



**HAWASSA UNIVERSITY**

**INSTITUTE OF TECHNOLOGY**

**SCHOOL OF ELECTRICAL AND COMPUTER ENGINEERING**

**OPTIMAL CO-ORDINATION SYSTEM FOR OVER CURRENT, & EARTH FAULT  
PROTECTION RELAYS IN SEBETA-I SUBSTATION BY USING WHALE  
OPTIMIZATION ALGORITHM**

A Thesis Submitted in

Partial Fulfillment of The Requirements For The Degree of Master Of  
Science in Power System and Energy Engineering

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Hawassa, Ethiopia

March, 2024



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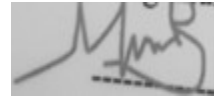
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## DECLARATION


I hereby declare that this thesis is submitted for the master of Electrical Power Engineering to the Department of Electrical Engineering, Hawassa University Institute of Technology. Apart from not helping recognize it, it is his own work, and he has presented for a degree at any other university for the same degree award. In addition, all sources of materials and researcher used in this thesis have been fully acknowledged. This is to certify that the statement made above by the candidate is true to the best of my knowledge.

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## ABSTRACT

Protection and coordination of substation system networks is one of the most substantial issues in power systems. Over-current, earth fault relays, and differential protection are the systems' most commonly used protective relays. The coordination of inverse time over-current relays is formulated as a linear programming problem. The optimization technique aims to minimize the relays' time dial settings (TDS). The settings for this type of relay can be categorized into two current and time settings. The most significant variable in the optimal coordination of over-current relays is the time multiplier setting (TMS). Protective relays are essential devices for electrical power protection systems. The choice of protection devices depends on the type and rating of the protected equipment. The primary function of the relay is to clear fault current flowing through the system at faults that have occurred in the protective line. This thesis focuses on optimal over-current, earth fault, and differential protection coordination schemes for the Sebeta-1 substations. The voltage level of this substation is 132KV, and it has eight low-voltage outgoing lines, two incoming feeders, two incoming power transformers, and two 132KV incoming lines. This substation system network is one of the oldest and most important substation system networks in Ethiopia's electric power Addis Ababa region, and also the maximum load of the city is connected from this substation. However, their coordination is not properly coordinated, and networks based on this improper coordination, interruption of power is frequently a phenomenon in the network. The main reasons are the system is saturated, the network system is old, there is a short circuit current, an earth fault, overloading, and also improper coordination and protection of the distribution network. When faults occur in one line, they create a high over-current. Due to the higher load, more of the network lines are out of service due to faults in some parts of the network. Clearly, in this case, the number of interrupted customers rises, and accordingly, the power quality decays. From analyzing the obtained results, it has been found that the whale optimization technique provides the most globally optimum solutions at a faster convergence speed. This algorithm finds the best solutions out of all optimization solutions. Using MATLAB programming gets the best optimization results.

**Keywords:** inverse time over-current relay, whales optimizer, Meta-heuristic technique, optimal coordination, Power system protection, Time dial settings.

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## NOMANCLATURE

PSM	Plug Setting Multiplier
GA	Genetic Algorithm
CT	Current Transformer
CTI	Coordination Time Interval
EEP	Ethiopian Electric Power
ETAP	Electrical Transient Analysis Program
MATLAB	Matrix Laboratory
IDMT	Inverse definite minimum time
LP	Linear Programming
$I_p$	pickup current
$I_f$	Fault Current
KV	kilo volt
WOA	Whales optimization Algorithm
TMS	Time Multiplier Setting
IEC	International electro technical Commission
$T_b$	Backup relay operating time
TP	Primary relay operating

## CHAPTER ONE

### INTRODUCTION

The choice of protection devices depends on the type and rating of the protected equipment. The primary function of the relay is to clear fault current flowing through the system if a fault has occurred in the protective line. A protective relay receives the signal from instrument transformers, analyzes and compares the data from the preset value, and when the value is above the threshold value, sends a tripping command to the circuit breaker and clears the fault. Based on this fault clearing function, all relays in the power system needed coordination and optimal setting for efficient fault clearance. Sebeta-1 substation is one of the most and the oldest substation networks in Addis Ababa city, Ethiopia, but their coordination is not properly coordinated. Based on this improper coordination, many power transformers are out of service due to faults, mainly circuit breaker damage and also the electrical system control burn. So they cannot isolate the fault but operate manually; the operators cannot open and close remotely. That's why the main distribution transformers are easily damaged. In addition to this, when a power interruption or fault is occurring in Sebeta-1, then two or more lines of interruption are frequently a phenomenon in that region. That means one transformer is out of service. The main reason that has happened is the improper coordination and protection of the substation network. That's why protection and coordination of substation system networks is one of the important issues in power systems. Overcurrent, earth fault, and differential protection relays are some of the most commonly used protective relays in these systems. The settings can be categorized into two for this type of relay: current and time settings. Transformer differential protection is the main protection for internal faults and short circuit current. This function acts as high-speed selective short-circuit protection. The differential protection principle is based on a current comparison of the two CTS. In normal operation and for external faults, the sum of currents entering and leaving the protection zone/area is expected to be zero. This consideration applies strictly to the primary current values in the high-voltage switching station. In contrast, the through-current transformer transformed secondary currents passed contain measuring errors.

Consequently, even in a healthy operation, the sum of the currents processed in the devices is not exactly zero. The differential protection tripping characteristic is designed to provide stability against current proportional errors, which may result from transformation errors of the current transformers, tap changer influences, or differential current caused by current transformer saturation in the case of through-fault conditions.

The characteristic branch “*a*” represents the sensitivity threshold of the differential protection (parameter Threshold  $I_{diff}$ ) and considers constant fault currents like magnetizing currents. Branch “*b*” (parameter Slope 1) considers current-proportional errors, which may result from transformation errors of the main current transformers, the device input current transformer, or the influence of tap changers. For high currents, which may give rise to current transformer saturation, the characteristic branch “*c*” (parameter Slope 2) provides for additional restraint. A proper relay setting plays a crucial role in reducing undesired effects of faults on the power distribution systems. For a relay configuration of an outgoing line, PS can be described by two variables: the minimum fault current and the maximum load current. However, the most important variable in the optimal coordination of overcurrent relays is the time multiplier setting (TMS). Protective relays are essential devices for electrical power protection systems. In real practice, every electrical power system can't leave without protection. Sebeta-1 can receive power from 6 different substation networks, such as Sebeta-II, Mekanissa, Sululta, Addis West, Kality One, and Shegole. And deliver to Sebeta city and Sebeta one industry.

Sebeta one substation has a 230/132KV voltage level. This power comes from Sebeta-II substation 230/132 KV 125MVA, from Sululta 230/132 KV 125MVA, from Shegole 230/132 KV 125 MVA, from Mekanissa 132/15 KV 50 MVA, and from Kality One 132/15 KV 50 MVA power transformers. All 15kV outgoing lines deliver power to Sebeta-1 city. There are 15 outgoing lines and three incoming feeders, but 15 outgoing lines are too big for this thesis, so I initiated only 8 outgoing lines, two incoming feeders, two power transformers, and two incoming lines. The all the feeders of 15 kV and the transmission lines of 132 kV are protected by overcurrent, earth fault, and differential protection relay as primary protection. Its aim is to get the optimal protection setting and then minimize the system disturbance time of the power supply.

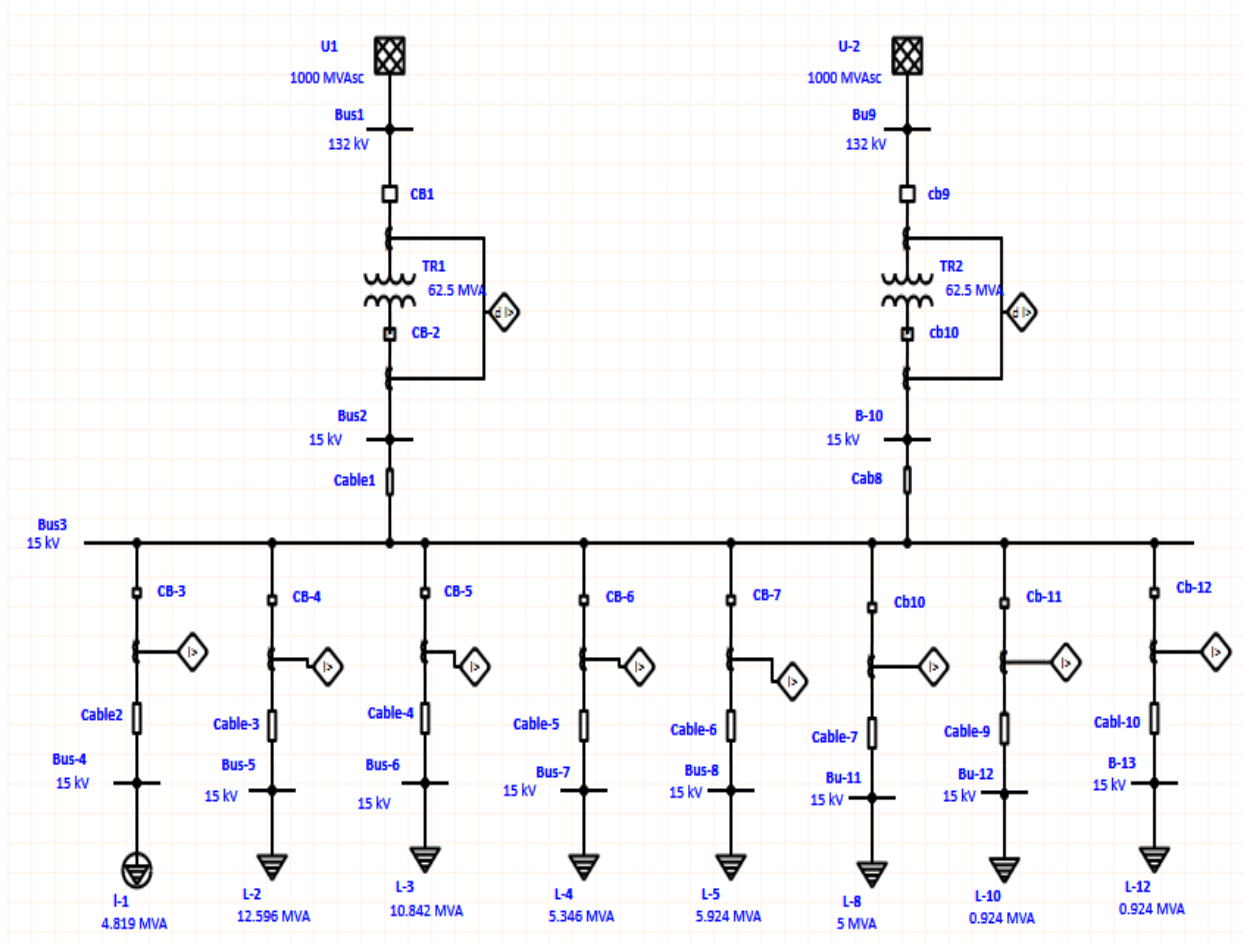


Figure1. 1Sebeta one substation single line diagram

The substation system operation is that the 132KV voltage is stepped down to 15kV by a step-down power transformer. There are 8 outgoing lines; each line has its own protection system. The demand for electrical power is generally increased from time to time at a faster rate, like in Ethiopian countries. So the requirement of power system equipment like power transformers, conductors of transmission lines, distribution lines, and also protective devices like relays, circuit breakers, and fuses is increased. Protective relays are essential devices for electrical power protection systems. In real practice, electrical power systems cannot live without protection.

## 1.2 Statement of the Problem

The substation protection system is an essential issue for all power systems, especially for the Sebeta-1 substation, because this substation is a very critical & old substation. That means 40% of the city load is connected to this substation. The substation is directly connected to a distribution network, increasing the protective equipment's operational frequency of the protective equipment, and it is very high compared with other power systems. However, relay coordination needs to be configured properly. This problem has occurred in ordinary in that substation. EEP, has no responsible department for protection systems; it is the cause of improper protection coordination systems within power systems from outgoing feeders to generation. EEP can supply a relay and assemble the micom digital relay and other electro-mechanical relays for the Sebeta-1 substation, but the protection coordination of all relays for both microprocessor relay and the electro-mechanical relay has set the same setting topology. This is one of the issues in that substation; b/c the CTI coordination is different from the two relays. There are 12 transformers total in that substation, but they are loaded, and when a fault occurs they create a very high short circuit current since the transformer has a very high load. Then transformer protection is one of the important issues in substations. The key objective of relay coordination is to sense the fault and disconnect the affected sections as quickly as possible.

To achieve this goal in relay coordination, optimum settings for the TDS and PS of each over-current coordination relay must be established. Sebeta-1 substation has eight 15kv outgoing lines and two incoming feeders. It's a supply for the Sebeta-1 sub-city. We have seen the coordination setting data and interviews with EEP employer's Protective relays, including over-current, earth fault, and differential protection relay parameters which don't follow any international standard or format; they are set by trial and error. So, the improper setting has exposed Sebeta-1 sub-city electric customers to frequent power interruptions. It is the cause of an improper protection coordination system from outgoing feeders to the source. These protection coordination problems significantly affect the Ethiopian electric power of the sebeta-1 substation in the Addis Ababa region. The consequences of this coordination concern damage to a lot of costly equipment before its standard lifetime. This problem damages the main device of the sebeta-1 substation. There are two power transformers, which are 50MVA damaged in the sebeta-1, and

one transformer, 12MVA, in the Mekanissa substation, is burning due to the Sebeta-1 fault in the Ethiopian electric power Addis Ababa region. Protection equipment, such as circuit breakers, fuses, and relays are used and also proper coordination of protective equipment is required in emergency or fault conditions. In this condition, the protection system needs to be strong and reliable. Based on these reasons, the sebeta-1 substation needed optimal coordinated settings for over-current, earth fault, and differential protection at this time. Otherwise, it is difficult to assure power system reliability and adequacy in existing power systems. These causes affect the country's investment and economy as well as people's daily activities. This thesis includes the optimal coordination and protection of the Sebeta -1 substation system network using proper coordination of the over-current relay, an earth fault relay, and a differential protection relay. Furthermore, the stated problem also causes broad irregularities, which directly pose a negative impact on the quality of real power. For this thesis, the Whale optimizations algorithm with the comparison of genetic algorithms has been used in the distribution system for optimal coordination of over-current and earth fault relays.

### **1.3 Objective of the study**

#### **1.3.1 General Objective:**

Optimal Co-ordination system for over current, and earth fault protection relay in Sebeta-I substations by using whale optimization algorithm

#### **1.3.2 Specific objective:**

- ✓ To analyze the load flow study
- ✓ To analyze the short circuit & earth fault current by using ETAP software
- ✓ Analysis of transformer differential protection current setting
- ✓ Minimize the (TMS) values of all primary protection systems
- ✓ To solve the improper coordination problem and to improve the optimal coordination protection system using the whale optimization algorithm.

## 1.4 Scope of the study

This project focuses on optimal protection and coordination of the Sebeta-I substation system network which is situated, in the Addis Ababa west Ethiopia Sebeta-I sub-city. The specified area of the problem faced is in the Sebeta-I substation network. The scope of this research is optimal over-current, an earth fault, and differential protection coordination for Sebeta-1 substation. It includes eight 15kV outgoing lines, two 15kv incoming feeders, two 132kv transformers incoming, and two 132kv lines incoming from the grid. Those protection branches work for all 15kv outgoing feeders.

## 1.5 Significance of the study

The significance of this research is a multipurpose advantage for different sectors. The international electricity market is ruled by its standards. The protection coordination system is essential for computing and modernizing the protection system in the Ethiopian Electric Power Company or *EEP*. As well, as eliminating or significantly minimizing circuit breaker failure, power transformer failure, earth transformer failure, and power interruption. It is the key to delivering uninterrupted power supply to service users. Also, minimize maintenance costs and time. In society, provide better electricity access and increases work efficiency.

## 1.6 Project Organization

This research paper contains six chapters. Chapter one includes the background/introduction of the project, the scope of the study, the significance of the study, and objectives and specific objectives of the study. Chapter two is also related to the theory of components and literature review. The next chapter, which is chapter three, has a methodology and data collection, and Chapter Four has data analysis design work and a simulation. Chapter five has results and a discussion of the design work using and simulation of ETAP and MATLAB software. The last chapter, which is chapter six, also the overall conclusion and recommendation using pleasant words, easy-understanding techniques with detailed descriptions, and essential tables and pictures.

## CHAPTER TWO

### LITERATURE AND LITERATURE REVIEW

#### 2.1 INTRODUCTION

This chapter compacts with the theoretical definition of protection coordination such as over-current protection, earth fault protection, and differential protection and also types of relay characteristics for the substation protection coordination studies. So, we have to use the device's desired lifetime and to deliver reliable power to the customers, they must need a protection device for each appliance and bays. Also, coordinate each protective device through the topology of the power flow path to assure a security of power supply. The electrical power system is a combination of the electrical system of the three sub systems that consists of generation, transmission and delivery systems.

Moreover, the transmission system is responsible for transmitting power from power plants to the customer. This transmission system consists of conventional and non-conventional sources. The wind, geothermal, biomass, hydro, and solar energy come in the category of non-conventional sources, which are mostly renewable energy sources. The mal-operation of the protection system is one of the key problems that power system engineers face. The protection of the distribution system might be assumed, radial and unidirectional, but after connecting power plants to the system, the system is no more radial and changed into loop systems which result in miss-coordination and configuration of the protective relay [1].

In the opening trial and error, a procedure was used to get the setting of overcurrent relays (OCRs) [2], in [3], the setting of OCRs was discovered through using the topological approaches in a multi-loop system. In [4]–[7], a different optimization technique was deployed for solving the problem of coordination of relays.

The key purpose of the power system protective devices is to sense and remove the nominated faulty parts as profligate as possible. To circumvent the problems of breakdown of the core protection systems (fault in relay or in breakers), there would be an organization of standby protection. Backup protection may be available either at the same station or on neighboring lines with an appropriate time delay. The organization among primary and backup relays is reached uncertainty. The characteristics of the relays satisfy the borderline limits. For discriminating tripping relay organization is very necessary in power system protection, and it also helps to

determine the delay time of all backup relays. The relay must trip for a fault in its zone to avoid any mal-operation of the protective devices.

In the protection system, a relay should not trip for a fault outside its zone except to back up a failed relay or circuit breaker.

Backup protection must be coordinated with primary protection such that the primary protection has sufficient time to remove the fault before the backup relay. The coordination time interval between the backup and the primary relay depends on various parameters, like operating time of the primary relay, operating time of circuit breaker associated with the primary relay, overshoot time of backup relay and signal travel time.

## **2.2 Fault and Types of Fault**

A power system is normally dried as a balanced symmetrical three-phase network. When a fault occurs, the symmetry is normally disturbed, resulting in unbalanced currents and voltages appearing in the network. By using symmetrical component analysis and replacing the normal system sources with a source at the fault location, it is possible to analyse these fault conditions. For the correct claim of protection equipment, it is important to know the fault current distribution to the system and the voltages in different parts of the system due to the fault. More, boundary values of the value of current at any relaying point must be known if the fault is to be cleared by perception. Based on the protection application, faults described near-end and far-end faults. They depend on the magnitude and distance of fault location far from the protective device point.

## **2.3 Types of Relays**

Protective relays are classified into different categories based on technology and application. Based on technology, relays are classified as electro-mechanical, static, and digital/numerical types. Based on application of the relays, classified as; differential, distance, over-current, earth fault & so on. This time we have to focus on technological advancement of relays crucial for their application.

### **2.3.1 Electro-mechanical Relay**

Electro-mechanical types of relays were the oldest forms of relay used for a long time in protection of power systems. It works on the principle of a mechanical force causing operation of a relay contact in response to a stimulus. The mechanical force is generated through current flow

in one or more windings on a magnetic core or cores, hence the term electro-mechanical relay [1]. The estimation value of such relays is that they make obtainable galvanic farewell between the inputs and outputs in a simple, low-cost and reliable form; therefore, for simple on/off changing functions where the output interactions have to carry substantial currents, they are still used.

## Static Relays

The term 'static' indicates that the relay has no moving parts. This is not severely the case for a static relay, as the output contacts are still normally attracted to armature relays. In a protection relay, the term 'static' refers to the absence of moving parts to create the relay characteristic. [1]

Outline of static relays started in the early 1960s. Their design is established on the use of analogue electronic devices instead of coils and magnets to create the relay specific. Early types used separate devices such as transistors and diodes in combination with resistors, capacitors, inductors, etc., but improvements in electronics enabled the practice of linear and digital circuits in later versions for signal handling and application of logic functions. Although elementary circuits may be committed to a number of relays, the vessel was still basically limited to a single protection resolution per case, though multifaceted functions required several cases of hardware properly connected. [2]

User program design was limited to the basic functions of modification of typical relay curves. They, therefore, can be seen in simple terms as an analogue electronic addition to electro-mechanical relays, with some extra give in settings and some saving in space wants. In some circumstances, the relay burden is reduced, assembly for reduced CT/VT output supplies.

A total of proposal problems had to be answered with static relays. In specific, the relays commonly require a reliable source of power and measures to prevent damage to vulnerable electronic circuits have to be devised. Substation environments are particularly hostile to electronic circuits due to electrical interference of various forms that are commonly found in possible arrangements for the supply. Resources are generated from the stately quantities of the relay that has the weakness of increasing the burden on the CT's or VT's, and there will be the smallest primary current or voltage below which the relay will not operate. This straight affects the likely sensitivity of the relay. So, sending an independent, highly consistent and secure source of relay power supply was significant attention. [1]

## Digital Relay

Digital protection relays presented a step change in technology. Microprocessors and microcontrollers substituted analogue routes used in static relays to implement relay functions. Initial examples began to be presented into service around 1980, and, with progress in processing capacity, digital relays can be observed as current technology for many relay applications. [2]

Paralleled to static relays, digital relays familiarize A/D conversion of all measured analogue amounts and use a microprocessor to appliance the protection algorithm. The microprocessor may use some nice things, including techniques, or use the Discrete Fourier Transform to appliances the algorithm. Conversely, the characteristic microprocessors used have limited dispensation capacity and memory likened to that provided in arithmetical relays.

The functionality inclines therefore to be restricted and restricted largely to the protection purpose itself. Supplementary functionality compared to that provide by an electro-mechanical or static relay is typically available, naturally taking the form of a broader range of settings, and greater truthfulness.

A communications link to a far-off computer may also be delivered. The restricted power of the microprocessors used in digital relays limits the number of examples of the waveform that can be measured per cycle. This, in opportunity, limits the speed of procedure of the relay in certain applications. Consequently, a digital relay for a particular protection gathering may have a longer operation time than the static relay comparable. However, the additional time is not significant in terms of overall tripping time and possible things of power system permanence. [1]

## 2.4 Classification of Protection Methods/Techniques

Based on application and relay types, a power company's used a different protection grading method. Among the various possible methods used to achieve correct relay co-ordination are those using either time, current and a combination of both. The common aim of all three methods is to give correct discrimination faults current within the system. [13]

### 2.4.1 Discrimination by Time

In this method, a suitable time setting is given to each of the relays adjusting the circuit breakers in a power system to confirm the breaker nearest to the fault opens first.

## 2.4.2 Perception by Current

Perception by current relies on the fact that fault current varies with the position of the fault because of the difference in fault current values between the source and the fault. Normally, the relays guiding the various circuit breakers are set to operate at properly tapered values of current such that only the relay nearby to the fault trips its breaker. [1]

## 2.4.3 Perception by Both Time and Current /IDMT/

Individually, the two methods defined so far have a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that more faults are cleared in the longest operating time. [12] On the other hand, discrimination by current can be applied only where there is appreciable impedance between the two circuit breakers concerned. It is because of the restrictions imposed by the independent use of whichever time or current co-ordination that the inverse time over-current relay typical has developed. Using this representative, the time of process is in reverse relative to the fault current level and the actual specific is a function of together 'time' and 'current' settings. The characteristics of the two relays are given different current/time settings. Because of a large variance in fault current between the two ends of the feeder, faster working times can be touched by the relays nearby to the bases where the fault level is the highest. The weaknesses of grading by time or current only are overcome. The choice of over-current relay appearances generally starts with choice of the correct specifics to be used for each relay, followed by current high-quality of the relay settings.

Finally, the grading margins and later time settings of the relays are resolute. An iterative technique is often required to determine conflicts, and may contain use of non-optimal appearances, current or time grading settings.

## 2.5 Relay Characteristics

The current/time tripping appearances of *IDMT* relays may want to be varied, allowing for the tripping time mandatory and the characteristics of other protection procedures used in the network. For these determinations, IEC 60255 defines a number of standard appearances as follows [12]:

- Standard Inverse (*SI*)
- Very Inverse (*VI*)
- Extremely Inverse (*EI*)

➤ Definite Time (*DT*)

Table 2. 1 Relay characteristics to IEC 60255 [2]

Relay characteristic	Equitation
Standard inverse	$T = TMS \times \frac{0.14}{Ir^{0.02} - 1}$
Very inverse	$T = TMS \times \frac{13.5}{Ir - 1}$
Extremely inverse	$T = TMS \times \frac{80}{Ir^2 - 1}$

### Standard Inverse (*SI*)

The small-set over-current and earth-fault phases can be given a definite-time or an inverse definite minimum time (IDMT) specific, whereas the great-set over-current and earth-fault phases article the definite-time characteristic alone. The settings of adjustments decide the act mode of stage I> whereas those of switches regulate that of stage I0>. In IDMT distinguishing, the operate time of the stage is reliant on the current value: the advanced the current value, the shorter the work time. Time/current curve groups are accessible, of which four observe with the IEC 60255 standard: the standard inverse.

### Very Inverse (*VI*) Overcurrent Relays

Very inverse over-current relays are mainly suitable if there is a significant reduction of fault current as the space from the power source grows, i.e. there is a significant increase in fault impedance. The VI work is exact such that the operational time is about doubled for reduction in current from 7 to 4 period's current relay setting. This documents the habit of the same time multiplier setting for several relays in sequences. [15]

The VI curve is much steeper and, therefore, the operation increases much faster for the same reduction in current compared to the standard inverse curve. This allows the requisite grading margin to be gotten with a lower TMS for the identical current setting, and later the tripping time on a basis can be minimized. [7]

### Extremely Inverse (*EI*) Overcurrent Relays

With this representative, the operation time is almost inversely relative to the square of the applied current. This creates it suitable for the protection of distribution feeder circuits in which

the feeder is subjected to peak currents when switching on. The long-time operating characteristic of the extremely inverse relay at normal peak load values of current also makes this relay particularly suitable for grading with fuses. It can be understood that use of the EI characteristic gives an acceptable grading margin, but practice of the VI or SI features in similar settings does not. Another application of this relay is in conjunction with auto-recloses in low voltage distribution circuits.

The common faults are temporary in nature and needless blowing and replacing of the fuses present in the last circuits of such a system can be escaped if the auto-reclosers are set to work before the fuse blows. If the fault persists, the auto-recloser locks itself in the closed position after one opening and the fuse blows to isolate the fault. [12]

### **Relay Current Setting**

Over-current relay confirms minimum working current, branded as the current setting of the relay. The current setting must be chosen for a relay does not operate at the maximum load current, to protect the circuit, but it does operate an equal or greater fault current to the minimum expected fault current. Although using a current setting is only just above the maximum load current in the circuit, a certain degree of protection against overloads as well as faults may be provided. The main function of over-current protection is to isolate primary system faults and not to provide overload protection. [15]

In overall, the current setting will be designated to be above the extreme short time rated current of the circuit elaborate. Since all relays have hysteresis in their current settings, the setting must be sufficiently high to allow the relay to reset when the rated current of the circuit is carried. The amount of hysteresis in the current setting is denoted by the pick-up of a relay. The value for a modern relay is typically 0.95. Consequently, a relay smallest current setting of at least 1.05 times the short-time rated current of the circuit is probable to be required. [13]

### **2.6 Relay Time Grading Margin**

The time intermission that must be acceptable between the operations of two adjacent relays in instruction to achieve correct perception between them is called the grading margin. If a grading margin is not provided, or is inadequate, more than one relay will work for a fault, foremost due to difficulties in defining the position of the fault and avoidable loss of supply to some consumers. The grading margin is subject to a number of causes [13]:

- i. Current error interrupting the time of the circuit breaker
- ii. Relay timing errors
- iii. The overshoot time of the relay
- iv. CT errors
- v. Final margin on completion of operation

## 2.7 Literature Review

Protection coordination is the main issue at the international level. Based on this, different literature has been published in journals or final thesis form. Most investigators have worked on over-current protection organizations. They use different points of view; some researchers use *IEEE* bus topology, and the case study area of the research earth fault has no vital role for interruption. [3] Most literature reviewed in this paper has worked on over-current, earth fault, and differential protection coordination.

The main problem that arises with over-current and earth fault protection is the difficulty in performing the relay coordination, especially in multi-loop, multi-source networks. Three approaches have been used for the setting of relays: the trial- and- error approach, the topological analysis approach, and the optimization approach [8]. Traditionally, the trial-and-error method was applied for relay setting in Ethiopian electric power (*EEP*), and protection engineers used their experience to set the pickup current based on the load current of the system. Another research work provides coordination of over-current relays for the radial and parallel feeder networks, analyzing the current time characteristics. Explanations and setup for circular and similar feeder systems are investigated.

Protection coordination by time was introduced to formulate all the system relays and system equipment operation into a set of optimization equations and constraints. Its persistence is to explore an optimal protection setting to minimize the system disturbance time as well as the time of disruption of the power supply. An evolutionary algorithm applied a constraint optimization tool to search for the optimal relay setting by linear programming to obtain minimized objective function of time. [5]

The authors have employed a topological analysis method (using linear graph theory and functional dependency) for determining the optimal break points. Despite the advantages of applying the topological approach, there is no guarantee that it selects the optimal relay settings

[4]. In additional words, it may assurance satisfy the proper coordination, but the working times of the relays are not small.

In the optimization approach, some researchers [6] used nonlinear programming for determining the optimal settings of the pickup current and linear programming for optimizing the time dial settings of the relays subject to the coordination constraints. Others [8] practically use the linear programming method only to reduce operating time while the pickup, currently nominated based on experience.

The authors of [7] used two constraints for each relay, one for close-in fault and one for far-end fault, and the objective function was considered as the sum of two additive values. The earliest one is the biased sum of the working times of the primary relays for close-in fault, and the additional one is the weighted sum of the working times of the primary relays for far-end fault. In [8], the objective function is a weighted sum of operating times of the primary relays for close-in faults. Subsequently, the lines are short and almost of equal length, identical weights were assigned for the working times of all the relays.

In this paper [9], the authors suggest a modified problem formulation to make the coordination process faster, through applying a whale's optimization algorithm technique, and problem dimensionality reduction. The first phase includes the calculation of a possible point; the second phase includes the generation of an iterative order of possible points that join to the optimal solution. In certainty, nonlinear programming is a time-consuming method. Because of each iteration of the non-linear programming, another linear programming is called for determining the direction search. On the other hand, the key problem is not controlling the optimal pickup settings, but optimal time dial settings. The main function is specified as a sum of the operating times of all primary relays for supreme close-in faults, and the limitations considered based on the maximum close-in faults as well. [5]

The optimization co-ordination of over-current and earth fault relays on interconnected power systems presented in this research paper. The procedure adopted for attention of backup relays in the optimal coordination of over-current and earth fault relays inside the system. The control of the Time Multiplier Setting (*TMS*) and the pickup current (*I<sub>p</sub>*) setting of the relays is the fundamental of the coordination study. The Whale optimization algorithm and Genetic Algorithm is the algorithm being put on to minimize the operating times of the relays. It has

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Linear Equations that are for the test bus system used and optimized using WOA & Genetic Algorithm.

In this paper, the optimal coordination of overcurrent, and earth faults was determined by a whale optimization algorithm (WOA) of power systems. The WOA is motivated by the Humpback whales' policy of apprehending prey using the bubble-net hunting tactic, a helpful feeding method used by collections of humpback whales as they flow bubbles to encircle and enclose their prey. The recommended WOA has unexpected exploration capability and speed as compared to other meta-heuristic techniques [50,51]; this distinctive makes the population members of WOA more discriminative when searching for the optimal solution compared to other meta-heuristic algorithms. The primary aim of our proposed WOA is to determine the optimal values of TDS and PS to minimize the operational period of over current, earth fault and differential protection relay with respect to backup and relay setting restrictions. The remaining of this paper is ordered as follows. The over current relay problem formulation.

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## CHAPTER THREE

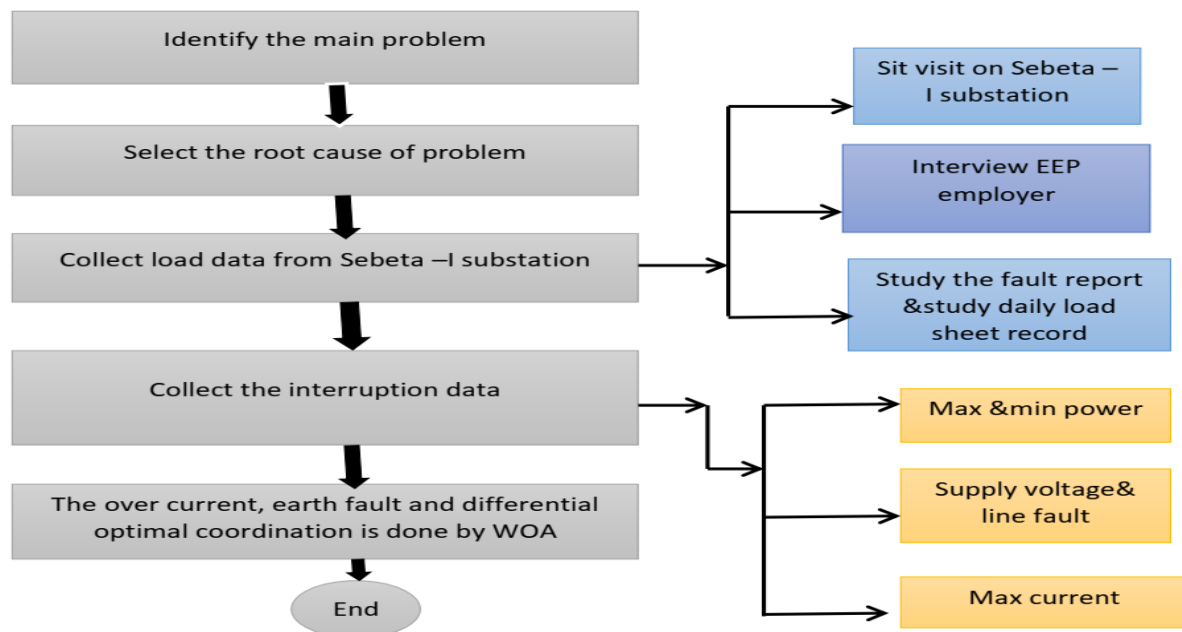
### METHODOLOGY AND DATA COLLECTION

#### 3.1 Methods

This study is focused on both quantitative and qualitative data-gathering methods. However, I am mostly concerned with the qualitative data gathering, since this type of data-gathering includes phenomena concerned with subjective phenomena. Collecting the required data from different sources is one of the initial tasks of this study. To get the data needed for this study, different data collection methods are used, like site-visiting, interviewing Sebeta-1 substation employees, studying the fault reports, and studying the daily load sheet record of Sebeta-1 substation and analytical calculations. The following ideas, methods, and procedures that are followed while doing this research

- Identifying the main problems
- Selecting the root causes of those problems
- Collect load data from Sebeta-1 substation system network
- Interpretation of the collected data, like maximum & minimum power, supply voltage, and maximum current.
- The over-current, earth fault & differential optimal coordination is done by using the **whale optimization technique.**

After the collection of the desired data analysis and interpretation of data by using different approaches. The proposed algorithms for this work solve the coordination problem of the systems.



Figur3. 1 Block diagrams of methodology

After achieving this data, the analysis was done for earth fault conditions using a single line to the ground fault and for over-current three-phase fault. After getting the current fault result, an analysis of the pickup current of each line, and plug setting multiplier ( $PSM$ ) is done. Finally, to minimize the equation of the objective function, to get the time multiplier setting ( $TMS$ ) and operating time ( $T$ ) of each coordinated relay by the equation of normal inverse over current.

### 3.1.1 Whale Optimization Algorithm

The whale optimization algorithm was developed by Mirjalili in 2016 as a novel nature-inspired heuristic technique to solve problems related to engineering and different mathematical optimization issues. The mutual activities of humpback whales are the origin of the whale optimization algorithm. This optimization algorithm technique is stimulated by humpback whales' bubble net hunting approach as they follow a circular-shaped route for chasing small fish near the surface. This feeding process is a characteristic behavior of humpback whales, making this optimization technique unique among other nature-inspired optimization techniques in designing the mathematical model of the whale optimization algorithm; three steps are involved in the bubble-net hunting process. The first step is searching for the prey, the second step is encircling the prey, and the third step is a spiral bubble-net feeding movement for the prey. Each step is defined in detail below.

### 3.1.2 Encircling Prey

The location of the target and prey is known and enclosed by the humpback whales. Since the optimal strategy for finding the prey in the exploration area is not categorized by all the whales primary, the existing best applicant regulation is supposed to be exposed by the entity closest to the optimum plan. By describing the best exploration agent, other search agents must be updated in the direction of the best search agent. The plan can be clarified as follows.

$$D = |\vec{C} * \vec{Z}(t) - \vec{Z}(t)| \quad (4)$$

$$\vec{Z}(t+1) = \vec{Z}(t) - \vec{A} * \vec{D} \quad (5)$$

Where  $t$  is the current iteration;  $Z$  denotes the provided best solution in the position vector  $Z$ ; and  $A$  and  $C$  are the coefficient vectors. It should be noted that  $Z$  will be amended in each iteration, where  $D$  is the distance of  $i$ th whale to the prey. In addition, the vectors  $A$  and  $C$  are calculated as, respectively, as follows.

$$\vec{A} = 2\vec{a} \cdot \vec{r} - \vec{a} \quad (6)$$

$$\vec{C} = 2 \cdot \vec{r} \quad (7)$$

Where  $r$  is randomly nominated vector having a range between zero and one, while, for the manipulation and consideration steps, the value of  $a$  is decrease's from two to zero.

## 3.2. Bubble-Net Attacking Method

To ideal this plan, two techniques working by humpback whales are presented as below

### 3.2.1. Shrinking Encircling Mechanism

A decrease in the estimation of  $a$  from two to zero through the iterations of Equation (7) results in this conduct. Likewise, by diminishing the value of  $a$ , which is a randomly chosen value in  $[-a, a]$ , the changing scope of  $A$  is additionally decreased. The original location of search agents is chosen amongst the primary location of every agent and the position of the best agent by picking irregular qualities for  $A$  in the interval  $[-1, 1]$ .

**3.2.2. Spiral Updating of Position:**-In this process, the separation between the whale positioned at  $(Z, W)$  and the prey positioned at  $(Z^*, W^*)$  is determined. From the previous point forward, for representing the spiral-shaped undertaking of humpback whales, a helix condition is composed among them between the whale location and the prey location as:

$$\vec{Z}(t+1) = \vec{D} \cdot e^{-bl} \cdot \cos(2\pi l) + \vec{Z}(t) \quad (8)$$

Where  $D$  determines the location or distances of the whale  $i$  to the prey and can be obtained as  $D = \vec{D} \cdot e^{-bl} \cdot \cos(2\pi l) + \vec{Z}(t)$ . Furthermore, it is a constant to represent the state of the logarithmic helix and  $l$  is an arbitrary number in the range  $[-1, 1]$  because of the concurrent swimming of humpback whales around the prey in a shrinking loop and succeeding a helix-formed path, the equal likelihood of choosing either the shrinking surrounding technique or the helix plan can be summarized as:

$$\vec{Z}(t+1) = \begin{cases} \vec{Z}(t) - \vec{A} * \vec{D} & \text{if } p \leq 0.5, \\ \vec{D} \cdot e^{-bl} \cdot \cos(2\pi l) + \vec{Z}(t), & \text{if } p \geq 0.5 \end{cases} \quad (9)$$

Where  $p$ , is the random number having a range between zero and one.

### 3.3. Search for Prey

A comparable technique reliant on the heterogeneity of vector  $A$  can be utilized when examining for the prey (searching). An arbitrary survey of humpback whales shows that they are given one another and distinguishable. In like manner, a moving search agent far from a reference whale is expected to be skilled in the behavior, where  $|A| > 1$ . Furthermore, the condition of a search agent in the exploration step is updated in the view of a subjective search agent rather than the best pursuit agent originating up until that point. The calculated model can be stated as

$$\vec{D} = |\vec{C} \cdot \vec{Z}_{rand} - \vec{Z}|, \quad (10)$$

$$\vec{Z}(t+1) = \vec{Z}_{rand} - \vec{A} \cdot \vec{D} \quad (11)$$

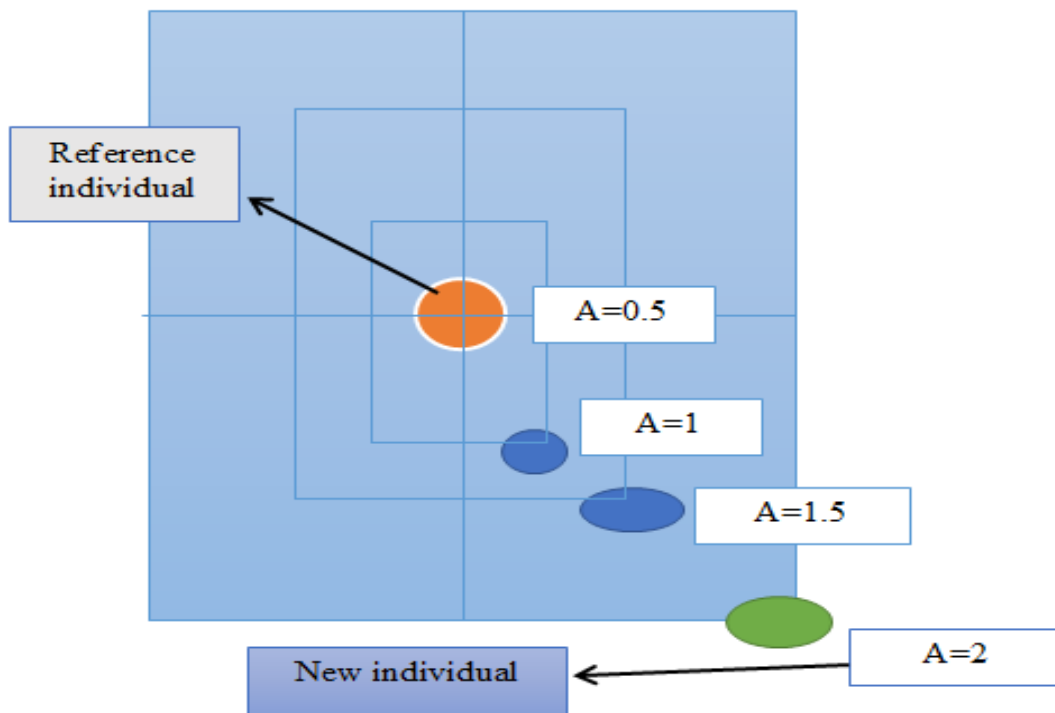


Figure 3.2 The flowchart of whale for search a prey

### 3.4. The Steps of WOA

The primary process of WOA is as follows: The WOA starts with a conventional set of randomly-created results. The locations of pursuit agents, considering an arbitrary determination of the hunt agent or the given the best result, are then updated. For exploration and exploitation, the parameter “a” is reduced from two to zero. When  $|\vec{A}| > 1$ , an arbitrary hunt agent is chosen, and when  $|\vec{A}| < 1$ , the best result is chosen for updating the positions of the pursuit agents. This improvement plan can modify the movement between among spiral and circular movements depending on the degree of p. Finally, the WOA is stopped when the criteria are met. Algorithm 1 represents the process code of the WOA. In addition, the flowchart of WOA is given in Figure 3.3.

### 3.2 Modeling

Based on a specific distribution network topology structure, a set value optimization model of inverse time over-current protection for the substation distribution networks based on the

improved WOA is established. The structure of the improved WOA algorithm model is described as the modeling process as follows:

1. Initialize population for n search agent
2. Calculation of the fitness value for each search agent
3. Choose the Best Search Agent
4. While ( $t < \text{Max } T$ )
5. Update  $w$ ,  $a$ ,  $A$ ,  $C$ ,  $l$ , and  $p$  for the search agent
6. for each search agent
7. If1 ( $p < 0.2$ )
8. If2  $|A| < 1$  - Select random agent and update position  $X(t+1) = X(t) - A * D$
9. Else if2 ( $|A| < 1$ ) - update position of agent
10. Else if2  $X(t+1) = \{w * X(t) - A * D \quad p < 0.5$
11. Else if1 ( $p \geq 0.5$ ) - update position of agent
12. Calculate Fitness for each search agent
13. Update optimal solution
14. Increment counter i.e.,  $t = t + 1$ ;
15. Return the best search agent and its fitness value. Whale's optimization and the maximum number of iterations find the optimal set value after several attempts and comparisons and this algorithm finds the best optimization solution.

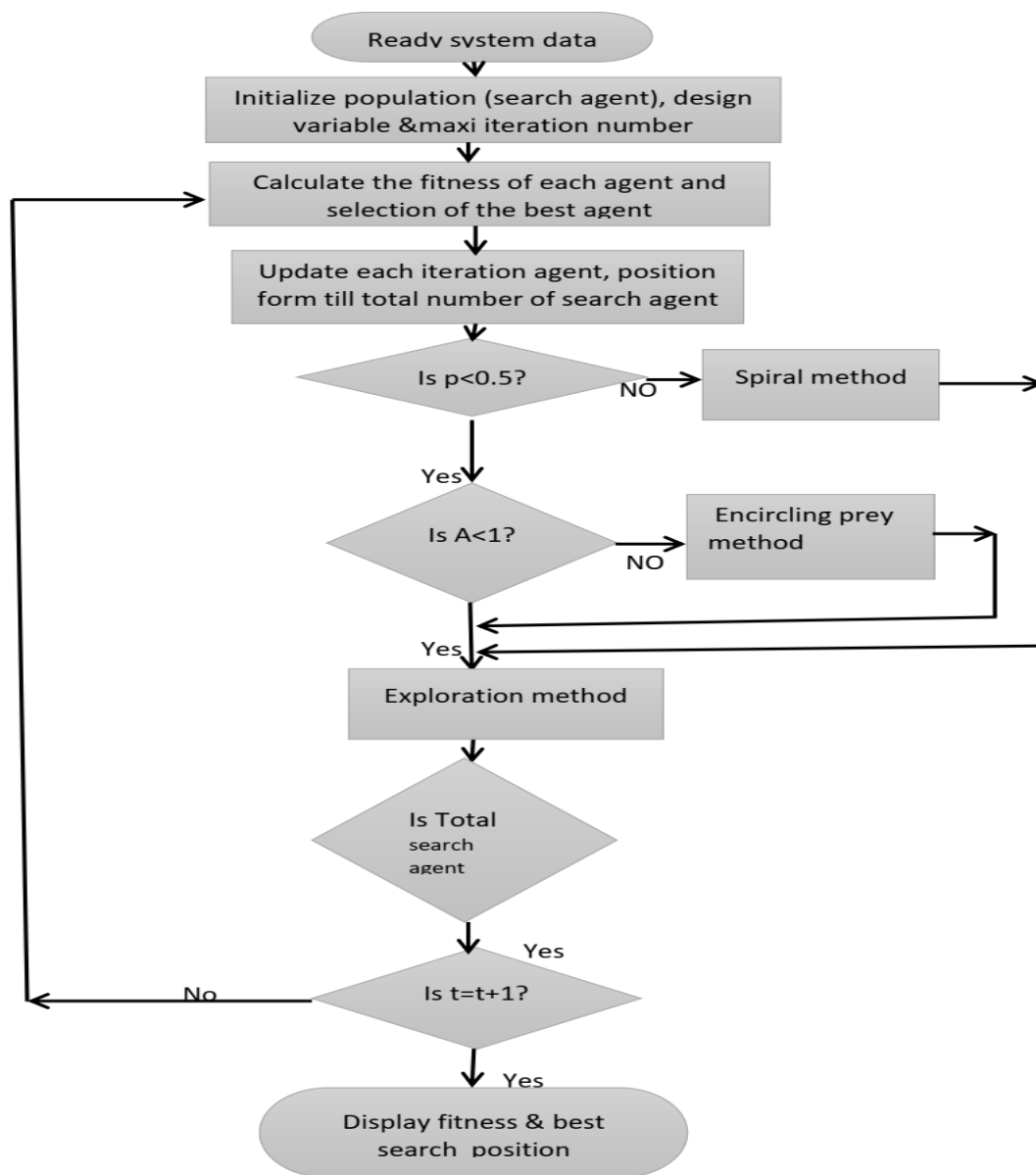


Figure3. 3 The flowchart of whale optimization algorithm (WOA)

**Convergence Factor Exponential Decay Strategy.**

Convergence issue  $\rightarrow a$  disturbs the global exploration ability of the algorithm technics, and the exponential function is familiarized to calculate  $\rightarrow a$ . The Convergence factor exponential decay strategy can replace the linear attenuation strategy of the basic WOA algorithm.

$$a = 2 * (1 - t / MaxT) \tag{12}$$

Where  $t$  is the present recapitulation number and  $T$  is the maximum repetition number. It can be seen from the equation that the convergence factor decreases non-linearly with the increase of iterations, which helps to balance the global search ability and local optimization ability of the WOA algorithm. The flow chart of the proposed algorithm for optimal coordination of overcurrent and earth fault relays. Each step of the flow chart can be concisely explained as follows: -

- The coordination of primary and backup relay pairs is essential in the formulation of the coordination of the steps of the constraints. The proposed algorithm generates all the relay pairs using topological tracking.
- Load flow program, Newton-Raphson load flow technique used in this application to determine the voltages at each bus and the line currents. This Electrical Transient Analysis Programming /ETAP/ software can analyze analysis of this load flow.
- Short circuit analysis is done using the same simulation software to find fault currents.
- The selection of current pickup value of the time-dependent unit can be determined according to the power system and relay design, and the experience of the protection engineer and international standards.

$$I_p = I_l \times 1.2 \quad (1)$$

- Minimization of objective function carried out and optimum values of  $TMS$  are determined using the whale's optimization algorithm programming technique in *MATLAB*. The values of  $TMS$  and minimization of objective function were further optimized using Whale's optimization algorithm in *MATLAB* programming and Genetic Algorithm in *MATLAB* Toolbox. A Genetic algorithm is a search technique used in calculating, to find exact or approximate results for optimization and search problems. Genetic algorithms are categorized as global search heuristics. *Genetic Algorithm* is a specific class of evolutionary algorithms that uses techniques stimulated by evolutionary biology such as legacy, mutation, selection, and boundary.

### 3.2 Linear programming problem

Linear Programming is applied to the coordination problem with 4 relays for the calculation of total working time for types of relays and given the constraints of the equation. Almost in all substations, the standard inverse relay characteristic is only used. Every time the fault occurs,

both are sensed by primary and backup relays both the primary. On the occurrence of a fault primary protection initiates first to clear then the fault as per the scheme of backup protection. In ring feeder distribution systems, over-current relay coordination is the highly constrained optimization objective. Allowing for two main relays for any line sections, i.e. one at each end, the loops are identified by the relay number. Then, by using the idea of a break point set (BPS), loops are broken at these points after a radial network. These break points are used as the initial point for setting up the relays. First relays at the break points are set with the lowest operating time and then the next set of relays is set as backup to BPS relays. This technique continues until all relays are set. The Real-Time Digital simulator which is part of the closed-loop relay test system is also used to coordinate the voltage ring distribution network.

ETAP is the greatest correct program of requirements as stated above. The load flow analysis gives the current, voltage, and power flow of the line, bus, transformer, circuit breakers, motors, and other equipment. Using the load flow study, we can solve the plug setting of the relay. Similar to the load flow study, the short circuit study is important to find the PSM of the relay. Then, by using this PSM,

We can discover the TMS of the backup relay. Thus, load flow and short circuit homework must be required in relay coordination. The strategies for over-current relay setting for the radial circulation system are:

**A. Plug Setting:** Plug setting is to be decided by considering three rules:

- The relays will reach at least up to the end of the next protected zone. This is required to confirm the backup protection
- The plug setting does not need to be less than the maximum normal load including permissible uninterrupted overload unless monitored by an under-voltage relay, else the relay will not allow the normal load to be delivered.
- In approximating the plug setting, an allowance must be made for the statistic that the relay pick-up varies from **1.05** to **1.3** times pug-settings, as per standards.

**B. Time Setting:**

- The time-multiplier setting duty is chosen to give the lowest likely time for the relay at the end of the radial feeder. In the previous sections towards the source, the time multiplier should be chosen to give selective intervals from the downstream relay at maximum fault conditions.
- The time multiplier setting would agree not only for the time of the breaker's time but also for the overshoot of the relay and permissible time errors in the time of operation of consecutive relays. It is a mutual practice to use a fixed selective interval of 0.25 seconds (considering 2-cycle breakers) between the successive relays. Time intermission between primary and secondary relays to be definite based on the operation time of primary relay, mistake in operating time of primary relay, breaker time to satisfy arc, overshoot time, factor of safety, error in operating time of secondary relay

In the ETAP software, the star view is a respectable feature to show particular coordination of relays. The star view of ETAP is a time-current curve that provides the relay organization between whole the relays of the system. ETAP simplifies the selection of relay lengthways with its model and production for the protection of feeders, transmission lines, transformers, generators, etc. The working time of the relay is contingent on the characteristics of the relay.

### 3.3 Optimal Coordination of Over-Current Relays

The Relay organization problem can be stated as a parametric optimization problem. The main function of operating times of the primary relays is minimized subject to the care of the operation of the backup relays coordinated. One possible approach to achieve minimum disturbance to the power system due to fault conditions is to minimize the operating times relays within the system. The main purpose is engaged as the sum of the time dial settings (TDS) of total primary relays, regardless of the type and position of the error. It does consider different constraints, basically relay characteristics. A typical Inverse Time Directional Over-current relay consists of two elements, an instantaneous unit and a time over current unit. The over-current unit has two values: current fixed pickup current value ( $I_p$ ) & the Time Dial setting (TDS). The current pickup value ( $I_p$ ) is the minimum current value for which the relay operates, in our case taking the value of peak up current by experience. The Time Dial Setting defines the operation time of the protective device for each coordination point.

$$T = \frac{k_1 * TDS}{I_f / I_p^{K_2} - 1} \quad (12)$$

Where:

IP - peak up current setting

K1 and K2 are constants having values K1 = 0.14 and K2 = 0.02, and TDS- time dial setting, and If fault current for normal inverse type relays respectively. In real practice, every power system protection system has its own backup device to ensure reliable protection management. Both protective systems should be coordinated together within their coordination margin, which is expressed by the time interval of either system or CTI.

### 3.4 Coordination Time Interval (CTI)

Coordination time intermission (CTI) is the standard to consider for an organization. It's a predefined organizational time interval, and it depends on the kind of relays. For electromagnetic relay, CTI is of the order of **0.3** to **0.4** s, while for a microprocessor-based relay, it is of the order of **0.1** to **0.2** s. To ensure the reliability of the protective system, the backup scheme shouldn't come into action unless the primary relay fails to take the appropriate action. Only when CTI is stopped, must the backup relay come into action. This can be stated by the equation below.

$$T_b - T_p \geq CTI \quad (13)$$

Where

TP is the operational time of the relay

TB is the operational time of the backup relay

CTI is the coordination time interval

All substation protection relays are micom and electro-mechanical relays. Micom relays and NR relays are widely applicable in our substation. There are fast responses to clear the fault and so many features inside. Due to fault conditions and considering our network topology, CTI takes **0.2**. It's applicable to all feeders. To achieve this goal in relay coordination, optimum

settings for the TDS and PS of each over-current relay must be established. The aim is to minimize the total operating time of all primary over-current relay systems. By satisfying the distinct constraints, as defined by the objective function.

$$\text{Minobj } F = \sum_{i=1}^N T_i$$

$N$  represents several relays within the network placed according to network topology which can be explained in load flow analysis.

### 3.5 Optimization System by Using WOA, & GA

Two parameters are to optimize the coordination system time dial setting (TDS) and peak up current setting ( $I_p$ ). As previously explained from the equation, TDS are linear functions, and  $I_p$  are nonlinear functions. This paper uses optimization techniques for TDS by using a whale optimization algorithm and a genetic algorithm. The objective function can be understood by *MATLAB* programming in whale optimization and the optimization toolbox of genetic algorithms in *MATLAB* software. For a typical optimization system, the TDS value has its range i.e based on the IEC and the IEEE. The constraint limit of the fitness function of the TDS value range is as shown below.

$$0.1 \leq \text{TDS} \leq 1.1$$

The TDS value must be within the limit. The peak-up current of the system can be set by using experience to calculate the existing load by some multiplying factor. The multiplier has been selected according to international standards, so take 20% above the system load. The nature of  $I_p$  has a nonlinear system that can solve this problem.

$$I_p = 1.2 * I_l$$

Where  $I_p$  Peak up current,  $I_l$  existing load current

### 3.6 Existing Coordination System

In EEP experience, the setting and coordination of protective relays do not use international optimization tools or any developed software system (does not consider international standards like IEC, ANSC IEEE, and so on). Sebeta-1 substation uses a time margin for coordination purposes by fixed **500ms**, and the peak-up current is set based on the nominal current of the current transformer. The existing system of Sebeta one substation peak up current setting has work based on the current transformer rating.

$$I_p = 0.85 * I_{ct}$$

But for 132kv bay the multiplier is different from the 15kv setting.

$$I_p = 1.2 * I_{ct}$$

### 3.7 Terminologies Related to Genetic Algorithm's

The genetic algorithm used different techniques to obtain the optimal value of the objective function. The character of each evaluation technique is listed below:-

- **Fitness Function** Fitness is a particular type of objective function that prescribes the optimality of a solution genetic algorithm so that a particular chromosome may be ranked against all the other chromosomes.
- **The chromosome** is a set of factors that define a planned solution to the problem that the genetic algorithm is frustrating to solve. The chromosome is often characterized as a simple string, while a comprehensive variety of other data organizations are also used.
- **Selection** Each consecutive generation, a proportion of the current population is selected to breed a new generation. Individual results are selected through a fitness-based procedure, where fitter solutions are classically more likely to be selected.
- **Reproduction** is the next step to generating a second-generation population of results from those selected through genetic operator crossover.

- Crossover is one of the genetic operators used to vary the program writing of a chromosome or chromosomes from one generation to the next. It is similar to replica and biological crossover.
- Mutation is a genetic operation that is used to keep the genetic range from one generation of a population of algorithm chromosomes to the next. It is equivalent to a biological mutation.

Based on the above methodology, optimize the value using the GA optimization toolbox by the above operators. It's given both TMS and relay working time [T] with a specific repetition.

### 3.8 Data Collection

Sebeta-1 substation data is collected for the design of load flow and short circuit analysis. For both analyses collect the existing pickup load of each feeder. Also, for calculation of the plug setting multiplier and minimization of objective function, collect current transformer data of the bays. In addition to this, identify types of relays for coordination time interval purposes.

Table 3.1 Existing load for Sebeta-1 substation

15Kv outgoing lines (Relays)	Peak up Current setting $I_p$ (A)	CT ratio (A)	Operating time (ms)	Relay type
1	336	800/1	500	Micom
2	640	800/1	500	Micom
3	800	800/1	500	Micom
4	656	800/1	500	Micom
5	496	800/1	500	Micom
6	280	800/1	500	Micom
7	380	800/1	500	Micom
8	300	800/1	500	Micom
TR-1 15KV Side	1920	2000/1	1000	Micom

TR-2 15KV Side	1920	2000/1	1000	Micom
TR-1 132KV Side	350	400/1	1500	Micom
TR-2 132KV Side	350	400/1	1500	Micom
132KV Incoming Line	350	600/1	2000	Micom

Table3. 2 Sebeta one substation new bay Data

Name of bays	Peak up Current setting $I_p$ (A)	CT ratio (A)	Voltage level (15KV)	Relay type
Outgoing line-1	229.2	800/1	15	Micom
Outgoing line-2	600	800/1	15	Micom
Outgoing line-3	516	800/1	15	Micom
Outgoing line-4	254.88	800/1	15	Micom
Outgoing line-5	281.76	800/1	15	Micom
Outgoing line-6	257.28	800/1	15	Micom
Outgoing line-7	216	800/1	15	Micom
Outgoing line-8	240	800/1	15	Micom
Transformer feeder-1	927	2000/1	15	Micom
Transformer feeder-2	927	2000/1	15	Micom
Transformer incoming-1	258	400/1	132	Micom
Transformer incoming-2	258	400/1	132	Micom

132KV Line	Incoming	180	600/1	132	Micom
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Table 3. 3 Sebete one Substation Transformer Data

Transformer name	Rating (MVA)	Voltage output (KV)	Existing peak (MW)
Transformer-1 (TR-1)	50	132/15	19.3
Transformer-2 (TR-2)	50	132/15	19.3

The first thing to do this work is collect interruption data from Sebete-1 substation daily longshot, describing the frequency and duration of interruptions on each line. So, to collect and review three years of interruption records caused by over-current, earth fault, and differential protection transformer interruption causes. Study day logs hit and interview Sebete-1 substation employers.

## CHAPTER FOUR

### DATA ANALYSIS, DESIGN AND SIMULATION

This chapter deals with the design, analysis, and simulation of Sebeta-1 substation protection coordination studies. The analysis has been done for earth fault conditions using a single line to the ground fault and for over-current three-phase fault. After getting the current fault result, analysis on the pickup current of each line, plug setting multiplier (*PSM*) is done. Finally, to minimize the equation of the objective function to get the time multiplier setting (*TMS*) and operating time (*T*) of each coordinated relay. The output of load flow and short circuit analysis is attached in the *appendix*.

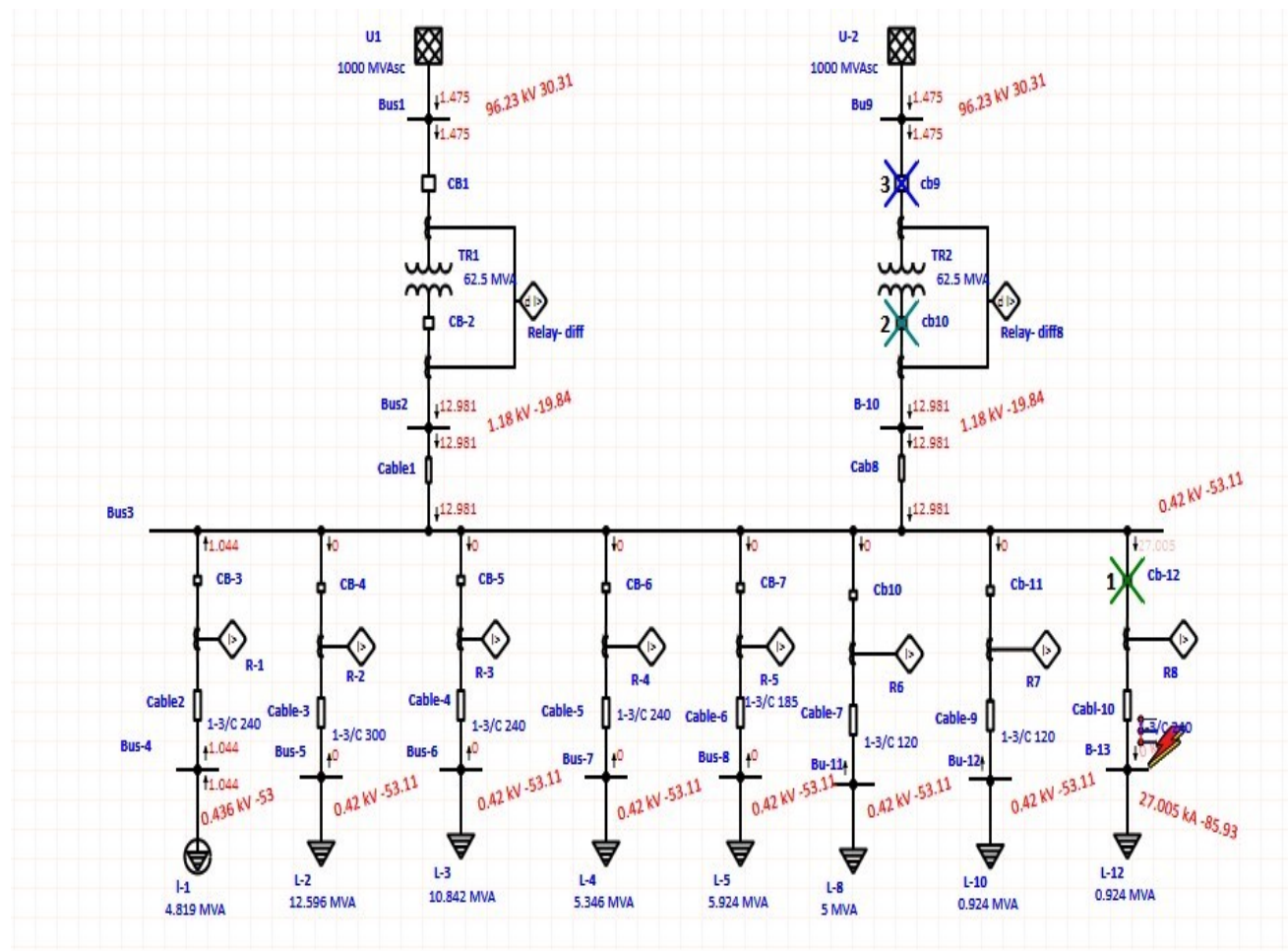


Figure4.1 simulation Sebeta-1substation

Desing the optimal protection cordinatiom of sebeta one substation system

## 4.1 Overcurrent Analysis

In the over-current case, use three-phase faults current to design short circuit analysis, and for pickup calculation, use 120% of the load current, which is the acceptable limit of the *EEP* standard.

### 4.1.1 15KV Outgoing Lines Over-current Calculation

#### Name of the Bay outgoing Line 1

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$

Load Current Line-1 = 191 A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per *EEP* guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 191 * 1.2 \\ &= 229.2A \end{aligned}$$

The secondary relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 229.2 / 800 \\ &= 0.2865A \end{aligned}$$

#### Time Multiplier Setting (TMS) of Line-1

To analyse the TMS of the system, consider short circuit current analysis of Line-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675KA$ .

The coordination ratio of fault current with pickup setting is plug setting multiplier.

$$PSM = \frac{I_f}{I_p} \quad 1$$

$$\begin{aligned} \text{PSM of Line-1} &= (9.675KA / 229.2)^{0.02} \\ &= 1.077 \end{aligned}$$

$$T = \frac{0.14 * TMS}{\left( \frac{9.675KA}{229.2} \right)^{0.02} - 1}$$

$$T = 1.818 * TMS - 1$$

**Name of the Bay outgoing Line2**

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$ 

Load Current Line-1 = 500 A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 500 * 1.2 \\ &= 600A \end{aligned}$$

The secondary relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 600 / 800 \\ &= 0.75A \end{aligned}$$

**Time Multiplier Setting (TMS) of Line-2**

To analyse the TMS of the system, consider short circuit current analysis of Line-2 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675KA$ .The coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$ 

$$\begin{aligned} \text{PSM of Line-2} &= (9675/600) ^{0.02} \\ &= 1.0571 \end{aligned}$$

$$T = \frac{0.14 * TMS}{9.675KA / 600^{0.02} - 1}$$

$$T = 2.451 * TMS-2$$

**Name of the Bay outgoing Line-3**

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$ 

Load Current Line-1 = 430 A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 430 * 1.2. \\ &= 516A \end{aligned}$$

The secondary relay current is

$$\begin{aligned} I_s &= I_p / CTR = 516 / 800 \\ &= 0.645A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-3

To analyse the TMS of the system, consider short circuit current analysis of Line-3 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of Line-3} &= (9675/516)^{0.02} \\ &= 1.0604 \end{aligned}$$

$$\begin{aligned} T &= \frac{0.14 * TMS}{\left( \frac{9.675KA}{720} \right)^{0.02} - 1} \\ T &= 2.31 * TMS-3 \end{aligned}$$

### Name of the Bay outgoing Line4

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$

Load Current Line-1 = 212.4A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 212.4 * 1.2. \\ &= 254.88A \end{aligned}$$

The second relay current is

$$I_s = I_p / \text{CTR} = 254.88 / 800 \\ = 0.3186 \text{ A}$$

#### Time Multiplier Setting (TMS) of Line-4

To analyse the TMS of the system, consider short circuit current analysis of Line-4 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675 \text{ KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\text{PSM of Line-4} = (9675 / 254.88)^{0.02} \\ = 1.075$$

$$T = \frac{0.14 * \text{TMS}}{9675 \text{ KA} / 254.88^{0.02} - 1}$$

$$T = 1.86 * \text{TMS-4}$$

#### Name of the Bay outgoing Line5

Voltage level: 15KV

CTR Ratio =  $800 / 1 \text{ A} = 800$

Load Current Line-1 = 234.8A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of existing system load.

$$I_p = I_L * 1.2 = 234.8 * 1.2 \\ = 281.76 \text{ A}$$

The second relay current is

$$I_s = I_p / \text{CTR} = 281.76 / 800 \\ = 0.3522 \text{ A}$$

### Time Multiplier Setting (TMS) of Line-5

To analyse TMS of the system, consider short circuit current analysis of Line-5 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-5} &= (9675/281.76)^{0.02} \\ &= 1.073 \end{aligned}$$

$$T = \frac{0.14 * TMS}{9.675 \text{KA} / 281.76^{0.02} - 1}$$

$$T = 1.92 * \text{TMS-5}$$

### Name of the Bay outgoing feeder, Line-6

Voltage level: 15KV

CTR Ratio =  $800/1\text{A} = 800$

Load Current Line-6 = 214.4A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 214.4 * 1.2 \\ &= 257.28\text{A} \end{aligned}$$

The second relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 257.8 / 800 \\ &= 0.3223\text{A} \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-6

To analyse TMS of the system, consider short circuit current analysis of Line-6 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\text{PSM of Line-6} = (9675/257.8)^{0.02}$$

$$= 1.079$$

$$T = \frac{0.14 * TMS}{\left(\frac{9675 \text{KA}}{257.8}\right)^{0.02} - 1}$$

$$T = 1.772 * TMS-6$$

### Name of the Bay outgoing feeder, Line-7

Voltage level: 15KV

CTR Ratio = 800/1A = 800

Load Current Line-7 = 180A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$I_p = I_L * 1.2 = 180 * 1.2.$$

$$= 216A$$

The second relay current is

$$I_s = I_p / \text{CTR} = 216 / 800$$

$$= 0.27A$$

### Time Multiplier Setting (TMS) of Line-7

To analyse TMS of the system, consider short circuit current analysis of Line-7 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\text{PSM of Line-7} = (9675/216)^{0.02}$$

$$= 1.079$$

$$T = \frac{0.14 * TMS}{\left(\frac{9.675 \text{KA}}{216}\right)^{0.02} - 1}$$

$$T = 1.772 * TMS-7$$

**Name of the Bay outgoing feeder, Line-8**

Voltage level: 15KV

CTR Ratio = 800/1A = 800

Load Current Line-8 = 200A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 200 * 1.2. \\ &= 240A \end{aligned}$$

The second relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 240 / 800 \\ &= 0.3A \end{aligned}$$

**Time Multiplier Setting (TMS) of Line-8**

To analyse TMS of the system, consider short circuit current analysis of Line-8 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of Line-8} &= (9675/240) ^{0.02} \\ &= 1.0767 \end{aligned}$$

$$T = \frac{0.14 * TMS}{\left(\frac{9.675 \text{KA}}{240}\right)^{0.02} - 1}$$

$$T = 1.825 * TMS-8.$$

**4.1.2 Transformer Feeder 15KV Side calculation****Name of the Bay Transformer Feeder-1 (TR-1)**

Voltage level: 15KV

CTR Ratio = 2000/1A = 2000

Load Current TR-1 = 772.5A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of existing system load.

$$\begin{aligned} IP &= IL * 1.2 = 772.5 * 1.2. \\ &= 927A \end{aligned}$$

The second relay current is

$$\begin{aligned} Is &= Ip / CTR = 927 / 2000 \\ &= 0.4635A \end{aligned}$$

### Time Multiplier Setting (TMS) of feeder TR-1

To analyse TMS of the system, consider short circuit current analysis of TR-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9.675KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of TR-1} &= (9675 / 772.5)^{0.02} \\ &= 1.048 \end{aligned}$$

$$T = \frac{0.14 * TMS}{9.675KA / 772.5^{0.02} - 1}$$

$$T = 2.916 * TMS - TR-1$$

### 4.1.3 Transformer Feeder 15KV Side Calculation

#### Name of the Bay Transformer Feeder-2 (TR-2)

Voltage level: 15KV

CTR Ratio = 2000/1A = 2000

Load Current TR-1 = 772.5A

Relay Nominal Current = 1A

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of existing system load.

$$\begin{aligned} I_P &= I_L * 1.2 = 772.5 * 1.2 \\ &= 927A \end{aligned}$$

The second relay current is

$$\begin{aligned} I_s &= I_p / CTR = 927 / 2000 \\ &= 0.4635A \end{aligned}$$

### Time Multiplier Setting (TMS) of TR-2

To analyse TMS of the system, consider short circuit current analysis of TR-2 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 9675KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of TR-2} &= (9675/927) ^{0.02} \\ &= 1.048 \end{aligned}$$

$$T = \frac{0.14 * TMS}{9.675KA / 1854^{0.02} - 1}$$

$$T = 2.916 * TMS-TR-2$$

#### 4.1.4 Transformer Incoming 132kV Side Calculation

##### Name of the Bay Transformer Incoming-1 (TI-1)

Voltage level: 132KV

CTR Ratio =  $400/1A = 400$

Load Current TR-1 = 215A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 215 * 1.2. \\ &= 258A \end{aligned}$$

The second relay current is

$$I_s = I_p / \text{CTR} = 258 / 400 \\ = 0.645 \text{ A}$$

### Time Multiplier Setting (TMS) of TI-1

To analyse TMS of the system, consider short circuit current analysis of TR-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 4.374 \text{ KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

NOTE: In this section, the 132kV side current in normal conditions is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

$$\text{For the 15kV side, } I = 50000 / (1.732 * 15).$$

$$= 1924.5008 \text{ A}$$

$$\text{For the 132kV side, } I = 50000 / (1.732 * 132).$$

$$= 218.693 \text{ A}$$

So, take the ratio of both 132 kV and 15 kV side current for the linear distribution of current flow within the system.

$$\text{Matching factor (CF)} = [15\text{kV}] / 132$$

$$\text{CF} = 1924 / 218.963$$

$$\text{CF} = 8.8$$

So the 132kV side load current is  $8.8 * 80 \text{ A} = 704 \text{ A}$ .

$$\text{PSM of TI} = (4374 / 704)^{0.02}$$

$$= 1.037$$

$$T = \frac{0.14 * \text{TMS}}{4374 \text{ KA} / 704 \text{ A}^{0.02} - 1}$$

$$T = 3.784 * \text{TMS-TI-1}$$

### 4.1.5 Transformer Incoming 132kV Side Calculation

#### Name of the Bay Transformer Incoming-1 (TI-2)

Voltage level: 132KV

$$\text{CTR Ratio} = 400/1\text{A} = 400$$

$$\text{Load Current TR-1} = 215\text{A}$$

$$\text{Relay Nominal Current} = 1\text{A.}$$

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 1.2 = 215 * 1.2. \\ &= 258\text{A} \end{aligned}$$

The second relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 258 / 400 \\ &= 0.645\text{A} \end{aligned}$$

### Time Multiplier Setting (TMS) of TI-2

To analyse TMS of the system, consider short circuit current analysis of TR-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 4.374\text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

NOTE: In this section, the 132kV side current in normal conditions is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

$$\begin{aligned} \text{For the 15kV side, } I &= 50000 / (1.732 * 15). \\ &= 1924.5008\text{A} \end{aligned}$$

$$\begin{aligned} \text{For the 132kV side, } I &= 50000 / (1.732 * 132). \\ &= 218.693\text{A} \end{aligned}$$

So, take the ratio of both 132 kV and 15 kV side current for the linear distribution of current flow within the system.

$$\text{Matching factor (CF)} = [15\text{kV}] / 132$$

$$\text{CF} = 1924 / 218.963$$

$$\text{CF} = 8.8$$

So the 132kV side load current is  $8.8 * 80\text{A} = 704\text{A}$ .

$$\begin{aligned} \text{PSM of TI} &= (4374/704)^{0.02} \\ &= 1.037 \end{aligned}$$

$$T = \frac{0.14 * TMS}{\left(\frac{4374 \text{KA}}{704 \text{A}}\right)^{0.02} - 1}$$

$$T = 3.784 * TMS - \text{TI-2}$$

#### 4.1.6, 132KV Incoming Line Calculation

##### Name of the Bay 132KV Incoming Line (IL)

Voltage level: 132KV

The 132KV incoming line current transformer, based on load flow analysis data for proper coordination of the substation, recommended a 600/1A current transformer. It's considering overload tolerance of the system.

CTR Ratio = 600/1A = 600

Load Current TR-1 = 150A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} \text{IP} &= \text{IL} * 1.2 = 150 * 1.2. \\ &= 180\text{A} \end{aligned}$$

The second relay current is

$$\begin{aligned} \text{Is} &= \text{Ip} / \text{CTR} = 180 / 600 \\ &= 0.30\text{A} \end{aligned}$$

#### Time Multiplier Setting (TMS) of IL

To analyse TMS of the system, consider short circuit current analysis of IL and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 4.374 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

NOTE: In this section, the 132kv side current in normal conditions is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

$$\text{For the 15kv side, } I = 50000 / (1.732 * 15).$$

$$= 1924.5 \text{ A}$$

$$\text{For the 132kv side, } I = 50000 / (1.732 * 132).$$

$$= 218.69 \text{ A}$$

So, take the ratio of both side currents for the linear distribution of current flow within the system.

$$\text{Current factor (CF)} = 15 \text{ KV} / 132 \text{ KV}$$

$$\text{Matching factor (CF)} = 1924.5 / 218.69$$

$$= 8.8$$

So the 132kv side load current is  $8.8 * 150 \text{ A} = 1320 \text{ A}$ .

$$\text{PSM of IL} = (4371 / 1320) ^{0.02}$$

$$= 1.0242$$

$$T = \frac{0.14 * TMS}{\left( \frac{4371 \text{ KA}}{1320 \text{ A}} \right)^{0.02} - 1}$$

$$T = 5.78 * TMS - I$$

## 4.2 Earth Fault Analysis

In an earth fault case, using phase to ground fault current to design short circuit analysis and for pickup calculation uses 20% of load current, which is an acceptable limit by the IEEE and IEC standards.

### 4.2.1 15KV outgoing lines Earth fault calculation

**Name of the Bay outgoing Line 1**

Voltage level: 15KV

CTR Ratio =  $800 / 1 \text{ A} = 800$

Load Current Line-1 = 191 A

Relay Nominal Current = 1A.

Relay type: micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per IEC guidelines, the acceptable tolerance of earth fault pickup current is 20% of the existing system load.

$$I_p = I_L * 0.2 = 191 * 0.2.$$

$$38.4 \text{ A}$$

The second relay current is

$$I_S = I_P / \text{CTR} = 38.2 / 800$$

$$= 0.0477 \text{ A}$$

### Time Multiplier Setting (TMS) of Line-1

to analyse TMS of the system, consider short circuit current analysis of Line-1 and relay.

Characteristics mentioned in the methodology section. The fault current between line to ground get from ETAP software fault current analysis is  $I_f = 11.272 \text{ KA}$

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\text{PSM of Line-1} = (11272 / 38.2)^{0.02}$$

$$= 1.120$$

$$T = \frac{0.14 * \text{TMS}}{4.198 \text{ KA} / 38.2^{0.02} - 1}$$

$$T = 1.166 * \text{TMS} - 1$$

### Name of the Bay outgoing Line 2

Voltage level: 15KV

CTR Ratio =  $800 / 1 \text{ A} = 800$

Load Current Line-1 = 500 A

Relay Nominal Current = 1A.

Relay type: micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of earth fault pickup current is 20% of the existing system load.

$$I_P = I_L * 0.2 = 500 * 0.2.$$

$$100 \text{ A}$$

The second relay current is

$$\begin{aligned} IS &= IP/CTR = 100/800 \\ &= 0.125A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-2

to analyse TMS of the system, consider short circuit current analysis of Line-2 and relay.

Characteristics mentioned in the methodology section. The fault current between line and ground gets from ETAP software fault current analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-2} &= (11272/100)^{0.02} \\ &= 1.0991 \end{aligned}$$

$$T = \frac{0.14 * TMS}{\frac{4198 \text{KA}}{12}^{0.02} - 1}$$

$$T = 1.412 * TMS-2$$

### Name of the Bay outgoing Line 3

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$

Load Current Line-1 = 430 A

Relay Nominal Current = 1A.

Relay type: micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of earth fault pickup current is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 0.2 = 430 * 0.2 \\ &= 86 \text{ A} \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= I_p/CTR = 86/800 \\ &= 0.1075A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-3

To analyse TMS of the system, consider short circuit current analysis of Line-3 and relay.

The characteristics mentioned in the methodology section. The fault current between line and ground gets from ETAP software fault current analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-3} &= (11272/86)^{0.02} \\ &= 1.1024 \end{aligned}$$

$$T = \frac{0.14 * TMS}{4198 \text{KA} / 120^{0.02} - 1}$$

$$T = 1.360 * TMS-3$$

#### Name of the Bay outgoing Line4

Voltage level: 15KV

CTR Ratio =  $800/1\text{A} = 800$

Load Current Line-1 = 212.4 A

Relay Nominal Current = 1A.

Relay type: micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of earth fault pickup current is 20% of the existing system load.

$$\begin{aligned} I_p &= I_L * 0.2 = 212.4 * 0.2 \\ &= 120 \text{ A} \end{aligned}$$

The second relay current is

$$\begin{aligned} I_s &= I_p / \text{CTR} = 120 / 800 \\ &= 0.15 \text{ A} \end{aligned}$$

#### Time Multiplier Setting (TMS) of Line-4

To analyse TMS of the system, consider short circuit current analysis of Line-4 and relay.

The characteristics mentioned in the methodology section. The fault current between line and ground gets from ETAP software fault current analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-4} &= (11272/120)^{0.02} \\ &= 1.095 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272KA / 120^{0.02} - 1}$$

$$T = 1.474 * TMS-4$$

### Name of the Bay outgoing Line-

Voltage level: 15KV

CTR Ratio = 800/1A = 800

Load Current Line-1 = 234.8 A

Relay Nominal Current = 1A.

Relay type: micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of earth fault pickup current is 20% of the existing system load.

$$IP = IL * 0.2 = 234.8 * 0.2.$$

$$46.96A$$

The second relay current is

$$IS = IP / CTR = 46.96 / 800$$

$$= 0.0587A$$

### Time Multiplier Setting (TMS) of Line-5

To analyse TMS of the system, consider short circuit current analysis of Line-5 and relay.

The characteristics mentioned in the methodology section. The fault current between line and ground gets from ETAP software fault current analysis is  $I_f = 11.272KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$PSM \text{ of Line-5} = (11.272 / 46.96)^{0.02}$$

$$= 1.115$$

$$T = \frac{0.14 * TMS}{11.272KA / 46.96^{0.02} - 1}$$

$$T = 1.218 * TMS-5$$

### Name of the Bay outgoing feeder, Line-6

Voltage level: 15KV

CTR Ratio = 800/1A = 800

Load Current Line-6 = 214.4A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of over loading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 214.4 * 0.2. \\ &= 42.88A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 42.88 / 800 \\ &= 0.0536A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-6

To analyse TMS of the system, consider short circuit current analysis of Line-6 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of Line-6} &= (11272 / 42.88)^{0.02} \\ &= 1.118 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272 \text{KA} / 42.88^{0.02} - 1}$$

$$T = 1.186 * TMS-6$$

### Name of the Bay outgoing feeder, Line-7

Voltage level: 15KV

CTR Ratio =  $800 / 1A = 800$

Load Current Line-7 = 180A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of over loading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 180 * 0.2. \\ &= 36A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 36 / 800 \\ &= 0.045A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-7

To analyse TMS of the system, consider short circuit current analysis of Line-7 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of Line-7} &= (11272/36)^{0.02} \\ &= 1.122 \end{aligned}$$

$$T = \frac{0.14 * TMS}{\frac{11.272 \text{KA}}{36}^{0.02} - 1}$$

$$T = 1.148 * TMS-7$$

### Name of the Bay outgoing feeder, Line-8

Voltage level: 15KV

CTR Ratio =  $800/1A = 800$

Load Current Line-8 = 200A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 200 * 0.2. \\ &= 40A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 40 / 800 \\ &= 0.05A \end{aligned}$$

### Time Multiplier Setting (TMS) of Line-8

To analyse TMS of the system, consider short circuit current analysis of Line-8 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-8} &= (11272/40)^{0.02} \\ &= 1.119 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272 \text{KA} / 40^{0.02} - 1}$$

$$T = 1.176 * TMS-8$$

### 4.2.2 Transformer Feeder 15KV Side Calculation

#### Name of the Bay Transformer Feeder-1 (TR-1)

Voltage level: 15KV

CTR Ratio =  $2000/1A = 2000$

Load Current TR-1 =  $772.5A$

Relay Nominal Current =  $1A$ .

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of over loading is 20% of the existing system load.

$$\begin{aligned} I_P &= I_L * 0.2 = 772.5 * 0.2 \\ &= 154.2A \end{aligned}$$

The second relay current is

$$\begin{aligned} I_S &= I_P / \text{CTR} = 154.2 / 2000 \\ &= 0.0771A \end{aligned}$$

### Time Multiplier Setting (TMS) of feeder TR-1

To analyse TMS of the system, consider short circuit current analysis of TR-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

$$\begin{aligned} \text{PSM of Line-TR-1} &= (11272/145.5)^{0.02} \\ &= 1.0895 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272KA / 154.5^{0.02} - 1}$$

$$T = 1.564 * TMS\text{-TR-1}$$

### 4.2.3 Transformer Feeder 15KV Side Calculation

#### Name of the Bay Transformer Feeder-1 (TR-2)

Voltage level: 15KV

CTR Ratio = 2000/1A = 2000

Load Current TR-1 = 772.5A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 772.5 * 0.2 \\ &= 154.2A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 154.2 / 2000 \\ &= 0.0771A \end{aligned}$$

#### Time Multiplier Setting (TMS) of feeder TR-2

To analyse TMS of the system, consider short circuit current analysis of TR-1 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

$$\begin{aligned} \text{PSM of Line-TR-1} &= (11272/145.5)^{0.02} \\ &= 1.0895 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272KA / 154.5^{0.02} - 1}$$

$$T = 1.564 * TMS-TR-2$$

#### 4.2.4 Transformer Incoming 132kV Side Calculation

##### Name of the Bay Transformer Incoming-1 (TI-1)

Voltage level: 132KV

CTR Ratio =  $400/1A = 400$

Load Current TR-1 = 215A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of over loading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 215 * 0.2. \\ &= 43A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 43 / 400 \\ &= 0.1075A \end{aligned}$$

##### Time Multiplier Setting (TMS) of TI-1

To analyse TMS of the system, consider short circuit current analysis of TR-2 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272KA$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$

NOTE: In this section, the 132kv side current in normal condition, is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

For the 15kv side,  $I = 50000 / (1.732 * 15)$ .

$$= 1924.5008A$$

For the 132kv side,  $I = 50000 / (1.732 * 132)$ .

$$= 218.693A$$

So, take the ratio of both 132 kV and 15 kV side current for the linear distribution of current flow within the system.

$$\text{Matching factor (CF)} = I [15\text{kV}] / I 132$$

$$\text{CF} = 1924/218.693$$

$$\text{CF} = 8.8$$

So the 132 kV side load current is  $8.8 \times 43\text{A} = 378.4\text{A}$ .

$$\text{PSM of TI-1} = (11272/378.4)^{0.02}$$

$$= 1.0702$$

$$T = \frac{0.14 * \text{TMS}}{11.272\text{KA} / 378.4\text{A}^{0.02} - 1}$$

$$T = 1.994 * \text{TMS-TI-1}$$

#### 4.2.5 Transformer Incoming 132kV Side Calculation

##### Name of the Bay Transformer Incoming-1 (TI-2)

Voltage level: 132KV

CTR Ratio =  $400/1\text{A} = 400$

Load Current TI-2 = 215A

Relay Nominal Current = 1A.

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$I_p = I_L * 0.2 = 215 * 0.2.$$

$$= 43\text{A}$$

The second relay current is

$$I_s = I_p / \text{CTR} = 43/400$$

$$= 0.1075\text{A}$$

##### Time Multiplier Setting (TMS) of TI-2

To analyse TMS of the system, consider short circuit current analysis of TR-2 and relay characteristics mentioned in the methodology section.

The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ .

Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f/I_p$

NOTE: In this section, the 132kV side current in normal conditions is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

$$\text{For the 15kV side, } I = 50000 / (1.732 * 15).$$

$$= 1924.5008 \text{A}$$

$$\text{For the 132 kV side, } I = 50000 / (1.732 * 132).$$

$$= 218.693 \text{A}$$

So, take the ratio of both 132 kV and 15 kV side current for the linear distribution of current flow within the system.

$$\text{Matching factor (CF)} = I [15\text{kV}] / I 132$$

$$\text{CF} = 1924 / 218.693$$

$$\text{CF} = 8.8$$

So the 132 kV side load current is  $8.8 * 43 \text{A} = 378.4 \text{A}$ .

$$\text{PSM of TI-1} = (11272 / 378.4)^{0.02}$$

$$= 1.0702$$

$$T = \frac{0.14 * TMS}{11.272 \text{KA} / 378.4 \text{A}^{0.02} - 1}$$

$$T = 1.994 * TMS - \text{TI-2}$$

#### 4.2.6, 132KV Incoming Line Calculation

##### Name of the Bay 132KV Incoming Line (IL)

Voltage level: 132KV

132KV incoming line current transformer, based on load flow analysis data for proper coordination of the substation, the ration of current transformer 600/1A. It's considering overload tolerance of the system.

$$\text{CTR Ratio} = 600 / 1 \text{A} = 600$$

$$\text{Load Current TR-1} = 300 \text{A}$$

$$\text{Relay Nominal Current} = 1 \text{A}.$$

Relay type: Micom numerical relay

**Pickup current calculation:** before calculating pickup current, consider permissible overloading of the existing load. As per EEP guidelines, the acceptable tolerance of overloading is 20% of the existing system load.

$$\begin{aligned} IP &= IL * 0.2 = 300 * 0.2. \\ &= 60A \end{aligned}$$

The second relay current is

$$\begin{aligned} IS &= IP / CTR = 60 / 600 \\ &= 0.1A \end{aligned}$$

### Time Multiplier Setting (TMS) of IL

To analyse TMS of the system, consider short circuit current analysis of IL and relay characteristics mentioned in the methodology section. The fault current get from ETAP software short circuit analysis is  $I_f = 11.272 \text{KA}$ . Coordination ratio of fault current with pickup setting is plug setting multiplier (PSM) =  $I_f / I_p$ .

NOTE: In this section, the 132kV side current in normal conditions is less than the downstream current flow, so we have to calculate the proper current coordination considering the transformer rating and voltage levels of both sides.

$$S = 1.732 * V * I$$

$$\begin{aligned} \text{For the 15kV side, } I &= 50000 / (1.732 * 15). \\ &= 1924.5A \end{aligned}$$

$$\begin{aligned} \text{For the 132kV side, } I &= 50000 / (1.732 * 132). \\ &= 218.69A \end{aligned}$$

So, take the ratio of both side currents for the linear distribution of current flow within the system.

$$\text{Current factor (CF)} = I_{[15kV]} / I_{132}$$

$$CF = 1924.5 / 218.69$$

$$CF = 8.8$$

So the 132kV side load current is  $8.8 * 60A = 528A$ .

$$\begin{aligned} \text{PSM of IL} &= (11272 / 528) ^{0.02} \\ &= 1.063 \end{aligned}$$

$$T = \frac{0.14 * TMS}{11.272KA / 528A^{0.02} - 1}$$

$$T = 2.222 * TMS-IL$$

### 4.3 Differential Transformer Relay Analysis

The differential protection is the main protection for transformer internal faults, but earth fault and over-current protections are the backup devices. This function acts as high speeds selective short-circuit protection. The differential protection principle is based on a current comparison. In normal operation, and for external faults, the sum of currents entering and leaving the protection zone/area is expected to be zero. This consideration applies strictly to the primary current values in the high-voltage switching station. In contrast, the through-the-current transformer transformed secondary currents passed contain measuring errors. Consequently, even in a healthy operation, the sum of the currents processed in the devices is not exactly zero. The differential protection tripping characteristic is designed to provide stability against current proportional errors, which may result from transformation errors of the current transformers, tap changer influences, or differential current caused by current transformer saturation in the case of through-fault conditions. The characteristic branch *represents* the sensitivity threshold of the differential protection and considers constant fault currents like magnetizing currents. The current-proportional errors may result from transformation errors of the main current transformers, the device input current transformer, or the influence of tap changers. EEP, guidelines

Transformer collects data

- SN (KVA) = 50000
- V1N (HV) = 132KV
- V2N (lv) = 15kv

Full load current = MVA/1.732\*(HV) KV

$$50000 / (1.732 * 132) = 218.699A.$$

Secondary full load current = MVA/1.732\*(LV) KV

$$50000 / (1.732 * 15) = 1924.557A.$$

#### 4.3.1 CT Secondary Current

IP FLC = Primary full load current/CT ratio

- $218.99/4000/1=218.99*1/400=0.5475$

$$\text{IS FLC} = 1924.557/2000/1 = 1924.557*1/2000 = 0.9623$$

CT Matching factor

$$\text{IPFLC} = 1/0.55 = 1.82$$

$$\text{IS FLC} = 1/0.96 = 1.042$$

For the correct matching factor, multiply with the second corresponding matching factor.

The correct matching factor for the primary side is

Source side  $1.82*0.55=0.91$ , Lv side  $1.042*0.6=0.63$  And the correct matching factor of the relay

4.3.2 Setting for differential relay becomes

- ✓  $\text{ID} \geq 30\%$
- ✓  $\text{ID} \geq 1200\%$
- ✓  $\text{Slope1} = 30\%$
- ✓  $\text{End section 2} = 150\%$
- ✓  $\text{Slope2} = 100\%$

4.3.3 For the differential relay test, we have the following parameters:

- ✚ Pick-up test
- ✚ Stability test
- ✚ Instability test
- ✚ Slope test:-
  - a/shot test
  - b/search test

Pick up current (Threshold I Diff $\geq$ ) calculation: This parameter sets the pickup threshold for the differential current and is referenced to the rated current of the protected object ( $I_{rated}$ ). The base setting for the transformer is  $0.3 I_{rated}$ , to cover the magnetizing current, current transformer magnetizing current, and relay tolerances. The error due to the on-load tap changer is considered as follows  $Thresho \quad d \text{ value} \geq 0.3 I_{rated}$ ,

I-PICK=

$$\text{ID} \geq 30\%$$

$$\text{ID (HV)} = 0.5475*0.3 = 0.164$$

$$\text{ID (LV)} = 0.9623*0.3 = 0.288$$

**Stability test calculation:** For checking stability, the current magnitude is above the pickup value and below the high differential value.

- a. **Stability analysis** of the angle of the two sides, which are the primer and second side, should be  $0^\circ, -120^\circ, 120^\circ$  and  $210^\circ, 90^\circ, 330^\circ$
- b. **Instability analysis** of the angle of the two sides should be the same but the magnitude of the two- side current should be different.

Table4. 1. Pick up current Setting value for differential relay

IPFLC	IS FLC	ID>(HV)	ID>(Lv)	ID>>(HV)	ID>>(Lv)
0.55	0.96	0.164	0.288	6.6	11.52

Table4. 2 Result  $I_p$ , PSM and minimized objective function for over current

Name of bays	CTR	PICKUP	PSM	OBJ of TMS
L-1	800/1	229.2	1.077	1.818
L-2	800/1	600	1.057	2.451
L-3	800/1	516	1.0604	2.31
L-4	800/1	254.88	1.075	1.86
L-5	800/1	281.76	1.073	1.92
L-6	800/1	257.3	1.079	1.772
L-7	800/1	216	1.079	1.772
L-8	800/1	240	1.0767	1.825
Feeder TR-1	2000/1	927	1.048	2.916
Feeder TR-2	2000/1	927	1.048	2.916
TI-1	400/1	258	1.037	3.784
TI-2	400/1	258	1.037	3.784
IL	600/1	180	1.0242	5.78

## Earth Fault

Table 4. 3 Result of  $I_p$ , PSM and minimized objective function for earth fault

Name of bays	CTR	PICKUP	PSM	OBJ of TMS
L-1	800/1	38.4	1.120	1.166
L-2	800/1	100	1.0991	1.412
L-3	800/1	86	1.1024	1.360
L-4	800/1	120	1.095	1.474
L-5	800/1	46.96	1.12	1.218
L-6	800/1	42.88	1.118	1.186
L-7	800/1	36	1.122	1.148
L-8	800/1	40	1.119	1.176
Feeder TR-1	2000/1	154.5	1.09	1.089
Feeder TR-2	2000/1	154.5	1.09	1.089
TI-1	400/1	43	1.070	1.994
TI-2	400/1	43	1.070	1.994
IL	600/1	60	1.063	2.222

After calculating all things, we have a summarized result in tables 4.1, 4.2, and 4.3. It shows using pick up load of existing data and total bay information to calculate the pickup current and plug setting multipliers of over-current and earth fault value of each line. The result of PSM in both conditions is within the limit ( $0.1 \leq PSM \leq 1.2$ ), its acceptable value of inverse time relays. Then we have to calculate to minimize the objective function to linear equation form.

## CHAPTER FIVE

### RESULT AND DISCUSSION

#### 5.1 RESULT

##### 5.2.1 Overcurrent Result

##### Coordination of line-1 WOA (whale optimization algorithm)

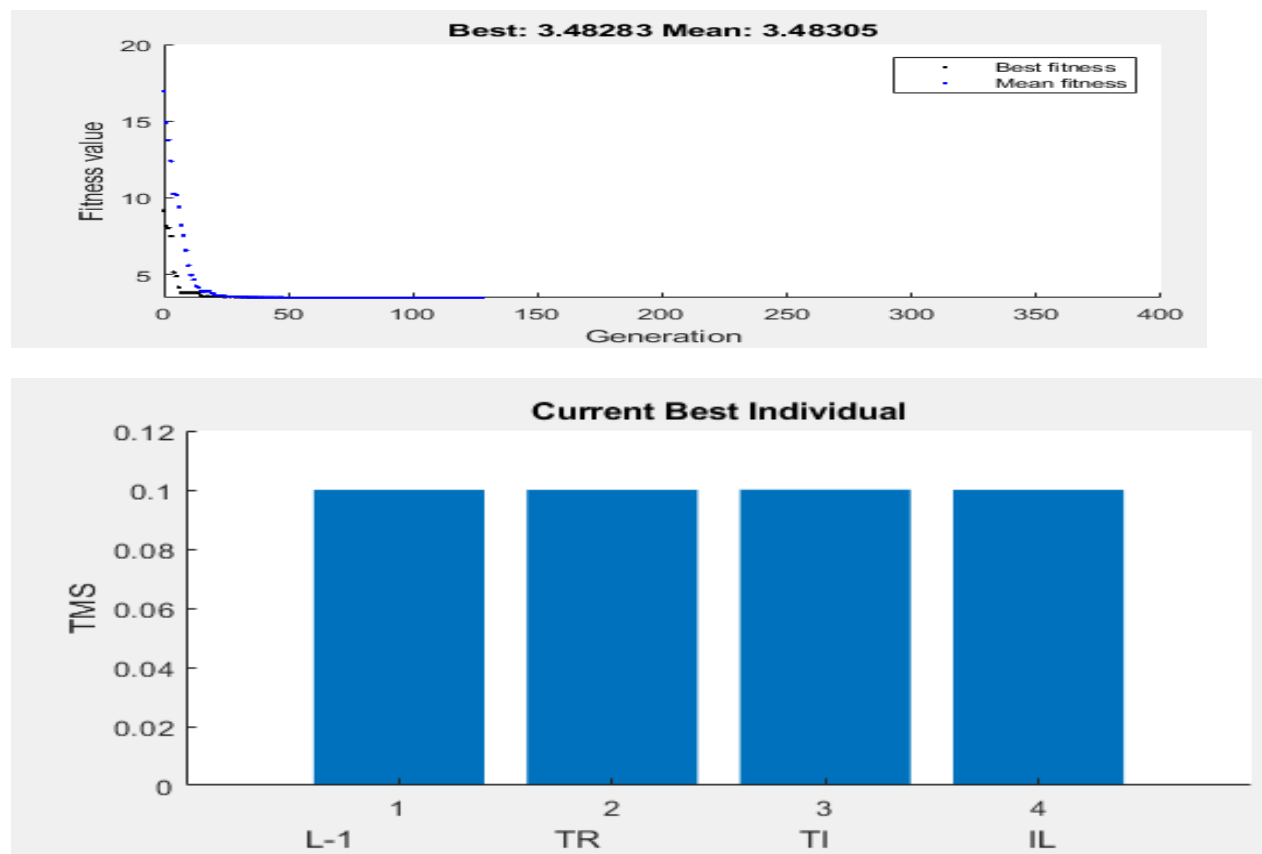


Figure5. 1Result of line-1 objective/fitness value and TMS

Table5. 1Operating time coordination of Line-1WOA

Bays	Outgoing line [L-1]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.31818	0.60978	0.98818	1.56618
Objective/fitness function in Sec	3.4823			

### Coordination of line-1 GA

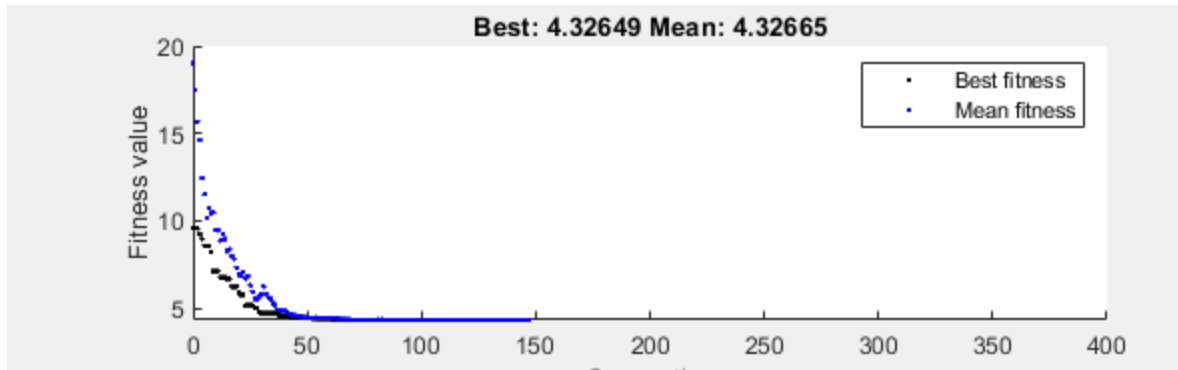


Figure5. 2 Result of line-1 objective/fitness value and TMS GA

Table5. 2 Operating time coordination of Line-1 GA

Bays	Outgoing line [L-1]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.41816	0.76808	1.2222	1.9158
Objective/fitness function in Sec	4.3242			

### Coordination of line-2-WOA

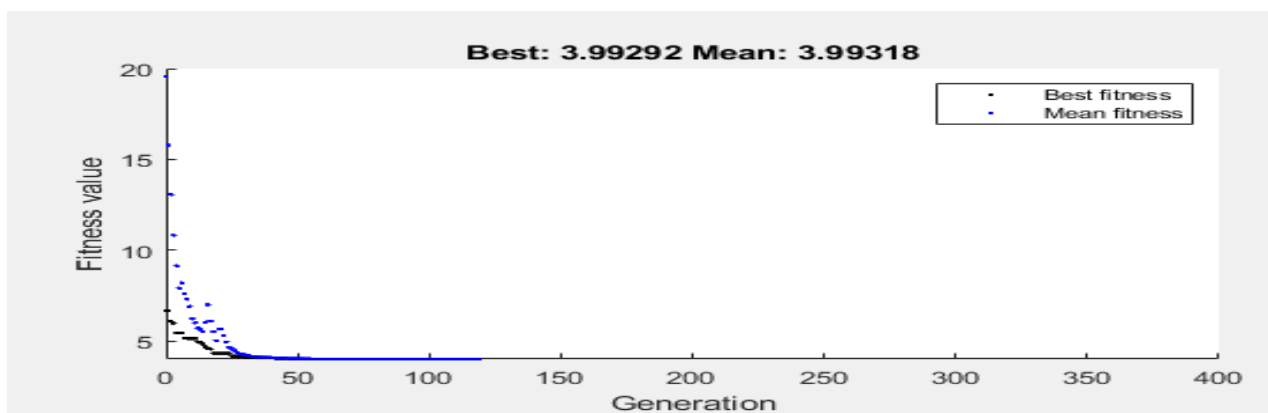




Figure5. 3 Result of line-2 objective/fitness value and TMS

Table5. 3 Operating time coordination of Line-2WOA

Bays	Outgoing line [L-2]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.4451	0.7367	1.1151	1.6931
Objective/fitness function in Sec	3.9931			

**Coordination of line-2-GA**

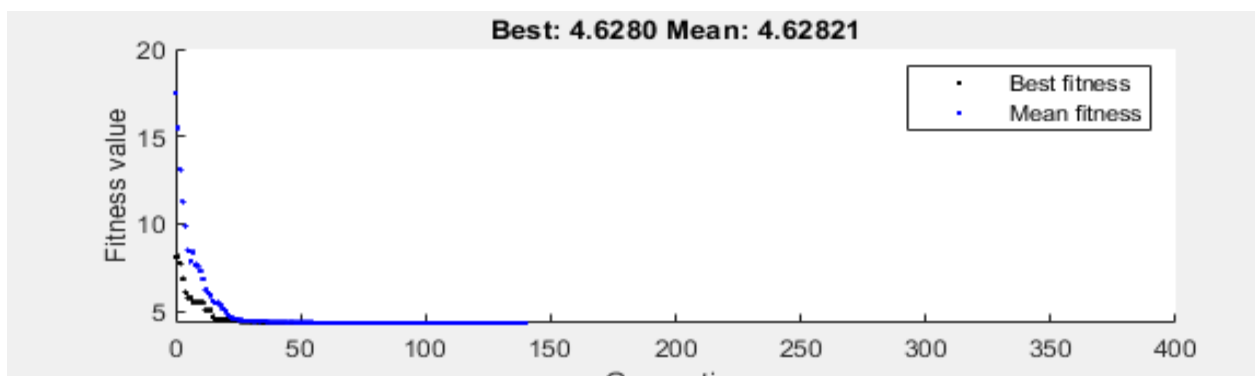


Figure5. 4 Result of line-2 objective/fitness value and TMS GA

Table5. 4 Operating time coordination of Line-2 GA

Bays	Outgoing line [L-2]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.49412	0.84404	1.29812	1.99172
Objective/fitness function in Sec	4.628			

**Coordination of line-3WOA**

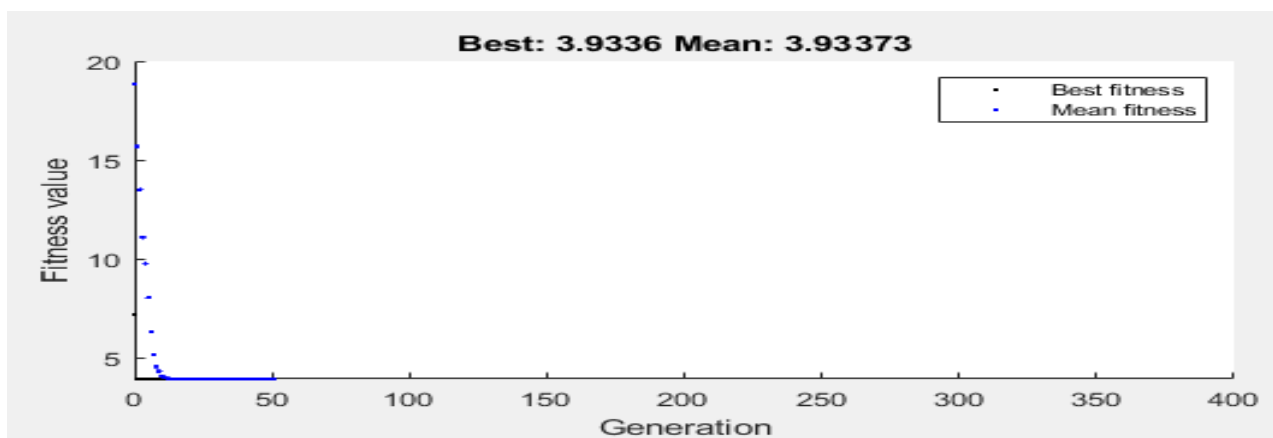


Figure5. 5 Result of line-3 objective/fitness value and TMS

Table5. 5 Operating time coordination of Line-3 WOA

Bays	Outgoing line [L-3]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.431	0.7226	1.101	1.679
Objective/fitness function in Sec	3.9336			

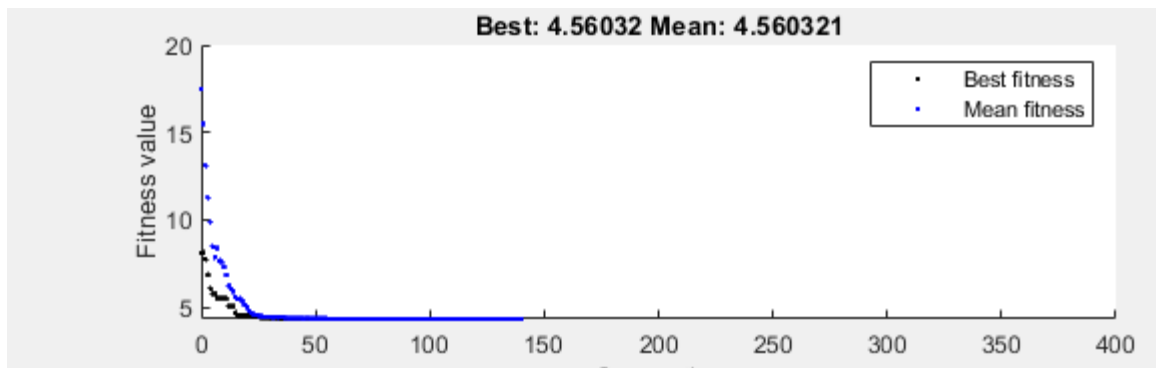


Table5. 6 Operating time coordination of Line-3 GA

Bays	Outgoing line [L-3]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.4772	0.82712	1.2812	1.9748
Objective/fitness function in Sec	4.56032			

**Coordination of line-4WOA**

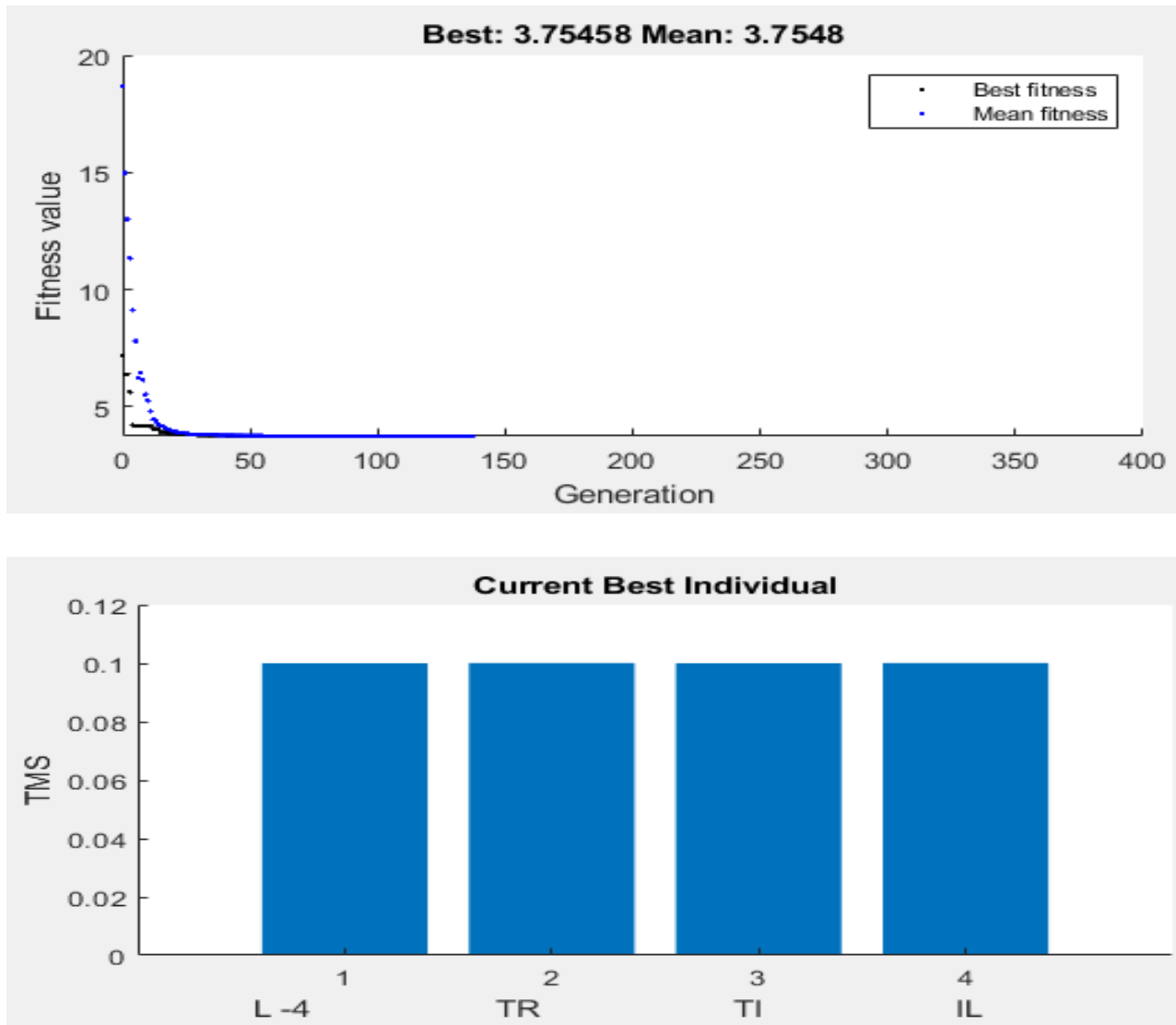


Figure5. 6 Result of line-4 objective/fitness value and TMS

Table5. 7 Operating time coordination of Line-4WOA

Bays	Outgoing line [L-4]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.386	0.6776	1.056	1.634
Objective/fitness function in Sec	3.7536			

**Coordination of line-4GA**

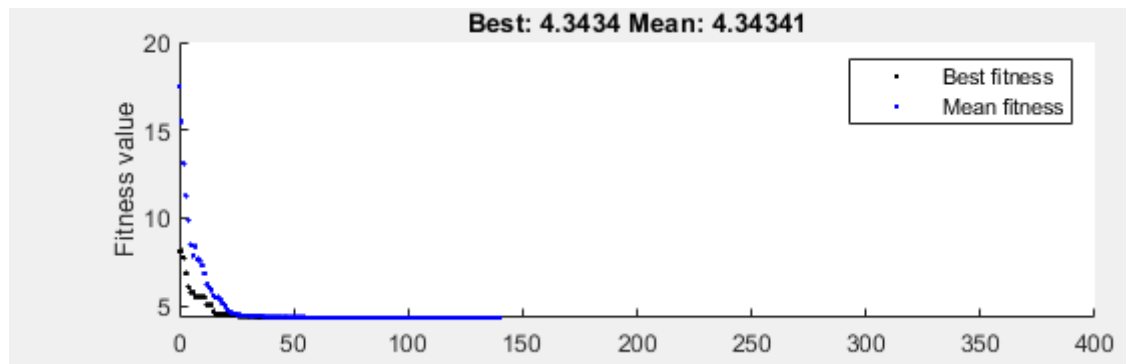


Figure5. 7 Result of line-4 objective/fitness value and TMS GA

Table5. 8 Operating time coordination of Line-4 GA

Bays	Outgoing line [L-4]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.4232	0.77312	1.2272	1.9208
Objective/fitness function in Sec	4.3443			

**Coordination of line-5 WOA**

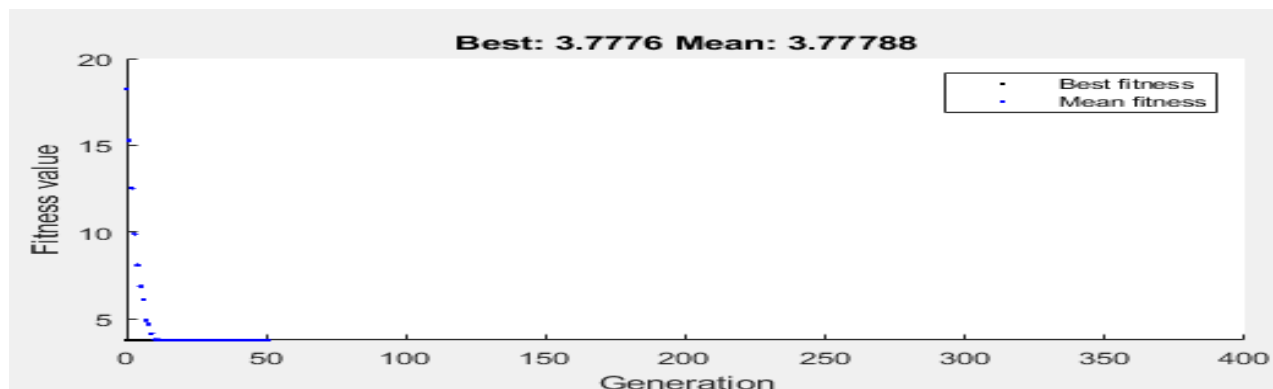




Figure5. 8 Result of line-5 objective/fitness value and TMS

Table5. 9 Operating time coordination of Line-5 WOA

Bays	Outgoing line [L-5]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.392	0.6836	1.062	1.640
Objective/fitness function in Sec	3.7776			

### Coordination of line-5 GA

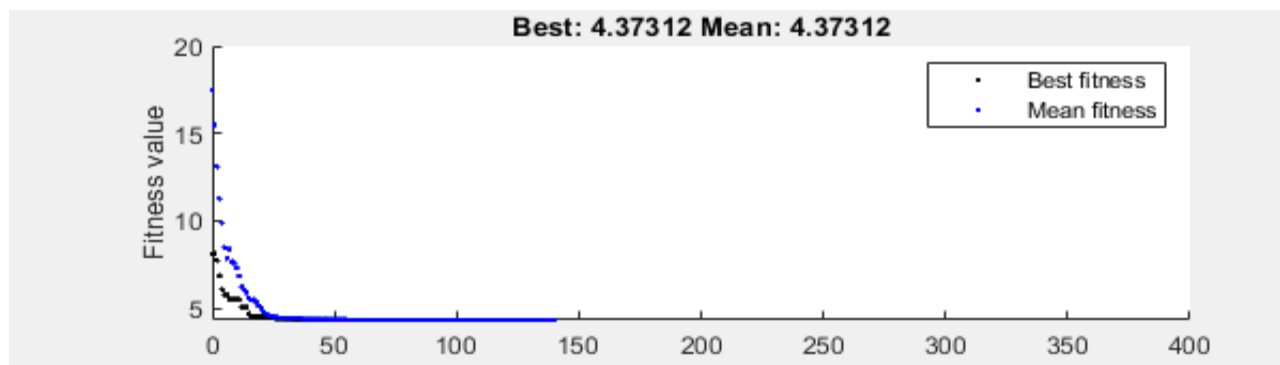


Figure5. 9 Result of line-5 objective/fitness value and TMS GA

Table5. 10 Operating time coordination of Line-5 GA

Bays	Outgoing line [L-5]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.4304	0.78032	1.2344	1.9280
Objective/fitness function in Sec	4.37312			

**Coordination of line-6 WOA**

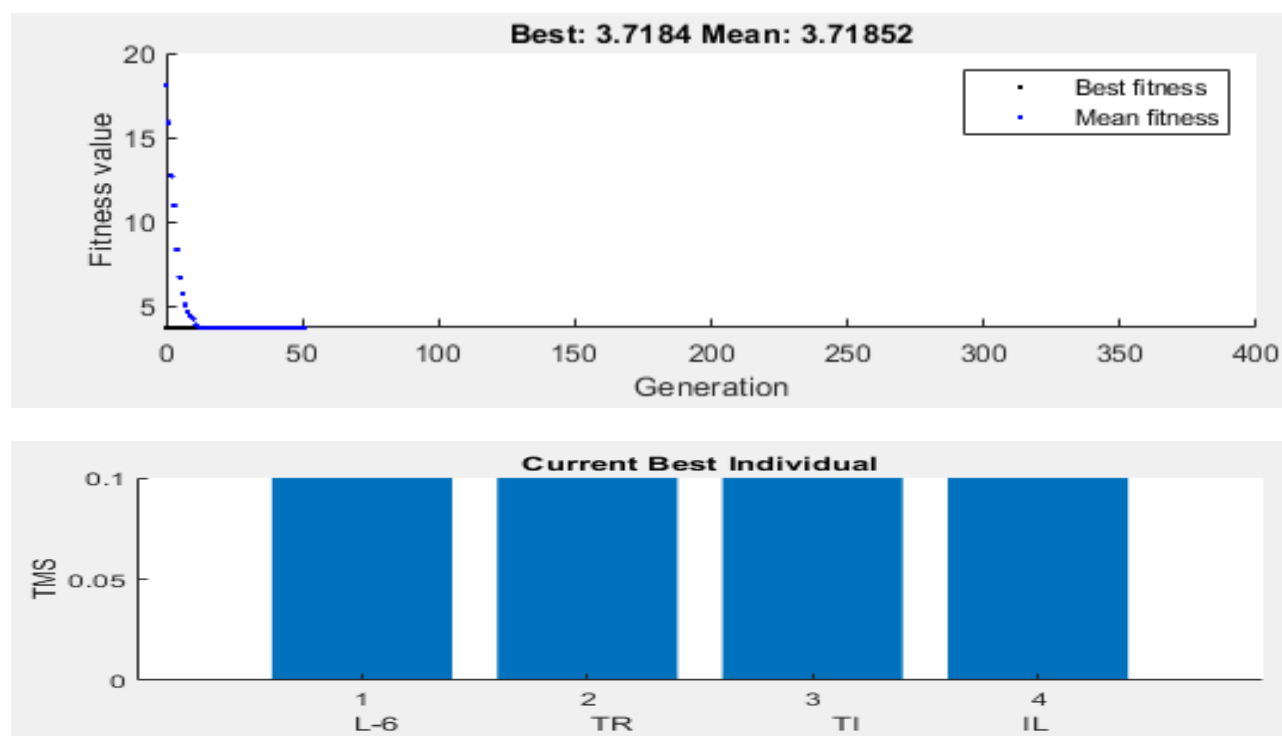


Figure5. 10 Result of line-6 objective/fitness value and TMS

Table5. 11 Operating time coordination of Line-6 WOA

Bays	Outgoing line[L-6]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3772	0.6688	1.0472	1.6252
Objective/fitness function in Sec	3.7184			

### Coordination of line-6 GA

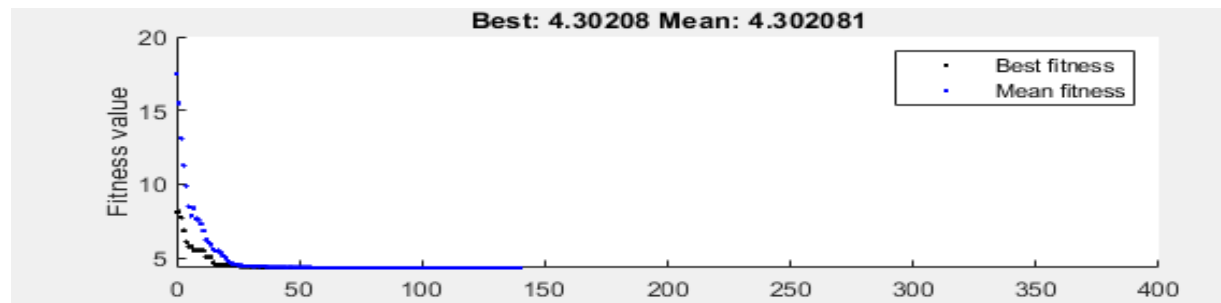


Figure5. 11 Result of line-6 objective/fitness value and TMS GA

Table5. 12 Operating time coordination of Line-6 GA

Bays	Outgoing line[L-6]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.41264	0.76256	1.21664	1.91024
Objective/fitness function in Sec	4.30208			

### Coordination of line-7 WOA

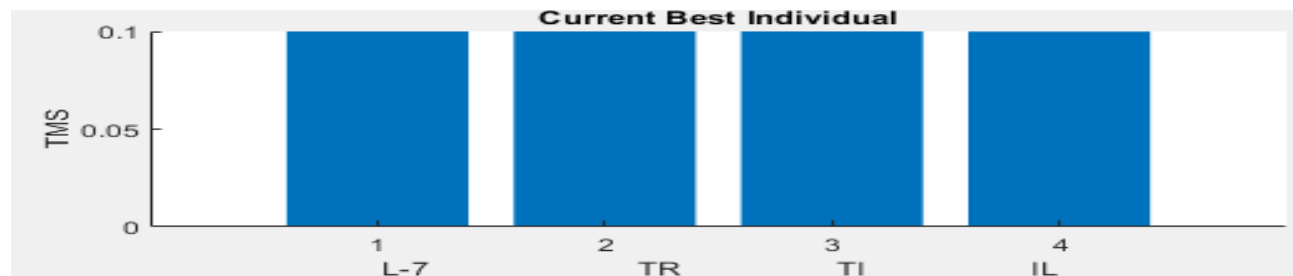
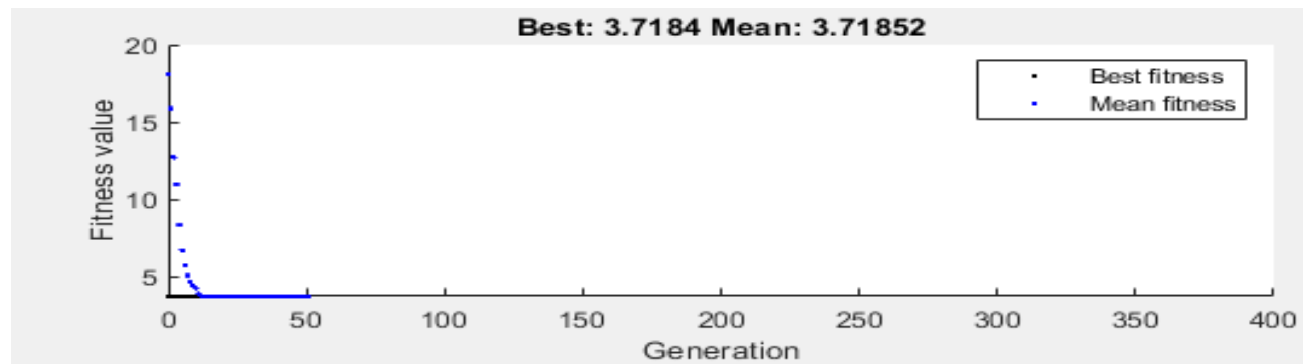


Figure5. 12 Result of line-7 objective/fitness value and TMS

Table5. 13 Operating time coordination of Line-7 WOA

Bays	Outgoing line[L-7]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3772	0.6688	1.0472	1.6252
Objective/fitness function in Sec	3.7184			

**Coordination of line-7 GA**

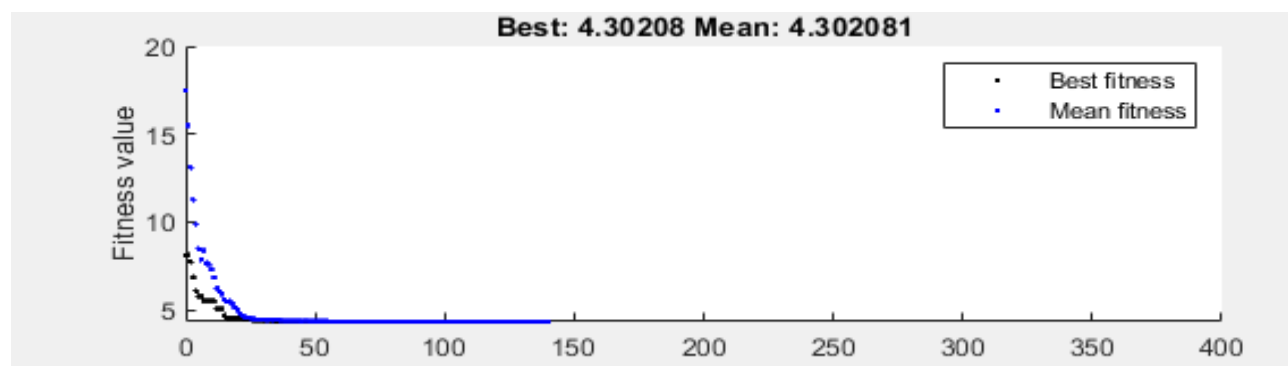


Figure5. 13 Result of line-7objective/fitness value and TMS GA

Table5. 14 Operating time coordination of Line-7 GA

Bays	Outgoing line[L-7]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.41264	0.76256	1.21664	1.91024
Objective/fitness function in Sec	4.30208			

**Coordination of line-8 WOA**

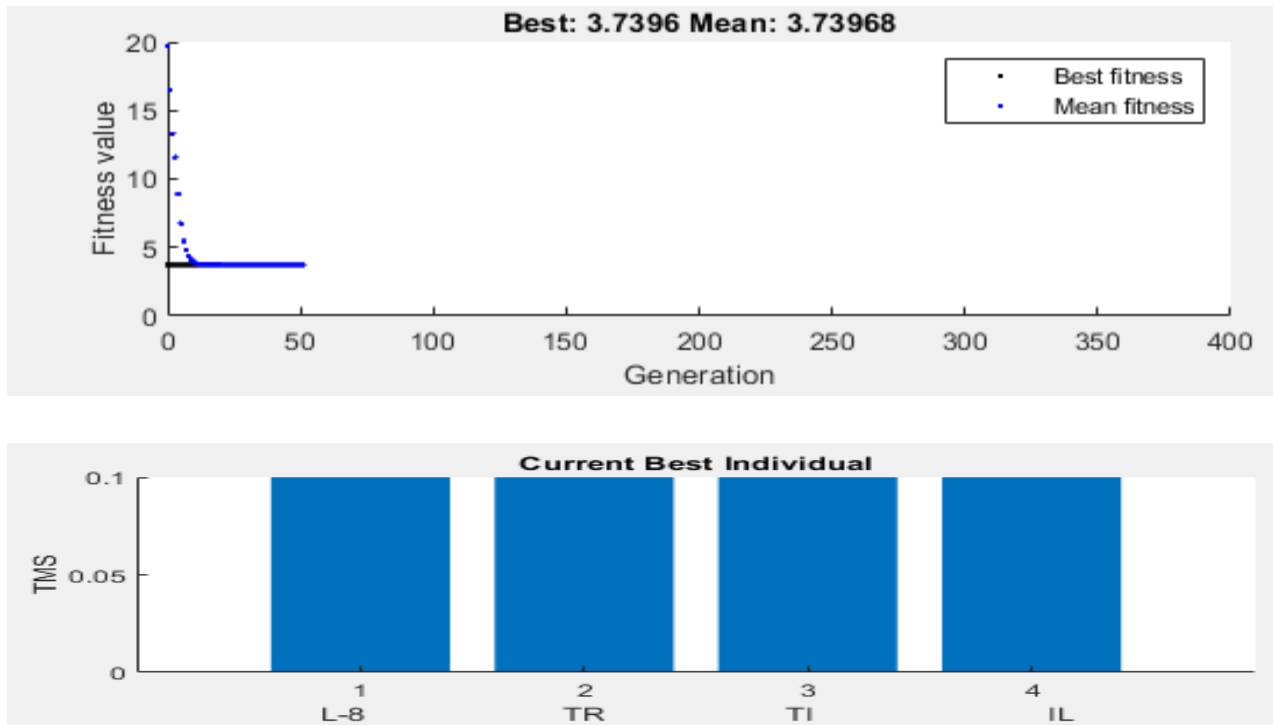


Figure5. 14 Result of line-8 objective/fitness value and TMS

Table5. 15 Operating time coordination of Line-8 WOA

Bays	Outgoing line[L-8]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3825	0.6741	1.0525	1.6305
Objective/fitness function in Sec	3.7396			

**Coordination of line-8 GA**

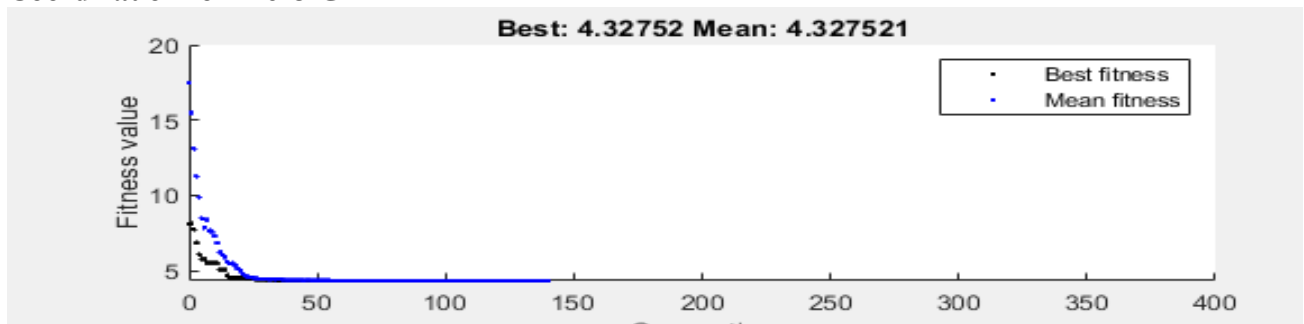


Figure5. 15 Result of line-8 objective/fitness value and TMS GA

Table 5. 16 Operating time coordination of Line-8 GA

Bays	Outgoing line[L-8]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.4190	0.76892	1.2230	1.9160
Objective/fitness function in Sec	4.32752			

### 5.2.2 Earth Fault Result

#### Coordination of line-1 WOA

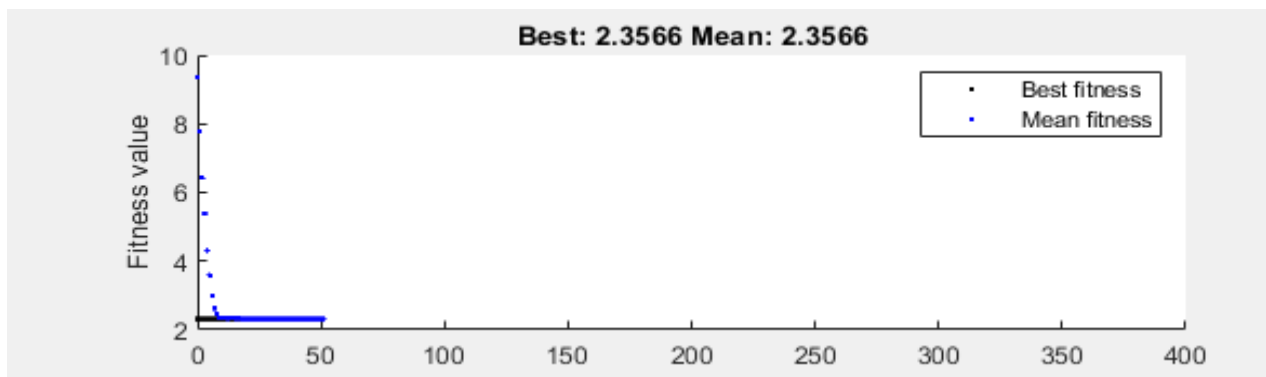


Figure 5. 16 Result of line-1 objective/fitness value and TMS

Table5. 17 Operating time coordination of Line-1WOA

Bays	Outgoing line [L-1]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3166	0.4730	0.6724	0.89460
Objective/fitness function in Sec	2.3566			

**Coordination of line-1GA**

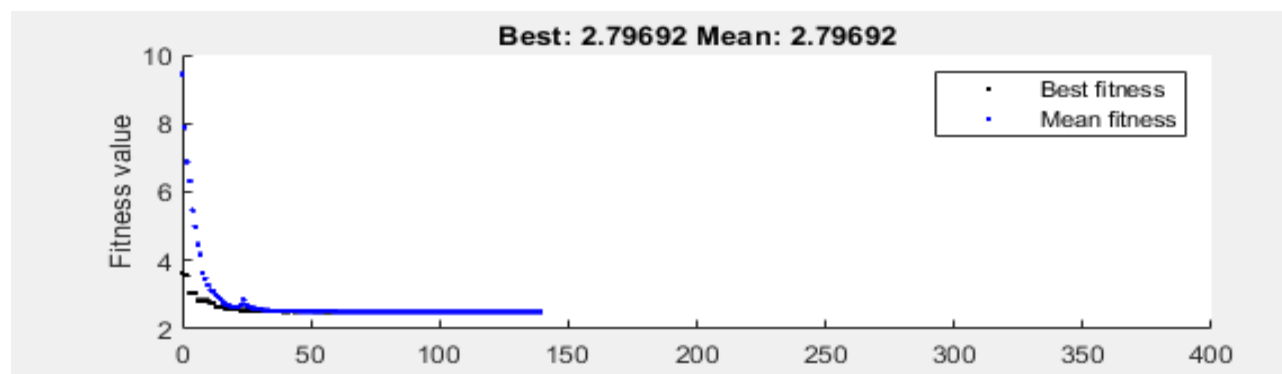


Figure5. 17 Result of line-1 objective/fitness value and TMS GA

Table5. 18 Operating time coordination of Line-1 GA

Bays	Outgoing line [L-1]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.33992	0.5706	0.80988	1.07652
Objective/fitness function in Sec	2.79692			

**Coordination of line-2 WOA**

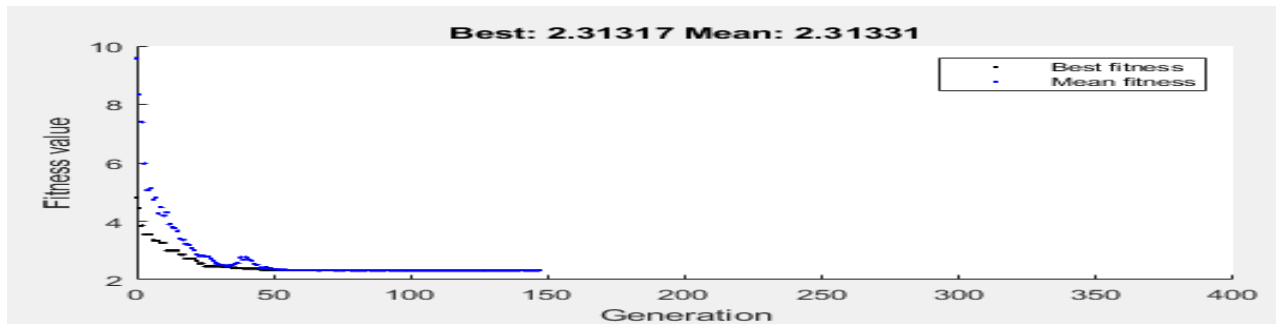


Figure5. 18 Result of line-2 objective/fitness value and TMS

Table5. 19 Operating time coordination of Line-2 WOA

Bays	Outgoing line [L-2]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3412	0.4501	0.6495	0.8715
Objective/fitness function in Sec	2.3123			

### Coordination of line-2GA

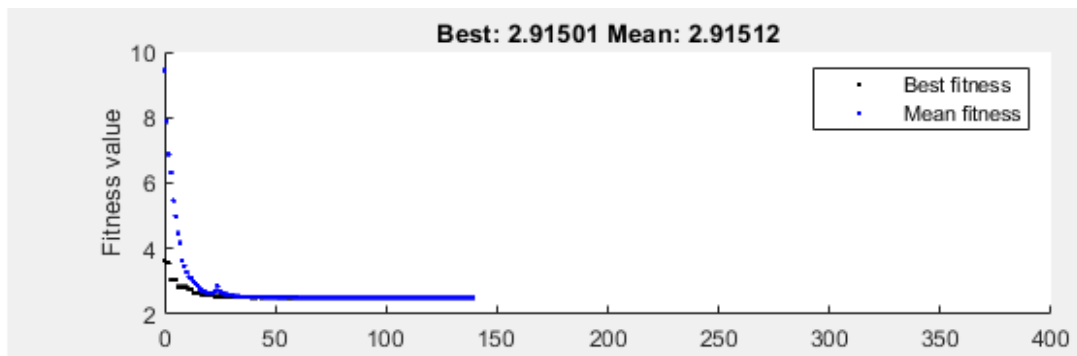


Figure5. 19 Result of line-2 objective/fitness value and TMS GA

Table5. 20 Operating time coordination of Line-2 GA

Bays	Outgoing line [L-2]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.36944	0.60012	0.8394	1.10604
Objective/fitness function in Sec	2.9150			

### Coordination of line-3WOA

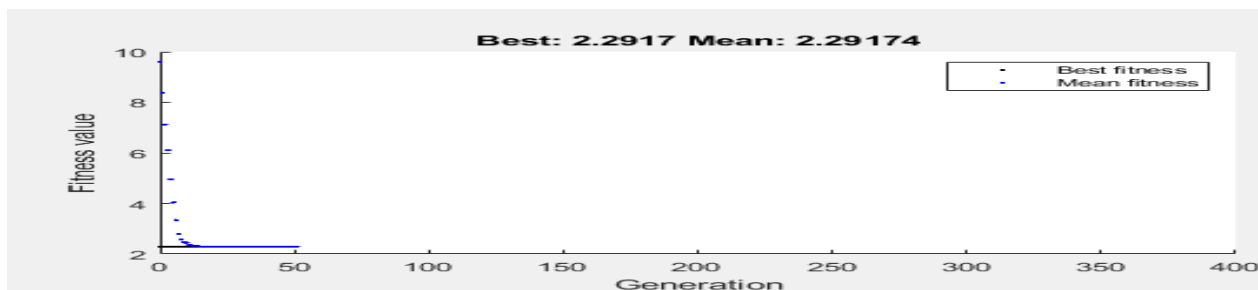


Figure5. 20 Result of line-3 objective/fitness value and TMS

Table5. 21 Operating time coordination of Line-3WOA

Bays	Outgoing line [L-3]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3360	0.4449	0.6443	0.8665
Objective/fitness function in Sec	2.2917			

**Coordination of line-3 GA**

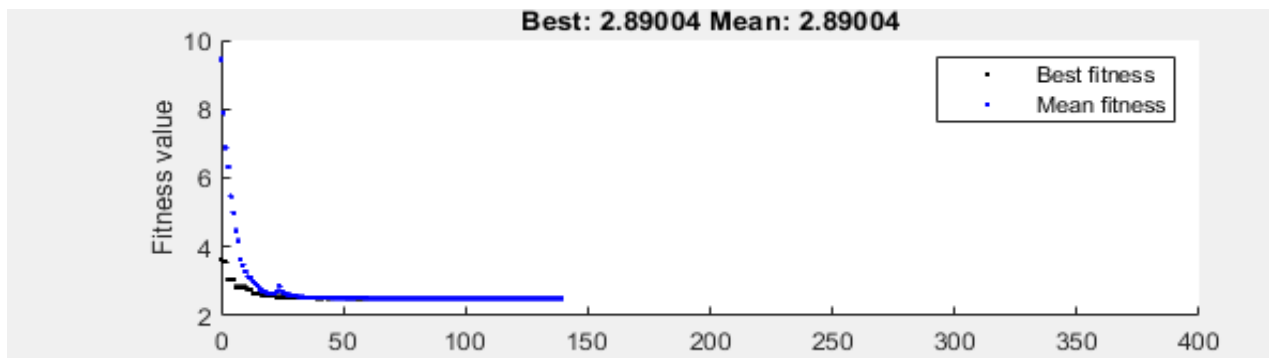


Figure5. 21 Result of line-3 objective/fitness value and TMS GA

Table5. 22 Operating time coordination of Line-3 GA

Bays	Outgoing line [L-3]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3632	0.59388	0.83316	1.0998
Objective/fitness function in Sec	2.89004			

**Coordination of line-4 WOA**

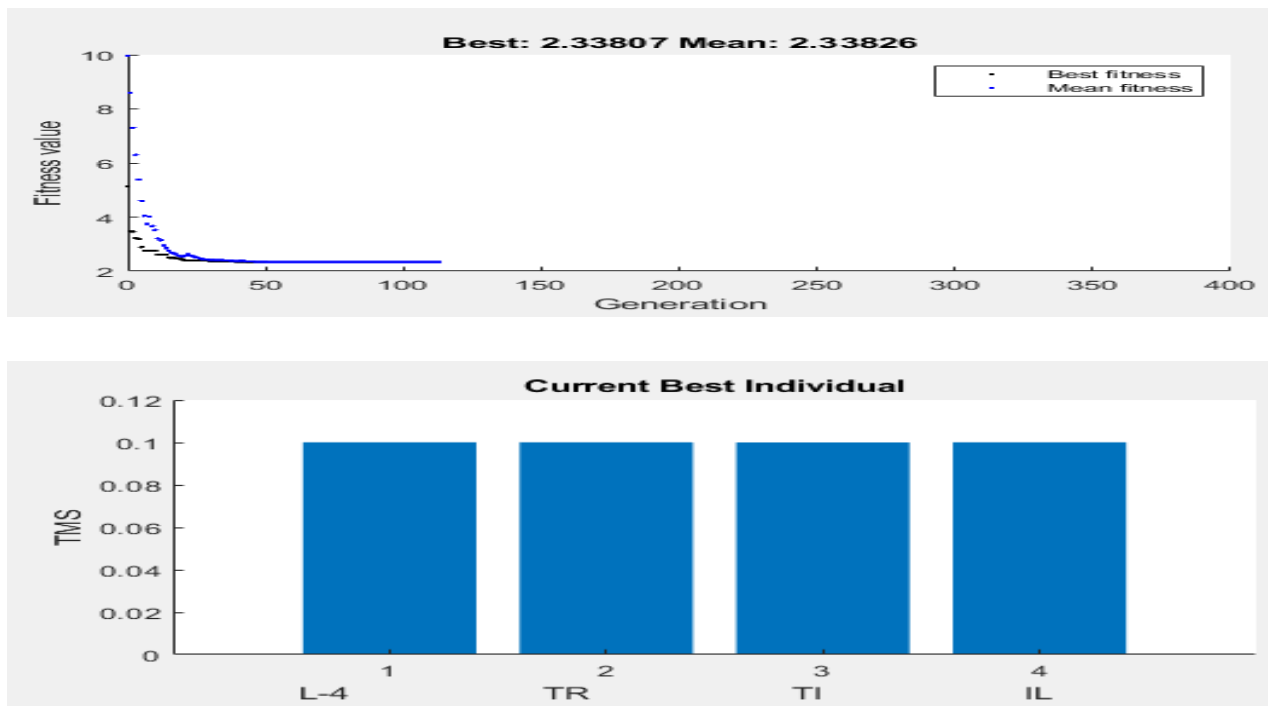


Figure5. 22 Result of line-4 objective/fitness value and TMS

Table5. 23 Operating time coordination of Line-4 WOA

Bays	Outgoing line [L-4]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3474	0.4563	0.6557	0.8779
Objective/fitness function in Sec	2.3373			

**Coordination of line-4 GA**

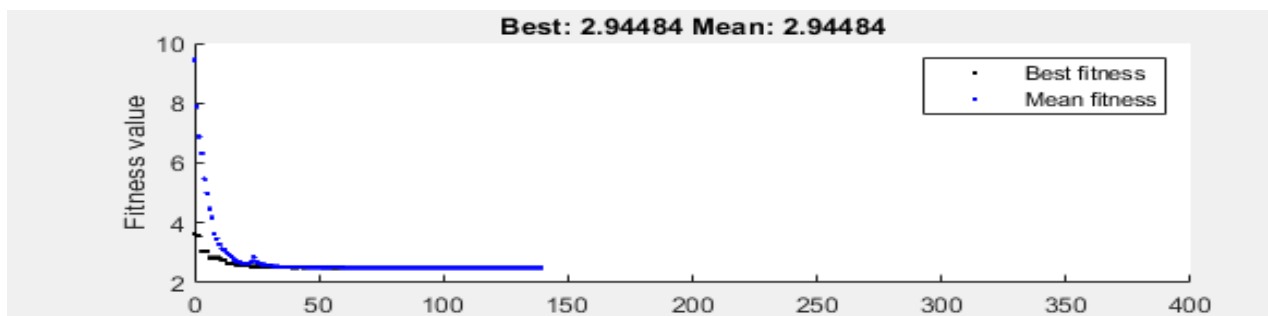


Figure5. 23 Result of line-4 objective/fitness value and TMS

Table5. 24 Operating time coordination of Line-4 GA

Bays	Outgoing line [L-4]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3769	0.60758	0.84686	1.1135
Objective/fitness function in Sec	2.94484			

**Coordination of line-5WOA**

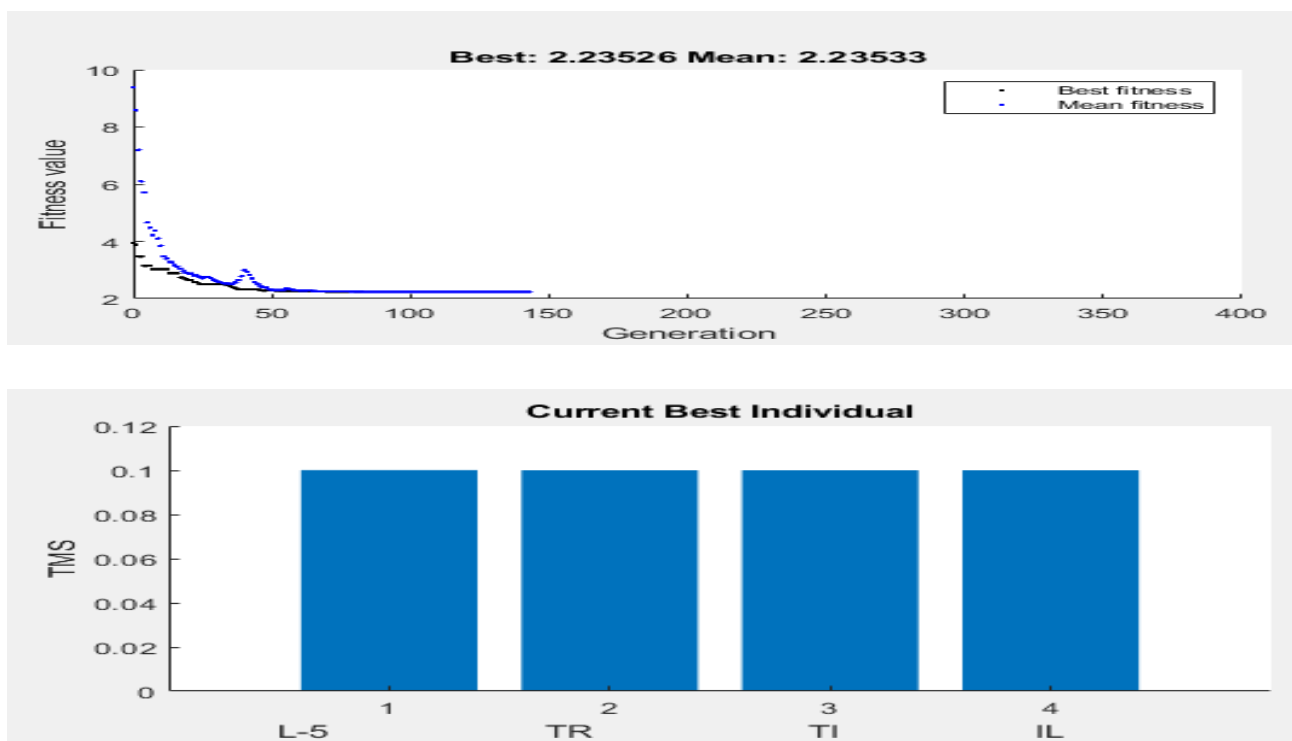


Figure5. 24 Result of line-5 objective/fitness value and TMS

Table5. 25 Operating time coordination of Line-5WOA

Bays	Outgoing line [L-5]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3218	0.4307	0.6301	0.8523
Objective/fitness function in Sec	2.2352			

### Coordination of line-5GA

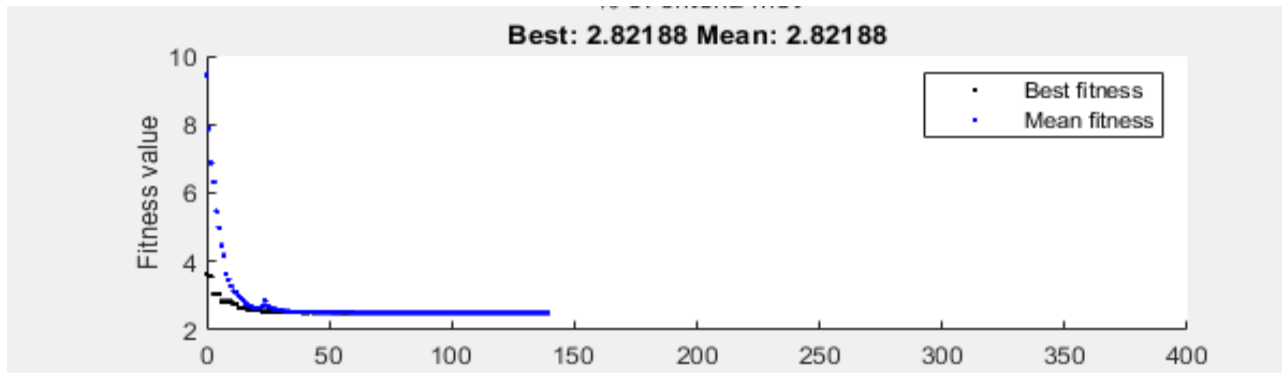
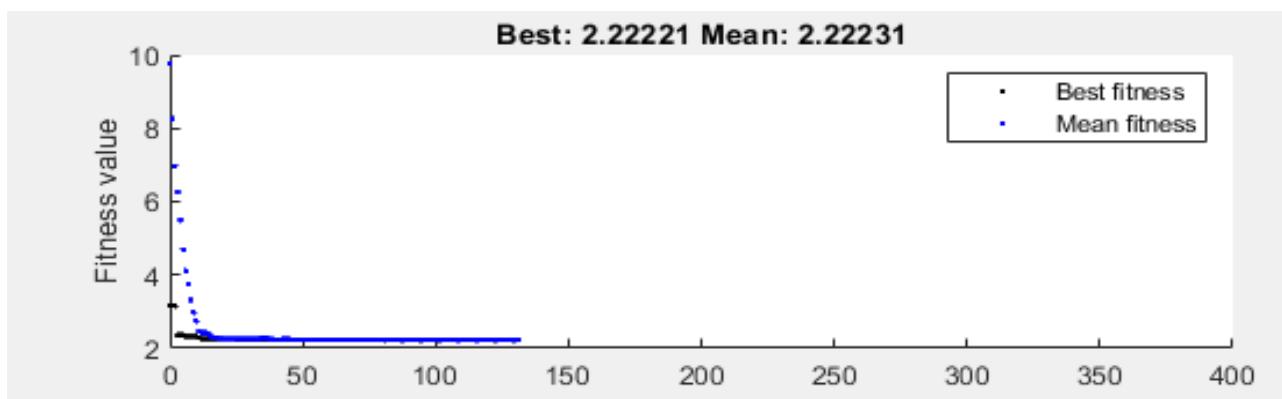


Figure5. 25 Result of line-5 objective/fitness value and TMS

Table5. 26 Operating time coordination of Line-5 GA

Bays	Outgoing line [L-5]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.34616	0.57684	0.81612	1.08276
Objective/fitness function in Sec	2.82188			

### Coordination of line-6 WOA



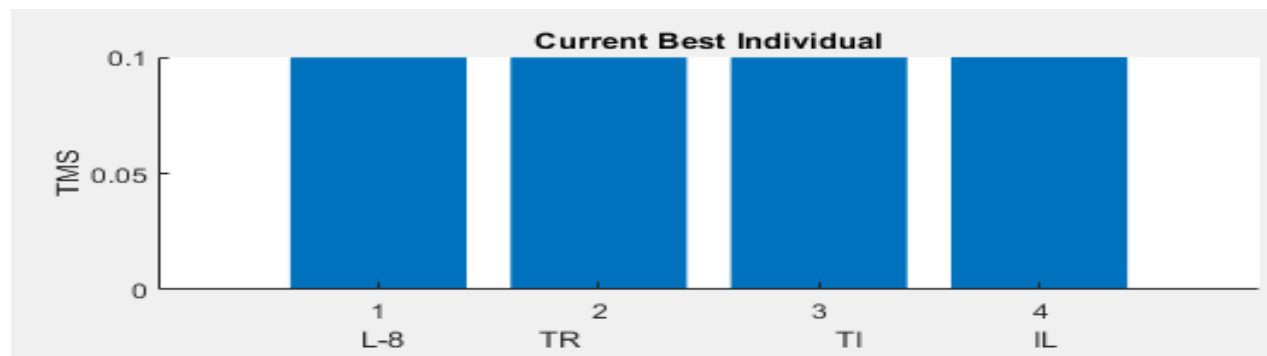


Figure5. 26 Result of line-6 objective/fitness value and TMS

Table5. 27 Operating time coordination of Line-6 WOA

Bays	Outgoing line [L-6]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3186	0.4275	0.6269	0.8491
Objective/fitness function in Sec	2.2221			

**Coordination of line-6 GA**

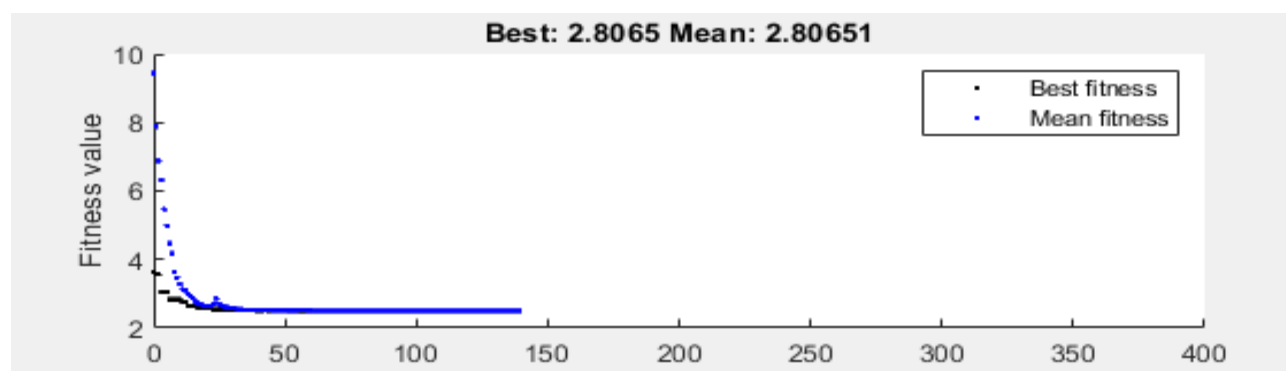


Figure5. 27 Result of line-6 objective/fitness value and TMS GA

Table5. 28 Operating time coordination of Line-6 GA

Bays	Outgoing line [L-6]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.34232	0.5730	0.81228	1.07892
Objective/fitness function in Sec	2.8065			

### Coordination of line-7 WOA

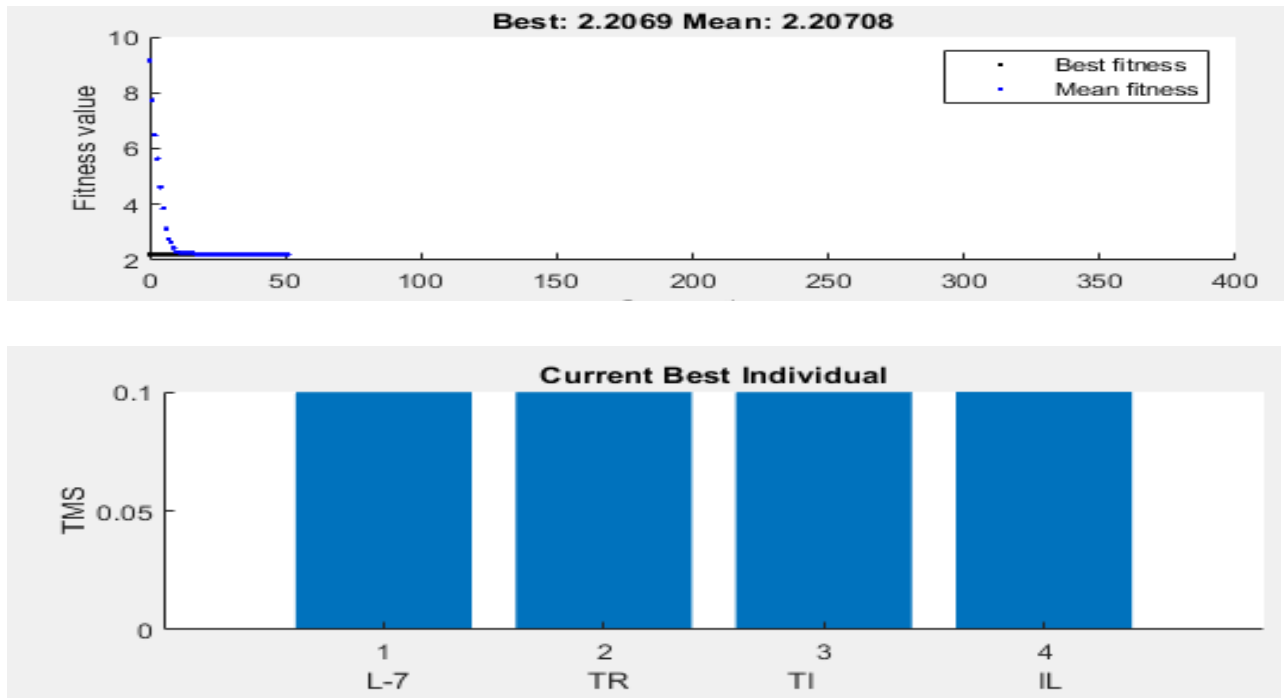


Figure5. 28 Result of line-7 objective/fitness value and TMS

Table5. 29 Operating time coordination of Line-7WOA

Bays	Outgoing line [L-7]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3148	0.4237	0.6231	0.8453
Objective/fitness function in Sec	2.2069			

### Coordination of line-7GA

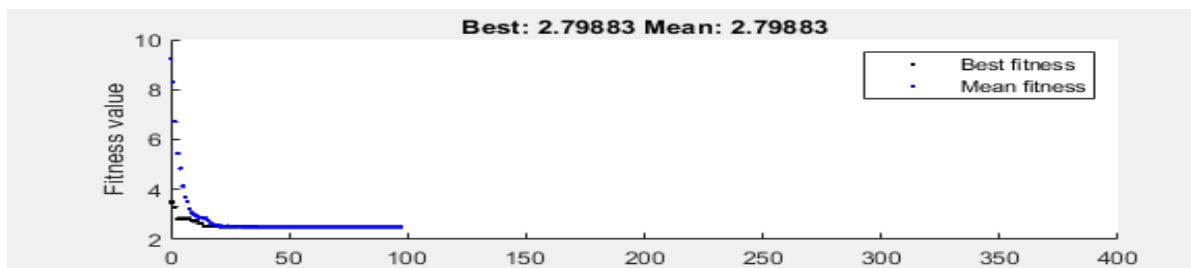


Figure5. 29 Result of line-7 objective/fitness value and TMS GA

Table5. 30 Operating time coordination of Line-7 GA

Bays	Outgoing line [L-7]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.33776	0.56844	0.80772	1.07436
Objective/fitness function in Sec	2.7883			

**Coordination of line-8WOA**

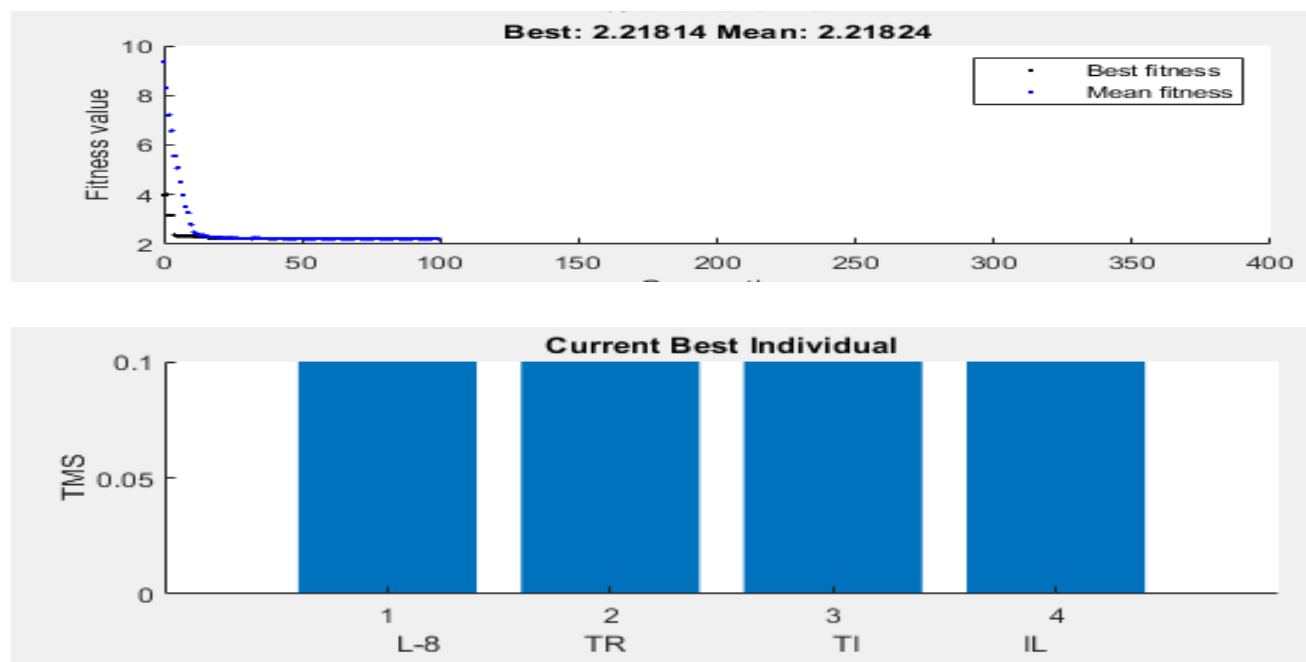


Figure5. 30 Result of line-8 objective/fitness value and TMS

Table5. 31 Operating time coordination of Line-8WOA

Bays	Outgoing line [L-8]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.3176	0.4265	0.6259	0.8481
Objective/fitness function in Sec	2.2181			

**Coordination of line-8 GA**

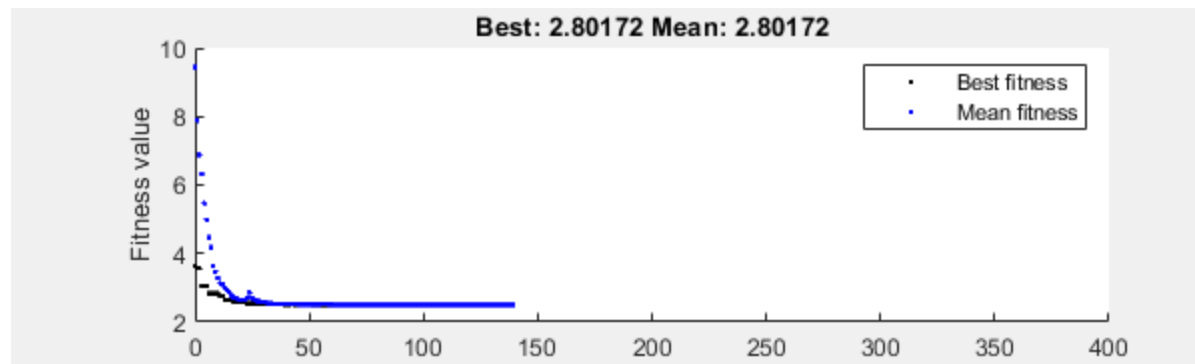


Figure5. 31 Result of line-8 objective/fitness value and TMS

Table5. 32 Operating time coordination of Line-8 GA

Bays	Outgoing line [L-8]	Transformer outgoing [TR]	Transformer incoming [TI]	132kv incoming line [IL]
Operating time [T] in Sec	0.34112	0.5718	0.81108	1.07772
Objective/fitness function in Sec	2.80172			

Table5. 33 Comparison of existing system with GA & WOA techniques

15Kv outgoing lines (Relays)	Pickup Existing Current setting $I_p$ (A)	New pickup current setting	CT ratio (A)	Existing Operating time (ms)	New operating time (ms) GA	New operating time (ms) WOA
1	336	229.2	800/1	500	418.16	318.18
2	640	600	800/1	500	494.12	445.1
3	800	516	800/1	500	477.20	431.0
4	656	254.6	800/1	500	423.20	386.0
5	496	281.76	800/1	500	430.40	392.0
6	257.3	214.4	800/1	500	412.64	377.2

7	216	180	800/1	500	412.64	377.2
8	240	200	800/1	500	419.0	382.5
15KV TR-1	1920	927	2000/1	1000	780.32	683.0
15KV TR-2	1920	927	2000/1	1000	780.32	683.0
132KV TR-1	350	258	400/1	1500	1234.4	1062.2
132KV TR-2	350	258	400/1	1500	1234.4	1062.2
132KV- IL	250	180	600/1	2000	1928.0	1640

## 5.2 DISCUSSION

The study was conducted using ETAP software for analyzing load flow and short circuit, calculating pickup current, secondary relay current, and plug setting multiplier. Then minimize the calculation of our detached occupation. Finally, to get the optimal value of  $TMS$  and operating time,  $T$  from the minimized objective function by using the (WOA) Whale optimization algorithm technique in *MATLAB* programming, and *GA* optimization technique in *MATLAB* toolbox. The result obtained from the optimization toolbox and command window describes two conditions. First, the results that are shown below in the figure are the  $TMS$  of each line from the incoming to the outgoing line and the final objective/fitness function of the coordination of the outgoing line ( $L$ ), transformer feeder ( $TR$ ), and transformer incoming ( $TI$ ) and 132KV incoming line ( $IL$ ). For the second step, the programming technique uses iteration to get the final optimal value.

The table describes each bay's operating time based on the result of  $TMS$  and total minimized objective function. The technique for identifying primary and backup relay coordination was set by relay topological location. Outgoing line relays play as primary protection, and incoming transformer relays act as backup protection for the outgoing line relay.

The optimization is done by using the whale's optimization algorithm in *MATLAB* programming and the genetic algorithm in the *MATLAB* toolbox; it satisfies the constraint limit

of the  $TMS$  value for all protection relays  $0.1 \leq TMS \leq 1.1$ . The setting of the pickup current is calculated based on the existing load of each feeder. Based on *IEC* standards, current pickup is above 20% of the load. So, calculate pickup current  $I_p = 1.2 * I_l$ . Analysis of the load flow and short circuit current of transformer saturation has been done using *ETAP* simulation software.

### Cost analysis

Protection coordination needed its own expenses for different protection equipment needs. Like, power transformers, auto transformers, current transformers, voltage transformers, circuit breakers, fuses, and protective relays. Sebata-1 substation has the old and the most loaded system. So, to implement this research paper, only an experienced (skilled) person on power systems in protection and the knowledge of configuration and installed protective relays in the substation is needed. Based on the above conditions, there is no cost for installation, material punches, delivery, and erection. This indicates the study of the research.

### Comparison of WOA with GA

WOA is a Meta heuristic proposed by Mirjalili Mohamed in 2016. It is inspired by social hierarchy and the hunting techniques of whales. Metaheuristic is a high level problem-algorithm framework (develop optimization algorithm). This algorithm finds the best solutions out of all possible solutions for an optimization.

Table 5. 34 comparison of GA with WOA for line 1 in one table

Bays	Operating time [T] in Sec by GA	Operating time [T] in Sec by WOA
Outgoing line [L]	0.41816	0.31818
transformer outgoing [TI]	0.7808	0.60978
Transformer incoming [TR]	1.2222	0.98818
132KV incoming [IL]	1.9158	1.56618
Objective/fitness function in Sec	4.3242	3.4823

Comparison of WOA with GA is shown in the above table. WOA operating time is less than GA operating time. Because the iterating process of the Whales optimization algorithm is faster when compared to the GA optimization algorithms. GA is a search-based optimization algorithm

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based on the principle of genetic and natural selection. Compared with the experimental function optimization test, the whale optimization algorithm has the characteristics of a simple principle, less parameter setting and stronger searching ability, and better results than genetic algorithms (GA). WOA has the same disadvantages of slow convergence speed, low solution accuracy, and being easy to fall into the local optimum. Finally, GA has solved a global and broad programming solution, but it is the old optimization technique. GA takes a short time to converge on the result but needs long iterations.

## CHAPTER SIX

### CONCLUSION AND RECOMMENDATION

#### 6.1 CONCLUSION

This research paper contains the coordination and protection system for the Sebeta-1 substation network using proper coordination of over-current relay, earth fault, and differential protection relay. The study was conducted using ETAP software for analyzing load flow and short circuit, calculating pickup current, secondary relay current, and plug setting multiplier. It depends on this *TMS* and *IP* value to evaluate the existing coordination system. Its result shows the expressed mode of load flow in each branch and system device.

Then minimize objective function. Finally, to get the optimal value of *TMS* and operating time *T* from the minimized objective function by using the (WOA) Whales optimization algorithm and the genetic algorithm (GA) optimization technique in *MATLAB* and *MATLAB* optimization toolbox optimization techniques. Protective relays are essential devices for electrical power protection systems. In real practice, electrical power systems cannot live without protection.

The choice of protection devices depends on the types and ratings of the protected equipment. The primary function of the relay is to clear fault current flowing through the system if a fault has occurred in the protective line. A protective relay receives the signal from instrument transformers, analysis and compares the data from the preset value, when the values are above the threshold value, send a tripping command to the circuit breaker, and clears the fault. Based on this fault clearing functions, all relays in the power system needed coordination and optimal setting for efficient fault clearance.

## 6.2 RECOMMENDATION

- Ethiopian electric power companies need to review the existing protection and coordination system based on international standards. Otherwise, the protection system of the substation can't be reliable, secure and also cause the customer and company a loss of money and investment.
- EEP must coordinate all the substation protection systems from both incomers up to each outgoing line and transformer protection systems must follow international standards.
- Further study on the optimal coordination of the substation network needs to be undertaken using the whale optimization algorithm programming techniques in order to improve the efficiency of the power system.
- EEP must share knowledge from other related companies that use the latest optimization techniques.

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## APPENDIX

### Short-Circuit Summary Report

#### 3-Phase, LG, LL, LLG Fault Currents

Bus		3-Phase Fault			Line-to-Ground Fault				Line-to-Line Fault				*Line-to-Line-to-Ground			
ID	kV	I <sup>m</sup> k	ip	I <sub>k</sub>	I <sup>m</sup> k	ip	I <sub>b</sub>	I <sub>k</sub>	I <sup>m</sup> k	ip	I <sub>b</sub>	I <sub>k</sub>	I <sup>m</sup> k	ip	I <sub>b</sub>	I <sub>k</sub>
L-5	15.000	9.653	23.917	3.147	11.272	27.928	11.273	11.273	8.360	20.712	8.360	8.360	10.911	27.032	10.911	10.911
L-1	15.000	9.680	24.070	3.147	11.272	28.090	11.296	11.296	8.383	20.845	8.383	8.383	10.927	27.170	10.927	10.927
L-7	15.000	9.661	23.961	3.147	11.272	27.975	11.272	11.279	8.366	20.750	8.366	8.366	10.915	27.072	10.915	10.915
L-3	15.000	9.667	23.995	3.147	11.272	28.011	11.272	11.272	8.372	20.781	8.372	8.372	10.919	27.103	10.919	10.919
L-2	15.000	9.698	24.180	3.153	11.72	28.385	11.384	11.384	8.399	20.941	8.399	8.399	11.056	27.568	11.056	11.056
L-4	15.000	9.655	23.810	3.146	11.272	27.787	11.272	11.275	8.362	20.620	8.362	8.362	10.871	26.809	10.871	10.871
L-6	15.000	9.655	23.810	3.146	11.268	27.787	11.268	11.268	8.362	20.620	8.362	8.362	10.871	26.809	10.871	10.871
L-8	15.000	9.655	23.810	3.146	11.273	27.787	11.273	11.273	8.362	20.620	8.362	8.362	10.771	26.809	10.871	10.871

\* All fault currents are in rms kA. Current ip is calculated using Method C.

LLG fault current is the larger of the two faulted line currents.

Project:	<b>ETAP</b>	Page:	8
Location:	<b>19.0.1C</b>	Date:	18-02-2024
Contract:		SN:	
Engineer:	Study Case: LF	Revision:	Base
Filename: alex2024		Config.:	Normal

**LOAD FLOW REPORT**

Bus		Voltage			Generation		Load		Load Flow					XFMR
ID	kV	% Mag.	Ang.	MW	Mvar	MW	Mvar	ID	MW	Mvar	Amp	%PF	%Tap	
B-10	15.000	99.523	-2.6	0.000	0.000	0.000	0.000	Bus3	22.596	1.359	875.5	99.8		
								Bus9	-22.596	-1.359	875.5	99.8		
B-13	15.000	99.442	-2.8	0.000	0.000	0.914	0.000	Bus3	-0.914	0.000	35.4	100.0		
* Bus9	132.000	100.000	0.0	22.619	2.394	0.000	0.000	B-10	22.619	2.394	99.5	99.4		
Bu-11	15.000	99.412	-2.8	0.000	0.000	4.941	0.000	Bus3	-4.941	0.000	191.3	100.0		
L-1	15.000	99.439	-2.8	0.000	0.000	0.914	0.000	Bus3	-0.914	0.000	35.4	100.0		
* Bus1	132.000	100.000	0.0	22.619	2.394	0.000	0.000	Bus2	22.619	2.394	99.5	99.4		
L-2	15.000	99.523	-2.6	0.000	0.000	0.000	0.000	Bus3	22.596	1.359	875.5	99.8		
								Bus1	-22.596	-1.359	875.5	99.8		
L-3	15.000	99.445	-2.8	0.000	0.000	0.000	0.000	B-10	-22.584	-1.272	875.5	99.8		
								B-13	0.914	0.000	35.4	100.0		
								Bus2	-22.584	-1.272	875.5	99.8		
								Bus-4	4.088	2.533	186.1	85.0		
								Bus-5	12.448	0.006	481.8	100.0		
								Bus-6	10.718	0.003	414.8	100.0		
								Bus-7	5.286	0.001	204.6	100.0		
								Bus-8	5.857	0.001	226.7	100.0		
								Bu-11	4.943	0.001	191.3	100.0		
								Bu-12	0.914	0.000	35.4	100.0		
L-4	15.000	99.426	-2.8	0.000	0.000	4.087	2.533	Bus3	-4.087	-2.533	186.1	85.0		
L-5	15.000	99.411	-2.8	0.000	0.000	12.444	0.003	Bus3	-12.444	-0.003	481.8	100.0		
L-6	15.000	99.409	-2.8	0.000	0.000	10.714	0.000	Bus3	-10.714	0.000	414.8	100.0		
L-7	15.000	99.427	-2.8	0.000	0.000	5.285	0.000	Bus3	-5.285	0.000	204.6	100.0		
L-8	15.000	99.420	-2.8	0.000	0.000	5.855	0.000	Bus3	-5.855	0.000	226.7	100.0		

\* Indicates a voltage regulated bus (voltage controlled or swing type machine connected to it)

# Indicates a bus with a load mismatch of more than 0.1 MVA

