INTELLIGENT PROTECTION COORDINATION SYSTEM

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2001

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ACKNOWLEDGMENTS

I wish to give sincere thanks to my supervisor Dr. K. K. Li for his support and guidance throughout the course of this work, especially in solving the problems in the protection relay setting coordination. I wish to thank Dr. L. L. Lai, Dr. W. L. Chan and Dr. C. T. Tse for their constructive discussions. Special thanks are also to Prof. A. K. David, head, Department of Electrical Engineering, Hong Kong Polytechnic University for his help and invaluable advice in the research.

Finally, I would like to thank all my colleagues in CLP Power Hong Kong Limited. I am particularly indebted to Mr. K. T. Lai and Mr. K. Y. Fung for their valuable guidance especially at the beginning stage of this project.

To

My lovely wife Priscilla for patience, loving care, and understanding;

My father Y. K. So (蘇元堅) and my mother H. Chan (陳杏) for their continuous support and care.

ABSTRACT

System disturbance may cause system instability. In order to prevent the system to fall into the unstable region, the protection system is employed to detect and isolate system disturbance. Fast and correct protection operations will resume supply swiftly in order to improve the supply reliability and availability. It is sometimes reported that protection mal-operation or mis-coordination may cause system black-out. A power network consists up to thousands of power apparatuses and requires enormous protection relays to protect the system. Various protection relays with different operating principles are employed to tackle different types of faults. Very often two or more relays with different operating principles, depending on the voltage level and importance, may be required to operate to protect the equipment. Each protection relay in the power system needs to be coordinated with the relays protecting the adjacent equipment. The overall protection coordination is thus very complicated. Unfortunately in a practical power network, it is almost impossible to obtain a set of protection settings that can satisfy the coordination between all adjacent relays. This thesis proposes a novel method called "Time Coordination Method" to coordinate all protection relay settings. The protection system is modeled as an objective function and a set of constraint equations that can be optimized by artificial intelligent optimization methods. It is also proved that the Time Coordination Method can handle the protection coordination during the dynamic fault current changing condition. This cannot be achieved by other conventional approaches. Through the use of time coordination method, the optimized protection system can also improve the supply reliability. The reliability algorithm is developed. The supply reliability indices are calculated by simulating all busbar faults, stuck breakers and protection failures. The faulty component will be isolated by a sequence of relay operations. As different fault location will result in different relay operations, the step-by-step simulation method is developed to evaluate the sequence of relay operations. The efficiency of the Time Coordination

Method is discussed. The key factor to improve the efficiency in order to put in future practical use is also explored.

Chapter 1

1 INTRODUCTION

1.1 Historical background

In the 21st century, electricity drives the development of economy, technology and society. Lighting, ventilation, entertainment and transportation are powered by electrical energy. The electric supply interruption shuts down electrical equipment resulting in the loss of tremendous business. Thus the reliability, security and availability of electric power system are of utmost concern to society. The power system protection is the front-line system to detect and remove system disturbance. An effective and efficient protection system can improve electric power reliability, security and availability significantly.

In the early stage of electric power system, fuse was the first form of protection to power apparatus. It was constructed from a piece of copper melting on excessive current flowing through it. As the power system was rapidly developed, the fuse element could not provide adequate protection for power system. The development of protection relays were started since the late 19th century by Andrews, L. [1, 2]. The first protection relay was designed for overcurrent protection by C.E.L. Brown [3]. His original relay had an aluminium disc which rotated in the horizontal plane, the drive being provided by a shaded-pole electromagnet. It employed eddy-current breaking and was basically similar to those modern designs. In deed, the fault current and protection relay operation time is of inverse time and current characteristics that was reported by Schuchardt [4]. The overcurrent relay therefore adopted inverse time and current characteristics that was the first non-unit protection to protect the circuit and provided backup protection function to the other parts of network.

In the early 20th century, the circulating current protection was proposed by Charles H. Merz and Bernard Price [5]. The philosophy of the circulating current design was that the system fault could be isolated without visible shock on the system and no other healthy breakers should be isolated. The circulating current protection could only operate on the fault occurred within the protected zone. The backup protection function to other parts of network could not be provided. It was the first unit protection scheme.

The drastic growth of electric power demand drives considerable investment on electric power network. The requirement of protection had become stressful as the generator capacity increases and transmission network grows. Various types of protection relays were proposed such as distance relay in 1922 [6], transformer differential protection in 1938 [7] [8] and traveling wave protection relay in 1978 [9]. Those types of relays are mutually cooperated to prevent unclear system fault to degrade the power system stability and reliability.

1.2 Challenge of power system protection

The complexity of power system network increases as the generation capacity grows, interconnections of HV and EHV networks, and the applications of high capacity transmission lines and power transformer increases. The ultra-fast protection scheme is therefore required to protect high power apparatus in order to reduce loss due to system disturbance. Unfortunately, the cost of ultra-fast protection scheme is high. The power system stability contradicts to the investment cost of power system protection. The challenge of protection engineer is to make balance of investment cost and degree of protection to power system.

The ultra-fast protection requires communication channels such as pilot-wire, power line carrier or fibre optics. Any disturbance on the communication channel or human operational error may cause mal-operation or no operation. Thus, backup protection is required to provide backup function to other parts of network. Nowadays, the technology of digital and telecommunication improves the relay capabilities. Protection relays can exchange information to protect the power system in a more intelligent way. The new trend of substation automation, protection integration, control and monitoring, brings new synergies to make protection system to aim at 100% reliability, security and availability.

1.3 Digital relay technology

The first digital relay was developed and reported by Rockfeller [10] in earlier 80's. Afterward, many literatures report new techniques on digital relays [11, 12, 13]. Nowadays, many new protection relays are microprocessor based. Their constructions typically consist of sampling, filtering, processing and trip circuit. Because of standardization of hardware, modem digital relays are dominated by the software algorithm. The digital technology provides unprecedented flexibility of relay design that cannot be provided in electronic or electro-mechanical designs. As protection relay setting can influence the relay characteristics, some new relays require more system information to fix the operation boundary [14]. The intelligent determination of relay settings is a challenge to protection engineers.

1.4 Protection and telecommunication

The first application of telecommunication in protection is the pilot wire used for circulating current protection for feeder [15]. Power line carrier, microwave and fibre optic were developed and applied in protection relay such as feeder circulating current protection, phase comparison protection, intertrip schemes and distance protection schemes. Those protections require high security dedicated telecommunication channel i.e. dedicated fibre optic and dedicated microwave channels. The trend of utility is to use the telecommunication network for other business, and therefore the telecommunication bandwidth for protection would be reduced. The dedicated telecommunication channel for protection will no longer be justified. Instead, the shared telecommunication channel will be applied for protection and will also be the new challenge to protection stability and reliability.

1.5 Information technology

Information technology is an emerging technology. Protection relays and their associated equipments contain numerous data such as fault events and fault waveforms. Those data can be transferred to control center for pre-fault and post-fault analysis. The knowledge system are developed to extract data from relays so that automatic fault analysis, fault location, suggestion of restoration process and automation of protection settings can be provided.

1.6 Substation automation

Substation automation integrates protection, control and monitor power apparatus. A modern microprocessor based protection relay with communication facility can also perform protection, control and monitoring functions. Data network can link up digital relays to form an automated substation. It brings new synergy for adaptive protection. The centralized system can coordinate all protection settings and transfer them to the relays. As the processing power of computer and communication technology are sky-rocketing, real time protection setting coordination adaptive to the changes of power system configuration is possible.

1.7 Artificial intelligence

The long-term goal of artificial intelligence is to make machine intelligence as good as humans, or even better. Nowadays, artificial intelligence also includes artificial neural network, fuzzy logic and evolutionary computation, each of which has becomes a field of its own. These fields have totally different principles and methodologies. For instance, neural network and its variants mainly tackle machine learning and pattern recognition. Fuzzy logic and its variants can help in decision making. Evolutionary computation and its variants are the best for searching and optimization. Electric power system is a highly non-linear system that cannot be controlled simply by conventional methods. In recent years, a lot of articles reported that the artificial intelligent methods can control and solve power system problems that cannot be solved by conventional methods.

1.8 Scope of study of this thesis

It would be ideal that the protection system can clear system fault instantly without loss of supply. In fact, the imperfection of current and voltage transformers and circuit breaker operations limit the fault clearance speed. Moreover, the operation of mis-coordinated protection relays sometime result in black out of a large area. The general objective of this project is to seek a method to optimize the protection system to reduce the impact of system fault disturbance, and maintain the electricity supply reliability, security and availability.

The scope of this thesis is confined to the development of protection coordination methods and intelligent optimization methods on protection settings.

The initiation of this thesis is the coordination of Inverse Definite Time Lag (IDMTL) Overcurrent (OC) relays. It represents the largest installed base of protective equipment on any distribution systems and may be considered as the backbone of any protection strategy. They are often used to back-up the main protection systems. If the back-up protections are not well coordinated, mal-operation can occur and, therefore, IDMTL OC relay coordination is a major concern of protection engineers. The method to solve this problem is proposed by the formulation of the IDMTL OC relay coordinations into the constrained optimization problem. The optimized relay settings can only be searched out by artificial intelligent searching method, say, genetic algorithm, instead of the conventional optimization methods such as steeper-decant and linear programming.

When solving IDMTL OC coordination problems, the protection relay coordination problems across various types of relays are revealed. In fact, mis-coordinations of two or more types of relays did occasionally occur resulting in large area black out. The conventional method of protection coordination is carried out on each individual type of relay, which ignores the operation of other types of relays. To overcome this problem, the Time Coordination Method (TCM) is proposed. It is developed for relay settings coordination disregarding the relay working principles.

The optimized relay settings have to take care of the dynamic change of power system configurations. In traditional relay coordination method, the practising engineer could only choose some typical system configurations to calculate the fault current distributions and then checking the relay coordination. Unfortunately, those configurations normally represent part of the power system and cannot reflect the overall behavior of the relays especially on this dynamic change of system configurations. In fact, the fault current redistributions due to the adjacent circuit tripping can alter the relay operation time especially for IDMTL OC relay. This thesis reports the findings on the dynamic equation for the IDMTL OC relay operation time for several step changes of fault current magnitude. It also proves that the TCM can search for the optimum relay settings that can incorporate such dynamic system configuration changes.

This thesis also reports the improvement of supply reliability by properly coordinated protection system to reduce the number of black-outs by reducing protection relay mal-operations. Various types and locations of system faults are simulated to test the protection relay operations resulting in the lost of supply buses. The reliability algorithm is developed to search for those lost of supply buses and to calculate their reliability indices accurately. This thesis reports the dynamic equation for IDMTL OC relay enhancing the relay operation time calculation for dynamic change of system configurations. It can accurately determine the sequence of relay operation and finally the lost of supply buses can be identified.

Eventually, the efficiency of the TCM is evaluated. The TCM computes the optimum relay settings by considering all possible types and locations of faults. The larger number of substations and feeders put in the TCM, the lower is the efficiency of the TCM in searching for the optimum relay settings. In fact, some system configurations may have no fault current flow due to all sources tripped out. Those configurations waste the TCM processing time and therefore should be taken out from the TCM process. It can be achieved by reducing the number of fault current changes handled by the TCM. On the other hands, the population size of Evolutionary Algorithm may be optimized for a particular network. Various number of fault current changes handled by the TCM and various population size for Evolutionary Algorithm are simulated. The results show that the TCM with correct number of fault current changes taken into consideration and correct population size for Evolutionary Algorithm can efficiently search for the optimized relay settings.

1.9 Organization of the thesis

Chapter 2 describes the basic principle of power system protection. The unit and non-unit protection schemes are introduced. Two main types of non-unit protections, Overcurrent and distance relays, are explained. Their operation principles, settings and coordinations are discussed.

Chapter 3 describes the development of the Time Coordination Method. The objective function, coordination constraints and setting pusher are the key elements to be discussed. The sophisticated technique of initialization is also described.

Chapter 4 describes the application of artificial intelligence in the time coordination method. The evolutionary computation methods such as Genetic algorithm, Evolutionary programming and Evolutionary Algorithm are used to optimize the protection relay settings. The major processes of initialization, generation, selection and termination are described. The comparison of these methods when applied in the Time Coordination Method is also discussed.

Chapter 5 describes the problem of dynamic change of fault current due to adjacent circuit tripping during protection setting coordination. The Time Coordination Method solving the captioned problem is described in detail. Furthermore, the coordination between overcurrent and distance relays by the Time Coordination Method is also discussed.

Chapter 6 describes how supply reliability can be improved by using Time Coordination Method. The reliability algorithm is developed to evaluate the effect on supply reliability due to mis-coordinated relay operations. In the reliability algorithm, the fault current re-distribution due to the adjacent circuits operation is considered in the relay operation time calculation especially for inverse definite time lag overcurrent relays. The generalized formula for the relay operation time on multiple step changes of fault currents is described.

Chapter 7 describes the efficiency of the Time Coordination Method. It can be improved by reducing the number of system configuration changes and the number of fault current changes which need to be handled. The various simulation results and analysis are discussed.

Chapter 8 concludes the finding in this thesis and discusses the work that can be carried out in the future.

1.10 Statement of originality

Original contributions or important developments of this thesis are given in the following statements:-

1. Protection relay setting coordination is conventionally carried out manually. Some commercial available coordination software can only coordinate simple radial-fed networks. The major contribution in this thesis is the development of the novel protection relay coordination technique named Time Coordination Method. Protection coordination can be carried out in a systematic approach. Protection coordination problems can be solved disregarding the network configuration and relay operation principles.

2. One of the milestones of this thesis is the modelling of the protection system into an objective value function and a set of system constraint equations. It provides the mathematical basis to initiate the rest of research works.

3. One of the major discoveries reported in this thesis is that the time coordination method is capable to coordinate the inverse definite time lag overcurrent relays in dynamic changes of system configuration due to adjacent circuit tripping. It is impossible for conventional protection coordination technique to handle this problem.

4. This thesis reports that coordination of zone 2 and 3 of distance relays with other protection relays of different operation principles is possible. No such finding has been reported so far to the knowledge of the author.

5. Another major part of work reported in this thesis is the development of the reliability algorithm correlating protection operations and supply reliability. It proves that the supply reliability can be improved by properly coordinated protection system. The time coordination method finds out the optimum relay settings and then the reliability algorithm is applied to calculate the supply reliability indices. The reliability algorithm simulates various types of fault at various locations to seek the loss of supply buses due to the mis-coordinated relay operations. The fault current re-distribution due to the tripping of circuits is considered. This is particular important especial to inverse definite time lag overcurrent relays. The generalized formula for the relay operation time on multiple step changes of fault currents is developed. It can accurately calculate the real relay operation time under dynamic condition.

6. The efficiency of Time Coordination Method should be considered in practical use. This thesis reports how the efficiency of the Time Coordination Method can be improved by selecting the proper number of fault current changes and proper population size for Evolutionary Algorithm.

1.11 List of publications

The papers are listed below

Referred Journal Papers:

[1] C W So, K K Li, "Overcurrent Relay Coordination by Evolutionary Programming", *Journal of Electric Power System Research*, Volume 53, pp 83-90, (2000).

[2] C W So, K K Li, "Time Coordination Method for Power System Protection by Evolutionary Algorithm", *IEEE Transactions in Industry Applications*, Vol. 36, No. 5, pp. 1235-1240, (2000).

[3] C W So, K K Li, "Intelligent Method for Protection Coordination", *IEE proceeding, Generation, Transmission and Distribution*, paper under review.

Conference Papers:

[1] C.W. So, K.K. Li, K.T. Lai, K.Y. Fung, 'Application of Genetic Algorithm for Overcurrent Relay Coordination', *IEE 6th International Conference on Developments in Power System Protection*, Nottingham, UK, March, pp. 66-69, (1997).

[2] So. C.W., Li K.K., Lai K.T., Fung K.Y. : 'Overcurrent Relay Grading Coordination Using Genetic Algorithm', *IEE APSCOM-97 International Conference*, Hong Kong, Vol. 1, pp. 283-287, November 11-14, (1997).

[3] C W So, K K Li, "Time Coordination Method for Power System Protection by Evolutionary Algorithm", *1999 IEEE Industry Application society Annual Meeting*, Phoenix Arizona, U.S.A., 3-7 October, Session 53, paper no 53.4, (1999).

[4] C.W. So, K.K. Li, "The Influence of Time Coordination Method on Supply Reliability", *2000 IEEE Industry Application Society Annual meeting*, Roma, Italy, 8-12 October, Volume 5, pp 3248-3253, (2000).

[5] K.K. Li, C.W. So, 'Evolutionary Algorithm for Protection Relay Setting Coordination", *IEEE-PES/CSEE International Conference on Power System Technology (PowerCon 2000)*, Perth, Australia, 4-7 December, Vol. 2, pp. 813-817, (2000).

Chapter 2

2 POWER SYSTEM PROTECTION

2.1 Introduction

System disturbance causes system instability. Protection system detects and isolates system disturbance. Fast and correct protection operations resume supply swiftly in order to improve supply reliability and availability. The unit protection dedicated for an apparatus is designed to provide fast and accurate isolation in case of fault. To safe guard the unit protection failure, the non-unit protection is designed to provide backup function to unit protection. The unit and non-unit protections form a self-contained system serving for about 100 years. Various apparatuses such as power transformer, generator and feeder need special design of unit and non-unit protections that can detect the apparatus disturbance accurately. The unit protection can only detect system fault within the protected apparatus. Instead, non-unit protections can detect system fault outside the located apparatus. The coordination of non-unit protection is a major concern to protection engineer.

2.2 Protection for electric power system

Electric power system consists of generation, transmission and distribution as shown in Fig 2.1.

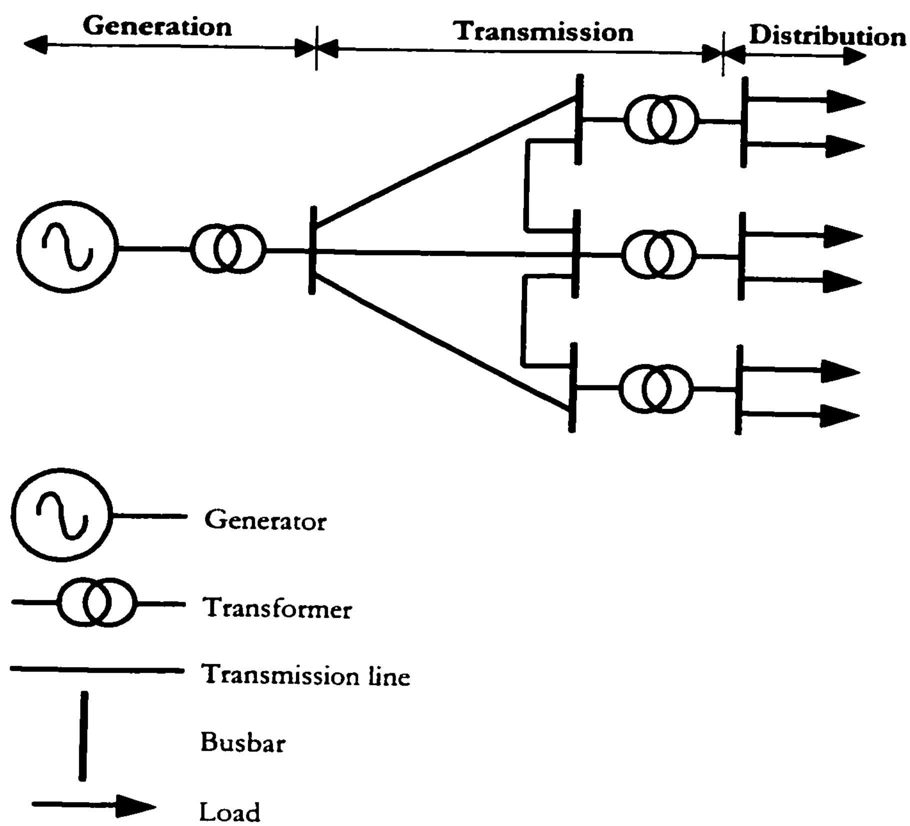


Fig. 2.1 Sample electric power network.

Protection relays detect system fault and isolate the faulty apparatus by sending trip command to the circuit breaker. Protection relay senses the power system fault qualities such as voltage and current signals as shown in Fig. 2.2.

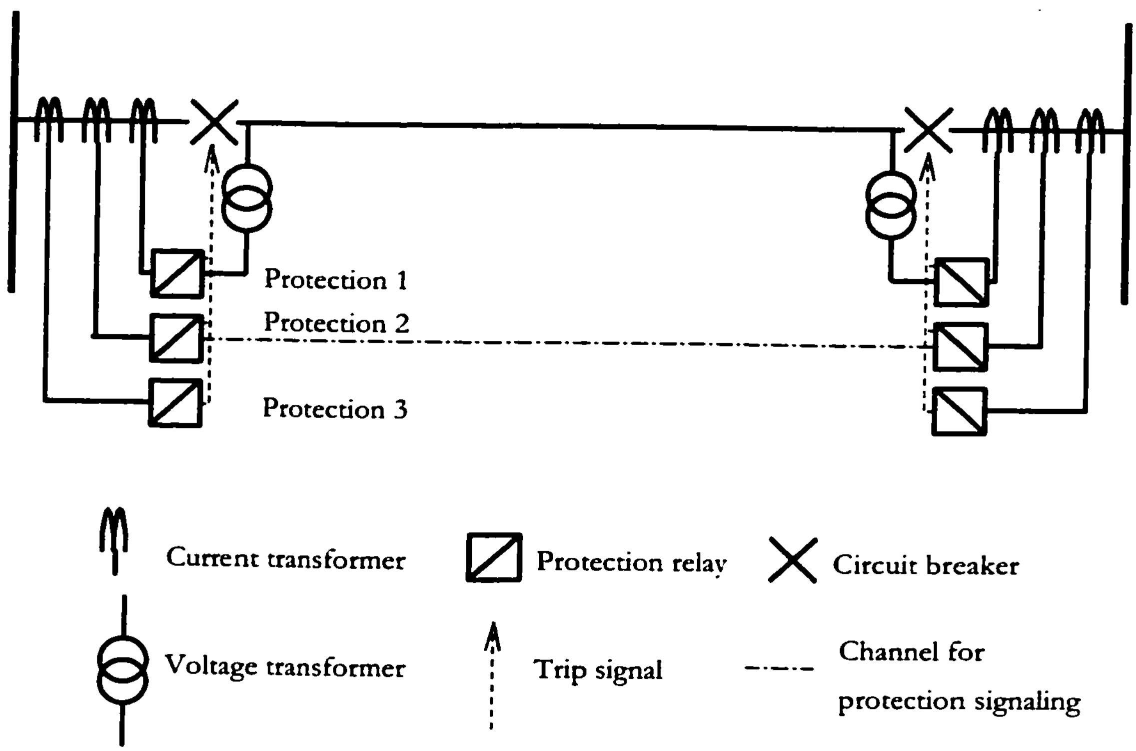
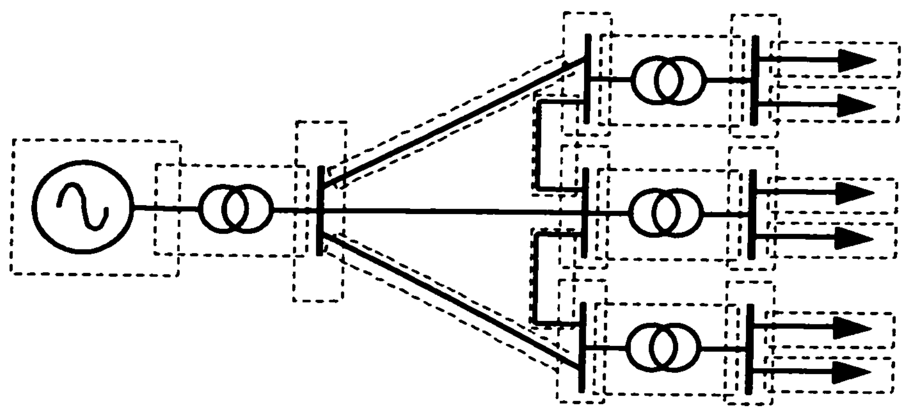


Fig. 2.2 Typical protection system connected with current and voltage transformers

The positions of current and voltage transformers determine the coverage of protection as shown in Fig. 2.2. Protection 2 is an unit protection which the protection coverage is defined by the two current transformer locations. Protection 1 and 3 are non-unit protections without definite protection zone. They use only local current and/or voltage information to detect system fault.

2.3 Unit protection

The coverage of unit protection is defined by the location of current transformers. To prevent blind spot, all unit protections are overlapped with adjacent unit protections as shown in Fig. 2.3.



Protection coverage of unit protection

Fig. 2.3 Unit protection schemes for power apparatuses

2.3.1 Current Differential Protection

Current differential protection is the most commonly used unit protection for generators, transformers, feeders and busbars as shown in Fig. 2.4, 2.5, 2.6 and 2.7 respectively.

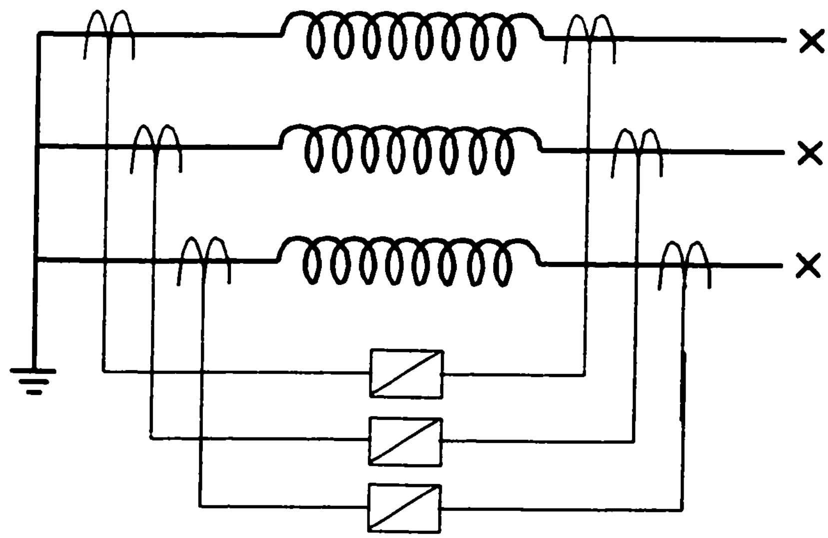


Fig. 2.4 Current differential protection for generator.

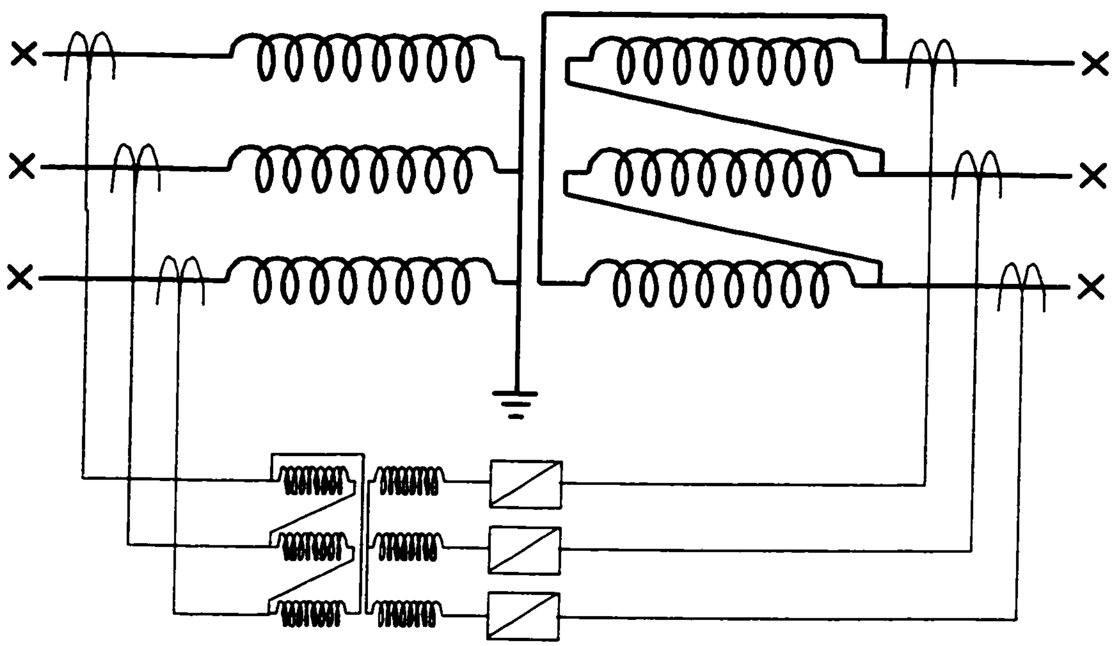


Fig. 2.5 Current differential protection for transformer.

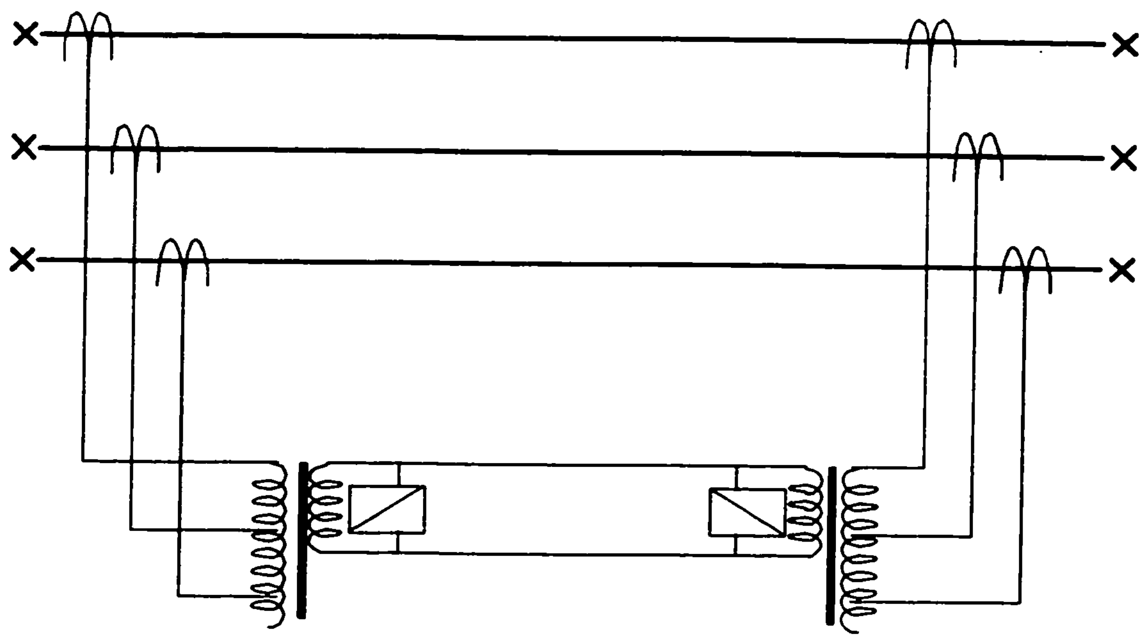


Fig. 2.6 Current differential protection using summation transformer for feeder.

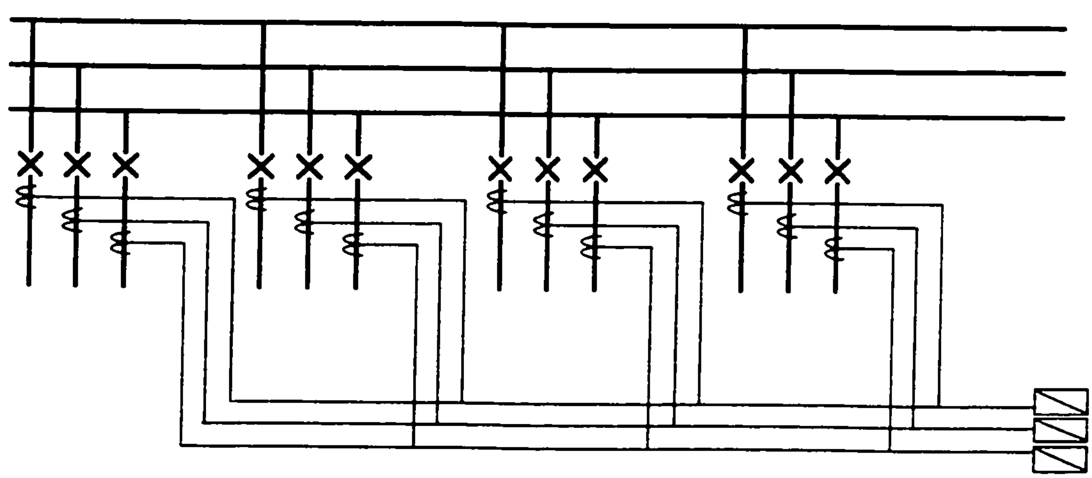


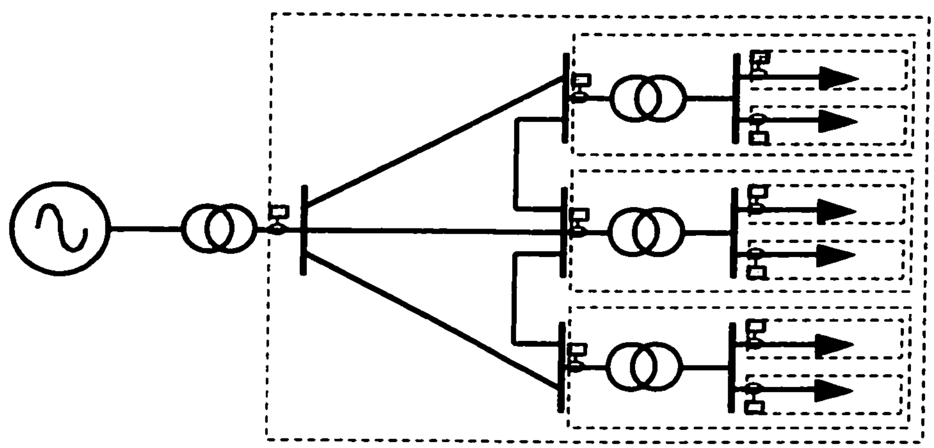
Fig. 2.7 Current differential protection for busbar.

The current differential protection applies the Kirchhoff's current law. The current signals from all terminals of the power apparatus are directly summed up. If the power apparatus is healthy, zero current results in no operation of the relay otherwise the resultant current will drive the relay to trip out the fault apparatus, i.e. generator, transformer and busbar as shown in Fig. 2.4, 2.5 and 2.7 respectively.

For feeder, to save communication channel, the summation transformer is applied to convert three phase current into one phase and through communication channel to remote end for comparison as shown in Fig. 2.6. As the feeder have capacitive current flowing through especially for cable circuit, current differential protection for feeder should not be too sensitive to capacitive current. On the other hands, the current differential protection should be stable under current transformer saturation due to through fault, but should be sensitive enough to detect high impedance fault. Due to the fact that the changes of system network do not affect the capacitive current of the feeder, the current differential protection settings for feeder may be determined at design stage and the setting do not need to be changed when the system configuration has been changed.

2.4 Non-unit protection

A non-unit protection has no definite protection zone. The coverage of non-unit protection depends on the fault current direction. The coverage of upstream relay will totally cover the downstream relay coverage as shown in Fig. 2.8.



Non-unit protection relay coverage

Non-unit protection relay

Current/Voltage transformer

Note : Assume the fault current flows from left to right.

Fig. 2.8 Non-unit protection for electric power apparatuses

Non-unit protection provides backup protection function to unit protection. The overcurrent and distance relays are two major non-unit protections used in existing power system.

2.4.1 Overcurrent relay

Overcurrent protection (OC) devices and their variants represent the largest installed base of protective equipment on any distribution systems and may be considered as the backbone of any protection strategy. They are often used to back-up the main protections. If the back-up protections are not well coordinated, mal-operation may occur and, therefore, OC grading coordination is a major concern of protection engineers.

The power system faults are categorized into shunt and series types. The majority system faults are shunt types. Phase-to-ground and phase-to-phase faults are two highest probability shunt type faults occurring in power system. Series type fault refers to open circuit fault The work in this thesis is developed mainly based on shunt type fault. The OC relay may function as an earth fault or phase fault protection depending on the current transformer (CT) connections. Power system faults may be classified as phase-to-ground, phase-to-phase and three-phase fault. The detection of earth to ground fault and the other two type of faults are different.

2.4.2 OC Earth fault detection

The single phase-to-ground or earth fault (EF) is depicted in Fig. 2.9. and assumed '**a**' phase-to-ground fault occurred.

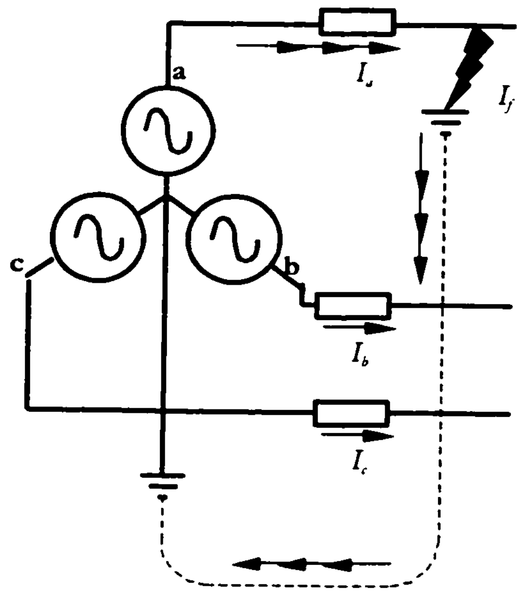


Fig. 2.9 Fault current distribution for 'a' phase-to-ground fault.

The symmetrical component [16] is an useful tool to analyze unsymmetrical fault. The 3-phase fault currents may be decomposed into the positive, negative and zero sequence components. The sequence network connection for a single phase-to-ground fault is as shown in Fig 2.10. The sequence values may be expressed as shown in Eqn (2.1) and (2.2).

$$I_f = 3i_0 = I_a + I_b + I_c \qquad \textbf{(2.1)}$$

$$I_0 = I_1 = I_2 \qquad \textbf{(2.2)}$$

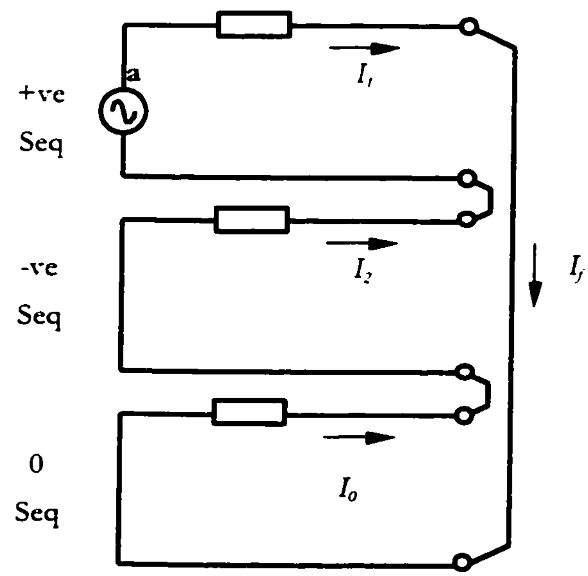


Fig. 2.10 Symmetrical component representation for a single phase to ground fault.

From Eqn (2.1) and (2.2), the CT connection summing up three phase currents as shown in Fig. 2.11 can produce the zero sequence current I_0. Obviously, no zero sequence current will flow into the relay under normal three-phase balance load condition. In fact, the ground impedance limits the earth fault currents. To increase the sensitivity, the fault setting of an EF relay may be set lower than the circuit rating. A typically relay setting to protect the circuit is 80% or less of the rated current

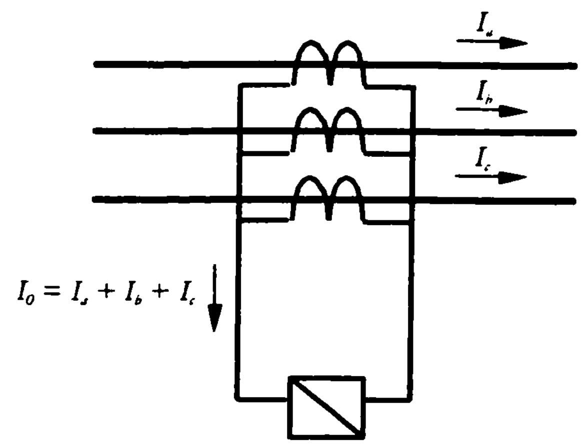


Fig. 2.11 Earth fault detection.

2.4.3 OC Phase fault detection

The phase fault OC relay is designed to operate when the fault current exceeds the relay setting. It should be stable in normal load conditions. The setting of phase fault OC is thus set above the circuit rating. The connection of phase fault OC relay is straightforward in one CT per phase. Due to economic reason, the OC relays may be arranged as shown in Fig. 2.12. It can provide two OC, say 'a' and 'c' phases and EF protection. Typically, each element has a flag that will drop when the individual element has operated. It provides the indication for fault investigation. The flag indication may indicate the fault as follows:

- Flage 'a' & 'e' indicates A phase earth fault
- Flage 'e' indicates B phase earth fault
- Flage 'c' & 'e' indicates C phase earth fault
- Flage 'a' indicates A-B phase fault
- Flage 'c' indicates B-C phase fault

- Flage 'a' & 'c' indicates A-C phase fault or A-B-C phase fault

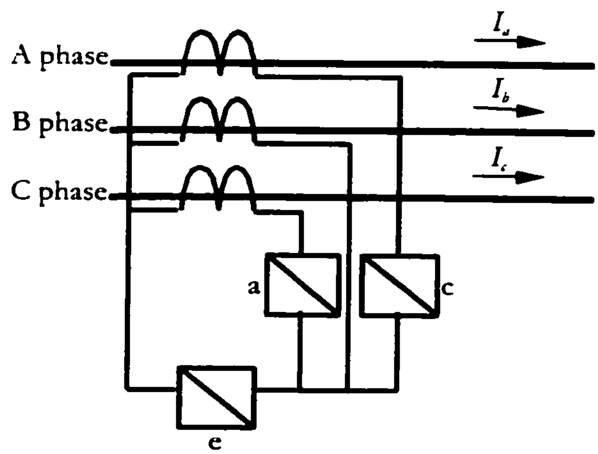


Fig. 2.12 Two overcurrent and one earth fault relay connection.

2.4.4 OC relay characteristic equation

Various OC characteristics are employed in existing power system to suit various system conditions. OC relays may be classified as directional and non-directional. They are further classified into instantaneous, definite time, and inverse definite time characteristics. The operation time for instantaneous overcurrent relay is simply trip the circuit whenever the fault current exceeds the relay setting. Definite time overcurrent relay will trip the circuit when the fault current over the relay current setting and sustained longer than the time delay setting of the relay.

The inverse definite time OC relay is the major relay used in the power system. It may be the main protection in distribution system. Its operation time is inversely proportional to the fault current magnitude. The operation time of inverse definite minimum time lag (IDMTL) according to the international standard of IEEE standard C37.112-1996 [26] and IEC 255-3, characteristic, may be calculated as shown in Eqn (2.3).

$$t(I) = \frac{A * TM}{(I^p - 1)} + c \qquad (2.3)$$

where

$t(I)$ is the relay operating time based on a constant current I.

$$A = \frac{K_d \theta}{\tau_s},$$

K_d is the drag magnet damping factor,

θ is the disk travel,

τ_s is the initial spring torque,

p is a constant,

c is a constant,

I is constant while the relay is operating.

To suit various system conditions and different requirements on IDMTL OC relays, various settings of A and p are designed as shown in Table 2.1.

Table 2.1 Setting table for various characteristics of IDMTL relays.

Characteristic of IDMTL relay	A	p	c
Standard Inverse (IEC)	0.14	0.02	0
Very Inverse (IEC)	13.5	1	0
Extremely Inverse (IEC)	80	2	0
Long Time Inverse (IEC)	120	1	0
Moderately Inverse (IEEE)	0.0515	0.02	0.1140
Very Inverse (IEEE)	19.61	2	0.491
Extremely Inverse (IEEE)	28.2	2	0.1217

For non-steady fault current, the dynamic equation from IEEE standard C37.112-1996 [26] is as shown in Eqn (2.4).

$$\int_0^{T_0} \frac{1}{t(I)} dt = 1 \tag{2.4}$$

Where the current I is piecewise constant for the time fragment T_0.

2.4.5 OC relay coordination

The purpose of OC relay coordination is to maintain an adequate operating time margin to allow for circuit breaker operation and resetting of relays. The operating time between them must have a specified grading margin, e.g. 0.4s in Eqn. (2.5) along the direction of fault current flow as shown in Fig. 2.13.

$$t_u - t_d \geq 0.4 \text{ seconds} \tag{2.5}$$

where

t_u is the operating time of relay Upstream

t_d is the operating time of relay Downstream

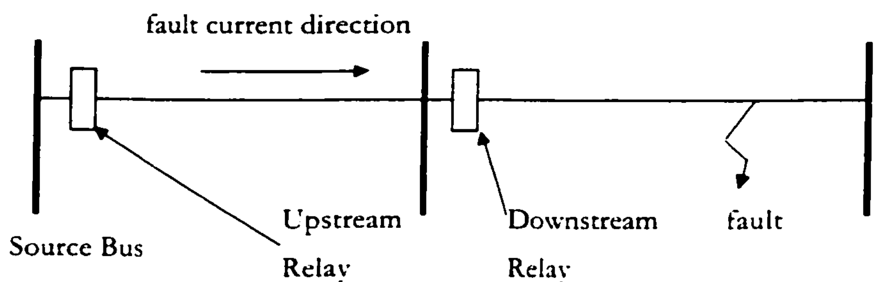


Fig. 2.13 Upstream and downstream relays relationship.

In a generalised busbar and branches system configuration as shown in Fig. 2.14, the upstream and downstream relationship among relays are determined by the current flowing directions.

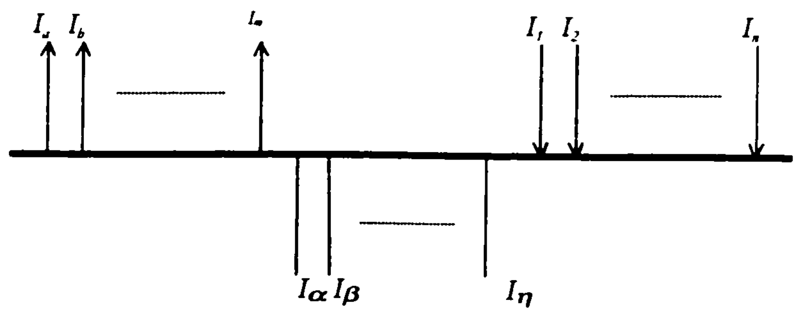


Fig. 2.14 General busbar layout.

Where

All branch currents $I_a, I_b ... I_m$ flow out of the busbar .

All branch currents $I_1, I_2 .. I_n$ flow into the busbar .

All branch currents $I_\alpha, I_\beta .. I_\eta$ are zero.

The relay sensed fault current I_1 to I_n should be related to those relays sensed fault current I_a to I_m and inhibited the operation of those relays sensed zero current I_α to I_η

2.4.6 OC relay time-grading and current-grading

For the typical distribution system as shown in Fig. A.1 in Appendix A, the IDMTL OC relay is used as the main protection for feeder.

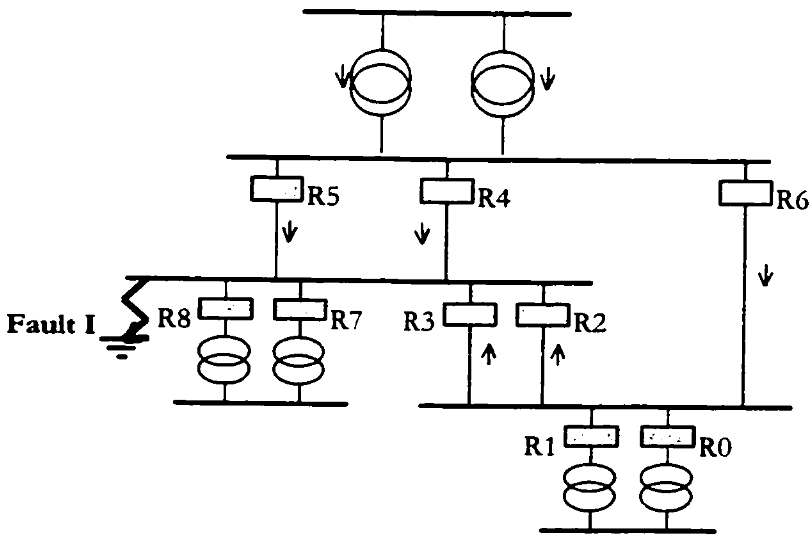


Fig. 2.15 Fault current distribution for Fault I.

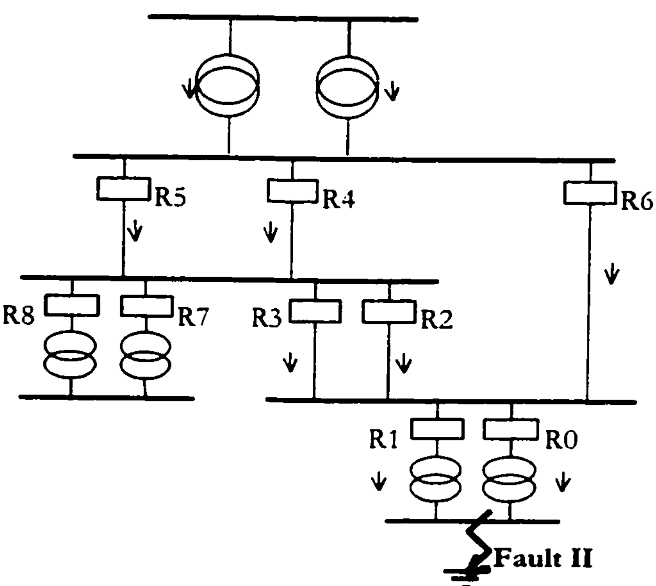


Fig. 2.16 Fault current distribution for Fault II.

Two typical fault cases (Faults I & II) of IDMTL OC relay coordination shown in Fig. 2.15 and 2.16 are used to illustrate the grading methodology. The operation of relay is based on the current magnitude of the primary circuit and the relay operation time is inversely proportional to the current magnitude. The operation of each OC relay is independent of the other relays. Considering case "Fault I", only the relays R2, R3 and R6 needed to be coordinated with each other. The time setting of R6 relay in the upstream, requires to grade with the time settings of the R2 and R3 relays in the downstream by a grading margin, say 0.4 sec. The current in branch R6 is approximately equal to the sum of current in branches R2 and R3. When any branch R2 or R3 is taken out of service, the current in branch R6 is approximately equal to the branch (R2 or R3) left behind.

For case "Fault II", the relay upstream/downstream relationships are changed as shown in Table 2.2 due to a change in fault location. Grading margin say 0.4 sec. for all relays listed in Table 2.2 must be satisfied in order to prevent unwanted operation. According to Table 2.2, the conventional grading graph is drawn with various relay coordination characteristics as shown in Fig. 2.17.

Table 2.2 Fault current fault diagram for fault case II.

Upstream relays	Downstream relays need to be graded
R6	R0, R1
R2	R0, R1
R3	R0, R1
R4	R0, R1, R2, R3
R5	R0, R1, R2, R3

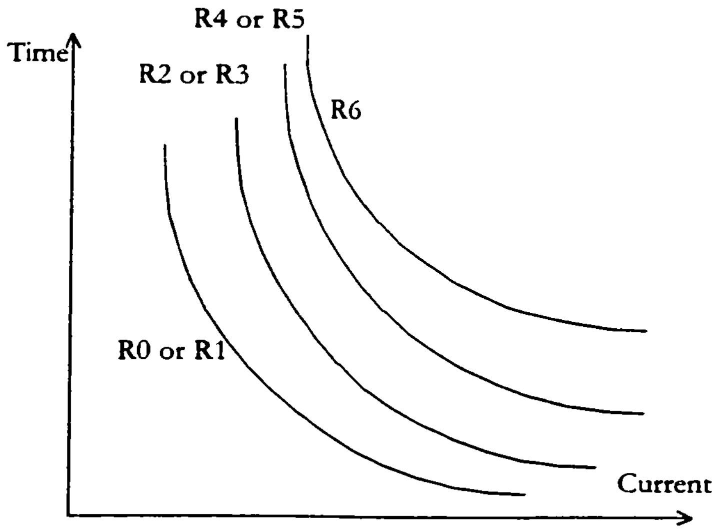


Fig. 2.17 Grading graph for Fault II.

As the relay settings cannot be changed automatically to handle the changing system configurations, the relay settings must cater for all possible fault cases within the coordination limit. A well-coordinated IDMTL OC relay system should give the shortest relay operation times with adequate coordination time margin for all fault cases.

For conventional coordination method, the protection engineer employs two simply methods, time grading and current grading as shown in Fig 2.18 and 2.19 respectively.

The time and current grading method can only handle a simple network such as radial fed circuits. They cannot easily find out the relay setting for ring fed system due to the fact that the fault current magnitude and direction may be changed due to the tripping of adjacent circuit.

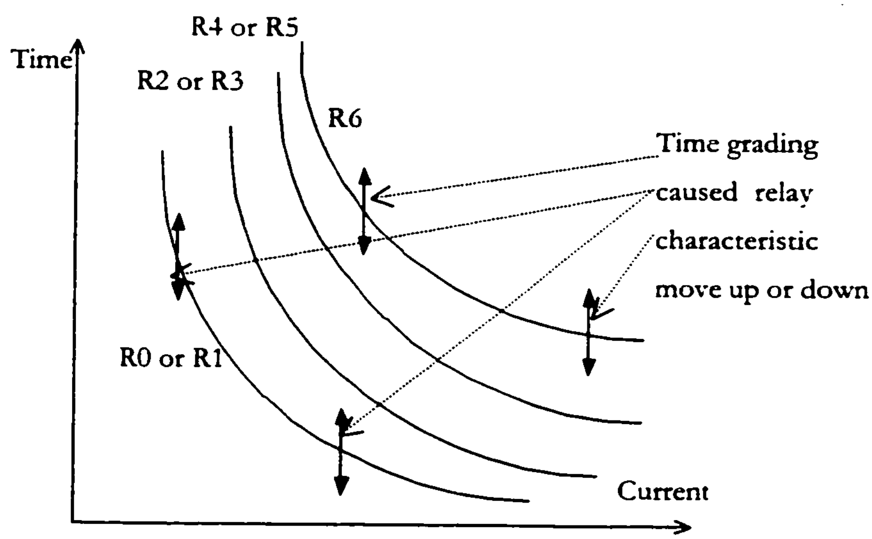


Fig. 2.18 Relay characteristic change by time grading.

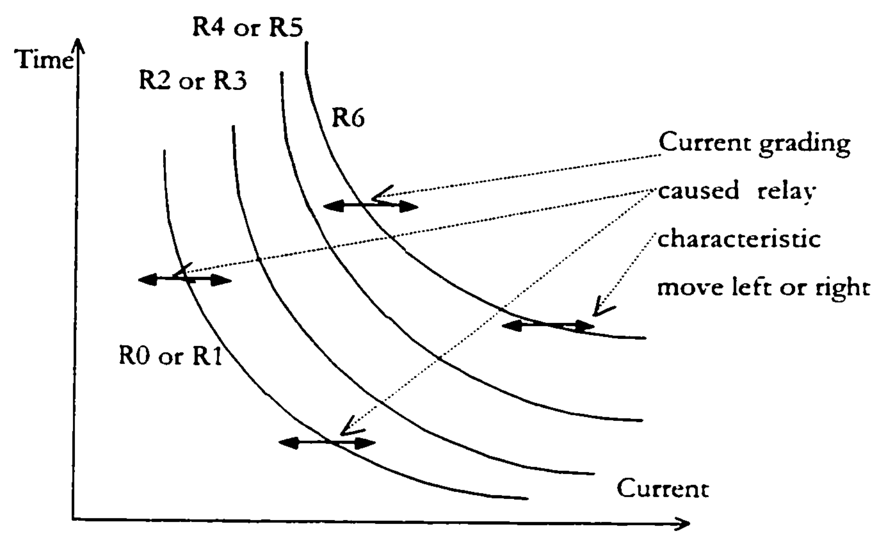


Fig. 2.19 Relay characteristic change by current grading.

2.4.7 Distance relay

Distance relay is widely used in transmission and distribution system as the main and backup protections. The basic principle of distance relay is the measurement of complex impedance Z where $Z=V/I$. Distance relay operates by comparing the calculated impedance and the setting of the protected line impedance. Various distance relay characteristics have been developed to suit the various system configurations and conditions. In this thesis, the distance relay with offset mho characteristic [48] as shown in Fig. 2.20 is considered to represent the largest installation of distance relay in utilities.

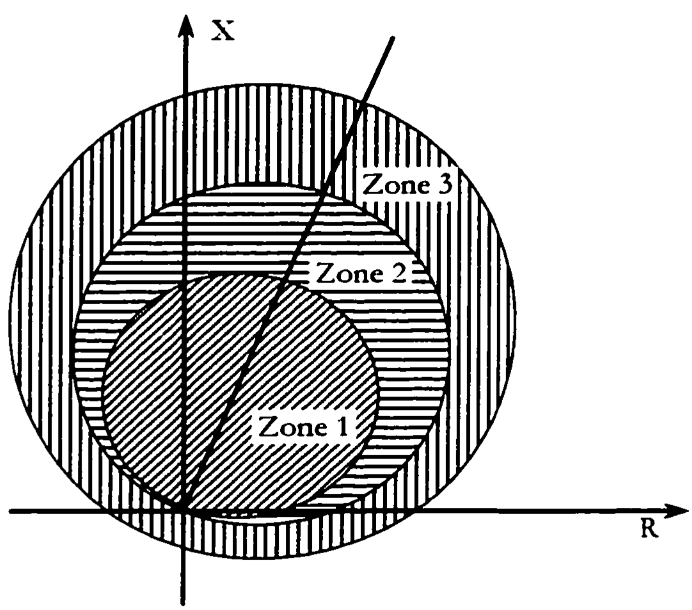


Fig. 2.20 Offset Mho - Distance Relay Characteristics.

The MHO distance relay may consist of 3 protection zones. Zone 1 is the instant operation zone. The zone 1 coverage is typically 70% or 80% of the protected line impedance to prevent reach beyond the protected line due to fault calculation error. As it operates instantly, zone 1 may be considered as a main protection and therefore no coordination is required. The zone 2 and 3 reaches of distance relays are delayed tripping zones. They typically operate when calculated impedance fault falling into zone 2 for 0.5 second or zone 3 for 1.0 second. Zone 2 and 3 may be considered as a back up to the upstream distance relay inline with the same direction of fault current. The coverage of zone 2 and 3 of distance relays are typically more than 100% of the protected line impedance and the zone 3 coverage is also more than zone 2 coverage. The coordination of distance relay zone 2 and 3 coverage and delay setting is required to prevent overreach of zone 2 or 3 to the downstream relays.

2.4.8 Mho distance relay

Zone 2 and 3 of distance relays are delayed operations. Three fault current and voltage measured by the relay may be considered as steady state values and the transient effect on voltage and current may be ignored.

The voltage magnitude under fault condition always drops to nearly zero causing huge measurement error of voltage resulting in large error in impedance calculation. To relieve the problem, voltage polarization is widely used. Two typical polarization methods are considered.

i) Sound phases polarization

ii) Memory polarization

In this thesis, the sound phases polarization is considered for distance relay. The relationship between sound phases polarization and faulty phase are listed in Table 2.3.

Table 2.3 Sound phases polarization and faulty phase relationships.

Fault type	Polarizing voltage
B-C phases fault	$-jV_a$
C-A phases fault	$-jV_b$
A-B phases fault	$-jV_c$
A phase to ground fault	$j(V_b - V_c)$
B phase to ground fault	$j(V_c - V_a)$
C phase to ground fault	$j(V_a - V_b)$

To overcome the residual current effect, earth fault compensation is employed as shown in Eqn (2.6)

$$I_a' = I_a + 3KI_0 \tag{2.6}$$

Where

K is a constant $K = \frac{1}{3}\left(\frac{Z_0}{Z_1} - 1\right)$

Z_0 is the zero sequence impedance of the protected line

Z_1 is the positive sequence impedance of the protected line

I_a is the faulty phase current of the protected line

I_0 is the zero sequence current of the protected line

The fault distance from the relaying point is calculated typically by amplitude or phase comparison technique. In this thesis, the phase comparison technique [49] is considered.

The graphical representation of phase comparison of a polarized mho relay is shown in Fig. 2.21 and the formulae are shown in Eqns (2.7) and (2.8).

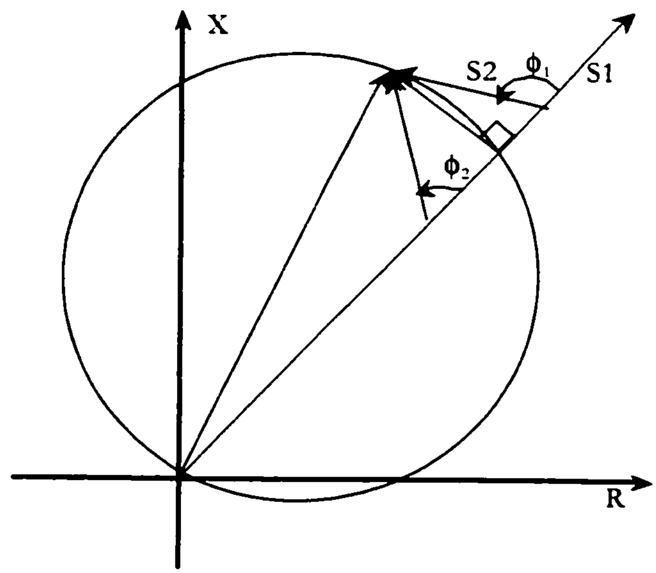


Fig. 2.21 Phase Comparison of Mho Characteristics.

$$S_1 = V'_p \tag{2.7}$$

$$S_2 = IZ_n - V' \tag{2.8}$$

and convert to Eqn (2.9) and (2.10)

$$S_x = (S_1 + S_2)/2 \tag{2.9}$$

$$S_y = (S_1 - S_2)/2 \tag{2.10}$$

Where

V'_p is the polarizing voltage, for instance for 'a' phase to earth fault with sound phase polarization $V'_p = j(V'_b - V'_c)$.

I is the faulty phase current, for instance for 'a' phase to earth fault I should follow Eqn (2.6) due to residual current compensation for all earth fault cases.

Z_r is the impedance setting of the distance relay.

V is the faulty phase voltage, 'a' phase to earth fault then $V = V_a$.

The criterion for operation is as shown in Eqn (2.11) and Eqn (2.12)

$$S_y \geq S_x \tag{2.11}$$

$$-\frac{\pi}{2} \leq (\arg(s_1) - \arg(s_2)) \leq \frac{\pi}{2} \tag{2.12}$$

2.5 Application of Unit and Non-Unit Protections in the Power System

The application of unit and non-unit protection for a typical transformer feeder circuit is shown in Fig. 2.22. The detail functions of protections are summarized in Table 2.4.

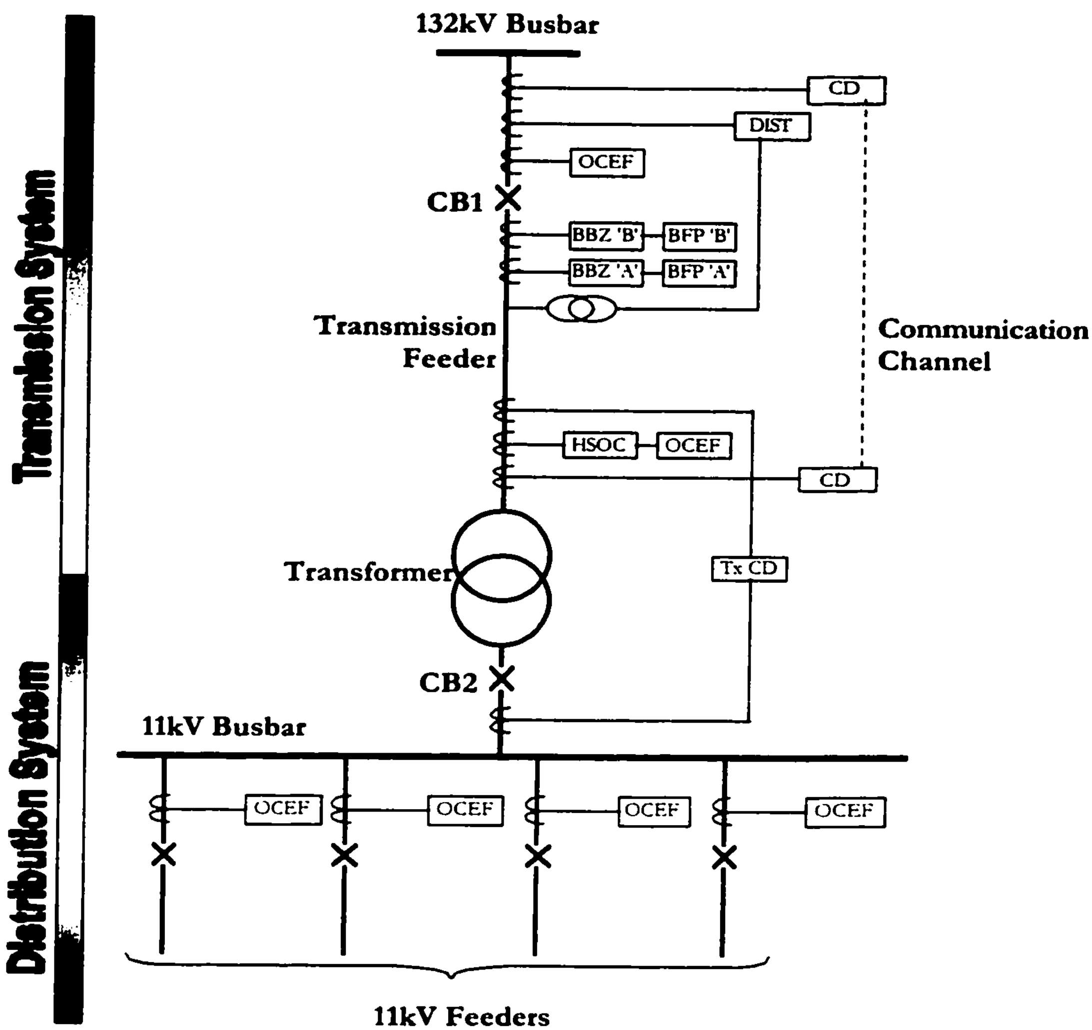
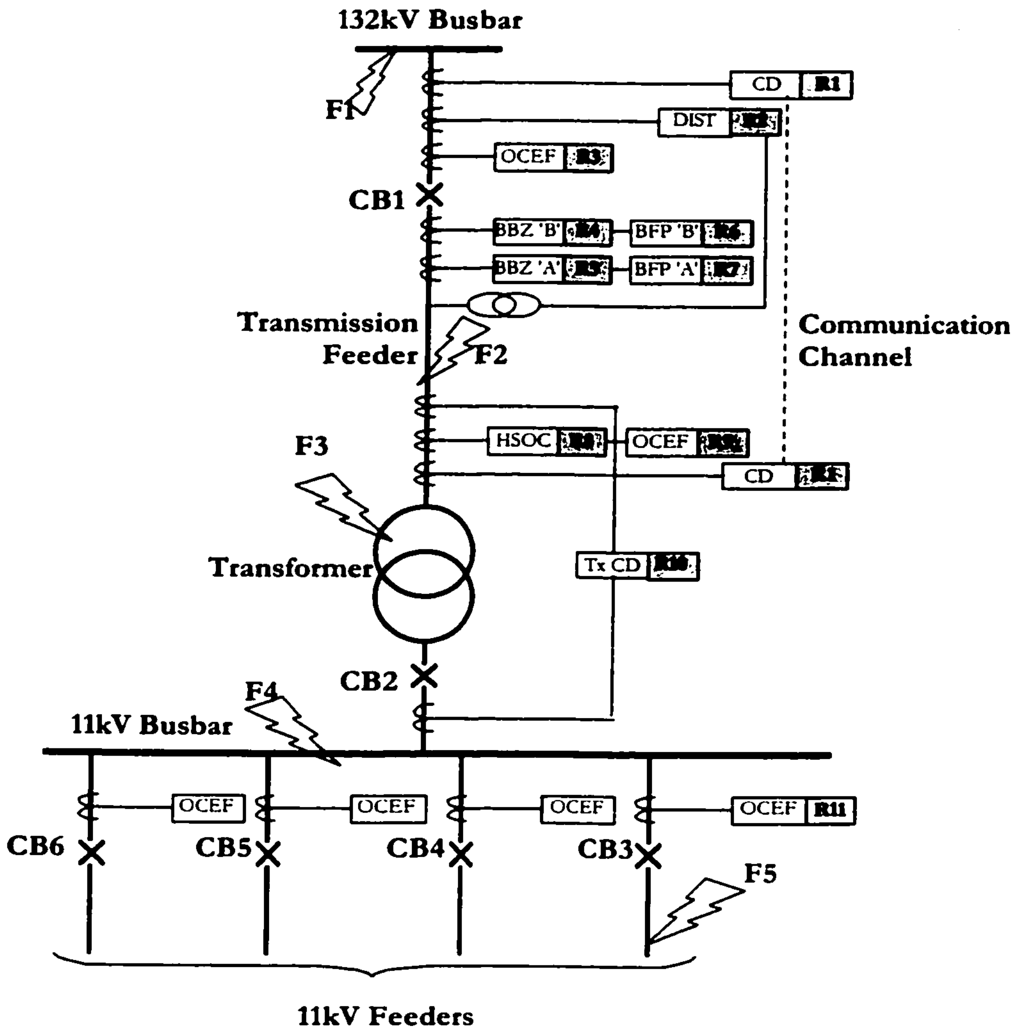


Fig. 2.22 Application of Unit and Non-unit Protections.

Table 2.4 Feeder Transformer Protection

Protection	Type	Protection Coverage	Function
BBZ	Main protection (Unit)	Busbar	Instantly clear system fault within busbar (the coverage of busbar protection zone should be the locations of all incoming and outgoing current transformers). Depending on the voltage level, two Busbar Zone Protections may be employed such as BBZ 'A' and BBZ 'B'.
BFP	Backup protection (Non-unit)	feeder, transformer and other feeder circuits	This is Breaker Failure Protection and as a backup protection initiated by unit protections. It will operate when the system fault cannot be cleared within a short time (i.e. 300 msec). Depending on the voltage level, two Breaker Failure Protections may be employed such as BFP 'A' and BFP 'B'.
CD	1st Main protection (Unit)	Feeder	Instantly clear system fault within the protected zone (between two current transformer).
Tx. CD	1st Main protection (Unit)	Transformer	Instantly clear system fault within the protected zone (between two current transformer).
DIST - Zone 1	2nd Main protection (Non-unit)	Feeder + 3~10% of Transformer HV winding	Instantly clear system fault within the protected zone (from VT pointing toward transformer).
DIST - Zone 2 & 3	Backup protection (Non-unit)	Feeder + 50% for Zone 2 or 90% for Zone 3 of Transformer HV winding	Time delayed operation where the fault occurred within the protected zone. Typically, time delay settings of Zone 2 and Zone 3 are 0.5 second and 1 second respectively.
HSOC	Main protection (Non-unit)	Transformer	Instantly clear system fault when the fault current exceeds the relay setting.
OCEF	Backup protection (Non-unit)	All power apparatuses	Phase and earth fault overcurrent protection providing backup to unit protections in transmission system and main protection for feeders and busbars in distribution system.



F1 to **F5** are the system fault locations.

Fig. 2.23 System Fault Analysis

Table 2.5 Protection Operation Against System Fault

Fault	The fault detected by relays U/N	Relay	Operation
F1 (132kV Busbar Fautl)	U	R4, R6	Instant operation by sending trip command to open all circuit breakers connected to the faulty busbar.
F2 (Transmission Feeder Fault)	U	R1	Instant operation, both end relays send trip command to open the breakers CB1 and CB2. The breaker failure protection R7 will be initiated.
	N	R2	Instant operation, R2 send trip command to open the breaker CB1 and send trip command through telecommunication channel to open the remote end breaker CB2. The breaker failure protection R6 will be initiated.
	N	R6, R7	R6 and R7 start the current check element when the breaker failure command received from R1 and R2 accordingly. If the fault current flow longer than the time delay setting (i.e. 300ms), R6 and R7 will send trip command to open all circuit breakers connected to the busbar where the faulty feeder connected.
	N	R3	The operation time of R3 will be inversely proportional to the fault current.
F3 (Transformer Fault)	U	R10	Instant operation, R10 send trip command to open the breaker CB2 and send trip command through elecommunication channel to open the remote end breaker CB1.
	N	R8	Instant operation if the fault current exceeds the relay setting. The relay setting of R8 should be greater than the through fault current (i.e. F4 fault current) such that the relay R8 will not operate when the fault outside the transformer.
	N	R2	If the fault occurred on the first 3% winding of the transformer, Zone 1 of R2 will detect the fault and the actions should be same as the fault on F2. If the fault occurred on the first 50% of the transformer, Zone 2 of R2 will detect the fault. The trip command will be sent by R2 after a small time delay (i.e. 0.5 second). If the fault occurred on the first 90% of the transformer, Zone 3 of R2 will detect the fault. The trip command will be sent by R2 after a small time delay (i.e. 1 second).
	N	R3,R9	Typically, the relay settings R3 and R9 are identical. The operation time of R3 will be inversely proportional to the fault current.
F4 (11kV Busbar Fault)	N	R3,R9	The R3 and R9 are the only two relays detecting 11kV busbar fault. The fault current should be less than the fault in F3 so that the operation time should be longer.
F5 (11kV Feeder Fault)	N	R11, R9, R3	The fault current will flow through relays R11, R9 and R3. The operation time of R11 should be faster than R9 and R3. The proper relay settings for R11, R9 and R3 should be determined.

Note : U - Unit protection

N - Non-unit protection

Distance relays may become unit protection if distance relays are installed at both ends and linked by communication channels..

To illustrate the applications of unit and non-unit protections, the simple fault analysis on feeder transformer circuit and the relay operations are as shown in Fig. 2.23 and Table 2.5 respectively. The unit protections for each power apparatus are overlapping. To prevent design fault of protection, two unit protections with different operation principles should be employed for 132kV circuits such BBZ 'A' and BBZ 'B' for busbar, CD and DIST for transmission feeder. For transformer, the main protections Tx. CD and HSOC are employed. Due to the high impedance of transformer, the fault current for a transformer is higher than the fault current at 11kV busbar. There is sufficient current for HSOC to identify whether the fault is inside or outside of the transformer, thus, the HSOC could be set as instant operation protection.

From the analysis, non-unit protections detect fault occurring at remote power apparatuses. Their operations are inversely proportional to the fault current, voltage and relay settings. If incorrect non-unit protection operations such as R9 faster than R11 operation for fault F5, the whole supply network will be tripped out. The systematic approach searching for correct relay settings is deterministic to increase power system reliability, security and availability.

Chapter 3

3 TIME COORDINATION METHOD

3.1 Introduction

Power system consists up to thousands of power apparatuses and requires even more protection relays to protect the system. The protection system consists of various relays with different operating principles to tackle different types of faults. Very often two or more relays with different operating principles depending on the voltage level and importance may be required to protect the equipment. Each protection relay in the power system needs to be coordinated with the relays protecting the adjacent equipment. The overall protection coordination is thus very complicated. Unfortunately in a practical power network, it is almost impossible to obtain a protection setting that can satisfy the coordination between all adjacent relays. In fact, there exists a certain number of blind spots of coordination in the protection of the power system.

Traditionally, protection relay coordination is done by individual type such as overcurrent and distance protection. The effect of coordination on other protection systems is usually not considered. Some works done on relay setting coordination on individual type of relays are shown in ref. [17-21]. This chapter presents a sophisticated protection setting coordination technique called the Time Coordination Method to search for the optimum protection settings. Overcurrent and distance relays are two commonly used non-unit protection relays that should be coordinated. The operation time of relays, coordination margin and coordination constraint violations in the Time Coordination Method are discussed in detail.

3.2 Relay operation time and power circuit isolation

A typical protection scheme is shown in Fig. 3.1. Very often two or more relays are required at various ends to detect and exchange system information in order to provide a fast fault clearance so as to increase the reliability of the power system.

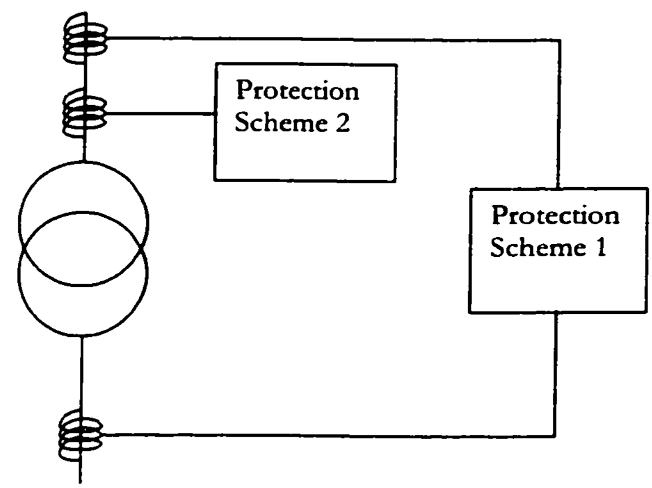


Fig. 3.1 Duplication of protection schemes

To clear a fault, the faulty apparatus will be tripped by either relay which detects the fault quicker and sends open circuit command faster. The fault clearance time may be expressed as Eqn (3.1).

$$E_{time} = \min(P_{time}) \qquad \textbf{(3.1)}$$

Where P_{time} is the operation time of the protection scheme protecting the apparatus

E_{3mr} is the minimum operation time of protection scheme (P_{3mr}) and is equal to the sum of minimum possible time the protective relays plus the operating time of the fault clearing device (breaker operation time).

If the faulty apparatus cannot be isolated, the backup protection located in the adjacent apparatus will take up the responsibility of the system recovery as soon as possible. The sequence of backup protection tripping actions will be carried out stage by stage until the system disturbance is cleared. Fig. 3.2 shows the backup stages for clearing the system disturbance.

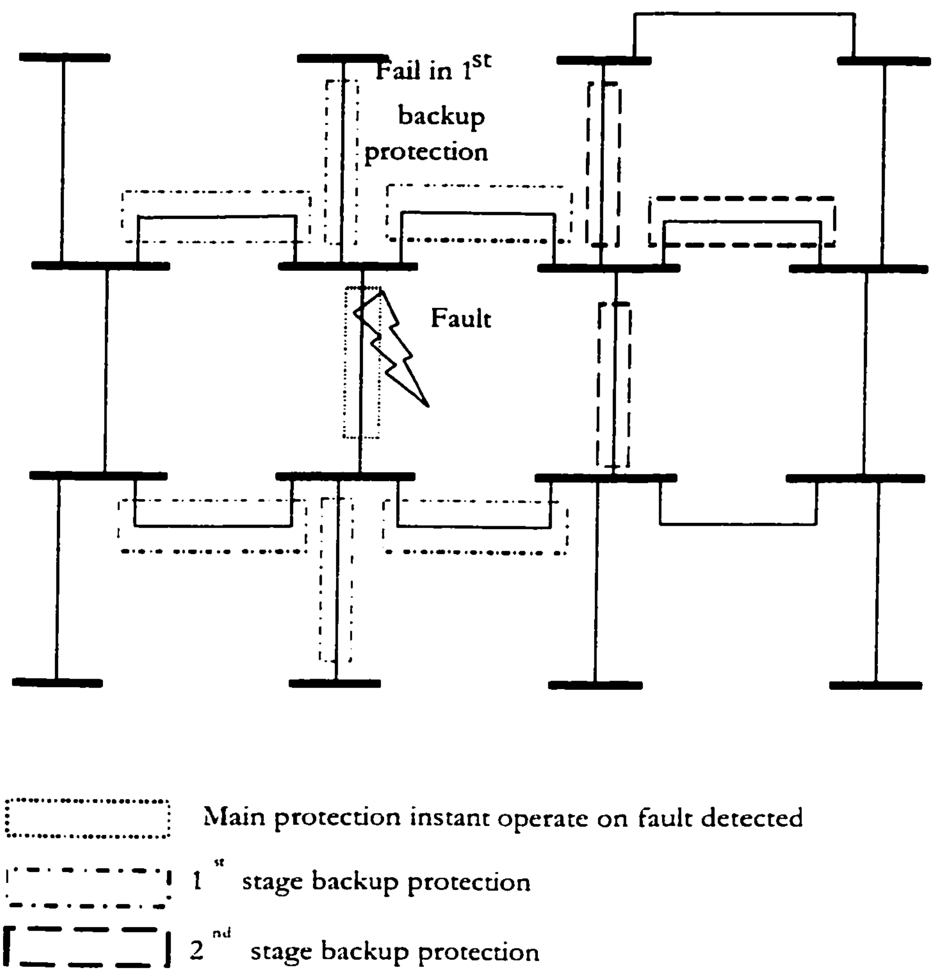


Fig. 3.2 Backup protection for the faulty apparatus and assume 1st stage backup protection failure

When the system fault failed to be cleared by the main protection, the 1st stage backup protection will take up the fault clearance responsibility. If one element of the 1st stage backup protection fails, the 2nd stage backup protection will take up the rest of fault clearance responsibility. A time delay exists between the main protection and the 1st stage backup, and between the 1st and 2nd stage backup protection. The formation of the 1st and 2nd stage obviously depends on the fault location. Ordinary protection system has no communication on information exchange for the location of fault occurrence and the stage of each relay. The relay setting should be the only parameter to control the tripping in the desirable sequence. A new method of coordination method called 'Time Coordination Method' is developed in this chapter to formulate all the protection relays and power apparatus operations into a set of optimization equations and constraints. Its purpose is to search for optimal protection settings to minimize the system disturbance time as well as the time of interruption of customer supply.

3.3 Process of Time Coordination Method

The key processes of Time Coordination Method are shown in Fig. 3.3. The time coordination is classified as constraint satisfaction optimization and each stage of coordination process is discussed as follows:

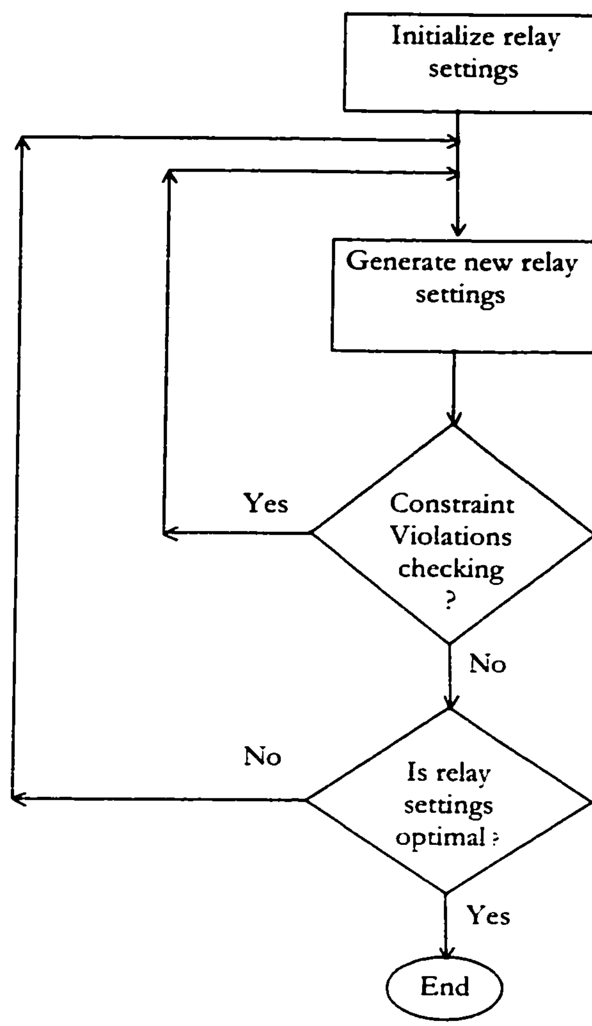


Fig. 3.3 Key processes of Time Coordination Method

3.4 Formulation of constrained optimization

Various types of backup protections are designed to suit the system requirements. The following typical backup protections are considered in the formulation of constrained optimization.

- Definite time delay overcurrent (TDOC)
- Inverse definite multiple time lag overcurrent (IDMTL)
- Directional inverse definite multiple time lag overcurrent (DIDMTL)
- Distance protection zone 2 (DIST2)
- Distance protection zone 3 (DIST3)

The relays setting methods and operating conditions are summarized in Table 3.1.

Table 3.1 Relay Setting Methods and operating conditions

Protection Type	Setting	Operating condition	Operation time
TDOC	T_{delay} $I_{setting}$	$I_{setting}<I$	T_{delay}
IDMTL	TM, CSM	CSM*CT ratio*Relay rating<I	f(I)
DIDMTL	TM, CSM	CSM*CT ratio*Relay rating<I	f(I)
DIST2	T_{ZONE2} $Z2_{REACH}$	$Z2_{REACH} > Zf$	T_{ZONE2}
DIST3	T_{ZONE3} $Z3_{REACH}$	$Z3_{REACH} > Zf$	T_{ZONE3}

Note :

I is the system current flow at the relaying point

Z_f is the measured impedance at the relaying point

T_{delay} is the delay time setting

$I_{setting}$ is the current setting

TM is the time multiplier

CSM is the current setting multiplier

CT is the current transformer at the relaying point

T_{ZONE2} is the time delay for distance zone 2

T_{ZONE3} is the time delay for distance zone 3

$Z2_{REACH}$ is the reach for distance zone 2 fault

$Z3_{REACH}$ is the reach for distance zone 3 fault

$f(I)=\frac{A*TM}{(I_{pu}^{p}-1)}$ where I_{pu} is the per-unit current, A and p are two constants

In the coordination of backup protection, the faster relay operation will decide the apparatus isolation time. The two adjacent apparatuses are formed into a coordination pair. They are protected by the backup relays and will be operated in sequence. The operation time difference between the coordination pair must conform to the grading margin. The number of system constraints is the product of the number of combination of coordination pairs, the number of combination of busbar faults, the number of possible system configurations, and the variation of fault types.

3.5 Grading margin

Grading margin is the minimum operation time difference which two relays that are required to be coordinated. There are several factors which affect the grading margin:

I. The fault current interrupting time of the circuit breaker.

II. The overshoot time of the relays.

III. Current and voltage transformer errors.

IV.Final margin on completion of operation.

The total amount of grading margin covering the above factors depends on the operating speed of the circuit breakers and the relay performance. At one time 0.5 sec. is a normal grading margin. With faster modern circuit breakers and lower relay overshoot time 0.4 sec. is reasonable, while 0.35 sec. may be feasible under the best possible conditions.

In some instances, however, rather than using a fixed grading margin, it is better to adopt a fixed time value, to allow for the operating time of the circuit breaker and relay overshoot, and a variable time that takes into account the relay errors, the C.T. errors and the safety margin.

As far as the IDMTL relays are concerned (according to British Standard BS142:1966, assumed that these comply with Error Class E10), Eqn (3.2) may be adopted:

$$t' = (0.2t + 0.25) \text{ sec.} \qquad \textbf{(3.2)}$$

where

t' = grading time interval.

t = normal operating time of relay nearest to the fault.

The fixed time value is made up to 0.1 sec. for the fault current interrupting time of the circuit breaker, 0.05 sec. for the relay overshoot time and 0.1 sec. for the safety margin. The variable time value is based on the normal limits of relay error with allowance for the effects of temperature, voltage, frequency and departure from reference setting.

In this thesis, the fixed grading margin is considered to simplify the coordination process.

3.6 Objective function

The effectiveness of the relay settings is evaluated by the objective function as shown in Eqn (3.3). The smaller the objective value, the better is the performance of the relay settings.

$$Objective=\alpha\times\sum R_i+\beta\times\sum CM_j+\chi\times\sum CV_k^{\delta} \qquad (3.3)$$

where

Ri is the relay operation time including the breaker operating time at that particular system configuration i

CM_j is the difference in the coordination margin difference between the coordination pair of equipment j and the relay setting to the preferred difference. In case of distance relays, it is the difference of the computed zone coverage setting and the corresponding preferred reach setting in percentage of length of protected line.

CV_k^{δ} is the number of constraint violations counting for all the coordination pairs for equipment k.

α, β, χ and δ are coefficients governing the amount of contribution to the overall objective value. α relates to the relay operation time; β relates to the coordination margin; and χ and δ relates to the number of constraint violations. They range from 0 to 1 and is set according to the user preference. For instance, the effect of relay operation time is reduced to zero if α is set to zero. If β is set close to 1, the computed relay setting will attempt to minimize the coordination margin as close as the grading margin, say 0.4s. In some system configurations, for example, system with a weak source, too much emphasis should not be placed on the minimization of the constraint violations, therefore, χ should be set closer to 0. The speed of minimization of constraint violation is controlled by δ. The number of constraint violations for some complicated systems may be up to ten thousand, δ is the moderation factor for the dominate effect of constraint violations to the objective function.

Note: In each system configuration, each coordination pair of equipment will be iterated by i, j, k

3.7 Problem domain

The objective function forms the problem domain which is a highly constrained combinatorial optimization. The optimal relay settings may be considered as the global optimum point on the solution searching space. The conventional searching methods, such as steeper-decant and non-linear programming, are performing a single-point search. Most probably the global optimum will not be reached just for one trial due to being trapped by the local optimums. Instead, multi-point search algorithm is more superior than single-point search. The searching process for the non-linear system with a lot of local optimum points is shown in Fig. 3.4. The multi-point search technique is employed in many problems [22]. The multi-point searching methods such as Genetic Algorithm [23], Evolutionary Programming [24] and

Modified Evolutionary Programming [25] will be discussed in Chapter 4. They are the promising methods in searching for the global optimum point in protection coordination problems. These methods randomly generate several sets of relay settings to increases the probability of converging to the global optimal setting and overcome the limitations of conventional rule based methods.

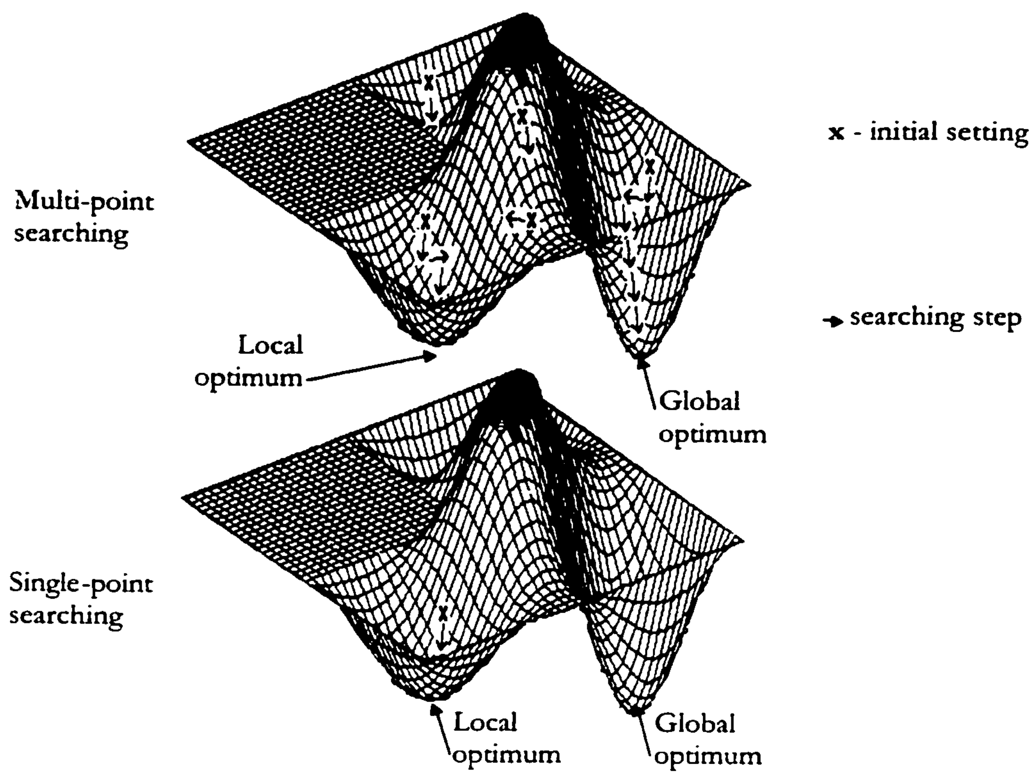


Fig. 3.4 Comparison of searching process for multi-point and single-point searches

3.7.1 Total relay operation time

The total relay operation time *Ri* is the summation of all protection relay operation time in all possible fault locations for all system configurations formed by the combination of circuit tripping.

The number of possible system configurations *C* is the number of grading configurations possibly occurred and can be calculated as shown in Eqn (3.4).

$$C = \sum_{m=1}^{N} (2^{BR(m)} - 1) \qquad (3.4)$$

Assume all the branches are in service, *N* is the number of busbars, *BR(m)* is the number of branches with fault current flow when a fault occurred on the busbar *m*. The number of system configurations for busbar fault is $2^{BR(m)}-1$.

Each system configuration may have different type and location of faults. Single-phase and three-phase busbar faults in various busbars should be considered that they are the highest possible system faults.

3.7.2 Coordination margin

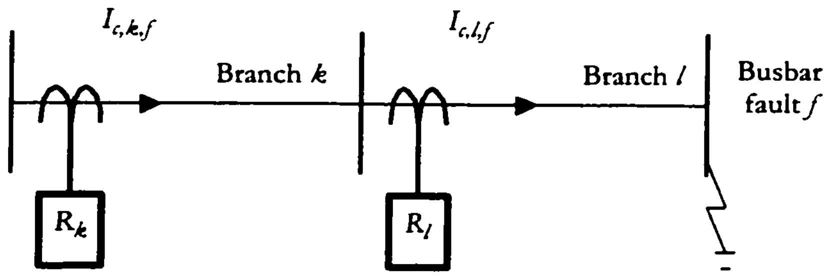


Fig. 3.5 Relay pair relationship

In Fig. 3.5, the fault current on the branch k under the grading configuration c having a fault on the faulty busbar f is defined as '$I_{c,k,f}$'.

The operating time of relay R_i for current $I_{c,k,f}$ is defined as '$t_{Ri(Ic,k,f)}$'

Faults are simulated according to the network configuration and fault locations. The direction and magnitude of fault current flowing in each branch is identified. The set of relays and the relay pair can then be identified.

R_s is the set of relays installed on the system and equals to:

$R_s = \{R_i,..R_r\}$; r is the number of relays

$P_{k,l}$ is the relay pair and defined as follows:

$P_{k,l} = (R_k, R_l)$

Relays R_k and R_l are located on the branch k and l respectively. Fault current $I_{c,k,f}$ and $I_{c,l,f}$ under configuration c and busbar fault f are flowing on the branch k and l respectively. $I_{c,k,f}$ and $I_{c,l,f}$ form the upstream and downstream relationship according to the current direction.

The coordination margin for the relay pair $P_{k,l}$ may be defined as shown in Eqn (3.5).

$$M_{c,k,l,f} = t_{Rk(Ic,k,f)} - t_{Rl(Ic,l,f)} \tag{3.5}$$

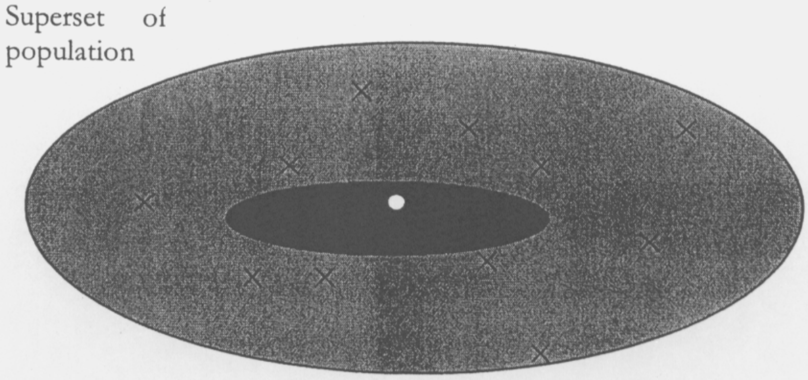
The coordination process is to make sure that all coordination margins $M_{c,k,l,f}$ must be greater than the grading margin, say 0.4 second, for all faults under all grading configurations for any relay pairs.

3.7.3 Constraint violation

In Eqn (3.3), CV_k is the number of constraint violations. Each relay settings will be checked under different coordination pairs defined in section 3.7.2. If the time difference of the coordination pair is less than the grading margin, CV_k will be incremented by one. More constraint violations of relay settings will result in larger objective value and will lead to less chance to survive in the subsequent optimization process.

3.8 Setting pusher

The multi-point search methods require the initialization of a set of relay settings as the initial points. Unfortunately, the pure random initialization frequently falls into the unfeasible solution area and is out of relay setting range resulting in too many constraint violations as shown in Fig. 3.6.



o The global optimum relay setting

x The initial relay setting distribution based on random generation.

Feasible solution area

Fig. 3.6 Fails of initialized relay setting that are out of the feasible solution area

Those failures in initialization cost too much computation. To overcome this problem, the '*Setting Pusher*' technique has been developed to push the relay setting from unfeasible into feasible solution area to save the initialization time. The action of the Setting Pusher is shown in Fig. 3.7.

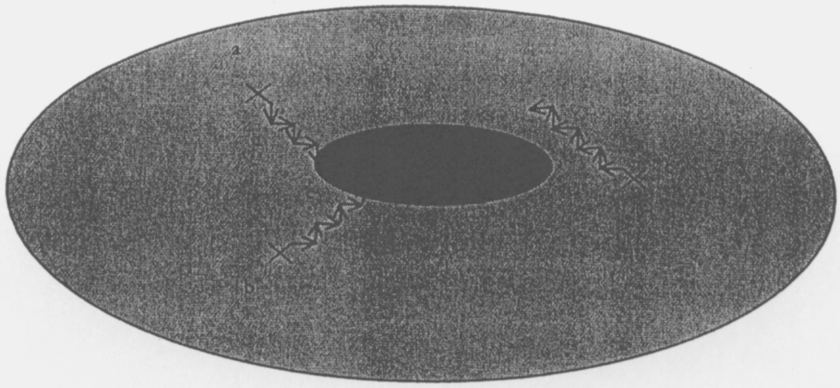


Fig. 3.7 Step actions by the Setting Pusher pushing the relay settings nearer to the feasible solution area.

At initialization, all generated relay settings will be checked against the constraints for the eligible initial relay setting. The ineligible relay settings will be modified during the constraint checking. The setting pusher will change the settings of upstream relays randomly. The modified settings will then be checked against the system constraints. This action will be repeated continuously until the relay setting satisfies all system constraints or the settings are out of ranges. Fig. 3.7 illustrates that the relay settings 'a' and 'b' are successfully pushed into the feasible solution area, but the relay setting 'c' is not. The unsuccessful relay settings will be discarded.

3.9 Fault calculation

The operation time of each set of relay settings should be calculated according to the fault current and voltage. Different type and location of faults should be iterated. The system configuration will be changed due to circuit tripping. The change of system configuration changes the fault current and voltage. Those changes should be considered in the Time Coordination Method.

Moreover, for protection coordination, the relays must be coordinated at highest fault level as well as coordinated at lowest fault level. Unfortunately, the IDMTL relay characteristic sometimes crosses in lower fault level cases as shown in Fig. 3.8. Thus, the protection coordination process should consider the IDMTL relay characteristics crossing feature.

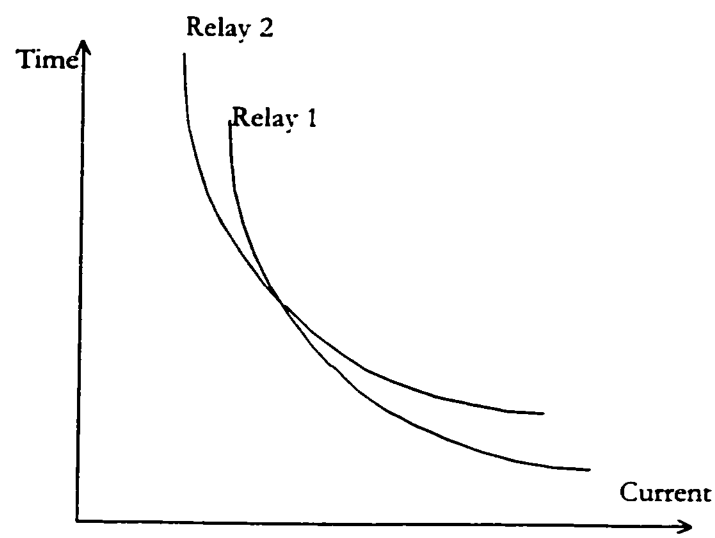


Fig. 3.8 Relay 1 grade with relay 2 at high fault level but cannot grade at low fault level

The coordinated relay settings should be tested under all types of faults. In fact, the single-phase and three-phase faults have highest probability and are adequate for the Time Coordination Method to coordinate all types of relays.

Chapter 4

4 APPLICATION OF ARTIFICIAL INTELLIGENCE

4.1 Introduction

Fuzzy logic [27, 28], neural network [29, 30] and evolutionary computation [23, 24, 25] are three main streams of artificial intelligence. They are successfully applied in many commercial and engineering applications [23, 24, 25]. In chapter 3, the Time Coordination Method is introduced to model the protection coordination problem as a constraint optimization problem. The optimum protection settings cannot be found out easily and is always trapped by local optimums. Many researches on constraint optimization reported that evolutionary computation is the most promising method to search for the global optimum solution [33, 34].

4.2 Evolutionary computation

Genetic algorithm (GA), evolutionary programming (EP) and Modified Evolutionary Programming (MEP) are three main branches of evolutionary computation [38]. They are multi-point search methods and share similar techniques in programming, a typical flow diagram for GA, EP & MEP is shown in Fig. 4.1. They require initialization to generate a set of relay settings, evolve new relay settings, select good relay settings for next generation and repeat the above process until reaching the predefined number of generations.

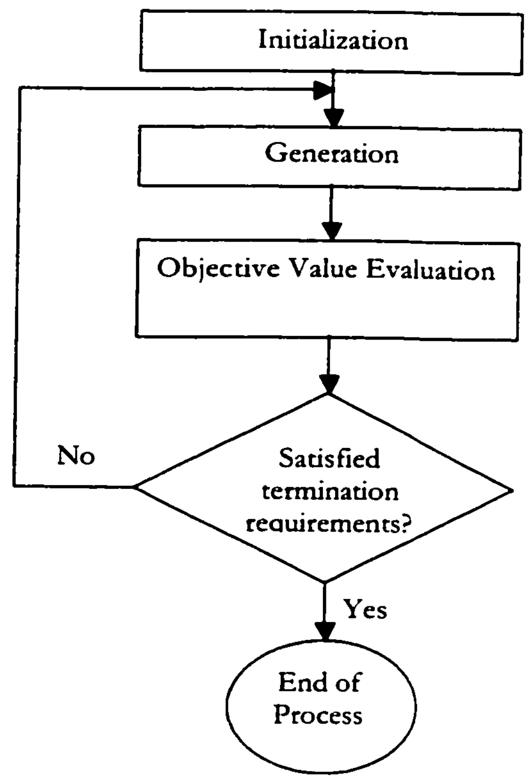


Fig. 4.1 Typical flow diagram for GA, EP and MEP

4.3 Initialization

The initialization generates several sets of relay settings in random to form the initial pool. The population size is the number of sets of relay settings in the initial pool and is determined based on the number of relay settings to be coordinated and the complexity of system. Those initialized sets of relay settings provide the starting points for searching. The greater the number of population size, the higher is the chance to search for the global optimum relay settings. Unfortunately, excessively large population size will result in over-crowing and slow down the searching process [35]. The right size of population is a critical parameter.

The initialization requires pure random process that can broaden the search area to increase the chance of searching for the global optimum relay settings. Unfortunately, protection setting coordination is a highly constrained problem, the pure random generated relay settings always fail to do so due to constraint violations [36]. For example, the random generated relay settings very often fail in the coordination time margin checking. The upstream and downstream relays are bound in a small range of coordination time margin. It is very difficult to generate the relay settings within two boundaries at pure random process. Any insufficient coordination margin may possibly cause undesirable tripping resulting in the system supply interruption. This is considered as a constraint violation. Those initialized relay settings with excessive constraint violations should be discarded. The initialization process will thus generate another set of relay settings to go through whole checking process again.

The successful rate of a pure random initialized protection relay settings without any constraint violation may be calculated in Eqn (4.1).

$$N = \prod_{j}^{n} \prod_{i=1}^{m} \frac{N_s(i,j)}{N_r(i,j)} \quad \textbf{(4.1)}$$

Where

For a system with n relays and each relay with m settings.

$N_s(i,j)$ is the number of steps satisfied all constraints of relay i setting j.

$N_r(i,j)$ is the number of settable steps of relay i setting j.

N is the successful rate of the protection relay settings without constraint violations.

For example, 10 relays, each relay has two settings with 100 steps and only 10% chance to satisfy all constraints, thus $N = (10/100)^{20} = 1 \times 10^{-21}$.

From Eqn (4.1), as the number of relays is increasing, the successful rate of the initialized relay settings without constraint violations is trending to zero. To maximize the successful rate, the setting pusher is developed in section 3.8 to push the random generated protection settings from unfeasible solution region to feasible solution region.

During the process of evolutionary computation, the continuous improvement of relay settings, i.e. reduction of the constraint violations, will be carried out. Thus, a small number of constraint violations are allowed at initialization process. The maximum number of constraint violations is defined. The count of constraint violations will be checked for each set of relay settings. If the number of constraint violations is greater than the maximum constraint violations, it will be discarded. Otherwise, it will be put into the initial pool for subsequent processes. The number of constraint violations will be reflected on the objective value as defined in section 3.6.

The initialization process will be terminated when the initial pool is at full strength. Those initialized sets of relay settings will be formatted for the evolutionary computation to process.

4.3.1 Genetic algorithm

Each set of relay setting called phenotype is mapped into bit stream called genotype and all relay settings in genotype are packed into a chromosome. Each relay setting will be determined according to the required number of bits to represent. The determination of number of bits in each chromosome is shown in Appendix A. After determining the number of bits required, the coding method will be applied. Either binary or gray coding methods are typically applied in GA and it can affect the efficiency. The Table 4.1 shows the difference between binary and gray coding.

Table 4.1 The difference between binary and gray coding

Decimal number	Binary coding	Gray coding
0	000	000
1	001	001
2	010	011
3	011	010
4	100	110
5	101	100
6	110	101
7	111	111

Form the Table 4.1, the gray coding only allows one bit change in each decimal number increment, but the binary coding from decimal 1 to 2 requires change last two bits. This is the main difference in coding the relay setting from phenotype to genotype and consequently affecting the efficiency of generation process. Finally, the relay setting will be mapped into a chromosome.

4.3.2 Evolutionary Programming and Modified Evolutionary Programming

Each set of initialized relay settings will be formulated into a column vector X_0 as shown in Eqn (4.2).

$$X_0 = \begin{Bmatrix} R_{1S1} \\ R_{1S2} \\ R_{2S1} \\ R_{2S2} \\ \cdot \\ \cdot \\ \cdot \\ \cdot \\ R_{nSj} \end{Bmatrix} \tag{4.2}$$

Where

R_{nSj} is the j setting in relay n.

Note

For example, R_1 is Inverse Definite Multiple Time Lag (IDMTL) Overcurrent (OC) Relay, R_{1S1} is the Current Setting Multiplier (CSM) and R_{1S2} is the Time Multiplier (TM).

The dimension of X_0 is the number of relay settings to be coordinated.

4.4 Generation

The generation process generates the new sets of relay settings. The number of new sets of relay settings is identical to the population size. The Relay setting improvements are carried out by the generation process. GA, EP and MEP are employed in different methods to generate new relay settings that will be discussed in the following sections.

4.4.1 Genetic algorithm

GA applies genetic operators 'crossover' and ' mutation' to generate new chromosome called off-spring.

Crossover

Crossover is a technique of exchanging information between two randomly selected chromosomes. It may exchange information at one, two and multi points. Many researches report that multi-point crossover is superior than one and two point crossover [37]. The detail operation of the crossover is shown in Appendix A.

Mutation

The mutation operator will only select one or a few bits depending on the length of chromosome. Those selected bits will be inverted from 1 to 0 or 0 to 1. In fact, mutation can introduce new genetic material to the chromosome. Unfortunately, most mutation processes are destructive that cause the relay setting out of range or failure in constraint checking. It should be reduced to a minimum.

4.4.2 Evolutionary programming

EP is different from GA. The relay settings do not mapped into chromosome. Instead, it produces the next relay settings by addition of Gaussian normal distribution noise in each relay setting that called mutation [34] as shown in Eqn. (4.3).

$$x_i' = x_i + \sigma_i \cdot N_i(0,1) \qquad \textbf{(4.3)}$$

$$\sigma_i = \sqrt{\beta_i \cdot \Phi(\bar{x}) + \gamma_i}$$

where

x_i is the element i in the string $\bar{x}$.

β_i is the scaling factor for EP mutation.

γ_i is the offset for EP mutation.

$\Phi(\bar{x})$ is the objective value of the string $\bar{x}$.

$N_i(0,1)$ is the Gaussian normal distribution noise.

The scale factor β_i and the offset γ_i control the performance of EP and typically set to 1 and 0 respectively.

4.4.3 Modified Evolutionary Programming

The generation of MEP is similar to EP that carried out by the mutation. It is different from GA and EP [39, 40]. The relay settings form the vector X_n according to Eqn (4.2). For the MEP process at generation *n*, the relay setting *k* at $X_n[k]$ generate the *n+1* generation of relay settings *k* $X_{n+1}[k]$ by Eqn (4.4).

$$X_{n+1}[k] = X_n[k] + \sigma_n[k] \times Pm_n[k] \times N(0,1) \quad \textbf{(4.4)}$$

$$\sigma_n[k] = \begin{Bmatrix} \sigma_{1S1\,nL}[k_j] \\ \cdot \\ \cdot \\ \cdot \\ \sigma_{nS_j\,nL}[k_j] \end{Bmatrix}$$

$$\acute{o}_{nS_j} n[k] = \sqrt{\beta \cdot \Phi(Xn[k]) + \gamma}$$

where

β is the scale factor for MEP mutation.

γ is the offset for MEP mutation.

$\Phi(X_n[k])$ is the objective value of the relay settings $X_n[k]$.

N(0,1) is the Gaussian normal distribution noise.

$Pm_n[k]$ is a mutation enabling matrix.

$\sigma_n[k]$ is a step matrix.

The step matrix $\sigma_n[k]$ is calculated before mutation process. This is generated from the objective value $\Phi(X_n[k])$ of the protection setting $X_n[k]$ and each entry $\sigma_{s_j,n}[k]$ is independent of the others.

The mutation enabling matrix $Pm_n[k]$ is designed to decrease the number of relay setting alternations in each mutation process. By experiment, the larger number of relay setting alternations, the larger will be the number of constraint violations. For the Genetic Algorithm, the single point crossover operator may provide smooth relay setting alteration and introduce smaller number of constraint violations, but the speed of searching for the optimum relay setting is slower. If multi-point crossover operator is applied, the relay setting alternations in each generation is larger and may cause larger number of constraint violations.

4.5 Objective value evaluation

After the generation process, all new generated relay settings will be evaluated against the objective value by using Eqn (3.3). The number of constraint violations, relay operation time and coordination margin will be evaluated according to the system configurations, fault types and fault locations. The constraint checking is playing an important role in the objective value evaluation. It checks the relay settings satisfaction in all constraints and counts the number of constraint violations. The larger number of constraint violations score higher objective value and result in less chance to survive in the next generation.

4.6 Selection

The objective values of old and new sets of relay settings are put into selection process to select the better relay settings for the next generation. The selection process cannot proceed purely based on the objective value. It is because better relay settings may be generated from some sets of relay settings with worse objective values after several generations. To preserve some potential good relay settings for the latter generations, some sophisticated selection techniques have been reported [41, 42]. In this thesis, elitism and tournament are considered.

4.6.1 Elitism

The objective values of old and new sets of relay settings will be converted to an expected frequency of selection. Firstly, the objective value is converted to raw fitness by Eqn (4.5).

$$f(v)=e^{Kv} \tag{4.5}$$

K is the fit factor which is a negative value and is determined according to the variation of the individual objective values. If the variation of individual objective value is larger, more negative value of K will be chosen.

There is problem if the raw finesses are directly used to determine the expected frequency of selection. In the first few generations, a few extremely superior sets of relay settings with very good objective values would be selected as parents too frequently. Those sets of relay settings will quickly dominate the population pool. The pre-mature dominance effect will therefore occur. Thus, the scaling method is applied to solve the above problem. The basic scaling principle is a linear transform of the raw finesses as shown in Eqn (4.6).

$$f(x) = slope * x + const \tag{4.6}$$

$$slope = (mult - 1) * avg \; / \; (max - avg)$$

$$const = ave * (max - mult*avg) \; / \; (max - avg)$$

Where

avg is the average objective value of old and new sets of relay settings.

max is the maximum of objective value of old and new sets of relay settings.

min is the minimum of objective value of old and new sets of relay settings.

Each time the selection process is called, a random number will be generated and compared with the candidate list. The chromosome will be selected if the candidate index match with the random number. It is called a roulette wheel game.

The scaling method can reduce the pre-mutual dominance effect by tuning the *mult* to one or two that can prevent the best set of relay setting to be selected in the next generation too frequently.

4.6.2 Tournament

The old and new sets of relay settings are put into stochastic selection via a tournament. The objective value of each set of relay settings faces competition against some randomly selected opponents. The set of relay settings should receive a *"win"* if it is at least as good as its opponent in each encounter. After a round of tournament, the number of *"win"* of relay settings will be sorted out. The tournament selection then eliminates those sets of relay settings with the least wins.

4.7 Termination

GA, EP and MEP will be terminated after a fixed number of generations. Due to the continuous improvement of each generation, the occurrence of the global optimum solution cannot be predicted. For some other optimization algorithms, the termination is based on checking the difference of the objective values between two conservative generations that approach the pre-defined value. This technique will fail in the protection coordination. It is because the local optimum relay settings always last for several generations that satisfy the termination criteria. The required number of generations is determined by the population size, network complex and the number of relay settings to be coordinate.

4.8 Application of GA for OC relay coordination in the TCM

4.8.1 Case study

The study network 1 as shown in Fig. A1 of Appendix A is studied. The system parameters and relay information are listed in Table A1 and A2 of Appendix A respectively. Six cases of different GA settings are listed in Table 4.2. One of relay settings improvement carried out GA is shown in Appendix A.

Table 4.2 GA and TCM settings

Case	GA control parameters		TCM control parameters			
	Population size	No. of generations	α	β	χ	δ
1.1	50	70	0.0	0.0	1.0	1.0
1.2	100	200	0.0	0.0	1.0	1.0
1.3	50	70	1.0	0.0	0.0	1.0
1.4	100	200	1.0	0.0	0.0	1.0
1.5	50	70	0.0	1.0	0.0	1.0
1.6	100	200	0.0	1.0	0.0	1.0

Note: TCM control parameter should refer to Eqn. (3.5)

In the study, other settings of GA are as follows:-

- Crossover ratio 0.4.
- Mutation probability 0.02.
- Elitism selection with fit factor = -20.

Other consideration of TCM is as follows:-

- Only three-phase busbar faults are simulated as only IDMTL OC relays are considered.

Table 4.3 Six cases of relay settings coordinated by TCM and optimized by GA

Relay	Setting	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
R 0	CMS (%)	99	99	99	99	99	99
	TM	0.1	0.1	0.1	0.1	0.1	0.1
R 1	CMS (%)	99	99	99	99	99	99
	TM	0.1	0.1	0.1	0.1	0.1	0.1
R 2	CMS (%)	93	68	110	95	95	51
	TM	0.2	0.34	0.17	0.19	0.18	0.24
R 3	CMS (%)	105	86	143	133	142	104
	TM	0.24	0.37	0.18	0.21	0.18	0.21
R 4	CMS (%)	100	86	123	197	104	155
	TM	0.57	0.55	0.35	0.23	0.33	0.25
R 5	CMS (%)	100	99	188	136	145	100
	TM	0.36	0.55	0.36	0.3	0.32	0.32
R 6	CMS (%)	147	106	196	198	154	145
	TM	0.6	0.69	0.39	0.36	0.55	0.35
R 7	CMS (%)	104	99	124	119	99	118
	TM	0.1	0.1	0.1	0.1	0.1	0.1
R 8	CMS (%)	99	99	99	99	99	99
	TM	0.1	0.1	0.1	0.1	0.1	0.1
Objective value		0.387	0.317	0.351	0.327	0.843	0.701
No of constraint violations		12	9	18	15	20	25

According to the TCM settings, they may be divided into three group, cases 1&2, 3&4 and 5&6 that are stressed on minimizing number of constraint violations, minimizing operation time and minimizing coordination margin respectively.

Two typical cases Fault I and II are selected for result analysis as shown in Fig. 4.2 and Fig. 4.3. The relays operation time and coordination margins are evaluated.

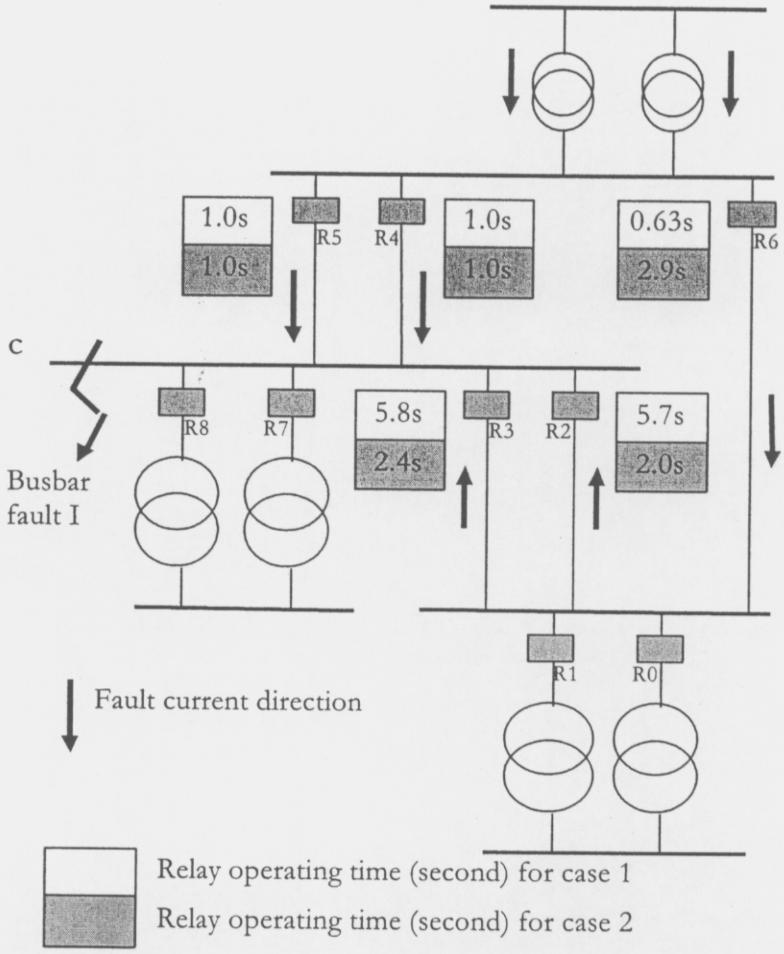


Fig. 4.2 Relays operating time for a 3-phase fault for cases 1 and 2 under Fault I

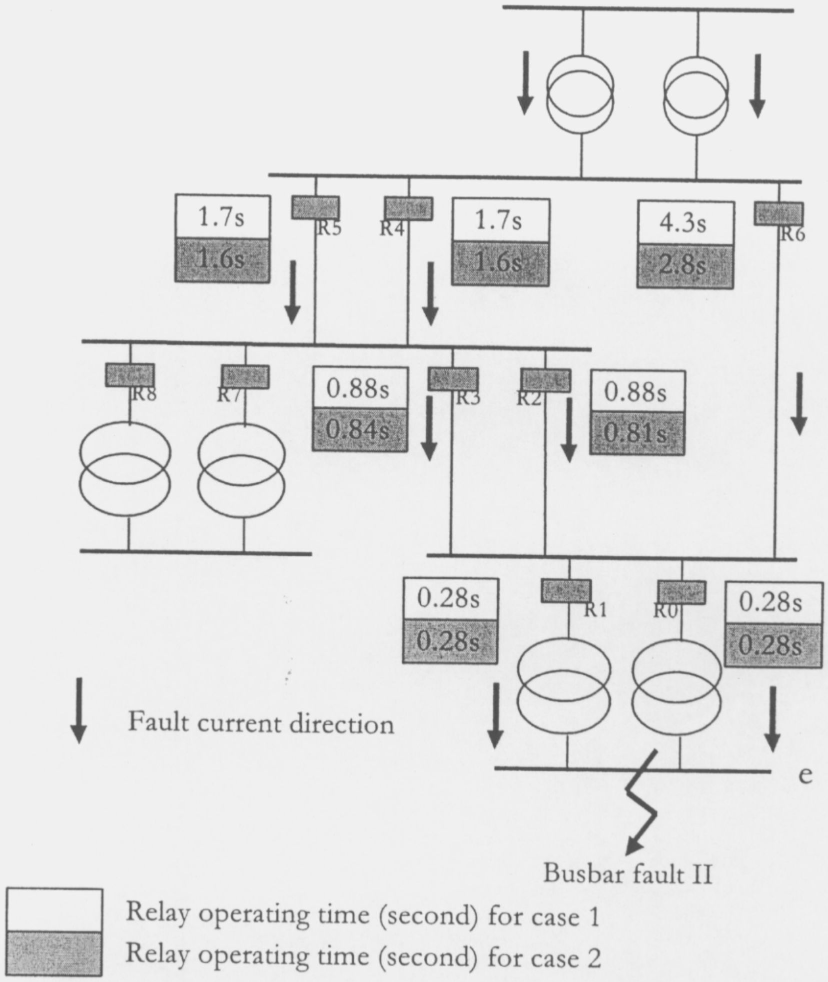


Fig. 4.3 Relays operating time for a 3-phase fault for cases 1 and 2 under Fault II

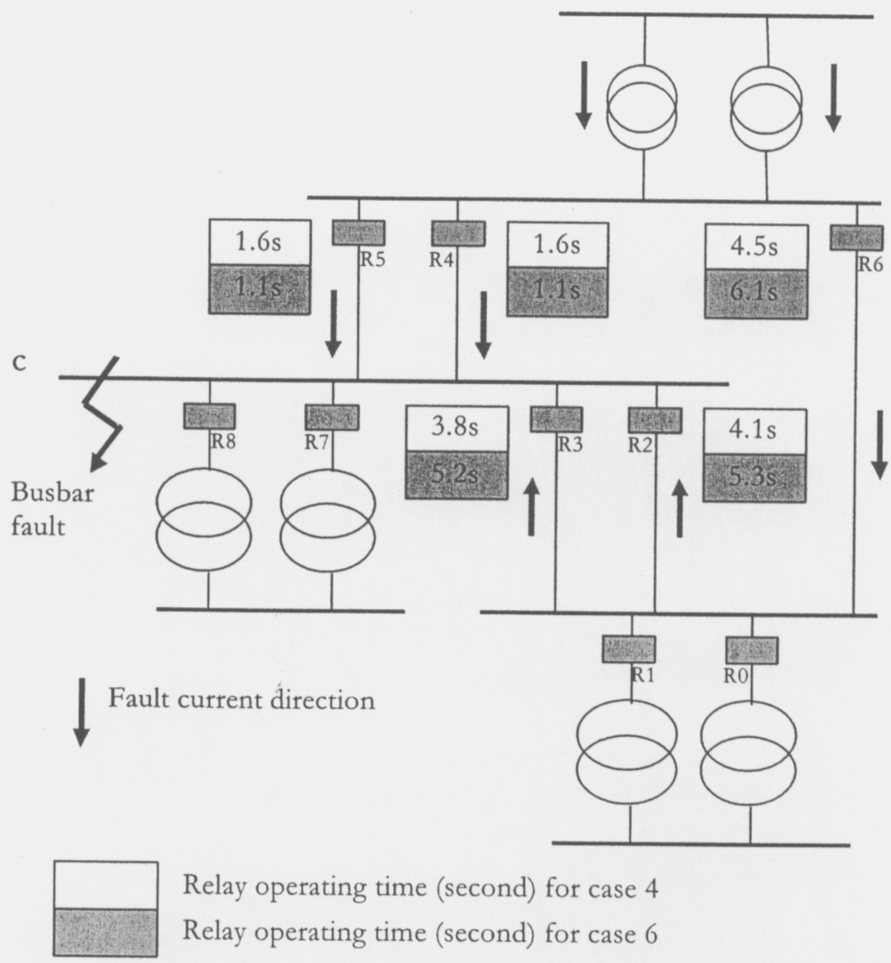


Fig. 4.4 Relays operating time for a 3-phase fault for cases 4 and 6 under Fault I

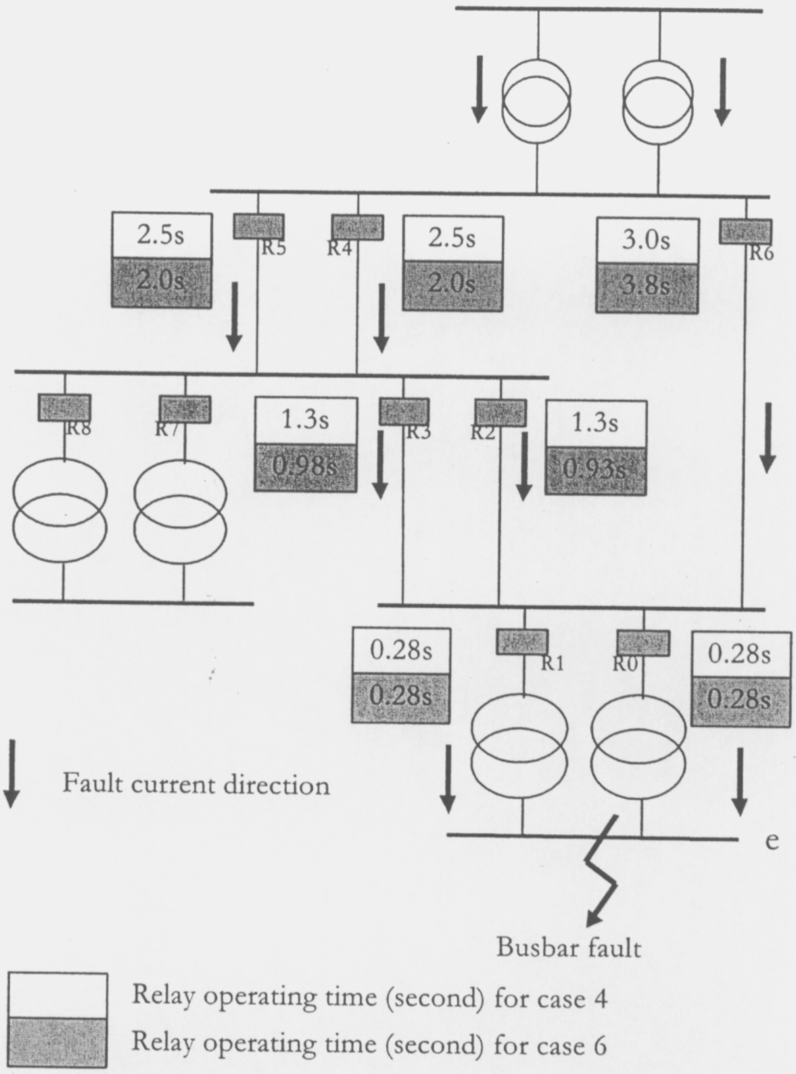


Fig. 4.5 Relays operating time for a 3-phase fault for cases 4 and 6 under Fault II

Table 4.4 Coordination margin of Fault I & II for cases 1, 2, 4 and 6

Case		1	2	4	6
Upstream operation time - Downstream operation time		Coordination margin (second)			
Fault I	R6 - R2	0.60	0.90	0.40	0.80
	R6 - R3	0.50	0.50	0.70	0.90
Fault II	R2 - R0	0.60	0.53	1.02	0.65
	R2 - R1	0.60	0.53	1.02	0.65
	R3 - R0	0.60	0.56	1.02	0.70
	R3 - R1	0.60	0.56	1.02	0.70
	R4 - R2	0.82	0.79	1.20	1.07
	R4 - R3	0.82	0.76	1.20	1.02
	R5 - R2	0.82	0.79	1.20	1.07
	R5 - R3	0.82	0.76	1.20	1.02
	R6 - R0	4.02	2.52	2.82	3.52
	R6 - R1	4.02	2.52	2.82	3.52

4.8.2 Discussion

From Table 4.3, the number of constraint violations of case 2 is the lowest. It is because the setting of the TCM for case 1 and 2 emphasize on minimizing the number of constraint violations. The objective value in case 2 is better than case 1 due to a larger population size and more generations for GA to search for the better solution. Similar results can be found between cases 3 & 4 and 5 & 6. From Table 4.4, the results also show that coordination margin of cases 1 and 2 are superior than case 4 and 6 while case 6 emphasize on minimizing the coordination margin. In conclusion, the setting of the TCM on minimizing constraint violations is the best.

4.8.3 Comparison among GA, EP and MEP

To compare the performance of GA, EP and MEP in TCM, the IDMTL OC relay coordination mentioned in section 4.8 is retested by EP and MEP. The settings of GA, EP and MEP are listed in Table 4.5.

Table 4.5 Setting of GA, EP and MEP

Algorithm	GA	EP	MEP
No of generation	200	200	200
Population size	100	100	100
Crossover ratio	0.4	-	-
Mutation probability	0.02	-	-
Fit factor	-20	-	-
Survive size	-	10	10
Offset	-	0	0
Scale factor	-	0.9	0.9
Mutation rate	-	0.1	0.1

Other considerations of TCM are as follows:-

- Only three-phase busbar faults are simulated and only the coordination of IDMTL OC relays are carried out for the study network.
- The objective function settings are shown in Table 4.6

Table 4.6 TCM objective function settings

α	β	χ	δ
0.0	0.0	1.0	1.0

The relay settings optimization process carried out GA, EP and MEP are detail explained in Appendix A, B and C respectively.

The optimized protection performances are summarized in Table 4.7.

Table 4.7 Optimized protection performances

Algorithm	GA	EP	MEP
Objective value	0.317	0.243	0.127
No of constraint violations	9	9	6

The objective values in each generation are recorded. The trending curves are plotted as shown in Appendix D for average, maximum and best objective values for GA, EP and MEP respectively.

According to the results shown in Table 4.7, MEP is better than GA and EP both in objective value and number of constraint violations.

In the GA trending curve shown in Fig. D.1 of Appendix D, the best objective value improvement has the staircase shape in the beginning portion of the curve. The average objective value curve is smoothly decreasing in the first 50 generations. The maximum objective value curve has small fluctuation and is overall decreasing. They are saturated after 50 generations. It is because the pre-mature dominance effect on the TCM application.

In the EP trending curve shown in Fig. D.2 of Appendix D, the best objective value improvement also has the staircase shape in the beginning portion of the curve and is longer than GA case. The average objective value curve is gradually decreasing. The maximum objective value curve fluctuates over the whole EP process. It is because the EP mutation operator is based on purely normal distribution variable to generate new relay settings and it sometimes distorts the relay settings and caused larger fluctuation in objective values. Instead, the GA is mainly based on crossover operator to generate new relay settings. Those two selected parents contain well-tested relay settings and obviously the new generated relay settings should be similar to their parents. On the other hand, the improvement of relay settings by EP is continuous and will slow down after 130 generations. It is because EP can get rid of the pre-mature dominance. In conclusion, EP is better than GA for the application of TCM.

In the MEP trending curve shown in Fig. D.3 of Appendix D, the best, average and maximum objective value curves are improving gradually and continuously. It is because MEP is the improved version of EP in particular for the TCM as described in section 4.4.3. One important finding in MEP is the promising search for the optimized relay settings. The simulation results prove that every time the average objective value curve approaches the best values curve, better relay settings will be generated. For the application of TCM, the solution domain is highly constrained by coordination constraints. It is very difficult to get improvement without expert knowledge of power system. MEP can search for the better relay settings in each generation. Thus, the relay settings optimized by MEP is better than GA and EP for the same number of generations and population size.

Chapter 5

5 ANALYSIS OF THE TIME COORDINATION METHOD

5.1 Introduction

The working principle of the Time Coordination Method (TCM) is described in Chapter 3. It is designed to coordinate protection system for all kinds of fault at all locations for all system configurations. The performance of the TCM especially in the dynamic change of system configurations due to adjacent circuit tripping will be discussed in this Chapter. This is missing in most protection coordination methods. Moreover, the application of the TCM to coordinate distance and overcurrent relays will also be discussed in this Chapter.

5.2 Current re-distribution

During system fault, the system configuration and fault current distribution may be changed due to adjacent circuit tripping. For the sample system shown in Fig. 5.1, the system configuration changes from Configuration A to B when relay R1 operates first to isolate Line 1 as shown in Fig. 5.2. Fault current will then be re-distributed. The resultant current passing through relays R2 and R3 under this condition will be changed from I_2 to I_3.

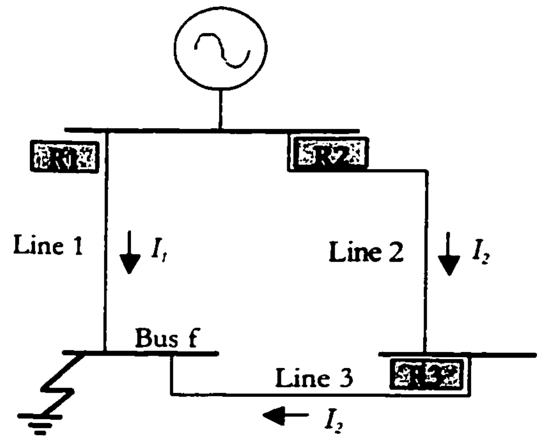


Fig. 5.1 Configuration A

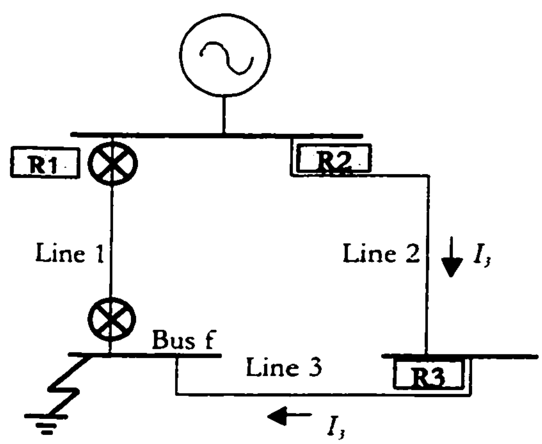


Fig. 5.2 Configuration B

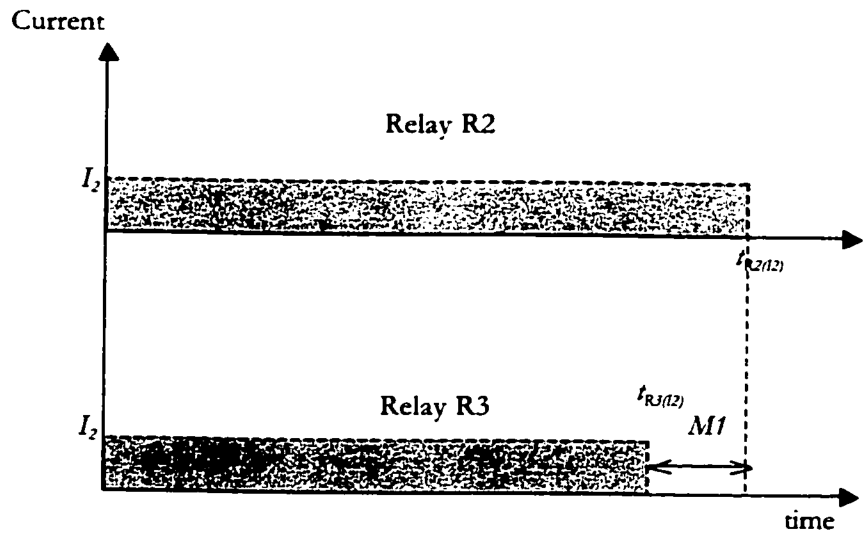


Fig. 5.3 Operating time of R2 and R3 due to I_2 only

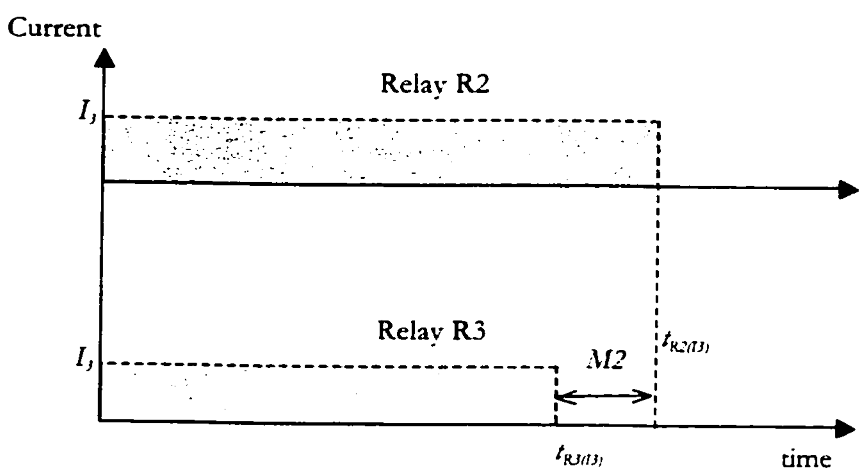


Fig. 5.4 Operating time of R2 and R3 due to I_3 only

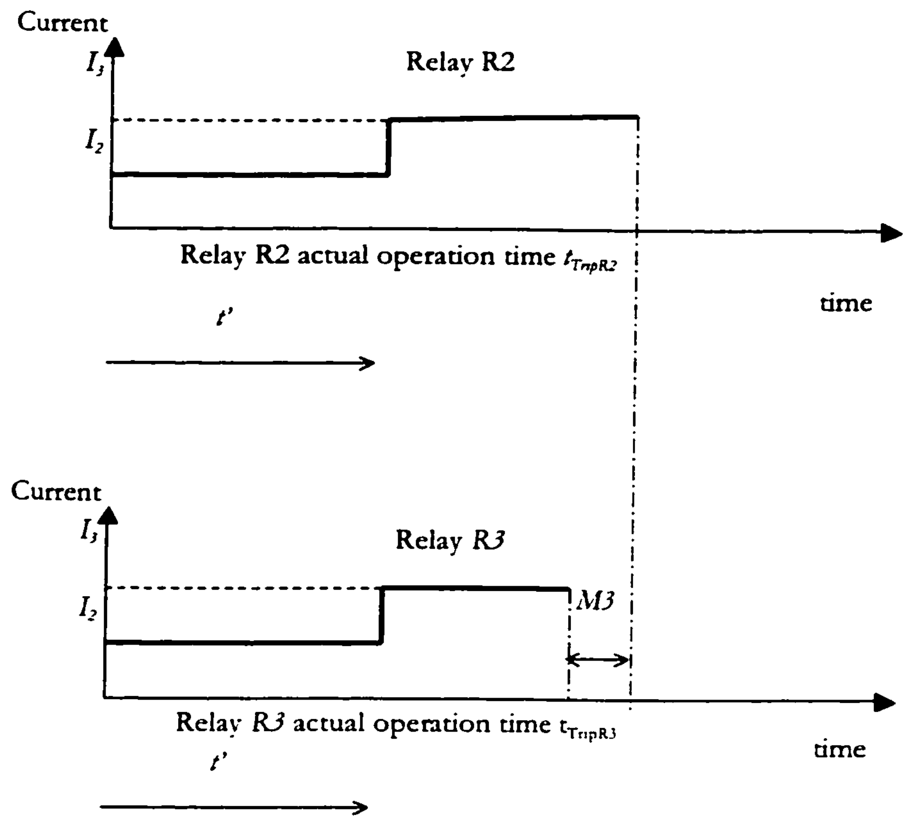


Fig. 5.5 Operating time of R2 and R3 when fault current changes from I_2 to I_3

If the fault current I_1 passing through R2 and R3 is constant, coordination margin M_1 between two relays is as shown in Fig. 5.3 If the fault current I_3 passing through R2 and R3 is constant, coordination margin of $M2$ between two relays is as shown in Fig. 5.4. During the fault current redistribution, the system configuration changes from A to B, the relay R2 and R3 experience current change from I_2 to I_3 as shown in Fig. 5.5. The coordination margin between R2 and R3 in such case is $M3$. By applying the IDMTL OC relay dynamic equation Eqn (2.4), the resultant operation time of R2 and R3 (t_{TripR2} and t_{TripR3}) may be calculated as shown in Eqn (5.1) and (5.2) respectively.

$$\int_0^{p_{R2}t_{R2}(I_2)} \frac{1}{t_{R2}(I_2)}dt + \int_{p_{R2}t_{R2}(I_2)}^{t_{TripR2}} \frac{1}{t_{R2}(I_3)}dt = 1$$

$$p_{R2} + \frac{1}{t_{R2}(I_3)}\left[t_{TripR2} - p_{R2}t_{R2}(I_2)\right] = 1$$

$$t_{TripR2} - p_{R2}t_{R2}(I_2) = (1 - p_{R2})t_{R2}(I_3)$$

$$t_{TripR2} = (1 - p_{R2})t_{R2}(I_3) + p_{R2}t_{R2}(I_2) \tag{5.1}$$

Similarly,

$$t_{TripR3} = (1 - p_{R3})t_{R3}(I_3) + p_{R3}t_{R3}(I_2) \tag{5.2}$$

The resultant coordination margin $M3$ as shown in Eqn (5.3) can also be found provided both $M2$ and $M1$ are larger than or equal to the coordination margin

$$M3 = t_{TripR2} - t_{TripR3} \tag{5.3}$$

$$= (1 - p_{R2})t_{R2}(I_3) + p_{R2}t_{R2}(I2) - (1 - p_{R3})t_{R3}(I_3) - p_{R3}t_{R3}(I2)$$

$$> (1 - p_{R2})t_{R2}(I_3) + p_{R2}t_{R2}(I2) - (1 - p_{R2})t_{R3}(I_3) - p_{R2}t_{R3}(I2)$$

$$= (1 - p_{R2})[t_{R2}(I_3) - t_{R3}(I_3)] + p_{R2}[t_{R2}(I2) - t_{R3}(I2)]$$

$$= (1 - p_{R2})M2 + p_{R2}M1$$

$$> GradingMargin$$

Note:

M1 is the coordination margin of R2 and R3 based on I_2 only and $M1 = t_{R2(I2)} - t_{R3(I2)}$ and assume *M1* is greater than grading margin.

M2 is the coordination margin of R2 and R3 based on I_3 only and $M2 = t_{R2(I3)} - t_{R3(I3)}$ and assume *M2* is greater than grading margin.

M3 is the resultant coordination margin when fault current changes from I_2 to I_3 and $M3 = t_{TripR2} - t_{TripR3}$

p is the ratio of relay accumulated operation at the instant of fault current changes to the total relay operation time based on the initial fault current alone, i.e. I_2 in this case. For example

$$p_{R2} = \frac{t'}{t_{R2(I2)}}, p_{R3} = \frac{t'}{t_{R3(I2)}}, p_{R3} > p_{R2}$$

Both *M1* and *M2* are greater than or equal to the grading margin.

The above equations can prove that the protection relay coordination can be maintained in dynamic fault current re-distribution such as changes in configuration. If the protection relays can be coordinated in both configurations A and B, they can still be coordinated if the system configuration change from A to B. In other words, if the protection system can fulfill the constraint checking in section 3.6.3 for all system configurations, the system can maintain the coordination margin for all dynamic changes of system configurations.

5.2.1 Simulation

The study network 1 as shown in Fig. A1 of Appendix A is studied and using EP described in chapter 4 to optimize the relay settings. Although MEP could also be applied in Network 1, EP method, however, will be illustrated to solve the coordination problem for Network 1. The system parameters and relay information are shown in Table A1 and A2 of Appendix A respectively. To simplify the problem, IDMTL OC relay and three-phase fault are considered. One set of relay settings improvement carried out by the EP is shown in Appendix B. Table 5.1 shows the optimum relay settings found by EP for 100 sets of initial relay settings and after 200 generations. After the computation, the objective value of the relay settings is optimized. It means that all relay operations and the coordination margin are optimized to a minimum. All the results have been checked for all configurations and satisfied all coordination requirements. Three typical cases are selected to illustrate the relay operations under three different fault conditions.

Table 5.1 Simulation result of optimum relay setting

Relay	CT Ratio	CSM	TM
R0	300/5	100%	0.10
R1	300/5	100%	0.10
R2	600/5	68%	0.27
R3	400/5	100%	0.27
R4	600/1	100%	0.50
R5	600/1	100%	0.50
R6	400/1	110%	0.62
R7	400/5	100%	0.10
R8	400/5	100%	0.10

5.2.2 Discussion

Three cases 5.1, 5.2 and 5.3 with different fault locations are simulated, the corresponding diagrams depicting detail changes of system configurations are shown in Fig. 5.6 to 5.11. Each case has two phases, system configuration will be changed from Phase 1 to Phase 2 after some circuit breakers tripped out. The relay coordination in phase 1 and 2 are subject to the condition defined in Section 5.2. The resultant operating time of relays in the major interconnectors are shown in Table 5.2.

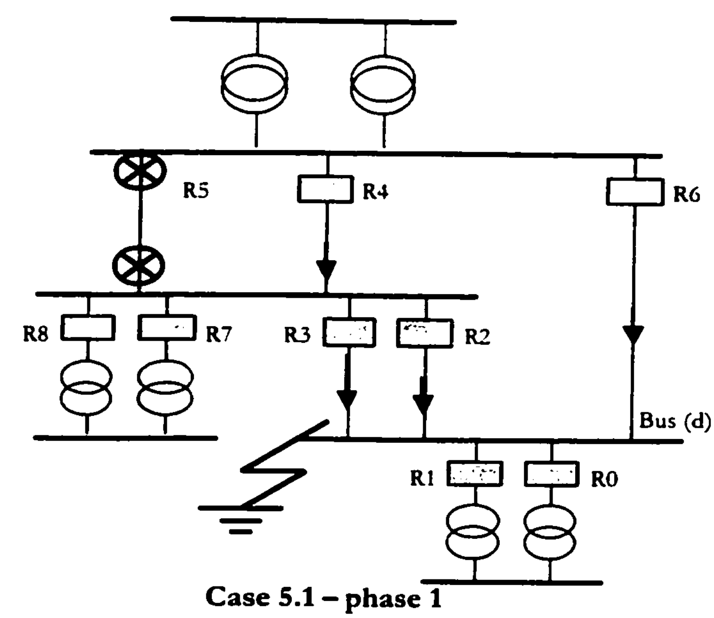


Fig. 5.6 Fault current distribution for Case 5.1 - phase 1

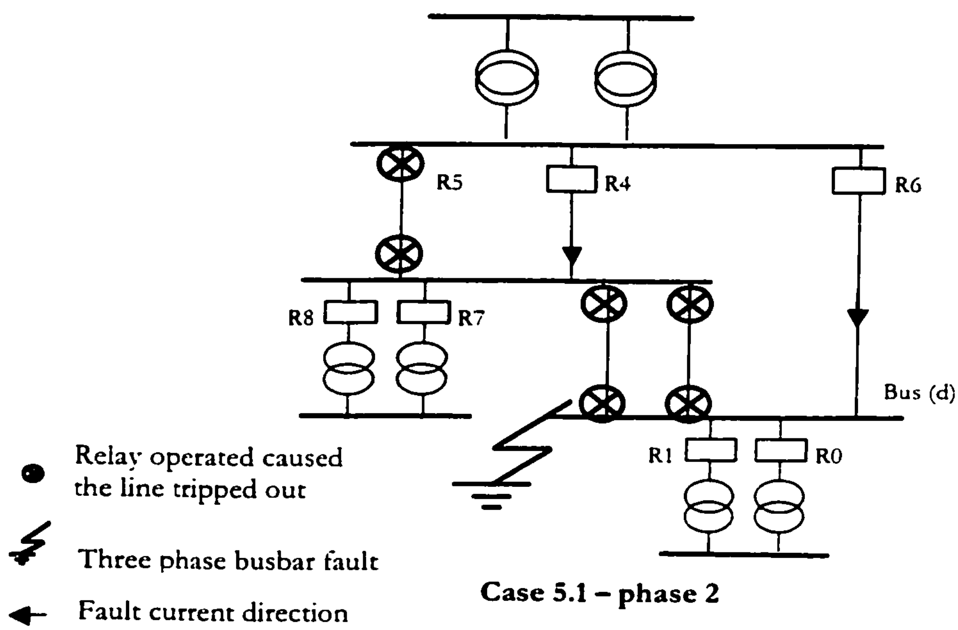
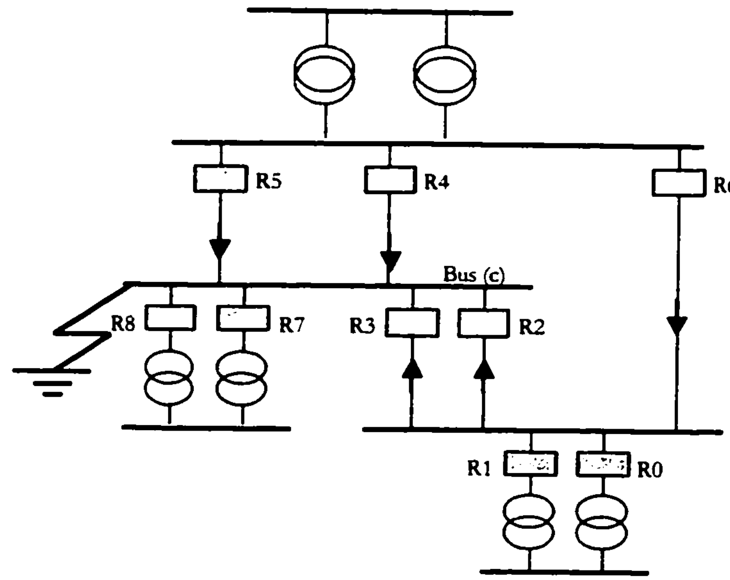
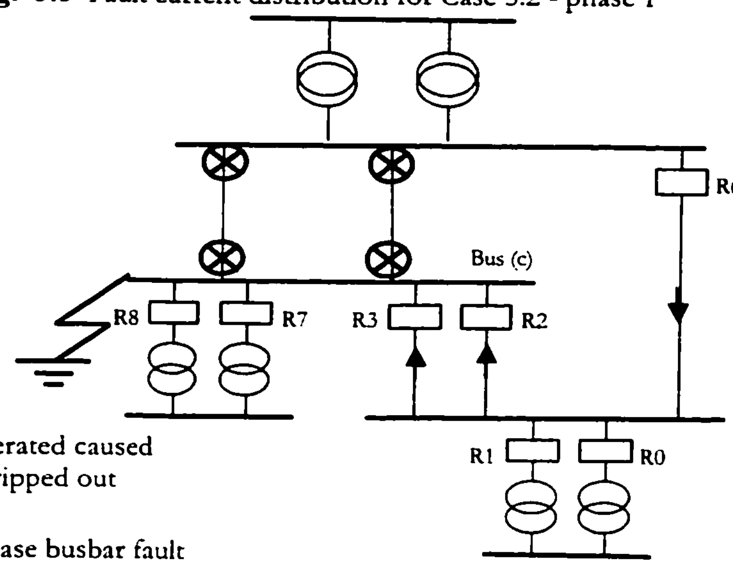


Fig. 5.7 Fault current distribution for Case 5.1 - phase 2



Case 5.2 – phase 1

Fig. 5.8 Fault current distribution for Case 5.2 - phase 1



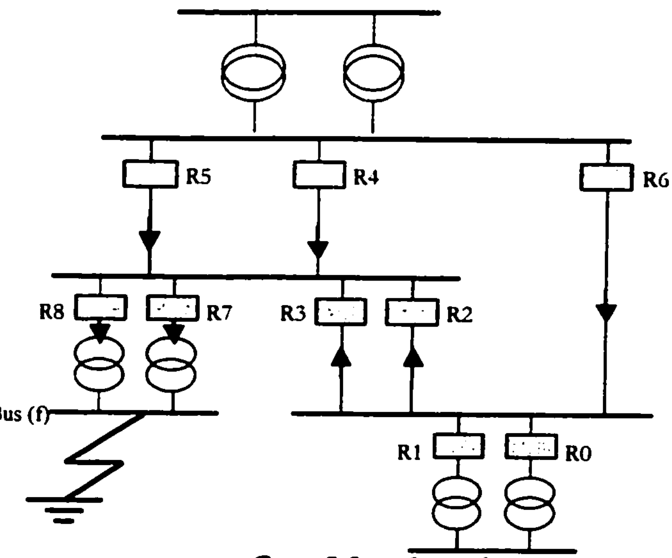
Relay operated caused the line tripped out

Three phase busbar fault

Fault current direction

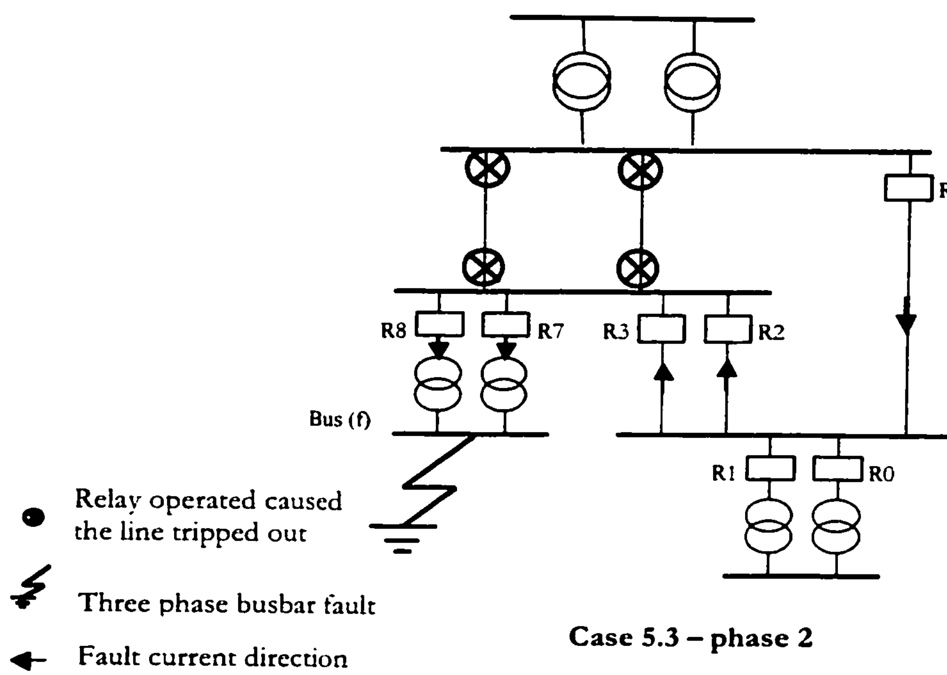
Case 5.2 – phase 2

Fig. 5.9 Fault current distribution for Case 5.2 - phase 2



Case 5.3 – phase 1

Fig. 5.10 Fault current distribution for Case 5.3 - phase 1



Case 5.3 – phase 2

Fig. 5.11 Fault current distribution for Case 5.3 - phase 2

Table 5.2 Resultant relay operation time (sec.)

	Case 5.1	Case 5.2	Case 5.3
T_{R2} =	0.82	1.54	4.27
T_{R3} =	0.82	1.52	4.24
T_{R4} =	1.33	1.24	2.72
T_{R5} =	-	1.24	2.72
T_{R6} =	1.73	2.16	4.69
$M_{42}=t_{R4}-t_{R2}$ =	0.51	-	-
$M_{43}=t_{R4}-t_{R3}$ =	0.51	-	-
$M_{62}=t_{R6}-t_{R2}$ =	-	0.62	0.42
$M_{63}=t_{R6}-t_{R3}$ =	-	0.64	0.45

The fault current flowing through the relays for Cases 5.1, 5.2 and 5.3 are shown in Table 5.3. The corresponding relay operation time solely due to the fault current distribution in Table 5.3 are shown in Table 5.4 under Phase 1 and 2 for each case.

Table 5.3 Relay operating currents

Relay current (A)							
Relay experiencing fault current	R2	R3	R4	R5	R6	R7	R8
Case 5.1-phase 1	3853	3853	7705	-	4534	0	0
Case 5.1-phase 2	0	0	0	0	5500	0	0
Case 5.2-phase 1	1222	1222	9278	9278	2444	0	0
Case 5.2-phase 2	2243	2243	0	0	4486	0	0
Case 5.3-phase 1	282	282	2141	2141	564	2482	2357
Case 5.3-phase 2	1364	1364	0	0	2728	1399	1329

Table 5.4 Relay operating time

Relay operation time (second) on each configuration										
	t_{R2}	t_{R3}	t_{R4}	t_{R5}	T_{R6}	T_{R7}	t_{R8}	$M_{42}^{*} = t_{R4}-t_{R2}$	$M_{62} = t_{R6}-t_{R2}$	$M_{63} = t_{R6}-t_{R3}$
Case 5.1-phase 1	0.82	0.82	1.33	-	1.82	-	-	0.51	-	-
Case 5.1-phase 2	-	-	-	-	1.67	-	-	-	-	-
Case 5.2-phase 1	1.70	1.67	1.24	1.24	2.49	-	-	-	0.78	0.81
Case 5.2-phase 2	1.09	1.08	-	-	1.83	-	-	-	0.74	0.75
Case 5.3-phase 1	-	-	2.72	2.72	17.46	0.38	0.39	-	-	-
Case 5.3-phase 2	1.55	1.52	-	-	2.34	0.55	0.58	-	0.79	0.81

Note : * M_{42} is equal to M_{43} in Case I-phase 1.

In each case, two relays will trip first and the system configuration will be changed from Phase 1 to Phase 2 (R2 and R3 in Case I, and R4 and R5 in Cases 5.2 and 5.3). Fault current distribution will then be changed. Other relays will continue to operate based on the re-distributed fault current. Their resultant operating time will consists of a portion '*p*' based on the initial fault current and a portion '(1-*p*)' based on the re-distributed fault current. The value of '*p*' for relay *R2*, *R3* and *R6* in all cases are shown in Table 5.5. The only exception is the value of '*p*' for R2 and R3 in Case 5.3 cannot be calculated as phase 1 fault current through the relay being less than their current settings. The resultant relay operation time for R2 can be calculated as shown in eqn. (5.4). Similar calculations are used for other relays.

$$Rt_{R2} = p_{[R2]} \times (t_{R2(\text{Case1})}) + (1 - p_{[R2]}) \times (t_{R2(\text{Case2})}) \tag{5.4}$$

Table 5.5 Ratio of relay operated under initial fault

	Case 5.1	Case 5.2	Case 5.3
$P_{[R2]}$ =	-	0.73	-
$P_{[R3]}$ =	-	0.74	-
$P_{[R6]}$ =	0.45	0.5	0.16

In Case 5.1, the interconnector R5 has been taken out of service for maintenance. When the fault occurs on Busbar *d*, fault current flowing through R4 is double of R2 and R3. In this case, the relay operation of R4 should be faster than the normal system configuration with the interconnection R5 in service. It is difficult for R4 to coordinate with R2 and R3, as R2 and R3 will be relatively slower than R4. The result in table 5.2 shows that the TCM optimized relay settings of R2, R3 and R4 can satisfy this operating condition with 0.51 second in both coordination margin M_{42} and M_{43}. Moreover, in phase 1 of case 5.1, there is no need for R2 and R3 to coordinate with R6 but R6 will experience a fault current change after the operations of R2 and R3. The resultant operation time of R6 is thus faster due to the increased fault current.

Case 5.2 demonstrates a change of current flow directions in R2 and R3. The coordination requirements are changed and R2 and R3 should then be required to coordinate with R6. When the fault occurs on Busbar *c*, according to the fault current distribution and relay operation calculations, R4 and R5 will operate first to trip two interconnectors R4 and R5. The system configuration will be changed from phase 1 to 2. R2, R3 and R6 will experience an increase of fault current causing faster operations. The result in Table 5.3 shows that the coordination margin among R2, R3 and R6 can be maintained for the case of fault current direction change.

Case 5.3 demonstrates that the protection system coordination can be maintained for taking into account the failure in operation of relay R7 and R8. When the fault occurs on Busbar *f*, according to the fault current distribution and relay operation calculations, the fault currents in the interconnectors R2 and R3 are inadequate to start the operation of the relays. R2 and R3 will only start to operate when R4 and R5 have operated and trip out the interconnectors. The result in Table 5.2 shows that adequate coordination margin is still maintained between R6 and R2 or R3 under such a complex condition.

5.3 Distance and overcurrent relay coordination

Study Network 2

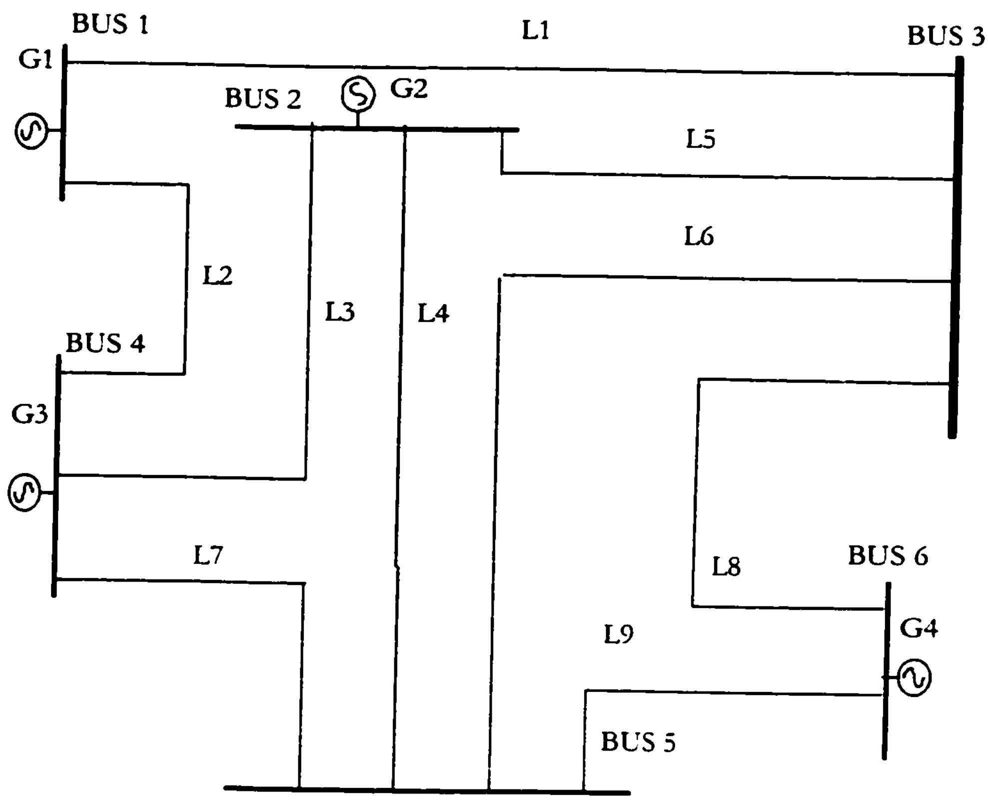


Fig. 5.12 Primary configuration diagram for Study network 2

Table 5.6 Generator information for study network 2

Generator	R0 (pu)	X0 (pu)	R1 (pu)	X1 (pu)	R2 (pu)	X2 (pu)
G1	0	0.01698	0.00038	0.02982	0.00038	0.02982
G2	0	0.01451	0.00008	0.01641	0.00008	0.01641
G3	0	0.00495	0.00026	0.01377	0.00026	0.01377
G4	0	0.04106	0.00021	0.05561	0.00021	0.05561

Table 5.7 Transmission line information for study network 2

Line	R	X	R_0	X_0
L1	0.00070	0.00618	0.00686	0.02622
L2	0.00006	0.00072	0.00079	0.00304
L3	0.00026	0.00294	0.00373	0.01244
L4	0.00026	0.00315	0.00180	0.00863
L5	0.00030	0.00365	0.00469	0.01573
L6	0.00015	0.00185	0.00234	0.00781
L7	0.00050	0.00520	0.00660	0.02190
L8	0.00014	0.01152	0.00195	0.01494
L9	0.00010	0.01090	0.00130	0.01110

Note: All per-unit (pu) values are 100MVAbase.

Table 5.8 Relay information for study network 2

Relay Type	Relay setting	max	Min	step
IDMTL OC	CSM	50%	200%	1%
IDMTL OC	TM	0.1	1.0	0.01
IDMTL EF	CSM	20%	80%	1%
IDMTL EF	TM	0.1	1.0	0.01
DIST 2	Reaching	100%	999%	1%
DIST 2	Time delay	400ms	1000ms	1ms
DIST 3	Reaching	100%	1999%	1%
DIST 3	Time delay	400ms	2000ms	1ms

In Chapter 2, the operation principles of distance and overcurrent relays are discussed. The distance relay is installed in sub-transmission and transmission network as the main and backup protection. The problems of distance protection coordination on zone 2 and zone 3 are addressed and reported in refs [19]. However, distance relay, overcurrent relay and other relay also act as backup protections in the power system. They operate on different principles and cannot be coordinated by conventional methods. In this section, the study network 2 as shown in Fig. 5.12 is studied. The generation, transmission and relay information are listed in Table 5.6, 5.7 and 5.8 respectively. All transmission lines at both ends are protected by inverse definite time phase fault overcurrent (IDMTL OC), inverse definite time earth fault overcurrent (IDMTL EF), earth fault distance zone 2 (DIST 2) and earth distance zone 3 (DIST 3). The protection relays for those generators are considered as a fixed setting which do not need to be included in the relay setting optimization.

The MEP is applied to optimize the relay settings. At initialization, the relay settings are generated in random, some unwanted relay settings may be generated resulting in wasting of computation. To minimize initialization time, some rules are established to control the generation of initial relay settings. Certain types of relays will impose a desirable pattern. For example, zone 2 reach of distance relays is normally equal to 150% of zone 1 reach and zone 3 reach is equal to 200% of zone 1 reach. In this study, the Time Coordination Method can find out the optimum reach in zone 2 and zone 3. The rule set in the simulation is that zone 1 reach must be less than zone 2 reach and zone 2 reach must be less than zone 3 reach. The rules employed in the simulation is listed in Table 5.9.

Table 5.9 Relays Setting Rules

Relay	Rule
IDMTL OC	CSM>100%
DIST 2	DIST 2 reach>DIST 1 reach
DIST 3	DIST 3 reach>DIST 2 reach
DIST 2	DIST 2 time delay > DIST 1 time delay
DIST 3	DIST 3 time delay > DIST 2 time delay

Note : DIST 1, DIST 2 and DIST 3 are the zone 1, zone 2 and zone 3 settings of distance relay.

5.3.1 Coordination improvement on distance and overcurrent relays

Consider the simple network shown in Fig. 5.13. The backup protection from Bus A to Bus B is used as an example. The relaying point at Bus A on line 1 has installed IDMTL, distance zone 2 and 3 (DIST 2 and DIST 3). According to the MEP statistical data, the relay settings of IDMTL, DIST 2 and DIST 3 are improving in each generation in the directions shown in Fig. 5.14 so as to optimize the coordination margin and protection coverage. Its major constraint is the settings of relays at Bus B on line 2 as shown in Fig. 5.15.

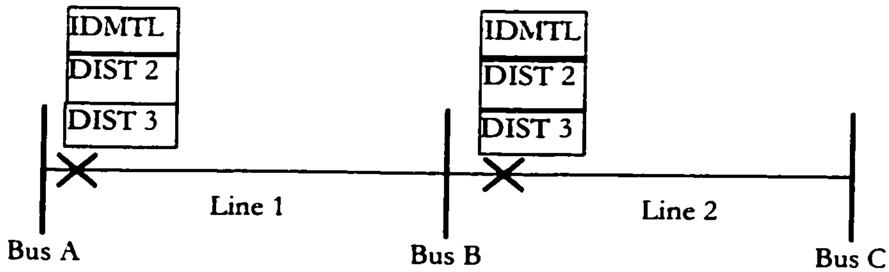


Fig. 5.13 Sample network

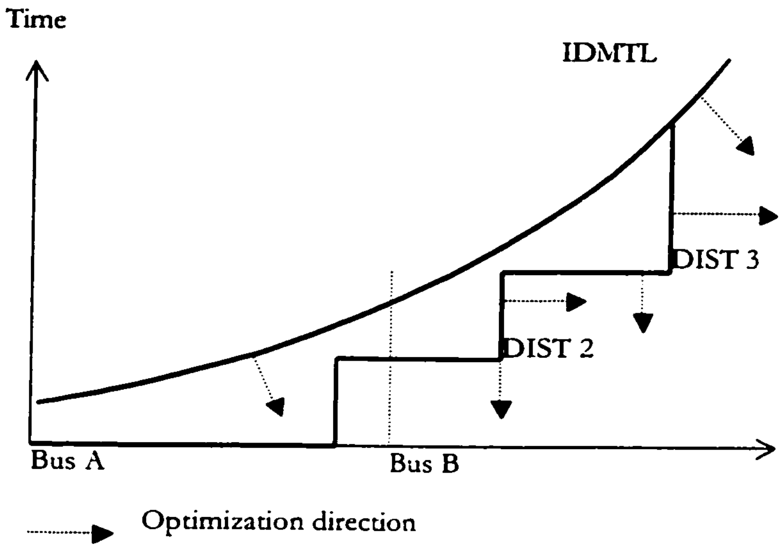


Fig. 5.14 Relay settings optimization direction

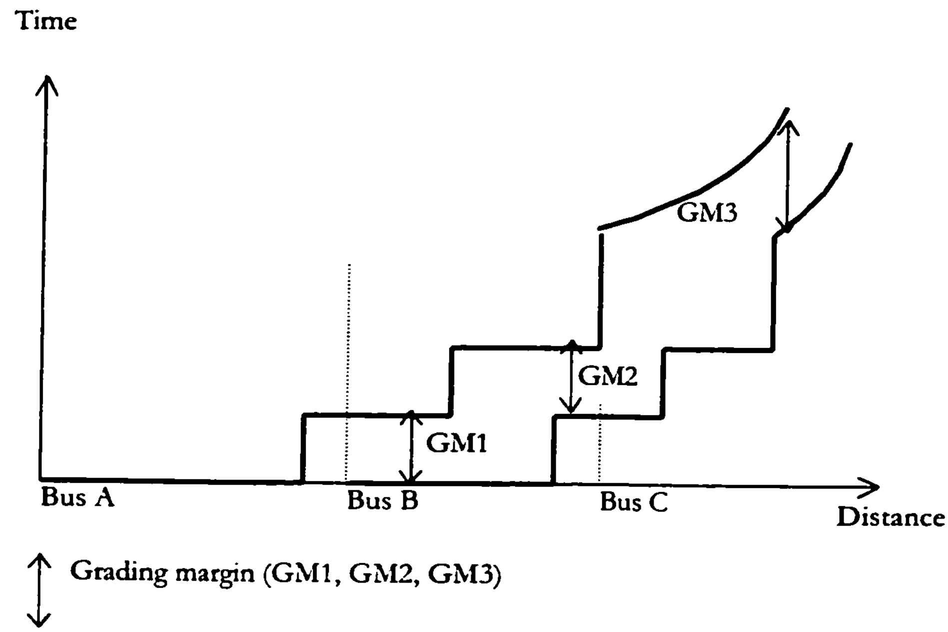


Fig. 5.15 Overall characteristic of Relays at Bus A and Bus B relays

The TCM will keep the coordination margin between relays at Bus A relative to relays at other buses at a minimum such as the coordination margin GM1 from DIST 2 at Bus A to DIST 1 at Bus B, and GM2 from DIST 3 at Bus A to DIST 2 at Bus B. For the fault occurred far beyond the reach of DIST 2 and DIST 3 at Buses A and B, the IDMTL at Bus A should also be coordinated with IDMTL at Bus B, for example GM3. In fact, the relay setting will be checked against all single-phase and three-phase busbar faults in all combination of transmission line and generator outages. The relays at Bus A are therefore constrained by other adjacent bus relays according to the fault current direction.

5.3.2 Effective Impedance of Ring fed Network

The zone 2 and zone 3 reaches of distance relays are normally set as the effective impedance from Bus A to Bus B plus a certain percentage of the next shortest line impedance. A typical example is shown in Fig. 516. The reach of DIST 2 at Bus A is assumed equal to the protected line impedance plus 30% of the next shortest line impedance, i.e. $K + 1{*}0.3\Omega$. The reach of DIST 3 is also assumed equal to the protected line impedance plus 80% of the next shortest line impedance, i.e. $K + 1{*}0.8\Omega$.

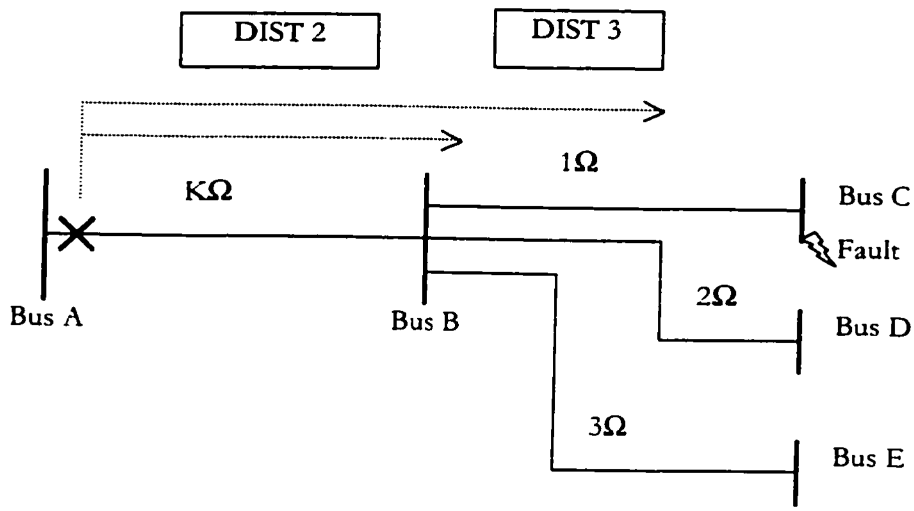


Fig. 5.16 Distance zone 2 and zone 3 reach for radial fed

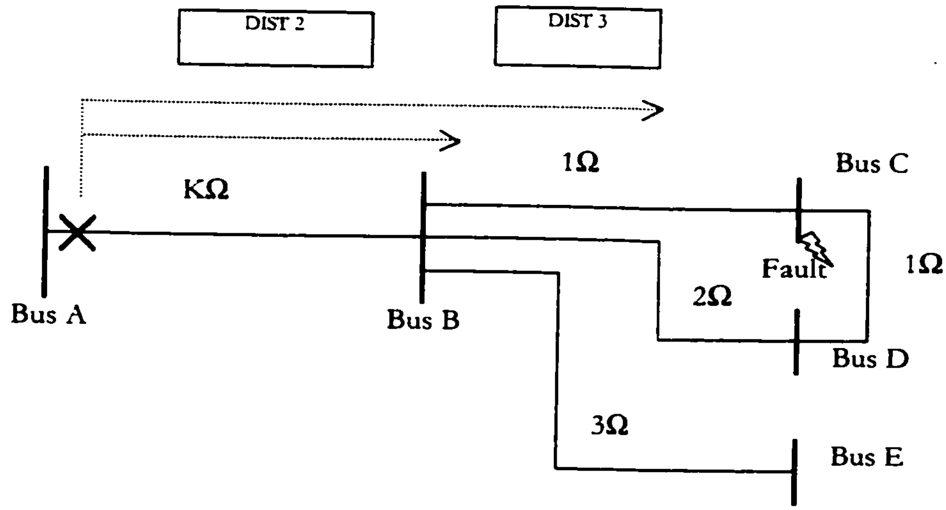


Fig. 5.17 Distance zone 2 and zone 3 reach for ring fed circuits

If Bus C to Bus D is interconnected by a line as shown in Fig. 5.17, the reach of DIST 2 will be $K + (1//(1+2)) * 0.3\Omega = K + 0.75 * 0.3\Omega$, and the reach of DIST 3 will be $K + (1//(1+2)) * 0.8\Omega = K + 0.75 * 0.8\Omega$. The reach of DIST 2 and DIST 3 is therefore dependent on the protected line impedance K. For long transmission line, the impedance K will be larger and the effectiveness of ring circuit will be reduced. The percentage of zone 2 and zone 3 reach will therefore be smaller. For the study network in this section, all transmission lines are inter-connected and the effect of inter-connections are considered for zone 2 and zone 3 reach of distance relays.

5.3.3 Discussion

Relay coordination is carried out using MEP with the process described in section 5.3. Table 5.10 shows the best set of initial relay settings from 200 sets of initialized relay settings. Table 5.11 shows the optimized relay settings by using MEP after 2000 generations. The performance of these relay setting are indicated by the sum of relay operating time, the number of constraint violations and objective value. After the computation, the objective value is significantly improved. It means that all relays have optimum operation for all single-phase busbar faults. The coordination margin and the number of constraint violations are always the minimum. Most of constraint violations occur in the low fault level conditions. Due to the IDMTL relay operation in low fault current is slow, some marginal IDMTL operations cannot coordinate with adjacent IDMTL or distance relays and will result in the failure in constraints checking. The Time Coordination Method can reduce the number of constraint failure significantly. The performance of relays before and after the setting computation is shown in Table 5.12.

Table 5.10 The Best Relay Settings among 200 initialized relay settings

Bus	Line	IDMTL OC		IDMTL EF		DIST 2	DIST 2	DIST 3	DIST 3
		CSM	TM	CSM	TM	reach	timer	reach	timer
Bus1	L1	105	0.1	77	0.52	110	1000	170	1810
Bus3	L1	105	0.1	77	0.52	150	870	230	1220
Bus1	L2	107	0.1	75	0.37	130	800	200	1240
Bus4	L2	107	0.1	75	0.37	120	560	180	810
Bus4	L3	107	0.1	78	0.38	110	990	200	1930
Bus2	L3	107	0.1	78	0.38	110	980	170	1990
Bus5	L4	100	0.1	79	0.75	110	980	170	1590
Bus2	L4	100	0.1	79	0.75	110	950	200	1620
Bus3	L5	100	0.1	76	0.22	110	870	180	1650
Bus2	L5	100	0.1	76	0.22	110	940	170	1420
Bus5	L6	102	0.1	75	0.2	110	870	170	1300
Bus3	L6	102	0.1	75	0.2	110	700	190	1570
Bus5	L7	100	0.1	69	0.84	110	980	170	2000
Bus4	L7	100	0.1	69	0.84	110	980	170	1820
Bus3	L8	100	0.1	80	0.74	110	960	170	1320
Bus6	L8	100	0.1	80	0.74	110	950	190	1730
Bus5	L9	100	0.1	80	0.79	110	400	180	810
Bus6	L9	100	0.1	80	0.79	110	950	170	1500

Table 5.11 Optimized relay settings

Bus	Line	IDMTL OC		IDMTL EF		DIST 2	DIST 2	DIST 3	DIST 3
		CSM	TM	CSM	TM	reach	timer	reach	timer
Bus1	L1	100	0.1	78	0.15	110	904	279	1629
Bus3	L1	100	0.1	78	0.15	113	501	197	1080
Bus1	L2	100	0.4	78	0.47	111	550	187	824
Bus4	L2	100	0.4	78	0.47	187	407	295	805
Bus4	L3	100	0.46	78	0.4	110	1000	273	1685
Bus2	L3	100	0.46	78	0.4	159	841	285	1518
Bus5	L4	100	0.24	78	0.25	115	431	271	1432
Bus2	L4	100	0.24	78	0.25	142	844	214	1260
Bus3	L5	100	0.13	78	0.1	141	403	212	1461
Bus2	L5	100	0.13	78	0.1	147	906	251	1968
Bus5	L6	100	0.1	78	0.13	124	420	292	1319
Bus3	L6	100	0.1	78	0.13	139	838	278	1027
Bus5	L7	100	0.25	78	0.35	163	817	266	1479
Bus4	L7	100	0.25	78	0.35	113	876	170	1977
Bus3	L8	100	0.21	78	0.2	157	555	298	868
Bus6	L8	100	0.21	78	0.2	110	440	218	1500
Bus5	L9	100	0.33	78	0.29	186	431	292	853
Bus6	L9	100	0.33	78	0.29	119	845	277	1943

Table 5.12 Performance of relay settings comparison

	Initial relay setting	Optimum relay setting
Sum of relay operation time (seconds) $\sum R_i$	1.81E+06	5.1E+04
Count of constraints violation	6600	886
Objective value	2980	17.7

Chapter 6

6 PROTECTION AND RELIABILITY

6.1 Introduction

The effectiveness of the TCM in dynamic fault current conditions and coordination between IDMTL and distance relays have been examined in Chapter 5. In this Chapter, it will be proved that the optimized protection system by the TCM can improve the supply reliability.

Power system consists of a combination of lines, transformers and incoming power sources including co-generators. The power cables, overhead lines and transformers form the main supply network, which provides a reliable power transmission from sources to loads. The study network 3 as shown in Fig. 6.4 is considered. The relay information, system parameters and their associated reliability data are shown in Table 6.1 and 6.2 respectively. Each feeder circuit is protected by current differential protection (CD) and inverse definite time lag (IDMTL) overcurrent (OC) and earth fault (EF) protection. The CD protection is a unit protection and consists of two remote end relays connected by a pilot wire cable to form the protection zone. The relay will operate if the differential current between two remote end exceeds the relay setting value. It operates on the system fault within the protection zone and operation is prohibited if the fault is out of the protection zone. The adjustable CD relay settings are the cable charging current and fault setting. They may be calculated during design and there is no need to change when there is a change in system configuration. In case of cable fault, the CD protection detects and isolates swiftly the two connected circuit breakers. If the CD protection is out of order or circuit breaker stuck, the fault cannot be cleared instantly and consequently has to be cleared by backup protections. This results in more circuits to be affected and the supply interruptions will be extended until the fault is totally isolated by opening more circuit breakers. Although, the chance of CD protection failure and stuck breaker is rare but the effect on supply reliability is significant. As the busbars in this layout has no busbar protection, a busbar fault may be treated in the same case as the CD protection failure or stuck breaker.

The IDMTL OC and EF will only operate on busbar fault or unclear system fault such as CD protection failure and stuck breaker. Incorrectly coordinated OC and EF relay settings will result in a larger area of supply outage. In this study, the OC and EF relays in the network are coordinated using the TCM. Different types of faults are applied to test the performance of the coordinated OC and EF relays. The supply reliability is calculated at the same time to find out the relationship between the TCM and supply reliability.

6.2 Principle of reliability

Billinton and Allan [43,44] introduce the basic principle of the supply reliability. The supply reliability influenced by the protection scheme is examined [47]. It may be computed by iterating the system faults and evaluating the protection relays performance. In this study, the influence of the operational faults on the supply reliability is not considered. The supply reliability for a busbar is calculated by finding the incorrect isolated busbar due to the busbar faults or the unclear system faults. The three classes of supply reliability calculations studied are: stuck breaker, busbar fault and CD protection failure.

The supply reliability calculation for stuck breaker is shown in Eqn (6.1) and (6.2).

$$\lambda_s(b) = \lambda_b \qquad \textbf{(6.1)}$$

$$U_s(b) = \lambda_b r_b \qquad \textbf{(6.2)}$$

Where

λ_b is the failure rate of stuck breaker.

r_b is the switching time to restore system due to stuck breaker.

$\lambda_S(b)$ is the supply b failure rate due to stuck breaker.

U_s(b) is the supply b restoring time.

The reliability calculation for busbar fault is shown in Eqn (6.3) and (6.4).

$$\lambda_b(b) = \lambda_f \quad \textbf{(6.3)}$$

$$U_b(b) = \lambda_f r_f \quad \textbf{(6.4)}$$

Where

λ_f is the failure rate of busbar.

r_f is the repair time of busbar.

$\lambda_b(b)$ is the supply b failure rate due to busbar fault.

U_b(b) is the supply b repair time.

The reliability calculation for the CD protection failure is shown in Eqn (6.5) and (6.6).

$$\lambda_p(b) = P_f \lambda_l \quad \textbf{(6.5)}$$

$$U_p(b) = P_f \lambda_l r_l \quad \textbf{(6.6)}$$

Where

λ_l is the failure rate of the cable.

r_l is the switching time of the cable.

P_f is the probability of CD protection failure.

$\lambda_p(b)$ is the supply b failure rate due to CD protection failure.

U_p(b) is the supply b restoring time.

The resultant supply reliability due to protection operation is hence shown in Eqn (6.7), (6.8) and (6.9).

$$\lambda(b) = \lambda_s(b) + \lambda_b(b) + \lambda_p(b) \tag{6.7}$$

$$U(b) = U_s(b) + U_b(b) + U_p(b) \tag{6.8}$$

$$r(b) = U(b) / \lambda(b) \tag{6.9}$$

Where

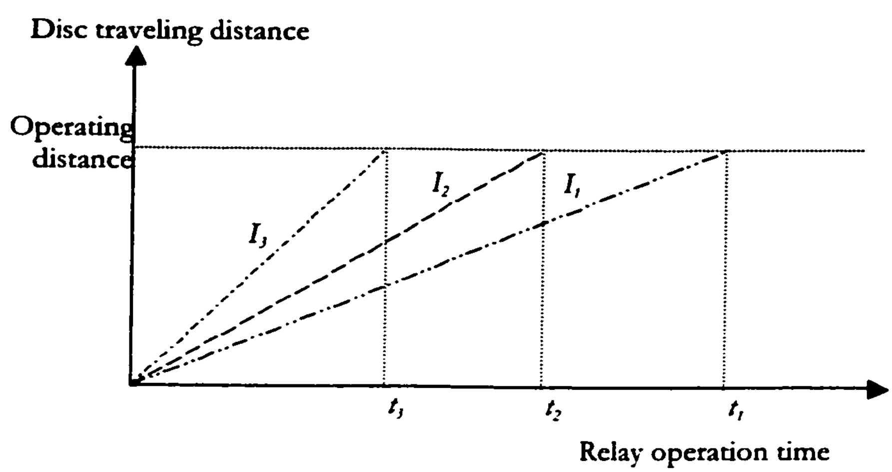
$\lambda(b)$ is the failure rate of supply b.

$U(b)$ is the repair time of supply b.

r(b) is the mean duration of supply b interruption.

6.3 Reliability algorithm for protection coordination

The supply reliability indices can be calculated by simulating all busbar faults, stuck breakers and protection failures. The faulty component will be isolated by a sequence of relay operations. As different fault locations will result in different relay operations, the step-by-step simulation method is developed to evaluate the sequence of relay operations. The relay operation time, for example the IDMTL OC relay, is depending on the fault current magnitude. Upon operation, the IDMTL OC relay sends the trip command to the breaker. Fig. 6.1 shows the relay operating times against the different operating currents I_1, I_2, I_3 where $I_1<I_2<I_3$.



-··-··-·· IDMTL OC relay traveling time t_1 at fault current I_1
----- IDMTL OC relay traveling time t_2 at fault current I_2
-·-·-·-·- IDMTL OC relay traveling time t_3 at fault current I_3

Fig. 6.1 IDMTL OC Relay operation times against the different fault currents

Unfortunately, the fault current magnitude in relaying point will change as a result of adjacent breaker operations. This is classified as the dynamic characteristic of the IDMTL OC relays mentioned in section 5.2. For instance, the final relay operation time of the three step changes of fault current from I_1, I_2 and then finally I_3, which contributes to consecutive operating time t_{f1}, t_{f2} and t_{f3}, assuming that $I_1 < I_2 < I_3$. As shown in Fig. 6.2, the IDMTL OC relay has started the operation from fault current I_1 and has traveled distance d_1 which is not sufficient to reach the operating distance. The fault current changed from I_1 to I_2 at t_{f1} and caused the relay travelled from d_1 to d_2. The second change of fault current occurred at time t_{f2} from fault current I_2 to I_3 and caused the relay to travel the rest of operating distance and send the trip command to open the breaker.

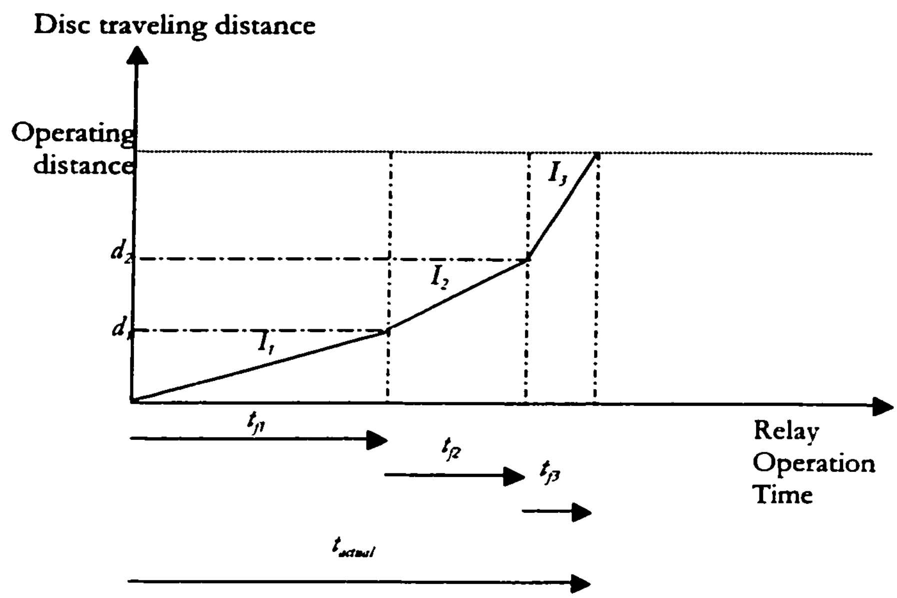


Fig. 6.2

Fig. 6.2 The actual OC relay operating time t_{actual} subject to currents I_1, I_2 and I_3 in consecutive times t_{f1}, t_{f2} and t_{f3}

Fault current will change at t_{f1} and t_{f2} due to other relay operations. The reliability should be recalculated to take into account the fault current redistributions. All the relay operation times should be updated. The fastest relay operation time will be chosen to calculate the remaining relay operation time. The calculation is repeated until the fault is completely isolated. The flow chart for the reliability calculation is shown in Fig. 6.3.

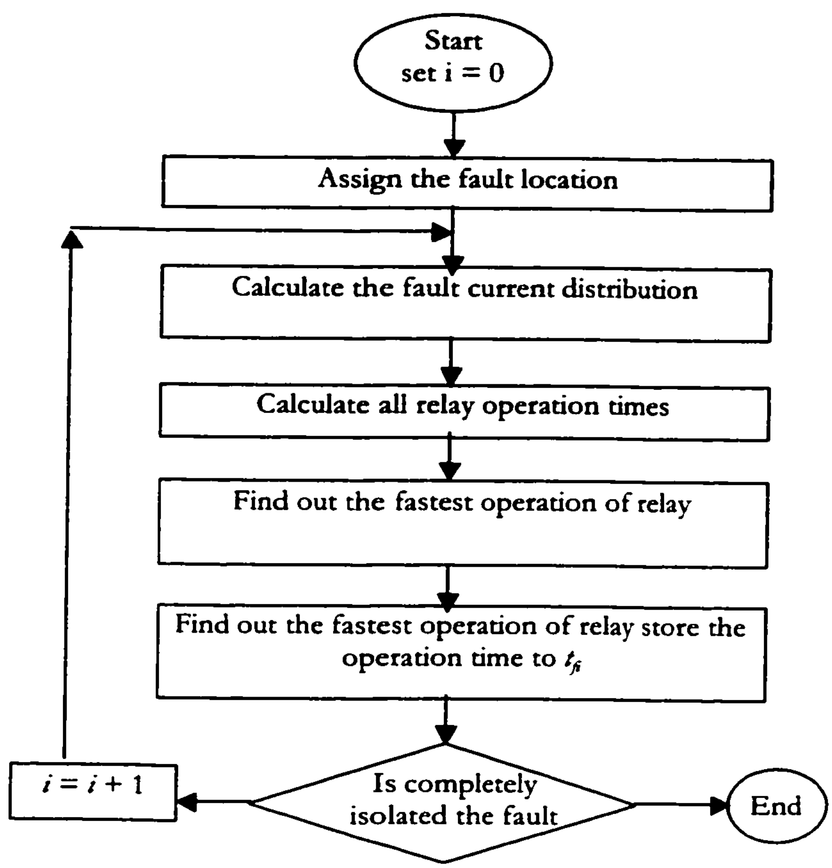


Fig. 6.3 The flow chart for the reliability algorithm to clear one simulated fault

The dynamic equation for the OC relay operation time calculation is defined by IEEE standard C37.112-1996 as shown in Eqn (6.10).

$$\int_0^{T_0} \frac{1}{t(I)} dt = 1 \qquad (6.10)$$

Where

$t(I)$ is the relay disc traveling time from 0 to the operating distance at fault current I.

For the three consecutive fault currents I_1, I_2, I_3 as shown in Fig. 6.2, the t_{actual} is calculated as follows.

$$\int_0^{t_{f1}} \frac{1}{t_1} dt + \int_{t_{f1}}^{t_{f1}+t_{f2}} \frac{1}{t_2} dt + \int_{t_{f1}+t_{f2}}^{t_{actual}} \frac{1}{t_3} dt = 1$$

$$\frac{t_{f1}}{t_1} + \frac{t_{f2}}{t_2} + \frac{1}{t_3}(t_{actual} - t_{f1} - t_{f2}) = 1$$

$$t_{actual} = \sum_{i=1}^{2} t_{fi} + t_3 (1 - \sum_{i=1}^{2} \frac{t_{fi}}{t_i}) \qquad (6.11)$$

Where

t_1, t_2, t_3 are the relay operating times at fault current I_1, I_2, I_3 respectively.

The generalized form of IDMTL OC relay operating time for n steps of fault currents with n consecutive fault currents is shown in Eqn (6.12).

$$t_{actual} = \sum_{i=1}^{n-1} t_{fi} + t_n (1 - \sum_{i=1}^{n-1} \frac{t_{fi}}{t_i}) \qquad \textbf{(6.12)}$$

The reliability algorithm updates all relay operating times, trips out the line with fastest relay operation, recalculates all the remaining relay operation times. This process is repeated until the fault current cease to flow in the network. The isolated busbars which indicate the loss of supply is identified. The reliability indices will be revised by using Eqn (7.1) and (7.2), (7.3) and (7.4) or (7.5) and (7.6) for the case of stuck breaker, busbar fault or CD protection failure respectively.

The reliability algorithm will simulate stuck breakers, busbar faults and CD protection failure cases. Each busbar supply reliability indices are calculated according to the number of isolations found during the process. The final supply reliability indices for each busbar will be calculated by using Eqn (7.7), (7.8), and (7.9).

6.4 Simulation

Study Network 3

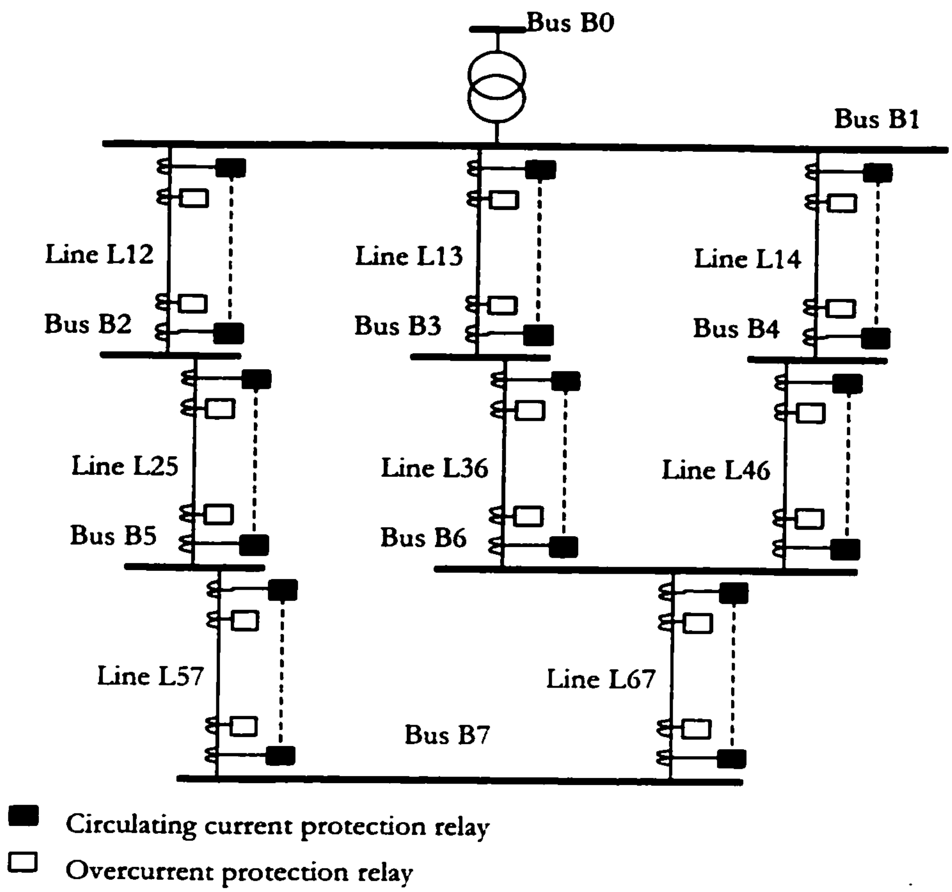


Fig. 6.4 Primary configuration diagram for Study network 3

Table 6.1 Overcurrent protection information for study network 3

Relay Type	Current Setting Multiplier (CSM)	CT Ratio	Time Multiplier (TM)	Failure Rate (yr-1)	Repair Time (hr)
IDMTL OC	[50%,200%] of 1%	400/1	[0.1,1.0] of 0.01	0.01	12
IDMTL EF	[20%,80%] of 1%	400/1	[0.1,1.0] of 0.01	0.01	12

Note: The each relay setting range from 'min' to 'max' in step of 'step' and write in the format of '[min,max] of step'.

Table 6.2 System information for study network 3

Circuit Name	R (pu)	X (pu)	R0 (pu)	X0 (pu)	Failure Rate (f/yr)	Switching Time(hr)
L12	0.40000	0.20000	0.40000	0.20000	0.0300	0.5000
L13	0.28000	0.19000	0.28000	0.19000	0.0900	0.5000
L14	0.24000	0.13000	0.24000	0.13000	0.2000	0.5000
L25	0.38000	0.19000	0.38000	0.19000	0.2800	0.5000
L36	0.30000	0.17000	0.30000	0.17000	0.2300	0.5000
L46	0.26000	0.15000	0.26000	0.15000	0.0100	0.5000
L57	0.40000	0.23000	0.40000	0.23000	0.0900	0.5000
L67	0.50000	0.22000	0.50000	0.22000	0.1500	0.5000

Note: All per-unit (pu) values are 100MVAbase.

Table 6.3 Busbar information for study network 3

Busbar Name	Failure Rate (f/yr)	Repair Time(hr)
B1	0.0004	10.0000
B2	0.0004	10.0000
B3	0.0004	10.0000
B4	0.0004	10.0000
B5	0.0004	10.0000
B6	0.0004	10.0000
B7	0.0004	10.0000

Table 6.4 Current differential protection information for study network 3

Relay Type	Failure probability (yr-1)	Repair Time (hr)
CD	0.01	12

Table 6.5 Circuit breaker information for study network 3

Breaker Type	Failure probability (yr-1)	Repair Time (hr)
Vacuum	0.01	15

The study network 3 as shown in Fig. 6.4 with digital IDMTL relays complying IEEE standard C37.112-1996 and IEC 255-3 is studied. As the digital IDMTL OC relay has the same operating characteristic as the electromechanical IDMTL OC relay, same relay terminology can be used. The relay information, system parameters and other information are listed in the Table 6.1 to 6.5 [47].

6.5 Results and discussion

The TCM is applied to find out the optimum IDMTL OC & EF relay settings. The relay settings are shown in case 6.3 in Table 6.6. To demonstrate the supply reliability improvement by the TCM, two sets of preset relay settings are studied. Case 6.1 employ a conventional approach to coordinate the IDMTL OC relays. Settings are obtained manually by time multiplier coordination using the log-log scale graph paper. The current distribution nature of the ring-fed network and the effect on relay operation time caused by current re-distribution due to adjacent circuit breakers tripping cannot be taken into account in the conventional approach. This is the main drawback of conventional approach. Case 6.2 focuses on minimum relay operating time and minimum possible relay settings are used without considering the coordination requirements. Three cases are checked against the number of constraint violations with the help of the TCM program and the results are listed in Table 6.7.

Table 6.6 Preset and the TCM optimized relay settings.

	Case 6.1		Case 6.2		Case 6.3	
	CSM	TM	CSM	TM	CSM	TM
L1-2 IDMTL OC	100	0.5	100	0.1	122	0.62
L1-3 IDMTL OC	100	0.5	100	0.1	117	0.86
L1-4 IDMTL OC	100	0.5	100	0.1	120	0.88
L2-5 IDMTL OC	100	0.3	100	0.1	118	0.24
L3-6 IDMTL OC	100	0.3	100	0.1	116	0.33
L4-6 IDMTL OC	100	0.3	100	0.1	116	0.53
L5-7 IDMTL OC	100	0.1	100	0.1	117	0.1
L6-7 IDMTL OC	100	0.1	100	0.1	116	0.22
L1-2 IDMTL EF	30	0.5	30	0.1	47	0.46
L1-3 IDMTL EF	30	0.5	30	0.1	53	0.74
L1-4 IDMTL EF	30	0.5	30	0.1	44	0.65
L2-5 IDMTL EF	30	0.3	30	0.1	40	0.12
L3-6 IDMTL EF	30	0.3	30	0.1	40	0.63
L4-6 IDMTL EF	30	0.3	30	0.1	40	0.42
L5-7 IDMTL EF	30	0.1	30	0.1	40	0.38
L6-7 IDMTL EF	30	0.1	30	0.1	40	0.11

Note :

Case 6.1 coordinated by conventional approach.

Case 6.2 minimum relay settings without coordination.

Case 6.3optimized relay settings coordinated by TCM

Table 6.7 Simulation result of supply reliability indices.

	Busbar	Failure Probability	Failure Frequency	Average Failure Duration
Case 6.1	B1	0	0	0
Case 6.2		0	0	0
Case 6.3		0	0	0
Case 6.1	B2	0	0	0
Case 6.2		0.124	0.2404	0.51581
Case 6.3		0	0	0
Case 6.1	B3	0	0	0
Case 6.2		0.199	0.3904	0.50973
Case 6.3		0	0	0
Case 6.1	B4	0.199	0.3904	0.50973
Case 6.2		0.199	0.3904	0.50973
Case 6.3		0	0	0
Case 6.1	B5	0.159	0.3104	0.51224
Case 6.2		0.482	0.9412	0.51211
Case 6.3		0.283	0.5508	0.5138
Case 6.1	B6	0	0	0
Case 6.2		0	0	0
Case 6.3		0	0	0
Case 6.1	B7	0.358	0.7008	0.51084
Case 6.2		0.358	0.7008	0.51084
Case 6.3		0.348	0.6808	0.51116
Case 6.1	Overall	0.716	1.4016	0.510845
Case 6.2		1.362	2.6632	0.511415
Case 6.3		0.631	1.2316	0.512342

Table 6.8 Number of constraint violations results.

	Case 6.1	Case 6.2	Case 6.3
No. of constraint violations	263	962	157

From Table 6.8, the number of constraint violations in case 6.3 is reduced significantly by the TCM compared with other cases. The major contribution of the TCM is the reduction in constraint violations. It means that the TCM can optimize the protection settings to provide a better isolation of the unclear faults.

The supply reliability results are shown in Table 6.7. The failure probability, failure frequency and average failure duration for the Busbars B1 and B6 are 0 for all cases. It implies that the Busbars B1 and B6 are the most secure Busbars. They have no chance to lost supply due to the busbar fault on other Busbars, the CD protection failure and stuck breakers on which the circuits are not connected to Busbars B1 and B6. Moreover, the reliability indices of Busbar B7 amount all 3 cases show that it is the most vulnerable Busbar.

The overall reliability indices of all three cases are calculated to summarize the overall system supply reliability. For instance, the overall failure probability of case 6.3 is 0.631. It implies that the overall system may experience 0.631 time of supply outage due to the Busbar fault, CD protection failure or stuck breaker. The overall failure probability and failure frequency of case 6.3 are 0.631 and 1.2316 respectively. They are superior than cases 6.1 and 6.2. It implies that the TCM can coordinate the relay settings to improve the system supply reliability.

Chapter 7

7 PERFORMANCE OF THE TIME COORDINATION METHOD UNDER VARIOUS CONTINGENT OPERATIONS

7.1 Introduction

The advantages of TCM are discussed in Chapter 5 and 6. This chapter will discuss the performance of the TCM. A modern protection system consists of various types of protection relays, which function to detect and isolate system abnormalities swiftly. Based on system configuration and voltage level, different main and backup relays are installed. The main protection relay works in unit protection principle and removes in-zone fault instantly. The backup protection relay is designed to backup the main protection relay in case it fails. The backup protection relays are discriminated by their operating time, which forms a sequence of backup relay operations for the unclear system fault. Any incorrect operation of the backup relays will result in a larger area of supply interruption [45] as well as decreasing the supply reliability. The backup protection relay coordination ensures that the fault clearance actions are in correct sequence and minimize the supply interruption. As the power system is changing from time to time, the coordination work should be carried out upon any significant change in power system conditions [46]. Based on the communication ability equipped in modern digital relay, the coordinated relay settings can be downloaded through the communication network. The TCM formulates the coordination of relay settings into a set of constraint equations and an objective function to manage the relay settings. In distribution network, the major backup protections are Inverse Definite Minimum Time Lag (IDMTL) overcurrent and earth fault relays. Their operations depends on the fault current magnitude. Thus, the relay operation is affected by the change of fault current as described in Chapter 5. In fact, the number of fault current handled by the TCM should be limited in a reasonable value to improve the efficiency of the TCM.

7.2 Application of Time Coordination Method in real system

To apply TCM in real system, the TCM should be distributed and modularized into Protection System Modeling, Fault Calculation Agent, Modified Evolutionary Programming, Protection Performance Evaluation and Reliability Evaluation as shown in Fig. 7.1.

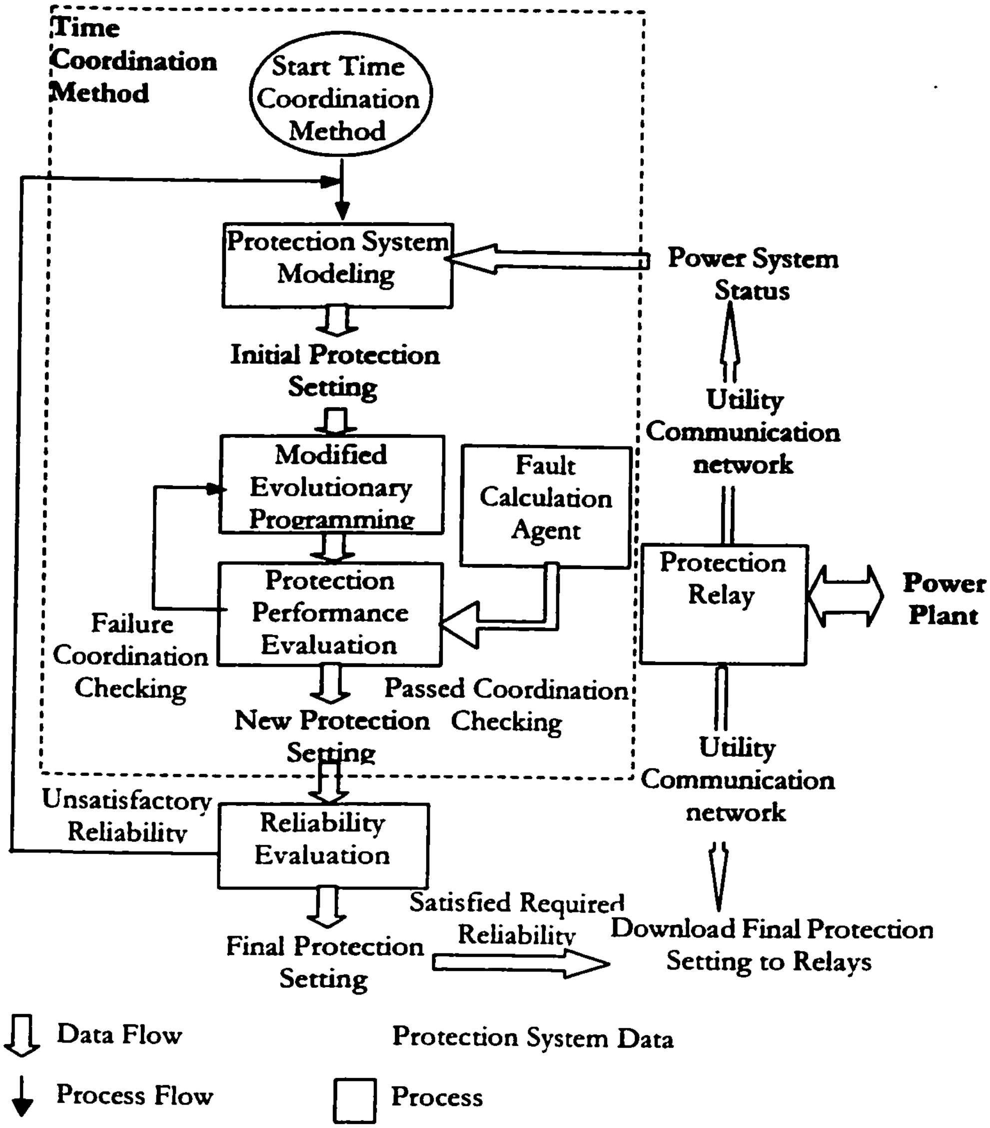


Fig. 7.1 Modules of Time Coordination Method

The power system data is transferred to the TCM through the utility communication network. TCM uses power system data to execute the Protection System Modeling for software objects formation construction. All power system elements such as relay, current transformer, voltage transformer, transmission line, power transformer and generator are created in centralized computer memory as a component of the system and corresponding data are stored. They are linked according to the physical arrangement as shown in Fig. 7.2. As a result of component operation, the fault current is redistributed and this alters the current relay operation. The Protection System Modeling also takes care of the relationship of the component operation time and the relay operation time as shown in Fig. 7.3. Those objects form the virtual system in TCM to provide a robust processing platform for data management.

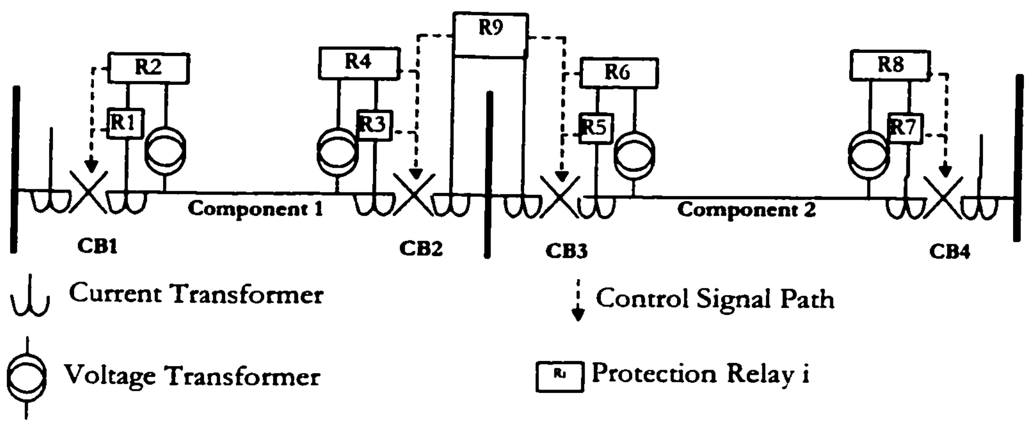
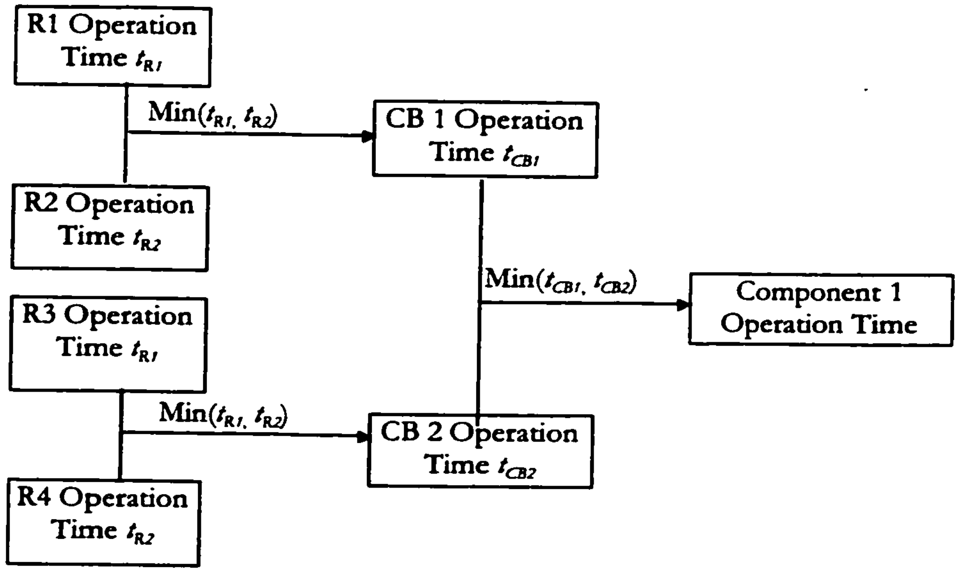


Fig. 7.2 Protection and Power System Components Modeling



Note: t_{Ri} is the relay R*i* operation time

Min is the minimum operator

Assuming a system fault occurring between CB1 and CB2

Fig. 7.3 Component 1 Operation Time

The Protection Performance Evaluation (PPE) module checks all protection relay settings against all coordination constraints described in Chapter 3. The coordination constraints are evaluated based on the fault current distribution, which are calculated by Fault Calculation Agent (FCA) module. The flow diagram for PPE and FCA is as shown in Fig. 7.4.

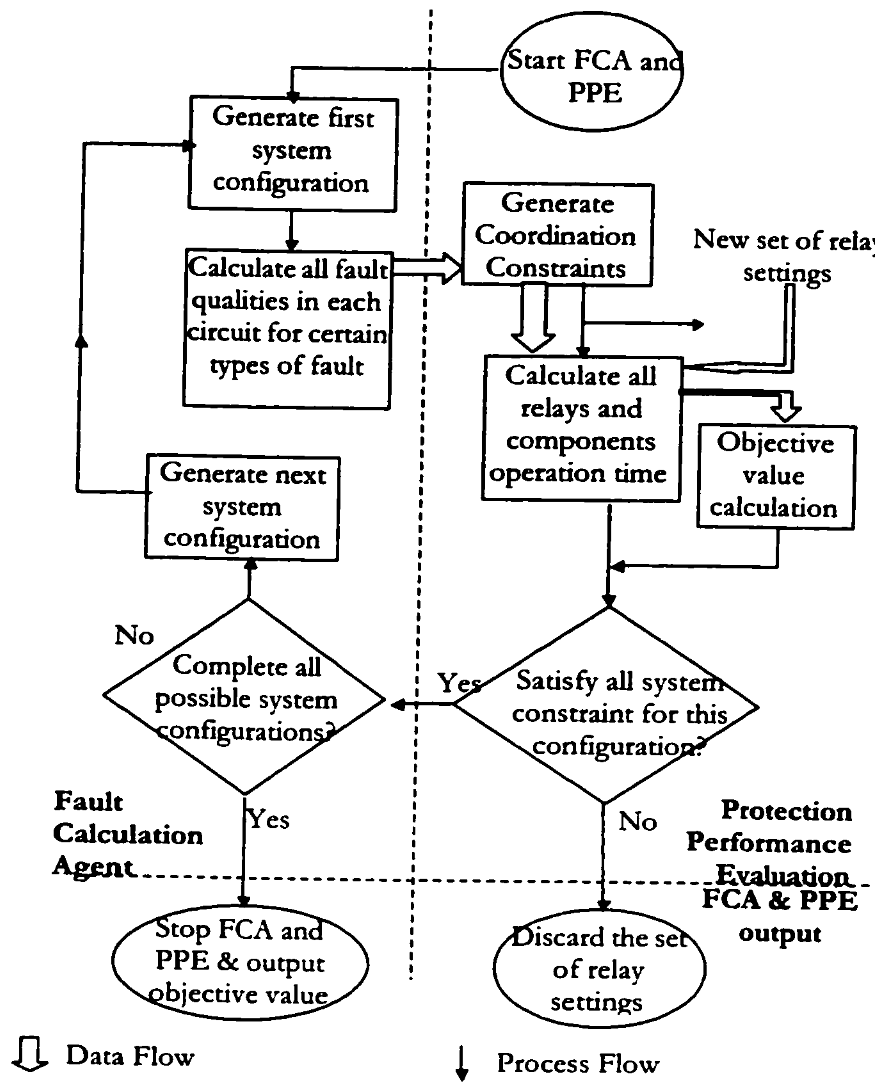


Fig. 7.4 Flow Diagram for Fault Calculation Agent and Protection Performance Evaluation

The modified TCM is applied to examine the efficiency. The study network 3 shown in Fig. 6.4 with 7 buses and 8 lines is considered. Each circuit is protected by circulating differential (CD) protection, Inverse Definite Minimum Time Lag (IDMTL) Overcurrent (OC) and Earth Fault (EF) protection. The CD protection is a unit protection with a fixed setting and do not need to change adaptively. The IDMTL OC & EF protection is a non-unit protection. It operates on excessive current flowing through the circuit which the TCM is applied to coordinate the settings.

7.3 Effectiveness of TCM

The effectiveness of TCM refers to the optimization of the relay settings so as to achieve a higher supply reliability, in which case the computation time may be longer. The efficiency of TCM, however, refers to a faster speed in searching for the relay settings, and in this case the supply reliability is not the main concern. The effectiveness and efficiency of TCM should try to achieve a balance. In fact, most of the faults can be cleared by two to three protection relay operations. For instance, in the network in Fig. 6.4 for a busbar fault occurred on Bus B5, if the relay located at Line L25 operates first, the relays located in other lines will experience a fault current change. If the relay located in Line L36 operates next, the relays located in Line L14, L46, L67, L57 will experience the second change of fault currents. Finally the relay located in Line L57 operates and the fault is completely cleared. The relay operation in Line L36 is definitely a mal-operation. In this case, the TCM should at least handle all the relay operations up to two step changes of fault current. It should also be able to handle other kinds of mis-coordinated relay operations which will caused fault current changes. In the result section, the efficiency of the TCM with different number of fault current changes will be examined. The more number of fault current changes to be handled, the larger is the number of system configurations should be considered.

During the constraint checking, the constraint violations are checked against whether the operation time difference between the upstream and downstream relays is smaller than the coordination margin. The objective value is also calculated during constraint checking. The TCM also minimizes of the number of constraint violations and can be reflected in the objective function.

7.4 Possible system configurations

The number of system configurations consists of the number of the combination of the circuits in service as shown in Eqn (7.1) and (7.2).

$$C=2^N \tag{7.1}$$

$$C' = \sum_{i=0}^{r} C_i^N \tag{7.2}$$

Where N is the number of circuits capable to switch in or out of the power system.

C is the total number of system configurations.

C' is the number of system configurations for a most of r out of N circuits that will carry out switching.

In the study network 3, the number of configurations is $C=2^8=256$, but some rare system configurations may be ignored in FCA and PPE. If the maximum allowable circuit outages = 3, the number of system configurations to process $C' = C_0^8 + C_1^8 + C_2^8 + C_3^8 = 93$. The processing time reduction due to the minimized system configurations is equal to $\frac{C'}{C} = \frac{93}{256} = 36.3\%$.

7.5 Simulation

The study network 3 as shown in Fig. 6.4 is studied. The system information of the study network 3 are shown in Table 6.1 to 6.5. 18 cases with the TCM with population size of 30, 50, 100; the number of generations is 500 or less; and maximum number of fault current changes to be handled by the TCM from 0 to 5 are simulated and the results are shown in Table 7.1. The trending curves of objective values for those 18 cases are recorded for the performance comparison as shown in Appendix E.

Table 7.1 Simulation Result with different population size, number of generations and maximum number of fault changes.

Case No.	Number of fault current changes	Population Size	No. of Generations	Objective Value	No. of Constraint violations	Time per Generation for Pentium II 350MHz	Supply Failure Rate (f/yr)	Supply Interruption Frequency (hr/yr)	Average Supply Interruption Duration (hours)
7.1	0	30	500	0.000670	10	0.912 sec	0.5070	0.9912	0.5115
7.2	0	50	500	0.000650	15	1.728 sec	0.9000	1.7620	0.5108
7.3	0	100	500	0.000730	9	3.563 sec	0.5070	0.9912	0.5115
7.4	1	30	300	0.019080	54	3.425 sec	1.5160	2.9636	0.5115
7.5	1	50	300	0.013250	101	6.325 sec	0.5220	1.0212	0.5112
7.6	1	100	300	0.018120	54	13.846 sec	0.9850	1.9320	0.5098
7.7	2	30	200	0.041800	159	16.201 sec	1.4900	2.9040	0.5131
7.8	2	50	200	0.031250	139	26.387 sec	1.2620	2.4632	0.5123
7.9	2	100	200	0.043790	142	55.318 sec	1.4800	2.8900	0.5121
7.10	3	30	250	0.056140	233	43.333 sec	0.9430	1.8328	0.5145
7.11	3	50	200	0.040770	165	69.390 sec	1.9720	3.8452	0.5128
7.12	3	100	170	0.050920	210	146.235 sec	1.8840	3.6844	0.5113
7.13	4	30	200	0.039870	148	91.011 sec	0.7260	1.4216	0.5107
7.14	4	50	200	0.025290	263	157.09 sec	0.6160	1.2016	0.5126
7.15	4	100	150	0.055530	176	294.16 sec	1.0480	2.0428	0.5130
7.16	5	30	200	0.039550	157	157.276 sec	0.6310	1.2316	0.5123
7.17	5	50	160	0.040720	186	311.256 sec	1.3560	2.6436	0.5129
7.18	5	100	120	0.048230	171	615.235 sec	1.5660	3.0636	0.5112

7.6 Result discussion

In Table 7.1, the processing time per generation in case 7.1 is the fastest and case 7.18 is the slowest. In fact, a larger population size results in more relay settings to be processed per generation. The larger the number of fault current changes is introduced, the more possible system configurations has to be checked for relay operations. The scale of objective values is proportional to the number of fault current changes to be handled. It refers to the Protection Performance Evaluation Unit and Fault Calculation Agent in checking against the same number of system configurations. The contribution of constraint violations in objective value is also proportional to the number of system configurations. Moreover, as the number of constraint violations shown in column 5 of Table 7.1 depends on the number of fault current changes, the comparison of the objective value is only valid for those cases with the same number of fault current changes, i.e. case 7.1 to 7.3, 7.4 to 7.6, 7.7 to 7.9, 7.10 to 7.12, 7.13 to 7.15 and 7.16 to 7.18. For cases 7.1 to 7.3, they have been checked based on no fault current change. The TCM then only checks the relay operations with single and three phase busbar faults at B1 to B7, i.e. 12 fault cases are being studied. In cases 7.16 to 7.18, the number of system configurations based on Eqn (7.2) for a fault in either busbar is $C^{8} = \sum_{i=0}^{5} C_i^{8} = 219$. As there are six busbars in the system and two types of fault are simulated, a total of 219 x 6 x 2 = 2628 fault cases are to be studied. Thus, the number of constraint violations for cases 7.16 to 7.18 are considerably larger than cases 1 to 13.

When a busbar fault occurred, two or more tripping should be carried out by OC relay to isolate the fault completely. For cases 7.1 to 7.6, since the number of fault current changes is less than 2, they are impractical to implement. The number of constraint violations and the processing time per generation of cases 7.7 to 7.9 are less than cases 7.10 to 7.18. Case 7.8 has the smallest number of constraint violations. Case 7.14 has better reliability indices with

0.6160 f/yr and 1.2016 hr/yr. It implies that case 7.13 to 7.15 has less chance in loss of supply due to relay mis-coordination. As the roll of distribution is to provide a reliable power network to customers, relay settings of case 7.14 should be the best for retaining the supply reliability.

The performance of MEP in the TCM for these 18 cases can be evaluated by investigating the objective value trending curves as shown in Appendix E. The shapes of every 3 conservative cases (i.e. case 7.1 to 7.3, 7.4 to 7.6, etc) are similar. The maximum object value trending curve for case 7.1 to 7.3 is coarse. It is because for case 7.1, the number of fault current changes is set to zero. The change of relay settings during the MEP generation process as described in section 4.4.3 can make very larger variation in the number of constraint violations and the total relay operation time. The fault current changes set to zero means only one system configuration should be handled by the TCM. The larger the number of fault current changes set in the TCM, the more the number of system configurations should be checked. It results in less variation of the number of constraint violations and the total relay operation time. Consequently, the range of fluctuation of the maximum objective value curve would be small. Similar phenomena can be found in the shape of maximum object value trending curve in cases 7.4 to 7.18.

From those trending curves, they show that the performance of MEP is depending on the population size, the number of generations and the number of fault current changes. For cases 7.13 to 7.15, a better objective value occurs in case 7.14 for population size of 50 rather than case 7.13 or 7.15, similar behaviors occur in every three consecutive cases. It implies that population size of 100 may be over-crowed, in which better protection settings are not easily to be selected to survive during the selection process in MEP.

Chapter 8

8 CONCLUSION AND FURTHER WORKS

8.1 Conclusion

8.1.1 Development of the Time Coordination Method

The development of Time Coordination Method is discussed in Chapter 3. Protection relays and power apparatus are formulated into an optimization equation and a set of constraint equations. It provides a systematical and mathematical approach to coordinate protection system. Its purpose is to search for a set of optimal protection settings to minimize the system disturbance time as well as the time of supply interruption. The sophisticated evaluation process inside the TCM can calculate the objective value which can be broken down into three key indicators to visualize the protection system performance, i.e. the total relay operation times, total coordination margins and total number of constraint violations. As the evaluation process of the TCM can cover all possible system faults, fault locations and system configurations, it is capable to handle the dynamic system conditions as proved in Chapter 5. The results show that the optimum protection relay settings found by the TCM can handle fault current re-distribution due to adjacent circuit tripping. It is also proved that the TCM can coordinate various types of protection relays disregarding the operation principles such as overcurrent and distance relays. The TCM is the backbone for the rest of research works carried out in this thesis.

8.1.2 Application of Modified Evolutionary Programming for the Time Coordination Method

The TCM searches for the optimal relay settings that are considered as the global optimum point on the solution searching space. The conventional searching methods, such as steeper-decant and non-linear programming, are performing a single-point search. Most probably the global optimum will not be reached just for one trial due to being trapped by the local optimums. Instead, multi-point search algorithm is more superior than single-point search due to the higher probability of escaping the traps of local optimums. The multi-point searching methods such as Genetic Algorithm, Evolutionary Programming are evaluated in Chapter 4. These methods randomly generate several sets of relay settings to increase the probability of converging to the global optimal solution and overcome the limitations of conventional rule based methods. According to the simulation results, the optimum protection relay settings cannot be simply found out by ordinary types of Genetic Algorithm and Evolutionary Programming. Taking the advantages of both methods, the Modified Evolutionary Programming which is tailor-made for the TCM has been developed. The simulation results show that the performance of Modified Evolutionary Programming is better than Genetic Algorithm and Evolutionary Programming for the TCM.

8.1.3 Relationship between coordination of protection system and supply reliability

The measurement of the performance of the coordinated protection system is crucial. The number of constraint violations, total relay operation times and total coordination margins in the objective value is a measurement of the optimized relay settings performance. On the other hand, they cannot provide a clear-cut value to convince the power system engineer to justify the application of the optimized relay settings found by the TCM. The reliability algorithm is therefore developed in Chapter 6 to link up the performance of the backup protection system and the supply reliability indices. The supply reliability for a busbar is calculated by finding the incorrect isolated busbar due to the busbar faults or the unclear system faults. Three classes of supply reliability calculations are incorporated into the reliability algorithm such as stuck breaker, busbar fault and CD protection failure. The simulation results show that the protection system coordinated by the TCM can significantly reduce the number of mal-operations in order to improve the supply reliability.

8.1.4 Efficiency of the Time Coordination Method and various contingent operations

It is proved that the TCM can coordinate the protection system to improve the supply reliability. Due to the technology improvement in computer, telecommunications and digital relay technology, the viability of using communication network to download the coordinated relay settings will be possible. The efficiency of the TCM is the successfully factor to apply in real system. The TCM is required to calculate the relay setting for all possible system configurations. The optimized relay settings should be capable to handle the change of fault current due to the tripping of adjacent circuits. In fact, most of the faults can be cleared by two to three protection relay operations. In Chapter 7, it has been proved that the reduction of the number of fault current changes and the MEP population size can improve the efficiency of the TCM. The results also show that a proper choice of the number of fault current changes and the MEP population size can further improve the quality of solution found by the TCM.

8.2 Further works

The further research suggested in this thesis is the development of the total intelligent protection system that is adaptive to all system conditions. Two major areas of further works are suggested in the following sections.

8.2.1 Improvement on optimization method

To become a total intelligent protection system, one constraint is the processing speed of the TCM. In Chapter 7, the processing time of each generation is revealed and it is exponentially increased as the number of fault current changes is increased. Although the processing power of computer is increasing while the cost of computer is decreasing, it is still far behind the growth of demand on software. The computer network technology provides the platform of parallel and distributed computing. The TCM can be de-centralized into many sub-processes to apply distributed computing to boost the processing speed. The Multi-agent system [50] and Ant Algorithms [51] can be applied to model the protection coordination problem into distributed computing architecture.

To investigate the application of multi-agent system and ant algorithm, the same sample system as shown in Fig. A1 of Appendix A is investigated. Let the protection settings for the sample system is **R[1]** = {*R1*(*t1*,*c1*), *R2*(*t2*,*c2*), *R3*(*t3*,*c3*), *R4*(*t4*,*c4*), *R5*(*t5*,*c5*), *R6*(*t6*,*c6*), *R7*(*t7*,*c7*), *R8*(*t8*,*c8*)} where *t1* is the TM setting of relay *R1*, *c1* is the CSM setting of relay *R1*, etc. Let the Multi-agent system have 8 Ant Agents running in 8 networked computers in which each ant is responsible for one relay. Other supporting agents such as Fault Calculation Agents, Reliability Algorithm Agents, Constraint Checking Agents and Ant Algorithms Coordination Agent are connected to the same network as shown in Fig. 8.1.

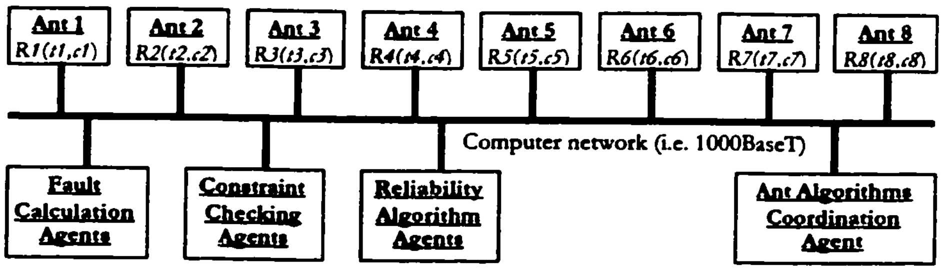
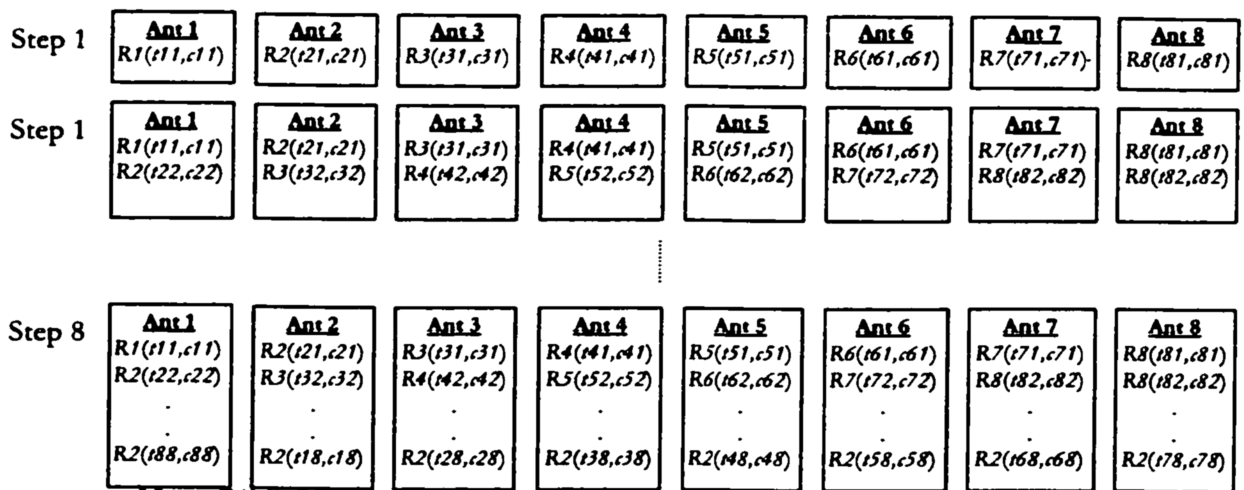


Fig. 8.1 Multi-agent system running ant algorithm

The ant algorithms is the application of the basic ant foraging behavior [52]. Ant always seeks the shortest path to forage food. If an obstacle has blocked the path, ant will try alternative ways to find food. Each ant lays down pheromone on its path to attract other ant to follow the way. Ant senses pheromone and tends to follow higher pheromone concentration way to go. If the way is the shortest distance, more ants will walk the way resulting in more pheromone to be laid down. For long run the process, ants can find out the shortest path for food foraging.

To apply ant algorithm, each protection relay is numbered and organized into a sequence. Each Ant Agent is responsible for one protection relay which can step through the whole sequence of relays to and from to search for the optimum protection settings. When one sequence walk is completed i.e. 8 steps for the sample system, the objective value and supply reliability will be evaluated. To speed up the process, fault calculation, constraint checking and reliability calculation should be running on separated agent computers. The overall processes coordination such as initialization, ant walk and termination may be carried out by the Ant Algorithms Coordination Agent. The processing diagram for the walk of Ant Agents is shown in Fig. 8.2.



Note: *Ri(tij,cij)* is the relay setting of relay *Ri* at step *j*.

Fig. 8.2 Ant Agents walks to generation relay settings

In Fig 8.2, each ant walks to the next relay settings in each step. For example, the Ant 1 agent has only relay setting *R1(t11,c11)* at step 1. The next walk of Ant 1 agent is relay *R2* with the settings *R2(t22,c22)* at step 2. The protection setting *R2(t22,c22)* is generated according to the concentration of pheromone. The objective value of the protection settings will be calculated at the end of step 8. The smaller the objective value, the higher is the concentration of pheromone. The pheromone will be distributed to other Ant Agents for next cycle of ant walk. The optimum protection settings should be found out for several cycles.

The beauty of Any Algorithms is the natural proved cooperation among Ant Colony to achieve the shortest path and is easy to apply. The simple communication protocol pheromone among Agents is simple to apply in distributed computing. The TCM can be easily broken down into sub-tasks and processing by Multi-Agent System. The processing speed of the TCM by applying Multi-Agent System and Ant Algorithms is expected to boost up the approach in real time coordination.

8.2.2 Real-time Time Coordination

The circuit outage may be clarified as planned and unplanned. Of course, for planned outage circuit, the network configuration has already been changed and TCM should be re-run to adopt the current system configuration. For unplanned outage, the current network configuration will not be reflected unless TCM is re-run. Due to the SCADA system advancement such as Distribution Management System (DMS), plant information can be obtained in a very small time interval to reflect the current system configuration. The Time Coordination Method may be further developed to coordinate the protection system in real time with facilities provided by DMS. The real time system information should be transferred from individual substations to the TCM to reflect current system configuration. Nowadays, utility communication network can connect to all equipment distributed in the power system. Digital protection relay collects plant information such as circuit breaker status, disconnectors status, etc. The information inside protection relays may be transferred to central TCM to construct the current system configuration. Unfortunately, different manufacturers has developed many different communication protocols to communicate their relays such as DNP (Distributed Network Protocol) for north America manufactures, IEC60870-5-103 for European manufactures, etc. Those protocols cannot communicate with other manufacturer's relays and it limits the information exchange and inter-operability.

The Electric Power Research Institute (EPRI) starts the development of Universal Communication Architecture (UCA) in 1992. Presently, UCA 2.0 [53] is released and some demonstration substations have been constructed [54,55]. Meanwhile, the standard IEC61850 (Communication Networks and Systems in Substations) has proposed in 1995 by International Electrotechnical Commission (IEC). It defines the next generation of standardized high-speed substation control and protection communications for all equipment in the substation. The EPRI UCA 2.0 and IEC61850 both move towards the standardization of the interoperability of different vendor Intelligent Electronic Devices (IEDs) in the substation. It is clear that both standardization efforts should be harmonized resulting in a single communication standard for the world market. In October 1997, the Edinburgh TC57 WG10-12 meeting has concluded with the agreement that only one standard for Substation Automation and Communication should be developed and to merge the North American and European approaches. In January 1998, it has concluded that harmonization is feasible. Major UCA models, data definitions, data types, and services may be included in the IEC61850 final standard. Therefore, IEC61850 will be a superset of UCA.

Nowadays, the IED with UCA communication has started to develop the UCA relay, UCA circuit breaker, etc. These equipment can report system status to system control center. If the TCM can coordination the protection settings in real time, the optimized relay settings can then transfer to the IED through UCA and IEC61850 communication. Thus, the total intelligent protection system can be evolved to protect the power system adaptively. In fact, there are a lot of technical problems to be solved in the application of UCA and IEC61850 into the TCM. Thus, a lot of software and hardware simulations need to be conducted to collect more data.

8.2.3 Adaptive Grading Margin

A fixed grading margin of 0.4 is used in this thesis. Although in general a fixed grading margin can fulfill the coordination requirement of conventional overcurrent relays, an adaptive grading margin which is depending on the upstream and downstream relays as shown in eqn (3.2) may provide additional advantages.

At present, conventional overcurrent relay is the largest base of relay installed in power system. New digital overcurrent relays are gradually installed in new power circuit or during relay replacement. Digital relays can provide more accurate operation time, no overshot and no setting departure. A smaller grading margin can be reasonably applied and is still within tolerable limit. To coordinate a mixture of conventional and digital overcurrent relays, the TCM can apply the adaptive grading margin as shown in eqn (3.2). A faster overall relay operation time is expected with reduced grading margin. As new digital relay provide a lot of new adaptive features such as emergency overcurrent protection for feeder current differential relay, TCM may be further developed into a system that can optimize all features provided by digital relays.

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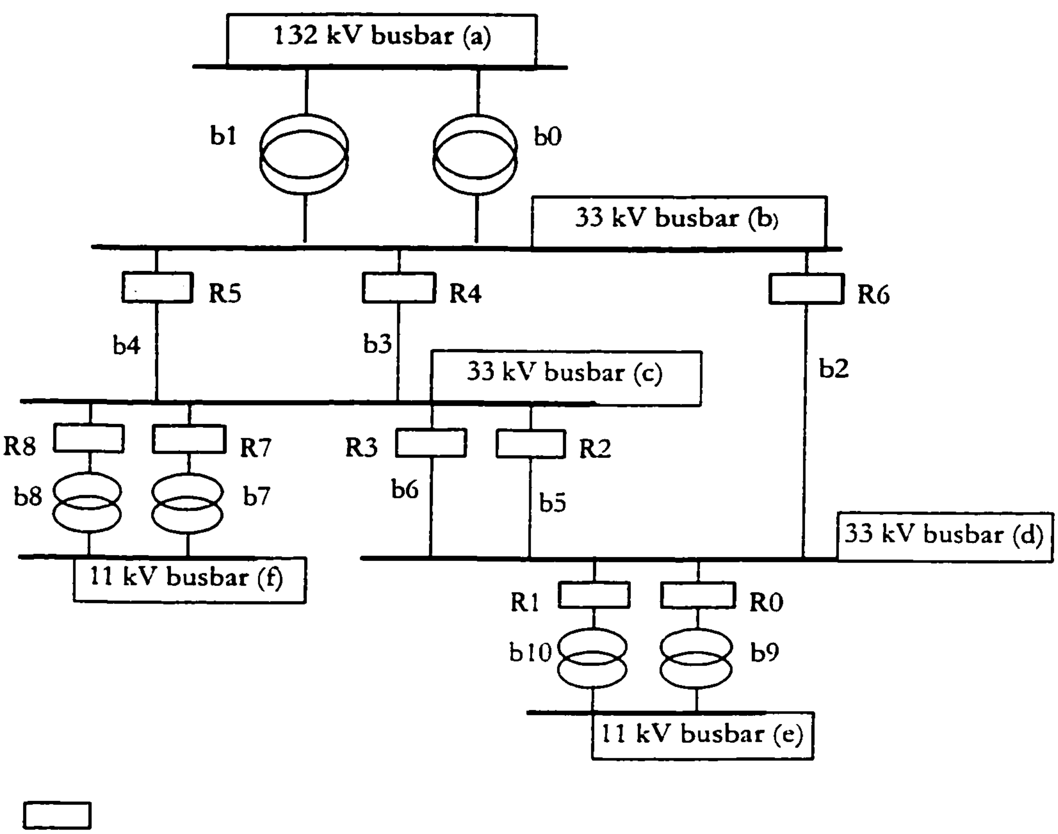
A GENETIC ALGORITHM

This appendix shows how Genetic Algorithm is applied for the study network 1 as shown in Fig. A1 to search for the optimum relay settings. The information of transmission line and protection are shown in Table A.1 and A.2 respectively.

Study Network 1



Note: All circuit parameters are in per-unit in 100MVA base.

Fig. A.1 Primary configuration diagram for Study network 1

Table A.1 Transmission line information for study network 1

Line	R	X
b0	0	0.157
b1	0	0.157
b2	0.29	0.39
b3	0.08	0.14
b4	0.08	0.14
b5	0.18	0.18
b6	0.18	0.18
b7	0	0.94
b8	0	0.99
b9	0	0.108
b10	0	0.108

Note: All per-unit (pu) values are 100MVAbase.

Table A.2 Protection information for study network 1

Relay	Relay Type	Current transformer ratio (A/A)	Relay rating (A)	Relay Setting 1 (TM)	Relay Setting 2 (CSM)
R0	IDMTL OC	300/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%
R1	IDMTL OC	300/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%
R2	IDMTL OC	600/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%
R3	IDMTL OC	400/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%
R4	IDMTL OC	600/1	1	[0.01,1.0] of 0.01	[50%,200%] of 1%
R5	IDMTL OC	600/1	1	[0.01,1.0] of 0.01	[50%,200%] of 1%
R6	IDMTL OC	400/1	1	[0.01,1.0] of 0.01	[50%,200%] of 1%
R7	IDMTL OC	400/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%
R8	IDMTL OC	400/5	5	[0.01,1.0] of 0.01	[50%,200%] of 1%

Note: The each relay setting range from 'min' to 'max' in step of 'step' and write in the format of '[min,max] of step'.

The process flow chart for GA is shown in Fig. A.2.

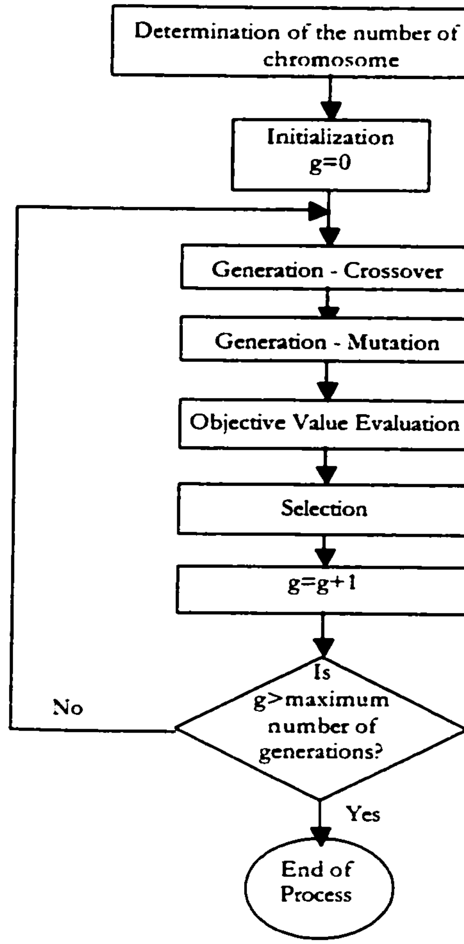


Fig. A.2 GA process flow chart

A.1 Determination of the number of bits of chromosome

From table A2, each relay has two settings Time Multipler (TM) and Current Setting Multipler (CSM). The number of bits required to represent TM and CSM are calculated as follows.

No. of bits for TM = $\log((1.0-0.1)/0.01)/\log(2) = 6.49 \cong 7$ bits

No. of bits for CSM = $\log((200\%-30\%)/1\%)/\log(2) = 7.4 \cong 8$ bits

The total number of bits of a chromosome = (No. of bits for TM + No. of bits for CSM) x No of relays = (7 + 8) x 9 = 135 bits.

A.2 Initialization

Several set of relay settings are randomly generated. Setting pusher is applied to speed up the initialization as discussed in section 3.8. The new generated relay settings will be mapped from phenotype into genotype using binary or gray coding as discussed in section 4.3.1 and they will be packed into a chromosome. The objective value of each set of relay settings is calculated according to the Eqn (3.3) in section 3.6. For the system having 9 IDMTL OC relays, those genotype bits will be packed into a chromosome as shown in Fig. A.3. The initialization process will be stopped when the number of initialized chromosomes reaches the pre-determined population size. The pool which contain all chromosome for generation process is formed.

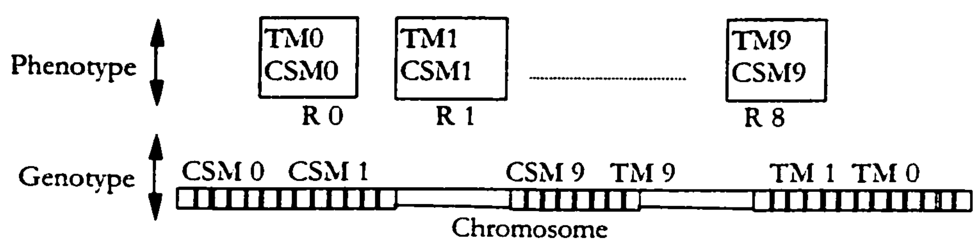


Fig. A.3 Structure of chromosome

The first 4 sets of relay settings with objective values in case 1.1 are list in the Table A.3.

Table A.3 4 initialized relay settings mapping from phenotype to genotype

Chromo-some	Object-ive value	CSM0	CSM1	CSM2	CSM3	CSM4	CSM5	CSM6	CSM7	CSM8	TM0	TM1	TM2	TM3	TM4	TM5	TM6	TM7	TM8
1	5.121	110	99	128	121	145	143	110	121	123	0.1	0.12	0.48	0.49	0.62	0.71	0.92	0.21	0.11
		01101110	01100011	10000000	01111001	10010001	10001111	01101110	01111001	01111011	0000000	0000011	0110110	0110111	1001010	1010111	1110101	0010000	0000001
2	1.654	100	100	121	132	180	176	190	100	100	0.1	0.1	0.38	0.4	0.68	0.77	0.68	0.1	0.1
		01100100	01100100	01111001	10000100	10110100	10110000	10111110	01100100	01100100	0000000	0000000	0101000	0101011	1010010	1011111	1010010	0000000	0000000
3	4.353	101	105	110	110	138	136	144	105	106	0.1	0.12	0.45	0.36	0.55	0.53	0.78	0.15	0.14
		01100101	01101001	01101110	01101110	10001010	10001000	10010000	01101001	01101010	0000000	0000011	0110010	0100101	1000000	0111101	1100001	0000111	0000110
4	2.367	100	102	105	113	143	138	166	103	104	0.1	0.14	0.65	0.44	0.58	0.43	0.77	0.11	0.12
		01100100	01100110	01101001	01110001	10001111	10001010	10100110	01100111	01101000	0000000	0000110	1001110	0110000	1000100	0101111	1011111	0000001	0000011

A.3 Generation

Two chromosomes are selected randomly from the pool. The crossover and mutation operators are applied and generate two new chromosomes. For instance, two chromosomes at before and after multi-point crossover operation are as shown in Fig. A.4 and A.5.

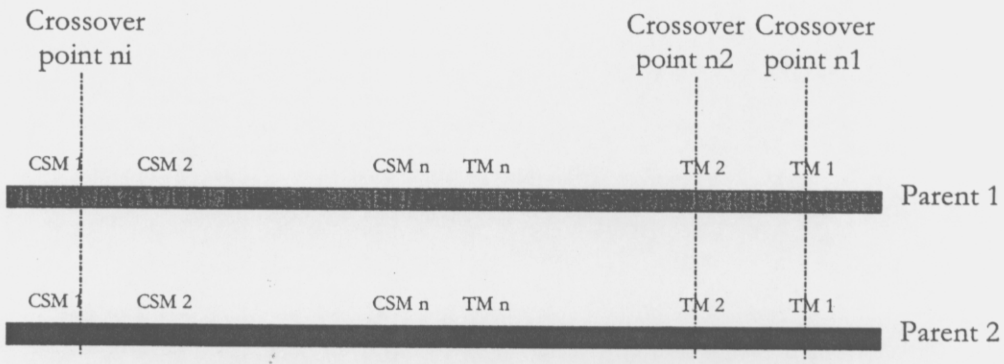


Fig. A.4 Before crossover

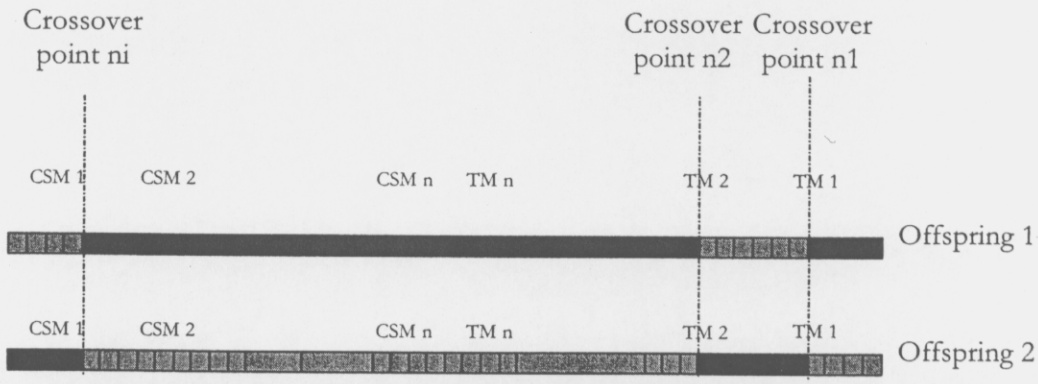


Fig. A.5 After crossover

Note : Current Setting Multiplier (CSM) and Time Multiplier (TM) are the IDMTL relay setting.

The number of crossover points and positions are selected randomly as shown in Fig. A.4. Information is exchanged at each crossover point. The crossover ratio is the ratio of the maximum number of crossover points and number of genes in a chromosome.

Two offsprings are formed as shown in Fig. A.5. They will pass to mutation operator with minimal chance to mutate some bits as shown in Fig. A.6.

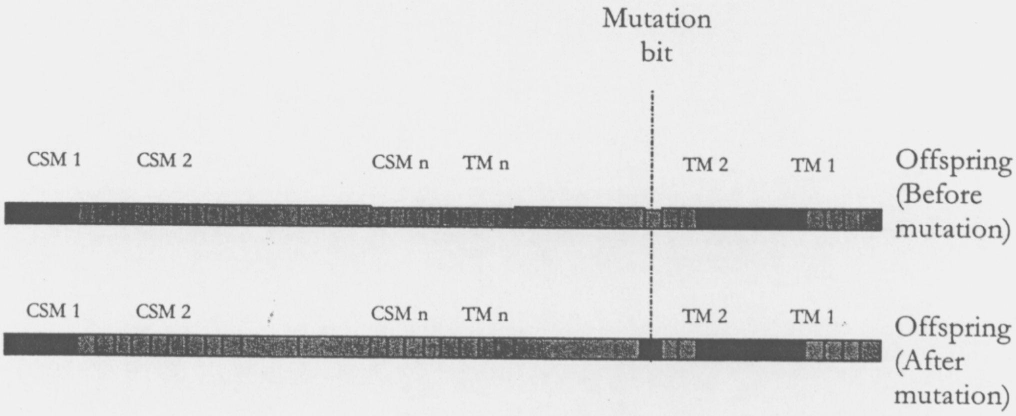


Fig. A.6 Mutation of chromosome

For instance, two chromosomes 1 and 4 are undergoing the crossover operation at three random points. Two new generated offsprings are generated as shown in Table A.4.

Table A.4 Crossover operation on chromosomes 1 and 4

Chromo - some	Object-ive value	CSM0	CSM1	CSM2	CSM3	CSM4	CSM5	CSM6	CSM7	CSM8	TM0	TM1	TM2	TM3	TM4	TM5	TM6	TM7	TM8
1	5.121	110	99	128	121	145	143	110	121	123	0.1	0.12	0.48	0.49	0.62	0.71	0.92	0.21	0.11
		01101110	01100011	10000000	01111001	10010001	1000111	01101110	01111001	01111011	0000000	0000011	0110110	0110111	1001010	1010111	1110101	0010000	0000001
4	2.367	100	102	105	113	143	138	166	103	104	0.1	0.14	0.65	0.44	0.58	0.43	0.77	0.11	0.12
		01100100	01100110	01101001	01110001	10001111	10001010	10100110	01100111	01101000	0000000	0000110	1001110	0110000	1000100	0101111	1011111	0000001	0000011
Offspring 1	6.215	110	99	137	113	143	139	110	121	123	0.1	0.12	0.42	0.44	0.58	0.43	0.77	0.11	0.12
		01101110	01100011	10001001	01110001	10001111	1000101	01101110	01111001	01111011	0000000	0000011	0101110	0110000	1000100	0101111	1011111	0000001	0000011
Offspring 2	2.158	100	102	96	121	145	142	166	103	104	0.1	0.14	0.71	0.49	0.62	0.71	0.92	0.21	0.11
		01100100	01100110	01100000	01111001	10010001	10001110	10100110	01100111	01101000	0000000	0000110	1010110	0110111	1001010	1010111	1110101	0010000	0000001

Three crossover points cause CSM2, SCM5 and TM2 exchange information. The objective values of offsprings 1 and 2are calculated and offspring 2 is better than its parents. The generation process will be stopped when the number of offsprings reaches the population size.

A.4 Selection

After the generation, the number of chromosomes for parents and offsprings double the population size. Half of them will be selected into the new pool for next generation process. The elitism is employed as discussed in section 4.6.1. It coverts the objective value into expected frequency. The smaller objective value chromosomes should have higher expected frequency. Those chromosomes will then be organized into a candidate list and the number of occurrence is proportional to their expected frequency. A part of candidate list with corresponding objective value and expected frequency is shown in Table A.5.

Table A.5 Candidate list

Candidate index	Chromosome	Objective value	Expected Frequency
1	1	5.121	1
2	2	1.654	5
3	3	4.853	2
4	4	2.367	4
5	2	1.654	5
6	4	2.367	4
7	2	1.654	5
8	1	5.121	1
9	2	1.654	5
10	4	2.367	4

The roulette wheel game for the 5 selections from the candidate list is shown in Table A.6.

Table A.6 Roulette wheel for 5 selections

Selection	Generated random number	Matched chromosome
1	4	4
2	1	1
3	7	2
4	6	4
5	9	2

Both chromosomes 2 and 4 are selected two times in 5 selections. It is because those chromosomes with smaller objective values should be selected with higher frequency.

A.5 Termination

After the per-determined number of generations, the whole process of GA will be terminated. The simulation results for different settings of GA are shown in section 4.8.

B EVOLUTIONARY PROGRAMMING

Evolutionary Programming is applied for the study network 1 as shown in Fig. A.1 to search for the optimum relay settings. The information of transmission line and protection are same as Appendix A. The process flow chart for EP is shown in Fig. B.1.

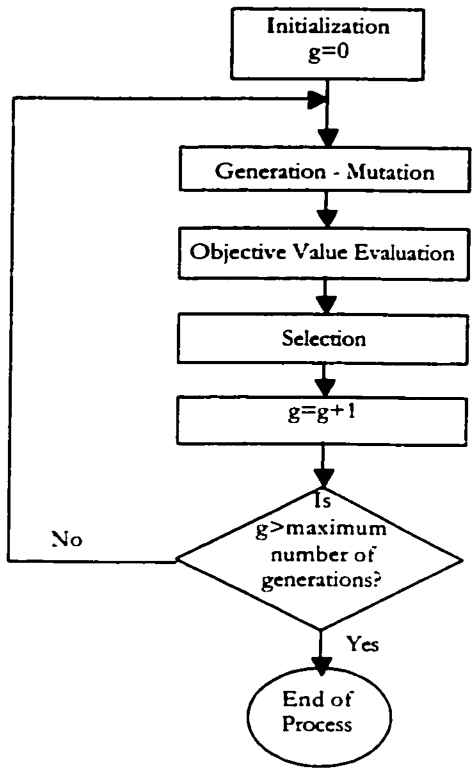


Fig. B.1 EP process flow chart

EP requires to initialize a set of relay setting same as section A.2 but do not require to map relay settings into chromosomes. Fixed population size is applied and the initialization will be terminated when the number of set of relay settings reach as the per-defined population size.

B.1 Generation

EP employs only mutation to generate new relay settings as discussed in section 4.4.2. As an example, the EP mutation is applied in the first 2 sets of relay settings of Table A.3. The detail steps are shown in Table B.1.

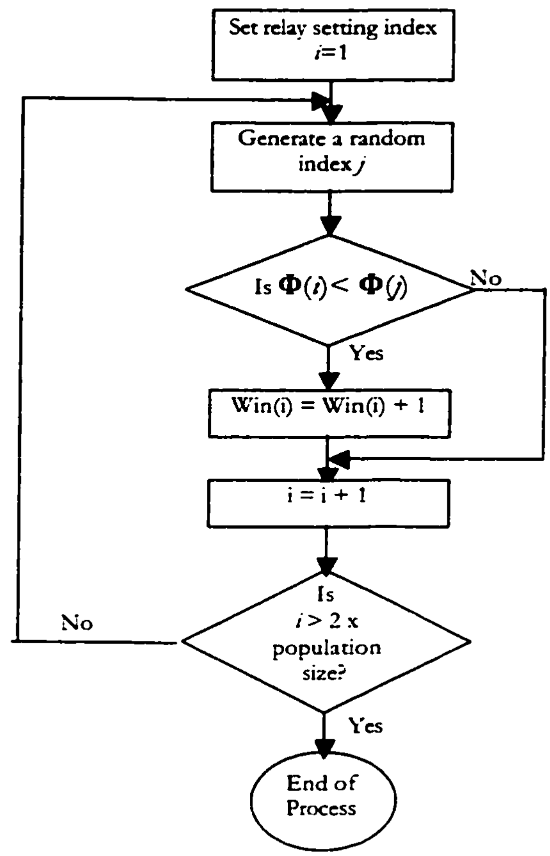
Table B.1 EP mutation for first 2 sets of relay settings of Table A.3.

Set of relay settings	Parameters	CSM0	CSM1	CSM2	CSM3	CSM4	CSM5	CSM6	CSM7	CSM8	TM0	TM1	TM2	TM3	TM4	TM5	TM6	TM7	TM8
1	Relay settings	110	99	128	121	145	143	110	121	123	0.8	0.12	0.48	0.49	0.62	0.71	0.92	0.21	0.11
	Object value Φ	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121
	Variation s	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263	2.263
	$N(0,1)$	0.330	0.429	-0.362	-0.266	0.037	0.578	0.326	-0.414	-0.397	-0.224	0.383	-0.509	0.017	-0.055	0.041	-0.135	0.060	0.228
	New relay settings	111	100	127	120	145	144	111	120	122	0.29	0.99	-0.67	0.53	0.50	0.80	0.61	0.35	0.63
	New object value Φ	N./A																	
2	Relay settings	100	100	121	132	180	176	190	100	100	0.1	0.1	0.38	0.4	0.68	0.77	0.68	0.1	0.1
	Object value Φ	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654
	Variation s	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286	1.286
	$N(0,1)$	-0.377	-0.938	-0.504	0.232	0.173	0.720	0.841	-0.116	0.769	0.503	0.236	0.274	0.312	-0.121	-0.244	-0.325	0.080	0.637
	New relay settings	100	99	120	132	180	177	191	100	101	0.75	0.40	0.73	0.80	0.52	0.46	0.26	0.20	0.92
	New object value Φ	1.611																	

In Table B.1, the sets of relay settings in the next generation are generated by adding noise in each setting. The objective values are calculated. Meanwhile, the relay setting range and constraint will be checked. In the new set of relay setting 1, the setting TM2 is out of the setting range and will be discarded. EP will then generate anther set of relay settings based on 1st set of relay settings. This process will continue until the new generated relay settings passing all setting range and constraint checks. On the other hand, the 2nd set of relay setting will generated the next generation by EP mutation. It fulfills all relay setting range and constraint checks which can then calculate the objective value. The objective value 1.611 for new generated relay setting is better than its parent 1.654. The generation process will be stopped until equal number of sets of relay settings is generated by EP mutation.

B.2 Selection

The selection process is to choose the sets of relay settings from old and new pool of relay settings to the next generation. The tournament is employed as discussed in section 4.6.2. To illustrate the selection process, the same set of initialized relay settings as shown in Table A.3 is used. The flow chart for tournament is shown in Fig. B.2.



Note :

$\Phi(i)$ is the objective value of i^{th} set of relay settings.
Win(i) is the count of wins during the tournament process.

Fig. B.2 Tournament process flow chart

After the tournament process, 4 sets of relay settings received a number of "Wins" are shown in Table B.2.

Table B.2 4 sets of relay settings with received wins after tournament process

Set of relay settings	Objective value	Wins
1	5.121	0
2	1.654	5
3	4.853	1
4	2.367	4

All sets of relay settings will be sorted according the number of "Wins". The first larger number of "Wins" equal to the number of population size will be selected for the next generation.

B.3 Termination

After the per-determined number of generations, the whole process of EP will be terminated. The simulation result to demonstrate the effectiveness of EP is shown in section 4.8.3.

C MODIFIED EVOLUTIONARY PROGRAMMING

Modified Evolutionary Programming is applied to the study network 1 as shown in Fig. A.1 is applied to search for the optimum relay settings. The information of transmission line and protection are same as Appendix A. The process of MEP such as initialization, selection and termination are same as EP as shown in Appendix B. The only difference between MEP and EP is the generation.

C.1 Generation

MEP only employs mutation to generate new relay settings as discussed in section 4.4.3. As an example, the MEP mutation is applied in the first 2 sets of relay settings of Table A.3. The detail steps are shown in Table C.1.

Table C.1 MEP mutation for first 2 sets of relay settings of Table A.3.

Set of relay settings	Parameters	CSM0	CSM1	CSM2	CSM3	CSM4	CSM5	CSM6	CSM7	CSM8	TM0	TM1	TM2	TM3	TM4	TM5	TM6	TM7	TM8
	Max. setting	115	120	198	188	190	186	199	120	123	0.9	0.44	0.81	0.92	0.93	0.94	0.98	0.61	0.52
	Mean setting	105	102	130	123	140	143	151	102	99	0.12	0.13	0.22	0.21	0.36	0.41	0.57	0.13	0.16
1	Relay settings	110	99	128	121	145	143	110	121	123	0.8	0.12	0.48	0.49	0.62	0.71	0.92	0.21	0.11
	Object value Φ	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121	5.121
	Step σ	1.131	-0.377	-0.067	-0.070	0.226	0.000	-1.933	2.389	2.263	1.973	-0.073	0.997	0.892	1.032	1.281	1.932	0.377	-0.314
	$N(0,1)$	0.330	0.429	-0.362	-0.266	0.037	0.578	0.326	-0.414	-0.397	-0.224	0.383	-0.509	0.017	-0.055	0.041	-0.135	0.060	0.228
	Mutation Enable	1	0	0	1	0	1	0	1	0	0	1	0	0	1	0	1	0	0
	New relay settings	110	99	128	121	145	143	110	120	123	0.80	0.09	0.48	0.49	0.56	0.71	0.66	0.21	0.11
	New objective value Φ	N/A																	
2	Relay settings	100	100	121	132	180	176	190	100	100	0.1	0.1	0.38	0.4	0.68	0.77	0.68	0.1	0.1
	Object value Φ	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654
	Step σ	0.643	-0.214	-0.038	-0.040	0.129	0.000	-1.099	1.358	1.286	1.121	-0.041	0.567	0.507	0.587	0.728	1.098	0.214	-0.179
	$N(0,1)$	-0.377	-0.938	-0.504	0.232	0.173	0.720	0.841	-0.116	0.769	0.503	0.236	0.274	0.312	-0.121	-0.244	-0.325	0.080	0.637
	Mutation Enable	0	0	1	0	0	0	1	1	1	0	1	0	1	1	0	0	1	0
	New relay settings	100	100	121	132	180	176	189	100	101	0.10	0.09	0.38	0.56	0.61	0.77	0.68	0.12	0.10
	New objective value Φ	1.589																	

In Table C.1, the previous generation statistic such as maximum and mean relay setting are calculated. The mutation enable is randomly assigned to the relay setting. New relay setting is generated according to Eqn (4.4). The objective values will be calculated. Meanwhile, the relay setting range and constraint will be checked. If the setting fails in setting range or constraint checks, it will be discarded and MEP will then generate anther set of relay settings. This process will continue until the new generated relay settings passing all setting range and constraint checks. By observation of the TCM process, most of the relay setting changes may introduce more constraint violations. The process of MEP introduces the mutation enabling matrix and step matrix that can make the change of relay settings more gradual. Thus, the yield of new generated relay by MEP mutation is higher than EP mutation. Two new sets of relay settings in Table C.1 fulfill all relay setting range and constraint checks which is better than the new relay settings generated by EP mutation in Table B.1. The generation process will be stopped until equal number of sets of relay settings is generated by MEP mutation.

The simulation result to demonstrate the effectiveness of MEP is shown in section 4.8.3.

D SIMULATION RESULT FOR COMPARISON OF GA, EP AND EA

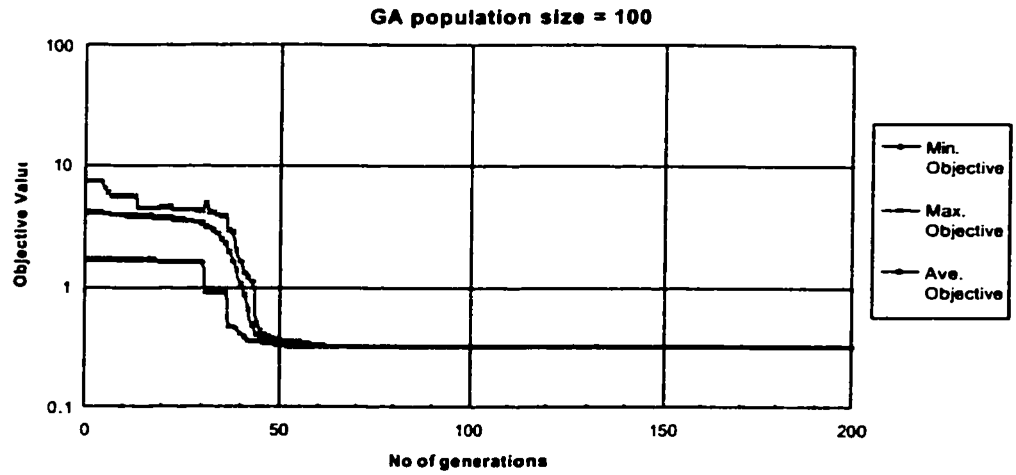


Fig D.1 GA trending curve

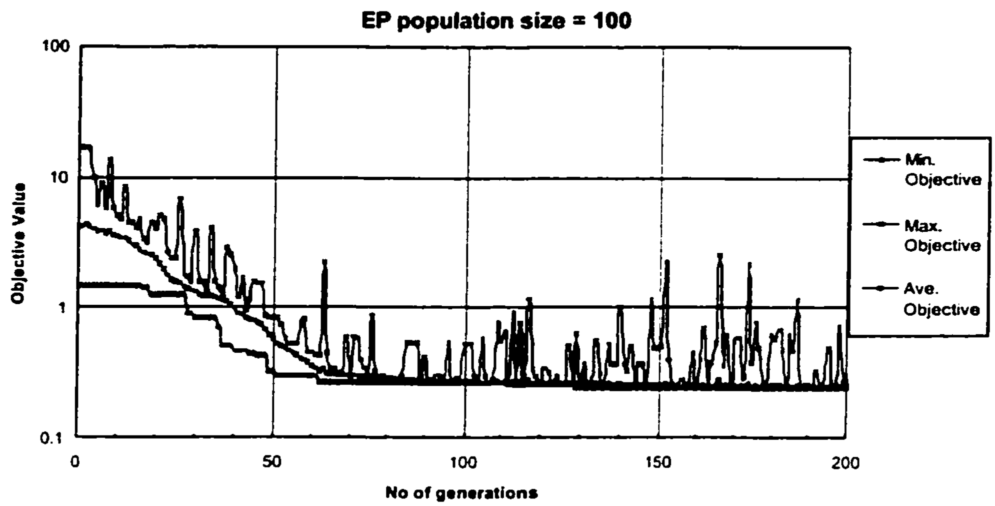


Fig D.2 EP trending curve

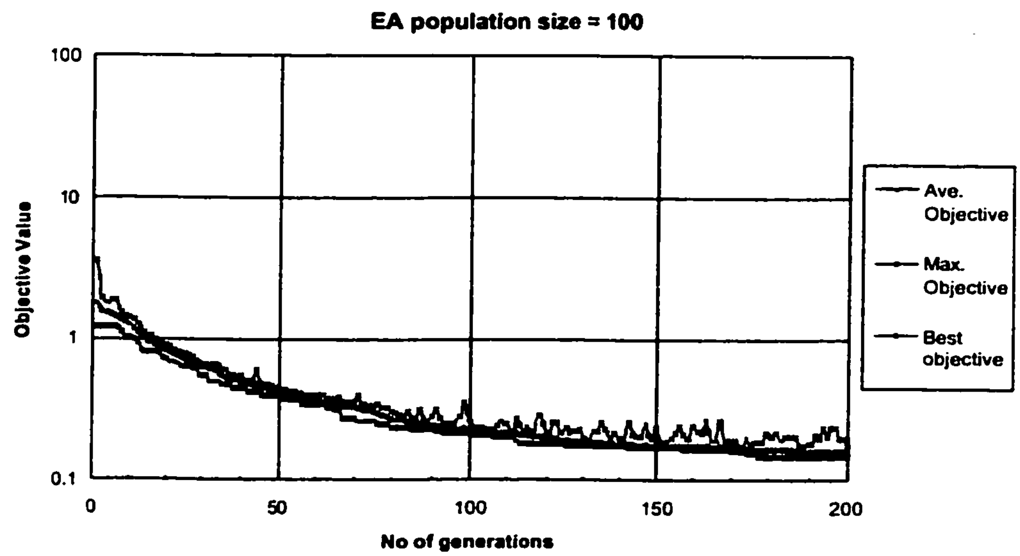


Fig D.3 EA trending curve

E SIMULATION RESULT FOR CHAPTER 7

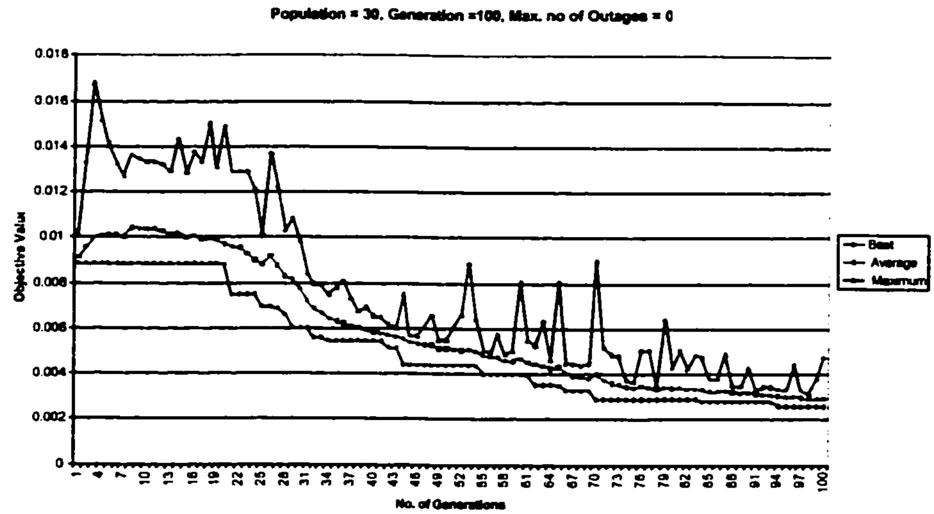


Fig E.1 Trending curve for case 1 for 100 generations

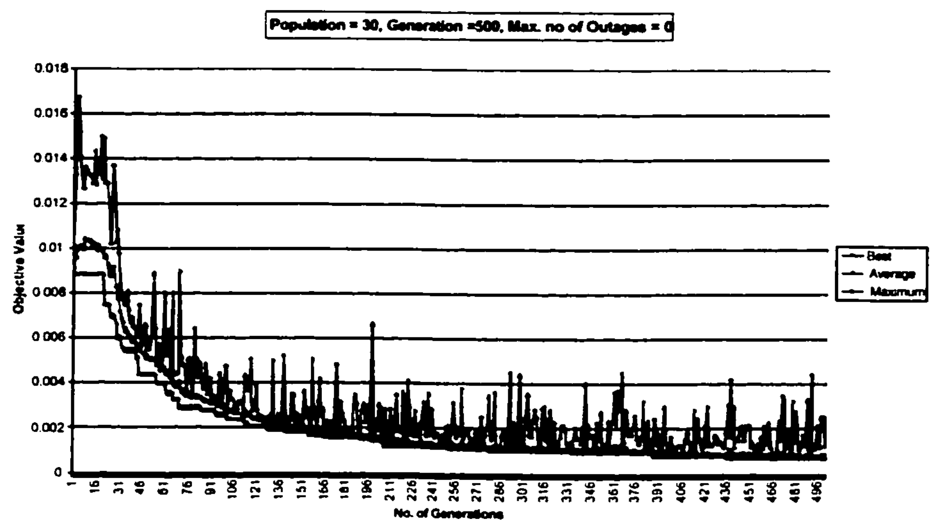


Fig E.2 Trending curve for case 1 for 500 generations

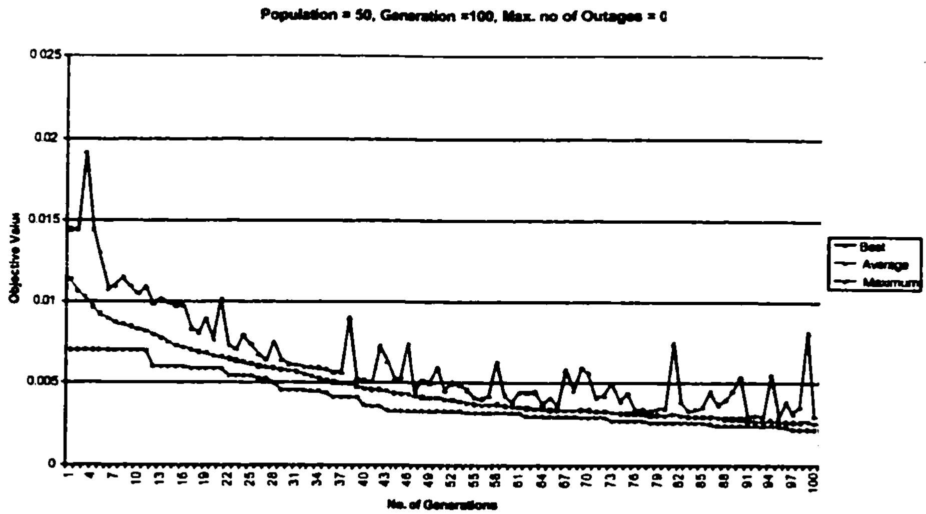


Fig E.3 Trending curve for case 2 for 100 generations

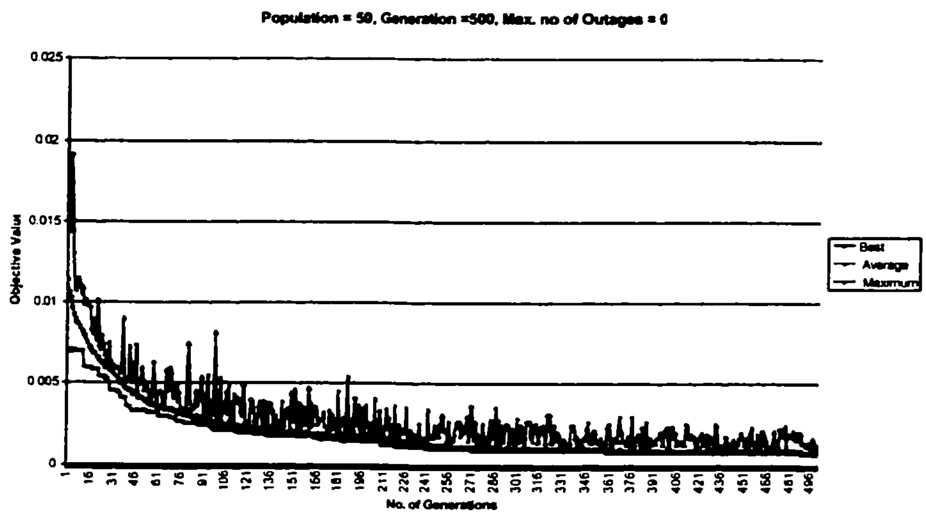


Fig E.4 Trending curve for case 2 for 500 generations

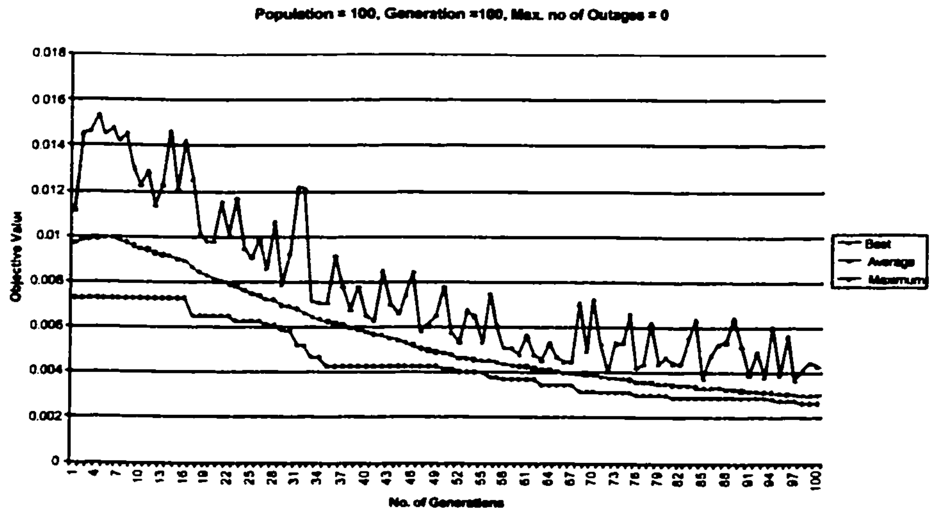


Fig E.5 Trending curve for case 3 for 100 generations

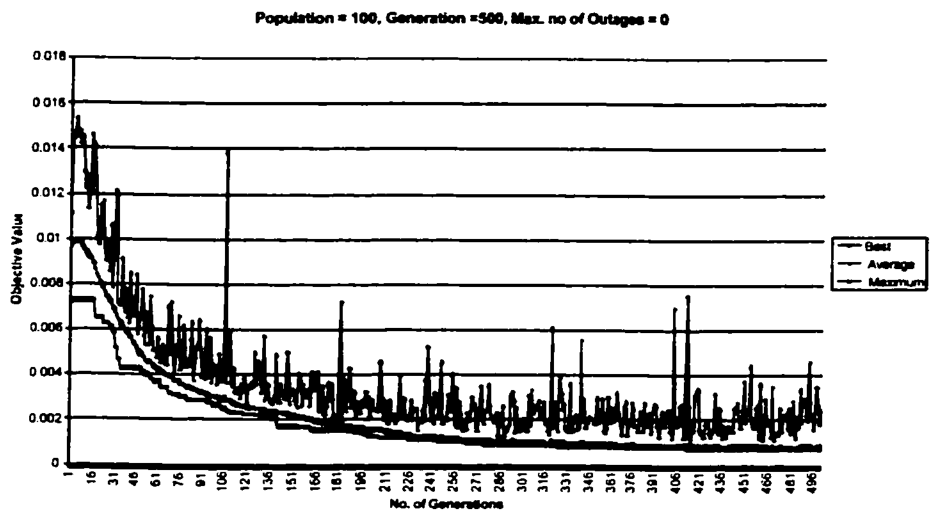


Fig E.6 Trending curve for case 3 for 500 generations

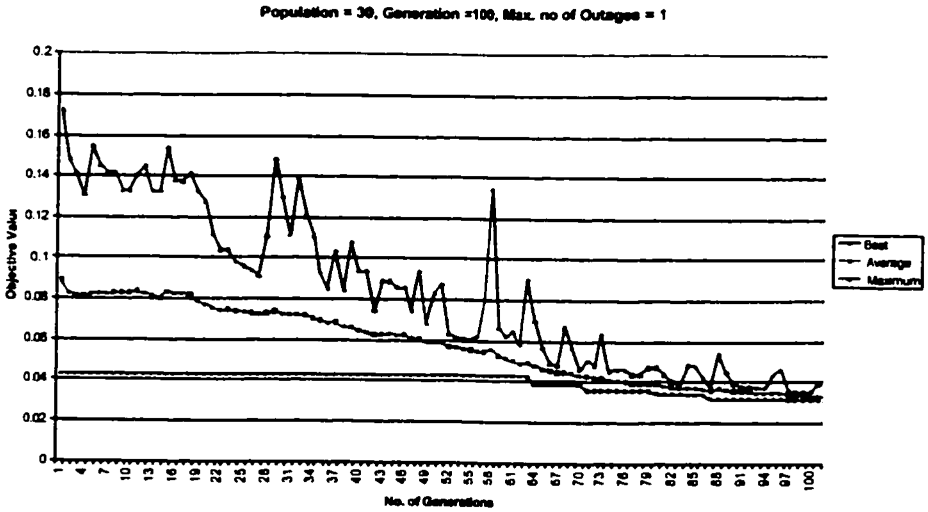


Fig E.7 Trending curve for case 4 for 100 generations

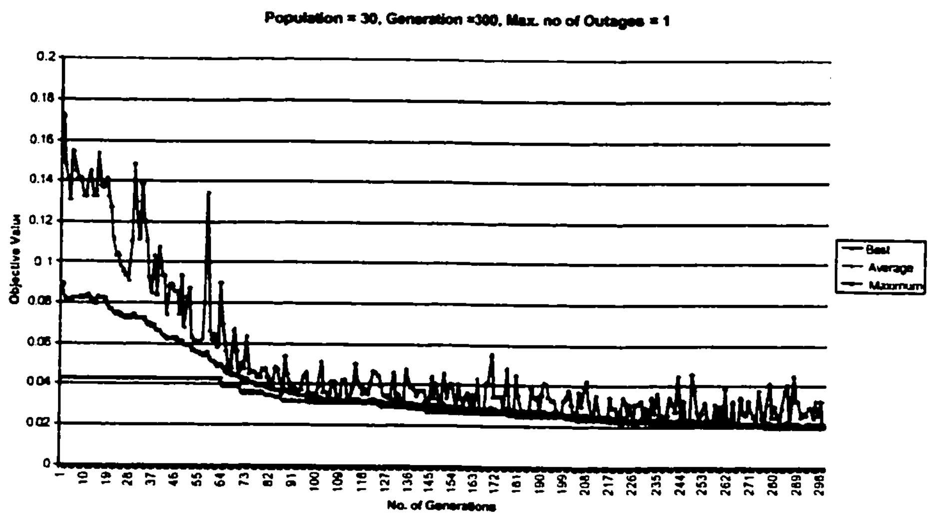


Fig E.8 Trending curve for case 4 for 300 generations

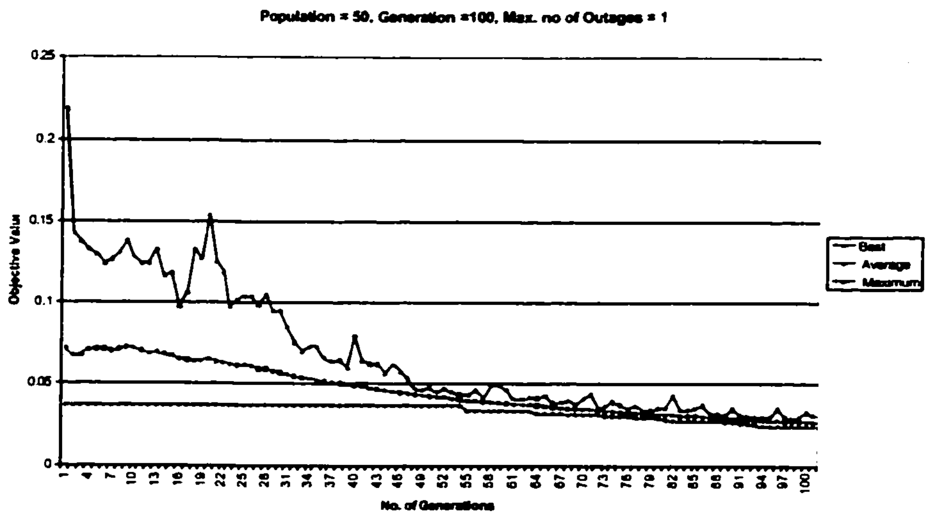


Fig E.9 Trending curve for case 5 for 100 generations

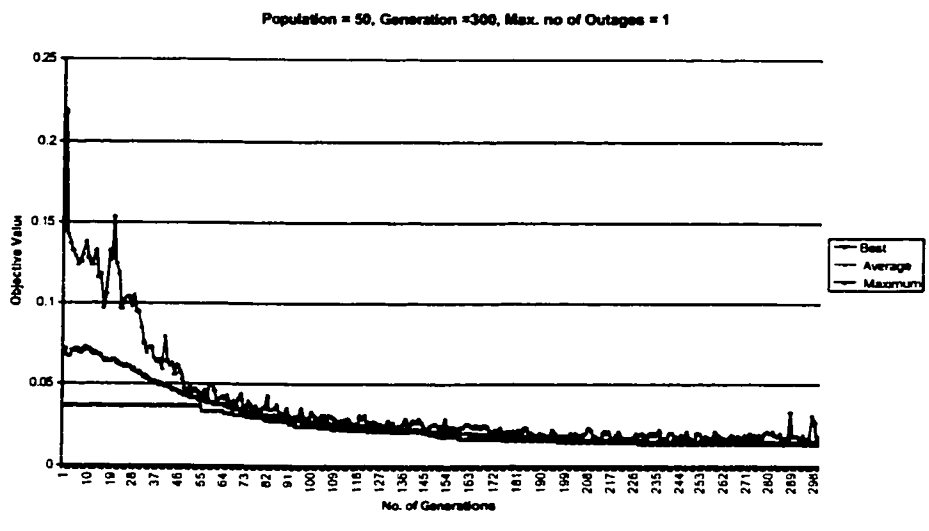


Fig E.10 Trending curve for case 5 for 300 generations

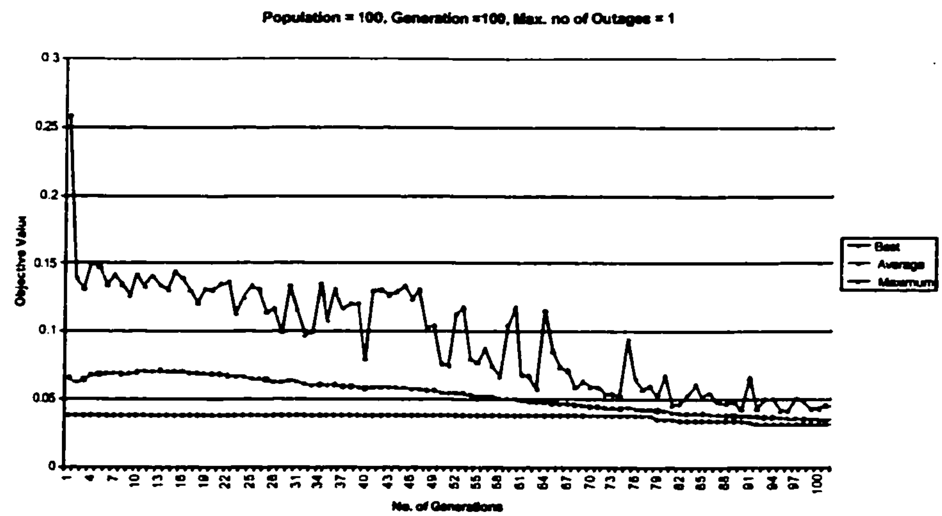


Fig E.11 Trending curve for case 6 for 100 generations

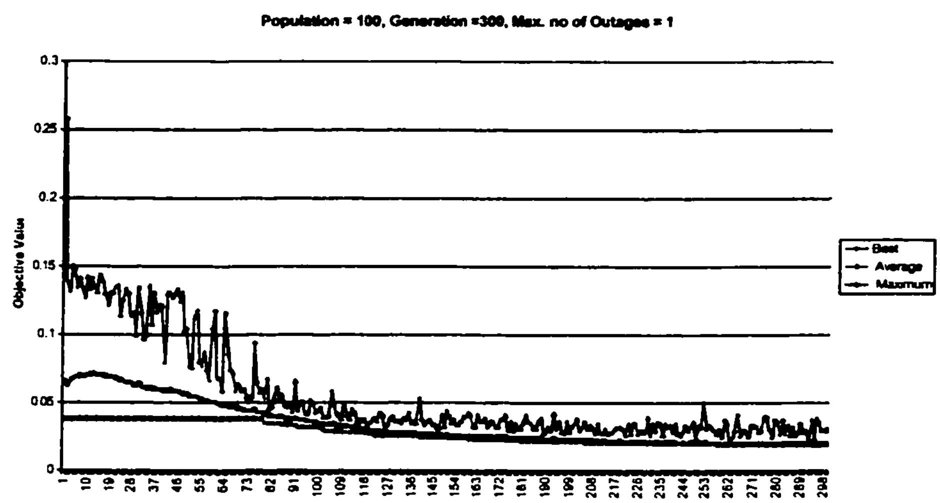


Fig E.12 Trending curve for case 6 for 300 generations

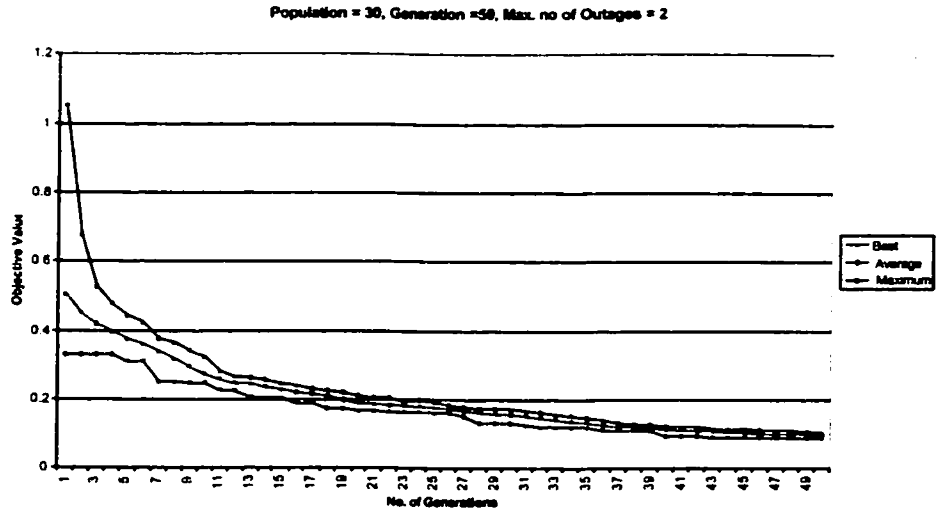


Fig E.13 Trending curve for case 7 for 50 generations

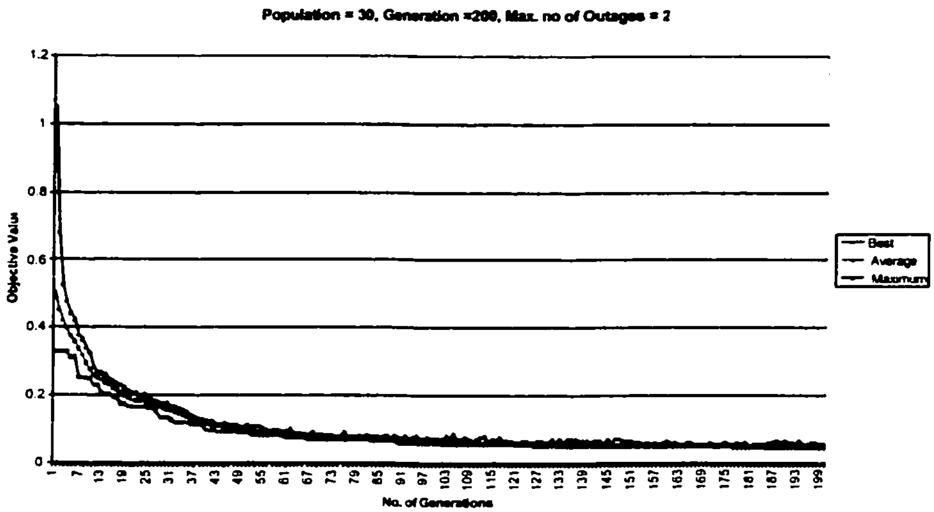


Fig E.14 Trending curve for case 7 for 200 generations

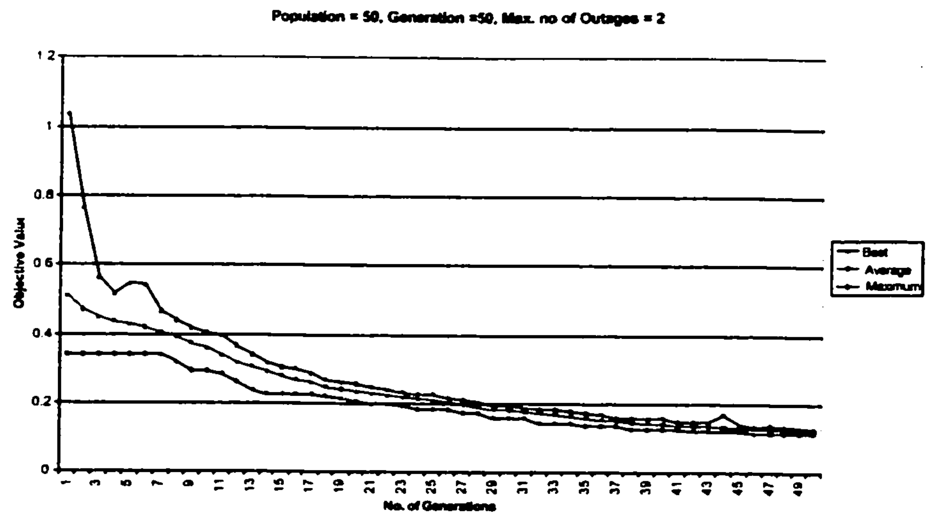


Fig E.15 Trending curve for case 8 for 50 generations

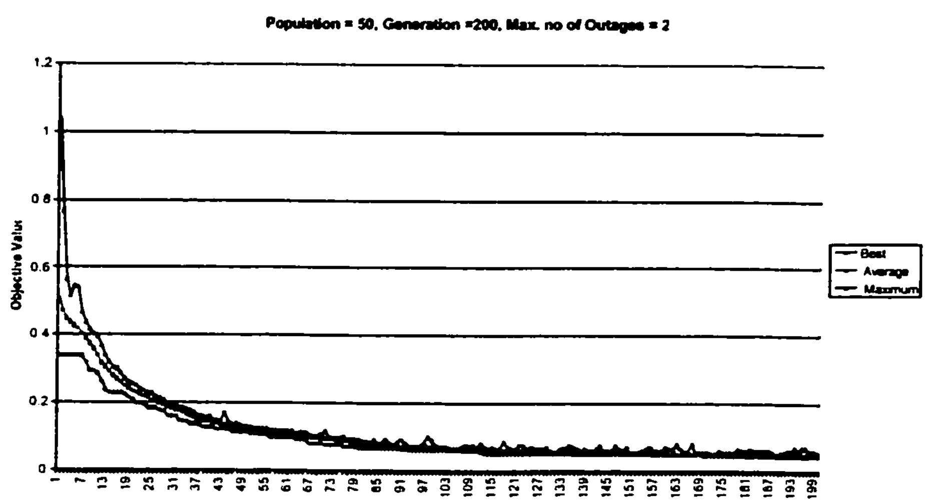


Fig E.16 Trending curve for case 8 for 200 generations

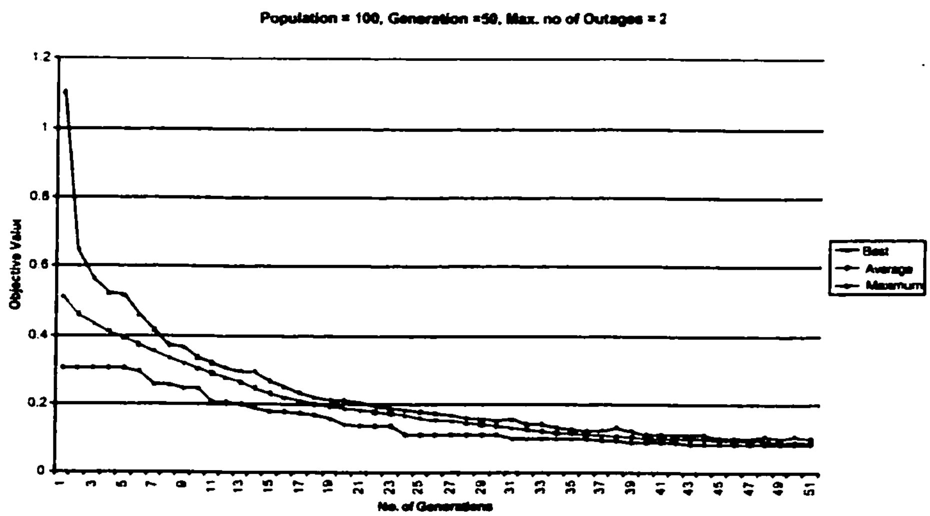


Fig E.17 Trending curve for case 9 for 50 generations

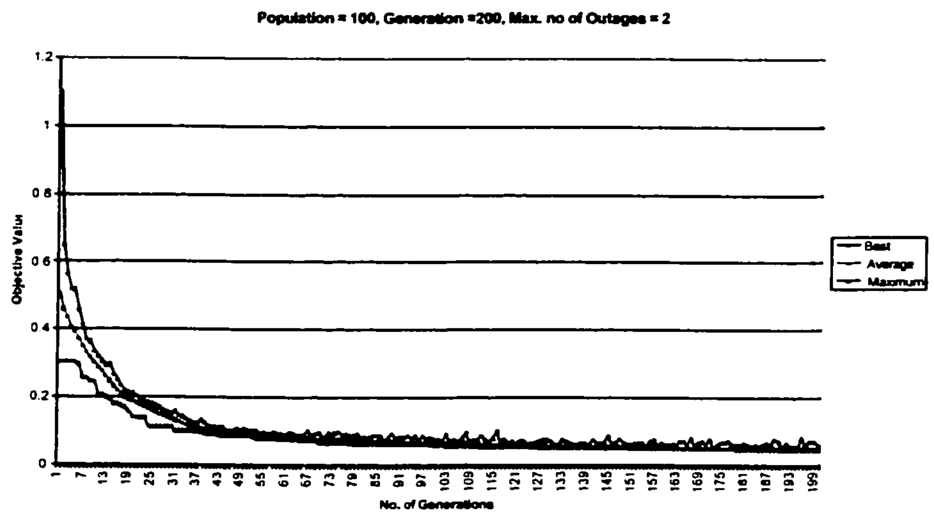


Fig E.18 Trending curve for case 9 for 200 generations

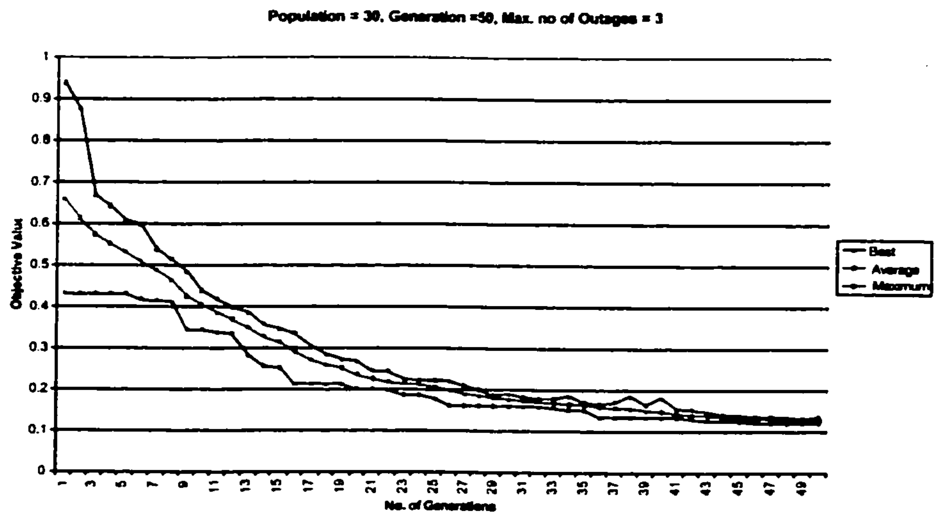


Fig E.19 Trending curve for case 10 for 50 generations

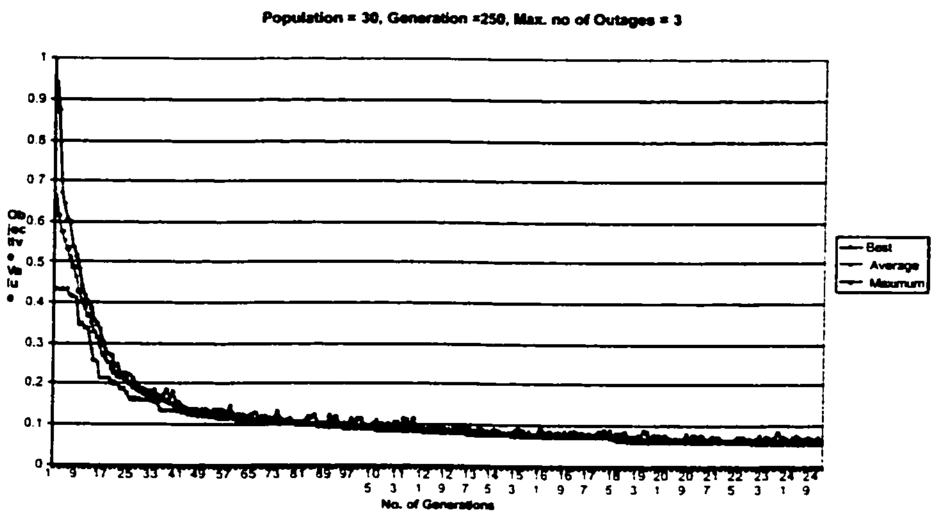


Fig E.20 Trending curve for case 10 for 250 generations

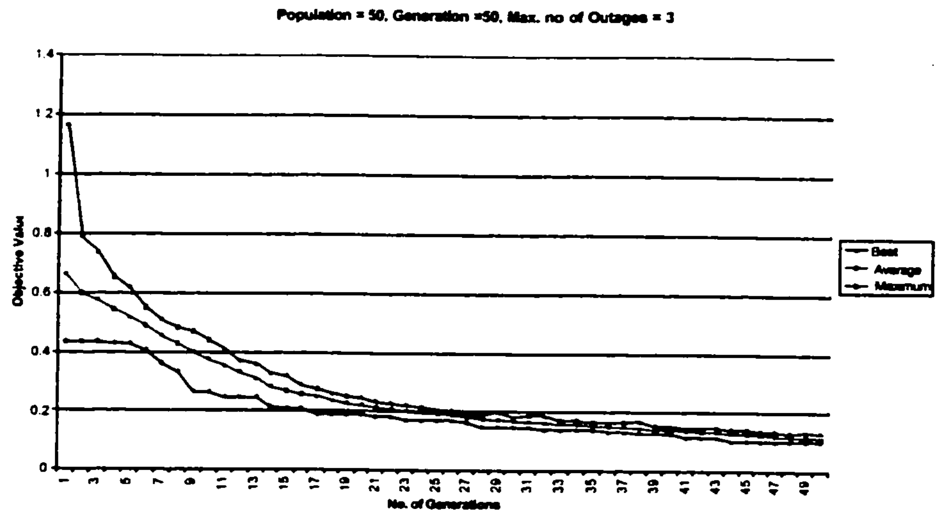


Fig E.21 Trending curve for case 11 for 50 generations

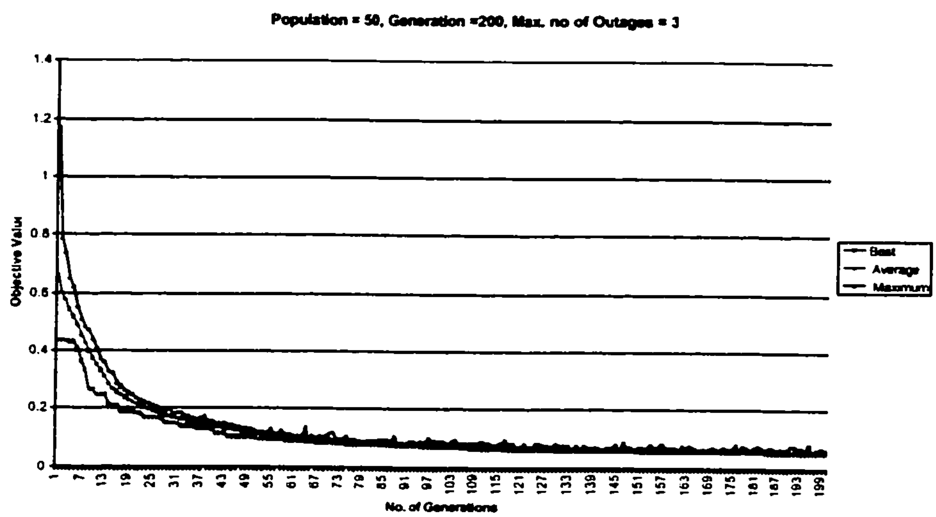


Fig E.22 Trending curve for case 11 for 200 generations

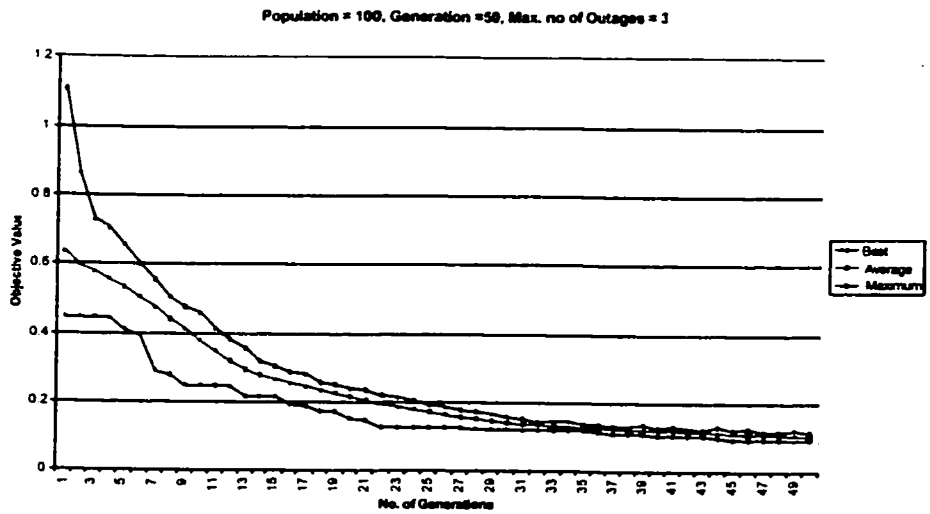


Fig E.23 Trending curve for case 12 for 50 generations

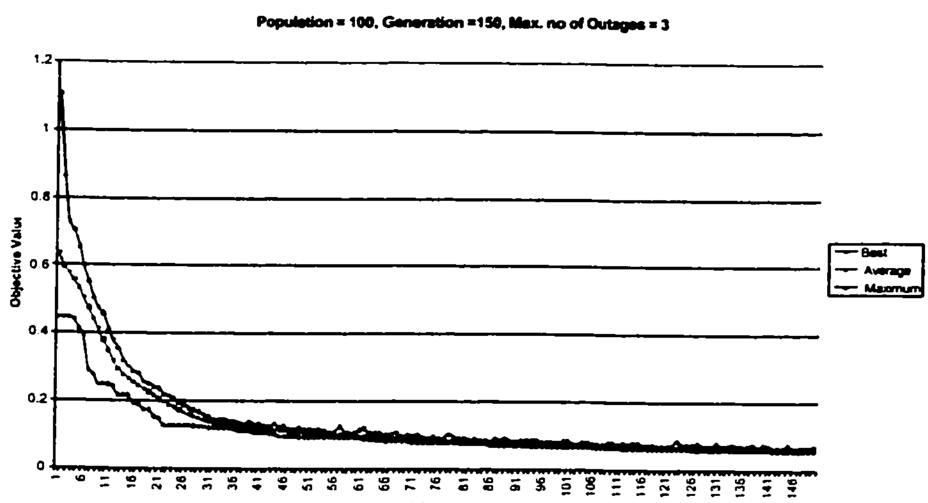


Fig E.24 Trending curve for case 12 for 150 generations

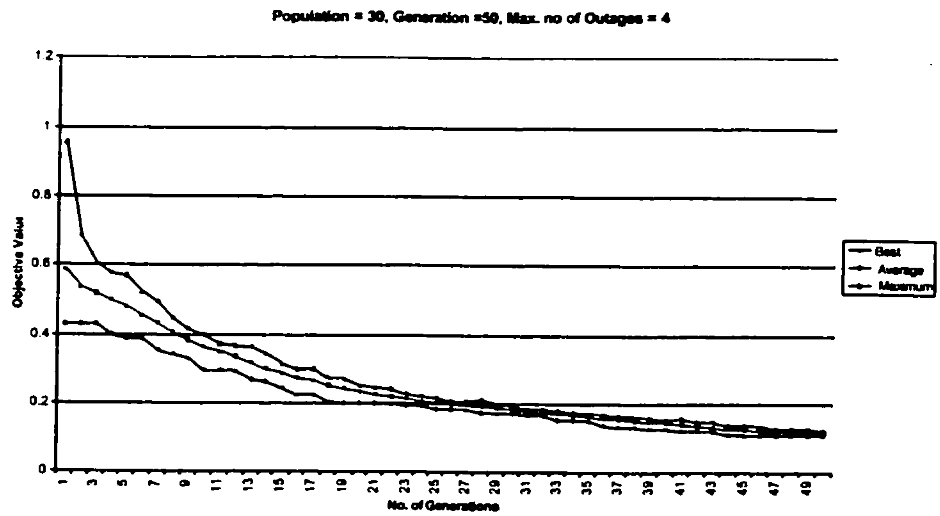


Fig E.25 Trending curve for case 13 for 50 generations

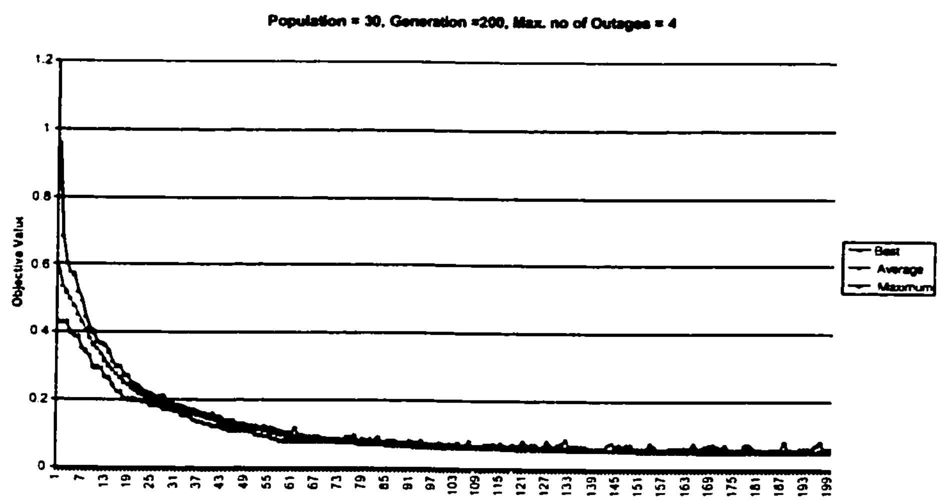


Fig E.26 Trending curve for case 13 for 200 generations

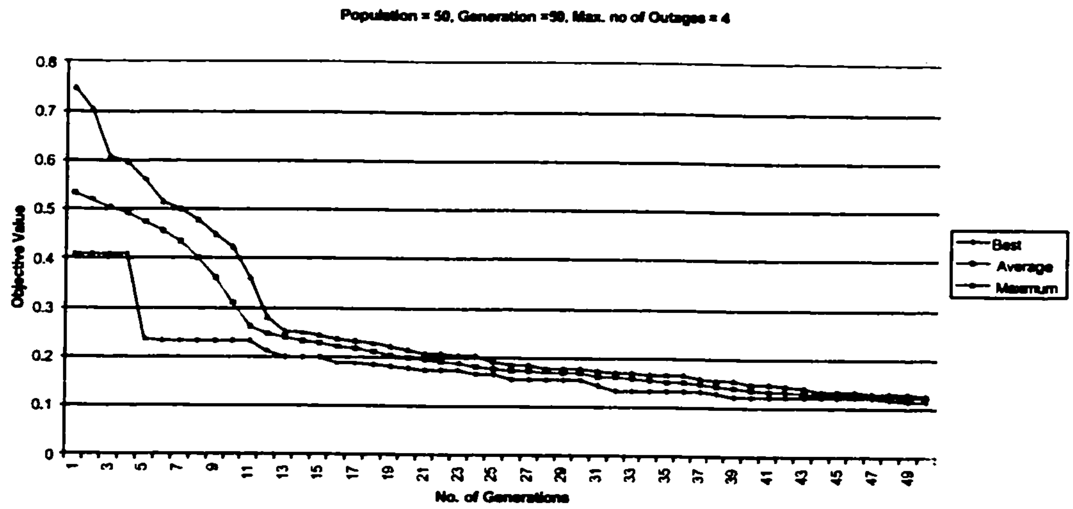


Fig E.27 Trending curve for case 14 for 50 generations

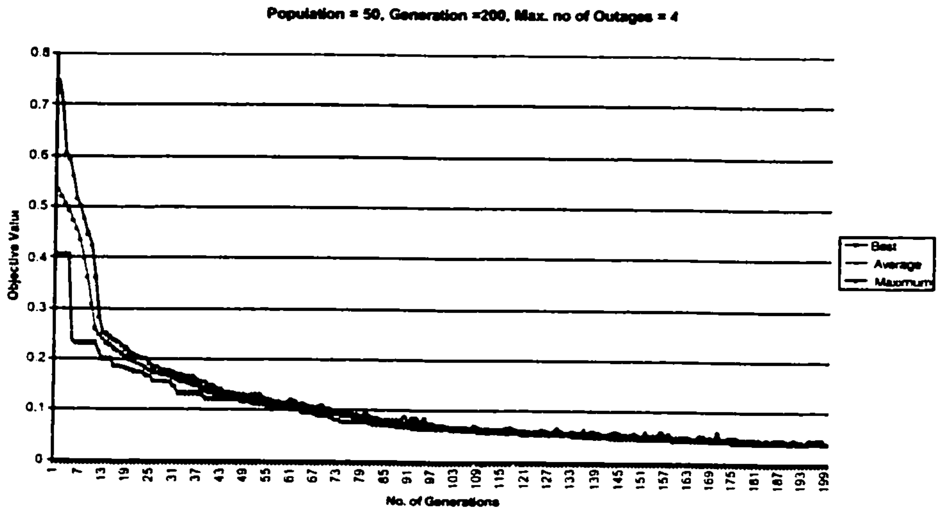


Fig E.28 Trending curve for case 14 for 200 generations

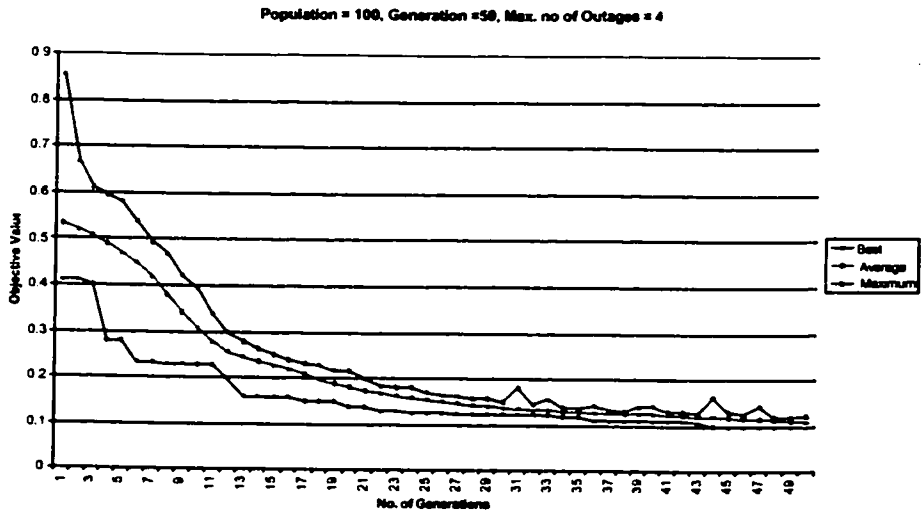


Fig E.29 Trending curve for case 15 for 50 generations

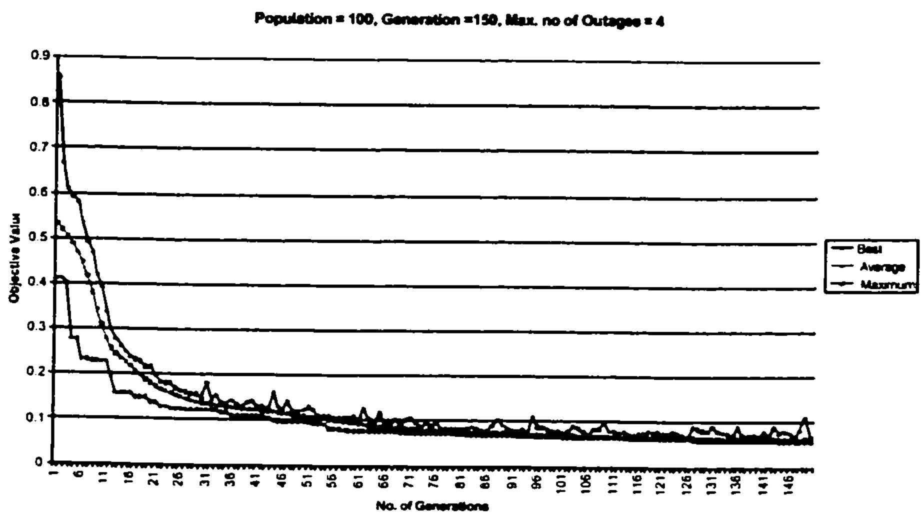


Fig E.30 Trending curve for case 15 for 150 generations

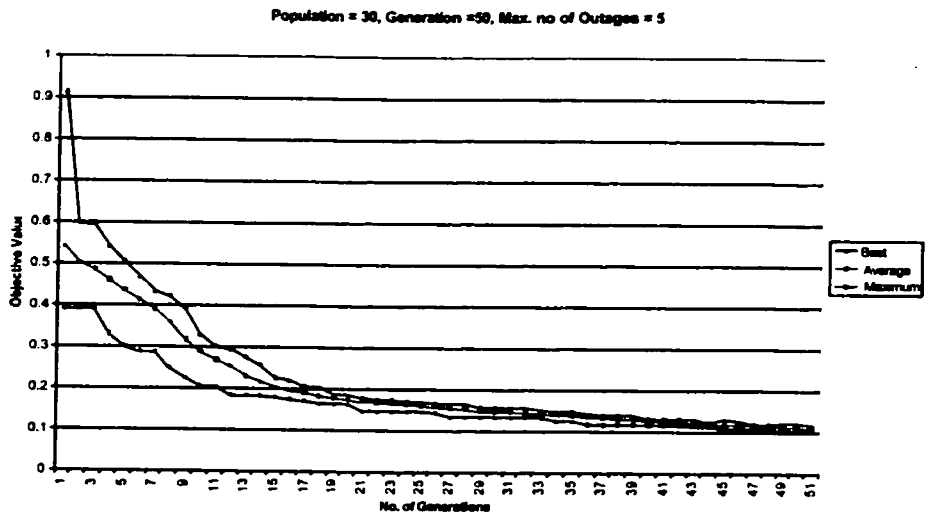


Fig E.31 Trending curve for case 16 for 50 generations

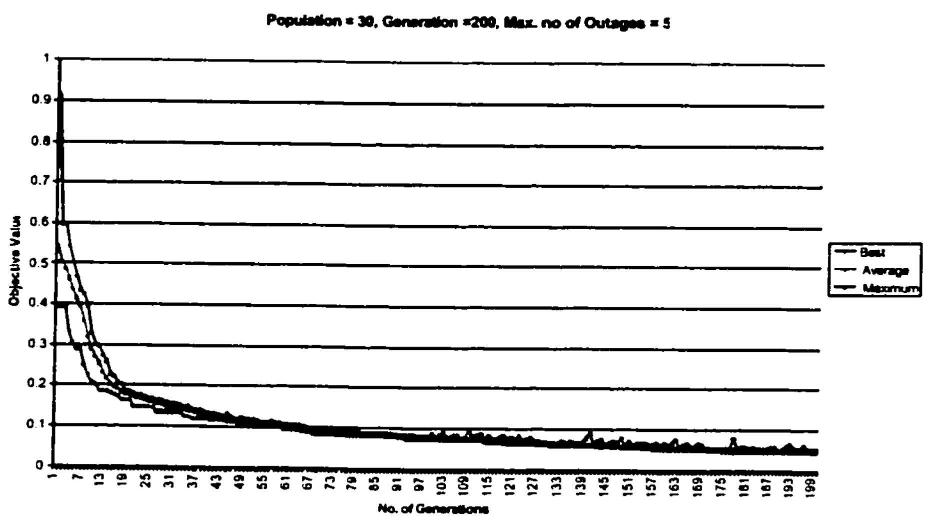


Fig E.32 Trending curve for case 16 for 200 generations

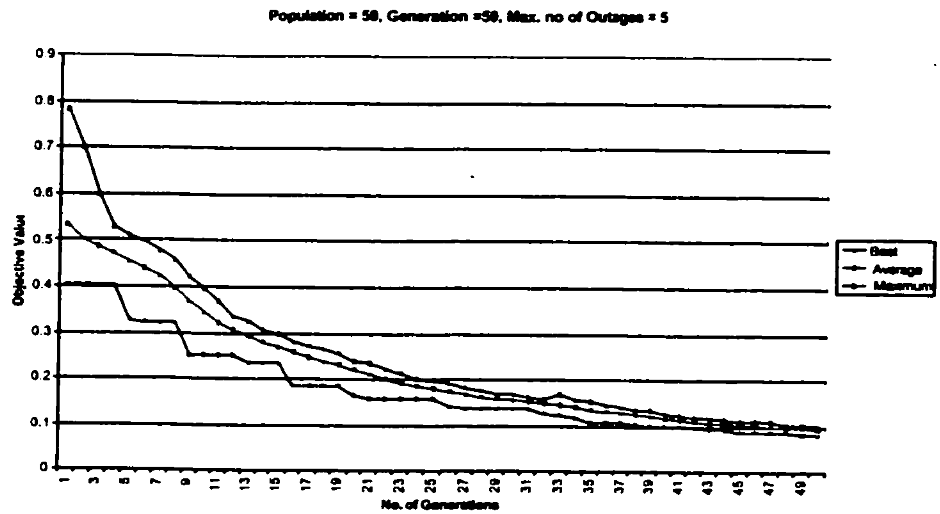


Fig E.33 Trending curve for case 17 for 50 generations

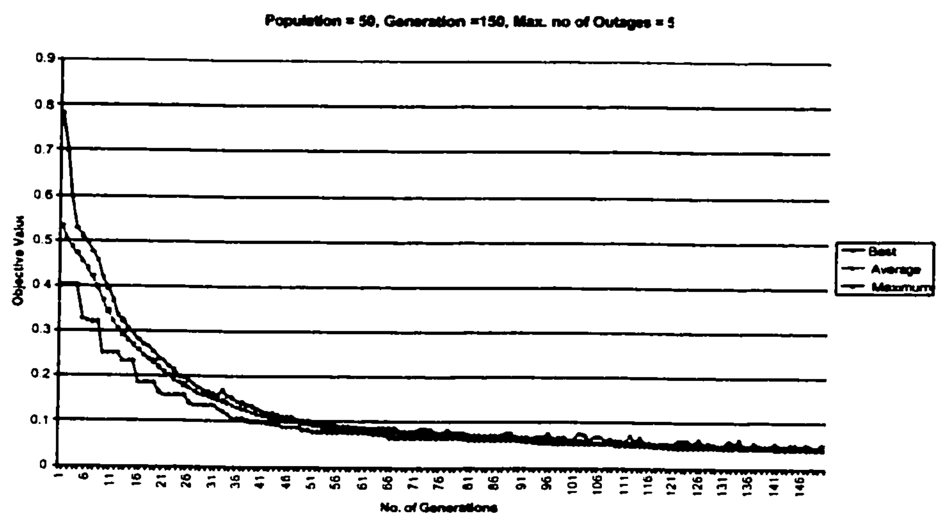


Fig E.34 Trending curve for case 17 for 150 generations

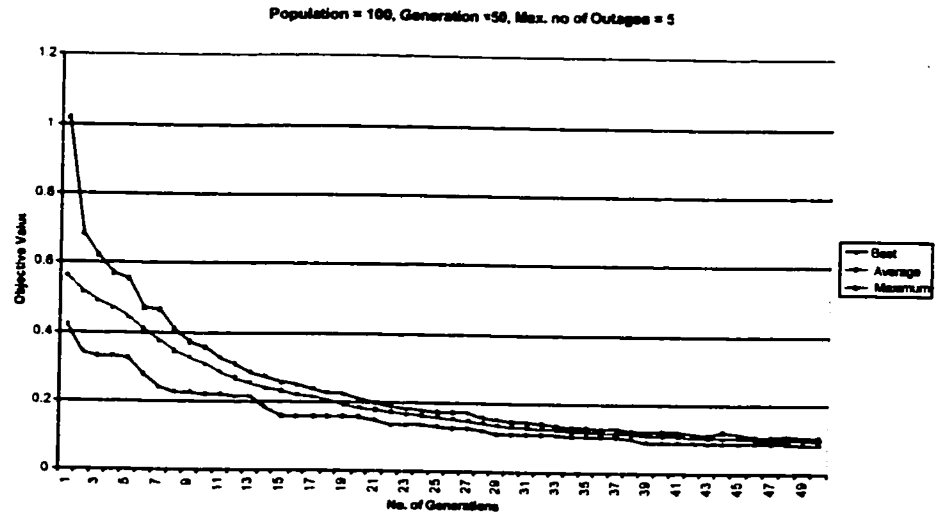


Fig E.35 Trending curve for case 18 for 50 generations

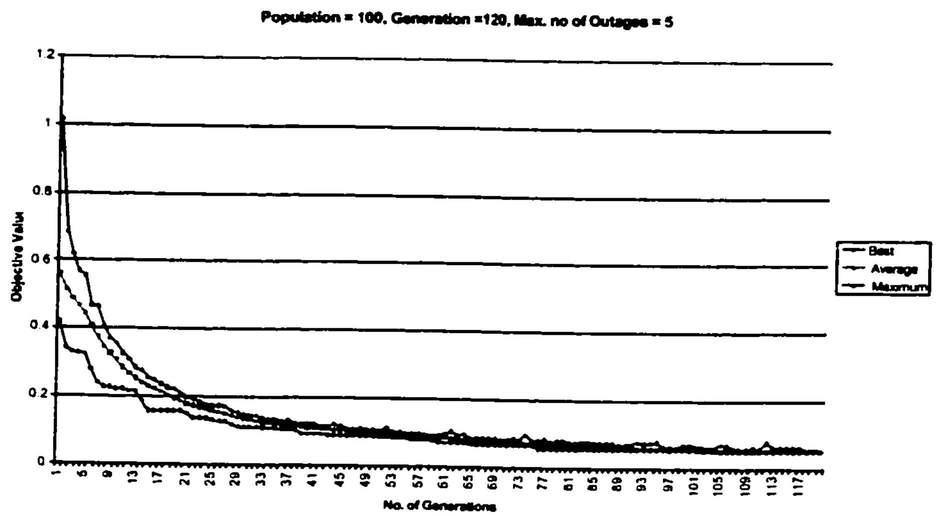


Fig E.36 Trending curve for case 18 for 120 generations