ADDIS ABABA UNIVERSITY

COLLEGE OF TECHNOLOGY AND BUILT ENVIRONMENT

School of Electrical and Computer Engineering

Master of Science in Power Engineering

Assessment and Mitigation of Relays Coordination Problems in the Protection System of Southwest Region Transmission Network of Ethiopian Electric Power System

By

Solomon Sinetibeb

A Thesis Submitted to the School of Graduate Studies of Addis Ababa University in Partial Fulfillment of the Requirements for Degree of Masters of Science in Power Engineering.

Thesis Advisor: - Dr. Eng. Fekadu Shewarega

May 2025

Addis Ababa, Ethiopia

ADDIS ABABA UNIVERSITY

COLLEGE OF TECHNOLOGY AND BUILT ENVIRONMENT

School of Electrical and Computer Engineering

Master of Science in Power Engineering

Assessment and Mitigation of Relays Coordination Problems in the Protection System of Southwest Region Transmission Network of Ethiopian Electric Power System

By

Solomon Sinetibeb

APROVED BY BOARD OF EXAMINERS

Chairman, Department of Graduate Committee	Signature
Fekadu Shewarega Advisor	Signature
Internal Examiner	Signature
Dr. Nagendra Prasad Singh External Examiner	Signature

Signed Declarations

This thesis is my original work and has not been presented for the fulfillment of degree in this or any other university and all source and materials used for the thesis have been acknowledged.

Name: Solomon Sinetibeb Lake

Signature: ______________________Date______________________

This is certifying that the above statement made by the student is correct and true to the best of my knowledge and belief. This thesis work has been submitted for examination with my approval as a university advisor.

Dr. Eng. Fekadu Shwarega

(Advisor)

Signature: ______________________Date 30.05.2025

Acknowledgement

First of all, I would like to thank God, for everything that has happened and not happened. Secondly, I would like to express my deep gratitude to Dr**. Eng. Fekadu Shewarega** for his willingness to be my advisor, his advice, suggestions as well as guidance throughout the study. He provided invaluable insights that have guided my thinking and understanding.

I would like to acknowledge Mr. Dereje Gezahegne EEP power system protection director for his willingness to use power factory license key and to all power system protection staff members for their cooperation to use DIgSILENT power factory license key, their idea, and support. Also, I would to thank Mr. Getahun Sisay for his facilitated logistics to collect system network data from different sites.

I am deeply indebted to my friends especially Mr. Ayalsew Tariku for his continues support throughout my thesis work. Lastly, I want to express my deep gratitude to my family for their encouragement and support overall in my life.

Abstract

The reliability and stability of transmission network basically depend on protection system coordination, especially on distance and overcurrent protection relays. In the EEP south west region transmission network, occurrence of improper relays operation such as unwanted relay tripping outside the designated protection zone and cascading events become significant issue. This thesis tries to assess existing setting coordination for distance and overcurrent protection relays and mitigate the coordination problems. The analysis is conducted through revision of literatures, data collection, system network modeling, short-circuiting simulation, coordination evaluation, problem mitigation, and finally, concludes and provides recommendation to the authorized body.

The detailed system network model is built for the regional transmission network based on collected system data such as transmission line parameters, relay types, relay settings, relay location etc. Then simulations are conducted using an integrated power system analyzing tool DIgSILENT power factory 2024 SP1 software.

The simulation results have shown that the existing protection system exhibited several coordination violations and long coordination time interval (CIT), which may cause to extended fault clearance time if primary protection system fails to operate. To address these, PSO algorithm was utilized to determine optimal relays operating time setting with satisfying the coordination and relay setting limit constraints.

The optimal relays setting, which obtained from PSO algorithm, were verified using simulation. The results showed that the operating time of protection relays provided a clear discrimination time of 0.2 second between backup and primary protection relays, which reduce the risk of cascading outages with fast fault clearance. These findings demonstrated that the proposed method significantly mitigate the relays coordination problems and enhance the reliability of transmission system. In addition to assessment and mitigation, this thesis offered actionable recommendation for the EEP to enhance relays selectivity across the regional transmission network.

Keywords - *Coordination time interval, Distance protection relay, Overcurrent protection relay, Particle swarm optimization, Protection relay coordination, and Selectivity.*

Table of Contents

List of Figures

List of Table

List of Abbreviations

BB	Bus Bar
CB	Circuit Breaker
CTI	Coordination Time Interval
Ds	Distance
DFW	Directional Forward
DIgSILENT	Digital Simulation of Electrical Networks
DOCRs	Directional Overcurrent Protection Relays
DT	Definite Time
EEP	Ethiopian Electric Power
DRs	Distance Protection Relays
IC	Incoming
IEC	International Electro-Technical Commission
IEEE	International Journal of Electrical and Electronic Engineering
MATLAB	Mathematics Laboratory
OC	Overcurrent
OCRs	Overcurrent Protection Relays
OG	Outgoing
PSM	Plug Setting Multiplier
PSO	Particle Swarm Optimization
SCADA	Supervisory Control and Data Acquisition
SI	Standard Inverse
SS	Substation
TMS	Time Setting Multiplayer

List of Symbols and Variables

S	Second
R	Resistance
X	Reactance
I>	Overload pickup current setting
I>>	Short-circuit pickup current setting
I>>>	Instantaneous short-circuit pickup current setting
Ie>	Earth-fault first stage pickup current setting
Ie>>	Earth-fault second stage pickup current
tI>	Operating time for overload current setting
tI>>	Operating time for short-circuit protection setting
Ω	Ohm
∞	Infinity

Chapter 1

Introduction

1.1 Backgrounds

Modern power system composed from various components, like generators, transmission lines, reactors, transformers etc. Each of them should be protected against faults to ensure safe and reliable system operations. For this, protection relays are essential devices to detect abnormal electrical behaviors and initiate corrective actions. The relays measure electrical quantities such as voltage, current, frequency, impedance etc. to identify the faulted conditions on transmission and distribution network.

Once fault is sensed, the protection relay trigger the circuit breaker (CB) in order to isolate disturbance quickly [1]. The primary goals of quick isolations are:

- To minimize system disturbance duration and severity,
- To prevent system element damage during disturbance,
- To ensure reliable and high-quality power supply to the customers.

In addition to fault detection and isolation, protections relays played critical role on maintain system operational continuity. They are essential for enhancing overall system reliability in power transmission and distribution network. Therefore, protection system are typically designed to operate with main and backup function both in parallel to enhance fault coverage and reliability [2]. With ongoing system expansion driven by economic development, an effective coordination between backup and main protection relays becomes vital to avoid unnecessary interruptions.

In an electric power system, faults may occur at any point, and thus should be detected by both primary and backup protection relays [3]. Although, both protection relays are capable of detecting faults, the primary protection relays are expected to operate first and isolate the disturbance. when primary protection relay fails to operate, backup protection relays should be activated to clear the system disturbance [4]. Cascaded events and unintended tripping outside the designated protection zones are an indication for poor relays setting coordination within the system [5].

Electric power plants, high voltage transmission lines, and substations are crucial components, which transfer electric power from power plant to the national grid and ensure reliable delivery of quality electric power across the country. In Ethiopia, a high-voltage transmission line now reaches over 20000 kilometers, operating at voltage levels ranging from 132 kV to 500 kV and has above 192 substations currently under operation nationwide [6]. Of these, 10 substations are located in the south west region transmission network.

1.2 Statement of the problem

Protection relays setting coordination and its associated impact on the transmission network becomes serious issue in Ethiopia. It is commonly observed that the system component outages triggered by fault outside the designated protection zone, as well as cascading system outages throughout a year. Since relays setting coordination has critical impact on transmission network reliability and stability. It is essential to assess the condition of existing system protection relays setting coordination. Enhancing system reliability through addressing the coordination issues are needed, rather than continuing with usual trend of EEP routine setting upgrade practice.

The transmission network in EEP southwest region has been identified with improper relays setting coordination. Frequent system component outages have been reported due to faults that originating from high-voltage transmission lines and medium voltage feeders located outside the intended protection zones. Therefore, relays setting coordination in this region is critical issue that needs to be thoroughly investigated.

Improper protection relay setting compromises power system secure operations, which may lead to widespread service interruptions. System restoration following such event often requires significant time, during which residential, commercial, and industrial customers are experience for prolonged power outages. This is not only affecting customers but also leads to significant financial loss for the EEP due to reduced electricity sales.

Southwest transmission network of EEP supplies broader geographical area. In its coverage area, occurrence of system component outages triggered by faults outside the respected protection zones, as well as cascading events should be needed detailed analysis. This calls to assess protection relays setting coordination and mitigation of problems.

The problem focused in this thesis is to analyze the performance of protection relays within the EEP southwest transmission system, identify the relays coordination problem and mitigate it.

1.3 Objectives

❖ **General objective**

The general objective of this thesis is to analyze the performance of overcurrent and distance protection relays within the network of southwest region of EEP system and mitigate problems.

❖ **Specific objectives**

The specific objectives of the study include;

- ✓ To collect relevant data for the southwest transmission network of EEP system.
- ✓ To develop the software model of the transmission network using DIgSILENT power factory 2024 SP1 software.
- ✓ To carry out short circuit simulation and analyze the performance of existing protection system for the transmission network.
- ✓ To identify relays coordination problems in the transmission network.
- ✓ To determine optimal relays operating time to mitigate the coordination problems.
- ✓ To carry out simulations with optimal relays setting for the protection system.
- ✓ To analyze results and compare the performance of protection system with optimal settings and those of existing protection system.
- ✓ To draw conclusions and provide recommendations to the concerned authorized body.

1.4 Methodology

The procedures followed throughout this study are the following:

1. **Literature review**

A number of articles, journals, papers and any other relevant document for the thesis are revised throughout the study.

2. **Data collection**

Relevant data were gathered through direct filed visit and from various departments of EEP, such as power system network planning and power system protection offices.

3. System network modeling

Based on the collected data, the detailed transmission network model was developed using DIgSILENT power factory 2024 SP1 software.

4. Short circuit simulations

Line to ground, double line to ground, two-phase, and three-phase fault scenarios were simulated using the modeled network. For those scenarios, fault current magnitude and corresponding protection relay operating time responses are recorded in order to evaluate system protection relays setting coordination.

5. Protection relays setting coordination assessment and problem mitigation

Relays that operate incorrectly, such as tripping for faults outside the respected protection zones and cascade tripping events were identified. For those relays, the respected optimal operating time was investigated by utilizing PSO algorithm with a fixed predetermined pickup current setting. Then the outcome of PSO algorithm is validated using simulation, through replacing the existing relays setting by the optimized value.

6. Conclusion and recommendation to the authorized body

Based on findings of the simulation, recommendations were formulated and proposed to power system protection office of the EEP to address relays setting coordination problems efficiently.

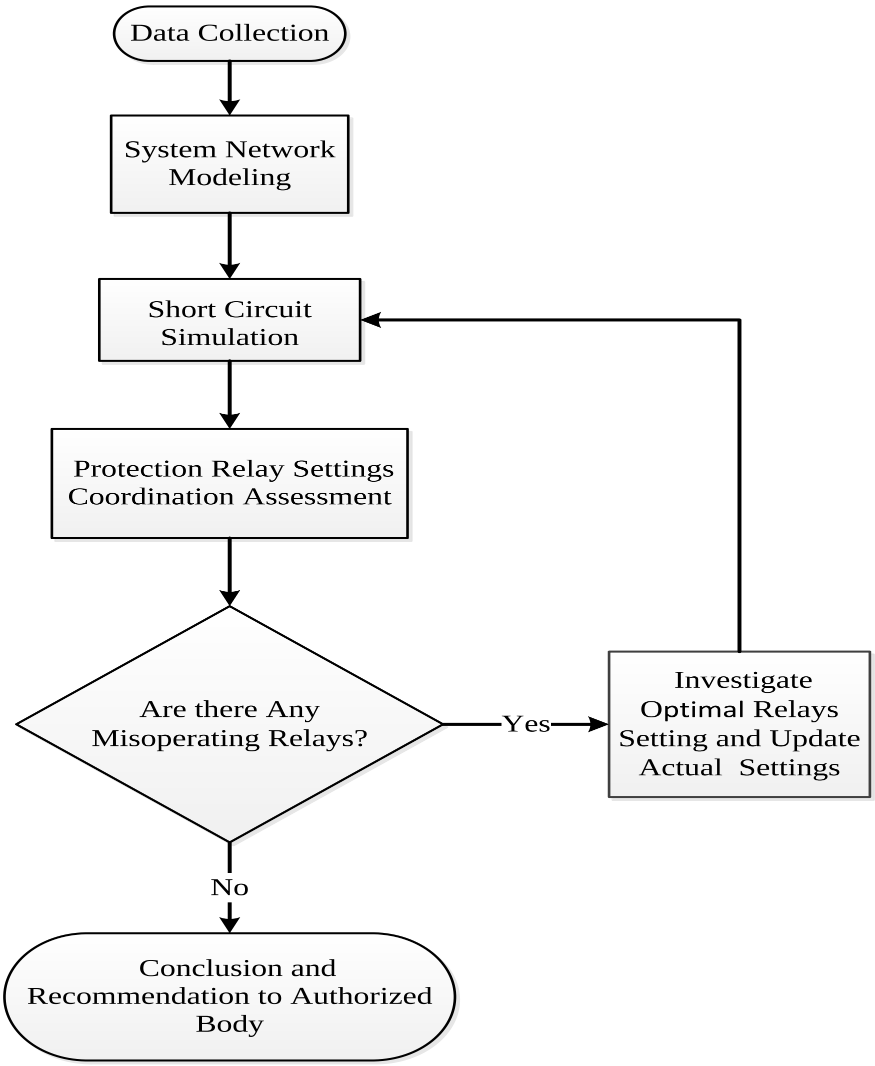

Figure 1.1 : Flow chart of the methodology that followed through this thesis work

1.5 Scope and significance of the study

This thesis tries to assess the existing setting coordination for distance and overcurrent protection relays within the EEP Southwest Region transmission system. It also tries to address the relays setting coordination problems through determining proper pickup current setting for overcurrent protection relays (OCRs) and investigating optimal operating time setting by applying PSO algorithm. The study mainly focused on OCR and distance protection relay Zone II operating time. Therefore, Zone three and Zone four setting for distance protection relays and breaker failure settings are not included in this study.

The significance of this thesis lies on its contribution to improve system protection by addressing the coordination problems in relays setting. This thesis gives several practical benefits:

- To assess existing protection relays setting coordination within the system.
- To help reduce unwanted system interruption caused by relays coordination problems.
- To enhance system reliability and stability by analyzing and recommending optimal relays setting.
- To support EEP in solving the relays setting coordination challenges.
- To propose practical procedures in relays setting coordination mitigation for real-world applications.

1.6 Organization of the thesis

The thesis is organized in five chapters as outlined below:

Chapter One- Introduction:

This chapter gives basic overview on protection system, which includes problem of statement, thesis objectives, employed methodology, scope and significance of the thesis.

Chapter Two-Power system protection and relays coordination:

This chapter gives a theoretical overview on electrical faults, their causes and consequences, and fault analysis methods. It also reviews power system protective equipment, particularly protection relays, their coordination philosophies, and solutions in relays setting coordination

Chapter Three-Data collection and problem formulation:

This chapter outlines relevant data that collected from various sources and through direct filed visits, system network modelling, problem formulation used to determine optimal relays setting, and solution to coordination problems.

Chapter Four- Result analysis and discussions:

This chapter presents simulation result, result analysis and discussion of the thesis.

Chapter five-Conclusion and Recommendations:

This is the final chapter that summarizes thesis conclusions and provides recommendations. It also discusses limitation of the thesis and suggests direction for future work.

Chapter 2

Power System Protection and Relays Coordination

2.1 Introductions

The theories and literature review relevant to this thesis are presented in this chapter. Section 2.2 discusses power system protection. Section 2.3 covers the nature of electric power system faults, causes and consequences. In section 2.4 the theoretical aspect of short-circuit analysis described briefly. Section 2.5 and 2.6 present an overview on protection system coordination philosophies and solutions in relays setting coordination problems. Finally, Section 2.7 provides a review of related literature to this thesis.

2.2 Power system protection

Protection is one of the main disciplines in electrical engineering that focused on fault detection and isolation from health system. Protection is very useful to any electrical equipment or humans to protect from any electrical injury. The equipment that detects fault and sends commands to the CB to isolate the faulted section is called protection relay.

Objectives of power system protection are:

- ✓ Limit service interruption duration.
- ✓ Prevent human from injury during disturbance.
- ✓ Minimize component damage.

In electric power system, the most important protection equipment that used in transmission and distribution networks are circuit breaker (CB) together with protective relays, voltage and current transformers in order to isolate disturbance from other healthy system. The theoretical aspect for this equipment's is briefly discussed as follows:

2.2.1 Circuit breaker

According to [1], circuit breaker (CB) is an electromechanical switching device capable of making, breaking, and carrying current under normal operating conditions as well current breaking under fault conditions. Based on interrupting medium CB generally categorized as:

- Magnetic CB
- Vacuum CB
- SF6 gas CB
- Air blast CB
- Oil type CB etc.

2.2.2 Protection relay

Protection relay is a devices that senses fault, send commands to the CB, and isolate the faulted section from the rest of the system [7]. Protection relay is detecting an abnormal condition by constantly measuring electrical quantities. The quantities are voltage, frequency, impedance, current, power etc. in which the value is different under normal and abnormal conditions. If one or more of these quantities changed in its value, fault is sensed. After detecting fault, protection relay operates and close the tripping circuit of circuit breaker, which result in opening circuit breaker and isolate the defected section. Most of the relays used in electric power system are operated based on voltage and current measurement, which is supplied by voltage and current transformers.

Types of protective relays

Recently in modern electric power system, various types of protection relays are in use to protect system components from different type of faults. Generally, protective relays can be classified based on their constructions, functions or applications [1]. However, protective relays are generally classified based on constructions and applications, it also categorized according to several other criteria, summarized as follows [8]:

A. Based on operating characteristics
   - ✓ Definite time protection relay
   - ✓ Invers time protection relay
   - ✓ Instantaneous protection relays etc.
B. Based on logic
   - ✓ Over fluxing protection relay
   - ✓ Restricted earth fault protection relay
   - ✓ Current differential protection relay
   - ✓ Directional and non-directional overcurrent protection relay
   - ✓ Distance protection relays etc.

C. Based on actuating parameter
   - ✓ Current actuating protection relay
   - ✓ Voltage actuating protection relay
   - ✓ Frequency actuating protection relay
   - ✓ Power actuating protection relay etc.

D. Based on application
   - ✓ Primary protection relay
   - ✓ Backup protection relay

E. Based on operating mechanism
   - ✓ Electromagnetic
   - ✓ Static and
   - ✓ Mechanical types

Since overcurrent, distance, differential, and restricted earth fault protection relays are basically used in transmission system protection, their operating principles, functions, and application areas are discussed in the following sections.

Overcurrent protection relay

This type of protection relay is a current actuating type protection relays, which operates when the value of current exceeds the predetermined setting value. This relay protects power system component against excessive currents that comes from short circuits, ground faults, overloads, etc. According to [9], overcurrent protection relays are a fault sensing device by measuring the quantity of current to be functional for isolation of defective sections. Overcurrent protection relays categorized as either directional or non-directional based on their operating logic. The parameters related to overcurrent protection relays are discussed as follows:

Pickup current: – is the minimum current in which the relay starts to operate. This protection relay operates when the fault current exceeds the pickup setting value. Pickup current should be greater than maximum load current and below minimum fault current. Practically, pickup is set closer to maximum load of the system elements because it is better to discriminately trip the slight overload of system than to trip for minimum fault currents [10]. If pick up current takes in between maximum load current and minimum fault current of the system component, it may sacrifice safety sensitivity and allow long-term overload that causes in consequential distraction of system components. Considering the above, pickup current for overcurrent protection relay is determined as $1.2*I_n$ where, I_n is the lowest nominal current of the installed equipment to intend maximum load tolerance of the system elements [11]. Additionally, earth-fault pickup current is determined as 1/10 or 10% of overcurrent pick up current setting [12], [13].

Plug Setting Multiplier (PSM): - is defined as the ratio between fault current and pick up current value [10]. This can be expresses in Eq. (2.1).

$$\mathrm{PSM} = \frac{\text{Fault current}}{\text{Pick up current}} \tag{2.1}$$

Where, PSM is Plug Setting Multiplier.

Time Setting Multiplayer (TSM): is the multiplication factors that used for calculation relays operating time during fault conditions and the range of this value depends on relay types and their manufacturers [7], [9]. Overcurrent protection relay based on operating characteristics categorized in to three. These are:

- **Instantaneous overcurrent protection relay**

Instantaneous over-current protection relay is one of the current actuating types of protection relay in which it does not have time delay whenever fault current exceeds the pickup current. Instantaneous settings are established by fixing pickup current above the external protection zones maximum fault currents [14] in order to coordinate relays properly.

- **Definite time over-current protection relay**

In this type of protection relay definite time elapses between the instant of fault detection and relay contact closing. The operating time for this relay, is same for the fault current values that exceeds the pickup setting value. The relays operating time verses current characteristics curve is illustrated in Figure 2.1. This protection relay takes long or short time to clear fault current depending on setting.

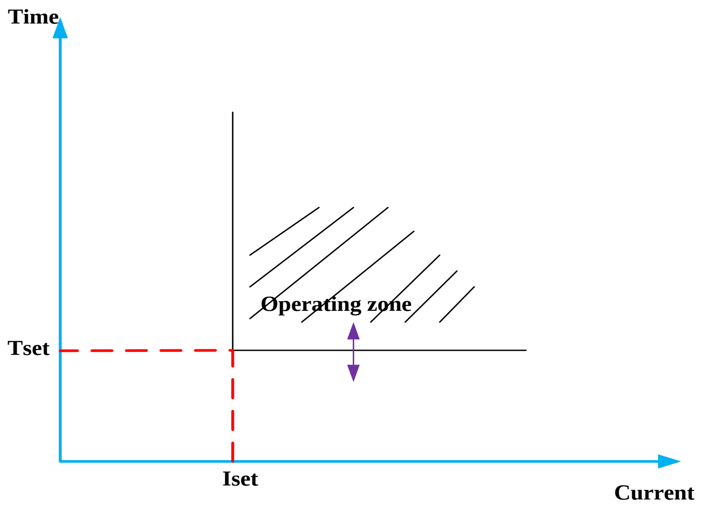

Figure 2.1: Definite time OCRs operating time-current characteristic curve

❖ **Invers-time overcurrent protection relay**

This type of protection is a type of overcurrent protection type in which the relay operating time is inversely proportional to the fault current magnitude [15]. The operating time-current characteristics curve is given in Figure 2.2. This relay like other types of protection relay does not operate for the current less than the pickup setting value. At high fault current, the operating time decreases steadily. The advantage of invers-time characteristics over definite time relay characteristics is that on high fault current the protection relays operate with much shorter time without the risk of system components.

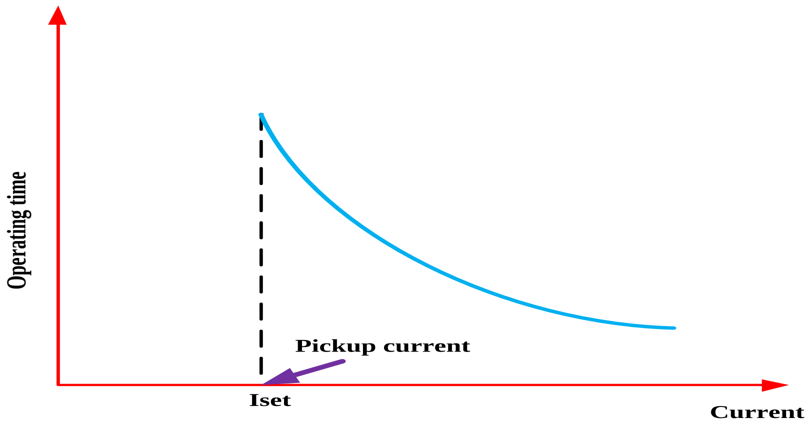

Figure 2.2: Invers time overcurrent protection relays operating time-current curve

IEC 60255 categorized inverse time-overcurrent protection relays as standard invers, long-invers, very-invers, and extreme invers. The formula for operating time calculation for these types of protection is summarized in Table 2.1.

Table 2.1: Operating time definitions for invers time overcurrent protection relays [3], [16]

Relay characteristic	IEC 60255 relay operating time calculation formula
Standard invers (SI)	$T_{op}=\frac{0.14}{P.S.M^{0.02}-1}\times TMS$
Very invers (VI)	$T_{op}=\frac{13.5}{P.S.M-1}\times TMS$
Extremely invers (EI)	$T_{op}=\frac{80}{P.S.M^{2}-1}\times TMS$
Long-time invers (LI)	$T_{op}=\frac{120}{P.S.M-1}\times TMS$

Where T_{op} is operating time and TMS is Time Multiplier Setting.

To have best relays setting coordination, selection of operating characteristic is one of the main tasks for any protection engineers. Comparisons of different overcurrent relay-operating characteristics on setting coordination are made in [7], [9] and they found that IEC standard inverse relay operating characteristic gives better coordination than other types of relays characteristic.

Distance protection relay

Distance protection relay is one in which impedance is an actuating quantity and widely used in transmission line protections. The basic operating principles of distance protection relay is based on voltage and current measurements, in which it responds for impedance between the relay terminal and fault location [16]. When the measured impedance less than the setting value distance protection relay operates. Since, impedance is directly proportional to length for a transmission line; the exact location can be determined properly whenever the relay seats properly. Based on characteristics distance protection relay can be categorized as Moh, reactance, impedance, quadrilateral, offset Moh, etc. Each type of distance protection relays has their own functions, application area, and theories behind; the theories for these distance protection relays are briefly described in next section.

✓ Impedance type distance protection relay

This type of protection relay responds for the ratio of rms voltage to rms current flow. The voltage to current ratio is measured as impedance magnitude. If the magnitudes of measured impedance less than the setting value, protection relay sense's fault in its desired protection zone and start operation. Based on operating logic this protection relay is non-directional. The typical characteristic is given in Figure 2.3.

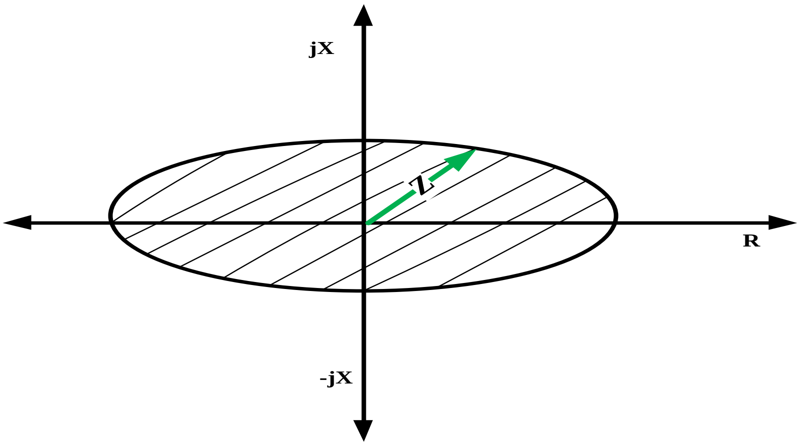

Figure 2.3: Impedance type distance protection relays R-X characteristics curve

To keep free from adjacent line fault, directional protection relays used in conjunction with this type of protection relay. Direction relay is used for justify the fault direction, and allow or block relay operations. This can be achieved through connecting the output contact in series with impedance protection relay.

- ✓ **Mho distance protection relay**

This type of protection relay has circular characteristics, which passes through the origin of R-X plot. Since, the third quadrant on R-X plane is outside relays operating zone, faults on bus side does not see by this relay. So, mho distance protection relay is always preferred over impedance distance protection relays.

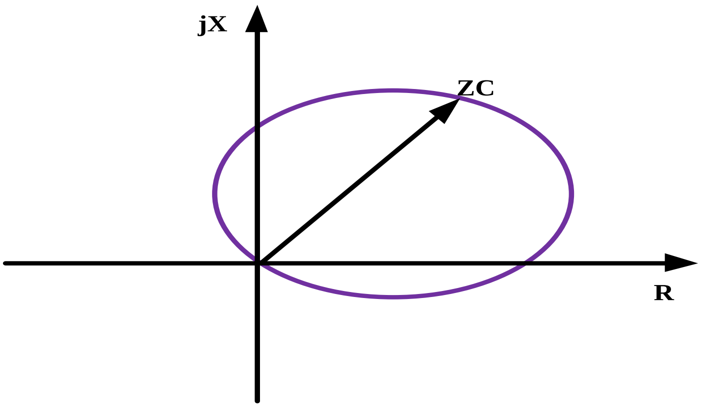

Figure 2.4: Moh relay operating characteristic plotted on R-X plane

- ✓ **Reactance type of distance protection relay**

This type of protection relay has straight line characteristics, which respond only for reactance. The operational logic is non-directional and used to supplement Moh protection relay. Its application area especially for short transmission line where arch resistance is same magnitude throughout the line length [17].

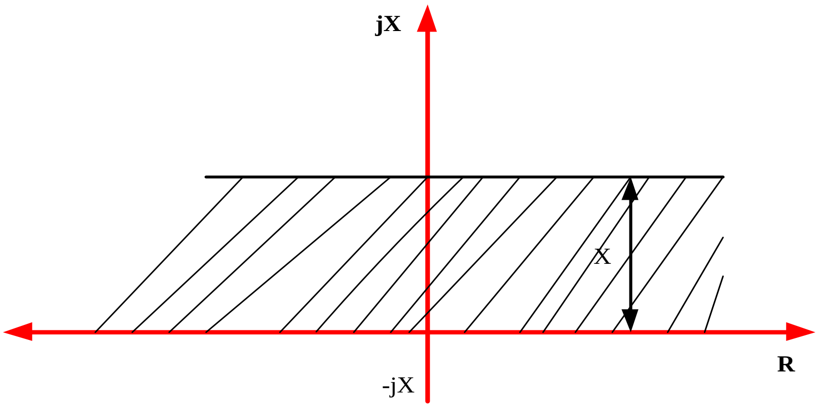

Figure 2.5: Reactance relay operating characteristics plotted on R-X plane

From the plot, the relay operates only on first and second quadrant but does not operate on third and fourth quadrants.

- ✓ **Quadrilateral distance protection relay**

This type of distance protection relay consists of four straight lines as shown in Figure 2.6 below. If impedance seen by the relay inside this region, the relay trip otherwise it does not operate. Quadrilateral type of distance protection relay provides flexible protection during high fault resistance. This type of protection relay is used for short-transmission line for high footings resistance.

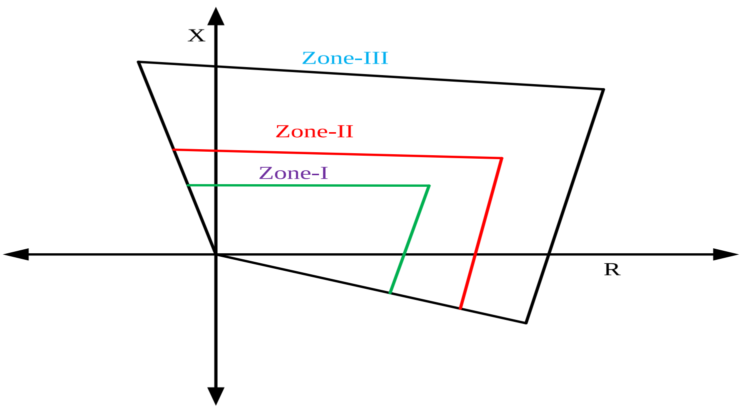

Figure 2.6: Quadrilateral type of distance protection relay operating characteristics R-X plot

Differential protection relay

Differential protection relay is a type of protection relay in which it operates when the difference exceeds the setting value. In a current differential protection scheme, the current input comes from two or more side of protected equipment. The current meets at a junction point where the protection relay is connected properly. Based on kickoff current low, the resultant current flowing through the relay coil is summation of these input currents which comes from different part of the circuit. The magnitude and polarity should be adjusted in such a way that the sum of current equal to zero under steady state operating conditions. When there is abnormality happened in the circuit, the sum of current no longer become to zero, as a result difference current flow in to the relay coil thereby the relay being operated successfully. In differential protection scheme, there are a set of instrumental transformers each connected at either side of the protected equipment.

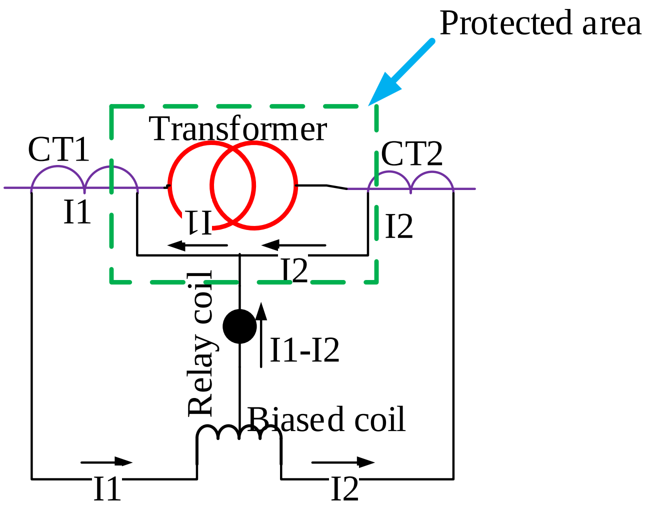

Figure 2.7: Schematic diagram for current differential protection relay

Differential protection relay does not operate by external fault current while operate whenever an internal fault current created if the protection system is configured and installed correctly. Based on operating characteristics, differential protection relay is instantaneous type. Therefore, differential protection relay does not need coordination with other system protection relays in power transmission network.

Restricted earth fault protection relay

Restricted earth fault (REF) protection is a form of differential protection, which can be used in transformer or generator protections. It is specifically designed to detect faults lower than the nominal load current [18]. This type of protection particularly useful when either differential or overcurrent protection are insufficient to detect fault current. The protection scheme is used to protect individual winding sets.

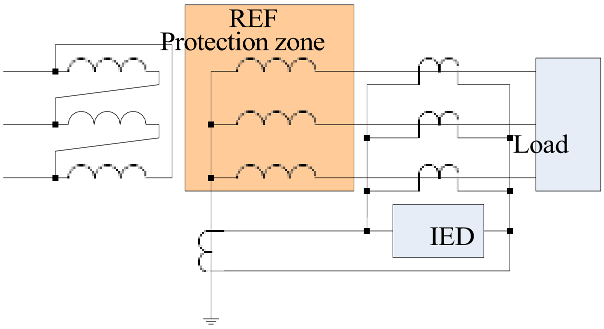

Figure 2.8: Restricted earth fault protection for a star side of transformer

The current transformer measuring current in each phase and neutral point are connected in parallel, currents are balanced for the external fault, and resulting in stable operation. When a fault inside the star side winding of a transformer can create unbalance current, which causes to operate REF protection.

Generally, protection relays are used to protect the system components against from electric power system fault. Therefore, it is necessary to discuss the nature, causes and consequences of power system faults.

2.3 Electric power system faults, causes, and consequences

2.3.1 Electric faults

Faults are undesirable creation of conducting or blocking current path. Under normal system operating conditions, a system operates with balanced three-phase AC current flow. Whenever insulation of any system component fails at any points short-circuit or fault may happen. Recently, various causes of faults exist in the world. Some of the causes are:

- Tree falling across the transmission lines, heavy winds, and lighting strikes.
- Collisions involving vehicles and aircraft with poles and transmission line towers.

- Small animals or birds shorting conductors or entering switchgear equipment.
- Conductor breakage due to excessive mechanical loading or physical damage.
- Failure of system components and improper system operations etc.

2.3.2 Consequence of electric system faults

Electric fault can interrupt power supply, damage system elements or components, and if not controlled properly may cause to nationwide blackouts. Power system faults may lead any of the following consequences:

- A significant reduction in line voltage across the major parts of power system, potentially resulting in widespread service outages and wastage in power production.
- The formation of electric arc during fault can damage equipment and pose serious risks to human being.
- Disturbance in system stability, which may lead to complete system blackout.

As discussed in section 2.2.2, power system faults are abnormal conditions in electric power system network that disturber normal current flow. The fault types are different depending upon fault impedance, which described briefly in the following section.

2.3.3 Types of power system fault

Fault current is limited by fault impedance in which it may composes in to electric arc and presents of additional object in the fault path. Fault impedance may be constant or may vary during fault conditions.

Impedance of an additional object in the fault path is mainly considered as resistive, and the value may be high or zero, based on this fault impedance is unpredictable in quantity [19]. Faults can be categorized in two major categories depending on impedance. These are:

I. High fault impedance
II. Low fault impedance

High impedance fault

This fault type is a fault in which the fault impedance in the current path is high, such as road, sand, grass etc.

Low impedance fault

Low impedance fault is a fault in which the fault impedance is low that include conventional shunt faults like:

a) Line-ground faults

b) Double line-to- ground faults
c) Phase-to-phase faults
d) 3-phase balanced faults etc.

Experiences have been shown that about 70% of fault created in the world is single line to ground fault [1]. Except balanced three-phase fault other power system faults are unbalanced mode. Since power system faults can cause system voltage reduction, high current flow, may damage system component, system instability, which may lead to complete system blackout, it is important to analyze faults properly. For this, short circuit analysis plays vital role in determining fault current magnitude, which assists in verifying equipment rating and proper selection of protective equipment.

2.4 Short circuit analysis

Electric power system is designed to supply system loads as much as safe as reliable manner. Adequate handling of short-circuit is the major tasks in design and operation of power system. Even though, electric system designed as free from any fault as possible, faults still occurred. A well-designed power system must isolate the disturbance safely and quickly with no equipment damage and with minimum number of customer interruption. Short-circuit calculation is the calculation of fault current that flows during disturbance. Short-circuit calculation used for checking of equipment ratings during planning stage [20], which uses less detail network modeling where extreme-case estimations are applied.

Some of the typical applications of short-circuit analysis at planning stages are:

- ✓ Protective relays setting determination.
- ✓ Thermal limit verification for transmission line and power cable.
- ✓ Verification of fault current capacity at load points.
- ✓ Protective relays setting coordination evaluation.
- ✓ Verifying system short circuit current not exceeds from the defined equipment capacity

Also, the typical applications of short-circuit analysis system at specific operating conditions are:

- ➢ Protective relay setting coordination evaluation at a specific operating point.
- ➢ Verifying short-circuit limit does not exceed system reconfiguration.
- ➢ Calculation of fault current at any protective relay locations.

- Mutual interfacing of parallel line analysis during fault conditions.

In terms of system modeling, superposition or complete short-circuit calculation method is an accurate calculation method that calculates the expected short circuit current on the network for a specific operating point [20]. IEC 60909 calculation methods is a simplification of complete or superposition methods, which accomplishes close-to-reality without the need of preceding load flow calculation and associated definition of actual operating point.

2.5 Protection relays coordination

As discussed in the previous section, protective relays based on application categorized as primary and backup. Backup protection relay also categorized as remote and local. To protect power system elements adequately with minimum power supply interruptions protection system is dividing into various primary protective zones. Each system element has its own separate primary protection zone in which a given protective relay is responsible. Primary protection zones around each system elements are given in the dashed line of Fig.2.9.

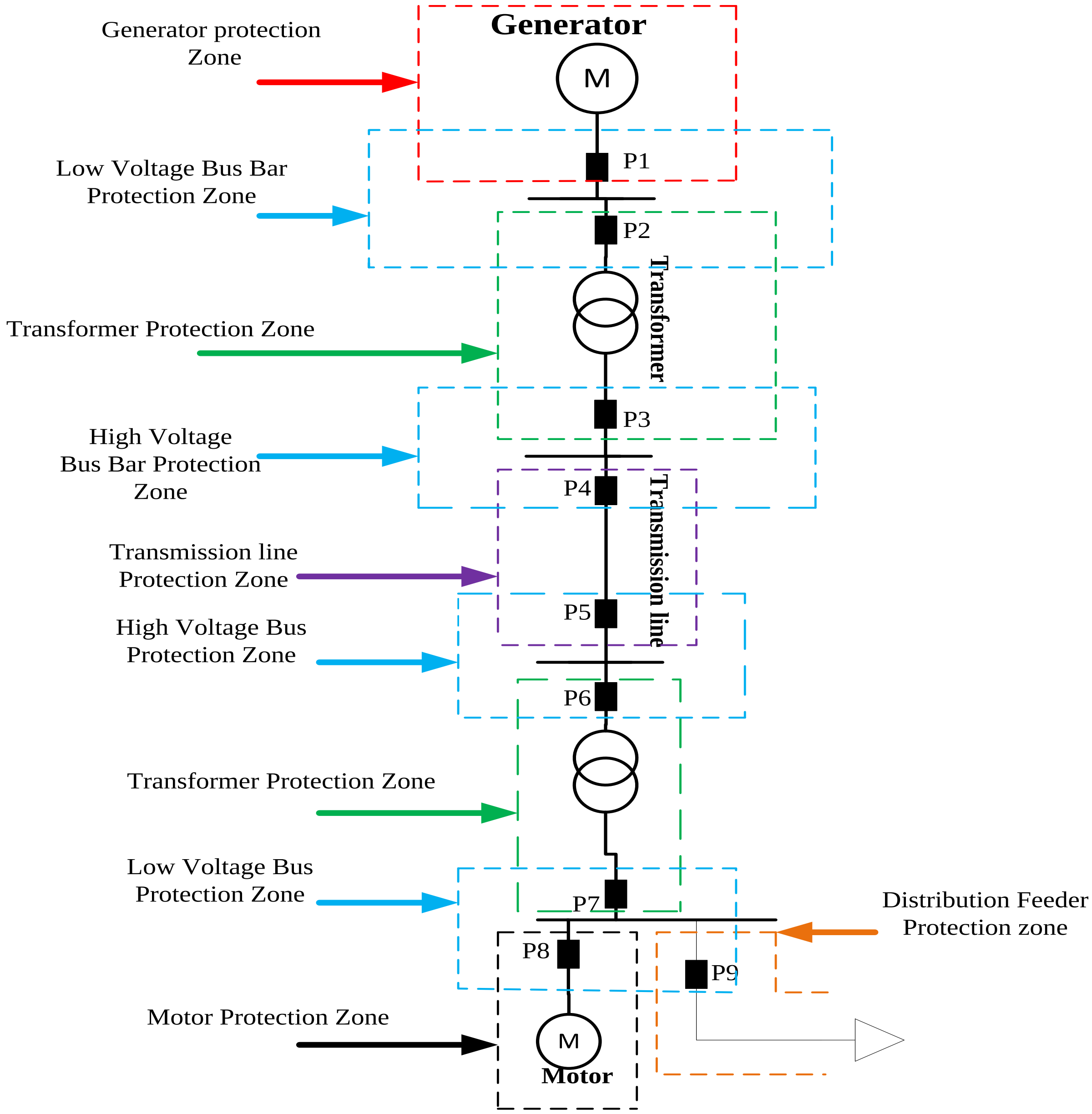

Figure 2.9: Primary protection zones for each system elements [1]

However, any power system elements have their own primary protection system. Also, have its own backup protection system, which is responsible whenever primary protection system failed to operate. In order to operate these protective relays accordingly, the system relays should be coordinated properly. To have selective protection, backup protection relays should have long time than primary protection relays. The backup protection relays minimum operating time depends on the operating time of primary protection relay, operating time of CB, overshoot time of protection relays, safety margins, and errors. The minimum standard CTI between backup and primary protection relays are in between 0.2 and 0.5 second based on protection relays operating mechanism [4], [14], [21], [22], [23].

2.6 Problems and solutions in relays setting coordination

Relays setting coordination problem arise from selectivity and fast fault clearance, where primary relay trips first, and its backup relay should trip after primary relay with sufficient CTI to ovoid cascade tripping event within the system. Protection relays setting coordination is a complex task, especially at the level of transmission system [24]. Protection of transmission line is conducted using different protection scheme. Among them, distance and directional overcurrent protection functions are the basic, which should be operate in a proper coordinated manner. However, conducting of coordination between these relays are not trivial with the use of conventional methods, it becomes basic and laborious. Solutions to relays setting coordination problem by applying optimization techniques [24], [25].

Optimization refers to finding optimal value for the discussion variables, which provides maximum or minimum of one or more desired objectives. As with any analysis, the first stage in optimization is formulating of problem subjected to the constraints. Recently, various optimization techniques are used to solve problems related to relays setting coordination. Each has its own field of applications, advantages and disadvantages behind. The theoretical aspect of each optimization methods is beyond this study. In this study, the coordination tasks for system protection relays treated by utilizing Particle Swarm Optimization (PSO) algorithm. The theory behind PSO algorithm is presented in the following section, but the overall taxonomy of optimization technique is summarized in Figure 2.10.

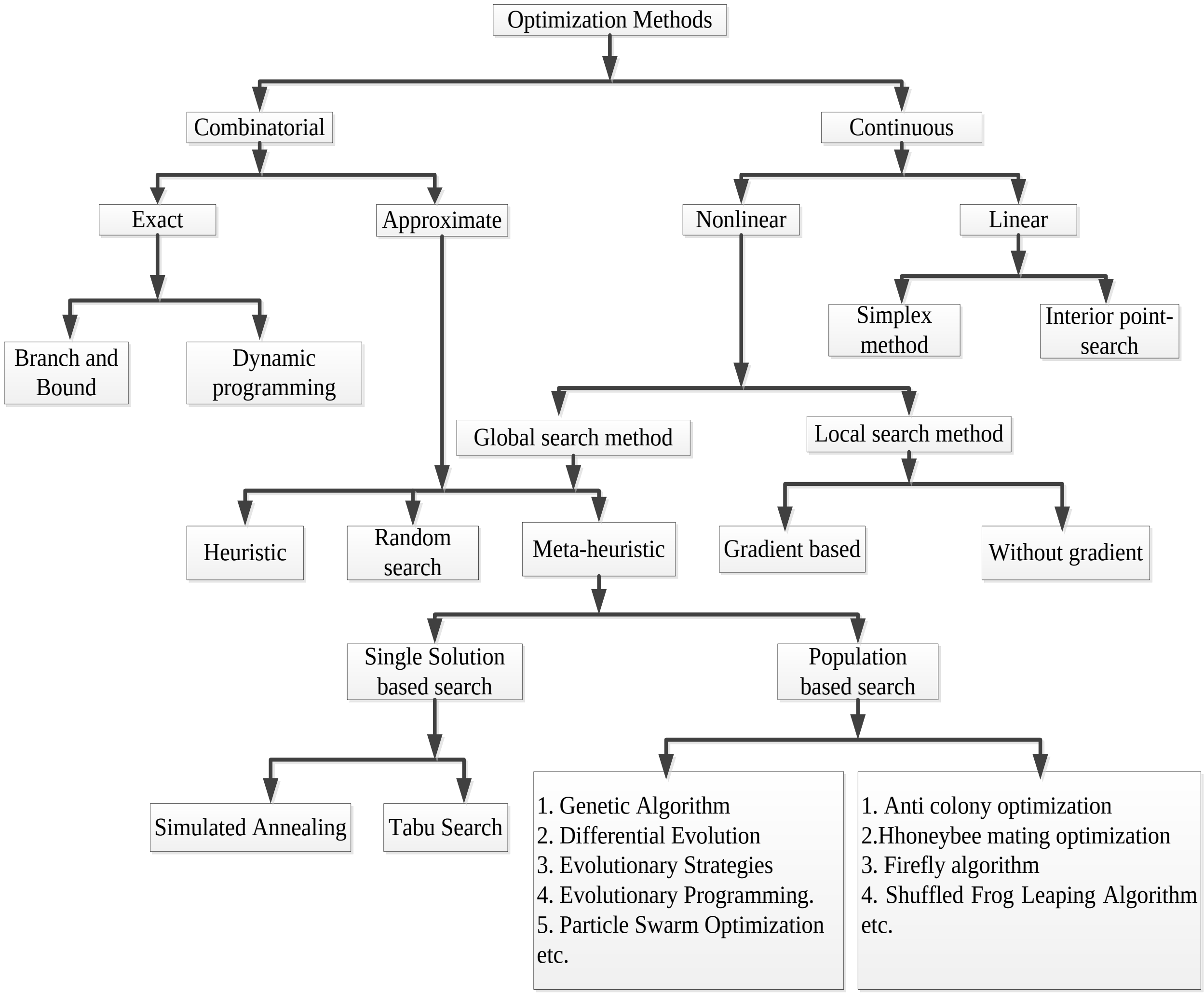

Figure 2.10: Taxonomy of optimization methods [22]

Particle Swarm Optimization is one of the swarm or population-based algorithms that determine solutions to the problems. PSO inspired by social behavior of birds and fish flocks or a school of fish searching food that means each individual in a group move toward a good region based on their environment adaptation. As compared to other optimization methods, PSO has its own advantage and disadvantages.

Advantages of PSO algorithm are: -

- Simple to implement.
- Relatively few parameters to tune.
- Robustness.
- Higher probability and efficiency to find the global optima
- Fast convergence

Disadvantages of PSO algorithm are:

- ❖ Premature convergence and trapping on solving higher dimensional problems.
- ❖ Difficult to initialize the control parameter.

Particle swarm optimization algorithm is used in environmental, health-care, industrial, commercial, smart city etc. According to [26], PSO algorism is faster, more efficient, cheaper, few parameters required to adjust in implementation. Also, it is suit to solve non-linear, non-convex, continues, discreet types of problem.

2.7 Literature Review

Numerous studies have been carried out to address the coordination problems related to distance and overcurrent protection relays. These studies aim to ensure system reliability and stability with minimizing relays operating time, and maintain proper selectivity between the protection devices. Brief overviews of various literatures are presented as follow:

For a typical IEEE nine bus bar transmission system, proper distance and overcurrent relays setting determined and validated using MATLAB and ETAB software's respectively [2]. The results showed that the determined relays setting in the system are appropriate and effective.

In [3], overcurrent and distance protection relays setting coordination was analyzed with considering various overcurrent relay operating characteristics. For each characteristic, the optimal Time Multiplayer Setting (TMS) was determined using genetic algorithm, with a fixed pickup current (Iset) and predefined distance protection relay second & third zone operating time should be 0.3 seconds and 0.6 seconds respectively. The study concluded that standard invers OCR characteristics yield better optimal coordination performance as compared to other OCR characteristics.

In [4], the coordination problem for overcurrent protection relays setting is formulated using mixed integer and linear programing approach. By considering three coordination constraints, the optimal TMS settings were determined using Gomory's cutting plane method, based fixed pickup current setting (I_{set}), with IEC standard invers operating characteristics. It found that the method provided systematic and computationally efficient for relay coordination problem.

In [5], protection relays setting coordination for the northwestern part of Turkish national power transmission network was assessed using DIgSILENT power factory software. The study found that the system protection relays operated in the expected sequence and were optimally coordinated.

A complex nonlinear optimization problem was formulated for simultaneous coordination of DRs and DOCRs [7]. Optimal relays setting including DRs second zone operating time (T_{Z2}s), pickup current settings (I_{set}s) and time multiplier settings (TMSs) for DOCRs were determined using Hybrid Genetic Algorithm (HGA). The formulated approach was evaluated using IEEE-14 bus bar test system; the results showed that the method produced feasible and robust settings for both distance and DOCRs, with satisfying all coordination constraints under various network topologies.

In [9], the coordination performance of OCRs for incoming and outgoing feeders was analyzed using three different relay operating characteristics: standard invers, very invers and extremely invers. The study found that standard invers relay operating characteristics provide better coordination than very invers and extreme invers types, and making it more suitable for achieving effective protection system.

In [15], overcurrent protection relays setting for a sampled 230 kV power transmission system is analyzed, with a predetermined pickup current, fixed T_{Z2}s, T_{Z3}s operating time, and considered 0.2 second CTI.

In [21], the coordination problem for DOCRs was formulated by incorporating the coordination constraints that include DRs and BFRs both with and without pilot protection schemes. The TMS settings for DOCRs were optimized using genetic algorithm (GA), while keeping distance protection relay second zone operating time (T_{Z2}s), Pickup current setting (I_{set}s), and operating time of breaker failure relays fixed. The study effectively demonstrated that GA capable to achieve reliable coordination among these protection devices under various configurations.

In [23], the coordination problem between DOCRs and DRs was formulated with considering the discrimination time between backup DOCRs operating time and primary distance protection relay zone two operating time (T_{Z2}s), as well as between backup DRs T_{Z2}s and primary DOCRs operating time. The problem was solved using a combined genetic algorithm and liner program.

In[27], coordination of protection relays for high voltage transmission line that connecting Payakumbuh and Koto Panjang substations was investigated. The TMS setting for both overcurrent and earth-fault protection relays were calculated manually, based on fixed operating times for distance protection relay: 0 seconds for first zone operating time, 0.4 seconds for second zone operating, and 1.2 second for third zone operating time. It is found that the TMS values for overcurrent and ground fault protection relay is 0.45 second and 0.63 second respectively.

In [28], the coordination of OCRs for a 132/33 kV transmission substation was analyzed using MATLAB model under various operating modes and with different relay operating characteristics. The study found that while protection relays could be properly coordinated across all relay characteristics, the standard invers relay characteristics provided superior coordination performance compared to other types.

In [29], protection relays coordination in Saddik Kerdesler substation are investigated. For this, first time multiplayer settings for farthest overcurrent and earth-fault protection settings from the power source have been determined. Then with a fixed second and third zone distance protection relays operating time, proper TMS for upper steam cascaded overcurrent relays were calculated using conventional method with coordination constraints under consideration.

In [30], the coordination of DOCRs and DRs under different protection schemes are investigated. For those schemes, linear programing is employed for determining optimal TMS values for overcurrent protection relays with considering a fixed second zone operating time for distance protection relay and I_{set}s for directional overcurrent protection relays.

In [31], dual simplex, path follow, and homogenies linear programing algorithm are employed for calculating distance protection relays zone two operating time (T_{Z2}s) and time multiplayer setting (TMS) for overcurrent protection relays under T_{Z2}s as identical and different values. It is found that path follow linear programing method gives better result than other linear programing methods.

In [32], the coordination problem for distance and DOCRs was formulated and solved using a combined approach, with integer Linear programing (LP) and Particle Swarm Optimization (PSO) methods. The study considered coordination constraints to ensure proper relay selectivity, and hybrid enhanced effectiveness in achieving optimal relay settings and coordination.

In [33], the coordination problem for DRs and DOCRs was formulated with considering Minimum CTI between backup distance protection relay zone two operating time and primary overcurrent protection relays operating time, as well as between backup overcurrent protection relay operating time and primary distance protection relay zone two operating time. For the problem multiple-embedded crossovers PSO (ME-CPSO) method was employed. The result showed that the approach achieves proper relay coordination.

In [34], the coordination of cascaded overcurrent protection relays setting for Addis Ababa region 132 kV transmission network was assessed under both faulty and normal load flow conditions, with considering 0.35 seconds as discrimination between backup and main protection relays. it is found that most of the system protections relays did not operate in the expected sequence. For these relays, appropriate settings were determined conventionally through hand calculations and ensure proper selectivity.

Based on the literature review, numerous studies have been conducted on distance and overcurrent protection relays coordination using various optimization techniques and system models. However, no prior study has specifically investigated on distance and overcurrent protection relays setting coordination within the EEP transmission network. As a result, the existing condition of relays setting coordination within the system is not clear. Therefore, this study aims to assess distance and overcurrent protection relays setting coordination in the EEP South West Region transmission network, with providing proper coordination problem mitigation.

Chapter 3

Data Collection and System Network Modeling

3.1 Introduction

In this chapter, general description about southwest region transmission network of EEP is discussed in section 3.2. Cascading outages as well as out of zone tripping event resulting from faults and corresponding relays in operation included in section 3.3. The collected data used for modeling the EEP southwest transmission network has been presented in section 3.4. Simulation software's that were used in this study are briefly described in section 3.5. The transmission network modeling of EEP southwest region transmission system is analyzed in section 3.6. Formulation of optimization problems aimed to determine optimal time multiplier setting for overcurrent protection relays, and optimal Zone 2 operating time setting (T_{Z2}) for distance protection relays are discussed in section 3.7. Finally, solutions to the formulated problem are analyzed in section 3.8. These efforts are fundamental to assess and mitigate the relays coordination problems within the southwest transmission system of EEP.

3.2 Southwest region transmission network

Southwest transmission network is one of the elven EEP regional transmission systems. The transmission system supplies area within Gamibella region, Southwest Ethiopian region, and some part of western Oromia region. The transmission system covers wide geographical area, which operates at voltage level ranging from 66 kV to 230 kV. The region has 10 substations with 5 autotransformers and 15 power transformers.

3.3 Cascading and out of zone tripping events in the EEP southwest region transmission system

Protection relays operating outside the respective protection zones are an indication for improper relays coordination and failure mode of protection system. This may be the main cause for cascading outages due to series tripping initiated by component failure within the system.

Based on one-year daily log sheet fault record data, some of cascading outages and out of zone tripping incidences that occurred in EEP southwest transmission network has been summarized in Table 3.1.

Table 3.1: Summary of selected out of zone events and cascading outages in the EEP southwest transmission network

Outages	Fault current magnitude (A)	Date (G.C)	Operated Protection relays	Cause
33 kV Dimma feeder	RS=997.6	03/09/2023	Feeder OCR	Short circuit fault on 33 kV Dimma feeder
132/66/33 kV transformer	RS=301.6		HV side OCR	
132 kV Bonga-Mizan line	RS=306.3		Backup OCR	
66 kV Tepi line	RG=549.9	04/08/2024	Line OCR	Short circuit fault on 66 kV Mizan-Tepi line
132/66/33 kV transformer	RG=384		Transformer HV Side OCR	
132 kV Bonga-Mizan line	RG=387.9		Backup OCR	
Two-230/132 kV transformers at Bedelle SS	RS=254	13/11/2024	230 kV side OCRs	Short circuit fault on Metu-Gamibella line
Two-230/132 kV transformer at Bedelle SS	ST=247	24/05/2024	230 kV side OCRs	
33 kV Gurudi feeder	AB=1600.73	07/09/2023	Feeder OCR	Short circuit fault on 33 kV Gurudi feeder
230/132 kV transformer	AB=230.8		Transformer 230 kV side OCR	
33 kV Gera feeder	AB=957.8	19/01/2024	Feeder OCR	Short circuit fault on 33 kV Gera feeder
230/132 kV transformer	AB=159.78		Transformer 230 kV side OCR	
132 kV Jimma II-Jimma I line	ST=696.3	23/11/2023	Backup OCR	Short circuit fault on 132 kV Bonga Mizan line
132 kV Jimma II-Jimma I line	RS=711.6	12/04/2024	Backup OCR	

As presented in Table 3.1, Southwest transmission system exhibit relays setting coordination problems, as the analysis of recorded indicates that the protection system do not operate in the expected sequence. This indicates that the transmission network experiencing relays setting coordination problems.

3.4 Transmission network data

The transmission network data used for modeling southwest EEP transmission system were collected from different sources and through direct filed visit. These data include transmission lines, transformers, earthing transformers, protection relays, and power sources, which are presented in the following subsections.

3.4.1 Transmission line data

The transmission line data is obtained from multiple sources, such as official documentation, system data bases, and direct field visits.

In order to model transmission lines accurately on DIgSILENT Power factory software, several electrical and physical parameters are required. These includes series Reactance(X), series Resistance (R), shunt Capacitance (C), shunt Conductance (G), line nominal current rating, line length, line voltage rating etc. of each line segment.

The necessary data for these parameters were obtained from EEP System Network Planning office. The specifications of transmissions line that obtained for Network panning office are given in Table 3.2 and 3.3.

It is important to notice that shunt conductance (G) of the transmission lines assumed to be negligible, as it has minimal impact on relays setting coordination analysis under faulted conditions.

Table 3.2: EEP southwest region transmission line relevant data

Line	Rated voltage (kV)	Line length in km	Rated Current in kA	Positive sequence impedance data		
				X1 Ω/km	R1 Ω/km	C1 μF/km
GG II - Jimma II	230	65.6	0.6878	0.4092	0.0861	0.0089521
Jimma II - Jimma I	132	7.66	0.398	0.424199	0.213478	0.0085991
Jimma II – Aba	132	74.77	0.398	0.426524	0.2131765	0.0085978
Jimma II- Agaro	230	34.82	0.6878	0.4092	0.0861	0.0089521
Jimma I- Bonga	132	102.27	0.398	0.424199	0.213478	0.0085991
Agaro- Bedelle	230	81.4	0.6878	0.4092	0.0861	0.0089521
Bonga- Mizan	132	88.3	0.398	0.424199	0.213478	0.0085991
Bedelle- Metu	230	90.34	0.7982	0.32606	0.1132589	0.0112121
Metu- Gamibella II	230	140	0.7982	0.326063	0.1132589	0.0112121
Mizan-Tepi	66	38.2	0.236	0.418867	0.501957	0.008725
Gamibella II- Gamibella I	66	2	0.236	0.418867	0.501957	0.008725

Table 3.3: Transmission line length, rated current, rated voltage, and corresponding zero-sequence impedances.

Line	Rated voltage level in kV	Line length in km	Rated current in kA	Zero- sequence impedance data		
				X0 in Ω/km	R0 in Ω/km	C0 in μF/km
GG II - Jimma II	230	65.6	0.6878	0.71411372	0.53936067	0.0070280
Jimma II to Jimma I	132	7.66	0.398	1.214477937	0.46544830	0.0056284
Jimma II-Aba	132	74.77	0.398	1.195764894	0.47769191	0.0052900
Jimma II-Agaro	230	34.82	0.6878	1.192113153	0.48919299	0.0070278
Jimma I-Bonga	132	102.27	0.398	1.214477028	0.46545073	0.0056269
Agaro-Bedelle	230	81.4	0.6878	1.192112039	0.48919275	0.0070286
Bonga-Mizan	132	88.3	0.398	1.195764439	0.47769377	0.0052881
Bedelle-Metu	230	90.34	0.7982	0.733643571	0.53797785	0.0068531
Metu-Gamibella II	230	140	0.7982	0.733643571	0.53797785	0.0068531
Mizan-Tepi	66	38.2	0.236	1.459787	0.69287	0.0051624
Gamibella II -Gamibella I	66	2	0.236	1.458357	0.8077707	0.0051638

3.4.2 Transformer data

Southwest region of the EEP transmission network consists of several two winding and three winding transformers. These necessary data used for modelling both types of transformers are collected form EEP Power System Network Planning Office. The specifications collected from this office are given on the following three tables.

Table 3.4: Positive sequence impedance data in (per unit) for three-winding transformers

Transformer location	Rated power in MVA	Rated voltage ratio in kV	Positive sequence impedance					
			Reactance X1 In PU			Resistance R1 In PU		
			HV-MV	MV-LV	LV-HV	HV-MV	MV-LV	LV-HV
Bonga substation (SS)	25/25/12	132/33/15	0.1073	0.0638	0.18987	0.00478	0.00246	0.00325
Jimma I SS	16/16/8	132/33/15	0.1073	0.0626	0.17915	0.00656	0.00337	0.00402
Jimma II SS	63/63/21	230/132/15	0.1116	0.0196	0.10393	0.00278	0.00137	0.00376
Mizan SS	25/25/12	132/66/33	0.0678	0.0402	0.11149	0.00140	0.00135	0.00143
Metu SS	40/20/20	230/66/15	0.0678	0.0402	0.11149	0.00140	0.00135	0.00143
Agaro SS	16/16/8	132/33/15	0.1073	0.0626	0.17915	0.00656	0.00337	0.00403
Agaro SS	63/63/23	230/132/15	0.1116	0.0196	0.10393	0.00278	0.00137	0.00376
Bedelle SS	63/63/21	230/132/25	0.1116	0.0196	0.10393	0.00277	0.00137	0.00376
Gamibella II SS	40/20/20	230/66/33	0.0678	0.0658	0.14128	0.00140	0.00337	0.00197

Table 3.5: Zero sequence impedance data in (per unit) for three-winding transformers

Transformer location	Rated power in MVA	Rated voltage ratio in kV	Zero sequence impedance					
			Reactance X0 in PU			Resistance R0 in PU		
			HV-MV	MV-LV	LV-HV	HV-MV	MV-LV	LV-HV
Bonga SS	25/25/12	132/33/15	0.1021	0.06078	0.21397	0.00510	0.00303	0.01068
Jimma one SS	16/16/8	132/33/15	0.0835	0.04693	0.17045	0.00417	0.00234	0.00851
Jimma-II SS	63/63/21	230/132/15	0.1061	0.01870	0.09885	0.00529	0.00093	0.00493
Mizan SS	25/25/12	132/66/33	0.0853	0.04915	0.17996	0.00425	0.00245	0.00898
Metu SS	40/20/20	230/66/15	0.0645	0.03129	0.10605	0.00322	0.00156	0.00529
Agaro SS	16/16/8	132/33/15	0.0835	0.04693	0.17045	0.00417	0.00234	0.00851
Agaro SS	63/63/23	230/132/15	0.1061	0.01870	0.09885	0.00529	0.00093	0.00493
Bedelle SS	63/63/21	230/132/15	0.1061	0.01870	0.09885	0.00529	0.00093	0.00493
Gamibella-II SS	40/20/20	230/66/33	0.0645	0.04915	0.13407	0.00322	0.00245	0.00671

Table 3.6: Two winding transformers per unit impedance data

Transformer location	Rated power in MVA	Rated voltage ratio in kV	Positive Sequence impedance in PU		Zero Sequence impedance in PU	
			X1	R1	X0	R0
Metu SS	6.3	66/33	0.066977	0.001738	0.063629	0.003181
Jimma II SS	25	132/15	0.098549	0.003148	0.0936222	0.0046811
Jimma I SS	20	132/15	0.0992003	0.004448	0.0940502	0.0047025
Bedelle SS	12	132/15	0.1022964	0.0008525	0.0971816	0.00485908
Aba SS	25	132/15	0.999998	0.0045	0.0949997	0.00475
Mizan SS	6.3	66/15	0.0569749	0.0016904	0.0541262	0.00270631
Agaro SS	20	132/15	0.0990001	0.004448	0.0940502	0.0047025
Bedelle SS	16	132/33	0.0860897	0.0110812	0.0645673	0.00322837

3.4.3 Earthing transformer data

An earthing transformer is used in delta side of power transformers to provide path for ground fault current. So, in order to model earthing transformers properly it requires data such as zero-sequence impedance, nominal voltage, rated current etc. These data were collected through direct a filed visit, which is given in Table 3.7.

Table 3.7: Parameters of earthing transformer

Earthing transformer location	Zero sequence impedance data in Ω	Rated voltages (kV)	Rated current (A)
Jimma II 132/15 kV transformer 15 kV side	95.71	15	9.623
Aba 132/33 kV transformer 33 kV side	302.4	33	6.67
Jimma I 132/15 kV transformer 15 kV side	137.1	15	9.622
Bonga 132/33/15 kV transformer 33 kV side	277.5	33	66.66
Bonga 15 kV BB132/33/15 kV transformer 33 kV side	122	15	7.7
Mizan 66/15 kV transformer 15 kV side	122	15	7.7
Mizan 132/66/33 kV transformer 33 kV side	277.5	33	66.66
Agaro 132/15 kV transformer 15 kV side	141.19	15	72.2
Bedelle 132/15 kV transformer 15 kV side	91	15	3.85
Bedelle 132/33 kV transformer 33 kV side	237.34	33	4.56
Metu 230/66/15 kV transformer 15 kV side	130	15	66.7
Metu 66/33 kV transformer 33 kV side	99.88	33	35
Gamibella II 230/66/33 kV transformer 33 kV side	203.48	33	4.373

3.4.4 Protection relay data

Since this study focused on assessment and mitigation of overcurrent and distance protection relays setting coordination problems, it should be model the system protection relays on DIgSILENT power factory software correctly. The necessary data for modelling include relay manufacturer, model/type, setting parameters, relay location etc. These data were collected from each substation through direct field visit. However, the complete data sheet is provided in Appendix A. The sample data for demonstration are given in Table 3.8.

Table 3.8: Protection relay manufacturer, model/type, and corresponding setting parameter

Relay No.	ANCI code	Branch	Relay model	Function	Pickup current	Curve (IEC)	CT ratio (In)	Time (s)
51	50/51	Tercha, 33 kV	Micom P123	I>	0.5*In	DT	150/1	0.25
				I>>	1*In	DT		0.05
				I>>>	1.3*In	IN		0
				Ie>	0.05*In	DT		0.05
				Ie>>	0.15*In	DT		0.02
				Ie>>>	0.3*In	IN		0
52	50/51	Isera, 33 kV	Micom P123	I>	0.5*In	DT	150/1	0.25
				I>>	1*In	DT		0.05
				I>>>	1.3*In	IN		0
				Ie>	0.13*In	DT		0.1
				Ie>>	0.26*In	DT		0.05
				Ie>>>	0.3*In	IN		0
53	50/51	Chida, 33 kV	Micom P123	I>	0.68*In	DT	150/1	0.25
				I>>	1*In	DT		0.1
				I>>>	1.3*In	IN		0
				Ie>	0.05*In	DT		0.05
				Ie>>	0.1*In	DT		0.02
				Ie>>>	0.3*In	IN		0
50	50/51	Aba, 33 kV incoming	Micom P123	I>	1.25*In	DT	400/5	0.5
				I>>	2.5*In	DT		0.1
				Ie>	0.5*In	DT		0.25
				Ie>>	1*In	DT		0.1

3.4.5 Power source (external grid)

The transmission networks are supplied by Ethiopian electric power national grid. To model power source accurately, several parameters are required, which includes short circuit current, short circuit power, X/R ratio, X0/X1 ratio, Z2/Z1 ratio, and R0/X0 ratio. These short circuit parameter can be determined from the grid under faulted conditions [20]. However, due to the complexity of calculating short-circuit data for large transmission system; it is important to use specialized software for such analysis. The necessary data used to model the power sources were obtained from EEP Power System Network Planning Office. The collected data is presented in Table 3.9.

Table 3.9: Grid representation for GG II 230 kV bus bar and Bedelle 132 kV bas bar (Source: EEP Power System Network Planning Office).

Grid representation	GG II 230 kV bus bar	Bedelle 132 kV bas bar
Short Circuit Power	5546.21 MVA	702.69 MVA
Short Circuit Current	13.9222 kA	3.0735 kA
Z2/Z1 ratio	0.984	0.999
R/X ratio	0.183	0.279
X0/X1 ratio	0.226	0.163
R0/X0 ratio	0.477	0.112

3.5 Network modeling and simulation software

In transmission system, variety of specialized software tools is employed depending on the focus of modeling and simulation. DIgSILENT power factory, PSSE, and ETAP software are widely employed in transmission network for conducting short circuit, stability, load flow, reliability, and contingency analysis. Also, MATLAB widely used in transmission as well as distribution system for modelling, simulation, and analysis of electric system. MATLAB has a capability of performing optimization for solving linear, non-linear, constrained, non-constrained, and mixed integer problems by applying different techniques.

Mathematical calculation of short-circuit current and proper relays setting for a complex network are challenging and time-consuming task. It is more effective to use advanced software tools for analysis. So, DIgSILENT power factory 2024 SP1 software is employed for network molding and short circuit calculation. Also, MATLAB software employed for implementing for PSO algorithm in order to investigate optima relays operating time throughout this study.

DIgSILENT power factory software is a comprehensive tool used to analyze distribution, transmission, generation, as well as industrial electric system.

Some of the key features of DIgSILENT power factory software are:

- ❖ Power factory core functions such as definition, modification, output, documentations, and organization of cases.
- ❖ Interactive and integrate single line graphic and data case handling.
- ❖ Integrated mathematical calculation functions.

- ❖ Have huge single database etc.

Its huge database supports different functions like time domain RMS simulations, load flow simulation, system network modelling and analysis, short circuit analysis, relay coordination analysis, reliability analysis, contingency simulation and optimal power flow study etc.

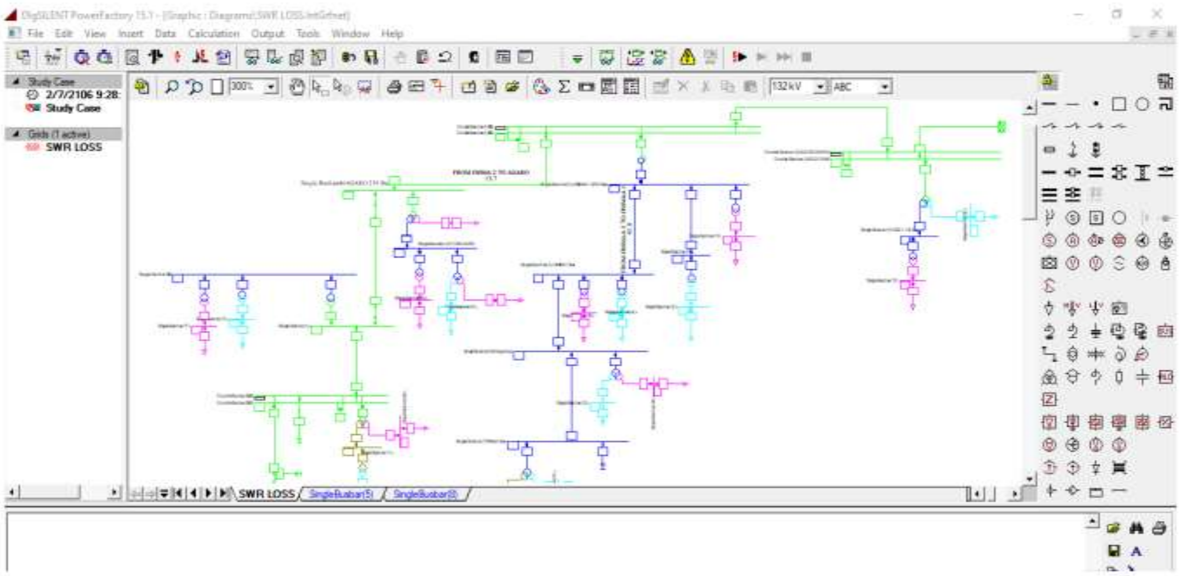

Figure 3.1: DIgSILENT power factory software main interfacing windows

DIgSILENT power factory software primarily uses in graphical environment, in which the relevant data is inserted through drawing network components and editing data for these objects.

3.6 System network modeling

Electric power system network is composed of alternators, transmission lines, transformers, shunt components etc. The detail network model for these system components was developed using DIgSILENT power factory 2024 SP1 software, based on collected data such as transmission line parameter, transformer specifications, protection relay types with its respective setting value etc.

After building the network model, basic load flow simulation was conducted to verify the accuracy and functionality of network configuration. Most of the transmission lines are protected by distance protection relays, while OC relays serve as a backup. Also, for transformers differential relay used as primary whereas overcurrent protection relay used as backup and for distribution feeder only overcurrent protection relay is employed.

This study considers only the system components that are in operating conditions and the distribution networks are not included here. However, to evaluate the coordination between transformer and distribution feeder OCRs, a representative conductor is modeled for each respective distribution feeders. Furthermore, all protection relays in the system are modeled with their corresponding current and voltage transformers.

The complete network model of the EEP Southwest Region transmission system is illustrated in Figure 3.2.

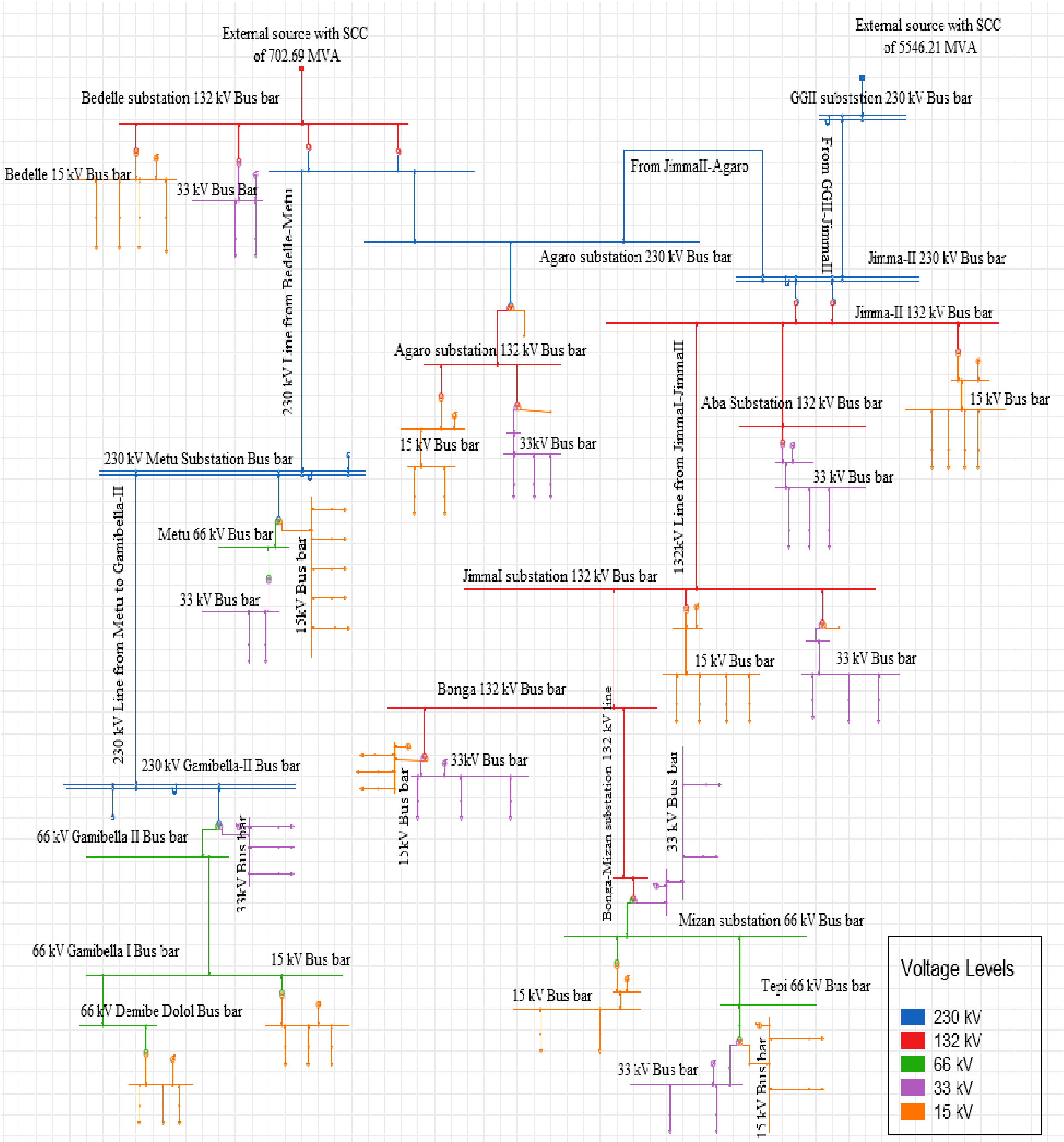

Figure 3.2: Transmission system illustration for the EEP Southwest transmission network

3.7 Formulation of relays coordination problems

The goal of coordination problem formulation is to determine optimal relays setting through minimizing overall operating time of primary protection relays with meting the coordination constraints. In this section, an objective function is introduced first that used for optimization. Then coordination constraints for distance and overcurrent protection relays are explained.

3.7.1 Objective Function

The second zone operating time for distance protection relays and TMS for overcurrent protection relays are considered as an optimization variable with a fixed predefined pickup current setting. The aim of an objective function is to calculate optimal relays setting by minimizing overall operating time for primary protection relays. Equation (3.1) define this function, as referenced in [7] and [21];

$$OF = \sum_{i=1}^{n} t_i + \sum_{j=1}^{m} T_{Z2j} \tag{3.1}$$

Where, t_i is operating time for overcurrent protection relay i, T_{Z2j} is second zone operating time for distance protection relay j, OF is objective function, n is the number of overcurrent protection relays, m is the number of distance protection relays.

The operating time-current characteristics for overcurrent protection relay is represented based on IEC 60255 standard invers, as referenced in [3], [22], and [35]. This function is defined in Equation (3.2).

$$T_{op} = \frac{0.14 * TMS}{PSM^{0.02} - 1} \tag{3.2}$$

Where, T_{op} is operating time for overcurrent protection relay, TMS is Time Multiplier Setting, PSM is Plug Setting Multiplayer.

In this study, pickup current (I_{set}) for both earth-fault and overcurrent protection relays are predetermined as follows:

- **Overcurrent protection setting**: Set as 1.2 times the lowest installed equipment’s nominal current (I_n) within the network [9].
- **Earth-fault protection relays**: for transformers and transmission lines, pickup current is determined as 10% of overcurrent protection relay setting [15], [36]. For delta side of transformers, it determined as 1.2 times natural continuous current rating of earthing transformer.

3.7.2 Coordination Constraints

Coordination constraints are categorized in to two main groups, which are selectivity constraints and relays setting limit.

I. Selectivity constraints

In order to provide selective protection system, the operating time of backup protection relays must be longer than that of their respective primary protection relays. This ensured that the backup protection relay will only operate when primary system protection fails, with fast fault clearance of primary protection relay. As referenced in [7], Equation (3.3) defines the coordination requirements for every cascaded over-current protection relays.

$$\begin{cases} t_b^{F1} - t_p^{F1} \geq CTI \\ t_b^{F2} - t_p^{F2} \geq CTI \end{cases} \tag{3.3}$$

Where, t_b^{F1} is the operating time for backup protection relays at near end fault at F1, t_p^{F1} is the operating time for primary relay at near end fault point F1, t_b^{F2} is the operating time for backup protection relay at far-end fault point F2, t_p^{F2} is the operating time of primary protection relay at far-end fault point F2. This can be summarized in diagram as shown in Figure 3.3.

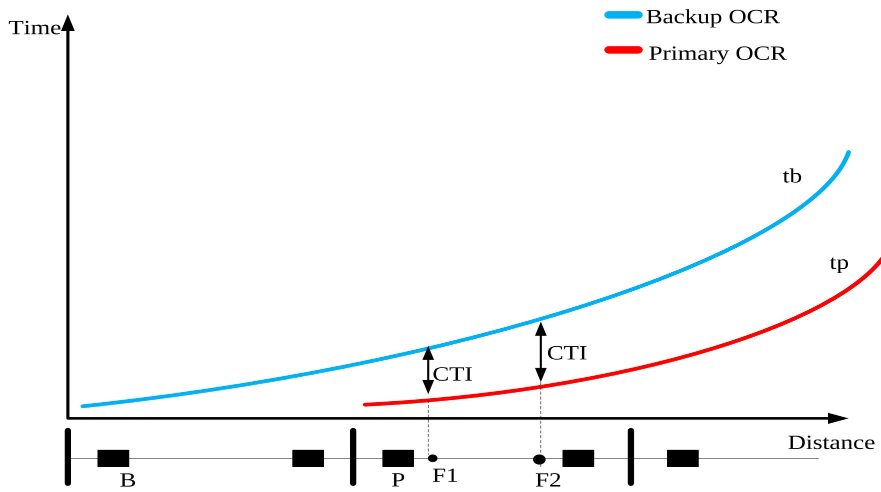

Figure 3.3: Illustration of selectivity for cascaded directional overcurrent protection relays on a transmission line [8] [17].

Based on Figure 3.3, it is clear that for both near and far-end fault point, the operating time for backup directional overcurrent protection relay needs to be longer than that of primary protection relay.

The selectivity between DRs and DOCRs should also be preserved. Figure 3.4 provides an illustration for this relationship.

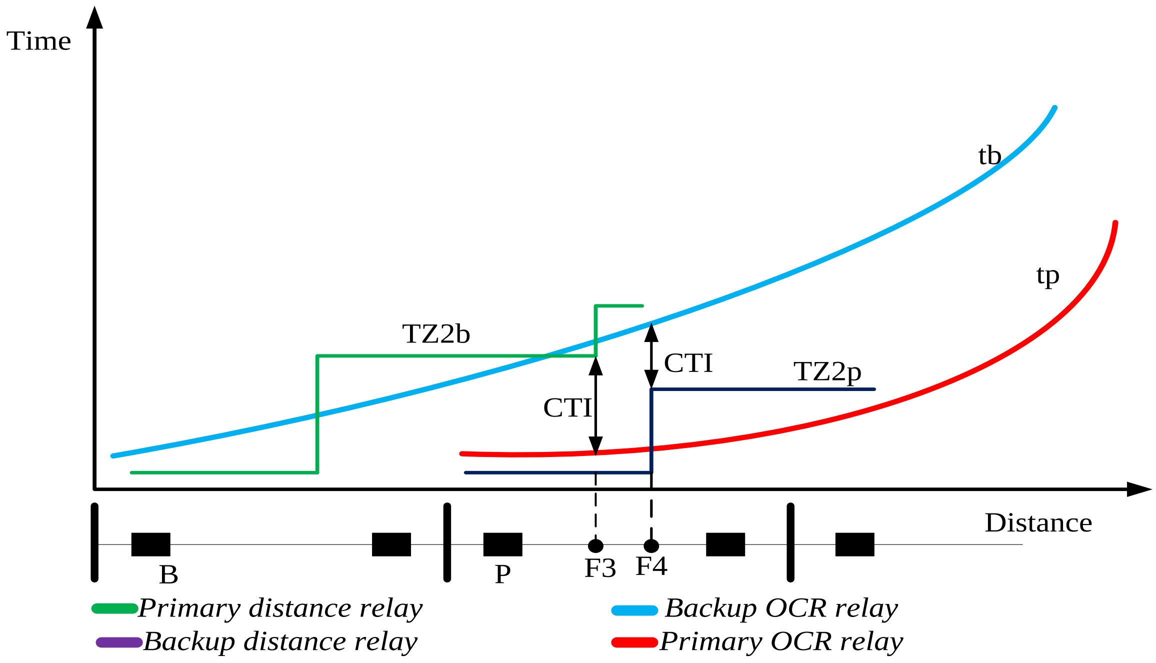

Figure 3.4: Selective illustration between DOCR and DRs for the transmission line [8], [17]

Based on Fig. 3.4, the running time for backup DOCR should be longer than that of corresponding primary DRs second zone running time. Similarly, the running time second zone backup DRs should be longer than that of the respected primary DOCRs running time. The coordination constraints between these protection relays are defined in Equation (3.4), as referenced in [7]:

$$\begin{cases} t_b^{F4} - T_{Z2p} \geq CTI \\ T_{Z2b} - t_p^{F3} \geq CTI \end{cases} \quad (3.4)$$

Where, t_b^{F4} is the working time of backup DOCR for the fault at point F4, T_{Z2p} is the working time for DR zone two at fault point F4, T_{Z2b} is the working time for backup DR with the fault current at F3, t_p^{F3} is the working time of DOCR for the fault point at F3.

Additionally, selectivity should also be maintained between incoming and outgoing feeder protection relays, as well as between transformer and incoming feeder protection relays. This coordination is illustrated in diagram as shown in Figure 3.5 below.

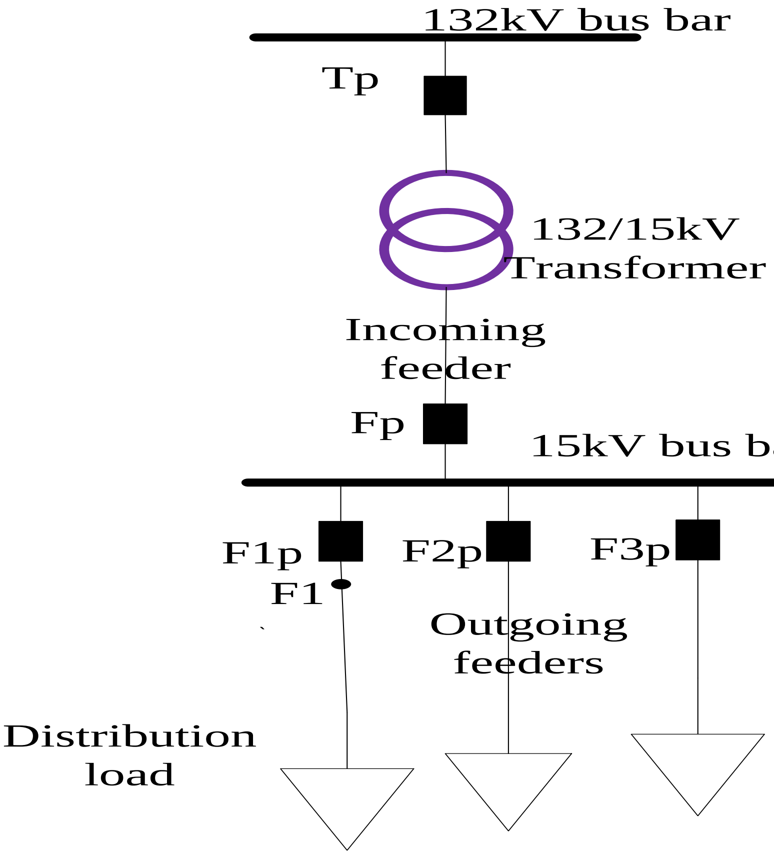

Figure 3.5: Illustration of selectivity among overcurrent relays for transformer, incoming feeder and outgoing feeders [9].

Based on Figure 3.5, protection relays of outgoing feeder should be operated first for the fault location at F1. Incoming feeder protection relay should operate whenever outgoing feeder protection relays (F1P) fail to clear the fault. This can be expressed mathematically in Equation (3.5).

$$\begin{cases} t_{Fp}^{F1} - t_{F1p}^{F1} \geq CTI \\ t_{Tp}^{F1} - t_{Fp}^{F1} \geq CTI \end{cases} \qquad (3.5)$$

Where, t_{Fp}^{F1} is the working time for incoming feeder protection relay at fault point F1, t_{F1p}^{F1} is the working time for outgoing feeder OCR at fault point F1, t_{Tp}^{F1} is the working time for transformer OCR at fault point F1.

From Equation (3.5), the distribution outgoing feeder protection relays must operate before incoming feeder protection relay. Additionally, the incoming feeder protection relay should operate before transformer OCR for the fault at point F1.

II. Protection relay settings constraint

The time multiplayer setting values for overcurrent protection relays are constrained within specified lower and upper bounds, as defined by the following inequality [7]:

$$TMS_i^{min} \leq TMS_i \leq TMS_i^{max} \tag{3.6}$$

For protection OCR i, the maximum and minimum Time Multiplayer Settings are represented by TMS_i^{max} and TMS_i^{min} respectively.

In addition, ensuring coordination, protection engineers must also consider the duration of high fault currents in medium voltage feeders. To reduce the impact of these fault currents, second and third stage protection settings should be applied:

- ✓ According to [37], second stage setting for the pickup for feeders are typically set three times first stage pickup current.
- ✓ As per [15], the instantaneous(third-stage) pickup current setting must also be higher than that of external system equipment maximum fault current expected.

3.8 Solution to coordination problems using PSO algorithm

As discussed in section 2.6, protection relays coordination problems arise from selectivity of primary and backup protection as well as fault clearance time. Therefore, protection relays should be coordinated properly to ensure selective and fast fault clearance within the system. Relay coordination involves on determination of proper settings for the system protection, in which faults should be cleared quickly and selectively without any unwanted system interruptions. This task using conventional method is time consuming and do not achieve optimal solutions. To address these challenges, Particle Swarm Optimization (PSO) algorithm applied in this thesis. PSO algorithm effectively explores an optimal solution for the system protection relays through minimizing operating time with satisfying the coordination constraints that were discussed in section 2.8. PSO algorithm is simple to implement and has ability to converge quickly to a good solution. The procedure for implementing PSO algorithm is:

i. Define an objective function.
ii. Initialize the system with an initial population.
iii. Evaluate each particles fitness value.
iv. The evaluated fitness values for each particle compare with its best historical value.
v. If the current fitness value is better than the historical best, set the current value as best and its position as the position of best.
vi. Find the global best i.e. the best fitness value from the population.
vii. If the current global best value is better than the historical global best, set the current value as best and its position as the best of global best position.
viii. Update parameters (velocity and position).
ix. Repeat the step.

Flow chart of PSO algorithm is given in Figure 3.6.

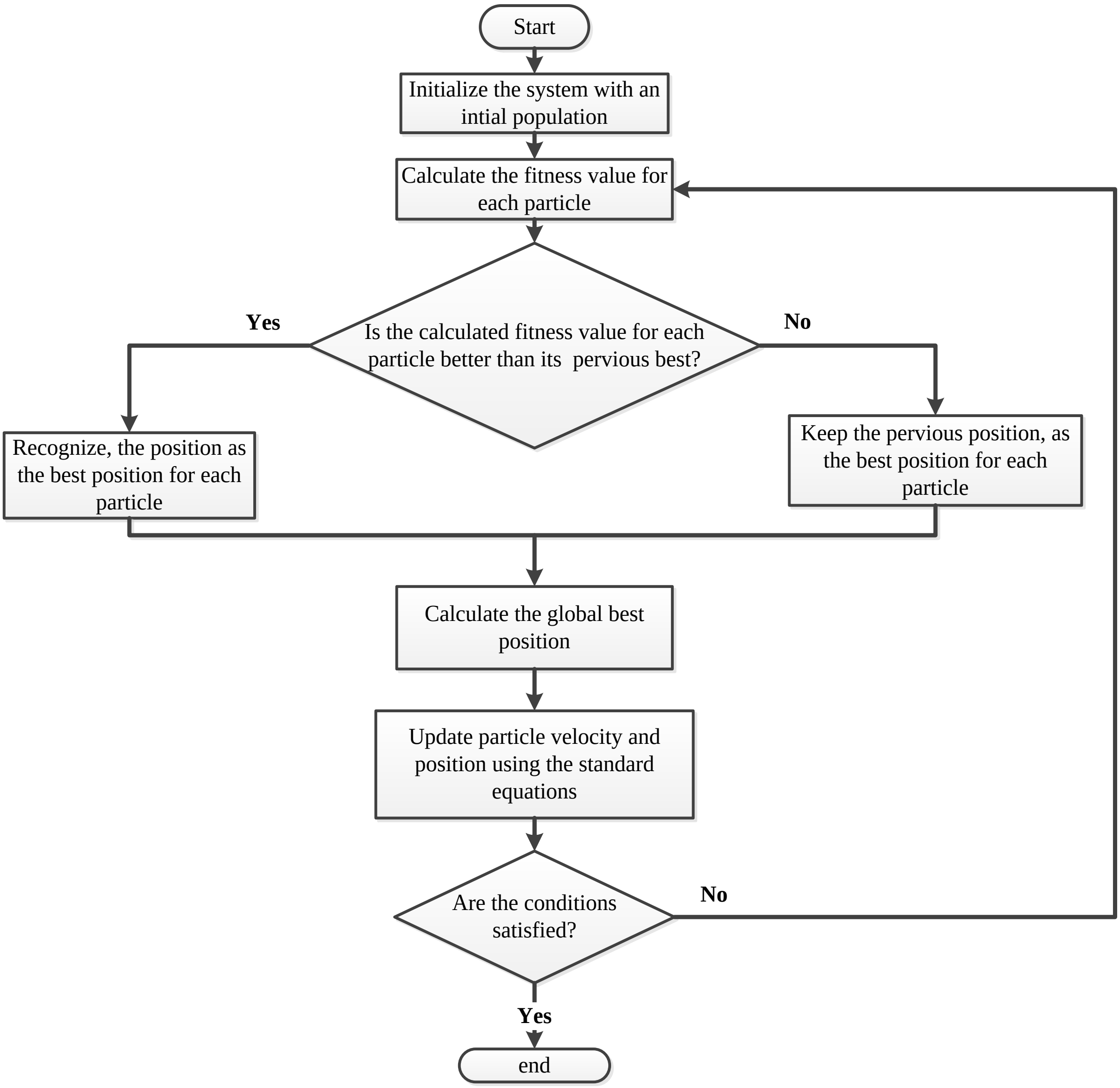

Figure 3.6: Flow chart illustrating PSO algorithm steps for relays coordination optimization

Particle Swarm Optimization (PSO) algorithm key components, together with their respective mathematical representations, are described as follows:

i. Particle position (pos(i)): Each particle in the search space represents the candidate solution for that particular component [38].
ii. Velocity (vel (i)): Define how fast and in what direction the particle will move in the search space at any timestamp t.
iii. Velocity update equation: Controls exploitation and exploration behavior of particles [38], [39], [40], [41]. The following equation is used to update velocity of the particle:

$$vel_i(i+t) = w*vel_i(t)+c1*rand()*(pbest_i(t) - pos_i(t)) + c2*Rand()*(gbest_i(t)-pos_i(t)) \quad (3.7)$$

Where:

c1 = Cognitive coefficient, c2 = Social coefficient, w = Inertia weight, Rand () and rand () = Random numbers generated in the distribution of [0, 1] where pbest and gbest are local best position and global best position of the particle.

iv. Particle position update equation: The movement of each particle across the search space is conducted by position update equation, which is achieved by adding new velocity to the current particle positions.

$$Pos_i(t+1) = pos_i(t) + vel_i(t+1) \quad (3.8)$$

Generally, the performance of PSO algorithm depends on control parameters such as cognitive coefficient (c1), social coefficient (c2), inertia weight, and randomness (rand () & Rand ()). Details for these control parameters are [38]:

- Cognitive and social coefficient (c1 & c2): The cognitive coefficient is a control factor, which aims to move the particle towards best fitness position, while social coefficient is control factors that direct the particle towards the global position identified by any particle within the population. As observed from Eq. (3.7), the search towards optimal solution is governed by acceleration coefficient (c1 and c2). So, proper controls of these components are essential to determine optimum solution accurately and efficiently. As described in [42], time varying acceleration coefficients (c1 and c2) is very essential to avoid premature convergence during early stage of optimization by enhancing local search and encouraging particle to move toward the global optima at the end of search.

  High cognitive coefficient and low social coefficient at the beginning allow particle to move around the search space rather than moving toward the swarm. On the other hand, low cognitive coefficient and large social coefficient allow the particles to converge the global optima at the end of optimization. These time varying acceleration components are represented mathematically as follows [42]:

$$c1 = c1\_start - (((c1\_start - c1\_end)*iter)/maxiter) \quad (3.9)$$
$$c2 = c2\_start - (((c2\_send - c1\_start)*iter)/maxiter) \quad (3.10)$$

Where c1_sart, c1_end, c2_sart, and c2_end are positive constants, iter and maxiter are current iteration number and maximum number of iteration allowable respectively. To accomplish better optimization, the acceleration coefficients should be set as c1_sart = 2.5, c1_end = 0.5, c2_start = 0.5, and c2_end = 2.5 respectively [42].

- Randomness (Rand () & rand ()): Generated from distribution in [0, 1] to create wide search space and avoid premature convergence throughout the search process.
- Inertia weight (w): The inertia weight plays critical role in balancing of locale search and global search by controlling the current velocity of particle contribution to its velocity in the next iteration [40]. Greater w promotes exploration, while small w promotes exploitation. Therefore, throughout process, inertia weight (w) should be changed in order to enhance exploration and exploitation. As proposed in [43], inertia weight decrease linearly from w_{max} to w_{min} throughout iterations with inertia weight vary in the range of 0.4 and 0.9. The time varying inertia weight components are represented mathematically as follow:

$$w = w_{max} - (((w_{max} - w_{min}) * iter)/maxiter) \qquad (3.11)$$

Where:

W_{max} is maximum iteration, w_{min} is minimum iteration, iter is the current iteration number, and maxiter is maximum iteration.

Chapter 4

Simulation Studies and Discussion of Results

4.1 Introductions

The results and discussion of protective relays setting coordination assessment and problem mitigation are presented in this chapter. Findings are organized into four sections. Section 4.2 presents the result of existing protection system coordination. Section 4.3 provides optimal relays setting, which obtained from PSO algorithm. Section 4.4 presents the verification results for the optimized relays setting. Finally, Section 4.5 result analysis and comparison are conducted.

4.2 Simulation and assessment of coordination problems with the existing relays setting

This section presents the result of coordination assessment for distance and overcurrent protection relays. The assessment is based on protection relays' operating time responses. All simulations have been conducted in accordance with IEC 60909 standards.

Although simulations were performed for various fault scenarios, only fault magnitude and operating time responses under maximum fault current conditions are reported in this study. Thus, maximum fault currents for both interphase as well as ground faults are typically occurred in close proximity to the power source. Remote backup protection relays are commonly shared by the downstream network components. To avoid redundant documentation, fault current readings and operating time responses for remote backup relays presented once throughout the study.

For a comprehensive analysis, the coordination of protection relays analyzed in to two main parts:

- ❖ Coordination among overcurrent protection relays.
- ❖ Coordination among distance and overcurrent protection relays.

It is crucial to remember the minimum coordination time interval (CTI), also referred to as grading margin 0.2 seconds should be maintain between backup and primary protection relays across all cases. Simulation results, analysis, and discussions are organized and presented through a series of cases, as detailed in the following subsections.

Case 1: Fault scenario simulated on Jimma I substation distribution outgoing feeders

Jimma I Substation has:

- Two power transformers
- Three 33 kV distribution feeders
- Four 15 kV distribution feeders

To assess the performance of protection system, various fault scenarios were simulated on the distribution feeders. These faults were simulated near the protection relays to evaluate the relays responsiveness under extreme condition. The corresponding readings for cascaded protection relays (relays in series from load to source) were recorded. Thus include:

- Measured fault current magnitude
- Operating time of system protection relays

Table 4.1 gives a summary of these outcomes. Additionally, the time-overcurrent curve and tripping time under a specific short-circuit fault current of 2.006 kA on one of the distribution feeders was simulated. The response curve and operating times for cascaded protection relays are given in Fig. 4.1.

Figure 4.1: Time-Overcurrent curve as well as operating time responses for relays R31, R33, and R35 with a 3-phase short-circuit fault current of 2.106 kA on distribution feeder.

According to relays operating time result shown in Fig. 4.1, the transformer overcurrent protection relay R35 trips at 0.385 second, whereas incoming feeder protection relay R33 operates later at 0.62 second. This implies that a remote backup protection relay (R35) is operating before the local backup protection relay (R33), which violates the principle of selectivity in protection system. Based on this the existing relays setting should be reviewed and adjusted to establish proper coordination.

Table 4.1: Actual setting operating time responses for cascaded protection relays under fault conditions on distribution outgoing feeders at Jimma I Substation.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
On 33 kV Industry OG feeder	R31	50/51	Industry, 33 kV	2106	0.1	4434	0.02
On 33 kV Industry OG feeder	R33	50/51	Incoming, 33 kV	2106	0.62	4435	0.62
On 33 kV Industry OG feeder	R34	50/51	33 kV, neutral	-	-	4435	1.02
On 33 kV Industry OG feeder	R35	50/51	132/33/15 kV Transformer, 33 kV	610	0.385	548	0.22
On 33 kV Industry OG feeder	R36	50/51N	HV neutral	-	-	548	1.031
On 33 kV Industry OG feeder	R83	50/51	Jimma II, 132 kV line	610	0.639	348	0.7
On 33 kV Limu feeder	R30	50/51	Limu, 33 kV	2106	0.1	4434	0.06
On 33 kV Limu feeder	R33	50/51	132/33/13 kV transformer, 33 kV	2106	0.62	4435	0.62
On 15 kV Agri feeder	R41	50/51	Agri, 15 kV	5775	0.27	185	0.07
On 15 kV Agri feeder	R40	50/51	Incoming, 15 kV	5775	0.12	185	0.415
On 15 kV Agri feeder	R39	50/51N	15 kV earthing transformer	-	-	185	2
On 15 kV Agri feeder	R37	50/51	132/15 kV transformer	689	0.17	0	∞
On 15 kV Agri feeder	R38	50/51N	HV neutral	-	-	0	∞

According to the relays operating time presented in Table 4.1, the 132/33/15 kV transformer OC protection relay (R35) trips before 33 kV incoming (IC) feeder OC protection relay (R33) for both short-circuit and earth fault scenario on 33 kV distribution outgoing (OG) feeders. Similarly, the 132/15 kV transformer and 15 kV incoming feeder protection relays operate prior to 15 kV distribution feeder protection relay (R41) for a short-circuit fault on distribution feeder. Furthermore, the CTI between the remaining 15 kV feeder's protection relay and their respective incoming feeder protection relay is less than 0.2 second, which is below the recommended minimum value for proper selectivity.

These observations indicated that the improper coordination of system protection relays are the root causes for upstream relays trip before downstream relays, especially in cases where 33 kV distribution feeder protection systems fail to clear fault current. This improper coordination compromises the selectivity of overall protection scheme in this substation.

Case 2: Fault scenarios on Agaro substation distribution outgoing feeders

Agaro Substation is equipped with:

- One autotransformer
- Two power transformers
- Five distribution feeders

In order to evaluate the substation protection system operation, various fault scenarios were simulated on the distribution feeders, with fault location placed close to their respective protection relays. The measured fault current magnitude and corresponding operating time for cascaded overcurrent protection relays at maximum fault current scenario are summarized in Table 4.2.

Additionally, for selected cascaded overcurrent protection relays, the time-overcurrent plot and their corresponding operating time responses are presented in Figure 4.2. The result corresponds to line-to-ground fault on Agaro city distribution feeder, with a zero-sequence fault current ($3I_0$) magnitude of 189 A.

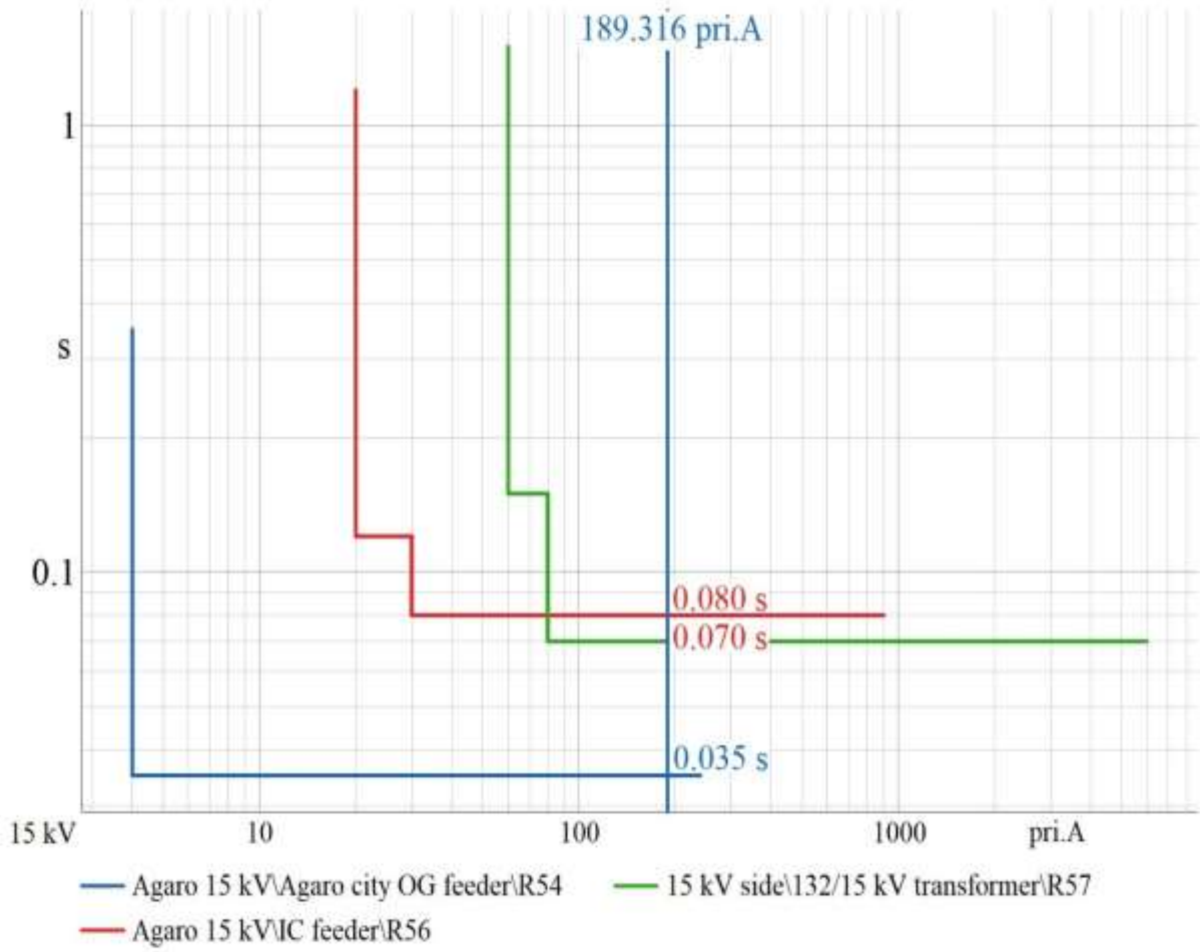

Figure 4.2: Operating time for R54, R56, and R57 protection relays based on their existing setting for a line- to-ground fault on Agaro city distribution outgoing feeder, with a zero-sequence fault current($3I_0$) of 189 A.

According to operating time results shown in Figure 4.2, earth-fault protection relay R57, located on low-voltage side of the transformer, trips before incoming feeder relay R56. Additionally, the CTI between incoming and outgoing feeder protection relay is only 0.045 second, which is significantly below the recommended minimum CTI 0.2 second. This may lead to cascading outages, where upstream devices trip unnecessarily. As a result, large number of customers could be affected by power interruptions, compromising the reliability of system.

Table 4.2: Existing relays setting tripping time responses for cascaded protection relays of Agaro substation distribution feeder fault circumstance.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$-fault current (A)	operating time (s)
On Gatera 33 kV	R60	50/51	Gatera, 33 kV	1892	0.03	2231	0.03
	R63	50/51	Incoming, 33 kV	1892	0.06	2231	0.06
	R64	50/51N	33 kV, neutral	-	-	2231	0.82
	R65	50/51	132/33/15 kV transformer	473	0.761	239	0.17
	R66	50/51N	132/33/15 kV transformer neutral	-	-	239	0.72
	R68	50/51	230/132 transformer, 132 kV	481	0.237	223	0.03
	R67	50/51	230/132 transformer, 230 kV	276	0.03	37	0.03
	R69	50/51	230/132 transformer, neutral	-	-	186	0.03
On Gera, 33 kV	R61	50/51	Gatera, 33 kV	1892	0.03	2231	0.03
	R63	50/51	Incoming, 33 kV	1892	0.06	2231	0.06

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$-fault current (A)	operating time (s)
On Agaro city 15 kV	R54	50/51	Agaro city, 15 kV	5373	0.035	189	0.035
	R56	50/51	Incoming, 33 kV	5373	0.08	189	0.08
	R57	50/51N	Earthing transformer, 15 kV	-	-	189	0.07
	R58	50/51	132/15 kV transformer	679	0.761	0	∞
	R68	50/51	230/132 transformer, 132 kV	679	0.167	0	∞
	R67	50/51	230/132 transformer, 132 kV	395	0.03	0	∞

According to the relays operating time results presented in Table 4.2, the 230/132/15 kV autotransformer OC protection relay (R67) trips before all downstream protection relays for a short-circuit fault near the distribution feeder relays. Particularly, it operates prior to 132/33/15 kV transformer relay (R65), 132/15 kV transformer relay (R58), 33 kV IC feeder (R63), and 15 kV IC feeder relay (R56). Additionally, for a single line-to-ground fault near 15 kV feeder protection relay, 132/15 kV transformer low-voltage side earth-fault protection relay (R57) operates before 15 kV IC feeder protection relay (R56). These results clearly indicate mis-coordination among the system protection relays, which may be due to incorrect protection relays setting. To address this issue and enhance selectivity protection system, it is recommended that optimal relays setting should be analyzed and implemented.

Case 3: Fault scenarios on Aba substation distribution outgoing feeders

Aba Substation consists of:

- Three 33 kV distribution outgoing feeders
- One 16 MVA, 132/33 kV power transformer

To assess the effectiveness of substation protection system coordination, short-circuit fault as well as line-to-ground fault scenarios were simulated on the distribution feeders, with fault location positioned near their respective protection relays. The measured fault current magnitudes and corresponding operating time responses for cascaded overcurrent protection relays under these fault scenarios are summarized in Table 4.3. Additionally, for selected cascaded protection relays, the existing setting time-overcurrent curves and their respective operating time results for a short circuit fault on the distribution feeder with a fault current magnitude 2.072 kA is illustrated in Figure 4.3.

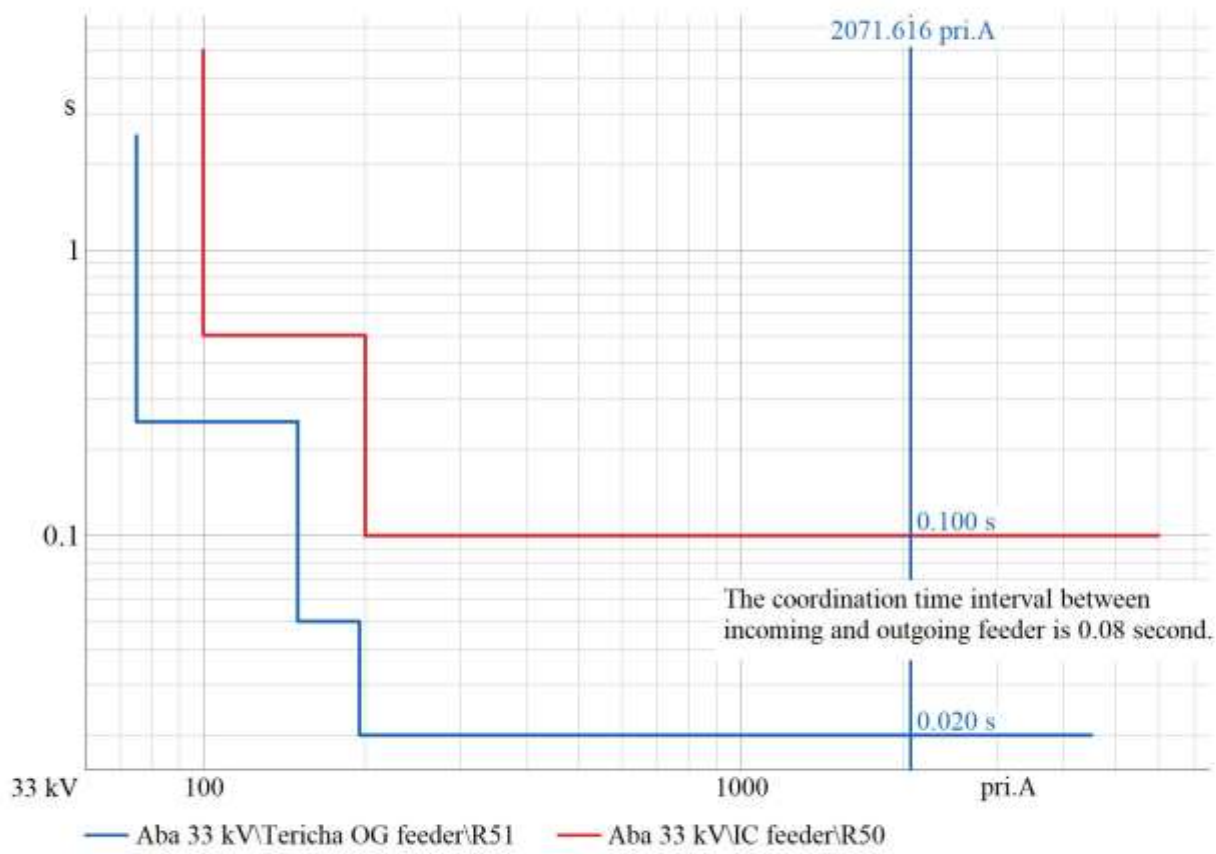

Figure 4.3: Protection relay R51 (primary) and R50 (backup) time-overcurrent curve and their operating times for a 2.072 kA short-circuit fault on 33 kV Terich feeder.

According to the relays operating time response shown in Figure 4.3 above, the protection relays are operated in the expected sequence, but the CTI is only 0.08 second, which is below the recommended minimum value 0.2 second. Such narrow CTI increases the risk of cascading outages, as backup protection relay may operate too soon after primary relay, potentially disconnecting additional parts of the network unnecessarily. This highlights the need for adjusting relay settings to create proper selectivity across the system protection relays.

Table 4.3: Existing cascaded protection relay settings operating time responses for Aba Substation distribution feeders fault circumstance.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On Tercha 33 kV	R51	50/51	Tercha, 33 kV	2072	0.02	178	0.02
	R50	50/51	Incoming, 33 kV	2072	0.1	178	0.1
	R49	50/51N	Earthing transformer, 33 kV	-	-	178	2
	R47	50/51	132/33 kV transformer	563	0.52	0	∞
	R48	50/51N	HV neutral	-	-	0	∞
	R84	50/51	Jimma-Aba 132 kV	563	0.813	0	∞
On Isera 33 kV	R52	50/51	Isera, 33 kV	2072	0.02	178	0.02
	R50	50/51	Incoming, 33 kV	2072	012	178	0.12

According to the relays operating time result presented in Table 4.3, the protection relays of this substation operated in the expected sequence. But, not optimally coordinated, because the CTI between incoming feeder protection relay and outgoing feeder's protection relay is less than 0.2 second. This may cause to cascading outage of the system components.

Case 4: Fault scenario on Bonga substation distribution outgoing feeders

Bonga Substation is equipped with three 33 kV and three 15 kV distribution OG feeders, as well as one 25/25/12 MVA, 132/33/15 kV transformer. Three phases short-circuit and line-to-ground faults were simulated on the distribution outgoing feeders near their respective protection relays. The fault current magnitude and corresponding operating times for cascaded protection relays are summarized in Table 4.4. Additionally, for selected cascaded protection relays, the time-overcurrent curve and their corresponding operating time responses for a short-circuit fault current of 1.968 kA on the distribution feeder is given in Figure 4.4 as shown below.

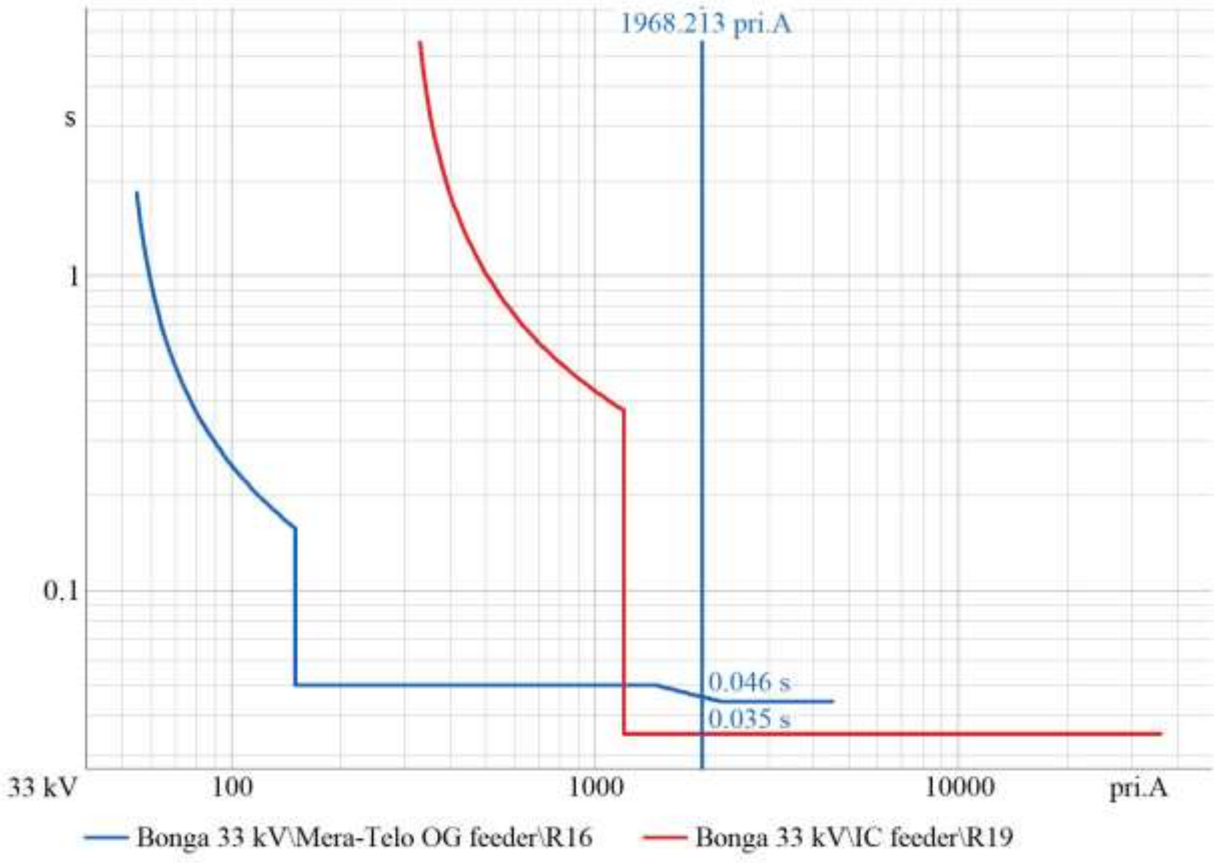

Figure 4.4: Time-overcurrent characteristics curve and corresponding operating time responses of relay R16 and R19 for a short-circuit fault on Mera-Telo distribution feeder, with a fault current of 1.968 kA.

Based on the relays operating time result shown in Figure 4.4 above, the incoming feeder protection relay R19 trips before outgoing feeder protection relay R16 in response to a short-circuit fault current on the distribution feeder.

Table 4.4 Existing relay setting operating time responses of cascaded protection relays for faults on Bonga substation distribution feeders with a given fault current scenario.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time(s)	$3I_0$ fault current (A)	operating time (s)
On Meratelo, 33 kV	R16	50/51	Meratelo, 33 kV	1968	0.046	192	0.058
	R19	50/51	Incoming, 33 kV	1968	0.035	192	0.03
On Bonga university, 33 kV feeder	R18	50/51	Bonga university, 33 kV	1968	0.046	192	0.058
	R19	50/51	Incoming, 33 kV	1968	0.035	192	0.03
	R20	50/51N	Earthing transformer, 33 kV	-	-	192	0.52
	R27	50/51	Transformer, HV	488	0.54	0	∞
	R26	50/51N	Transformer, HV neutral	-	-	0	∞
On 15 kV Bonga city OG feeder	R22	50/51	Bonga city, 15 kV	1766	0.03	244	0.03
	R24	50/51	Bonga Incoming, 15 kV	1766	0.378	244	0.17
On 15 kV wushiweshe OG feeder	R23	50/51	Wushiweshe, 15 kV	1766	0.03	244	0.03
	R24	50/51	Bonga Incoming, 15 kV	1766	0.378	244	0.17
	R25	50/51N	Earthing, 15 kV	-	-	244	0.12
	R27	50/51	Transformer, HV	234	1.19	0	∞

According to the operating time results shown in Table 4.4 above, 33 kV incoming feeder protection relay trips before outgoing feeder protection relays for both short-circuit and line to ground fault scenario. Also, for a line-to-ground fault on the distribution feeders, the earth-fault protection relay of 132/33/15 kV transformer operates before 15 kV incoming feeder protection relay. So, it should be reviewed proper settings and adjusted to mitigate the coordination problems and ensure relays selectivity.

Case 5: Fault scenarios on Mizan substation distribution outgoing feeders

Mizan substation has:

- Three-33 kV
- Three-15 kV distribution feeders
- One 25/25/12 MVA, 132/66/33 kV transformer
- One 6.3 MVA, 66/15 kV power transformer

Different fault scenarios were simulated on the distribution feeders near their respective protection relays. The resulting fault current magnitude and corresponding operating time responses for cascaded protection relays are summarized in Table 4.5 as shown below. Also, for certain cascade protection relays that exhibited coordination problems under practical conditions, the time-overcurrent characteristics curve as well as their corresponding operating time responses with a short-circuit fault on 66 kV Mizan-Tepi line, for a fault current of 0.77 kA, is given in Figure 4.5 as shown below.

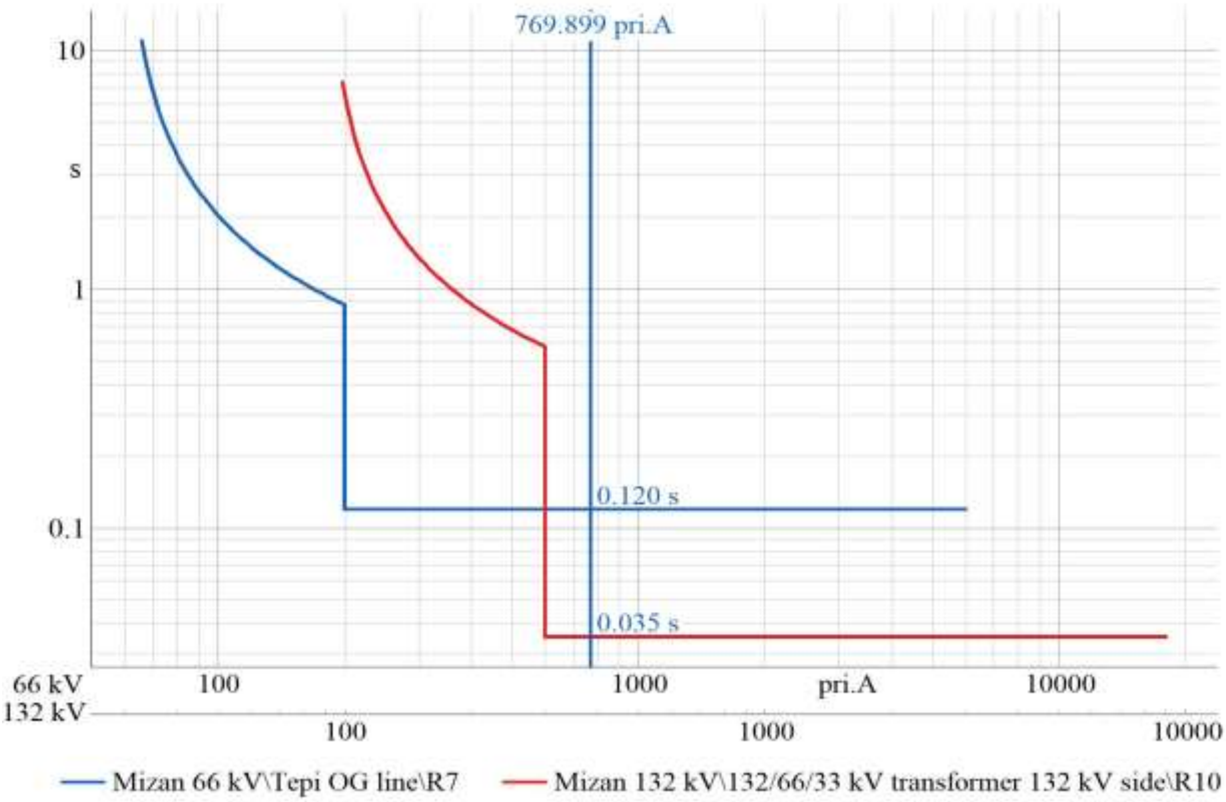

Figure 4.5: Existing settings time-overcurrent characteristics curve and operating time response for cascaded protection relay R7 and R10 with a short-circuit fault of 770 A on 66 kV Mizan-Tepi line.

Based on the relays tripping time result shown in Figure 4.5 above, the protection relay R10 trips before the protection relay R7 in response to a short circuit fault on the line 66 kV Mizan-Tepi line.

Table 4.5: Actual settings operating time response for cascaded protection relays for faults on Mizan Substation distribution feeders.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On 66 kV Mizan-Tepi line	R7	50/51	Tepi, 66 kV	770	0.12	896	0.07
	R8	50/51	132/66/33 kV transformer, 66 kV	770	1.374	695	1.071
	R9	50/51N	132/66/33 kV transformer, 66 kV neutral	-	-	695	0.52
	R10	50/51	132/66/33 kV transformer, 132 kV	381	0.035	84	0.05
	R11	50/51N	132/66/33 kV transformer, 132 kV neutral	-	-	84	0.12
	R28	67	132 kV Bonga-Mizan Line	381	0.944	84	1.236
Dimma 33 kV feeder	R12	50/51	Dimma, 33 kV	894	0.08	160	0.07
	R14	50/51	Mizan, 33 kV Incoming	894	0.07	160	0.52
Chena 33 kV feeder	R13	50/51	Chena, 33 kV	894	0.02	160	0.02
	R14	50/51	Mizan 33 kV Incoming feeder	894	0.07	160	0.52
	R15	50/51N	Earthing transformer, 33 kV	-	-	160	1.2
	R10	50/51		223	0.811	0	∞

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
Mizan 15 kV feeder	R1	50/51	Mizan, 15 kV	1630	0.03	245	0.02
	R3	50/51	Mizan 15 kV Incoming feeder	1630	0.22	245	0.04
	R4	50/51	Earthing transformer, 15 kV	-	-	245	0.82
	R5	50/51	66/15 kV transformer, 66 kV	406	0.718	0	∞
	R8		66/15 kV transformer, 66 kV neutral	406	2.529	0	∞
	R10			243	0.699	0	∞

Based on the relays operating time results presented in Table 4.5, the132/66/33 kV transformer OC protection relay R10 trips before the 66 kV Mizan-Tepi line protection relay R7 for both short-circuit and earth fault scenario on 66 kV line. Additionally, the CTI between 33 kV IC feeder protection relay and 33 kV outgoing feeder protection relay is less than 0.2 second, which indicates improper coordination. Similar coordination problems are also observed between 15 kV incoming feeder protection relay and 15 kV distribution feeder protection relays. Based on these findings, frequent coordination problems in this substation are attributed due to improper relay settings. To solve these problems and enhance system reliability, an optimal relays setting should review and implemented.

Case 6: Fault scenario on Jimma II substation distribution outgoing feeders

Jimma II substation has:

- ✓ Two-63 MVA autotransformers
- ✓ One 25 MVA power transformers
- ✓ four 15 kV distribution outgoing feeders

For the maximum fault current scenario on distribution feeders, the simulated fault current magnitude and corresponding operating time for cascaded protection relays are summarized in Table 4.6 as shown below.

Also, for two particular cascaded protection relays, the time-overcurrent characteristics curve and their corresponding operating time responses for a short-circuit fault on the distribution feeder with a fault current of 7.023 kA is given in Figure 4.6 as shown below.

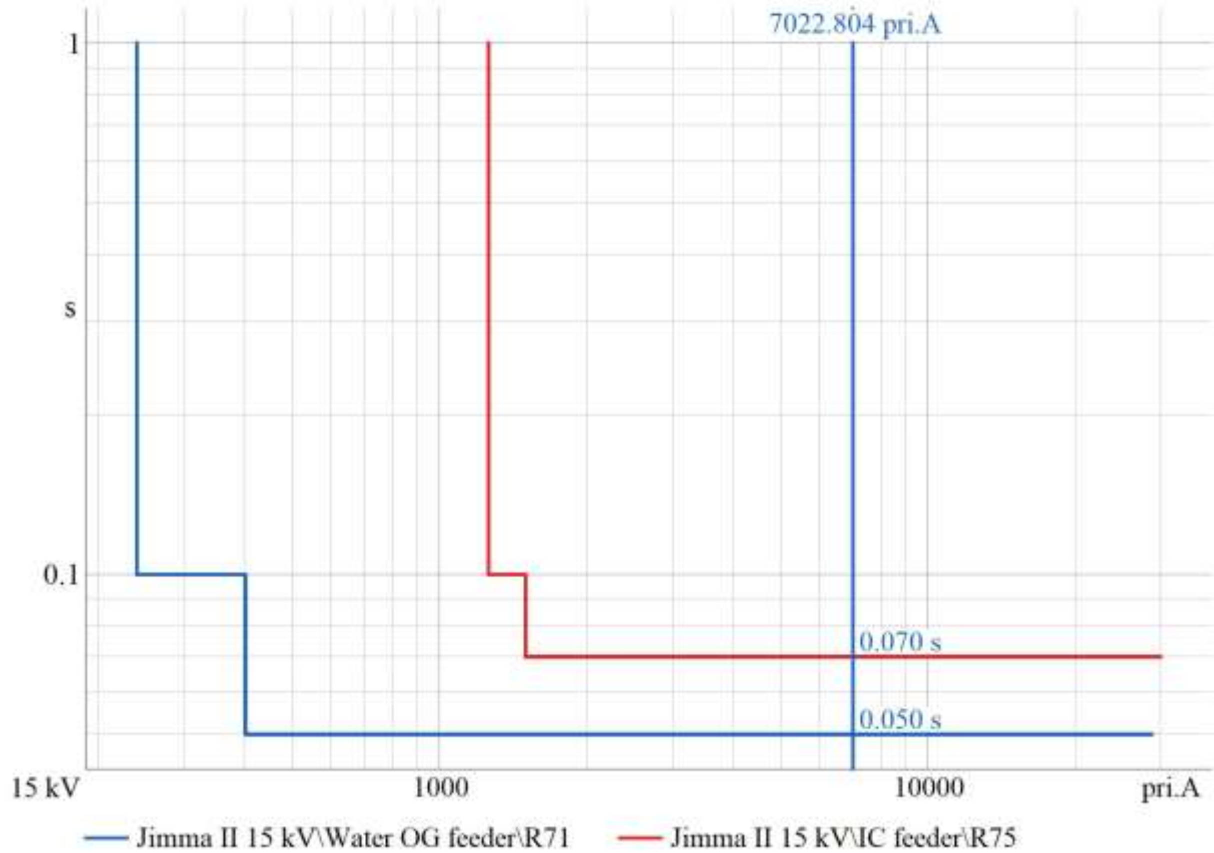

Figure 4.6: Actual setting time-overcurrent curve and operating time responses for protection relays R71 and R75 with a short-circuit fault current of 7.023 kA.

Based on relays operating time result of Fig. 4.6, protection relays are operated in the expected sequence. But they are not coordinated correctly, because the CTI between the relays is less than 0.2 seconds. This may cause to cascading events with in the system.

Table 4.6: Fault current magnitudes and existing setting operating time responses of cascaded protection relays for faults on Jimma II Substation distribution outgoing feeder.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On Water 15 kV feeder	R71	50/51	Water, 15 kV feeder	7023	0.05	274	0.05
	R75	50/51	Jimma II, 15 kV feeder	7023	0.07	274	0.07
	R76	50/51N	Earthing transformer, 15 kV	-	-	274	1.681
	R77	67	132/15 kV transformer	801	0.199	0	∞
	R78	67N	132/15 kV transformer neutral	-	-	0	∞
	R80	67	230/132 kV transformer, 132 kV	400	14.565	0	∞
	R79	67	230/132 kV transformer, 230 kV	230	0.831	0	∞
	R81	67N	230/132 kV transformer neutral	-	-	0	∞
On Serbo 15 kV feeder	R72	50/51	Serbo, 15 kV feeder	7023	0.05	274	0.05
	R75	50/51	Jimma II, 15 kV feeder	7023	0.07	274	0.07

Based on the relays working time presented in Table 4.6, the substation protection system operated in the expected sequence. But, the CTI between backup and primary protection relays is under the minimum requirement. Such low CTI may compromise selectivity of protection system, which coordination problem mitigation is recommended to ensure adequate coordination margins.

Case 7: Fault scenario on Gamibella II substation distribution feeders

Gamibella II Substation is equipped with three-33 kV distribution feeders, one-66 kV transmission line, and one-40/20/20 MVA, 230/66/33 kV power transformer. For maximum fault scenario on 33 kV distribution feeders, the fault current magnitude and corresponding operating time responses for overall cascaded protection relays are summarized in Table 4.7. Additionally, for a fault on 66 kV line with a short-circuit fault current of 1.068 kA, the existing setting time-overcurrent plot and their corresponding operating time responses for three-cascaded protection relays are given in Figure 4.7 as shown below.

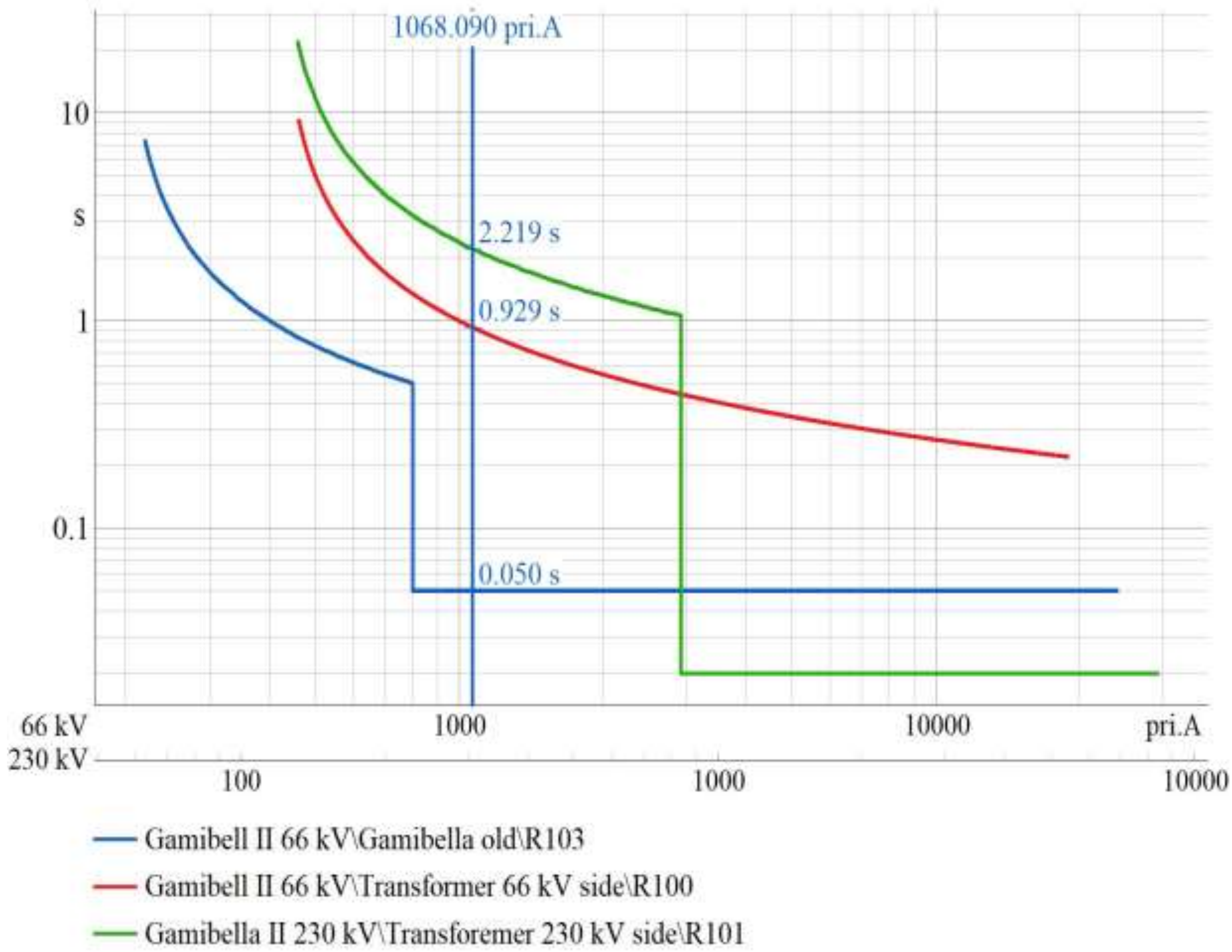

Figure 4.7: Operating time responses for cascaded protection relays based on existing settings for a short-circuit fault on 66 kV Gamibella II-Gamibella I line, with a fault current magnitude of 1.068 kA.

Based on the relays operating time result shown in Figure 4.7, the relays are operated in the expected sequence. But the critical CTI is relatively long for this severe fault current. Therefore, to increase system protection overall responsiveness, protection relays setting should be analyzed and optimized.

Table 4.7: Fault current readings and operating time responses of cascaded protection relays based on actual settings for a fault on distribution outgoing feeders at Gamibella II Substation.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On 66 kV Gamibella II-Gamibella I line	R103	67	66 kV Gamibella II-Gamibella I line	1068	0.05	1083	0.05
	R100	67	230/66/33 kV transformer, 66 kV	1068	0.93	1083	0.509
	R99	50/51N	230/66/33 kV transformer, 66 kV neutral	-	-	1083	0.497
	R101	67	230/66/33 kV transformer, 230 kV	307	2.161	70	1.651
	R102	50/51N	230/66/33 kV transformer, 230 kV neutral	-	-	70	4.694
Gamibella university 33 kV feeder	R94	50/51	Gamibella university, 33 kV	1865	0.237	258	0.271
	R97	50/51	Gamibella, 33 kV incoming	1865	0.851	258	1.06
	R98	50/51N	Earthing, 33 kV	-	-	258	1.286
	R101			268	2.136	0	∞
Guniganig33 kV feeder	R96	50/51	Guniganig, 33 kV	1865	0.254	258	0.273
	R97	50/51	Gamibella, 33 kV incoming	1865	0.967	258	1.095

According to the operating time results presented in Table 4.7, the protection system of this substation is operated the expected sequence. But, the CTI between backup and primary protection relays is relatively long. This is undesirable, which extend fault current duration particularly in cases where primer protection system fails to operate and may leads to equipment damage.

Case 8: Fault scenario on Metu substation distribution outgoing feeders

Metu substation has two-33 kV and five-15 kV distribution feeders, one-40/20/20 MVA, 230/66/15 kV transformer, and also one-6.3 MVA, 66/33 kV transformer. For maximum fault scenario on the distribution feeders, fault current magnitude and corresponding working time for cascaded protection relays are summarized in Table 4.8 below.

Table 4.8: Fault current measurement and corresponding operating time responses based on actual settings of cascaded protection relays for fault on the distribution outgoing feeders at Metu substation.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	Operating time (s)
On Metu university 15 kV feeder	R119	50/51	Metu university, 15 kV	4907	0.05	196	0.03
	R114	50/51	Metu SS, 15 kV feeder	4907	0.17	196	0.5
	R113	50/51N	Earthing transformer, 15 kV	-	-	196	1.02
	R109	50/51	230/66/15 kV transformer, 230 kV	321	0.7	0	∞
	R110	50/51N	230/66/15 kV transformer, 230 kV neutral	-	-	0	∞
On Metu city 15 kV feeder	R118	50/51	Metu city, 15 kV	4907	0.07	196	0.12
	R114	50/51	Metu SS, 15 kV feeder	4907	0.17	196	0.5
On Gobe 33 kV feeder	R106	50/51	Metu Gobe, 33 kV	863	0.02	386	0.02
	R107	50/51	Metu SS, 33 kV feeder	863	0.02	386	0.02
	R108	50/51N	Earthing, 33 kV	444	0.22	0	∞
	R111	50/51	66/15 kV transformer, 66 kV	444	2.5	0	∞
	R112	50/51N	66/15 kV transformer, 66 kV neutral	-	-	0	∞
	R109	50/51	230/66/15 kV transformer, 230 kV	163	0.7	0	∞

According to the relays tripping outcomes shown in Table 4.8, the coordination time interval between 15 kV incoming and distribution feeders' protection relay is less than 0.2 second for short-circuit faults. Such short CTI may cause to cascading outages and compromise system stability. For ground fault condition, the relays operated in the correct sequence with proper coordination. In contrast, 33 kV incoming feeder protection relay and outgoing feeder protection relays operated simultaneously for both short-circuit and ground faults on the distribution feeders. To address these coordination problems, it is recommended that the relays setting should be reviewed and optimized properly.

Case 9: Fault scenario on Bedelle substation distribution feeders

Bedelle Substation has:

- ✓ Two 63 MVA, 230/132 kV autotransformer
- ✓ One 20 MVA, 132/15 kV power transformer
- ✓ One 16 MVA, 132/33 kV power transformer
- ✓ Four-15 kV and two-33 kV distribution feeders.

For the condition of occurring on the distribution feeders, fault current magnitude and corresponding operating time responses for cascaded protection relays are summarized in Table 4.9 as shown below.

Table 4.9: Fault current measurement and corresponding operating time response based on actual relays setting for a fault on the distribution outgoing feeders at Bedell substation.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On Bedelle beer factory 15 kV feeder	R130	50/51	Beer Factory, 15 kV	7570	0.12	281	0.12
	R128	50/51	Bedelle SS, 15 kV feeder	7570	0.32	281	0.32
	R127	50/51N	Earthing, 15 kV	-	-	281	0.5
	R125	50/51	132/15 kV transformer	860	0.82	0	∞
On Bedelle city 15 kV feeder	R129	50/51	Bedelle city,15 kV	7570	0.03	281	0.03
	R128	50/51	Bedelle SS, 15 kV feeder	7570	0.32	281	0.32
On Dega 33 kV feeder	R137	50/51	Dega, 33 kV	2437	0.03	352	0.03
	R135	50/51	132/33 kV transformer, 33 kV	2437	0.17	352	0.17
	R136	50/51N	Earthing, 33 kV	-	-	352	1.14
	R133	50/51	132/33 kV transformer, 132 kV	613	0.05	-	-

According to operating time results shown in Table 4.9, it is observed that the 132/33 kV transformer protection relay (R133) trips before 33 kV incoming feeder protection relay (R135) in response to a short-circuit fault on the distribution outgoing feeders. This indicates incorrect relay coordination, since upstream equipment protection relay trips before downstream protection relay. Additionally, the CTI between 33 kV incoming feeder relay and 33 kV outgoing feeder protection relays is only o.14 Seconds. This short interval may nor provide sufficient backup time margin and increase the risk of cascading outages if primary relay fails to operate as expected. To improve protection system reliability and selectivity it is necessary to review and optimize the current relay settings, and ensuring proper time grading between the protection layers.

Case 10: Fault scenario on 132 kV transmission lines

The Southwestern region of Ethiopian electric power transmission network has four 132 kV transmission lines. Similarly to the previous cases, various fault scenarios on these lines were simulated, and the operating time responses for both distance and overcurrent protection relays were analyzed.

Initially, the fault current magnitudes and corresponding running time responses for cascaded OCRs are summarized in Table 4.10. Subsequently, for the fault currents simulated at the start and end-points of second zone operating region for distance protection relays, the running time responses for both primary distance and backup directional overcurrent protection relays, as well as the running time responses for primary directional overcurrent and backup distance protection relays are presented in Table 4.11. Additionally, the time-overcurrent characteristics curves and operating time responses for protection relay R45 and R83, based on their existing setting, is given in Figure 4.8 with a short-circuit fault current of 2.77 kA.

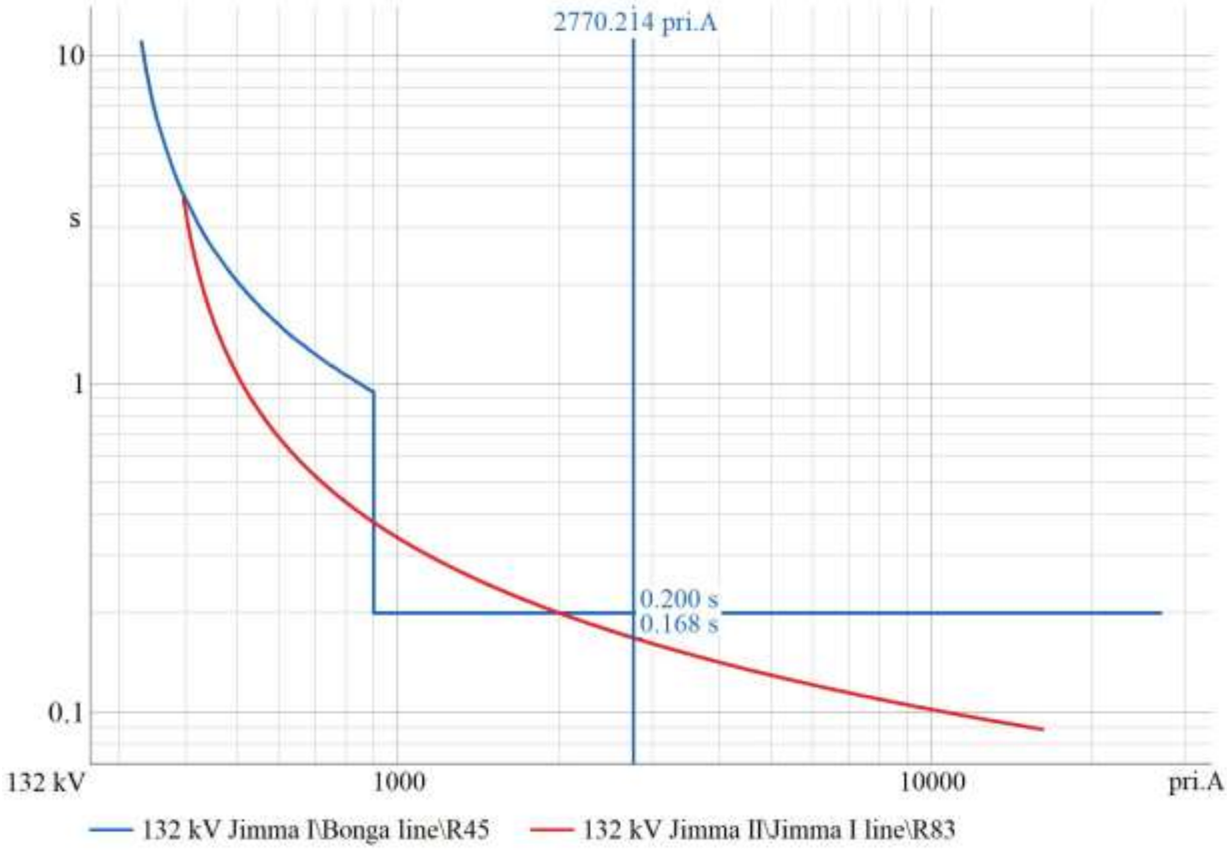

Figure 4.8: Operating time response for overcurrent protection relay R45 and R83 based on their existing settings for a fault on 132 kV Jimma I-Bonga transmission line with short circuit fault current of 2.77 kA.

From the above figure, it is evident that backup overcurrent protection relay R83 trips before primary relay R45 for a fault on 132 kV Jimma I-Bonga transmission line. This indicates that the relays are not properly coordinated, because the backup relay should operate only if primary relay fails. So, existing relays setting requires investigation on optimal setting values and ensure selectivity of the system protection.

Table 4.10: Fault current magnitude and existing setting operating time responses for cascaded overcurrent protection relays for a fault on 132 kV transmission lines.

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
Bonga-Mizan transmission line	R28	67	Bonga-Mizan, 132 kV line	1085	0.12	1260	0.12
	R45	67	Jimma I-Bonga, 132 kV line	1085	0.22	423	0.22
Jimma I-Bonga transmission line	R45	67	Jimma I-Bonga, 132 kV line	2770	0.2	4438	0.081
	R83	67	Jimma II-Jimma I, 132 kV line	2770	0.168	4438	0.183
	R37	67N	132/15 kV transformer at Jimma II SS, 132 kV neutral	-	-	522	0.17
Jimma II-Jimma I	R83	67	Jimma II-Jimma I, 132 kV	3299	0.02	9188	0.02
	R80	67	230/132 kV transformer, 132 kV	1649	0.946	395	0.257
	R79	67	230/132 kV transformer, 132 kV	947	0.387	112	0.484
	R81	67N	230/132 kV transformer, neutral	-	-	283	2.052

Fault	Relay No.	ANSI code	Location	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
Jimma two-Aba transmission line	R84	67	Jimma II-Aba, 132 kV	3242	0.02	8276	0.06
	R80	67	230/132 kV transformer, 132 kV	1621	1.065	352	0.267
	R79	67	230/132 kV transformer, 132 kV	930	0.397	100	0.421
	R81	67N	230/132 kV transformer, neutral	-	-	252	2.221
	R37	67N	132/15 kV transformer at Jimma II SS, 132 kV neutral	-	-	7444	0.099

From the relays operating time results presented in Table 4.10, it is observed that the CTI between backup and primary protection relays are less than 0.2 second for a fault on Bonga-Mizan transmission line. Additionally, for a short-circuit fault current of 2.77 kA on Jimma I-Bonga transmission line, the backup protection relay R83 operates before primary relay R45, which indicates improper coordination. Moreover, for a double line-to-ground fault with a zero-sequence fault current ($3I_0$) of 4.438 kA on Jimma I-Bonga transmission line, the CTI between primary and backup protection relays, as well as between primary and other corresponding primary protection relays, which share a common bus bar is also less than 0.2 second.

This insufficient CTI may result in cascading system outages. In contrast, for the third fault scenario on Jimma II-Jimma I transmission line, the cascaded protection relays are operated in the expected sequence with proper coordination. However, in case of a double line-ground fault with a $3I_0$ fault current of 8.3 kA on Jimma II-Aba transmission line, the CTI between protection relay R77 (which shares common bus bar) and protection relay R84 is only 0.039 seconds. Overall, the operating time results of Table 4.10 indicted that the CTI between most backup and primary protection relays are less than the recommended minimum CTI 0.2

second. To resolve these coordination problems, it is essential to investigate and update protection relays settings by employing optimization techniques.

The operating time response summery for backup distance and primary DOCRs, as well as for backup DOCRs and primary distance protection relays are presented in Table 4.11 as shown below.

Table 4.11: Operating time results for distance and overcurrent protection relays (existing settings) with a short-circuit fault currents on a given location.

Fault	Relay No.	ANSI Code	Relay Location	Role of Protection	Operating Time (s)
80% from R86	R86	21	Bonga-Mizan, 132 kV	Primary	0.3
	R45	67	Jimma I-Bonga, 132 kV	Backup	1.233
120% from R87	R28	67	Bonga-Mizan, 132 kV	Primary	0.772
	R87	21	Jimma I-Bonga, 132 kV	Backup	0.2
80% from R87	R87	21	Jimma I-Bonga, 132 kV	Primary	0.2
	R83	67	Jimma II-Jimma I, 132 kV	Backup	0.254
120% from R88	R45	67	Jimma I-Bonga, 132 kV	Primary	0.2
	R88	21	Jimma II-Jimma I, 132 kV	Backup	0.4

From the relays operating time of Table 4.11, it is observed that backup distance relay R87 trips before primary directional overcurrent protection relay R45 for a short-circuit fault located at 120% of Bonga-Mizan transmission line, which violates the selectivity principle of protection systems. Also, for a short-circuit fault at 80% of Jimma I-Bonga transmission line, the CTI between backup directional overcurrent protection relay R83 and primary distance protection relay R87 is only 0.054 seconds, which is below the minimum CTI requirements. This insufficient margin can compromise system stability and may lead to unnecessary cascade tripping.

Generally, the operating time results presented in Table 4.11 indicates that the coordination between distance and overcurrent relays is not proper. The existing settings do not satisfy selectivity criteria essential for reliable operation. Therefore, simultaneous coordination of distance and overcurrent protection relays should be carefully reviewed, and optimal settings should be calculated and applied to ensure proper coordination of system protection.

Case 11: Fault scenario simulated on 230 kV transmission lines

The Ethiopian electric power Southwest region transmission network has five 230 kV transmission lines. Similarly to case 10, this section analyzes the existing cascaded protection relays setting coordination.

First the existing setting for cascaded overcurrent protection relay’s fault current magnitude and operating time results are summarized in Table 4.12. Second, Table 4.13 presents the operating time results of:

- ❖ Backup distance protection relays and primary DOCRs for a short-circuit fault occurring at the end of backup distance protection relays second zone operating region.
- ❖ Backup DOCRs and primary distance protection relays for a fault located at the beginning of primary distance protection relays second zone operating region.

Additionally, the operating time result of overcurrent protection relay R211, R139, R46 and, R124 for a fault on Metu-Gamibella II transmission line with a short-circuit fault current of 1738.38 is given in Figure 4.9 as shown below.

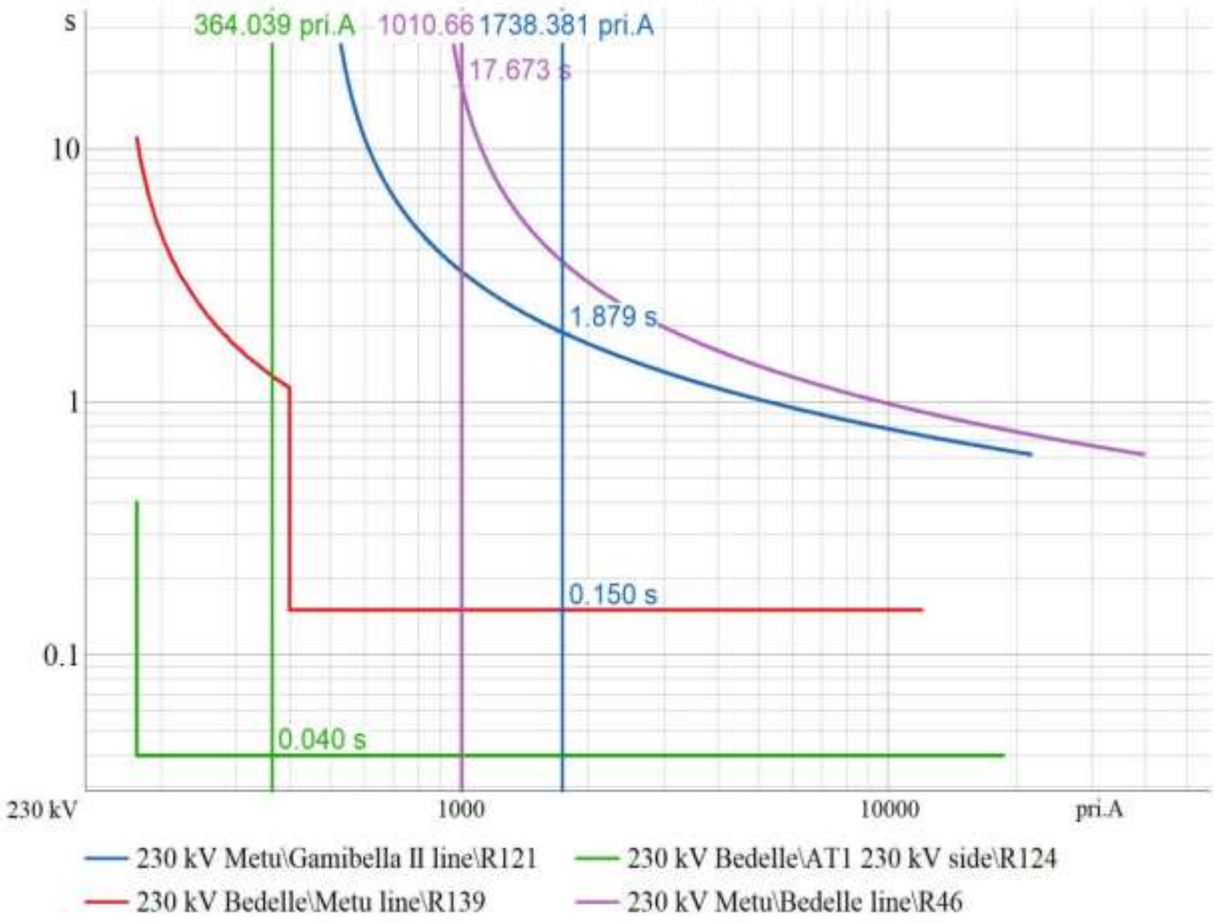

Figure 4.9: Fault current magnitude and corresponding operating time for cascaded protection relays for a fault on 230 kV Metu-Gamibella II transmission line (Short-circuit fault current: 1738.38 A).

From, relays operating time result shown in Figure 4.9 above, cascaded backup overcurrent protection relays R139 and R124 are tripped before primary protection relay R121 for a given short-circuit fault current on Metu-Gamibella transmission line.

Table 4.12: Fault current reading and actual setting operating time responses of cascaded overcurrent protection relays for fault on 230 kV transmission lines.

Fault	Relay No.	ANSI Code	Relay Location	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
On Metu-Gamibella, 230 kV line	R121	67	Gamibella II, 230 kV line	1738	2.118	2145	1.147
	R139	67	Metu, 230 kV line	1738	0.15	763	0.15
	R46	67	Bedelle, 230 kV line	1011	19.84	239	12.118
On Metu-Gamibella, 230 kV line	R121	67	Gamibella II, 230 kV line	1738	2.118	2145	0.877
	R139	67	Metu, 230 kV line	1738	0.15	763	0.15
	R124	50/51	230/132 kV transformer at Bedell, 230 kV	364	0.04	264	0.04
	R122	50/51	230/132 kV transformer at Bedell, 132 kV	634	7.279	459	2.353
	R123	50/51 N	230/132 kV transformer at Bedell, neutral	-	-	195	1.711
On Bedelle-Metu, 230 kV line	R139	67	Metu, 230 kV line	2757	0.15	3002	0.15
	R124	50/51	230/132 kV transformer, 230 kV	577	0.04	1041	0.04
	R122	50/51	230/132 kV transformer, 132 kV	1006	2.392	1807	1.214

Fault	Relay No.	ANSI Code	Relay Location	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
Bedelle-Metu, 230 kV line	R139	67	Metu, 230 kV line	2757	0.15	3002	0.15
	R46	67	Bedelle, 230 kV line	1603	4.77	1358	1.554
Jimma II – Agaro, 230 kV line	R82	67	Agaro, 230 kV	3811	0.1	11425	0.1
	R93	R82	Jimma II, 230 kV	3811	1.852	302	2.03
Agaro-Jimma II transmission line	R70	67	Jimma II, 230 kV	911	∞	2990	0.941
	R104	67	Agaro, 230 kV	911	∞	791	1.941
	R124	50/51	230/132 kV transformer, 230 kV	456	0.04	295	0.04
	R122	50/51	230/132 kV transformer, 132 kV	794	3.093	512	1.531
Jimma II - GG II transmission line	R90	67	GG II, 230 kV	826	∞	8714	0.7
	R70	67	Jimma II, 230 kV	826	∞	282	∞
	R104	67	Agaro, 230 kV	826	∞	60	∞
	R124	50/51	230/132 kV transformer, 230 kV	413	0.04	22	∞
	R122	50/51	230/132 kV transformer, 132 kV	2666	1.625	4339	∞
Agaro-Bedelle, 230 kV line	R46	67	Bedelle, 230 kV line	2666	2.55	2202	0.817
	R82	67	Agaro,230 kV line	1155	0.1	2809	0.1
	R93	67	Jimma, 230 kV line	577	2.53	1046	∞
Bedelle-Agaro, 230 kV line	R104	67	Agaro, 230 kV line	1006	13.224	1817	1.03
	R124	50/51	230/132 kV transformer, 230 kV	577	0.04	656	0.04
	R122	50/51	230/132 kV transformer, 232 kV	1006	0.1	1135	0.1

Based on the relays operating time result presented in Table 4.12, the following observations were made:

- ✓ Backup overcurrent protection relay R139 trips before primary protection relay R121 for a fault on Metu-Gamibella II transmission line with a shot-circuit fault current of 1.738 kA.
- ✓ Backup protection relay R124 trips before primary protection relay R139 for a fault on Bedelle-Metu transmission line with a shot-circuit fault current of 2.757 kA.
- ✓ For a fault on Agaro-Jimma II transmission line with a short-circuit fault current of 0.911 kA, neither primary protection relay R70 nor locale backup protection relay R104 operated, but the remote backup protection relay R124 tripped. This scenario could lead to a large-scale customer power interruption.
- ✓ For a fault on Agaro-Bedelle transmission line, the backup protection relays R124 and R82 tripped before their respective primary protection relays R104 and R46.
- ✓ Finally, for a fault on GG II-Jimma II transmission line with a short-circuit fault current of 0.826 kA, the remote backup protection relays R124 and R122 operated, while primary and locale backup protection relays failed to respond.

Table 4.13: Actual setting tripping time responses for distance and overcurrent protection relays with short-circuit fault at a given location.

Fault	Relay No.	ANSI code	Relay Location	Role of protection	Operating time (s)
80% from R91	R91	21	Jimma II-Agaro, 230 kV line	Primary	0.4
	R93	67	GG-Jimma II, 230 kV line	Backup	0.138
120% from R92	R82	67	Jimma II-Agaro, 230 kV line	Primary	0.1
	R92	21	GG-Jimma II, 230 kV line	Backup	0.4
80% from R142	R142	21	Metu-Gamibella, 230 kV line	Primary	0.5
	R139	67	Bedelle-Metu, 230 kV line	Backup	0.17
120% from R141	R121	67	Metu-Gamibella, 230 kV line	Primary	2.296
	R141	21	Bedelle-Metu, 230 kV line	Backup	0.5
80% from R141	R141	21	Bedelle-Metu, 230 kV line	Primary	0.5
	R46	67	Agaro-Bedelle, 230 kV line	Backup	12.54
120% from R145	R139	67	Bedelle-Metu, 230 kV line	Primary	0.17
	R145	21	Agaro-Bedelle, 230 kV line	Backup	0.4
80% from R145	R145	21	>>	Primary	0.4
	R82	67	Jimma II-Agaro, 230 kV line	Backup	0.1
120% from R91	R90	67	Jimma II-GG II, 230 kV line	Primary	∞
	R91	21	Agaro-Jimma II, 230 kV line	Backup	0.4
80% from R144	R144	21	Agaro-Jimma II, 230 kV line	Primary	0.4
	R104	67	Bedelle-Agaro, 230 kV line	Backup	∞
120% from R120	R70	67	Agaro-Jimma II, 230 kV line	Primary	∞
	R120	21	Bedelle-Agaro, 230 kV line	Backup	0.4
80% from R143	R143	21	Jimma II-GG II, 230 kV	Primary	0.4
	R70	67	Agaro-Jimma II, 230 kV line	Backup	∞
120% from R144	R90	67	Jimma II-GG II,230 kV line	Primary	∞
	R144	21	Agaro-Jimma II, 230 kV line	Backup	0.4

According to the relays operating time presented in Table 4.13, directional overcurrent protection relays and distance protection relays are not properly coordinated. To address this coordination problem, it is essential to investigate and determine optimal relays setting value for ensuring selective and reliability of the protection system.

4.3 Determination of optimal settings for the system protection relays

With a fixed predetermined pickup current setting, the optimal TMS value for overcurrent and earth-fault protection relays as well as optimal zone 2 operating time for DRs were investigated using PSO algorithm. The procedure followed for implementing of PSO algorithm is described in section 3.9, while coordination problem formulations are discussed in section 3.8 of chapter three. Also, the values for control parameters as well as equations for velocity updating and position updating are included in section 3.9.

The generated curve for PSO algorithm is given in Fig.4.10 as shown below. Although optimal TMS and second-zone operating time value for overcurrent and distance protection relays are investigated for the entire system, only a subset of final result obtained from PSO algorithm together with predetermined pickup current setting is presented in Table 4.14 for illustration. But the overall system protection relays optimal setting obtained from PSO algorithm is provided in Appendix C.

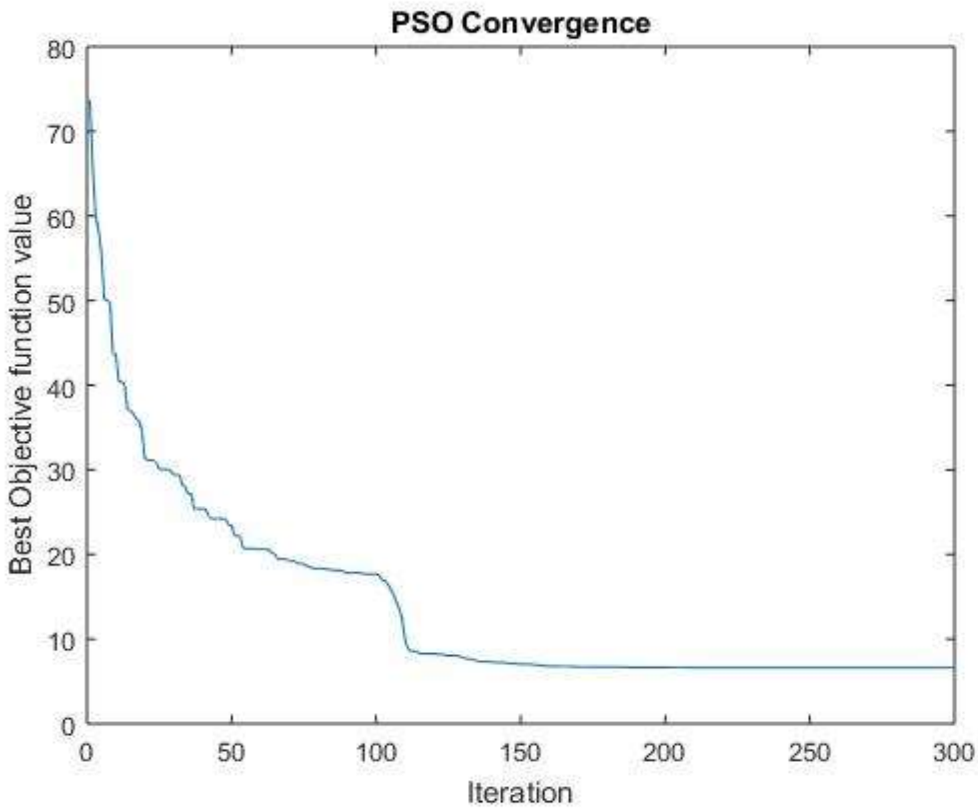

Figure 4.10: Convergence curve of PSO algorithm

From Fig.4.10, the value of objective function decreases rapidly during the start of optimal relays setting search and converges approximately after 200 iterations, which indicates that the algorithm of PSO found optimal solution to the formulated coordination problem.

Table 4.14: Protection relays optimal setting obtained from PSO algorithm

Location	Branch	Function	Current setting in Pri.A	Curve	Time setting (s)
Agaro substation	Agaro city, 15 kV feeder	I>	480	IEC SI	0.025
		I>>	1440	DT	0.1
		I>>>	2400	IN	0
	Gimbe, 15 kV feeder	I>	480	IEC SI	0.025
		I>>	1440	DT	0.1
		I>>>	2400	IN	0
	132/15 kV transformer, 15 kV	I>	920	IEC SI	0.067
	132/15 kV transformer, 132 kV	I>	105	IEC SI	0.125
	Gurudi, 33 kV feeder	I>	90	IEC SI	0.05
		I>>	270	DT	0.2
		I>>>	450	IN	0
	Gatera, 33 kV feeder	I>	90	IEC SI	0.05
		I>>	270	DT	0.2
		I>>>	450	IN	0
	Gera, 33 kV feeder	I>	90	IEC SI	0.05
		I>>	270	DT	0.2
		I>>>	450	IN	0
	132/33/15 kV transformer, 33 kV	I>	336	IEC SI	0.075
	132/33/15 kV transformer, 132 kV	I>	84	IEC SI	0.15
	230/132 kV transformer, 230 kV	I>	188	IEC SI	0.125
	230/132 kV transformer, 132 kV	I>	240	IEC SI	0.115

The above table shows that the optimal time multiplayer setting obtained from PSO algorithm and mathematically predetermined pickup current setting of the system protection relays.

To verify the result of PSO algorithm, the relays performance should be evaluated. The following section present simulation results for the optimized relays setting and based on simulation result verification of system protection relays are conducted.

4.4 Simulation with optimal settings of system protection relays

Following a similar procedure with section 4.2, this section verifies that the system protection relays, based on optimized settings, coordinated properly. This is demonstrated by presenting the simulation results. The simulation result of protection relays operating time presented as follow:

Case 1: Fault scenario on Jimma I SS distribution outgoing feeders

For selected three cascaded protection relays, the time-overcurrent characteristics curve based on optimized settings and their corresponding operating time responses are presented for a fault on industry distribution feeder, with a short-circuit fault current of 2.106 kA. This result is illustrated in Figure 4.11 as shown below.

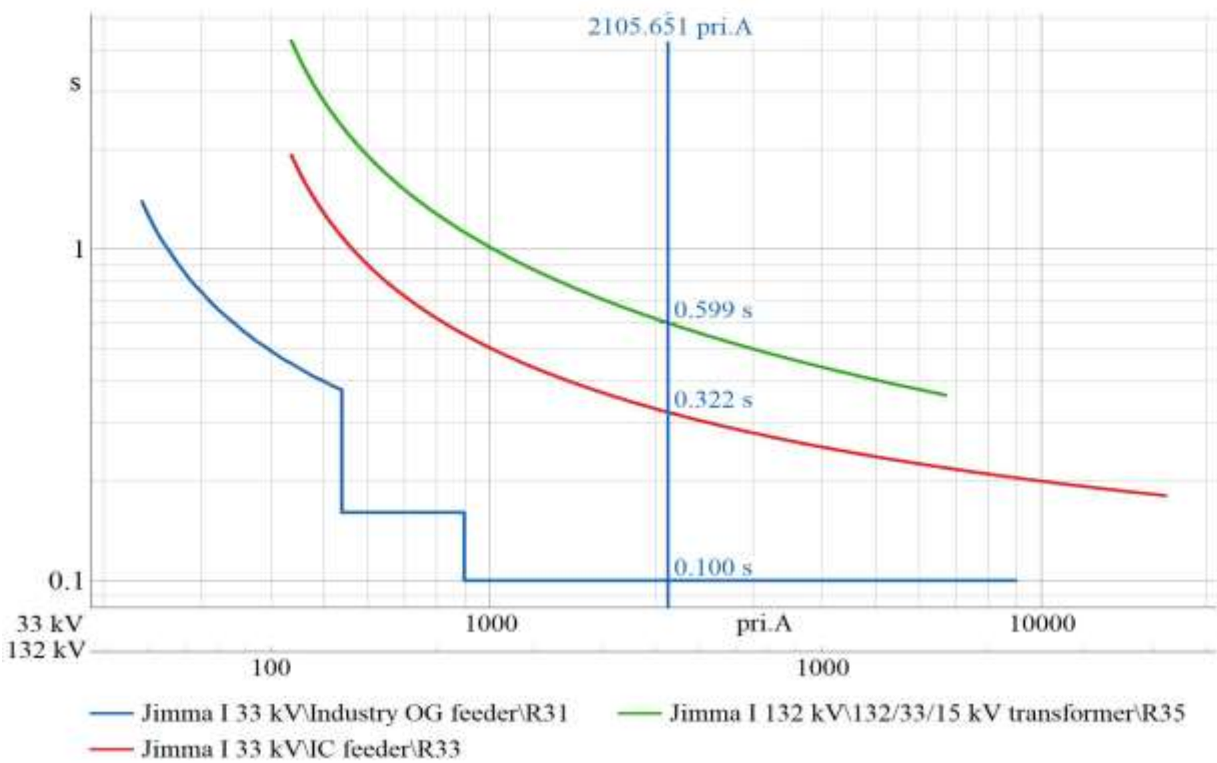

Figure 4.11: Operating time responses of protection relays R31, R33 and R35 with optimal settings for a fault on industrial feeder with a short-circuit current of 2.106 kA.

Based on the relay operating time results presented in Figure 4.11, the cascaded protection relays operated in the expected sequence and demonstrated optimal coordination. This evidenced by the CTIs between primary and backup protection relays, all of which exceed 0.2 seconds. A summary of the fault current measurement and operating time responses for the substation overall protection system are presented in Table 4.15.

Table 4.15: Fault current magnitude and optimized setting operating time responses of cascaded overcurrent protection relays for a fault on Jimma I substation distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On 33 kV Industry OG feeder	R31	2106	0.1	4434	0.086
	R33	2106	0.322	4435	0.291
	R34	-	-	4435	0.509
	R35	526	0.599	548	0.745
	R36	-	-	548	0.948
	R83	610	1.743	348	1.248
On 33 kV Limu OG feeder	R30	2106	0.1	4434	0.086
	R33	2106	0.322	4435	0.291
On 15 kV Agri (R1) OG feeder	R41	5775	0.02	185	0.091
	R40	5775	0.289	185	0.308
	R39	-	-	185	0.552
	R37	689	0.483	0	∞
	R38	-	-	0	∞
	R83	755	1.735	0	∞
On 15 kV R2 OG feeder	R44	5775	0.02	185	0.091
	R40	5775	0.289	185	0.308

From the relays operating time result of above Table, the protection system of Jimma I substation operated in the expected sequence, with satisfying minimum CTI requirements between backup and primary protection relays.

Case 2: Fault scenario on Agaro SS distribution outgoing feeders

For this case, three cascaded protection relays time-overcurrent characteristics curve is analyzed. The result of curve and their corresponding operating time responses for a fault on Agaro Substation distribution feeder are presented in Figure 4.12.

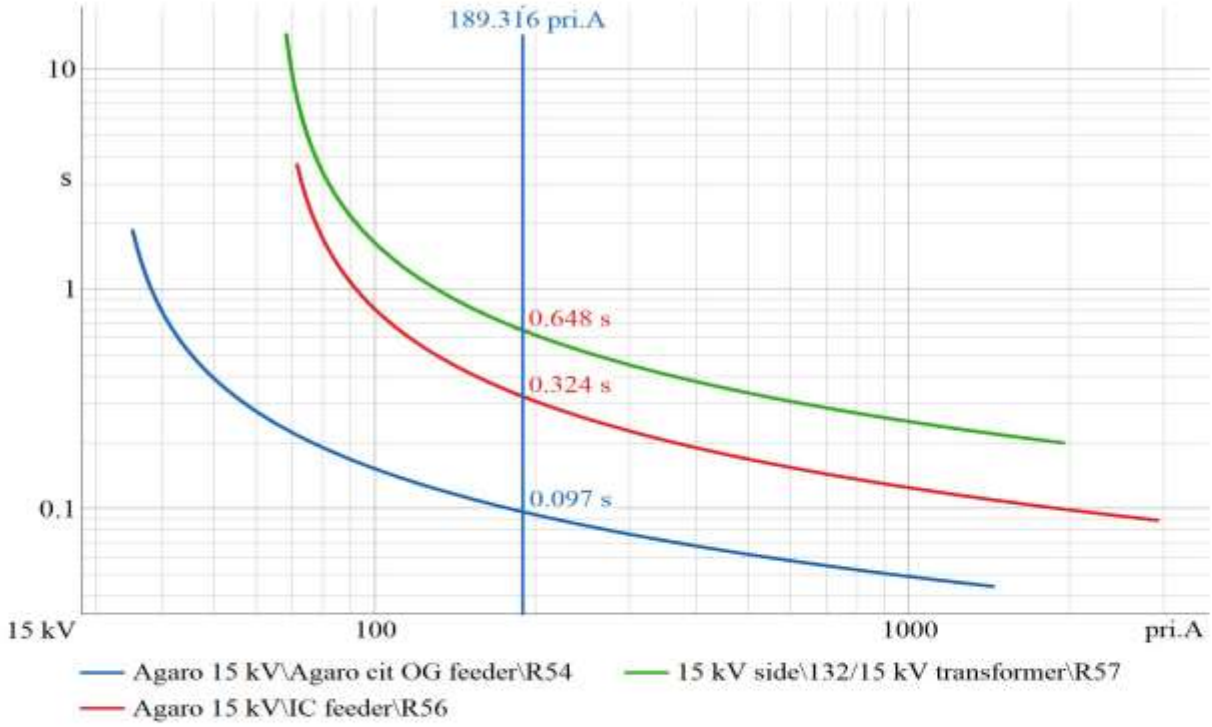

Figure 4.12: Protection relay R54, R56, and R57 operating time response based on optimized settings for line-to-ground fault on 15 kV feeder with zero sequence ($3I_0$) fault current of 189 A.

Based on the relays operating time result presented in Figure 4.12, the outgoing feeder protection relay R54 operated before incoming feeder protection relay R56 and transformer protection relay R57. Since the CTI between backup and primary protection relay exceeds 0.2 second with fast fault clearance, the relays are considered to be coordinated optimally. The fault current magnitude and corresponding optimized setting operating time responses for all protection relays at Agaro substation are summarized in Table 4.16 as shown below.

Table 4.16: Fault current magnitude and corresponding optimized relays setting operating time responses of cascaded OCRs for a fault on Agaro substation distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
On 33 kV Gatera OG feeder	R60	1892	0.02	2231	0.099
	R63	1892	0.289	2231	0.314
	R64	-	-	2231	0.652
	R65	498	0.524	239	0.519
	R66	-	-	239	0.726
	R68	498	1.26	223	0.767
	R67	271	1.619	37	0.772
	R69	-	-	186	1.171
On 33 kV Gera OG feeder	R61	1892	0.02	2231	0.099
	R63	1892	0.289	2231	0.316
On 15 kV Agaro city OG feeder	R54	5373	0.02	189	0.097
	R56	5373	0.28	189	0.324
	R57	-	-	189	0.648
	R58	611	0.517	0	∞
	R68	611	0.810	0	∞
	R67	350	0.832	0	∞
On 15 kV Gimey OG line	R55	5373	0.02	189	0.097
	R56	5373	0.28	189	0.324

Based on the operating time results presented in Table 4.16, the primary protection system operated before the corresponding backup protection system with sufficient CTI and fast fault clearance. This indicates that the system protection relays are coordinated optimally, because the CTI between backup and primary protection relays are exceed 0.2 second.

Case 3: Fault scenario on Aba substation distribution outgoing feeders

For two selected cascaded overcurrent protection relays, the optimized relays setting time – overcurrent characteristics curve and their corresponding operating time responses for short-circuit fault current of 2.072 kA on 33 kV Tercha feeder is given in Figure 4.13 as shown below.

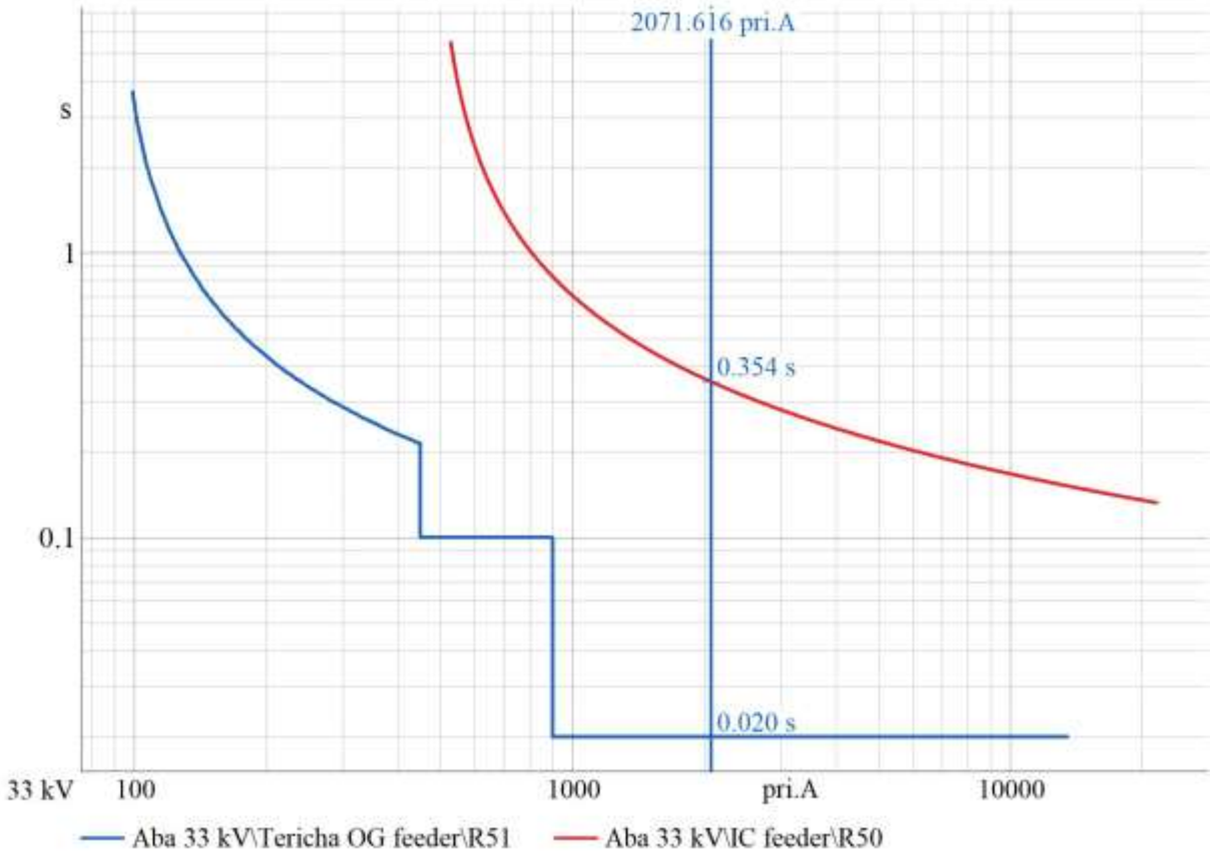

Figure 4.13: Optimal protection relay setting time-overcurrent characteristics curve and operating time responses for a short-circuit fault current of 2.072 kA on Aba Substation distribution feeder.

From the relays operating time of Figure 4.13, the protection relays are operated in the expected sequence. Also, the coordination time interval (CTI) between relay R50 and R51 is 0.334 seconds, which is greater than the minimum required CTI, indicating that the relays coordination properly. The overall substation protection system fault current measurement and their corresponding operating time results for a fault on the distribution outgoing feeders with the given fault current are summarized in Table 4.17 as shown below.

Table 4.17: Fault current measurement and optimized setting operating time responses of cascaded overcurrent protection relays for a fault on Aba substation distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
33 kV Tercha outgoing line	R51	2072	0.02	179	0.057
	R50	2072	0.353	179	0.298
	R49	-	-	179	0.523
	R47	563	0.572	0	∞
	R48	-	-	0	∞
	R84	553	0.83	0	∞
33 kV Isera outgoing line	R52	2072	0.02	179	0.057
	R50	2072	0.353	179	0.299

Based on the operating time results presented in the above table, the substation protection system of this substation is operated in the expected sequence and no mis-operation observed. These results confirm that the protection system, based on optimized settings is coordinated optimally, because the CTI between backup and main protection relays exceed 0.2 second.

Case 4: Fault scenario on Bonga substation distribution outgoing feeders

For two selected cascaded overcurrent protection relays, the optimized settings time-overcurrent characteristic curves and their corresponding operating time responses for a short circuit fault current of 1968.213 A, on Bonga substation distribution outgoing feeder, is presented in Figure 4.14 as shown below.

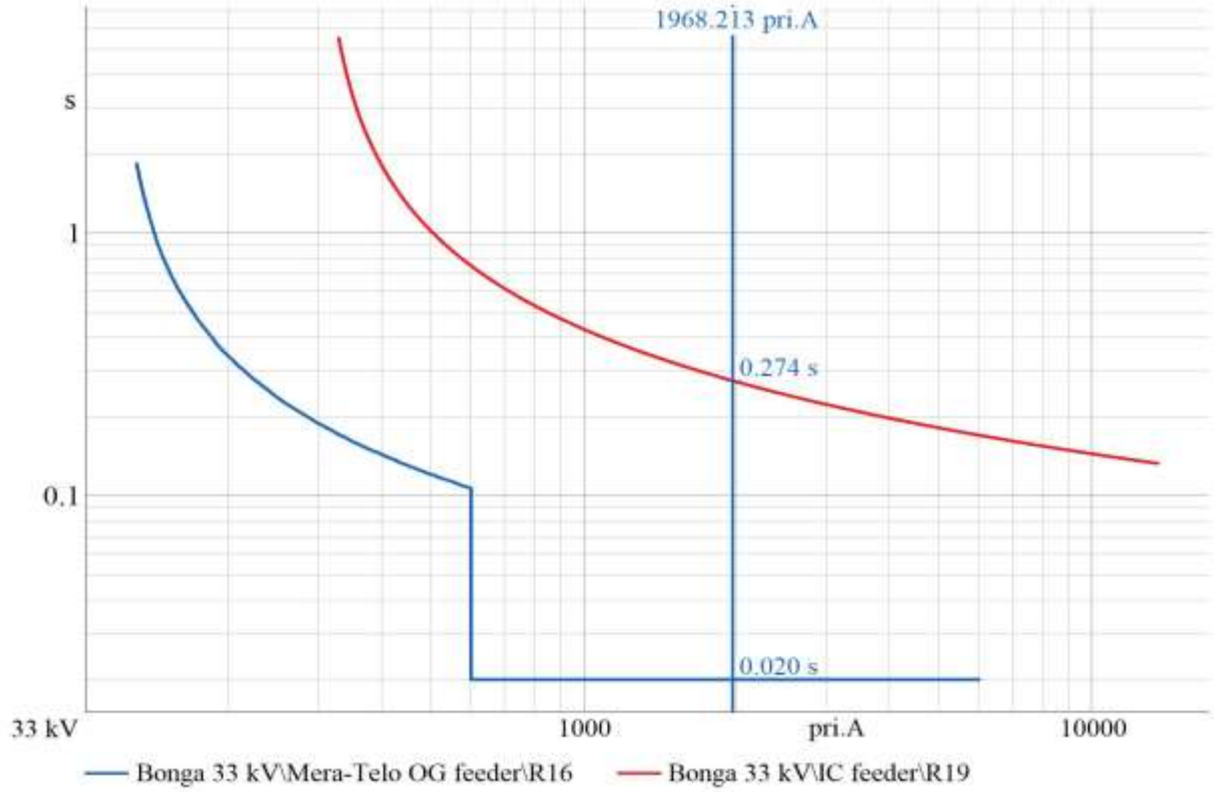

Figure 4.14: Optimal setting operating time responses of protection relays R16 and R19 for a fault on Mera-Telo distribution feeder, corresponding to a short circuit fault current of 1.968 kA.

Based on relays operating time result presented in Figure 4.14, the protection relay of distribution outgoing feeder operated before the protection relay of incoming feeder with the fault on outgoing feeder, which indicates correct coordination. Also, the coordination time interval (CTI) between backup and main protection relay is 0.254 seconds, which exceeds the minimum required threshold 0.2 second, confirmed adequate selectivity. The overall substation protection system fault current magnitude and their corresponding operating time responses for the fault scenario on distribution outgoing feeders are summarized in Table 4.18 as shown below.

Table 4.18: Fault current records and optimal operating time responses of cascaded overcurrent protection relays for a fault scenario on Bonga substation distribution feeders.

Fault location	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
33 kV Mera-Telo outgoing feeder	R16	1968	0.02	194	0.061
	R19	1968	0.274	194	0.266
33 kV Bonga university outgoing feeder	R81	1968	0.02	194	0.056
	R19	1968	0.274	194	0.264
	R20	-	-	194	0.468
	R27	488	0.539	0	∞
	R26	-	-	0	∞
	R45	488	2.298	0	∞
	R83	488	3.1	0	∞
15 kV Chiri outgoing feeder	R21	1770	0.02	244	0.051
	R24	1770	0.297	244	0.271
15 kV Bonga city outgoing feeder	R22	1770	0.02	244	0.065
	R24	1770	0.297	244	0.27
	R25	-	-	244	0.509
	R27	234	1.192	0	∞

Based on the relays operating time result presented in Table 4.18, the primary protection relays operated before the corresponding backup protection relays as expected. Additionally, the CTI between backup and primary protection relays all greater than 0.2 second, which is confirmed that the protection system meets the required selectivity criteria. These results provide clear evidence to the protection system, configured with optimized setting values, are coordinated properly.

Case 5: Fault scenario on Mizan substation distribution outgoing line and feeders

For two selected protection relays, the optimized setting time-overcurrent characteristics curves and their corresponding operating time results for a short-circuit fault current of 769.9 A, on 66 kV Mizan-Tepi transmission line is illustrated in Fig. 4.14 as shown below.

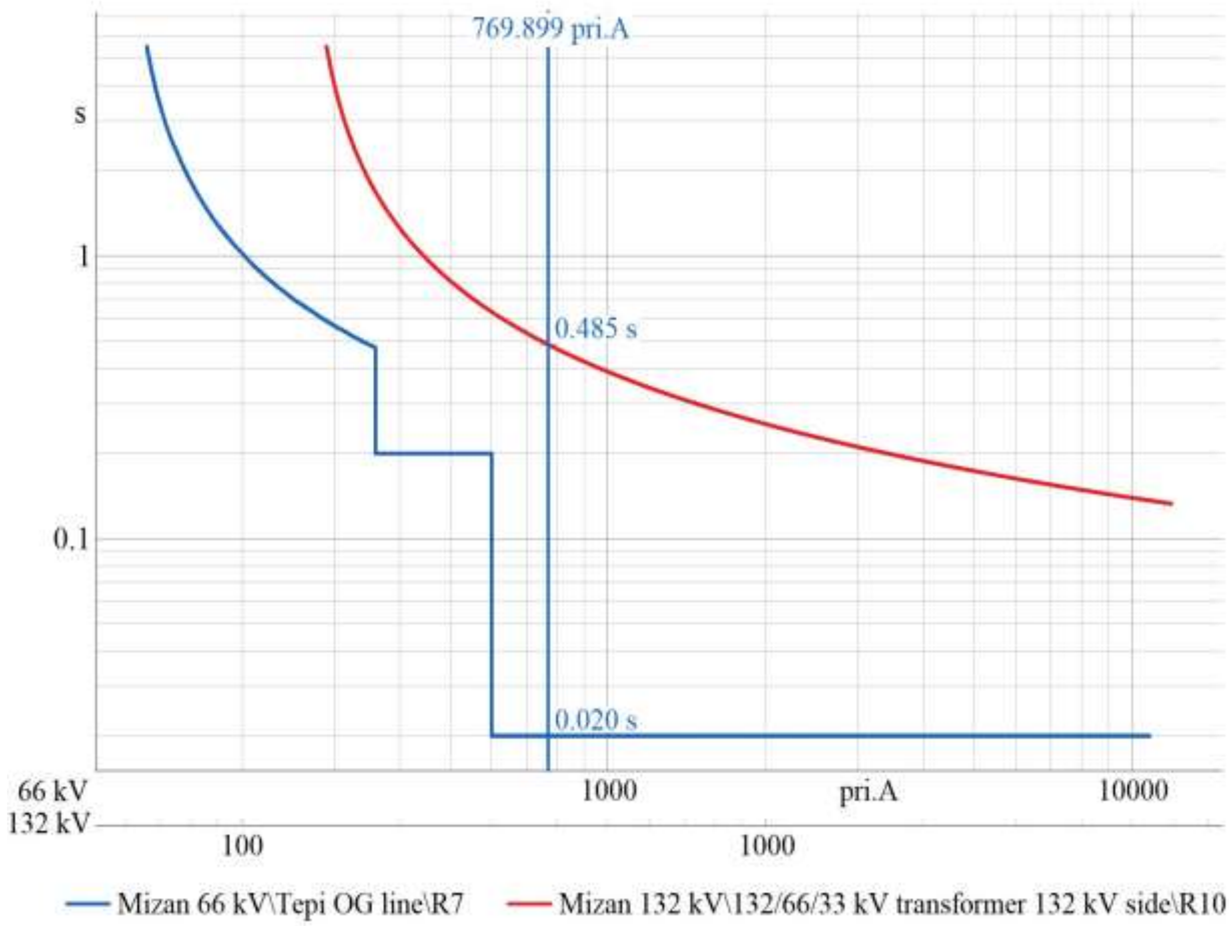

Figure 4.15: Operating time responses of protection relay R7 and R10 investigated optimal setting operating time responses for a fault on 66 kV Mizan-Tepi line with a short circuit fault current of 0.77 kA.

Based on the relays operating time result presented in Figure 4.15, the line OC protection relay operates prior to transformer overcurrent protection relay for a given short circuit fault on 66 kV line. The coordination time interval between these two protection relays is 0.465 second, which is above the minimum standard requirement of 0.2 second. This indicates that the coordination relays are proper. Additionally, the overall substation protection system fault current measurement and corresponding relays operating time responses based on their optimized setting for the fault current occurring on medium voltage feeders are summarized in Table 4.19 as shown below.

Table 4.19: Cascaded overcurrent protection relays fault current measurement and optimized setting operating time responses for a fault on Mizan substation distribution feeders.

Fault	Relay No.	3-Φ fault current (s)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
66 kV Tepi outgoing line	R7	770	0.02	896	0.05
	R8	770	0.445	695	0.268
	R9	-	-	695	0.49
	R10	381	0.484	84	0.288
	R11	-	-	84	0.542
	R28	381	1.425	84	0.766
33 kV Dimma outgoing feeder	R12	894	0.02	160	0.067
	R14	894	0.381	160	0.273
33 kV Chena city outgoing feeder	R13	894	0.02	160	0.067
	R14	894	0.381	160	0.272
	R15	-	-	160	0.471
	R10	223	0.942	0	∞
15 kV Mizan outgoing feeder	R1	1630	0.02	245	0.051
	R3	1630	0.299	245	0.256
	R4	-	-	245	0.523
	R5	406	0.511	0	∞
	R8	406	0.734	0	∞
	R10	243	0.727	0	∞
15 kV Sheko outgoing feeder	R2	1630	0.02	245	0.051
	R3	1630	0.299	245	0.523

According to the operating time result of Table 4.19, primary protection relays are operated before backup protection relays. Also, all system protection relays of a substation are operated in the expected sequence. This result shows that the protection system of this substation based on optimized settings are coordinated optimally and all the coordination problems of this substation that was discussed in section 4.2 are mitigated.

Case 6: Fault scenario on Jimma II distribution feeders

For two selected cascaded OC protection relays at Jimma II substation, the optimized relays setting, corresponding time-overcurrent plot, and their respective operating time responses for a short-circuit fault current of 7.023 kA, on 15 kV water outgoing feeder is given in Figure 4.16 as shown below.

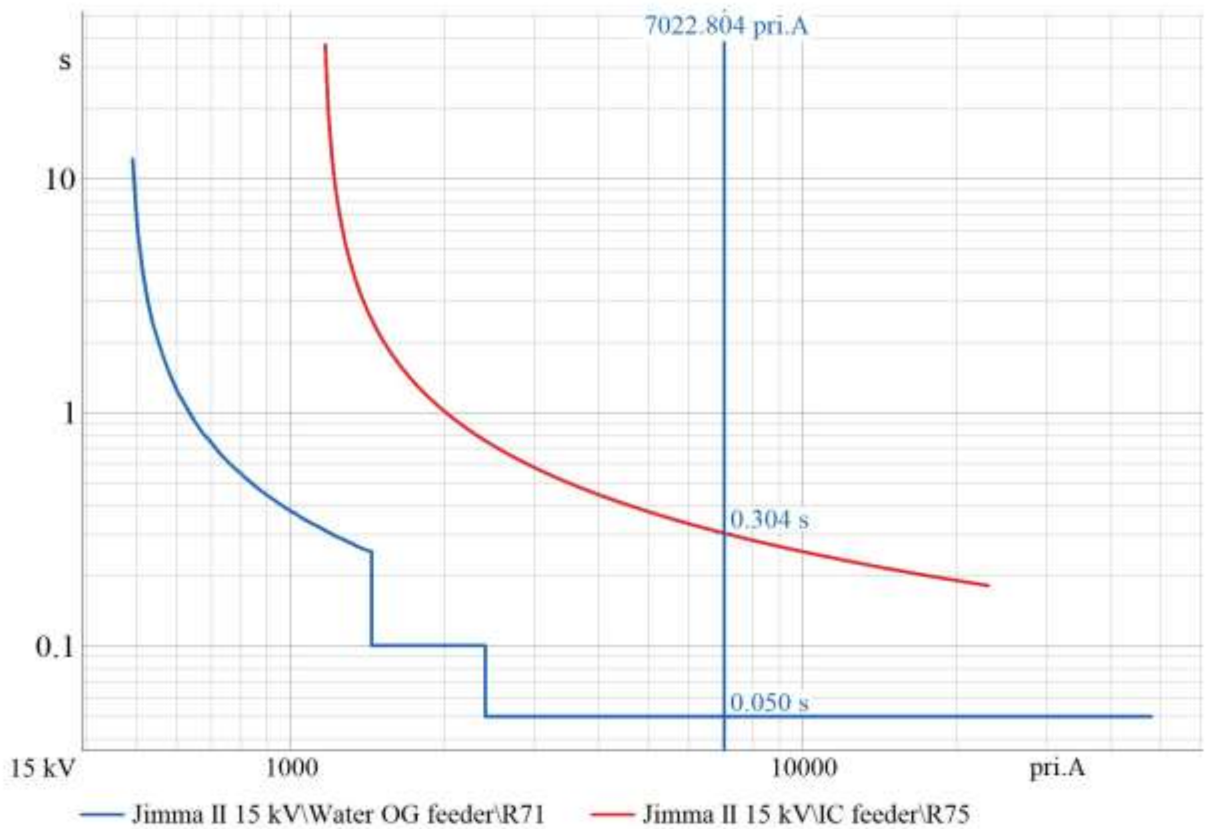

Figure 4.16: Operating time responses for overcurrent protection relays R7 and R10, based on the investigated optimized setting, with a short- circuit fault current of 7.023 kA on 15 kV distribution feeders.

From the relays operating time result shown in Figure 4.16, it is evident that the protection relay of distribution feeder operates before the incoming feeder protection relay. Also, the CTI between these two protection relays is 0.254 second, which exceeds the minimum requirement for proper relays setting coordination. This confirmed that outgoing and incoming feeder protection relays are well coordinated. Also, the overall protection system of a substation fault current magnitude and their corresponding operating time results for the occurrence of fault on the distribution outgoing feeders are summarized in Table 4.20 as shown below. This table gives a comprehensive overview for substation protection system performance within the protection hierarchy under the given fault scenarios.

Table 4.20: Cascaded overcurrent protection relays fault current magnitude and respective optimized relays setting operating time result for a fault on Jimma II substation distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
On 15 kV water OG feeder	R71	7023	0.05	275	0.099
	R75	7023	0.304	275	0.319
	R76	-	-	275	0.521
	R77	801	0.528	0	∞
	R78	-	-	0	∞
	R80	400	1.996	0	∞
	R79	230	2.08	0	∞
	R81	-	-	0	∞
On 15 kV Serbo OG feeder	R72	7023	0.05	275	0.1
	R75	7023	0.304	275	0.327

Based on the relays operating time result presented in Table 4.20, it is observed that primary protection system operates before their corresponding backup relays. This indicates that the protection system functions with an intended sequence, with no evidence of mis-operation among the system protection relays. Also, confirmed that the protection relays within Jimma-II substation are coordinated optimally, in accordance with optimized relay setting.

Case 7: Fault scenario on Gamibella II distribution outgoing feeders and line

For three selected overcurrent protection relays at Gamibella II Substation, the optimized settings time-overcurrent simulation results have been analyzed. The simulated operating time responses for a short circuit fault current magnitude of 1.068 kA, on 66 kV Gamibella II-Gamibella I line indicted that the system protection relays operated in the expected sequence with satisfying minimum discrimination time requirement. The results are illustrated in as shown below.

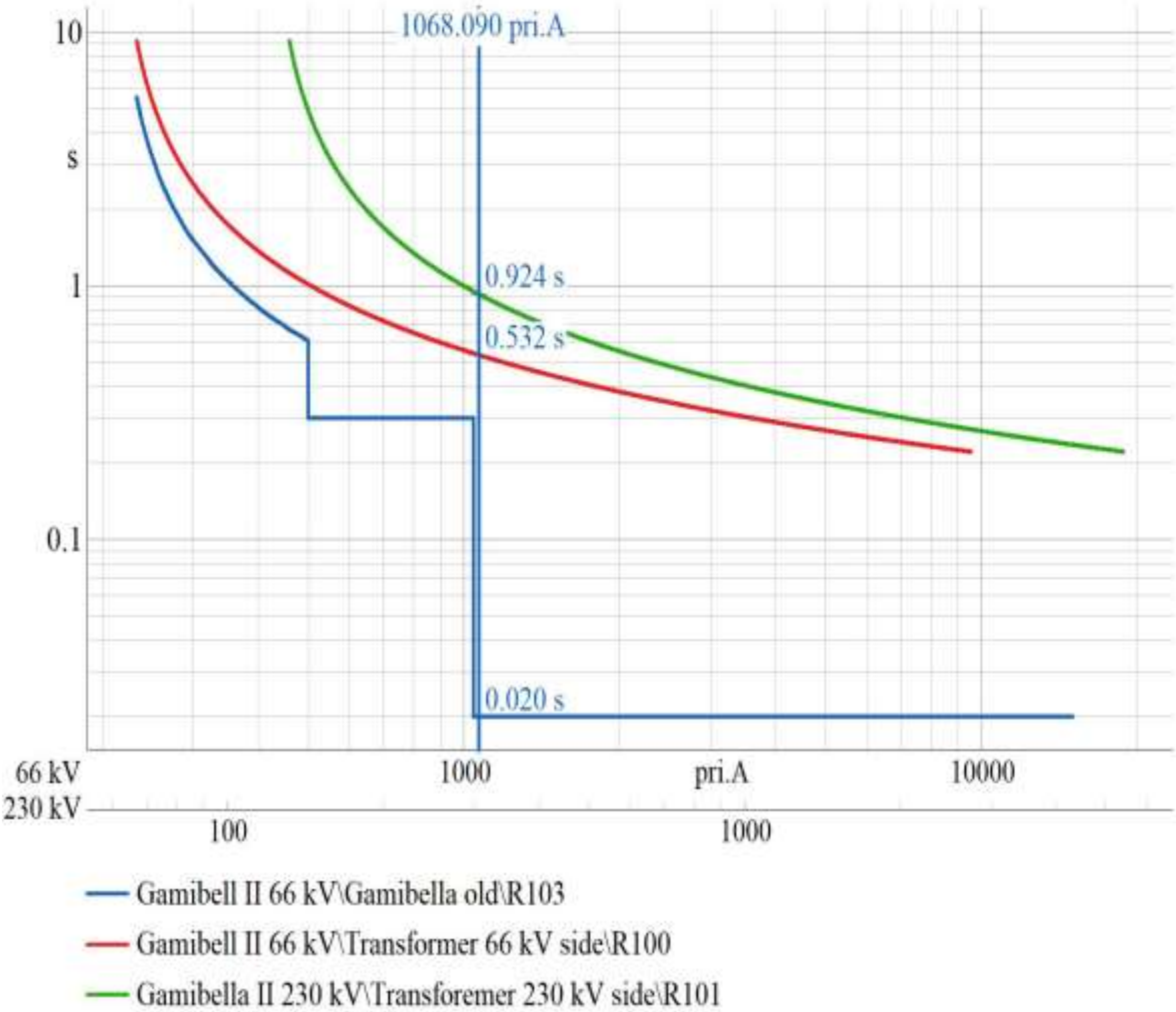

Figure 4.17: Operating time responses for protection R103, R100, and R101 based on the investigated settings for a fault on the 66 kV Gamibella II-Gamibella I line with a short circuit current of 1.068 kA.

Based on relays operating time result presented in Fig 4.17, the line protection relay R103 operated before the transformer high-voltage and low-voltage side protection relays (R100 and R101). Also, the CTI between transformer and line overcurrent protection relays exceed the minimum required interval 0.2 second, which indicted that these relays are coordinated properly. In addition to this, the overall fault current magnitude and corresponding operating time responses for this substation with fault scenario simulated on the distribution feeder, under the given fault current are summarized in Table 4.21 as shown below.

Table 4.21: Cascaded overcurrent protection relays fault current measurement and operating time results based on optimized settings for the fault scenario on Gamibella II Substation distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (A)
66 kV Gamibella-old outgoing line	R103	1068	0.02	1083	0.098
	R100	1068	0.532	1083	0.439
	R99	-	-	1083	0.659
	R101	307	0.925	70	0.448
	R102	-	-	70	0.682
33 kV university outgoing feeder	R94	1865	0.05	258	0.089
	R97	1865	0.328	258	0.303
	R98	-	-	258	0.549
	R101	268	1.299	0	∞
33 kV Guniganig outgoing feeder	R96	1865	0.05	258	0.09
	R97	1865	0.328	258	0.31

Based on relays operating time result presented in Table 4.21, the primary protection relays are operated before the corresponding backup protection relays, with maintaining acceptable CIT between them. This result is verified that the optimized relays setting effectively addresses the coordination problems within this substation.

Case 8: Fault scenario on Metu substation distribution outgoing feeders

The overall substation protection system fault current magnitude and their corresponding operating time responses with the fault scenario on Metu substation distribution feeders are summarized in Table 4.22 as shown below.

Table 4.22: Cascaded overcurrent protection relay fault current readings and optimized operating time response for a fault on the distribution feeders on Metu Substation.

Fault	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
15 kV Metu university outgoing feeder	R119	4907	0.02	196	0.097
	R114	4907	0.289	196	0.326
	R113	-	-	196	0.674
	R109	321	0.62	0	∞
	R110	-	-	0	∞
	R139	376	2.035	0	∞
	R122	376	2.977	0	∞
	R124	656	2.664	0	∞
	R123	-	-	0	∞
15 kV Metu outgoing feeder	R118	4907	0.02	196	0.098
	R114	4907	0.289	196	0.328
15 kV Supi outgoing feeder	R117	4907	0.02	196	0.098
	R114	4907	0.289	196	0.328
33 kV Gobe outgoing feeder	R106	863	0.02	386	0.099
	R107	863	0.268	386	0.38
	R108	444	0.558	0	∞
	R111	444	0.817	0	∞
	R112	-	-	0	∞
	R109	144	3.449	0	∞
	R110	-	-	0	∞
33 kV Masha outgoing feeder	R105	863	0.02	386	0.099
	R107	863	0.268	386	0.38

Based on relays operating time result presented in Table 4.22, the substation protection system operated in the expected order with satisfying minimum CTI between cascaded protection relays. This indicated that the protection systems of Metu Substation, under the optimized settings, are optimally coordinated resulted in faults isolation with maintaining system selectivity.

Case 9: Fault scenario simulated on Bedelle substation outgoing feeders

The overall substation protection system fault current magnitude and corresponding operating time responses, based on optimized settings, for the fault scenario simulated on distribution outgoing feeders, are summarized in Table 4.23 as shown below.

Table 4.23: Fault current magnitude and corresponding operating time results for cascaded overcurrent protection relays of Bedelle substation based on optimized settings, for the fault scenarios on distribution feeders.

Fault	Relay No.	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
Bedelle beer factory, 15 kV feeder	R130	7570	0.02	281	0.054
	R128	7570	0.356	281	0.339
	R127	-	-	281	0.737
	R125	860	0.567	0	∞
Bedelle city, 15 kV feeder	R129	7570	0.02	281	0.098
	R128	7570	0.27	281	0.499
Chora feeder, 15 kV	R131	7570	0.02	281	0.099
	R128	7570	0.34	281	0.51
Dega, 33 kV feeder	R137	2437	0.2	352	0.098
	R135	2437	0.289	352	0.309
	R136	-	-	352	0.514
	R133	613	0.577	0	∞
Kollo-three, 33 kV feeder	R138	2437	0.2	352	0.098
	R135	2437	0.289	352	0.309

Form relays operating time result of above table, the system protection relays are operated in the expected sequence with proper CIT, because the CTI between each pair of consecutive backup and primary relays are greater than 0.2 second. This result verified that the optimized relays setting effectively solve the coordination problems that were discussed previously in section 4.2.

Case 10: Fault scenario on 132 kV transmission lines

The optimized relays setting time-overcurrent characteristic curve and corresponding operating time responses for overcurrent relay R45 and R83, with a short-circuit fault current of 2.77 kA, on 132 kV Jimma I-Bonga transmission line is presented in Figure 4.18.

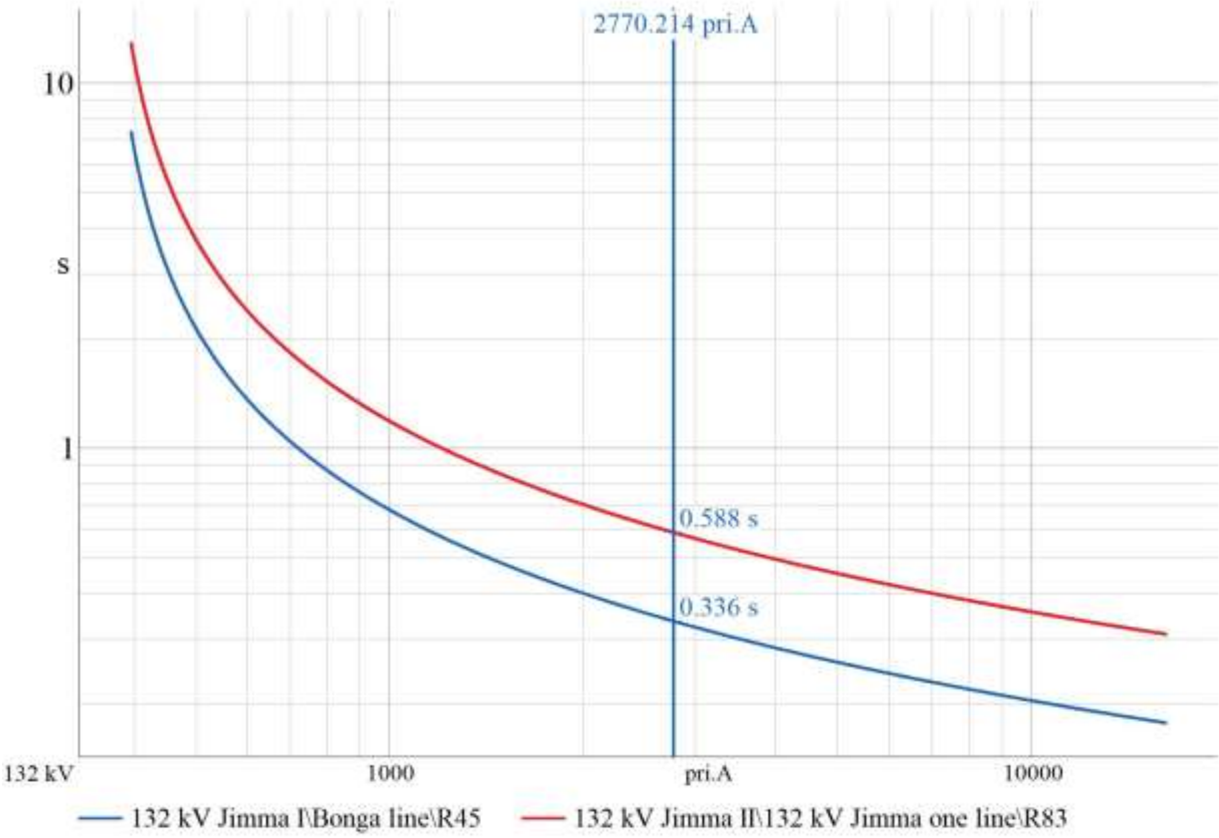

Figure 4.18: Optimized relays setting operating time responses for protection relay R45 and R83 with a fault on 132 kV Jimma I-Bonga transmission line, corresponding to a short-circuit current of 2.77 kA.

According to relays operating time result given in Figure 4.18, the protection relays are operated in the expected sequence with satisfying minimum coordination time requirement, which demonstrated proper coordination. The overall substation protection system fault current measurement and corresponding operating time responses for cascaded overcurrent protection relays with the fault scenario on 132 kV transmission lines are summarized in Table 4.24 as shown below.

Table 4.24: Cascaded overcurrent protection relays fault current measurement and respective operating time responses based on optimized settings, for the fault scenario on 132 kV transmission lines.

Fault	Relay No.	3-Φ fault current (A)	Operating time (s)	$3I_0$ fault current (A)	Operating time (s)
Bonga-Mizan, 132 kV line	R28	1085	0.295	1260	0.277
	R29	1085	0.498	423	0.485
Jimma I-bonga, 132 kV line	R45	2770	0.366	4438	0.29
	R83	2770	0.588	4438	0.747
	R37	-	-	522	0.501
Jimma II-Jimma I, 132 kV line	R83	3299	0.719	9188	0.536
	R80	1649	0.935	395	0.847
	R79	947	0.939	112	1.05
	R81	-	-	283	1.529
Jimma II-Aba, 132 kV line	R84	3242	0.145	8276	0.039
	R80	1621	0.959	352	0.875
	R79	930	0.964	100	1.085
	R81	-	-	252	1.37
	R85	-	-	7444	0.262

Based on the operating time results presented in Table 4.24, the system overcurrent protection relays are operated in the expected sequence, with the CTI between cascaded protection relays were all greater than or equal to 0.2 second, confirmed proper coordination. The operating time results based on optimized settings for primary DOCRs and backup DRs, as well as primary DRs and backup DOCRs under a short-circuit fault scenario at the start and end points of distance protection relay zone II are summarized in Table 4.25.

Table 4.25: Operating time results for primary DOCRs and backup DRs, as well as primary DRs and backup DOCRs, based on optimized relays setting for a given fault location.

Fault	Relay No.	Role of Protection	Operating time (s)
80% from R86	R86	Primary	0.4
	R45	Backup	1.09
120% from R87	R28	Primary	0.318
	R87	Backup	0.56
80% from R87	R87	Primary	0.56
	R83	Backup	0.98
120% from R88	R45	Primary	0.262
	R88	Backup	0.59

According to the relays operating time result presented in Table 4.25, the primary directional overcurrent protection relays operated before backup distance protection relays. Similarly, the primary distance protection relays operated before backup directional overcurrent protection relays. In all cases, the CTI between primary and backup relays are greater than 0.2 second, which confirms that the system protection relays are coordinated optimally based on optimized settings.

Case 11: Fault scenario on 230 kV transmission lines

The optimized relays setting time-overcurrent characteristic curves and their corresponding operating time responses for DOCRs of 230 kV transmission lines, with the fault scenario on Metu-Gamibella II transmission line for a short circuit fault current of 1.738 kA is presented in Figure 4.19 as shown below.

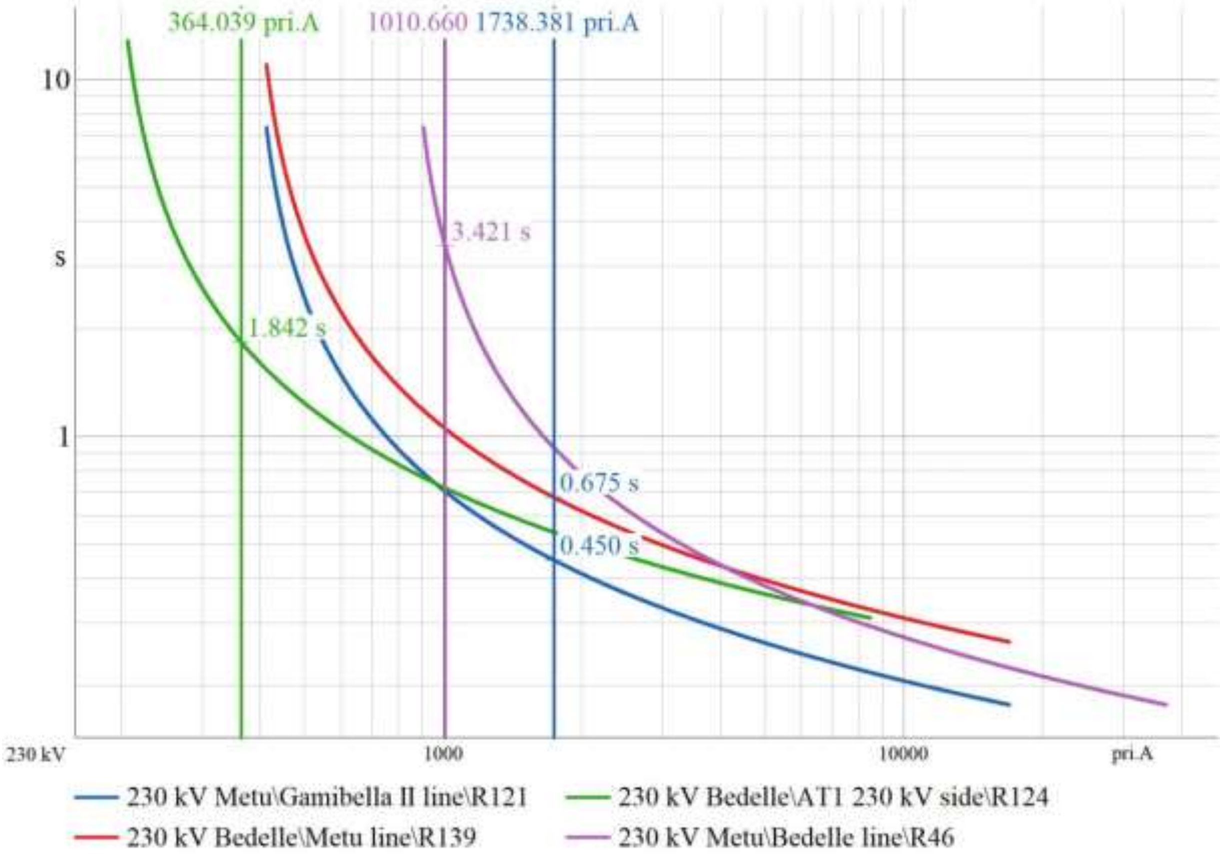

Figure 4.19: Optimized settings time-current characteristics curve and respective operating time results for cascaded OCRs for short-circuit fault current of 1.738 kA on 230 kV Metu-Gamibella line.

According to relays operating time result presented in Figure 4.19, the system overcurrent protection relays are operated in the expected sequence, ensuring correct coordination between backup and primary protection relays. The overall substation protection system fault current measurement and corresponding tripping time for the fault scenario on 230 kV transmission lines are summarized in Table 4.26 as shown below.

Table 4.26: Cascaded overcurrent protection relays operating time responses based optimized settings for the fault scenario on 230 kV transmission lines with a given fault current.

Fault	Relay No.	3-Φ fault current (A)	operating time (s)	$3I_0$ fault current (A)	operating time (s)
Metu-Gamibella II, 230 kV line	R121	1738	0.497	2145	0.415
	R139	1738	0.746	763	0.93
	R46	1011	2.524	239	1.19
Metu-Gamibella II, 230 kV line	R121	1738	0.497	2145	0.415
	R139	1738	0.746	763	0.93
	R124	364	2.195	264	1.115
	R122	634	4.923	459	1.13
	R123	-	-	195	1.38
Bedelle-Metu, 230 kV line	R139	2757	0.581	3002	0.586
	R124	577	0.935	1041	0.819
	R122	1006	1.058	1807	0.798
Bedelle-Metu, 230 kV line	R139	2757	0.581	3002	0.586
	R46	1603	1.048	1358	0.849
Jimma-II to Agaro, 230 kV line	R82	3811	0.587	11425	0.374
	R93	3811	0.912	302	0.878
Jimma II to Agaro, 230 kV line	R70	911	0.214	2990	0.531
	R104	911	0.928	791	0.805
	R124	456	1.259	295	1.199
	R122	794	1.443	512	1.06
Jimma II to GG II, 230 kV line	R90	826	0.55	8714	0.46
	R70	826	0.772	282	1.575
	R104	826	1.1	60	3.38
	R124	413	1.499	22	3.68
Agaro-Bedelle, 230 kV line	R46	2666	0.6	4339	0.523
	R82	2666	0.851	2202	0.738
Bedelle-Agaro, 230 kV line	R104	1155	0.682	2809	0.287
	R124	577	0.929	1046	0.818
	R122	1006	1.051	1817	0.72

According to relays operating time result shown in Table 4.26, the protection system operated in the expected sequence with the CTI between backup and primary protection relays all greater than 0.2 second, confirming proper selectivity. This serve as clear evidence that the protection system, based on optimized settings, are coordinated effectively. The tripping time responses for primary DOCRs and backup DRs, as well as primary DRs and DOCRs, for a specific three phase-fault location are summarized in Table 4.27 as shown below.

Table 4.27: Operating time responses based on investigated optimal settings for distance and DOCRs under a short-circuit fault scenarios on 230 kV lines at specified fault locations.

Fault	Relay No.	Role of Protection	Operating Time (s)
80% from R91	R91	Primary	0.89
	R93	Backup	1.123
120% from R92	R82	Primary	0.643
	R92	Backup	0.87
80% from R142	R142	Primary	0.5
	R139	Backup	0.976
120% from R141	R121	Primary	0.558
	R141	Backup	0.76
80% from R141	R141	Primary	0.76
	R46	Backup	1.014
120% from R145	R139	Primary	0.611
	R145	Backup	0.86
80% from R145	R145	Primary	0.85
	R82	Backup	1.198
120% from R91	R90	Primary	0.664
	R91	Backup	0.89
80% from R144	R144	Primary	0.81
	R104	Backup	1.057
120% from R120	R70	Primary	0.63
	R120	Backup	0.87
80% from R143	R143	Primary	0.97
	R70	Backup	1.231
120% from R144	R90	Primary	0.584
	R144	Backup	0.81

Based on the relays operating time result presented in Table 4.27, the primary directional overcurrent protection relays are operated before backup distance protection relays. Also, the primary distance protection relays are operated before backup directional overcurrent protection relays, as expected. Additionally, the CTI between backup and primary relays are all greater than 0.2 second, confirming proper system relays coordination. Therefore, all system protection relays are optimally coordinated based on optimized setting values.

The optimized setting R-X plot and operating time for distance protection relay R120, corresponding to a short circuit fault at 70% of Bedelle-Agaro transmission line, is illustrated as shown below in Figure 4.20.

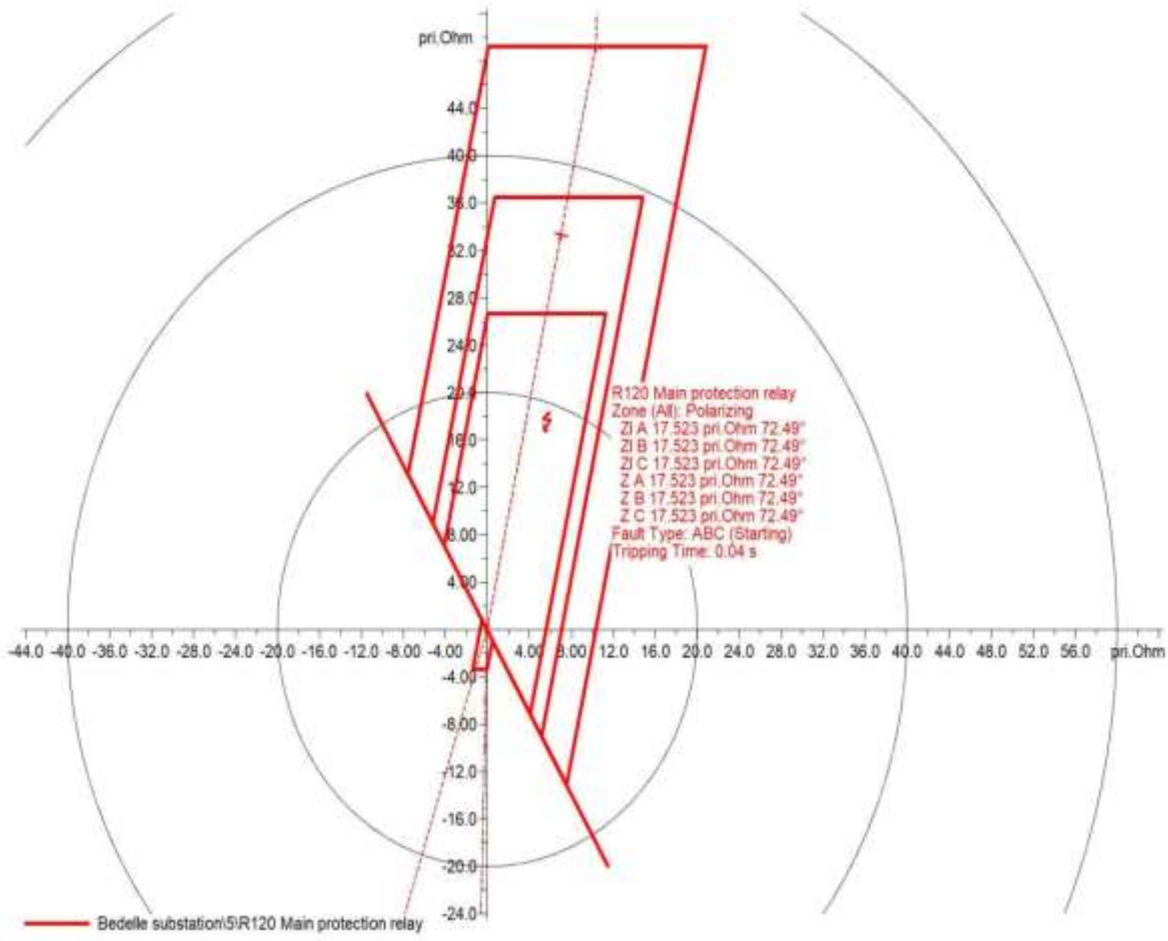

Figure 4.20: R-X plot simulation result of protection relay R120 with optimized setting, for a short circuit fault at 70% of Bedelle-Agaro transmission line.

Generally, the simulation results demonstrated that the protection system based on optimized settings, are coordinated properly.

4.5 Analysis and comparison of simulation results

As observed from simulation result, the protection system based existing setting is not properly coordinated. But, based on optimized setting the protection system is coordinated properly with ensuring acceptable CIT between backup and primary protection relays i.e. the CTI is greater than or equal to 0.2 second. These compared to existing protection relays' setting the optimized setting gives fast fault clearance with improving of selectivity. Also, the existing relays pickup current setting for most system overcurrent protection relays within the network is very sensitive, which may cause for unwanted system interruption, but the determined pickup current setting improves sensitivity.

Chapter 5

Conclusion, Recommendation and Suggestions for Future Work

5.1 Introduction

The study findings are summarized in this section with presenting key conclusions. Also, based on results recommendation is offered for farther improvement. Additionally, outline areas for future works, and highlight challenges encountered throughout this study.

5.2 Conclusions

This thesis presented a comprehensive assessment and mitigation of problems on overcurrent and distance protection relays setting coordination in the EEP Southwest Region transmission system. The study was driven by persistent challenges in the region, such as protection relays operating outside their designated zones and cascade tripping problems that compromises the protection system selectivity and reliability.

The detailed network model was developed using DIgSILENT power factory 2024 SP1 software based on actual system data. Short-circuit simulations revealed several coordination problems between backup and primary protection relays, notably in substation such as Agaro, Jimma I, Jimma II, Mizan, Bedelle etc. These problems were mainly attributed to improper relays operation.

To address the identified problems, PSO algorithm was employed to determine optimal TMS for OCRs and optimal Zone-II operating times for distance protection relays. The optimized relays setting significantly mitigated the protection system coordination problem across the network. Simulation result demonstrated that acceptable CTI between backup and primary protection relays i.e. greater than or equal to 0.2 second.

Key findings of this thesis include:

- The initial improper CTI were corrected to the acceptable standards i.e. 0.2 second.

- The optimized relays setting efficiently minimize the unwanted system interruptions.
- PSO algorithm is an effective and efficient tool in solving protection relays setting coordination problems in power system transmission and distribution network.

Generally, this study provides both methodological framework and practical solution to relays setting coordination problems mitigation within the transmission system. Therefore, findings of this thesis can help EEP to enhance selectivity and reliability of protection system in the Southwest Region and also across the national grid.

5.3 Recommendation

Based on finding of this study, the following points are recommended for power system protection office to improve protection system performance:

- EEP should adopt optimized distance and overcurrent protection relays setting analyzed in this study to ensure proper selectivity and reduce the risk of cascading system outages.
- Institutionalized periodic evaluation of relays setting coordination should be adopt, especially after system expansions or operational changes, to establish continued coordination under new network configuration.
- Modern optimization algorithms, such as PSO, should be incorporated into standard practice for proper setting determination.
- Protection engineers should receive advanced training on simulation tools like DIgSILENT power factory and optimization techniques to build in-house capacity of protection relays coordination analysis and problem mitigation.
- Up-to-date and accurate documentation of system protection relays, transformers, lines, and fault record data should be maintained for all substations to support reliable analysis.
- EEP should establishing standard guideline on relays setting coordination, including recommended CTI, and preferred operating characteristics.
- Similar studies should be conducted on the other regions of EEP transmission network to establish consistent protection performance and reliability across the national grid.

5.4 Future Work

While this study has successfully assessed and mitigate coordination problems on distance and overcurrent protection relays within the EEP Southwest Region transmission system, several opportunities exist for further analysis and development. The following future work is recommended:

- Future research should include coordination analysis for breaker failure, and differential relays to provide comprehensive protection scheme across the network.
- Future studies should explore integration of communication-aided schemes, particularly to enhance high-speed fault detection and clearance, within the transmission network.
- Future studies should explore the uses of real-time SCADA to implement adaptive relay coordination schemes that adjust settings dynamically based on system conditions.
- Optimal setting analysis for distance protection relay zone-3 and zone-4 operating time in the southwestern transmission system of EEP is recommended for further system selectivity improvement, especially for backup protection in remote fault scenario.

5.5 Challenges

One of the main challenges encountered during this study was inconsistent availability of DIgSILENT power factor software license key. This limitation caused in delays of running simulation, model validation, result analysis, particularly during critical phases of the thesis work. Consequently, the restricted access required to adjustments the thesis timeline when the license key becomes available.

Bibliography

[1] T. Gonen, *Electic Power Transmission System Engineering: Analysis and Design*, Second edi. New York: CRC Press, 2015.

[2] R. Mohammed, "RECOMMENDED PROTECTION SCHEME SETTING COORDINATION FOR NINE BUSBARS TRANSMISSION GRID," Tun Hussein Onn Malaysia, Malaysia.

[3] S. A. Bisharathu Beevi A MTech Scholar and A. Professor, "Optimal Coordination of Over Current and Distance Relays," *Int. J. Eng. Res. Technol.*, vol. 3, no. 10,october, pp. 748–753, 2014.

[4] P. N. Korde and P. P. Bedekar, "Determining Optimum Time Multiplier Setting of Overcurrent Relays Using Mixed Integer Linear Programming," *Int. J. Electron. Commun. Eng.*, vol. 15, no. 3, pp. 116–121, 2021.

[5] M. Bagriyanik and A. Ozdemir, "Assessment of Protection Relay Coordination in Turkish National Power Transmission System to Prevent Cascading Events," *Int. Conf. Adv. power Syst. Autom. Prot.*, pp. 1–5, 2009.

[6] Ethiopian Electric power, "https://www.eep.com.et." Accessed: Dec. 23, 2024. [Online]. Available: https://www.eep.com.et/?page_id=781

[7] Y. Damchi, J. Sadeh, and H. R. Mashhadi, "Optimal Coordination of Distance and Directional Overcurrent Relays Considering Different Network Topologies," *Iran. J. Electr. Electron. Eng.*, vol. 11, pp. 231–240, 2015.

[8] "Types of Electrical Protection Relays or Protective Relays," https://www.electrical4u.com/. Accessed: Aug. 06, 2025. [Online]. Available: https://www.electrical4u.com/types-of-electrical-protection-relays-or-protective-relays/

[9] H. Prasetijo and D. T. Nugroho, "Overcurrent relays coordination : comparison characteristics standar inverse, very inverse and extremly inverse," *J. Phys. Conf. Ser.*, vol. 1367, no. 1, 2019, doi: 10.1088/1742-6596/1367/1/012051.

[10] M. Rojnić, R. Prenc, H. Bulat, and D. Franković, "A Comprehensive Assessment of Fundamental Overcurrent Relay Operation Optimization Function and Its Constraints," *Energies*, vol. 15, no. 4, pp. 1–20, 2022, doi: 10.3390/en15041271.

[11] A. Berrachedi, M. Ioualalen, and A. Hammad, "SysML and Petri Nets Based Methodology for Analysis and Performance Evaluation in WSNs," in *International Conference on Simulation and Modeling Methodologies, Technologies and Applications*, Springer, 2021, pp. 106–117.

[12] I. power engineering Society, "IEEE Standards," *IEEE spectrom*, 2003.

[13] A. O. Taiwo, "Transmission line protection using POTT scheme," California State University, Sacramento, 2019.

[14] H. H. El-Tamaly and A.-H. M. El-sayed, "A new technique for setting calculation of digital distance relays," in *2006 Eleventh International Middle East Power Systems Conference*, IEEE, 2006, pp. 135–139.

[15] C. So and T. Hoang, "Line protection for a sampled 230kV power system," MSc Project, Department of Electrical and Electronic Engineering, California State University, Sacramento, 2012.

[16] O. G. Mrehel, H. B. Elfetori, and A. O. Hawa, "Implementation and Evaluation a SIMULINK Model of a Distance Relay in MATLAB / SIMULINK," *Int. Conf. Electr. Electron. Eng. Clean Energy Green Comput. (pp. 132-137). Soc. Digit. Inf. Wirel. Commun.*, pp. 132–137, 2013.

[17] M. Khederzadeh, "Back-up protection of distance relay second zone by directional overcurrent relays with combined curves," *IEEE Power Eng. Soc. Gen. Meet. PES*, pp. 1–6, 2006, doi: 10.1109/pes.2006.1709262.

[18] Technical Manual, "MiCOM P40 Agile P443-TM-EN-3.1," *Gen. Electr.*, 2014.

[19] V. De Andrade and E. Sorrentino, "Typical expected values of the fault resistance in power systems," in *2010 IEEE/PES Transmission and Distribution Conference and Exposition: Latin America, T and D-LA 2010*, 2011, p. 9. doi: 10.1109/TDC-LA.2010.5762944.

[20] DIgSILENT GmbH, "DIGSILENT Power Factory Version 2023 User's Manual".

[21] T. A. A. Almuhsen and A. J. Sultan, "Coordination of Directional overcurrent, Distance, and Breaker failure relays using Genetic Algorithm including pilot protection.," *IOP Conf. Ser. Mater. Sci. Eng.*, vol. 1105, no. 1, p. 15, 2020, doi: 10.1088/1757-899x/1105/1/012001.

[22] A. M. Noor Shah Rizal, "Optimal Coordination of Overcurrent Relay Protection Using Evolutionary Programming," MSc Thesis, Institute of Graduate Studies, Department of Electrical Engineering, Malaya university, 2018.

[23] J. Sadeh, V. Aminotojari, and M. Bashir, "Optimal coordination of overcurrent and

distance relays with hybrid genetic algorithm," *10th Int. Conf. Environ. Electr. Eng. EEEIC.EU 2011 - Conf. Proc.*, p. 5, 2011, doi: 10.1109/EEEIC.2011.5874690.

[24] R. N. Meira, R. L. de Araújo Pereira, and N. S. D. Brito, "A new method for optimal coordination of overcurrent and distance relays," *J. Control. Autom. Electr. Syst.*, vol. 34, no. 4, pp. 858–871, 2023.

[25] C. Guochen, C. Guowei, and W. Haijun, "Problems and solutions in relay setting and coordination," *PROCEEDINGS-CHINESE Soc. Electr. Eng.*, vol. 23, no. 10, pp. 51–56, 2003.

[26] S. Talukder, "Mathematicle modelling and applications of particle swarm optimization," MSc Thesis, Institute of Technology, School of Engineering, Blekinge University, Sweden, 2011.

[27] Z. Zulkarnaini and M. Rizki, "Study of coordination on protection relay in high voltage transmission 150 kV (Payakumbuh - Koto Padang, West Sumatra)," *MATEC Web Conf.*, vol. 215, pp. 1–7, 2018, doi: 10.1051/matecconf/201821501021.

[28] F. G. Luis G.perez, Alberton J.Urdaneta, Elmer Sorrentino, Felipe Garayar, Ales Urizar, Juan C, Ledezma, Gladys de Alcal, Nelson Carrion, Carlos Canache, Jose Fernandez, Oldberg Sanz, "Comarision of time coordination feasibility criteria for a subtransmission system protection scheme," *ADBU J. Eng. Technol.*, vol. 7, no. 2, pp. 314–319, 2018, [Online]. Available: https://journals.dbuniversity.ac.in/ojs/index.php/AJET/article/view/378

[29] A. Shobole, M. Wadi, and M. R. Tur, "Protection coordination in electrical substation part-2 unit protections (differential and distance protection)-case study of Siddik Kardesler Substation (SKS), Istanbul, Turkey," *Gazi Univ. J. Sci.*, 2017.

[30] L. G. Perez *et al.*, "Comparison of time coordination feasibility criteria for a subtransmission system protection scheme," *Proc. IEEE Int. Caracas Conf. Devices, Circuits Syst. ICCDCS*, pp. 314–319, 1998, doi: 10.1109/iccdcs.1998.705856.

[31] S. Jamali and M. Pourtandorost, "New approach to coordination of distance relay zone-2 with overcurrent protection using linear programming methods," *39th Int. Univ. Power Eng. Conf. UPEC 2004 - Conf. Proc.*, vol. 2, p. 5, 2004.

[32] A. A. M. Birjandi and M. Pourfallah, "Optimal coordination of overcurrent and distance relays by a new particle swarm optimization method," *Int. J. Eng. Adv. Technol.*, vol. 1, no. 2, 2011.

[33] M. Farzinfar, M. Jazaeri, and F. Razavi, "A new approach for optimal coordination of distance and directional over-current relays using multiple embedded crossover PSO,"

Int. J. Electr. Power Energy Syst., vol. 61, pp. 620–628, 2014.

[34] Seifu Tedla, "Assessment on protection coordination Case study of Ethiopian Existing Power Network in Addis Ababa region / 132kV Substation," Bahir dar uiversity, 2018.

[35] P. P. B. P.N.Kored, "Determing Optimal Time Multiplier Setting of Overcurrent Relays Using Mixed Integer Linear Progrmmaing," *Int. J. Electron. Commun. Eng.*, vol. 1, pp. 24–29, 2019.

[36] Power systems relay committe, *IEEE Guide for Protective Relay Applications to Power Transformers*. New York, 2000.

[37] S. P. E. C. LTD, "A typical power system network," *6th Compr. Prot. Train. Progr.*.

[38] L. Abualigah, "Particle Swarm Optimization: Advances, Applications, and Experimental Insights," *Comput. Mater. Contin.*, vol. 82, no. 2, pp. 1539–1592, 2025, doi: 10.32604/cmc.2025.060765.

[39] Y. Shi, R. E.-1998 I. international conference on, and undefined 1998, "A modified particle swarm optimizer," *ieeexplore.ieee.orgY Shi, R Eberhart1998 IEEE Int. Conf. Evol. Comput. 1998•ieeexplore.ieee.org*, Accessed: Sep. 20, 2025. [Online]. Available: https://ieeexplore.ieee.org/abstract/document/699146/

[40] M. G. M. Hamami and Z. H. Ismail, "A Systematic Review on Particle Swarm Optimization Towards Target Search in The Swarm Robotics Domain," *Arch. Comput. Methods Eng.*, no. 0123456789, 2022, doi: 10.1007/s11831-022-09819-3.

[41] A. G. Gad, *Particle Swarm Optimization Algorithm and Its Applications: A Systematic Review*, vol. 29, no. 5. Springer Netherlands, 2022. doi: 10.1007/s11831-021-09694-4.

[42] A. Ratnaweera, S. K. Halgamuge, and H. C. Watson, "Self-Organizing Hierarchical Particle Swarm Optimizer With Time-Varying Acceleration Coefficients," *IEEE Trans. Evol. Comput.*, vol. 8, no. 3, pp. 240–255, Jan. 2004, doi: 10.1109/TEVC.2004.826071.

[43] S. Kessentini and D. Barchiesi, "Particle Swarm Optimization with Adaptive Inertia Weight," *Int. J. Mach. Learn. Comput.*, vol. 5, no. 5, pp. 368–373, 2015, doi: 10.7763/ijmlc.2015.v5.535.

Appendix A: Protection Relay Data

Table A. 1: Distance protection relay types and setting data for the system network

Relay No.	Location	Branch	Relay type	CT & VT ratio	Distance element		Operating time (s)
R87	Jimma I SS	Jimma I-Bonga, 132kV line	Micom P442	300/1 A, 132kV/100V	Line length=102.3km	Z1=37.72 Ω	tz1=0
						Z2=66Ω	tz2=0.2
					Line impedance=47.17 Ω	Z3=105.4 Ω	tz3=1
						Z4=9.9434 Ω	tz4=1.5
R92	GG II SS	GG II-Jimma II, 230 kV line	Siprotec 7SA52	800/1 A, 230kV/100V	Line length=67.21km	Z1=6.37 Ω	tz1=0
						Z2=11.52 Ω	tz2=0.4
					Line impedance=7.644 Ω	Z3=17.09 Ω	tz3=1
						Z4=2.52 Ω	tz4=1
R86	Bonga SS	Bonga-Mizan, 132 kV line	Micom p442	150/1 A, 132kV/100V	Line length=88.3 km	Z1=32.56 Ω	tz1=0
						Z2=48.84 Ω	tz2=0.3
					Line impedance=40.7 Ω	Z3=89.53 Ω	tz3=1
						Z4=8.14 Ω	tz4=1.5
R89	Jimma II	Jimma II-Aba, 132 kV line	Micom P442	300/1 A, 132kV/100V	Line length=7.66 km	Z1=2.745 Ω	tz1=0
						Z2=26.57 Ω	tz2=0.4
					Line impedance=3.431 Ω	Z3=27.95 Ω	tz3=0.6
						Z4=0.66 Ω	tz4=1

Relay No.	Location	Branch	Relay type	CT & VT ratio	Distance element		Operating time (s)
R91		Jimma II-Agaro, 230 kV line	P443	800/1 A, 230kV/100V	Line length=38.6 km	Z1=3.427 Ω	tz1=0
						Z2=8.809 Ω	tz2=0.4
					Line impedance=4.284 Ω	Z3=15.6 Ω	tz3=1
						Z4=0.428 Ω	tz4=1
R88		Jimma II-Jimma I, 132 kV line	P442	300/1 A 132kV/100V	Line length=7.66 km	Z1=3.427 Ω	tz1=0
						Z2=8.809 Ω	tz2=0.4
					Line impedance=3.431 Ω	Z3=15.6 Ω	tz3=0.6
						Z4=0.428 Ω	tz4=1
R142	Metu SS	Metu-Gambella, 230 kV	P443	400/1 A, 230kV/100V	Line length=90.4 km	Z1=4.1Ω	tz1=0
						Z2=8.0 Ω	tz2=0.5
					Line impedance=5.18 Ω	Z3=16 Ω	tz3=2.5
						Z4=9 Ω	tz4=2.5
R141	Bedelle SS	Bedell-Metu, 230 kV line	P443	400/1 A, 230kV/100V	Line length=90.4 km	Z1=4.1Ω	tz1=0
						Z2=8.0 Ω	tz2=0.5
					Line impedance=5.18 Ω	Z3=16 Ω	tz3=1
						Z4=1.036 Ω	tz4=1.5

Table A. 2: Protection relays type and their corresponding setting for overcurrent and earth fault protection of transformers.

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	Characteristics	Time setting (s)
R37	50/51	Jimma I SS	132/15 kV transformer, 132 kV	PCS-9611	100/5	I>	6	DT	2
						I>>	24	DT	0.15
						Ie>	0.2	DT	2
						Ie>>	10	DT	0.15
R38	50/51N			Micom P120	100/1	I>	1.2	DT	2
						I>>	6	DT	0.15
R39	50/51N		132/15 kV transformer, 15 kV	PCS-9691E	200/5	Ie>	2.5	DT	2
						Ie>>	5.5	DT	0.15
R35	50/51		132/33/15 kV transformer, 132 kV	Vamp 130	100/1	I>	0.84	SI	0.1
						I>>	0.25	SI	0.1
R36	50/51N					Ie>	0.25	SI	0.35
R34	50/51N		33 kV side	Vamp 130	50/1	Ie>	0.1	DT	1.44
R67	67	Agaro	230/132 kV transformer, 230 kV	Micom P141	150/1	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
					100/1	Ie>	0.15	SI	0.025
						Ie>>	0.3	SI	1
R68	67		230/132 kV transformer, 230 kV	Micom P141	200/1	I>	1	SI	0.025
						I>>	3	DT	1
						Ie>	0.5	SI	0.025
						Ie>>	1.5	DT	1
R58	50/51		132/15 kV transformer, 132 kV	Micom P141	100/5	I>	3.5	SI	0.125
						I>>	10.5	DT	0.05
						Ie>	0.4	SI	0.125
						Ie>>	1.2	DT	0.05
R57	50/51N		132/15 kV transformer, 15 kV	Micom P141	200/1	I>	0.3	DT	0.15
						I>>	0.4	DT	0.05
R65	50/51		132/33/15 transformer 132 kV	Vamp 130	100/1	I>	0.84	SI	0.17
						Ie>	0.21	SI	0.3
R64	50/51N		132/33/15 transformer 33 kV	Vamp 130	100/1	Ie>	0.25	DT	0.46
						Ie>>	0.75	DT	0.3
R66	50/51N		132/33/15 transformer 132 kV	Vamp 130	100/1	Ie>	0.07	DT	0.6
						Ie>>	0.35	DT	0.2

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	Characteristics	Time setting (s)
R27	50/51	Bonga	132/33/15 kV transformer, 132 kV	Micom P122	150/1	I>	0.3	DT	1.5
						I>>	1.5	DT	1
				Micom P120	100/5	Ie>	0.8	DT	2
						Ie>>	1.5	DT	0.5
R25	50/51N		132/33/15 kV transformer, 15 kV	Micom P121	100/5	Ie>	0.3	DT	1
						Ie>>	0.75	DT	0.1
R20	50/51N		132/33/15 kV transformer, 33 kV	Micom P120	200/1	Ie>	0.4	DT	1
						Ie>>	0.75	DT	0.5
R79	67	Jimma II	230/132 kV transformer, 230 kV	Micom P141	300/1	I>	0.63	SI	0.125
						I>>		DT	
						Ie>	0.11	SI	0.125
						Ie>>		DT	
R80	67		230/132 kV transformer, 132 kV	Micom P141	400/1	I>	0.83	SI	0.125
						I>>		DT	
					100/1	Ie>	0.63	SI	0.7
						Ie>>		SI	
R77	67		132/15 kV transformer, 132 kV	Micom P141	200/1	I>	0.66	SI	0.045
						Ie>	0.22	SI	0.045
R76	50/51		132/15 kV transformer, 15 kV	Micom P141	1200/1	Ie>	0.96	SI	0.3
R101	67	Gamibella-II SS	230/66/33 kV transformer, 230 kV	Micom P141	200/1	I>	0.6	SI	0.3
						I>>			
						Ie>	0.1	SI	0.3
						Ie>>			
R102	67N		230/66/33 kV transformer, 230 kV	Micom P141	100/1	Ie>	0.2	SI	0.7
						Ie>>			
R100	67		230/66/33 kV transformer, 66 kV	Micom P141	400/1	I>	1.05	SI	0.125
				Micom P141		Ie>	1	SI	1

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	Characteristics	Time setting (s)
R98	50/51N		230/66/33 kV transformer, 33 kV	Micom P123	100/1	Ie>	0.8	SI	0.25
R108	67	Metu SS	66/33 kV transformer, 66 kV	Micom P127	100/1	I>	0.57	DT	1.5
						I>>	1.65	DT	1.65
						I>>	2.75	DT	2.75
						Ie>	0.5	DT	0.5
						Ie>>	1	DT	1
R109	50/51		230/66/15 kV transformer, 230 kV	Micom P141	200/1	I>	0.7	DT	0.7
						Ie>	0.35	DT	1
R110	50/51N		230/66/15 kV transformer, 230 kV	Micom P125	100/1	Ie>	1.8	DT	1
R111	50/51		230/66/15 kV transformer, 66 kV	Micom m P123	300/1	I>	0.7	DT	2.5
						I>>	1.5	DT	0.25
						Ie>	0.4	DT	2.5
						Ie>>	0.5	DT	0.3
R112	50/51N		230/66/15 kV transformer, 66 kV	Micom P125	100/1	Ie>	1.6	DT	0.5
R113	50/51N		230/66/15 kV transformer, 15kV	Micom P125	100/1	Ie>	1.6	DT	0.5
R126	50/51N	Bedelle SS	132/15 kV, transformer, 132 kV	Micom P125	150/1	Ie>	0.1	SI	0.025
						Ie>	0.5	DT	0.5
R125	50/51			Micom P123	150/1	I>	0.7	SI	0.05
						I>>	2.8	DT	0.2
						Ie>	0.102	SI	0.05
						Ie>>	0.403	DT	0.2
R124	50/51		230/132 kV transformer, 230 kV	Micom P123	400/1	I>	0.44	DT	0.04
						I>>	1.55	DT	0.1
						Ie>	0.08	SI	0.4
						Ie>>	1.5	DT	0.1
R122	50/51		230/132 kV transformer, 132 kV	Micom P123	400/1	I>	0.76	SI	0.2
						I>>	2.5	DT	0.1
						Ie>	0.14	SI	0.4
						Ie>>	2.5	DT	0.1

Table A. 3: Protection relays types and their respective setting data for the distribution feeders, and transmission lines.

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R51	50/51	Aba SS	Tercha, 33 kV feeder	Micom P123	150/1	I>	0.5	DT	0.25
						I>>	1	DT	0.05
						I>>>	1.3	IN	0
						Ie>	0.05	DT	0.05
						Ie>>	0.15	DT	0.02
						Ie>>>	0.3	DT	0
R52	50/51		Isera, 33 kV feeder	Micom P123	150/1	I>	0.5	DT	0.25
						I>>	1	DT	0.05
						I>>>	1.3	IN	0
						Ie>	0.13	DT	0.1
						Ie>>	0.26	DT	0.05
						Ie>>>	0.3	DT	0
R53	50/51		33 kV Chida OG feeder	Micom P123	150/1	I>	0.68	DT	0.25
						I>>	1	DT	0.1
						I>>>	1.3	IN	0
						Ie>	0.05	DT	0.05
						Ie>>	0.1	DT	0.02
						Ie>>>	0.3	DT	0
R50	50/51		132/33 kV transformer, 33 kV	Micom P123	400/5	I>	1.25	DT	0.5
						I>>	2.5	DT	0.1
						Ie>	0.5	DT	0.25
						Ie>>	1	DT	0.1
R40	50/51	Jimma-I SS	132/15 kV transformer, 15 kV	Micom P123	800/1	I>	0.86	SI	0.05
						I>>	3.45	DT	0.1
						Ie>	0.1	SI	0.05
						Ie>>	0.4	DT	0.1
R43	50/51		Old city, 15 kV feeder	Micom P123	400/1	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
						Ie>	0.025	SI	0.025
						Ie>>	0.075	DT	0.01
R31	50/51		Industry, 33 kV feeder	Vamp 245	150/1	I>	0.5	DT	0.5
						I>>	3.6	DT	0.04
						Ie>	0.1	DT	0.245

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R30	50/51		Limu, 33 kV feeder	Vamp 245	75/1	I>	1.2	DT	0.16
						I>>	3.6	DT	0.04
						Ie>	0.14	DT	0.26
						Ie>>	0.4	DT	0.08
R32	50/51		Shebi Sombo, 33 kV feeder	Vamp 245	75/1	I>	0.6	DT	0.24
						I>>	3.6	DT	0.04
						Ie>	0.1	DT	0.1
						Ie>>	0.2	DT	0.08
R33	50/51		132/33/15 kV transformer, 33 kV	Vamp 245	600/1	I>	0.5	DT	1.56
						I>>	1.5	DT	0.56
						Ie>	0.058	DT	1.56
						Ie>>	0.15	DT	1
R35	67		Jimma II, 132 kV line	Micom P123	300/1	I>	1	SI	0.15
						I>>	3	DT	0.1
						Ie>	0.1	SI	0.35
						Ie>>	3	DT	0.1
R45	67		Bonga, 132 kV line	Micom P127	300/1	I>	1	SI	0.15
						I>>	3	DT	0.2
						Ie>	0.1	SI	0.35
						Ie>>	3	DT	0.2
R56	50/51	Agaro SS	132/15 kV transformer, 15 kV	Micom P123	1000/1	I>	0.5	DT	0.25
						I>>	1.5	DT	0.05
						Ie>	0.02	DT	0.12
						Ie>>	0.08	DT	0.03
R55	50/51		Gimbe, 15 kV feeder	Micom P123	400/1	I>	0.8	DT	0.15
						I>>	1.5	DT	0
						Ie>	0.01	DT	0.01
						Ie>>	0.02	DT	0
R54	50/51		Agaro city, 15 kV feeder	Micom P123	400/1	I>	0.8	DT	0.15
						I>>	1.5	DT	0
						Ie>	0.01	DT	0.01
						Ie>>	0.02	DT	0
R60	50/51		Gurude, 33 kV feeder	PCS 9611	75/1	I>	1	DT	1
						I>>	3	DT	0.01
						Ie>	0.05	DT	0.1
						Ie>>	0.1	DT	1

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R62	50/51		Gera, 33 kV feeder	PCS 9611	75/1	I>	1	DT	1
						I>>	3	DT	0.01
						Ie>	0.05	DT	0.1
						Ie>>	0.1	DT	1
R61	50/51		Gatera, 33 kV feeder	PCS 9611	75/1	I>	1	DT	1
						I>>	3	DT	0.01
						Ie>	0.05	DT	0.1
						Ie>>	0.1	DT	1
R63	50/51		132/33/15 kV transformer, 33 kV	Vamp 245	400/1	I>	0.7	DT	1.5
						I>>	3.5	DT	0.04
						Ie>	0.25	DT	0.74
						Ie>>	1.25	DT	0.08
R46	67		Bedelle, 230 kV line	Micom P442	800/1	I>	1.2	SI	0.35
						Ie>	0.2	SI	0.35
R21	50/51	Bonga SS	Chiri, 15 kV feeder	Micom P123	75/1	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
						Ie>	0.1	SI	0.025
						Ie>>	0.2	DT	0.01
R23	50/51	Bonga SS	Wushiweshe, 15 kV feeder	Micom P123	200/1	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
						Ie>	0.1	SI	0.025
						Ie>>	0.2	DT	0.01
R22	50/51	Bonga SS	Bonga city, 15 feeders	Micom P123	150/1	I>	1.2	SI	0.025
						I>>	3.6	DT	0.01
						Ie>	0.07	SI	0.025
						Ie>>	0.3	DT	0.01
R24	50/51	Bonga SS	132/33/15 kV transformer, 15 kV	Micom P123	600/1	I>	0.75	SI	0.075
						I>>	3	DT	0.15
						Ie>	0.07	SI	0.075
						Ie>>	0.28	DT	0.15
R16	50/51	Bonga SS	Meratelo, 33 kV feeder	Micom P123	100/1	I>	0.5	SI	0.075
						I>>	1.5	DT	0.05
						Ie>	0.1	SI	0.025
						Ie>>	0.3	DT	0.05

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R17	50/51		Gimbo, 33 kV feeder	Micom P123	100/1	I>	0.5	SI	0.075
						I>>	1.5	DT	0.05
						Ie>	0.1	SI	0.025
						Ie>>	0.3	DT	0.05
R18	50/51		Bonga university, 33 kV feeder	PCS9611	75/1	I>	1	SI	0.05
						I>>	4	DT	0
						Ie>	0.15	SI	0.05
						Ie>>	0.6	DT	0
R19	50/51		132/33/15 kV transformer, 33 kV	Micom P123	600/1	I>	0.5	SI	0.075
						I>>	2	DT	0.15
						Ie>	0.08	SI	0.075
						Ie>>	0.32	DT	0.15
R29	67		Jimma I, 132 kV line	Micom P127	150/1	I>	1	SI	0.2
						I>>	3	DT	0.2
						Ie>	0.2	SI	0.4
						Ie>>	3	DT	0.2
R28	67		Mizan, 132 kV	Micom P127	150/1	I>	1	SI	0.2
						I>>	3	DT	0.2
						Ie	0.2	SI	0.4
						Ie>>	3	DT	0.2
R84	67	Jimma-II SS	Aba, 132 kV line	Micom P142	300/1	I>	1.2	SI	0.045
						Ie	0.2	SI	0.045
R82	67		Agaro, 230 kV line	Micom P443	800/1	I>	0.5	SI	0.35
						I>>	1.5	DT	0.1
						Ie>	0.1	SI	0.35
						Ie>>	0.2	DT	0.2
R75	50/51		132/15 kV transformer, 15 kV	Sepam S20	1200/1	I>	0.96	SI	0.1
						I>>	1.88	VI	0.3
						Ie>	0.16	SI	0.1
						Ie>>	0.825	VI	0.3
R83	67		Jimma I, 132 kV line	P142	300/1	I>	1.2	SI	0.045
						I>>	3	DT	1
						Ie>	0.15	DT	0.65
R93	67	GG II SS	Jimma II, 230 kV line	7SJ63	800/1	I>	1.2	SI	0.025
						I>>	5.54	DT	0.15
						Ie>	0.12	SI	0.25
						Ie>>	5.5	DT	0.15

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R97	50/51	Gamibella II SS	230/66/33 kV transformer, 33 kV	Sepam S20	400/1	I>	1.05	SI	0.2
						I>>	2	DT	0.1
						I>>>	3.15	DT	0.3
						Ie>	0.05	SI	0.2
						Ie>>	0.4	DT	0.1
						Ie>>>	1.575	DT	0.3
R96	50/51		Guniganig, 33 kV feeder	Sepam S20	100/1	I>	1.2	SI	0.1
						I>>	9	DT	10
						Ie>	0.2	SI	0.1
						Ie>>	9.9	DT	10
R95	50/51		Fugido, 33 kV feeder	Sepam S20	100/1	I>	1.2	SI	0.1
						I>>	8	DT	10
						Ie>	0.2	SI	0.1
						Ie>>	9.9	DT	10
R94	50/51		Gamibella university, 33 kV feeder	Sepam S20	100/1	I>	1.2	SI	0.1
						I>>	8	DT	10
						Ie>	0.2	SI	0.1
						Ie>>	9.9	DT	10
R103	67		Gamibella I, 66 kV line	Micom P141	400/1	I>	0.5	SI	0.1
						I>>	2	DT	0.05
						Ie>	0.09	SI	0.1
						Ie>>	0.5	DT	0.05
R115	50/51	Metu SS	Gore, 15 kV feeder	SPAJ 142 C	150/5	I>	1	DT	0.5
						I>>	2.4	DT	0.05
						Ie>	0.1	DT	0.2
						Ie>>	0.15	DT	0.05
R116	50/51		Yayo, 15 kV feeder	SPAJ 142 C	150/5	I>	1	DT	0.5
						I>>	2.4	DT	0.05
						Ie>	0.1	DT	0.2
						Ie>>	0.15	DT	0.05
R118	50/51		Metu, 15 kV feeder	SPAJ 142 C	150/5	I>	1	DT	0.5
						I>	2.4	DT	0.05
						Ie>	0.1	DT	0.2
						Ie>>	0.15	DT	0.05

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R119	50/51		Metu university, 15 kV feeder	PCS9611	150/1	I>	1	SI	0.05
						I>>	2.25	DT	0
						Ie>	0.15	SI	0.05
						Ie>>	0.25	DT	0
R114	50/51		230/66/15 kV transformer, 15 kV	Micom P126	1200/1	I>	0.7	DT	2
						I>>	1.4	DT	0.25
						I>>>	2.8	DT	0.15
						Ie>	0.05	DT	0.5
						Ie>>	0.4	DT	0.05
R105	50/51		Masha, 33 kV feeder	PCS9611	75/1	I>	0.7	SI	0.05
						I>>	1	DT	0
						Ie>	0.15	SI	0.05
						Ie>>	0.3	DT	0
R106	50/51		Gobe, 33 kV feeder	PCS9611	75/1	I>	0.7	SI	0.05
						I>>	1	DT	0
						Ie>	0.15	SI	0.05
						Ie>>	0.3	DT	0
R107	50/51		66/33 kV transformer, 33 kV	Micom P127	150/1	I>	0.3	SI	0.15
						I>>	0.5	DT	0
						Ie>	0.15	SI	0.15
						Ie>>	0.5	DT	0
R121	67		Gamibella, 230 kV line	Micom P442	800/1	I>	1.2	SI	0.35
						I>>			
						Ie>	0.2	DT	0.375
						Ie>>			
R128	50/51	Bedelle SS	132/15 kV transformer, 15 kV	Micom P123	600/5	I>	0.9	DT	1.1
						I>>	2	DT	0.3
						Ie>	0.05	DT	1.1
						Ie>>	0.1	DT	0.3
R130	50/51		Beer, 15 kV feeder	Micom P123	200/5	I>	0.38	DT	0.8
						I>>	2	DT	0.1
						Ie>	0.025	DT	0.8
						Ie>>	0.05	DT	0.1
R129	50/51		Bedelle city, 15 kV feeder	Micom P123	400/5	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
						Ie>	0.025	SI	0.025
						Ie>>	0.075	DT	0.01

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R132	50/51		Gechi, 15 kV feeder	Micom P123	200/5	I>	1	DT	0.35
						I>>	2	DT	0.1
						Ie>	0.025	DT	0.1
						Ie>>	0.05	DT	0.01
R131	50/51		Chora, 15 kV feeder	Micom P123	400/5	I>	0.2	SI	0.8
						I>>	2	DT	0.1
						Ie>	0.025	DT	0.8
						Ie>>	0.05	DT	0.1
R135	50/51		132/33 kV transformer, 33 kV	SPAJ 142 C	300/1	I>	1	DT	1
						I>>	1.2	DT	0.15
						Ie>	0.2	DT	1
						Ie>>	0.4	DT	0.15
R137	50/51		Kollo-three, 33 kV	Micom P123	100/1	I>	0.25	DT	0.25
						I>>	0.5	DT	0.01
						Ie>	0.05	DT	1
						Ie>>	0.1	DT	0.01
R139	50/51		15 kV Metu, 230 kV line	Micom P442	400/1	I>	0.4	DT	0.15
						I>>	1	DT	0.15
						Ie>	0.1	DT	0.3
						Ie>>	1	DT	0.15
R3	50/51	Mizan SS	66/15 kV transformer, 15 kV	Micom P123	300/1	I>	0.9	SI	0.1
						I>>	1	DT	0.2
						Ie>	0.2	DT	0.04
						Ie>>	0.4	DT	0.2
R1	50/51		Mizan, city 15 kV feeder	Micom P123	200/5	I>	1.15	SI	0.025
						I>>	3	DT	0.01
						Ie>	0.1	SI	0.025
						Ie>>	0.15	DT	0
R2	50/51		Sheko, 15 kV feeder	Micom P123	75/1	I>	0.5	SI	0.025
						I>>	1.5	DT	0.01
						Ie>	0.1	SI	0.025
						Ie>>	0.3	DT	0
R14	50/51		132/66/33 kV transformer, 33 kV	Micom P123	600/1	I>	0.3	SI	0.1
						I>	0.6	DT	0.09
						Ie>	0.1	DT	1.5
						Ie>>	0.32	DT	0.01

Relay No.	ANSI code	Location	Branch	Relay type	CT ratio (A)	Stage	Current setting (A)	characteristics	Operating Time (s)
R12	50/51		Dimma, 33 kV feeder	Micom P123	100/1	I>	0.5	SI	0.05
						I>>	1.5	DT	0.06
						Ie>	0.1	DT	0.5
						Ie>	0.3	DT	0.05
R13	50/51		Chena, 33 kV feeder	Micom P123	100/1	I>	0.5	SI	0.05
						I>>	1.01	DT	0.06
						Ie>	0.1	DT	0.6
						Ie>>	0.2	DT	0

Appendix B: Particle Swarm Optimization Algorithm

Objective function of PSO algorithm

```
function [OF] = objective_functions(TMS)
%Variable Assignment
TMSr54=TMS(1);TMSr55=TMS(2);
TMSr56=TMS(3);TMSr58=TMS(4);
TMSr60=TMS(5);TMSr61=TMS(6);
TMSr62=TMS(7);TMSr63=TMS(8);
TMSr65=TMS(9);
% Parameter Constants
PSMm54=5373/480;PSMb54=5373/920;
PSMm55=5373/480;PSMb55=5373/920;
PSMm56=5373/920;PSMb56=611/105;
PSMm58=611/105;
PSMm60=1892/90;PSMb60=1892/336;
PSMm61=1892/90;PSMb61=1892/336;
PSMm62=1892/90;PSMb62=1892/336;
PSMm63=1892/336;PSMb63=473/84;
PSMm65=473/84;
%Operating Time Calculation
top=[];
top(1)=(TMSr54*0.14)/(PSMm54^0.02-1);top(2)=(TMSr55*0.14)/(PSMm55^0.02-1);
top(3)=(TMSr56*0.14)/(PSMm56^0.02-1);top(4)=(TMSr58*0.14)/(PSMm58^0.02-1);
top(5)=(TMSr60*0.14)/(PSMm60^0.02-1);top(6)=(TMSr61*0.14)/(PSMm61^0.02-1);
top(7)=(TMSr62*0.14)/(PSMm62^0.02-1);top(8)=(TMSr63*0.14)/(PSMm63^0.02-1);
top(9)=(TMSr65*0.14)/(PSMm65^0.02-1);
% Constraints
v=[];
v(1)=(TMSr56*0.14)/(PSMb54^0.02-1)-((TMSr54*0.14)/(PSMm54^0.02-1));
v(2)=(TMSr56*0.14)/(PSMb55^0.02-1)-((TMSr55*0.14)/(PSMm55^0.02-1));
v(3)=(TMSr58*0.14)/(PSMb56^0.02-1)-((TMSr56*0.14)/(PSMm56^0.02-1));
v(4)=(TMSr63*0.14)/(PSMb60^0.02-1)-((TMSr60*0.14)/(PSMm60^0.02-1));
v(5)=(TMSr63*0.14)/(PSMb61^0.02-1)-((TMSr61*0.14)/(PSMm61^0.02-1));
v(6)=(TMSr63*0.14)/(PSMb62^0.02-1)-((TMSr62*0.14)/(PSMm62^0.02-1));
v(7)=(TMSr65*0.14)/(PSMb63^0.02-1)-((TMSr63*0.14)/(PSMm63^0.02-1));
%Penalty for Constraints
for L=1:7;
    if v(L)<0.2
        y(L)=1;
    else
        y(L)=0;
    end
end
%Objective Function
OF= sum(top)+10000*sum(y);
End
```

Main PSO algorithm

```
clearvars
clc
clearvars
close all
% Problem setup
```

```
LB=[0.025,0.025,0.025,0.025,0.05,0.05,0.05,0.05,0.05];
UB=[1.5,1.5,1.5,1.2,100,100,100,4.2,3.2];
m = 9;               % Number of decision variables
n = 4000;            % Number of particles
Maxiter = 500;       % Maximum number of iterations
% Inertia weight bounds
w_max = 0.9;
w_min = 0.4;
% Cognitive and social coefficient bounds
c1_start = 2.5;    % strong self-confidence
c1_end   = 0.5;    % rely less on self
c2_start = 0.5;    % not much social learning
c2_end   = 2.5;    % learn more from others
% Initialize positions and velocities
pos = zeros(n, m);
vel = zeros(n, m);
% Particle Initialization
    for i=1:n
        for j=1:m;
       pos(i,j)=round(LB(1,j)+rand()*(UB(1,j)-LB(1,j)),3);
        end
    end
% Evaluate initial fitness
z = zeros(n,1);
% Fitness Evaluation
for i=1:n
z(i,1)=objective_functions(pos(i,:));
end
pbest_val=z;
 pbest=pos;
[fminval,ind]=min(z);
gbest=pbest(ind,:);
iter=1;
% Main PSO loop
while iter<=maxiter
   % === Adaptive parameters ===
    w = w_max - ((w_max - w_min) * iter / maxiter);
    c1 = c1_start - ((c1_start - c1_end) * iter / maxiter);
    c2 = c2_start + ((c2_end - c2_start) * iter / maxiter);
  for i=1:n
      % Update personal best
  if z(i,1)<=pbest_val(i,1);
    pbest(i,:)=pos(i,:);
    pbest_val(i,1)=z(i,1);
  end
  end
   % Update global best
[fbestval,ind1]=min(pbest_val);
if fbestval<=fminval
  fminval=fbestval;
  best_values(iter) = fminval;
  gbest=pbest(ind1,:);
end
%update velocities and positions
   for i=1:n
       for j=1:m;
       vel(i,j)= round(w*vel(i,j)+c1*rand()*(pbest(i,j)-
pos(i,j))+c2*rand()*(gbest(1,j)-pos(i,j)),3);
       pos(i,j)=vel(i,j)+pos(i,j);
       %boundary handling
       if pos(i,j)<LB(j)
```

```
            pos(i,j)=LB(1,j);
        elseif pos(i,j)> UB(j)
                pos(i,j)=UB(1,j);
        end
        end
        % Evaluate new position
        z(i,1)=objective_functions(pos(i,:));
    end
    % Progress Display
    disp(['iteration:',num2str(iter)]);
    disp(['best objectve function value:',num2str(fminval)]);
    disp(['best position:', num2str(gbest)]);
    iter=iter+1;
end
 plot(1:maxiter,  best_values);
xlabel('Iteration'); ylabel('Best Objective function value'); title('PSO
Convergence')
```

Appendix C: Optimal Protection Relays Setting

Table C.1: Directional and non-directional overcurrent protection relay optimal setting data.

Relay No.	Stage	Current setting (A)	Time setting (s)	Characteristic
R1	I>	240	0.025	IEC SI
	I>>	720	0.1	DT
	I>>	1200	0	DT
R2	I>	90	0.025	IEC SI
	I>>	270	0.1	DT
	I>>	450	0	DT
R3	I>	291	0.07	IEC SI
R5	I>	66	0.126	IEC SI
R7	I>	120	0.1	IEC SI
	I>>	360	0.1	DT
	I>>>	600	0	DT
R8	I>	240	0.075	IEC SI
R10	I>	131	0.08	IEC SI
R12	I>	120	0.025	IEC SI
	I>>	360	0.1	DT
	I>>	600	0	DT
R13	I>	120	0.025	IEC SI
	I>>	360	0.1	DT
	I>>	600	0	DT
R14	I>	252	0.056	IEC SI
R16	I>	120	0.025	IEC SI
	I>>>	600	0	DT
R17	I>	120	0.025	IEC SI
	I>>	500	0	DT
R18	I>	120	0.025	IEC SI
	I>>	600	0	DT
R19	I>	522	0.042	IEC SI
R21	I>	90	0.025	IEC SI
	I>>	270	0.1	DT
	I>>>	450	0	DT
R22	I>	180	0.025	IEC SI
	I>>	540	0.1	DT
	I>>>	900	0	DT
R23	I>	240	0.025	IEC SI
	I>>	720	0.1	DT
	I>>>	1200	0	DT

Relay No.	Stage	Current setting (A)	Time setting (s)	Characteristic
R24	I>	552	0.041	IEC SI
R26	I>	130.5	0.083	IEC SI
R28	I>	180	0.075	IEC SI
R29	I>	180	0.125	IEC SI
R30	I>	90	0.05	IEC SI
	I>>	540	0.1	DT
	I>>>	900	0.04	DT
R31	I>	90	0.05	IEC SI
	I>>	540	0.1	DT
	I>>>	900	0.04	DT
R32	I>	90	0.05	IEC SI
	I>>	540	0.1	DT
	I>>>	900	0.04	DT
R33	I>	336	0.071	IEC SI
R35	I>	84	0.157	IEC SI
	I>>	400	0.5	DT
R37	I>	105	0.132	IEC SI
R40	I>	920	0.068	IEC SI
R41	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R42	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R43	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R44	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R45	I>	360	0.1	IEC SI
R46	I>	826	0.1	IEC SI
R47	I>	132	0.092	IEC SI
R50	I>	480	0.08	IEC SI
R51	I>	90	0.025	IEC SI
	I>>	300	0.1	DT
	I>>>	900	0	DT
R52	I>	90	0.025	IEC SI
	I>>	300	0.1	DT
	I>>>	900	0	DT
R53	I>	90	0.025	IEC SI
	I>>	300	0.1	DT
	I>>>	900	0	DT

Relay No.	Stage	Current setting (A)	Time setting (s)	Characteristic
R54	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R55	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R56	I>	920	0.068	IEC SI
R58	I>	105	0.125	IEC SI
R60	I>	90	0.05	IEC SI
	I>>	270	0.2	DT
	I>>>	450	0	DT
R61	I>	90	0.05	IEC SI
	I>>	270	0.2	DT
	I>>>	450	0	DT
R62	I>	90A	0.05	IEC SI
	I>>	270	0.2	DT
	I>>>	450	0	DT
R63	I>	336	0.075	IEC SI
R65	I>	84	0.15	IEC SI
R67	I>	188	0.125	IEC SI
R68	I>	240	0.115	IEC SI
R70	I>	376	0.035	IEC SI
R71	I>	480	0.04	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R72	I>	480	0.04	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R73	I>	480	0.04	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R74	I>	480	0.04	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R75	I>	1152	0.08	IEC SI
R77	I>	132	0.145	IEC SI
R79	I>	189	0.35	IEC SI
R80	I>	332	0.32	IEC SI
R82	I>	826	0.14	IEC SI
R83	I>	360	0.185	IEC SI
R84	I>	360	0.045	IEC SI
R90	I>	376	0.03	IEC SI
R93	I>	826	0.195	IEC SI

Relay No.	Stage	Current setting (A)	Time setting (s)	Characteristic
R94	I>	120	0.04	IEC SI
	I>>	360	0.2	DT
	I>>>	600	0	DT
R95	I>	120	0.04	IEC SI
	I>>	360	0.2	DT
	I>>>	600	0	DT
R96	I>	120	0.04	IEC SI
	I>>	360	0.2	DT
	I>>>	600	0	DT
R97	I>	420	0.06	IEC SI
R100	I>	212	0.195	IEC SI
R101	I>	120	0.15	IEC SI
R103	I>	212	0.075	IEC SI
	I>>	500	0.34	DT
	I>>>	1040	0.00	DT
R104	I>	376	0.05	IEC SI
105	I>	90	0.05	IEC SI
	I>>	270	0.2	DT
	I>>>	450	0	DT
R106	I>	90	0.05	IEC SI
	I>>	270	0.2	DT
	I>>>	450	0	DT
R107	I>	132	0.075	IEC SI
R108	I>	66	0.175	IEC SI
R109	I>	120	0.09	IEC SI
R111	I>	210	0.088	IEC SI
R114	I>	924	0.079	IEC SI
R115	I>	120	0.05	IEC SI
	I>>	360	0.2	DT
	I>>>	600	0	DT
R116	I>	180	0.05	IEC SI
	I>>	540	0.2	DT
	I>>>	900	0	DT
R117	I>	120A	0.05	IEC SI
	I>>	360	0.2	DT
	I>>>	600	0	DT
R118	I>	240	0.05	IEC SI
	I>>	720	0.2	DT
	I>>>	1200	0	DT
R119	I>	180	0.05	IEC SI
	I>>	540	0.2	DT
	I>>>	900	0	DT
R121	I>	376	0.1	IEC SI
R122	I>	332	0.175	IEC SI
R124	I>	188	0.175	IEC SI

Relay No.	Stage	Current setting (A)	Time setting (s)	Characteristic
R125	I>	91	0.135	IEC SI
R128	I>	720	0.085	IEC SI
R129	I>	480	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R130	I>	120	0.025	IEC SI
	I>>	1440	0.2	DT
	I>>>	2400	0	DT
R131	I>	120	0.025	IEC SI
	I>>	1440	0.1	DT
	I>>>	2400	0	DT
R132	I>	480	0.025	IEC SI
	I>>	1440	0.2	DT
	I>>>	2400	0	DT
R133	I>	105	0.148	IEC SI
R135	I>	360	0.094	IEC SI
	I>>	1080	0.36	DT
R137	I>	120	0.05	IEC SI
	I>>	360	0.1	DT
	I>>>	600	0	DT
R138	I>	120	0.05	IEC SI
	I>>	360	0.1	DT
	I>>>	600	0	DT
R139	I>	376	0.15	IEC SI

Table C. 2: Distance protection relay second zone operating time optimal setting

Relay No.	Protected Transmission line	Second zone operating time(s)	Relay type
R141	230 kV Bedelle to Metu SS	0.76	Micom P442
R142	230 kV Metu to Gamibella II SS	0.5	Micom P442
R143	230 kV Jimma II to GG II SS	0.8	Micom P443
R144	230 kV Agro to Jimma II SS	0.81	Micom P443
R145	230 kV Agaro to Bedelle SS	0.86	Micom P443
R120	230 kV Bedelle to Agro SS	0.87	Micom P443
R91	230 kV Jimma II to Agaro SS	0.4	Micom P443
R92	230 kV GG II to Jimma II SS	0.86	SIPROTEC 7SA52
R86	132 kV Bonga to Mizan SS	0.45	Micom P442
R87	132 kV Jimma I to Bonga SS	0.55	Micom P442
R88	132 kV Jimma II to Jimma I SS	0.54	Micom P442
R89	132 kV Jimma II to Aba SS	0.35	Micom P442