1. Maximum and Minimum fault level in MVA or kA.
2. Maximum and Minimum R/X Ratio (Resistance by Reactance ratio)
3. Maximum and Minimum Impedance Ratio viz. Z2/Z1, X0/X1, R0/X0.

Where,

Z2 : Negative Sequence Impedance

Z1 : Positive Sequence Impedance

X0 : Zero Sequence Reactance

X1 : Positive Sequence Reactance

R0 : Zero Sequence Resistance

The short circuit fault level and Thevenin impedance of the above 5 substations in the above form of parameters must be obtained from Indian counterpart on an annual basis to represent the equivalent Indian grid as the Indian grid is an infinitely growing grid and will impact the fault level of Bhutanese grid.

As of March 2020, the fault level and Thevenin impedances of the above five substations are given in Table 1. Since the Indian and Bhutanese grid soft file in PSSE were obtained by BPC earlier, hence the simulation for the 3-phase short circuit fault level was carried out in PSSE.

The result of short circuit fault simulation is available on request.

Table 1 Three-Phase short circuit fault level and Thevenin Impedance

Sl. #	Indian Substation	3-Ø Fault (MVA)	Fault Current (kA)	Thevenin Impedance	X/R (pu)
1	400kV Binaguri	18650	26.919	0.000691+j0.005857	8.47843
2	400kV Alipurduar	12094	17.456	0.001064+j0.009033	8.48957
3	220kV Birpara	5734	15.048	0.003516+j0.018857	5.36279
4	132 kV Salakati	1216	5.319	0.013030+j0.089520	6.87034
5	132 kV Rangia	2366	10.349	0.015804+j0.043714	2.76594

With the above sources modelled as external grid in DIgSILENT, the 3-phase short circuit fault and single line to ground fault were simulated with peak generations of Bhutan system. The results of 3-phase short circuit fault and single line to ground fault simulations of entire buses of Bhutan Power System is available on request.

The 3-phase short circuit fault will be used to calculate the overcurrent protection settings while single line to ground fault will be used for earthfault protection settings in the later chapters.

This should be an annual exercise whereby we get the system fault level of the above five substations and model it as an external grid in our systems. Our system must be updated accordingly. Such exercise will bring us closer to the reality of our system through desktop simulations.

** The* fault *level of above Indian substation is of 2020, and our continuous effort to get the latest data from Indian counterpart couldn't be successful, however Bhutan Power System Operator is following up with National Load Dispatch Center, New Delhi, India. The same issue will also be floated in the India-Bhutan Operation Coordination Meeting and is expected to be resolved soon.*

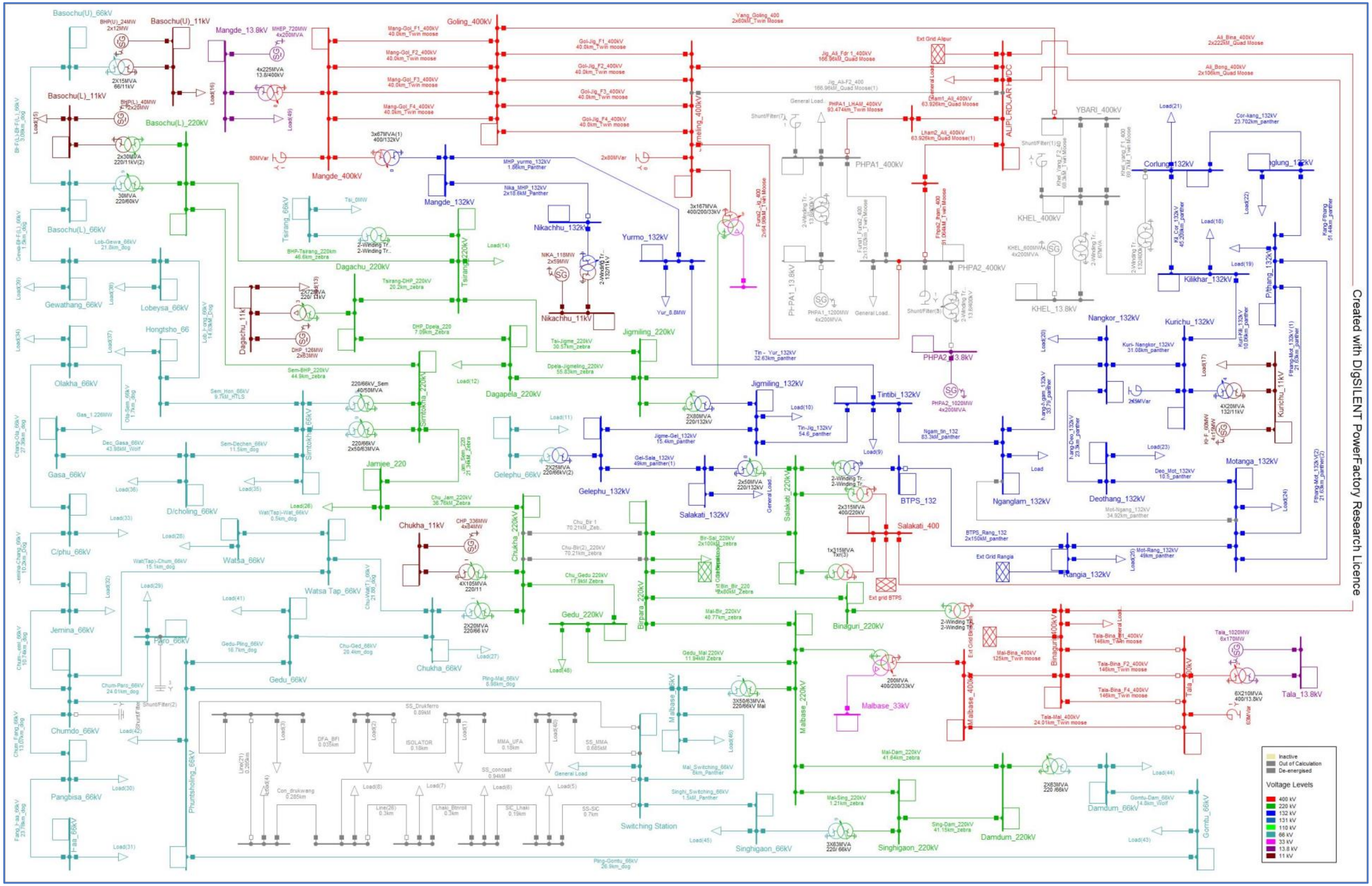


Figure 2 Single line diagram of Bhutanese Power System

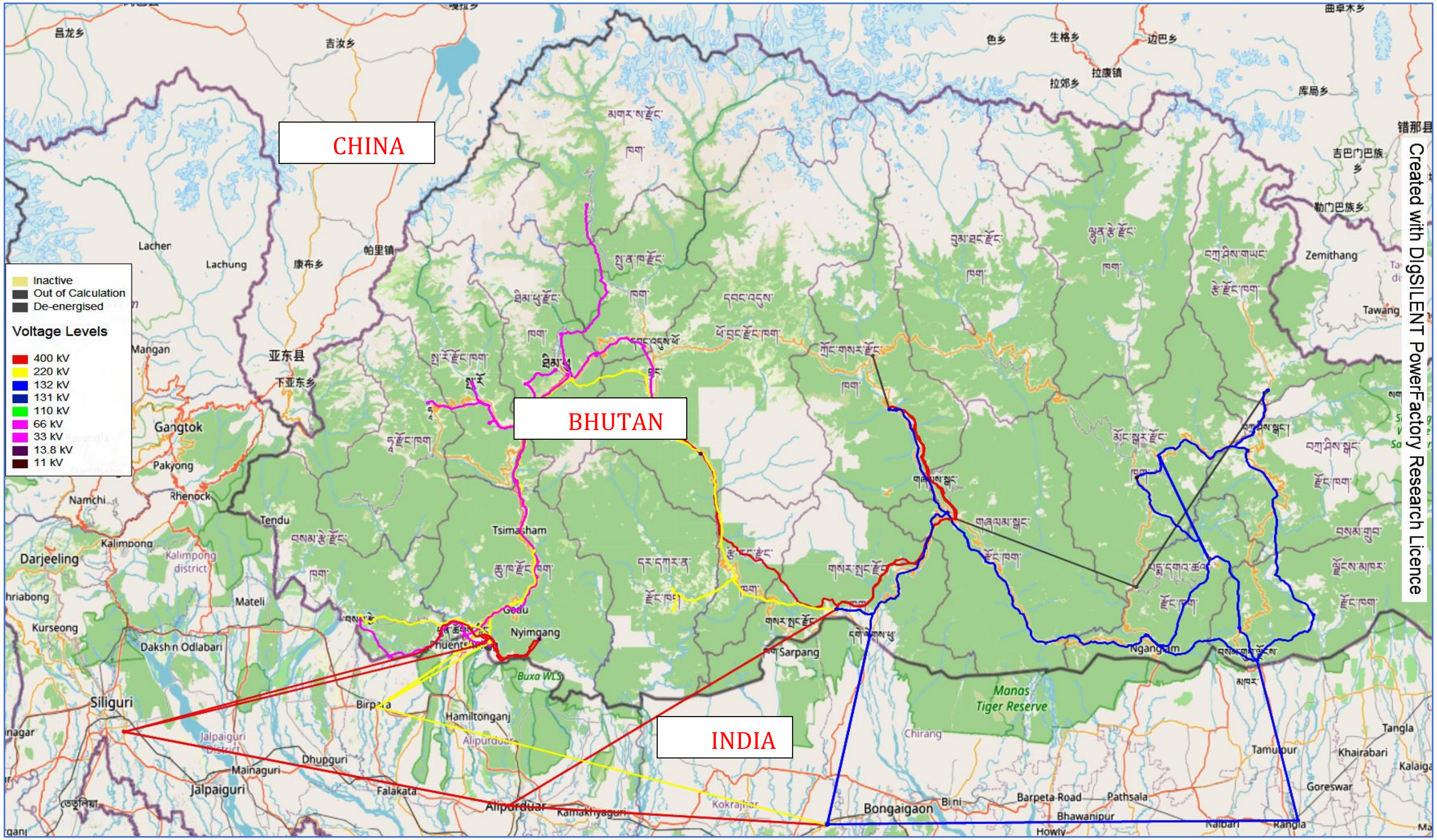


Figure 3 Geographic Diagram of Bhutan Power System through WMS/WMTS Service

3 OVERCURRENT PROTECTION AND RELAY COORDINATION

3.1 Overcurrent Relay and its Characteristics

Under a normal operating condition, the load current flows through the transmission and distribution lines to the load centers. When a fault strikes the lines, the huge flow of short circuit current occurs either to the ground or within the phases depending on the nature of the faults.

The power system requires an overcurrent (OC) relay which allows the load currents to flow smoothly while triggering the Circuit Breaker (CB) tripping for currents beyond its permitted values. The permitted value of current beyond which the relay gets actuated is the 'Pickup Setting' of the overcurrent relay.

Now the question raises how fast the tripping should be? Low setting will create nuisance tripping, thereby affecting the reliability. Higher setting will allow wider delay time, thereby posing the substation equipment and lines to huge electrical stress, ultimately leading to its failure.

Several practices have been followed with pros and cons of each scheme such as the current grading (instantaneous relay) and time grading (Definite Time Characteristics). Amalgamation of current and time grading forms the Inverse Definite Minimum Time characteristics (IDMT). Nonetheless, the current and time graded schemes are used alongside the IDMT protection for enhancing the protection capability.

With IDMT characteristics, the requirement of 'Time Dial' or 'Time Multiplier Setting (TMS)' comes into picture. Lower the TMS, faster will be the tripping and vice versa. IEC 60255 defines the standard characteristics [5] as Standard Inverse Curve (SI), Very Inverse Curve (VI), Extremely Inverse Curve (EI), Long Time Inverse Curve (LTI).

Overcurrent protection can be non-directional or directional. The power system consists of several layer of hierarchy in terms of voltage and current, hence each of the hierarchical structures has its own overcurrent relays so that the fault downstream is cleared by the nearest CB. These overcurrent relays in hierarchical

order needs to be coordinated through current and time setting such that the faults are cleared by the nearest CB in minimum time without or with minimal power interruption to the consumers.

The protection relays operate based on the input pickup current and its speed of operation will be determined by the time setting. There are several types of over current relay depending on the time current characteristics, as given below.

a) Instantaneous Over Current Relay

Most of the electromechanical instantaneous relay (ANSI 50) doesn't have the intentional time delay. It only has the current setting, and its operation is instantaneous to the set current. Such relay operates in time lesser than 100 ms and the default time delay is due to the equipment inherent conditions. Here for any fault current which crosses the set point it will trip the CB instantaneously.

Even if there is a transient fault of higher fault magnitudes, the relay will instantly trip the CB, thereby creating unwanted blackouts. While the power system is instantly protected from faults, it compromises the reliability to the valued customers.

b) Definite Time Overcurrent Relay

On the contrary, definite time overcurrent relay has the instantaneous element along with intentional time delay. As soon the fault current crosses the set point it will operate in definite time. The operating time is constant irrespective of the fault current magnitudes. The setting of such relays requires the pickup current setting and the operating time in seconds.

For the lower fault current magnitudes, the intentional time delay might be sufficient however even for higher fault currents, the operating time is same. The effect of high fault current on the system might create catastrophe before the relay trips on its set operating time for instance like in case of fault and generator bus.

In fact, for higher magnitude fault, the fault should be cleared as fast as possible to prevent the equipment damage. When transient fault occurs, as there is an intentional time delay, the reliability of the power system is greatly improved.

c) Inverse Definite Minimum Time (IDMT) Overcurrent Relays

To overcome the defects of the above two relays, inverse definite minimum time over current characteristics becomes necessary as shown in Figure 4 [3]. Here the settings need to be done for pickup current and the TMS. TMS will determine the operating time of the relay as per the fault current magnitudes. Higher the fault current magnitudes lower the tripping time and vice versa.

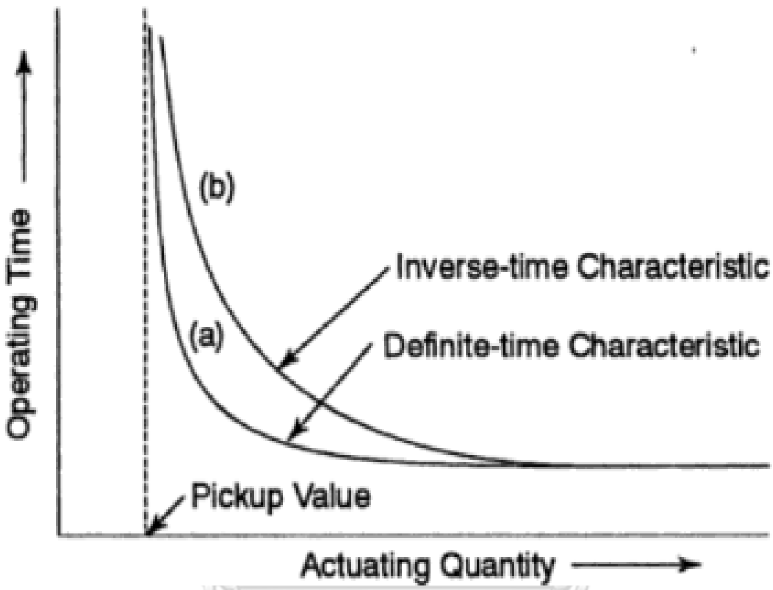


Figure 4 Time current characteristics of definite time and inverse time relays [3]

There are several IDMT curves and in numerical relay the user can design a new curve as per the requirements by selecting the current vs. the operating time characteristics.

In general, IEC 60255 defines the following IDMT relay characteristics and is depicted in Figure 5 [5].

$$t(I) = TMS \times \left(\frac{k}{\left(\frac{I}{I_S}\right)^{\alpha} - 1} \right) \tag{4.1}$$

Where,

t(I) :*Operating time in seconds*

TMS :*Time Multiplier Setting*

I :*Fault Current*

I_S :*Pickup Current setting*

k & α :*Curve type constant*

Table 2 Curve type constant

Curve Type	**k**	**α**
Standard Inverse	0.140	0.020
Very Inverse	13.5	1
Extremely Inverse	80	2
Long Time Standard Inverse	120	1

Accordingly, we get the following equations.

a) Standard Inverse or Normal Inverse

$$T_{op} = \frac{0.14 \times TMS}{PSM^{0.02} - 1} \tag{4.2}$$

b) Very Inverse

$$T_{op} = \frac{13.5 \times TMS}{PSM - 1} \tag{4.3}$$

c) Extremely Inverse

$$T_{op} = \frac{80 \times TMS}{PSM^{2} - 1} \tag{4.4}$$

d) Long Time Inverse

$$T_{op} = \frac{120 \times TMS}{PSM - 1} \tag{4.5}$$

The ratio of (I/I_S) is defined as Plug Setting Multiplier (PSM).

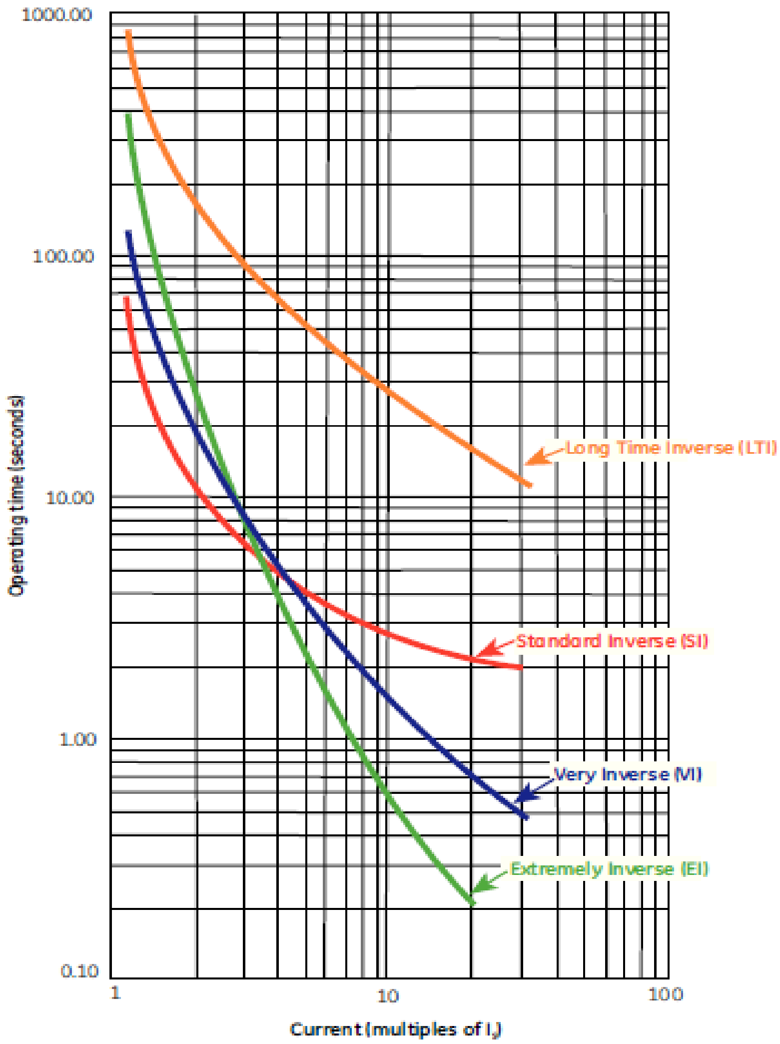


Figure 5 IEC60255 IDMT Relay Curves

The Electromechanical relays manufactured by Alstom has two characteristics viz. 3.0 second relay and 1.3 second relay.

- 3.0 second relay (3.0 s): Relay trips at 3.0 s for 100% plug setting and TMS of 1.0.
- 1.3 second relay (1.3 s): Relay Trips at 1.3 s for 100% plug setting and TMS of 1.0.

The 3.0 s and 1.3 s relays are used for 33 kV and 11 kV feeders in substation in eastern Bhutan and will be used accordingly during the relay coordination at latter part of this chapter. 3.0 s relays are used in 1 A CT secondary while 1.3 s relays are

used in 5 A CT secondary. The 1.3 s relays type operates faster by 2.31 time the normal standard curve operating time.

3.2 Directionality in Overcurrent Relay

While the problem of clearing higher fault magnitudes in a minimum time and vice versa seems satisfactory however the operation of relays with respect to certain directions becomes necessary when the power flow is bidirectional as shown in Figure 6. Hence, we have two kinds of relays.

a) Non-Directional Overcurrent Relays
b) Directional Overcurrent Relays

As the name suggests, non-directional relays operate based on the fault current irrespective of fault position viz. forward or reverse direction. When the substation is of radial in configurations, and the power flow occurs only in one direction, its suitable to use non directional relays as it is usually cheaper.

However, in case of a ring feeder where the power flow is bidirectional, the system requires the relays to operate in certain direction to discriminate the fault. A non-directional relay in a ring circuit would operate in forward as well as reverse fault location, hence it would be difficult to locate the fault. Therefore, directional as well as non-directional relays are required according to the power system configurations.

Having discussed various time-current relay characteristics and its pros & cons, however in the context of real-world application we are required to use the combination of various time current characteristics such as IDMT and the high-set element. The feeder may have SI curve and instantaneous element or DT relay along with directional features depending upon the protection requirements. Each of these curves will be coordinated upstream as well as downstream with suitable coordination time interval (grading margin). The coordination must exist between each of the curves in one hierarchy of protection.

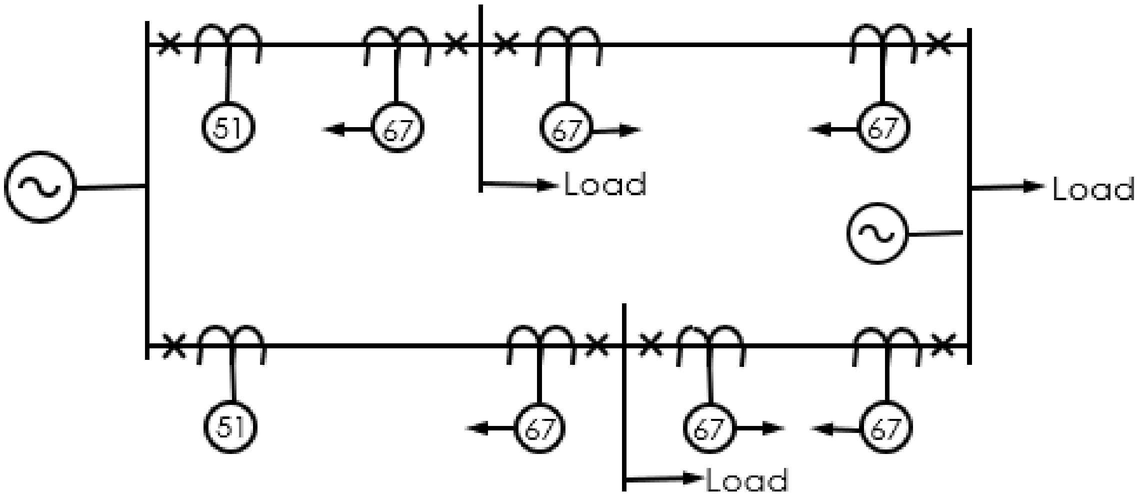


Figure 6 Multiple sources and Ring Feeders

3.3 Coordination Time Interval (CTI) or Grading Margin

After having calculated the TMS for the lowest hierarchical feeder with operating time of about 100 ms, now the question is how fast the upstream breaker should trip if the feeder doesn't clear the fault. When the fault strikes the line, the fault current is sensed concurrently by the upstream as well as concerned feeder relays however due to certain time discrimination, the feeder CB trips thereby resetting the relays to its original position. The upstream relay acts as the backup protection and will trip in case the feeder CB fails to trip.

The time difference required between the upstream and downstream CB for the maximum fault is called the 'Coordination Time Interval (CTI)' or 'Grading Margin'. To find out the grading margin, we need to consider the CB trip time, relay overshoot and some tolerance for errors. With filed calibration, CTI of 300 ms is taken for electromechanical relays while 200 ms is taken for static relays [5] as given in Table 3.

Table 3 Coordination Time Interval

Description	**Electromechanical Relays (ms)**	**Numerical Relays (ms)**
CB Trip Time (5 cycles)	80	80
Relay Overshoot	100	0
Allowance for errors	120	120
Total	300	200

Higher the grading margin, better is the selectivity of tripping however, we need to adjust all hierarchy within TMS of 1.0. The total tripping time, in worst case scenario should be below 2.0 s so that it doesn't intercept with equipment damage curve. For electromechanical relays, CTI of 300 ms chosen between the upstream and downstream breakers. If there exist several layers of protection whereby the total time exceeds 2.0 s or TMS doesn't suffice, then the grading margin may be reduced to acceptable values, or some protection hierarchy may be compromised.

3.4 Equipment Damage Curve

The equipment installed in the power system such as the transformers, cables, conductors, etc. are rated based on a continuous duty cycle. However, such equipment has the capability curve which indicates the amount of load that it can carry safely without having a permanent impact on the equipment for certain duration. The in-depth knowledge of such curve would enable the utility company to meet the peak demand without having to invest in new equipment. This would require the analysis of the daily load duration curve on normal system configurations and the possible impact on its loading due to the contingencies.

Hence, the consideration of maximum loading of the equipment in reference to the equipment damage curve may be done with general understanding of the daily load duration curve or the overloading may be configured in the thermal overloading features of numerical relays.

a) Transformer Capability Curve/ Transformer Damage Curve ($I^2t=k$)

This curve determines the limit of permanent damage that a transformer is subjected under a certain thermal and mechanical stress limit. The relay setting must conform to the thermal and mechanical limits as prescribed by the IEEE C57.109-1993 for liquid-immersed transformers [9] and IEEE C57.12.59-2001 for dry-type transformers [10].

Transformers can be loaded beyond its nameplate rating to certain degree within its Transformer Damage Curve (TDC) [11] as given in the Table 4 [11].

Table 4 Transformer short-time thermal load capability

Time	Times rated current
2 s	25.0
10 s	11.3
30 s	6.3
60 s	4.75
5 min	3.0
30 min	2.0

Loading the transformer beyond this limit will deteriorate the transformer permanently thereby decreasing the life of transformer in long run. The TDC shows the effect of thermal overloading of transformers and the mechanical effect posed by the high fault currents. The pickup current setting of the overcurrent relay of the transformer must not lie beyond the TDC. IEEE C37.91-2008 categorizes the transformers into four category [12].

Table 5 Category of Transformer Ratings

Category	Single Phase (Rating)	3-phase (Rating)
I	5kVA~500kVA	15kVA~500kVA
II	501kVA~1667kVA	501kVA~5000kVA
III	1668kVA~10000kVA	5001kVA~30000kVA
IV	>=10000kVA	>=30000kVA

Category I

The I^2t limit of 1250 defines the capability curve for this category. 'I' is the fault current in multiples of the transformer base current, and it depends on the per unit short circuit impedance. The maximum short circuit current in per unit for this category is the inverse of its per unit short circuit impedance. A Transformer with 4% impedance results to 25 pu short circuit current viz. 1/0.04. The short circuit current of 25 pu defines the time to 2 s as per the I^2t limit of 1250.

$$T= (1250/25^2)=2 \text{ s}$$

The graphical representation is given below in Figure 6 [11].

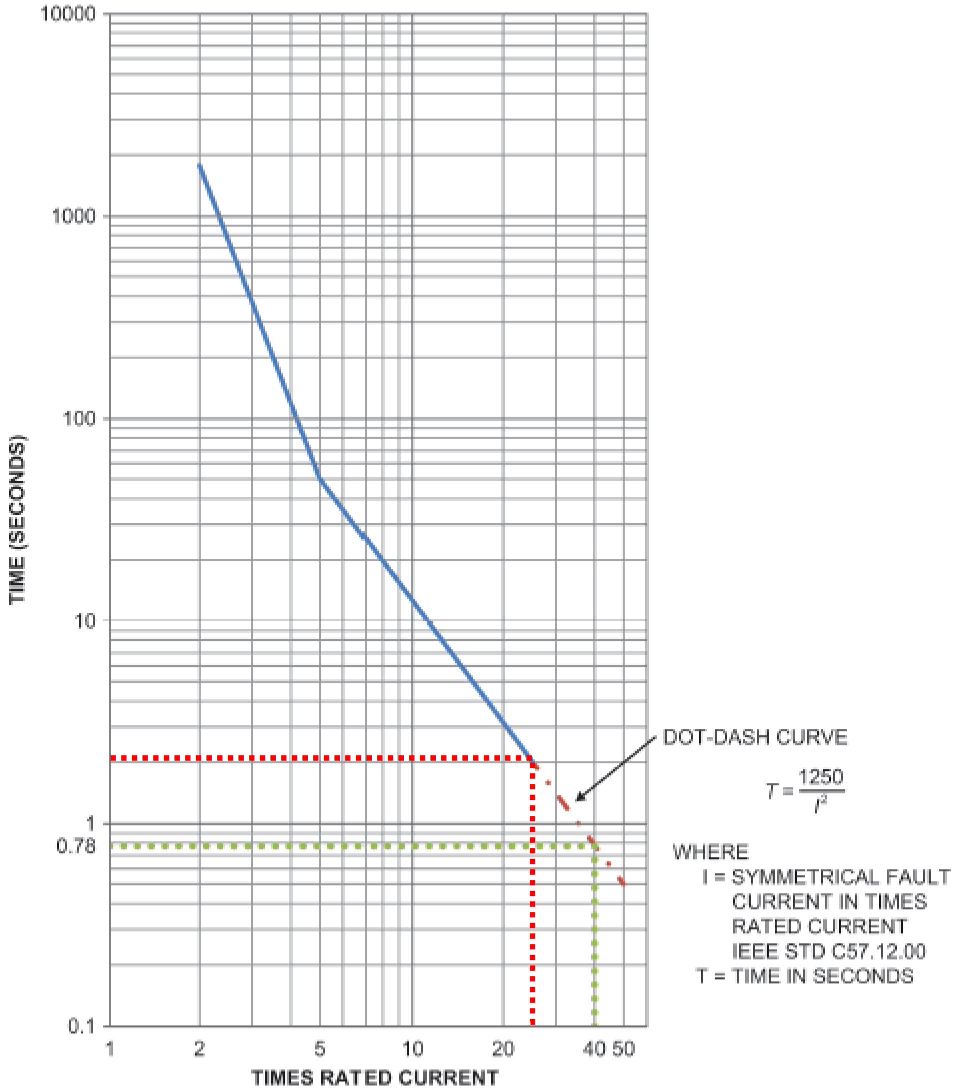


Figure 7 Category 1-Transformer Damage Curve

Category II

For this category additional curve is considered, in respect of the fault frequency that the transformer is exposed to in its entire life. For Category II, a fault frequency of more than 10 times and 5 times for category III are being considered. This results into two curves as shown in Figure 8 [11] viz. infrequent fault (blue steady curve) and frequent faults (blue steady curve along with dotted curves) based on its fault impedances. For the earlier, the curve is limited to 2 s. For the later, curves are obtained incorporating the maximum anticipated fault current which is usually taken

as 50% to 100% of the maximum possible fault currents. The value of 'k' is taken as 2.0 s for the worst-case mechanical duty. Consider a transformer with 7% impedance.

$$Maximum\ fault\ current\ (p.u.) = \frac{1}{Z\%} = \frac{1}{0.07} = 14.29\ p.u$$

$$k = I^2 \times t = 14.29^2 \times 2 = 408.4$$

Considering the fault currents to be 70% of the maximum possible fault currents.

$$I = 0.7 \times 14.29 = 10$$

$$t = \frac{k}{I^2} = \frac{408.4}{10^2} = 4.08\ s$$

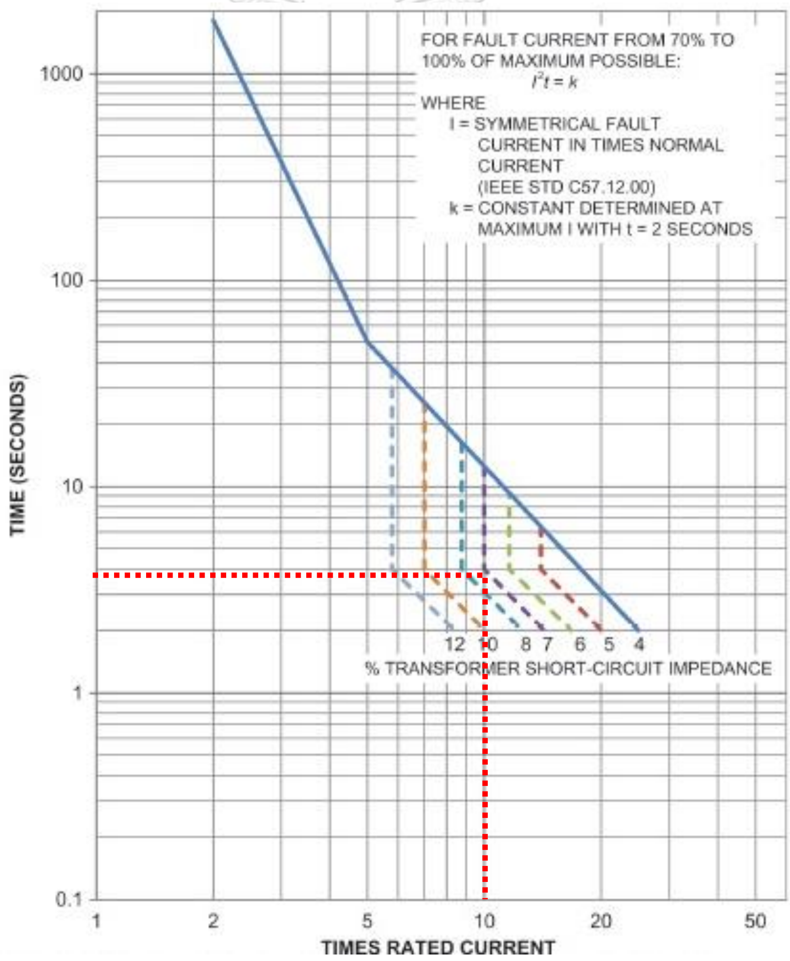


Figure 8 Category 2-Transformer Damage Curve

For category IV transformers the mechanical duty of fault currents is taken as 50% to 100% of the maximum possible fault currents.

Therefore, while considering the pickup current setting for transformer, it isn't necessary to limit to 100% or 110% but we can go with higher settings but not beyond the transformer capability curves. The transformer capability curve defines time duration corresponding to the pickup setting. This time cushion will allow operators to react on shifting the load to other circuits this achieving the normalcy of transformer loading without power supply interruption.

b) Cable (Conductor) Damage Curve

High temperatures caused by continued overload, nonlinear loads, or uncoordinated fault protection result into decreased cable life, ultimately leading to insulation failure. Proper selection of cable and its rating must ensure its satisfactory performance for overload as well as withstand short circuit conditions.

In protection coordination, the cable should be able to withstand the maximum through-fault current for a time equivalent to the tripping time of the upstream protective device. This ensures the upstream relay trips the circuit before the cable gets damaged. Hence the cable damage curve should be on the right while the upstream relay should be preferably on the left as shown in the Figure 9 [13].

c) Current Transformer Saturation

Current transformer produces a scaled down replica of primary current to a lower secondary value which are applied to protective relays. The ability of reproduce the secondary currents depends on the Accuracy Limit Factor (ALF) and the Knee Point Voltage (KPV). If CTs are operated beyond the ALF or KPV, saturation occurs thereby distorting the secondary current output which is not proportional to the primary current. In the worst case, the secondary output current may be zero. The CT saturation phenomenon slows down the relay operation, and relays might not even operate.

CT saturation will occur where the system fault is much higher than ALF and KPV of the CT. The possibility of CT saturation must be studied along with the measurement of the actual burden connected across the secondary circuits. To avoid CT saturation,

instantaneous element must be utilized with its setting just below the CT saturation current or probably ALF.

In the case of Nangkhor Substation, fault level has increased since 2001, hence it is recommended to connect all CT to full ratio despite less load and check the possibility of saturation after measuring the actual burden. Numerical relays such as MiCOM P14N must be installed and activate the instantaneous element just below the Accuracy Limit Fault Current.

Most of CTs installed across Bhutan is of IS/IEC 60044-1 : 2003. Though the rated continuous thermal current isn't mentioned in the nameplate however as per the above standard, the preferred values should be 120 % to 150 % and 200 % of rated primary current [14].

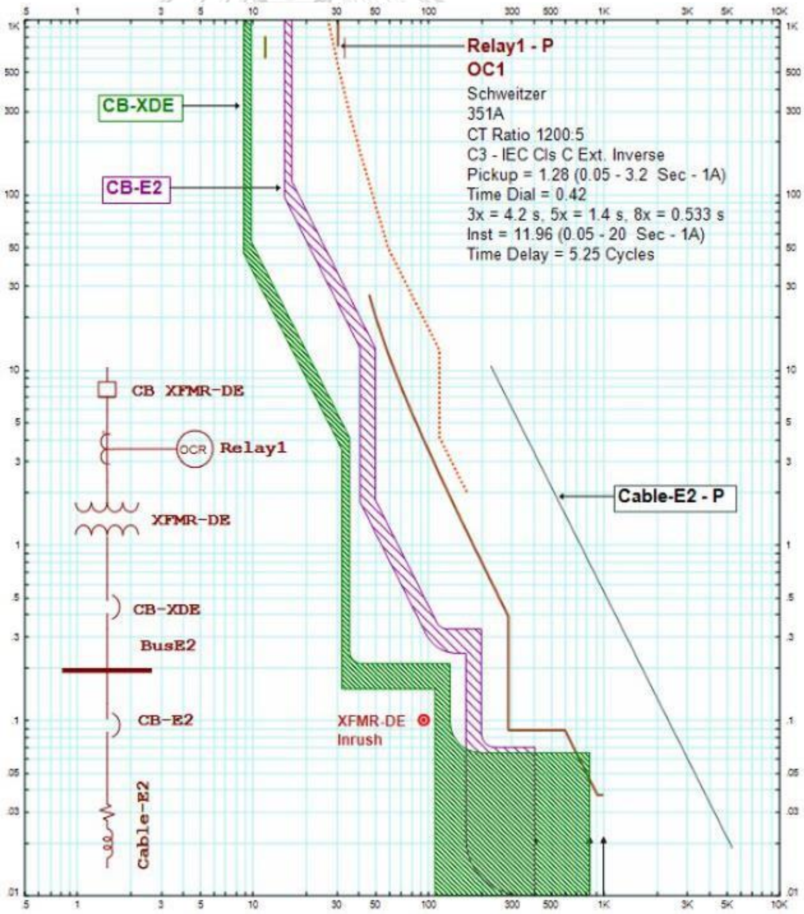


Figure 9 Cable damage curve coordination

4 SUBSTATION OPERATION CONFIGURATIONS

The relay setting involves the calculation of the fault clearing time against the set current using certain relay curve, wherein the maximum short circuit current is used to determine the TMS. However, depending on the substation operation configurations the fault level of bus changes.

For instance, the fault level of 11 kV buses in Nangkhor Substation as shown in Figure 10 is 46.9 MVA when Bus Coupler (BC) is ON as compared to 29.9 MVA when it is OFF. This results into two sets of relay parameters as the fault level changes with available source feeding it.

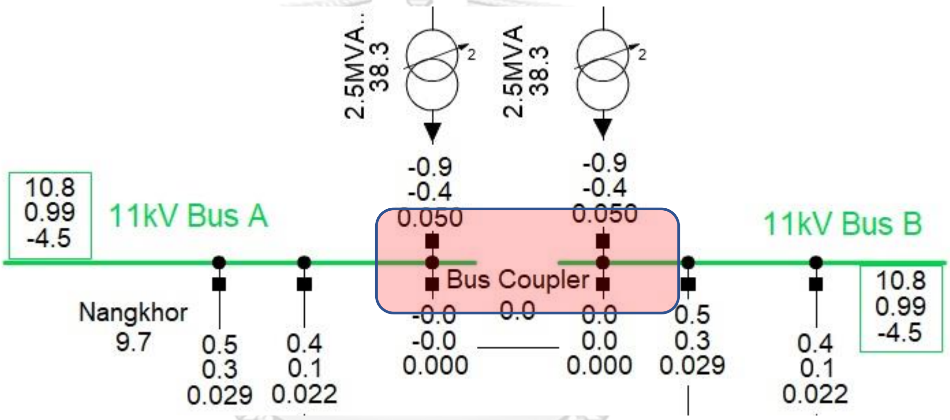


Figure 10 Bus Coupler operation scenario

Selection of either of the settings would mean the possibility of miscoordination in different operation scenario. It would be impractical to discipline the operation system like, operate with BC in OFF condition, as the real field scenario demands various substation configuration to operate to have reliable power supply.

Relay coordination would have been much simpler for a single transformer and a bus in vertical configurations, however, in real field there are bus sectionalizer and parallel transformers installed to achieve maximum reliability.

Often, for industrial applications, the manufacturers develop an interlocking circuit whereby BC cannot be put ON if Incomers 1 and 2 are in closed position. While this sounds satisfactory for industries as their load are fixed. However, for a power utility

company, the load is dynamic and parallel operation of transformers will be required in case of contingencies.

In such cases, the system requires automatic relay setting adaptation based on the substation operation configurations. While in electromechanical relay, it is not feasible, the numerical relays can be made smarter by enabling automatic changeover of protection groups.

Numerical relay capable of multifunction protection groups must be installed, with each group being independent with its own setting. The logic for automatic adaptation of setting groups must be prepared through hardwire as well as in the relays through programmable scheme logics.

Considering input 1 and 2 to be respective incomers and input 2 as BC in Figure 11, the following logics for MiCOM P14N relay, activates setting Group 1 when BC is OFF and enables Group 2 settings when BC is ON [15]. The relay setting of respective operation conditions must be uploaded in respective groups.

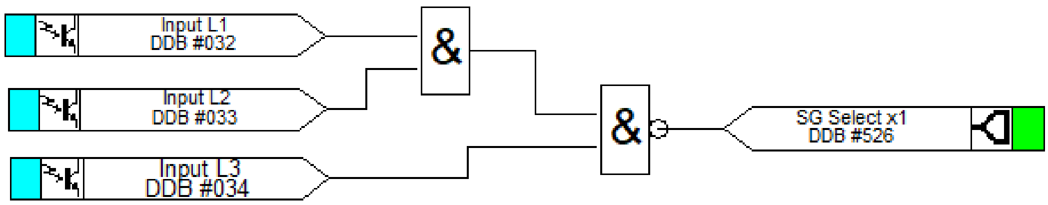


Figure 11 Programmable Scheme Logic for Group Selection

Such schemes will enable the protection system to be smarter thus improving the reliability and the integrity of the protection. Depending on the fault level sensed by the status of CB, the relay changes its setting automatically via the group.

4.1 Overcurrent Relay Coordination

Relay Coordination should be done at the design stage of any substation based on the fault level and the expected load. However, during the Operation and Maintenance (O&M) phase, due to the change in system fault level or the upgradation executed, the revision of relay coordination becomes mandatory.

A revision of relay coordination is required to be done based on the limitation of the existing equipment, therefore selection of the pickup setting and time setting may vary slightly. Here the focus will be on latter part. A pilot case study has been carried out for 132/33/11 kV Nangkhor Substation, located in eastern Bhutan.

DIgSILENT software has been used for modelling, simulations and verifying the results of the relay coordination. The details of over current relay coordination are given as follows.

4.1.1 Prerequisites of Relay Coordination

Prior to relay coordination, one must be aware of the system configurations along with the details of equipment. The details of the relay and its features are also to be studied. One must be aware of the cable and conductor ampacity, the equipment damage curves, etc. The details of prerequisites are as given below.

a) Single Line Diagram
b) Short Circuit Fault level of each bus
c) Details of CT, PT, transformers, etc.
d) Ampacity of Cables, Conductors, etc.
e) Details of Relay Characteristics

The task of relay coordination requires the protection engineers to collect the power system data as given above. The system fault level needs to be obtained from the concerned authority or conduct the short circuit simulations as discussed in earlier chapter and accordingly design the substation after selecting the suitable components.

The short circuit current will depend on various system operation configurations. It is advisable to have the base case on load flow wherein, short circuit studies can be done at any time or whenever addition or deletion of source occurs.

i. Single Line Diagram (SLD)

The SLD for Nangkhor Substation has been attached as in Figure 12. It has 3 voltage level viz. 132 kV, 33 kV and 11 kV. 132/33 kV, 5 MVA, YNd1 transformers connects the 132 kV and 33 kV system. Similarly, 2.5 MVA, 33/11 kV, Dyn11 transformers connects the 33 kV and 11 kV system.

Since 33 kV system is on delta configuration, an earthing transformer with zigzag winding has been installed on 33 kV bus to allow an artificial neutral path to the fault currents during earth faults. The loads are being catered via 33 kV and 11 kV feeders.

132 kV and 33 kV system configuration are of main and transfer bus scheme while 11 kV bus is a single bus with bus coupler which connects one half of the bus with the other one and provides the operational flexibility.

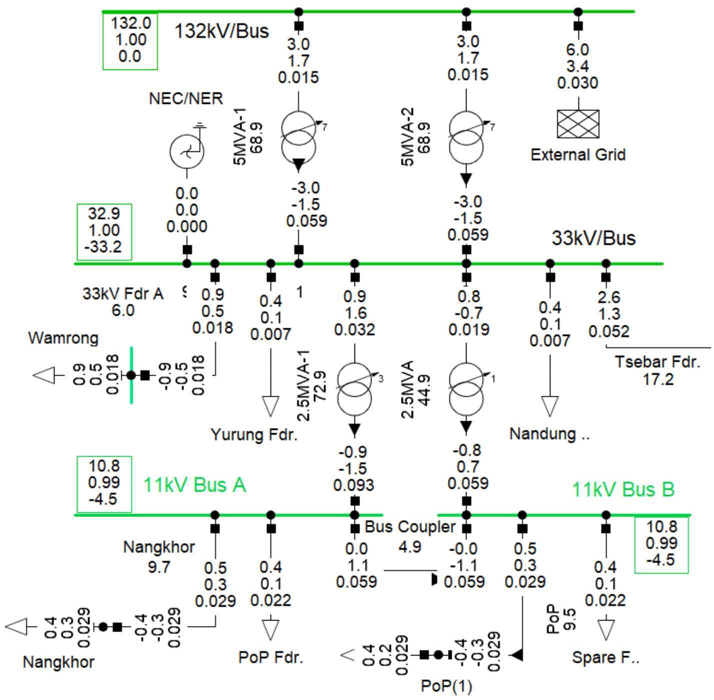


Figure 12 Single Line Diagram of 132/33/11 kV Nangkhor Substation

ii. 3-Phase Short Circuit Current Level for Overcurrent Relay Setting

The load flow and short circuit studies developed in earlier chapter has been used for relay setting and coordination consideration. The load flow and short circuit study consists of only transmission lines, interconnecting transformers, and generators however our requirements for relay coordination would be the entire sub system connected to every bus. For this there are two methods.

a) Create a sub system as a part of the load flow and short circuit studies.
b) Create a separate system with external grid as its source. The fault level of the external grid is determined from the load flow and short circuit studies.

While both the methods are similar, however second method is recommended as it is much simpler. To study protection coordination of one substation, it is not necessary run the short circuit simulation of the entire grid repeatedly. Modelling external source with fault level obtained from short circuit studies of entire grid would solve the issue. A 3-phase short circuit fault needs to be simulated for each bus.

For the feeders, the maximum fault level anticipated is, when the 3-phase fault is close to the bus. A fault close to the CT of a feeder can be assumed around 1% to 5% of the line length and simulated accordingly. Any fault away from the feeder CT towards the load end is subjected to the impedance of the lines hence the fault currents will be lesser.

The maximum fault current is particularly important in determining the CB interrupting capacity and understanding the transformer/cable/conductor damage curve. The maximum short circuit fault current should always be below the equipment damage curve and relay coordination must be conducted without intercepting the damage curves. The 3-phase short circuit fault level varies for different buses and its configuration as given below. The various substation operation schemes are designated as cases below.

i. Case A : 11 kV BC in OFF position and both Incomers ON

ii. Case B : 11 kV BC in ON position and both 11 kV Incomers are ON

iii. Case C : 11 kV BC in ON position and one 11 kV Incomer is OFF

Case A and C are identical in terms of the fault level. In Case A, the BC does not come into protection hierarchy. While for Case C too, the BC does not come into protection hierarchy for faults on the feeders connected to common bus with Incomer, however the BC come into hierarchy for faults on feeders of other bus wherein the supply is fed via the BC.

In Case A and Case C, the source of fault current is only one transformer while for Case B, two transformers supply the fault current, hence the 3-phase short circuit level will change. The Table 6 shows the MVA fault level and fault current for different operation scenarios, to which relay coordination needs to consider.

Therefore, it must be understood that two sets of relay settings need to be calculated based on the two sources of fault current. But the question is how do we change the relay setting based on fault current sources? Well for electromechanical relays, it does not have the option however with modern numerical relays, each setting can be uploaded in respective groups and its activation should be done based on the logics of CB operation.

What if the source of fault current is four? Here the modern numerical relays have the capacity of four independent group settings, so each setting can be allocated respectively. However, if the source of fault current is beyond four, then it is not possible as of now even with numerical relays, therefore protection priority must be done.

Table 6 Three-phase short circuit simulated fault current.

Fault Simulation location	Case A		Case B		Case C	
	Fault Lvel (MVA)	Fault Current (A)	Fault Level (MVA)	Fault Current (A)	Fault Level (MVA)	Fault Current (A)
132 kV Bus	1031.8	4513.0	1031.8	4513.0	1031.8	4513.0
HV(132 kV) Side of 5MVA Txr. 132/33 kV	54.1	236.8	54.1	236.8	54.1	236.8
LV Side of 5MVA Txr. 132/33 kV	54.1	947.1	54.1	947.1	54.1	947.1
33 kV Bus	108.3	1894.3	108.3	1894.3	108.3	1894.3
33 kV Radial Feeders	108.3	1894.3	108.3	1894.3	108.3	1894.3
HV(33 kV) Side of 2.5MVA Txr. 33/11 kV	29.9	523.3	23.6	410.2	29.9	523.3
LV(11 kV) Side of 2.5MVA Txr. 33/11 kV	29.9	1569.9	23.4	1230.6	29.9	1569.9
11 kV Bus A	29.9	1569.9	46.9	2461.2	29.9	1569.9
11 kV Bus B	29.9	1569.9	46.9	2461.2	29.9	1569.9
11 kV Feeders on Bus A	29.9	1569.9	46.9	2461.2	29.9	1569.9
11 kV Feeders on Bus B	29.9	1569.9	46.9	2461.2	29.9	1569.9
11kB Bus Coupler	0.0	0.0	23.4	1230.6	29.9	1569.9

It should be noted that there is no BC for 33 kV system, where there are two transformers feeding the bus. Nonetheless, the outage of any of the two transformers feeding the load, will alter the fault level and needs to be calculated accordingly. Since the outage of transformer is rare as there isn't BC, hence it is assumed that the transformers are in continuous service all the time.

The change in the system operating conditions alters the short circuit fault level. Accordingly separate relay coordination setting may be calculated and implemented according to the system configurations. Or the system operation interlocks may be designed and practiced according to the relay coordination principles.

If the relay is numerical, then automatic change of relay setting via different group may be designed using the Opto features. The Programmable Scheme Logic (PSL) may be programmed using the CB status of respective sources [15].

iii. Details of Instrument Transformers, Cables, and Conductors

The details of Current Transformer (CT), Voltage Transformer (VT), cables, etc. are necessary for conducting the relay coordination. In general, there is a practice of selecting CT secondary current of either 1 A or 5 A. If the distance between the CTs and the measuring equipment is long, then usually 1 A CT is selected else 5 A CTs are selected. However, owing to the complexities faced during differential coordination where we encounter mix of 1 A and 5 A CT, now a days most of the CTs are with 1A CT uniformly.

The 11 kV CTs of Nangkhor Substation is 5 A CT secondary current. However, the Core-3 of 11 kV Incomer CT is of 1 A which is used for differential relay connection along with 1 A CT secondary of HV side (33 kV) of transformer. The details of CTs and PTs are given in Table 7.

Table 7 Details of instrument transformers

Sl. #	Feeder	Available CT Ratio	Connected CT Ratio
1	11 kV Feeders Type-I	100-50/5A	100/5A
2	11 kV Feeders Type-II	100-50/5A	50/5A
3	11 kV Bus Coupler	150-75/5A	150/5A
4	11 kV Incomers (LV Side of 2.5MVA, 33/11 kV Transformer)	150-75/5A	150/5A
5	HV (33 kV) Side of 2.5MVA, 33/11 kV Transformer)	50-25/1A	50/1A
6	33 kV Feeders	30-15/1A	30/1A
7	33 kV Incomers (LV Side of 5MVA, 132/33 kV Transformer)	100-50/1A	100/1A
8	HV (132 kV) Side of 5MVA, 132/33 kV Transformer)	50-25/1A	25/1A
9	11 kV Potential Transformer	11000V/110V	
10	33 kV Potential Transformer	33000V/110V	
11	132 kV Potential Transformer	132000V/110V	

While the 33 kV feeders are terminated to the 33 kV outdoor bus via Aluminium Conductor Steel Reinforced (ACSR) Dog, the 11 kV feeders (8 nos. of feeders) are connected via Cross Linked Polyethylene (XLPE) 3-Core 185 sq.mm cable till the

gantry. The ACSR Dog conductor connects the cable at the gantry and runs along the towns and villages.

The ampacity of XLPE, 185 sq.mm, 3-Core 11 kV Armored Cables Aluminium Conductor, in air at 40°C ambient temperature is 327 A while it is 302 A if underground at an ambient temperature of 25°C [16, p. 28]. The parameters for Aluminium conductors are taken from the 'Manual on Transmission Planning Criteria' of Central Electricity Authority of India [7].

Here it is observed that, the cable ampacity is much higher than the installed CT rating. Hence the feeder loading capacity is limited by the CT. The details are shown in Table 8.

Table 8 Feeder Details

Sl.#	**Feeder Details**	**Cable/Conductor**		**Power (MVA)**	**CT Ratio (Ip)**	**MVA as per CT**	**Feeder Capacity (MVA)**
		Size	**Ampacity (A)**				
1	11 kV Busbar	50x10mm^2, Copper	400	7.621	-	-	7.621
2	11 kV Incomer-1 &2	XLPE 3C, 185Sq.mm	327.0	6.230	150	2.858	2.858
3	11 kV Nangkhor				100	1.905	1.905
4	11 kV PoP						
5	11 kV Pemagatshel						
6	11 kV Spare						
7	11 kV Station				60	1.143	1.143
8	11 kV Colony						
9	33 kV Yurung	ACSR Dog	298.1	17.038	30	1.715	1.715
10	33 kV Wamrong						
11	33 kV Tsebar						
12	33 kV Nanung						
13	33 kV Busbar	ACSR Wolf	406.3	23.222	-	-	23.222
14	2.5MVATxr-1 &2 (HV Side)				50	2.858	2.858
15	33 kV Incomer -1 & 2				100	5.716	5.716
16	5MVATxr-1&2 (HV Side)	ACSR Zebra	745.9	42.633	25	5.716	5.716

Where,

11 kV Incomer 1 :LV side of 33/11 kV, 2.5MVA Transformer-1

11 kV Incomer 2 :LV side of 33/11 kV, 2.5MVA Transformer-2

2.5MVA Txr-1 :HV side of 33/11 kV, 2.5MVA Transformer-1

2.5MVA Txr-2 :HV side of 33/11 kV, 2.5MVA Transformer-2

33 kV Incomer 1 :LV side of 132/33 kV, 5MVA Transformer-1

33 kV Incomer 2 :LV side of 132/33 kV, 5MVA Transformer-2

5MVATxr-1 :HV side of 132/33 kV, 5MVA Transformer-1

5MVATxr-2 :HV side of 132/33 kV, 5MVA Transformer-2

The above system was designed during 1999 when there was only 60 MW hydro power plant connected and synchronized with Indian grid at a single point. The eastern and western grid of Bhutan were not connected. But now, the network has changed significantly, Bhutan is interconnected to a single grid. The generation has increased to 2,326 MW from 60 MW. The fault level of Bhutan Power System in 2001 and 2022 were simulated and is a given in Table 9.

Table 9 Fault Level comparison in 2001 and 2022

Fault Level	3-Phase Fault (A)		SLG Fault (A)	
	2001	2022	2001	2022
11 kV Bus	2344	2461.16	3153	3275.25
33 kV Bus	1693	1894.29	1171	1222.97
132 kV Bus	1890	4513.04	1800	3429.17

The design of CT depends on the normal load current and the maximum short circuit current. The CT shouldn't saturate at maximum short circuit current [17].

Table 10 Fault Current vs. CT saturation at rated burden

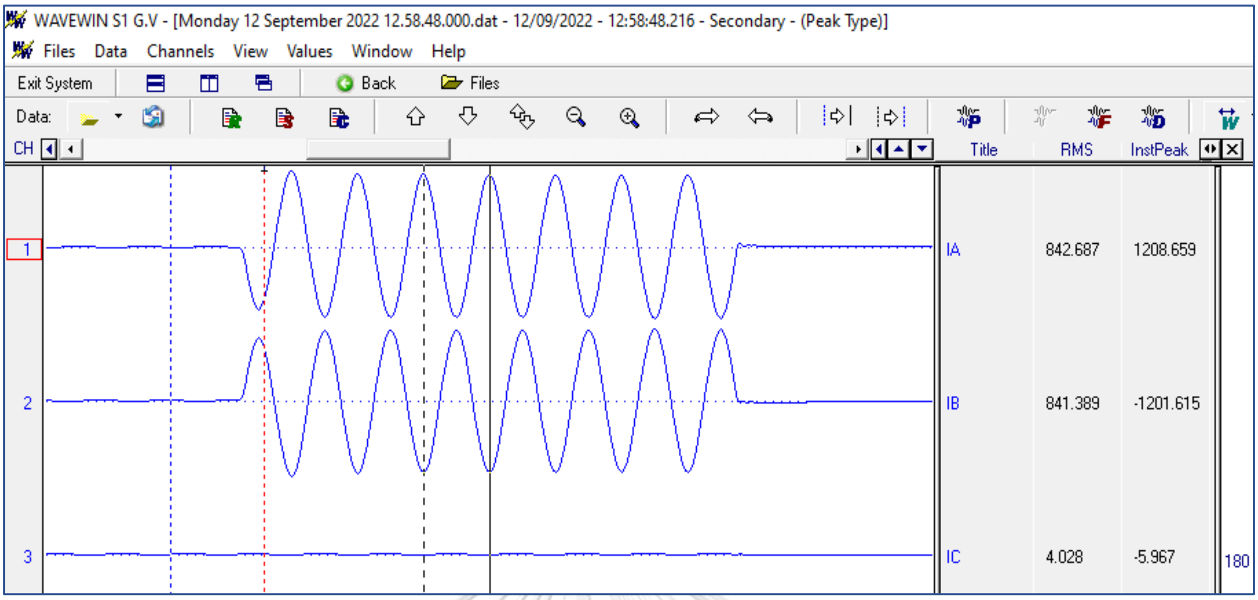
Feeders	CT Ratio	Class	Max. Fault (A)	CT Saturation (A)
11 kV Feeders	100/5	30VA, 5P10	3275.25	1000A
11 kV Incomers	150/5			1500
33 kV Feeders	30/1		1894.29	300
2.5 MVA Txrs.(HV Side)	50/1			500
33 kV Incomers	100/1			1000
5 MVA Txrs. (HV Side)	25/1		4513.04	2500

The ability of the above CTs to replicate the fault current on secondary side without undergoing any saturation at standard burden seems impractical. The fault current on 33 kV and 11 kV bus has not increased substantially due to the transformer impedances although 132 kV bus fault current has increased by double fold.

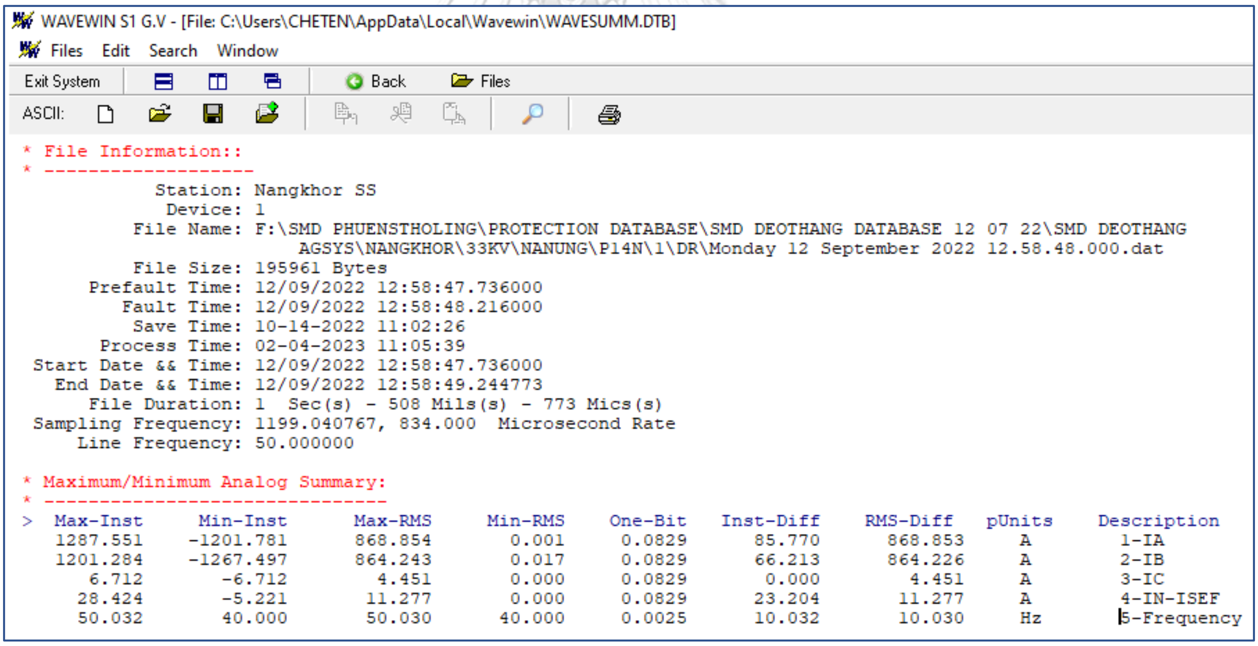
None the less, the saturation depends on the burden and if actual burden across the CT secondaries is much lesser than rated burden, then CTs can replicate higher fault current without saturation. Thus, mathematically the performance of CT is a function of the burden connected across its secondary windings [12].

In the case of Nangkhor Substation, there are fault waveform evidence as shown in Figure 13, that the existing CT could replicate the fault current without undergoing saturation for 868 A, although its saturation current at standard burden is around 300 A. This is only because the burden is very less.

An in-depth study on this issue must be conducted by measuring the actual burden at site and recommend accordingly.



a) Fault Waveform



WAVEWIN S1 G.V - [File: C:\Users\CHETEN\AppData\Local\Wavewin\WAVESUMM.DTB]

Files Edit Search Window

Exit System Back Files

ASCII:

```
* File Information::
* --------------------
             Station: Nangkhor SS
              Device: 1
           File Name: F:\SMD PHUENSTHOLING\PROTECTION DATABASE\SMD DEOTHANG DATABASE 12 07 22\SMD DEOTHANG
                          AGSYS\NANGKHOR\33KV\NANUNG\P14N\1\DR\Monday 12 September 2022 12.58.48.000.dat
           File Size: 195961 Bytes
       Prefault Time: 12/09/2022 12:58:47.736000
          Fault Time: 12/09/2022 12:58:48.216000
           Save Time: 10-14-2022 11:02:26
        Process Time: 02-04-2023 11:05:39
 Start Date && Time: 12/09/2022 12:58:47.736000
   End Date && Time: 12/09/2022 12:58:49.244773
       File Duration: 1  Sec(s) - 508 Mils(s) - 773 Mics(s)
 Sampling Frequency: 1199.040767, 834.000  Microsecond Rate
     Line Frequency: 50.000000

* Maximum/Minimum Analog Summary:
* --------------------------------
```

Max-Inst	Min-Inst	Max-RMS	Min-RMS	One-Bit	Inst-Diff	RMS-Diff	pUnits	Description
1287.551	-1201.781	868.854	0.001	0.0829	85.770	868.853	A	1-IA
1201.284	-1267.497	864.243	0.017	0.0829	66.213	864.226	A	2-IB
6.712	-6.712	4.451	0.000	0.0829	0.000	4.451	A	3-IC
28.424	-5.221	11.277	0.000	0.0829	23.204	11.277	A	4-IN-ISEF
50.032	40.000	50.030	40.000	0.0025	10.032	10.030	Hz	5-Frequency

b) Fault data

Figure 13 Fault Waveform and fault data from WAVEWIN Software

4.2 Relay Characteristics and Parameter Settings

For the existing substation, the relays are already installed hence the relay characteristics depend on whether it is electromechanical, static, or numerical relays. If the relay is numerical, then it has most of the characteristics such as normal inverse, very inverse or extremely inverse with high precision TMS selection. However, if the relay is mechanical, then it has few characteristics such as normal inverse with high set element or it can be just single relay curve only with predefined taps.

In case of Nangkhor Substation, the 11 kV relays are mechanical and has normal inverse curve. Even with the Normal inverse curve, there are two types of relays 1.3 s relay characteristics and 3.0 s relay characteristics. The 3.0 s relay curve is the normal inverse curve. With a plug setting of 100% and TMS of 1.0, a normal inverse curve trip in 3.0 s. But for 11 kV feeders, the relay characteristics is 1.3 s which means for the same setting, relay operates in 1.3 s. This means faster tripping of feeders.

For 33 kV feeders, the relays are upgraded with numerical relays, so there are options to select any curve as desired. Similarly, the distance and differential relays are also numerical relays. The details of relays are given in Table 11.

Table 11 Relay Details

<table>
<tr><th>Sl.#</th><th>11 kV System</th><th>Relay Model</th><th>Relay Curve</th><th>Brand</th></tr>
<tr><td>1</td><td>11 kV Feeders</td><td>CDG31 (1.3s)</td><td>IEC Standard Inverse</td><td rowspan="5">Alstom</td></tr>
<tr><td>2</td><td>11 kV Station/Colony Feeder</td><td>Fuse (6A)</td><td>-</td></tr>
<tr><td>3</td><td>33 kV Feeders</td><td>P14NB</td><td>Multiple Curves</td></tr>
<tr><td>4</td><td>33 kV Incomer-1 & 2</td><td>CDG31 (3.0s)</td><td>IEC Standard Inverse</td></tr>
<tr><td>5</td><td>5MVA Txr-1&2</td><td>CDG31 (3.0s)</td><td>IEC Standard Inverse</td></tr>
</table>

a) Full Load Current and Pickup Current Setting

The Full Load Current (I_{FL}) of a feeder is determined amongst the MVA capacity of cables and CT. Normally, the CT ratio and the cable ampacity is selected based on the system fault level and would be similar. However, with the change in system fault level and the increased demand, CTs and cables are changed thereby distorting the cable ampacity and the CT ratio.

Therefore, the I_{FL} should be determined by the minimum MVA capacity of either CT or cable. This is being done to protect the lower capacity equipment. In case of Nangkhor Substation, the MVA capacity of CT and Cables are 1.905 MVA and 6.23 MVA respectively for 11 kV feeders. hence, the I_{FL} is calculated as follows.

$$Full\ Load\ Current, I_{FL} = \frac{MVA \times 1000}{\sqrt{3} \times kV} = \frac{1.905 \times 1000}{\sqrt{3} \times 11} \cong 100A$$

The pickup current of an overcurrent relay is the minimum current required for the relay to close its contact. In electromechanical relay, when the pickup current is reached, the disc starts to rotate. The pickup current should ensure that even in the worst-case contingencies, supply does not get interrupted while maintaining the safety of the equipment.

A tolerance of 10% to 20% above the I_{FL} may be kept for pick up setting however if there are any contingencies to which the feeder must respond, then the tolerance may be increased depending on the thermal rating of equipment. The CT ratio of the 11 kV feeder is 100/5 A. Pickup current is calculated as follows.

$$Full\ Load\ Current, I_{FL} = 100A$$

$$Tolerance\ 20\%, I_{FL} = 100A \times 1.2 = 120A$$

$$Pickup\ Current\ (Secondary), I_S = \frac{CT_{Sec}}{CT_{Pri}} \times I_{FL} = \frac{5}{100} \times 120 = 6A$$

b) Relay Characteristics Curve and Time Multiplier Settings (TMS)

The coordination of relays must be done amongst the upstream and downstream relays with time and current as the variables. The time-current characteristic curves need to be selected as per the existing curves or one may create customized curve in case of numerical relays. In case of electromechanical relays, inherent relay characteristics curve is the only option.

Coordination of AR, Sectionalizer, Unitized Substation, Fuses, etc. must be conducted with the substation feeder. The coordination should be conducted from the last

protective device. However, in most cases such data along the feeders are unavailable or not installed. In such cases, the relays at the feeder of a substation must trip as fast as possible to clear the downstream faults.

For proper coordination, one may select the same relay characteristics curve for upstream or downstream relays. Generally, Standard Inverse relay curve is adopted. Numerical relays contain all the curve with several stages of curve; hence users may select different curves for each relay or utilize multiple curves for the relay and carry out the coordination accordingly. The formulas for the relay curves are defined by equation (4.2), (4.3), (4.4) and (4.5).

c) Instantaneous Relay Setting (Device 50)

The instantaneous relay or highset relay, performs better when there are significant differences in the impedance between two relaying point. In case of severe faults, device 50 clears away the fault faster than the time delayed relays. The setting criteria depends on the location and type of system element that needs to be protected, such as for lines between the substations, distribution lines or transformers [17].

i. *Lines between Substations*- Coordination should start from the lowest hierarchical substation and the setting should be at least 125% of the maximum fault of the downstream substation. The tolerance of 25% is provided to avoid the overlapping of the downstream instantaneous relay in case of the presence of significant DC component. Since the system X/R ratio increases significantly for 220kV and above system, the DC component also increases accordingly, hence it is advisable to have higher tolerance.

ii. *Distribution Lines*- The distribution feeder ends with distribution transformer hence the criteria of maximum fault level as in case of line between substations does not arise. In such case, the instantaneous settings may be set to 50% of the maximum short circuit current at the

relaying point or between 6 to 10 times the maximum current rating of the feeder.

iii. *Transformers*- The instantaneous relay on HV side must be between 125% to 150% of the maximum fault current of the LV side referred to HV side. The higher tolerance is chosen to avoid miscoordination due to high inrush currents.

The instantaneous relay of the feeders and incomer emanating from the same bus is subjected to same fault level, hence in such case the transformer instantaneous relay must be overridden to avoid loss of selectivity.

4.3 Case Study: Overcurrent Relay Coordination of Nangkhor Substation

Relay Coordination for 132/33/11 kV Nangkhor Substation is being selected as a case study. Nangkhor Substation has 132 kV, 33 kV and 11 kV buses along with a 33/11 kV adjacent Substation belonging to distribution department. The relay coordination of 33 kV Incomers will depend on adjacent distribution substation too, hence it would be interesting to work it out. Overcurrent relay coordination will be discussed here and other protections such as the earth fault, differential and distance relay will be discussed in later chapters.

4.3.1 11 kV feeders

The maximum fault current occurs for three phase faults near to the bus (close to CT) and is equivalent to the bus fault. Based on the fault level, the pickup settings and the TMS as per the desired operating time of 100 ms for all the 11 kV feeders needs to be calculated. A pickup tolerance of 10% may be selected. The operating time of 100 ms is chosen for fast fault clearing.

If there are protection devices downstream, then 'relay operating time' needs to be recalculated. Amongst the feeders, the relay with the slowest fault clearing time needs to be coordinated with 11 kV incomer or bus coupler relay. The time grading

of 300 ms is to be used for upstream relays as the relays are electromechanical. The 11 kV feeders have IEC Standard Inverse (SI) Curve (1.3 s).

For earthfault relay setting, single line to ground (SLG) fault is applied near the bus. The pickup setting of, 30% of the OC pickup setting is chosen based on the allowance of load unbalance. The calculation is executed in excel sheet in Table 15 (Next Chapter).

a) Overcurrent Relay Setting

The time dial of electromechanical relay does not have option of 0.09 (in reference to the calculations in Table 12), therefore the next higher TMS of 0.1 is adopted, thus the operating time of relay becomes 108 ms.

In this case, the actual tolerance is 0% though we intend to apply pickup setting tolerance of 10%. The CDG31 relay is an electromechanical relay with predefined taps. The next tap after 5 A is 6 A, which translates to 20% instead of 10% tolerance. The pickup setting can be as high as 150% if we have the thermal overload function which will define the time.

Since the relay is electromechanical, neither does it has thermal overload function nor it is possible to allow sufficient time delay, hence pickup setting of 100% is recommended. Further there is not any possibility of ring formation for this feeder, hence the maximum load is the usual peak load of the feeder.

As the reliability of the electrical power becomes critical, feeding the power via other feeders through ring formation becomes necessary. Sectionalizer or AR needs to be installed in the feeders to isolate the faulty portion and restore the power to the healthy portion of the line within seconds. In such scenarios, the feeders will have to bear the additional load of other feeders. The load might cross over 110% to 150% or more.

For countering such unforeseen circumstances, contingencies studies must be conducted and ensure that the feeders can be loaded up to 150% for a time duration of 30 minutes which is well below the respective transformer damage

curves. At any case, during normal operation, the feeders or transformers will be loaded up to 50-60%, and in rare case additional 50% may be allowed to cater to the outage of other feeders for certain period.

Numerical relay has the thermal overload settings which allows the pickup value of 150% and time to 30 minutes. The pickup current for the normal load may be 110%. When the load enters 110% and beyond, the thermal overload curve picks up and the tripping of the overcurrent is blocked and if the additional load remains for 30 minutes, it will trip the circuit breaker. So, within 30 minutes the operators in the field must conduct the necessary intervention to shift the load to other feeders and bring back the feeder to its normal loading criteria.

The instantaneous element of 10 times the CTR is chosen to protect the CTs from saturation since the ALF of CT is 10. The saturation might occur beyond ALF if the burden is lower than the declared burden, however for safety purpose standard burden is considered.

4.3.2 11 kV Bus Coupler (BC)

As discussed earlier, relay coordination needs to be studied under various operating conditions as follows.

Case A *:BC in OFF position and each transformer feeds Bus A and B separately.*

Case B *:Due to increased load disproportionately in each bus whereby both transformers require to be in service via the BC, to meet the total demand.*

Case C *:Transformer 1 or 2 is taken out of service for maintenance/testing, and entire load is fed by the other Transformer via the BC (Assuming total demand can be catered by single transformer)*

The protection tripping schemes for bus coupler needs to be decided first. Should the 11 kV feeders be coordinated with 11 kV bus Coupler and then to 11 kV incomer or bypass BC and coordinate feeders with respective incomers?

In the former case, when there is a 11 kV fault near to the bus, the feeder trips in about 100 ms. Following a grading margin of 300 ms, 11 kV BC will trip in case the 11 kV feeder CB fails, thereby isolating the other bus from fault. And 11 kV Incomer CB will trip thereafter within 300 ms if the fault persists.

The requirement of bus coupler tripping is to isolate Bus A from Bus B so that feeders on other bus are not affected due to the fault on opposite bus. The function of BC differs with faults on any feeder of a particular bus. For instance, if both 33/11 kV transformers are ON, and a fault strikes on a feeder, BC will function to isolate the other bus from effect of faults only and after given operating time, the incomer CB must trip to clear the faults (assuming feeder CB didn't clear the fault).

But if only one transformer is feeding the entire bus as in Case C, and if there is a fault on other side of the bus, the BC relay will come in protection hierarchical order, hence BC will clear the faults instead of incomer. In this case if there is a fault on Bus A, then incomer will trip directly instead of BC assuming that there is no infeed from other bus. The figure below depicts the above logic through path 1 and 2.

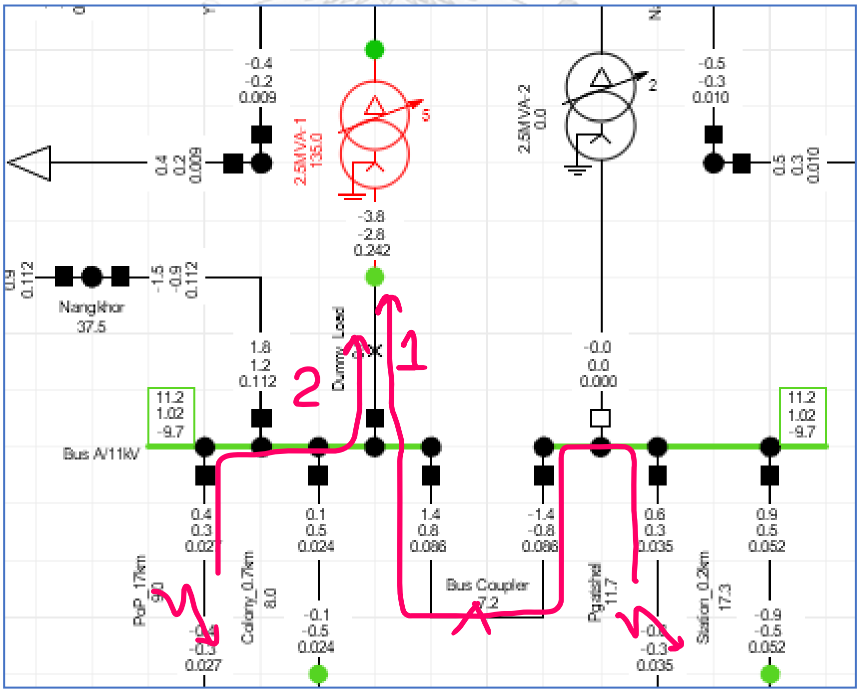


Figure 14 Function of BC based on System Operation Case C

With a CTI of 300 ms between 11 kV feeders and 11 kV bus coupler, in the event of near bus fault (3-phase) in which 11 kV feeder CB fails to clear the fault, the fault current will sustain for about 300 ms before bus coupler clears the fault. The voltage dip will be experienced by feeders of other bus too.

The voltage dip can be avoided by escaping relay coordination with 11 kV BC. Coordinate 11 kV feeders relay with 11 kV incomer relay. In this case, the relay setting of the slowest feeder must be copied to the BC relay. When a feeder trips, the BC also trips almost simultaneously thereby sectionalizing Bus A and B as fast as possible without having to experience the voltage dip by feeders on other bus. The effect of this would be the abrupt isolation of intermittent sources if connected to the system.

So, in such configuration, for any feeder tripping, Bus Coupler is going to trip thereby having to perform additional CB operation during restoration and further bus coupler CB's life will be shortened due to consecutive tripping by all feeders. The duty cycle of 11 kV existing VCB is 15000 operations only.

Further, if one incomer is out of service due to maintenance or faults in the transformer. Then any feeder tripping on Bus B will trip the BC so all feeders will go under blackout in Bus B which is undesirable.

With all the above scenarios, the best practice is to coordinate the BC with feeders and incomers in hierarchy. The bus CB should remain in OFF condition, and it must be operated only with one source. In case two sources and bus CB are desired to operate simultaneously then special settings must be conducted accordingly. Numerical relays should be installed with automatic adaptation of relay setting as per the system configurations as discussed earlier in 'Substation Operation Configurations'.

The relay settings calculations are done distinctively as **Case A & C Settings** and **Case B Settings** to incorporate the above scenario as shown in Tables 12 and 13 respectively.

4.3.3 Relay Setting for HV/LV side of 2.5 MVA, 33/11 kV Transformer.

a) LV Side of 2.5 MVA, 33/11 kV Transformer

The LV side of 33/11 kV, 2,5 MVA Transformer (11 kV Incomer), acts as a backup relay for feeders and bus coupler depending on the bus configuration. With BC and 11 kV feeders downstream and CTI of 300 ms, the 11 kV Incomer relays operates around 700 ms.

In the event of bus fault, 700 ms seems comparatively higher as it is coordinated to function as a backup for feeder protections only. Busbar differential protection may be deployed for busbar protection if felt necessary. Since the source of fault current is the transformer itself, the respective fault currents for relay coordination may be used as per the substation operation configurations.

b) HV Side of 2.5 MVA, 33/11 kV Transformer

The general practice of relay coordination is to time grade it, as per the protection hierarchy. With 11 kV incomer set to operate at 700 ms, the relay at HV side of 2.5 MVA transformer should operate at 1000 ms. If there is a 11 kV feeder fault, in accordance with the time grading, this relay will function as a backup for downstream relays and operate in 1000 ms to clear the fault, if the downstream CB fails to clear the fault due to any reason. While it is very logical and true but what if the fault lies in between HV side of transformer and the CT as indicated in Figure 15. The operating time of 1000 ms is remarkably high.

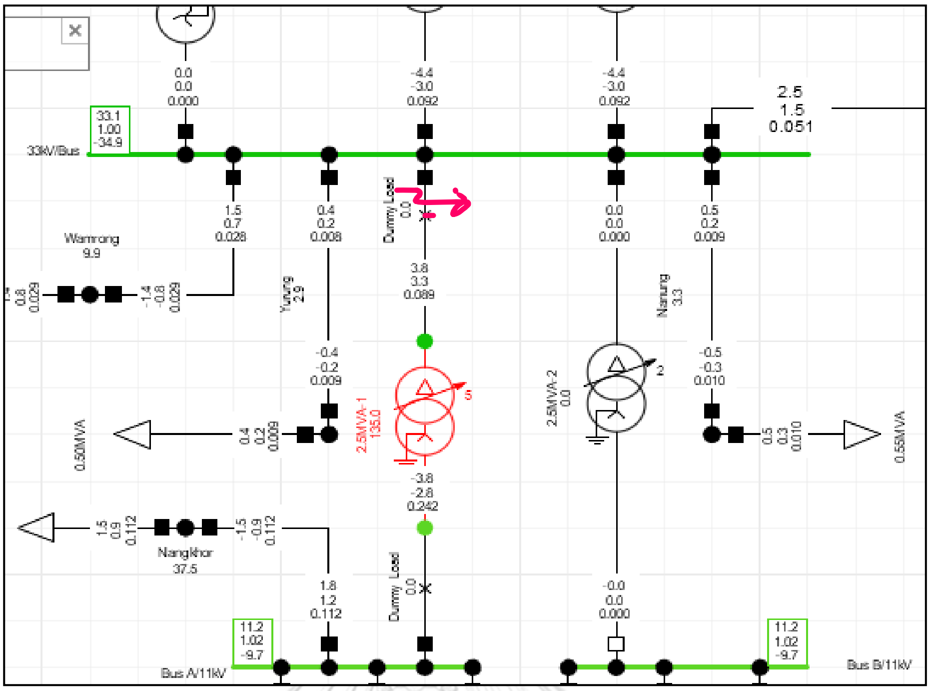


Figure 15 Fault scenario between HV side of transformer and CT

Power transformers must be protected with differential protection and OC relay will be a backup protection for downstream devices. In many lower capacity transformer, differential protection is not used owing to the economic considerations and more over the fault between HV bushing of the transformer and the CT is very rare as in Figure 15, for instance failure of lightening arrestor on HV side of transformer. If both transformers along with bus coupler is put to service, and if there is a fault withing the transformer zone of protection assuming no differential protection, then there will be two source of fault currents viz. 33 kV bus and the other transformer via the bus coupler. CB on HV side of Transformer must trip and 11 kV BC will trip instead of LV side CB due to the relay coordination.

While calculating the pickup setting and TMS there are two fault currents.

i. 3-phase fault on 33 kV Bus which is applicable for fault near CT towards transformers.

ii. Fault due to phase fault on 11 kV bus which will be replicated on HV side of transformer. This fault current will be different from 33 kV bus fault level.

Hence the dilemma. Which fault currents should be considered?

The relay on HV side of transformer acts as a backup for the downstream relays, hence the 11 kV bus fault replicated to the HV side of transformer should be used for relay coordination. While one may argue that we use the 33 kV bus fault level as it is the source of fault current for transformer, however it must be understood that a transformer needs to have differential as the primary protection and the overcurrent relay will be back up relays only.

Any fault within the transformer zone of protection, must be cleared off instantly by the differential relay such that the overcurrent relay will remain as a backup to differential relay and the downstream relays. If in case there is no differential relay, then it is the risk and compromise that protection engineer must take by carrying out the relay setting to the fastest possible settings.

4.3.4 Relay Setting for 33 kV feeders.

Like the 11 kV feeder settings, an operating time of 100 ms may be chosen for feeders. However, if there are substations, ARs, fuses, sectionalizer, etc. downstream of the feeder relay, the relay coordination needs to accommodate those settings. In many cases in Bhutan, there lies an adjacent substation belonging to Distribution Department, which is probably few kilometers away.

For instance, the 33 kV Tsebar Feeder emanates from 33 kV bus of Nangkhor Substation and terminates into 33/11 kV, 5 MVA Substation at Denchi. The distance between then is hardly 2 km.

In this case, the relay setting needs to be done from Denchi Substation. It has feeders, bus coupler, incomer at both 11 kV and 33 kV voltage levels. The time grading should start from 100 ms for feeders with a CTI of 200 ms as the relays are numerical. Thus, an operating time of 1.3 s is allocated to 33 kV Tsebar Feeder at Nangkhor Substation.

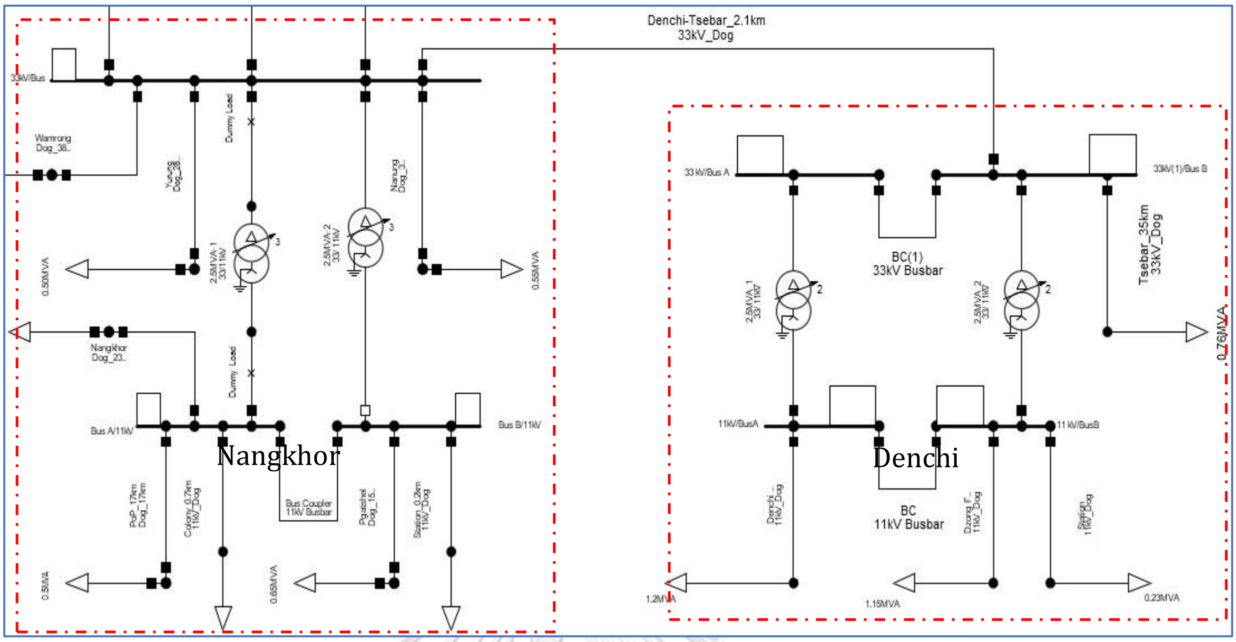


Figure 16 Relay coordination of distribution substation close of transmission substation

4.3.5 Relay Setting for HV/LV side of 5 MVA, 132/33 kV Transformer.

a) LV Side of 5 MVA, 132/33 kV Transformer

Here it is observed that, a pair of 5 MVA, 132/33 kV transformers are connected in parallel with 33 kV bus. There is no bus coupler. The source of 33 kV bus fault current are the two transformers, hence fault current required for calculating the TMS would change in the event of single transformer or both transformers in operation.

Normally, both transformers are put into operation however, due to periodic maintenance either of the transformer can be taken shutdown, so in such case the relay coordination needs to be studied considering the different operation scenario. The automatic change of protection groups in the relay as per the system configurations may be deployed.

The operating time for LV side of transformer (33 kV Incomer) will depend on the 33/11 kV system of Nangkhor as well as Denchi Substation. As per the relay setting of

Nangkhor Substation, the 33 kV incomer is to be time graded to 1.3 s. However, based on 33 kV Tsebar Feeder, the operating time results to 1.6 s.

For relay coordination we must consider the slowest feeder, hence the 33 kV incomer setting for Nangkhor substation would be based on the 33 kV Tsebar feeder which feeds 33/11 kV Denchi Substation. Therefore, the relay operating time for LV side of 5 MVA transformer would be 1.6 s.

This raises the question of much delayed tripping in case if 33 kV bus fault, however as discussed earlier, the bus should be protected through busbar differential as the primary protection and OC relay serves as the backup protection to busbar differential and the downstream relays only.

b) HV Side of 5 MVA, 132/33 kV Transformer

Like what has been discussed in HV side of 2.5 MVA Transformer, here too the selection of fault current comes into consideration viz. the 132 kV bus fault level and the 33 kV bus fault current replicated to the 132 kV side of 5 MVA transformer. For the OC coordination, we need to use the 33 kV bus fault current replicated to 132 kV side of transformer with an operating time of 1.9 s.

Power transformers are usually protected by the transformer differential protection; hence the OC relay acts as the backup for differential protection and the downstream relays. Depending on the substation operation configuration, at maximum fault the OC relay should operate at about 1.9 s to clear the fault which hasn't been cleared by downstream relays or the transformer differential relay. The relay setting with operating time of 1.9 s is well below the transformer damage curve.

Consider a three-phase fault in between HV bushing and the CT, let's assume that differential protection failed due to some technical reasons. Now the responsibility of tripping lies to backup overcurrent relay with its operating time of 1.9 s.

Looking at the 132 kV system, three nos. of 132 kV lines emanates from 132 kV Nangkhor Substation bus and terminates to 132 kV Kurichhu, Deothang and Nganglam Substation. The distance relays at these substation sees fault in Zone 2. The

operating time of Zone 2 is 350 ms which is much faster than the overcurrent relay. But this would lead to substation blackout and such incidents must be avoided. Nonetheless, coordination must be done between Zone 2 settings. However, operation of differential protection must be always reliable.

4.3.6 Relay Coordination Chart

With all the details explained, the relay coordination chart is prepared for two cases as **'Case A & C'** and **'Case B'.** 11 kV Feeders are coordinated with BC, followed by Incomer and HV side of 33/11 kV Transformers. Similarly, 33 kV Feeders are coordinated with 33 kV Incomer, followed by HV side of 132/33 kV Transformers. CTI of 300 ms is used.

11 kV Feeder relays doesn't have instantaneous element. Yet then, the possibility of CT saturation is foreseen, hence instantaneous elements are proposed for 11 kV feeders.

It is to be noted that for feeders having lesser load, CT with lower capacity suffices the requirement. However, the PSM due to the fault current is far beyond the ALF of CT, thus necessitating the use of full ratio. Hence, it is recommended to use full CT ratio as given below. The calculations are as follows for Case A.

Feeder

3-Phase Bus fault current (Simulation Result)	: 1569.9 A
Voltage (L-L)	: 11 kV
Full Load	: 0.65MVA
Full load Current Primary (Full Load/√3×11)	: 34.12 A
Pickup Current Setting Tolerance	: 10%
Pickup Current, Primary (I_P)	: 37.53 A
CT Ratio Available	: 100-50/5 A
CT Ratio Selected	: 50/5 A
CT Secondary	: 5A
Pickup Current, Secondary [I_P×(CT_{sec}/ CT_{pri})]	: 3.75 A

Plug Setting Chosen	: 3.75A
Actual Tolerance	: 9.92%
PSM= (Fault Current/(CTRx Pickup current))	: 41.86
Desired operating Time(t_q= 0.1)	: 0.1 s
TMS=[(t_q*[(PSM)$^{0.02}$-1]/0.14]x2.31 for 1.3sec SI Curve	: 0.13

The selection of lower CT ratio as per the calculated setting results in PSM of 41.86. CT has an ALF of 10, hence during the faults, CT is bound to saturate at standard burden. Therefore, it is recommended to use full CT ratio of 100/5 A, thus lowering the possibility of CT saturation. In the above case CT ratio of 100/5 A with 5 A pickup setting is recommended.

Table 12 Overcurrent relay coordination excel template for Case A & C

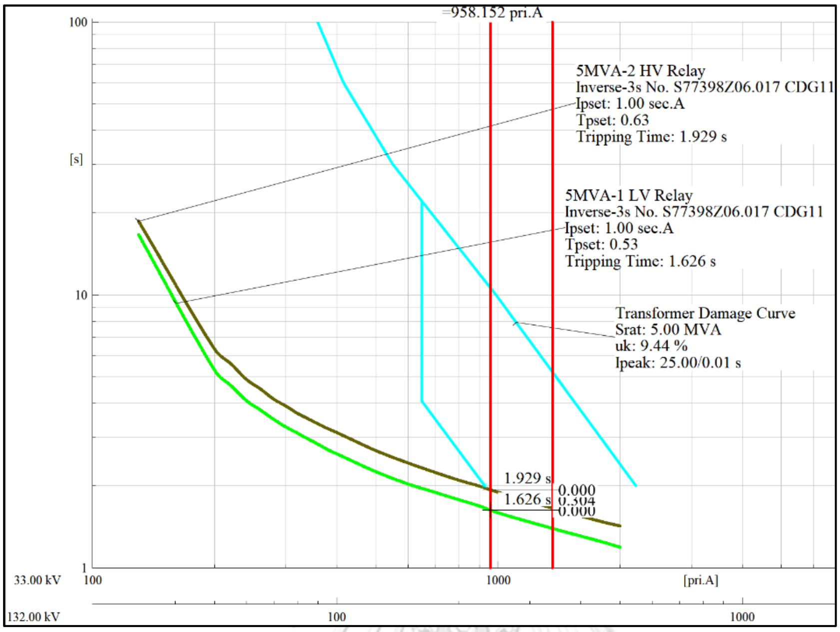
Case A&C:- Overcurrent Relay Setting Calculation Work Sheet for 132/33/11 kV Nangkhor Substation, Pemagatshel									
Sl. #	**Relay Setting Parameters**	**11 kV**			**33 kV**				**132 kV**
		Feeders	**Bus Coupler**	**2.5MVA LV Side**	**2.5MVA, HV side**	**Feeders**	**Tsebar Fdr.**	**5MVA, LV side**	**5MVA, HV side**
1	3-Phase Bus fault current, A	1569.90	1569.90	1569.90	523.30	1894.29	1894.29	947.14	236.79
2	Voltage (L-L), kV	11.00	11.00	11.00	33.00	33.00	33.00	33.00	132.00
3	Full Load, MVA	1.91	2.50	2.50	2.50	1.72	5.00	5.00	5.00
4	Full load Current Primary, A	99.99	131.22	131.22	43.74	30.01	87.48	87.48	21.87
5	Pickup Current Setting Tolerance	10%	10%	10%	10%	10%	10%	10%	10%
6	Pickup Current (Primary), A	109.99	144.34	144.34	48.11	33.01	96.23	96.23	24.06
7	CT Ratio Available, A/A	(100-50)/5	(150-75)/5	(150-75)/5	(50-25)/1	(30-15)/1	(150)/1	(100-50)/1	(50-25)/1
8	Selected CT Ratio Primary, A	100.00	150.00	150.00	50.00	30.00	150.00	100.00	25.00
9	CT Secondary , A	5.00	5.00	5.00	1.00	1.00	1.00	1.00	1.00
10	Pickup Current (Secondary), A	5.50	4.81	4.81	0.96	1.10	0.64	0.96	0.96
11	Plug Setting Chosen, A	5.00	5.00	5.00	1.00	1.10	0.64	1.00	1.00
12	Actual Tolerance	0.01%	14.31%	14.31%	14.31%	10.00%	9.74%	14.31%	14.31%
13	PSM= (Fault Current/(CTR x Pickup current))	15.70	10.47	10.47	10.47	57.39	19.73	9.47	9.47
14	Desired operating Time(tq= 0.1s),	0.10	0.40	0.70	1.00	0.10	1.30	1.60	1.90
15	TMS=[(tq*[(PSM)0.02-1]/0.14] for 3.0s curve or multiply by 2.31 for 1.3s SI Curve	0.09	0.32	0.55	0.34	0.06	0.57	0.53	0.62
16	Adopted TMS	0.10	0.32	0.55	0.34	0.06	0.57	0.53	0.62
17	Actual Operating Time (s)	0.11	0.40	0.70	1.00	0.10	1.30	1.60	1.90
18	High Set element, DT (50), A	5.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
19	Operating time for Highset, DT, (s)	0.10	0.40	0.70	1.00	0.10	1.30	1.60	1.90

Table 13 Overcurrent relay coordination excel template for Case B

Case B:- Overcurrent Relay Setting Calculation Work Sheet for 132/33/11 kV Nangkhor Substation, Pemagatshel									
Sl. #	**Relay Setting Parameters**	**11 kV**			**33 kV**				**132 kV**
		Feeders	**Bus Coupler**	**2.5MVA, LV side**	**2.5MVA, HV side**	**Feeders**	**Tsebar Fdr.**	**5MVA, LV side**	**5MVA, HV side**
1	3-Phase Bus fault current, A	2461.2	1230.6	1230.6	410.2	1894.3	1894.3	947.1	236.8
2	Voltage (L-L), kV	11.0	11.0	11.0	33.0	33.0	33.0	33.0	132.0
3	Full Load, MVA	1.905	2.500	2.500	2.500	1.715	5.000	5.000	5.000
4	Full load Current Primary, A	99.99	131.22	131.22	43.74	30.01	87.48	87.48	21.87
5	Pickup Current Setting Tolerance	10%	10%	10%	10%	10%	10%	10%	10%
6	Pickup Current (Primary), A	109.99	144.34	144.34	48.11	33.01	96.23	96.23	24.06
7	CT Ratio Available, A/A	(100-50)/5	(150-75)/5	(150-75)/5	(50-25)/1	(30-15)/1	(150)/1	(100-50)/1	(50-25)/1
8	Selected CT Ratio Primary, A	100.00	150.00	150.00	50.00	30.00	150.00	100.00	25.00
9	CT Secondary , A	5.0	5.0	5.0	1.0	1.0	1.0	1.0	1.0
10	Pickup Current (Secondary), A	5.50	4.81	4.81	0.96	1.10	0.64	0.96	0.96
11	Plug Setting Chosen, A	5.00	5.00	5.00	1.00	1.10	0.64	1.00	1.00
12	Actual Tolerance	0.01%	14.31%	14.31%	14.31%	10.00%	9.74%	14.31%	14.31%
13	PSM= (Fault Current/(CTRx Pickup current))	24.61	8.20	8.20	8.20	57.39	19.73	9.47	9.47
14	Desired operating Time(tq= 0.1s),	0.1	0.4	0.7	1.0	0.1	1.3	1.6	1.9
15	TMS=[(tq*[(PSM)0.02-1]/0.14] for 3.0sec curve or multiply by 2.31 for 1.3sec SI Curve	0.11	0.28	0.50	0.31	0.06	0.57	0.53	0.62
16	Adopted TMS	0.11	0.28	0.50	0.31	0.06	0.57	0.53	0.62
17	Actual Operating Time (s)	0.101	0.400	0.700	1.000	0.100	1.300	1.600	1.900
18	High Set element, DT (50), A	50.00	50.00	50.00	10.00	10.00	10.00	10.00	10.00
19	Operating time for Highset, DT, S	0.1	0.4	0.7	1	0.1	1.3	1.6	1.9

4.3.7 Graphical Analysis [DIgSILENT] of Results

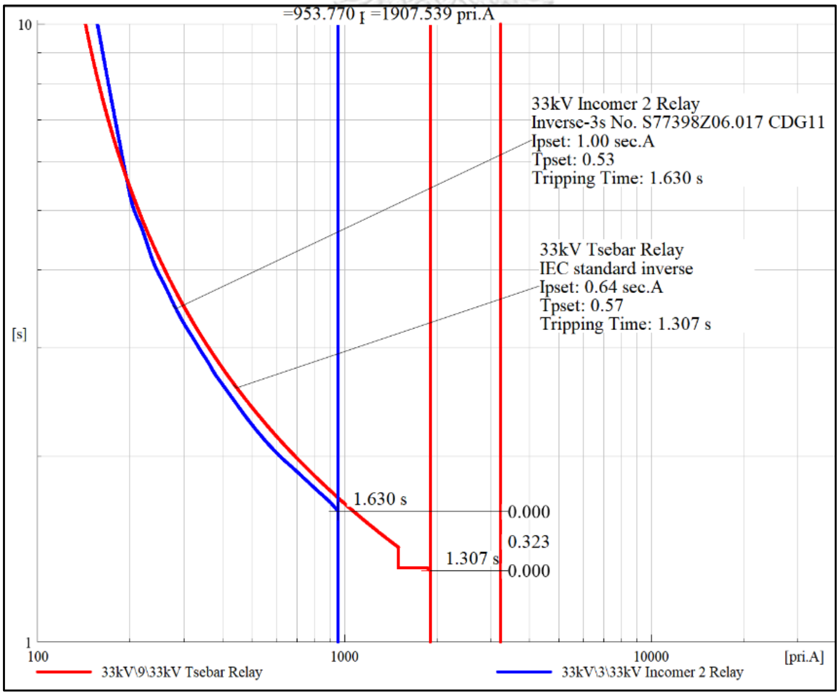
a) HV and LV Side of 5 MVA, 132/33 kV Transformer OC Coordination



The simulations were conducted for 3-phase short circuit fault on 33 kV bus and graphical analysis showed a grading margin on 304 ms between HV and LV side of transformer.

Figure 17 OC Relay Coordination (HV &LV side of 5MVA Txr)

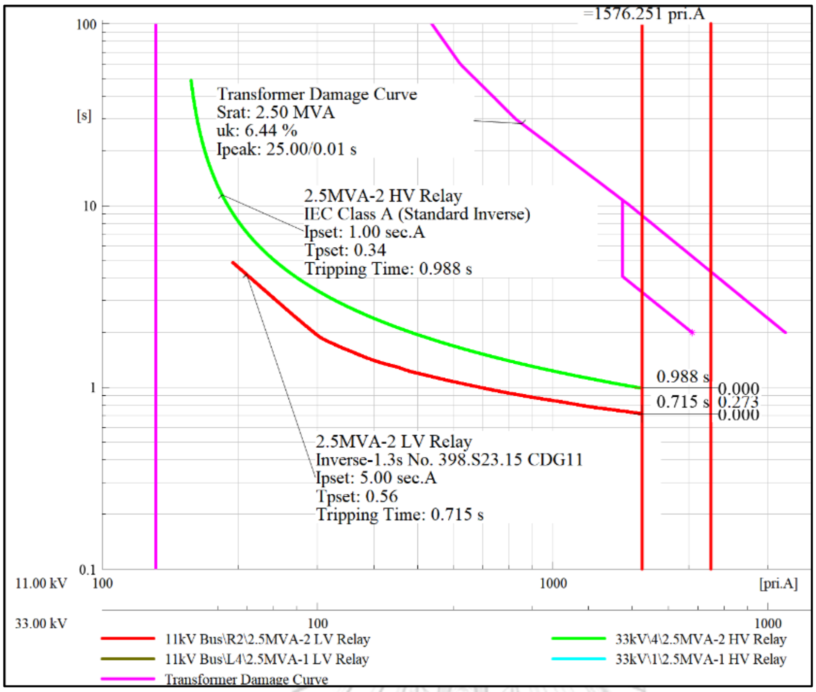
b) Coordination of slowest 33 kV Feeder with 33 kV Incomer



Three phase short circuit fault was simulated on slowest feeder and the graphical analysis showed a grading margin of 323 ms with the Incomer.

Figure 18 Coordination of slowest 33 kV Feeder with 33 kV Incomer

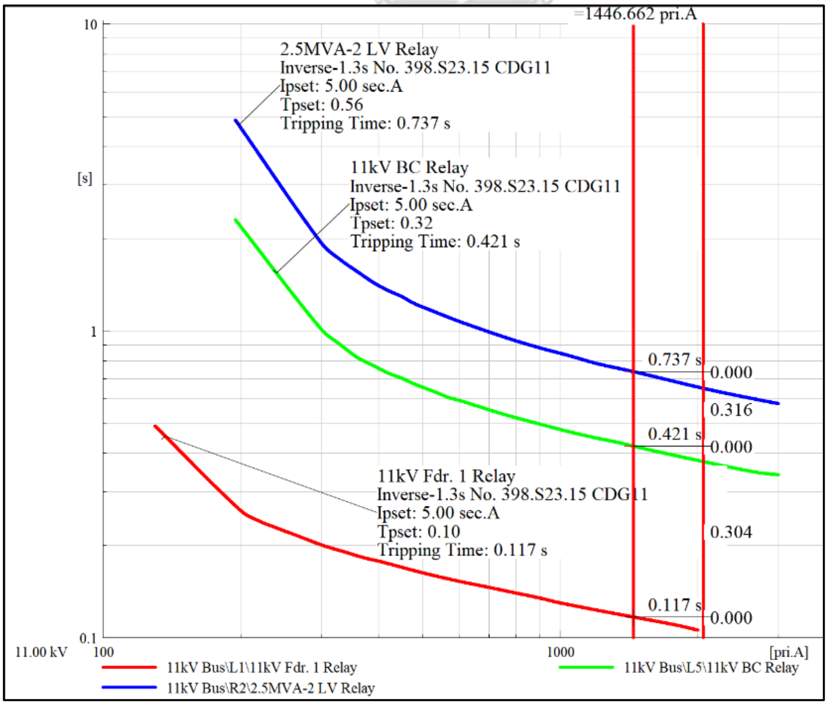
c) Case A -HV and LV Side of 2.5 MVA, 33/11 kV Transformer OC Coordination



Three phase short circuit fault on 11 kV bus fault was simulated with BC in OFF position, and the grading margin observed is 273 ms between the HV and LV side of transformer.

Figure 19 Coordination of HV and LV side of 2.5 MVA, 33/11 kV Transformer

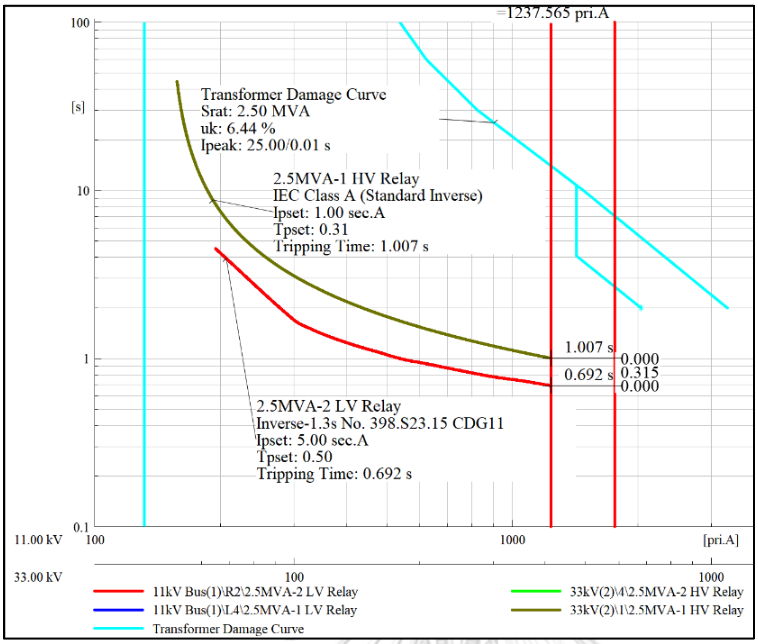
d) Case C -OC Coordination for 11 kV Feeder, 11 kV BC and 11kV Incomer



Three phase short circuit fault was applied on the feeder, and the grading margin observed between feeder and BC is 304 ms and 316 ms between BC and the 11 kV Incomer.

Figure 20 Coordination of Feeder, BC and Incomer

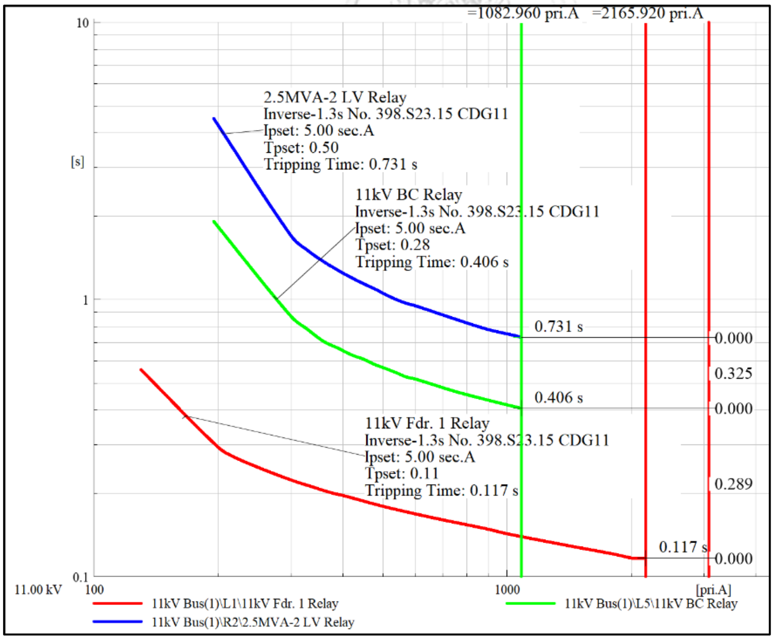
e) Case B- HV and LV Side of 2.5 MVA, 33/11 kV Transformer OC Coordination



Three phase short circuit bus fault was applied with both Incomers and BC in closed position and the grading margin observed is 315 ms.

Figure 21 Coordination of HV and LV side of 2.5 MVA, 33/11 kV Transformer

f) Case B-OC Coordination for 11 kV Feeder, 11 kV BC and 11 kV Incomer



Three phase short circuit fault was applied on the feeder, and the grading margin observed between feeder and BC is 289 ms and 325 ms between BC and the 11 kV Incomer.

Figure 22 Coordination of Feeder, BC and Incomer

Thus, the above results proves that the relay coordination never loses its coordination time interval for any faults hence the results are satisfactory.

Existing Settings and miscoordination observed for 132/33/11 kV Nangkhor Substation

g) HV and LV Side of 5 MVA, 132/33 kV Transformer OC Coordination

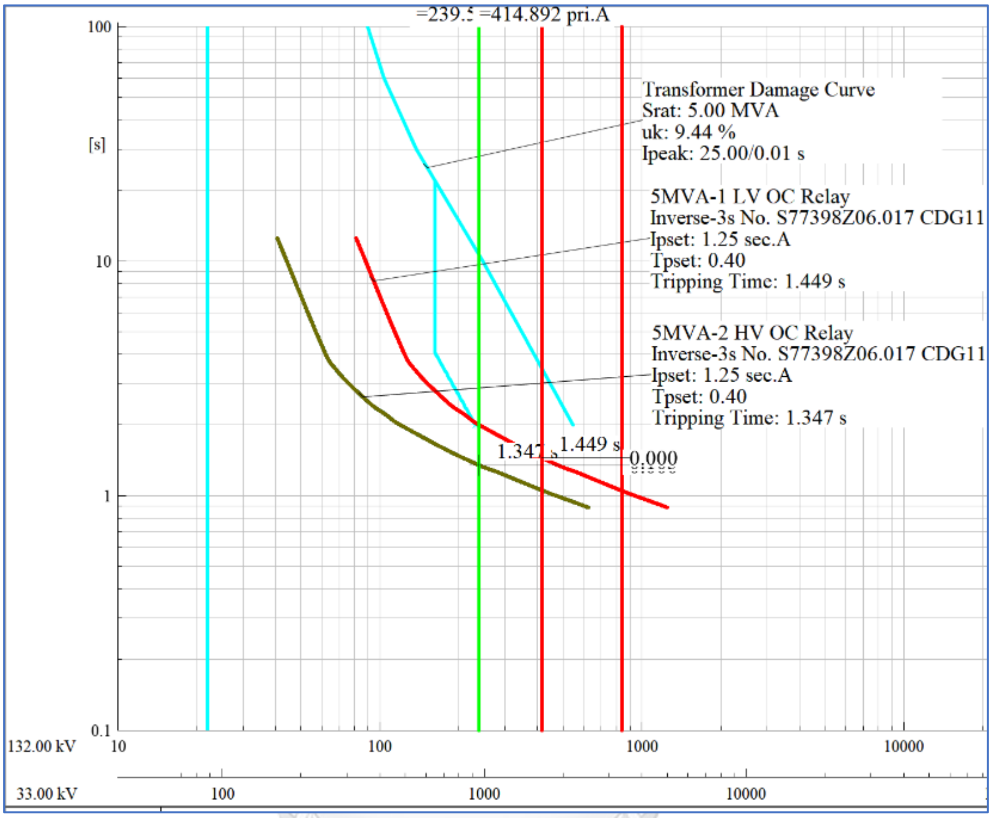


Figure 23 Existing Setting miscoordination between HV & LV side of 5 MVA transformer

A three-phase unbalanced short circuit fault was simulated in the 33 kV bus, and it is observed that HV side of transformer trips faster than the LV side by 102 ms. The LV side of Transformer relay curve intersects with the transformer damage curve for frequent faults. This event if triggered will impart a permanent damage to the transformer hence it must be avoided.

h) Coordination of 33 kV Feeder with 33 kV Incomer

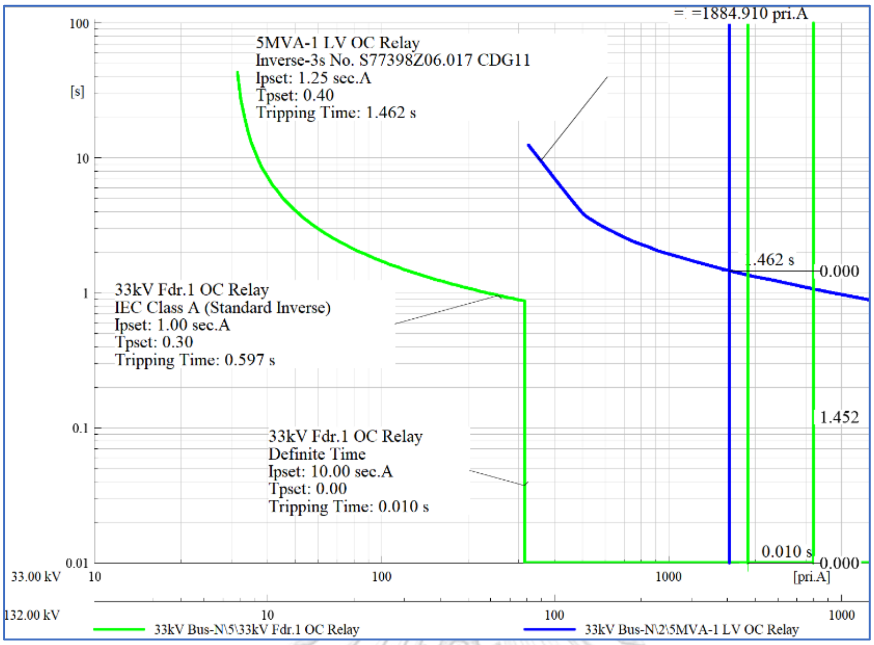


Figure 24 Existing setting miscoordination between 33 kV feeders and its incomer

The graph depicts that for a 3-phase short circuit fault on the feeder, the CTI observed between feeder and incomer relay with DT is 1452 ms, which is too high given that all the 33 kV feeders are set with the same setting hence no fastest or slowest feeder. Even without DT on feeder, the CTI is 865 ms, this indicating lack of proper coordination.

i) Case A -HV and LV Side of 2.5 MVA, 33/11 kV Transformer OC Coordination

In Figure 25, the CTI between the HV and LV side of transformer is observed to be 360 ms without DT element on the HV side of transformer. With DT element, the CTI is 1239 ms. While the CTI is satisfactory but then the instantaneous element of HV side trips the HV side of transformer when the fault current crosses 787.5 A. Therefore, miscoordination can occurs therefore, high set coordination needs to be checked.

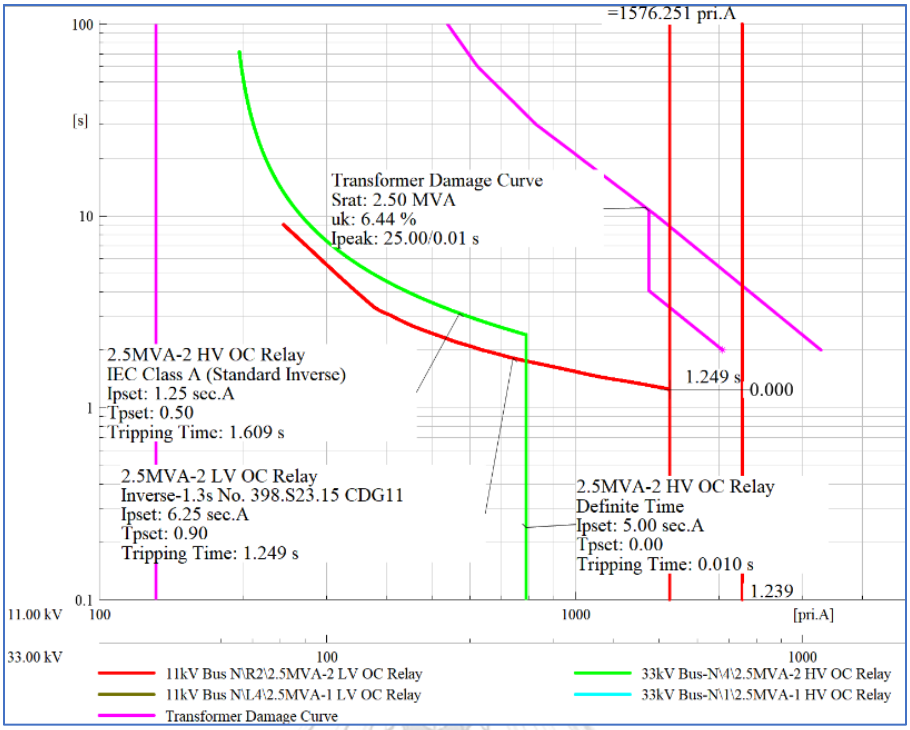


Figure 25 Existing miscoordination between HV & LV V side of 2.5MVA Transformer

j) Case B- HV and LV Side of 2.5 MVA, 33/11 kV Transformer OC Coordination

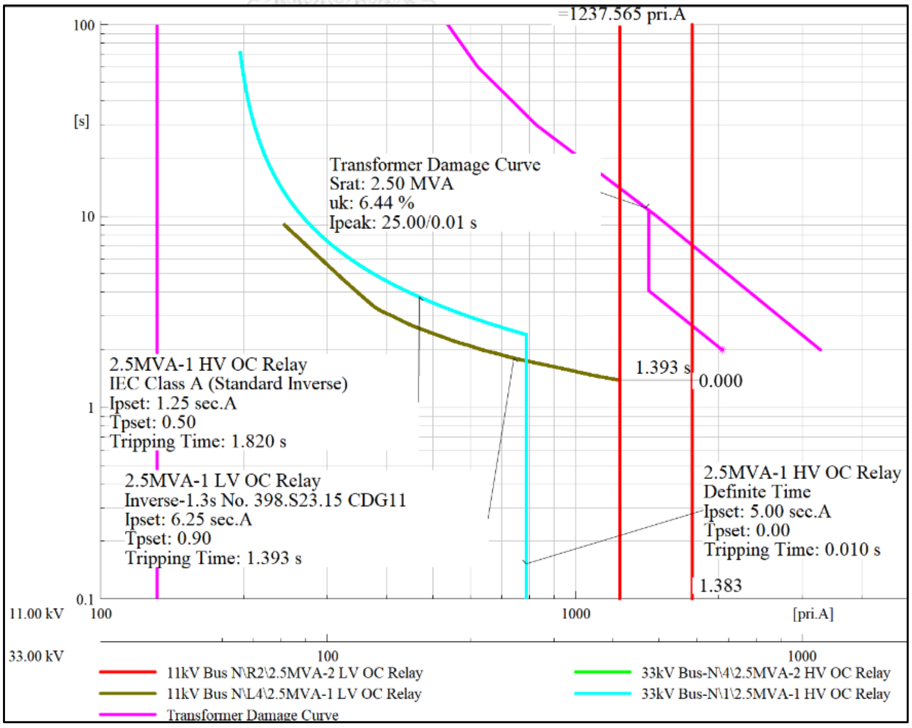


Figure 26 Case B- HV and LV Side of 2.5 MVA, 33/11 kV Transformer OC Coordination

For Case B where both transformers and BC are in service, the CTI observed between HV and LV side of transformer neglecting DT on HV side is 427 ms, while with inclusion of DT, the CTI is 1383 ms. Therefore, high set element coordination is required.

k) Case B-OC Coordination for 11 kV Feeder, 11 kV BC and 11 kV Incomer

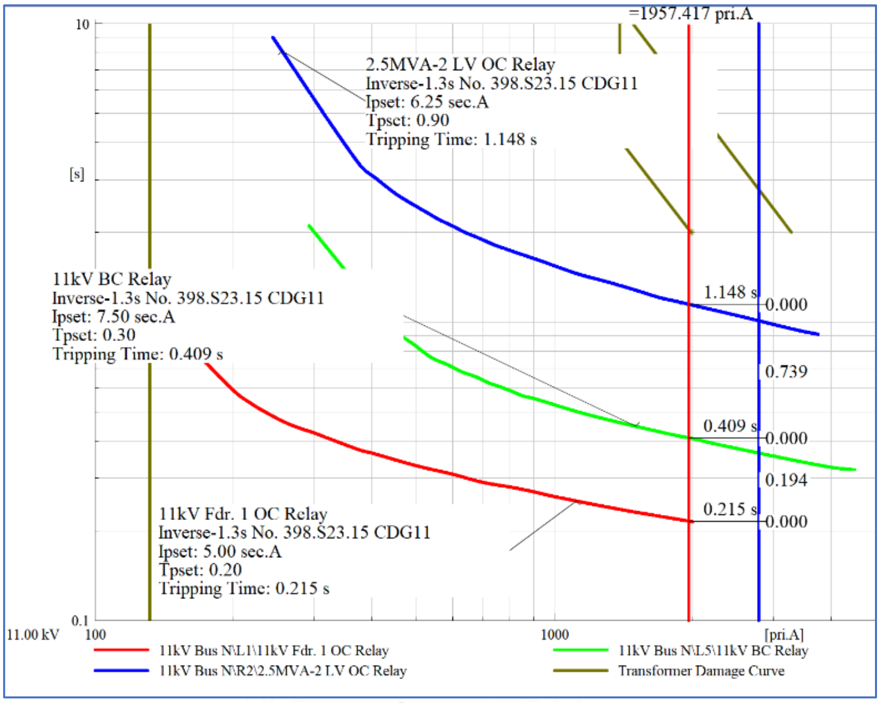


Figure 27 Case B-OC Coordination for Feeder, BC and Incomer

As can be seen from the Figure 27, the integrity of CTI is lost. The CTI observed between BC and the Incomer is 739 ms while it is 194 ms between the feeder and the BC. If the BC fails to clear the persisting fault on 11 kV feeder, then there is a substantial delay in tripping by the incomer relay.

l) Case C: OC Coordination of 11 kV System

Here too, the CT loses its integrity. The CT between BC and the incomer is 922 ms while it is 272 ms between feeder and BC. There exists substantial delay in fault clearing time by the incomer relay.

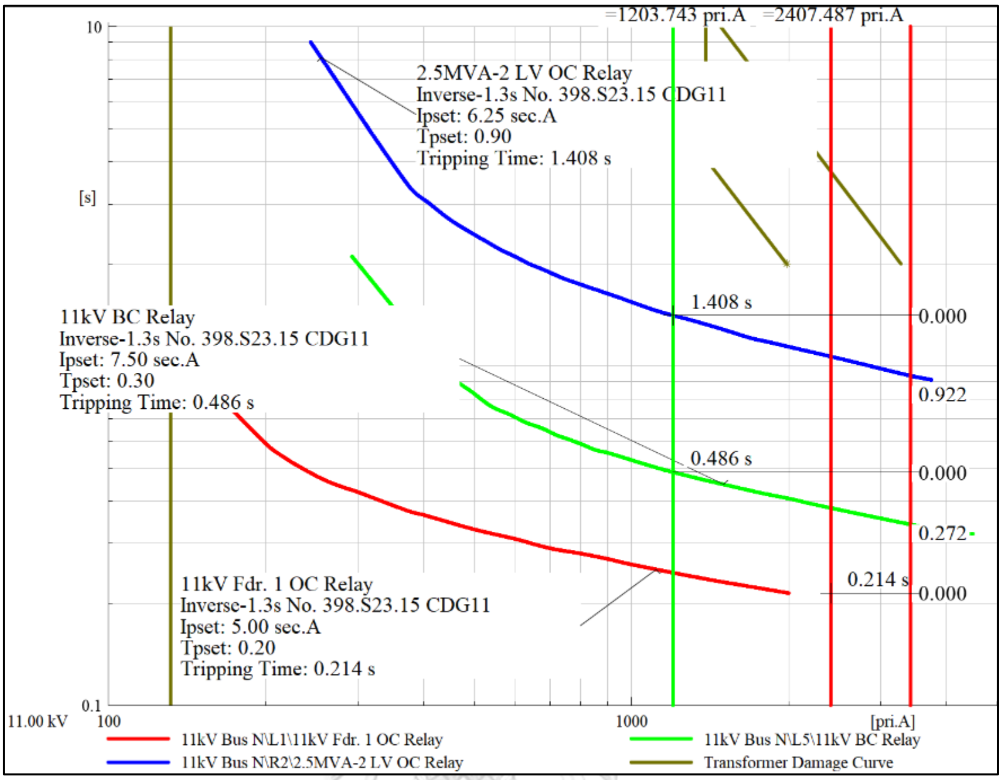


Figure 28 Case C: OC Coordination of 11 kV System

4.4 Amendments recommended in BPC Relay Setting Guidelines

2.0 Setting of Transformer Protection Relays		
2.2 Overcurrent and Earth Fault Setting		
Clause	BPC Version	Proposal
2.2.1.2	For 220kV and above transformers, the thermal overload function inbuilt in the differential relay shall be enabled. For other transformers, the thermal overload element shall be enabled based on the anticipated loading.	The thermal overload setting if available shall be enabled for all transformers with 150% pickup setting for 30 minutes, else set to 110% continuous loading.
2.2.2.1	The pickup setting for the stage 1 (IDMT) overcurrent protection (I>) shall be set at 150% of the full load current of the transformer as per the sample setting calculation shown below.......	The overcurrent pickup setting shall be 110% of full load. The thermal overload setting if available shall be enabled for all transformers with 150% pickup setting for 30 minutes.
2.2.2.2	TMS of the overcurrent relay for transformer shall be calculated using the transformer name plate details. [Using transformer short circuit level as fault current with 1.5s fault clearing time]	TMS of the overcurrent relay for transformer shall be with a CTI/grading margin of 300 ms upstream and downstream relay if electromechanical relay else 200 ms for numerical relays. However, if total relay coordination time permits, 300 ms grading margin may be used for numerical relay also.
		The maximum fault level on LV side shall be considered for OC relay coordination of transformer. While the maximum fault on HV side might be different, it is assumed that differential relay will cater to the need.
2.2.2.5	The characteristic curve of highset element shall be instantaneous or definite time (DT). The time delay of the highset setting on LV side of transformer shall be set 50 milliseconds higher than the LV side relay. 50milliseconds higher than the bus coupler relay and that on the HV side shall be set.	A CTI/grading margin of 300 ms shall be followed for DT relay coordination. Inrush current phenomenon in transformer and CT saturation must be taken care while setting the Instantaneous relay.

3.0 Setting of Distribution Feeder Protection Relays		
3.1 Overcurrent and Earth Fault Protection Relays		
Clause	BPC Version	Proposal
3.1.1.4	For proper coordination, the characteristics curve of all the outgoing 33 kV and 11 kV feeders shall be set to Very Inverse (VI). The upstream HV feeders including transformers shall be set to Normal Inverse (NI).	For the optimal coordination of the distribution feeders, suitable curve shall be selected as per the protection devices available downstream. If no protection devices are available downstream, it is recommended to use similar curve for upstream and downstream relay.
3.1.2.1	The pickup setting for the stage 1 (IDMT) overcurrent protection for 33 kV and 11 kV distribution feeders (I>) shall be set at 150% of the full load current of the feeder or 100% of the full connected CT ratio.	The pickup setting for the stage 1 (IDMT) overcurrent protection for 33 kV and 11 kV distribution feeders (I>) shall be the minimum ampacity of Cables/Conductors or CT whichever is lower with 10% tolerance.
3.1.2.2	TMS of 11 kV feeder protection relays shall be set at 0.20 and TMS for 33 kV feeder protection relays shall be set at 0.30 for proper coordination with downstream protective devices in the distribution feeder.	TMS of feeder protection relays shall be determined by the anticipated fault clearing time. For a feeder without any protective device downstream, the fault clearing time shall be 100 ms. For those feeders having protection devices downstream, the fault clearing time shall be graded as per the protection hierarchy. The grading margin/ CTI shall be 300 ms for electromechanical relays and 200 ms for numerical relays.
3.1.2.3	The first stage (High-set) overcurrent protection (I>>) shall be set at 500% of the full load current of the feeder or the full connected CT ratio.	The first stage (High-set) overcurrent protection (I>>) shall be set at 500% of the connected CT ratio or CT saturation may be considered.
3.1.2.4	The highset element shall have instantaneous or definite time (DT) characteristic curve. The DT delay shall be set to 100 milliseconds. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.	The highset element shall have instantaneous or definite time (DT) characteristic curve. In case of DT, time delay shall be set to 100 ms for lowest protected feeder as per 3.1.2.2. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay. DT shall be coordinated with upstream relays with grading margin as given in 3.1.2.2. In case of instantaneous relay, the inrush current imposed by distribution transformer on the feeder and the CT saturation current should be considered.

4.0 Setting of Bus Coupler/Busbar Relays		
4.1 Overcurrent and Earth Fault Protection Relays		
Clause	BPC Version	Proposal
4.1.1.2	The characteristic curve of bus coupler overcurrent and earthfault relays in distribution systems shall be set to Very Inverse (VI). For HV systems, it shall be set to Normal Inverse (NI).	The characteristic curve of bus coupler overcurrent and earthfault relays in distribution systems shall be set to Standard Inverse (SI)
4.1.2.1	The pickup setting of bus coupler overcurrent relay shall be set to 100% of the full connected CT ratio or 150% of the maximum current flow possible through it when all the incomers are in service.	The pickup setting of bus coupler overcurrent relay shall be set to 110% of the full connected CT ratio and thermal overload setting shall be 150% in coordination with one of the feeding transformers. Auto activation of group setting may be enabled to cater to the change in fault level as a result of single or dual transformer feeding the bus.
4.1.2.2	TMS of bus coupler overcurrent relay shall be set higher than the downstream feeders but lower than the LV side of transformers.	The TMS setting of bus coupler shall be as per the CTI/grading margin viz. 300 ms for electromechanical relays and 200 ms for numerical relays.
4.1.2.3	The first stage (High-set) overcurrent protection (I>>) shall be set at 500% of the full connected CT ratio or 150% of the maximum current flow possible through it when all the incomers are in service.	The first stage (High-set) overcurrent protection (I>>) shall be set at 500% of the full connected CT ratio and shall be coordinated with upstream and downstream highset element with CTI. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay. If instantaneous element is activated the inrush current and CT saturation must be considered for adopting its setting.
4.1.2.4	The highset element shall be set with instantaneous or definite time (DT) characteristic curve. The DT delay shall be set 50 milliseconds higher than the downstream feeder relays. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.	
4.1.2.5	The other highset stages shall be kept disabled, however if required the second stage highset overcurrent setting shall be set at least 1,000% of the full connected CT ratio or 1,000% of the maximum current flow possible through it when all the incomers are in service. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.	The other highset stages shall be kept disabled, however if required the second stage highset overcurrent setting shall be set at least 1,000% of the full connected CT ratio. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.

4.5 Recommendations for overcurrent setting and coordination.

a) Conduct the load flow and short circuit studies of Bhutanese Power System in conjunction with Indian grid as given in earlier Chapter 2, through software preferably a common for protection coordination study as well. Update the database as and when necessary.

b) Prepare a single line diagram (SLD) of the substation in protection coordination software such as DIgSILENT, CAPE, etc.

c) Simulate '3-phase to ground fault' to obtain maximum fault current values. 3-phase short circuit fault shall be used for overcurrent coordination .

d) Find out if there are fuses/AR/substations to be coordinated downstream of feeders. Start the relay coordination from the lowest protective device.

e) Select the IEC/ANSI standard curves such as NI, VI, EI or LTI. It is recommended to use SI curve in general for downstream and upstream relays. Mixing of curves complicates the analysis however if mixing is used, detailed analysis should be conducted thoroughly for all case scenarios.

f) As a general practice, operating time of minimum of 100 ms is set for lowest protection device in protection hierarchy, while 2000 ms may be used for topmost protection device. The selection of operating time range must be always below the equipment damage curve (I^2t).

g) A minimum coordination time interval (CTI) or grading margin of 300 ms should be ensured between each protection hierarchy for electromechanical relays. While 200 ms can be used for numerical relays. Optimization of the CTI must be done to ensure adequate protection for all protection hierarchy; hence the CTI may vary to accommodate within its specified range defined in clause 'f'.

h) For coordination purpose, we assume the fault near the CT of respective feeders which is equivalent to the bus fault. Any faults away from bus will be lesser, hence the coordination ensures maximum protection.

i) The pickup setting of the feeders should be defined by the rating of CT or cables/conductors, etc., whichever is lower. In the event the total demand exceeds the rating of equipment, upgradation should be proposed.

j) The substation operation configurations need to be standardized especially in the usage of bus coupler BC). When BC is 'OFF', respective transformers supply the fault currents to its respective buses and feeders. On the contrary, when BC is put 'ON' all transformers connected supplies the fault currents.

   Therefore, the operation of BC results in different fault currents which needs to be considered while doing the relay coordination. Relay coordination should be calculated for the above cases and settings done as per the substation operation configurations.

   In case of electromechanical relays, manual setting may be required. For numerical relays, the settings of different scenarios should be saved in various group setting (1,2,3,4, etc.) and it may be enabled or disabled as per the operating conditions.

k) Irrespective of the clause j, the feeders must be coordinated with BC which in turn be coordinated to the upstream incomer for the bus.

l) If there are distributed generations like wind and solar downstream of the relay, ensure the time delay effect of BC is below the LVRT (low voltage ride through) of the distributed generation. Therefore, settings of BC must be done adequately taking into all the above case scenarios.

m) The setting of the OC relays on either side of transformers should be done as per the maximum fault that is possible on LV side. The HV side OC relay should be coordinated with LV side relay at a replicated fault of LV on HV side, even though the fault current on HV side will be much greater due to the upstream sources. If any fault occurs in between HV bushing and the CT, differential relays must clear the fault and OC relay remains as backup only.

n) If there is a feeder emanating from substation and connects to distribution substation. The relay coordination should begin from distribution substation. The

time multiplier setting (TMS) of the feeder will depend on the CTI of the distribution substation.

Similarly, the operating time of upstream relay on transmission substation will depend on the maximum operating time of either the feeders with distribution substation or any feeders in transmission substation with adequate CTI.

In any case the operating time limit must not be violated and if violation occurs, necessary adjustment of CTI must be done to ensure the operating time is within its specified range. *Violation of operating time limit posse serious risk to the equipment.*

o) In case of two transformers being connected to bus without BC, relay coordination studies must be done with single transformer as well as both transformers. The fault on LV bus will be different in case if any transformer is taken out of service. hence settings may be applied accordingly.

p) The pickup setting of transformer may be kept at 100% of its rated current while 150% with a time delay of 30minutes may be enabled in thermal overload features. The overloading of transformer should always be always under the transformer damage curve.

If in case the anticipated loading due to emergency arises, the time delay duration may be increased if the loading is below 150% or the loading % can be increased while decreasing the time delay simultaneously.

q) The high set element 50, must be coordinated similarly with appropriate CTI. The setting of 50 maybe done with the equipment fault level or the system fault level whichever is lower.

5 EARTH FAULT PROTECTION AND RELAY COORDINATION

5.1 Earth Fault Relay Setting

The fault current is classified as positive sequence, negative sequence, and zero-sequence currents. During normal conditions where all phase currents are equal and displaced by 120°, only positive sequence currents occur. However, 100% balanced load are practically impossible, hence it results into negative and zero-sequence components. Unlike the positive sequence current, negative sequence has the rotation opposite the that of the power system.

The Earth Fault relay works based on the zero-sequence currents. According to Kirchhoff's Current Law, the total current entering a junction, or a node is equal to the current leaving the node. The unbalance currents from phase A, B and C when connected to a common point result into residual current or zero-sequence current. The Earth Fault relay is connected to the residual path as shown in Figure 29.

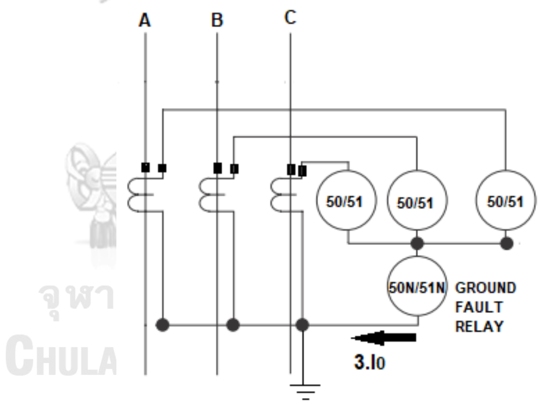


Figure 29 Residual Connection of Earth Fault Relay

(Image taken from https://www.electricaltopics.info/2021/03/basic-of-ground-overcurrent-protection.html)

Unlike Overcurrent Relay, where the pickup current is set above the maximum load current, pickup setting for ground fault relay must be above the maximum anticipated zero-sequence unbalance current of the feeder. If even the load is well balanced, however due to switching actions, zero-sequence current will arise, thus

pickup setting must be from 25% to 50% of the phase relay pickup current as per IEEE Std C37.230-2007 [18].

For the relay setting calculation, maximum fault currents from Single Line to Ground (SLG) fault must be considered. Like overcurrent relay coordination, the Coordination Time Interval of 300 ms and 200 ms is also followed for electromechanical and numerical relays respectively for Earth Fault relay.

The types of relay characteristics as discussed in Chapter 3.1 holds true for Earth Fault relay. For electromechanical relays, the relay characteristics curves are almost constant for overcurrent and Earth Fault relay while in numerical relays, user has the options to select curves for overcurrent and Earth Fault as desired.

Since the Earth Fault relays operates based on zero-sequence currents, hence the vector group of transformer plays a significant role in deciding the settings of the relay. If the transformer is delta-star, any single line to ground fault on star side and downstream will result into zero-sequence current, however since HV is delta, zero-sequence current will not be detected. The fault current distribution in transformers is depicted [17] by the Figure 30.

A phase-to-earth fault on star side is seen as phase-to-phase fault on delta side and the current sensed by the relays on delta side is equal to $1/\sqrt{3}$ times the current on star side.

A phase-to-phase fault on star side is seen as three phase faults on delta side. The current in star winding is equal to $\sqrt{3}/2$ times the current that flows on delta side on the phase with highest current value. As seen from the Figure 30, the current distributes on delta in the ratio of 1:1:2 and 0:1:1 in star side. For a three-phase fault on star side, the current is proportional in all phases.

In the above cases it is observed that ground fault on star side results in zero-sequence current on star side while on delta, zero-sequence is not detected. So, overcurrent relay may be used to protect the Earth Fault on secondary.

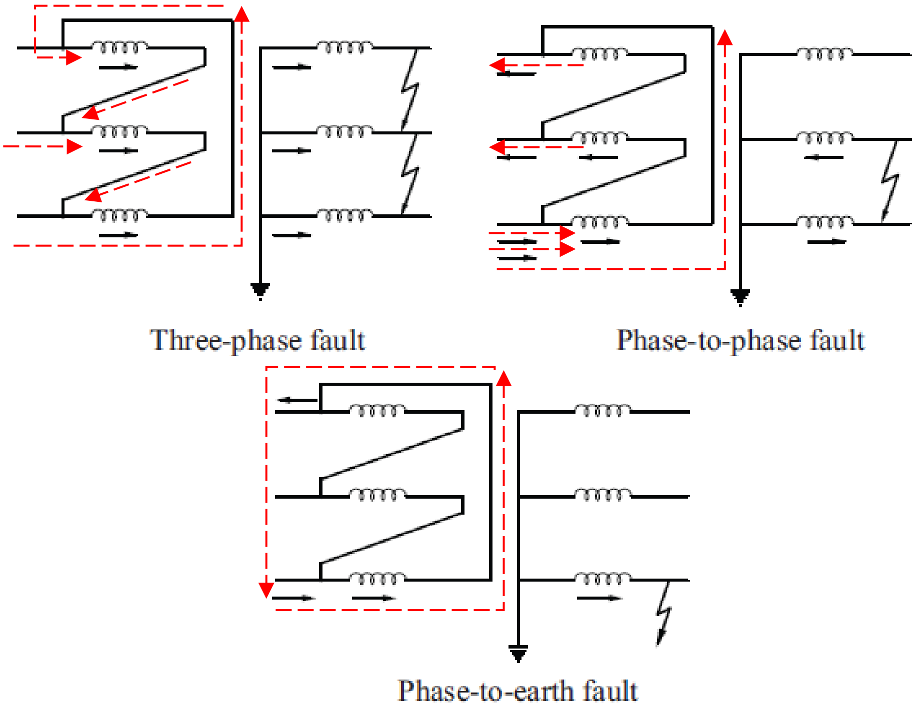


Figure 30 Fault Current Distribution in Dy Transformer

Therefore, the Earth Fault relay coordination reaches its limit as it reaches delta winding and a new hierarchical Earth Fault coordination with lowest setting must be setup upstream of delta side of transformer. However, if the transformer is star-star, then the coordination must continue upstream progressively.

In case of Nangkhor Substation, the LV side of 5 MVA Transformer is delta, and the 33 kV delta system is artificially grounded through earthing transformer. Therefore, 33 kV feeders need not be coordinated with its upstream relays.

5.2 Single Line to Ground Fault for Earth Fault Relay Setting

For the Earth Fault relay setting and coordination, maximum short circuit currents from single line to ground faults is being considered.

Table 14 Single Line to Ground Fault

Fault Simulation Location	Case A (Fault Level)		Case B (Fault Level)		Case C (Fault level)	
	(MVA)	Current (A)	(MVA)	Current (A)	(MVA)	Current (A)
132kV Bus	261.33	3429.17	261.33	3429.17	261.33	3429.17
HV(132kV) Side of 5MVA Txr. 132/33kV	261.33	3429.17	261.33	3429.17	261.33	3429.17
LV Side of 5MVA Txr. 132/33kV	x	x	x	x	x	x
33kV Bus	23.30	1222.97	23.30	1222.97	23.30	1222.97
33kV Radial Feeders	23.30	1222.97	23.30	1222.97	23.30	1222.97
HV(33kV) Side of 2.5MVA Txr. 33/11kV	23.30	1222.97	23.30	1222.97	23.30	1222.97
LV(11kV) Side of 2.5MVA Txr. 33/11kV	12.87	2026.56	10.4	1637.62	12.87	2026.56
11kV Bus A	12.87	2026.56	20.80	3275.25	12.87	2026.56
11kV Bus B	12.87	2026.56	20.80	3275.25	12.87	2026.56
11kV Feeders on Bus A	12.87	2026.56	20.80	3275.25	12.87	2026.56
11kV Feeders on Bus B	12.87	2026.56	20.80	3275.25	12.87	2026.56
11kB Bus Coupler	0.00	0.0	10.4	1637.62	12.87	2026.56

Based on the fault level in Table 14, relay setting has been calculated for Case A, B and C as in Table 15 and 16.

The pickup setting of 30% of the phase pickup current is selected for earth fault relay setting. Since the 11 kV relays are electromechanical, CTI of 300 ms is chosen.

Table 15 Case A&C: Earthfault Relay Setting Calculation Work Sheet for 132/33/11 kV Nangkhor Substation, Pemagatshel

Sl. #	Relay Setting Parameters	11 kV			33 kV			132 kV
		Feeders	**Bus Coupler**	**2.5MVA LV Side**	**2.5MVA, HV side**	**Feeders**	**Tsebar Fdr.**	**5MVA, HV side**
1	Single Line to Earth Fault ($3I_0$), A	2026.56	2026.56	2026.56	1222.97	1222.97	1222.97	3429.17
2	CT Primary, A	100.00	150.00	150.00	50.00	30.00	150.00	25.00
3	CT Secondary , A	5.00	5.00	5.00	1.00	1.00	1.00	1.00
2	OC Pickup Current (Secondary), A	5.00	5.00	5.00	1.00	1.10	0.64	1.00
3	EF Pickup Setting (30% of OC Pickup)	1.50	1.50	1.50	0.30	0.30	0.20	0.30
4	PSM= (Fault Current/(CTR x Pickup current))	67.55	45.03	45.03	81.53	135.89	40.77	457.22
5	Desired operating Time (tq= 0.1s+CTI)	0.100	0.400	0.700	0.100	0.100	0.700	0.100
6	TMS=[(tq*[(PSM)0.02-1]/0.14] for 3.0sec curve or multiply by 2.31 for 1.3sec SI Curve	0.14	0.52	0.91	0.07	0.07	0.38	0.09
7	Adopted TMS	0.15	0.52	0.91	0.10	0.10	0.39	0.10
8	Actual Operating Time (s)	0.104	0.400	0.698	0.152	0.136	0.709	0.107
9	High Set element (50), A	6.00	6.00	6.00	5.00	5.00	4.00	6.00
10	Operating time for Highset, S	0.10	0.40	0.70	0.10	0.10	0.70	0.10

Table 16 Case B: Earth Fault Relay Setting Calculation Work Sheet for 132/33/11 kV Nangkhor Substation, Pemagatshel

Sl. #	Relay Setting Parameters	11 kV			33 kV			132 kV
		Feeders	**Bus Coupler**	**2.5MVA LV Side**	**2.5MVA, HV side**	**Feeders**	**Tsebar Fdr.**	**5MVA, HV side**
1	Single Line to Earth Fault ($3I_0$)	3275.25	1637.62	1637.62	1222.97	1222.97	1222.97	3429.17
2	CT Primary, A	100.00	150.00	150.00	50.00	30.00	150.00	25.00
3	CT Secondary , A	5.00	5.00	5.00	1.00	1.00	1.00	1.00
2	OC Pickup Current (Secondary), A	5.00	5.00	5.00	1.00	1.00	1.00	1.00
3	EF Pickup Setting (30% of OC Pickup)	1.50	1.50	1.50	0.30	0.30	0.20	0.30
4	PSM= (Fault Current/(CTRx Pickup current))	109.17	36.39	36.39	81.53	135.89	40.77	457.22
5	Desired operating Time(tq= 0.1s+CTI),	0.100	0.400	0.700	0.100	0.100	0.700	0.100
6	TMS=[(tq*[(PSM)0.02-1]/0.14] for 3.0sec curve or multiply by 2.31 for 1.3sec SI Curve	0.16	0.49	0.86	0.07	0.07	0.38	0.09
7	Adopted TMS	0.16	0.49	1.00	0.10	0.10	0.39	0.10
8	Actual Operating Time, sec	0.100	0.400	0.814	0.152	0.136	0.709	0.107
9	High Set element (50), A	6.00	6.00	6.00	5.00	5.00	4.00	6.00
10	Operating time for Highset, sec	0.10	0.40	0.70	0.10	0.10	0.70	0.10

5.3 Graphical Analysis

a) Earth Fault Relay Coordination of 11 kV System- Case A & C

When a SLG fault close to the CT (1% of line length) is applied on a feeder, a fault current of 1957.49 A is injected. The simulation results shows that the feeder trips in 160 ms, BC in 540 ms and LV side of transformer (11 kV Incomer) in 919 ms. The grading margin observed is about 380 ms.

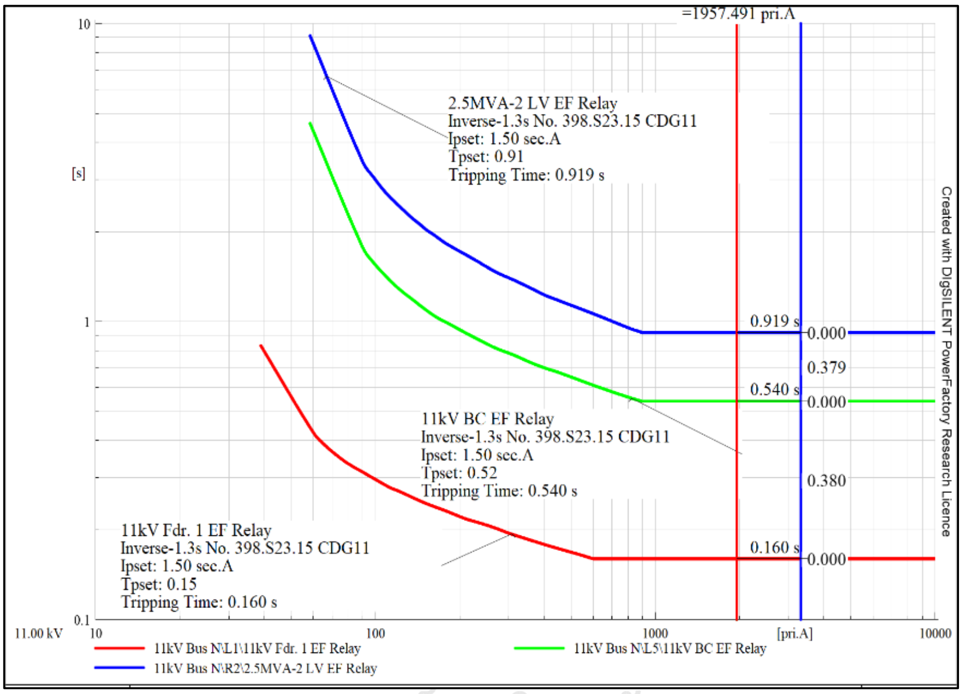


Figure 31 Earth Fault Relay Coordination of 11 kV System- Case A & C

However, it is interesting to know that the 11 kV feeder relay follows a definite time curve after 600 A. The BC and LV side of transformer follows the same pattern after 900 A. This is due to the limitation of the relay coil to take in only 20 times the pickup setting current. Hence for feeder 20 times the pickup setting of 30 A is 600 A. Similarly, for BC and LV side of transformer, 20 times the pickup setting of 45 A is 900 A.

The above case indicates that the relay follows standard inverse curve up to 20 times the pickup setting and thereafter follows a definite time (DT) curve. Increase

the pickup setting to a higher value will extend the standard inverse curve but then the sensitivity of the protection will be lost.

Therefore, to reduce the fast fault clearance, DT relay may be installed for feeder with pickup setting at 600 A with fault clearing time as 100 ms. Similarly, DT relay for BC may be set at 900 A with fault clearing time of 400 ms. Incomer DT relay is recommended to set at 900 A with fault clearing time of 700 ms.

Here it must be remembered that for coordination, the slowest feeder needs to be considered for coordinating with upstream relays. The coordination is done with 11 kV feeders, 11 kV BC and 11 kV Incomer. Since the HV side of 2.5 MVA, 33/11 kV transformer is delta, Earth Fault coordination is not required.

b) Earth Fault Relay Coordination of 11 kV System- Case B

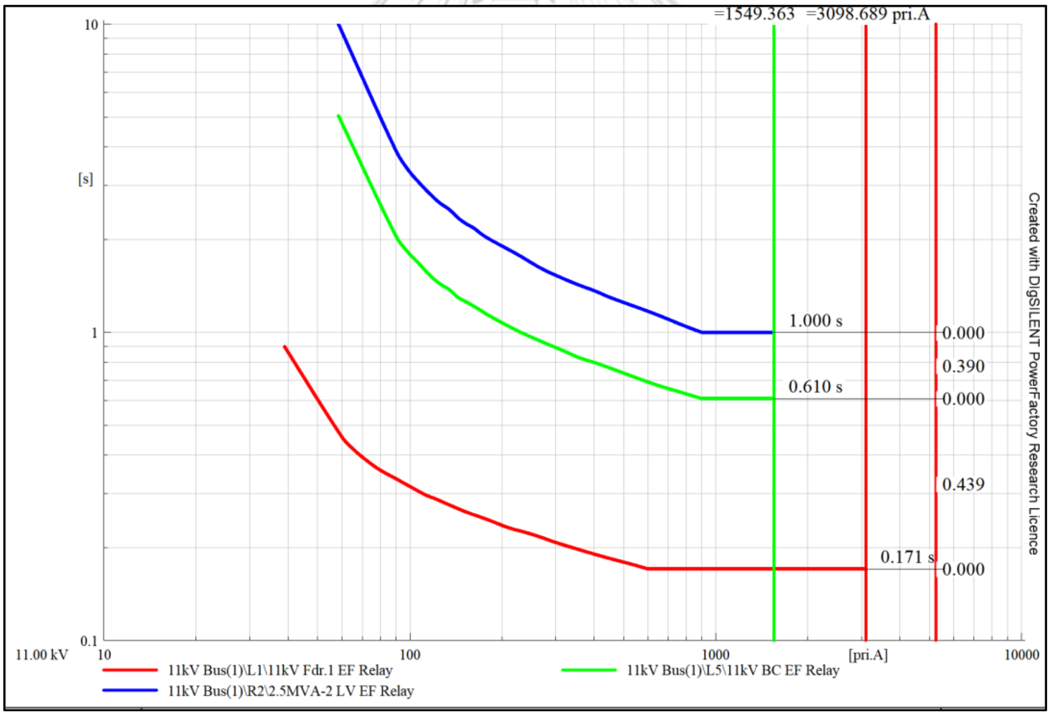


Figure 32 Earth Fault Relay Coordination of 11 kV System- Case B

Here, the fault current is increased due to two sources. When a SLG fault close to the CT (1% of line length) is applied on a feeder, a fault current of 3098.69 A is injected. The simulation results shows that the feeder trips in 171 ms, BC in 610 ms

and LV side of transformer in 1000 ms. The grading margin observed is about 439 ms between feeder and BC. For BC and LV side of transformer, grading margin of 390 ms is observed.

It must be noted that the fault current of a feeder is divided equally between the two sources, hence, two fault current graph is shown above. Here too, DT relay can be used settings replicated from Case A & C.

c) Earth Fault Relay Setting of 33 kV system.

Since the 33 kV incomer does not detect the zero-sequence current due to the delta winding of 5 MVA transformer, hence the 33 kV feeders earth fault relay needs no coordination with upstream relay.

With a pickup setting of 0.3, the curve saturates at 20 times the pickup current and follows the DT curve. Hence for 33 kV feeders with 30/1 A CT ratio, the DT may be set to 198 A with 100 ms as the operating time.

Similarly with Feeder 4, with CT ratio of 150/1 A and the pickup setting of 0.2, the DT may be set to 600 A with 700 ms.

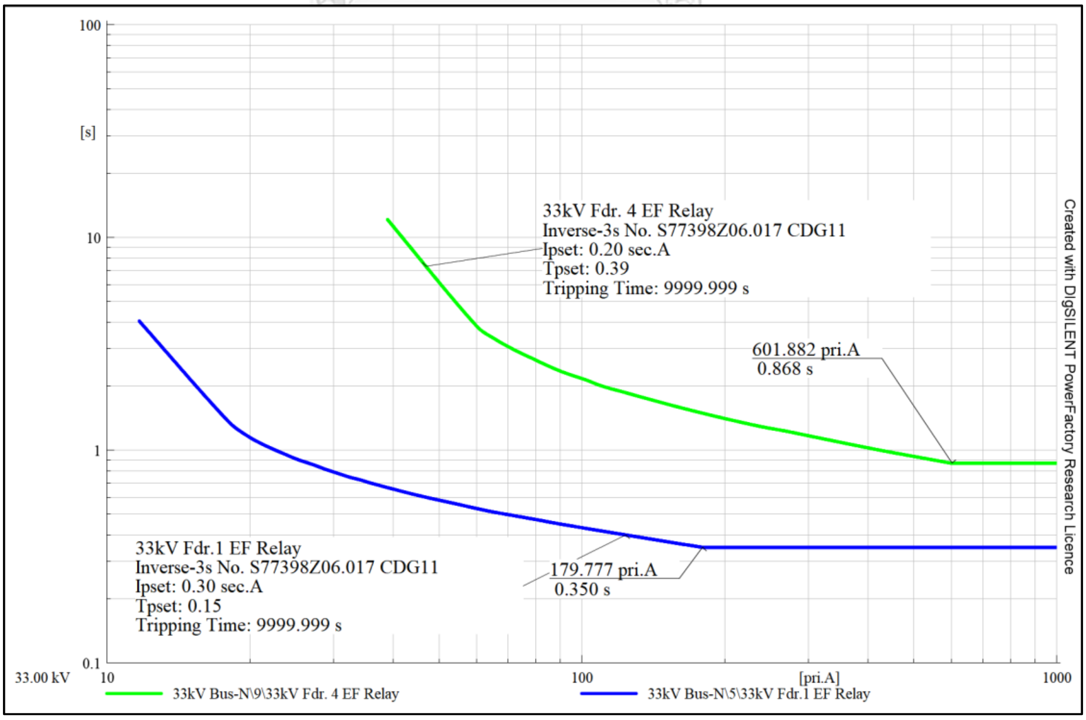


Figure 33 Earth Fault Relay Setting of 33 kV System.

d) Earth Fault Relay Setting of 132 kV System.

Like 33 kV system, the Earth Fault relay of 132 kV side of 5 MVA transformer need not be coordinated with its LV winding due to its delta configurations. Thus, to protect the Earth Fault between the HV windings and the CT, the Earth Fault relay may be set to a pickup setting of 0.3 and the DT setting may be set at 150 A with 100 ms relay operating time.

Existing Settings and Miscoordination Observed

e) Earth Fault Relay Coordination of 11 kV System- Case A & C

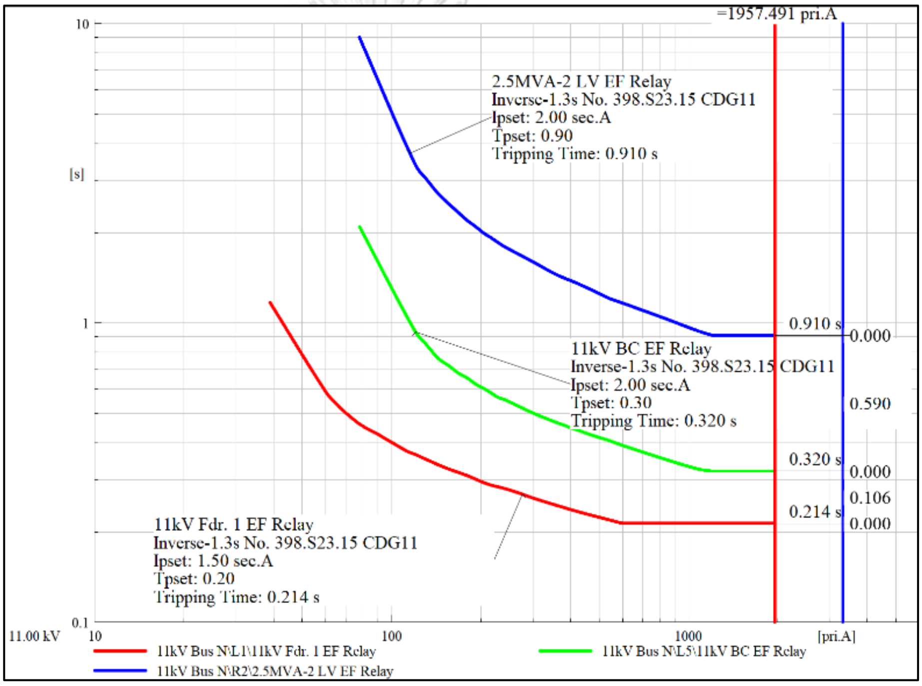


Figure 34 Existing Earth Fault setting and miscoordination of 11 kV system Case A & C

The graph indicates haphazard CTI. The CTI between feeder and the BC is 106 ms while it is 590 ms between BC and the LV side of transformer. The CTI lacks consistency. Further the relay gets saturated and follows the DT curve, hence requirement of DT at 20 times the pickup current setting is desired.

f) Earth Fault Relay Coordination of 11 kV System- Case B

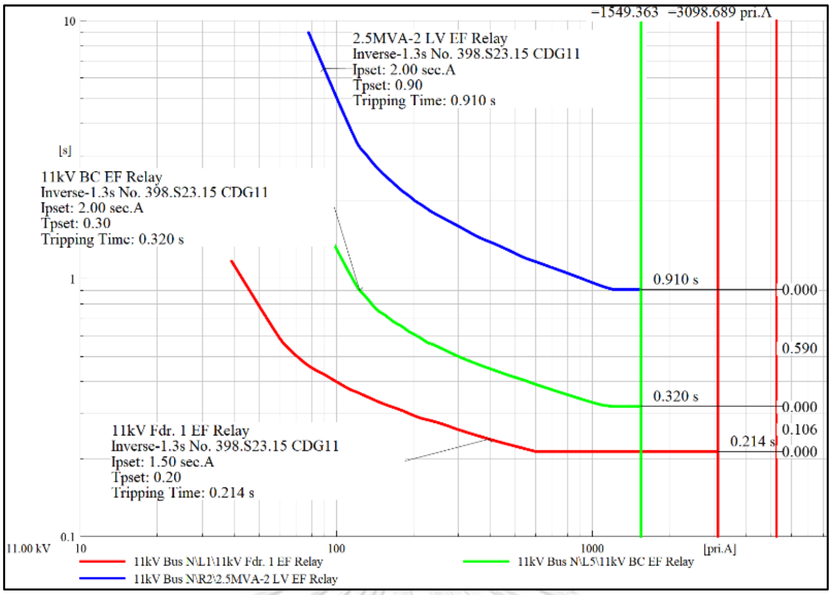


Figure 35 Existing Earth Fault setting and miscoordination of 11 kV system Case B

Since the relay coils saturates for the simulated fault current, hence the change of configurations does not make any difference. The operating time remains the same and the CTI is also the same as in Case A & C.

g) Earth Fault Relay Setting of 33 kV System.

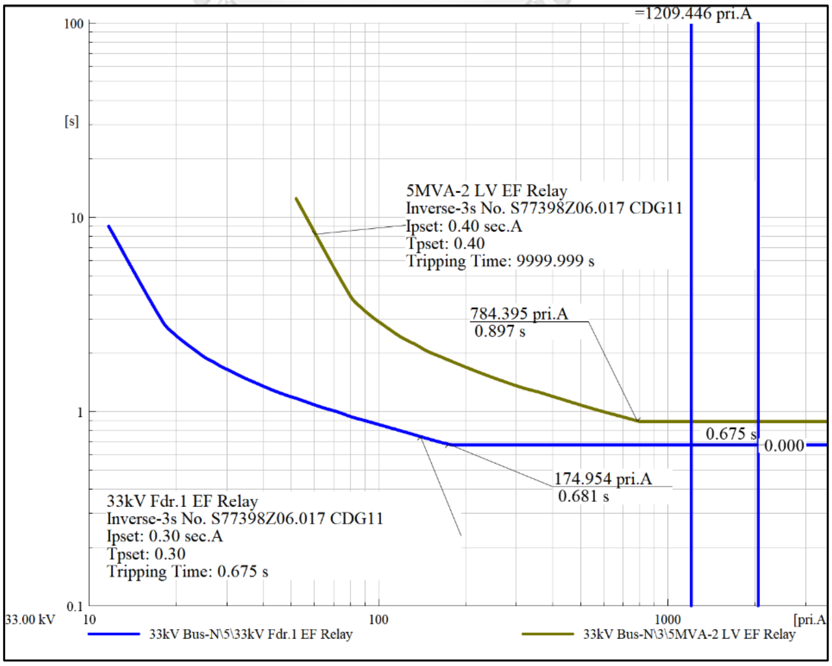


Figure 36 Earth Fault Relay Setting of 33 kV System.

As can be seen, the fault clearing time is 675 ms which is too high. Further the LV side Earth Fault relay need not be coordinated as it is the delta winding.

h) Earth Fault Relay Setting of 132 kV System.

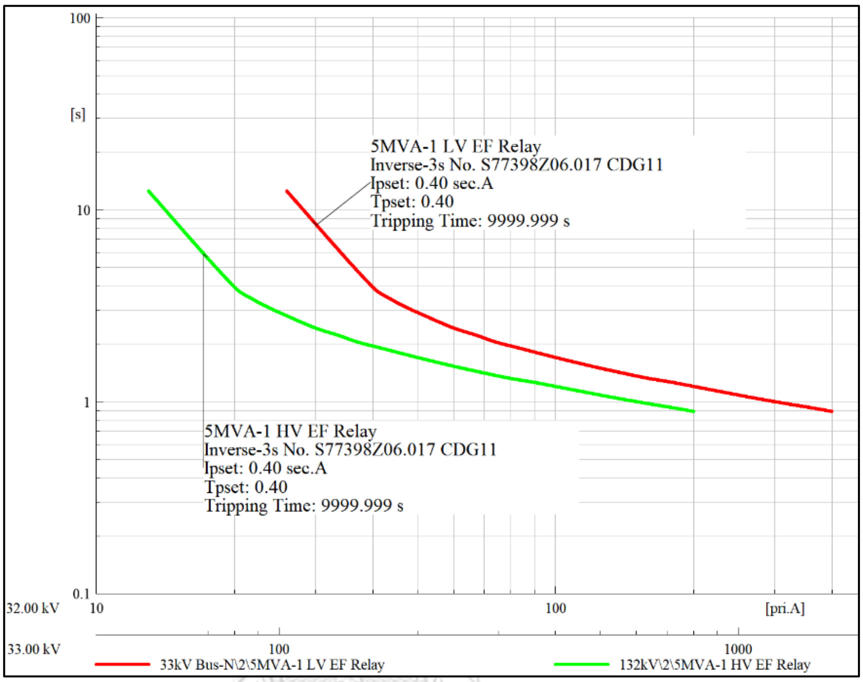


Figure 37 Earth Fault Relay Setting of 132 kV System.

SLG was applied to 33 kV bus however since LV side of 5MVA transformer is delta, it does not sense the zero-sequence current as depicted by the graph above. Hence, there is no requirement to install Earth Fault relay or conduct coordination.

The Earth Fault relay on HV side, which is star connection, will trip for Earth Fault between the HV windings and the Current Transformer.

5.4 Amendments recommended in BPC Relay Setting Guidelines

2.0 Setting of Transformer Protection Relays		
2.2.3 Earth Fault Protection Setting		
Clause	BPC Version	Proposal
2.2.3.1	The pickup setting of the Earth Fault relay (IN>) of the transformer shall be set at 50% of the full load current of the transformer.	The Earth Fault protection for transformers depends on the vector group. In case the of delta winding, zero-sequence current is not detected hence earthfault protection is not required. In case of star winding, Earth Fault protection shall be considered. The pickup setting of 25% to 50% may be considered depending on the maximum anticipated unbalanced zero-sequence current.
2.2.3.2	TMS of the Earth Fault relay for transformer shall be calculated as shown below: (refer the guidelines)	The operating time shall be in addition of CTI to the operating time downstream relays. In case of no coordination requirement, operating time of 100 ms may be considered with coordination with the differential protection.
2.2.3.3	The first stage highset Earth Fault protection setting (IN>>) shall be set at 250% of the full load current of the transformer.	The highset with intentional time delay me be set in accordance with the relay saturation curve, typically the value of current which is 20 times the pickup setting.

3.0 Setting of Distribution Feeder Protection Relays		
3.1.3 Earth Fault Protection Setting		
Clause	BPC Version	Proposal
3.1.3.1	The pickup setting for the stage 1 Earth Fault protection shall be set at 50% of the full load current of the feeder or 50% of the full connected CT ratio.	The pickup setting for the stage 1 Earth Fault shall be above the maximum anticipated unbalance zero-sequence current and may be 25% to 50% of the phase relay pickup current.
3.1.3.2	TMS for Earth Fault protection relay shall be set equal to the TMS of the overcurrent relay.	TMS for Earth Fault protection relay shall be derived from the fastest fault clearing of 100 ms if no downstream relay exists, followed by CTI of 300 ms for electromechanical and 200 ms for numerical downstream stream relays.
3.1.3.3	The first stage highset element of Earth Fault protection shall be set at 250% of the full load current of the feeder or full connected CT ratio.	The highset with intentional time delay may be set in accordance with the relay saturation curve, typically the value of current which is 20 times the pickup setting. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.

3.1.3.4	The characteristic curve of highset element shall be instantaneous or definite time (DT) and the DT delay shall be set equal to the highset element of overcurrent protection. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.	The intentional time delay shall be in coordination with addition of CTI to the setting of downstream relays. If no relay exists downstream, operating time of 100 ms may be considered.

4.0 Setting of Bus Coupler / Busbar Relays		
4.1.3 Earthfault Protection Setting		
Clause	BPC Version	Proposal
4.1.3.1	The pickup setting of bus coupler Earth Fault relay (IN>) shall be set to 50% of the full connected CT ratio or 50% of the maximum current flow possible through it when all the incomers are in service.	The pickup setting for the stage 1 Earth Fault shall be above the maximum anticipated unbalance zero-sequence current and may be 25% to 50% of the phase relay pickup current.
4.1.3.2	TMS of bus coupler Earth Fault relay shall be set equal to the TMS of overcurrent protection.	TMS for Earth Fault protection relay shall be derived from addition of CTI of 300 ms for electromechanical and 200 ms for numerical downstream relays.
4.1.3.3	The first stage (High-set) overcurrent protection (IN>>) shall be set at 250% of the full connected CT ratio or 250% of the maximum current flow possible through it when all the incomers are in service.	The highset with intentional time delay may be set in accordance with the relay saturation curve, typically the value of current which is 20 times the pickup setting. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.
4.1.3.4	The characteristic curve of highset element shall be instantaneous or definite time (DT) and the DT delay shall be set equal to the highset element of overcurrent protection. The setting shall be rounded off to the next higher figure or as limited by the setting possible in the relay.	The intentional time delay shall be in coordination with addition of CTI to the setting of downstream relays. If no relay exists downstream, operating time of 100 ms may be considered.

5.5 Recommendations for Earth Fault relay setting and coordination.

a) Conduct the load flow and short circuit studies of Bhutanese Power System in conjunction with Indian grid as given in earlier chapter, through software preferably a common for protection coordination study as well. Update the database whenever necessary.

b) Prepare a single line diagram (SLD) of the substation in protection coordination software such as DIgSILENT, CAPE, etc.

c) Simulate 'Single Line to Ground Fault' to obtain maximum fault current values. The fault current shall be used to set the relay.

d) Find out if there are fuses/AR/substations to be coordinated downstream of feeders. Start the relay coordination from the lowest protective device.

e) Select the IEC/ANSI standard curves such as NI, VI, EI or LTI. It is recommended to use SI curve in general for downstream and upstream relays. Mixing of curves complicates the analysis however if mixing is used, detailed analysis should be conducted thoroughly for all case scenarios.

f) As a general practice, operating time of minimum of 100 ms is set for lowest protection device in protection hierarchy, while 2000 ms may be used for topmost protection device. The selection of operating time range must be always below the equipment damage curve (I^2t).

g) A minimum coordination time interval (CTI) or grading margin of 300 ms should be ensured between each protection hierarchy for electromechanical relays. While 200 ms can be used for numerical relays. Optimization of the CTI must be done to ensure adequate protection for all protection hierarchy; hence the CTI may vary to accommodate within its specified range defined in clause 'f'.

h) For coordination purpose, assume the fault near the CT of respective feeders which is equivalent to the bus fault. Any faults away from bus will be lesser, hence the coordination ensures maximum protection.

i) The pickup setting of the Earth Fault relay should be above the maximum anticipated unbalanced zero-sequence current. If even the load is well balanced,

due to switching actions, zero-sequence current will arise, thus pickup setting must be from 25% to 50% of the phase relay pickup current.

j) The substation operation configurations need to be standardized especially in the usage of bus coupler (BC). When BC is 'OFF', respective transformers supply the fault currents to its respective buses and feeders. On the contrary, when BC is put 'ON' all transformers connected supplies the fault currents.

   Therefore, the operation of BC results in different fault currents which needs to be considered while doing the relay coordination. Relay coordination should be calculated for the above cases and settings done as per the substation operation configurations.

   In case of electromechanical relays, manual setting may be required. For numerical relays, the settings of different scenarios should be saved in various group setting (1,2,3 & 4) and it may be enabled or disabled as per the operating conditions.

k) Irrespective of the clause 'j', the feeders must be coordinated with BC which in turn be coordinated to the upstream incomer for the bus.

l) If there are distributed generations like wind and solar downstream of the relay, ensure the time delay effect of BC is below the LVRT (low voltage ride through) of the distributed generation. Therefore, settings of BC must be done adequately taking into all the above case scenarios.

m) The setting of the Earth Fault relays on either side of transformers should be done as per the winding configurations. Delta configurations does not detect the zero-sequence current, hence doesn’t require Earth Fault relay. The star winding detects the zero-sequence current hence Earth Fault relay should be installed.

   If LV is star, coordination must start from lowest protection device and ends with the LV side of transformer. The relay setting for HV side of transformer considering HV is delta, is independent of the downstream relays hence Earth Fault relay setting should start from HV side of transformer and cascade upward.

If there is no upstream Earth Fault relay, then the setting may be done considering Earth Fault relay as back up to differential relay.

For instance,

a. If the transformer has vector group Dyn11, then the Earth Fault relay on HV side need not be coordinated with downstream relay since it has delta winding. In such case, the Earth Fault relay must be coordinated with differential protection.

b. If the transformer has Yy configurations with neutral grounded on both sides, then the similar concept of OC coordinated may be followed. The upstream and downstream then may be coordinated accordingly.

n) If there is a feeder emanating from substation and connects to distribution substation. The relay coordination should begin from distribution substation. The time multiplier setting (TMS) of the feeder will depend on the CTI of the distribution substation.

Similarly, the operating time of upstream relay on transmission substation will depend on the maximum operating time of either the feeders with distribution substation or any feeders in transmission substation with adequate CTI.

In any case, the operating time limit must not be violated and if violation occurs, necessary adjustment of CTI must be done to ensure the operating time is within its specified range. *Violation of operating time limit possess serious risk to the equipment.*

o) In case of two transformers being connected to bus without BC, relay coordination studies must be done with single transformer as well as both transformers. The fault on LV bus will be different in case if any transformer is taken out of service. hence settings may be applied accordingly.

p) The high set element 50, must be coordinated similarly with appropriate CTI. The setting of 50 with intentional time delay may be done with 20 times the pickup setting of Earth Fault relay.

6 DIFFERENTIAL PROTECTION (TRANSFORMER PROTECTION)

6.1 Introduction to transformer internal protection

Transformer is the costliest equipment in a substation which needs to be protected adequately. Failure of transformer, besides causing huge financial losses, creates much wider system blackout. The degree of protection provided to transformer may vary upon the voltage level, the MVA capacity, the strategic locations, etc.

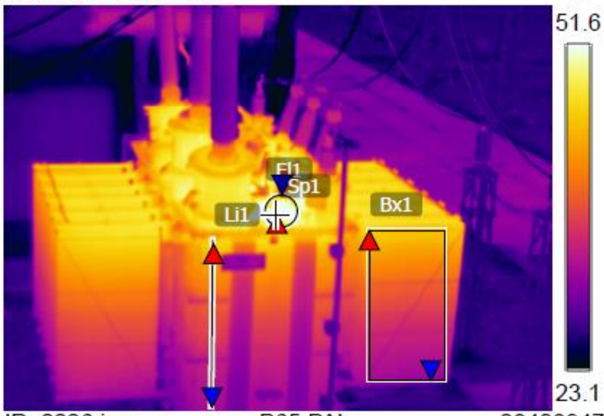
The following devices are used for transformer protection and can be categorized follows:

1. Internal Protection
   a. WTI-Winding Temperature Indicator (Alarm & Trip)
   b. OTI-Oil Temperature Indicator (Alarm & Trip)
   c. Buchholz Relay (Alarm & Trip)
   d. MOLG (Magnetic Oil Level Gauge)
   e. OSR-Oil Surge Relay
   f. PRV/PRD (Pressure Relief Device or Valve)
2. External Protection
   a. Transformer differential protection (87T)
   b. Overcurrent protection (50/51/67)
   c. Earth fault protection (50/51/67)
   d. Restricted Earth fault protection (REF)

Temperature profile of transformers

The heating profile of transformers needs to be understood before we discuss how to measure the temperature. The heating of transformers under charged condition is not uniform across the windings. The top portion of the windings get heated much more than lower end, thus under charged conditions the top portion of transformer gets heated to maximum, and it decreases as we go towards the bottom. The image taken by the thermographic camera is produces as follows.

5/8/2020 5:05:53 PM °C



IR_2226.jpg P65 PAL 23403947

5/8/2020 5:06:03 PM

DC_2227.jpg

As the transformer gets heated from the top, hence the temperature measuring oil pockets are located on the top of tank cover. Filled with oil, the pockets are in direct contact with the top oil of transformer tank. Thus, the thermal sensing bulb of temperature measuring devices such as the WTI and OTI are installed in these pockets.

Oil Temperature Indicator (OTI)

The temperature of the oil needs to be transferred to the measuring and protection devices. This is being done by Oil Temperature Indicator (OTI). It consists of thermal sensing bulb, capillary tube filled with suitable fluid, and the indicator mechanism. The thermal sensing bulb is screwed in the OTI pocket. The thermal sensing bult is connected to the indicator via a flexible steel capillary tube. The capillary tube may be liquid filled, vapor filled, gas filled, or mercury filled. The pressure developed by the expansion of substances inside the capillary tube is being exerted on the operating bellow. The lever of the operating bellow is mechanically connected to the indicator system which is calibrated to indicate the measured temperature. The capillary tube is also connected to the compensating coil which is being used to compensate the changes in the volume due to ambient temperature.

The movement of black indicator is dependent on the temperature sensed by the bulb, so it deflects clockwise or anticlockwise as per the temperature of the oil. On the contrary the red indicator is purely a mechanical device. As the black indicator moves clockwise, it gets blocked by the red indicator thus black indicator pushes the

red to its measured temperature together. But when temperature cools down, black indicator returns following anticlockwise direction but red does not move as it is purely mechanical. So, this red indicator will depict the highest temperature recorded by the transformer. It can be manually reset. It has two switches, generally mercury switch meant for alarm and trip command.

Temperature settings for 'Alarm' and 'Trip' functions should be set in the OTI for thermal protection as given below.

$$OTI_{Alarm} = T_{ambient} + T_{declared}$$

Where,

$T_{ambient}$: *Ambient temperature*

$T_{declared}$: *Declared temperature rise above the ambient temperature on the name plate.*

The trip temperature is set 10°C above the alarm temperature to provide cushion between the alarm and trip function.

$$OTI_{Trip} = OTI_{alarm} + \beta$$

Where $\beta = 10°C$

Winding Temperature Indicator (WTI)

As the name suggests, WTI measures the temperature of windings. The construction and working principle are like OTI. The measured temperature by the WTI is the temperature of oil along with the resistance. It is almost impossible to place the thermal sensing bulb near/on the windings due to high voltage hence thermal imaging is done to indicate the temperature.

As the load increases, the temperature of the winding (I^2R) increases which gets transferred to the transformer oil in the tank. The thermal sensing bulb then senses the temperature of the oil and relays to the bellows which will indicate the temperature. It is to be noted that the bushing CT is connected to the WTI through a resistance. When load increases, current increases which passes through the resistance, hence increases the temperature of the resistance which is proportional to the heat of the windings.

Depending on the size of transformer, it may have WTI on either HV or LV side or both sides. The WTI may have mercury switch each for alarm (S1), trip (S2), fan (S3), and pump(4) depending on the transformer type. The flash point of transformers is typically above 150°C because of which the WTI/OTI indicator temperature scale is up to 150°C. This debars users from setting the temperature beyond the flash point of transformer oil.

The temperature setting for WTI alarm and trip is calculated like the OTI temperature calculations.

Buchholz Relay

Buchholz relay is a gas operated device meant to detect the incipient fault inside the transformer. As the incipient fault develops, several gases such as ethane, methane, carbon dioxide, hydrogen, acetylene, etc. are emitted which gets accumulated in the buchholz relay chamber. As the amount of gas increases, the oil inside the buchholz chamber gets displaced, thus initiating alarm and trip command depending on the level of gas.

If buchholz relay operates, then the transformer should be shut down and detail testing of oil needs to be done to ascertain its healthiness. If the result of DGA (Dissolved Gas in Oil Analysis) indicates certain faults, it is advisable to conduct the repair and maintenance otherwise transformer will get damaged.

However, in some cases it will be a false signal due to leakage of DC or contact. In any case, a detail preventive checks and testing is required if buchholz relay operates. DGA test needs to be done frequently and the trend of gas occurrence must be noted and analyzed.

Gas Description		Key Gas Concentration (in ppm) Normal Limits* (<)	Action Limits** (>)	Potential Fault Type
Hydrogen	H_2	150	1,000	Corona, Arcing
Methane	CH_4	25	80	Sparking
Acetylene	C_2H_2	15	70	Arcing
Ethylene	C_2H_4	20	150	Severe overheating
Ethane	C_2H_6	10	35	Local Overheating
Carbon monoxide	CO	500	1,000	Severe overheating
Carbon dioxide	CO_2	10,000	15,000	Severe overheating
Total Combustibles	TDCG	720	4,630	

* As the value exceeds this limit, sample frequency should be increased with consideration given to planned outage in near term for further evaluation.

** As value exceeds this limit, removal of transformer from service should be considered.

This table is derived from information provided within ANSI/IEEE C57.104

MOLG/OSR/PRD

Magnetic Oil Level Gauge (MOLG) checks the level of oil in the conservator. The oil level in the conservator rises and fall depending on the expansion and contraction of transformer oil due to temperature variation caused by load. If the oil level falls below the reserved level, an alarm will be initiated to the control room. The maintenance personal needs to check the level of oil and necessary topping up of oil needs to be done after checking the oil miscibility and filtration. MOG usually does not have trip command.

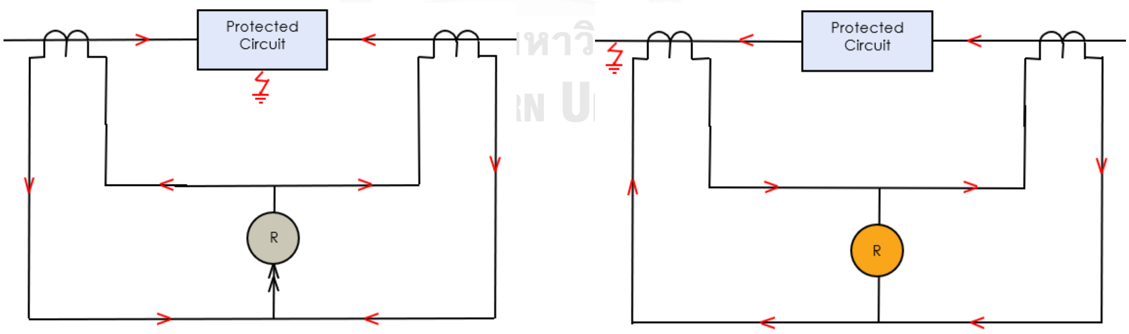
Oil Surge Relay (OSR) is installed between the OLTC (On Load Tap Changer) conservator and the OLTC tank. Unlike buchholz relay, OSR is oil operated device which works based on the excessive oil surges.

Pressure Relief Device (PRD) is the mechanical protection device for transformer. If in case there is a fault and the DC is not available for tripping, then before the tank burst, the PRD will operate at specific pressure forcing the oil out of transformer, thereby saving the transformer from bursting, and avoiding damage to other equipment.

6.2 Differential Protection

The protection of transformers, busbars, short line, and generators is a unit protection with well-defined zones of protections. The relay must not operate for faults outside the zone. It works on the principle of sum of currents entering and exiting the protected zone must be equal. This necessitates the Merz Price principle of differential protection. For 10 MVA or more, 3 phase self-cooled rating, the commonly used protection is the current differential protection [12] as shown in Figure 38.

Differential protection is a unit protection which operates within its specific zone. The zones are specified within the high voltage side CT and low voltage side CT. The star points of both HV and LV CTs are made towards the equipment to be protected.



(a) Relay Operates (b) Relay Restrains

Figure 38 Differential relay working principle

For delta/star transformer, an Earth Fault on the star winding generates zero sequence current while delta winding will not sense any zero-sequence current. For stability, the zero-sequence current must be eliminated from the star winding. This is

being done by connecting CT in delta. And the CTs for delta windings are connected in star to cater the phase shift across the transformer.

Generally, CT connection (star or delta) are made opposite to that of main transformer vector (star or delta) for zero sequence current filtering and phase shift compensation [12]. Due to the CT rating, if it is not possible to eliminate zero sequence current or the phase shift, auxiliary CTs are also used [12].

6.2.1 Working Principle

Differential protection functions based on Kirchhoff's current law in which the currents flowing into a node is equal to sum of the currents flowing out of the node. Ideally, the vector sum of currents through the differential relay is zero during normal operation. However, when the fault occurs within its zone of protection, the phase angles of the current reverses, thus leading to the differential circulating current, which will trigger the operation of relay based on its predetermined values.

Although in ideal case, differential current is zero but, there always exists differential current due to the measurement errors of current transformers, the tap changers, relay accuracy, etc. Hence, the predetermined value needs to be defined. Any differential current beyond the predetermined values will trip the circuit breaker, indicating the occurrence of fault within its zone.

The pre-determined value needs to accommodate the CT ratio errors at nominal and maximum taps. Let us consider the following case example of 5 MVA, 132/33 kV, Transformer with a tapping range of +5% to -15% at a step of 1.25%. The On Load Tap Changer (OLTC) has 17 taps.

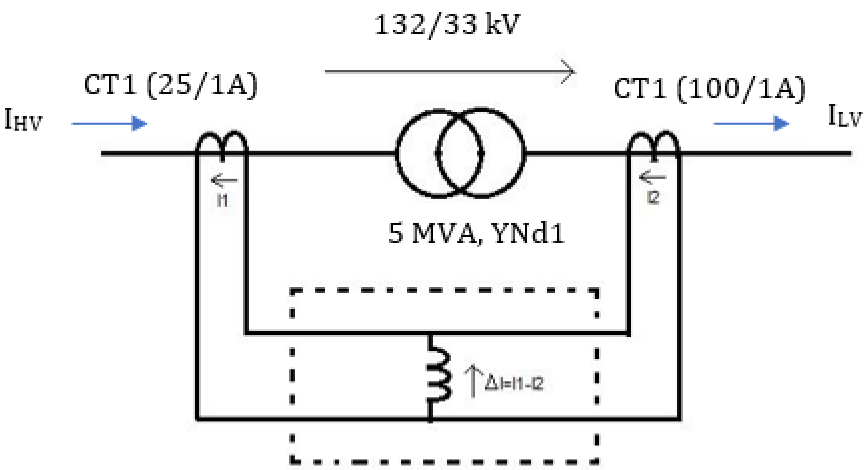


Figure 39 Differential Protection of 5 MVA, 132/33 kV, YNd1 Transformer

Table 17 Differential current at various tap position of transformer

Tap Position	HV (Voltage)	Tapping Range	HV Current (A)	LV Current (A)	CT Ratio		Differential Current Id (1-2)
					HV: 25/1A	LV: 100/1A	
					Secondary Current (1)	Secondary Current (2)	
1	138600	5.00%	20.83	87.48	0.83	0.87	-0.05
5	132000	0.00%	21.87	87.48	0.87	0.87	0.00
17	112200	15.00%	25.73	87.48	1.03	0.87	0.15

For the above transformer, the current variation is 15% at maximum tap (assuming vector group and CT ratio correction is being done with Interposing CT).

$$I_{d,min,pickup} = I_{d,\max tap}\% + Measurement\ Error\ (CT, Relay\ etc.)\%$$

With the CT measurement error, CT mismatch, errors, etc., the typical minimum pickup is between 30% to 35% of the nominal current [12].

6.2.2 CT Ratio Compensation or Amplitude Correction

The CT connection on HV side must be in delta connection to eliminate the zero-sequence current, while LV side should be connected in star.

a) Case *1- No Tap Changer*

Full Load Current 132 kV Side :5MVA/(1.732x132 kV)=21.869A

CT Secondary Current (25/1A) :21.87/25=0.875

Full Load Current 33 kV Side :5MVA/(1.732x33 kV)=87.477A

CT Secondary Current (100/1A) :87.477/100=0.875

But the HV side CT connections need to be connected in delta hence the Interposing Current Transformer (ICT) is required. The CT secondary circuits of HV side must be connected to ICT, to match the amplitude of the current produced by the LV side.

Current from 132 kV Side : 0.875A

Current from 33 kV Side : 0.875 A

Since the delta connection is required from HV side hence the required ICT is,

$$Required\ ICT\ Ratio = 0.875/\frac{0.875}{\sqrt{3}} = 0.875/0.5052$$

b) Case 2- With Tap Changer

The 5MVA transformer under study has a tapping range for of +5% to -15% at a step of 1.25%. The On Load Tap Changer (OLTC) has 17 taps. Hence the ratio error due to the tap changer must be accommodated in the selection of ICT.

ICT should be considered based on the mid-tap position.

$$Mid\ Tap\ Position = \frac{100 + \frac{Summation\ of\ Tap\ Extreme}{2}}{100} \times Rated\ Voltage$$

$$Mid\ Tap\ Position = \frac{100 + \frac{(5-15)}{2}}{100} \times 132 = 125.4\ kV$$

Primary Current on HV side based on mid tap position *($I_{FLP,mid\ tap}$)*

$$I_{FLP,mid\ tap} = \frac{5000\ kVA}{\sqrt{3} \times 125.5kV} = 23.002\ A$$

Secondary Current on HV side based on mid tap position *($I_{FLS,mid\ tap}$)*

$$I_{FLS,mid\ tap} = \frac{23.002}{25} = 0.9208A$$

CT Secondary Current on LV side (100/1A) =0.875 A

Since the HV side is star winding, the CT secondary needs to be connected in delta to eradicate the zero-sequence current, hence the ICT shall be used on HV side. This means, the current of 0.9208A needs to be stepped down form start connection to 0.875A is delta connection.

Therefore, the ratio of ICT will be as follows.

$$ICT\ Required = {}^{0.9208}\Big/_{\left({}^{0.875}/_{\sqrt{3}}\right)}$$

$$ICT\ Required = 0.9208/0.5051$$

6.2.3 Vector Correction

The differential current, after the CT ratio compensation is ideally zero, as the current on HV and LV side of relay are equal in magnitude and opposite in phase. However, in the above case there is phase shift. The vector group is YNd1. Currents in delta winding lags the star winding by 30° as shown in Figure 40 .

CT secondary connections are opposite to the transformer winding connection; hence delta connections are made for CT secondary of HV side of transformer while CT secondaries are connected in star for LV side of transformer. This is being done for zero sequence current filtering.

Therefore, Interposing CT must be connected to CT secondaries on HV side of transformer, firstly to compensate the CT ratio mismatch, filter the zero-sequence current and then to compensate the phase angle.

The phase shift compensation can be done either on HV or LV side. Since the delta connection is required for HV side of Transformer through ICT, hence the connections shall be carefully done on HV side as shown in Figure 41. The installation of interposing CT should accommodate all the requirements. The details of circuit connection are given below.

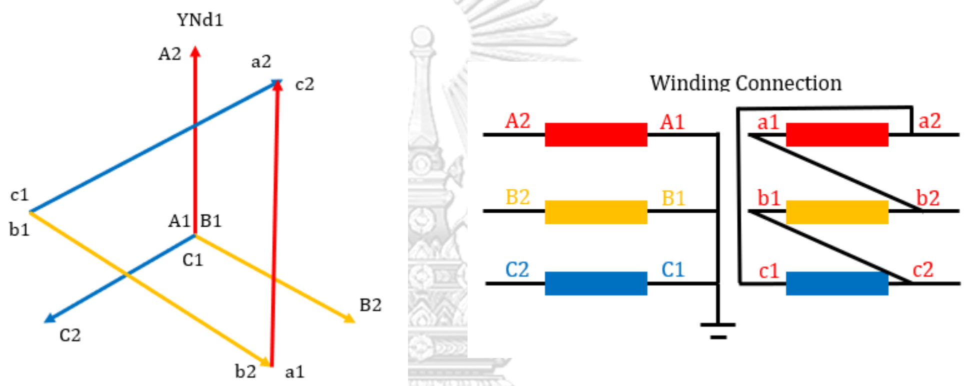


Figure 40 Transformer Winding Connection

Since the ICT is being installed at CT secondaries of HV side, hence the phase angle of CT connection must be shifted by 30°.

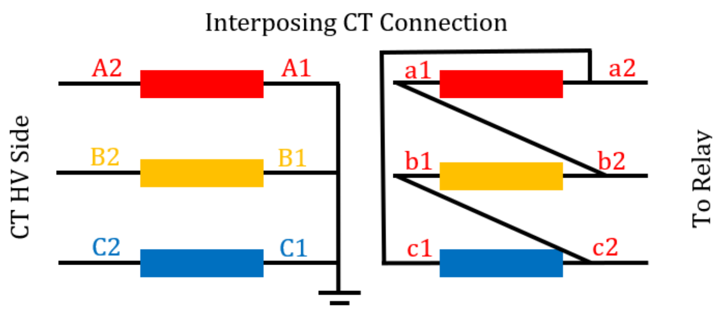


Figure 41 Interposing CT connection.

6.2.4 Zero Sequence filtering

In differential protection of star delta or delta star transformer, zero sequence current filtering must be done on star side of the transformer so that the relay maintains its stability under through fault condition.

The SLG fault on any phase of star winding will result in zero sequence current, which will not be detected by delta side since the current circulates within the delta windings. Therefore, to filter the zero sequence current the CT secondary connections on the star side of the transformer is made into delta connection using Interposing CT as discussed above.

6.2.5 Magnetic Inrush

When the transformer is energized, huge current occurs for few cycles on one side of transformer, and this may result into differential current tripping the circuit. Inrush currents are also generated while charging a parallel transformer, and when the system recovers from out of zone faults.

To avoid false differential tripping due to magnetizing inrush current, following methods may be followed.

a) Time delay: Since the magnetizing inrush current typically occurs for about 100 ms for 100 kVA transformers and up to 1 second for power transformers, hence for lower rated transformers, sufficient time delay may be provided. Usually, differential protection is not provided for transformers below 5MVA, and in such cases also, time delayed overcurrent relay can avoid the tripping given the suitable time setting.

b) Harmonic Restraints: The inrush current is characterized by 2nd harmonics; hence harmonic restraint features may be enabled especially in numerical relays which will block the tripping.

c) Gap detection : The magnetizing inrush current waveform has significant gap in each cycle where the current is substantially zero. While the fault currents

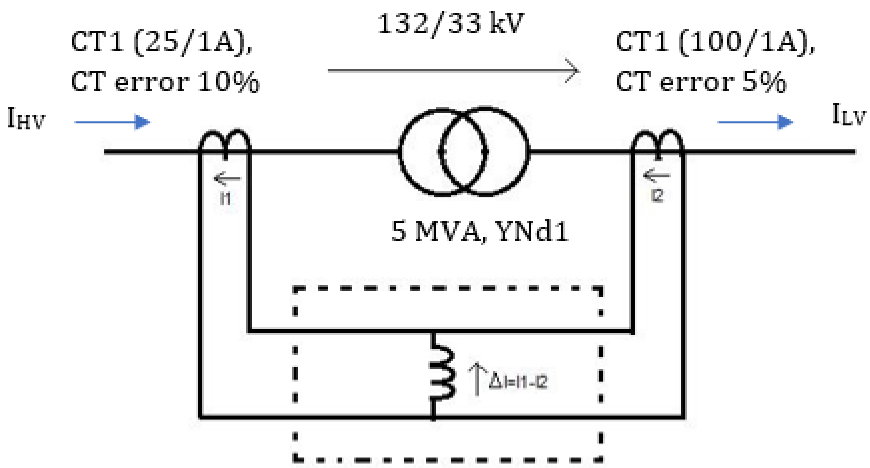
pass through zero very quickly. Numerical relays can detect this gap and can be made to restrain.

6.2.6 Transient Over fluxing

The overexcitation of the transformer due to excessive voltage at the transformer terminals results into differential current. This is because, as voltage exceeds its rated value, the flux also increases and after certain point it enters the saturated region of magnetic current. Due to this, large magnetizing current occurs at one side of transformer, because of which there appears to be a differential current leading to false tripping. The over fluxing is characterized by the presence of 5^{th} harmonics hence IEEE Std C37.91-2008 recommends 5^{th} harmonic restraint features be enabled to avoid false tripping.

6.3 Calculation of Differential Currents

In the earlier case example, let us assume that the CT on HV side has an error of 10% and 5% error of CT on LV side. The case example is reproduced below.



Assuming a through fault current from 50A to 500A, it is observed that the differential current increases proportionately with increase in fault current as shown in Table 18. A fixed differential setting poses serious tripping issues even when the out of zone fault current increases. Setting the pickup current higher, will decrease the sensitivity of the protection. So, the concept of percentage bias differential protection emerges.

Here, the operation of the relay depends on variable pickup setting obtained based on the differential current as a function of through current. Thus, the pickup setting increases based on the differential current versus through current curve.

Table 18 Differential current vs. fault currents

Tap Position	**CT Primary Current (HV), I_{HV} (A)**	**CT Primary Current (LV), I_{LV} (A)**	**CT Secondary Current (HV) CT error 10%, I_1 (A)**	**CT Secondary Current (HV) CT error 5%, I_2 (A)**	**Differential Current Id (I_1-I_2) (A)**
Normal Tap (5)	50	200	2.20	2.10	0.10
	100	400	4.40	4.20	0.20
	200	800	8.80	8.40	0.40
	300	1200	13.20	12.60	0.60
	500	2000	22.00	21.00	1.00
Maximum Tap (17)	50	170	2.20	1.79	0.42
	100	340	4.40	3.57	0.83
	200	680	8.80	7.14	1.66
	300	1020	13.20	10.71	2.49
	500	1700	22.00	17.85	4.15

6.4 Percentage Restrain Characteristics for Bias Differential (BD)

The operation of bias differential relay depends on the ratio of 'Operate' to 'Restraint' current. The magnitude of the differential current forms the basis of 'Operating Current' and is given by the following formula.

$$Operating\ Current, I_{op} = |I_1 + I_2|$$

The restraint current (I_{res}) is obtained as the mean through current.

$$I_{res} = \frac{|I_1| + |I_2|}{2}$$

Where;

I_1 : HV Current

I_2 : LV Current

As discussed in earlier chapter, the loading of transformer is being done for 150% for about 30 mins. in the worst-case scenario. Assuming CT secondary of 1 A, 1.5 A

secondary current will be flowing in the secondary circuit, hence the minimum bias current or I_{res} may be recommended to 1.5 pu.

1st Bias Slope Setting

The initial setting is calculated at low load. As the load increases, the differential current ($I_{W1}+I_{W2}$) also increases as shown in Figure 42, due to OLTC tap positions, relay, and CT measurement errors, therefore the bias setting should also increase to ensure stability.

This incremental setting should be defined by a bias slope which must be above the maximum anticipated unbalance current. This is to ensure the differential relay does not trip when operating in extreme normal operating conditions.

The slope of 1st Bias determines the maximum anticipated unbalance to which the following factors are taken into account [12]

a. The actual CT ratio mismatch in % (ΔCT_{err})
b. The measurement errors of main CTs and the auxiliary/interposing CTs which typically accounts to 5% errors (CT_{err})
c. The percentage differential current produced by the operation of transformers at extreme taps (Δ Max Tap%). The sample calculation is given in Table 18.

Therefore, the bias slope 1 is the sum of the above factors.

$$Slope\ 1\ Bias\ (\%)\ setting = \Delta CT_{err} + CT_{err} + \Delta\ \text{Max Tap} + \text{safety margin}$$

In Bhutan Power System, most of the CT ratio mismatch are below 10% and the tapping range of transformer are ±10%. Nonetheless, tapping range of +5% and -15% are available in eastern grid of Bhutan. The differential relays are static and numerical in nature.

For a numerical relay, CT ratio mismatch need not be considered as the relay algorithm takes care of it. Hence the recommended slope may be in between 30% to 40% as per the above parameters.

2nd Bias Slope Setting

The second bias slope is to compensate the transient phenomenon errors such as the CT saturation on through faults as the restraint is remarkably high. This slope is effective beyond the knee point of the transformer. The recommended slope is typically 70% or utility may develop their own methods of calculation [12]. The differential pickup along with bias settings are depicted in Figure 42.

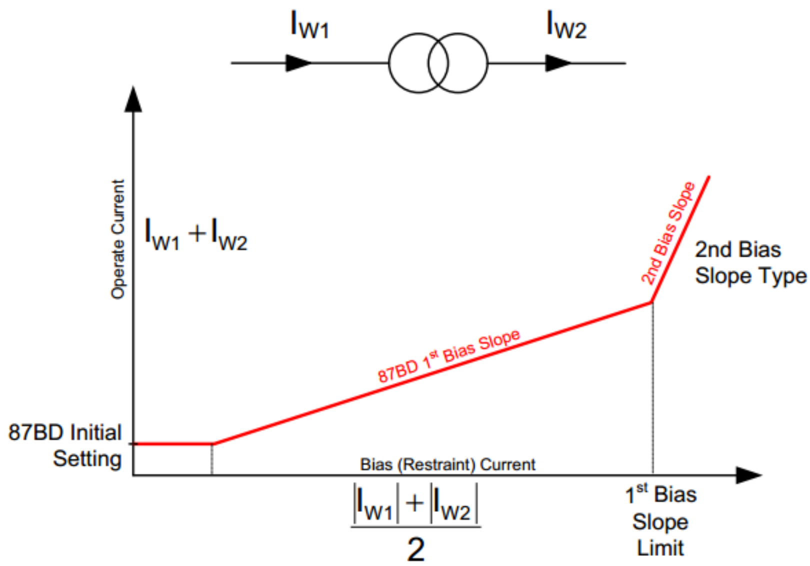


Figure 42 Differential pickup and biased settings

Source: https://electengmaterials.com/differential-protection-relay-87/

6.5 Simulations for various cases

The simulations for 132/33 kV, 5 MVA, YNd1 transformer with +5% to -15% tapping range were conducted in DIgSILENT for various cases and is given below.

a) Effect of Tap Change on Differential Current

The loading of transformer was varied from 40% to 150% along with variation of tap changer from normal to extreme tap. Continuous loading of 120% is done while 150% loading is limited to 30 minutes.

Table 19 Operation of Transformer at extreme position (Loading and tap change) and the differential current.

Tap Position	Tapping Range	Load (MVA)	CT Ratio		Differential Current, Primary Id (A)
			HV: 25/1A	LV: 100/1A	
			Stabilizing Current Primary (A)	Stabilizing Current Primary (A)	
1	5.00%	2.00	9.08	38.16	1.82
5	0.00%	2.00	9.01	36.05	0.00
17	15.00%	2.00	8.81	29.96	5.29
1	5.00%	4.00	19.73	82.87	3.95
5	0.00%	4.00	19.41	77.65	0.00
17	15.00%	4.00	18.63	63.33	11.18
1	5.00%	6.00	32.97	138.49	6.59
5	0.00%	6.00	31.84	127.36	0.00
17	15.00%	6.00	29.51	100.32	17.70
1	5.00%	7.50	47.25	198.45	9.45
5	0.00%	7.50	43.85	175.40	0.00
17	15.00%	7.50	38.66	131.45	23.20

The maximum differential current of 23.2 A is observed when the transformer is loaded up to 150% at Tap 17. Since the pickup setting is 0.3 pu which means 30 A primary current, hence the relay does not mal operate even with extremes cases of transformer operation.

Further with increase in load and tap position, slope one gets activated, hence the pickup setting increases proportionately.

b) Differential Relay operation for Pickup Setting=0.3pu, Slope 1= 35% and Slope 2= 75%

Table 20 Differential Relay operation under various fault condition

Pickup Setting= 0.3pu, Slope 1=35% and Slope 2=75%, Operating at Normal Tap and 100% Loading							
Fault Type	**Stabilizing Current (A)**			**Differential Current (A)**			**Tripping Time (s)**
	A-Phase	**B-Phase**	**C-Phase**	**A-Phase**	**B-Phase**	**C-Phase**	
Normal Load Flow	101.15	101.15	101.15	0	0	0	9999.99
Fault on 132 kV Bus : Since the source of fault current is the 132 kV feeders and there are no fault current sources downstream of the transformer, hence differential relay doesn't operate.							
Fault on 33 kV Bus (Out of Zone Fault)							
LLLG	994.78	994.78	994.78	0	0	0	9999.99
LL	0	862.64	862.64	0	0	0	9999.99
SLG	587.28	293.64	293.64	0	0	0	9999.99
LLG	262.41	860.94	883.54	0	0	0	9999.99
Fault on HV Winding (In Zone Fault)							
LLLG	7157.04	7157.04	7157.04	14314.09	14314.09	14314.09	0.015
LL	3712.41	3712.41	7424.82	7424.82	7424.82	14849.64	0.015
SLG	5587.04	5587.04	0	11174.09	11174.09	0	0.015
LLG	6221.05	3619.65	7291.06	12442.11	7239.3	14582.13	0.015
Fault on LV Winding (In Zone Fault)							
LLLG	497.37	497.37	497.37	994.78	994.78	994.78	0.015
LL	0	431.32	431.32	0	862.64	862.64	0.015
SLG	440.46	293.64	293.64	880.93	0	0	0.015
LLG	262.41	561.67	527.97	0	916.24	978.67	0.015

Where,

LLL :3 Phase Short Circuit

LL :2 Phase Short Circuit

SLG :Single Phase to Ground

LLG :2 Phase to Ground

The above results indicates that the differential relay does not operate for out of zone fault however, when the fault exists within its zone of protection, huge differential current flows which trips the circuits. The operating time of '9999.99' indicates no relay operation while '0.015 s' indicates relay tripping within 15 ms.

6.5.1 Graphical Display

3-phase short circuit fault was simulated on LV side of transformer and the relay tripped within 15 ms as shown in the figure below.

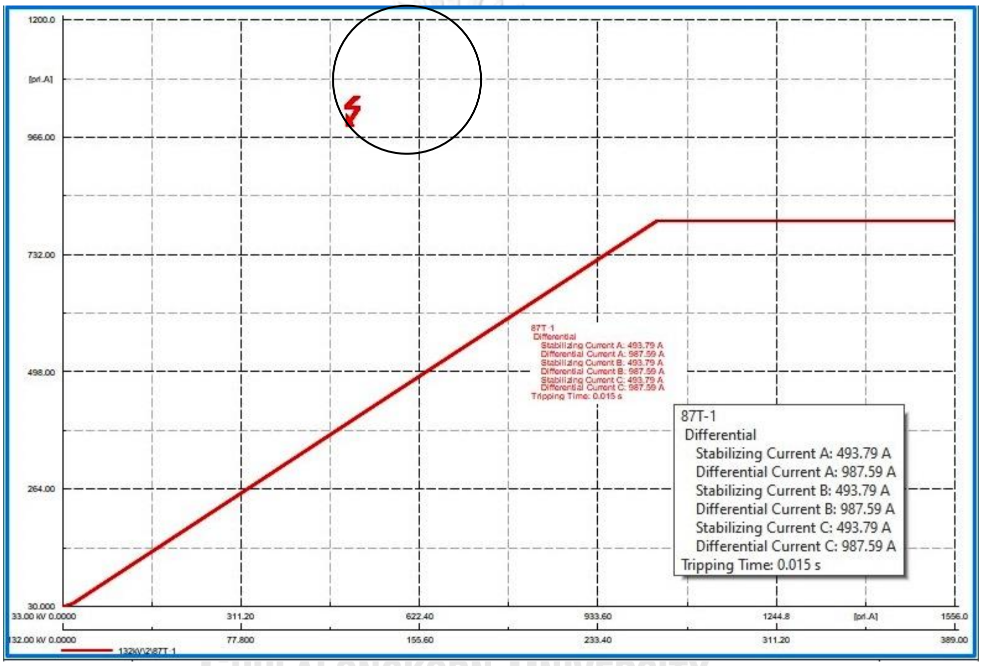


Figure 43 Differential relay operation for in zone fault at LV side

The differential current lies on operation zone hence, the relay trips. While during normal operation the differential current is zero as shown by the figure below.

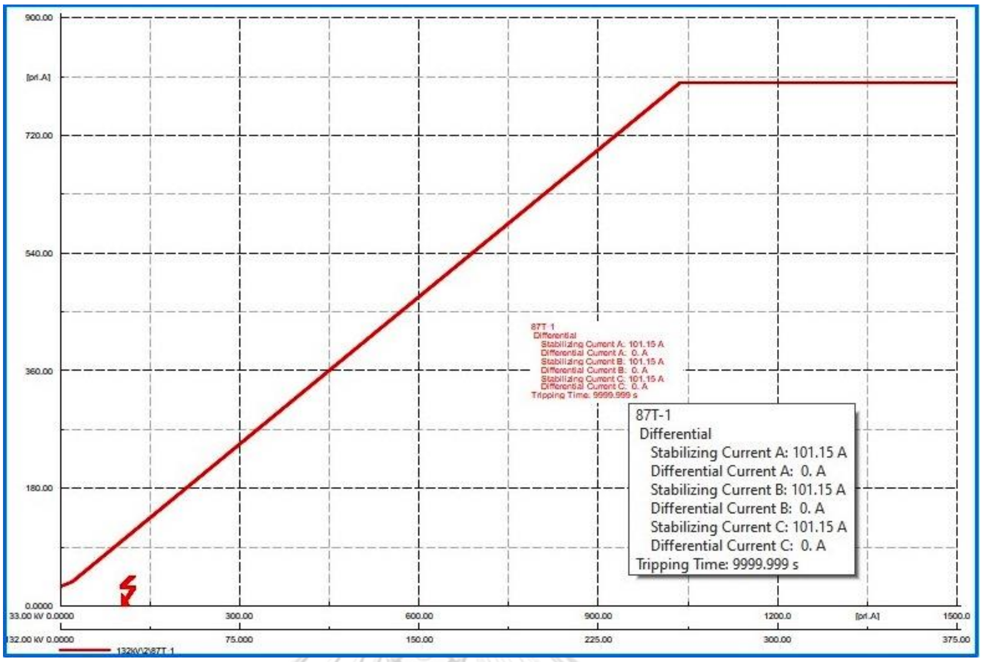


Figure 44 Status of differential relay for normal operation

6.6 Restricted Earth Fault Protection

Often the transformers are exposed to the earthfault. To protect against the earth fault, there must be a zero-sequence current path. The neutral of star windings or the artificial neutral earthing through zig zag transformer offers the flow to zero sequence currents.

The type of neutral earthing decides the magnitude of the earth fault current. Neutral earthing may be solidly, or resistance earthed.

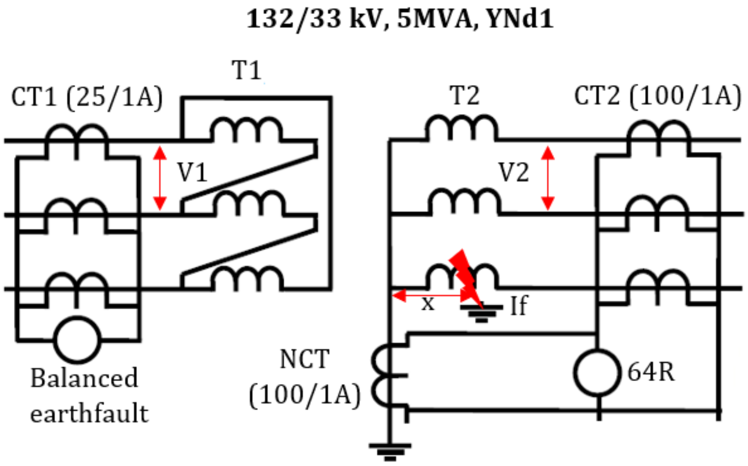
Resistance Earthing of Star Winding

Occurrence of earth fault in any windings results into a current which is limited by earthing impedance. The magnitude of the fault current is proportional to the distance of the fault from the neutral point. The voltage at the fault point will be proportional to its distance from the neutral point.

The short-circuited turns distort the transformer ratio. The ratio obtained between the primary winding and the fault location in the winding indicates the fault position.

Thus, it is evident that the current flowing through the transformer terminals is proportional to the square of the proportion of the windings short circuited.

Let us assume the following case.



Where,

CT1/CT2	*: Current Transformer (HV/LV Side)*
T1/T2	*: No. of Turns on HV/LV Winding*
V1/T2	*: Line to Line Voltage on HV/LV Side*
NCT	*: Neutral Current Transformer*
If	*: Fault Current*
x	*: Distance of fault location from neutral point*
64R	*: Restricted Earthfault Relay*

The secondary current of CT on HV side of transformer is given by,

$$I = \frac{x^2}{\sqrt{3}}$$

Thus, if differential setting of 64 REF is 10%, then for relays to operate 'I' must be greater than 10%.

$$\frac{x^2}{\sqrt{3}} > 10\%$$

$$x > 41.62\%$$

This indicates 58.38% is protected or 41.67% of the winding is unprotected. The summary is tabulated as given below.

Table 21 Differential relay setting (64R) vs. the % of winding protected.

Differential Setting (64R)	Protected Winding (%)
10%	58.38
20%	41.14
30%	27.92
40%	16.76
50%	6.94

Higher the differential setting, the % of winding protected is reduced. ESI 48-3 1977 recommends the differential setting to be in between 10% to 25% of minimum earthfault current for resistance earthed system.

Solid Earthing of Star Winding

Since there is no resistance to limit the fault current, hence the leakage reactance of the winding will try to limit the fault current to about 3 to 5 times the full load current. ESI 48-3 1977 recommends the differential setting to be in between 10% to 60% of the winding rated current for solidly earthed system.

Often instantaneous Earth Fault protection, restricted to the protection of transformer faults are deployed. Such schemes restrain from operation for external or out of zone faults. This is known as balanced earthfault or restricted earthfault and is connected in the unearthed residual path of the parallel connection of the phase CT secondaries.

6.7 Amendments recommended in BPC Relay Setting Guidelines

2.0 Setting of Transformer Protection Relays		
2.1 Transformer Differential Protection Setting		
Clause	BPC Version	Proposal
2.1.1	The pickup of differential element shall be set at 0.2pu and bias element shall be set at 1.2pu.	The pickup setting of differential element shall be the sum of OLTC tapping limit, CT mismatch error, CT accuracy error (5%), and safety margin of 10%. The bias element may be set to 1.5 pu owing to the 150% overloading of transformer in worst case scenario.

6.8 Recommendations for Differential Protection Settings

a) Calculate the CT mismatch error between the HV and LV CT.

b) Find out the tapping range of on load tap changer of transformer and calculate the maximum differential current at extreme taps.

c) The typical minimum value of pickup current is 30% to 35% of the nominal current considering the CT errors, tapping range, etc.

d) The Slope 1 may be set to 30% to 40% depending on the CT ratio mismatch, CT errors, CT measurement errors and safety margin. The settings may vary for electromechanical /static and numerical relays.

e) Slope 2 may be set to 70% to 80% to compensate the transient phenomenon errors such as the CT saturation on through faults.

7 DISTANCE PROTECTION

7.1 Introduction

As the impedance of the line is proportional to its distance, a relay capable of measuring the impedance can be used to determine the distance of faults. Distance relay operates for a fault within the selected reach point, thus ensuring the discriminations for faults in other line sections. Unlike overcurrent and earthfault protection, the fault coverage of the protected line by distance protection is independent of the variations in source impedances.

The basic principle is the division of voltage by current at the relaying point which results in apparent impedance. The apparent impedance is then compared with the predetermined impedance known till the reach point. Should the apparent impedance be less than the predetermined value, it is an indication of fault between the reach point and the relay. The fundamental of distance relay is shown by Figure 45.

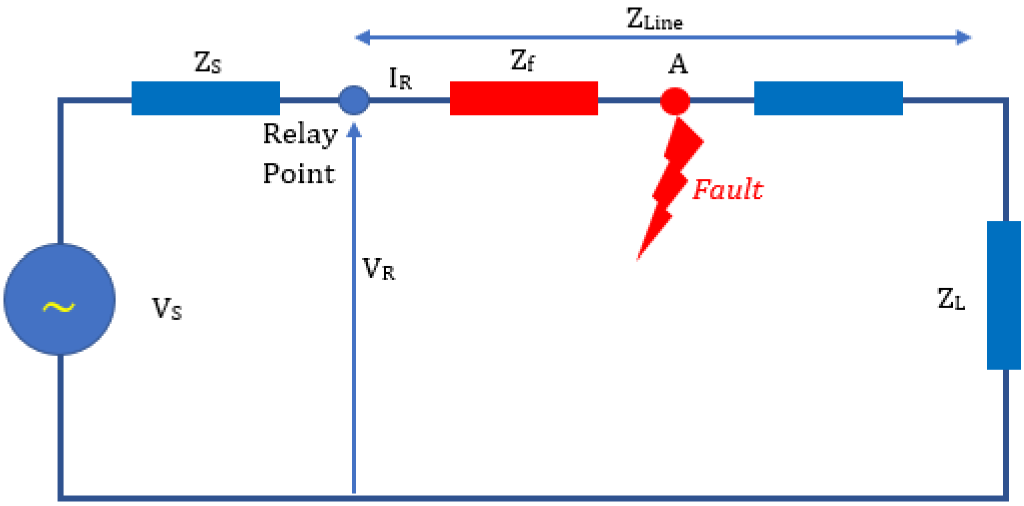


Figure 45 Distance Relay Principle

Where,

V_S : *Source Voltage,*

Z_S : *Source Impedance*

V_R : *Voltage at Relaying Point*

I_R : *Current at Relaying Point*

Z_f : *Fault Impedance*

Z_{Line} : *Line Impedance*

ZL : *Load Impedance*

Consider a fault at point 'A'.

Impedance measured by the relay (Z_R):

$$Z_R = \frac{V_R}{I_R} = Z_f$$

Therefore, the impedance relay will operate if $Z_f<Z$, where Z is the line impedance set in the relay.

The intersection of the boundary characteristics of the relay and the line impedance locus, forms the reach point of the relay. As the reach point is the ratio of voltage and current along with the phase angle, hence RX diagram may be plotted for better analysis.

Distance relay caters to line faults, secondary side faults, deadline charging and abnormal system conditions such as power swing. Impedance relay and Mho relays are the broad categories of distance relay.

7.2 Zones of Protection

Distance protection is divided into several zones as shown in Figure 46. The reach settings and tripping times of the respective zones must be carefully selected for proper coordination. Numerical relays have up to five zones.

Zone 1- For electromechanical or static relay, zone one is set to 80% of the protected line and is instantaneous. 85% reach setting may be safe for numerical relays. The balance of 15- 20% is the safety margin to accommodate the overreach due to instrument transformers errors, inaccuracies in line impedance data and relay errors. Zone 2 must cover the remaining 15-20% of the protected line.

Zone 2- The reach is minimum of 120% of protected line, to cover the remaining section of protected line. Setting of 100% of the protected line with 50% of the

shortest adjacent line are also practiced. Intentional time delay of about 350 ms is set.

Zone 3- This zone provides the backup protection for all faults on adjacent line. The reach should be at least 1.2 times the impedance set in the relay for a fault at the remote end of the second line section. On an interconnected system, the effect of fault current infeed at the remote end busbar must be considered while setting the zone 3 settings. This is because the due to the infeed fault current, the impedances seen by the relay may be greater than the actual impedance of the fault location.

Zone 4- Numerical relays are associated with additional zones and is often used to provide back-up protection for the local busbar. It involves the application of a reverse reach setting of the order of 25% of the Zone 1 reach.

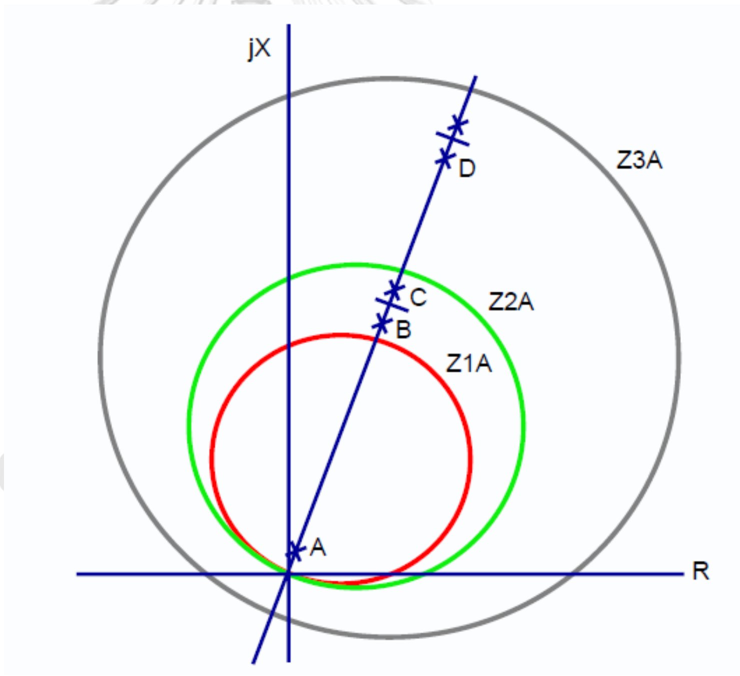


Figure 46 Zones of Protection

7.3 Distance Relay Characteristics

The numerical relays measure the absolute impedance, to determine the operation or relays within its defined zone in RX diagram. On the other hand, electromechanical or static relays compares the measured fault voltage with the

replica of voltage derived from fault current. The difference is then compared with the impedance setting to determine its zone of operation.

Relay impedance comparators obtains the operating characteristics through the comparison of either the relative amplitude or the phase of the two quantities. When the operating characteristics are plotted on the RX diagram, it is either straight lines or circles.

The relay characteristics pertaining to the distance relays are explained below.

7.3.1 Amplitude and Phase Comparison

The impedance element in the distance relay compares the voltage and the current quantity measured by the relay. The comparison may vary with the technology used such as the balanced beam (amplitude comparison), induction cup (phase comparison) for electromechanical relays. Static distance relays employ diode and operational amplifiers. Numerical relays use algorithms and digital sequence comparators are observe in digital relays.

The impedance characteristics obtained from any comparators are similar. For instance, circular impedance characteristics centered at the origin of RX diagram is obtained by V & I comparator. Similarly, the sum or difference of V & I when applied to the phase comparator yields similar characteristics.

7.3.2 Plain Impedance Characteristics

Independent of the phase angle between the voltage and current, impedance characteristics is a circle on RX diagram as shown in Figure 47. The center of the circle is the origin (A) and the setting in ohms forms the radius (M). The ohmic circle is the pivotal point for the relay operation. If the fault impedance is lesser than the radius, relay operates all along the vector AL and AM, irrespective of the directions and beyond 'M' and 'L' it restrains. The angle BAR forms the line angle.

So, if the setting is 80%, then the relay will operate for forward as well as reverse line from the relaying point 'A'.

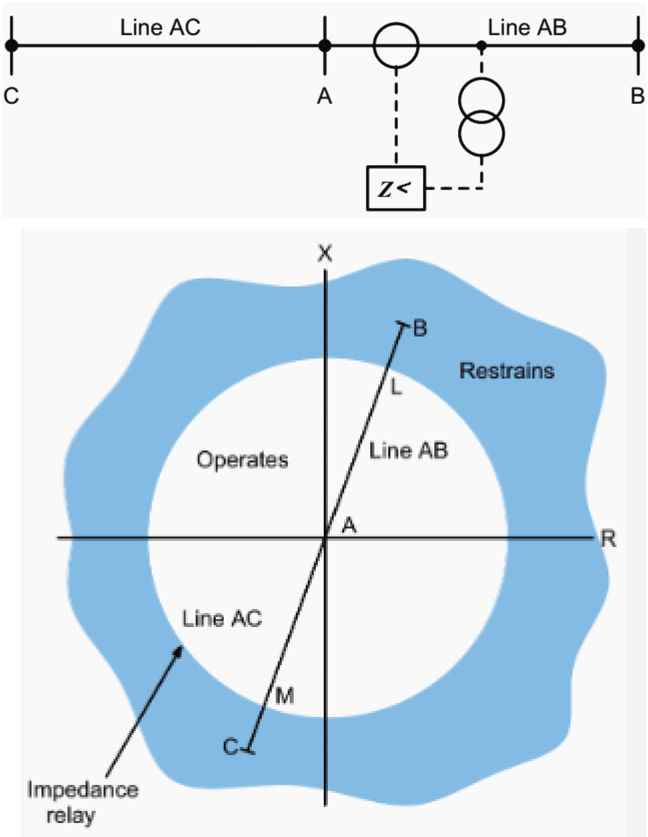


Figure 47 Impedance Relay

Image taken from https*://electrical-engineering-portal.com/distance-relay-characteristics)*

However, the fault detection is non directional confusing the location of fault by the operators and lineman. Thus, it requires directional element to provide correct sense of direction. Besides the non-uniform fault resistance coverage, it is susceptible to power swing.

With the addition of directional element to the distance relay as shown in Figure 48, the operating zone or forward direction is defined by semi-circle APLQ in the RX diagram. With directional element, fault discrimination is distinctive with distance relay.

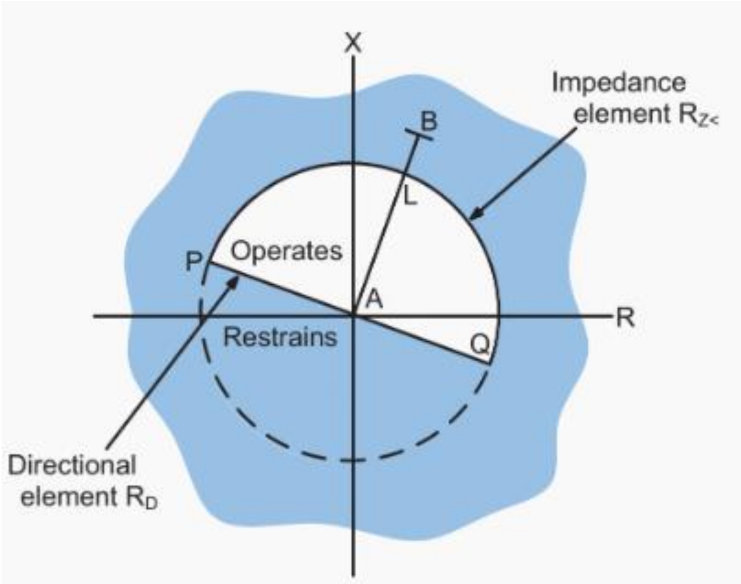


Figure 48 Impedance Relay with Directional Element

(Image taken from https://electrical-engineering-portal.com/distance-relay-characteristics)

Since there are directional element and the impedance element in this case, hence for a parallel feeder protection, proper coordination between the directional and impedance element becomes difficult. Directional element may restrain while impedance element tries of operate or wrong operation of the relay will occur, which is termed as **'contact race'**.

7.3.3 Self-Polarized Mho Relay

With a straight-line characteristic on an admittance diagram, the mho impedance element eliminates the **'contact race'** problems by combining the discriminating qualities of reach control as well as directional control. The contact race occurs if there is separate reach and directional element.

Discriminating features is being obtained by employing a voltage restraint polarizing signal. In fact, Mho relay is a voltage restraint directional relay. The torque equation for the mho relay or admittance relay is given by;

$$Torque, T = K_3 V_R I_R Cos(\theta - \tau) - K_2 V_R^2 - K_4$$

Where,

$K_3 V_R I_R Cos(\theta - \tau)$: *Directional Element (Operating Torque)*

$K_2 V_R^2$: *Polarizing Signal (Restraining Torque)*

V_R, I_R : *Voltage and Current measured by the Relay*

K : *Constant*

The net torque will be positive if the torque generated by directional element is greater than that of the voltage restraint coil.

$$K_3 V_R I_R Cos(\theta - \tau) - K_4 > K_2 V_R^2$$

$$\frac{K_3 V_R I_R Cos(\theta - \tau)}{K_2 V_R I_R} - \frac{K_4}{K_2 V_R I_R} > \frac{K_2 V_R^2}{K_2 V_R I_R}$$

$$\frac{K_3 Cos(\theta - \tau)}{K_2} - \frac{K_4}{K_2 V_R I_R} > \frac{V_R}{I_R}$$

$$\frac{V_R}{I_R} < \frac{K_3 Cos(\theta - \tau)}{K_2} - \frac{K_4}{K_2 V_R I_R}$$

$$Impedance\ measured\ by\ Relay, Z_R = \frac{V_R}{I_R}$$

$$Impedance\ set\ in\ the\ relay, Z_S = \frac{K_3 Cos(\theta - \tau)}{K_2}, and\ \frac{K_4}{K_2 V_R I_R} \cong 0,$$

$$\because\ K_2 V_R I_R \gg K_4$$

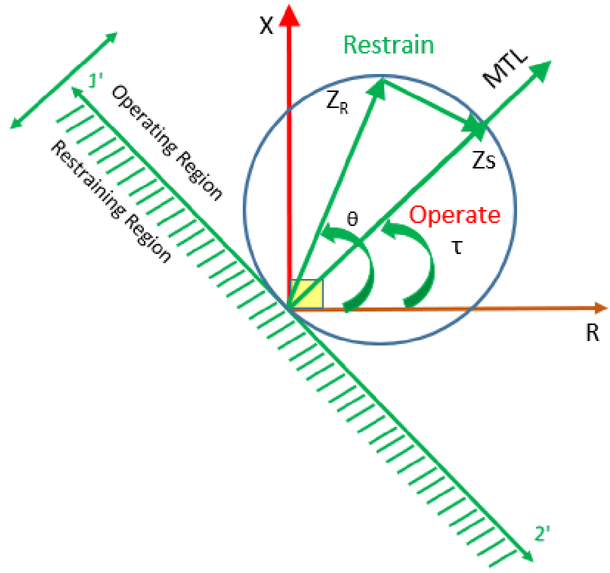


Figure 49 Mho Impedance Relay

The plane 1'-2' is the zero-torque line of the directional element which separates the operating region and the restraining region. The operating region is further confined to the area inside the relay by the set impedance. Outside of the circle forms restraining region. The measured impedance may move around the circle depending on the value of θ and τ.

However, for arching fault conditions, such as the earthfault connected to tower footing resistance or tree touching the line, the line angle tends to change due to the change in the resistive component of the fault impedance.

In such a scenario, a relay having equivalent line angle and the relay characteristic angle, will under-reach under resistive fault conditions as depicted in Figure 50.

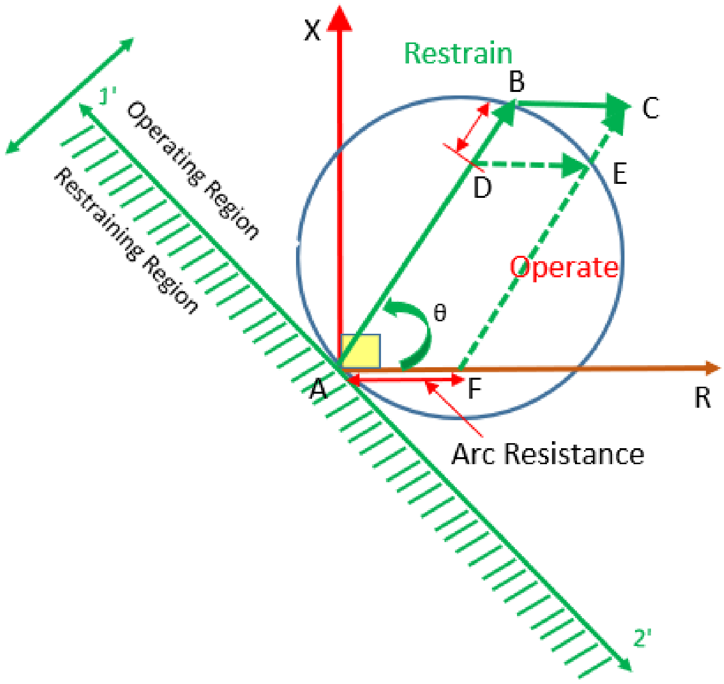


Figure 50 Effect of Arc Resistance on Mho Impedance Relay

Because of the fault resistance 'AF', the line impedance shifts from 'AB' to 'FC'. The actual fault resistance is BC however due to the circular characteristics of mho relay; the line impedance intersects at 'E'. Upon projection, the relay measures the impedance 'AD' instead of 'AB', hence the relay under reaches.

$$\%\,Underreach = \frac{DB}{AB} \times 100$$

Therefore, mho relay is more prone to arc resistance fault.

7.3.4 Offset Mho characteristics.

In a worst-case scenario, the voltage may collapse to zero or near-zero, thus the self-polarized directional features of impedance relays get lost. Relay fails to operate for faults.

In such case, offset mho characteristics can be used to shift the mho characteristics to embrace the origin, thus forming a non-directional feature which can cater to the close faults in forward and reverse directions. Current bias must be used.

The main application of the offset mho relays are as follows.

Zone 3 or Reverse Zone

In this case, fault impedance is detected by the mho element and/or zone 3 measuring unit. The reverse reach obtained by offset mho provides the backup protection to bus bar faults. Quadrilateral characteristics can also be used to provide the third zone and reverse zone features.

For Switch on To Fault (SOTF) protection, the time delay of Zone 3 will be bypassed momentarily following line energization so that the un-intended fault such as the non-removal of earth switch will be cleared as fast as possible.

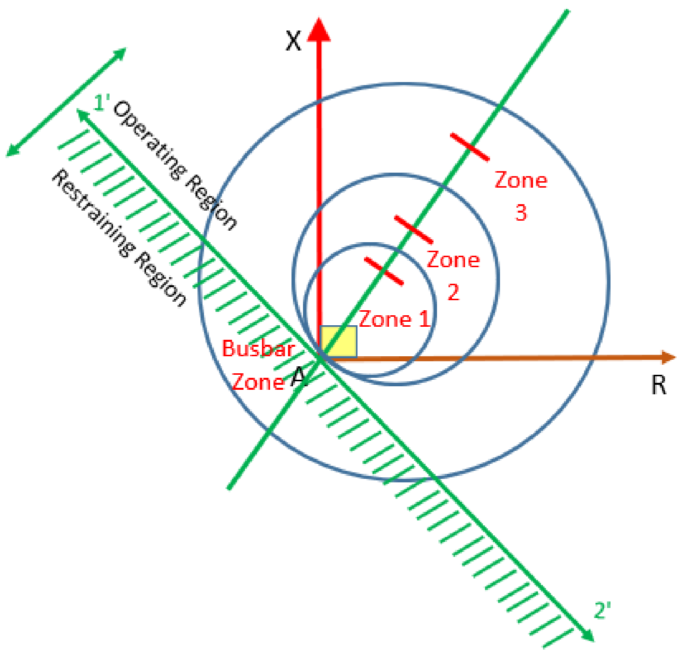


Figure 51 Third Zone and Busbar Backup Zone with Offset Mho relay

Carrier starting unit in Distance Schemes with carrier blocking.

Offset mho element can be used to initiate the carrier signaling wherein the carrier signal is transmitted for faults external to the protected line but within the reach of

offset mho relay. Carried aided tripping will prevent the operation of Zone 2 or 3 at remote substation. Besides the offset mho characteristics, the close to zero voltage faults can also be mitigated by fully cross polarized mho characteristics or partially cross polarized mho characteristics.

Fully cross polarized mho characteristics refers to the addition of percentage of other healthy phases voltage to the main polarizing voltage. This provides the substitute phase reference in the event of fault. Partially cross polarized uses relatively smaller portion of cross polarization. The percentage of cross polarization must be sufficient to provide directional control.

7.3.5 Lenticular Characteristics

Often the reach of Zone 3 is comparatively large to provide remote backup protection of the adjacent feeders. In the process, there is a high probability that the offset mho element may operate under maximum load transfer conditions.

Maximum load transfer is characterized with resistive coverage, hence instead of circular mho, lenticular shape can be utilized, such that the aspect ratio of lens will enable the maximum fault resistance coverage as shown in Figure 52.

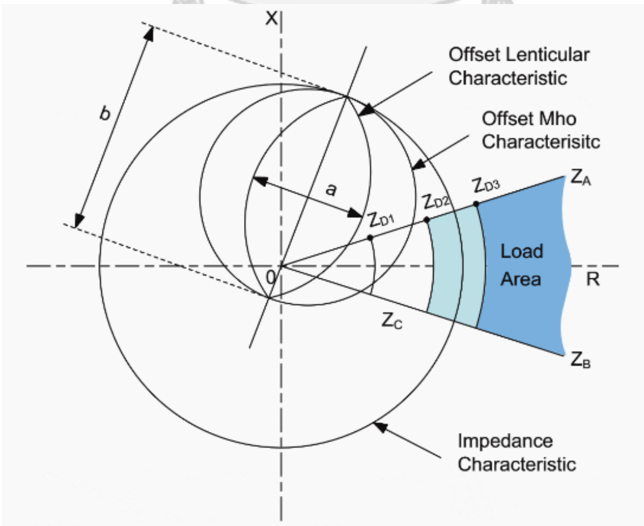


Figure 52 Minimum Load Impedance with Lenticular Characteristics (Image taken from https://electrical-engineering-portal.com/distance-relay-characteristics)

When the load impedance is reduced from ZD3 to ZD1, equivalent increase in load current occurs and the operating regions can be adjusted by the aspect ratio of the lens (a/b). However, modern numerical relays use load encroachment (load blinders) detection instead of lenticular characteristics.

7.3.6 Quadrilateral Characteristics

Quadrilateral characteristics are characterized by polygonal impedance with independently adjustable forward and resistive reach setting, thus securing enhanced resistive coverage than the mho characteristics especially for short lines. The possibility of reach error problems for resistive earthfault can be avoided by employing alternative phase current polarization of the reactance reach line. The Figure 53 depicts the quadrilateral characteristics.

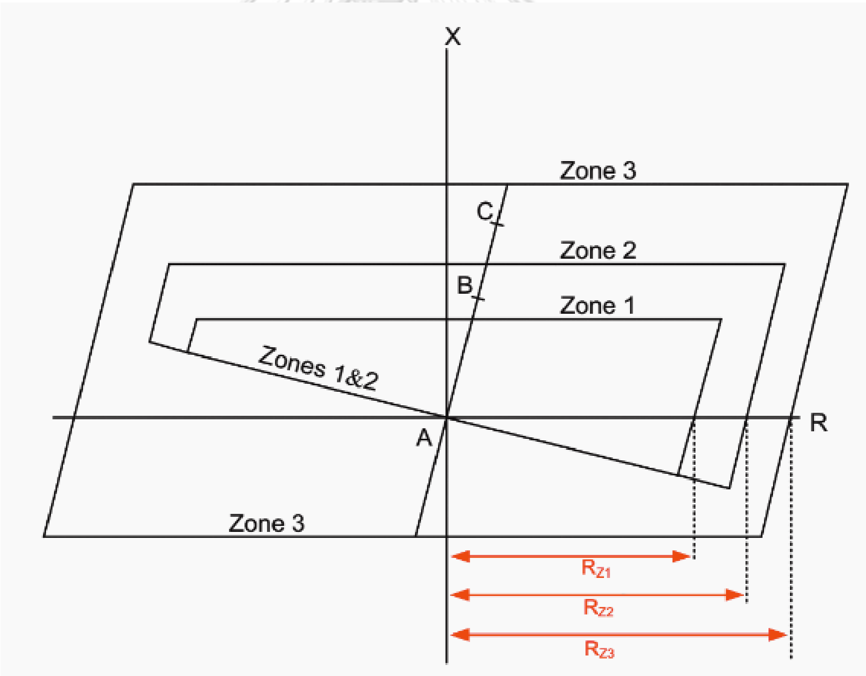


Figure 53 Quadrilateral Characteristics

(Image taken from https://electrical-engineering-portal.com/distance-relay-characteristics)

Due to the flexibility of the polygonal impedance characteristics, modern numerical relays often use quadrilateral characteristics.

7.4 Case Study of Distance Relay Setting in 132 kV Eastern Grid of Bhutan

Amongst various lines and substation in the 132 kV eastern grid of Bhutan, 132 kV Kanglung-Phuentshothang-Motanga has been considered as there is a double circuit line between Phuentshothang and Motanga. Further, there exists many adjacent lines along with large size power transformers connected to it. The outgoing line from Motanga Substation to Rangia, Nganglam and Deothang has been considered. The network is shown in Figure 54.

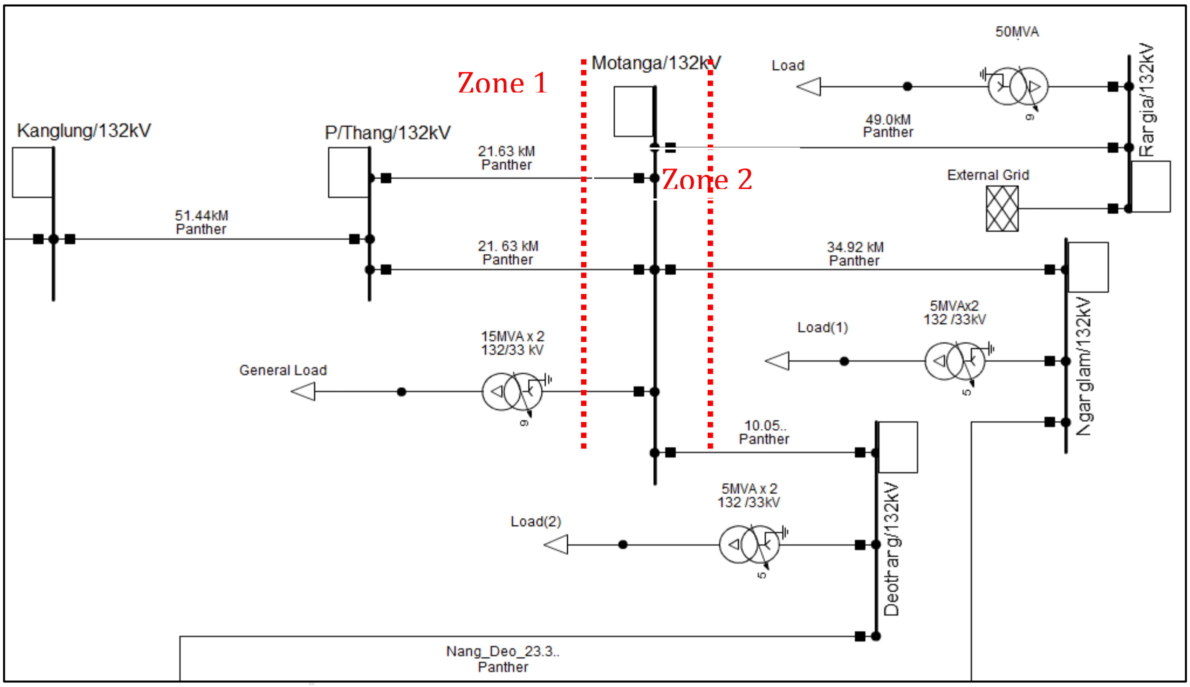


Figure 54 Single Line Diagram of the Case Study

Let us carry out the settings for distance relay at 132 kV, P/Thang Substation for the Motanga Feeders as per the existing criteria. The distance relay setting criteria in Bhutan is based on the criteria defined by Central Electricity of India [19]. Eastern Regional Power Committee, Ministry of Power, India communicated to Bhutanese counterparts vide letter NO.ERPC/PROTECTION/2015, dt. 06.10.2015 through fax Message no. 150.

Since the line is double circuit hence the parameters of the lines need to be changed accordingly and the criteria setting will be based on guideline of Central Electricity of India.

For double circuit Panther conductor, R1= 0.1622 Ωs/km and X1=0.4130 Ωs/km

Based on the above guidelines, the distance relay settings are calculated for 132 kV P/Thang Motanga Line as given below.

7.4.1 Zone Settings for Distance Relay

Zone 1 Setting (Z_1)

Sl.#	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
1	Zone-1	Forward	80%	Instantaneous (0)	As per CEA

$$Z_1 = 80\%\ of\ impedance\ of\ protected\ line\ \times line\ length$$

$$Z_1 = \frac{80}{100} \times (0.1622 + j0.4130) \times 21.63$$

The above calculation results in primary value, but relays require the input in secondary values, thus the primary value needs to be converted into secondary values.

$$\frac{Z_s}{Z_p} = \frac{Current\ Transformer\ Ratio(CTR)}{Potential\ Transformer\ Ratio(PTR)}$$

$$Z_s = Z_p \times \frac{CTR}{PTR}$$

Where, Z_p and Z_s are the impedances in primary and secondary values, respectively.

Therefore, the Zone 1 impedance in secondary value is;

$$Z_1 = \frac{80}{100} \times (0.1622 + j0.4130) \times 21.63 \times \frac{600/1}{132000/110}$$

$$Z_1 = \frac{80}{100} \times (1.7544 + j4.4666) = 1.4035 + j3.5733$$
$$= 3.839\measuredangle 68.556°\ \Omega s$$

Operating time =0 s, i.e., instantaneous.

Zone 2 Setting (Z_2)

Sl. #	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
2a	Zone-2	Forward	For single circuit : 120% of the protected line For double circuit : 150% of the protected line	0.5 s to 0.6 s-if Z2 reach overreaches the 50% of the shortest line: 0.35 s otherwise	As per CEA
2b	Zone-2 (for 220kV and below voltage Transmission lines of utilities)	Forward	120% of the protected line, or 100% of the protected line+50% of the adjacent shortest line	0.35s	

$$Z_2 = 120\%\ of\ impedance\ of\ protected\ line\ \times line\ length \times \frac{CTR}{PTR}$$

$$Z_2 = \frac{120}{100} \times (0.1622 + j0.4130) \times 21.63 \times \frac{600/_1}{132000/_{110}}$$

$$Z_2 = \frac{120}{100} \times (1.7544 + j4.4666) = 2.1053 + j5.3599$$
$$= 5.7586\measuredangle 68.556°\ \Omega s$$

Operating time =0.35 s. 0.5 to 0.6 s if Z_2 reach overreaches the 50% of the shortest line.

Zone 2 encroachment to Next Voltage Level at Motanga Substation

Impedance seen by the Distance Relay at P/Thang including the transformer impedance (15 MVA, 9.37%) at Motanga Substation is calculated as follows.

$$Z_{2'} = \left(Impedance \times ProtectedLineLength \times \frac{CTR}{PTR}\right) + (Transformer\ Impedance)$$

$$Z_{2'} = ((0.1622 + j0.4130) \times 21.63 \times \frac{600}{1200}) + (\frac{132^2}{15} \times 0.0937 \times \frac{600}{1200})$$

$$Z_{2'} = 56.1751 + j4.4666$$
$$= 56.3525\measuredangle 4.5461°\Omega s\ for\ single\ transformer$$

For two transformers in parallel operation, the 25 MVA, 132/33 kV Power Transformer of the factory about 50 m away from the substation needs to be considered :

$$Z_{2'} = ((0.1622 + j0.4130) \times 21.63 \times \frac{600}{1200}) + (\frac{132^2}{25} \times 0.1249 \times \frac{600}{1200})$$

$$Z_{2'} = 45.2793 + j4.4666 = 45.4991\measuredangle 5.6337°\ \Omega s$$

When paralleled:

Z_2=(56.3525x45.4991)/(56.3525+45.4991)=27.1738 **Ω**s

In both cases, the measured impedance is more than the set impedance hence the Zone 2 does not encroach to the next voltage level of Motanga Substation.

Zone 2 overreach condition for 50% of the shortest line.

A fault occurs within its protected zone 1, and the fault impedance seen by the relay is more than the zone 1 impedance. In fact, the fault impedance seen by the relay should be lesser so that the relay will operate. This phenomenon is called Underreach which means it is not able to protect 100% of the line. Underreach is generally caused by remote infeed.

On the contrary, the tendency of the relay to operate for fault beyond its reach setting is called as Overreach and is mostly observed in double circuit line due to the mutual inductance or the load at remote substation.

Condition for Overreach $1.2Z_L > Z_L + 0.5Z_S$

Where:

Z_L *: Impedance of the protected line*

Z_S *: Impedance of shortest adjacent line*

The shortest line is the 132 kV, Druk Metallurgy Limited (DML) Feeder which is 0.49 km.

$$Z_{2'} = (Impedance \times (Protected\ Line\ Length \times \frac{CTR}{PTR}) + (Impedance \times 50\%\ of\ Shortest\ Line\ Length) \times \frac{CTR}{PTR})$$

$$Z_{2'} = (0.1622 + j0.4130) \times ((21.63 \times \frac{600}{1200}) + (50\% \times 0.49) \times (0.1622 + j0.4130) \times \frac{600}{1200})$$

$$Z_{2'} = 1.7741 + j4.5172 = 4.8531\measuredangle 68.558°\ \Omega s$$

Since Zone 2 set impedance is more than the total impedance including 50% of the shortest line, the Z2 overreaches 50% of the adjacent shortest line. Hence the operating time may be 0.5 s.

Zone 3 Setting (Z_3)

Sl.#	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
3	Zone-3	Forward	120% of the (Protected Line + Next longest line)	0.8-1.0s	As per CEA

Zone 3 acts as a backup protection for the adjacent longest line. The 49 km transmission line from Motanga Substation to Rangia Substation is the longest line. Should the distance relay for Motanga-Rangia fails, then the Zone 3 of the distance relay at P/Thang Substation for Motanga Feeder should operate and clear the fault.

$$Z_3 = 120\% \times Impedance \times (Protected + adjacent\ longest) line\ length \times \frac{CTR}{PTR}$$

$$Z_3 = 120\% \times (0.1622 + j0.4130) \times (21.63 + 49.00) \times \frac{600}{1200}$$

$$Z_3 = 6.8737 + j17.5021 = 18.8035\measuredangle 68.556\ \Omega s$$

It is prudent to check if Zone 3 encroaches the next voltage level of the longest adjacent line. If it encroaches, then time delay must be increased to coordinate with

the relay setting of the transformers. This will allow the relays at the transformer side to operate prior to Zone 3 tripping.

In our case, the next voltage level of longest adjacent substation (Rangia Substation) is 33 kV, which is derived from 2 nos. of 132/33 kV, 25 MVA transformers. It has an impedance of 12.49% at normal tap position.

Distance relay will operate if the fault impedance measured by the relay is less than the set impedance in the relay. If there is a 3-phase short circuit fault, at 33 kV bus of Rangia Substation and if the impedance seen by the relay at P/Thang Substation for Motanga Feeder is less than the set impedance, relay will operate. This means Zone 3 encroaches the next voltage level at Rangia Substation.

Impedance seen by the distance relay at P/Thang including the transformer impedance at Rangia Substation is calculated as follows.

$$Z_{3'} = (Impedance \times (Protected + adjacent\ longest) line\ length \times \frac{CTR}{PTR}) + (Transformer\ Impedance)$$

$$Z_{3'} = ((0.1622 + j0.4130) \times (21.63 + 49.00) \times \frac{600}{1200}) + (\frac{132^2}{25} \times 0.1249 \times \frac{600}{1200})$$

$$Z_{3'} = 49.2532 + j14.5851 = 51.3674\measuredangle 16.4953° \Omega s\ for\ single\ transformer$$

For two transformers in parallel operation:

$$Z_{3'} = ((0.1622 + j0.4130) \times (21.63 + 49.00) \times \frac{600}{1200}) + (\frac{132^2}{25} \times \frac{0.1249}{2} \times \frac{600}{1200})$$

$$Z_{3'} = 27.4907 + j14.5851 = 31.1201\measuredangle 27.9481°\ \Omega s$$

In both cases, the measured impedance is more than the set impedance hence the Zone 3 does not encroach to the next voltage level of Rangia Substation. If it

encroaches, then the time delay should be coordinated with the relay setting of transformers at Rangia Substation.

Zone 4 Setting (Z_4)

Sl.#	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
4	Zone-4	Reverse	10%- for long lines (for line length of 100 km and above), 20%-for short lines (for line length of less than 100 km)	0.5	As per CEA

Zone 4 is function as a backup protection for the bus bar protection of the relaying point substation in reverse direction unlike other zones of protection. If the lines emanating from the relaying point substation is more than 100 km, the protected line reach setting is taken as 10% of Zone 1 impedance and if less than 100 km, it is 20%.

Sine the lines under consideration in this study case is below 100 km, the setting shall be 20% of Zone 1 impedance.

$$Z_4 = 20\% \times Impedance \times Protected\ line\ length \times \frac{CTR}{PTR}$$

$$Z_4 = 20\% \times (0.1622 + j0.4130) \times (21.63) \times \frac{600}{1200}$$

$$Z_4 = 0.3508 + j0.8933 = 0.9597\measuredangle 68.556\ \Omega s$$

Here, it should be noted that in the event of fault at the busbar of the substation, busbar differential should operate. In case there is no busbar differential protection, then the Zone 2 of the adjacent line from the adjacent substation should clear the fault. If in case it does not, then Zone 4 of the relay at the relaying substation will operate to clear the fault.

The operating time is 500 ms.

7.4.2 Resistive Reach for Phase to Phase and Phase to Ground Faults

From the above calculations the distance relay settings are as given below.

$$Zone\ 1\ (Z1): 3.839\measuredangle 68.556°\ \Omega s$$
$$Zone\ 2\ (Z2): 5.7586\measuredangle 68.556°\ \Omega s$$
$$Zone\ 3\ (Z3): 18.8035\measuredangle 68.556\ \Omega s$$
$$Zone\ 4\ (Z4): 0.9597\measuredangle 68.556\ \Omega s$$

The RX diagram for the above settings is given in Figure 55.

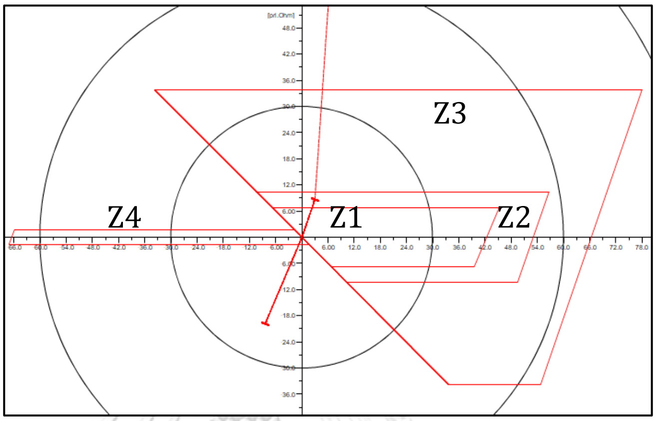
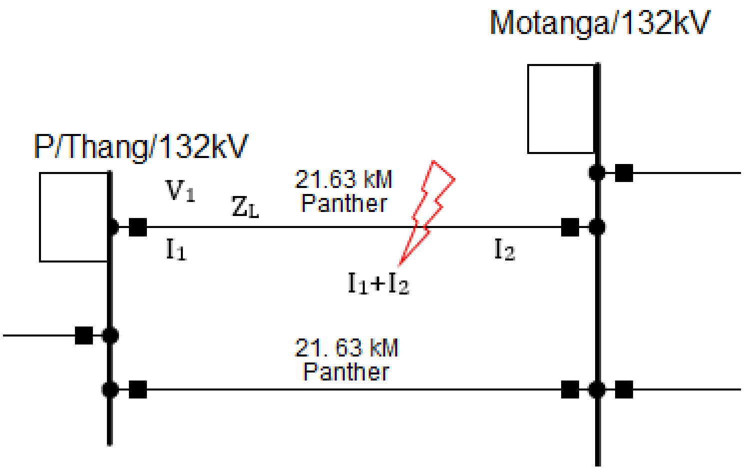


Figure 55 Zone Reach Settings

Case A : Assume a phase fault occurred between 132 kV P/Thang to Motanga line.



$$V_1 = Z_L I_1 + (I_1 + I_2) R_f$$

Where:

Z_L : *Impedance of the protected line*

I_1 : *Fault Current injected from P/Thang Substation*

I_2 : *Fault Current injected from Motanga Substation*

R_f : Arc Resistance

Dividing the above formula by I_1

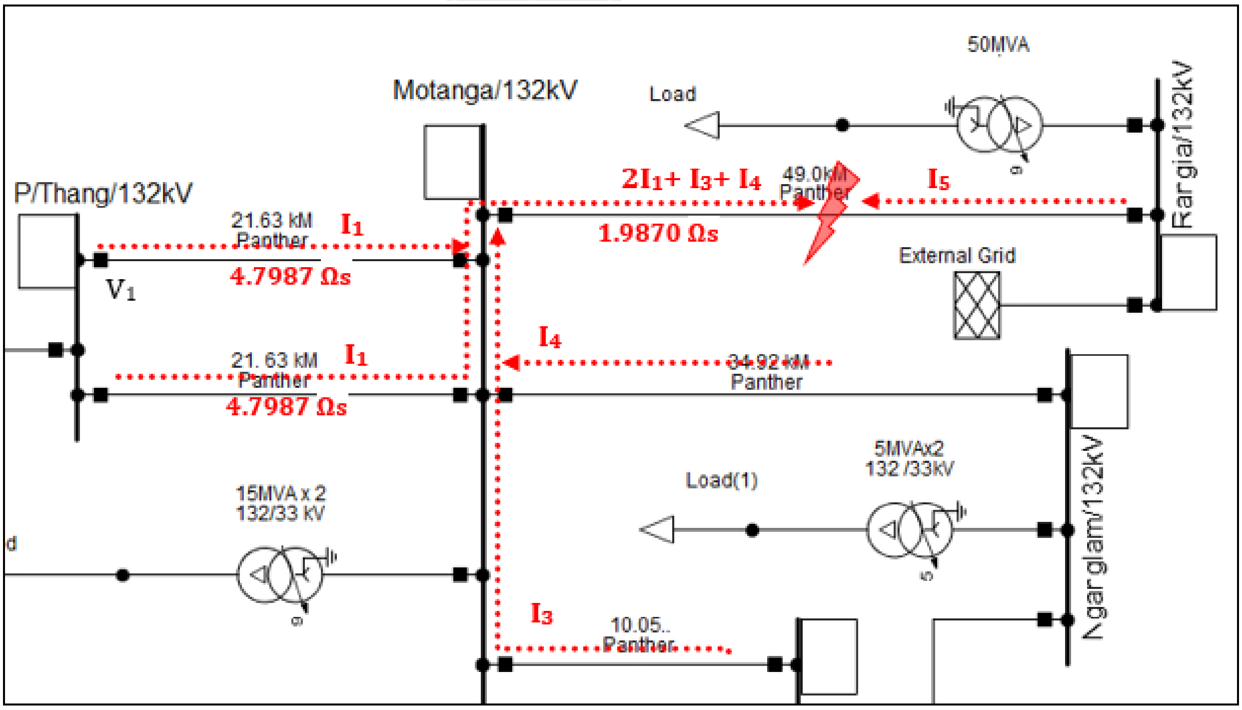
$$\frac{V_1}{I_1} = RR_{Z2-Ph} = Z_L + \left(1 + \frac{I_2}{I_1}\right) R_f = 4.7987 + \left(1 + \frac{I_2}{I_1}\right) R_f$$

Where, $RR_{Z2\text{-}Ph}$ denotes the Resistive Reach of Zone 2 for phase fault.

The ratio of I_2/I_1 I called as the infeed factor. If I_2 is equal to I_1, the fault lies equi-distance from both substations. If $I_2>I_1$, it indicates that the fault lies closer to Motanga Substation and vice versa. This is because more the resistance of the line lesser is the fault current injected.

If the fault lies in Zone 2, the fault current I_2 will be much higher than I_1 hence the infeed factor will increase.

Case B : Assume a phase fault occurred between 50% of 132 kV Motanga-Rangia line.



Voltage sensed by Relay at Phuentshothang Substation

$$V_1 = (I_1 \times 4.7987) + [(2I_1 + I_3 + I_4) \times 1.9870] + [(2I_1 + I_3 + I_4 + I_5) \times R_f]$$

Dividing the above equation by I_1 we get:

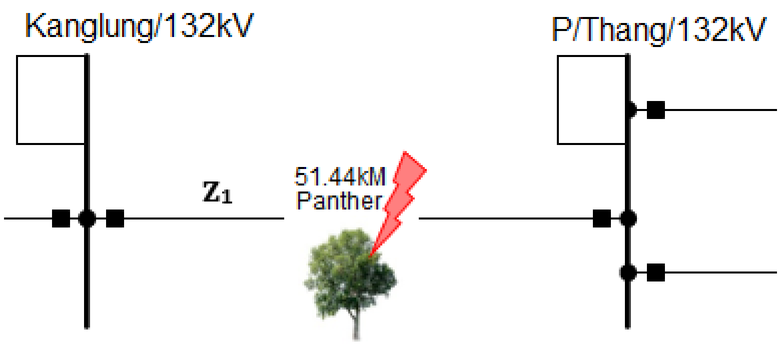
$$\frac{V_1}{I_1} = RR_{Z3-Ph} = (4.7987) + \left[\left(2 + \frac{I_3 + I_4}{I_1}\right) \times 1.9870\right] + [(2 + \frac{I_3 + I_4 + I_5}{I_1}) \times R_f]$$

Where, $RR_{Z3\text{-}Ph}$ denotes the Resistive Reach of Zone 3 for phase fault.

It is observed that the Resistive Reach of Zone 3 is greater than that of Zone 2. Similarly. Resistive Reach of Zone 2 should be greater than that of Zone 1.

$$RR_{Z3-Ph} > RR_{Z2-Ph} > RR_{Z1-Ph}$$

Case C : Assume an earth fault occurred between 132 kV Kanglung-P/Thang line.



Suppose an earthfault occurs between A-phase to ground at point 'F'. Voltage sensed by Relay at Kanglung Substation will be the sum of positive, negative and zero sequence voltage.

$$V_A = V_{1A} + V_{2A} + V_{0A}$$

Where 1, 2 and 0 denotes positive, negative and zero sequence components.

$$V_A = I_1 Z_1 + I_2 Z_2 + I_0 Z_0$$

For transmission line the positive sequence impedance is equal to the negative sequence impedance.

$$V_A = Z_1(I_1 + I_2) + I_0 Z_0$$

We know that residual current, $I_R = I_1 + I_2 + I_0$, thus $I_1 + I_2 = I_R - I_0$

$$V_A = Z_1(I_R - I_0) + I_0 Z_0$$

$$V_A = Z_1 I_R - Z_1 I_0 + I_0 Z_0$$

$$V_A = Z_1 I_R + I_0(Z_0 - Z_1)$$

$$\frac{V_A}{I_R} = Z_1 + \frac{I_0(Z_0 - Z_1)}{I_R}$$

$$\frac{V_A}{I_R} = Z_1 + \frac{I_0(Z_0 - Z_1)}{3I_0}, \because I_R = 3I_0$$

$$\frac{V_A}{I_R} = Z_1 + \frac{(Z_0 - Z_1)}{3} = Z_1(1 + \frac{(Z_0 - Z_1)}{3Z_1)} = Z_1 + (1 + K_Z)$$

Where $K_Z = (Z_0 - Z_1)/3Z_1$ and is known as the ***'Residual Compensation Factor'.*** In absence of the Residual Compensation Factor, relay under reaches for earth fault.

7.4.3 Resistive Reach Setting Calculations

Resistive Reach for Phase-to-Phase Fault (R_{pp})

The Resistive Reach (R_{pp}) is the maximum tolerance in terms of impedance of the distance relay, to trip in addition to the line impedance irrespective of the fault location within the zone. In case of quadrilateral R-X diagram, + R_{pp} and - R_{pp} on each side of the quadrilateral defines the resistive reach. R_{pp} is set for each zone and is denoted by R_{1pp}, R_{2pp}, R_{3pp}, and R_{4pp}, for Zone1, 2,3 and 4 respectively. Zone 3 and 4 shares the same reach and is denoted by $R_{3pp\text{-}4pp}$.

The R_{pp} must be calculated using the maximum anticipated phase-to-phase fault resistance so that it covers the maximum fault. Hence, for a phase-to-phase fault, the value of R_{pp} should be greater than the maximum arc fault resistance.

Arc Resistance is calculated by Van Warrington formula as given below.

$$Calculated\ Arc\ Resistance, R_a = \frac{(28710 \times L)}{I_f^{\ 1.4}}$$

Where:

L : Maximum spacing between phase conductors (m)

I_f : Maximum anticipated phase to phase fault currents

The spacing between the conductor is a known quantity, therefore depending on the various fault level, the arc resistance can be calculated. The resistance for phase-to-phase setting must be greater than the arc resistance.

The standard spacing between the conductor is given in the 'Safety Code, 2008' [20], and the typical value of arc resistance is calculated with various anticipated fault currents as given in Table 22.

Table 22 Typical values of Arc Resistance

Conductor Spacing (m)	Voltage (kV)	Arc Resistance for Various Fault Level (Ohms)		
		If =1 kA	If =5 kA	If =10 kA
0.7	11	1.27	0.13	0.05
1.5	33	2.72	0.29	0.11
3.5	66	6.34	0.67	0.25
6.8	132	12.32	1.29	0.49
8.4	220	15.22	1.60	0.61

However, the maximum phase fault resistive reach must not encroach the load, thereby causing nuisance tripping under heavily loaded conditions. For this, the R_{3pp} must be lesser than the impedance of worst-case load scenario as shown in the Figure 56.

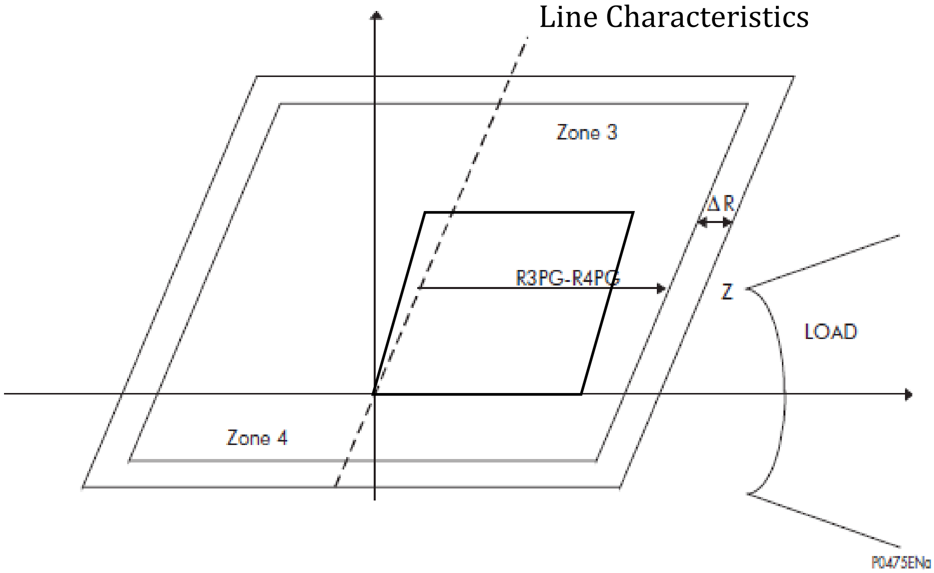


Figure 56 Phase to Phase Resistive Reach with Power Swing and Load Impedance (Image taken from MiCOM P442 Manual)

The thermal rating of ACSR panther conductor [7] is 413 A at a maximum conductor temperature of 75℃ and an ambient temperature of 40℃. The worst-case load impedance is calculated as follows.

$$Minimum\ Load\ Impedance\ Secodary, Z_{load} = \frac{V_{min}}{1.5 \times Thermal\ Rating\ of\ Conductor} \times \frac{CTR}{PTR}$$

Where:

V_{min} : Minimum Phase to Ground Voltage of the line in normal condition (kV)

CTR : Current Transformer Ratio

PTR : Potential Transformer Ratio

The Grid Code Regulation 2008 of Bhutan [21], specifies that the minimum voltage of a transmission lines at all time shall not deviate beyond ±10%. Thus, minimum voltage is 0.9 pu. The conductor used for 132 kV lines is Aluminium Conductor Steel Reinforced (ACSR) Panther (210 mm^2).

$$Z_{load}(Secondary) = \frac{0.9 \times \frac{132}{\sqrt{3}} \times 1000}{1.5 \times 413} \times \frac{600}{1200} = 55.36\ \Omega s$$

The phase-to-phase resistive reach of Zone 3 and 4 i.e., $R_{3pp\text{-}4pp}$ must be always lesser than the minimum load impedance. Normally the $R_{3pp\text{-}4pp}$ is around 80% of the distance from the line characteristics impedance.

Nonetheless, due to the power swing blocking represented by ΔR, it is prudent to provide a suitable margin in between the load and the resistive reach of Zone 3 and 4 such that besides the resistive reach encroaching the load impedance, the load also doesn't encroach the resistive reach characteristics.

Therefore, setting the $R_{3pp\text{-}4pp} \leq 60\%$ of the distance from the line characteristics impedance would solve the problem. The minimum load impedance (primary) as calculated above is 55.36 Ωs. The maximum permissible resistive reach with respect to load resistance is calculated as follows.

$$R_{3pp-4pp} < 60\% \times Z_{load}$$

$$R_{3pp-4pp} < 60\% \times 55.36$$

$$R_{3pp-4pp} < 33.22\ \Omega s$$

At the inception of the fault on the line, the over-reach or under-reach will occur, based on the direction of power flow (Import or export) in the protected line. To avoid this the resistive reach of each zone would be set lesser than 10 times its reach of respective zones. Therefore, the maximum allowed resistive reach setting w.r.t zone reach is calculated as follows.

$$R_{1pp} = 10 \times |Z_1\ Impedance\ Reach| = 10 \times 3.8390 = 38.390\ \Omega s$$

$$R_{2pp} = 10 \times |Z_2\ Impedance\ Reach| = 10 \times 5.7586 = 57.586\ \Omega s$$

$$R_{3pp} = 10 \times |Z_3\ Impedance\ Reach| = 10 \times 18.8035 = 188.035\ \Omega s$$

$$R_{4pp} = 10 \times |Z_4\ Impedance\ Reach| = 10 \times 0.9597 = 9.577\ \Omega s$$

Since setting 10 times the zone reach, encroaches the load, hence the criteria with 60% of Load Resistance for $R_{3pp\text{-}4pp}$ shall be used.

The resistive reach of Zone 1 and 2 must be lesser or equal to Zone 3. While Zone 4 resistive reach can be used for providing reverse directional decisions for Blocking or Permissive Overreach schemes, in such a scheme Zone 2 resistive reach must be less than or equal to 80% of the $R_{3pp\text{-}4pp}$ [22].

$$R_{2pp} \leq 80\% \times R_{3Ph-4Ph}$$

$$R_{2pp} \leq 80\% \times 33.22$$

$$R_{2pp} \leq 26.58\ \Omega s$$

Similarly, Zone 1 Resistive Reach must be 80% of R_{2pp}.

$$R_{1pp} \leq 80\% \times R_{2pp}$$

$$R_{1pp} \leq 80\% \times 26.58$$

$$R_{1pp} \leq 21.26\ \Omega s$$

Or the R_{ph} for all zones may be kept the same as that of $R_{3pp\text{-}4pp}$.

Considering a typical primary resistive coverage of 14.5 Ωs for phase-to-phase faults, the minimum secondary reaches is:

R_{Ph} (min) = Resistive Coverage x (CTR/PTR)

R_{Ph} (min) = 14.5 x [(600x110)/(1x132000)]=14.5x0.5=7.25 Ωs.

Resistive Reach for Phase to Earth Fault

For earthfault setting, the minimum resistance must cover the arc resistance, tower footing resistance and tree resistance however, it must not encroach the minimum load impedance. Similar to the phase-to-phase fault resistive reach, the phase to earthfault resistive reach should be lesser than 10 times the corresponding earth loop reach.

The minimum load impedance as calculated before is 55.36 Ωs. For normal operation, the resistive reach of Zone 3 and 4, phase to earth fault ($R_{3pg\text{-}4pg}$) should

not encroach the load impedance. Therefore, $R_{3pg\text{-}4pg}$ must be less than 80% of the load impedance to avoid load encroachment during heavy fault.

$$R_{3pg-4pg} < 80\%\ of\ the\ load\ impedance\ (Z_{load})$$

However due to the power swing blocking (△R), Zone 3 and 4 is surrounded by a large impedance and the load should not encroach the power swing characteristics. The Power Swing Block is generally defined by within 10 to 30 % of R_{3pp}. Let's assume △R is 20%.

$$Minimum\ Load\ Impedance\ including\ \Delta R, Z_{load} = 80\% \times 55.36 = 44.29$$

$$R_{3pg-4pg} < 80\% \times 44.29$$

$$R_{3pg-4pg} < 35.43\ \Omega s$$

For the Zone 2 resistive reach setting (R_{2pg}), it may be less than 80% of the resistive reach setting of Zone 3.

$$R_{2pg} < 80\%\ of\ R_{3pg}$$

$$R_{2pg} < 80\%\ of\ 35.43$$

$$R_{2pg} < 28.34\ \Omega s$$

Similarly for Zone 1 resistive reach settings ($R_{1ph\text{-}e}$):

$$R_{1pg} < 80\%\ of\ R_{2pg}$$

$$R_{1pg} < 80\%\ of\ 28.34$$

$$R_{1pg} < 22.67\ \Omega s$$

Or the R_{pg} for all zones may be kept the same as that of $R_{3pg\text{-}4pg}$.

Considering a typical primary resistive coverage of 40.0 Ωs for phase-to-ground faults, the minimum secondary reaches is:

R_{Pg} (min) = Resistive Coverage x CTR/PTR

R_{Pg} (min) = 40.0 x [(600x110)/(1x132000)]=40.0x0.5=20.00 Ωs.

Thus, the resistive reach setting is tabulated as follows.

Table 23 Resistive Reach Setting for Various Zones

Sl.#	Description	Resistive Reach Settings (Ωs)
1	$R_{3pg\text{-}4pg}$	35.43
2	R_{2pg}	28.34
3	R_{1pg}	22.67
4	$R_{3pp\text{-}4pp}$	33.22
5	$R_{2ph\text{-}ph}$	26.58
6	R_{1pp}	21.26

Residual Compensation Factor

For ACSR Panther Conductor (210 mm^2), the positive and zero sequence impedances are as follows.

Z1= 0.162217+j 0.386116 Ωs

Z0= 0.40563+j 1.622174 Ωs

$$Residual\ Compensation\ Factor, K_Z = \frac{Z_0 - Z_1}{3Z_1}$$

$$K_Z = \frac{(0.40563 + \mathrm{j}\ 1.622174) - (0.162217 + \mathrm{j}\ 0.386116)}{3(0.162217 + \mathrm{j}\ 0.386116)}$$

$$= 1.0027\measuredangle 11.65°\ \Omega s$$

Power Swing

Under a well-balanced power system condition, the power generated is equal to its consumption thereby attaining a nominal frequency. However, the system experiences a sudden fluctuation in the power due to line switching, loss of loads, generator disconnection or the power system fault.

This leads to the oscillations in machine rotor angles and depending on the magnitude of disturbances, the system tries to attain a new equilibrium which is referred to as stable power swing.

If unchecked, these disturbances will create huge fluctuation of system parameters such as the generator rotor angles and the power flow, ultimately leading to the loss of synchronism amongst generators and the neighboring utility system.

Most of the numerical distance relays are equipped with inbuilt Power Swing Blocking (PSB) features to differentiate the power swing with fault. If the relay senses the power swing, it will block the distance and other protection function from operating.

Power Swing causes the deviation of the impedance from the normal load impedance to an area of tripping characteristics. But it is imperative that the relay shouldn't trip during stable power swing.

The power swing is detected by ΔR (Resistive) and ΔX (Reactive) and it surrounds the entire phase fault trip characteristics as given Figure 57 below.

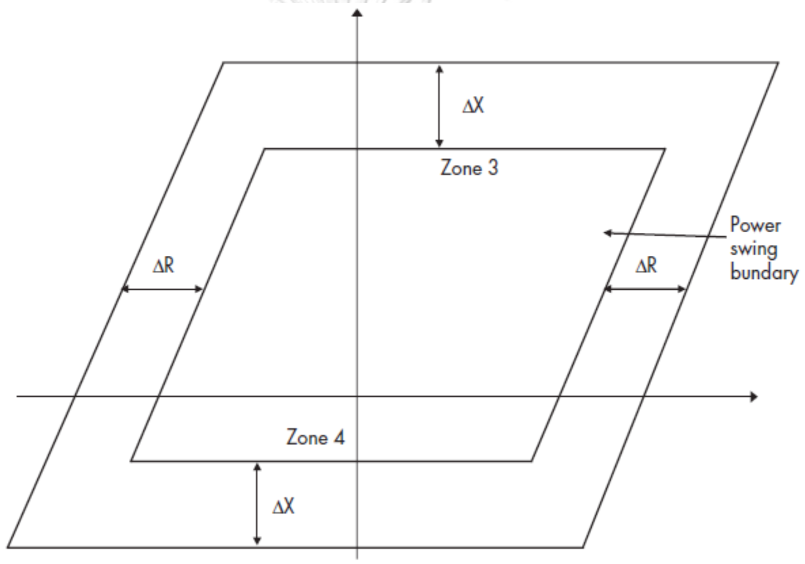


Figure 57 Power Swing detection characteristics

When a fault occurs in the system, the locus of the impedance moves rapidly from the load impedance to the tripping zones. On the other hand, the movement of impedance locus during power swing takes longer than 5 ms to enter the Zone 3 and 4 trip characteristics [22].

The setting of ΔR and ΔX are calculated as follows.

$$\Delta R = \Delta X = 0.032 \times \Delta f \times R_{min\,load}$$

Where:

Δf : Power Swing Frequency

In this case example, $R_{min\ load}$ is 55.36 Ωs and worst-case power wing frequency may be taken as 5 Hz.

$$\Delta R = \Delta X = 0.032 \times 5 \times 55.36 = 8.86\ \Omega s$$

With all the above calculations, the template setting for distance relays has been prepared as in Table 25 and can be specifically used for MiCOM P44x Relays.

7.5 Excel Template created for Distance Relay Setting (MiCOM P44x)

Red Font indicates the user inputs, rest are automated in calculations. The format is being derived from BPC practicing format and modified with additional data to suit the interest of research.

Table 24 Excel template for distance relay setting

Sl.#	Parameters	Line Segment	P/Thang-Motanga	Motanga-P/Thang	Kilikhar-Corlung	Corlung-Kanglung	Kanglung-P/Thang
		Voltage	132 kV	132 kV	132 kV	132 kV	132 kV
1.00	***Details of Protected Line***						
1.01	Type of Line (S/C: Single Circuit, D/C: Double Circuit)		D/C	D/C	S/C	S/C	S/C
1.02	Length of Protected Line	km	21.630	21.630	45.209	23.702	51.440
1.03	Pos. Seq. Resistance per km	Ωs	0.1400	0.1400	0.1622	0.1622	0.1622
1.04	Pos. Seq. Reactance per km	Ωs	0.4010	0.4010	0.3861	0.3861	0.3861
1.05	Zero Seq. Resistance per km	Ωs	0.3540	0.3540	0.4056	0.4056	0.4056
1.06	Zero Seq. Reactance per km	Ωs	1.3300	1.3300	1.6222	1.6222	1.6222
1.07	Mutual Resistance per km	Ωs	0.263	0.263	0.000	0.000	0.000
1.08	Mutual Reactance per km	Ωs	0.822	0.822	0.000	0.000	0.000
1.09	Pos. Seq. Impedance per km	Ωs	0.4247	0.4247	0.4188	0.4188	0.4188
1.10	Zero Seq. Impedance per km	Ωs	1.3763	1.3763	1.6721	1.6721	1.6721
1.11	Pos. Seq. Resistance of Protected Line, R1	Ωs	3.028	3.028	7.334	3.845	8.344
1.12	Pos. Seq. Reactance of Protected Line, X1	Ωs	8.674	8.674	17.456	9.152	19.862
1.13	Pos. Seq. Impedance of Protected Line, Z1	Ωs	9.187	9.187	18.934	9.927	21.543
1.14	Pos. Seq. Impedance Angle	°	70.726	70.726	67.184	67.184	67.184
1.15	Zero Seq. Resistance for Protected Line, R0	Ωs	7.657	7.657	18.338	9.614	20.866
1.16	Zero Seq. Reactance for Protected Line, X0	Ωs	28.768	28.768	73.337	38.449	83.445

1.17	Zero Seq. Impedance for Protected Line, Z0	Ωs	29.769	29.769	75.595	39.633	86.014
1.18	Zero Seq. Impedance Angle	°	75.065	75.065	75.930	75.930	75.930
2.00	***Details of Adjacent Shortest Line (ASL)***		***DML***	***Kanglung***	***Kanglung***	***P/Thang***	***Motanga***
2.01	Type of Line (S/C: Single Circuit, D/C: Double Circuit)		S/C	S/C	S/C	S/C	D/C
2.02	Length of the ASL	km	0.490	51.440	23.700	51.440	21.630
2.03	Pos. Seq. Resistance of ASL per km	Ωs	0.1622	0.1622	0.1622	0.1622	0.1400
2.04	Pos. Seq. Reactance of ASL per km	Ωs	0.3861	0.3861	0.3861	0.3861	0.4010
2.05	Pos. Seq. Impedance of ASL per km	Ωs	0.419	0.419	0.419	0.419	0.425
2.06	Pos. Seq. Resistance for Protected Line, R1'	Ωs	0.079	8.344	3.845	8.344	3.028
2.07	Pos. Seq. Reactance for Protected Line, X1'	Ωs	0.189	19.862	9.151	19.862	8.674
2.08	Pos. Seq. Impedance for Protected Line, Z1'	Ωs	0.205	21.543	9.926	21.543	9.187
2.09	Pos. Seq. Impedance angle	°	67.184	67.184	67.184	67.184	70.726
3.00	***Details of Adjacent Longest Line (ALL)***		***Rangia***	***Kanglung***	***Kanglung***	***P/Thang***	***Motanga***
3.01	Type of Line (S/C: Single Circuit, D/C: Double Circuit)		S/C	S/C	S/C	S/C	D/C
3.02	Length of the ALL	km	49.000	51.440	23.700	51.440	21.630
3.03	Pos. Seq. Resistance of ALL per km	Ωs	0.1622	0.1622	0.1622	0.1622	0.1400
3.04	Pos. Seq. Reactance of ALL per km	Ωs	0.3861	0.3861	0.3861	0.3861	0.4010
3.05	Pos. Seq. Impedance of ALL per km	Ωs	0.419	0.419	0.419	0.419	0.425
3.06	Pos. Seq. Resistance for Protected line, R1"	Ωs	7.949	8.344	3.845	8.344	3.028
3.07	Pos. Seq. Reactance for Protected line, X1"	Ωs	18.920	19.862	9.151	19.862	8.674
3.08	Pos. Seq. Impedance for Protected line, Z1"	Ωs	20.522	21.543	9.926	21.543	9.187
3.09	Pos. Seq. Impedance angle	°	67.184	67.184	67.184	67.184	70.726
4.00	***Details of Transformers***						
4.01	In Zone 2		*Motanga*	*P/Thang*	*Corlung*	*Kanglung*	*P/Thang*
	Transformer-1 Rating	MVA	15.00	10.00	10.00	5.00	10.00
4.02	Voltage Rating	kV	132.00	132.00	132.00	132.00	132.00

4.03	Impedance	%	9.37%	9.54%	10.18%	9.44%	9.54%
4.04	Total number of parallel transformers	Nos.	2	2	2	2	2
4.05	Transformer-2 Rating	MVA	25.00	10.00	10	5.00	10.00
4.06	Voltage Rating	kV	132.00	132.00	132	132.00	132.00
4.07	Impedance	%	10.71%	9.54%	10.16%	9.44%	9.54%
4.08	Transformer-3 Rating	MVA	-	-	-	-	-
4.09	Voltage Rating	kV	-	-	-	-	-
4.10	Impedance	%	-	-	-	-	-
4.11	Impedance when only Transformer-1 is connected [kV^2/(MVA))x p.u. Impedance]	Ωs	108.84	166.22	177.38	328.97	166.22
4.12	Impedance when only Transformer-2 is connected [kV^2/(MVA))x p.u. Impedance]	Ωs	74.64	166.22	177.03	328.97	166.22
4.13	Impedance when only Transformer-3 is connected [kV^2/(MVA))x p.u. Impedance]	Ωs	-	-	-	-	-
4.14	Total impedance when all transformers are in service	Ωs	44.278	83.11	88.60	164.48	83.11
4.11	*In Zone 3*		*Rangia*	*Kanglung*	*Kanglung*	*P/Thang*	*Motanga*
4.12	Transformer-1 Rating	MVA	25.00	5.00	5.00	10.00	15.00
4.13	Voltage Rating	kV	132.00	132.00	132.00	132.00	132.00
4.14	Impedance	%	12.49%	9.44%	9.44%	9.54%	9.37%
4.15	Total number of parallel transformers	Nos.	2	2	2	2	2
4.16	Transformer-2 Rating	MVA	25.00	5.00	5.00	10.00	25.00
4.17	Voltage Rating	kV	132.00	132.00	132.00	132.00	132.00
4.18	Impedance	%	12.49%	9.44%	9.44%	9.54%	10.71%
4.19	Transformer-3 Rating	MVA	-	-	-	-	-
4.20	Voltage Rating	kV	-	-	-	-	-
4.21	Impedance	%	-	-	-	-	-

4.22	Impedance when only Transformer-1 is connected [$kV^2/(MVA)$)x p.u. Impedance]	Ωs	87.05	328.97	328.97	166.22	108.84
4.23	Impedance when only Transformer-2 is connected [$kV^2/(MVA)$)x p.u. Impedance]	Ωs	87.05	328.97	328.97	166.22	74.64
4.24	Impedance when only Transformer-3 is connected [$kV^2/(MVA)$)x p.u. Impedance]	Ωs	-	-	-	-	-
4.25	Total impedance when all transformers are in service	Ωs	43.53	164.48	164.48	83.11	44.28
5.00	***CT & PT Details at Relaying Point***						
5.01	CT Primary	A	600	600	600	600	600
5.02	CT Secondary	A	1	1	1	1	1
5.03	PT Primary	kV	132	132	132	132	132
5.04	PT Secondary	V	110	110	110	110	110
5.05	CT/PT Ratio		0.50	0.50	0.50	0.50	0.50
6.00	***Grounding Factor Kg = $(Z_0-Z_1)/(3*Z_1)$***						
6.01	**Magnitude of grounding Factor Kg =** $(Sqrt.((X_0-X_1)^2+(R_0-R_1)^2)/(3*(Sqrt.(R_1^2+X_1^2)))$		0.748	0.748	1.003	1.003	1.003
6.02	**Angle of Grounding Factor Kg**=(arc Tan($(X_0-X_1/(R_0-R_1))$)-(arc Tan(X_1/R_1))*180*7/22	°	6.271	6.271	11.643	11.643	11.643
6.03	kZ1, kZ2, kZ3. kZ4		0.748	0.748	1.003	1.003	1.003
6.04	Angle Kg	°	6.271	6.271	11.643	11.643	11.643
7.00	***Zone Reach Setting Calculations (Quadrilateral)***						
7.01	Zone 1: For all Voltage levels						
a	80% of Protected Line Impedance*(CTR/PTR)	Ωs	3.675	3.675	7.574	3.971	8.617
7.02	Zone 2: 400kV System and above						

a	120% of Protected Line Impedance *(CTR/PTR) for single circuit line OR	Ωs	5.512	5.512	11.360	5.956	12.926
b	Zone 2 : (150% of Protected Line Impedance) *(CTR/PTR) for double circuit line	Ωs	6.890	6.890	14.200	7.445	16.158
c	*Check if Z2 overreaches the 50% of the shortest line (Overreaches if $1.2Z_2>100\%Z_{Line}+0.5Z_S$)*	Ωs	4.645	9.979	11.948	10.349	13.068
d	*Overreach :Yes or No (If Yes time delay 0.5s else 0.35s)*		Yes	No	No	No	No
7.03	Zone 2: 220kV System and below						
a	120% of Protected Line Impedance *(CTR/PTR) OR	Ωs	5.512	5.512	11.360	5.956	12.926
b	Zone 2: (100% Protected Line Impedence+50% of next shortest line Impedance)x(CTR/PTR)	Ωs	4.645	9.979	11.948	10.349	13.068
c	Zone 2 Reach (Higher of 'a' and 'b')	Ωs	5.512	9.979	11.948	10.349	13.068
7.05	*Check if Z_2 encroaches to Next Voltage Level at Substation in Zone 2 if Transformer 1 is in service (Z_L+Z_{T1})*	Ωs	59.014	87.706	98.155	169.446	93.884
a	*(Encroaches if $Z_2>Z_L+Z_{T1}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.06	*Check if Z_2 encroaches to Next Voltage Level at Substation in Zone 2 if Transformer 2 is in service (Z_L+Z_{T2})*	Ωs	41.916	87.706	97.981	169.446	93.884
a	*(Encroaches if $Z_2>Z_L+Z_{T2}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.07	*Check if Z_2 encroaches to Next Voltage Level at Substation in Zone 2 if all Transformers are in service ($Z_L+Z_{Parallel\ Transformer}$)*	Ωs	26.733	46.150	53.767	87.205	52.328

a	*(Encroaches if $Z_2>Z_L+Z_{parallel\ Transformer}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.09	Zone 3 (120% of (protected line + the next longest line))	Ωs	17.825	18.438	17.316	18.882	18.438
7.10	*Check if Zone 3 encroachment to next voltage level at remote substation if Transformer-1 is in service (Z_L+Z_{T1})*	Ωs	58.379	179.848	178.912	98.848	69.786
a	*(Encroaches if $Z_3>Z_L+Z_{T1}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.11	*Check if Zone 3 encroachment to next voltage level at remote substation if Transformer-2 is in service (Z_L+Z_{T2})*	Ωs	58.379	179.848	178.912	98.848	52.687
a	*(Encroaches if $Z_3>Z_L+Z_{T2}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.12	*Check if Z_3 encroaches to Next Voltage Level at remote substation in Zone 3 if all Transformer are in service ($Z_L+Z_{Parallel\ Transformer}$)*	Ωs	36.617	97.607	96.671	57.291	37.504
a	*(Encroaches if $Z_3>Z_L+Z_{Parallel}$), if 'yes' coordinate time delay with fault clearing time of remote transformer*		No	No	No	No	No
7.13	Zone 4 (10% of protected line Impedance for long lines(>100km) or 20% for lines below 100 km	Ωs	0.919	0.919	1.893	0.993	2.154
8.00	***Resistive Reach Settings***						
8.01	Primary full load current, thermal rating of conductor	A	413.0	413.0	413.0	413.0	413.0
8.02	Resistance at maximum load current (R_L)=(0.9*(PT Primary*10^3)/1.732)/(1.5*Primary full load current)*(CTR/PTR)	Ωs	55.360	55.360	55.360	55.360	55.360

8.04	R_{1pp} for Z_1 (80% of R_{2pp})	Ωs	21.258	21.258	21.258	21.258	21.258
8.05	R_{2pp} for Z_2 (80% of R_{3pp})	Ωs	26.573	26.573	26.573	26.573	26.573
8.06	$R_{3pp\text{-}4pp}$ for Z_3 & Z_4 (60% of R_L)	Ωs	33.216	33.216	33.216	33.216	33.216
8.07	Max. R_{1pp} :10*|Z_1 Impedance Reach|	Ωs	36.748	36.748	75.736	39.706	86.174
8.08	Max. R_{2pp} :10*|Z_2 Impedance Reach|	Ωs	55.122	55.122	113.603	59.559	129.261
8.09	Max. R_{3pp} :10*|Z_3 Impedance Reach|	Ωs	178.252	184.383	173.158	188.820	184.383
8.10	Max. R_{4pp} :10*|Z_4 Impedance Reach|	Ωs	9.187	9.187	18.934	9.927	21.543
8.11	R_{1pg} for Z_1 (80% of R_{2pg})	Ωs	22.676	22.676	22.676	22.676	22.676
8.12	R_{2pg} for Z_2 (80% of R_{3pg})	Ωs	28.344	28.344	28.344	28.344	28.344
8.13	$R_{3pg\text{-}4pg}$ for Z_3 & Z_4 (80% of $R_L(1\text{-}\Delta R)$)	Ωs	35.430	35.430	35.430	35.430	35.430
9.00	***Relay Operating Time Delay***						
9.01	Zone 1 Operating time (tZ1)	s	0.000	0.000	0.000	0.000	0.000
9.02	Zone 2 Operating time (tZ2)	s	0.350	0.350	0.350	0.350	0.350
9.03	If Zone 2 Overreaches 50% of the shortest line (400kV and above)	s	0.5	NA	NA	NA	NA
9.04	Zone 3 Operating Time (tZ3)	s	0.800	0.800	0.800	0.800	0.800
9.05	Zone 4 Operating Time (tZ4)	s	0.500	0.500	0.500	0.500	0.500
10.00	***Power Swing Settings (ΔR & ΔX)***						
	ΔR & ΔX	%	20.00%	20.00%	20.00%	20.00%	20.00%
10.01	ΔR :10 to 30% of Z_3 R_{3pp}	Ωs	6.643	6.643	6.643	6.643	6.643
10.02	ΔX :10 to 30% of Z_3 R_{3pp}	Ωs	6.643	6.643	6.643	6.643	6.643

7.6 Simulations

The 132 kV transmission lines located in eastern Bhutan is being used for the study purposes. The single line diagram is shown as in Figure 58. The transmission line from 132 kV Kilikhar Substation to Kanglung Substation via Corlung Substation will be used for simulation as the actual relay setting data of the field is available. Comparison shall be made between the existing field settings with calculated ones.

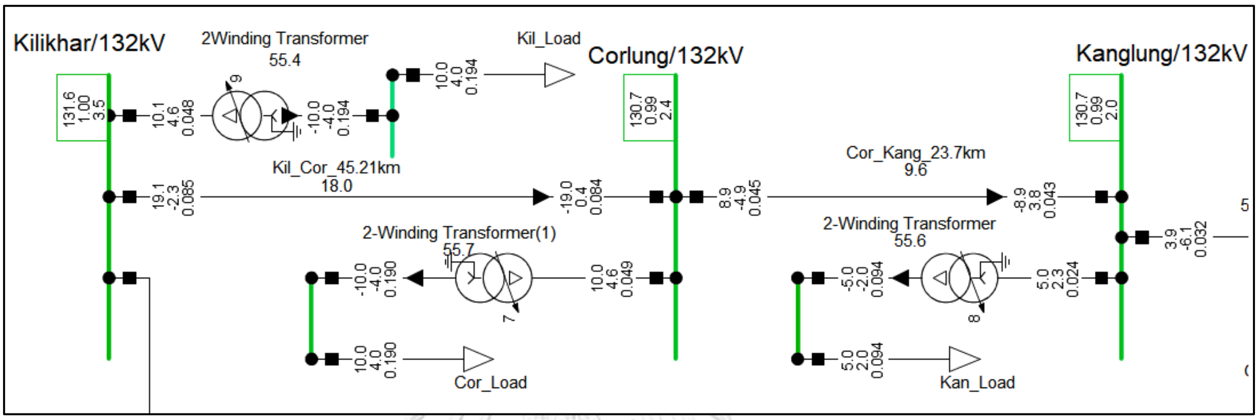


Figure 58 Single Line Diagram for distance relay simulation

The above transmission line protection has MiCOM P442 relay installed hence the MiCOM P44x model has been selected for simulation in DIgSILENT for simulation. The calculated relay setting parameters has been configured in the above relays. The reach settings are as shown in Figure 59.

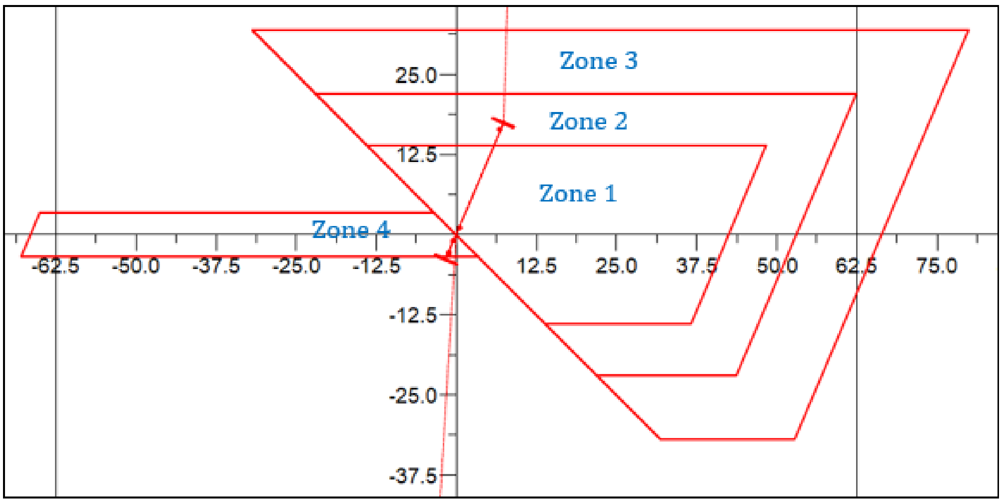


Figure 59 Zone Reaches of MiCOM P44x Relay

i. *Simulation of three phase short circuit fault in Zone 1 at 50% of line length.*

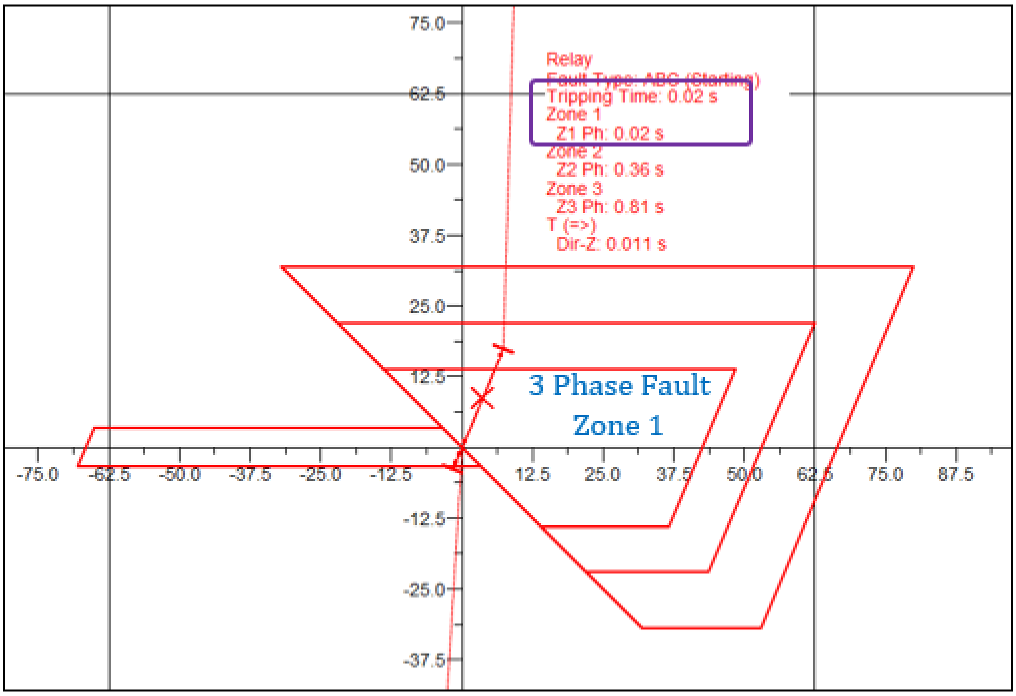


Figure 60 Three Phase Fault in Zone 1

ii. *Simulation of three phase short circuit fault in Zone 2 at 132 kV Bus of Corlung Substation.*

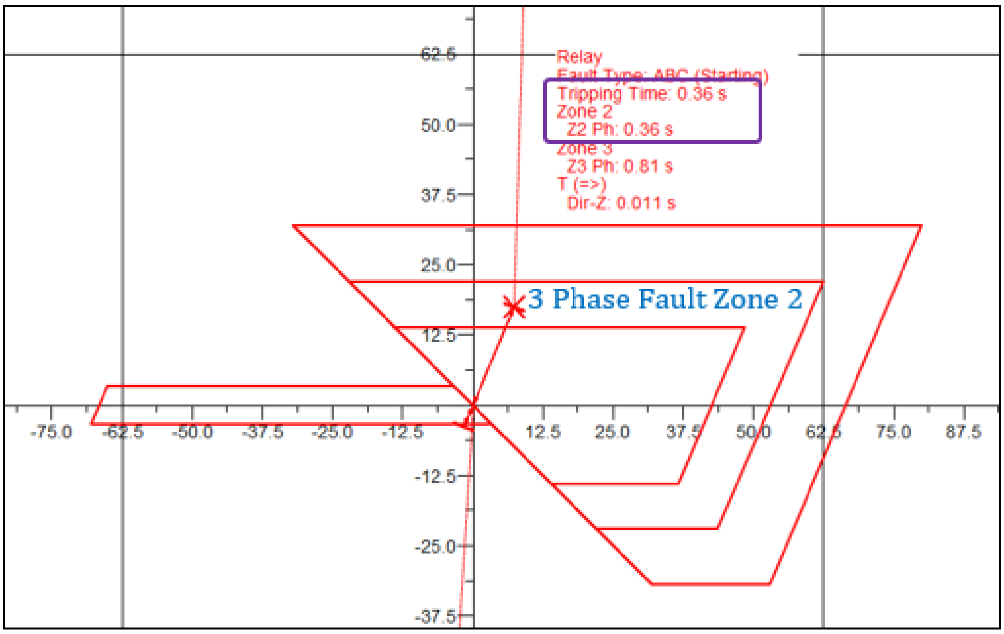


Figure 61 Three Phase Fault in Zone 2

iii. *Simulation of three phase short circuit fault in Zone 3 at 70% of adjacent line length.*

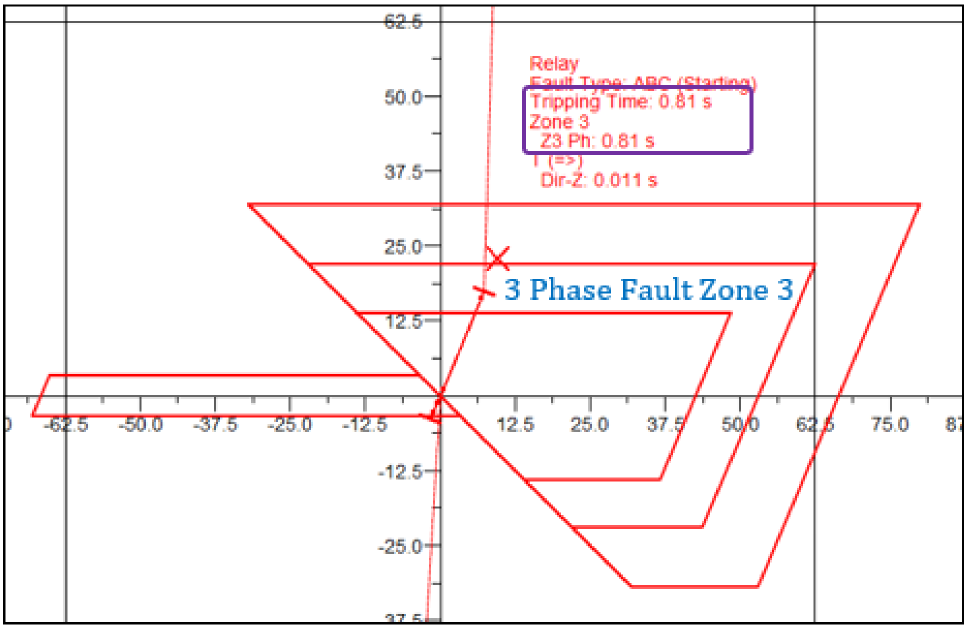


Figure 62 Three Phase Fault in Zone 2

iv. *Simulation of three phase short circuit fault in Zone 4 (Reverse) at Kilikhar Substation.*

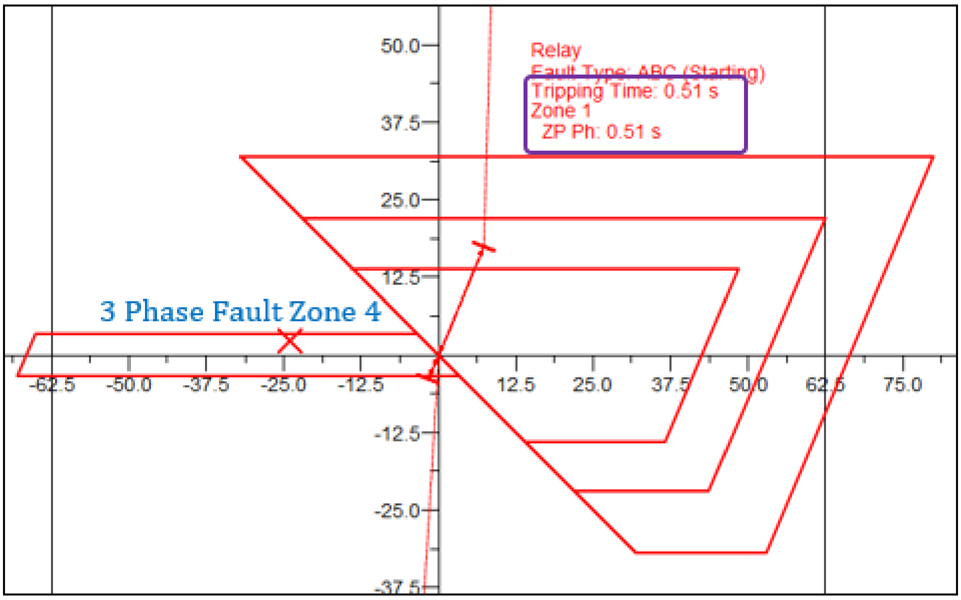


Figure 63 Three Phase Fault in Zone 4 (Reverse)

7.7 Comparison of the calculated and existing Settings and the observations

After the simulation of distance protection with calculated settings, existing setting were also checked and simulated. The setting from existing relays were downloaded to verify the settings. The comparative of calculated and existing settings is given below in Table 25.

Table 25 Calculated vs. Existing Distance Relay setting for MiCOM P444

Zones	Descriptions (MiCOM P444)	132 kV Kili_Corlung		132 kV Corlung_Kili		132 kV Corlung_Kang		132 kV Kang_Corlung	
		Calculated settings	Existing Setting	Calculated settings	Existing Setting	Calculated settings	Existing Setting	Calculated settings	Existing Setting
Zone 1	Direction	Forward	Forward	Forward	Forward	Forward	Forward	Forward	Forward
	Z Reach (Ωs)	7.574	8.120	7.574	8.344	3.971	4.372	3.971	4.520
	(+) R Resistance (PG) (Ωs)	22.676	11.900	22.676	33.870	22.676	33.870	22.676	10.500
	(+) R Resistance (PP) (Ωs)	21.258	5.650	21.258	25.400	21.258	25.400	21.258	4.250
	Line Angle (°)	67.184	67.200	67.184	68.400	67.184	68.400	67.184	67.200
	(+) X Angle (°)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	time (s)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zone 2	Direction	Forward	Forward	Forward	Forward	Forward	Forward	Forward	Forward
	Z Reach (Ωs)	11.948	12.190	11.360	11.590	10.349	11.310	11.360	6.780
	(+) R Resistance (PG) (Ωs)	28.344	13.470	28.344	33.870	28.344	33.870	28.344	11.380
	(+) R Resistance (PP) (Ωs)	26.573	7.220	26.573	25.400	26.573	25.400	26.573	5.130
	Line Angle (°)	67.184	67.200	67.184	68.400	67.184	68.400	67.184	67.200
	(+) X Angle (°)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	time (s)	0.35	0.350	0.35	0.400	0.35	0.400	0.35	0.350
Zone 3	Direction	Forward	Forward	Forward	Forward	Forward	Forward	Forward	Forward
	(+) X Reach (Ωs)	17.316	24.370	13.888	19.930	18.882	22.250	13.888	13.570
	(+) R Resistance (PG) (Ωs)	35.430	18.190	35.430	33.870	35.430	33.870	35.430	14.010
	(+) R Resistance (PP) (Ωs)	33.216	11.940	33.216	25.400	33.216	25.400	33.216	7.760
	Line Angle (°)	67.184	67.200	67.184	68.400	67.184	68.400	67.184	67.200
	(+) X Angle (°)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	time (s)	0.0	0.8	0.0	0.8	0.0	0.8	0.0	0.8
Zone 4	Direction	Reverse	Reverse	Reverse	Reverse	Reverse	Reverse	Reverse	Reverse
	(+) X Reach (Ωs)	1.893	2.030	1.893	1.093	0.993	1.093	1.893	1.130
	(+) R Resistance (PG) (Ωs)	35.430	18.190	35.430	33.870	35.430	33.870	35.430	14.010
	(+) R Resistance (PP) (Ωs)	33.216	11.940	33.216	25.400	33.216	25.400	33.216	7.760
	Line Angle (°)	67.184	67.200	67.184	68.400	67.184	68.400	67.184	67.200
	(+) X Angle (°)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	time (s)	0	0.500	0	1.000	0.5	1.000	0	0.500

Some of the observations are as follows:

a) The existing distance relay settings observed in the relays are different probably due to the manufacturers or the service personal implementing their own methods of setting the relay despite the existence of CEA guidelines.

b) The resistive reach settings are quite haphazard because of which a resistive fault in Zone 1 is falsely detected by Zone 3 as given in the Figure 64. The permissible tower footing resistance is less than 10 Ωs and in the worst case the resistive fault will be higher than 10 Ωs. In such a case, relay will always overreach, therefore it is imperative to calculate the resistive reach settings based on the worst-case scenario.

c) The residual compensation factor for the 132 kV lines under consideration is non uniform. For instance, the residual compensation factor of 132 kV Kanglung-Corlung transmission line is taken as $1\angle 11.7°$, while for 132 kV Corlung-Kanglung transmission line, it is $0.689\angle 6.1°$. The calculated setting is $1.003\angle 11.643°$.

d) The time settings are also different such as for Zone 2 settings the operating time is 0.35 s however sometimes it is taken as 0.4 s. Similarly, for the reverse zone, operating time is occasionally taken as 1.0 s. The operating time setting as per the CEA guidelines for Zone 2 and reverse zone is 0.35 s and 0.5 s respectively.

e) The requirement of uniform application of distance relay settings is found to be necessary to avoid confusion in haphazard tripping.

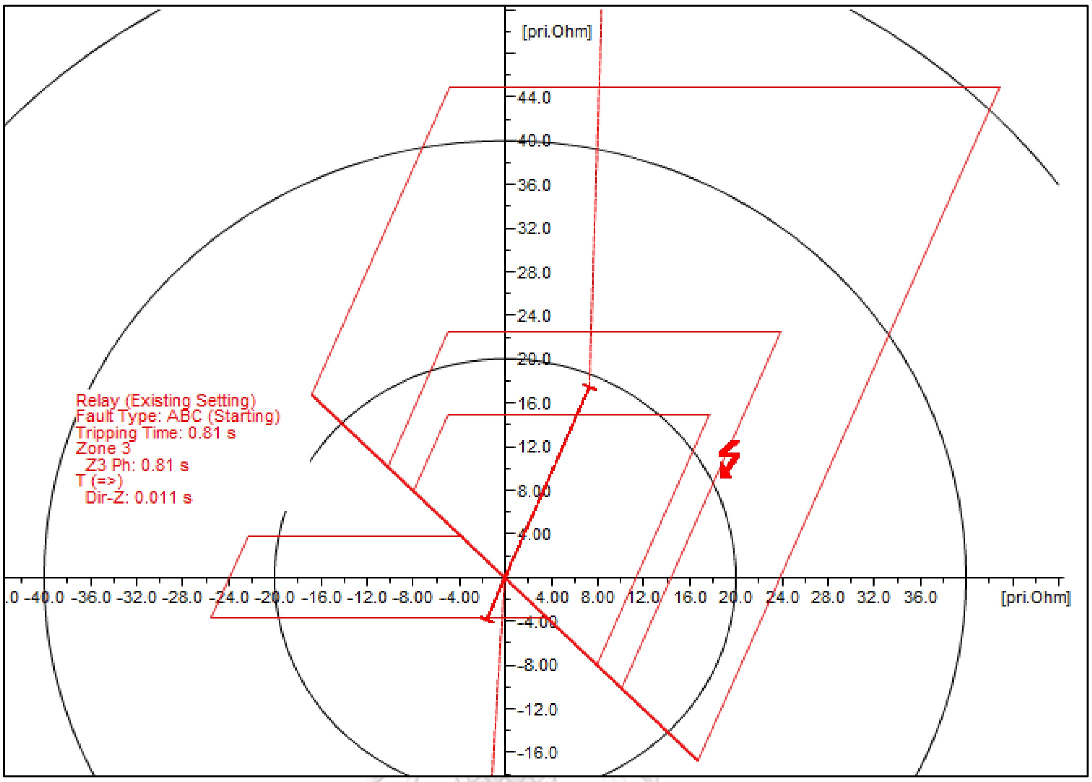


Figure 64 Resistive fault of 10 Ωs at 50% of line length in Zone 1 is detected in Zone 3 by the Relay for 132 kV Kili_Corlung line.

7.8 Recommendations for distance relay settings

a) Prepare a database in DIgSILENT and simulate the load flow and short circuit studies. Add protection relays in the feeders and carry out the configurations as per the calculated setting parameters.

b) Compile the details of the protected line as in Section 1 of Table 25. If the actual field data is not available, recommended values from 'Manual on Transmission Planning Criteria' of Central Electricity Authority, New Delhi [7] may be used since the tower structures are similar except the geographical condition.

c) Compute the details of the adjacent shortest and longest line as in Section 2 & 3.

d) Compute the details of transformers in Zone 2 & 3 located substations as in Section 4.

e) Compute the details of current and voltage transformers as in Section 5.

f) Based on the positive and zero sequence impedance, calculate the grounding factor magnitude and angle.

g) Zone 1 Reach Setting may be 80% of protected line impedance for irrespective of voltage levels.

h) Zone 2 Reach Setting

   i. 400 kV Lines : 120% of Protected Line Impedance for single circuit line and 150% of Protected Line Impedance for double circuit line.

      1. Check if Zone 2 overreaches 50% of the shortest line (Overreaches if $1.2Z_2 > 100\%Z_{Protected\ Line} + 0.5Z_{Shortest\ Line}$). If Zone 2 overreaches, then recommended time delay is 0.5 s else 0.35 s.

   ii. 220 kV and below lines : 120% of Protected Line Impedance or 100% Protected Line Impedence+50% of next shortest line Impedance, whichever is higher.

      1. Check if Zone 2 encroaches to next Voltage Level at Substation in Zone 2 if Transformer 1 or 2 or combined is in service (depending on the number if transformers and various parallel operating conditions). If it encroaches, then coordinate time delay with fault clearing time of remote end transformer.

i) Zone 3 Reach Setting :120% of (protected line + the next longest line).

   i. Check if Zone 3 encroaches to next Voltage Level at Substation in Zone 3, if Transformer 1 or 2 or combined, is in service (depending on the number if transformers and various parallel operating conditions). If it encroaches, then coordinate time delay with fault clearing time of remote end transformer.

j) Zone 4 Reach Settings

   i. >100km Line length: 10% of protected line Impedance) or

   ii. <100km Line length : 20% for lines below 100 km.

k) Resistive Reach Setting Calculations

i. The minimum load impedance is calculated by the following formula. Minimum voltage may be 0.9 times the rated voltage.

$$Z_{load} = \frac{V_{min}}{1.5 \times Thermal\ Rating\ of\ Conductor} \times \frac{CTR}{PTR}$$

ii. The phase-to-phase resistive reach of Zone 3 and 4 i.e., $R_{3pp\text{-}4pp}$ less than or equal to 60% of the distance from the line characteristics impedance to accommodate the power swing block and to avoid the load encroachment.

iii. The phase-to-phase resistive reach of Zone 2 i.e., R_{2pp} may be less than or equal to 80% of the distance from the line characteristics impedance $R_{3pp\text{-}4pp}$.

iv. Similarly, phase-to-phase resistive reach of Zone 1 i.e., R_{1pp} may be less than or equal to 80% of the distance from the line characteristics impedance R_{2pp}.

v. The phase-to-ground resistive reach of Zone 3 and 4 i.e., $R_{3pg-4pg}$ may be less than 80% of the minimum load impedance. 80% of the minimum load impedance may be considered for the above calculation cushioning 20% for power swing.

vi. The phase-to-ground resistive reach of Zone 2 i.e., R_{2pg} may be less than 80% of phase-to-ground resistive reach of Zone 3 and 4.

vii. Similarly, the phase-to-ground resistive reach of Zone 1 may be less than 80% of phase-to-ground resistive reach of Zone 2.

viii. The maximum reach settings should not be more than 10 times the respective zone reach settings.

The flow chart has been prepared to have an overview of the distance relay setting as shown in Figure 65.

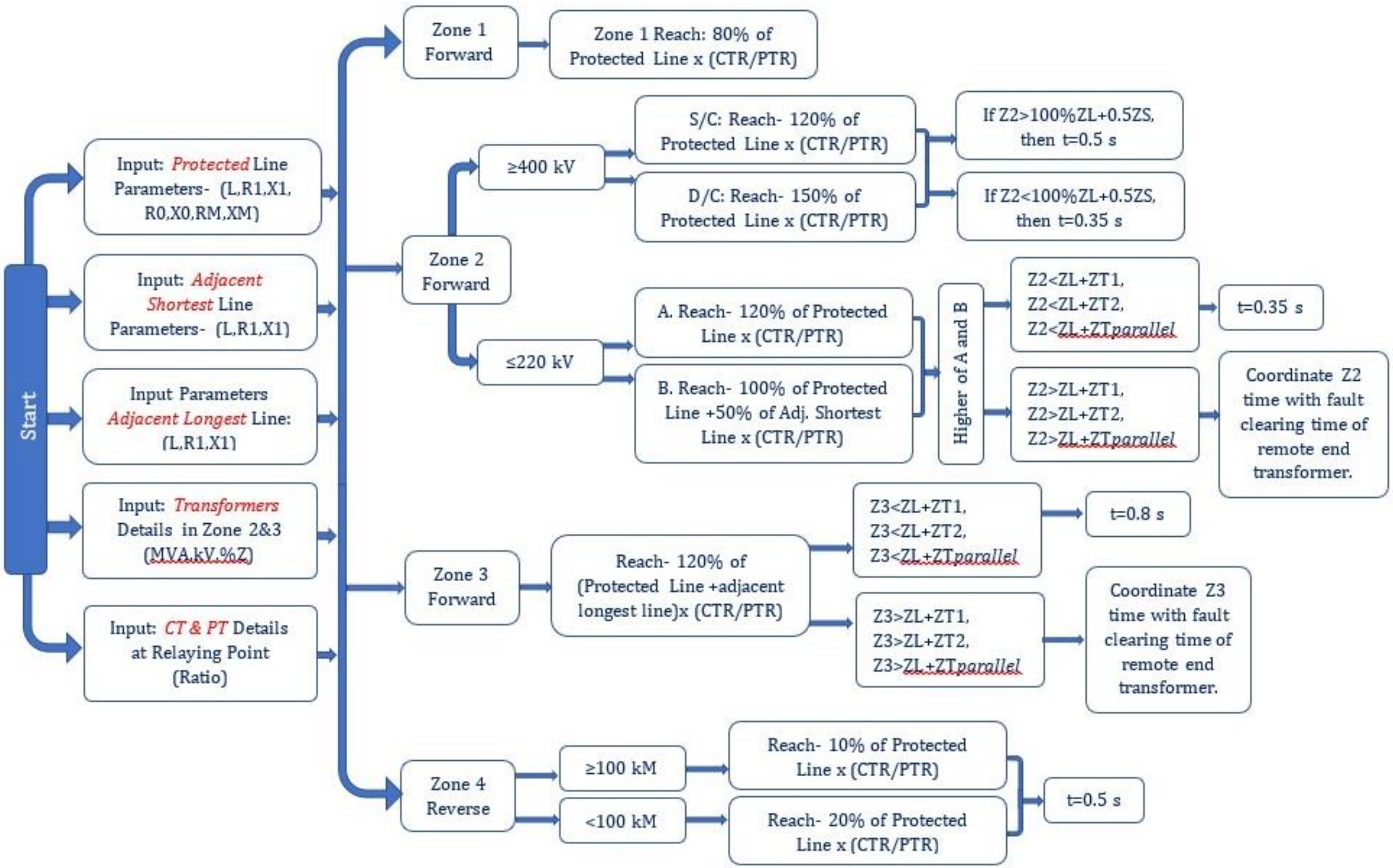


Figure 65 Distance Relay Setting Flow Chart

8 LIMITATIONS OR DRAWBACKS OF EXISTING PROTECTION SYSTEM

After the extensive simulations of the existing relay settings, the deficiency in the protection system of the pilot substations and network under study is observed as follows.

1. *Types of Relays in transmission and distribution system*

The protection system equipment in Bhutan's Power System is a mix of electromechanical, static, and numerical relays. The electromechanical and static relays are being upgraded with numerical relays based on the priority of the requirement due to reasons of economic in nature.

Wherever electromechanical relays exist, it is quite impossible to set the relay setting as per the calculated values hence the nearest available taps are being used. Although robust, often the tripping contacts gets burnt out during the fault thereby requiring upstream relays to clear the faults. The measurement errors are higher in case of electromechanical relays, which distorts the CTI and leads to the constriction of total fault clearing times.

2. *Miscoordination and loss of CTI in transmission and distribution system*

In case of overcurrent and earth fault relay settings of feeders and transformers, the miscoordination was observed along with haphazard CTI. The upstream relays tripped before the downstream relays due to incorrect pickup setting and the TMS. Even in those cases where downstream relays tripped prior to upstream relays, the CTI was non uniform.

3. *Lack of Relay Criteria Settings for transmission and distribution system*

In case of transformer differential relays, the pickup settings were defined as 0.2 pu irrespective of transformers which leads to incorrect tripping even in normal conditions. The pickup setting should differ with transformers depending on the tapping range.

While the relay setting guidelines for distance relay protection of transmission lines was provided by CEA India however its implementations were not executed properly, like for example the resistive reach settings, overreach, and encroachment.

Most of the 11 kV substations have 5A CT secondary while most numerical relays have 1A CT secondary. Because of this the 11 kV protection systems in substations in eastern Bhutan are electromechanical relays which devoid the power system parameters during faults as no data are recorded.

Further the 33 kV and 11 kV feeders are very long, some even beyond 100 km. When the fault strikes the end of the line, it is most likely that the relay at substation won't detect it due to the line impedance. Fuses, auto reclosers, intelligent switches, sectionalizer, etc. needs to be installed and coordinate it in protection hierarchy. As of now although auto reclosers are installed however most of them are non-functional.

The settings of relays are haphazard as of now with many of the settings done based on excel sheets devoid of protection software simulations. Hence, this poses a serious blockade for efficient protection coordination. It is of utmost priority and importance to start the protection coordination using protection software as a means of virtual field simulation before implementing the calculated relay settings.

The CT and VT are the most critical equipment besides the relays in protection system hence the coordination of the CT parameters with the existing and anticipated future fault scenarios must be considered while procuring the CT. The instruments transformers with default parameters will create nuisance when the power system expands.

All in all, the protection system in Bhutan lacks the standard criteria settings and the rigorous post fault tripping analysis to verify the conformation of the relay setting values with that of the actual fault scenario. The first edition of relay setting guidelines has been released in August 2022, and needs to be revisited as soon as possible to have a clarity and visibility in the protection system parameters.

9 RECOMMENDATIONS AND WAY FORWARD

The power system of Bhutan is still at infancy stage when it comes to the criteria settings of protection. Although certain standard criteria have been used however it differed amongst substations. Different vendors have their own default settings in absence of standard criteria settings from BPC, thereby creating confusion in post fault tripping analysis. Therefore, Bhutan Power System requires certain criteria settings which can be adopted to maintain the desired protection of the power system.

The protection coordination needs to be standardized throughout the power system of Bhutan. While the recommendations pertaining to each topic has been made in earlier section, the following are the overall recommendations in respect of protection coordination.

a) Prepare a load flow data base in power system software such as DIgSILENT, CAPE, ETAP, etc. The data base building itself requires many standard parameters of lines and substation depending on the types of equipment, its degraded capacity over time, the rating based on ambient temperature and altitude, etc. The selection of parameters must also be standardized.

b) The database must be updated annually based on the changes in the network. The updated database must be made available used uniformly across any departments.

c) The fault level of 5 Indian substation (132 kV Rangia, 132 kV Salakati, 400kV Alipurduar, 220kV Birpara and 400 kV Siliguri Substation) interconnected to Bhutanese grid must be sought on an annual basis from Indian counterparts by the concerned agency and accordingly update it in the database. Bhutan's grid is a tiny, miniscule when compared to gigantic Indian grid, hence fault level of Bhutanese power system will be impacted by the Indian grid.

d) The protection database must be built up using the same database and simulation of the settings be carried out prior to its implementation in the field.

e) The scope of the database must include from generation, transmission, and distribution, until the last protective device such as the fuses, AR or sectionalizer on the feeders. Separate database may be created in a new page however it must be linked or extended from the mother database so that during the simulation the effect of entire system comes in picture.

f) The power system equipment must be standardized such as the vector groups of transformers in reference to the protection coordination criteria. The instrument transformers must also be purchased based on the system fault level. Such criteria must be reviewed periodically.

g) BPC must have access to the IEEE websites (https://ieeexplore.ieee.org/) which contains all the IEEE international standards along with the international journals. This is a forum whereby international power system experts, academicians, etc. bring up the experiences and ideas in the form of papers. Any settings that we adopt must be in conformation with the international standards or if BPC comes up with any ideas/improvements/experiences in protection coordination, it can also be floated to the international audience by means of publishing paper.

h) Frequent internal/external workshop or conferences must be carried out or participated with respect to power system protection and everyone's experiences must be accounted while setting the criteria. Writing papers or participating in the conferences exposes the employees to the status of the technological advancement in the power system at international level. Further, it conforms your engineering practice to the international acceptance.

i) Each of the simulation software have their own pros and cons. DIgSILENT along with geographic information system enables the user to locate the feeders, protection devices along the lines, etc. and has much of the desired modules in a package. CAPE and ETAP has their own pros and cons however all the databases are interconvertible. Hence it is recommended to maintain a standard database and use it if we want to reap the benefits of each software which are unique to each software else stick to one.

j) To upgrade the technical capacity of engineers in protection, it is imperative to send engineers on specialized workshops and training which will focus on a particular topic say, distance protection for over a week. Such training includes the theoretical aspects to simulation in software and the practical field application. For such trainings, beside the tutors, learners must be well prepared with sufficient experiences to understand, simulate and apply the concepts in real world scenario.

10 CONCLUSION

The thesis on ' An Improvement in Protection Coordination and Criteria Settings for Bhutanese Power System ' emerged because of dire necessity rather than just a thesis topic. Bhutanese Power System is young and fragile and susceptible to almost total collapse in the event of disconnection from Indian grid. Further to make the matter worse, lack of consistent protection coordination and criteria setting sets the power system in limbo as and when the fault occurs in the system.

Bhutan's economy is driven by hydropower hence any blackout is a loss of revenue for the nation. Therefore, this study fills up the vacuum created by the lack of effective protection coordination in the field thereby improving the reliability of power system in Bhutan.

The study commences with the database building in DIgSILENT with modelling of entire Bhutanese Power System. The five interconnected Indian Substation to Bhutanese grid has been modelled as external grid. Accordingly, various short circuit fault level has been simulated.

The overcurrent and ground fault coordination and simulation has been done as an example for 132/33/11 kV Nangkhor Substation, eastern Bhutan. The existing settings has been checked thoroughly and revision has been proposed. Further, BPC in August 2022, released first edition of relay setting guidelines which has also been referred. Numerous recommendations have been made for the relay setting guidelines.

Similarly, the criteria setting for differential protection has also been discussed. The initial pickup settings along with the 1^{st} and 2^{nd} Bias Slope Setting has been defined and the simulation in respect of it, has been done on 132/33 kV YNd1, 5MVA Transformer located at Nangkhor Substation. Simulations of various fault scenarios and the operating times has also been noted.

Finally, the distance protection of the 132 kV eastern grid has been chosen. In reference to the CEA guidelines, the criteria have been set and simulated for 132 kV Kilikhar-Corlung-Kanglung transmission line. This is because, the actual filed setting

data is available which is being compared with the calculated data obtained from this study. The distance relay setting excel template has been made for easier use by field personal. The recommendations are also made.

Last but not the least, several recommendations have been made in wholesome, on alleviating the relay coordination expertise in BPC. The general recommendations are vital for BPC to change the technical ambience, environment and working culture in collaboration with the technical experts. All in all, the vastness of the topics covered along with intense data collection in this study has just paved a much broader way for specialized short-term courses/trainings for immediate future. And with it, the Digital Power Grid in Bhutan would not be a distant dream but a reality.

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