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Power System Protection and Switchgear

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*This book is dedicated to the memory of our
beloved teacher, mentor and guide*

Dr Madhav Anant Date

(19.4.1924 to 14.2.2002)



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Foreword

Power system protection and switchgear is a topic which touches our lives every day, in a very non-intrusive manner. Reliable protection of electric energy systems against faults like short circuits is in fact, the cornerstone of power system reliability. In turn, it is one of the important reasons for electricity having been accepted as a cost-effective and efficient medium for transmission of energy (or power) over large distances. The technology of power system protection has evolved a lot since the era of electromechanical and solid-state relays. In fact, today's relays are computers which can detect faults from the voltage and current signals recorded by Current Transformers (CT) and Voltage Transformers (VT), by using digital signal processing techniques. Thus, the requirement of learning this subject has changed significantly over a period of time and in fact, this book addresses this need in a comprehensive manner.

This book by Profs. Bhuvanesh Oza, Nirmal Kumar C Nair, Rashesh Mehta and Vijay H Makwana provides a right blend of the classical and modern treatment in protection which is so very important for a beginner. The book begins with an introduction to the philosophy of protection which is followed by exposure to electromechanical, solid-state and numerical relays. In particular, the treatment of numerical relays covers the basic methods of phasor estimation through Discrete Fourier Transform (DFT) and its specialisations for protection like half-cycle and full-cycle algorithms. Subsequently, authors give due diligence to apparatus protection (generators, motors, transformers and bus-bar) as well as transmission line protection.

No treatment of power system protection can be complete without introduction to that complex switch called circuit breaker which has to handle hundreds of MVA while breaking the current due to the inductive nature of the circuit. Authors devote three chapters to this aspect.

The task of learning is never complete unless one can test his/her ability to solve some challenging problems or explain a few important concepts. The book with a bank of multiple choice questions, review questions and numericals can help a student test his understanding of the subject.

To summarise, in my opinion, this book will be an important resource for beginners as well as practitioners in the field of power system protection.

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*Department of Electrical Engineering,
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Preface

Power system protection begins with the detection of faults by relays. Protecting the healthy section of the power system from damage during faults or abnormal conditions is achieved by tripping signals from relays. These signals initiate the opening of the appropriate circuit breakers in the network. Switchgear includes equipment like the circuit breakers, current and potential transformers, isolators, earthing switches, fuses, etc. Relays and switchgear, together, play an important role in ensuring stable operation of electrical power systems under normal as well as faulty or abnormal conditions.

The primary objective of this book is to offer a comprehensive coverage of syllabi of various universities at the undergraduate level along with the detailed treatment of recent developments of numerical/digital relaying. This book is a collective outcome based on extensive teaching and professional experiences of the authors. The book is written by the authors in a way that enables the students learn protection and switchgear in a professional manner apart from catering to the needs of the syllabus and exams. It offers a mixed and attractive blend of detailed theoretical treatment and intensive application practices that helps comprehend the role of protective relays and circuit breakers. The text contains several solved examples with detailed explanations that will sustain the interest of students while learning protection and circuit-breaking practices. The theoretical and mathematical background for these practices is elaborated extensively in the book. The ac power and dc control circuit representation of protection schemes using standard international conventions is followed throughout the text. The illustrations of relay-setting calculations and design of protective schemes using actual field data and system conditions provide a major tool for students in becoming better prepared for the future challenges in the protection and switchgear practices and research.

The typical syllabi of undergraduate courses on Power System Protection, Switchgear and Protection, and Electrical Switchgear of universities in India are covered comprehensively in this text. This book can also be used as a reference text for postgraduate courses on Advanced Power System Protection or Numerical Protection of Power System. The detailed treatment of various protection and switchgear applications based on field experience in relaying design will be useful to power-system engineers working in the electric utilities and industry. This book can also be used as a quick handbook by field engineers.

The content of this book is organised in 17 chapters. Chapter 1 presents the philosophy and requirements of protective relaying systems. The constructional aspects and realisation of characteristics for various electromagnetic, static and numerical relays are covered in chapters 2, 3 and 4. Chapters 5 to 11 cover the fundamentals and practical schemes for protection of generators, transformers, transmission lines, bus-zones, and induction motors. Approach of numerical relaying for each type of protection is also introduced in these chapters. Chapter 12 is dedicated to testing, commissioning and maintenance of relays. Chapter 13 covers the necessary aspects of protective current and potential transformers. Chapters 14, 15, and 16 provide explanation of circuit-breaking fundamentals, various types of electrical switchgear and testing of circuit breakers respectively. Finally, overvoltage protection is discussed in Chapter 17.

The Web supplements can be accessed at <http://www.mhhe.com/oza/psps> and contain the following material:

For Instructors

- Solution manual, PowerPoint lecture slides

For Students

- Interactive quiz, Model question paper with solution

We express our special acknowledgement and gratitude to our former HOD, the late Dr M A Date. He had done his PhD in Power System Protection from Germany and was deeply interested in the subject. An ardent scholar of the subject with research inclination, he was often consulted by utilities and industry for solving real-life field problems. Many of his students have played an important role in operation, protection and control of power systems in industry and utilities in India and abroad. He was a loving teacher to one co-author, Bhuvanesh, and we are happy to recognise his silent contribution to the area of protection.

We are deeply indebted to Prof. S A Khaparde of IIT Bombay for writing a foreword for the book.

We extend our special thanks to Mr P H Rana, Director, Gujarat Urja Vikas Nigam Ltd. (GUVNL), for interactions on the relevance of numerical protection. We also thank Dr K K Thakkar, who was formerly with Jyoti Switchgears Ltd., Mogar, Gujarat, for bringing forth useful suggestions on the topic of static relays. We would like to mention especially the encouragement that we received from the support and motivation provided by the late Prof. J N Shah during the preparation of the previous version of the book. Dr Shah was formerly with the government engineering colleges of Bhavnagar, Ahmedabad, and Morbi and afterwards he was appointed the Director of SVM Institute of Technology, Bharuch, Gujarat.

One of the co-authors, Rashesh, who has studied Digital Protection under the tutelage of Prof. S A Soman at IIT Bombay, acknowledges the guidance and motivation provided by him. Rashesh has also attended a workshop on WAMS and Digital Protection by Prof. A G Phadke, Virginia Tech, USA (who is a pioneer and expert in the area of digital relaying) at CPRI, Bangalore, in February 2007. He acknowledges the knowledge and experience shared by Prof. Phadke during the workshop. We thank our past students—Prof. Vivek Pandya, HOD, Om Shanti Engineering College, Rajkot and Mr Tarang Thakkar, working as relaying consultant at Baroda—for having shared their suggestions during the course of developing the chapters on relaying. We are also thankful to Mr Ashutosh Mishra, deputy engineer (GEB) for his contribution in co-ordinated relay settings for interconnected systems during his post-graduate studies under Prof. B A Oza. The authors acknowledge M/s Areva T&D Ltd., VXL Landis and Gyr Ltd., ABB Ltd., and Jyoti Ltd. for granting permission to incorporate details of their products.

Our special thanks are due to Dr B R Parekh and past HODs of BVM Engineering College, Prof. J C Panchal and Prof. D N Bhatt, for providing opportunities to teach various topics and develop laboratory facilities related to this book. Laboratory work plays a very important role in knowledge building and we acknowledge his contribution in helping us understand the subject in a better way. We also owe our gratitude to AICTE for having provided funding twice—in 1988 and 1999—for developing and modernising the power-system protection laboratory at BVM under their MODROBS support scheme. Our appreciation is also due to our former colleague, Dr Sukumar Brahma, currently working as Assistant Professor, New Mexico State University, USA, for academic interactions during the laboratory development. The co-author, Dr Nirmal Nair, would like to take this opportunity to acknowledge the support extended by the Department of Electrical and Computer Engineering at University of Auckland, New Zealand, during the course of development of this book.

Reviews conducted for our book have played an important role in giving a multifaceted and inclusive touch to the contents. We have tried to implement as many creative suggestions as possible and also improved upon the text based on the constructive criticism that we received. We are thankful to all the reviewers for taking interest in the project and for their involvement and contributions. Their names are given below.

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We also take this opportunity to thank all our colleagues, students and friends, both current and former, for all their encouragement and support. Last, but not the least, a very special thanks to all our family members for their cooperation and patience.

We accept the fact that our book will have a few flaws, errors or mistakes. We are positively open for any criticism, feedback, creative suggestions. The feedback can be provided on the webpage at <http://www.mhhe.com/oza/psps>. Based on the feedback obtained, we shall surely try to improve the content of the future editions of this book.

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Special Features

Introduction

Each chapter begins with an Introduction that gives a brief summary of the background and contents of the chapter.

Microprocessor-Based Digital Protection

4

Introduction

One of the issues with electromechanical or static relays is that the relays are not in an operated condition during normal behavior of the power system. They operate only under abnormal or faulty conditions of the power system. This may not happen very frequently and in certain cases it may happen very rarely. Hence the integrity of a relay operation can be confirmed only by frequently testing the relays. There is no continuous check on their operational integrity. By using a digital computer for power system protection and microprocessor-based relays, one can address this issue. One very important advantage of microprocessor-based relays is that they can perform the functions of protection, measurement and control simultaneously. With the national and international grids having long ultra high voltage tie lines transferring the bulk of power, the use of microprocessor based relays is not only proving to be effective but also more or less essential.

The term 'microprocessor' is used here as a generic term. 8-bit microprocessors were initially used for protective relay applications. With further progress in microprocessor technology, the more advanced microprocessors like the 16-bit microprocessor began to be used to implement relay algorithms. Most recently, digital signal processors (DSPs) are being used for protective relays. The term used for these relays are microprocessor-based relay, digital relay and numerical relay; given in the chronological order of their development. In the description, all other peripheral components except CPU will remain almost similar. The CPU is a device which is updated or replaced with technological developments. We have preferred the term 'numerical relays' in this text as it is widely used in industrial and professional practice. Let us first discuss the advantages of these relays.

4.1 ADVANTAGES OF NUMERICAL (DIGITAL) RELAYING

1. **Self-checking Facility** All components like processor, memory, analog I/O system, digital I/O ports, dc control supply, etc., are self-checked by the relay and a warning, annunciation or corresponding defensive action is initiated if any error or problem is detected.

11.6 NUMERICAL MOTOR-PROTECTION RELAY (Courtesy Areva T & D Ltd.)

A modern numerical motor-protection relay is designed to offer a wider range of functions and more user-related possibilities for motor protection, supervision and control. The numerical relay can perform a full range of motor-protection functions based on load current such as thermal overload, short-circuit, excessive start time, locked rotor, unbalance, earth fault, loss of load, etc. The optional monitoring of temperature sensors or of thermistors provides continuous monitoring of the temperature inside the motor.

11.6.1 Thermal Overload Protection

The numerical motor protection relay produces a thermal image of the motor from the positive and negative sequence components of the currents consumed by the motor, in such a way as to take into account the thermal effects created in the stator and in the rotor. The negative sequence component of currents consumed in the stator generates large amplitude of eddy currents in the rotor, which create a substantial temperature rise in the rotor winding. The composition carried out by the relay results in an equivalent thermal current I_{eq} , the image of the temperature rise caused by the current in the motor. The current I_{eq} is calculated according to the following formula:

$$I_{eq} = \sqrt{I_1^2 + K_r I_2^2}$$

where,

K_r = negative sequence current recognition factor (0 to 10 in steps of 1)

K_r can be set at I_d/I_B for a given motor

where I_d = starting current of the motor

I_B = normal rated full-load current

Starting from this equivalent thermal current, the thermal state of the motor θ is calculated after every 5 cycles (every 100 ms for a 50 Hz system) by the relay according to the formula,

$$\theta_{i+1} = (I_{eq} I_B)^2 \cdot [1 - e^{-\tau/\tau_0}] + \theta_i \cdot e^{-\tau/\tau_0}$$

in which

I_B = thermal overload current threshold

θ_i = value of the thermal state calculated previously (5 cycles earlier, so 100 ms for a 50 Hz system, 83.3 ms for a 60 Hz system)

τ = time constant of the motor

As a function of the operating conditions of the motor, the relay uses one of the following three thermal time constants:

1. The thermal time constant τ_1 which is applied when the equivalent thermal current I_{eq} lies between 0 to $2I_B$, that is, when the motor is running (normal load or overload conditions)
2. The starting time constant τ_2 which is applied when the equivalent thermal current I_{eq} is greater than $2I_B$, that is, when the motor is in the starting phase or locked-rotor condition
3. The cooling time constant τ_3 which is applied when the motor is shut down; in this case, the motor no longer consumes current and the value of the thermal state θ therefore decreases as time passes according to the formula given as follows:

$$\theta_{i+1} = \theta_i \cdot e^{-\tau/\tau_3}$$

A thermal overload signal is generated when the value of the thermal state θ reaches 100%.

Numerical/Digital Approach

Numerical/Digital protection approach is included in the chapters for apparatus protection. The operational strategies of recent commercial relays are discussed to familiarise students with the latest technology.

Detailed Topics

Microprocessor based, digital/numerical protection, concepts and physical significance of digital signal processing essential for numerical protection are explained with mathematical background.

Fundamentals of circuit-breaking phenomenon using mathematical as well as graphical approach, physical significance of the technical terms and correlation between relay setting calculations and circuit breaker design is highlighted.

Protection against lightning overvoltages with all necessary details of modern practices and important practical aspect of insulation coordination is highlighted.

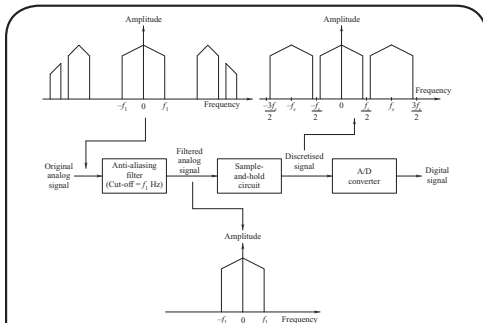


Fig. 4.12 Anti-aliasing filtering prior to sampling at a rate of f_s Hz

For numerical relaying applications, typical sampling rates range from 4 to 96 samples per cycle. The lower limit on the sampling rate is imposed by Nyquist criteria, and the upper limit is imposed by computations to be done between the two samples. Conversion time of ADC is not an issue now as ADCs have conversion times in terms of 15–30 μ s.

4.4 ESTIMATION OF PHASORS

Let us understand how to calculate or estimate the value of impedance in a numerical distance relay. The information available to the processor is in the form of digital samples which are in discrete-time domain. They are acquired at a particular sampling rate as mentioned in the previous section. So to evaluate the value of impedance, first of all it is necessary to estimate the voltage and current phasor. To understand the concept, let us take a single-phase circuit as shown in Fig. 4.13. The system frequency is 50 Hz.

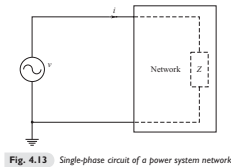


Fig. 4.13 Single-phase circuit of a power system network

$$V_{pn} \times 1.05 \times 1.5 \times 1.15 \times 1.2 \times 1.5 = 3.3 V_{pn} \text{ for lines at 400 kV}$$

where, V_{pn} is the phase-to-neutral voltage.

It is a good practice to make an allowance for one or two extra insulator discs to take care of the possibility of an insulator unit in the string becoming defective and also for hot line maintenance, over and above those required to withstand the above overvoltage.

17.6 INSULATION COORDINATION

Insulation coordination is the proper matching of insulation of transmission lines and other equipment with the characteristics of protective devices so that the surges entering the station are conducted to ground through the protective devices without damaging the insulation. The present practice is to locate the lightning arresters as close as possible to the transformer which is the costliest equipment in the substation. The lowest insulation is therefore chosen for the transformer which is governed by the characteristics of the lightning arrester.

An insulation coordination scheme for a substation covers the following parameters:

1. Protective characteristics of lightning arrester
2. Transformer Basic Impulse Level (BIL)
3. Impulse levels for circuit breakers, disconnecting switches (isolators), busbars, supports and other apparatus at the terminals

17.6.1 Protective Characteristics of Lightning Arresters

The important settings to be selected for the protective characteristics of a lightning arrester are the voltage rating and the discharge-current capacity. Arrester rating must equal or exceed the maximum permissible rms power-frequency voltage applied between its terminals under normal or abnormal conditions of operations, including fault conditions. On EHV transmission systems with effectively earthed neutrals, the voltage between phases and earth under faulty conditions does not generally exceed 75–80% of the highest phase to phase system voltage. The arrester voltage rating is therefore based on 75–80% of the maximum system voltage. 10 kA arresters are generally used for 220 kV and 400 kV systems. Protection level of the lightning arrester should be decided by knowing the BIL of the transformer.

17.6.2 BIL of Transformers

The BIL of a transformer can be decided by referring to relevant IS specification. To coordinate the arrester protective level with impulse withstand strength of the transformer, a margin in terms of ratio (generally taken as 1.2) between the insulation withstand strength (BIL) and impulse protective level of the lightning arrester has to be maintained.

17.6.3 Insulation Levels for other Substation Equipments

The insulation strength of the remaining substation equipment (circuit breakers, isolators, busbar supports, CT, PT, etc.) is kept generally greater than the selected BIL of the transformer to provide the equipment with as good protection and is economically justified. Hence this insulation strength is kept generally 10% higher than the BIL of the transformer. This presumes that the lightning arresters are located very near to the transformer terminals. In case additional lightning arresters are applied elsewhere in the substation, lower

the construction of the contacts of circuit breakers should be avoided and surfaces should also be as smooth as possible. The contacts should be changed when they become heavily pitted following several breaking and making operations.

14.7 QUENCHING OF AC ARC

It is well known that when a sudden short circuit occurs in a power system, the fault current can be represented as,

$$i = \frac{E_m}{\omega L} \left[e^{-\frac{R}{L}t} + \sin(\omega t - \phi) \right]$$

This is the case when a fault occurs at the instantaneous value of voltage zero. The wave shape is as shown in Fig. 14.2.

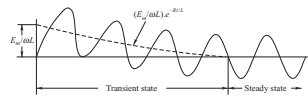


Fig. 14.2 Wave shape of fault current

$\frac{E_m}{\omega L} e^{-\frac{R}{L}t}$ is also known as transient component or dc offset. A sinusoidal ac wave is superimposed on this dc offset. If the fault occurs at an instantaneous voltage equal to V_{max} , there would no dc offset and the fault current will just be a steady-state sinusoidal fault current given by,

$$i = \frac{E_m}{\omega L} \sin(\omega t - \phi)$$

When such a fault current is to be interrupted, high voltage is developed across the contacts of a circuit breaker when the arc due to this fault current is quenched. This fact is discussed in the following paragraphs.

The equivalent single-phase circuit for any power system can be approximated as shown in Fig. 14.3. The loop equation for the above circuit can be written as,

$$v = R_i + L \frac{di}{dt} + \frac{1}{C} \int i dt \quad (14.3)$$

where, $v = E_m \sin(\omega t)$

Neglecting R and solving for complementary function or transient solution,

$$\left[LD^2 + \frac{1}{C} \right] i = 0 \quad \text{where } D = \frac{d}{dt}$$

or

$$D = \pm \frac{j}{\sqrt{LC}}$$

Hence, the solution will be,

$$i = Ae^{\frac{j}{\sqrt{LC}}t} + Be^{-\frac{j}{\sqrt{LC}}t}$$

Standard Field Practices

Standard field practices for testing of relays are explained in the chapter on testing, which can be very much useful to protection engineers. Indigenous and low-cost designs of academic lab set-up for relay testing can be a good aid to teachers.

overvoltage produced. Before this happens, the spark gap SG sparks over at this overvoltage and the relay AX_2 gets energised. The 'NC' contact of AX_2 disconnects the injection transformer from the supply mains. Auxiliary relay AX_1 is used for initiating the operation of contactor and to avoid chattering of the contactor when the relay under test operates. The relay coil can be shorted by a selector switch SS_2 so that the test current can be comfortably adjusted. Removal of shorting link gives the start pulse to a digital timer and operation of the relay under test gives the stop pulse to the timer (through the contact of AX_2). Thus time of operation of relay at any current can be measured and time-current characteristic can be confirmed.

For experiments to be conducted in laboratory of educational institutes, a low-cost test-set is developed by the authors. The output cannot be guaranteed to be perfectly harmonic-free, but for demonstrating to the students it serves its purpose. The pictorial view of this test-set at BVM Engineering College is shown in Fig. 12.2.

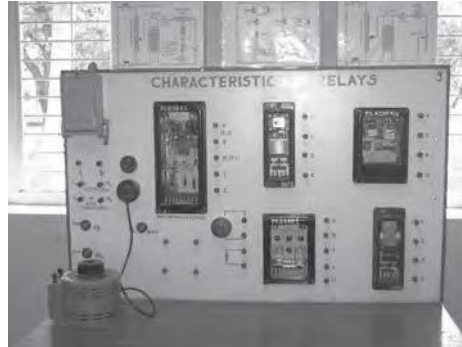


Fig. 12.2 Pictorial view of low-cost test set at BVM engineering college

Example 7.1 A single-line diagram of a simple radial feeder is given in Fig. 7.18. Using standard IDMT characteristic (Fig. 2.5), calculate the relay settings of all the phase relays. Assume suitable discrimination time. Relevant data is as follows:

Rated current of the relay = 1 A

Setting range of plug-setting = 50–200% of 1 A in 7 equal steps

Setting of relay R_3 : PS = 75%, TMS = 0.1

Solution **Plug-settings** PS of the relay R_2 > $(1.3/1.05) \times$ PS of the relay R_3
 > $(1.3/1.05) \times 450$ (in primary terms)
 > 557.14 A (in primary terms)
 > 92.85% of CT rating

The PS of R_2 is selected as 100% of 1 A as an immediate higher step to 92.85% available is 100%.

Similarly, the PS of R_1 is selected as 75% of 1 A.

Worked Examples

Worked examples of relay setting calculations and actual field design problems are sufficiently provided with detailed step-by-step calculations and circuit diagrams.

Illustrations

The book is profusely illustrated with schematics used in field practice which follow international conventions of protective relay drawings. Comprehensive coverage of apparatus protections is provided.

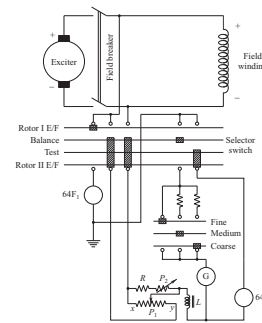


Fig. 5.16 Rotor first and second earth-fault protection of generator

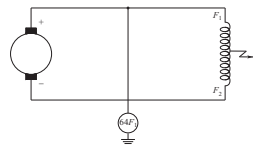


Fig. 5.17 Selector switch on 'rotor I E/F' position

REVIEW QUESTIONS

- Why are distance relays generally preferred to IDMT overcurrent relays for the protection of transmission lines?
- Give reasons for the following statements:
 - Distance relays cannot be applied for the transmission lines employing auto-reclosing circuit breakers at both the ends of the lines.
 - Reactance relays are a better choice for short transmission lines whereas mho relays are applied for long lines.
 - The power swing in a power system may mal-operate a distance relay.
 - An impedance relay under-reaches in case of a fault incorporating resistance in the fault path, whereas a reactance relay is immune to the fault resistance.
- What are the limitations that restrict the reach of the first and third zones of a three-zone distance relay?
- Compare the suitability of the following distance relay schemes for the protection of (a) long transmission lines, and (b) short transmission lines.
 - Mho relays
 - Reactance relays with mho starting
 - Plain impedance relays with directional starting
- How is the mal-operation of a distance relay due to loss of potential prevented?
- Draw a schematic connection diagram for the dc circuit of a distance scheme of protection and explain with its help, the three-step operation of the distance unit.
- Draw the dc control circuit for protection against close-in faults.
- With appropriate mathematical proof, show that line to ground voltage and compensated currents are supplied as inputs to enable the distance relay to measure the positive sequence impedance from the relay point to the fault point in case of an earth fault.
- Give an outline of a comprehensive distance protection scheme built around six relays.
- Draw a dc control circuit for an out-of-step blocking of a distance relay.
- How many distance protection units are required to protect a transmission line against phase and ground faults? With appropriate mathematical back-up, show how such a relay will measure positive sequence impedance between the relay point and the fault point for an L-L fault.
- On the R-X plane, show the impedance vector of a line-section having an impedance of $2 + j5$ ohms. On the same diagram, show the operation

Review Questions

Each chapter contains a set of Review Questions with answers for the numerical problems. These review questions provide the essence of the concepts discussed in each chapter.

Multiple Choice Questions

Multiple Choice Questions enable the students to have a clear comprehension of the subject matter. Answers to all the Multiple Choice Questions are provided at the end of the book.

MULTIPLE CHOICE QUESTIONS

- In comparison to the knee-point voltage (KPV) of a measuring CT used to feed current to a 1 A meter, the KPV of a protective CT used to feed current to a 1 A relay shall be
 - equal
 - lower
 - higher
 - double
- The material preferred as core of protective CTs is
 - nickel-iron
 - hot-rolled non-oriented silicon steel
 - cold-rolled oriented silicon steel
 - none of the above
- The additional type test required to be preferred for a CVT as compared to an electromagnetic PT is
 - temperature rise test
 - ferro-resonance test
 - lightning impulse test
 - HV power frequency wet withstand test
- For a differential protection scheme, to fulfill the requirement of stability against external faults, it is necessary to have
 - $KPV > I_f(R_{CT} + R_L)$
 - $KPV = 2I_f(R_{CT} + R_L)$
 - $KPV > 2I_f(R_{CT} + R_L)$
 - $KPV < 2I_f(R_{CT} + R_L)$

where,
 I_f = secondary equivalent of maximum fault current
 R_{CT} = resistance of CT secondary winding
 R_L = lead resistance
 KPV = Knee-Point Voltage

Research Papers

- G. D. Rockefeller, "Fault Protection with a Digital Computer", IEEE Transactions on Power Apparatus and Systems, Vol. 88, No. 4, pp 438-461, April 1969.
- B. J. Mann and I. F. Morrison, "Digital Calculation of Impedance for Transmission Line Protection", IEEE Transactions on Power Apparatus and Systems, Vol. 90, No. 1, pp 270-279, January/February 1971.
- B. A. Oza, "P.C. Based Software and Hardware Scheme for On-line Protection of 3-phase Alternator", Journal of Engineering and Technology, Sardar Patel University, March 2001.
- B. A. Oza, "An Integration Based Algorithm for High Speed Digital Distance Relaying", Journal of Engineering and Technology, Sardar Patel University, March 2001.
- Bhuvanesh A. Oza and Sukumar Brahma, "Development of Power System Protection Laboratory through Senior Design Projects", IEEE Transactions on Power Systems, Vol. 20, no. 2, pp 532-537, May 2005.

Books

- Protective Relays: Their Theory and Practice (Vol I)
A. R. Van C. Warrington
Chapman and Hall Ltd.
- Protective Relays: Their Theory and Practice (Vol II)
A. R. Van C. Warrington
Chapman and Hall Ltd.
- The Art and Science of Protective Relaying
C. Russell Mason
Wiley Eastern Ltd.
- Power System Protection (Vol I)
Edited by The Electricity Council
Peter Peregrinus Ltd.

References

At the end of the book, a comprehensive list of book and journal references are provided.

International Codes

A list of internationally used codes for relays and protective circuit drawings are given in the form of an annexure at the end of the book. The codes will be helpful in reading the drawings for protective relaying circuits.

List of International Codes for Drawings of Circuits for Protective Relaying

Code	Description of device
1	Master element
2	Time-delay starting or closing
3	Checking or interlock relay
4	Master contactor
5	Stopping device
6	Starting circuit breaker
7	Anode circuit breaker
8	Control power disconnecting device
9	Reversing device
10	Unit sequence switch
12	Over-speed device
13	Synchronous speed device
14	Under-speed device
15	Speed or frequency matching device
17	Shunting or discharge switch
18	Accelerating or decelerating device
19	Starting to running connection control
20	Valve
21	Distance relay
22	Equalizer circuit breaker
23	Control device
25	Synchronizing check
26	Apparatus thermal device
27	Under-voltage relay
28	Flame detector
29	Isolating contactor
30	Annunciator relay
31	Separate excitation relay
32	Directional power relay
33	Position switch
34	Master sequence device
35	Break operating or slipping short circuiting device
36	Polarizing voltage device

Introduction and Philosophy of a Protective Relaying System

The modern electrical power systems cater to demands that are spread over large areas containing major components like generators, transformers, transmission and distribution lines, induction motors, and the like. It is evident that in spite of all necessary precautions taken in the design and installation of such systems, they do encounter abnormal conditions or faults. Some of them, like short circuits, may prove to be extremely damaging for not only the faulty component but

1

Introduction

to the neighbouring components and to the overall power-system network. It is of vital importance to limit the damage to a minimum by quickly isolating the faulty section, without disturbing the operation of the rest of the system.

The purpose of this chapter is

- (a) to discuss the fundamental concepts underlying power-system protection, and
- (b) to present an overview of the scope for this textbook.

1.1 TYPES OF FAULTS

The flow of current to the undesired path and abnormal stoppage of current are termed as faults. These faults are classified as

- (a) Symmetrical (balanced) faults and
- (b) Asymmetrical (unbalanced) faults

Symmetrical faults are those faults which involve all the three phases. Triple-line (L-L-L) and triple-line to ground (L-L-L-g) faults are symmetrical faults.

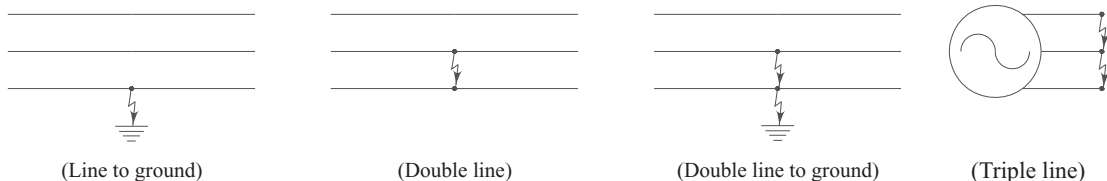


Fig. 1.1 Faults in a power system

The faults involving only one or two phases are categorised as asymmetrical or unbalanced faults. Single line to ground (L-g), double line (L-L) and double line to ground (L-L-g) faults are asymmetrical faults. Figure 1.1 shows various types of faults. For a 3-phase power system, there can be 10 different faults, namely, R-g, Y-g, B-g, R-Y, Y-B, B-R, R-Y-g, Y-B-g, B-R-g, R-Y-B. The R-Y-B and R-Y-B-g are practically the same faults. When an R-Y-B-g fault occurs, the three-line fault currents may be ten times (or even higher) of the rated normal maximum current for which the electrical equipment is designed. However, the vector sum is zero. Hence no current passes to the ground, and therefore, with regard to fault-current values, R-Y-B or R-Y-B-g faults are same. So their fault-current analysis is identical. They, however, differ in case of overvoltages.

1.1.1 Causes and Consequences of Faults

A symmetrical triple-line-to-ground fault can occur in case of switching ON of a circuit breaker when the earthing switch is inadvertently kept ON. Two phases can be bridged together either in the machines or in the transformers because of failure of insulation between phases, particularly when conductors of different phases are in the same slot of a stator of a machine. In the transmission lines, two phase wires may get shorted together by birds, kite strings or tree limbs. Moreover, in monsoon, the two phase conductors may swing due to winds and storms. Also, the dielectric strength of air reduces in monsoon. When the distance between these conductors is reduced due to swinging, a power-arc may occur between them causing a line-to-line fault. A line-to-ground fault is the commonest fault and can occur because of flashover across the line insulators or because of failure of line insulators, due to lightning or switching overvoltage or due to defective insulators. A line-to-ground fault can occur in machines and transformers too. Abnormal stoppage of current can occur due to open conductors or as a result of voltage breakdown at equipment due to the occurrence of faults of the first kind in some parts of the system.

The damage caused by faults is of two kinds: (i) thermal damage, and (ii) electrodynamic damage to the electrical equipment. Fault current ranging from approximately two times to about 8–10 times the rated full load current (Continuous Maximum Rating - CMR) of the equipment to be protected will heat the conductor and hence the insulation around it. The equilibrium temperature thus reached exceeds the temperature-withstand value of the insulation used. The insulation will thermally breakdown resulting into another fault if remedial steps are not taken. This is known as ‘thermal breakdown’ of the insulation and such a breakdown will occur after a certain time duration, the value of which depends upon the magnitude of the current. For avoiding such a breakdown, the equipment is required to be isolated from a healthy system by using time-delayed relays (refer Chapter 2).

When the fault current exceeds 8–10 times the full-load rating of the equipment, the repelling forces generated due to this large current would deshape and destruct the whole equipment structurally. The instantaneous tripping feature is required to be used to avoid such an ‘electrodynamic’ damage; as such destruction would occur just within 6 to 8 cycles.

It would be worthwhile to have an idea of probability of incidence of faults on the different elements of a power system. Table 1.1 shows the probability of occurrence of a fault in different elements of a system.

Faults that occur on overhead lines form the maximum percentage. Therefore, further statistics of faults on overhead lines will be really interesting to observe. Table 1.2 shows the frequency of different types of faults occurring in overhead lines. It is very clear that line-to-ground fault is the most common fault.

Table 1.1 Fault Statistics

<i>Element</i>	<i>Percentage of faults</i>
Overhead transmission lines	45–55%
Underground cables	8–12%
Switchgears	13–17%
Power transformers	10–14%
CTs and PTs	1–3%
Control-circuit equipments	2–4%
Miscellaneous	7–9%

Table 1.2 Statistics of faults on overhead lines

<i>Type of fault</i>	<i>Percentage of occurrence</i>
Line to ground faults	80–90%
Double-line faults	6–10%
Double-line-to-ground faults	3–7%
Triple-line faults	2% or less

Again faults can be transient (temporary) in nature or sustained. The power arc between two phases or flashover across line insulator due to overvoltage is a transient fault. It may take a few cycles or few seconds. Obviously, the relay would sense this fault and it is cleared. But, if the faulty line is catering to a large amount of power, the generators may go out of step. Hence when a breaker trips in a substation, the operating staff is permanently instructed to make the breaker ON, as the fault will have subsided by then. Also, if the damage due to such a transient fault is likely to occur after 4 seconds, the breaker should trip after about 3 seconds, since the transient fault may have subsided after about a second. Such a practice avoids instability of a power-system and therefore cascaded tripping in the worst case. Thus unnecessary early tripping of a transmission line or any other electrical equipment may sometimes more likely cause power-system instability. This is sometimes more harmful in comparison to not tripping a breaker when a fault has occurred. Thus, the role of a protection engineer becomes more involved and crucial.

It is very obvious that a very high-fault current can cause destruction or damage to the equipment of a power system, and the voltage would drop drastically. Network companies can lose revenue due to long interruption in service, as the repairs of the damaged equipment could take time. On the other hand, industries will also be in trouble because of loss of production and the inconvenience caused. Last, but not the least, is the loss of synchronism. The synchronism between machines working in the system could be lost and the power system can most likely become unstable if the fault persists. This can lead to widespread blackout of power. Hence one has to find a remedy for clearing the faults, i.e., isolating the faulty section from the rest of the healthy system. The consequences of an open circuit are unbalance in the system or single phasing.

1.1.2 Fault-Current Calculations

The fault calculations are necessary to compute the value of fault MVA or short-circuit MVA and the voltages at various points in the power-system network. This further helps in determining the protective relay settings so as to fulfill the requirements of a protective system as explained later. Moreover, the selection of ratings for circuit breakers and other switchgear components like current transformers, bus-bars, isolators, etc., are based on these fault calculations. The fault analysis will be different for symmetrical and asymmetrical faults.

The understanding of per unit method is a prerequisite for the study of fault calculations. A brief introduction of fault calculations is presented here.

The basic understanding of symmetrical fault calculations can be obtained from R - L series circuit transient. A detailed treatment on this is given in Chapter 14 (Circuit Breaking Fundamentals). A symmetrical short-circuit is assumed on a 3-phase alternator without load to find out the fault currents. There are three types of direct-axis reactances of a generator, classified according to its transient behaviour. They are sub-transient (X''_d), transient (X'_d) and steady-state (X_s) reactances. The sub-transient reactance is generally used in the fault calculations. For small systems, a network reduction method like Thevenin's theorem is used. As the power system network is large and complicated, the use of computers for the calculations becomes necessary. The fault calculations are also termed *short circuit studies*. The first step in short-circuit study is to form the bus impedance matrix (Z_{bus}).

As the majority of faults are asymmetrical, the calculations for asymmetrical faults are significant. The network will not be symmetrical, so it cannot be solved directly. The solution has to be obtained by using the technique of symmetrical components. The concept of symmetrical components was introduced by CL Fortescue in 1918. It results in three single-phase networks which are assumed temporarily for the purpose of analysis. These three networks do not have mutual coupling between them. Hence, the analysis is further simplified.

The positive, negative and zero sequence impedances or reactances of all the components of a power system are required. Using them, the sequence impedance or reactance diagrams of these components are worked out. The interconnection of these sequence-reactances depend on the type of fault, namely, L-g, L-L and L-L-g. After proper interconnection, the sequence network diagrams are formed which can be reduced using network rules. Sequence network results are then superimposed to obtain 3-phase network results. Finally, the sequence-current components can be obtained which lead to the phase-current values for unbalanced faults. The detailed analytical description is generally given in any book on power-system analysis.

1.1.3 Symmetrical Components

We first assume an arbitrary set of 3-phase phasors given as I_R , I_Y and I_B . These three phasors are supposed to be made up of three sets of sequence (symmetrical) components:

(1) Positive-sequence Components It consists of three phasors with equal magnitudes and having 120° phase displacement among them and with positive sequence as shown in Fig. 1.2(a). A positive sequence means that I_{R1} follows I_{Y1} and I_{B1} follows I_{R1} in an anticlockwise direction. The anticlockwise direction is considered positive for polar representation.

(2) Negative-sequence Components It consists of three phasors with equal magnitudes and having 120° phase displacement among them and with negative sequence as shown in Fig. 1.2(b). Negative sequence means opposite of positive sequence as explained above.

(3) Zero-sequence Components It consists of three phasors with equal magnitudes and with zero phase displacement as shown in Fig. 1.2(c).

The correlation of the three arbitrary phasors with the symmetrical components is given as

$$\begin{aligned} I_R &= I_{R0} + I_{R1} + I_{R2} \\ I_Y &= I_{0} + I_{1} + I_{2} \\ I_B &= I_{B0} + I_{B1} + I_{B2} \end{aligned} \quad (1.1)$$

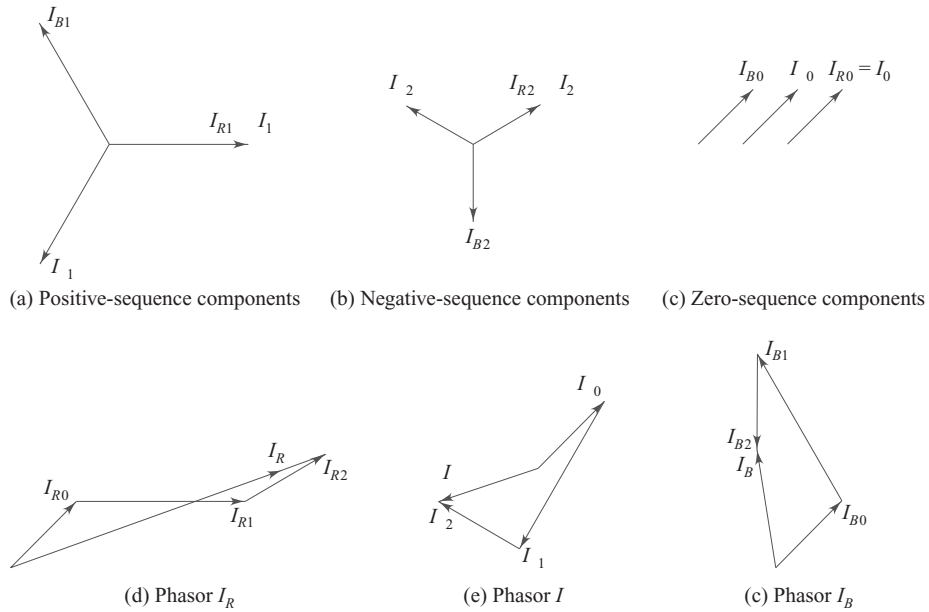


Fig. 1.2 Correlation of phasors with the sequence components

where,

I_{R0}, I_0, I_{B0} are a zero-sequence set

I_{R1}, I_1, I_{B1} are a positive-sequence set

I_{R2}, I_2, I_{B2} are a negative-sequence set

Equation (1.1) can be confirmed vectorially in Figures 1.2(d), 1.1(e) and 1.1(f).

We can consider that the phasors I_R, I, I_B are components of a current vector I . The sets of sequence components are represented by I_0, I_1 and I_2 for zero-sequence, positive-sequence and negative-sequence current vectors. Using matrix notation, we can write,

$$\begin{bmatrix} I_R \\ I \\ I_B \end{bmatrix} = \begin{bmatrix} I_{R0} \\ I_0 \\ I_{B0} \end{bmatrix} + \begin{bmatrix} I_{R1} \\ I_1 \\ I_{B1} \end{bmatrix} + \begin{bmatrix} I_{R2} \\ I_2 \\ I_{B2} \end{bmatrix} \quad (1.2)$$

In vector notation, Eq. (1.2) can be written as

$$I = I_0 + I_1 + I_2 \quad (1.3)$$

Now we will establish an interrelation among the sequence components. A complex number $a = e^{j\frac{2\pi}{3}} = 1 \angle 120^\circ = -0.5 + j 0.866$ is used for interrelation.

The components I_{R0}, I_{R1} and I_{R2} are selected as the reference variables and the rest of the components are expressed in terms of these reference variables. The operator 'a' can give relations tabulated in Table 1.3.

Table 1.3

Common expressions based on operator a	
$a^2 = 1 \angle 240^\circ$	
$a^3 = 1 \angle 0^\circ$	
$a^4 = a = 1 \angle 120^\circ$	
$1 + a + a^2 = 0$	

So, we get

$$\begin{bmatrix} I_R \\ I \\ I_B \end{bmatrix} = I_{R0} \begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix} + I_{R1} \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} + I_{R2} \begin{bmatrix} 1 \\ a \\ a^2 \end{bmatrix} \quad (1.4)$$

which can be written as

$$\begin{bmatrix} I_R \\ I \\ I_B \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} I_{R0} \\ I_{R1} \\ I_{R2} \end{bmatrix} \quad (1.5)$$

The symmetrical component current vector I_s is made up of I_{R0} , I_{R1} and I_{R2} . The symmetrical component transformation matrix is defined as A where,

$$A = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \quad (1.6)$$

$$\text{So in matrix notation, } I = A I_s \quad (1.7)$$

To develop the reverse relation with I_s on LHS, we need to find the inverse of A . As $\det A = 3(a - a^2)$, i.e., $\det A \neq 0$, the A^{-1} is possible and can be obtained as,

$$A^{-1} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \quad (1.8)$$

So we have a reverse relation as

$$I_s = A^{-1} I \quad (1.9)$$

i.e.,

$$\begin{bmatrix} I_{R0} \\ I_{R1} \\ I_{R2} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} I_R \\ I \\ I_B \end{bmatrix} \quad (1.10)$$

Once we obtain I_{R0} , I_{R1} and I_{R2} ; the remaining six components can be calculated by using the properties of the positive, negative and zero sequence sets. In a similar way, relations between phase voltages and sequence voltage components can be written. After these calculations, the further steps depend on the type of the unsymmetrical fault.

1.2 ABNORMALITIES

During certain situations, a power system behaves abnormally. Some of these abnormalities in a generator are unbalanced loading, field failure, overloading, overvoltage, prime-mover failure, pole-slipping, etc.

A transformer may behave abnormally due to over-heating or over-fluxing. An induction motor can run abnormally due to undervoltage, overloading, unbalanced loading, stalling, etc. These abnormalities are dealt with in the chapters of apparatus protection in this book. The sustained abnormal operation of the power system is equally harmful as faults.

1.3 FUNCTIONS OF PROTECTIVE RELAY SCHEMES

Protective relay schemes have to sense a fault and perform the following four broad functions:

1. To operate the correct circuit breakers so as to disconnect only the faulty equipment from the system as quickly as possible, thus minimising the trouble and damage caused by faults when they do occur
2. To operate the correct circuit breakers to isolate the faulty section from the healthy system in case of abnormalities like overloads, unbalance, undervoltage, etc.
3. To clear the fault before the system becomes unstable
4. To identify distinctly as to where the fault has occurred

1.4 MAJOR COMPONENTS OF AN ELECTRICAL POWER SYSTEM

Figure 1.3 shows the major components using the single-line diagram of a typical power system. Electrical power is usually generated at voltages between 11 kV and 22 kV, since this gives the most economical balance between the cost of copper, the cost of insulation and the cost of mechanical strength to resist centrifugal force. This power is then transmitted at a voltage of 132, 220, 400 kV or higher depending on line length and amount of power. For a given amount of power to be delivered, the current is inversely proportional

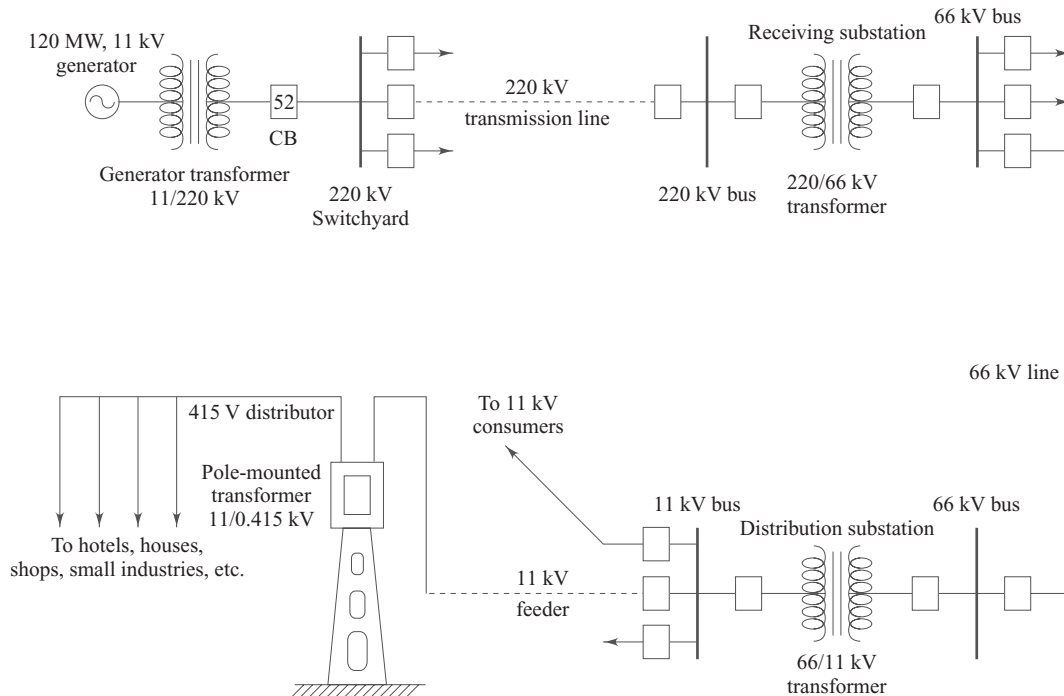


Fig. 1.3 Single-line diagram of a power system

to the voltage of transmission. Thus, higher voltages lead to reduction of conductor size and/or of power loss. Bulk power can be transmitted at higher voltages over a long distance. This power is received by a receiving substation where it is stepped down to a voltage of 66 kV or 132 kV depending on distance of further transmission. The 66 kV transmission line terminates at a distribution substation, where the voltage is stepped down to 11 kV. Emanating 11 kV feeders, then, feed power to 11 kV consumers and pole-mounted transformers in different areas of cities and villages. Pole-mounted transformers step down the voltage to 415 volts for use by the consumers.

The components, shown in Fig. 1.3, are required to be protected in case of faults and abnormalities. Succeeding chapters of this book deal with apparatus protection. In Chapter 5, different protective schemes for generators are discussed. Chapter 6 explains transformer protection. Different methods of protection of transmission lines are described in chapters 7, 8 and 9. Chapter 10 deals with bus-zone protection. Protection of induction motors is explained in Chapter 11.

Different components of the system are isolated by circuit breakers. In case of a fault or abnormality, one or more of electrical quantities (such as current, voltage, phase angle, power, frequency, etc.) will be sensed by relays with the help of transducers (CTs and PTs). The relays will operate as per their characteristics and on their operation, a signal will be transmitted to circuit breakers. The fault or abnormality is said to be cleared when the faulty section is isolated by circuit breakers.

In a power system, there is an economic limit to the amount that can be spent on a protective system. The protective system to be employed depends upon many factors such as probability of occurrence of faults, probability of failure of equipment, importance of equipment, cost of the system or plant, location of plant, etc. However, broadly speaking, the protective gear should not cost more than 5% of the total cost of the plant or the system to be protected. Table 1.4 shows the breakup of costs of protection for typical equipment. As a breaker is needed to manually make or break the transmission line or electrical equipment, its cost is not usually considered under protective gear.

Table 1.4 Percentage cost of a relaying system

Total average cost	100
Relays	0.54%
Relay panels	0.27%
Wiring	0.11%
Relay room	0.12%
Current transformers	3.10%
Potential transformers	1.08%
Total cost of protective gear	5.22%

1.5 BASIC TRIPPING CIRCUIT WITH SYSTEM TRANSDUCERS

Basic connections of a protective relaying system are shown in Fig. 1.4(a). Whenever a fault occurs on a feeder, the current transformer transmits the fault current to current coil of a protective relay. (If the relay is a two-quantity relay, potential transformer transmits the voltage under fault conditions to the potential coil of the relay). The relay operates as per its characteristic and its contacts close. The closure of the contact energises the coil of an auxiliary relay [Fig. 1.4(b)].

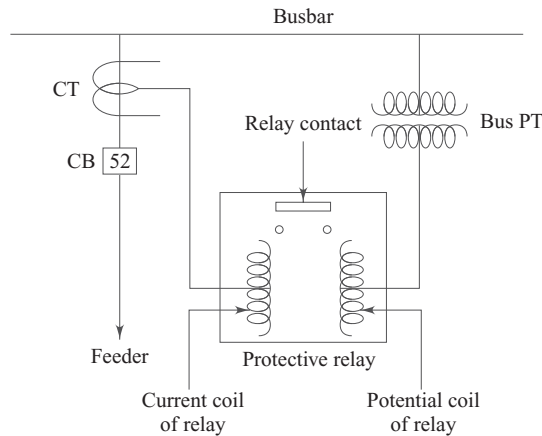


Fig. 1.4(a) An ac circuit

The auxiliary relay is provided for two main reasons. Firstly, if the protective relay contact is required to carry a high trip coil current, it will be required to be sturdy enough and hence the weight of the moving system of the protective relay will increase. This will reduce its sensitivity. Hence, a protective relay is reserved for only sensing the fault and the auxiliary relay contact does the function of carrying the high trip coil current. Secondly, many other functions such as annunciations, alarms, interlocks, etc., are required to be performed when the relay operates. This requires many contacts to be simultaneously operated. A multi-contact auxiliary relay does these functions.

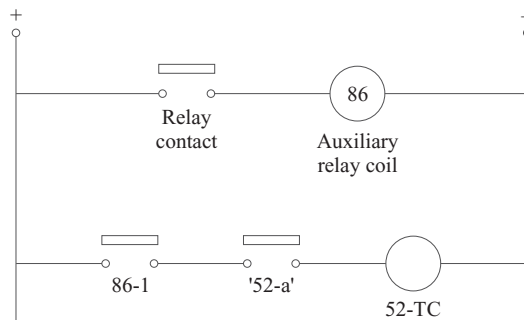


Fig. 1.4(b) A dc control circuit

On operation of the auxiliary relay, the trip coil of a circuit breaker is energised and the breaker trips. Thus, the faulty section is isolated from the rest of the healthy system. The protective relay resets because there is no flow of current through the current coil of the relay. A '52-a' switch is an auxiliary switch provided in the circuit breaker. It is a mechanical switch, which is ON when the circuit breaker is ON and OFF when the circuit breaker is OFF.

The trip coil of a circuit breaker is required to be energised only for a short while. A circuit-breaker tripping takes a time ranging from 1 to 5 cycles. A trip coil is not designed for energising it continuously once the breaker trips. It is possible that auxiliary relay contact may get locked (closed) due to some internal mechanism failure. This would mean a continuous current through the trip coil [refer Fig. 1.4(b)] if no '52-a'

switch of the circuit breaker is provided in the trip circuit. The trip circuit is isolated by a 52-a switch once the breaker trips. This is the reason why “NO (Normally Open)” contact of a 52-a switch is provided in the trip circuit as shown in Fig. 1.4(b).

The elements of Fig. 1.4 (i.e., circuit breaker, CT and PT and protective relay) are said to be components of switchgear. These component, i.e., relays, circuit breakers and transducers (CT and PT) are discussed at length in this book. Chapter 2 gives the constructional features of different types of protective relays of the electromechanical type. Chapter 3 is dedicated to their static equivalents. In Chapter 4, numerical protection using digital signal processors or microprocessors is introduced. Chapter 13 deals with the details of the current transformers and potential transformers used in protective systems. The principles of circuit-breaking, constructional aspects and short-circuit testing of circuit breakers are described in Chapters 14, 15 and 16 respectively. Lightning protection is explained in Chapter 17.

1.6 TESTING AND MAINTENANCE OF RELAYS

The reliability of a relaying system demands that the relays are periodically tested for their integrity. The scheduled maintenance will ensure guarantee for proper functioning of relays. Chapter 12 deals with testing, commissioning and maintenance of relays.

1.7 ZONES OF PROTECTION

Since a power system consists of equipments of varied nature (e.g., generators, transformers, transmission lines, busbars, etc.), it is divided into a number of protective zones, each covering one type of equipment. There will be circuit breakers and relays associated with each zone. The zones of protection are overlapped so that there is no ‘blind’ spot, which is unprotected. The portion, which remains unprotected so that a fault occurring in this portion would not be cleared at all, is known as a ‘blind’ spot. Figure 1.5 gives an idea of overlapping of zones.

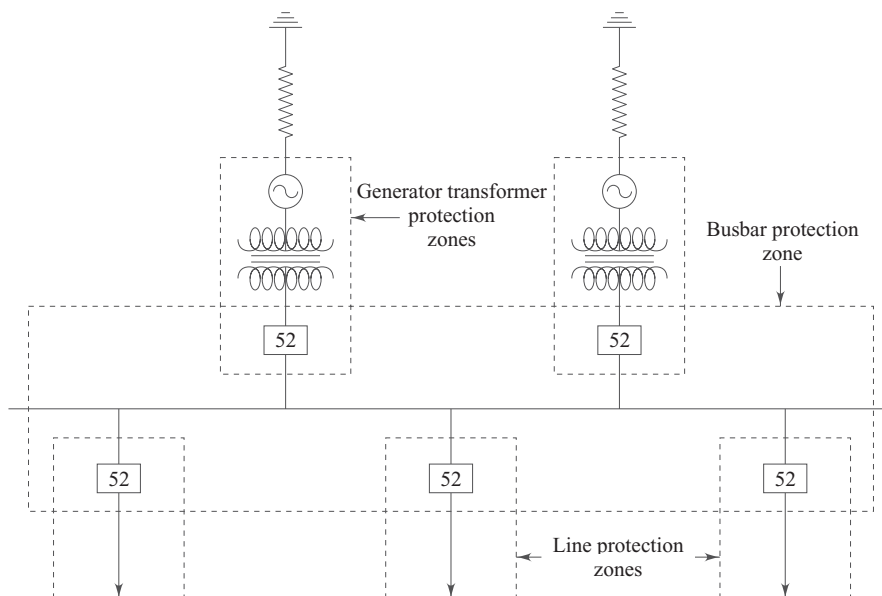


Fig. 1.5 Zones of protection

These zones are decided by locations of current transformers. Figure 1.6 shows how current transformers can be located for overlapping zones as shown in Fig. 1.5. Obviously, for the fault in an overlapped portion, the relays in both the concerned zones will trip isolating a larger portion of the power system unnecessarily. But this has to be accepted to avoid the blind spot, i.e., the unprotected portion.

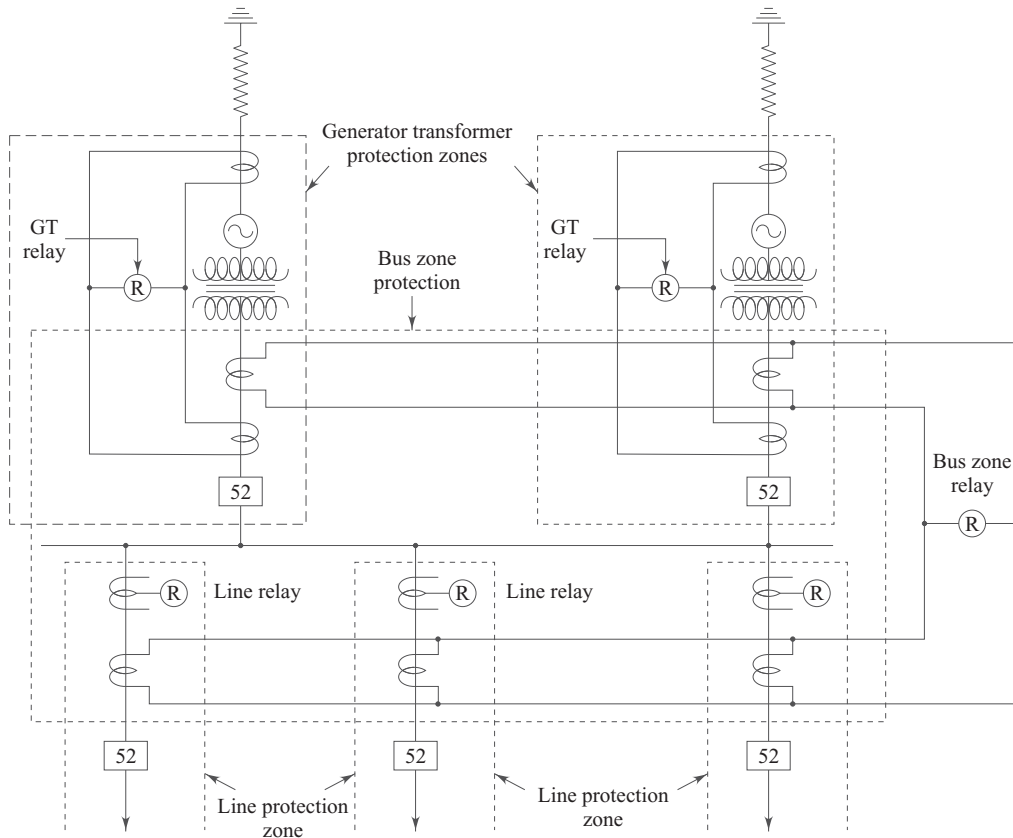


Fig. 1.6 CT locations for overlapping zones

1.8 REQUIREMENTS OF A PROTECTIVE SYSTEM

The following important requirements are to be satisfied by a protective system:

(1) Reliability Reliability depicts the quality of the protective system. Less the probability of failure, better the reliability. Failure can occur in relays, circuit breakers, control circuits and due to erroneous conversion by system transducers. Regular and thorough maintenance of protective equipment, knowledge of personnel operating the system and inherent design features and fabrication make the protective system reliable.

(2) Selectivity Selectivity means isolation of a faulty section exclusively from the rest of the healthy system. Selectivity is absolute if the protection operates for internal faults in any element of the power system. Selectivity is said to be relative if coordinated settings of protective relays of different zones are decided based on certain rules which will be discussed in the relevant chapters of the book. Differential protection can

be said to be absolutely selective, whereas current–time graded overcurrent protection and distance protection are the examples of relative selectivity.

(3) Speed It is obvious that faster the speed of operation of elements of a protective system (relays and breakers), less is the damage to the equipment. As such, the equipments are short-time rated for high fault currents, and, therefore there will be practically no damage to the equipments if the relays and breakers operate fast. The time-setting of the relays has to be decided on the basis of this short-time rating of equipments to be protected.

Another important reason, how the speed can help, can be appreciated by considerations of power system stability. If the faults are not cleared in time (depending on the magnitude of short circuit power), the generators of the power system may go out of step (loose synchronism) and complete shut down of all the generators of the system may occur resulting in total dark-out of power. This is what is called *cascade tripping*. Reference to Fig. 1.7 will make it clear that the shorter the time a fault is allowed to persist, the more a load can be transferred between given points of the power system without loss of synchronism.

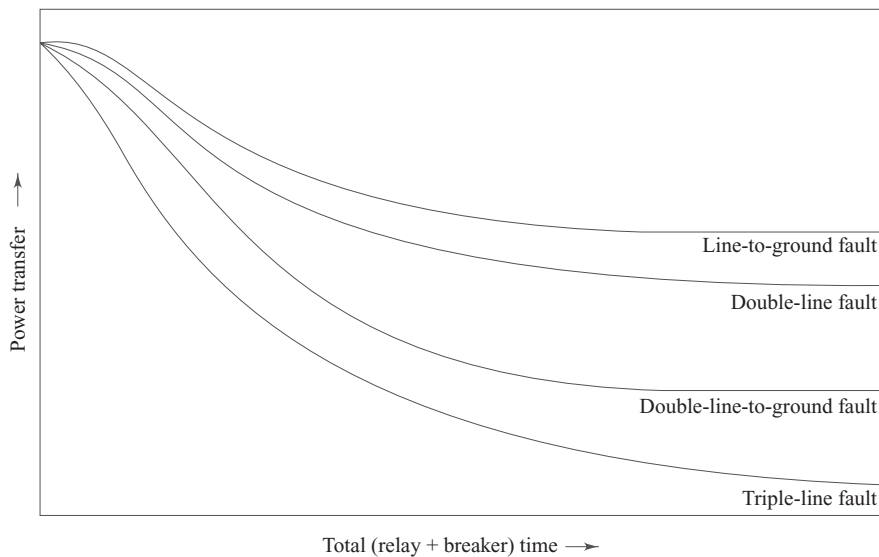


Fig. 1.7 Power transfer during various faults without loss of synchronism

Relays should not be made to operate faster than 5 to 10 milliseconds, as otherwise they may unnecessarily operate due to transient conditions like lightning and switching surges.

(4) Discrimination A protective system should be able to discriminate between fault and load conditions even when the minimum fault current is less than the maximum load current. A fault and an overload, sometimes, look similar to the protective scheme. There must be some methods and means to discriminate between such similar-looking conditions. There are other situations also, where the relay has to be sharp enough to distinguish between the two. The magnetising inrush current at the instant of switching shall not be misinterpreted as an actual internal fault. In modern interconnected systems, conditions like power swings can mislead a distance relay to maloperate while protecting the transmission lines. Further explanation of the techniques of discrimination implemented by various relays is given in respective chapters.

(5) Stability The term stability is often used to describe the quality of a protective system by virtue of which it remains inoperative under specified conditions usually associated with high values of fault currents. Strictly speaking, it is a quality that only unit systems can possess because they are required to remain inoperative under all conditions associated with faults outside their own zones.

(6) Sensitivity Sensitivity refers to the minimum level of fault current at which operation occurs. In other words, it is the fault setting and is usually expressed in operating quantity referred to the primary of a transducer. There is a difference between the sensitivity of a relay and the sensitivity of a protective system. The sensitivity of a relay is expressed as the apparent power in VA required causing its operation; thus a 1-VA relay is more sensitive than a 3-VA relay.

1.9 RELAY OPERATING CRITERIA

Primarily, it seems that a relay should operate when either a current or voltage or power exceeds beyond a certain limit or decreases below a certain limit. Thus, the relay seems to be operating under faulty conditions. But, as such, this is not the only criterion for the relay to operate. The relay criterion is to be so chosen that it should occur only under fault condition against which the relay is designed to protect the power system but should never occur under conditions against which the system does not require interruption.

The relay operating criteria becomes complicated as the relay should operate in faulty conditions and it should not operate when there is no fault. The relay should operate for the faults in its operating zone only and should remain stable for external faults. The relay should operate only for abnormal situation it is called for to operate. The other relays will look after other abnormalities, and the relay in consideration should ignore the other abnormalities barring the only one for which it should be a guard. The relay should not operate even when a certain abnormality, fault or phenomenon looks like a fault. Let us understand the following examples to make the relay operating criteria clearer.

A simple way to protect a circuit is to compare the currents entering and leaving the circuit and make the differential current pass through the relay. Hence any passage of current through the relay indicates diversion of current to the undesired path, i.e., fault. This simple principle soon becomes complicated because of the spill current through the relay in case of non-identical current transformers. This spill current has to be segregated from the relay current due to a minute fault. Moreover, in transformer protection, inrush of magnetising current, which appears on one side of the transformer only would cause relay operation if discriminatory blocking features were not added. Such a blocking feature, called harmonic restraint, sometimes has to be unblocked because harmonics may appear during fault conditions also which demand tripping.

As a second example, in case of generator protection, field failure relay should not operate for either pole slipping conditions or due to power swings. Similarly, a reverse power relay should operate for failure of prime-mover only and not for internal faults in the generator. As a third instance, no relay in any protective system should operate when a potential transformer fuse fails.

We will discuss in detail about the complexity of relay-operating criteria in the succeeding chapters.

1.10 MAIN AND BACK-UP PROTECTION

Main or primary protective schemes are used in the first line of defence. There must be a second line of defence provided by back-up schemes, which will clear the fault if the primary relays or the transducers feeding them or the circuit breakers to which they give the signal to clear the fault, fail to operate for some reasons.

There are three kinds of back-up relaying:

- (a) Relay Back-up** In this relaying scheme, the main relays, their current transformer cores, potential transformer cores, etc. are duplicated. This system of back-up protection is very costly and used only if the equipment to be protected is very costly and important.
- (b) Breaker Back-up** When a feeder breaker fails to trip on a fault, the feeder fault becomes virtually a busbar fault. In breaker back-up scheme, a time-delay relay is operated by the main relay and it is connected to trip all the other breakers on the bus if the proper breaker has not tripped within pre-set time.
- (c) Remote Back-up** Remote back-up is provided by a relay on the next station towards the source. This remote relay will trip in a delayed time if the breaker in the faulty section has not tripped due to some reason. This is the most widely used form of back-up protection.

1.11 EVOLUTION OF PROTECTIVE RELAY TECHNOLOGY

Electromechanical, Static, Microprocessor Based and Numerical Relays

Electromechanical relays have a long history of application. They are rugged and reliable and are still used in power system protection. But as these relays consist of moving parts, there are problems of friction, low torque, high burden and high power consumption for auxiliary mechanism.

With the advent of ICs (Integrated Circuits) and chips, the static protective relays have replaced the electromagnetic relays. They have many advantages such as low burden, precise and complex characteristic and small size. The details of static relays are given in Chapter 3. Static relays, as the second-generation relays, are manufactured as semiconductor devices which incorporate transistors, ICs, capacitors and microprocessors. A static relay has a comparator circuit, which compares two or more voltages and currents and gives an output which is applied to an output relay which finally closes the contact. The performance of static relays is better than electromagnetic relays as they are fast acting, and the accuracy of measurement is better than that of electromagnetic relays.

The evolution of the 'numerical relays' began with the development of microprocessors and digital computers in the early 1960s. During this period, digital computers gradually provided alternatives for dc boards and network analysers that had been in use. The computer-programming based solutions for power system analysis like load-flow analysis, short-circuit studies and stability problems started becoming available. Successful implementation for these problems of power-system provided the motivation for trying out digital computers for protective relaying. Digital computers, during that period, were slower and expensive to be applied to relaying. This did not stop the academic interest of researchers in exploring relaying algorithms for solving problems of power system protection. The pioneering work in this area was carried out by Rockefeller followed by B J Mann and IF Morrison. Then followed the new developments in technology like Large Scale Integration (LSI) and Very Large Scale Integration (VLSI), which resulted in faster processors at lower costs. The modern microprocessor matched with the requirement of speed and economy for implementation of complex algorithms, following which there was enough interest and scope in research and development in the academic as well as industrial community. Most of the earlier applications of computers were offline, but now with the advancement in computer technology, it is increasingly applied to online implementation which includes signal-processing, process control and communication.

Initially, these relays were known as microprocessor-based (dedicated) relays. Following the development of the digital signal processor (DSP), which has many inbuilt features useful for relaying algorithm applications, these relays came to be referred to as *digital relays* or *numerical relays*. These relays are also known as digital

or numerical relays (in general) because their operational characteristics are realised by programming in a microprocessor or a digital signal processor (DSP). These relays have a continuous online self-checking feature that monitors the integrity of their operation even during a no-fault condition. Coupled with this, there are many other advantages in the usage of these relays; viz., flexibility and complicated characteristics which cannot be delivered by their static or electromagnetic equivalents.

The noteworthy development in the area of communication technology for interconnection between microcomputers in a system has also provided a boost in application instances of numerical relays. As a matter of fact, power-system engineers now have a big challenge to integrate protective relaying practices with the advancements in areas like networking, communication and wide area measurements. Chapter 4 of this book highlights the introduction of this latest addition to power-system protection technology.

MULTIPLE CHOICE QUESTIONS

1. The faults occurring actually are mostly
 - (a) L-g faults
 - (b) L-L-g faults
 - (c) L-L faults
 - (d) L-L-L faults
2. Most faults occurring in the field are in
 - (a) switchgears
 - (b) cables
 - (c) CTs and PTs
 - (d) overhead lines
3. A protective scheme comprises of
 - (a) only protective relays
 - (b) only circuit breakers
 - (c) both protective relays and circuit breakers
 - (d) none of the above
4. The burden of an overcurrent relay is helpful in deciding
 - (a) transformation ratio of a CT
 - (b) volt-ampere rating of a CT
 - (c) transformation ratio of a PT
 - (d) volt-ampere rating of a PT
5. Abnormalities generally occur in
 - (a) transformers
 - (b) generators
 - (c) transformers and generators both
 - (d) transmission lines

Electromagnetic Relays

As mentioned in Chapter 1, a protective relay responds to abnormal conditions in an electrical power system by generating a trip signal to the circuit breaker to isolate the faulty section of the system, with minimum possible interruption to service.

This chapter deals with the construction of electromagnetic relays and their characteristics in brief. Though electromagnetic relays are not being installed in newer substations, there are still existing substations, power stations, large industries and distribution networks where these relays are still operational. Moreover, multinational manufacturers continue to manufacture these relays. The major advantages of these relays are their ruggedness and high immunity to voltage spikes due to lightning and switching surges.

2

Introduction

Electromagnetic relays have several disadvantages compared to their static equivalents, e.g., less sensitivity, more maintenance, less life, higher failure rate, larger size of current transformers and potential transformers, large size of their own, etc. The advent of highly complex fabrication techniques, heat sinks, very large-scale integrated circuits, etc., make static relays economically viable when the total cost of protective relaying is considered. Chapter 3 will deal with static equivalents of electromechanical ones. In general,

a relay can be considered as a black box whose inputs are connected to CT and/or PT and/or transducer output and whose output is based on required characteristic using elements that could be electromagnetic, static, microprocessor-based or digital/numerical. In Chapter 4, we will discuss numerical relays.

2.1 CLASSIFICATION OF RELAYS

Protective relays are classified in many ways. Some of the effective ways of classifying them are as follows:

1. Based on the number of operating quantities: Single-quantity (single input) relays, two-quantity (two input) relays or multi-quantity (multi-input) relays; e.g., an overcurrent (i.e., a level detector) is a single-quantity relay, and a differential relay and a distance relay are examples of two input relays.
2. Relays are also classified by the quantity they measure or the functions they perform, e.g., overcurrent relays, over/undervoltage relays, distance relays, directional relays, overfluxing relays, thermal relays, underpower relays, etc.
3. A third classification of relays is by their time of operation; e.g., instantaneous relays, time-delayed relays, inverse time current relays, etc.

4. Relays can also be classified by their constructional features; e.g., attracted armature-type relays, induction disc-type relays, induction cup-type relays, balanced beam-type relays, etc.
5. Relays which use electromagnetic principles in their operations are called electromechanical or electromagnetic relays, ones that use static (electronic) components in their construction are known as static and the relays which use pre-programmed microprocessor and digital circuits are said to be digital or numerical relays.
6. Special function relays such as reinforcing relays, tripping relays, alarm relays, etc.

2.2 THERMAL RELAYS (OVERLOAD RELAYS)

Before discussing thermal relays, the difference between overload and overcurrent needs to be clarified. When the electrical equipment draws more current from the line to which it is connected, the equipment is said to be overloaded. Overload does not mean a fault. When the fault occurs, a current is diverted to an undesired path because of failure of insulation or other abnormal conditions. The current drawn from the line because of such a fault is termed an *overcurrent*. If a transformer rated for 100 A, is loaded by 120 A, it is said to be overloaded. The magnitude of the overcurrent, on the other hand, will be comparatively higher than the overload.

An electrical equipment can withstand overload for many minutes or sometimes for a few hours depending on the magnitude of the overload. Accordingly, the thermal overload relays are required to operate after a longer time as compared to overcurrent relays, which have to operate within a few seconds or even milliseconds.

The term 'thermal relay' may suggest a device which directly measures temperature. More often in fact, it is used to describe a device which measures the heating effect of a current, the temperature measurement being, thus, obtained indirectly.

In earlier times, a simple bimetal strip, thermocouple or RTD, or more complex thermosensitive devices were used. But all these devices take a very long time to reset. Thus, hot restart of an induction motor or hot energising of a transformer or any other electrical equipment was not possible, potentially causing heavy production losses for the end consumer and loss of revenue earned by electricity boards. The improvements to this feature using static relays will be discussed in the relevant chapter.

An important point to be understood and very relevant to protection engineers is matching the thermal relay characteristic with the thermal withstand characteristics of the electrical equipment to be protected. This point will be elaborated in detail in the following chapters.

However, at this juncture, one should be aware that the heat developed by electrical equipment is proportional to I^2Rt , where I is the current, R is the resistance of the winding of the equipment and t is the time for which the current passes. This, in turn, causes further increase in temperature of the winding. Fortunately, heat is also dissipated (naturally, by forced air, by water, by some gas, etc.) and the rate at which it is dissipated is proportional to t_d^4 , where t_d is the temperature differential (temperature reached – ambient temperature). This will stabilise the temperature at a point (value of current) where heat generated equals the heat dissipated. This temperature is known as *equilibrium temperature*. During normal loading of equipment, this equilibrium temperature is well within the temperature withstand value. This withstand temperature depends on the type of insulating material used. When current exceeds 110% of the rated current of the equipment, the equilibrium temperature will exceed the withstand limit of the insulation provided. Certain points are to be understood at this stage:

- (i) The time within which the temperature of the electrical equipment exceeds the temperature withstand limit of the insulation is inversely proportional to the value of the overload.

- (ii) If a graph is drawn for time v/s current with respect to (i), it is an inverse characteristic where the time reduces exponentially. The exponential rate is defined by the time constant τ . A typical curve is shown in Fig. 2.1.

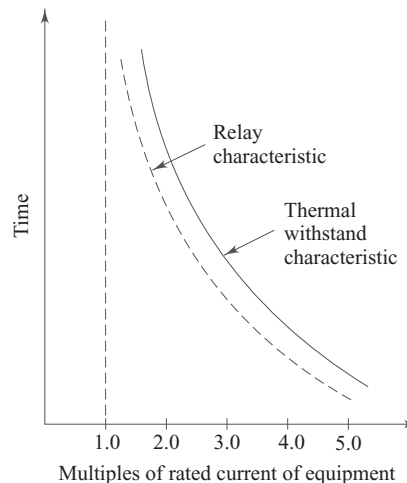


Fig. 2.1 Characteristic of thermal relay

- (iii) The relay is connected across a CT secondary. The relay setting is to be chosen appropriately and the time constant of the relay and that of the electrical equipment should be approximately the same. If so, the temperature of the relay and the temperature of the equipment will be same for a given value of the overload.

The characteristic of the thermal relay and thermal withstand characteristic of the equipment are shown together in Fig. 2.1. The thermal withstand characteristic shows that for a given current, insulation will be damaged after a certain allowable time. Obviously, the relay should isolate the electrical equipment from the source before this time is reached so that the equipment is not damaged further and no fault is developed resulting in saving of a large downtime.

Equally important is that, a margin of around 10% (in terms of time) should be allowed. Too fast tripping is not desirable because 120% or 140% of the rated current can be safely withstood by insulation for about an hour or so. This overload may be transient and may vanish within 15 minutes or half an hour. It is also quite possible that we may have to overload the equipment for a small time deliberately. The relay in such cases should not operate for an allowable withstand time. Hence the characteristic matching curve is as shown in Fig. 2.1.

The relay characteristic is supplied by the manufacturer as time of operation v/s multiples of set value. In Fig. 2.1, the relay characteristic is drawn in terms of the CT primary current.

Thermal relays are used for overload protection of electrical equipments.

2.3 INSTANTANEOUS OVERCURRENT RELAYS

Instantaneous overcurrent relay is one, which has no intentional time-delay. In actual practice there can be no zero time of operation. If a relay operates within 20 to 60 milliseconds, it is said to be an instantaneous overcurrent relay. It is a general practice to define the time of operation of the instantaneous relay at five times the set value.

There can be various forms of construction for instantaneous overcurrent relay; e.g., attracted-armature type, induction-disc type, induction-cup type and reed relay. As these have become outdated, we will discuss only the construction as a static relay.

Drop-off to pick-up ratio of such relays should be more than 90%. Relays having a resetting ratio (drop-off to pick-up) of 97% are available in the market. This ratio should not be 100%, as it would result in chattering at the pick-up current.

In ac applications, when the current passes through zero, a humming sound results in attracted armature-type relay. This is because flux will pass through zero when the current passes through zero. When flux passes through zero, an armature tends to detach, producing a humming sound. But in static relays, as ac is converted to proportional dc, the problem is automatically solved.

Vibrations may cause mal-operation of the electromechanical relays. To avoid this, a slight spring bias is required in electromagnetic relays. This reduces the sensitivity of the relay. Such a problem does not exist in static relays.

Most of the relays are provided with in-built instantaneous overcurrent relay. Instantaneous overcurrent relay by itself alone is rarely used. Instantaneous overcurrent relay is prone to transient overreach. We will elaborate this point in succeeding chapters. The instantaneous overcurrent relays are applied for short-circuit protection of electrical equipment in case of high current values.

2.4 TIME-DELAYED OVERCURRENT RELAYS

The delay in operation of a relay is an important requirement in protection engineering to achieve selectivity and back-up protection. The definite amount of time delay is one type of delaying arrangement, which yields the time-graded system. The time of operation being inversely proportional to the current magnitude is another type of delaying arrangement, i.e., time-current grading.

The various time-delayed relays are covered by the following general equation:

$$t = \frac{k}{(\text{PSM})^n - 1} \quad (2.1)$$

where,

t = time of operation of a relay

$\text{PSM} = (I/I_p)$

I = fault current

I_p = pick-up current

k and n = constants which determine the relay characteristics.

The various types of time-delayed overcurrent relays used in practice are described in succeeding sections.

2.5 DEFINITE-TIME OVERCURRENT RELAYS

The definite-time overcurrent relay operates at the end of a definite set time, once the current exceeds a pre-set value. This pre-set value of the current is termed as *pick up*.

In early days, there were many electromagnetic or electromechanical arrangements prevalent to delay the operation of a relay or drop-off of a relay. With the advent in static (discrete components) methods of time-delay, nowadays, static versions are used. This method will be discussed in Chapter 3.

If $k \rightarrow 0$ and $n \rightarrow 0$ in Eq. 2.1, the definite time characteristics will be obtained. Generally, an instantaneous overcurrent unit is provided as in-built arrangement in the same relay casing. Obviously, the setting range of instantaneous overcurrent unit will be higher. It is a general practice for overcurrent time delayed units to have ranges as follows:

Pick-up setting is in the range of 50–200% of relay rated current (rated current being 1 A or 5 A). Time-setting ranges normally available in the market are

- 0.1–1 s
- 1–10 s
- 3–30 s
- 6–60 s, etc.

The high-set instantaneous unit is provided with a setting range of 400–2000% of the relay rated current. An additional facility to inhibit instantaneous operation is given by setting the instantaneous unit at ∞ (infinite).

The definite-time overcurrent relays find their application for protection of a radial feeder where current grading is not possible and time-grading is required to be employed. These are also used for overload alarm of generators and stalling protection of induction motors. These applications will be dealt with in relevant chapters.

2.6 INVERSE-TIME OVERCURRENT RELAYS

In the inverse-time overcurrent relays, the time of operation of a relay is inversely proportional to the current passing through the relay coil.

The electromagnetic construction is still used and the principle of operation is of induction-disc type. Truly speaking, the construction of analog energy meters and these relays are the same, the difference being that the disc travel in inverse time relays is limited by back-stop on one side and contacts on another. One quantity cannot produce torque, hence split phase or lag coil construction is used.

The CT secondary terminals are brought to the main coil of the relay. The restraining torque is provided by a spiral spring. The constant speed of the disc is due to the damping permanent magnet below which the disc passes. The disc is made spiral to compensate for increasing mechanical torque of the spiral spring.

Ranges of setting are obviously required as the setting may be required to be changed when feeder capacity has to be increased due to more demand. This is done by tappings on the coil. Tappings are brought out such that for any tapping, the whole of active length of the coil is covered so that leakage flux is negligible. Tappings are terminated on a plug setting bridge. Mechanical restraining torque being constant, pick-up current can be varied (as driving torque is proportional to amp-turns) by changing the tappings and hence the number of turns.

When the disc completes its travel (once the current exceeds plug-setting), the moving contacts short the fixed contacts; thus relay operation is complete. Higher the main current, the higher is the driving torque and, consequently, more is the disc-speed, resulting in lesser time of operation. In this way, a relay gives inverse time–current characteristic.

Current setting ranges are available for phase relays as 50–200% of relay rated current, in seven equal steps. For ground relays, the construction is similar to phase relays but ranges are 5–20%, 10–40% and 20–80% (all in seven equal steps). The reason will be discussed in other chapters dealing with equipment protection.

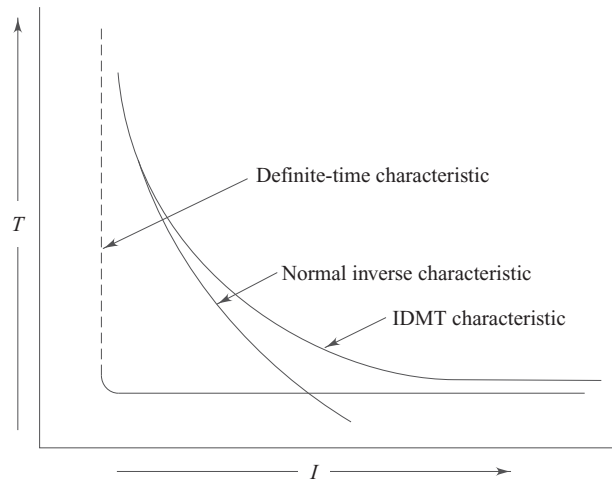


Fig. 2.2 Characteristics of time-delayed overcurrent relays

Figure 2.2 shows three characteristics on the same graph. Normal inverse characteristic follows the equation $It = k$. This causes certain difficulties that will be discussed in Chapter 7. The definite-time-delay characteristic is also shown. The hybrid of the two (which is very useful) is the normal inverse IDMT characteristic. Figure 2.3 shows the internal construction of a typical IDMT overcurrent relay.

In any overcurrent relay, two facilities are common:

- (i) CT shorting arrangement to avoid high voltage being induced in CT secondary and relay coil, thereby the control panel too.
- (ii) Trip-circuit isolation arrangement to avoid tripping of equipment being protected while the relay is being tested periodically.

The glossary of common terms used in conjunction with inverse time overcurrent relays is given as follows:

(1) Plug-Setting (PS) This is given in terms of either ampere or percentage of relay-rated current. Plug-setting is the threshold above which the relay will start operating.

(2) Plug-Setting Multiplier (PSM) The multiple of plug-setting current is known as PSM. The characteristics are plotted usually in terms of operating time v/s PSM.

(3) Time Multiplier Setting (TMS) The operating time for inverse time–current relays is different for different values of the current. The operating time is specified in terms of seconds at 10 times the plug-setting with TMS at 1.0. If a lower time of operation is required, the TMS can be changed. TMS is given in the form of a dial calibrated from 0 to 1.0. The arrangement moves the back-stop of the disc.

(4) Resetting Time The time within which the disc of the relay comes to the normal state from its fully operated state, once the current is discontinued, is known as resetting time. The resetting time is specified for the time dial at 1.0. It should be noted that the term *resetting* indicates the return of the disc to the original position and is different from the term *drop out* (refer glossary).

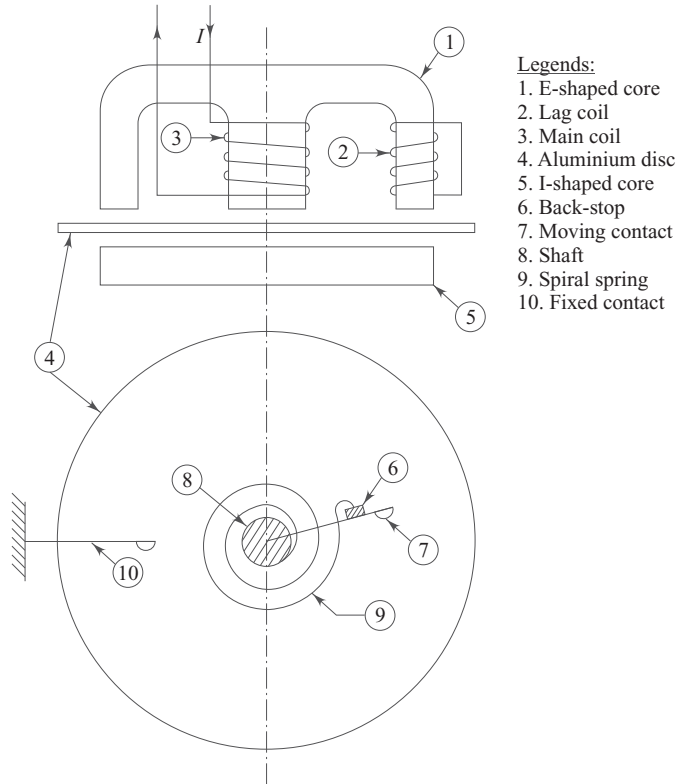


Fig. 2.3 Electromagnetic-type induction disc relay

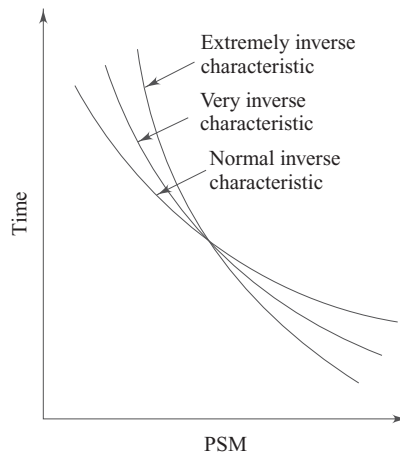


Fig. 2.4 Characteristic curves of inverse-time overcurrent relays

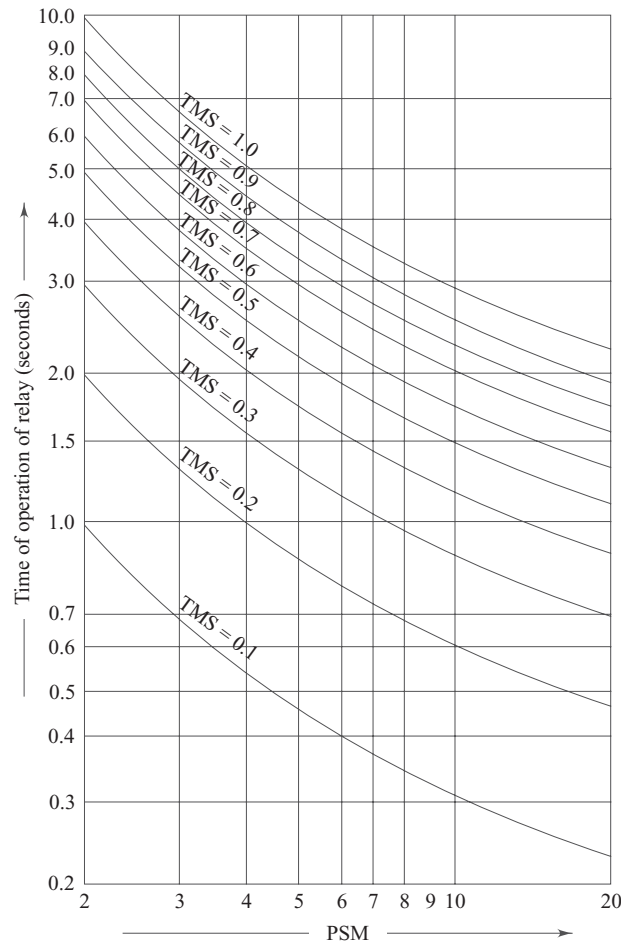


Fig. 2.5 Time-current characteristics of IDMT relay (normal inverse)

(5) Overshoot or Overtravel This is defined as the time to close the contacts at twenty times the plug-setting with maximum disc travel ($TMS = 1.0$) subtracted from the time to reach the point when the current must be shut off in order to prevent the contacts from closing due to momentum of the disc.

Characteristic curves and typical internal-circuit diagram of normal inverse IDMT overcurrent relays are shown in Figs 2.5 and 2.6 respectively.

The time of operation of a normal inverse IDMT overcurrent relay can be calculated by the approximate formula as follows:

$$\text{Time of operation of a relay} = \frac{3}{\log_{10} \text{PSM}} \times \text{TMS}$$

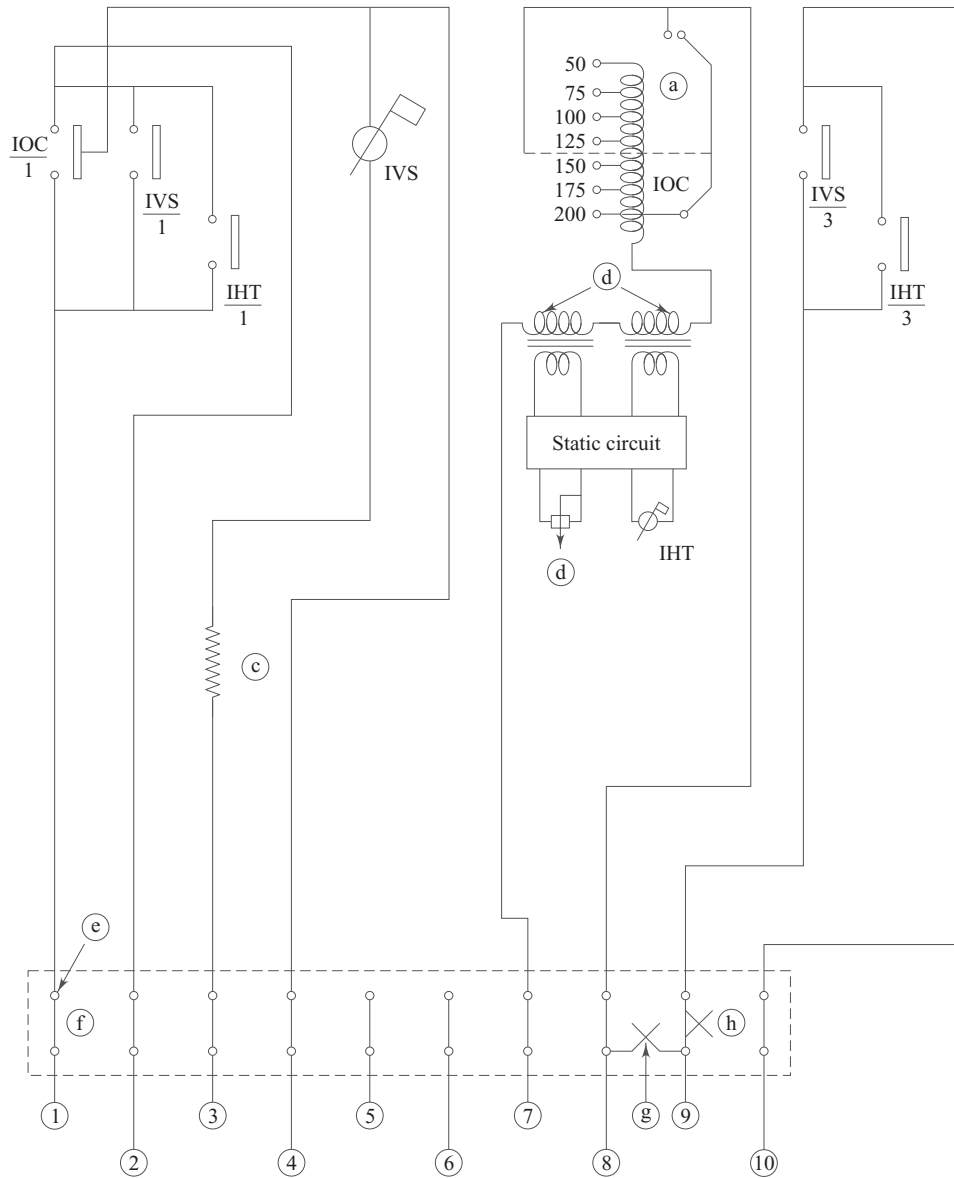


Fig. 2.6 Internal-connection diagram of inverse time overcurrent relay type IOC (Courtesy: V X L Landis and Gyr Ltd.)

Legends for Fig. 2.6

IOC : Main Relay Coil

IOC/1 : Moving contact mounted on disc-shaft

IVS : Auxiliary shunt-reinforcing unit (voltage operated)

IVS/1, IVS/3 : Contacts of IVS unit

IHT : High-set instantaneous unit

IHT/1, IHT/3 : Contacts of high-set unit

- (a) : Maximum tap shorting bar
- (b) : Auxiliary current transformer
- (c) : Internal resistor, if required
- (d) : Setting pot for setting high-set unit
- (e) : Red handle for test switch
- (f) : Test switch for trip isolation
- (g) : CT shorting switch
- (h) : Current test jack

Terminal Designation

- (1), (3) : Auxiliary supply
- (2) : Trip
- (4) : Test
- (7), (8) : Input from current transformer
- (9), (10) : Alarm

Other relays available are as follows:

(i) Very inverse IDMT relays The characteristic of these relays is steeper than that of normal inverse relays (refer Fig. 2.4).

(ii) Extremely inverse IDMT relays The characteristic of such relays is more steeper than very inverse relays (refer Fig. 2.4).

(iii) Non-directional normal inverse self powered IDMT relays These relays are useful in unattended substations (refer Section 2.8).

(iv) Voltage controlled overcurrent relays Refer Section 2.9.

(v) Long time-delay relays (taking 30 seconds at 5 times the plug-setting) It may be used for dual (overcurrent cum overload) purpose.

(vi) 1.3 second normal inverse IDMT relays (Time of operation of the relay is 1.3 seconds at TMS = 1.0 and PSM = 10)

The general equation that covers the standard inverse-type characteristics is given as follows:

$$\text{Time of operation of a relay} = \frac{\beta}{(\text{PSM})^{\alpha} - 1} \times \text{TMS}$$

The value of constants α and β vary for different characteristics. These values are given as follows:

Slope of the time-current curve set	α	β
Normal inverse	0.02	0.14
Very inverse	1.00	13.5
Extremely inverse	2.0	80.0
Long Time inverse	1.00	120.0

2.7 IDMT OVERCURRENT RELAYS

For the relay depicted in Fig. 2.3, the electromagnet gets saturated at high current values. Accordingly, the disc speed does not increase as given by the inverse law. This fact gives rise to a feature known as *Definite Minimum Time* feature, and the characteristic obtained is known as Inverse Definite Minimum Time-lag (IDMT) characteristic (Fig. 2.5).

Figure 2.6 shows an internal connection diagram of a typical IDMT overcurrent relay giving a normal inverse characteristic.

Referring to Fig. 2.2 and Eq. 2.1, $n = 1$ gives the normal inverse characteristic, and the IDMT characteristic can be obtained with $n = 0.02$ and $k = 0.14$.

2.8 NON-DIRECTIONAL NORMAL INVERSE-TIME-OVERCURRENT RELAYS WITHOUT THE NEED OF AUXILIARY SUPPLY

The basic construction and internal-connection diagram of a non-directional, self-powered, normal inverse overcurrent relay is shown in Figures 2.7 and 2.8, respectively. An ac series tripping is used where a reliable dc tripping source is not available. The tripping power in case of these relays is taken from CT secondary.

This unit (IAS) is fitted with a normally closed heavy duty contact. Under normal condition, a CT secondary current is not allowed to pass through the trip coil of the circuit breaker which is bypassed by the NC (Normally Closed) contact of IAS. When the unit operates, the CT secondary current flows through the trip coil and trips the breaker.

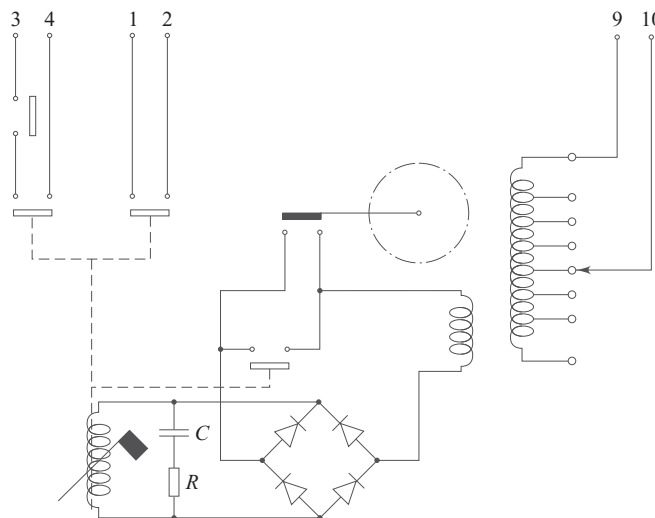


Fig. 2.7 Self-powered IDMT relay (Courtesy: Areva T&D Ltd.)

2.9 VOLTAGE-CONTROLLED INVERSE-TIME OVERCURRENT RELAYS

In case of comparatively smaller sized generators, if a fault occurs, the steady-state current is less than the rated current as synchronous impedance is more than 100%. Under this condition, a simple inverse-time overcurrent relay cannot be used as it cannot be set properly. Instead, the voltage-controlled overcurrent relay

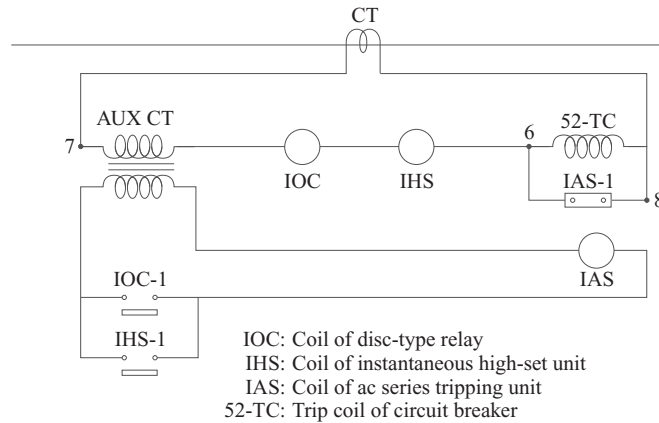


Fig. 2.8 Internal-connection diagram of relay-type IOC-NN

is required to be used in this case. The relay offers two time–current characteristic curves. One curve offers overload protection under normal voltage condition. When a fault occurs, voltage collapses and hence plug-setting changes to 40% of its original value. The time of operation of the relay will, thus, be reduced. The second curve, hence, offers short-circuit protection of a generator.

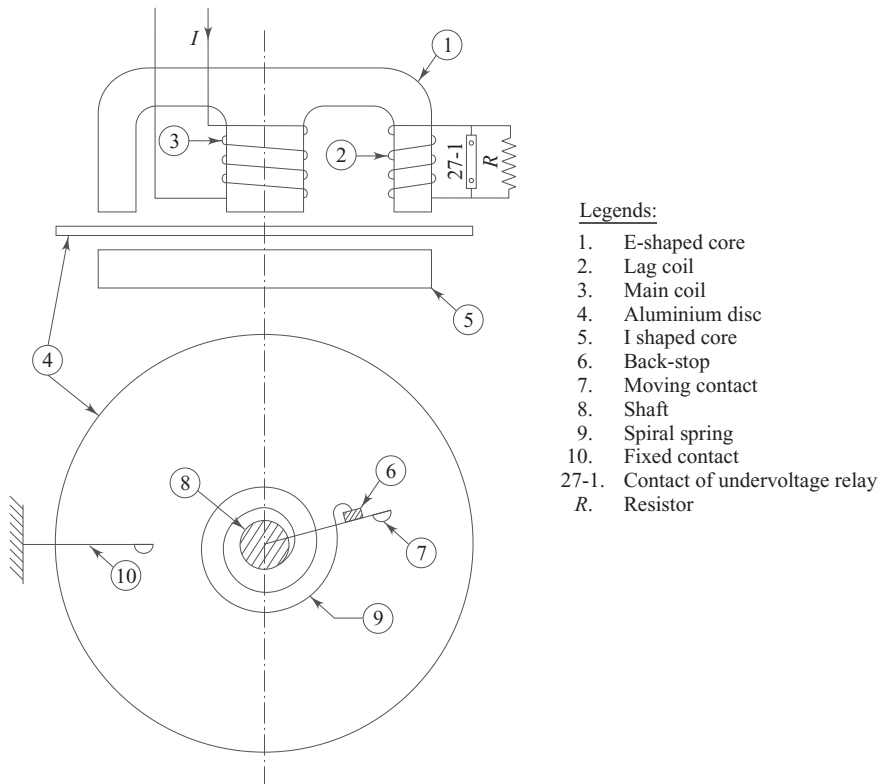


Fig. 2.9 Voltage-controlled inverse time overcurrent relay

General Description

Referring to Fig. 2.9, a non-directional relay with a shading coil is provided. The shading-coil circuit is completed through a resistor which is shorted by the normally closed contact of an instantaneous undervoltage unit incorporated in the same case.

The relay has two operating characteristics, viz., an overload characteristic and a fault characteristic, determined by the operation of the instantaneous undervoltage unit monitoring the generator voltage. Under overload conditions, when the generator voltage is usually near normal, the instantaneous undervoltage unit is usually energised and the short across the resistor in the shading coil circuit is removed (refer Fig. 2.9). The relay operates on a long IDMT or overload characteristic matching the thermal withstand characteristic of a generator. Under fault condition, when the generator voltage falls below the setting of the undervoltage unit, the undervoltage unit is de-energised, the resistor is short-circuited and the torque on the disc is increased by 2.5 times so that the nominal setting currents are 0.4 times of those marked on the plug-board and the relay operates in accordance with the fault characteristic. Both the characteristics of the relay are shown in Fig. 2.10.

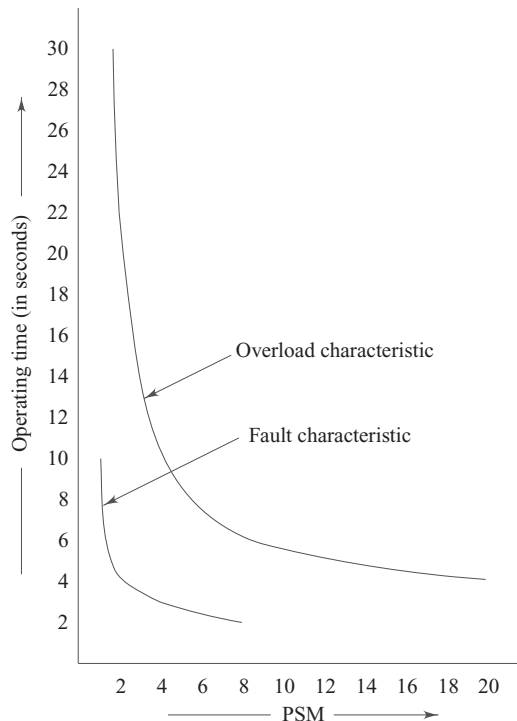


Fig. 2.10 Characteristic of voltage-controlled overcurrent relay

2.10 INDUCTION-CUP RELAYS

The principle of production of torque by induction referred in Section 2.6 can also be used in induction-cup relays. In this case a cylindrical cup replaces a disc. A cup is allowed to move within a 4-pole or 8-pole stator core. As the travel of the moving contact is very small, the induction-cup relays are fast acting. Such a

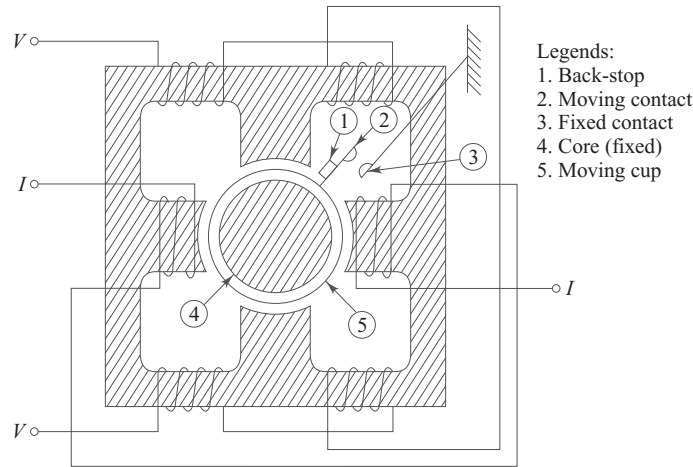


Fig. 2.11 Four-pole induction-cup relay

construction, as shown in Fig. 2.11 is used for realising directional feature in a relay. A detailed treatment for directional relays is given in Section 2.13 of this chapter.

Induction-cup units are used as the in-built elements in directional overcurrent relays (to be discussed in Section 2.14) to give directional control to the relay. These units find application as a phase comparator relay to be discussed in Section 2.12.

2.11 DIFFERENTIAL RELAYS

2.11.1 Circulating Current Differential Protection

Figure 2.12 illustrates the principle of a circulating current differential protection. The principle can be best explained by Kirchhoff's current law. As shown in Fig. 2.12, the currents entering and leaving the equipment to be protected are compared. If these currents are not equal, it means that a third branch has been created and the current equal to the difference of the two currents being compared flows through this third branch, which signifies a fault. The current proportional to this fault-current is made to pass through the relay, which senses the fault current leading to its operation.

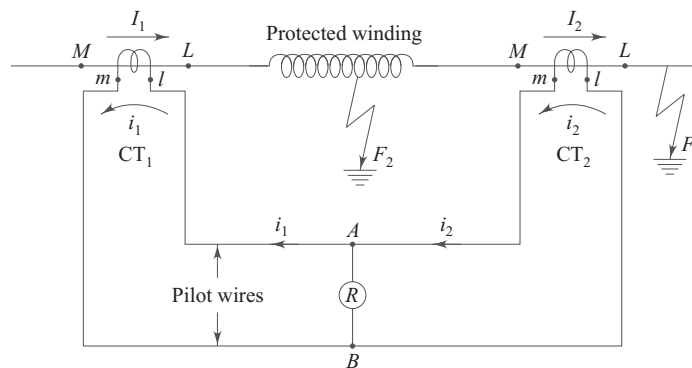


Fig. 2.12 Principle of simple differential relay

Referring to Fig. 2.12, if there is no internal fault, i.e., in normal load condition and external (through) fault (such as at F_1) condition, the currents entering and leaving the protected winding will be same in magnitude and phase relation. Therefore instantaneous values of CT secondary currents, i_1 and i_2 , will be same at all instants. This, obviously, means that the current through the relay ($i_1 - i_2$) will be zero and the relay will not operate. However, for an internal fault, such as at F_2 , the balance of the currents I_1 and I_2 is disturbed, i.e., $I_1 \neq I_2$. Hence $i_1 \neq i_2$ and the differential or spill current ($i_1 - i_2$) will flow through the relay. If this current is higher than the relay pick-up, the relay will operate isolating the protected equipment from the system.

The protected equipment and the current transformers are installed on the turbine floor if it is a generator and in the switchyard in case of a transformer or busbar. The relay is installed in the control room; hence the control wiring is required to be done. These wires are known as pilot wires and the currents i_1 and i_2 are known as circulating pilot currents. The relay is of instantaneous type. The zone of protection extends from CT₁ to CT₂ as shown in Fig. 2.12.

The polarity of CT is very important in differential protection, because otherwise sum of two currents i_1 and i_2 , i.e., $i_1 + i_2$ will flow through the relay. Naturally, the relay will operate under this condition, giving rise to uncalled tripping of the circuit breaker.

The circulating current differential protection is applied for differential protection of generators, restricted earth fault protection of transformer, busbar differential protection and protection of motors. The details of application are discussed in relevant chapters.

2.11.2 Opposed Voltage Differential Protection

Figure 2.13 illustrates the principle of an opposed voltage differential protection scheme. The voltage induced in secondary of CT₁ is proportional to I_1 and that induced in the secondary winding of CT₂ is proportional to I_2 . Hence, the current proportional to $I_1 - I_2$ flows through the operating coils of relays at both the ends. During cases of normal operating condition and external fault (considering identical current transformers on both the sides), the secondary currents of current transformers on two sides oppose each other and their voltages are balanced. Hence, no current flows in pilot wires and relays. During internal fault, however, a spill current proportional to $I_1 - I_2$, which can be proportional to $I_1 + I_2$ should the fault be fed from both the ends, flows through the relay coils and if this is higher than the relay pick-up, the relays operate to isolate the protected equipment from the system.

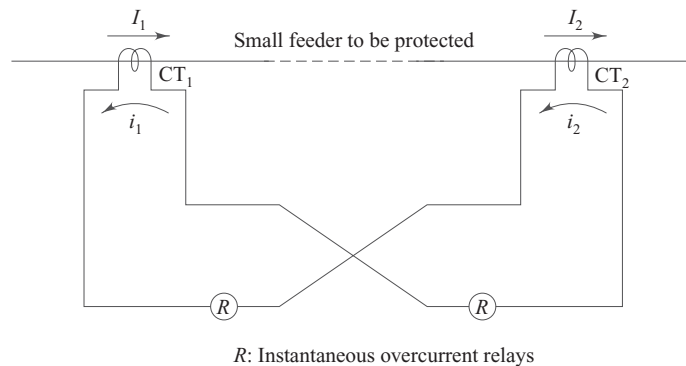


Fig. 2.13 Opposed voltage differential protection

Since no current flows through the secondaries of current transformers under normal operating conditions, the whole of the primary amp-turns are used for exciting the transformers. This creates large flux causing saturation of CTs and inducing high overvoltage, which can damage the insulation of CT secondaries. For this reason, the current transformers used in such protective scheme are coreless or of air-core type. As $\phi = NI/\text{reluctance}$ and as reluctance of air path is high, the flux reduces to a small value even with high primary amp-turns, none of which are balanced by secondary amp-turns in normal condition.

Because the current is zero under normal conditions, this scheme forms a basis for its application in pilot-wire unit protection of feeders.

2.11.3 Biased or Percentage Differential Protection

The protective scheme discussed in Section 2.11.1 gives a perfect discrimination if both the CTs have exactly an identical saturation characteristic. However, in practice it is found that the characteristics of two CTs never coincide exactly even if they are produced by the same manufacturer. This may lead to flowing of a spill current even though the primary currents are equal (no internal fault). If this spill current exceeds the setting of the relay, an undesirable operation may occur. This spill current is especially large for a heavy external (through) fault. One of the methods to avoid the uncalled operation of the relay is to provide a biased differential scheme of protection.

The biased differential relay has two coils. One coil is known as the restraining coil or bias coil, which restrains the operation of the relay. The other coil, the operating coil, produces the operating torque for the relay as already explained in Section 2.11.1. When the operating torque exceeds the restraining torque, the relay operates. The operating coil is connected at the midpoint of the restraining coil as shown in Fig. 2.14. If the restraining coil has N turns, the current i_1 flows through $N/2$ turns and i_2 flows through the other half of the turns $N/2$. As the torque is proportional to the amp-turns and the average amp-turns being equal to

$$\frac{i_1 N}{2} + \frac{i_2 N}{2},$$

the average restraining current will be equal to $(i_1 + i_2)/2$.

The relay has two types of settings. The first setting is known as the basic setting or sensitivity setting. The basic setting is the value of the operating coil current above which the relay can operate. This is often marked in terms of percentage of rated current of a relay. The other setting is termed as the bias setting. Bias setting is defined as the ratio of minimum current through operating coil for causing operation to the average restraining current.

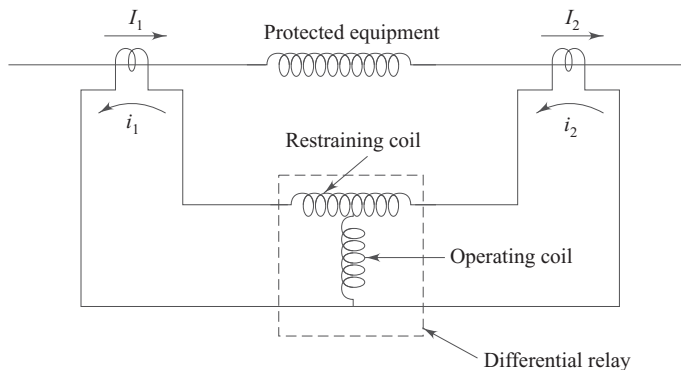


Fig. 2.14 Biased differential relay

i.e.,

$$\% \text{ bias} = \frac{(i_1 - i_2)}{(i_1 + i_2)/2} \times 100$$

If the pick-up ratio $\frac{(i_1 - i_2)}{(i_1 + i_2)/2}$ for a particular case is more than the pre-set bias and the current $(i_1 - i_2)$ is more than the basic setting, the relay will operate. The term *pick up ratio* should not be mixed up with the general term pick-up of a relay. The term pick-up ratio only means that the relay becomes operative if the pick-up ratio is higher than the bias setting. In case of external faults, there can be a high spill current $(i_1 - i_2)$. But $(i_1 + i_2)/2$ will also be high, reducing the pick-up ratio below the bias setting, thus making the relay stable against external faults.

The operating characteristic of such a relay is given in Fig. 2.15. The effect of increased bias setting is to increase the slope of the characteristic. When the pick-up ratio is more than the bias setting, the pick-up ratio point will lie in the positive torque region of Fig. 2.15 and if this ratio is less than the bias setting, the relay will be in the blocking region. Figure 2.15 also shows that for a high through fault, the current $(i_1 - i_2)$ no more remains equal to zero because of CT errors and ambiguity of CT saturation characteristics at this high current, but takes a shape as shown in the figure. The figure makes it clear that the application of the simple differential scheme discussed in Section 2.11.1 cannot be applied in such a case.

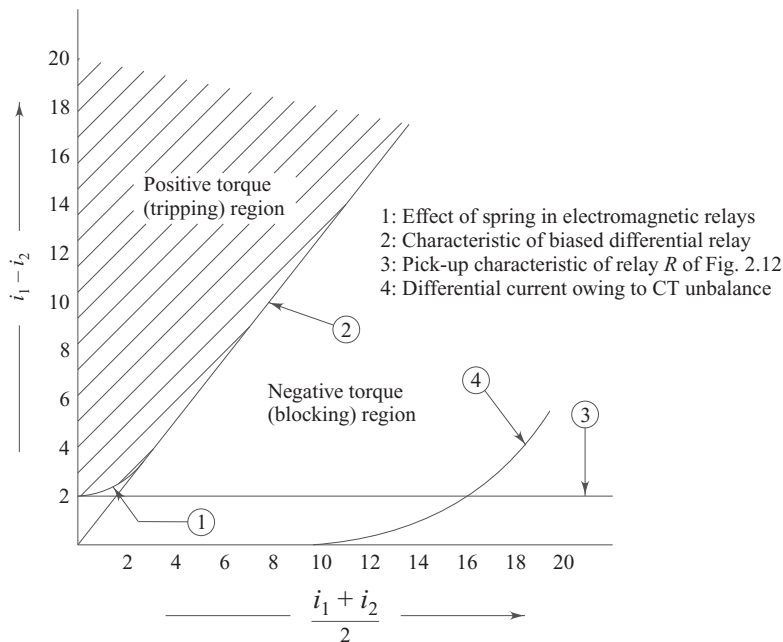


Fig. 2.15 Characteristic of biased differential relay

The biased differential relays are used for the differential protection of large power transformers and generators.

2.12 TWO-INPUT RELAYS

The differential relays described in the previous section represent a two-input relay wherein both the inputs are current-dependent. However, the majority of two-input relays are fed with quantities which constitute a mixture of voltage and current at the relaying point.

The two-input relays can be broadly classified into two categories: viz., amplitude comparator and phase comparator.

A two-input comparator relay which compares the magnitude of two quantities is known as amplitude comparator and a comparator relay that measures the phase relationship between two quantities is known as a phase comparator. Examples of amplitude comparators are a biased differential relay and an impedance relay. Examples of phase comparators are a directional relay and a reverse power relay.

In general, the amplitude comparators have a threshold set at a ratio equal to unity while the phase comparators have a threshold at a phase difference between two quantities equal to 90° . For the threshold condition, a duality between an amplitude comparator and a phase comparator exists. An inherent amplitude comparator of this type can be converted into a phase comparator at 90° and vice-versa if the input quantities are changed to the sum and difference of the original two input quantities.

Consider an amplitude comparator, which compares the magnitude of two quantities. Now if we feed the quantities $(KI + V)$ and $(KI - V)$ to this comparator, it will become a phase comparator measuring the phase relation between KI and V , irrespective of the magnitude of KI and V . This is shown in Figs 2.16(a), 2.16(b) and 2.16(c). Similarly, a phase comparator can become an amplitude comparator [Figs 2.17(a) to (c)].

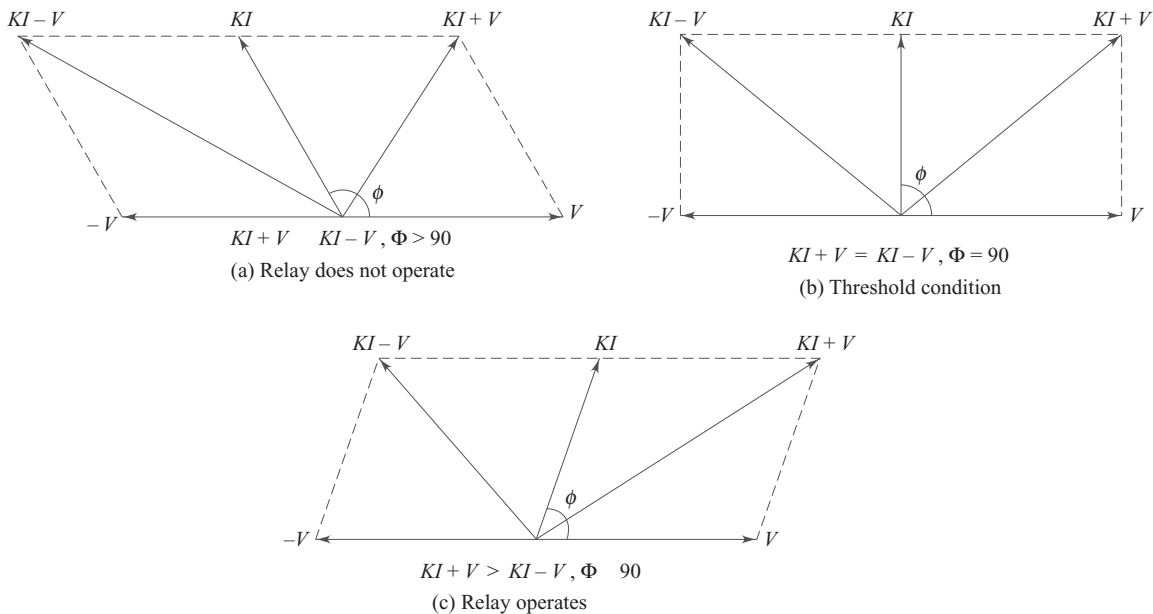


Fig. 2.16 An amplitude comparator as a phase comparator

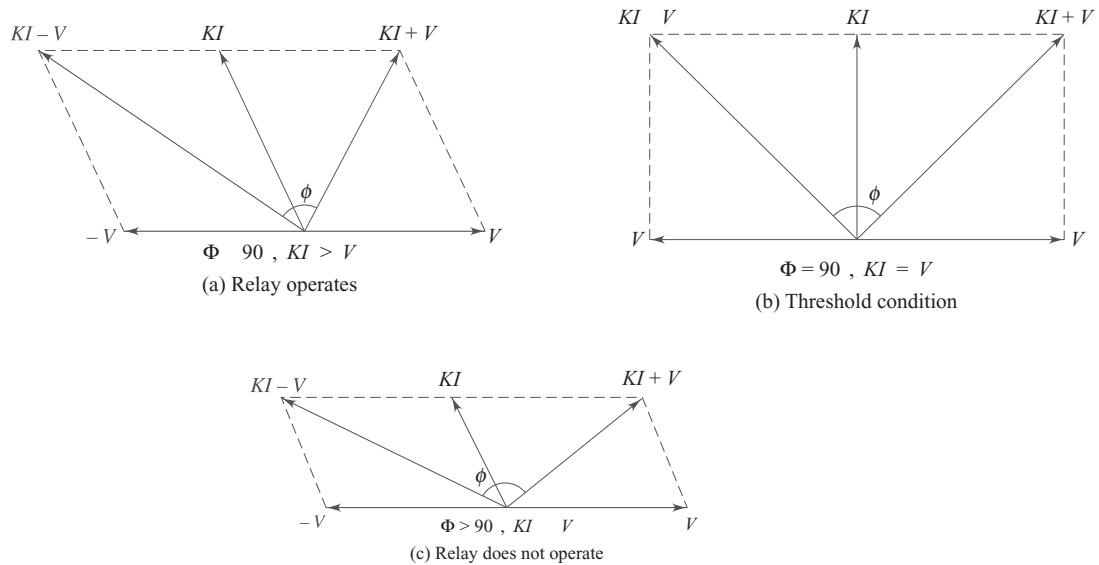


Fig. 2.17 A phase comparator as an amplitude comparator

The two-inputs fed to the relay are obtained from a suitable combination of the two quantities, usually current and voltage, at the relay point. Various combinations will yield relays with various protective zones (relay characteristics).

These characteristics are usually represented on a R -plane where the current is considered to lie on the horizontal axis (or R axis) and the voltage will be represented by different radii emanating from the origin.

If the current taken as the reference is considered to lie along the horizontal line, a point on this line would represent a voltage drop in a resistance. Similarly, the vertical line through the origin represents a voltage drop in a reactance and any other radius would represent a voltage drop in impedance. This plane is, therefore, called the R -plane or the impedance plane. If per unit value of the current is considered to flow, the point on this plane, would represent impedance.

Instead of current, if voltage is taken as a reference, the representation in the admittance plane is achieved.

Two input relays, most frequently used in practice, will be discussed in succeeding sections.

2.13 DIRECTIONAL RELAYS

Non-directional relays discussed in foregoing sections operate or start operating when the current exceeds plug-setting or pick-up, irrespective of the direction of flow of current. It is an amplitude comparator. Electrical driving torque is compared with the fixed mechanical torque of spring.

But in many applications, current and/or time are not sufficient to discriminate between faults in two different sections. Then it will be essential to add the third discriminating dimension which is the direction. Bus voltage being a reference, the direction of current is compared with voltage.

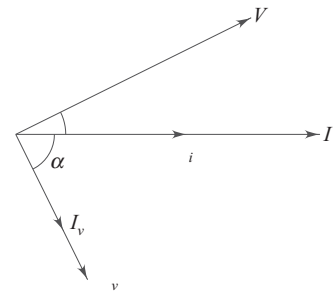


Fig. 2.18 Phasor diagram

This construction is known as induction cup structure (refer Section 2.10). The principle is same as that of an induction disc relay.

The vector diagram (Fig. 2.18) of a directional relay can be drawn as shown.

$$\begin{aligned} \text{Torque can be expressed as } T &\propto \phi_i \phi_v \sin \alpha \\ \text{But as } \phi_i &\propto I, \quad \phi_v \propto I_v \quad \text{and} \quad I_v \propto V \\ T &\propto VI \sin (90^\circ - \phi) \\ T &\propto VI \cos \phi \end{aligned}$$

The characteristic representing this torque is drawn in Fig. 2.19.

Maximum torque angle $\theta = 0$ in this case. If angle ϕ is less than $+90^\circ$ and more than -90° , the torque will be positive. Also, as the angle between V and I decreases, torque increases. For the angle ϕ more than $+90^\circ$ and less than -90° , $\cos \phi$ will be negative and the cup will rotate in the negative direction, the movement being hindered by backstop. Thus, this relay measures the angle between V and I , irrespective of the magnitudes of V and I . This does not mean that V and I are not important. At the time of fault, a fault current is enough but the value of the voltage depends upon the location of fault. The actuating mechanism of the relay has to compensate for frictional torque and slight spring bias (to avoid mal-operation due to vibration in case of electromechanical relays). Thus, only some minimum amount of torque is required in this compensation. A certain minimum value of voltage (and hence a certain minimum distance of fault from the relay) is thus required (for each angle ϕ between V and I) to just operate the relay. The relay does not operate if the fault occurs up to this distance even if the direction is correct. This region is known as *dead zone*.

The $-$ axis of Fig. 2.19 is known as zero torque line as the angle Φ between V and I is 90° .

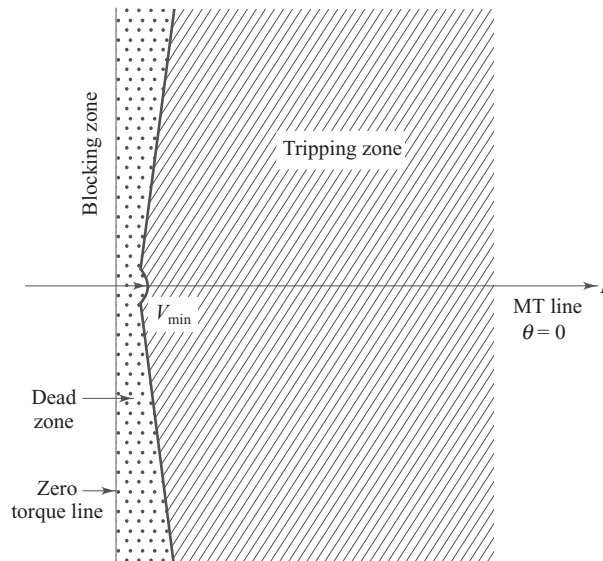


Fig. 2.19 Characteristic of directional relay

As $\cos 90^\circ = 0$, the torque exerted on the cup is zero. At $\phi = 0$ (i.e., phase difference between V and I equal to θ or 0 in Fig. 2.19), $\cos \phi = \cos 0 = 1$ and hence maximum torque is exerted on cup. Thus this line (at which $\phi = 0$) is known as maximum torque line (MT line).

As such, the characteristic angle or MTA (Maximum Torque Angle) θ equal to zero has no meaning. When a fault occurs the angle between V and I varies between 70° to 90° depending on the fault location. Hence directional relays should be designed for MTA equal to this angle (decided based on the relay location from source). The torque in this case will be, $T \propto VI \cos(\phi - \theta)$, where θ is the maximum torque angle. Further discussion of this interesting application aspect is reserved for Chapter 7 of this book.

2.14 DIRECTIONAL OVERCURRENT RELAYS

Directional overcurrent relays are a combination of directional and overcurrent relay units in the same enclosing case. *Directional Control* is a design feature that is highly desirable for this type of a relay. With this feature, an overcurrent unit is inoperative, no matter how large the current may be, unless the contacts of the directional unit are closed. This can be easily accomplished by connecting the directional unit contacts in series with the lag coil as shown in Fig. 2.20. When the lag coil is open (directional contacts not operated), no operating torque is developed in the overcurrent unit.

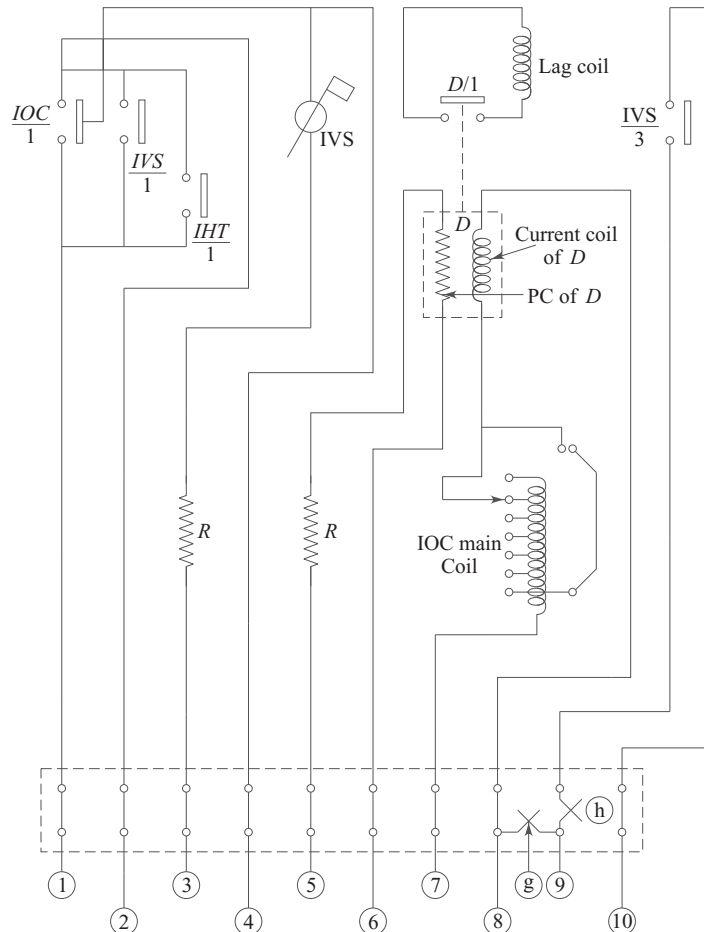


Fig. 2.20 Directional overcurrent relay-type IDP-IN (Courtesy: VXL Landis and Gyr Ltd.)

2.15 IMPEDANCE RELAYS

Impedance relay compares the local current with the local voltage and operates if the ratio of the measured voltage to current (i.e., impedance) is less than the set impedance, K . This is illustrated in Fig. 2.21. The origin represents the relaying point.

The line to be protected is shown at an angle Φ with the R axis; Φ depends upon R/X ratio of the system.

From the definition of the impedance relay, it can be easily appreciated that the impedance characteristic will be a circle of radius K with the origin at O of the R axis.

Impedance relay as an amplitude comparator compares KI with V as shown in Fig. 2.22. In threshold condition, $V = KI$. If $V < KI$, relay operates and if $V > KI$, relay blocks (V and I are voltage and current respectively at a relay point). KI is the operating quantity and V is the restraining quantity.

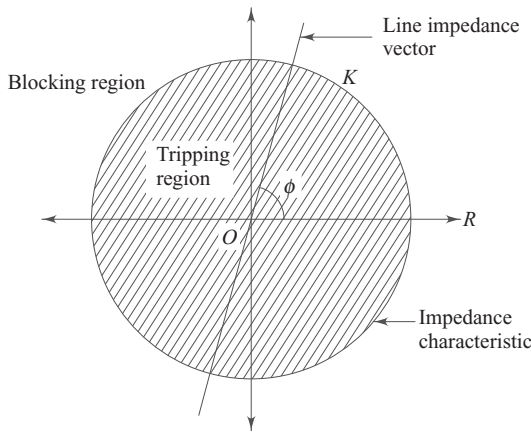


Fig. 2.21 Impedance characteristic

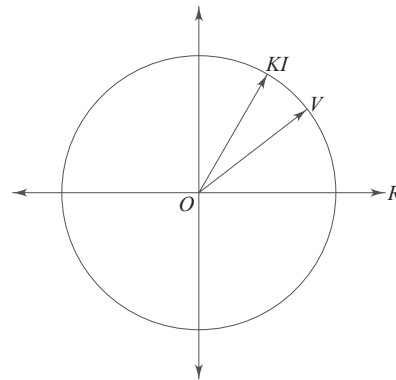


Fig. 2.22 Amplitude comparator impedance relay

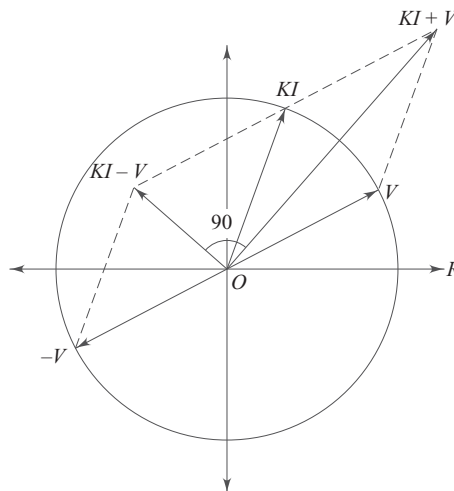


Fig. 2.23 Phase comparator impedance relay

A phase comparator impedance relay compares $\overline{KI} + \overline{V}$ and $\overline{KI} - \overline{V}$. In the threshold condition, the phase angle between $\overline{KI} + \overline{V}$ and $\overline{KI} - \overline{V}$ is 90° as shown in Fig. 2.23. The relay operates if this angle is less than 90° and blocks for the angle greater than 90° .

2.16 REACTANCE RELAYS

Reactance relay measures the reactance of the line to be protected and operates if the measured reactance is less than the set reactance K , as shown in Fig. 2.24.

The relay characteristic obviously will be a horizontal line $X = K$ (Fig. 2.24).

The input quantities for an amplitude comparator are $(2KI - V)$ and V . In the threshold condition (Fig. 2.25), $2KI - V = V$. For $2KI - V < V$ the relay blocks and for $2KI - V > V$ the relay operates. $(2KI - V)$ is the operating quantity and V is the restraining quantity.

The reactance relay as a phase comparator measures the phase angle between $\overline{KI} - \overline{V}$ and \overline{KI} . If the phase angle between the said quantities is less than 90° , the relay operates. Figure 2.26 shows the threshold condition (phase angle = 90°). The vector KI (or vector K) is at an angle of 90° to the R axis. This angle is said to be the characteristic angle of the relay.

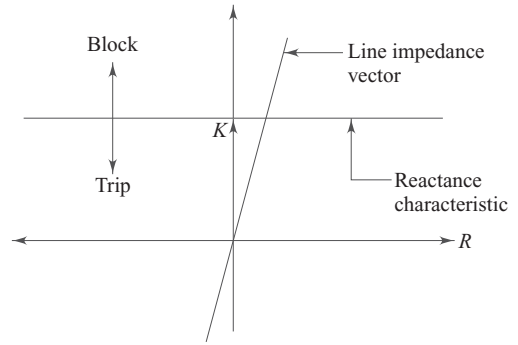


Fig. 2.24 Reactance characteristic

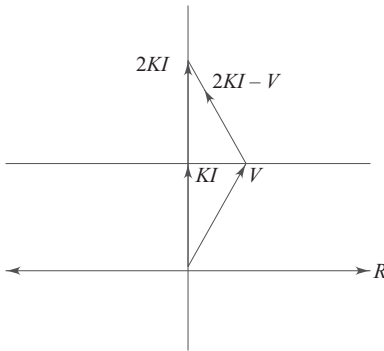


Fig. 2.25 $|2KI - V| = |V|$ for threshold condition

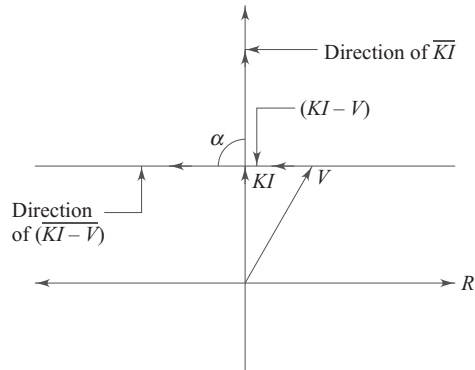


Fig. 2.26 $\alpha = 90^\circ$ for threshold condition

2.17 OHM RELAYS

A relay which measures a particular component $Z \angle \theta$, of a line impedance vector Z , (Fig. 2.27) is known as an ohm relay. It is also called an angle impedance relay. The characteristic angle of the relay is, thus, θ degrees as shown in Fig. 2.27.

Ohm characteristic (Fig. 2.27) is a modified reactance characteristic with a characteristic angle θ instead of 90° .

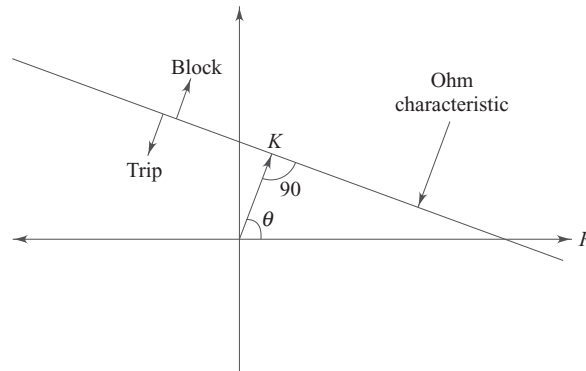


Fig. 2.27 Ohm characteristic

The input quantities to be fed to the the amplitude comparator or phase comparator acting as an ohm relay are the same as those described in reactance relay because the ohm relay is just a modified reactance relay.

2.18 MHO RELAYS

A relay which measures component $\angle \theta$ of a line admittance vector is defined as a mho relay. Angle admittance relay is the alternative name given to this relay.

The relay has a circular characteristic (Fig. 2.28) with the circle passing through the origin of the R axis and its diameter making an angle θ with R axis, where θ is the designed characteristic angle of the relay.

An amplitude comparator mho relay compares magnitudes of input quantities $(2V - KI)$ and KI , and operates if $KI > 2V - KI$. Figure 2.29 shows the threshold condition.

As a phase comparator, the mho relay is fed with quantities $(KI - V)$ and V . In the threshold condition, the phase angle between $(KI - V)$ and V is 90° (Fig. 2.30). The geometrical treatment, which yields a clear physical picture, is given in the foregoing paragraphs.

The various characteristics described in sub-sections 2.15 to 2.18 find their application in distance protection of transmission line. As an illustrative example, the principle of impedance relay to a transmission line in the distance scheme of protection is explained as follows.

Referring to Fig. 2.31, when it is desired to protect a line as shown, the relay will measure the voltage equal to KI drop and the current I , K being the set impedance.

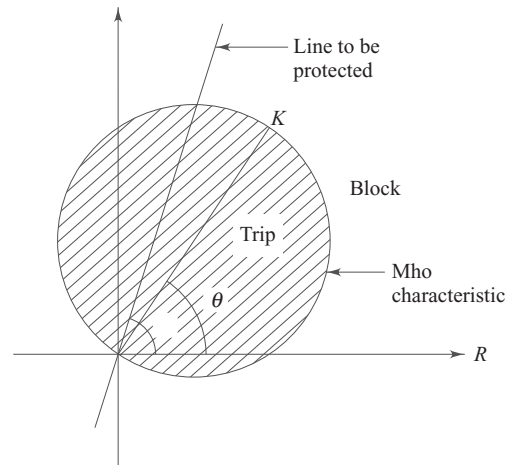


Fig. 2.28 Mho characteristic

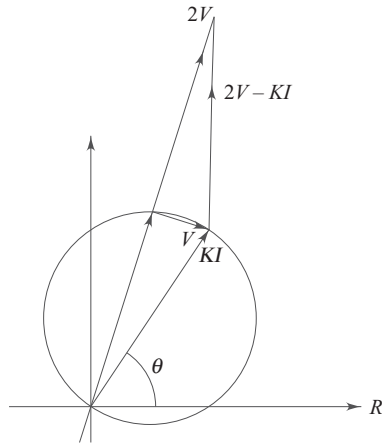


Fig. 2.29 $|2V - KI| = |KI|$, for threshold condition

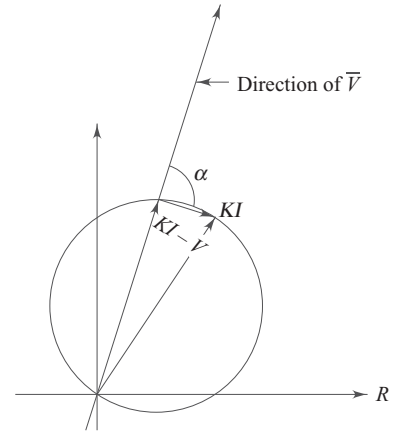


Fig. 2.30 $\alpha = 90^\circ$, for threshold condition

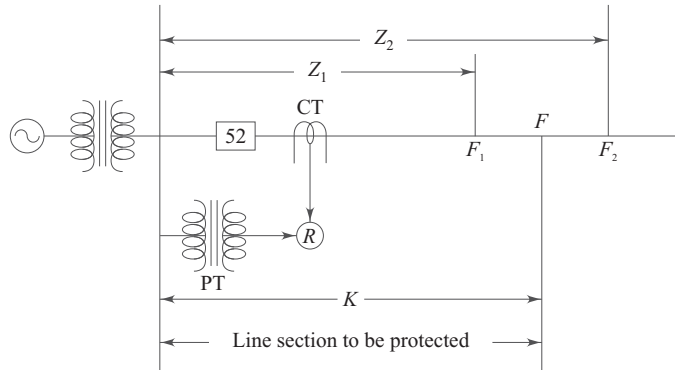


Fig. 2.31 The principle of application of an impedance relay

The relay is so designed that it will measure the ratio of voltage to current and will operate when the measured ratio is less than the set impedance. The ratio of voltage to current is impedance and as the impedance is proportional to the line length, i.e., distance of fault from relaying point, the relay is termed as a distance relay.

For a threshold case, when a fault occurs at F ,

$$V = KI$$

and

$$\frac{V}{I} = K$$

For a fault at F_1 within the zone to be protected,

$$V_1 = I_1 Z_1$$

i.e.,

$$Z_1 = \frac{V_1}{I_1} = K$$

Hence the relay operates. For an external fault, such as at F_2 ,

$$V_2 = I_2 Z_2$$

or

$$Z_2 = \frac{V_2}{I_2} > K$$

Accordingly, the relay blocks. This simple principle of a distance relay is explained graphically in Fig. 2.32.

A special two-input relay, which is usually employed in field failure and power swing blocking is a modification of the mho relay where the characteristic does not pass through the origin. This characteristic is known as the offset mho characteristic (Fig. 2.33) and the relay is known as the offset mho relay.

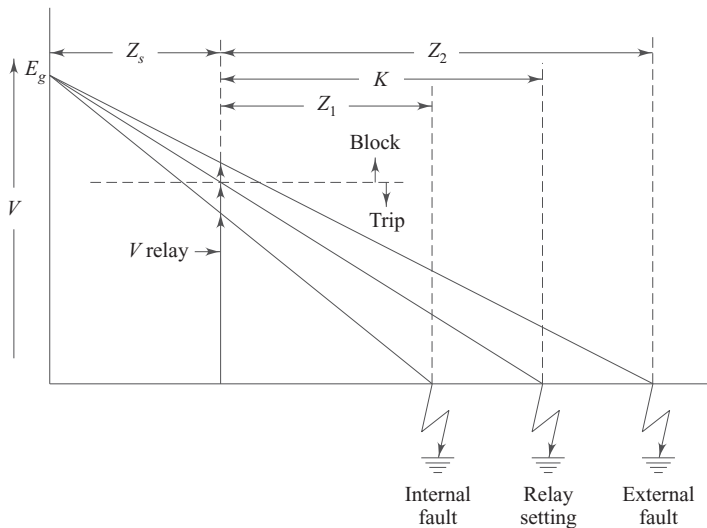


Fig. 2.32 Graphical representation of Fig. 2.31

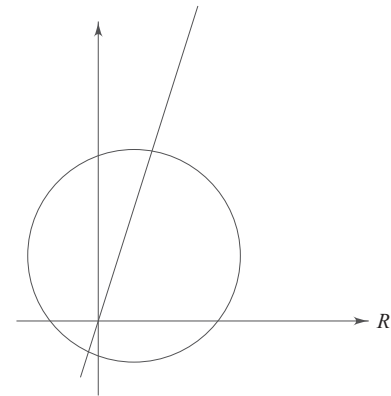


Fig. 2.33 Offset mho characteristic

Further details of application of different two-input relays will be dealt with in succeeding chapters of apparatus protection.

Input quantities for different types of relays used as amplitude comparators and phase comparators are tabulated in Tables 2.1 and 2.2, respectively.

Table 2.1 Amplitude comparators

Sr. No.	Type of Relay	Input Quantities	
		Quantity 1	Quantity 2
1.	Directional	$KI + V$	$KI - V$
2.	Impedance	KI	V
3.	Mho	KI	$2V - KI$
4.	Ohm	$2KI - V$	V
5.	Reactance	$2KI - V$	V

Table 2.2 Phase comparators

Sr. No.	Type of Relay	Input Quantities	
		Quantity 1	Quantity 2
1.	Directional	KI	V
2.	Impedance	$KI + V$	$KI - V$
3.	Mho	$KI - V$	V
4.	Ohm	$KI - V$	KI
5.	Reactance	$KI - V$	KI

2.19 AUXILIARY RELAYS

The relays discussed in previous sections were measuring relays. There are other auxiliary relays required in the protective schemes of different equipment of a power system.

2.19.1 Tripping Relays

These are auxiliary relays provided as independent units to coordinate the tripping outputs of a number of protective relays. The functions of a tripping relay are

1. To multiply the number of available contacts of the protective scheme where more than one circuit breaker has to be tripped. More tripping contacts are also required for functions like control, alarm, annunciation, etc.
2. To increase the rating of tripping contacts
3. To relieve the measuring relay from the duty of tripping a circuit breaker

A tripping relay must be reliable because of its central controlling position. It should also be fast, since its operating time adds to that of the measuring relays.

Most tripping relays are of the attracted-armature type. High-speed operation is obtained by using light moving parts and short travel.

2.19.2 Time-Lag Relays

Time-lag relays are required in conjunction with overcurrent relays in time-graded discriminative protection of radial feeders for medium voltage distribution networks. They can also be used in conjunction with control and alarm functions where time-lag is required allowing for completion of certain sequence of operation. Moreover, time-lag relays are employed in conjunction with protective relays where a waiting period is required to allow for transients to die down.

Time delay can be provided by several means. A short delay can be given to an attracted-armature type relay by a slug. Slug is a solid copper cylinder fitted over a portion of the core. A delay in pick-up of 0.05 second is readily obtained. Drop-off delays of the order of 0.1 to 3 seconds can be obtained by the same technique.

Drop-off time lags can also be obtained by providing a diode across the coil to provide a path for inductive discharge current. $R-C$ circuits can also be used.

Time delays can also be provided by an actuating mechanism.

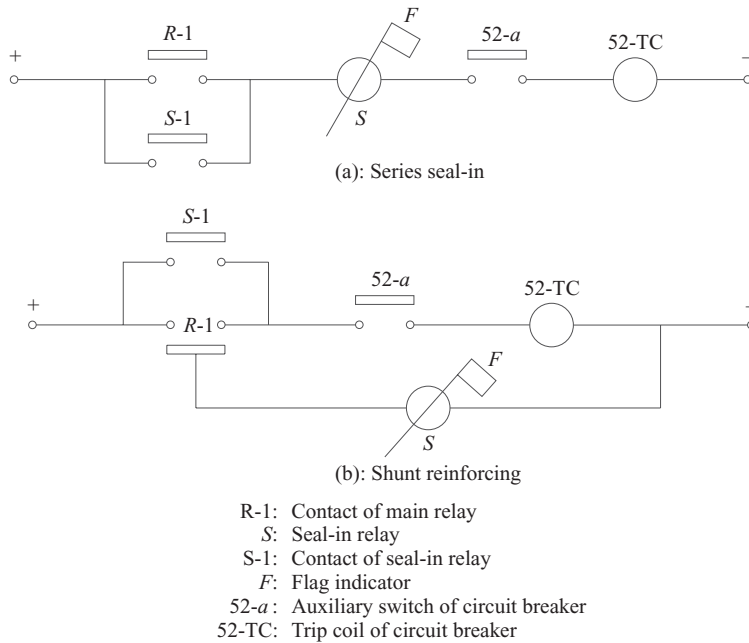
2.19.3 Repeat Contactors

Repeat contactors are used to increase the contact capacity of the main protective relay. There are two arrangements in common use.

Shunt reinforcing repeat contactors relieve, to a great extent, the measuring protective relay contacts from carrying the trip coil current. Here, the de-energisation of protective relay drops off the reinforcing contactor (relay) also.

Series seal-in contactors carry out the same function as the former, but in this case the de-energisation of a repeating relay is brought about only after opening of the circuit breaker.

Both the arrangements are shown in Figs 2.34(a) and 2.34(b).



Note: Auxiliary switch operates in conjunction with the circuit breaker.
52-a closes when breaker closes and opens when the breaker opens.

Fig. 2.34 Repeat contactors

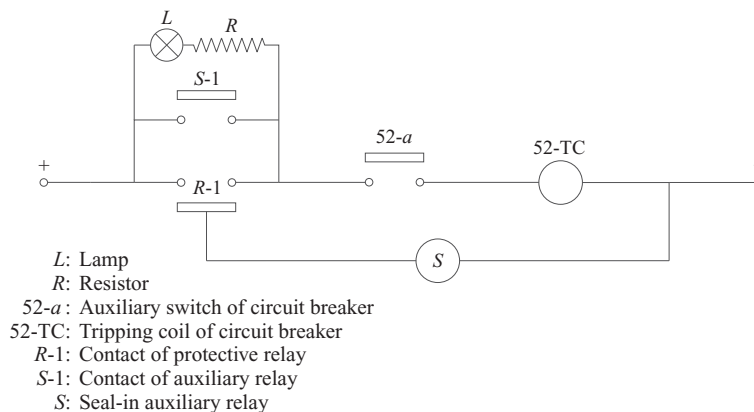


Fig. 2.35 Simple arrangement of trip circuit supervision

2.19.4 Trip Circuit Supervision

A trip circuit, which normally remains in de-energised condition, leads to the necessity of establishing a continuous check on its integrity.

The simplest arrangement is the healthy trip lamp connected across the contacts of a protective relay. The lamp in series with the resistive element is lit by a small current, which is not sufficient to cause the operation of the circuit breaker although circulated through the trip coil while the circuit breaker is closed (refer Fig. 2.35). The lamp can be replaced by a relay to give a remote indication and an audible alarm. However, this scheme does not give indication of the healthiness of the trip circuit when the circuit breaker is open.

A more comprehensive scheme is shown in Fig. 2.36. Relays *A* and *B* will operate in series and both must reset to drop out the relay *C*. The latter has a short time lag on drop-out to cover transient conditions. Supervision is, thus, maintained continuously whether the circuit breaker is open or closed.

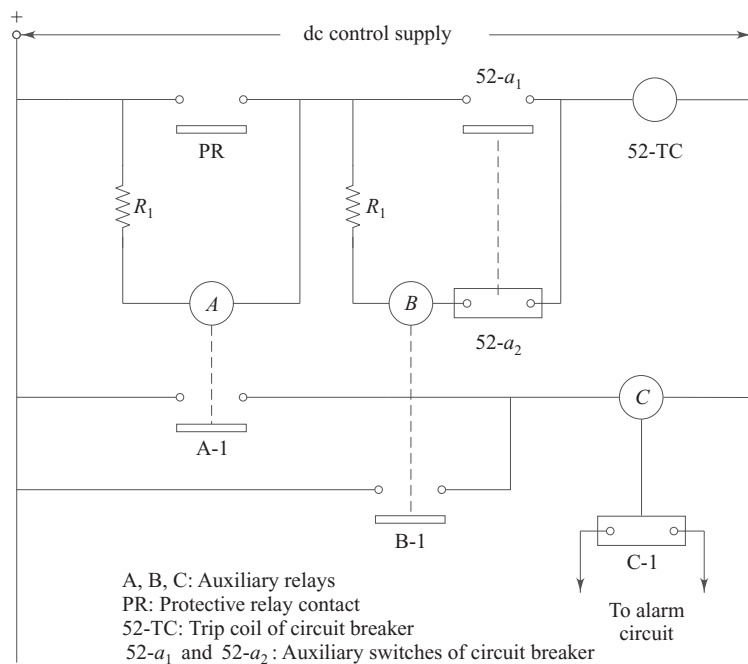


Fig. 2.36 Simple arrangement of trip circuit supervision

2.19.5 Annunciators

Relays that give audible and visual alarms are used to annunciate the primary relay operations. For power stations and major substations, segregation of alarm for each primary circuit is desirable. For such situations, the annunciator type of alarm equipment was developed.

Basically, an annunciator alarm equipment consists of a facia (or window) housing a number of indicating lamps.

Initiation of an alarm condition causes one of the lamps in the facia to flash and simultaneously an audible alarm is sounded. The latter may be cancelled by operating a remote push button situated in the control room

or by pressing a local accept push-button on the front of the facia. Acceptance of the alarm steadies the flash in the light and enables the alarm inscription in front of it to be read. The annunciator can be reset by a reset push button when the alarm condition is vanished.

Facias are designed to take 6, 9, 12, 18 or more indications according to requirements.

Example 2.1 An induction motor is to be protected against overload. Nameplate details are 3-phase, 6.6 kV, 1250 kW, 0.8 p.f. The motor can withstand 10% overload continuously. The time constant of heat withstand characteristic is 10 minutes. A thermal relay is connected across a C.T. of 200/1 ratio. The time constant of the relay is also 10 minutes. The range of settings is 70–130% of I A in steps of 5%. Suggest the relay setting.

Solution Rated current = $\frac{1250}{\sqrt{3} \times 6.6 \times 0.8} = 136.68 \text{ A}$

Considering 10% overload, the setting is to be decided on 136.68×1.1 , i.e., 150.35 A.

CT secondary equivalent is 0.7517 A.

Hence, a 75% setting is suggested.

Example 2.2 A 150 MVA, 132/66 kV, DY-II, 3-phase transformer is to be protected against short circuit. An instantaneous overcurrent relay is used to protect it. The magnetising inrush current of the transformer is 10 times the rated current. The setting range is 400–2000% of I A in steps of 50%. The CT ratio is 1000/1 A. Suggest the setting of a relay.

Solution Rated current of transformer on 132 kV side = $\frac{150 \times 10^3}{\sqrt{3} \times 132} = 656.07 \text{ A}$

Magnetising inrush occurs when the transformer is energised. Relay should not operate due to that current.

Magnetising inrush = $656.07 \times 10 = 6560.7 \text{ A}$

CT secondary equivalent is 6.56 amp or 656%.

Therefore, 700% is suggested.

Example 2.3 Figure 2.37 shows a portion of a power system in a single-line diagram. Find out the operating time of the relay if the relay used is IDMT relay (normal inverse) with 50–200% setting in seven equal steps. A high set instantaneous relay is inbuilt with a setting range of 400–2000%. The time of operation of IDMT relay can be approximated by the formula $\frac{3}{\log_{10} \text{PSM}} \times \text{TMS}$. Find out the time of operation of relay for fault currents of 500 A and 1200 A. The plug setting of the relay is 75% of I A and the time multiplier setting is 0.2. An instantaneous high set unit is set at 1000%.

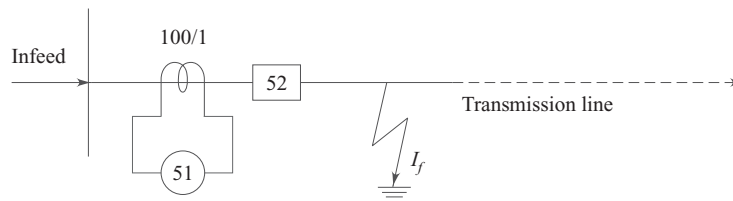


Fig. 2.37 Example 2.3

Solution To carry out the example faster, one need not reflect the current on CT secondary side.

$$\text{PS of relay} = 100 \times 0.75 = 75 \text{ A}$$

$$\text{PSM} = 500/75 = 6.66$$

$$\log_{10} \text{PSM} = 0.824$$

$$\text{Time of operation} = 0.728 \text{ seconds}$$

For a fault current of 1200 A, time of operation can be similarly found out, but that will be wrong as the current has exceeded the high-set setting. Hence, the relay will operate within 3 cycles (60 milliseconds).

Example 2.4 Figure 2.38 shows a single-line diagram of a portion of a power system in a single-line diagram.

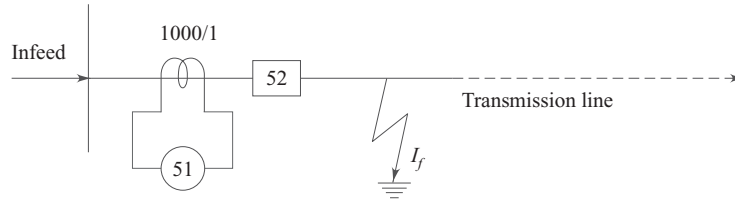


Fig. 2.38 Example 2.4

The data of the example is as follows:

- (i) CT ratio: 1000/1 A
- (ii) Minimum current at which the relay is desired to operate = 900 A
- (iii) Overload withstand = 10% above normal current
- (iv) Desired operating time for a fault current of 8000 A is 2.0 seconds.
- (v) High set instantaneous unit should operate at 12,500 A (range 400–2000% in steps of 100%).

IDMT relay (normal inverse) with a standard curve is used. Find out its settings.

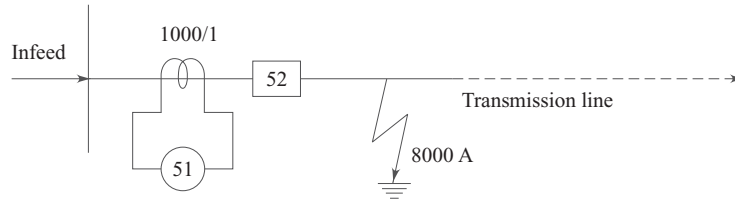


Fig. 2.39 Example 2.4

Solution Figure 2.39 shows a portion of a power system in a single-line diagram with specifications given in the example.

Maximum rated current (MCR or CMR) = 900 A

Considering overload, it will be 990 A. 990 as a percentage of 1000 A (CT primary rating) is 99%. Hence PS = 100%.

$$\text{Time of operation of relay} = \frac{3}{\log_{10} \text{PSM}} \times \text{TMS}$$

$$2.0 = \frac{3}{\log_{10} \text{PSM}} \times \text{TMS}$$

$$\dots \left[\text{PSM} = \frac{8000}{1000} = 8 \right]$$

$$= \frac{3}{0.903} \times \text{TMS}$$

$$\therefore \text{TMS} = 0.6$$

$$\text{Setting of high-set unit} = \frac{12500}{1000} = 12.5$$

Hence, 1300% is selected.

Example 2.5 Figure 2.40 shows a portion of power system in a single-line diagram. Find out the time of operation of relays R_1 and R_2 for a fault immediately after relaying point R_2 . Relay R_1 is voltage monitored overcurrent relay, the PS of which reduces to 40% of the set value if voltage collapses below 70% of rated voltage.

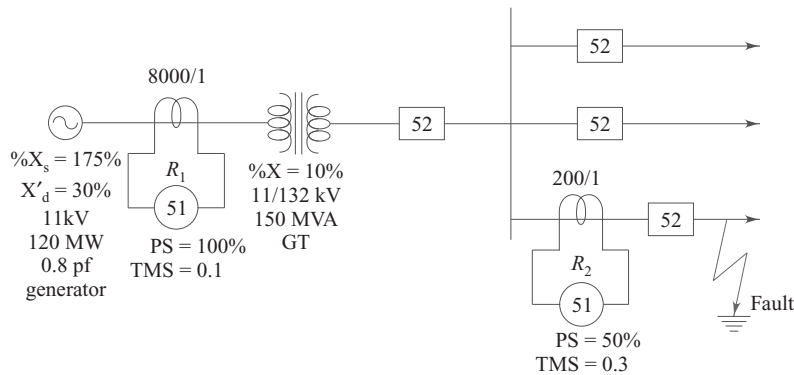


Fig. 2.40 Example 2.5

Solution It is required to find the fault current for the fault immediately after the relaying point R_2 . For a three-phase fault, a positive sequence network is drawn as shown in Fig. 2.41. Generator reactance will be in steady-state as relay R_1 is backing up. For base MVA of 150 MVA, from positive sequence network of Fig. 2.41,

$$\text{Fault MVA} = 150/1.85 = 81.08 \text{ MVA}$$

\therefore fault current on the 132 kV side is 354.63 A and that on the 11 kV side is 4255.6 A.

$$\text{PSM of relay } R_2 = 354.63/100 = 3.5463$$

$$\begin{aligned} \text{Time of operation of relay } R_2 &= \frac{3}{\log_{10} \text{PSM}} \times \text{TMS} \\ &= \frac{3}{0.5497} \times 0.3 = 1.637 \text{ s} \end{aligned}$$

PSM of relay R_1 will reduce to 40% of its set value as the voltage will collapse below 70%.

$$\text{PS of relay } R_1 = 8000 \times 0.4 = 3200 \text{ A}$$

$$\therefore \text{PSM of relay } R_1 = 4255.6/3200 = 1.33$$

$$\begin{aligned} \text{Time of operation of relay } R_1 &= \frac{3}{\log_{10} \text{PSM}} \times \text{TMS} \\ &= \frac{3}{0.1238} \times 0.1 = 2.423 \text{ s} \end{aligned}$$

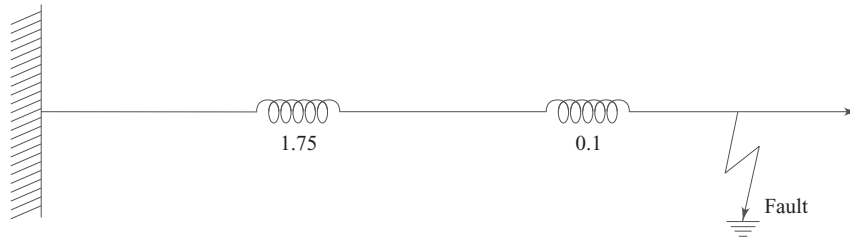


Fig. 2.41 Example 2.5

GLOSSARY OF COMMON TERMS USED IN CONJUNCTION WITH RELAYS

1. **Operating force or torque** That which tends to change the state of the contacts, i.e., 'NO' contact becomes closed and 'NC' contact opened.
2. **Restraining force or torque** That which opposes the operating force and tends to prevent the changeover of the state of contacts.
3. **'NO' contact** The contact which remains open when the relay is in de-energised condition
4. **'NC' contact** The contact which remains closed when the relay is in de-energised condition
5. **Pick-up** The value of electrical quantity (voltage, current, etc.), which is the threshold above which the relay commences to change the state of contact (or the relay will be energised)
6. **Drop-out or reset** The value of electrical quantity which is the threshold below which the relay contacts return to the normal state.
7. **Characteristic of a relay** The locus of the pick-up or reset.
8. **Reinforcing relay** One, which is energised by the contacts of the main relay and with its contacts parallel with those of the main relay which relieves the main relay contact from their current carrying duty.
9. **Seal-in relay** Similar to a reinforcing relay except the fact that it is connected to stay in the energised condition. Its coil current is interrupted by an auxiliary switch of the circuit breaker.
10. **Back-up relay** A relay, which operates, usually after a slight delay, if the main relay (primary relay) does not operate to trip its circuit breaker.
11. **Consistency or repeatability** The accuracy with which the relay can repeat its characteristics.
12. **Power swing** An oscillation between groups of synchronous ac machines caused by an abrupt change in load conditions.
13. **Flag or target** A visual device, usually spring or gravity operated, for indicating the operation of a relay.
14. **Instantaneous Relay** One, which has no intentional time delay (and operates in less than or equal to 60 milliseconds).
15. **Time-delay Relay** One, which is fitted with delaying means.
16. **Burden** The power absorbed by the circuits of a relay expressed in VA in ac applications.
17. **Operating Time** The time which elapses from the moment when the actuating quantity attains a value equal to pick-up value until the relay operates its contacts.
18. **Reach** The remote limit of zone of protection provided by the relay.

19. Over-reach When the relay operates for the fault beyond its zone of protection, it is said to have over-reached.

20. Under-reach When the relay does not operate for the fault within its zone of protection, it is said to have under-reached.

One will be able to understand these and other terms better once he/she reads this book thoroughly.

The international conventional practice for schematics In all electrical drawings and schematics, it is the international convention that all the circuit breakers are always shown in open condition and all relays in de-energised condition.

REVIEW QUESTIONS

1. Clearly distinguish the terms 'overload' and 'overcurrent'.
2. Draw the thermal withstand curve of an electrical equipment and thermal relay characteristic on the same graph and explain its relevance.
3. Enlist the applications of instantaneous overcurrent relays.
4. What is the significance of resetting time? Should it be high or low?
5. What is the significance of resetting ratio? What should be its ideal value?
6. Explain what is meant by the following terms as applied to overcurrent relays:
 - (i) Plug-setting
 - (ii) Resetting time
 - (iii) Overshoot
7. Explain the term PSM and TMS with reference to IDMT relays.
8. Describe an induction disc-relay with a diagram giving methods of time-setting and current-setting.
9. Explain the function of lag coil in an IDMT relay.
10. Define the following terms as applied to protective relays: Burden, Pick-up, Reset, Operating time, Reach.
11. Describe the principle of circulating current differential protection.
12. Giving a neat circuit diagram, explain the opposed voltage scheme of differential protection.
13. Define basic setting and bias setting as applied to a biased differential relay.
14. Explain the principle of operation of a percentage differential relay with relevant characteristic.
15. With a neat sketch, explain induction-cup type directional relay.
16. Prove the duality between an amplitude comparator and a phase comparator.
17. How is directional control realised in an electromagnetic-type directional overcurrent relay giving inverse time-current characteristics?
18. How is definite minimum time achieved in an IDMT relay?
19. Define ohm and mho characteristics for distance relays. Draw these characteristics on an impedance plane and explain how they can be obtained by an amplitude comparator and a phase comparator.
20. Suggest some suitable areas in the field of power system protection where thermal relays may be used.
21. Describe different auxiliary functions of relays.
22. On an R - X diagram, show the impedance radius vector of a line section having an impedance of $2.0 + j5$ ohms. On the same diagram, show the operating characteristics of an impedance relay, a reactance relay and a mho relay, each of which is adjusted to just operate for a dead short circuit at the end of the line section. Assume that the operating characteristics of the mho relay lies on the impedance vector.
23. Find the plug-setting and time of operation of IDMT overcurrent relay for the system shown in Fig. 2.42.
 Data:
 CT ratio: 100/1 A
 Rated full load current of induction motor: 90 Amp.
 Relay rating: 1 A, setting range: 50–200% of 1 A in 7 equal steps,
 TMS selected = 0.1
 Fault current, $I_f = 550$ A

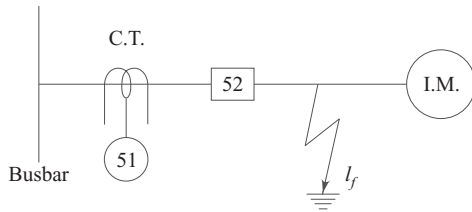


Fig. 2.42 Question (23)

(PS = 100%, time of operation = 0.4052 s)

24. A percentage differential relay employed in the protective scheme of Fig. 2.43 has a minimum pick-up of 0.05 A, and 10% slope. A high resistance ground fault has occurred near the grounded neutral end of the generator winding while the generator is carrying load. The resulting current magnitudes are given in Fig. 2.43. Assuming that the CTs have 400/1 amp ratio and no inaccuracies, will the relay trip the breaker under this condition? Would the relay

operate at the given value of the fault current if the generator were carrying no load with the breaker open?

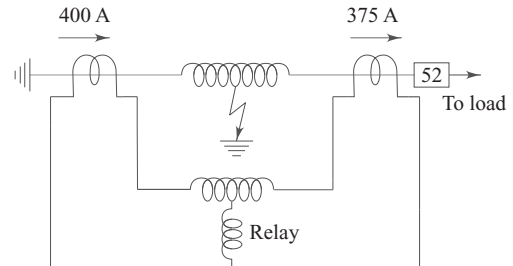


Fig. 2.43 Question (24)

(Relay will not operate while the generator is carrying load, relay will operate under no load condition)

MULTIPLE CHOICE QUESTIONS

- Overcurrent relay is a
 - single-input comparator
 - dual-input comparator
 - multi-input comparator
 - none of the above
- The rating of the coil of an electromagnetic relay is generally
 - 1 and 5 A
 - 5 and 10 A
 - 10 and 25 A
 - 50 and 100 A
- The rating of voltage coil in an electromagnetic relay is generally
 - 110 and 220 volts
 - 220 and 400 volts
 - 1100 and 2200 volts
 - 2200 and 3300 volts
- The function of a tripping relay is to
 - multiply the number of contacts of protective scheme
 - increase the rating of the tripping contacts
 - relieve the measuring relay from the duty of tripping a circuit breaker
 - all of the above
- The shape of the disc in an induction disc-type overcurrent relay is
 - circular
 - spiral
 - elliptical
 - rectangular

Static Relays

The term *static relay* generally refers to a relay where active semiconductor devices such as diodes, transistors, ICs, etc. are employed for processing the electrical input signals in

3

order to obtain the desired relay characteristic. The operation of the final contact may be either initiated by a solid-state device or an electromechanical device.

Introduction

3.1 ADVANTAGES OF STATIC RELAYS OVER ELECTROMAGNETIC RELAYS

The rapid changeover of technology from electromagnetic relays to static relays can be attributed to several advantages the latter possess. The major ones of these are as follows:

1. **Reduced Burden** Static relays pose a reduced burden on protective current transformers and protective potential transformers as compared to electromagnetic relays because of lower VA requirements of the static circuits.
The advantages of reduced burden are
 - (i) Better accuracy of CTs and PTs
 - (ii) Difficulties faced due to CT saturation are overcome; for the same current, the voltage required is reduced and hence the CT is operated in the lower part of linear characteristic
 - (iii) CTs and PTs of lower VA rating are required which results in the reduction of size and cost of CTs and PTs
2. **No Moving Parts** Solid-state devices have no moving elements. Hence, in static relays there are no problems of contact bounce, arcing, contact erosion, dry contact, spring restraint, etc. Moreover, the static relays have operational advantages like high torque, absence of friction, etc.

3. **Fast Response** Very small operating time of the order of one cycle or even less can be achieved with static relays.
4. **Precise Characteristic** The relaying characteristics could be controlled more precisely.
5. **Sensitivity** The ease of providing amplification enables greater sensitivity to be achieved.
6. **Miniaturisation** Since compact and small sized ICs are available, the size of a static relay gets reduced. This saves panel space.
7. **Robustness** High resistance to vibration and shocks as there are no moving parts. This is especially true in relays employing ICs.
8. **Less Maintenance** With the absence of bearing friction and contact trouble, maintenance required is greatly reduced.
9. **Flexibility** A variety of functions like sensing of negative phase sequence component of current or voltage, filtering harmonics, differentiation, integration, etc., can be performed with greater flexibility by static circuits and hence these relays can match the requirements of protection more closely.
10. **Low Resetting Time** Resetting time can be reduced using static circuitry. Where fast automatic reclosing of circuit breakers is involved, the resetting time of a relay may be a critical parameter for obtaining selectivity.
11. **Low Overshoot** As the over-travel time is practically negligible in static relays (because of absence of moving parts), discrimination time between successive relays can be reduced.
12. **Low Transient Over-reach** As the input signal can be easily differentiated by static circuits, the transient over-reach of static instantaneous overcurrent relays is quite low.
13. High drop-off to pick-up ratio (refer Chapter 7).

3.2 LIMITATIONS OF STATIC RELAYS

1. **Vulnerability to Voltage Transients** Static relays are prone to voltage spikes. Such voltage transients can occur due to
 - (i) operation of breaker in the primary circuit of CTs and PTs,
 - (ii) breaking of control circuit, and
 - (iii) atmospheric disturbances.

Such voltage spikes can easily override the signal and cause serious malfunctions of the static relay or can even damage the semiconductor components. Good filtering of the auxiliary supply, surge suppression and shielding are the important requirements of the static relays to avoid these problems.
2. **Variation of Characteristic with Temperature and Age** The characteristics of semiconductors are affected due to variations in the surrounding temperature. Silicon transistors are much less prone to temperature effects than germanium transistors. Temperature effects can also be minimised by appropriate use of thermistors or appropriate compensating circuits. Ageing can be minimised by presoaking for a number of hours at a relatively high temperature.

3. **Overload Capacity** The static relays have lower short time overload capacity compared with electromagnetic relays. However, with improvement in semiconductor technology, there is a significant rise in thermal overload capacity of static relays nowadays.
4. **Reliability** Electromechanical relays have high reliability due to the fact that they have smaller number of components and that each component possesses good reliability due to long experience gained in manufacturing practices. Static relays were less reliable initially for a few years till the discrete components proved their reliability. Careful choice and quality control play a vital role in reliability of static relays. Due to the advent of integrated circuits, which replaced discrete components, the reliability of static relays has considerably improved. Improved testing facilities and accelerated life tests also have increased the reliability of static relays and hence they are replacing electromechanical relays in the field at a very fast pace.

3.3 BASIC ELEMENTS OF STATIC RELAYS

Instead of building complicated circuits with discrete components like diodes, transistors, resistors, capacitors, etc., it is of great advantage to build them in an integrated form, the ICs.

ICs employ either TTL (Transistor to Transistor Logic) or MOS (Metal Oxide semiconductor) logic. C-MOS (Complementary MOS) logic is more in use. It has the advantages of small size and extremely low power consumption. However, they have to be handled with care, as they are susceptible to damage due to static voltages. ICs of digital (logic) circuits, operational amplifiers, registers, counters, analog to digital converters, digital to analog converters and a multitude of other devices are available commercially.

ICs are classified as small scale (SSI), medium scale (MSI) and very large scale (VLSI). LSIs and VLSIs have been made possible because of great strides made in the fabrication and etching technologies. Transistors, which form the bricks of the ICs are now available in the fractional micron ranges, thus leading to very high densities and consequent reduced sizes of chips. Application specific ICs (ASICs), which are custom-built for particular specific applications have also come to the fore recently. Thus, it would be possible to build ICs functioning as a particular type of protective relay or a combination of two or three types.

Some of the TTL chips in common use are listed below:

7400	Quad 2 – input NAND
7402	Quad 2 – input NOR
7405	Quad 2 – input AND
7414	Hex Schmitt Trigger Interface
7420	Dual 4 – input NAND
7430	Single – input NAND
7432	Quad 2 – input OR
7476	Dual JK Flip-Flop with preset and preclear
7486	Quad 2 EX – OR
7489	64 bit RAM Memory
7490	Decade counter
7495	Shift Register 4 bits, parallel in and out
74121	Monostable Multivibrator
74150	Dual selector 1 of 16
74154	Data Distributor 1 of 16

555	Astable/Monostable multivibrator
74181	Arithmetic Unit
8223	256 bits ROM
741	Operational Amplifier
747	Dual Operational Amplifier
LM 324	Quad – Operational Amplifier

The operational amplifier is a very powerful circuit element useful for a variety of analog operations. Fundamentally, it is a differential amplifier with additional stages incorporated to get a convenient output level.

3.3.1 Level Detector

The use of an operational amplifier as a level detector is shown in Fig. 3.1. Some static relay manufacturers use a transistor as a level detector. Figure 3.2 shows a simple level detector in which the input voltage has to exceed the opposing voltage of the bias battery before any output is produced.

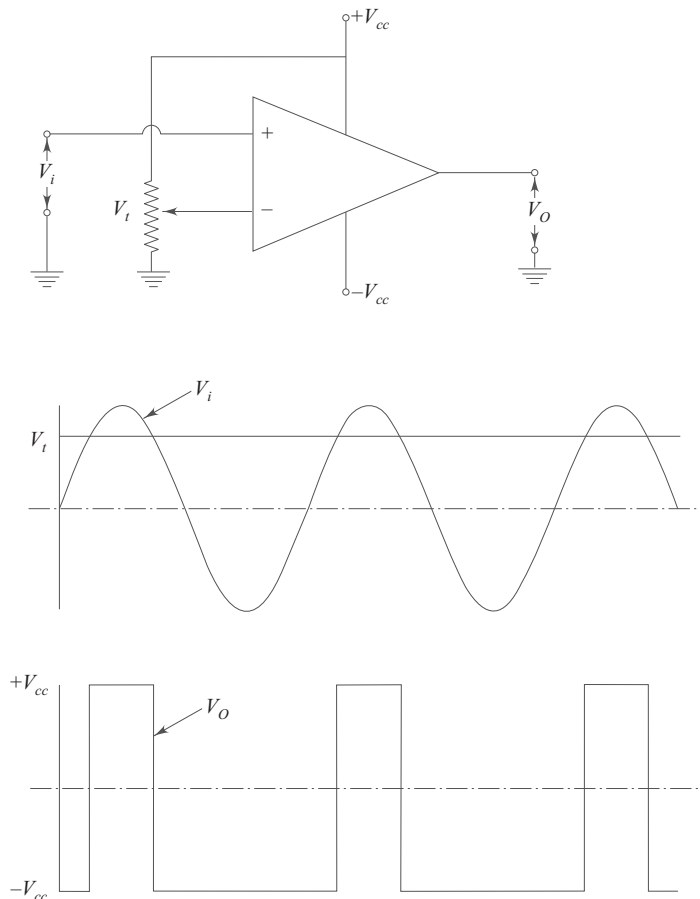


Fig. 3.1 Application of op-amp as a level detector

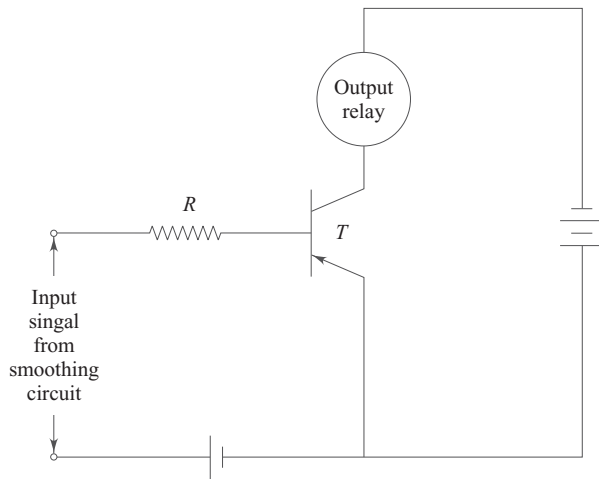


Fig. 3.2 Transistor as a level detector

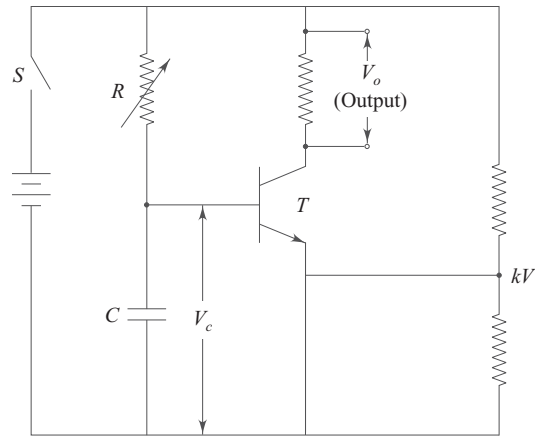


Fig. 3.3 Time delay circuit

3.3.2 Time-Delay Circuit

As has been stated in Section 2.5 of Chapter 2, time delay circuits employing resistance and capacitance in series are very common in manufacturing practices.

Figure 3.3 gives a simple R - C time-delay circuit. The transistor conducts when the voltage across the capacitor $V_c > kV + V_{BE}$ and the delay is controlled by the R C charging time.

For long delays of the order of a few seconds, such R - C charging circuits can be employed along with transistor switching amplifier circuits as shown in Fig. 3.3. Since transistor currents are very small, long delays of the order of minutes or even hours can be obtained specially if low-leakage tantalum capacitors are employed.

3.3.3 Output Circuit

Figure 3.4 shows one typical output circuit in which an SCR is used and a relay in the anode circuit of a thyristor gives a trip signal to the circuit breaker.

Because of low triggering current requirement, a thyristor is easily triggered by a small voltage signal (5 volts, 0.1 milliamp). To prevent wrong operation, it is customary to design a suitable circuit (not shown in Fig. 3.4) so that a triggering signal will not trigger the thyristor unless it lasts for at least 2 milliseconds.

3.3.4 DC Auxiliary Supply and Surge Suppressors (Surge Absorbers)

The static relay circuitry needs dc power supply for its functioning. One of the methods to feed dc auxiliary supply to the static relay circuitry is shown in Fig. 3.5.

The voltage supplied to the relay circuit is held constant by the zener diodes Z . Should the voltage rise, the zener diode D conducts and the overvoltage relay gets energised giving an overvoltage alarm.

Many other circuits for feeding auxiliary supply are given in Reference 2.

Capacitor C in Fig. 3.5 is used for absorbing transient overvoltage spikes. The sources of such transient overvoltages are treated in Reference 5. These overvoltage spikes hardly trouble the electromagnetic relays because of their high level of insulations and high inertia of the moving system; whereas these transients do affect the static relays in the form of either wrong operation due to short time impulses (time taken for operation of a static relay is of the order of microseconds) or damage to semiconductor components.

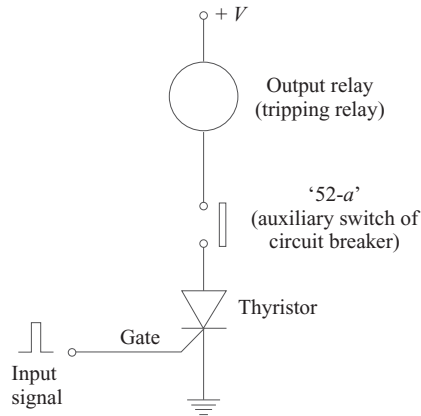


Fig. 3.4 Output circuit

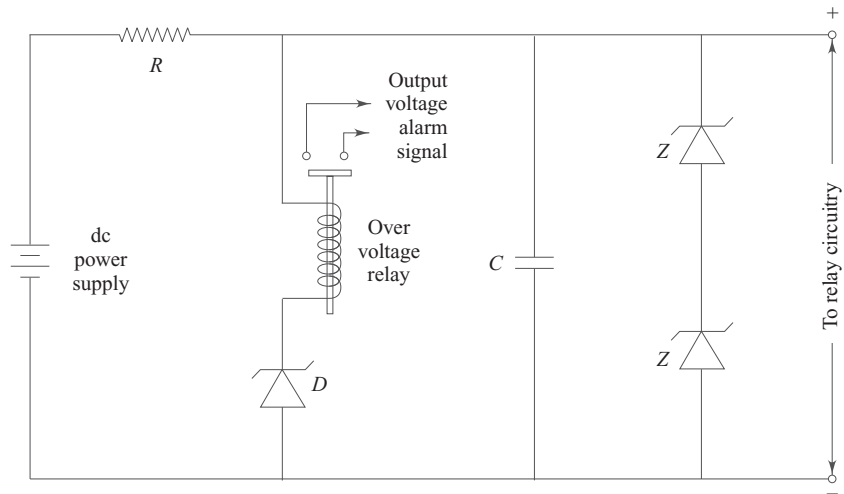


Fig. 3.5 Auxiliary supply and surge suppressor circuit

Many designs for surge absorbers are dealt with in Reference 2.

3.3.5 Comparators

We have already discussed two input comparator relays. The directional relay and reverse power relay are phase comparator relays, while the differential relay and distance relay are amplitude comparator relays. These comparators can be realised in many ways. A few typical methods of realisation of amplitude and phase comparators are discussed briefly here.

Amplitude Comparators Figure 3.6 shows how a biased differential relay can be realised. Figure 3.7 gives a simple circuit of a distance relay.

Phase Comparators

It has already been discussed that a two input phase comparator relay generally gives an output signal if the phase difference between two input quantities is less than 90° . Principles of two such phase comparators are

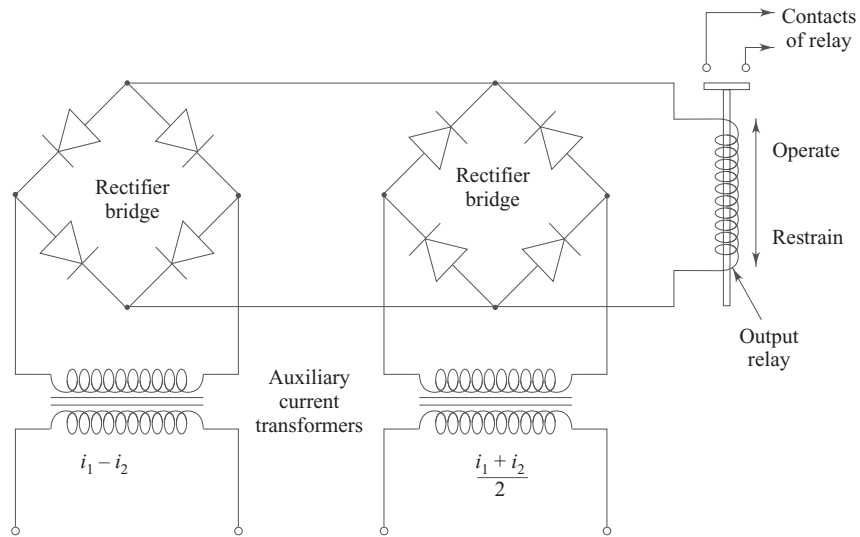


Fig. 3.6 An amplitude comparator for static differential relay

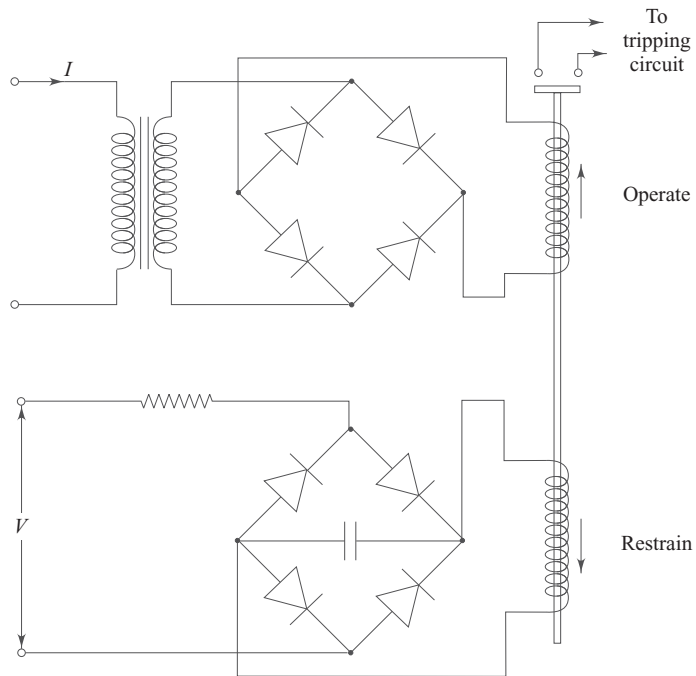


Fig. 3.7 An amplitude comparator for static distance relay

shown in block diagrams of Fig. 3.8(a) and 3.9(a). Fig. 3.8(b) and 3.9(b) show the corresponding waveforms. Input quantities can be any of the sets of quantities given in Table 2.2 of Section 2.18 in Chapter 2 and we can get a corresponding type of relay.

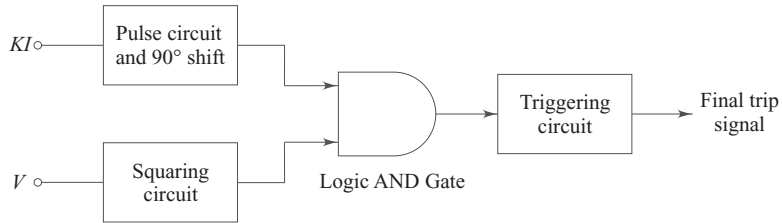


Fig. 3.8(a) Block and spike phase comparator

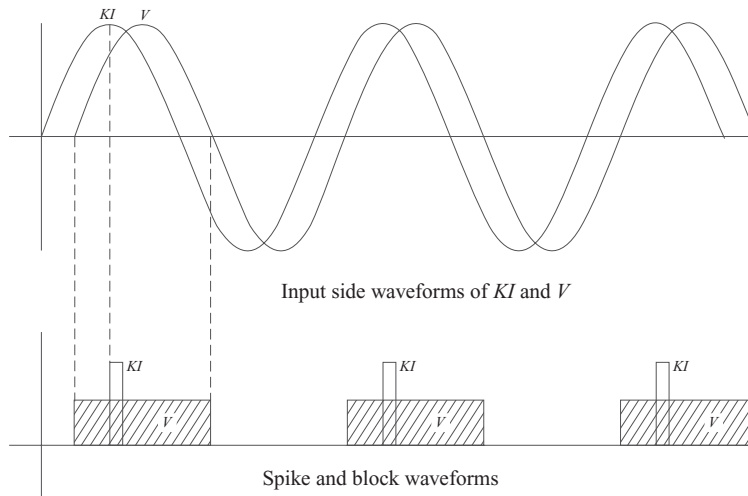


Fig. 3.8(b) Waveshapes of block and spike phase comparator

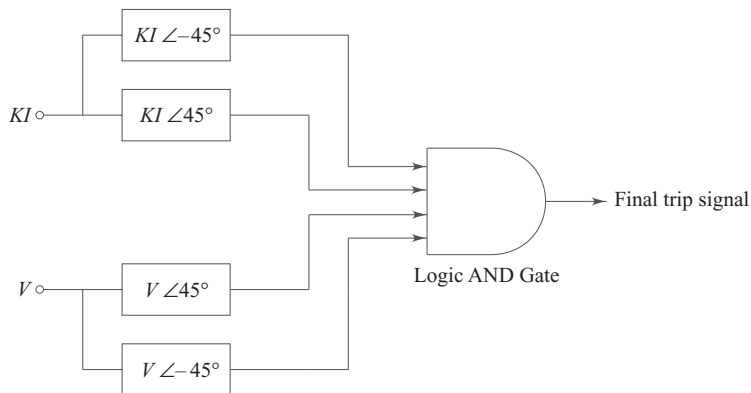


Fig. 3.9(a) Phase splitting phase comparator

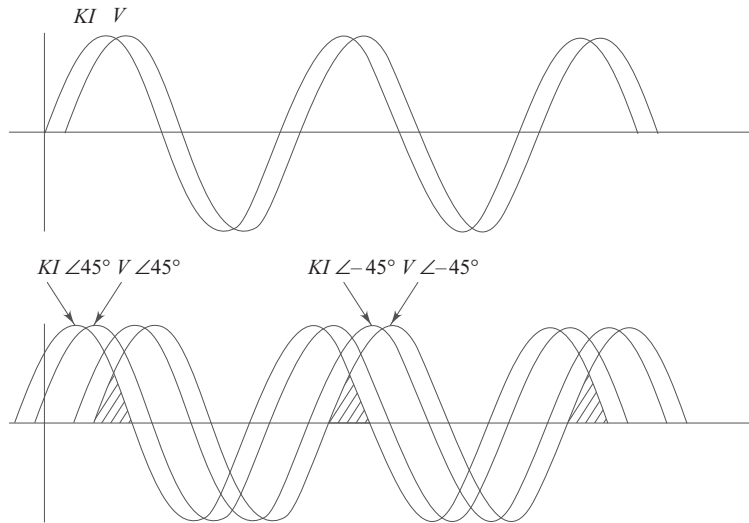


Fig. 3.9(b) *Waveshape of phase splitting phase comparator*

Many circuits of phase comparators (amplitude and phase comparators) are discussed in reference 2.

3.4 STATIC RELAYS

There are many static relay designs prevalent in practice. Every manufacturer have their own philosophy of rigging up static circuitry. Because of space limitations, it is not possible to give the exhaustive coverage of all the static relays. A few typical designs are discussed in the following subsections as illustrative examples. Other static relay circuits, however, are going to be treated in the chapters of apparatus protection.

3.4.1 Static Definite Time Overcurrent Relay (Courtesy: Areva T&D Ltd.)

The operation of the relay is illustrated by block diagram of Fig. 3.10.

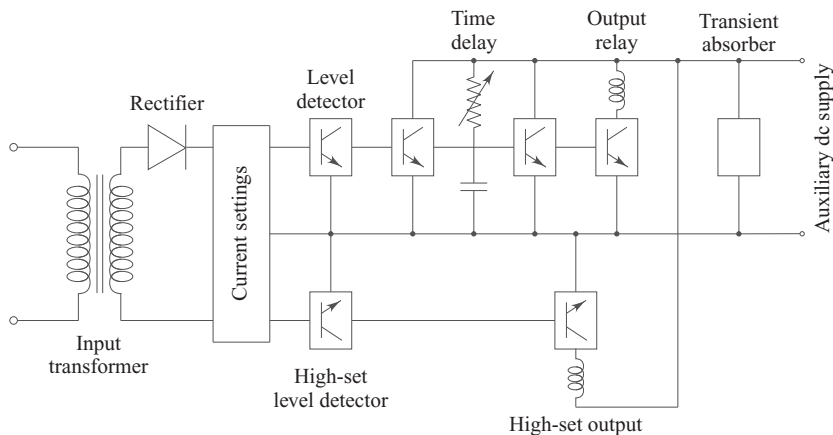


Fig. 3.10 *Static definite time overcurrent relay (Courtesy: Areva T&D Ltd.)*

When the peak of the input signal exceeds the reference level, the time delay circuit starts and after a pre-set time delay drives the output relay. Instantaneous high-set unit uses the alternate half cycle for measurement and through a separate level detector drives a separate output relay. The static circuitry is fully protected against high transient voltages and accidental reversal of auxiliary supply polarity.

3.4.2 Static IDMTL Overcurrent Relay (Courtesy: Jyoti Ltd., Vadodara, India)

Figure 3.11 shows a block schematic of a static IDMTL (Inverse Definite Minimum Time Lag) overcurrent and earth-fault relay. The main CT secondary current is reduced to a smaller proportionate value (nominal value 25 milliamps) using intermediate current transformers mounted inside the relay casing. This current is converted into proportionate voltage signal using resistive burden, the value of which can be adjusted. This voltage signal after rectification and filtering is fed to a shaping circuit, which consists of a combination of linear and non-linear elements. This part of the circuit generates an inverse type of characteristic. The voltage V_2 (refer Fig. 3.11), proportional to the square of the relay input current, is fed to an integrator, the time constant of which can be adjusted in the form of time multiplier setting (TMS) control. The output of the integrator block is given to a level detector, which will trip the output relay as soon as the integrated voltage V_3 exceeds the set value of the level detector. The charging of the integrator capacitor is governed by a pick-up unit level detector. The integrator capacitor is allowed to charge only when the relay current is above pick-up level, which is indicated by the glowing light-emitting diode (LED).

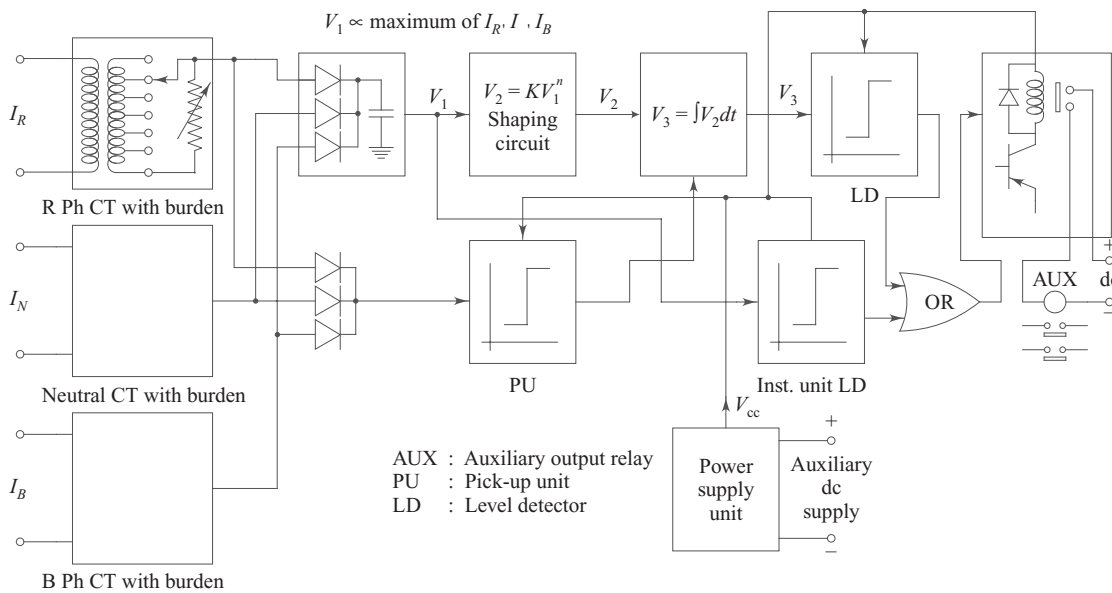


Fig. 3.11 Static IDMTL O/C and E/F relay (Courtesy: Jyoti Ltd., Vadodara)

The maximum value amongst all the voltages proportional to the relay current is selected by means of diodes and is fed to the instantaneous unit level detector which will trip an output relay, the moment the relay current exceeds the set value of the instantaneous unit, bypassing the IDMTL circuitry.

The stabilised voltage bias is given to the relay circuit with the help of a voltage stabiliser block.

The relay is protected from high voltage spikes by a surge diverting network (not shown). A diode connected in the power supply unit prevents the damage to the relay because of reversed polarity connection of dc auxiliary supply voltage.

3.4.3 Static Distance Relay

Figure 3.12 shows a block diagram of a two-input phase comparator relay, which can be used either as a directional relay or as a distance relay depending on the input quantities being fed. Figure 3.13 shows the waveforms seen at the output of each block. Two inputs A and B are first filtered to avoid harmonics as they may lead to wrong zero-crossing detection. A zero crossing detector converts the sinusoidal wave into the square wave, the amplitude of the square wave remains same, irrespective of the amplitude of input sinusoidal wave. A zero crossing detector is an operational amplifier comparing the input signal with ground as a reference. The output of the zero crossing detector is differentiated and negative spikes are clipped by a clipping diode.

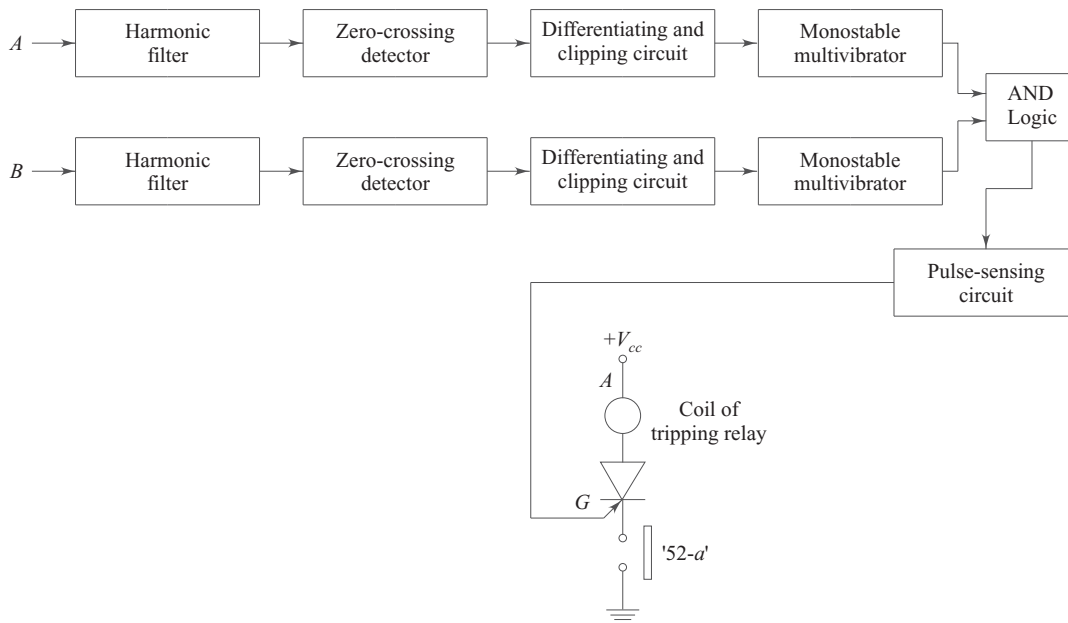


Fig. 3.12 Two-input phase comparator relay

The output of the differentiator stage is fed to the monostable multivibrator, the width of the square wave so obtained being adjusted to 5 milliseconds (90° in 50 Hz systems). The output square waves of monostable multivibrator for both the inputs are logically AND gated. The AND gate will give output, obviously, if the phase difference between two input quantities is less than 90° . The output of the AND gate is fed to the pulse-sensing circuit (differentiator), which triggers the thyristor used in the triggering circuit. The quantities to be fed are summarised in Table 2.2 of Chapter 2.

3.4.4 Static Generalised Overcurrent Relay

The overcurrent relays discussed in previous sections were either the instantaneous overcurrent relays, definite-time overcurrent relays or inverse-time overcurrent relays. The relay being presented in this section is a generalised overcurrent relay, which can realise any of the characteristics as desired. The relay can be made to give either definite time characteristic, inverse current–time characteristic, very inverse current–time characteristic or extremely inverse current–time characteristic.

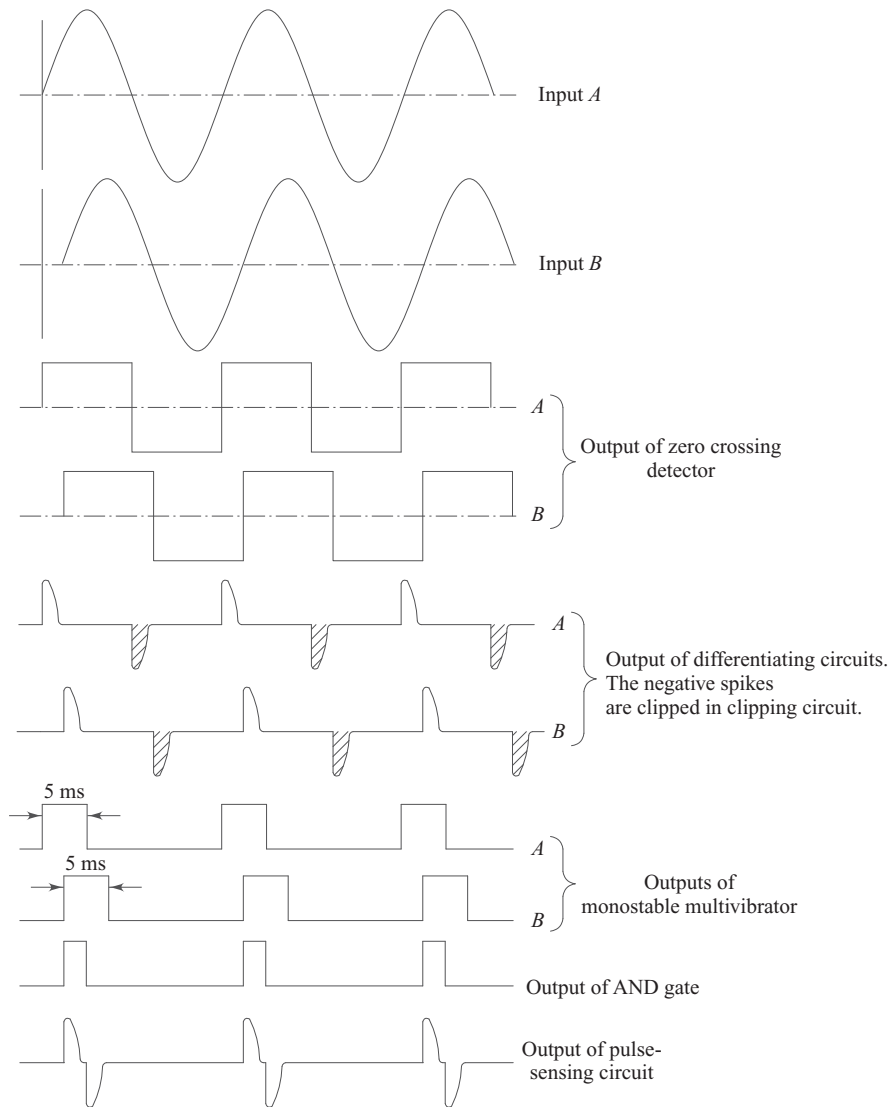


Fig. 3.13 Waveforms of Fig. 3.12

Figure 3.14 gives the block diagram of a generalised overcurrent relay. Firstly, voltage proportional to CT secondary current is rectified. The output of the rectifier is then converted into logarithmic value by the logarithmic circuit. This logarithmic value is amplified (according to the required value of n , the power of current I) to a desired value. The next stage is the antilogarithmic circuit, which converts the amplified logarithmic signal to give I^n . The output of the antilog is integrated with the help of an integrator. The ramp signal of the integrator is then compared with a reference voltage by a comparator (level detector). When the voltage of the integrator output crosses the reference voltage, the level detector gives the output signal which can be fed to an output unit that finally generates a trip signal for the circuit breaker. To prevent the relay from tripping at the normal rated current, the charging process in the integrator is suitably blocked.

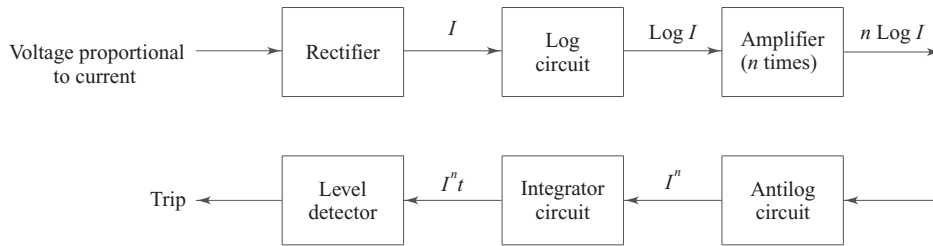


Fig. 3.14 Block diagram of generalised overcurrent relay

REVIEW QUESTIONS

- What are the advantages and limitations of static relays?
- Evaluate the static relays vis-à-vis the electro-mechanical equivalents with respect to the following parameters of relays:
 - Burden
 - Response
 - Resetting Time
 - Overshoot
 - Precision
 - Sensitivity
- How will you realise the following circuits in a static relay?
 - Level detector
 - Time delay circuit
 - Output circuit
- Draw and explain the block diagram and waveshapes of input and output signals for a block and spike phase comparator.
- Draw a block diagram of static definite-time overcurrent relay.
- Explain a static IDMT overcurrent relay, giving a neat block diagram.
- State one method of achieving a static distance relay.
- Is it possible to achieve various overcurrent relay characteristics in a single static relay? How?

MULTIPLE CHOICE QUESTIONS

- As compared to an electromagnetic overcurrent relay, the following is not a feature of a static overcurrent relay.
 - low burden
 - no moving parts
 - fast response
 - more transient over-reach
- The component used to achieve time delay according to inverse time overcurrent characteristic in a static relay is
 - differentiator
 - comparator
 - R-C circuit
 - integrator
- The static distance relay can be achieved by using
 - a level detector
 - a two-input phase comparator
 - a two-input amplitude comparator
 - either (b) or (c)
- As compared to the numerical relays, static relays do not have the feature of
 - low burden
 - no moving parts
 - flexibility due to programming approach
 - miniaturisation
- The component used in the output circuit of a static relay is
 - opamp
 - comparator
 - capacitor
 - thyristor

Microprocessor-Based Digital Protection

One of the issues with electromechanical or static relays is that the relays are not in an operated condition during normal behavior of the power system. They operate only under abnormal or faulty conditions of the power system. This may not happen very frequently and in certain cases it may happen very rarely. Hence the integrity of a relay operation can be confirmed only by frequently testing the relays. There is no continuous check on their operational integrity. By using a digital computer for power system protection and microprocessor-based relays, one

can address this issue. One very important advantage of microprocessor-based relays is that they can perform the functions of protection, measurement and control simultaneously. With the national and international grids having long ultra high voltage tie lines transferring the bulk of power, the use of microprocessor based relays is not only proving to be effective but also more or less essential.

4

Introduction

The term 'microprocessor' is used here as a generic term. 8-bit microprocessors were initially used for protective relay applications. With further progress in microprocessor technology, the more advanced microprocessors like the 16-bit microprocessor began to be used to implement relay algorithms. Most recently, digital signal processors (DSPs) are being used for protective relays. The term used for these relays are microprocessor-based relay, digital relay and numerical relay; given in the chronological order of their development. In the description, all other peripheral components except CPU will remain almost similar. The CPU is a device which is updated or replaced with technological developments. We have preferred the term 'numerical relays' in this text as it is widely used in industrial and professional practice. Let us first discuss the advantages of these relays.

4.1 ADVANTAGES OF NUMERICAL (DIGITAL) RELAYING

1. **Self-checking Facility** All components like processor, memory, analog I/O system, digital I/O ports, dc control supply, etc., are self-checked by the relay and a warning, annunciation or corresponding defensive action is initiated if any error or problem is detected.
2. **Reliability and Dependability** This is achieved due to the proven digital technology being used. Self-checking facility also contributes for increased reliability and dependability.

3. Numerical relays are immune to variations in parameters of components as there are no solid-state components like op-amp in static relays.
4. **Very Low Burden** Numerical relays offer very low burden on CTs and PTs. This is helpful in fulfilling the ideal requirement that sensors should not consume any power. If a sensor consumes power from the quantity it measures, it will lead to distortion of the measured signal.
5. **Flexibility and Compactness** As an example, to provide magnitude scaling and phase-shift to a voltage signal, extracting line-to-line voltage from phase to neutral voltage is much simpler with computer relaying because equations can be implemented by programming. Also, programming feature helps in including multiple characteristics in a single relay. Further, generic hardware can be developed for different relays, which reduces the cost of inventory.

In-built software can be changed to simulate different types of relaying characteristics depending on the requirements. Thus, a flexible relay is realised which can perform all protection functions, e.g., overcurrent, undervoltage, directional and distance protection for a transmission line. Some of these relays also function as event recorders and fault locators. These multifunctional numerical relays have made panels for the protection systems very compact. Figures 4.1(a) and 4.1(b) shown below illustrate the space-saving achieved by retrofitting an old distance scheme with a numerical distance relay scheme.



Fig. 4.1(a) Old distance relay scheme



Fig. 4.1(b) Numerical distance relay scheme

6. **Simplicity of Interfacing with CT and PT** For example, an open delta connection of PT secondary for getting zero sequence voltage is not required. It can be mathematically computed inside the processor.
7. **Fiber Optical Communication in Substation LAN** Once the analog signals from CTs and PTs are digitised, they can be converted into optical signals and transmitted on a substation LAN using fiber optic network. With higher levels of EMI (Electromagnetic Interference) immunity offered by fiber

optic cables, it has become the transmission medium of choice in substation environments. This leads to automation, multiplexing of multiple analog signals, reduction in complexity of wiring and thereby reducing burden on CTs.

- 8. Adaptive Relaying** Adaptive protection is a recent protection philosophy that permits and acts to make adjustments in various protection functions automatically in order to make them more suitable to prevailing power system conditions. Generally, the changes occur at the source level or at the load level. The system network is also affected by opening/closing of tie-line breakers. Grid connection of distributed generation is also a contributing factor for change in system configuration.

Adaptive relaying allows to automatically change the settings or characteristics of relays to adapt with the existing (modified) system conditions. This change of settings is decided by a master computer located at load dispatch centres which is usually placed higher in hierarchy and equipped with software for real-time calculations of modified settings. The modified settings are communicated to the relays whose settings are to be adapted. Hence, numerical relays with communication capabilities are essential for implementing adaptive relaying.

- 9. Storage of Historical Data** Facility of storage of pre-and post-fault data is provided in numerical relays. This data can be used for measurement of fault current and statistical analysis of fault occurrences.

- 10. Time Synchronisation with GPS System** GPS (Geographical Positioning System) is a cluster of 24 satellites of Pentagon, USA, which give a timing pulse every 1 microsecond for defense purposes. It is utilised for the benefit of power system monitoring, control and protection by having synchronised phasor measurement units based on GPS signals. Numerical relays have incorporated this feature. Time stamping of relay operations allows us to capture the sequence of relay operations which helps in the diagnosis of the exact cause of complex situations like blackouts. Moreover, by synchronising the sampling processors for different signals which may be hundreds of kilometers apart, it is possible to put their phasors on the same phasor diagram (refer Fig. 4.2). A Phasor Measurement Unit (PMU) as shown in Fig. 4.3, is used for this purpose. When such PMUs are placed at multiple critical locations, the arrangement is known as Wide Area Measurement System (WAMS).

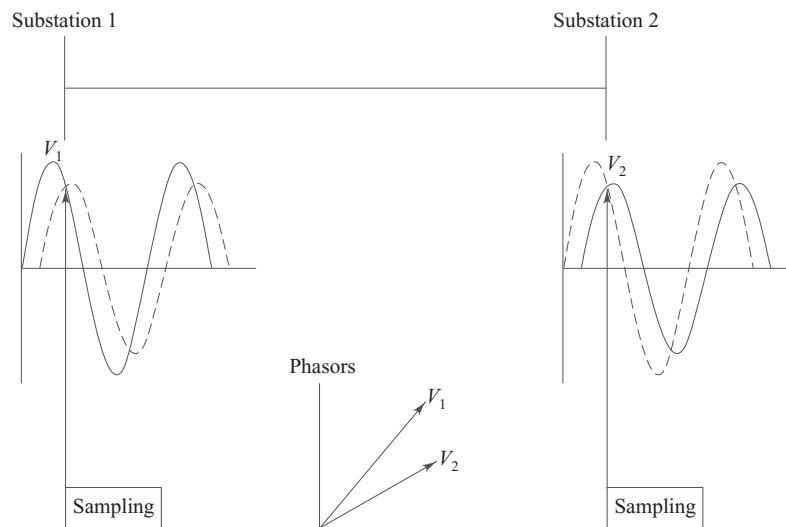


Fig. 4.2 Synchronisation of samples

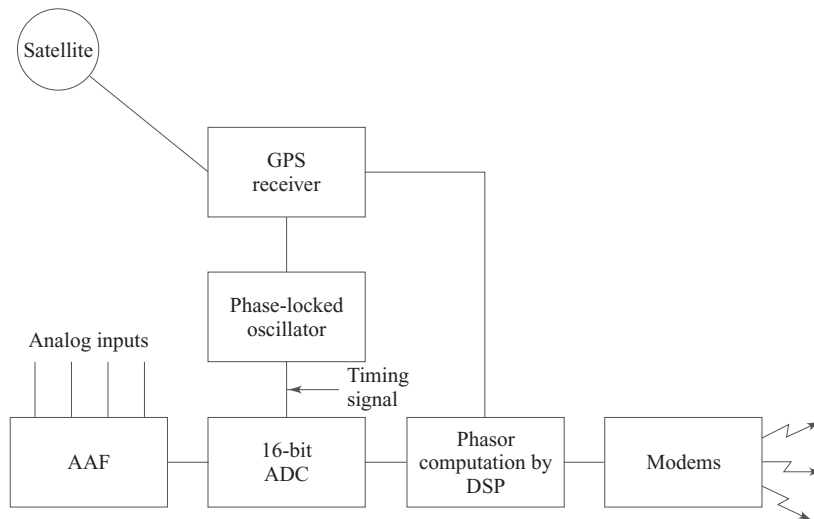


Fig. 4.3 A phasor measurement unit (PMU)

11. Merging of Protection, Control and Metering (IED) Numerical relays have features meeting the control and metering requirements. So merging them into a single entity is possible. Nowadays, there is a new term introduced for this entity, namely, IED (Intelligent Electronic Device). Any device incorporating one or more processors with the capability to receive or send data/control signals from or to an external source is known as IED. Electronic multifunction meters, digital relays, controllers are examples of IEDs. IEDs help in implementing the concept of unmanned substations in electrical distribution systems where all control, metering and protection functions can be done in a remote control room.

12. Benefits of Metering The benefits of metering are as given below:

- No separate connections for CT and PT are required.
- Metering of all parameters like A, V, Hz, kW, kWh, P.F., kVA, kVAR, etc., is possible.
- Accuracy class may be as high as 0.5% class.
- Since separate meters are not required, there is space saving.
- Networking of IEDs for metering of all feeders is possible at a single node.
- Measurement of THD (Total Harmonic Distortion) and individual harmonic levels for voltage and current waveforms is possible.

13. Benefits of Control Functions The following functions of control are incorporated in numerical relays:

- ON/OFF control for circuit breaker and isolator
- Flexibility of auxiliary supply voltage for control circuits; generally all models of relays have flexible auxiliary voltage acceptability of 80-380 V ac/dc.
- Trip circuit supervision
- Local/remote selection
- Alarm/trip signal generation at a remote place

- (f) Blocking of particular operation/protection
- (g) Indication through LED, mimic generation
- (h) Condition monitoring of circuit breaker like electrical wear, preventive maintenance alarm, circuit breaker travel time, gas pressure monitoring, etc.
- (i) Spring charging control
- (j) Interlock for operation
 - (a) Closing interlocks
 - (b) Tripping interlocks
- (k) Complex logic generation using I/Os.
 - (a) A number of inputs and outputs are possible.
 - (b) Analog inputs transducers like RTDs (Resistance Temperature Detectors) are also possible.
 - (c) Logic gate functions like AND, OR, NAND, NOR are possible.
 - (d) Flip-flops and timers are available.

14. Wide range of Facilities Numerical relays have a vast range of facilities. Industrial customers have been quite enthusiastic and innovative in maximising utilisation of these features for best returns on their capital investment. Some features appreciated and adopted by the industry are

- (a) *Group setting* Virtually more than one relay
- (b) *Self-monitoring/internal relay failure*
- (c) *Circuit-breaker failure protection (CBFP)*
- (d) *Events, e.g., start-trip/history/disturbance recorder for fault analysis*
- (e) *Load-shedding with intelligence* Use of df/dt , dv/dt functions
- (f) *Auto-synchronisation of alternators with infinite bus or other alternators.*
- (g) *Fast Bus Transfer Scheme* For bus transfer, the conventional scheme has been using discrete relays. Nowadays, the Fast Bus Transfer Scheme is possible using numerical relays.
- (h) *Transformer Differential Scheme* Features like ratio and phase-angle correction, zero-sequence current and harmonic filtration are utilised. Variable bias characteristic is available.
- (i) *Numerical Distance Protection Relays*

These relays provide the following features:

- Flexibility of selecting quadrilateral or mho characteristics
- Switch-on-to-fault (SOTF) feature
- Fuse failure
- Loss of voltage
- Fault locator
- Disturbance recorder
- Weak in-feed and current reversal
- Autoreclosure
- Check synchronisation
- Directional/non-directional overcurrent and earth fault protection
- Local breaker back-up (LBB) protection
- Overvoltage/undervoltage protection

4.2 NUMERICAL RELAY HARDWARE

4.2.1 Organisation

Numerical relays have inbuilt computing devices, and digital techniques are being used to acquire data regarding current and voltage derived from power systems through CT and PT. These are called analog inputs, which when processed arrive at the decision for trip or non-trip of the associated circuit breaker.

The online computing device is a fast-acting microprocessor or digital signal processor (DSP). The entire operation from data acquisition to decision making can be completed in about 20 milliseconds (i.e., 1 cycle). The relay operates on in-built software which includes the settings governed by the relay tripping logic. These settings can be set by communication channels from local or remote or HMI (Human Machine Interface).

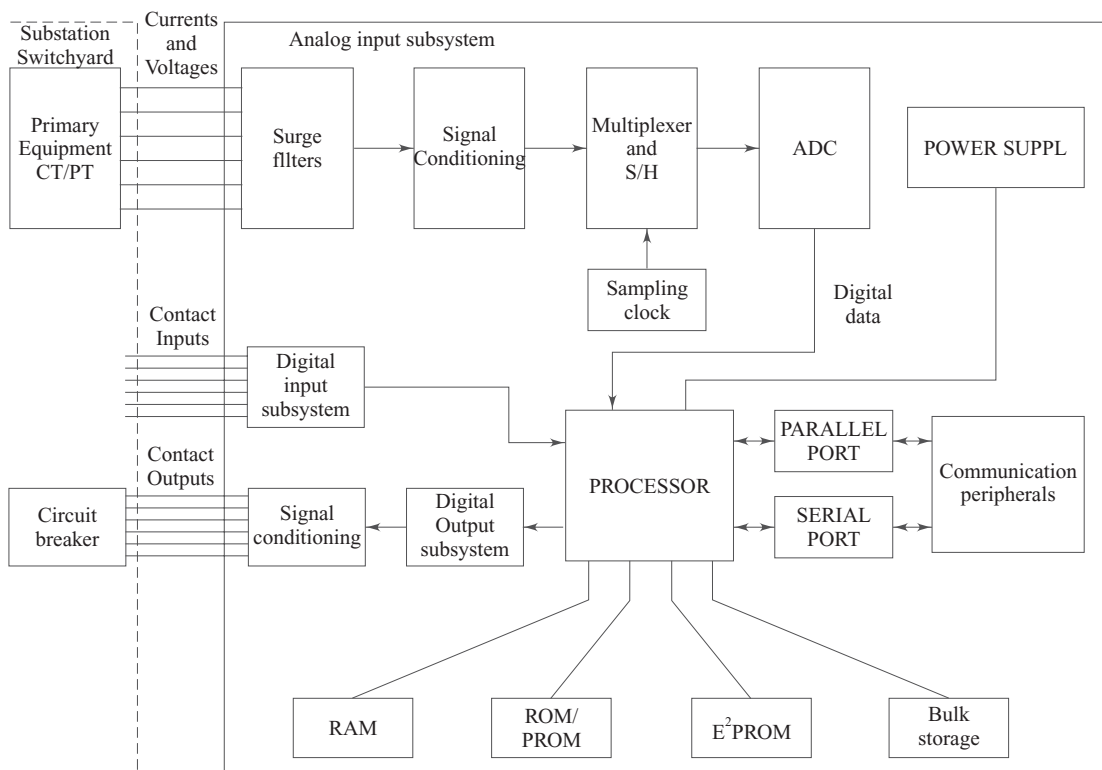


Fig. 4.4 Organisation of a numerical relay

Figure 4.4 shows the internal organisation of a numerical relay. The broad classification of the components inside a numerical relay is elaborated as follows:

- (a) **Analog Input Subsystem** Analog signals like currents and voltages are derived from the switchyard of the substation. These analog signals are then multiplexed, sampled and converted to digital signals. This process is known as *discretisation* in the area of digital signal processing. Moreover, surge filters are required for protection of the low-voltage digital components. Signal conditioning is required to adjust and match voltage levels to the input range of an ADC. An analog low-pass filter is also required

to block the higher unwanted frequency components to avoid aliasing. The details are explained later.

- (b) **Digital Input Subsystem** Digital input consists of the status of other relays and the circuit breaker (open or close) in the associated network.
- (c) **Processor** Fast acting microprocessors and microcontrollers were typically used in earlier times. Nowadays, digital signal processors (DSP) are used in numerical relays, which are faster in comparison to microcontrollers. Earlier, DSPs used specialised multiplication hardware and instructions to achieve fast multiplications, and contained additional hardware, such as wide accumulator registers, to increase numeric fidelity. Clock speeds of current mainstream DSPs have increased between 50 MHz to 100 MHz, with the latest DSPs executing at 200 MHz or higher. Some high-end DSP processors include two multiplication units and can compute two instructions in every cycle. At 200 MHz, each instruction pair thus requires only 5 ns.
- (d) **Data and Program Storage** The Random Access Memory (RAM) of a computer holds the acquired samples from the input system. It also acts as a buffer storage for additional samples if the relaying algorithm takes time. Apart from this storage, the RAM acts as what is called a *data scratch pad*, i.e., a temporary storage to be used during the filtering algorithm and relay algorithm execution. The ROM (Read Only Memory) stores the program permanently. The ROM is used for storing the relay logic and the monitor program required for interaction between the user/operator and the relay. The EE-PROM (Electrically Erasable Programmable Read Only Memory) is needed for storing parameters which need to be changed from time to time, for example, relay settings. Flash Memory has replaced EE-PROM in recent times.

The bulk storage memory is required for storing historical data files. This is used for storing time-tagged event data, fault related data tables and recording of significant transient events of the power system.

The digital filter program is essential to all relaying applications. The data samples acquired within the RAM are passed through the digital filter program. The algorithms for extracting phasors are discussed later.

- (e) **Digital Output Subsystem** This subsystem is used to give trip signals, alarm and control signals to the external system.
- (f) **Power Supply** The relay has to be operative even if the station supply is not available. Thus, an uninterrupted dc supply is provided to the numerical relay by means of battery-charger sets.
- (g) **Communication Peripherals and Protocol** Communication facility is available with various communication ports like RS 232/485, RJ 45, etc. Communication between the numerical relay and a personal desktop/laptop computer can be established through Ethernet and fiber optical cables.

A specific set of communication rules is called a *protocol*. Each relay manufacturer has patented protocols for communication with their relays. Even communication protocols are different for relays of different platforms of the same manufacturers like SPA, Modbus, Profibus, LON, IEC 60870 series, etc. There is no problem with patented communication protocols as individual communication is possible. But with the modern concept of substation integration and automation (i.e., SCADA and EMS) interoperability of relays with some common communication protocol has to be realised. In

these schemes, all the relays of the substation are integrated with some common network for the substation level and also remote communication. Due to this requirement, a common communication protocol IEC 61850 has been developed.

The approach of IEC 61850 is to subdivide functions into the smallest possible objects called *logical nodes*, which communicate with each other. Each logical node has its own set of data. The data are exchanged following the rules, which are called *services*. These generic data and services are mapped to a mainstream communication stack comprising Manufacturing Message Specification (MMS), Transmission Control Protocol/Internet Protocol (TCP/IP), and Ethernet. Features of IEC 61850 can be summarised as follows:

- (i) It is based on the Ethernet standard.
- (ii) It has standard communication with TCP/IP.
- (iii) It has a standardised language for describing a substation.
- (iv) It defines the structure for protection and control.
- (v) It establishes communication between bay devices.
- (vi) It stores fault records in the Comtrade format.
- (vii) It has time synchronisation with SNTP (Simple Network Time Protocol).

4.2.2 Facilities available in Commercial Numerical Relays

1. **Input/Output** Inputs may be CT, PT, external contacts, etc., while outputs will be contacts to be used for the various executions.
2. **Software** Every company has its own software used for relay configuration, setting LED assignments, etc.
3. **HMI (Human Machine Interface)** Some primary data can be available on the local display of the unit, i.e., menu through a PC (Personal Computer). It will display the data, viz., service values, fault current and voltage prior to the fault and during the fault, time to operate the relay, distance of the fault, indications and tripping phase affected, carrier inter-trip, carrier signal send/receive, etc.
4. **Communication** This is done with the relay by the PC through software for the respective make of the relay. The relay can be set, configured and read by PC, and the stored data can be taken in the PC for analysis.
5. **DR (Disturbance Recorder)** The relay has a storage facility of events and disturbances. The DR can take waveforms of voltage and current for each phase and the neutral phase. The decision-taking time by the relay, operating time of the relay, tripping time, carrier send/receive are precisely recorded by the relay. The DR is useful in analysis which can further lead to upgrading of coordination equipment if necessary.
6. **Logic** Charts can be prepared in the relay for assigning special functions in addition to the existing functions of the relay.
7. **Metering** The numerical relays also have metering facility with maximum/minimum records.
8. **Group Settings** Generally, four groups of setting values can be stored and any one can be made active. The present set of active groups can be viewed in the menu.

4.3 DIGITAL SIGNAL PROCESSING

The theoretical background of the concepts of digital signal processing is essential for wholesome understanding of numerical relaying. A separate course on digital signal processing is generally included in the undergraduate level electrical-engineering degree course. However, the concepts are reviewed here for completeness of the topic.

The block diagram of digital signal processing is shown in Fig. 4.5. Various components and aspects of digital signal processing are explained below.

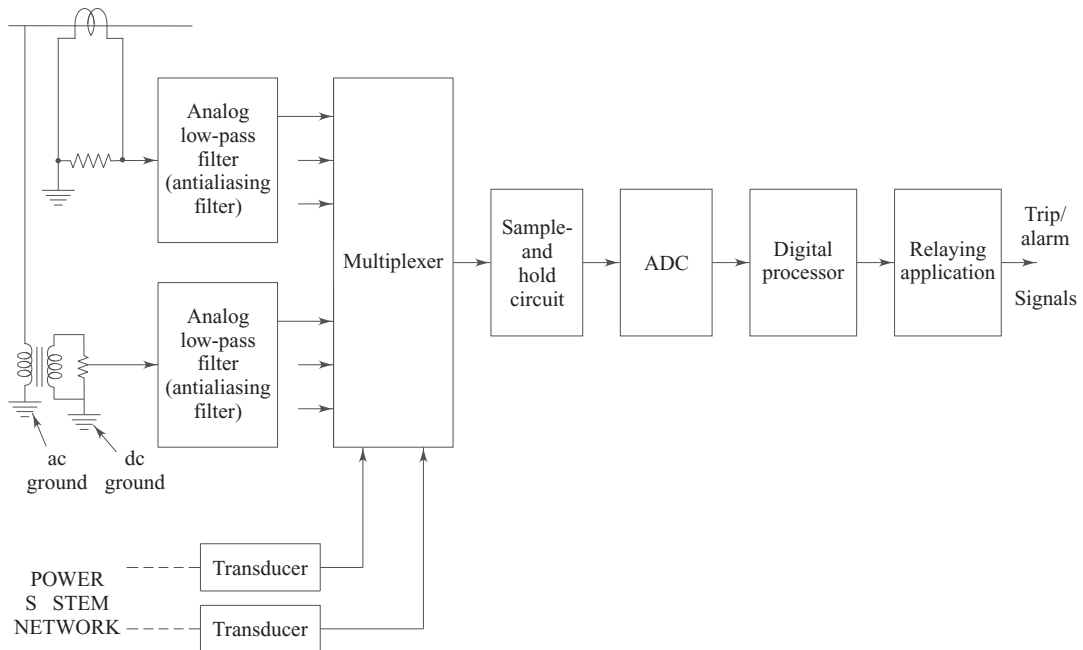


Fig. 4.5 Block diagram of digital signal processing

4.3.1 Data Acquisition System

The components of a data acquisition system are shown in Fig. 4.5. The current and potential transformers are used for two purposes. Firstly, they are used to scale down the levels to become compatible with that of the digital subsystem. Secondly, they provide isolation between the power circuit and the measuring and protective hardware. These scaled-down analog signals must be converted to voltage signals suitable for conversion to digital form. The voltage developed across a resistor connected to the secondary of a CT injects the current juice to the numerical relay. Moreover, a resistive potential divider arrangement across the P.T.'s secondary feeds the required potential juice.

For other electrical and thermal signals, suitable transducers are used which convert the primary relaying quantities to equivalent dc analog quantities. Digital inputs to the numerical relay are usually the contact status, obtained from other relays or circuit breakers. When the digital inputs are derived from contacts within the yard, it is necessary to apply surge filtering and (or) optical isolation in order to isolate the numerical relay from the transient surges. Surges are induced on wiring connected to the relays like that of power supply,

analog and digital inputs. Industry standards have been prepared to define the requirements of surge filtering. IEEE standard: C 37.90a, which is generally called the SWC standard defines the surge wave as follows:

- (1) **Oscillatory wave** 1–1.5 MHz, 2.5–3 kV, decay to half value in greater than 6 μ s.
- (2) **Unidirectional (Fast Transient)** 4–5 kV, rise time less than 10 μ s, decay to half value in 100–200 μ s.

IEC standard 255–4 also defines a surge wave with similar specifications.

Surge filters for analog signals are shown in Fig. 4.4. The surges are produced due to faults and switching operations on the power system or the control room itself. Suppression of these surges can be achieved by careful grounding and shielding of leads and equipments as well as low-pass filtering. Surge filters are low-pass filters with cut-off frequencies of the order of hundreds of kHz. They do not affect the relaying input signals. Nonlinear energy absorbing Metal Oxide Varistors (MOVs) may also be used in addition to the low-pass filters in some designs.

4.3.2 Sample and Hold (S/H) Circuit

Figure 4.6 shows a simplified diagram for the sample-and-hold. The S/H circuit is an analog circuit which acts like a voltage memory device. The analog input voltage is acquired and stored on a high-quality capacitor with low leakage and low dielectric absorption characteristics. An electronic switch is connected to the hold capacitor. OPAMP-1 is an input buffer amplifier with high input impedance. OPAMP-2 is the output amplifier; it buffers the voltage on the hold capacitor.

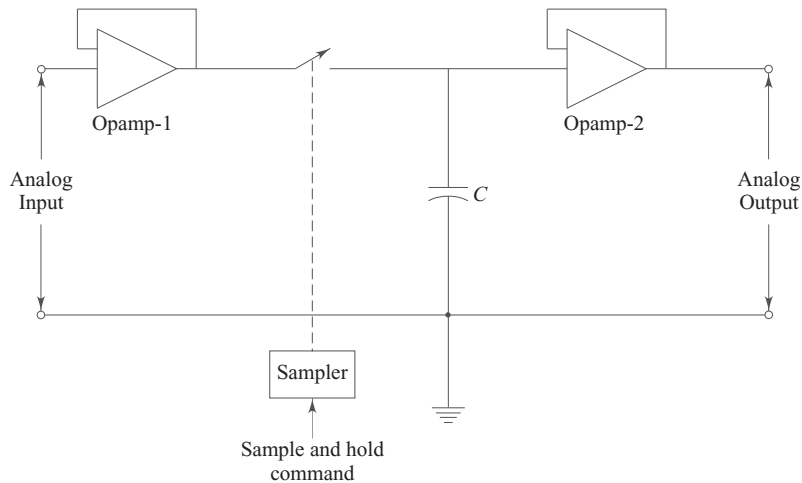


Fig. 4.6 Sample and hold circuit

Two schemes are available for sampling, viz.,

- (a) Non-simultaneous sampling
- (b) Simultaneous sampling

In a relaying application, generally the three-phase currents and the three-phase voltages are to be acquired. So the magnitude as well as phase of each signal is significant, and hence all signals must be sampled at the same instant. Hence, a simultaneous sampling scheme is preferred. Figure 4.7 shows a simultaneous sampling scheme.

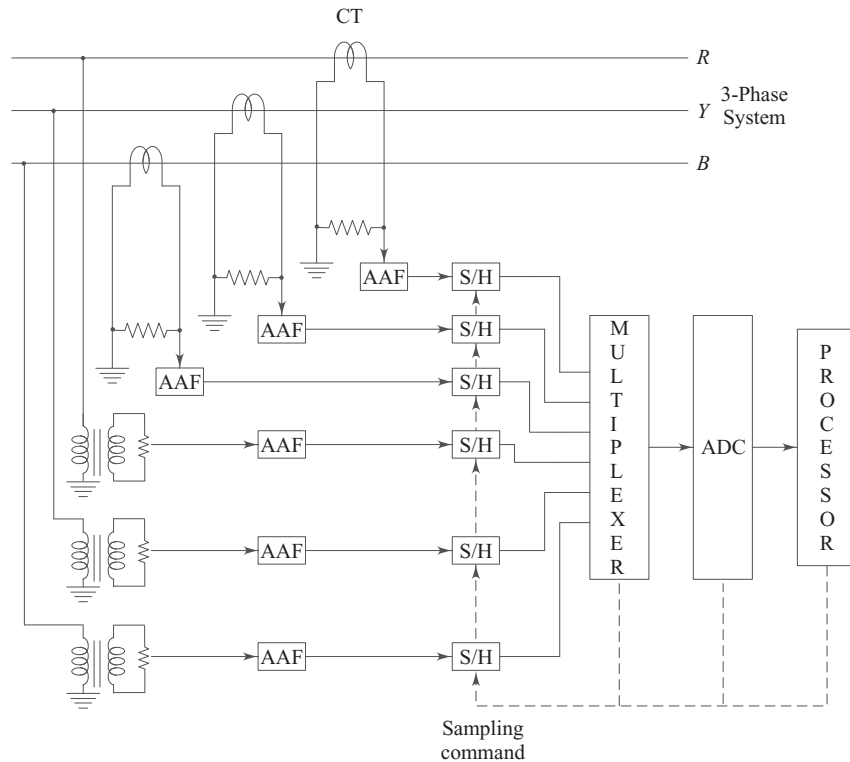


Fig. 4.7 Simultaneous sampling scheme with single ADC

All the input analog signals are sampled at the same instant. Then the multiplexer takes the different signals inside as per the sequence and the ADC interfacing are coordinated by proper programming. Nowadays, multichannel ADCs with simultaneous sampling are also available. So S/H and multiplexer functions are incorporated within the ADC itself. Generally, the successive approximation type ADCs having conversion time in the range of 15 to 30 μs are used for relaying applications. The time between two sampling instants has to accommodate the conversion time of the ADC and allow the processor to take the digital value inside the input buffer RAM. Also, the sampling rate must fulfill the Nyquist criterion. Discretisation has its own issues, which can be resolved as explained below.

4.3.3 Sampling Theorem (Nyquist Criterion)

If the sampling frequency ω_s , defined as $2\pi/T_s$ (where T_s is the sampling period) is greater than $2\omega_1$ or,

$$\omega_s > 2\omega_1 \quad (4.1)$$

where, ω_1 is the highest-frequency component present in the analog signal $x(t)$ then the signal $x(t)$ can be reconstructed completely from the sampled signal $x(t)$. This is depicted in frequency domain in Fig. 4.8. If this is not done, i.e., $\omega_s < 2\omega_1$ then three misleading or problematic effects are observed in the sampled output. These effects are (1) Aliasing, (2) Same output, and (3) Folding. They are described as follows:

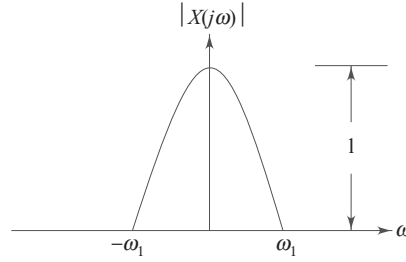


Fig. 4.8 Frequency spectrum of analog input signal

(a) Aliasing It is the phenomena by which the frequency component $\omega_s - \omega_1$ (in general $n\omega_s \pm \omega_1$ where n is an integer) will appear in the output as if it were a frequency component at $\omega = \omega_1$. It is not possible to distinguish the frequency spectrum at $\omega = \omega_1$ from that at $\omega = n\omega_s \pm \omega_1$. The frequency $n\omega_s \pm \omega_1$ is called an alias of ω_1 .

We have already seen in the sampling theorem that f_s shall be greater than $2f_0$, i.e., T_s shall be lesser than $\frac{1}{2} T_0$, now let us see its significance, by understanding the aliasing effect with an example.

As seen above,

$$\begin{aligned} x(n) &= \sin(2\pi f_0 (n \cdot T_s)) \\ &= \sin(2\pi f_0 (n \cdot T_s) + 2\pi m) = \sin(2\pi (f_0 n \cdot T_s + m)) \\ &= \sin\left(2\pi \left(f_0 + \frac{m}{n \cdot T_s}\right) n \cdot T_s\right) \end{aligned}$$

Let m be an integer multiple of n , i.e., $\frac{m}{n} = k$, where k is an integer. Also, $T_s = \frac{1}{f_s}$,

$$\therefore x(n) = \sin(2\pi (f_0 + kf_s)n \cdot T_s) \quad (4.2)$$

This leads to the conclusion that if an analog signal with frequency f_0 is sampled at a frequency f_s samples/s, then the output will be same for values of a sine wave of f_0 Hz and another sine wave of $(f_0 + kf_s)$ Hz, where k is a positive or negative integer.

In practice, the input analog signal will essentially be a fundamental frequency signal along with higher frequency signals in the form of harmonics (some of which may be useful and required for decision making by relay) and unwanted noise signals.

Let us take an example of fifth harmonic component of 250 Hz. Let us assume a pure sine wave input of 250 Hz for the purpose of simplicity.

$$\text{So, } f_0 = 250 \text{ Hz}$$

$$\text{So } T_0 = \frac{1}{250} = 4 \text{ ms}$$

$$\text{As } f_s = 200 \text{ Hz, } T_s = \frac{1}{200} = 5 \text{ ms}$$

This sampling frequency does not fulfill the Nyquist criteria, which says that $f_s > 2f_0$. For $f_0 = 50$ Hz, this f_s of 200 Hz is as per the sampling theorem. But we have taken a case where we suppose there is a component of 250 Hz in this input signal of 50 Hz.

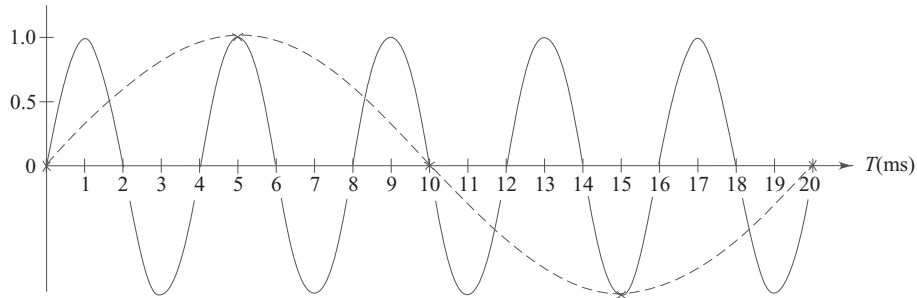


Fig. 4.9 250 Hz signal sampled at a frequency $f_s = 200$ Hz

So when samples are taken, the values captured for this fifth harmonic component are tabulated below. The values at these sampling instants are indicated by 'x' in Fig. 4.9. The sampled value is a sine wave of frequency 50 Hz.

Table 4.1 Magnitudes of sampled input sequence

Sampling Instant in ms	Magnitude
0	$x(0) = 0$
5	$x(1) = 1$
10	$x(2) = 0$
15	$x(3) = -1$
20	$x(4) = 0$

This graphically confirms the mathematical expression,

$$x(n) = \sin(2\pi(f_0 + kf_s)n \cdot T_s)$$

Thus, the 250 Hz component will take an alias of 50 Hz after sampling. This can mislead the decision making in the relay. Thus, it needs to be re-emphasised that the sampling frequency should be chosen properly. Sufficient information regarding higher useful components shall be obtained. So $f_s > 2f_1$, where f_1 is the highest component to be used for the algorithm. All further components with frequency greater than f_1 Hz shall be removed at the input level before the sample-and-hold circuit by using Anti-Aliasing Filters (AAF) as shown in Fig. 4.7.

(b) Same Output If the sampling frequency is same or an even integral multiple of the analog input signal frequency then the sampled signals will have the same value at all instants. This is shown in Fig. 4.10.

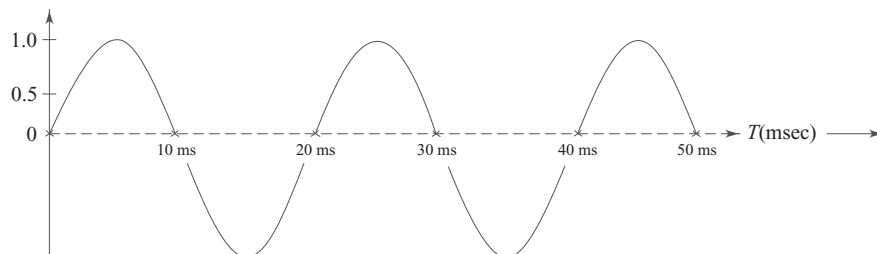


Fig. 4.10 Analog sine wave of 50 Hz frequency

Let us consider a continuous-time analog signal of a sinusoidal nature.

$$\text{Let } x(t) = \sin \omega_0 t \quad (4.3)$$

where; $\omega_0 = 2\pi f_0$, and $f_0 = 50$ Hz as shown in Fig. 4.10.

Let the sampling frequency f_s be defined as samples taken per second. So sampling period is $T_s = \frac{1}{f_s}$ s.

The samples taken at successive sampling instants with a gap of $T_s = 1/f_s$ s will have values as tabulated below:

Table 4.2 Values of successive samples

Sample	Value
$x(0)$	$\sin (2\pi f_0 (0.T_s))$
$x(1)$	$\sin (2\pi f_0 (1.T_s))$
$x(2)$	$\sin (2\pi f_0 (2.T_s))$
$x(3)$	$\sin (2\pi f_0 (3.T_s))$
\vdots	\vdots
$x(n)$	$\sin (2\pi f_0 (n.T_s))$

$$\text{Let } f_s = 100 \text{ Hz,}$$

$$\therefore T_s = \frac{1}{f_s} = \frac{1}{100} = 0.01 \text{ s} = 10 \text{ ms}$$

$$\text{As } f_0 = 50 \text{ Hz,}$$

$$\therefore T_0 = \frac{1}{f_0} = \frac{1}{50} = 0.02 \text{ s} = 20 \text{ ms}$$

$$\therefore T_s = \frac{1}{2} T_0$$

As per Table 4.2,

$$\begin{aligned} x(0) &= \sin (2\pi f_0 (0.T_s)) \\ &= \sin(0) = 0 \end{aligned}$$

$$\begin{aligned} x(1) &= \sin \left(2\pi \cdot \frac{1}{T_0} \cdot (1.T_s) \right) \\ &= \sin \left(2\pi \cdot \frac{1}{T_0} \cdot (1.T_s) \right) \\ &= \sin \pi = 0 \end{aligned}$$

$$\begin{aligned} \text{Similarly, } x(2) &= \sin \left(2\pi \cdot \frac{1}{T_0} \cdot \left(2 \cdot \frac{1}{2} T_0 \right) \right) \\ &= \sin 2\pi = 0 \end{aligned}$$

The sampling instants are denoted by the 'x' sign in Fig. 4.10. The values at all sampling instants are zero. So we get the same output at all sampling instants.

So whenever we deal with a periodic wave like a sine wave or a cosine wave, the sampling period T_s shall be carefully decided as we know that

$$x(n) = \sin (2\pi f_0 (n.T_s)) = \sin (2\pi f_0 (n.T_s) + 2\pi m) \quad (4.4)$$

where m is an integer.

(c) Folding The phenomenon of the overlap in the frequency spectra is known as folding. Figure 4.11 shows the regions where folding occurs. This creates a problem in deciding the cut-off frequency of the low-pass filter to be kept after the sampling.

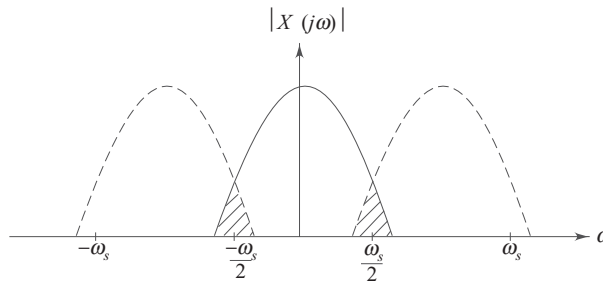


Fig. 4.11 Folding error

4.3.4 Anti-Aliasing Filter (AAF)

To impose a strict band limit on the input signal, AAFs are used before sampling. AAF is a low-pass filter. It introduces magnitude scaling and phase shifting, which has to be taken care of in the software by providing correction or compensation in the algorithm. The cut-off frequency f_1 of the AAF is based on the requirement of the algorithm used for protection of a particular equipment.

The role of an AAF is depicted in Fig. 4.12 below. It removes higher frequency noise and unwanted signals so that they do not create alias in the sampling process.

As seen in Fig. 4.12, after sampling, in frequency domain, we observe repeating spectrums which are actually pseudo-spectrums. These spectrums are displaced by f_s Hz. So, it is difficult to discriminate between original signal lobe and replicated lobes due to the aliasing effect as explained in the previous topic. To have a gap between these spectrums is essential. This gap is due to the condition $f_s > 2f_1$. If $f_s = 2f_1$ then there will be no gap and it will be easy to demarcate. If $f_s < 2f_1$ then there will be an overlap and hence it will be difficult to demarcate. For the purpose of filtering out these pseudo-spectrums, digital filtering algorithms are implemented in the program inside the processor.

4.3.5 Sampling Rate Criteria

Sampling rate is represented in samples per cycle. So if the sampling rate is 4 samples per cycle then sampling frequency is $4 \times 50 = 200$ samples per second, for a 50 Hz input signal. The sampling rate is also related to the estimation technique implemented in the algorithm for the phasors. The considerations which guide the selection of a sampling rate are given as follows:

Table 4.3 Selection criteria for sampling rate

S. No.	Lower Sampling Rate	Higher Sampling Rate
1.	Larger time available for computations in between two sampling instants	Lesser time available for computations in between two sampling instants
2.	Less samples, so less computations in estimation	More samples, so more computations in estimation
3.	Not so good reconstruction of original analog signal; larger errors due to random noise	Better reconstruction of original analog signal; smaller errors due to random noise
4.	More delay involved in anti-aliasing filter	Smaller delay involved in anti-aliasing filter

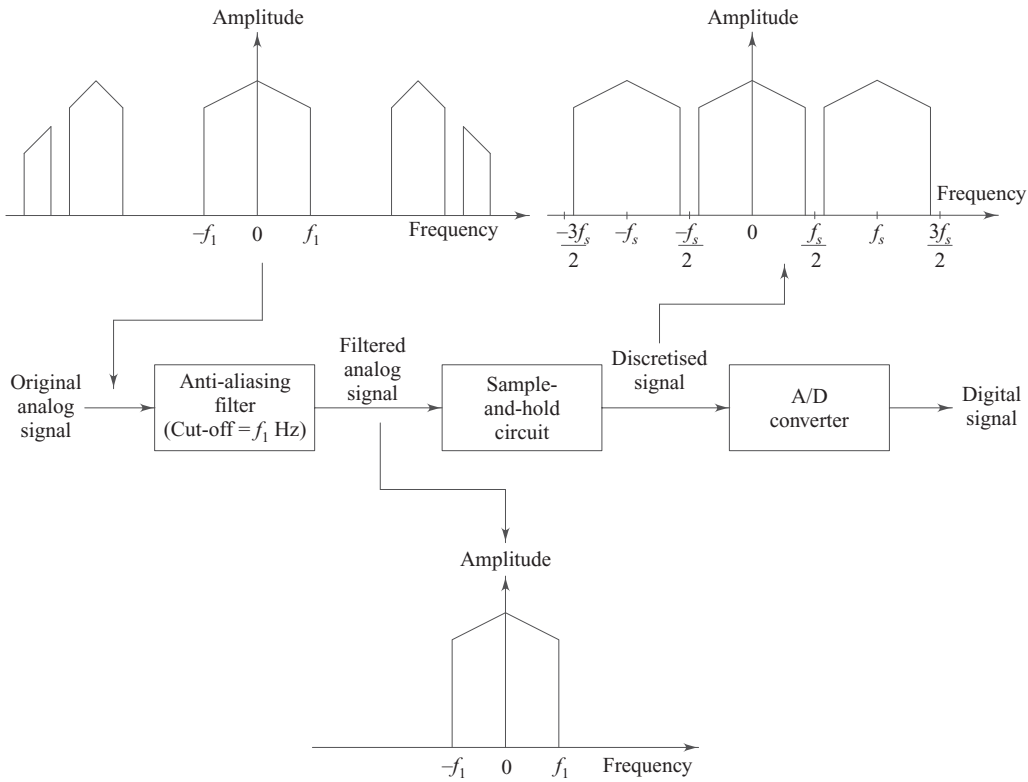


Fig. 4.12 Anti-aliasing filtering prior to sampling at a rate of f_s Hz

For numerical relaying applications, typical sampling rates range from 4 to 96 samples per cycle. The lower limit on the sampling rate is imposed by Nyquist criteria, and the upper limit is imposed by computations to be done between the two samples. Conversion time of ADC is not an issue now as ADCs have conversion times in terms of 15–30 μ s.

4.4 ESTIMATION OF PHASORS

Let us understand how to calculate or estimate the value of impedance in a numerical distance relay. The information available to the processor is in the form of digital samples which are in discrete-time domain. They are acquired at a particular sampling rate as mentioned in the previous section. So to evaluate the value of impedance, first of all it is necessary to estimate the voltage and current phasor. To understand the concept, let us take a single-phase circuit as shown in Fig. 4.13. The system frequency is 50 Hz.

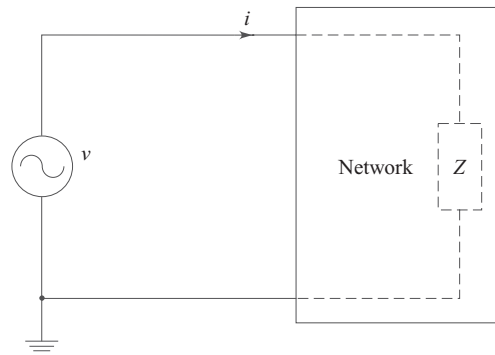


Fig. 4.13 Single-phase circuit of a power system network

The instantaneous voltage and current are given by

$$v(t) = V_m \sin(\omega t + \phi_v) \quad (4.5)$$

$$i(t) = I_m \sin(\omega t + \phi_i) \quad (4.6)$$

We will first estimate the voltage phasor ($V_m \angle \phi_v$). As there are two unknowns, the minimum number of samples required in a cycle to estimate unknowns is two. The sampling period is taken as Δt seconds. Let the sampling instants be t_1 and t_2 respectively.

$$V_1(t_1) = v_1 = V_m \sin(\omega t_1 + \phi_v)$$

Let

$$\theta_1 = \omega t_1 \text{ and } \theta_2 = \omega t_2$$

So,

$$v_1 = V_m \sin \theta_1 \cos \phi_v + V_m \cos \theta_1 \sin \phi_v$$

$$v_2 = V_m \sin \theta_2 \cos \phi_v + V_m \cos \theta_2 \sin \phi_v$$

Now, $V_m \cos \phi_v$ and $V_m \sin \phi_v$ are unknowns. So we represent them in the matrix form as

$$\begin{bmatrix} v_1 \\ v_2 \end{bmatrix} = \begin{bmatrix} \sin \theta_1 & \cos \theta_1 \\ \sin \theta_2 & \cos \theta_2 \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} \quad (4.7)$$

So,

$$\begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} = \begin{bmatrix} \sin \theta_1 & \cos \theta_1 \\ \sin \theta_2 & \cos \theta_2 \end{bmatrix}^{-1} \begin{bmatrix} v_1 \\ v_2 \end{bmatrix} \quad (4.8)$$

Hence,

$$\begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} = \frac{1}{\sin(\theta_1 - \theta_2)} \begin{bmatrix} \cos \theta_2 & -\cos \theta_1 \\ -\sin \theta_2 & \sin \theta_1 \end{bmatrix} \begin{bmatrix} v_1 \\ v_2 \end{bmatrix} \quad (4.9)$$

So,

$$V_m \cos \phi_v = \frac{v_1 \cos \theta_2 - v_2 \cos \theta_1}{\sin(\theta_1 - \theta_2)} \quad (4.10)$$

and

$$V_m \sin \phi_v = \frac{v_2 \sin \theta_1 - v_1 \sin \theta_2}{\sin(\theta_1 - \theta_2)} \quad (4.11)$$

It should be noted that if $\theta_1 - \theta_2 = \pm m\pi$ where m is an integer then $\sin(\theta_1 - \theta_2) = 0$, which does not lead to successful estimation. This is in line with what we have presented under the topic of sampling theorem.

On obtaining the above, V_m and ϕ_v are computed as follows:

$$V_m = \sqrt{(V_m \cos \phi_v)^2 + (V_m \sin \phi_v)^2} \quad (4.12)$$

and

$$\phi_v = \tan^{-1} \frac{V_m \sin \phi_v}{V_m \cos \phi_v} \quad (4.13)$$

Similarly, current estimate can be obtained. Impedance can be computed as a ratio of voltage and current estimate.

A generic form of the expression for unknown voltages is given by the following equation:

$$V_m^k \cos \phi_v^k = \frac{V_{k-1} \cos \theta_k - V_k \cos \theta_{k-1}}{\sin(\Delta\theta)} \quad (4.14)$$

$$V_m^k \sin \phi_v^k = \frac{V_k \sin \theta_{k-1} - V_{k-1} \sin \theta_k}{\sin(\Delta\theta)} \quad (4.15)$$

In the above expression, we have replaced the sample-2 by the most recent k^{th} sample. Similarly, the sample-1 is replaced by $(k-1)^{\text{th}}$ sample. Also, in generic form, the first sample is obtained at $t = 0$ and the angle corresponding to the k^{th} the sample is given by $\theta_k = k\omega_0 \Delta t$. Here, the sampling window or data window has 2 samples per window as shown in Fig. 4.14.

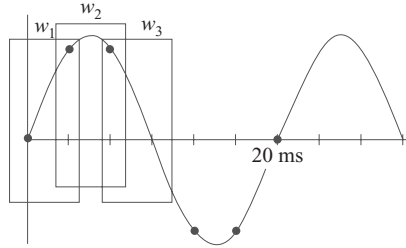


Fig. 4.14 Two sample window for estimation

The data windows w_1 , w_2 , w_3 contain the respective set of samples which are used in estimation. Each window has 2 samples, hence it is called a 2-sample window. A new sample is added in each window and the older sample is removed from computation.

In any relaying application, computations for estimation have to be completed before the arrival of the next sample. If a uniform sampling rate with period of Δt seconds is used then,

$$\theta_{k-1} - \theta_k = \Delta\theta, \text{ a constant.}$$

4.4.1 Implementation of 2-sample Window in Ideal Conditions

To understand the concept of a 2-sample window, let us take an input sinusoidal voltage signal $v(t) = 100 \sin(2\pi \times 50 \times t + 30^\circ)$ and sampling period of 5 ms (4 samples per cycle or 200 samples per second). Sampling is initiated at $t_0 = 0$ s.

The sequence of the first 10 voltage samples is shown graphically on the waveform in Fig. 4.15.

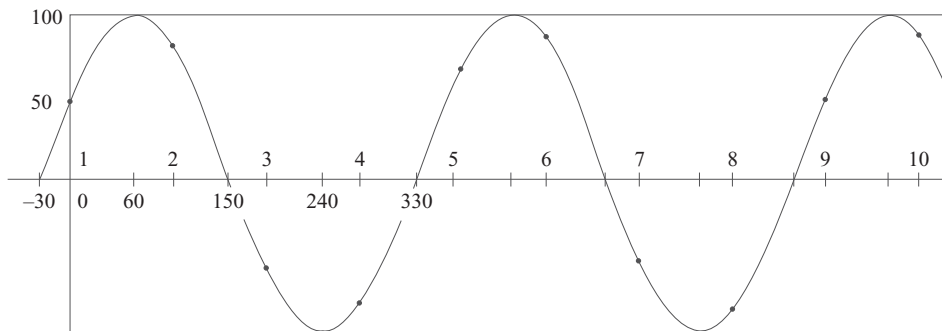


Fig. 4.15 Samples at $f_s = 200$ Hz for voltage signal with $f_0 = 50$ Hz

Using the equations derived in the previous topic, to obtain values of the estimate of V_m and ϕ_v , V_m can be computed using 2 samples per window and the result is $V_m = 100$ V, for each data window. Students can try this out as an exercise using any programming language tool or software package.

4.4.2 Implementation of 2-sample Window with Real-life Conditions

During real conditions, the voltage signal will not be a perfect sinusoidal. Also, PT, ADC etc., introduce errors which can be modeled as noise. The noise has a zero mean and its standard deviation gives the accuracy of the meter. Typically, noise is modeled by zero mean Gaussian distribution. This means that if a 0–100 V voltmeter

Table 4.4 Magnitude of sampled voltage at successive sampling instants

Sample No.	1	2	3	4	5	6	7	8	9	10
$T(\text{ms})$	0	5	10	15	20	25	30	35	40	45
V	50.0	86.6	-50	-86.6	50.0	86.6	-50	-86.6	50.0	86.6

has a standard deviation of 1% then a measurement of say 100 V will be measured anywhere between 97–103 V, for 99% of instants. This is explained by Fig. 4.16.

The mathematical expressions for mean and standard deviation are given as follows. Let x_1 to x_n be n -samples under consideration. Then

$$\text{mean, } M = \frac{\sum_{i=1}^n x_i}{n} \quad (4.16)$$

$$\text{Standard deviation, } \sigma = \sqrt{\frac{\sum_{i=1}^n (x_i - M)^2}{n}} \quad (4.17)$$

Variance = σ^2 , square of standard deviation

To test the 2-sample window method of estimation with noise, we can use the random number generator for normal distribution available in the software packages for representing the standard deviation of noise.

Standard deviation increases with increase in noise level, because it is dependent on noise. It can be found from results that actual estimates are far removed from the mean, which is highlighted by the increase in standard deviation. So the effect of noise is associated with the number of samples included in a data window. In actual conditions, a method to filter noise is a prerequisite to estimation of V_m and ϕ_v . This requires redundancy in measurement, i.e., more samples per window. Redundancy in measurement is defined as the ratio of the actual number of measurements used for estimation to the minimum number of measurements required for estimation.

4.4.3 Three Samples per Data Window

As the minimum number of samples required in a data window for estimation is 2 and we include 3 samples in each data window, the redundancy factor in this technique is 3/2, i.e., 1.5. Students can perform an exercise using programming and prove that for the same input signal, noise is better estimated or standard deviation of the estimate reduces by using a large data window.

The sinusoidal voltage signal is considered as an input to derive the expression for finding estimate. The last three samples are depicted below in terms of equations.

$$V_k = V_m \sin(\omega t_k + \phi_v) \quad (4.18)$$

$$V_{k-1} = V_m \sin(\omega t_{k-1} + \phi_v) \quad (4.19)$$

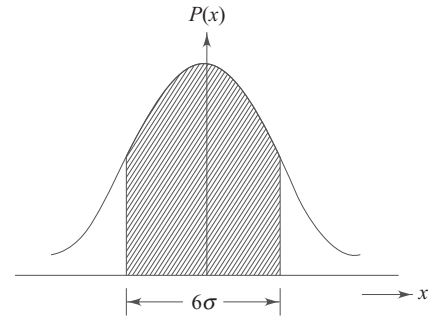
$$V_{k-2} = V_m \sin(\omega t_{k-2} + \phi_v) \quad (4.20)$$

Using the trigonometric relationship, replacing ωt by θ ,

$$V_k = V_m \sin \theta_k \cos \phi_v + V_m \cos \theta_k \sin \phi_v$$

$$V_{k-1} = V_m \sin \theta_{k-1} \cos \phi_v + V_m \cos \theta_{k-1} \sin \phi_v$$

$$V_{k-2} = V_m \sin \theta_{k-2} \cos \phi_v + V_m \cos \theta_{k-2} \sin \phi_v$$


Fig. 4.16 Gaussian distribution

Rearranging to obtain matrix notation,

$$\begin{bmatrix} V_k \\ V_{k-1} \\ V_{k-2} \end{bmatrix} = \begin{bmatrix} \sin \theta_k & \cos \theta_k \\ \sin \theta_{k-1} & \cos \theta_{k-1} \\ \sin \theta_{k-2} & \cos \theta_{k-2} \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} \quad (4.21)$$

To add the effect of noise, we can rewrite as

$$b = Ax + e \quad (4.22)$$

where, e represents vector of the noise in the last three samples

x is the vector of unknown to be found

b is the vector of samples

A is the vector of sine and cosine of last three sampling instants

Hence,

$$\begin{bmatrix} V_k \\ V_{k-1} \\ V_{k-2} \end{bmatrix} = \begin{bmatrix} \sin \theta_k & \cos \theta_k \\ \sin \theta_{k-1} & \cos \theta_{k-1} \\ \sin \theta_{k-2} & \cos \theta_{k-2} \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} + \begin{bmatrix} e_k \\ e_{k-1} \\ e_{k-2} \end{bmatrix} \quad (4.23)$$

The above equations cannot be solved in the simple way as done for 2-samples per window technique. We will have to resort to using the least-square estimation technique which is utilised wherever the unknowns are to be estimated with redundant measurements and the noise is too large.

4.4.4 Least-Square Estimation

The error or noise in the sample is required to be estimated and eliminated. To perform this task the method of least-square estimation is used.

The problem definition here can be like this: "We want to find a vector x such that Ax is nearest to vector b ". To find a solution, we define a residual vector e such that $e = b - Ax$. The Euclidian length of the vector $\sqrt{e_1^2 + e_2^2 + \dots + e_k^2}$ gives a measure of distance between Ax and b . We have to minimise the length of the residual vector e .

Instead of minimisation of the length of the residual vector, we can perform square of the length as the minimum is reached at a value which is the optimal value of x . This is also helpful in avoiding the problem of square roots in calculating the gradient.

So we can write the function which will give an optimal value of x . The scalar $1/2$ is introduced for ease; it does not affect the optimal value of x .

$$f(x) = \frac{1}{2} e^T e = \frac{e_1^2 + e_2^2 + \dots + e_k^2}{2} \quad (4.24)$$

$$f(x) = \frac{1}{2} (b - Ax)^T (b - Ax) \quad (4.25)$$

$$f(x) = \frac{1}{2} (b^T b - b^T Ax - x^T A^T b + x^T A^T Ax)$$

The minimum can be obtained by equating the gradient of this objective function to zero.

The gradient of the objective function $f(x)$ is given by

$$\nabla f(x) = 0 \quad (4.26)$$

Hence, $\nabla \left(\frac{1}{2} (b^T b - b^T Ax - x^T A^T b + x^T A^T Ax) \right) = 0$

$$\begin{aligned} A^T Ax - A^T b &= 0 \\ A^T Ax &= A^T b \end{aligned}$$

So

$$Ax = b$$

∴

$$e = b - Ax = 0 \quad (4.27)$$

This condition fulfills the elimination of error and gives the optimal value of x .

Applying this relation to the set of equations obtained for the 3-sample technique, we get,

$$\begin{bmatrix} \sum_{j=k-2}^k \sin^2 \theta_j & \sum_{j=k-2}^k \sin \theta_j \cos \theta_j \\ \sum_{j=k-2}^k \sin \theta_j \cos \theta_j & \sum_{j=k-2}^k \cos^2 \theta_j \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} = \begin{bmatrix} \sum_{j=k-2}^k \sin \theta_j V_j \\ \sum_{j=k-2}^k \cos \theta_j V_j \end{bmatrix} \quad (4.28)$$

Use the above equation to find out $V_m \cos \phi_v$ and $V_m \sin \phi_v$ and further find the magnitude V_m and phase ϕ_v as explained in the previous section.

The exercise based on the random number generator for evaluating expressions using software tools can be carried out. This will give results which lead to the conclusion that standard deviation reduces in the estimation process while using least-square estimation based on redundancy in measurement.

4.4.5 Comparison of 2-Sample and 3-Sample Technique

It should be clear to the reader by now that in the 2-sample technique, the data window is smaller and in the 3-sample technique, the data window is bigger. The error in estimate is more in the 2-sample technique as compared to the 3-sample technique. However, the equations exhibit that there are less computations in the 2-sample window and more computations in the 3-sample window for finding estimates of magnitude and phase of an input signal. Noise is filtered more effectively in the 3-sample per window technique.

So it leads to the observation that the basic conflict between speed and accuracy is also present in numerical relaying. The advancement in technology of fast processors is helping to address the problem of speed. There are many mathematical functions available in a digital signal processor to help in reducing the computation time for such cumbersome computations which are generally required to be completed in the period available between two sampling instants.

4.5 FULL-CYCLE FOURIER ALGORITHM

To understand the full-cycle Fourier algorithm, let us introduce the specification *time-span of a data-window*. Rather than specifying a data-window by the number of sample points, let us generalise it to be a data-window of one cycle time-span with k number of samples ($k > 2$) taken in a cycle.

The sampling rate is also generally specified in terms of samples per cycle. Typically, in a protective relaying algorithm, the use of 12 samples per cycle is a normal practice. If we consider a one-cycle data window with k samples then the equations are simplified and will reduce down to what is called the Fourier series.

Here, we use the convention of writing k samples as samples 0, 1, 2, ..., $k-1$.

In the $b = Ax + e$ form, we can write

$$\begin{bmatrix} V_{k-1} \\ V_{k-2} \\ \vdots \\ V_0 \end{bmatrix} = \begin{bmatrix} \sin \theta_{k-1} & \cos \theta_{k-1} \\ \sin \theta_{k-2} & \cos \theta_{k-2} \\ \vdots & \vdots \\ \sin \theta_0 & \cos \theta_0 \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} + \begin{bmatrix} e_{k-1} \\ e_{k-2} \\ \vdots \\ e_0 \end{bmatrix} \quad (4.29)$$

Using least square estimation, noise can be eliminated as follows:

$$\begin{bmatrix} \sum_{j=0}^{k-1} \sin^2 \theta_j & \sum_{j=0}^{k-1} \sin \theta_j \cos \theta_j \\ \sum_{j=0}^{k-1} \sin \theta_j \cos \theta_j & \sum_{j=0}^{k-1} \cos^2 \theta_j \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} = \begin{bmatrix} \sum_{j=0}^{k-1} \sin \theta_j \cdot V_j \\ \sum_{j=0}^{k-1} \cos \theta_j \cdot V_j \end{bmatrix} \quad (4.30)$$

Let us make an attempt to simplify.

$$\begin{aligned} \sum_{j=0}^{k-1} \sin \theta_j &= \sum_{j=0}^{k-1} \frac{\sin 2\theta_j}{2} \\ &= \sum_{j=0}^{k-1} \sin 2(\omega_0 \cdot j \cdot \Delta t), \text{ putting } \theta_j = \omega_0 \cdot j \cdot \Delta t \end{aligned} \quad (4.31)$$

We know that $\omega_0 \cdot k \cdot \Delta t = 2\pi$,

$$\therefore \omega_0 \cdot \Delta t = \frac{2\pi}{k}$$

$$\text{Therefore, } \sum_{j=0}^{k-1} \sin 2\omega_0 \cdot \Delta t \cdot j = \sum_{j=0}^{k-1} \sin \frac{4\pi}{k} \cdot j$$

The above summation will be zero for any value of $k > 2$.

$$\text{Alternatively, } k \cdot \Delta t = \frac{2\pi}{\omega_0}$$

It is apparent that

$$\sum_{j=0}^{k-1} \sin 2\omega_0 \cdot j \Delta t = \int_0^{\frac{2\pi}{\omega_0}} \sin 2\omega_0 \cdot t \cdot dt = 0 \quad (4.32)$$

So the two off-diagonal terms of the coefficient matrix A are zero. Now, let us evaluate the diagonal elements of this matrix.

$$\sum_{j=0}^{k-1} \sin^2 \theta_j = \int_0^{\frac{2\pi}{\omega_0}} \sin^2 \omega_0 t \cdot dt \quad (4.33)$$

$$\sum_{j=0}^{k-1} \cos^2 \theta_j = \int_0^{\frac{2\pi}{\omega_0}} \cos^2 \omega_0 t \cdot dt \quad (4.34)$$

These two terms are equal and can be proved to be equal to $k/2$. Thus, coefficient matrix A becomes diagonal,

$$\begin{bmatrix} k/2 & 0 \\ 0 & k/2 \end{bmatrix} \begin{bmatrix} V_m \cos \phi_v \\ V_m \sin \phi_v \end{bmatrix} = \begin{bmatrix} \sum_{j=0}^{k-1} \sin \theta_j \cdot V_j \\ \sum_{j=0}^{k-1} \cos \theta_j \cdot V_j \end{bmatrix} \quad (4.35)$$

This yields decoupling of the two unknowns which reduces computations.

$$V_m \cos \phi_v = \frac{2}{k} \sum_{j=0}^{k-1} v_j \cdot \sin \theta_j \quad (4.36)$$

$$V_m \sin \phi_v = \frac{2}{k} \sum_{j=0}^{k-1} v_j \cdot \cos \theta_j \quad (4.37)$$

The voltage signal $v(t) = V_m \sin(\omega t + \phi_v)$ can also be represented as

$$\begin{aligned} v(t) &= V_m \cos \phi_v \sin \omega t + V_m \sin \phi_v \cos \omega t \\ v(t) &= V_s \sin \omega t + V_c \cos \omega t \end{aligned} \quad (4.38)$$

$$\text{where, } V_s = V_m \cos \phi_v \quad (4.39)$$

$$\text{and } V_c = V_m \sin \phi_v \quad (4.40)$$

let us write in generalised form for L^{th} data-window,

$$V_s^L = \frac{2}{k} \sum_{j=L-k+1}^L v_j \cdot \sin \theta_j \quad (4.41)$$

$$V_c^L = \frac{2}{k} \sum_{j=L-k+1}^L v_j \cdot \cos \theta_j \quad (4.42)$$

The equations for $V_m \cos \phi_v$ and $V_m \sin \phi_v$ can also be obtained by discrete Fourier transform as will be seen in the next sub-section.

For finding each term in the summation expression for estimates, it is required to evaluate $\sin \theta_j$ and $\cos \theta_j$ in microprocessor or DSP. Generally, the minimum number of samples is 4 for which we need to evaluate $\sin 0$, $\cos 0$, $\sin 90$, $\cos 90$ for which constants can be initialised in the program. Another convenient sampling rate is 12 samples per cycle, where $\sin 0$, $\cos 0$, $\sin 30$, $\cos 30$, $\sin 60$, $\cos 60$, etc., are required, which can be easily initialised by assigning their values (numbers) in the DSP program.

The illustration taken previously in the 2-sample and 3-sample data window can be also evaluated in this case. It can be found that the standard deviation of error reduces, which leads to the inference that accuracy of estimation is improved by considering full-cycle for a data window.

The full-cycle Fourier algorithm is known for its capacity to filter out harmonics. As such, this algorithm can be considered to be a digital filter for removing noise as well as unwanted harmonics.

4.6 HALF-CYCLE FOURIER ALGORITHM

The data-window in the previous case for a full-cycle Fourier algorithm includes the samples present in one full cycle. But the computation for the estimates for magnitude and phase of voltage and current has to be carried out after every sample, because the oldest sample will be dropped and one latest will be included in the data-window. So for higher sampling rates, the time available between two sampling instants will also be less. So to finish estimation process within that time, there will be the need to reduce computations. This will increase the speed of the algorithm. For this purpose, one can try out half cycle data window. If there are k even number of samples per half cycle, then the half-cycle Fourier algorithm will result in the following equations:

$$V_c^L = \frac{2}{k} \sum_{j=L-k+1}^L v_j \cdot \cos \theta_j \quad (4.43)$$

$$V_s^L = \frac{2}{k} \sum_{j=L-k+1}^L v_j \cdot \sin \theta_j \quad (4.44)$$

It can be proved that the numbers of samples per window are half than the full-cycle algorithm, the estimation time is reduced at the cost of accuracy.

4.7 PRACTICAL CONSIDERATIONS FOR SELECTION OF ALGORITHM

(1) Delay in Estimation during Fault Conditions Let us take a look at what happens to estimation when a fault occurs. Estimation of fault current is important.

Figure 4.17 shows the fault current waveform during pre-fault as well as post-fault condition. The 3-sample data-window W_1 contains the information before the fault. So the estimate has not exceeded the setting. The first post-fault sample is seen in the data window W_2 . This data window has two pre-fault samples also. So it cannot give a correct estimate of the fault current. There will be an error in the estimation of current phasor. Window W_3 is also similarly not useful. Window W_4 has all 3-samples of the post-fault current. Thus, the delay that needs to be kept purposefully before taking a decision for fault is equal to the length of the data-window.

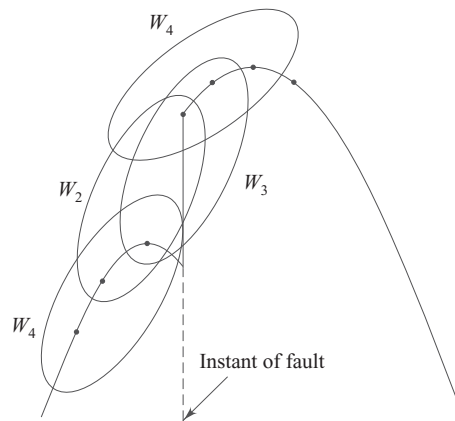


Fig. 4.17 Estimation during fault condition

So a 1-cycle data window introduces a delay of 1 cycle in the estimation. This delay is critical for certain situations like saturation of CT by a dc offset current, because after occurrence of a fault, the CT takes one cycle to saturate due to the dc offset current. The estimation and decision-making of a numerical relay should be over before one cycle elapses after a fault instant.

So under such situations, a half-cycle window will be useful. It will not give lower accuracy as a 3-sample data-window and will also increase speed to avoid the CT saturation problem.

(2) Mitigation of DC Offset Current Component Generally, a dc offset current component is present in the fault current. It does not have a zero mean as is the case with other types of noise. So the least-square based estimation algorithm will not be able to eliminate this noise. Therefore, the 3-sample, half-cycle and full-cycle algorithms cannot tackle this problem.

One solution to this problem is to filter out the dc offset current by using mimic impedance in the hardware connection. Mimic impedance has the same X/R ratio as that of the transmission line to be protected. The artificial introduction of mimic impedance either in hardware or by software is done in order to avoid the problem of mal-operation due to dc offset current component in the fault current seen by the numerical relay.

Let us understand analytically how this functions.

Figure 4.18 shows a current source having a sinusoidal component plus dc current component connected to $R_1 + jX_1$ impedance having the same ratio of X/R as that of a transmission line to be protected.

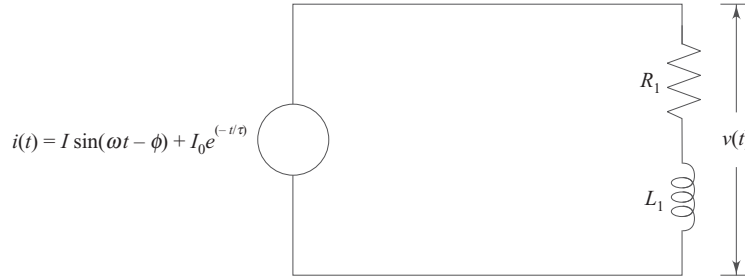


Fig. 4.18 Analysis for mimic impedance

The voltage appearing across the impedance is obtained as

$$v(t) = R_1 i + L_1 \frac{di}{dt} \quad (4.45)$$

Substitute the value of i and expand

$$\text{So,} \quad v(t) = R_1 I \sin(\omega t - \phi) + \omega L_1 I \cos(\omega t - \phi) + R_1 I_0 e^{-t/\tau} - \frac{L_1}{\tau} I_0 e^{-t/\tau}$$

Let θ be angle between Z_1 and R_1 , such that $\theta = \tan^{-1} \frac{X_1}{R_1}$, $R_1 = Z_1 \cos \theta$, $X_1 = Z_1 \sin \theta$

$$\begin{aligned} v(t) &= Z_1 I \sin(\omega t - \phi + \theta) + I_0 e^{-t/\tau} \left[R_1 - \frac{L_1}{\tau} \right] \\ v(t) &= Z_1 I \sin(\omega t - \phi + \theta) + L_1 I_0 e^{-t/\tau} \left[\frac{R_1}{L_1} - \frac{1}{\tau} \right] \end{aligned} \quad (4.46)$$

It is clear from Eq. (4.46) that if we select $\frac{L_1}{R_1} = \tau$, the time constant of the transmission line, then the voltage seen by the numerical relay will be free from the dc offset component.

Hence,

$$v(t) = Z_1 I \sin(\omega t - \phi + \theta) \quad (4.47)$$

The voltage seen by the relay is scaled in this process. Magnitude scaling is by the value of Z_1 and phase-shifting is by the value of θ . So corrections for these two are required to be implemented using either a software algorithm or the hardware.

Practically, this is used in numerical distance relays, where the problem of a decaying dc offset component is acute. The Fourier filtering algorithm for other types of noise will be equally effective after removing the dc offset current component.

4.8 COMPARATIVE SUMMARY OF ESTIMATION ALGORITHM

The estimation algorithms actually act as digital filters for extracting the fundamental component from the input sample coming from the S/H circuit. This input sample will have harmonics as well as noise as shown in Fig. 4.19.

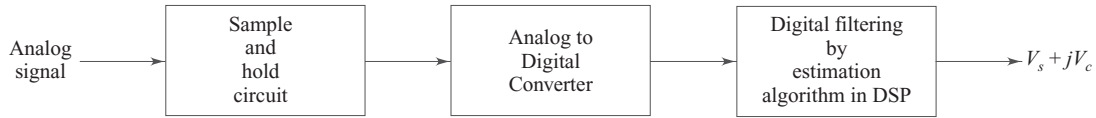


Fig. 4.19 Estimation algorithms as digital filters

The summary is tabulated as follows:

Table 4.5 Summary of phasor estimation algorithms

Sr. No.	3-Sample Algorithm	Half-cycle Fourier Algorithm	Full-cycle Fourier Algorithm
1.	Accuracy is poor	Accuracy is better	Accuracy is best
2.	Speed of response is fastest	Speed of response is faster	Speed of response is fast
3.	Cannot filter all harmonics and noise	It can filter harmonics and noise better than a 3-sample algorithm; Can reject odd harmonics but cannot reject even harmonics	It can filter harmonics and noise in the best (most accurate) way. Can reject odd and even harmonics efficiently

The full-cycle Fourier algorithm is identical to a Discrete Fourier Transform (DFT). Let us have a look at the DFT to establish the correlation.

4.9 DISCRETE FOURIER TRANSFORM (DFT)

The implementation of DFT to extract the fundamental component from a sinusoidal input will be explained in this section.

Let us have a sinusoidal input signal of frequency ω_0 .

$$x(t) = \sqrt{2} \cdot X \cdot \sin(\omega_0 t + \phi)$$

This signal can be written in phasor representation as a phasor,

$$\bar{X} = X e^{j\phi} = X (\cos \phi + j \sin \phi) \quad (4.49)$$

Let there be N samples per cycle.

Hence
$$f_0 = \frac{1}{N \cdot t_s}$$

where, t_s is the sampling time.

$$f_0 = 50 \text{ Hz, frequency of input signal}$$

So, the k^{th} sample at output of the S/H circuit can be denoted as

$$x_k = \sqrt{2} \cdot X \cdot \sin\left(\frac{2\pi}{N} k + \phi\right) \quad (4.50)$$

Hence, $f_s = \text{sampling frequency} = N f_0$

The final expression for implementing DFT is given as

$$X(m) = C_1 \sum_{k=0}^{N-1} x_k \cdot e^{\frac{-j2\pi km}{N}} \quad (4.51)$$

where,

$m = 0$ will give dc component

$m = 1$ will give fundamental component

$m = 2$ will give 2nd harmonic component

k = represents k^{th} sample

N = Total number of samples per cycle

$C_1 = 2/N$ is commonly used for numerical relaying with a constraint of $C_1 C_2 = 1/N$

C_2 = Constant in expression of Inverse Discrete Fourier Transform (IDFT)

= 1/2 for numerical relaying application

$$\text{IDFT is done by } x_k = C_2 \sum_{m=0}^{N-1} X(m) \cdot e^{\frac{-j2\pi km}{N}} \quad (4.52)$$

To extract fundamental component, $m = 1$ is chosen.

$$\text{Hence, } X_1 = \frac{2}{N} \sum_{k=0}^{N-1} x_k \cdot e^{\frac{-j2\pi k}{N}} \quad (4.53)$$

$$\therefore X_1 = \frac{2}{N} \sum_{k=0}^{N-1} x_k \left(\cos\left(\frac{2\pi}{N} k\right) - j \sin\left(\frac{2\pi}{N} k\right) \right)$$

$$\therefore X_1 = X_c - jX_s \quad (4.54)$$

$$\text{where, } X_c = \frac{2}{N} \sum_{k=0}^{N-1} x_k \left(\cos\left(\frac{2\pi}{N} k\right) \right) \quad (4.55)$$

$$X_s = \frac{2}{N} \sum_{k=0}^{N-1} x_k \left(\sin\left(\frac{2\pi}{N} k\right) \right) \quad (4.56)$$

Substituting x_k from Eq. (4.50) in Eq. (4.55) and Eq. (4.56), we get,

$$\begin{aligned} X_c &= \frac{2}{N} \sum_{k=0}^{N-1} \sqrt{2} \cdot X \cdot \sin\left(\frac{2\pi}{N} k + \phi\right) \cdot \cos\left(\frac{2\pi}{N} k\right) \\ &= \frac{\sqrt{2}}{N} \cdot X \sum_{k=0}^{N-1} 2 \left(\sin\left(\frac{2\pi}{N} k\right) \cdot \cos \phi + \cos\left(\frac{2\pi}{N} k\right) \cdot \sin \phi \right) \cos\left(\frac{2\pi}{N} k\right) \\ &= \frac{\sqrt{2}}{N} \cdot X \sum_{k=0}^{N-1} 2 \sin\left(\frac{2\pi}{N} k\right) \cdot \cos\left(\frac{2\pi}{N} k\right) \cdot \cos \phi + 2 \cos^2\left(\frac{2\pi}{N} k\right) \cdot \sin \phi \\ &= \frac{\sqrt{2}}{N} \cdot X \cdot N \cdot \sin \phi \end{aligned}$$

$$X_c = \sqrt{2} \cdot X \cdot \sin \phi \quad (4.57)$$

$$\text{Similarly, } X_s = \sqrt{2} \cdot X \cdot \cos \phi \quad (4.58)$$

But, $\bar{X} = X (\cos \phi + j \sin \phi)$, using Eq. (4.57) and Eq. (4.58) in Eq. (4.49)

$$\therefore \bar{X} = \frac{1}{\sqrt{2}} (X_s + jX_c) \quad (4.59)$$

As $X_1 = X_c - jX_s$ as per Eq. (4.54), we get

$$\bar{X} = \frac{1}{\sqrt{2}} (jX_1) \quad (4.60)$$

Thus Eq. (4.60) gives the phasor calculated to obtain the filtered fundamental frequency phasor from the input signal which comprised of fundamental plus other frequency components.

Thus, DFT rotated by 90° gives the original phasor.

In this chapter, we have explained the aspects of hardware configuration and concepts of digital signal processing. The algorithms for phasor estimation are also derived. Specific algorithms for fault detection for various types of protections are incorporated in the respective chapters.

REVIEW QUESTIONS

- Discuss the comparative benefits and limitations of electromagnetic, static and microprocessor based digital relays.
- Explain the advantages of digital relays.
- What is adaptive relaying? Which feature of numerical relays make them suitable for adaptive relaying?
- With the help of a block diagram, explain the organisation of a numerical relay.
- What are GPS and WAMS? How are numerical relays adaptable to WAMS?
- Give the main features of IEC 61850, the standard for substation integration and automation.
- What do you mean by IED? What are the main features of IED?
- Draw the block diagram and explain various components involved in digital signal processing for a numerical relay.
- Draw the block diagram of a simultaneous sampling scheme for data acquisition system.
- State the Nyquist criterion for deciding sampling frequency. What is its significance?
- Explain the following terms with reference to sampling.
 - Folding
 - Aliasing
- Explain the role of anti-aliasing filters in a data acquisition system.
- Discuss the criteria for selection of sampling rate.
- Derive the expressions for estimation of phasors using a 2-sample data window.
- Derive the expressions for least-square estimation of phasors using 3-sample technique.
- Derive the expressions for estimation of phasors using a full-cycle Fourier algorithm.
- Derive the expressions for estimation of phasors using a half-cycle Fourier algorithm.
- Compare the methods for estimation of phasors based on
 - 3-sample data window
 - half-cycle Fourier algorithm
 - full-cycle Fourier algorithm
- Explain how delay in estimation of phasors is related with the length of a data-window.
- Explain the mitigation of a decaying dc offset component for numerical distance relaying using mimic impedance technique.
- With the help of derivation for discrete Fourier Transform (DFT), explain how it can be used for estimation of phasors based on the Fourier algorithm.

MULTIPLE CHOICE QUESTIONS

- The IEC 61850 is an international standard related to
 - substation automation and integration
 - structure of protection and control
 - Ethernet standard and TCP/IP
 - all of the above

2. Numerical relays are useful for
 - (a) protection
 - (b) measurement and storing
 - (c) control
 - (d) all of the above
3. GPS stands for
 - (a) Group Protection Services
 - (b) General Protection Services
 - (c) Geographical Positioning System
 - (d) none of the above
4. Let ω_s be the sampling frequency in a digital relay and ω_1 be the highest frequency component in the analog signal input. For proper reconstruction of the analog signal,
 - (a) $\omega_s = \omega_1$
 - (b) $\omega_s < 2\omega_1$
 - (c) $\omega_s \geq 2\omega_1$
 - (d) $\omega_s > 2\omega_1$
5. The algorithm preferred for estimation of fault current in a numerical relay to achieve the best accuracy is
 - (a) 3-sample algorithm
 - (b) half-cycle Fourier algorithm
 - (c) full-cycle Fourier algorithm
 - (d) none of the above

Generator Protection

Generators are the most expensive equipment in an ac power system. A 210 MW turbo-generator which includes an alternator, a steam turbine, a boiler and other ancillaries costs more than hundred crores in Indian rupees. The generator also represents the most complicated unit demanding an extensive protection system comprising a large variety of protective relays.

The protective system of a generator must be carefully chosen since an inadvertent operation of the relay is almost as serious as a failure of operation. This is because the disconnection of a large generator may overload the rest of the system and cause power oscillations resulting in an unstable power system. On the other hand, failure to clear a fault promptly may cause extensive damage to the generator and may again lead to disruption of the whole system.

Another difficulty with the generator protection system is the fact that, unlike other equipments, opening a breaker to isolate the defective generator is not enough to prevent further damage, since the generator will continue to supply power to its own fault until its field excitation has been suppressed. It is, therefore, necessary to remove the field supply, shut off the steam, water or fuel supply to the prime-mover, trip the boiler and shut off all the auxiliaries of the generator. Further, carbon dioxide is pumped into some large machines to extinguish any burning of insulation, which could have been initiated by the rotor movement.

5

Introduction

Major faults and abnormal conditions in case of generators

1. Failure of insulation of the stator winding
2. Failure of insulation of the rotor winding
3. Unbalanced loading
4. Field failure
5. Overload
6. Overvoltage
7. Failure of prime-mover
8. Loss of synchronism
9. Over-speed
10. Under-frequency
11. Over-heating

Protective schemes employed for generator protection

1. Differential protection
2. Inter-turn fault protection
3. Stator earth-fault protection
4. Overcurrent and earth-fault protection
5. Rotor earth-fault protection
6. Negative phase-sequence protection
7. Field failure protection
8. Overload protection
9. Overvoltage protection
10. Reverse power protection
11. Pole-slipping protection
12. Back-up impedance protection
13. Under-frequency protection

Class A, Class B and Class C Protections

If a fault is of a very serious nature and impacts the generator, generator-transformer, prime-mover or boiler (i.e., the fault is likely to cause a direct and critical damage to the unit even after isolating the unit from the infinite bus), the protective scheme that operates is known as a Class A protection.

Actions initiated when Class A protection operates

- (i) Generator breaker is tripped
- (ii) Generator field breaker is tripped
- (iii) Incomer breakers of unit auxiliary transformer are tripped
- (iv) Tie breakers between the auxiliary station bus and auxiliary unit bus are closed
- (v) Boiler trips
- (vi) Prime-mover trips
- (vii) All unit auxiliaries are tripped
- (viii) 'Class A Trip' annunciation appears

The consequences of certain faults are such that the generator is not required to be isolated from the infinite bus immediately; but prime-mover and boiler are tripped immediately. Because of this tripping, the generator will lose input and hence the power output will gradually reduce. Because of this action, the generator does not speed up and the stored kinetic energy is utilised. The protective scheme, which initiates the sequence as depicted above, is said to be a Class B protection.

Actions initiated when Class B protection operates

- (i) Boiler is tripped
- (ii) Turbine is tripped
- (iii) 'Class B Trip' annunciation will appear.
- (iv) Class A protection will operate through low forward power relay. Low forward power relay is a time-delayed relay.

Generally, in large generators, a low forward-power relay is used to sense the power output. When the power output reduces to around 0.5% of the rated power, low forward power relay trips and hence Class A protection operates.

The consequences of certain faults are such that the generator is only required to be isolated from the infinite bus. The generator thus will feed its auxiliaries only (i.e., the generator will feed house load only). Once the cause of the fault is found and the fault is cleared by a relevant breaker, the generator can once again be synchronised with the system. The process of synchronising does not take much time. The protective scheme, which thus trips the generator breaker only, is known as Class C protection.

Appendix I gives the list of Class A, Class B and Class C protections. Also, the conditions which operate the alarm only are listed in Appendix I.

In the following sections related to the faults and abnormalities for generators, their causes and consequences, protection schemes, types of relays used and relay-setting calculations are discussed.

5.1 DIFFERENTIAL PROTECTION

5.1.1 Causes and Consequences of Stator Insulation Failure

The breakdown of insulation may result in a fault between conductors and between the conductor and the iron core. The breakdown may be caused by overvoltage or by overheating, which in turn, can be caused by overloads, unbalanced currents, ventilation troubles or failure of the cooling system. It may also be caused by damage to the insulation by conductor movement due to forces exerted by short circuits or out-of step conditions.

It is obvious that the short-circuit currents caused by these faults can cause enormous damage to the generator winding and core. Hence, these faults should be cleared by high-speed instantaneous relays.

It is the standard practice to recommend differential protection for generators of 10 MW rating and above. For small machines the voltage-monitored time overcurrent relays (refer Section 2.9 of Chapter 2) are used.

Faults between conductors can sometimes be repaired by re-taping or replacing the conductor, but faults between the conductor and the iron laminations are a serious matter because the arc (due to fault) may sinter the laminations together which may necessitate rebuilding the core. However, the grounding impedance greatly influences the protection offered by different relays in case of ground faults in the generator. In very large generators, it is a usual practice to limit the earth-fault current to a very low value (as we shall see later); hence a separate stator-earth-fault protection is desired. In this case, differential protection is reserved for phase faults only as the fault current will be very high since it is limited by the reactance of the generator only.

5.1.2 Differential Protection

A simplified scheme of differential protection is shown in Fig. 5.1(a). As discussed in Chapter 2 (Section 2.11.1), the differential protection is a unit system of protection and it responds to internal faults only. It must be stable against external faults. Figure 5.1(b) shows that the voltage across the relay coil is zero in the case of external fault and hence the relay does not operate. However, if emfs induced in secondaries of CT_1 and CT_2 are not equal or if the relay is not connected at the equipotential points, there will be some voltage across the relay coil. This problem, due to which there could be an unwanted operation of the relay, can be solved either by using a biased differential relay or stabilising resistance, as discussed later. Figure 5.1(c) confirms that the relay will certainly operate in case of an internal fault. It is assumed that the power-system will feed the fault through CT_2 .

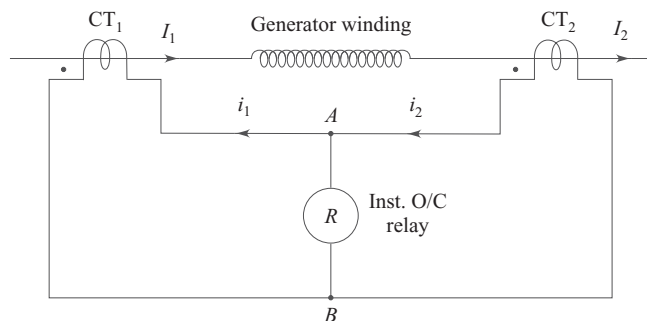


Fig. 5.1(a) Principle of generator differential protection

5.1.3 Requirements of Generator Differential Protection

The following are the requirements of generator differential protection:

1. As explained in Section 2.11.1 of Chapter 2, the current transformers CT_1 and CT_2 (Fig. 5.1(a)) need to be connected with correct polarity.
2. The differential protection shall operate sensitively for internal faults and it shall remain stable against external faults.
3. CTs on both the sides of the generator should have identical saturation characteristics. The non-identical CTs may not cause mal-operation for normal conditions, but can cause inadvertent tripping of the generator for very high through fault currents.

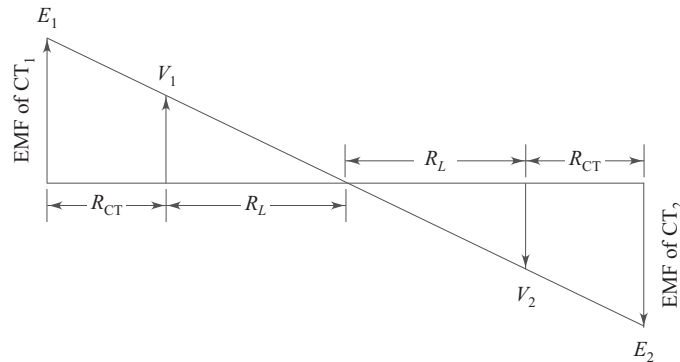


Fig. 5.1(b) Voltage distribution in CT secondary during external fault

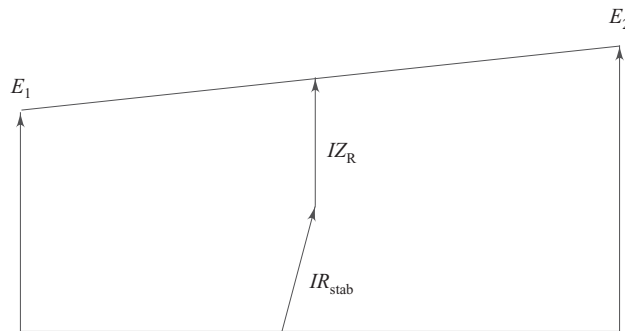


Fig. 5.1(c) Voltage distribution in CT secondary during internal fault

4. The relay coil should be connected to the points, which are equipotential [see points *A* and *B*, Fig. 5.1(a)], under normal conditions. The CTs and the machine to be protected are located at the turbine floor and the relay is located in the control room. Hence, normally, it is not possible to connect the relay coil to the equipotential points.

If the connections are not at equipotential points then the burdens on the two CTs are unequal, although the currents in the two CT primaries are equal. This may cause the heavily burdened CT to saturate during through fault conditions. This results in dissimilarity of ratio and phase angle errors of the CTs producing an out-of-balance (spill) current in the relay coil, which causes spurious operation of the relay.

5. Differential relay should be immune to harmonics.

Remedial Measures Employed to Fulfill the Requirements Listed Above

As previously discussed, ideally identical CTs and equal lead lengths [from CT₁ to relay and from CT₂ to relay in Fig. 5.1(a)] cannot be obtained in practice.

If the lead lengths are not equal, adjustable extra resistances can be connected in series with pilot wires so that the relay coil is connected to the equipotential points. For tackling the problem of non-identical CTs, a biased differential relay (refer Section 2.11.3, Chapter 2) can be used. The current through the bias (restraining) coil is made proportional to the through current, thus making the relay stable with negligible

loss of sensitivity on light faults. The biased differential relay can be set to pick-up at 5% of CT rating and the percentage bias setting is usually about 10%.

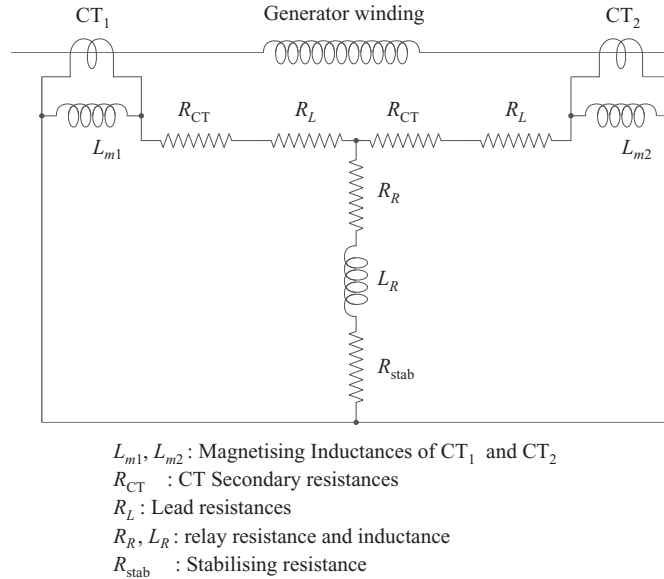


Fig. 5.2 CT and relay connections for differential protection of generator

Another way of getting rid of the problems of non-identical CTs and unequal lead lengths is the use of a stabilising resistance in series with the relay coil. The value of the stabilising resistance can be found out by considering the worst case; i.e., absolute saturation of one of the CTs while the other is working in its linear range. This is the simplest way of assessing the criteria of stability against through faults, since if the relay setting is greater than the spill current calculated by this method, stability is assured. Referring to Fig. 5.2 and for the worst condition assumed, L_{m1} is infinite and L_{m2} is zero.

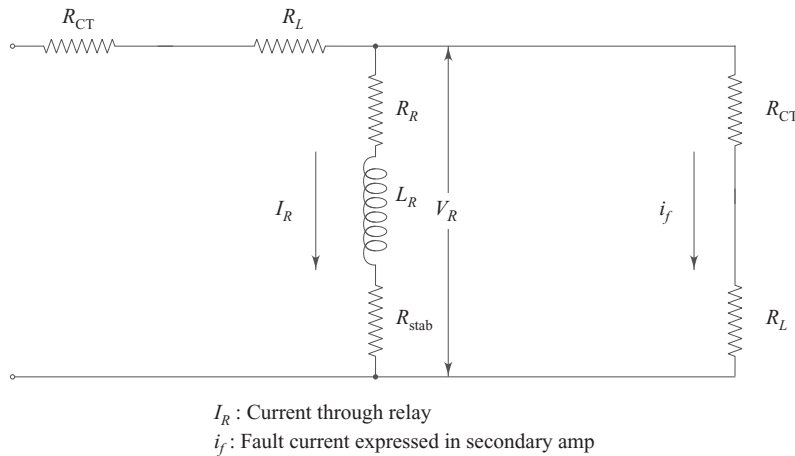


Fig. 5.3 Equivalent circuit of Fig. 5.2

From the equivalent circuit of Fig. 5.3, we can write the equation for voltage across the relay, V_R :

$$V_R = I_R (R_R + R_L) = i_f (R_{CT} + R_L) \quad (5.1)$$

Normally, R_L is small and hence

$$\therefore V_R = I_R R_R = i_f (R_{CT} + R_L) \quad (5.2)$$

$$\therefore I_R = i_f \frac{(R_{CT} + R_L)}{R_R} \quad (5.3)$$

The current through the relay I_R as given by Eq. (5.3) can be limited by connecting the stabilising resistance R_{stab} in series with the relay coil. I_R will, then, reduce to

$$I_R = i_f \frac{(R_{CT} + R_L)}{(R_R + R_{stab})} \quad (5.4)$$

The desired value of the stabilising resistance can be calculated from the expression:

$$R_{stab} = i_f \frac{(R_{CT} + R_L)}{I_S} - R_R \quad (5.5)$$

where, I_S = pick-up setting of a relay

R_{stab} need not be as high as indicated by Eq. (5.5); it can be about one-third of this value. This stabilising resistance assures stability against external faults and also avoids unwanted operation of the relay due to unequal lead lengths. On the other hand, this additional resistance appears to reduce sensitivity of the relay for in-zone faults and create dangerously high voltage across the CT during heavy external faults. The loss of sensitivity can be reduced by putting much of this extra resistance in extra turns of the relay. The loss of sensitivity is, however, not that serious as it seems because in an interconnected system the internal fault is fed from both ends making the differential current to be the sum of CT secondary current, i_1 and i_2 (Fig. 5.1). The problem of high voltage is taken care of by the relay design to be discussed in the subsequent paragraphs.

Another way of guaranteeing stability against external faults is the selection of CTs. The Knee Point Voltage (KPV) of the CTs should be high. The larger the KPV, greater will be the working range of the CTs and higher will be the saturation flux density (refer Chapter 13). For this reason, grain oriented silicon steels having high saturation levels are used as core materials for protective CTs. It is customary to choose the KPV (for the CTs) equal to twice the operating voltage V_R given by Eq. (5.1).

The saturation of a CT is largely due to the dc components of short circuit current. To prevent this, CT cores are made larger or air gaps are introduced in the cores. The best solution is the use of ironless CTs (linear couplers).

The mal-operation of the relay due to harmonics is taken care of by the relay design discussed in the next sub-section.

5.1.4 The Relay

The relay (Fig. 5.4) consists of an operating coil connected in series with a small choke and a capacitor forming a series resonant circuit. This circuit, tuned to the supply frequency, rejects the harmonics produced by CT saturation. This circuit is supplied from a saturating autotransformer. This magnetic saturation helps in reducing high voltages produced due to heavy internal faults. Certain designs use a non-linear resistor (a varistor) connected in series with the operating coil circuit, for the same purpose. The capacitor C not only helps in suppressing the harmonics but also makes the relay insensitive to the dc components of offset current waves.

Different designs of such instantaneous differential relays are available in the protective relay market.

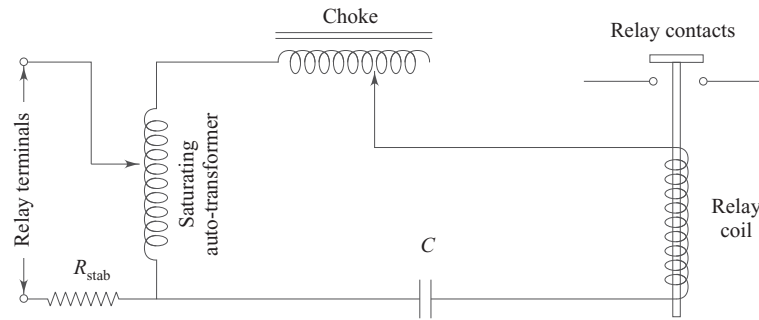


Fig. 5.4 An instantaneous overcurrent relay used for generator differential protection

5.1.5 Protective Scheme

Figures 5.5(a) and 5.5(b) show ac and dc control circuits respectively of a generator differential protection which are self-explanatory. Surge diverters divert the high-frequency transient surges so that no unwanted tripping occurs because of short-duration transient spikes. The star-connected generators are considered here, as they are common.

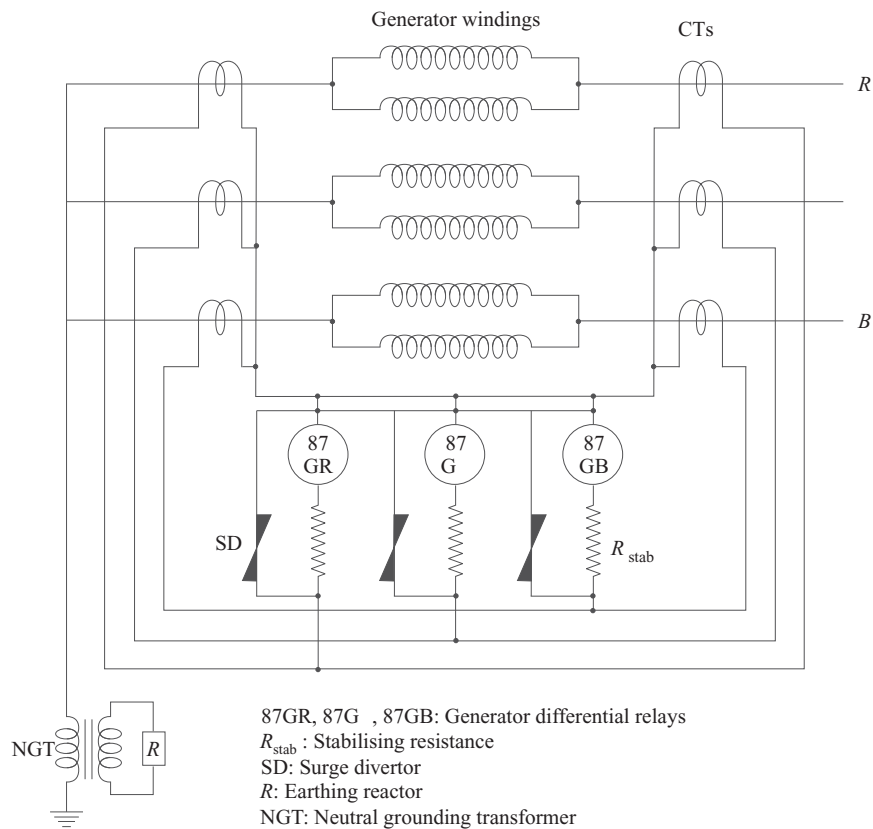


Fig. 5.5(a) AC circuit of generator differential protection

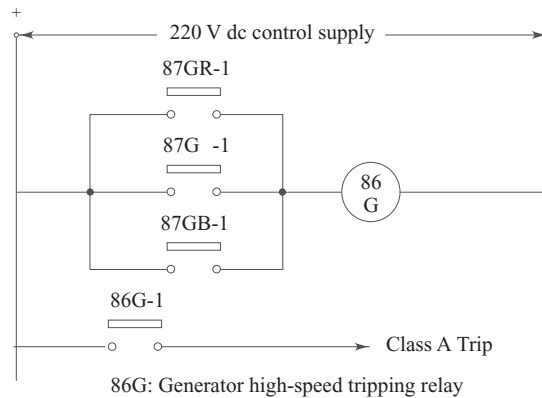


Fig. 5.5(b) DC circuit of generator differential protection

Differential protection is a Class A protection. Figure 5.5(b) does not give a complete control circuit. The detailed ac and dc circuits are too large and cannot be covered in this book.

The internal fault has to be cleared without any time delay, otherwise the damage to the stator core and windings would take the generator out of service for a long time as repairs may take a few months. This results in loss of power and, in turn, loss of revenue. Hence, differential protection operates instantaneously.

5.1.6 Relay Setting

We will consider the typical data for calculating relay settings.

Data

1. Generator

210 MW, 247 MVA, 15.75 kV, 9050 A. Through fault withstand 10 pu, $\delta'_d = 30.5\%$, $\delta''_d = 21.4\%$, $\delta_2 = 26.1\%$, $\delta_0 = 10\%$, $\delta_s = 225\%$. (δ_s is not required because the differential relays are fast-acting and the generator on fault, during that time, is in sub-transient or at the most, in the transient state of operation).

2. CTs

10000/5 A

KPV > 350 V

$R_{CT} = 1.5 \Omega$

(KPV = Knee Point Voltage

R_{CT} = CT secondary resistance)

3. Lead resistance = 0.4Ω

4. Relay

Rated current : 5 A

Setting range : 5-20% of 5 amp

Burden : 0.9 VA-1.0 VA

5. Neutral Grounding Transformer

50 kVA, 15.75 kV/240 V

Single phase, 50 Hz

6. Earthing Reactor

Air core, Air cooled

3 mH, 50 Hz, 145 A, 240 V

Setting Generator differential relays are set to pick-up at 5% to 10% of CT secondary rating. We select 10% of 5 A, i.e., 0.5 A. It is clear that the relay, in this case, will not be able to detect an earth-fault in the generator windings, because the fault current for earth-fault even at the terminal of the generator will be 0.025% of the rating of the generator. This is calculated as follows:

Referring to Fig. 5.5(a), the neutral grounding impedance Z_n , referred to the primary of neutral grounding transformer will be

$$Z_n = \frac{(15.75 \times 10^3)^2}{240^2} \times 2\pi f \times 3 \times 10^{-3} = 4059 \Omega$$

The fault current I_f , for the earth-fault at the terminal of the generator will be

$$I_f = \frac{15.75 \times 10^3}{\sqrt{3} \times 4059} = 2.24 \text{ A} = 0.025\% \text{ of generator rating}$$

The fault current will still be less for faults at the other locations of generator windings. The earth-fault protection will be dealt with in detail in the relevant section. The fault current for the $L-L$ fault at the terminal of the generator will be 330% of the CT rating. This can be calculated using I_d and I_2 . The calculation of the fault current for phase-phase fault at other locations of the generator winding is complicated because the impedance of the winding increases as the square of the number of turns involved. Furthermore, there is no linear relationship between the location of fault and winding reactance involved because of increased magnetic leakage. Also, the voltage is not proportional to the turns involved. However, the value of 330% of CT rating suggests that the relay setting of 10% is sensitive enough. Moreover, the fault current fed to the generator from the system will improve the sensitivity in case of fault near the neutral. This discussion proves that sensitivity of the protective system is assured.

Stabilising Resistance Using Eq. (5.5),

$$R_{\text{stab}} = i_f \frac{(R_{CT} + R_L)}{I_S} - R_R$$

where, $i_f = \frac{(9050 \times 10)}{2000} = 45.25 \text{ A}$

and $R_R = \frac{\text{Burden}}{(I_S)^2} = \frac{0.9}{(0.5)^2} = 3.6 \Omega$

$$R_{\text{stab}} = 45.25 \times \frac{(1.5 + 0.4)}{0.5} - 3.6 = 168.35 \Omega$$

Hence, one-third of this value, i.e. 56.11 Ω or 60 Ω can be connected.

Knee Point Voltage

$$\begin{aligned} V_R &= i_f (R_{CT} + R_L) \\ &= 45.25 (1.5 + 0.4) = 85.975 \text{ V} \end{aligned}$$

Therefore, KPV should not be less than (85.975×2) , i.e., approximately 172 V. This proves that the given value of KPV of CT is satisfactory since it is greater than 350 V.

Example 5.1 An 11 kV, 3-phase, 50 Hz, 50 MVA, star-connected generator is protected by the simple Merz-price protection. The CTs used are 3000/5 A. The relay is set to operate for a current of 150 milli-amperes.

Under direct through-fault condition of 14 times full load, the CTs at one end will have a voltage that is 85% of that at the other end.

The relay having a resistive impedance of 100 ohms is connected to the physical midpoint of the pilots. The pilot wire has a resistance of 0.54 ohm per 100 metres. The distance between the two sets of CTs is 250 metres.

Determine the extra resistance required to be connected in series with the relay to have a stability factor of 3 for this fault condition.

Solution

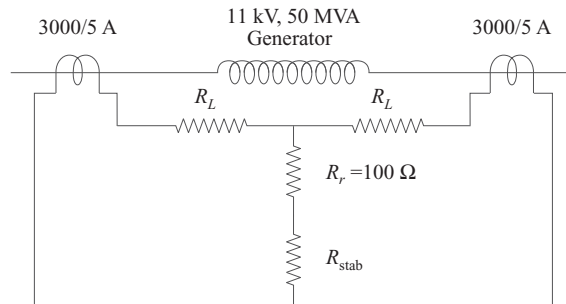


Fig. 5.6 Example 5.1

Referring to Fig. 5.6, resistance of pilots,

$$2R_L = 2 \times 250 \times \frac{0.54}{100} = 2.7 \text{ } \Omega$$

Full load current of the generator,

$$I_{FL} = \frac{50 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 2624.32 \text{ A}$$

Fault current,

$$I_f = 14 \times 2624.32 = 36740.47 \text{ A}$$

This current, when reflected to CT secondary, will have a value

$$i_f = \frac{36740.47 \times 5}{3000} = 61.23 \text{ A}$$

Voltage required to circulate current in the pilot wires,

$$E + 0.85E = 61.23 \times 2.7 = 165.33 \text{ V}$$

$$\therefore 1.85 E = 165.33$$

$$\therefore E = 89.37 \text{ V}$$

Now referring to Fig. 5.7, from similar triangles MAB and MPQ ,

$$\begin{aligned} \frac{AB}{PQ} &= \frac{AM}{MP} \\ \frac{E}{0.85E} &= \frac{250 -}{=} \\ &= 135.13 \text{ m} \end{aligned}$$

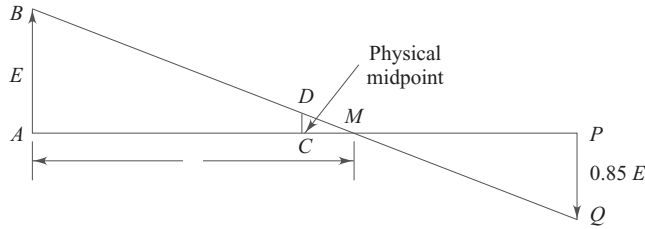


Fig. 5.7 Voltage distribution in CT secondary circuit (Example 5.1)

Similarly, using triangles MAB and MCD ,

$$\frac{CD}{AB} = \frac{MC}{MA}$$

$$\therefore V_R = I_R (R_R + R_{stab}) = CD$$

$$CD = \frac{MC}{MA} \times AB = \frac{10.13}{135.13} \times 89.37 = 6.7 \text{ V}$$

$$\therefore I_R (R_R + R_{stab}) = 6.7$$

Here, stability factor

$$\frac{I_S}{I_R} = 3$$

$$I_R = \frac{I_S}{3} = \frac{0.15}{3} = 0.05 \text{ A}$$

$$R_{stab} = \frac{6.7}{0.05} - R_R = 134 - 100 = 34 \Omega$$

Hence, the stabilising resistance should not be less than 34Ω .

Example 5.2 A generator having a rated current equal to 1000 A is to be protected by a circulating current differential relay using a stabilising resistor. The through fault stability is required up to 10 times full load current. Assuming one set of CTs at one end completely saturated, CT ratio 1000/1 A, CT secondary resistance = 1.5 ohms and total lead burden = 1 ohm (from CT to relay), determine the required stabilising resistance. The relay picks up at 0.1 A and has a resistive burden of 50 ohms.

Solution Using Eq. (5.2),

$$V_R = i_f (R_{CT} + R_L)$$

$$V_R = 10 \times 1.0 (1.5 + 1)$$

$$= 10(2.5) = 25 \text{ V}$$

Using Eq. (5.5),

$$R_{stab} = \frac{V_R}{I_S} - R_R$$

$$= 250 - 50 = 200 \Omega$$

Considering the stability factor as 3,

$$\text{required value of } R_{stab} = \frac{200}{3} = 66.7 \Omega \text{ i.e., } 70 \Omega$$

5.1.7 Numerical Approach to Generator Differential Protection

For differential protection, the current entering the generator (current at neutral end) and the current leaving the generator (current at line end) can be sampled at regular intervals (sampling rate). The mathematical process could be explained as follows:

$$\text{Differential current} = I_{\text{diff}} = I_1 - I_2$$

$$\text{Stabilising current} = I_{\text{stab}} = I_1 + I_2$$

If $I_{\text{diff}} > K \times I_{\text{stab}}$, Class A protection is initiated. There can be two slopes (K) in the characteristic as shown in Fig. 5.8.

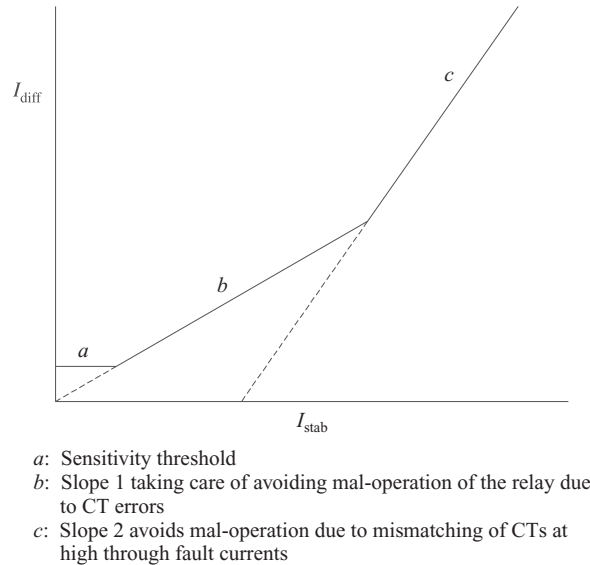


Fig. 5.8 Characteristic of differential protection of generator

As the interturn fault protection is basically differential protection (transverse differential protection), similar philosophy holds good.

5.2 INTER-TURN FAULT PROTECTION

5.2.1 Causes and Consequences of Failure of Insulation between Turns

The failure of insulation between two turns of the same phase causes an inter-turn fault. In lap wound machines, an inter-turn fault affects only a single pole-pitch but in a wave-wound machine, it will affect the whole stator. Such faults are associated with very high local currents, which can cause damage to the generator core. The inter-turn fault itself is not so dangerous but it leads to an earth-fault.

5.2.2 Protective Scheme

The differential protection scheme discussed in Section 5.1.5 above cannot take care of inter-turn faults, as during such a fault on a phase winding, the currents at the two ends would be equal. An inter-turn fault in this case would have to burn through the insulation to the ground or to another phase before it could be detected.

With generators having parallel windings, separately brought out to terminals, an arrangement shown in Fig. 5.9 is used. The protective scheme, basically, is similar to that discussed in Section 5.1 and the same requirements hold true. The relay used in differential protection can also be used here. The relay-setting calculations are to be made in a similar manner. It is evident that the arrangement of Fig. 5.9 provides back-up protection for phase-phase faults in a generator stator.

For small generators not having parallel stator windings, the inter-turn fault is detected by using a voltage operated watt-hour meter type relay. The relay is connected across the open delta of the PT secondary, which will have zero-sequence component of the unbalanced voltages produced due to fault.

Inter-turn fault protection is Class A protection and instantaneous in operation. However, some generating utilities or companies use inverse time overcurrent relays also. A very sensitive setting is preferred because the relay must respond when a single turn is short-circuited. On the other hand, the relay must not be responsive to any transient unbalance that may be envisaged during external faults. The time delayed relays will be stable against transients as the transients would have vanished by the time of relay operation. For severe inter-turn faults in this case, an in-built high-set instantaneous overcurrent element can be used so that its operation will save the generator from developing phase-to-earth or phase-phase fault. The biased differential relay cannot be used because the restraint caused by load current would make the relay too insensitive at full load.

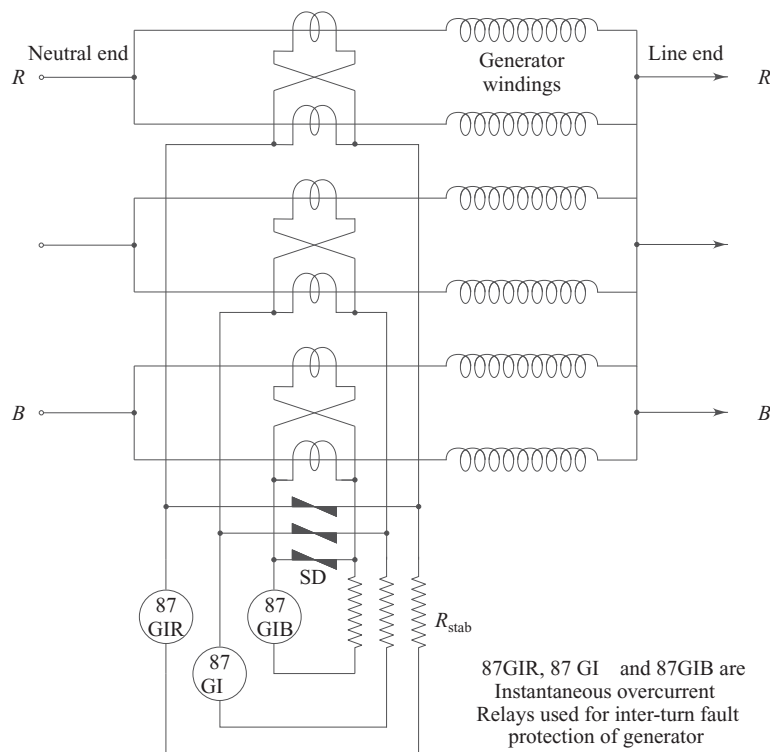


Fig. 5.9 Inter-turn fault protection

5.3 STATOR EARTH-FAULT PROTECTION

5.3.1 Introduction

The fault from a stator conductor to the core of a generator stator occurs due to failure of insulation between the conductor and core. As the conductor is at a high voltage, the core being earthed, the breakdown of insulation between the conductor and core will result in an arc between the conductor and core. The ground fault current will flow through this arc. If this earth-fault current is high, the arc energy will also be high resulting

in very high arc temperature. This high temperature can cause failure of insulation between laminations and can even sinter the laminations. This will result in increase of eddy current losses and damage to a large portion of stator core. Repair of such a damage will take quite a long time (of the order of a month or even more depending on damage) resulting in loss of revenue due to the absence of power that could have been otherwise generated. If the earth-fault occurs near the terminal, the destruction would be even irreparable necessitating complete replacement of the stator core.

The discussion reveals that the stator ground faults are very destructive faults if the ground fault current is large. Hence, for large generators, the ground fault current is usually limited to a very low value such that the resultant arc is not very intense. The arc temperature, in this case, will be very low and, therefore, the damage to the stator core can be reduced to a minimum. As such, no damage may occur during the time of relay operation and consequent tripping.

The earth-fault current can be limited by an impedance placed in the neutral circuit of the generator. It has been found from tests that to avoid the possibility of harmfully high transient overvoltages because of ferro-resonance, the resistance of the resistor should not be higher than $R_n = \frac{10^6}{6\pi fC} \Omega$.

where C is the capacitance of the generator stator circuit to earth per phase in microfarads and f is the system frequency. For a typical large generator having a value of C equal to 0.25 microfarads, the required neutral resistor will be of 4246 ohms. For a 15.75-kV generator, the ground fault current for the fault at the terminal of the generator will be $\frac{15.75 \times 10^3}{\sqrt{3} \times 4246} = 2.14 A$

The neutral of the generator, which is normally at zero potential, will rise to a steady state potential equal to 9086.44 volts (4246×2.14) due to such an earth-fault. The peak value for this rms calculation will be 12.85 kV. Hence a high ohmic resistor with high voltage rating will be required. The modern practice, instead, is to use a resistance (or reactor) loaded distribution transformer as shown in Fig. 5.10. The ohmic value of the resistor will hence, reduce to $4246 \times \frac{N_2^2}{N_1^2}$, where N_2 and N_1 are the number of turns of secondary and primary windings respectively, of the distribution transformer. This distribution transformer is known as a neutral grounding transformer or NGT in short.

It has been suggested that to avoid a large magnetising current flow to the neutral grounding transformer, when a ground fault occurs, the high voltage rating of the transformer should be at least 1.5 times the phase to the neutral voltage rating of the generator. The low voltage rating may be suitable to the voltage rating of the protective relay, to be discussed later. For a 15.75 kV generator, the primary (HV) rating of the NGT will be 13.64 kV. The preferred standard rating is 15.75 kV. The secondary rating can be 240 V. This will reduce the value of the neutral grounding resistor (or reactor) to 0.985 ohm $\left[4246 \times \frac{240^2}{15750^2} \right]$. Also, this resistor (or reactor) has to be rated for 240 V only. The additional advantage of using an NGT is that the voltage-operated relay to be discussed later can be connected across the secondary.

If the neutral grounding transformer is required to be continuously rated, its kVA rating should be at least

$$\text{kVA} = \frac{10^3 V_G V_T}{\sqrt{3} N^2 R}$$

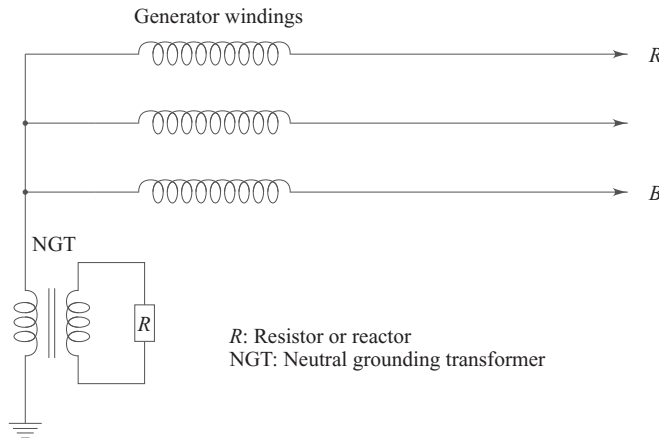


Fig. 5.10 Generator neutral grounding

where

V_G = Phase to phase voltage rating of the generator in kV

V_T = High voltage rating of the NGT in kV

N = Turns ratio, i.e., ratio, of primary rated voltage to secondary rated voltage of NGT.

R = Ohmic value of the resistor connected across the secondary of NGT

Similarly, the continuous rating of the resistor should be at least

$$\text{kW} = \frac{10^3 V_G^2}{3N^2 R}$$

Thus, high impedance grounding (or non-effective grounding as it is known) of the neutral of a generator is a necessity to reduce the ground fault current and its destructive effects. This non-effective grounding consequently produces two effects. Firstly, in case of earth-fault on one of the three phases, the potential of two other healthy phases with respect to the earth rises from its normal phase-to-neutral potential by the potential of the neutral point; i.e., $V_{ph-n} + I_f Z_n$, where Z_n is the neutral circuit impedance. Hence, the insulation between the stator conductor and core has to be designed to withstand this value. This extra cost of insulation extends up to the primary of a generator–transformer only. Reduction in the earth-fault current assumes much higher priority than this comparatively small addition in cost.

Secondly, the larger the neutral impedance, more will be the portion of the winding unprotected in case of earth-fault, or more will be the sensitivity required of the current-based earth-fault relay. In the limiting case, the current-based earth-fault relay will be rendered useless for earth-fault protection. The voltage-based protection scheme to be discussed later is the remedy to address this difficulty.

5.3.2 Protective Schemes

For small generators and in case where the neutral of the generator stator windings is earthed through small impedance, a restricted earth-fault protection can be employed. (Refer Chapter 6 for the details of restricted earth-fault protection.)

The fault current I_f , for the earth-fault in the generator winding (say R phase) will, in this case (Fig. 5.11), be

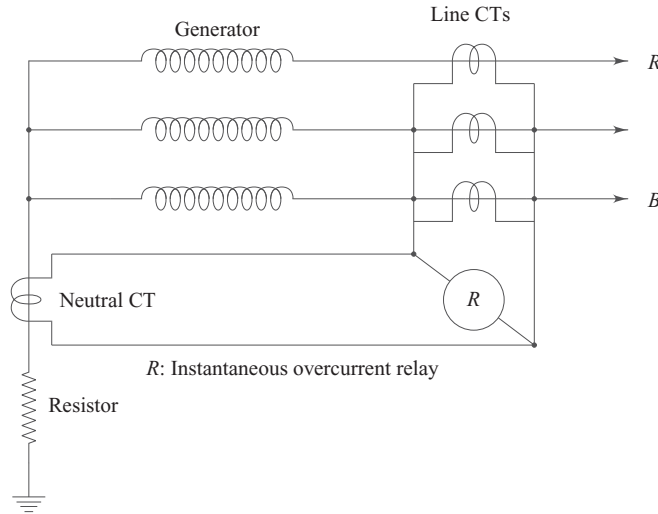


Fig. 5.11 Restricted earth-fault protection of generator

$$I_f = \frac{1000 \times V_G \times P}{\sqrt{3} \times Z_n \times 100}$$

where

V_G = Phase-to-phase voltage rating of the generator in kV

P = Location of fault expressed as a percentage of the winding from the neutral end

Z_n = Ohmic rating of neutral impedance

or,

$$I_f = \frac{10V_G P}{\sqrt{3} Z_n} \quad (5.6)$$

This fault current I_f , will be negligibly small for the fault near the neutral. The percentage of winding unprotected, hence, can be found out as follows:

Let Q be the relay pick-up expressed as a percentage of the CT rating and P_{CT} be the CT primary rating. The relay pick-up current, then, is

$$I_{pu} = \frac{QP_{CT}}{100} \text{ (primary) A} \quad (5.7)$$

The relation between P and Q can be established by equating equations 5.6 and 5.7.

Therefore,

$$\frac{10PV_G}{\sqrt{3}Z_n} = \frac{QP_{CT}}{100}$$

$$\therefore P = \frac{QP_{CT} \times \sqrt{3} \times Z_n}{1000 V_G} \quad (5.8)$$

As an example, if the relay pick-up is 5% of the CT rating, the CT ratio is 50/5 A and if the machine is rated at 11 kV with $Z_n = 200$ ohms

then,

$$P = \frac{5 \times 50 \times \sqrt{3} \times 200}{1000 \times 11} = 7.87\%$$

This means that 7.87% of the winding from the neutral will not be protected, or 92.13% of the winding from the terminal will be protected.

Equation 5.6 suggests that higher the value of the neutral impedance, less is the value of the earth-fault current and hence less the threat of the damage to the generator stator core. But the consequence of the reduction of earth-fault current is clearly seen from Eq. 5.8. A greater portion of the winding is unprotected if higher ohmic value of neutral impedance is selected, as there is a limit to the lowest possible value of sensitivity (Q) of the relay. Thus the limitation of current-based earth-fault protection is either an increased value of the earth-fault current or an increased portion of unprotected winding of the generator.

It is evident that in the case where the differential protection scheme is provided, the restricted earth-fault scheme is not required and the same analysis as above holds good for the differential scheme also. It is obvious that the restricted earth-fault scheme is cheaper than the differential scheme of protection for earth-fault. The phase faults, in this case, can be looked after by overcurrent relays discussed in Chapter 2.

For large generators, as we have discussed in Section 5.1.6, the earth-fault current even at the terminals of the generator is of the order of 0.025% of the generator rating. The fault current will still be less for faults at the other locations of the generator windings. For such low currents, no differential or restricted earth-fault protection scheme can be employed as the current operated relays in such cases, will be required to be of unrealistic sensitivity. Hence the normal practice is to provide voltage-operated relays for stator earth-fault protection. The fact that zero sequence voltage will be developed in case of earth-faults is made use of in the protection scheme of stator earth-fault protection.

The voltage-operated relay can be connected across the open delta of the secondary of generator potential transformer. The voltage across the relay coil so connected will be zero for healthy conditions and for faults not involving earth, whereas residual voltage will be developed across the relay coil in case of an earth-fault. Higher the earth-fault current, higher will be the zero sequence residual voltage. The relay giving inverse voltage time characteristic is often used for this purpose. However, there are two reasons why such a relay is not used as a main protection. Firstly, the relay is a time-delayed relay and secondly, it does not protect full winding. Hence such a scheme of protection is useful as a standby (back-up) earth-fault protection.

It can be, obviously, argued that earth-fault at the neutral of the generator is not harmful as there is no flow of fault current. But if an insulation failure at the neutral is allowed to remain undetected, the machine is, in fact, directly earthed and a second earth-fault is likely to cause total destruction of the machine owing to exceptionally large fault currents and accompanying mechanical stresses.

The most effective way to cover 100% winding for earth-fault protection, is to make use of a third harmonic (zero sequence) line-to-neutral voltage developed by most machines in normal conditions. The relaying scheme making use of this principle is indicated in Fig. 5.12. Figure 5.13 shows how the scheme operates.

As has been stated above, the generators develop a third harmonic voltage of 1% to 3% even under healthy condition. Referring to Fig. 5.13, the relay 2 has a blocking filter which makes it rather insensitive to fundamental frequency voltage. This relay has a very sensitive third harmonic voltage setting. It is set to 0.3 to 0.6 V (neutral PT secondary voltage is 110 V). Hence, under normal service, the relay 2 is picked-up and its contact is open. Relay 3 is sensitive to fundamental frequency voltage and is set to operate for rated generator voltage. Hence, under healthy conditions, the relay 3 remains energised and its contact is closed.

If a fault occurs near the generator neutral, the third harmonic voltage V_n becomes very small ($V_n = 0$, for the fault at the neutral), hence the relay 2 will de-energise and its contact will get closed. The alarm or tripping, therefore, will be given as desired.

95% relay 1 with a blocking filter (blocking the fundamental frequency voltage) is set to a higher value of the third harmonic voltage than that produced by a machine running under normal conditions. Hence, under

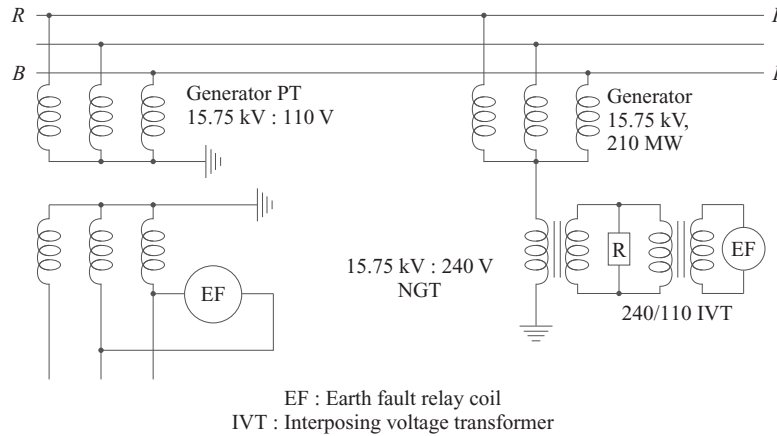


Fig. 5.12 100% Stator earth-fault protection of generator

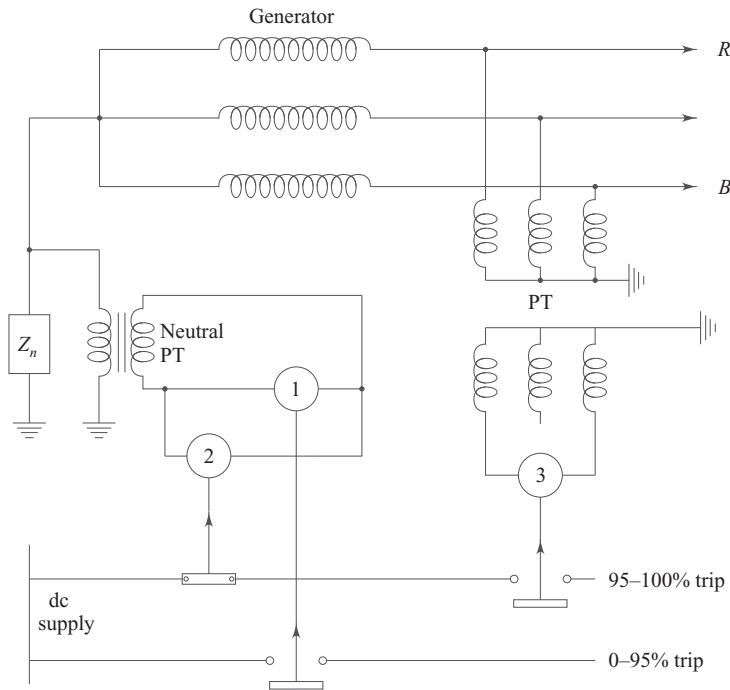


Fig. 5.13 Operation of 100% stator earth-fault scheme of protection of Fig. 5.12 (Courtesy: ABB Ltd.)

normal service condition, the relay 1 remains de-energised. Should the fault occur at any location within 95% of winding from the terminal, the relay 1 operates, closes its contacts and the circuit breaker is tripped. Interlocking contact of the relay 3 is desired because it will open out while stopping the machine manually and will avoid unwanted tripping of 100% stator earth-fault scheme, as otherwise such a tripping will be established by closure of contact of the relay 2 while stopping the machine. When starting the machine under no fault condition, the relay 2 must always operate before the relay 3.

This is how a 100% stator earth-fault protection is made effective. The protection is Class A protection. The relays used in the scheme have adjustable time delay.

Example 5.3 An 11 kV, three-phase, 30 MVA, star-connected alternator is protected by an earth-fault relay having 10% setting. If the neutral resistance limits the maximum earth-fault current to 40% of full-load value, determine the value of the resistor and percentage of the winding protected. Find also the value of the earth resistor needed to allow only 9.5% of the winding to be left unprotected. CT ratio is 2000/1 A.

Solution Full-load current of the generator,

$$I_{FL} = \frac{30 \times 10^3}{\sqrt{3} \times 11} = 1574.6 \text{ A}$$

Maximum earth-fault current, i.e., the current for the earth-fault at the terminal of the generator,

$$I_{f\max} = 1574.6 \times 0.4 = 629.8 \text{ A}$$

The value of this earth-fault current can also be found by the equation

$$I_{f\max} = \frac{3E_{ph}}{Z_1 + Z_2 + Z_0 + 3Z_n}$$

where E_{ph} is phase-to-neutral voltage of the generator; Z_1 , Z_2 , Z_0 are positive, negative and zero sequence impedances respectively and Z_n is the neutral circuit impedance. Normally, Z_n is much large compared to Z_1 , Z_2 and Z_0 and hence the earth-fault current can be approximated as

$$I_{f\max} = \frac{E_{ph}}{Z_n}$$

For finding out the value of neutral resistor,

$$\frac{E_{ph}}{Z_n} = \frac{11 \times 10^3}{\sqrt{3} \times R_n} = 629.8$$

∴

$$R_n = 10.08 \Omega$$

The earth-fault current for the earth-fault at $p\%$ of the winding from the neutral end,

$$I_f = \frac{11 \times p \times 10^3}{\sqrt{3} \times 100 \times R_n} = 6.3 \text{ pA}$$

This when equated to sensitivity of the relay, (i.e., 10% of 2000 A.)

$$6.3p = 200$$

$$p = 31.74$$

This means that 31.74% of winding is unprotected or 68.26% of the winding is protected.

For allowing only 9.5% of the winding unprotected, the earth-fault current will be

$$I_f = \frac{11 \times 9.5 \times 10^3}{\sqrt{3} \times 100 \times R_n}$$

$$\therefore \frac{603.33}{R_n} = 200 \quad (200 \text{ A being the sensitivity of relay in primary amperes})$$

∴

$$R_n = 3.016 \Omega.$$

This will certainly increase the maximum earth-fault current

$$I_{f\max} = \frac{11 \times 10^3}{\sqrt{3} \times 3.016} = 2105.72 \text{ A}$$

$$= 133.73\% \text{ of full-load current of the generator}$$

This calculation clearly indicates that any effort to increase the portion of the winding protected will increase the maximum earth-fault current if the relay sensitivity is kept constant.

The relations between the percentage of the winding unprotected, value of the neutral resistance, magnitude of maximum earth-fault current and sensitivity of the current-based relay are tabulated in Table 5.1.

Table 5.1

Sr. No.	Relay sensitivity 10			Relay sensitivity 5		
	Neutral resistance ohms	Magnitude of maximum earth fault current of full load current	Percentage of the winding unprotected	Neutral resistance ohms	Magnitude of maximum earth fault current of full load current	Percentage of the winding unprotected
1.	10.08	40	31.74	10.08	40	15.87
2.	3.016	133.73	9.5	6.03	66.85	9.5
3.	40.33	10	Full winding unprotected	4.033	100	6.35
4.	31.75	12.7	100	2.688	150	4.23
5.	1.58	255.27	5	40.33	10	63.7
				63.50	6.35	100

5.3.3 Numerical Approach to Stator Earth-Fault Protection

The third harmonic (or zero sequence) voltage available across open delta of a generator PT secondary windings can be fed to a numerical relay unit for generator protection (voltage across secondary of NGT can, instead, be fed). If we call this voltage V_0 , it can be processed and made to trip the generator as suggested by the flow chart of Fig. 5.14.

The counter increments at every sample. A sampling rate of 1 millisecond is assumed. The counter avoids any possibility of mal-operation due to transient appearance of zero sequence voltage and also provides a time delay of 60 milliseconds which is usual with stator earth-fault protection.

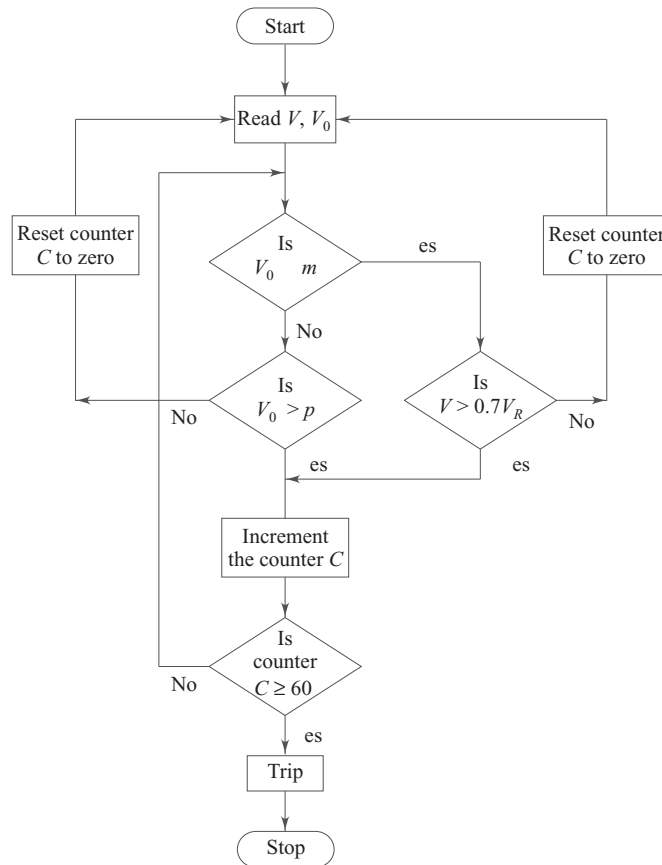
5.4 ROTOR EARTH-FAULT PROTECTION

5.4.1 Introduction

If the rotor winding is ungrounded, as is the usual practice, a fault to earth has no effect, but a second fault to earth will increase the current in part of the winding and may also unbalance the air-gap fluxes so that there will be serious vibrations which may lead to serious damage. A rotor second earth-fault may also cause local heating which may slowly distort the rotor causing dangerous eccentricity; this can also cause vibrations and serious damage.

5.4.2 Protective Scheme

Figure 5.15 shows one of the methods of detecting rotor earth-faults. The field circuit, as shown in Fig. 5.15, is biased by a dc voltage. If a ground fault occurs, current will pass through a very sensitive dc relay which can initiate alarm or a class A trip as required. The relay is a sensitive polarised moving iron relay. The dc voltage is impressed because in case of ac, the relay cannot be made very sensitive. This is because the relay may pick-up due to the current that normally flows through the capacitance of the rotor winding to its core and thereafter through the bearings to ground. This current can be comparatively high if the resonance is established between this capacitance and the relay inductance. Also, even if this current is small, it will pit the bearings unless a special collector brush is fitted to the rotor shaft.



V : Rated voltage of generator
 V_0 : Zero sequence voltage available across open delta of a generator PT secondary windings
 $m = 90\%$ of p , where p is the third harmonic voltage generated by the machine under normal operating conditions (p is expressed as percentage of rated voltage)

Fig. 5.14 Generator 100% stator earth-fault protection

In unattended stations, the protective relaying equipment must be arranged to trip the main and field breakers of the generator when the first ground fault occurs. In attended stations, the usual practice is to sound an alarm at the occurrence of the rotor first earth-fault. Should the second earth-fault occur, the main and field breakers of the generator must be instantaneously tripped. However, this practice involves a little risk because the vibration caused by a second earth-fault cannot be stopped instantly and also the two ground faults may occur together or in quick succession.

The detailed scheme of first and second earth-fault protection of the rotor is shown in Fig. 5.16. The circuit of Fig. 5.17 is for the selector switch on 'Rotor first earth-fault' position. Figure 5.18 gives the control circuit for alarm and annunciation. Figure 5.19 is the simplified circuit for selector switch on 'Balance' position. Figure 5.20 is the control circuit for effecting tripping of the main and field breakers of the generator. The protective scheme of Fig. 5.16 uses a selector switch having four positions as shown. P_1 and P_2 are coarse and fine potentiometers respectively and L is a choke. The selector switch is at 'rotor I E/F' position initially.

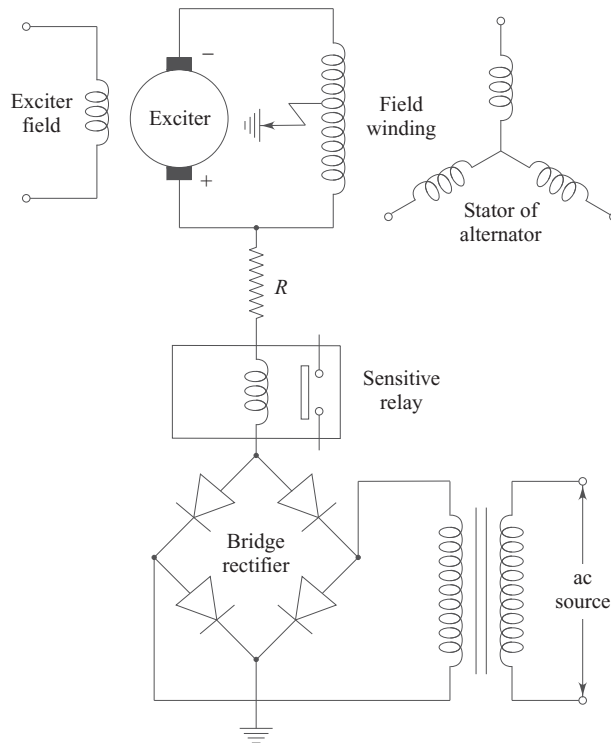


Fig. 5.15 Rotor earth-fault protection

Should the earth-fault occur on the rotor winding as shown in Fig. 5.17, rotor first earth-fault relay $64F_1$ will operate. The operation of $64F_1$ will energise the timer relay $2/64F_1$ (Fig. 5.18). After the preset time, an alarm will be sounded in the control room of the power station.

Once the alarm is heard, the operator will change the selector switch to 'Balance' position. The reader will appreciate that in the 'Balance' position, the circuit reduces to a Wheatstone bridge circuit (Fig. 5.19) with parts of the field winding F_1 and F_2 (Fig. 5.17), resistive part y of potentiometer P_1 and parallel combination of x and R plus P_2 (Fig. 5.16) as four arms. This bridge can now be balanced using coarse, medium and fine controls respectively of a selector switch (Fig. 5.16) and using the coarse pot P_1 and fine pot P_2 . Choke L protects the galvanometer and relay $64F_2$ against switching transients.

Once the balancing is done, selector switch is to be changed to 'test' position. The only change in the circuit of the 'test' position is that the galvanometer is replaced by the rotor second earth-fault relay $64F_2$. As the bridge is already balanced, no current passes through the coil of earth-fault relay $64F_2$ and it does not operate. The operation of $64F_2$ can be tested here by disturbing the balance. It is to be noted that no tripping will be effected during testing as the selector switch is on 'test' position (Fig. 5.20).

After testing and balancing again, the selector switch is shifted to 'rotor II E/F' position. Should the second earth-fault occur, the balance will be disturbed and relay $64F_2$ will trip the generator. $64F_1$ and $64F_2$ are moving coil type dc relays and are made sensitive to about 1 mA.

It is worthwhile to note that the rotor first earth-fault will initiate an alarm while the second earth-fault protection is a Class A protection. The second earth-fault protection is instantaneous in operation.

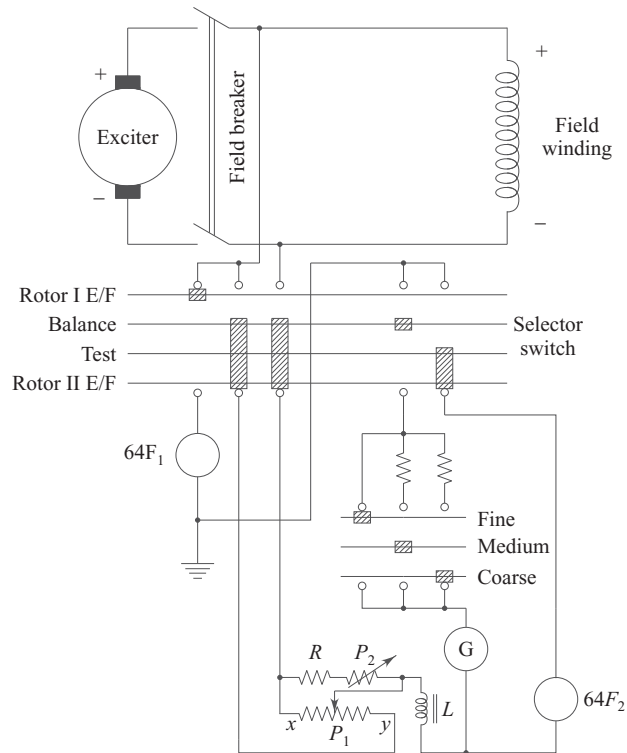


Fig. 5.16 Rotor first and second earth-fault protection of generator

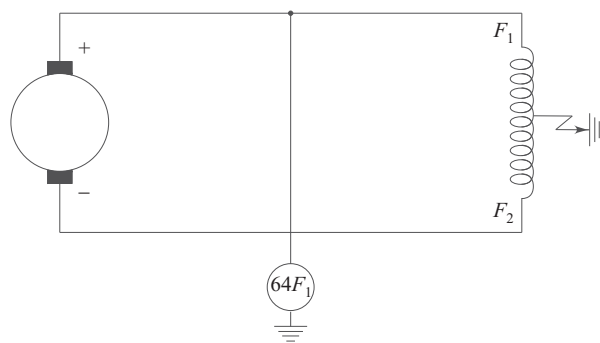


Fig. 5.17 Selector switch on 'rotor I E/F' position

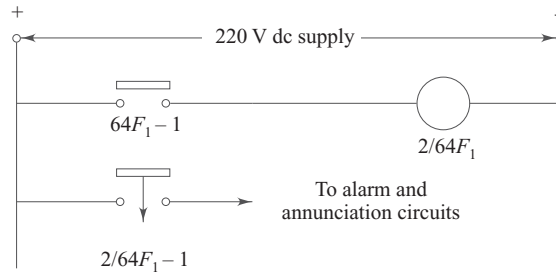


Fig. 5.18 DC control circuit for rotor I E/F

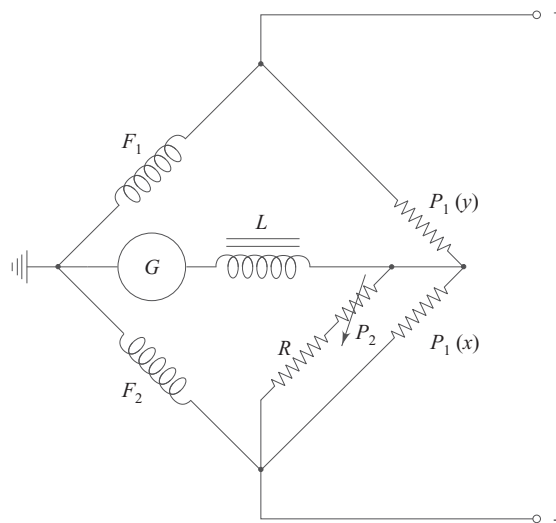


Fig. 5.19 Selector switch in 'balance' position

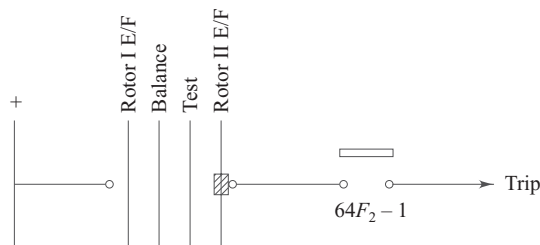


Fig. 5.20 DC control circuit for rotor II E/F

5.5 NEGATIVE PHASE SEQUENCE PROTECTION (PROTECTION AGAINST UNBALANCED LOADING)

5.5.1 Introduction

The negative sequence component of unbalanced stator currents induces double frequency currents in the rotor during normal synchronous rotation. If the degree of unbalance is large, severe overheating can be caused in the structural parts of the rotor which tend to soften and weaken slot wedges and retaining rings, these components are otherwise also, normally, already under great stress in large turbo-alternators.

The system conditions that would cause these harmful unbalanced conditions are

- (i) open-circuiting of the phase or failure of one contact of circuit breaker
- (ii) an unsymmetrical fault near the power station which is not promptly cleared
- (iii) a fault in the stator winding

The time for which the rotor can withstand this condition varies inversely as the square of the negative sequence current, i.e., $I_2^2 t = K$, where K is a constant, which varies from 7 for a large steam turbo-alternator to about 60 for a salient pole hydro machine.

It is important for the protective relay to have a time-current characteristic $I_2^2 t = K$, which closely matches with that of the machine because while it is important to disconnect the generator if K is exceeded, it is more necessary not to take it off from the system unnecessarily.

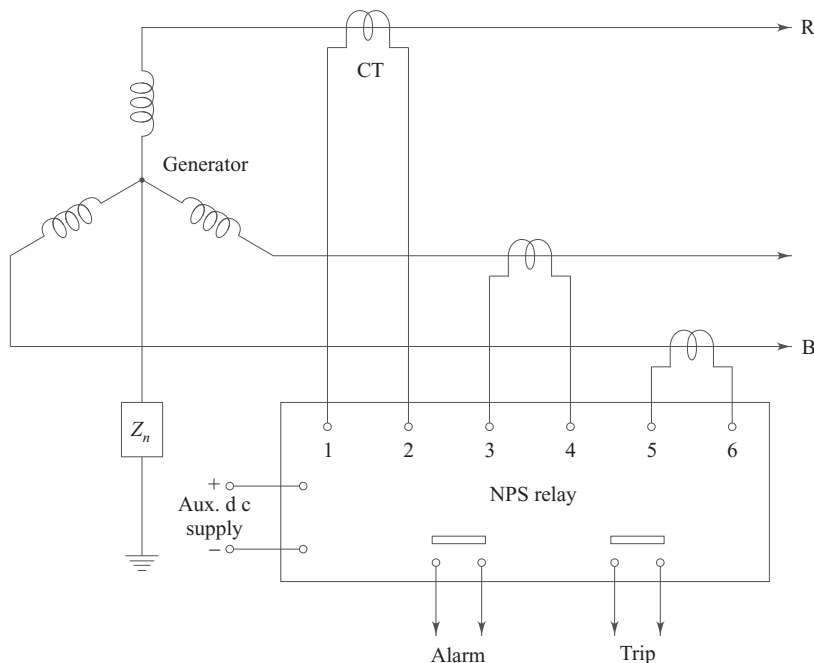
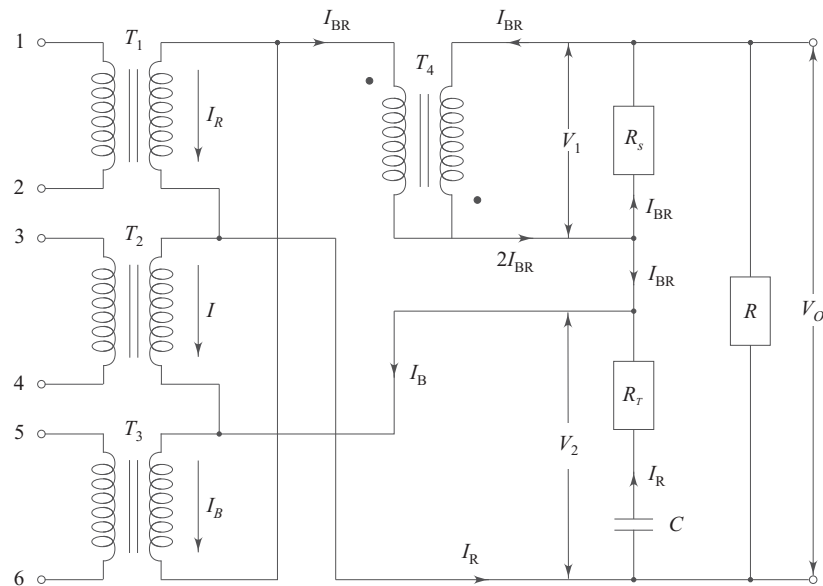


Fig. 5.21 Negative phase sequence relay for generator protection (Courtesy: Areva T&D Ltd.)



$$\text{where } R_T = \frac{R_s}{2}, \quad \frac{1}{\omega C} = \frac{\sqrt{3}}{2} R_s$$

T_1, T_2, T_3 : Input transformers with tapings for adjustment
(the secondaries are connected in delta to eliminate zero sequence current)
 T_4 : Transformer providing 180° phase shift for I_{BR}
 R_s, R_T, R : Resistors
 C : Capacitor

Fig. 5.22 Internal circuit of NPS filter (Courtesy: Areva T&D Ltd.)

5.5.2 Static Negative Phase-sequence Relay (Courtesy: Areva T&D Ltd.)

Referring to Figs 5.21 and 5.22, the inputs from the current transformers, which are connected in each phase of the generator output leads, are fed to a negative sequence filter which gives an ac output voltage proportional to I_2 , the negative phase sequence current. The output voltage is indicated in the vector diagram of Figs 5.23(a) and 5.23(b). This voltage after rectification (Fig. 5.24) passes to the squaring circuit and signal proportional to I_2^2 , so obtained, is then applied to main timing circuit to give the required relationship between I_2^2 and t . The timer output is fed into a resistor chain, the output of which is selected by a potentiometer K . When this output exceeds the reference voltage, it provides one of the inputs to a two-input AND gate. The other input comes from a low set (of the order of 0.3 second) timer which is activated by a starter circuit, when the negative sequence current exceeds the pre-set value. When both the inputs to the AND gate are present, the hinged armature relay is energised. This is done because the large generators can withstand negative sequence current equal to 5% of its rated current continuously.

The alarm setting is normally adjustable from 70–100% of NPS current setting for tripping. If NPS current of generator exceeds this value, a timer starter starts the definite time unit, which after a definite time setting (of the order of 5 seconds) gives an alarm.

A noteworthy point in NPS protection is that the negative phase sequence currents are generated because of open circuiting of a pole of a circuit breaker of the generator, or an unsymmetrical fault in the generator

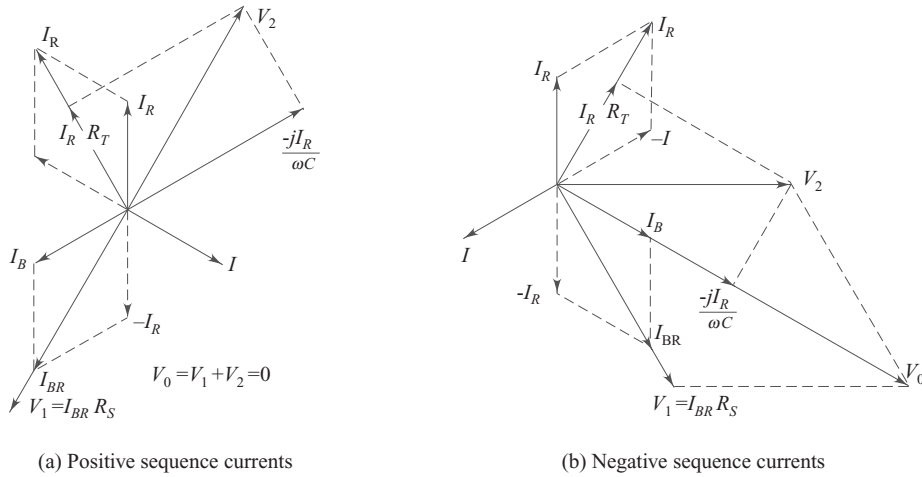


Fig. 5.23 Current vectors

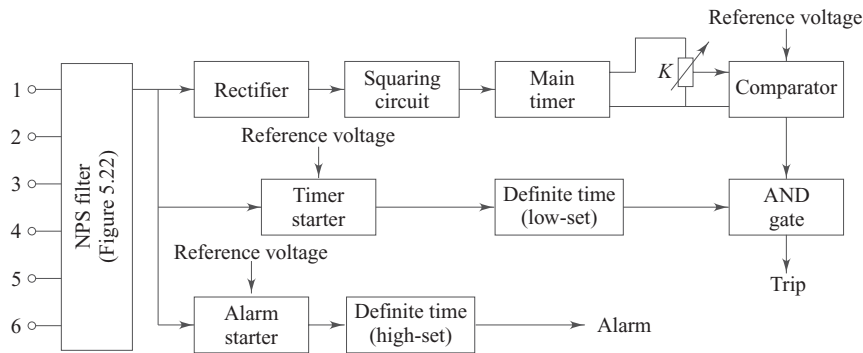


Fig. 5.24 Block diagram of NPS relay (Courtesy: Areva T&D Ltd.)

winding or on a transmission line emanating from the switchyard of the power plant. The fault in a line will be cleared by the relevant protective relaying. If not, then it will be a fault fed by the generator. If they are generated by a stator fault, such faults will be instantaneously cleared by differential protection. This, obviously, means that the operation of an NPS relay does not require the generator to be stopped and field to be opened and suppressed immediately. Thus NPS protection is a Class B protection.

5.5.3 Algorithm for Numerical Relay

In numerical relays, for comprehensive generator protection, negative sequence current protection is one of the functions of the relay. The withstand capability of a rotor for negative sequence current is specified by the manufacturer in terms of $\int i_2^2 dt$. This integration of square of rotor current i_2 is obtained by implementing a thermal model of the rotor which can compute the rotor temperature rise. This temperature rise is used to determine accurately an operating limit for the negative sequence current.

5.6 FIELD FAILURE PROTECTION (PROTECTION AGAINST LOSS OF EXCITATION)

5.6.1 Introduction

Field failure can be caused by a faulty field breaker or failure of the exciter. When a generator loses its field, the speed of the generator will increase and hence it will act as an induction generator. Therefore, induced currents will be generated in the rotor. These rotor currents will overheat the rotor core. The time to reach high rotor overheating depends on the rate of slip.

As the machine over-speeds, it takes a higher share of the load with reference to other generators of the system. The stator current, hence, increases overheating the stator and its windings. The magnitude of the stator currents depends upon the speed of the generator.

Moreover, when a generator loses excitation, it draws reactive power from the system. The generator was supplying reactive power before it lost field. Hence the total reactive power load on the system will be nearly double the reactive power supplied by the generator earlier. If the system is unable to feed this large reactive power requirement, the power system will be unstable resulting in collapse of voltage. As such, the quick acting automatic voltage regulators can relieve the system to a great extent. However, this relief is dependent on the rate and amount of voltage reduction. This is the reason for the need of the field failure relay to be accompanied by an undervoltage relay.

If the system is capable of supplying additional reactive power to the generator, the field of which has failed, there is no risk of system instability. There is no immediate danger to a set operating as an induction generator. If steps are taken to shed the load automatically to approximately half-load, this condition can be tolerated for several minutes. The size of the machine relative to the system is an important factor to be considered while setting the time-delay. Hence field failure protection is a Class B protection.

5.6.2 Field Failure Relay

An under-current relay across a shunt in the field circuit can detect loss of excitation. The relay, normally, remains energised and on loss of fields, drops off causing tripping as desired. This relay must be low-set as field current may be required to be varied over a wide range to adjust terminal voltage of the generator. Because the field winding of the alternator is highly inductive with large coefficient of self-inductance, the time constant L/R is so large that on loss of field, the current through the relay decays very slowly making the protective scheme too sluggish. Hence, such a scheme of protection is not used in practice.

When excitation is lost, the equivalent generator impedance traverses a path from the first quadrant into a region of the fourth quadrant, as shown in Fig. 5.25, as the generator starts running at a super-synchronous speed. Hence the most reliable relay is a mho relay with its characteristic in the negative reactance area as shown in Fig. 5.25. Figure 5.25 also shows that the relay will not operate in out-of-step condition of the generator.

Referring to Fig. 5.25 for the mho relay described above, it is usual to offset the relay characteristic by an amount equal to half the value of Z_d and set the diameter equal to Z_s . In this way, mal-operation on power swings and loss of synchronism not accompanied by loss of field is prevented.

As previously stated, it is not always necessary to isolate the generator from the system immediately after the loss of field relay operates unless there is a danger of system instability. The best indication of stability of a system is the system voltage. Thus, the protective relaying system should be arranged to operate instantaneously in case of collapse in system voltage, this condition being detected by an instantaneous under-voltage relay, set to drop off, should the voltage drop to a value below 70% of normal voltage.

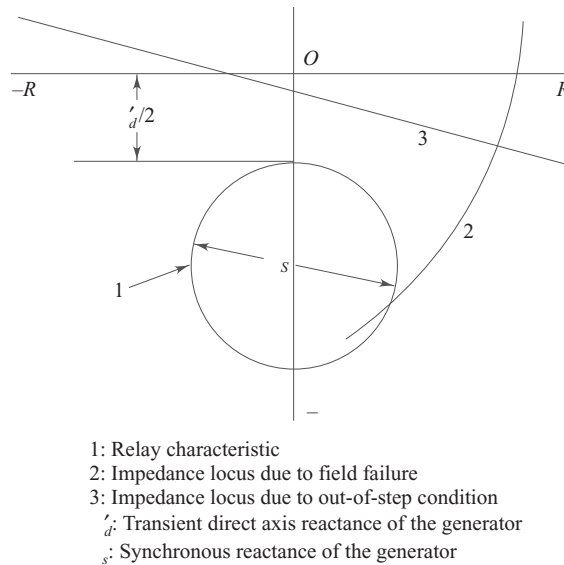


Fig. 5.25 Characteristics of field failure relay

5.6.3 Protective Scheme

Figure 5.26 shows the ac circuit of a protective scheme for field failure protection. As the relay is the off-set mho relay giving the characteristic in a negative reactance area, it is required to be fed by current and voltage signals through CT and PT. The field failure relay (40G) is arranged to give a characteristic as shown in Fig. 5.26.

Figure 5.27 is the dc control circuit for field failure protection (Courtesy Areva T&D Ltd.). The dc control circuit is explained below.

1. During loss of field, 40G operates, closing 40G-1 and energising 40GX.
2. 40GX-1 closes energising timers 2B/1 and 2B/2 and auxiliary relay 2BX.
3. Auxiliary relay 2BX seals in through contacts 86G1-1 and 2BX-1. The auxiliary relay 2BX and its sealing circuit is significant. Immediately after loss of field, the machine will start accelerating. Once its speed rises, it will act as an induction generator and owing to super-synchronous speed, it takes a larger share of the load with respect to other generators of the power system. Hence, the machine starts decelerating. However, because of large inertia constant, a speed variation occurs, i.e., the speed oscillates around and finally rests at a steady-state speed with respect to the new load. In such a case, the impedance seen by field failure relay (off-set mho relay) may oscillate and may intermittently fall out of the mho circle. This will cause relay 40G to energise and de-energise intermittently. Hence, the contact 40G-1 would close and open intermittently. Therefore, the energisation of 40GX will also be intermittent. Thus, if the timer 2B/1 is not sealed, it can perhaps never complete its counting time or an unbearable delay in operation of the field failure protection may occur resulting in drastic damage as the timer will de-energise and stop counting time with the opening of 40GX-1. Obviously, the risk of damage to the generator under protection and the system as a whole starts from the initiation of field failure. The sealing circuit thus ensures that once the field failure is initiated, the timer is held energised till the goal of completing its count is achieved. 40GX-2 closes, preparing the circuit for final trip relay 40GZ. Thus, final tripping requires that the impedance seen by the relay 40G must lie

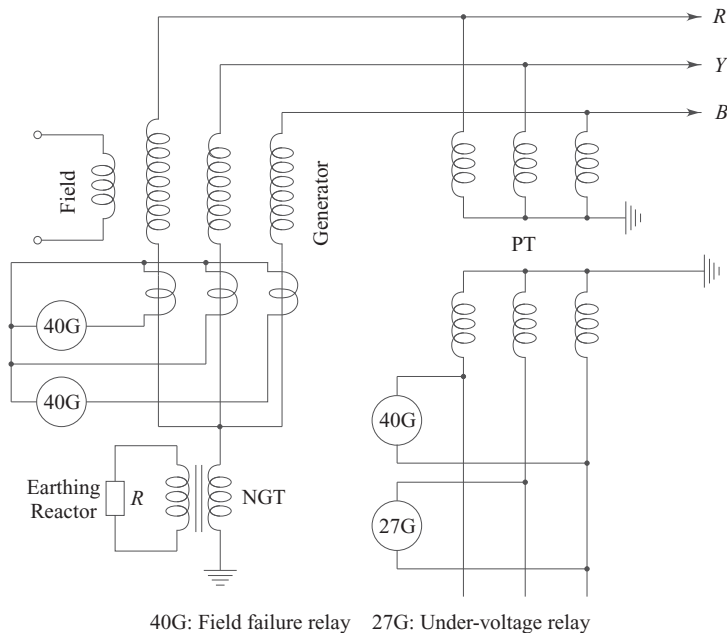


Fig. 5.26 Protective scheme for field failure protection

within its characteristic. If the condition which caused field failure has permanently vanished by the time 40GZ can operate, it will never operate as 40GX-2 will become open and no final tripping can occur as required.

4. Timer 2B/1 and 2B/2 operates after a pre-set time delay. Timer 2B/2 is set at higher time-setting than that of 2B/1. Timer 2B/2 is a resetting timer for the whole protective scheme as we shall see shortly.
5. 2B/1-1 closes, energising auxiliary relay 2B .
6. 2B seals in through 2B -1.
7. 2B -2 closes and energises final trip relay 40GZ, provided 40GX-2 is not still restored.
8. 40GZ, being the final trip relay, is sealed through 86G₁-1 and 40GZ-1.
9. 40GZ-2 closes and energises Class B trip relay 86G₂.
10. If the field has resumed before 2B/1-1 closes, 40GZ does not operate and final tripping is not established as desired, but relays 2BX, 2B and timers 2B/1 and 2B/2 are still energised. These are required to be reset. Timer 2B/2 after completion of its time-setting operates and hence contact 2B/2-1 closes energising the auxiliary relay 40G . Opening of contact 40G -1 resets all the relays (i.e., 2BX, 2B , 2B/1 and 2B/2). 86G₁ will operate through low forward power relay and hence 40GZ will de-energise. Thus, the whole protective scheme is reset, ready for the next operation when required.
11. If field failure is sustained, Class B tripping relay 86G₂ initiates Class B tripping sequence.
12. If field failure is accompanied by heavy voltage dip, contact 27G-1 closes simultaneously with the closure of 40GX-2, energising final trip relay 40GZ instantaneously, thus establishing Class B trip without any time-delay.
13. The interlocking 'NC' contact 86G₁-1 is required to make sure that the annunciation of field failure is not given to the operator under Class A trip condition (one contact, which is not shown in control

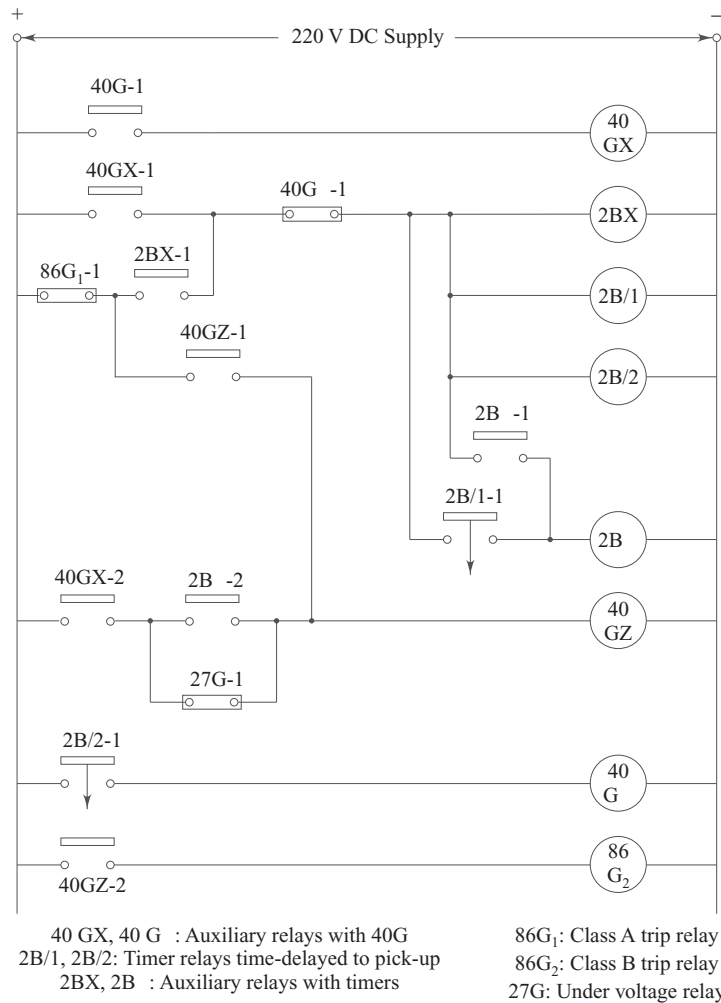


Fig. 5.27 DC control circuit (Courtesy: Areva T&D Ltd.)

circuit, of 40GZ gives annunciation). Under any protection scheme (such as differential protection, stator earth-fault protection, etc.), which calls for Class A protection to operate, the field breaker is tripped as a part of Class A trip sequence. This means intentional failure of field. This condition should not be accompanied by field failure alarm or annunciation as it may mislead the operator. The operation of Class A trip relay 86G₁, will open the 'NC' contact 86G₁-1 thus disconnecting the seal-in circuit of all the relays 2BX, 2B, 2B/1, 2B/2 and also it will not allow 40GZ to be sealed-in; thus avoiding the annunciation.

5.7 OVERLOAD PROTECTION

When the generator is overloaded, the winding insulation will get overheated to the same proportion as the overload. If the permissible temperature limit of the insulation is exceeded, the insulation will puncture

resulting in a stator fault. So the stator winding temperature must be maintained within safe limits. If a generator is loaded beyond its rated capacity, usually an alarm is sounded so that the operator can throttle the steam control valve of the turbine to relieve the generator from overload. A definite time overcurrent relay can be used for the protection against overload.

As the overloading will be symmetrical in all the three phases, a single-phase relay fed from CT on any one of the phases is sufficient for the purpose. The relay can be set to operate at 105–110% of the rated current of the generator.

5.8 OVERVOLTAGE PROTECTION

Apart from transient overvoltage caused by lightning, etc., overvoltage can be associated with overspeed or it can be caused by a defective voltage regulator.

The protection against transient high frequency or impulse overvoltage due to lightning and switching surges can be offered by lightning arrestors. But overvoltage relay is required to protect the stator conductor insulation of the generator against power-frequency overvoltages.

On modern steam-driven generators, the voltage regulators act sufficiently fast to prevent serious overvoltage from occurring when the generator loses its load and terminal voltage increases either due to acceleration, or as a consequence of line charging current.

The most suitable overvoltage relay will have two units; an instantaneous unit tripping on 25% (steam) or 40% (hydro) overvoltage, and an inverse time unit starting at 10% overvoltage. The relay will be energised from a PT secondary.

In the modern protective scheme, the operation of an overvoltage relay, initially causes the alarm to be sounded and thus warns the operator. Should the automatic voltage regulator not restore the voltage to normal within pre-set time, the machine has to be tripped completely as the overvoltage can deteriorate the generator insulation. Thus overvoltage protection is a Class A protection.

5.9 REVERSE POWER PROTECTION

5.9.1 Introduction

Reverse power protection is against failure of prime-mover of an alternator. When the prime-mover of one of the alternators fails in a power plant, the alternator will not stop but will run as a synchronous motor taking power from the bus. There is no harm for the alternator when it is run as a synchronous motor but the reversal of power is harmful to the prime-mover.

Referring to Fig. 5.28, the normal flow of power is from the alternators to the bus. If now the input to the prime-mover of any one of the alternators stops, the busbar will feed that alternator and make it run as a synchronous motor. The prime-mover will act as a load on the motor. This means that flow of power is reversed. The reversal of power is sensed by a reverse power relay.

The effect of reversal of power on different prime-movers is discussed below:

Steam Turbines A steam turbine needs to be protected against overheating when its steam supply is cut off and its generator runs as a motor. The turbine then acts as a pump and the steam is trapped. Hence, the turbine blades get overheated due to windage. In modern steam turbines the steam may be at a very high temperature and it is difficult to envisage the steam as a coolant. However, the heat caused by turbulence of the trapped steam can de-temper and damage the turbine blades.

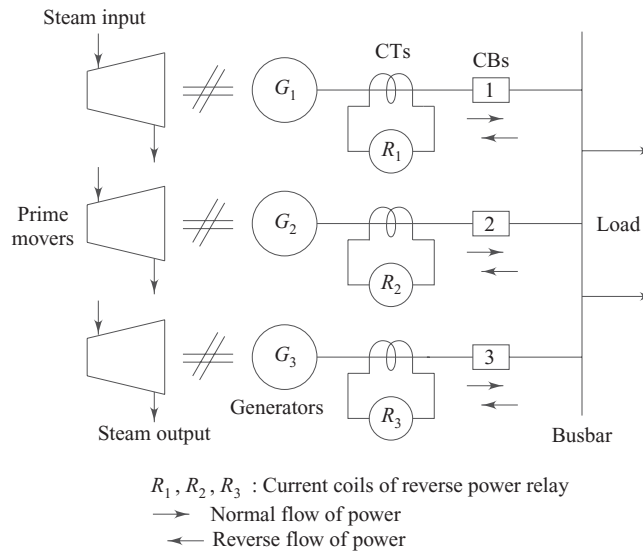


Fig. 5.28 Need for reverse power protection

For small turbines the relays are set to operate when forward power reduces below 3% of the rated power. For large turbines, the sensitive setting of 0.5% of rated power is used. These relays are known as 'low forward power relays'.

Hydro Turbines On reversal of power, the water flow reduces and hence bubbles are formed causing cavitation in the turbine. The turbine blades can be damaged due to the forces generated as a result of cavitation. Relays are set to operate at about 3% of the reversal of power.

Diesel Engines Motoring protection for diesel engines is necessary to prevent the danger of fire or explosion resulting from unburnt fuel.

Gas Turbine A gas turbine, when it runs as a pump, will load the generator working as motor. Protection should be applied based on the motoring load on the system. Relays are normally set to operate for 10% reversal of rated power.

A reverse power relay is basically a directional relay with leading maximum torque angle. This is because the alternator runs as an over-excited synchronous motor.

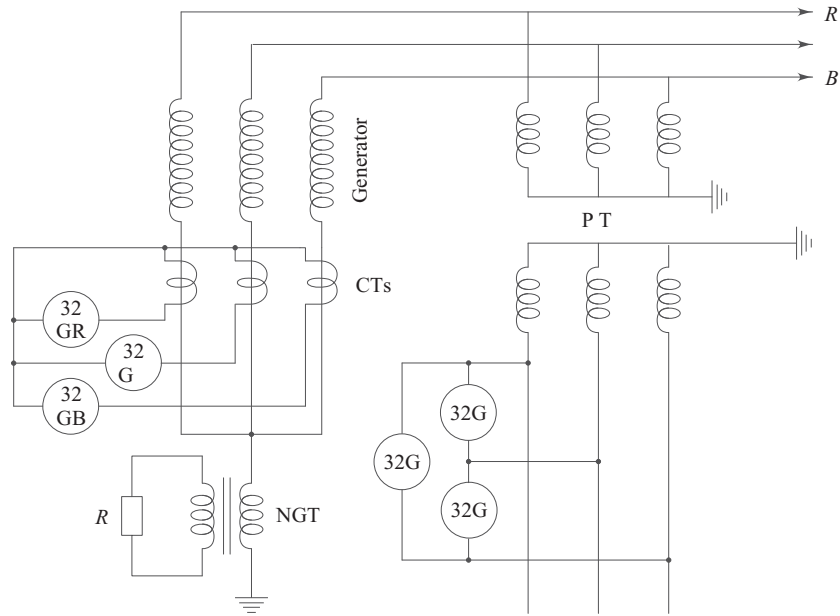
A reverse power relay is a time-delayed relay because of the following reasons:

1. As the overheating of the turbine blades does not occur instantaneously once the generator starts motoring, instantaneous tripping is not required.
2. In case of an internal fault in the generator, differential protection will act instantaneously. But the busbar will feed the internal fault and if the reverse power relay is not provided with the time-delay, it will also operate simultaneously with the operation of the differential relay. In such a case, the operators will be in doubt whether the tripping of the generator is due to failure of turbine or an internal fault. The reverse power relay has to operate only due to failure of the prime-mover.
3. Sufficient time-delay should be provided to prevent undesired operation on transient power reversals such as those occurring during synchronising or system disturbances.

5.9.2 Protective Scheme

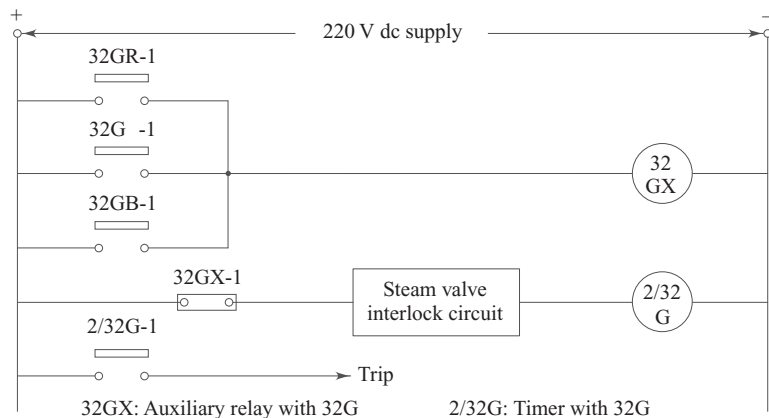
Figures 5.29 and 5.30 show an ac circuit and dc control circuit respectively. Low forward-power relays, 32GR, 32G and 32GB, remain in operated conditions in the normal mode of generator operation. These relays are set to drop off when the forward power reduces below 0.5–3% of the rated power of the generator.

Hence, on reversal of power, these relays drop off which leads to de-energisation of the auxiliary relay 32GX. When 32GX de-energises, its contact 32GX-1 starts the timer 2/32-G. After the pre-set time-delay,



32G: Reverse power relay

Fig. 5.29 Reverse power protection scheme



32GX: Auxiliary relay with 32G

2/32G: Timer with 32G

Fig. 5.30 DC control circuit for reverse power protection

the generator trips. The steam stop valve interlock circuitry ensures that the reverse power protection does not operate while manually starting or stopping the unit.

Reverse power protection is a Class A protection.

5.10 POLE-SLIPPING PROTECTION

5.10.1 Introduction

Loss of synchronism or pole-slipping is caused by excessive load, faults in the power system or insufficient field excitation.

When the generator is running at full load, it operates at some load angle δ_1 . As the load is increased abruptly, either due to excessive load or fault somewhere in the power system, the generator slows down and if the generator has not become unstable, i.e., working within its transient stability limit, the rotor of the generator will regain synchronism at a new load angle δ_2 , higher than δ_1 . But if the poles of the generator have slipped with respect to the synchronous speed beyond the transient limit, the generator will continue to slow down and stability is lost.

The generator has to be protected against this abnormality.

This is because, the generator (the pole of which have slipped) can become a cause of danger to the whole power system. If such a generator is not isolated from the infinite bus, a cascade tripping of many or all the generators of the system may occur. Moreover, the generator, the poles of which have slipped beyond stability limit, cannot regain synchronism and hence it is required to be tripped completely. Hence it is a Class A protection. The relay is a two-input relay fed from CT and PT both.

5.10.2 Pole-slipping Relay

The relay makes use of the fact that when synchronism is lost, the impedance measured by a distance relay (refer to power swings in Chapter 8) will progress through the line impedance vector on locus as shown in Fig. 5.31.

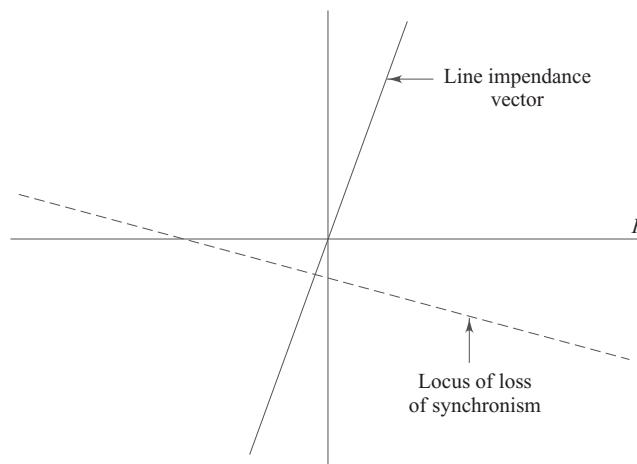


Fig. 5.31 Locus of pole-slipping

The relay used for the protection against pole-slipping consists of a directional unit (Fig. 5.32) with a lag angle θ_1 and a blinder unit with a lag angle θ_2 which has reverse resistance reach, R . The two characteristics are arranged to operate in conjunction with a time-delay unit. Operation of the relay occurs if the time taken for the pole-slipping locus to pass between the two characteristics exceeds the time-setting. The relay can only become operative when the ac current exceeds a predetermined level and establishes the dc supply. An instantaneous overcurrent relay can be used, here, as an overcurrent starter. The overcurrent starter ensures that the pole-slipping relay does not operate during manual starting and stopping of the generator.

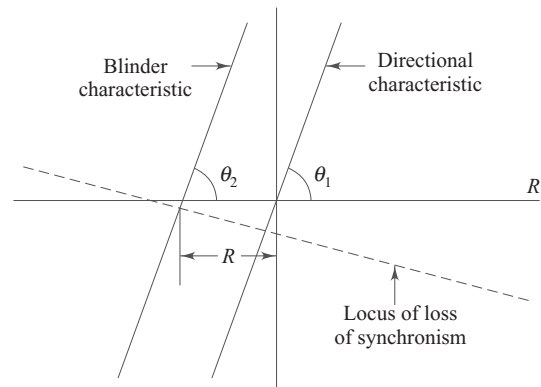


Fig. 5.32 Pole-slipping relay characteristics

The dc control circuit of Fig. 5.33 is explained below.

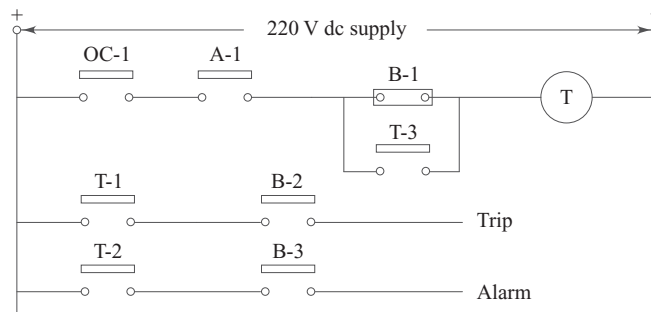


Fig. 5.33 DC control circuit of pole-slipping protection (Courtesy: Areva T&D Ltd.)

When a pole-slipping condition exists, the impedance vector traverses a locus from right to left, because the generator is delivering power, as shown in Fig. 5.32. When the impedance seen by the relay goes to the left of the directional characteristic A, the element A operates, contact A-1 closes and the timer gets energised because the overcurrent starter contact OC-1 will be in the closed condition (overcurrent starter is set approximately at the rated current of the generator). After pre-set time, timer operates (the timer is set according to the rate of slip). If it times out before the impedance goes to the left of the reverse reach blinder characteristic B, contacts T-1, T-2 and T-3 are closed. Finally, when the impedance goes to the left of the characteristic B, the element B operates to close contacts B-2 and B-3 giving trip and alarm signals.

If the impedance never goes to the left of the characteristic B, which is the case of the generator not having lost stability, the element B will not operate and no tripping takes place.

If during pole-slip, the impedance passes through characteristics A and B and reaches to the left of the characteristic B, before the timer has operated, the element B operates opening B-1 to remove the dc supply to the timer and inhibit the operation of the protective scheme. This condition will arise in case of the internal fault in the generator or generator transformer, busbar fault or fault very near to the power station. These faults need to be taken care of by other protections. The scheme also does not operate in case of field failure as impedance locus never goes to the left of the blinder characteristic B.

5.10.3 Setting of Pole-slipping Relay

Data

1. *Generator ratings* 210 MW, 9050 A, 247 MVA, 15.75 kV, $\epsilon'_d = 30.5\%$, $\epsilon''_d = 21.4\%$
2. *Generator-transformer rating* 250 MVA, 15.75/240 kV, $\%X = 14\%$
3. *System fault level* = 10000 MVA
4. CT ratio = 10000/5 A
5. PT ratio = 15.75 kV/110 V
6. Rate of slip = 1600 per second
7. System impedance angle = 75

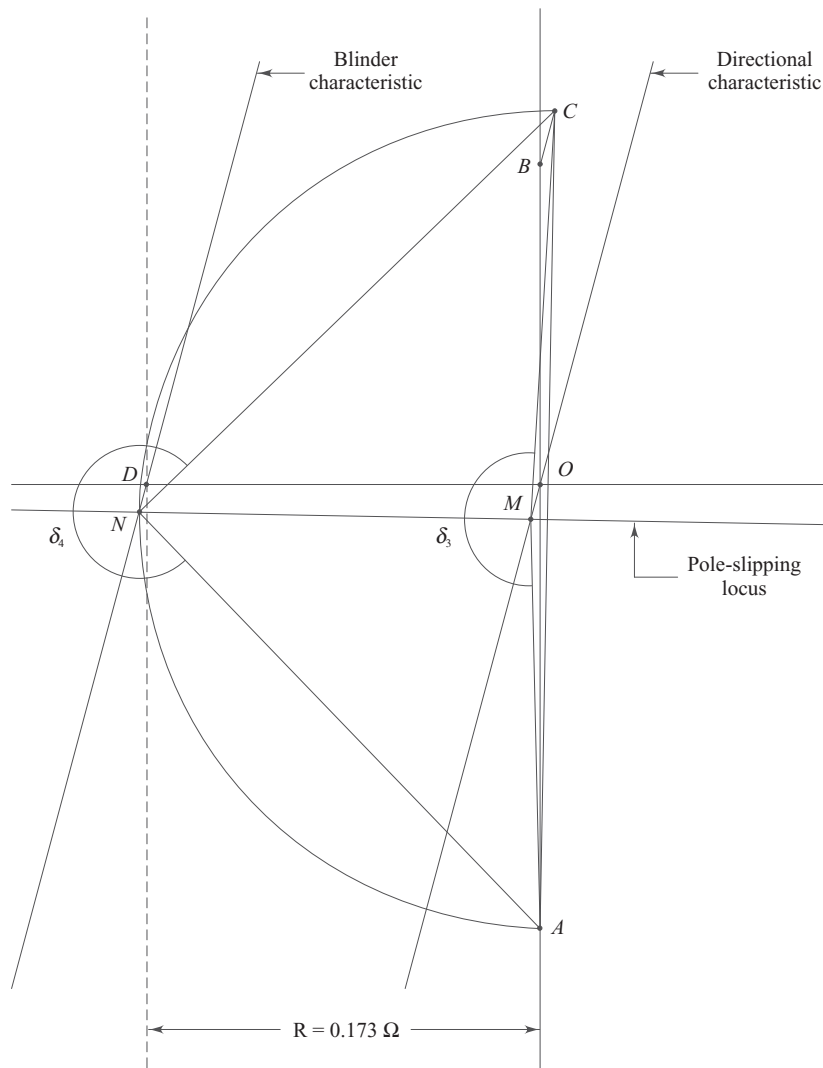


Fig. 5.34 *Setting of a pole-slipping relay*

Relay-setting (Refer Fig. 5.34)

1. Generator pole-slipping reactance = OA
= 90% of sub-transient reactance

$$0.9 \times \frac{21.4}{100} \times \frac{(15.75)^2}{247} = 0.1934 \Omega.$$

Draw OA to scale on the negative reactance axis as the relay looks back for the generator reactance (PT location is at the terminals of the generator).

2. Transformer reactance = OB

$$= \frac{14}{100} \times \frac{(15.75)^2}{250} = 0.1389 \Omega$$

Draw OB to scale on the positive reactance axis as the relay looks forward for the transformer reactance.

3. Source impedance = BC

$$= \frac{(\text{kV})^2}{\text{System Fault MVA}} = \frac{(15.75)^2}{10000} = 0.0248 \Omega$$

Draw BC to scale at an angle 75° to resistance axis.

4. Join AC . Draw pole-slipping characteristic which is a perpendicular bisector of AC (refer 'power swings' in Chapter 8).
5. Draw characteristic of directional unit passing through the origin at an angle of 75° to the resistance axis. This characteristic cuts the pole-slipping locus at M . $\angle AMC = \delta_3 = 183.5^\circ$.
 δ_3 is the load angle of the generator (the poles of which are slipping) at the point M , when the pole-slipping locus crosses the directional characteristic.
6. With AC as a diameter, draw a semicircle which cuts the pole-slipping locus at the point N . $\angle ANC = \delta_4 = 270^\circ$, inner angle ANC obviously will be 90° . The modern generators provided with fast acting automatic regulators can be allowed to slip up to the load angle of 270° without losing synchronism.
7. Draw blinder characteristic passing through N at an angle of 75° to resistance axis.
8. Negative resistance reach = OD

$$= 0.173 \Omega \text{ (primary)}$$

$$= 0.173 \times \frac{\text{CTR}}{\text{PTR}}$$

$$= 0.173 \times \frac{10000}{5} \times \frac{110}{15750} = 2.4156 \Omega \text{ (secondary)}$$

9. Timer setting

$$\begin{aligned} \text{Time setting} &= \frac{\delta_4 - \delta_3}{\text{Rate of slip}} \\ &= \frac{270 - 183.5}{1600} \times 1000 = 54.06 \text{ milliseconds} \end{aligned}$$

10. *Setting of Overcurrent starter (Instantaneous overcurrent relay):*
Overcurrent starter can be set at 110% of the generator rating.

$$\begin{aligned}
 \text{Setting of starter} &= \frac{9050 \times 1.1}{10000} \times 1000 \\
 &= 99.55\% \text{ of CT rating (or relay rating)} \\
 &= \text{say } 100\% \text{ of relay rating.}
 \end{aligned}$$

5.11 BACK-UP IMPEDANCE PROTECTION

Generators shall be provided with back-up protection against line faults so that failure of main protection on lines does not cause damage to generators. Four types of relays are available for the back-up protection, viz., the simple inverse time overcurrent relay, voltage-controlled overcurrent relay, single-step definite-time impedance relay and single-step definite-time off-set mho relay.

The overcurrent types of relays alone cannot be applied as the synchronous reactance of the generator is large, and hence the steady-state fault current for the fault near the generator is less than the rated full-load current of the generator. It is to be noted here that because the back-up relays operate after a certain time-delay, the generator reactance, by this time, will change from sub-transient through transient to synchronous reactance. The voltage control feature also becomes ineffective when the automatic voltage regulators are used in conjunction with the generators because they tend to maintain the normal voltage at the generator terminals. Therefore, distance measuring units are generally preferred.

The normal practice is to set the distance relay to reach into the system to cover the longest line taking off from the hv bus, under the maximum generating conditions. Such a setting on an impedance type of relay covers a vast area in the third and fourth quadrants of the R - X plane, as shown in Fig. 5.35. As the back-up impedance characteristic and field failure characteristic overlap as shown, it rules out a time-setting on field failure timer greater than that on the distance back-up timer as otherwise, the distance back-up could mal-operate for field failure condition.

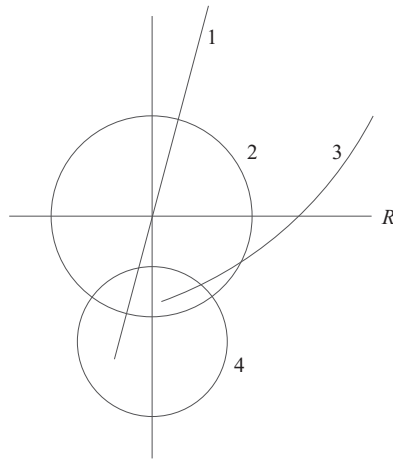
In such cases, therefore, off-set mho characteristic, as shown in Fig. 5.36, will be the most suitable as the question of overlapping of characteristics does not arise. It is true that the backward reach of such relays into generator windings is considerably less than that of the impedance type of relays but such additional back-up protection at the cost of likely mal-operation under field failure condition is not justified because of adequate protections, otherwise available, e.g. generator differential, stator earth-fault, etc. Back-up impedance protection is, obviously Class B protection.

5.12 UNDER-FREQUENCY PROTECTION

Due to inadvertent splitting of the interconnection of the power system, isolated areas of the system may become deficient in generation and the frequency of the same may drop considerably. In order to maintain control of the system under this condition, some form of load relief is needed.

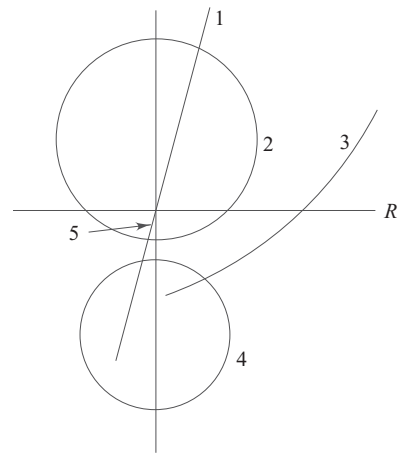
If the frequency goes down, the speed of the turbine gets reduced. Hence the steam may get condensed on the turbine blades damaging them. The steam-turbine sets will be damaged badly if the frequency goes down to 46 Hz in the 50 Hz system. Moreover, the power station auxiliaries will be overloaded because of reduction in frequency.

It is a normal practice nowadays to employ automatic load-shedding if the frequency goes down. However, the under-frequency relays are also used with modern generator-protection practice so that the alarm can be sounded if frequency drops to a value below 50 Hz. Moreover, if the frequency drops drastically, the tripping can be effected.



- 1: Line impedance vector including impedance of unit GT
- 2: Impedance characteristic of a back-up impedance relay
- 3: Locus of loss of excitation
- 4: Field failure relay characteristic

Fig. 5.35 Application of back-up impedance relay using impedance characteristics



- 1: Line impedance vector
- 2: Off-set Mho characteristic of a back-up relay
- 3: Locus of loss of excitation
- 4: Field failure relay characteristic
- 5: Backward reach into generator winding

Fig. 5.36 Application of an off-set mho relay

5.12.1 Effect of Restructuring of Power Systems on Frequency Control

Recently, in India, the concept of Availability Based Tariff (ABT) has been implemented as a part of restructuring of power systems. Its purpose is to bring discipline in scheduling of generation and inter state as well as intra-state transfer of power. The tariff for supply and drawal of power has been correlated with the operating frequency of the interconnected grid. The punishment for unscheduled interchange (UI) has been formulated in terms of UI mechanism. Also higher tariff is provided to help in restoring the system frequency in case of shortage of generation due to sudden failure of generators at one or more stations. Because of this UI mechanism, the frequency now remains well within the 49.5 to 50.0 zone. This situation leads to review of previous settings of under-frequency relays.

5.13 MISCELLANEOUS PROTECTIONS

5.13.1 Over-speed

When a generator loses its load either due to opening of its breaker or due to sudden tripping of a long line emanating from the power station, the generator over-speeds. The speed governor, however, acts to throttle the steam before any great increase in speed takes place in case of steam turbo-alternators. In hydro-sets, on the other hand, the water flow cannot be stopped or deflected quickly and hence over-speed can occur. Over-speeds, in such a case of over 150% of normal are possible.

Overvoltage or over-frequency relays can be employed in case of hydro-alternators.

5.13.2 Stator Overheating

The main causes of stator overheating are ventilation failure, overloading, failure of cooling system, short-circuited laminations and failure of core-bolt insulation.

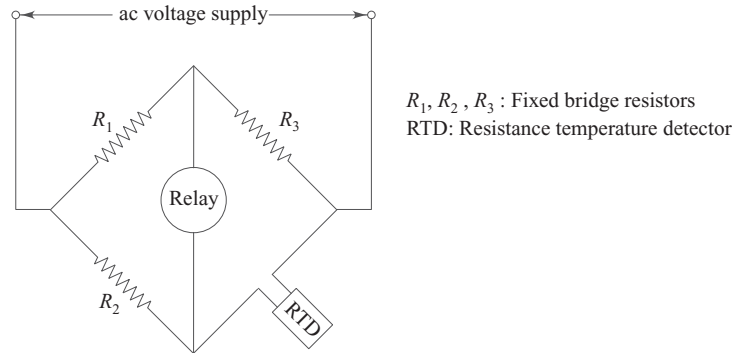


Fig. 5.37 Stator overheating protection

The method used to protect the stator of the generator against overheating is given in Fig. 5.37. The method uses resistance temperature detectors (RTD) embedded in slots at different locations in the stator windings. If overheating occurs, the resistance of RTD changes, disturbing the balance of the bridge, and thus operates a relay. The relay can be arranged to sound an alarm and annunciate the condition in the control room.

5.13.3 Vibration

Vibration takes place due to unbalanced stator currents or rotor ground faults. The vibration can result from a mechanical failure or abnormality also. The protection against unbalanced currents (NPS protection) and rotor earth-fault protection will prevent or minimise vibration under these conditions. The general practice is to provide vibration recorders that can also be used to sound an alarm, should the amplitude of vibration cross a pre-set limit.

5.13.4 Bearing Failure and Bearing Overheating

Failure of oil cooling equipment or failure of lubrication system may cause bearing overheating and, in turn, failure of bearing.

The temperature of the oil can be monitored by an instrument with alarm contacts. The failure of the oil cooling equipment is detected in large machines by comparison of inlet and outlet temperatures of the oil.

5.13.5 Generator Potential Transformer Fuse Failure

When one of the fuses of the potential transformer blows, the magnitude and phase relation of certain secondary voltages change. Such an effect cause certain relays (such as undervoltage relays, distance type relays, etc.) to operate undesirably. The voltage balance scheme can be used to prevent undesired operation of critical relays and to actuate an alarm when a fuse blows.

5.13.6 Auxiliary Failure

Because of failure of auxiliaries like condensate extraction pump, loss of vacuum is resulted. On loss of vacuum, it is usual to reduce the load until the condition is controlled. If however, the vacuum continues to fall until a dangerous value is reached, a vacuum relay closes its contacts and the set is automatically shut down.

The failure of the auxiliary, like induced draught fans, can cause loss of boiler pressure. In this case, a steam pressure device is arranged to remove the load from the turbine.

Many other annunciating and tripping (if required) devices do not fall under the scope of this book. Power station control and instrumentation deal with such devices. These devices will automatically (and if auto control is lost or found slow-acting, manually also) annunciate the abnormal condition due to auxiliary failure and also reduce the load on the generator by throttling steam input to the turbine or trip the generator if required.

5.14 NUMERICAL APPROACH TO GENERATOR PROTECTION

A dedicated microprocessor or microcomputer can be used to monitor rotor earth-fault, field failure, overload, overvoltage, reverse power, pole-slipping and under-frequency. Back-up mho protection can also be applied. The method of sampling and philosophy (flow chart) can be easily developed as discussed in differential protection, negative-phase sequence protection and stator earth-fault protection. Many of the generator-protection schemes are based on impedance measurement (field failure protection, pole-slipping protection and back-up mho protection). Digital impedance measurement techniques are dealt with in Chapter 4 of this book.

5.A.1 APPENDIX I

Class A, Class B and Class C Protections and Conditions Causing Alarm

Class A Protections

1. Differential protection
2. Stator earth-fault protection
3. Inter-turn fault protection
4. Overcurrent and earth-fault protection (for small generators)
5. Rotor second earth-fault protection
6. Overvoltage protection
7. Reverse power protection
8. Pole-slipping protection
9. Generator-transformer overall differential protection (refer Chapter 6)
10. Local breaker back-up protection (refer Chapter 10)
11. Generator transformer restricted earth-fault protection (refer Chapter 6)
12. Differential protections of unit auxiliary transformers
13. Generator-transformer over-fluxing protection (refer Chapter 6)
14. Generator-transformer Buchholz trip (refer Chapter 6)
15. Generator-transformer pressure relief device operated
16. Unit auxiliary transformer Buchholz trip
17. Unit auxiliary transformer pressure relief device operated
18. Unit auxiliary transformer OLTC Buchholz trip
19. Unit auxiliary transformer instantaneous overcurrent protection
20. Overcurrent protection of excitation transformer (of static excitation system, if installed)

21. Generator rotor overvoltage relay
22. Thyristor block failure (of static excitation system)
23. Generator–transformer and unit auxiliary transformer mulsifire protection
24. Automatic voltage regulator failure relay operated
25. Vacuum failure in outlet of LP turbine

Class B Protections

1. Negative phase sequence protection
2. Field failure protection
3. Back-up impedance protection
4. Under-frequency protection
5. Generator–transformer oil and winding temperature very high (Chapter 6)
6. Unit auxiliary transformer back-up overcurrent protection
7. Unit auxiliary transformer winding and oil temperature very high
8. Very high excitation transformer temperature
9. Thyristor (excitation system) fan supply failure
10. Very high stator water conductivity
11. Very high stator water flow
12. Master fuel trip relay of boiler has operated
13. Very high LP/HP heater water level
14. Thrust bearing (turbine) failure
15. Very low lubrication oil (turbine bearing) pressure
16. Very high and very low boiler drum level
17. Very high turbine bearing temperature
18. HP turbine inlet pressure low
19. Loss of boiler water
20. Loss of ID fans
21. Loss of FD fans
22. High condenser water level
23. Excessive over-firing in boiler

Class C Protections

1. Generator–transformer back-up earth-fault protection (Chapter 6)
2. Generator–transformer back-up overcurrent protection (Chapter 6)

Many of these protections, particularly those related to boilers and turbines are not dealt with here as they are not within the scope of this book. However, an exhaustive list is given.

Conditions Operating Alarm

(Refer Table 5.2)

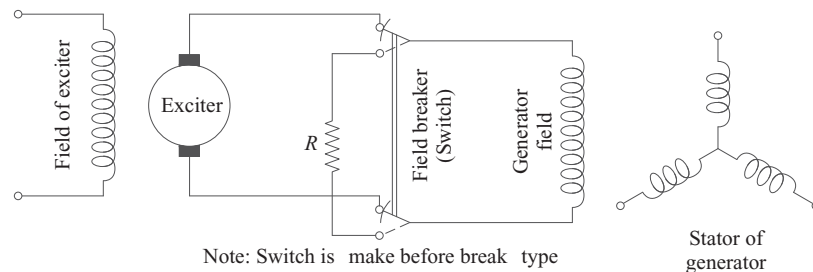
Table 5.2

S. No.	Abnormal Condition	Steam turbo Alternator		Hydro Generator
		Air Cooled	Hydrogen Cooled	
1.	Overload			
2.	Rotor first earth-fault			
3.	Condenser vacuum low			
4.	Hydrogen pressure, temperature or density Abnormal			
5.	Bearing oil pressure low			
6.	Bearing temperature high			
7.	Stator temperature high			
8.	Rotor vibration			
9.	Generator PT fuse failure			
10.	Battery voltage low			
11.	Automatic voltage regulator failure			

5.A.2 APPENDIX 2

Field Suppression

It has already been discussed that the field is required to be disconnected from the exciter in case of operation of Class A protection. When the field is disconnected, the dc current through the field coil tries to reduce to zero. But, because the field coil is an inductive coil having high inductance, the current cannot reduce to zero abruptly. The electromagnetic energy $(1/2)LI^2$ gets stored in the inductance of the field coil. The high voltage produced because of high rate of change of current being interrupted, may deteriorate the insulation of the field coil leading to rotor earth-fault. Also, the field winding may get distorted, due to high electromagnetic forces generated.


Fig. 5.38 Field suppression

Field suppression is a remedy to such a situation. The circuit of Fig. 5.38 shows how field is suppressed. When the field breaker is opened due to operation of Class A protection, the arrangement is made (Fig. 5.38) such that the field is shorted by a discharge resistor R . Hence the stored energy of the field gets dissipated into the resistor.

5.A.3 APPENDIX 3**Information Required for Designing Protection Scheme for Generator and for Relay Settings****I. Generator**

1. Active power rating in kW/MW
2. kVA/MVA rating
3. Voltage rating
4. Full load rated current
5. Through fault withstand
6. Synchronous reactance, X_s
7. Direct axis transient reactance, X'_d
8. Direct axis sub-transient reactance, X''_d
9. Negative sequence reactance, X_2
10. Zero sequence reactance, X_0
11. Nature of cooling the stator winding
12. Nature of cooling of rotor
13. $I_2^2 t$ withstand constant, K
14. Generator NPS current withstand
15. Allowable slip
16. Overload withstand

II. Current Transformers

1. Class of CT
2. Knee point voltage
3. Magnetising current
4. CT secondary resistance
5. CT ratio

Actually, the CT requirements are engineered based on generator particulars and type of protections employed. CT requirements for different types of protections are different and will be discussed in Chapter 13.

III. Pilot Lead Resistance**IV. Types of Relays Used for Different Types of Protections and their Technical Particulars****V. Neutral Grounding Transformer**

1. kVA rating
2. Voltage ratings of primary and secondary
3. Continuous rating/intermittent rating

VI. Type of Earthing of the Neutral

1. Resistance/reactance or any other type of earthing
2. Continuous duty/intermittent duty
3. Voltage rating
4. Current rating/power rating

VII. Potential Transformer

1. Voltage ratio
2. VA rating

Once again, this is based on requirements of the relays

REVIEW QUESTIONS

1. Why are three different classes (Class A, B and C) of protections provided in case of generator protection?
2. What are the CT requirements for generator differential protection? What is done in the relay design to avoid high voltage across high impedance differential relay in case of internal fault of a generator connected to an infinite bus?
3. Explain the circulating current differential protection for generators. Why does the relay tend to operate on heavy external faults? How does the introduction of suitable resistance in the differential circuit stabilise the operation of the relay for external faults, without hindering the operation of the relay on internal faults?
4. What are the difficulties experienced in differential protection of a generator? How are they overcome?
5. Following is the data for simple differential protection of a generator:

Generator

3 phase, 11 kV, 120 MW, 0.85 p.f.

CTs: 7500/5 A (CT secondary resistance is not greater than 1.5 ohms).

Lead resistance (go and return to each CT from a relay) = 1.0 ohm.

Instantaneous over-current relay

Rated current : 5 A

Setting range : 5-20% of 5 A

Burden : 1 VA at 10% tap

Calculate the value of stabilising resistance for a through fault current of 10 pu. Also suggest the

KPV required for CTs. Relay is set at 10% tap. Choose suitable stability factor.

(80 Ω , 247 V, 3)

6. An 11 kV, 20 MW, 3 phase, 0.85 power factor, star-connected generator is protected against internal faults by differential protection scheme. Generator reactances are as follows:

$$X''_d = 20\%, X'_d = 30\%, X_2 = 25\%, X_0 = 10\%$$

- (a) Draw a detailed (three phase) a.c. circuit for the protective scheme.
- (b) Select a suitable CT ratio.
- (c) Decide the ohmic value of the neutral circuit impedance if the maximum earth-fault current is to be limited to 20% of the full load current. If 40% of winding is to be left unprotected, what should be the sensitivity of the differential relay? Ignore the generator reactances for calculating earth-fault current.
- (d) Calculate the value of the fault current for the L-L fault at the terminals of the generator for which differential protection will operate.

(1500/1 A, 25.7 Ω , 65 mA, 4753.46 A)

7. Generator rating

13.8 kV, 0.85 p.f., 3 phase, Y-connected, 120 MW

$$X''_d = 20\%, X'_d = 30\%, X_2 = 20\%, X_0 = 10\%$$

CT ratio = 7500/5 A

$$R_{CT} \leq 1.5 \Omega$$

Because of through fault CT₂ saturates to give induced emf equal to 75% of that of CT₁.

Lead resistance

CT₁ to relay : 1.5 Ω

CT₂ to relay : 2.5 Ω

- Find out the value of R_{stab} considering stability factor of 2.5, if relay is set at 10% of 5 A and relay burden is 3 VA. **(65.34 Ω)**
8. Explain the transverse differential protection scheme as used for protection of generator from inter-turn faults.
 9. Would the generator inter-turn fault protection operate for phase-to-phase fault within the generator? Would your generator differential protection operate for inter-turn fault? Give your concluding remarks based on the answers to these questions.
 10. Why does earth-fault in a stator winding of a generator pose a serious problem?
 11. Explain how a generator is protected against earth-faults in stator winding. What is the necessity for limiting the fault current in the stator?
 12. A star-point of a 20 MVA, 6.6 kV, 3 phase, 50 Hz star connected generator is earthed over a resistance to limit the maximum earth-fault current to 80% of the full load value. The earth-fault relay of the generator is supplied from a CT of ratio 1000/5 A connected in neutral circuit and is set to operate at a current of 0.8 A. Determine (a) the value of the earthing resistance, and (b) the percentage of winding protected by relay. Neglect stator impedances. **(2.72 Ω , 88.57%)**
 13. A neutral of the 5 MW, 6.6 kV, 0.85 p.f., star-connected, 3 phase, 50 Hz generator is grounded through the impedance. If the earth-fault current for the terminal fault is to be limited to half the full load value of the rated current of the generator, find the ohmic value of the neutral impedance. If 80% of the winding is required to be protected, determine the pick-up of a relay connected across a 600/1 A CT in the neutral circuit. Give your comments on the resulting values obtained and the earth-fault protection scheme of this example. **(14.81 Ω , 85 mA)**
 14. A neutral point of a 3 phase, 11 kV, 50 Hz, 120 MW star-connected generator is earthed through a neutral grounding transformer (NGT), the secondary of which is loaded by a resistor for limiting the earth-fault current. The capacitance of the generator stator winding to earth per phase is 0.2 μ F. Find out
 - (i) the kVA rating and the nominal voltage ratio of the neutral grounding transformer, the secondary voltage of the NGT being 240 V
 - (ii) the ohmic and power rating of the resistor
 - (iii) the earth-fault current when the earth-fault occurs at the terminal of the generator **(13.17 kVA, 11000/240 V, 2.525 Ω , 7.6 kW, 1.197 A)**
 15. **A generator has ratings as given below**
 6.6 kV, 50 MW, Y-connected, 50 Hz, 3 phase, 0.85 p.f., capacitance to earth for generator stator winding per phase is 0.3 μ F.
 - (i) Find out the neutral grounding impedance and earth-fault current for the terminal earth-fault.
 - (ii) Find out the voltage of the neutral with respect to the earth due to terminal earth-fault.
 - (iii) Find out the ratio and kVA rating of NGT if the earth-fault relay is rated at 240 V.
 - (iv) If neutral impedance is to be connected in the secondary of NGT, what should be its value in ohmic rating and power rating?
(3536.77 Ω , 1.077 A, 3810.5 volts, 6600/240 V, 7.11 kVA, 4.438 Ω , 4.105 kW)
 16. Explain, with the help of a relevant drawing, the protective scheme of 100% stator earth-fault protection of a large generator.
 17. **Generator rating**
 15.75 kV, 200 MW, Y-connected, 3 phase, 0.85 p.f. grounded by a neutral grounding impedance of 1 Ω connected across the secondary of NGT 15.75 kV/240 V.
 If a relay connected in parallel across the neutral impedance (rated at 240 V) and normal 3rd harmonic generation of a generator is 3% of the rated voltage, find out the setting of a relay (setting range: 2 to 8% in seven equal steps). If the relay has normal inverse voltage-time characteristic with

$$\text{Time of operation} = \frac{3}{\log_{10} \text{PSM}} \times \text{TMS}$$
 where, $\text{PSM} = \frac{\text{Voltage across relay}}{\text{Relay setting}}$
- find the time of operation of the relay for an R-g fault at 25% winding location from the line terminal. Also, find out the earth-fault current. Assume TMS to be 0.2. **(4%, 0.58 s, 1.58 A)**
18. Why cannot the setting of an ac earth-fault relay be made very sensitive whereas that of rotor earth-fault relay can be as sensitive as 1 mA?
 19. If a rotor earth-fault protection fails, which protection will give back-up?

20. Why is it necessary to provide protection to a generator in the event of the following types of faulty conditions?
 - (i) Heavy unbalanced load
 - (ii) Rotor earth-fault
21. Which part of the generator is damaged due to heavy unbalanced currents? How and why?
22. Explain with the help of block diagram and vector diagram, a static negative phase sequence current relay.
23. How would you avoid mal-operation of field failure protection scheme in case of loss of synchronism between generator and power system?
24. Is field failure protection of class A type or class B type?
25. What is the function of the resetting relay 40GY in a dc circuit of field failure protection?
26. Field failure protection is to be applied to 200 MW, 15.75 kV, 3 phase, Y-connected, 0.85 p.f. generator.
 $X_d'' = 20\%$, $X_d' = 30\%$, $X_s = 200\%$
 CTR = 10000/5 A
 PTR = 15750/110 V
 Find out the settings of field failure relay in ohmic value.
(Offset $X_{d/2}' = 2.208 \Omega$, Diameter $X_s = 29.44 \Omega$)
27. Is the overvoltage protection time-delayed or instantaneous? Why?
28. Explain the implementation of generator differential relay in a numerical relay.
29. Draw and explain the algorithm used in a numerical relay for providing stator earth-fault protection in a generator.
30. How is the negative phase sequence protection achieved in a numerical relay?
31. How is the generator protected against failure of prime mover?
32. Why is 'low forward power protection' a very important protection for a large generator?
33. Briefly discuss the possibility of mal-operation of a reverse power relay during starting of the generator.
34. State the necessity and explain the principle and action of the following protections:
 - (i) Reverse power protection
 - (ii) Field failure protection
35. What are the causes and consequences of pole-slipping of a large generator?
36. Explain how a generator is protected against loss of synchronism.
37. An offset mho relay is used for the protection of a large generator against field failure. Determine the settings of a relay using the following data:
Generator
 11 kV, 120 MW, 0.85 p.f., 3 phase, $X_d'' = 21\%$, $X_d' = 30\%$, $X_s = 200\%$, $X_2 = 20\%$, $X_0 = 10\%$.
 CT ratio : 8000/5 A
 PT ratio : 11 kV/110 V
(Offset $X_{d/2}' = 2.057 \Omega$, Diameter $X_s = 27.424 \Omega$)
38. Discuss the causes and consequences of (i) overvoltage, and (ii) under-frequency in case of a large generator. Explain the protective schemes for protection against both the eventualities stating whether the protections are Class A or Class B. Support your answer by relevant drawings.
39. State whether the following protections applied to the generator are time delayed or instantaneous. Give reasons for your answer:
 - (i) Protection against unbalanced loading
 - (ii) Field failure protection
 - (iii) Pole-slipping protection
 - (iv) Overvoltage protection
40. Why is an offset mho relay preferred for generator back-up distance protection?
41. What should be the reach of back-up mho relay for generator protection?
42. For a 6.6 kV, 2 MW, Y-connected, 3 phase, 0.85 pf, 50 Hz generator, $X_s = 200\%$, $X_d'' = 20\%$, $X_d' = 30\%$. A back-up overcurrent relay used has a TMS of 0.7. The overcurrent relay follows standard IDMT curve. For a dead short circuit at the generator terminals, the PS changes to 30% of its original setting because of voltage collapse. Find out the original PS and time of operation of the relay for dead short circuit. CT ratio: 300/1 A.
(75%, 11.46 s)
43. Which is the equipment that is protected by an under-frequency relay used for generator protection scheme? What is the consequence if you do not protect this equipment?
44. Why is it necessary to operate a field-suppression switch in addition to the generator breaker in the event of an internal fault in the generator? Show

- how it can be achieved with the help of circuit diagram?
45. What information about a generator would you like to get from the manufacturer for designing a generator protection scheme?
 46. Discuss briefly the possibility of wrong operation of protective relays used on generators and generator-transformers at the time of starting the machines.
 47. Give reasons for the following statements:
 - (a) Generator differential protection does not operate for earth-faults within the generator winding.
 - (b) A stabilising resistance is connected in series with the relay coil in differential protection of generators.
 - (c) Stator earth-fault even at the neutral of the generator winding should also be cleared.
 - (d) In the event of first earth-fault of the rotor of a generator, an alarm is sounded.
 - (e) It is necessary to protect a large generator against heavy unbalanced loads.
 - (f) Protection against unbalanced currents is a class B protection.
 - (g) Field failure protection is a Class B protection.
 - (h) An offset equal to $X_d'/2$ is provided in the field failure relay characteristic.
 - (i) For reverse power protection of an alternator, a time-delayed relay is used.
 - (j) Pole-slipping relay will not operate in case of field failure and faults very near to the generator.
 - (k) For the back-up overcurrent protection of a generator, off-set mho relays are used instead of impedance relays.
 - (l) Large generators should be provided with automatic field suppression schemes operating in the event of internal faults.
 48. Giving reasons, state whether the following statements are true or false.
 - (a) The neutral of the large generator is solidly grounded.
 - (b) The protection against inter-turn faults will operate for phase-to-phase fault in a generator.
 - (c) Unbalanced currents flowing through stator windings of a generator are harmful mainly to the generator stator core.
 - (d) The protection against unbalanced loading of a generator is a Class A protection.
 - (e) During field failure of a generator connected to an infinite bus, a generator works as a synchronous motor absorbing active power from infinite bus.
 - (f) Protection against pole-slipping of a large generator is provided only for protecting a turbine of the generator and not for any other purpose.
 - (g) A turbine is damaged in case of under frequency of a system because it runs at less speed than its rated speed and it is not designed to run at lower speed.

MULTIPLE CHOICE QUESTIONS

1. The part of a generator which is prone to damage under heavy unbalanced loading of the generator is the
 - (a) stator core
 - (b) stator winding
 - (c) rotor core
 - (d) rotor winding
2. If the field of the generator connected to an infinite bus collapses, it is harmful to the
 - (a) rotor winding insulation
 - (b) stator winding insulation
 - (c) whole power system
 - (d) all of the above
3. The overcurrent starter in pole slipping relay is set for
 - (a) rated full-load current of the generator
 - (b) half the generator rated current
 - (c) three times the generator rated current
 - (d) double the generator rated current
4. Rotor first earth-fault is used by the protective scheme to
 - (a) trip the generator main breaker
 - (b) provide alarm to initiate further setting of the protective scheme

- (c) trip the generator field breaker
 - (d) none of the above
5. The reverse power protection is necessary when the prime-mover is a
- (a) steam turbine (b) diesel turbine (c) gas turbine (d) any of the above

Transformer Protection

6

The power transformer is one of the most important components in a power-system network. Because of its relatively simple construction, it is a highly reliable piece of equipment. Being a static device, totally enclosed and oil immersed, it rarely develops faults. The consequences of even a rare fault may be serious unless the transformer is quickly disconnected from the system.

The varied characteristics of the power transformer under different types of faults greatly affect system conditions, which tend to make the application of protective relaying complicated. It is thus worthwhile to review the different types of faults generally encountered by a transformer before considering the application of protective gear.

Introduction

6.1 FAULTS IN TRANSFORMERS

For the purpose of discussion, faults can be divided into three main classes:

- (a) Faults in the auxiliary equipment of the transformer
- (b) Internal faults in the transformer windings
- (c) External faults

Let us understand the practical implications of these classes of faults.

6.1.1 Faults in the Auxiliary Equipment

These faults are usually minor faults. They do not affect the transformer immediately but, if allowed to persist, these may develop into faults within the transformer. Therefore, such faults must be detected. The various faults in auxiliary equipment are as follows:

(i) Oil Leakage in the Transformer Tank If the oil leaks from the transformer tank due to some reason, the oil level in the tank will drop. In the worst case, the connections to bushings and parts of the winding will get exposed to air. This will increase the temperature of the windings. This, in turn, would damage the insulation of the windings. The conservator tank is provided with an oil-level indicator having an alarm facility. If the oil level drops below a predetermined level, the alarm will ring. It allows the operator to initiate necessary actions.

(ii) Deterioration of Dielectric Strength of Oil The oil level in the transformer fluctuates because of variations in the temperature of the oil due to changes in the load. Hence, the transformer is provided with a conservator tank. The oil tank of the transformer is fully filled with oil, whereas only half the conservator tank is filled with oil. The upper half portion is meant for allowing changes of level of the oil. The conservator tank breathes air through a dehydrating breather so that moisture does not enter into the oil. The entry of moisture would, otherwise, drastically deteriorate the dielectric strength of the oil. The dehydrating breather comprises of an oil cup along with a container filled with silica gel. The atmospheric air first passes through the oil cup and then through the silica gel. Thus moisture gets absorbed in two stages, i.e., in the oil cup and in the silica gel. Due to the recent trend of using an oil cup, the frequency of replacement of moist silica gel with dried silica gel is reduced.

(iii) Failure of Ventilation System The temperature of oil and windings will increase due to failure of the cooling system of the transformer. The cooling system may fail due to blocking of the radiator, failure of oil pump/pumps or failure of some/all fans. An oil-temperature indicator with alarm and trip facilities along with a winding-temperature indicator having similar facilities are used to avoid damage to the transformer by overheating. Normal operation of the oil pump can also be monitored by an oil-flow indicator.

(iv) Weakening of Insulation Between Laminations of Core and Core-bolt Insulation Weakening of insulation between laminations of the core and core bolt will result in increased eddy current losses and hence rise in temperature of the core. This may, consequently, lead to failure of the insulation of the winding which means a major fault.

(v) Improper Joints or Connections The local heating generated by improper joints or connections may slowly lead to a deterioration of the oil if the joint is oil-immersed. The oil-temperature indicator and/or winding-temperature indicator (both with alarm contacts) can be used to indicate such problems. Gas-operated relays, discussed later, can also be used to sound an alarm and actuate the trip circuit if the condition calls for it.

(vi) Inter-turn Faults If only a few turns of any of the windings are shorted, the electrical relays will not operate but the local overheating caused by the fault may slowly deteriorate the insulation and, consequently, a major fault may occur.

For all such incipient faults, an oil-level indicator, oil-temperature indicator, winding-temperature indicator and gas-operated relays are used as protective devices.

6.1.2 Internal Faults

When the insulation between windings and between the winding and the core fails, it is termed an electrical fault. There can be phase-to-phase faults, phase-to-ground faults, faults between h.v. and l.v. windings or inter-turn faults. The faults occurring in oil can be sensed by gas actuated relays but the faults outside the oil have to be taken care of by electrical relays only. As such, for the heavy electrical faults inside the oil, gas-actuated relays are not entirely relied upon as we shall see later.

Such faults can develop because of overload, loose connections or over-voltages due to lightning or switching surges and also as a consequence of minor faults. These electrical faults have to be cleared by the transformer-protection scheme using different types of relays to be discussed in succeeding sections.

6.1.3 External Faults

The through faults can occur due to overloads or external short-circuits. When such faults occur, the transformer must be disconnected only after allowing a predetermined time during which other protective gear should be operated. A sustained overload condition can be detected by thermal relays which gives an alarm so that the situation can be attended to or the supply disconnected, if necessary. For the external short-

circuit condition, time-graded overcurrent relays are usually employed. Proper coordination of this back-up transformer protection should be made with the primary protection of the associated power supply network.

The reliability of a power transformer depends upon adequate design, care in erection, proper maintenance and the provision of certain protective equipments.

6.2 GAS-OPERATED RELAYS

The minor faults, discussed earlier, create local heat which at 350 °C, causes the oil to decompose into gases that rise through the oil and accumulate at the top of the transformer. Whenever a fault in a transformer develops slowly, heat is produced locally which begins to decompose solid or liquid insulating materials and thereby leading to the production of inflammable gases.

Such conditions can be detected by gas-actuated relays.

6.2.1 Buchholz Relays

The Buchholz relay operates an alarm when a specified amount of gas has accumulated. This type of relay can only be fitted to the transformers which are equipped with conservator tanks as it is installed in between the main tank and the conservator tank, i.e., on the pipe connecting the two.

Construction The relay consists of an oil-tight container having two internal floats which operate and actuate mercury switches which in turn are connected to the external alarm or tripping circuits. A schematic diagram of a Buchholz relay is shown in Fig. 6.1.

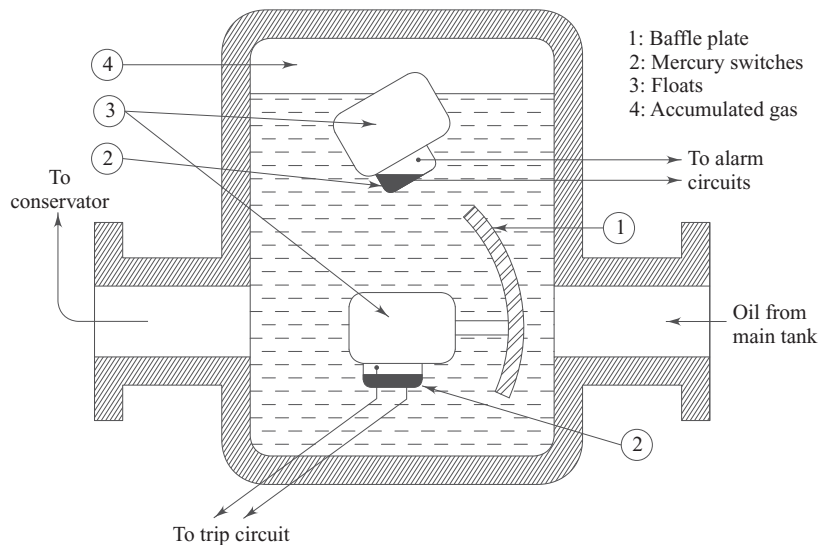


Fig. 6.1 Buchholz relay

The relay is normally full of oil and the floats remain engaged in seats due to buoyancy. The floats are made of aluminum.

Operation In the event of an incipient fault within the transformer, gas is generated in small bubbles which pass upwards through the relay to the conservator tank. In the process of passing through the relay, they become trapped in the housing of the relay and the oil level falls. The upper float is now no longer under the upward thrust and under the action of the counter-weight attached to it, the float falls down in such a manner so as to tilt the mercury switch. The tilting of the mercury switch shorts the two contacts and the alarm circuit is completed thereby giving a warning, well in advance, that a serious fault is slowly developing.

In the case of a serious fault within the transformer, the gas generation is in much larger quantity and the oil is displaced in the relay by the gases, towards the conservator tank, with the result that the baffle plate is deflected by the force of oil and gas mixture tilting the lower float, and hence the mercury switch. The trip coil of the transformer breaker, thus, gets energised and the breaker isolates the transformer from the supply.

The relay is also useful in indicating any loss of oil that a transformer might suffer, as the loss of oil will cause the oil level to drop in the relay. Then the top float will indicate the condition by shorting the alarm contacts.

This relay can be safely used even on a transformer with forced oil cooling as the surges set up in the oil due to the starting of the oil pumps will not materially affect the performance and there will be no uncalled tripping.

6.2.2 Sudden Pressure Relay

In transformers having a gas cushion instead of a conservator tank, the tripping unit of the Buchholz relay is not applicable and in such a case, a sudden pressure relay is used as shown in Fig. 6.2. The relay operates on the basis of the rate of the rise of pressure. It has a diaphragm which is deflected by a differential oil pressure; the diaphragm is bypassed by a hole which normally equalises the pressure on the two sides of the diaphragm and thus makes the relay responsive not to pressure but to the rate of the rise of pressure.

In some relays (Fig. 6.2) the diaphragm is not directly immersed in the transformer oil but inside the metal bellows full of silicon oil. The bellows are immersed in the transformer oil. This prevents incorrect operation under mechanical shocks and vibrations.

Figure 6.3 shows the operating time characteristics of this relay.

In India, most of the transformers are fitted with a conservator tank. Hence such a relay is, normally, not installed. In countries like USA, where transformers with gas cushions are used, sudden pressure relays find their application.

6.2.3 Drawbacks of Gas-Actuated Relays

The limitations of gas-actuated relays are enlisted as follows:

- (1) The vibrations and shocks caused by some reasons may mal-operate the mercury contacts resulting in unwanted tripping of the transformer.
- (2) As the minimum operating time of a Buchholz relay is about 0.1 second, it is considered slower.
- (3) Sudden pressure relays are faster, in operation, only for large faults. On the other hand, electrical relays can be used for larger faults where high speed is necessary. They can also be used for bushing flashovers and faults on leads which are outside the oil and hence do not create an oil surge.
- (4) The Buchholz relay is limited to applications for protection against incipient faults and non-electrical faults.

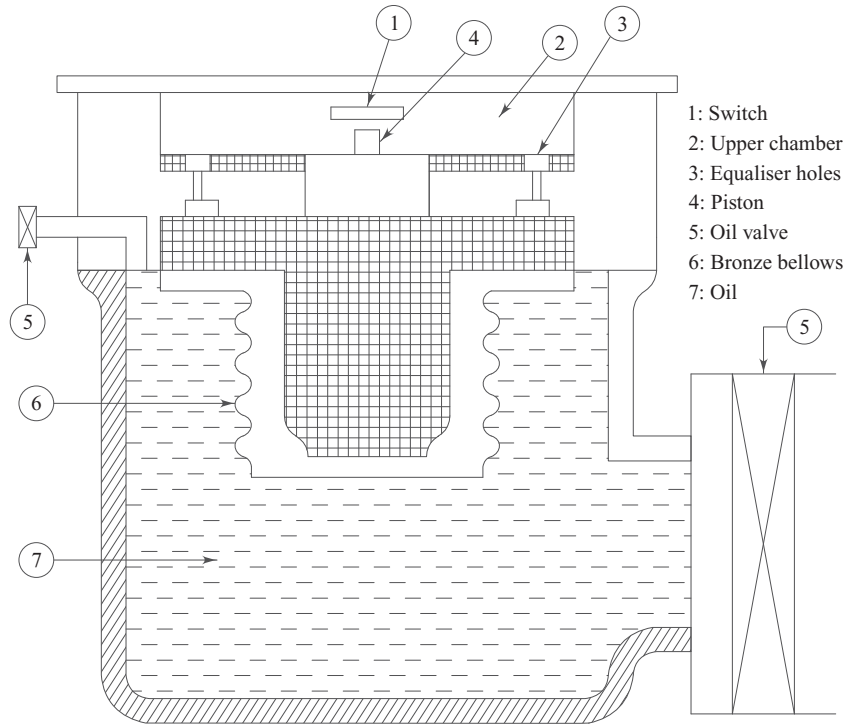


Fig. 6.2 Sudden pressure relay

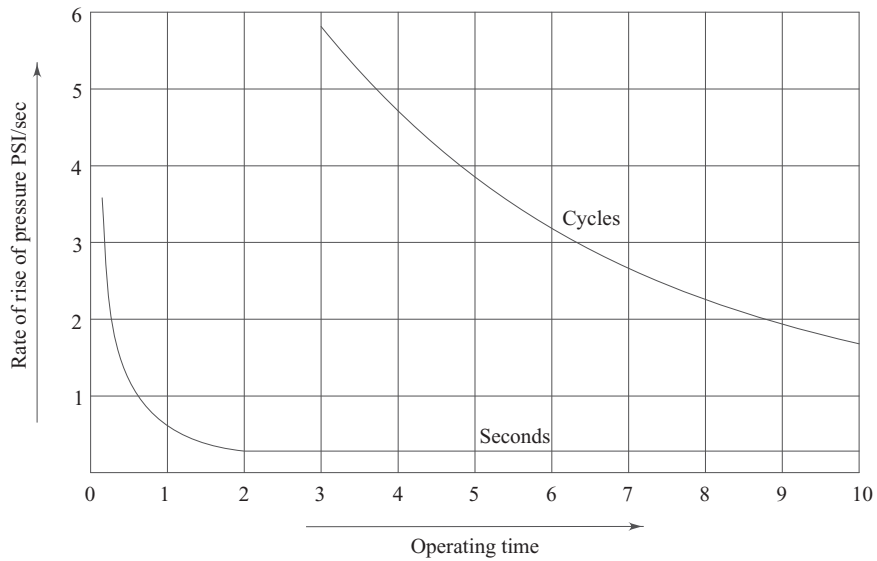


Fig. 6.3 Characteristic of a sudden pressure relay

6.3 OVERCURRENT PROTECTION

Transformers are provided with overcurrent protection against faults when the cost of differential relays cannot be justified. However, overcurrent relays are provided in addition to differential relays to take care of through faults and as a back-up to differential protection. The protection scheme using overcurrent relays is shown in Fig. 6.4.

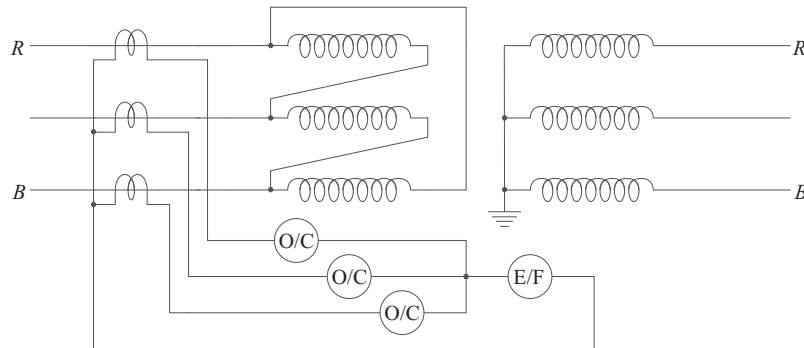


Fig. 6.4 Overcurrent and earth-fault protection of a transformer

While selecting the overcurrent protection of transformers, the following aspects need consideration:

1. **Magnetising current inrush** IDMT relays are not affected by the current inrush as they have enough time lag. Instantaneous overcurrent units should be set higher to avoid mal-operation. The setting of an instantaneous overcurrent relay on the primary side of the transformer should be a little above the asymmetrical value of the fault current for a three-phase fault on the secondary of the transformer. This setting is usually high enough to override magnetising inrush current.
2. Primary full-load current should be considered while setting the overcurrent relay. The plug-setting of the IDMT overcurrent relay is generally selected as 125% of the transformer rating to take care of normal overloads.
3. The same set of current transformers cannot be used for both differential protection and overcurrent protection, as the CT requirements for these protection schemes are different.

6.4 RESTRICTED EARTH-FAULT PROTECTION

Before discussing the restricted earth-fault protection, it is worthwhile to understand some aspects of neutral earthing of a transformer and the general fundamentals of earth-fault protection.

The h.v. side of a delta-star transformer is normally star-connected and the l.v. is delta-connected. The underlying reason is that the phase voltage (Ph-N voltage) of a star-connected h.v. winding gets reduced to $1/\sqrt{3}$ times the line voltage and the current to be carried per phase by the l.v. winding gets reduced to $1/\sqrt{3}$ times the line current, thus requiring a lower cross-sectional area of the conductor used in the l.v. winding.

If the neutral of the star-connected h.v. winding is isolated or non-effectively earthed (grounded through high impedance), the voltage of healthy phases with reference to the earth rises above its normal Ph-N value in case of a ground fault on any one of the phases. This voltage will be equal to the line voltage in case of

an isolated neutral system and can be as high as about 80% of the line voltage in case of a high-impedance grounded system, depending upon the value of the neutral impedance. This voltage rise is not limited to the insulation of a transformer only but also for line insulators of transmission lines emanating from a substation. The cost of insulation will be uneconomically large to cope up with this voltage stress. The solidly grounded systems do not suffer from this disadvantage. No doubt, the magnitude of an earth-fault current will be very high, but the considerations of voltage stress and economy assume priority in this case and hence h.v. systems are normally solidly (effectively) grounded.

When an earth-fault occurs on the star side of a transformer, the zero sequence current is absent in the delta side. Hence, as we shall discuss later, the differential protection scheme will be less sensitive in case of such faults. This very fact reveals the necessity for a separate earth-fault protection.

For internal earth-faults on the star side of a transformer, a restricted earth-fault scheme of protection is used, whereas a back-up earth-fault protection can be used for protection against earth-faults on the transmission lines emanating from a substation.

The restricted earth-fault scheme is discussed in the following paragraphs.

Power transformers are, generally, provided with a restricted earth-fault scheme. The restricted earth-fault protection, which employs the principle of circulating current differential protection, responds to the internal earth-faults in any one of the windings (which are star-connected) of the transformer. For external faults, the time graded earth-fault relays are used. The restricted earth-fault relay operates instantaneously for an internal fault.

Figure 6.5 explains the principle of a restricted earth-fault protection. Figure 6.5(a) shows the condition of an external earth-fault, while Fig. 6.5(b) shows the current flow through the relay in case of an internal fault. It is obvious in Fig. 6.5(a) that the fault current circulates in the pilot wires and no current passes through the relay. Hence, the relay does not operate.

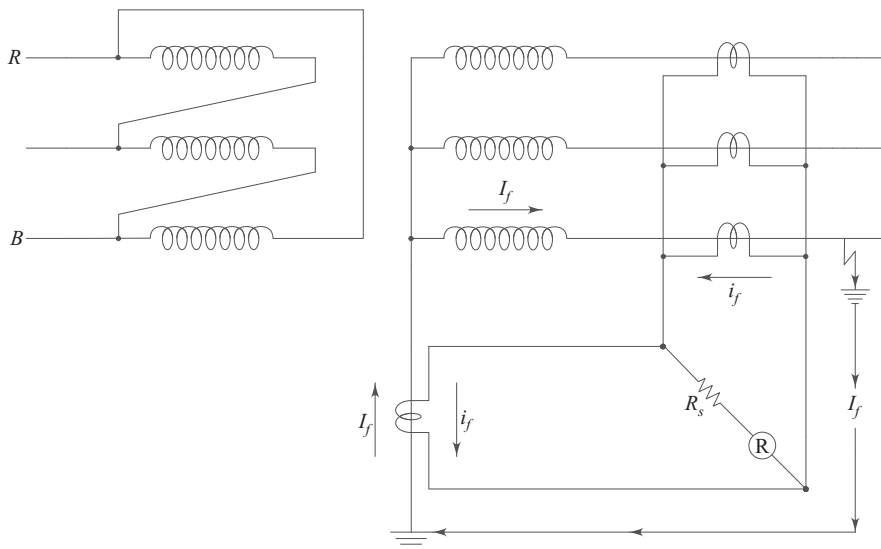


Fig. 6.5(a) External fault

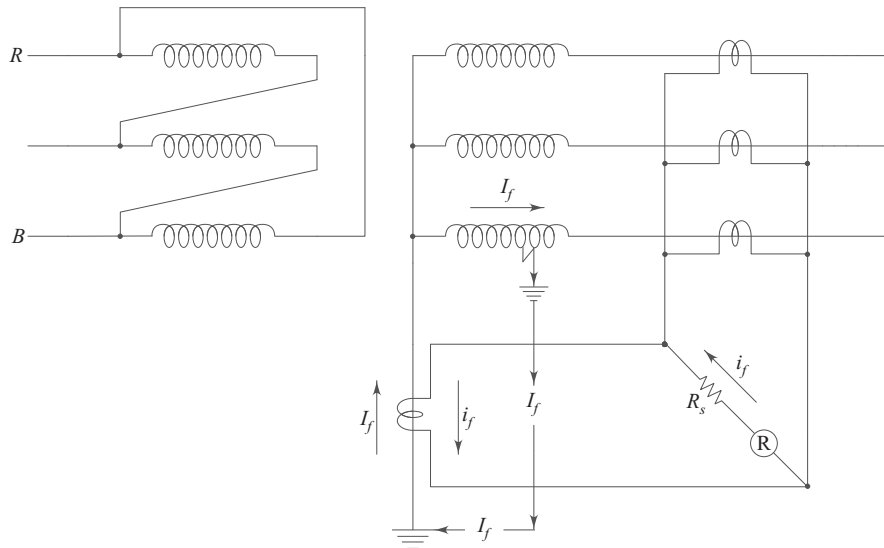


Fig. 6.5(b) Internal fault

For an internal fault [Fig. 6.5(b)], however, the fault current I_f flows in the neutral CT only and not in the line CTs. Hence, the CT secondary current i_f flows through the relay and the relay operates instantaneously if the current is more than the pick-up setting of the relay.

The earth-faults on the delta side of the transformer will be taken care of by an earth-fault element as shown in Fig. 6.4. This can be made to operate instantaneously as the residual current will be present only in the event of an earth-fault in the delta-connected side of the transformer, and hence this relay need not be coordinated with an earth-fault relay, if any, on the other side of the transformer.

6.4.1 The Relay Settings

For relay setting calculations, let us consider a case with the following data:

1. **Transformer** 250 MVA, 15.75/240 kV, D -11, % Impedance = 14%, solidly earthed.
2. **Current Transformers** Line and neutral CTs with ratios 1000/1 A, KPV > 550 V and R_{CT} 5 ohms.
3. **Relay** Instantaneous overcurrent relay. *Relay rating:* 1 A. *Relay Burden:* 0.9-1.0 VA. *Setting range:* 10–40% of 1 amp
4. **Lead resistance** 1.36 ohms

As the transformer is solidly earthed at its secondary (240 kV side), the fault current for the earth-fault will be high and a pick-up setting of 50% of the full-load rating of the transformer can be selected for the relay. The lower setting may make the relay too sensitive with the result that the relay may operate for through earth-faults, because of mismatch of the CTs.

$$\text{Rated current of the transformer} = \frac{250 \times 1000}{\sqrt{3} \times 240} = 601.4 \text{ A}$$

The CT secondary equivalent of this full-load current will be 0.6014 A. Therefore, pick-up setting of the relay can be 0.3007 A. Hence, the setting of 30% is selected. The relay should be immune to external earth-faults. Hence, such stability requirement demands the use of a stabilising resistance. Such a calculation has been already shown for the case of generator differential protection.

The earth-fault current for the earth-fault at the terminal of the transformer (after the line CT) can be calculated, based on the values of Z_1 , Z_2 and Z_0 ; the positive, negative and zero sequence impedances of the transformer. Considering $Z_0 = 10\%$, the fault current will be about 4.75 kA. This when reflected to CT secondary,

$$i_f = 4.75 \text{ A}$$

Referring to Eq. (5.2), Chapter 5,

$$\begin{aligned} V_r &= i_f(R_{CT} + R_L) \quad \text{where } R_L = \text{lead resistance} \\ &= 4.75(5 + 1.36) = 30.21 \text{ V} \end{aligned}$$

This suggests that KPV of the CTs should not be less than 60.42 volts. Also, referring to Eq. (5.5), Chapter 5,

$$i_s(R_r + R_{stab}) = V_r$$

where R_r = relay resistance

$$= \text{burden}/i_s^2 = 1.0/(0.3)^2 = 11.11 \Omega$$

$$R_{stab} = \frac{V_r}{i_s} - R_r = 89.59 \Omega$$

The stabilising resistance of one-third of this value can be selected.

6.5 DIFFERENTIAL PROTECTION

The differential protection scheme of a transformer employs a biased differential relay. The reasons for the use of a biased differential relay coupled with other involved requirements are discussed in the next section.

6.5.1 Problems in Application of Differential Protection

All the requirements of generator differential protection, generally, also apply to transformer differential protection. Moreover, the following additional problems are experienced in case of a transformer:

1. The transformer voltage rating is different for primary and secondary. Therefore, voltage rating of CTs used in primary and secondary are different. It is quite possible that the CTs on both the sides may be from different manufacturers. Under these circumstances, the CTs on both the sides are usually not identical with regard to their saturation characteristics. These non-identical CTs may cause high spill current to flow through the relay in case of heavy external fault. The resulting uncalled for tripping of the relay can be avoided by the use of a restraining coil in the differential relay, i.e., by the use of a biased differential relay.
2. The full-load currents of the transformers on primary and secondary sides are different. The ratio of the CTs used on both the sides, hence, have to be so selected that the pilot wire currents are same on both the sides. To achieve this, the CT ratios required on the two sides, usually, are different from standard ratios. Hence, CTs of standard ratios are employed in conjunction with interposing CTs. This will become much clearer in the illustrations of relay-setting calculations given in the relevant section.

These interposing current transformers are low voltage CTs rated for 660 volts and having a non-standard current transformation ratio to suit the required pilot current. These are specially built transformers for this application. Modern differential relays are incorporated with in-built interposing CTs of variable ratios. The numerical relays for transformer protection can perform such divisions or multiplications internally in the program. So interposing CTs are not required.

3. The primary current of the transformer is given by vectorial summation of KI_s and I_0 ,

$$\begin{aligned} \text{i.e., } I_p &= K \times I_s + I_0 \\ K &= V_s/V_p = \text{nominal transformation ratio} \\ I_s &= \text{secondary current} \\ I_0 &= \text{no-load current} = I_m + I_a \end{aligned}$$

I_m is used for exciting the transformer and I_a feeds the no-load losses.

The CT ratios are selected considering the nominal transformation ratio and hence some spill current will always flow through the relay because of the no-load current component of the primary current. This does not cause any problem to the performance of a differential relay because the no-load current of large transformers is of the order of 1–2% of the rated current, and the basic setting (pick-up setting) of the relay can take care of this small spill current.

4. The current transformers may have small ratio errors at the normal rated current. But during external short-circuits, the CT primary currents are unduly large. The ratio errors of the CTs on either sides differ during such conditions due to (i) inherent difference in CT characteristic, and (ii) unequal dc components in the short-circuit currents.

A biased differential relay can avoid unwanted operation of the relay under such circumstances.

- 5. Inherent phase-shift of currents in the transformers** The primary and secondary currents are not in phase in three-phase transformers connected in delta-star. This can be explained as follows:

Refer to the transformer winding connection of Fig. 6.6. It is evident that currents I_R and I_r are in phase because the two windings, through which these currents flow, are mounted on the same limb of the transformer. Hence vectors I_R and I_r are shown in phase in Fig. 6.7(a).

The line currents I_{RL} , I_L , I_{BL} are given by the following expressions:

$$\begin{aligned} I_{RL} &= I_R - I_B \\ I_L &= I - I_R \\ I_{BL} &= I_B - I \end{aligned}$$

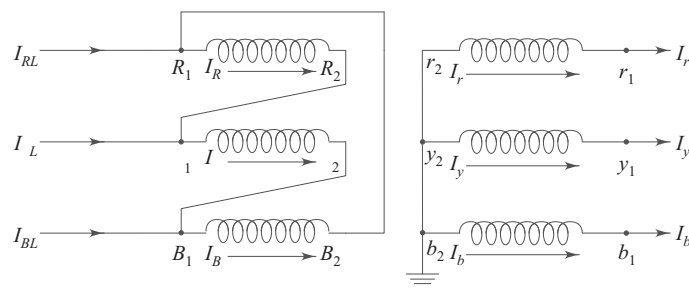


Fig. 6.6 Transformer winding connection

These currents are represented vectorially in Fig. 6.7(a). It is clear from this vector diagram that the secondary line current I_r leads the primary line current I_{RL} by 30° . Hence, this connection is said to be a 30° connection. Referring to Fig. 6.7(b), which compares the phase relationship of I_{RL} and I_r , the connection also gets a name '11 O'clock' connection or $D 11$ connection (meaning delta-wye 11). Another connection generally used is the $D 1$ connection or '1 O'clock' connection. This connection is left as an exercise to the reader.

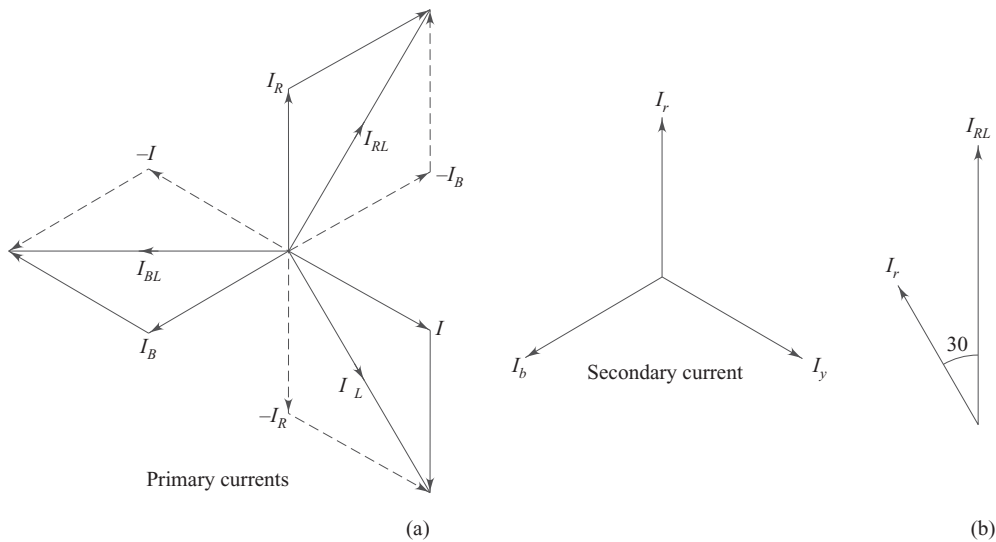


Fig. 6.7 Comparison of primary and secondary current vectors

Here, the differential relay responds to the vectorial difference between the currents entering (primary side) and leaving (secondary side) the transformer. For three-phase delta-wye transformers, the vectorial difference will always exist even at the rated load condition as shown by Fig. 6.7(a). This has to be taken care of, i.e., the two pilot currents have to be equal not only in magnitude but also in phase relation. The two pilot currents have to be taken care of by proper connection of CTs, on both the sides, i.e., by connecting CTs on the delta side of the transformer in star and those on the star side of the transformer in delta. This is shown in Fig. 6.8(a) and 6.8(b). Comparing the currents i_{RL} with i_{rl} , i_L with i_{yl} and i_{BL} with i_{bl} , it is evident that the pilot currents are equal in phase relation and no spill current flows through the operating coils of the relay in normal operation.

Figure 6.8(a) also suggests that the zero sequence currents are eliminated on both the sides. It is because of this elimination that the sensitivity of differential protection will reduce for earth-faults within the transformer. Referring to Fig. 6.8(c), the relay unit in R-phase will operate for external earth-fault in B-phase of star side if CTs are not properly connected. Thus, the scheme is not stable against external earth-faults. Thus to make the scheme immune to secondary external earth-faults, the CTs on the star side should once again be connected in delta as discussed earlier.

- 6. CT Ratio Errors** The CTs have some allowable ratio errors depending on the class of CTs used. The worst case is experienced when the errors of the CTs on the primary and secondary sides are cumulative. In such a case the spill current will flow through the operating coil of the relay, making it to operate particularly at a high through fault current. Biased winding (restraining winding) of the relay can avoid unwanted tripping of the relay in such a case.
- 7. Tap-changing** Power transformers are always provided with the tapplings to regulate the output voltage as required by the loading conditions. The ratios of the CTs (used for differential protection) on both the sides of the transformer are selected on the basis of a normal tap. Once the tap is changed, the pilot wire currents on both the sides will not be the same. Some spill current, in turn, will flow through the operating coil of the relay. This may tend to operate the relay, particularly for high through fault currents. Strongly biased differential relay can avoid such uncalled tripping.

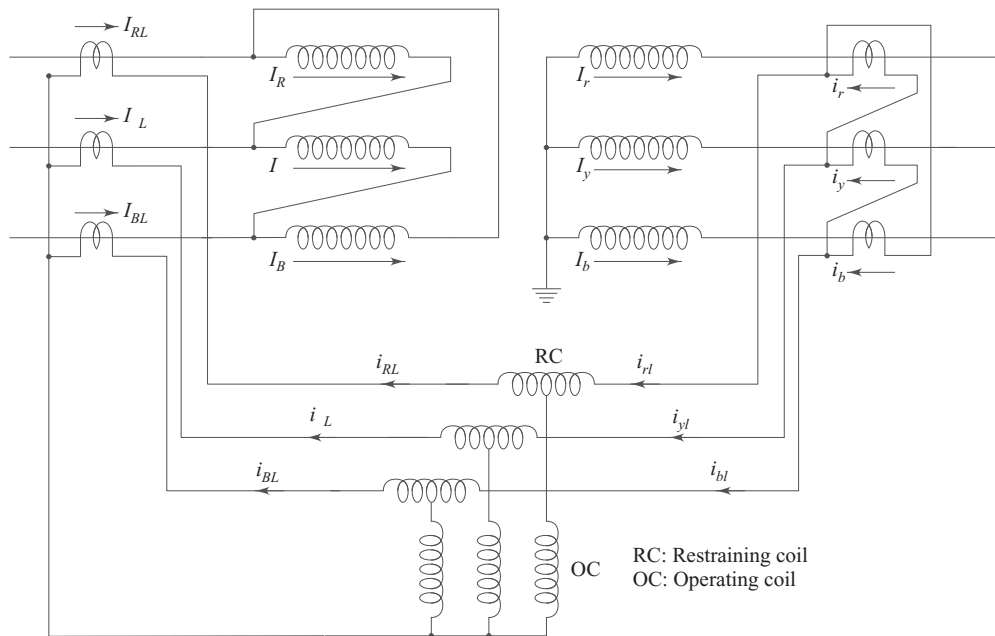


Fig. 6.8(a) CT connections in differential protection

- 8. Magnetising inrush current of the transformer** Any condition that calls for an instantaneous change in flux linkages in a power transformer will cause abnormally large magnetising currents to flow, and these will produce an operating tendency in a differential relay. As explained later, the largest inrush and greatest relay-operating tendency occur when a transformer is not connected to the load and is energised. Considerably smaller but still troublesome inrushes occur when a transformer with a connected load is energised or when a short circuit occurs or when it is disconnected. The occasional tripping because of inrush when a transformer is energised is objectionable because it delays putting back the transformer into service.

When a transformer is connected to the supply, with its secondary circuit open, the steady-state flux wave ϕ in the core is normally in quadrature with the supply voltage wave V as shown in Fig. 6.9, neglecting resistance drop of the exciting current in the primary windings. If the transformer is switched on at any point of the voltage wave, the asymmetry in the core flux will correspond to voltage asymmetry. If there is no residual flux and the switch is closed when the voltage wave is passing through its zero value, the peak value attained by the asymmetrical flux will be $2 \times \phi_{\max}$, where ϕ_{\max} is the maximum value of the steady-state flux. If, at the instant of closing the switch, the core has a residual flux ϕ_R , the resultant peak value of the flux becomes $2 \times \phi_{\max} \pm \phi_R$. If the primary circuit is closed at the peak value of the voltage wave then the commencement of the flux wave will be in accordance with the normal value and the peak attained will have a value of $\phi_{\max} \pm \phi_R$.

The instantaneous value of the asymmetrical flux linked with the transformer winding will be limited by core saturation and the air core inductance of the winding under consideration. Since the flux in the iron core cannot change instantaneously and since the core will saturate, the flux will be linked through the air core. As the air core inductance is small, the magnitude of the current ($I = N\phi/L$) to produce the required flux will be large. This is the origin of the inrush current phenomenon. The inrush current

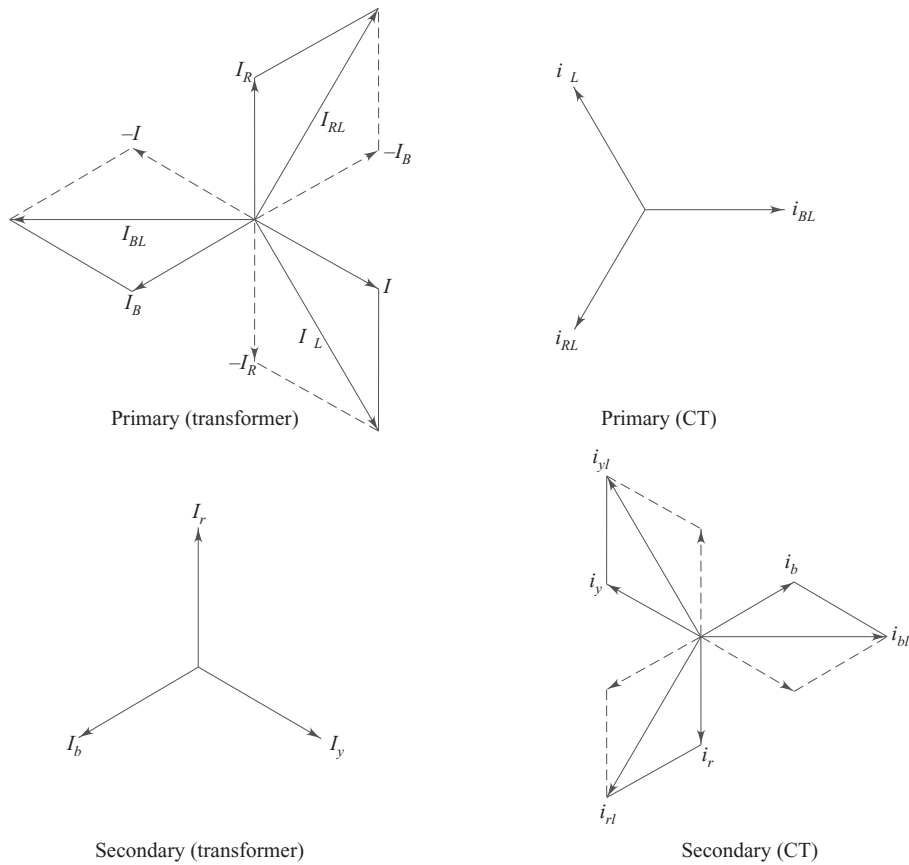


Fig. 6.8(b) Vector diagrams

gradually decays in successive cycles of the voltage wave due to resistance in the primary and also because the flux will link with the iron core slowly after few cycles. The rate of decay of the transient inrush current will be greater during the first few cycles because of shorter time constant of the circuit for decreased air-core inductance of the winding. In the determination of this time constant, eddy current loss has some effect during the first few cycles. The inrush current will reduce to a normal magnetising current after about 8 to 10 cycles, depending upon the time constant.

Since the inrush currents are large (they can be as high as 6 to 10 times the full-load current) and because this current exists only on the source side of the transformer, the current will appear in the operating coil of the differential relay and operate the relay. The biased winding cannot take care of

this problem because the pick-up ratio $\frac{(i_1 - i_2)}{(i_1 + i_2)/2}$ will be very high (of the order of 200%) and the bias

setting is usually 15–50%. If the setting is increased to a value higher than 50%, the differential relay will become highly insensitive to in-zone faults, not operating when called for.

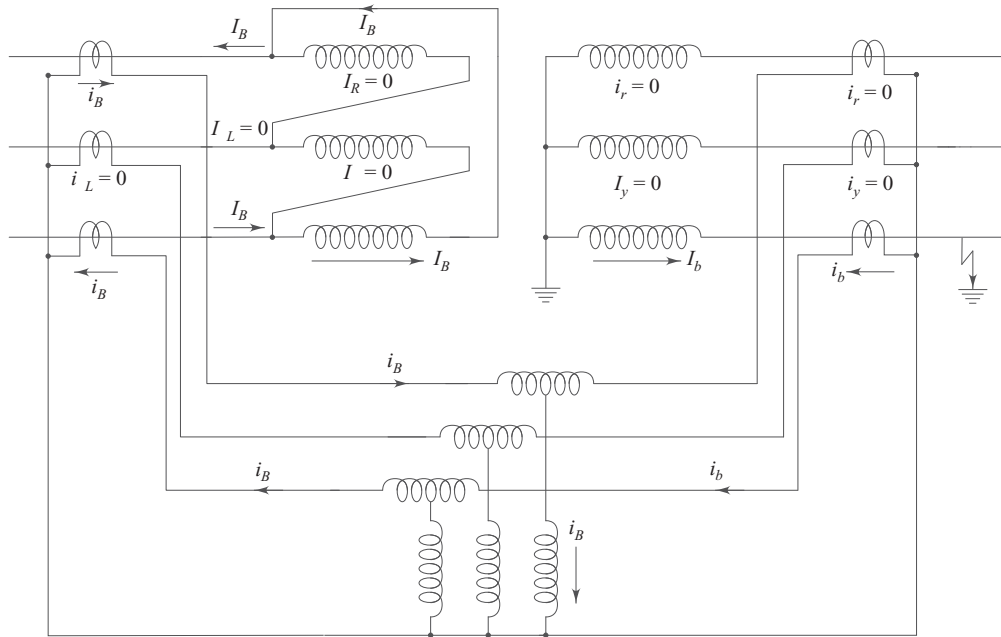


Fig. 6.8(c) Mal-operation of differential protection scheme for external earth-fault

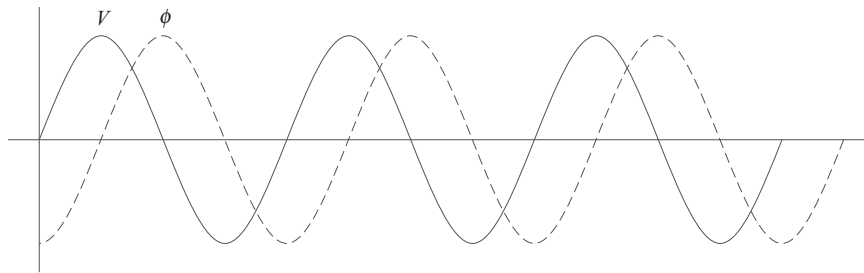


Fig. 6.9 Voltage and flux waves of an unloaded transformer

In the past, operation of the biased differential relays (used for transformer protection) was delayed until the magnetising inrush decays down. This is not a satisfactory solution as such a delay is applicable for internal faults as well.

There are several other solutions to this problem listed as follows:

- even harmonic cancellation
- harmonic restraint
- harmonic blocking
- resonance blocking
- DC bias
- wave-shape monitoring

We shall discuss here the first two solutions. The last solution is also briefly discussed. The reader may refer to Reference 1 for other solutions.

- (a) **Even Harmonic Cancellation** Owing to the saturated condition of the transformer core during inrush, the waveform of the inrush current is highly distorted. The average values of the amplitudes of harmonics compared with the fundamental (100%) are given in Table 6.1.

Table 6.1

Name of Component	Average Amplitude as a Percentage of Fundamental component in
DC component	55
2nd harmonic	63
3rd harmonic	26.8
4th harmonic	5.1
5th harmonic	4.1
6th harmonic	3.7
7th harmonic	2.4

The third harmonic component as well as its multiples can be eliminated by delta connection of transformer windings or CT secondaries. Triplen harmonics, hence, will not be found in pilot wires. The dc component can be filtered by connecting a capacitor in series with a relay coil. The magnitudes of the 5th and 7th harmonics are very small and hence can be neglected. The 2nd harmonic can be used as a discriminating feature between the magnetising inrush and genuine fault which is explained in the succeeding paragraphs.

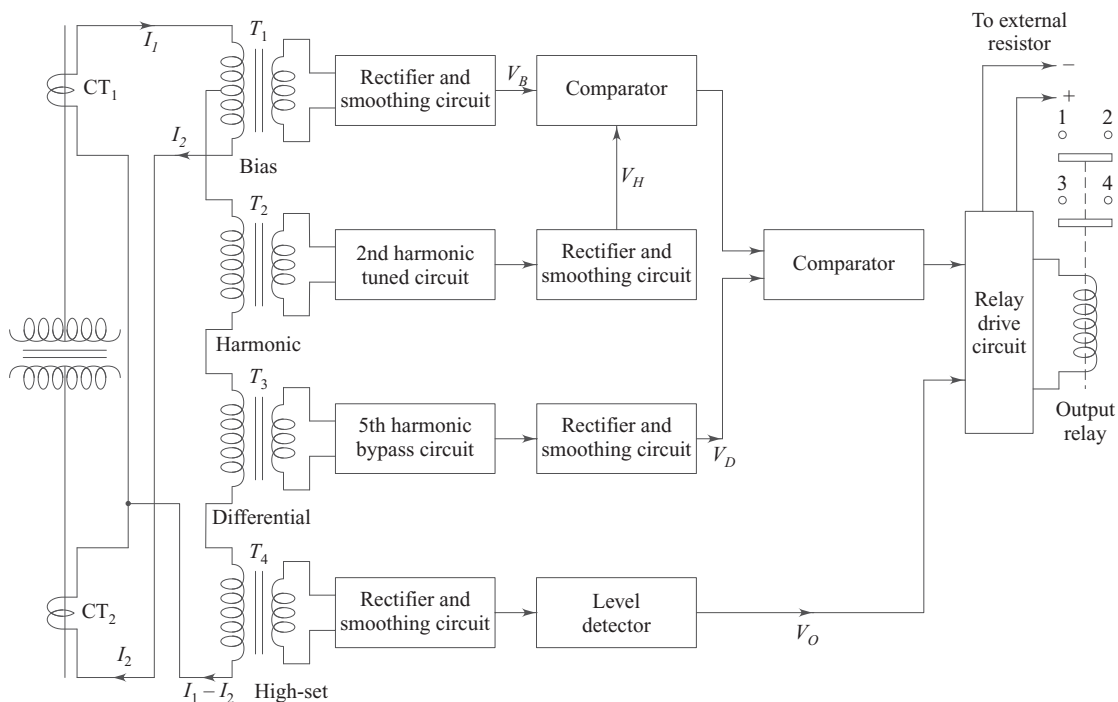


Fig. 6.10 Block diagram of static differential relay (Courtesy: Areva T&D Ltd.)

- (b) **Harmonic Restraint** A typical relay (Courtesy: Areva T&D Ltd.) having harmonic restraint feature is shown in Fig. 6.10. It uses three transactors (I to V converters), namely, T_1 , T_2 and T_3 and a current transformer T_4 . A voltage signal proportional to $(I_1 + I_2)/2$ delivered by the bias transactor T_1 is rectified and smoothed and is fed as V_B to a comparator. The voltage signal proportional to $(I_1 - I_2)$ delivered by T_2 is fed to the second-harmonic tuned circuit. The output of this circuit is proportional to the second-harmonic component present in $(I_1 - I_2)$. After rectification and smoothing, this signal V_H is fed to the comparator. The comparator allows the higher of the two inputs V_B or V_H to appear as the output. This output acts as an input to another comparator. The second input V_D proportional to $(I_1 - I_2)$ to this comparator comes from the transactor T_3 through the fifth harmonic bypass circuit and rectification circuit. This comparator logically decides whether the operating quantity (V_D) is m times the restraining quantity, where m is the prefixed bias setting. It will give an actuating signal to the output relay. The operation will be blocked if the second harmonic content in $I_1 - I_2$ is more than 20%. This helps the relay in discriminating between the actual internal fault and the inrush condition.

If the internal fault current contains a second-harmonic content more than 20 %, the operation will be blocked by the relay. To avoid this situation, a high-set feature is provided in the relay which operates in case of a severe internal fault. The output of the current transformer T_4 is proportional to $(I_1 - I_2)$ and is fed to the rectification circuit. The output of the rectification circuit is fed to the level detector. The reference of the level detector should be set higher than the probable magnetising inrush. The level detector will actuate the output relay directly.

- (c) **Wave-shape Monitoring** The harmonic restraint or blocking schemes exhibit a tendency to delay the operation of the differential relay under internal fault conditions. Although these delays are not of much significance for protection of a power transformer in networks of moderate size, it becomes necessary for very large transformers operating in large inter-connected networks to employ differential relays operating within one cycle of power frequency. Such fast-acting relays must, therefore, distinguish between inrush magnetising conditions, internal fault conditions and external fault conditions with or without saturation of CTs within one cycle. This is only possible if the relays are based on the nature of the waveform during the first and the subsequent cycles for these three possibilities.

Many schemes for this purpose have been proposed. These are mostly based upon the analysis of the wave-shape of the current in the leads of the power transformer. This current flows through the primary of the protective CT. The nature of the waveform of the corresponding secondary current i_s , for the inrush magnetising condition, is quite different from that on the primary.

Typical waveforms of the magnetising inrush current of transformer for the primary and secondary side of a CT are shown in Fig. 6.11(a) and 6.11(b), respectively. Thus it is necessary to design the relay on the behavior of the secondary of the CT rather than on the primary.

Some of the methods proposed are as follows:

- (i) Blocking of differential protection for one cycle by sensing of current behavior in the region of zero-crossing. This can be achieved with or without a microprocessor.
- (ii) Allowing the relay to operate only if the residual current exceeds a certain level for more than 2/3 of a period in one cycle. (It can be demonstrated that the interval is smaller than 2/3 of the period of a cycle for an inrush magnetising condition.)
- (iii) Fast extraction of the second and fifth harmonics which are predominant in an inrush magnetising current and comparison of these with the fundamental during the first cycle. This can be achieved with a digital signal processor and specially developed software.

Further elaboration of this interesting topic is beyond the scope of this book.

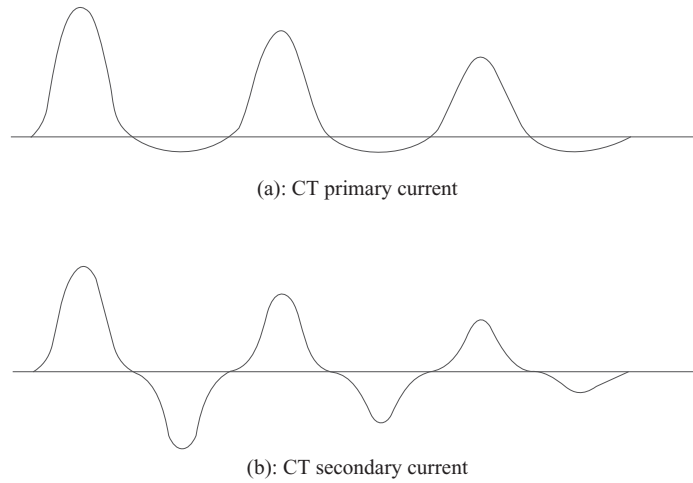


Fig. 6.11 Typical waveforms of magnetising inrush current

9. Saturation of Transformer Core When the voltage on the primary of a transformer exceeds the normal value, the magnetising current also increases. As it is customary to design the transformer such that they operate very close to the knee point of the B-H curve of core magnetisation, any tendency in increase of the voltage increases the magnetising current non-linearly. For large modern transformers, a 20% increase in voltage increases the magnetisation current four-fold. This may produce an operating tendency of differential protection scheme, which is not desirable. The remedy suggested by some manufacturers is the fifth-harmonic bypass feature, since such magnetising currents are rich in fifth harmonics. Some other manufacturers suggest an automatic manipulation of sensitivity threshold in case of over-saturation.

Example 6.1 Draw a detailed protection scheme for biased differential protection of a 11/132-kV, 150-MVA, DY-1 power transformer. Suggest suitable CT ratios. Also suggest the proper ICT for the scheme.

Solution Figure 6.12 shows the detailed biased differential protection scheme of a given power transformer.

Rated full-load current of the primary of the power transformer,

$$I_p = \frac{150 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 7872.95 \text{ A}$$

Therefore, the CTs on the primary side shall have a ratio of 7500/5 A. Secondary full-load current,

$$I_s = 7872.95 \times \frac{11}{132} = 656.08 \text{ A}$$

Hence, the CTs on the secondary side shall have a ratio of 750/1 A.

The CTs on both the sides can be star connected. The CT secondary equivalents of the primary and secondary full-load currents calculated above will be

$$\begin{aligned} i_p &= 5.249 \text{ A} \\ i_s &= 0.875 \text{ A} \end{aligned}$$

Referring to Fig. 6.12, i_{s2} has to be equal to 5.249 A, as the pilot currents on the two sides must be same. As the secondary of the ICTs is delta-connected, the secondary current i_{s1} of each ICT will be $5.249/\sqrt{3}$ A, i.e., 3.03 A.

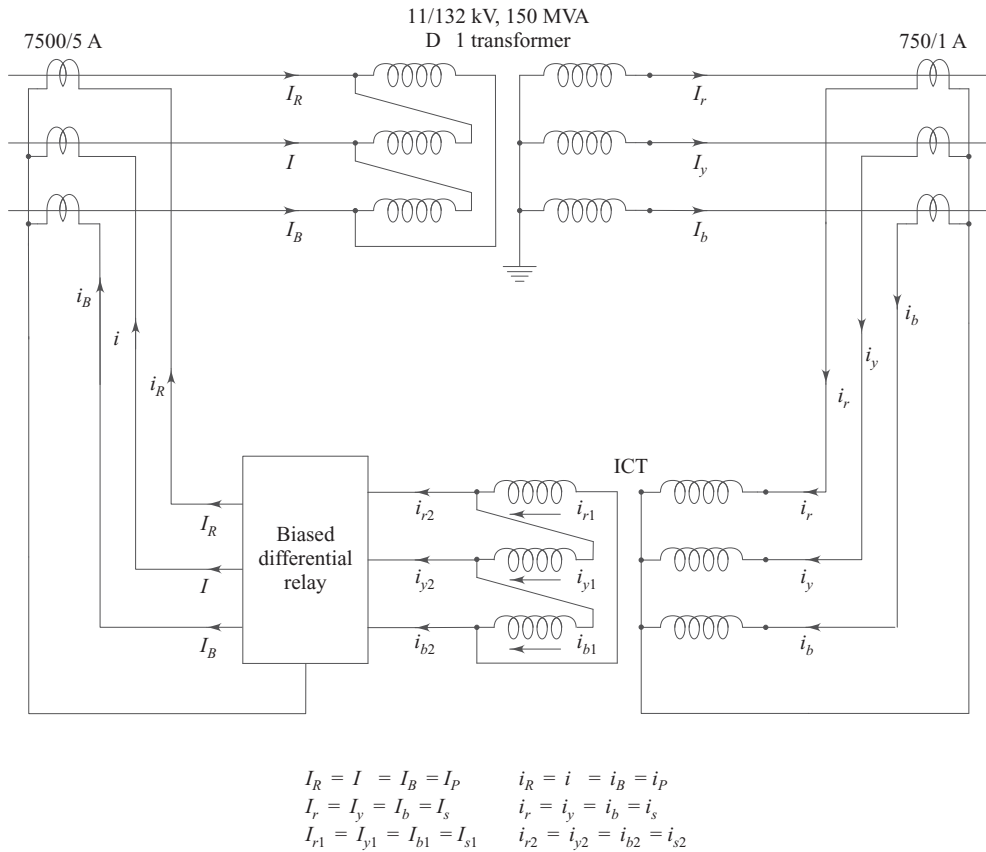


Fig. 6.12 Example 6.1

Thus the ICT shall be 0.875/3.03 A or 1:3.46 A. The phase relationship of the pilot currents (these have to be in phase) is taken care of by proper connections of ICTs.

Example 6.2 A 10-MVA, 132/33-kV, YD-1, three-phase, 50-Hz transformer is connected in delta on the l.v. side and in star with the star point earthed on the h.v. side. If the CTs on the h.v. have a ratio of 75/1 A, determine the CT ratio on the l.v. side.

What would be the current circulating through pilots for a through fault due to which a current of 5 times the full load occurs if the voltage tapping is set to 128 kV at the time of occurrence of fault?

Solution Figure 6.13 shows the detailed biased differential protection scheme of a given power transformer.

The primary full-load current of transformer,

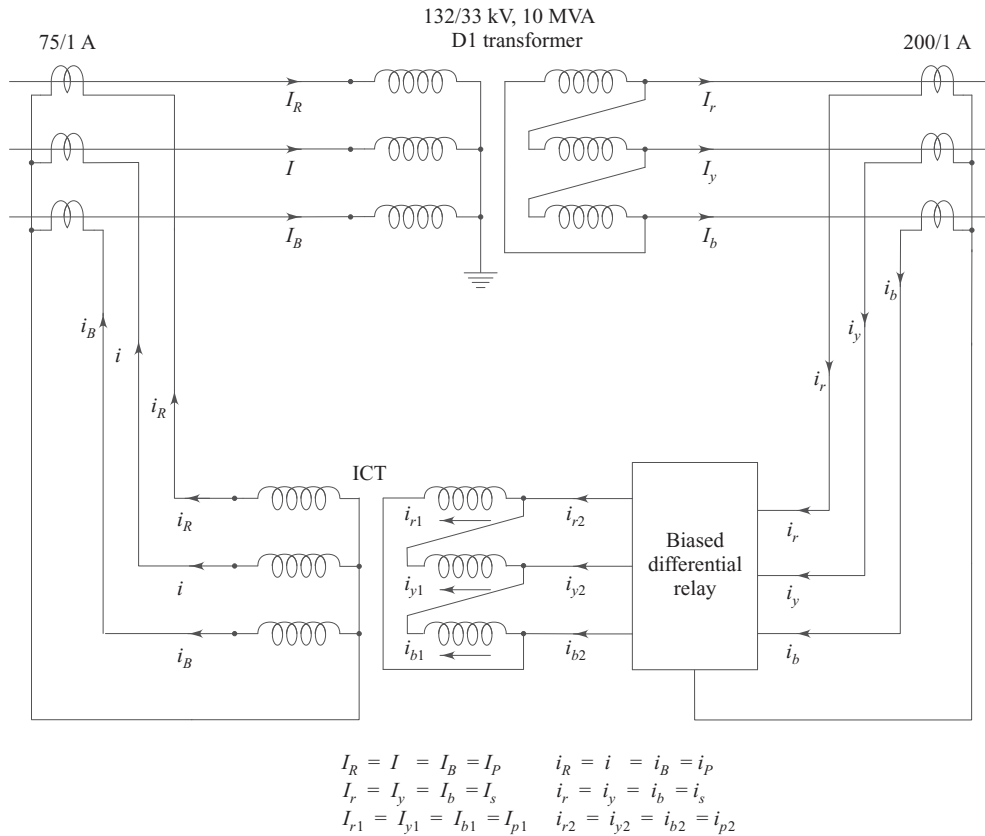
$$I_p = \frac{10 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 43.74 \text{ A.}$$

CTs on the primary side have a ratio of 75/1 A.

∴ the secondary equivalent current i_p will be,

$$i_p = 43.74/75 = 0.583 \text{ A}$$

The secondary full-load current of the transformer,


Fig. 6.13 Example 6.2

$$I_s = 43.74 \times \frac{132}{33} = 174.96 \text{ A}$$

Hence the CTs on the secondary side shall have a ratio of 200/1 A.

∴ the secondary equivalent current i_s will be

$$i_s = 174.96/200 = 0.875 \text{ A}$$

The CTs on both the sides can be star connected. Referring to Fig. 6.13, i_{p2} has to be equal to 0.875 A, as the pilot currents on the two sides must be same. As the secondary side of the ICT is delta connected, the secondary current i_{p1} of each ICT will be $0.875/\sqrt{3}$ A, i.e., 0.505 A.

Thus, the ICT shall be 0.583:0.505 A or 1.15:1 A. The phase relationship of the pilot currents (these have to be in phase) is taken care of by proper connections of ICTs.

For a through fault current equal to 5 times the full load current,

$$I_{sf} = 5 \times I_s = 5 \times 174.96 = 874.8 \text{ A}$$

Therefore, secondary equivalent,

$$i_{sf} = 874.8/200 = 4.37 \text{ A}$$

The primary fault current with a tap on 128 kV,

$$I_{pf} = I_{sf} \times \frac{33}{128} = 225.53 \text{ A}$$

i_{pf} , the secondary equivalent of I_{pf} will be,

$$i_{pf} = 3.007 \text{ A}$$

Therefore, the pilot current on the secondary winding of ICTs,

$$i_{pf1} = 3.01/1.15 = 2.615 \text{ A}$$

So the pilot current on the secondary side of ICTs,

$$i_{pf2} = \sqrt{3} \times 2.615 = 4.53 \text{ A}$$

After having discussed two application examples of a simpler kind, it will be easier to understand a detailed example of the setting of a differential relay discussed in the next sub-section.

6.5.2 Relay Setting Illustration

We will, now, consider an example of the setting of a transformer differential relay with typical data as given below:

Data

1. Transformer

250 MVA, 15.75/240 kV

Taps -5% to +7.5% on h.v. side

Connection D -11

Impedance 14%

2. Current Transformers

L.V. side 10000/5 A star connected

H.V. side 1000/1 A star connected

Interposing CTs on h.v. side 1/4.4 amp

Primary Star connected

Secondary Delta connected

Ratio error of all CTs $\pm 3\%$

3. Relay: Biased Differential Relay

Rating 5 A

Sensitivity setting 15% of 5 A (fixed)

Bias setting 15%, 30%, 45%

Instantaneous high set unit 10 times rated current (fixed)

Second-harmonic restraint Operation is prevented when second-harmonic content in the differential circuit exceeds 15%.

Fifth harmonic bypass This is provided to avoid possible mal-operation under overexcited conditions.

Solution Referring to Fig. 6.14, primary rated current of the transformer,

$$I_P = I_R = I = I_B = 9164 \text{ A}$$

Reflecting this current to secondary of CTs

$$i_P = i_R = i = i_B = 4.582 \text{ A}$$

This is the pilot current on the delta side of the transformer.

Now, secondary rated current of the transformer,

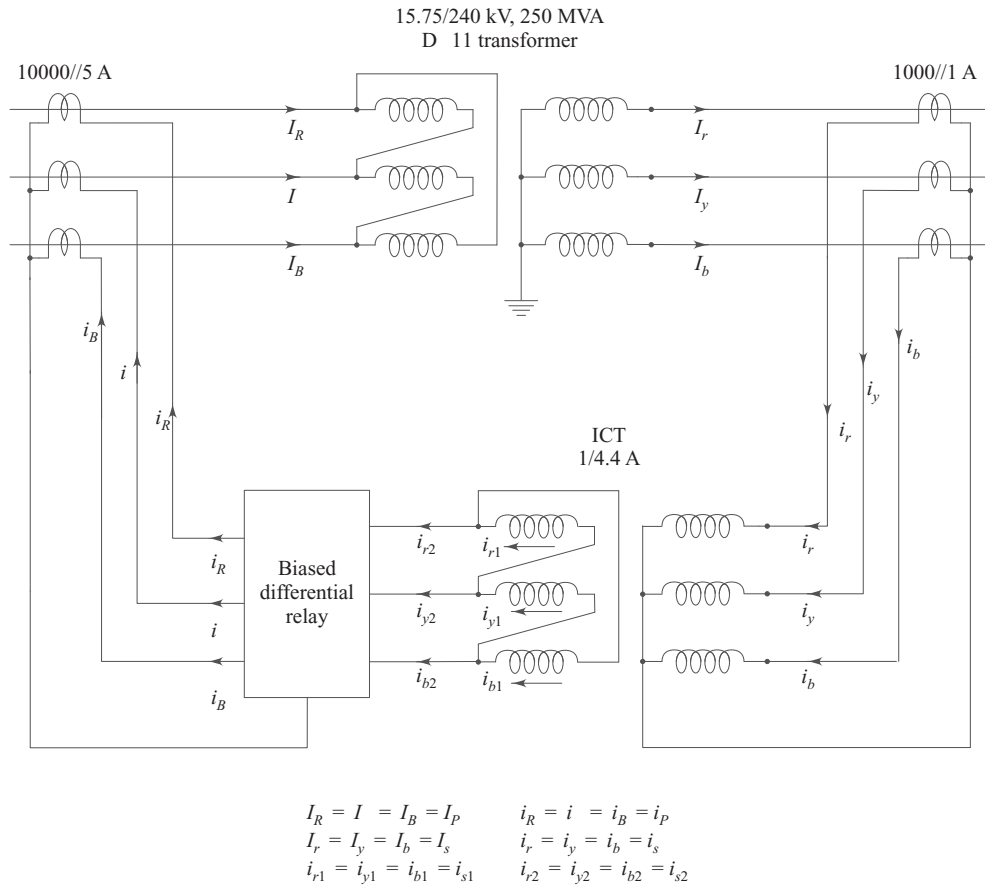


Fig. 6.14 Relay setting illustration

$$I_s = I_r = I_y = I_b = 601.4 \text{ A}$$

Reflecting this current to secondary of CTs

$$i_s = i_r = i_y = i_b = 0.6014 \text{ A}$$

This current, when transformed by CTs,

$$i_{s1} = i_{r1} = i_{y1} = i_{b1} = 2.646 \text{ A}$$

Hence, pilot current on the star side of the transformer will, in turn be,

$$i_{s2} = i_{r2} = i_{y2} = i_{b2} = i_{s1} \times \sqrt{3} = 4.583 \text{ A}$$

Comparison of these currents with i_p proves that the two pilot currents are equal and in phase, as is required. One can appreciate the need of ICTs here as the 240 kV CT with a ratio of 1000/4.4 A is non-standard.

Now, for deciding the relay setting, the highest tap is to be considered, i.e. 7.5%.

At this tap, the turns ratio will be $(240 \times 1.075 \times 10^3)/15750$ or 258000/15750.

Percentage bias is, now, to be selected such that the relay remains stable for a three-phase bolted short-circuit taking place after CTs on the secondary side. While selecting this bias setting, the consideration is to

be given for the tap-changing, possible CT saturation, mismatching of CT saturation characteristic and CT ratio error.

At the highest tap under consideration, the fault current on the primary and secondary side for the three-phase fault at the location stated above can be calculated on the basis of percentage impedance.

$$\begin{aligned} \text{i.e.,} \quad I_{sf} &= 601.4/0.14 = 4.3 \text{ kA} \\ I_{pf} &= 4.3 \times (258000/15750) = 70.43 \text{ kA} \end{aligned}$$

CT secondary equivalents of these currents are,

$$\begin{aligned} i_{pf} &= 35.22 \text{ A} \\ i_{sf} &= 4.30 \text{ A} \end{aligned}$$

Considering maximum and cumulative CT errors at +3% for CTs on the primary side and – 3% for CTs on the secondary side.

$$\begin{aligned} i_{pf} &= 36.27 \text{ A} \\ i_{sf} &= 4.17 \text{ A} \end{aligned}$$

This when reflected on the secondary of ICT, $i_{sf1} = 4.17 \times 4.4 = 18.35 \text{ A}$

Once again considering –3% error of ICT, $i_{sf1} = 17.80 \text{ A}$

Thus, $i_{sf2} = \sqrt{3} \times 17.80 = 30.83 \text{ A}$

$$\text{Differential current} = i_{pf} - i_{sf2} = 5.44 \text{ A}$$

and restraining current $= (i_{pf} + i_{sf2})/2 = 33.55 \text{ A}$

$$\text{Pick-up ratio} = \frac{i_{pf} - i_{sf2}}{(i_{pf} + i_{sf2})/2} = 16.21 \%$$

Giving consideration to a possible CT saturation and CT mismatching at this high through fault current, a bias can be set at 30% which is the next higher available setting.

For in-zone fault, the operation of the relay is assured because for a three-phase fault or a two-phase fault in the transformer secondary winding, the differential current will be high leading to a higher pick-up ratio than a set bias of 30%. As such, the operating coil current will be much higher because the internal fault will be fed from both the sides, since generally the transformer is connected to the infinite bus. For faults on the primary winding, the operating coil current will be still higher and perhaps higher than the setting of the high-set unit leading to a one-cycle operation of the relay. The earth-faults are taken care of by an earth-fault protection scheme on the primary side and restricted earth-fault protection on the secondary side.

The CTs will not saturate for large external fault currents if their knee point voltage is high. The relay manufacturer will give the CT requirements for the application.

Generally, the KPV is given by the formula,

$$\text{KPV} = 40 \times I (R_{ct} + R_l)$$

where, I = rated relay current = 5 A

$$R_{ct} = \text{CT secondary resistance} = 1.5 \Omega$$

$$R_l = \text{lead resistance} = 1.6 \Omega$$

$$\text{KPV} > 40 \times 5 (1.5 + 1.6) > 620 \text{ V}$$

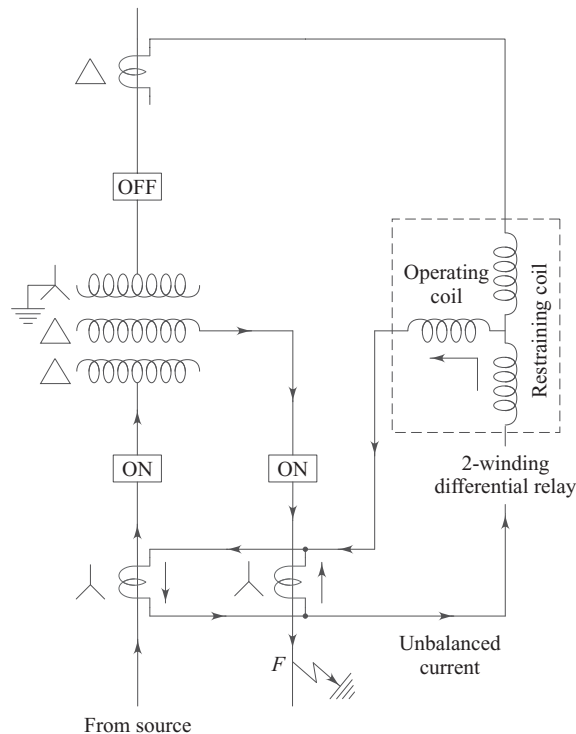


Fig. 6.15 Mal-operation of a 2-winding differential relay

6.5.3 Differential Protection of a Three-winding Transformer

A two-winding percentage differential relay cannot be used for the differential protection of a three-winding transformer. The mal-operation of a two-winding transformer relay is easily evident from Fig. 6.15. For an external fault as shown, there may be a sufficient unbalance current, due to CT mismatch and CT errors, to cause the differential relay to operate when not called for. The relay would lack the advantage of a through current restraint, the main feature of the percentage differential principle. The reason for this is that the pick-up ratio will be 200%. Thus, for a potential mal-operation, it is only necessary for the unbalance current to be above the pick-up current of the operating coil.

Figure 6.16 illustrates that if a three-winding differential relay is used, there will always be a through current restraint to restrain the operation of the relay when it is not required to operate.

6.5.4 Differential Protection of Large Auto-Transformers

A circulating current differential protection scheme employed for protection of large autotransformers is shown in Fig. 6.17. All CTs have the same ratio and a simple instantaneous relay is used since the protection is not affected by either magnetising inrush currents or tap changing (since magnetising inrush current passes through CTs on both the sides).

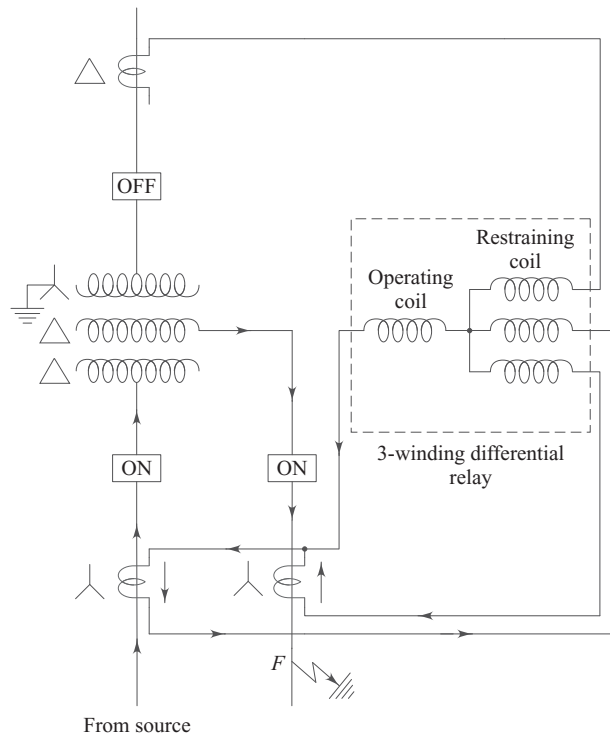


Fig. 6.16 3-winding differential relay for protection of 3-winding transformer

6.6 PROTECTION AGAINST OVERFLUXING

The transformers in generating stations need protection against the risk of damage, which may be caused when they are operated at flux density levels significantly greater than the designed values. These conditions are most likely to arise when the unit is on open circuit with the generator field energised; the speed of the machine is considerably below the synchronous speed and the regulator is trying to bring the voltage to the normal rated value. This may result in an unduly large value of Vf and hence a flux.

Increase in magnetic flux densities increase the iron losses and magnetising current of the transformer. The core and core bolts, as a result, get heated and the insulation of laminations is affected.

The increase in flux density is caused by an increase in the ratio Vf as $V = 4.44 f \phi N$. In other words, the flux density will increase either due to overvoltage or due to under frequency.

The basic operating principle of the relay used for the protection against overfluxing is to provide an ac voltage proportional to the Vf ratio. When the peak of the ac signal exceeds the dc reference, the relay starts operating. The relay is a time-lagged relay.

6.7 PROTECTION OF GROUNDING TRANSFORMERS

A grounding transformer is connected either in wye-delta or zig-zag and its purpose is to provide a grounding point for the power system.

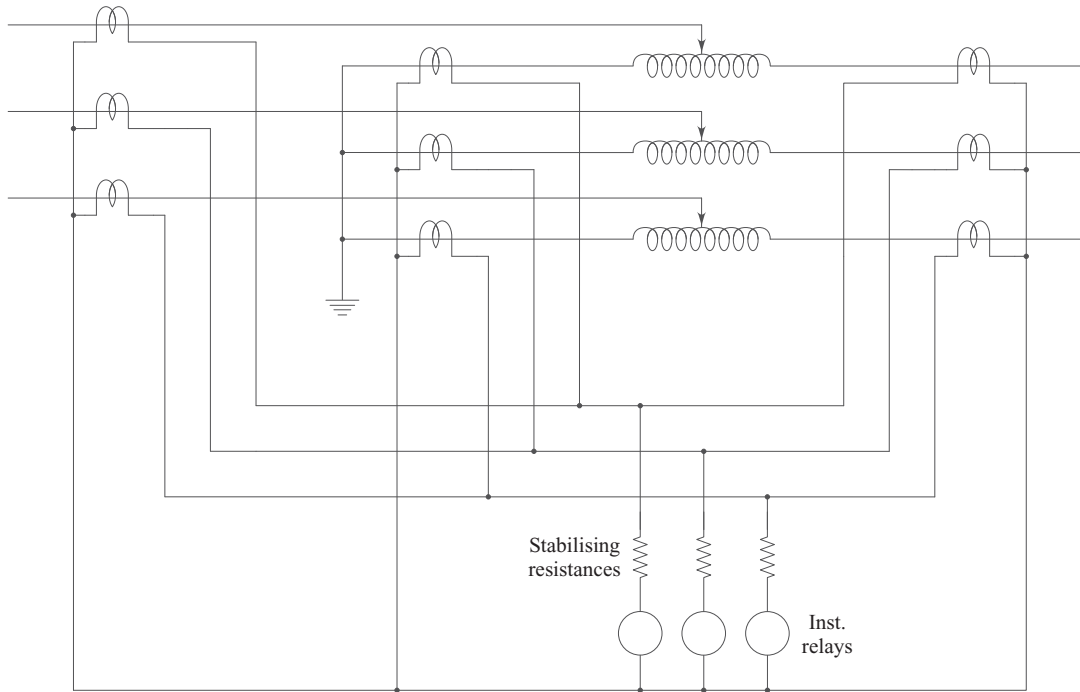


Fig. 6.17 Differential protection of an auto-transformer

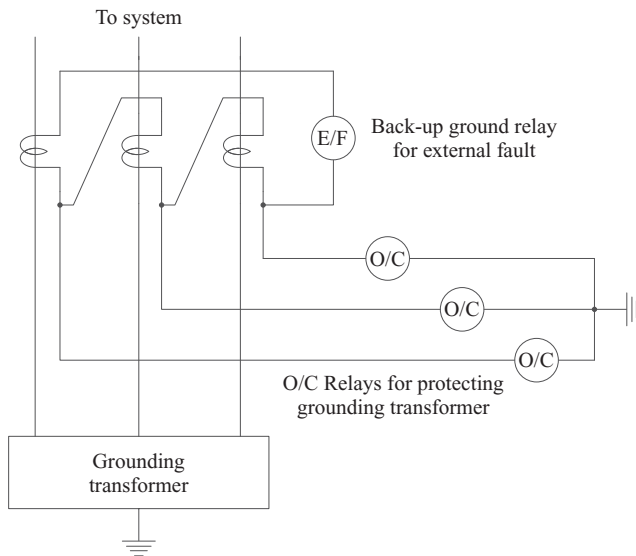


Fig. 6.18 Protection of a grounding transformer

Figure 6.18 shows the way to protect the grounding transformer. Only zero sequence currents flow through the primaries of the delta-connected CTs for the external earth-faults. This will result in the exclusive current flow in the earth-fault relay provided for back-up. Its time setting should be adjusted at a higher value to be selective with other relays that should operate for external faults. The remaining three overcurrent relays will protect the grounding transformer for internal faults in the transformer. Except for the exciting current and a very low current that may flow through the relays due to CT errors, no current is expected to pass through the grounding transformer unless there is a fault in the transformer. Hence these relays should be having a lower pick-up setting and faster operation. The pick-up setting of the overcurrent relays should be generally 20–50% of the continuous current rating of the grounding transformer.

6.8 PROTECTION AGAINST OVERHEATING

Overheating of the transformer winding or oil can be caused due to many reasons such as overload, failure of cooling fans or oil pumps, blocking of radiator, oil leakage, electrical short-circuiting of laminations or core bolt insulation failure, dry joints or connections, overfluxing, etc.

Temperature transducers like RTDs (Resistance Temperature Detectors) or thermocouples are embedded near each winding. These are wired to a bridge circuit. When the measured temperature increases above a safe limit, an audible alarm is issued. If corrective steps are not executed within a short time then the trip signal to the circuit breaker is given after a certain value of temperature is reached. Typical settings used for oil temperatures are given below:

Switch on air fans	: 60 C
Switch on oil pumps	: 70 C
Audible and visual alarm	: 85 C
Trip Signal to circuit breaker	: 95 C

6.8.1 Oil Thermometer

In oil-filled transformers, an oil thermometer is commonly used as a semi-effective device. It is provided with alarm contacts connected to give a warning to the operator in the control room whenever there is an abnormally high oil temperature. It is located so as to monitor the temperature of the hottest area in the oil in the transformer tank. This thermometer is sometimes also used to start cooling fan motors to extend the loading capability of the transformer.

As the transformer oil has a higher time constant, this thermometer which measures oil temperature is not dependable as a fault-detecting unit.

6.8.2 Winding Thermometer

In this thermometer, the bulb is embedded near the winding. Hot circulating oil surrounds this thermometer bulb. A small heater is connected across the CT secondary to heat the bulb. Thus, the heat transferred to the bulb is dependent on the load current as well as the temperature of oil near the winding. The thermometer is designed and adjusted to match its characteristic with the heating curve of the transformer winding.

The measurement of a winding thermometer is nearer to the actual thermal condition of the transformer than that of the oil thermometer.

6.9 SCHEMES FOR SMALL TRANSFORMERS

None of the protective schemes discussed so far can be provided for small distribution transformers up to a few hundred of kVA. The increased cost of these protective schemes is a big restraint for adopting them. Even gas-actuated relays are not provided on small transformers.

The primary (h.v.) of such transformers is protected by drop-out fuses and the low voltage side is protected by rewirable type kit-kat fuses. However, the modern trend is to protect the transformer by a moulded case circuit breaker provided on the secondary. The Rural Electrification Corporation (REC) has standardised MCCB characteristics for the protection of distribution transformers.

No doubt, the incipient faults like inter-turn faults in one phase winding where only a few turns are involved will not be looked after by one of the fuses or MCCB, but one has to take this calculated risk and no economically viable comprehensive protection has been developed for such faults till date. Perhaps, this is one of the reasons why the rate of failure of such small transformers is high.

6.10 TRANSFORMER PROTECTION USING A NUMERICAL RELAY

The recent practice of protecting a power transformer is to use a comprehensive numerical relay. The following protection functions are available in modern numerical relays.

6.10.1 Differential Protection

In Fig. 6.19, if there is no fault in the transformer, the current I_2 leaves the transformer. In this case, the secondary currents i_1 and i_2 are the same. Currents i_1 and i_2 just circulate in the pilots and no current flows through the operating element M . No doubt, the current may flow through this element due to CT mismatch when a heavy through fault occurs. This has to be avoided by proper stabilisation.

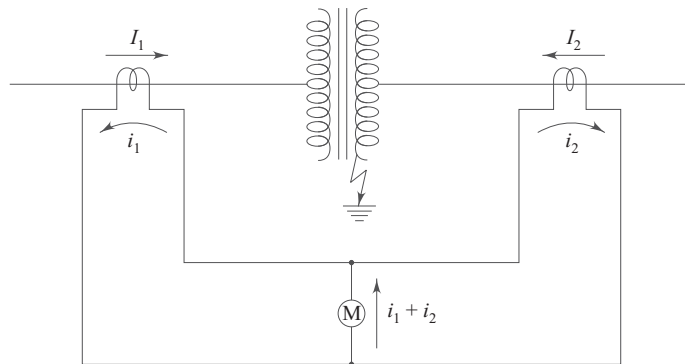


Fig. 6.19 Principle of differential protection

In case of an internal fault, the current $(i_1 + i_2)$ flows through the operating element M as shown in Fig. 6.19. The relay operates in this case, tripping the transformer by tripping breakers on both sides.

A numerical relay usually is required to be fed by the data of the transformer to be protected and instrument transformer data. MVA rating, primary and secondary voltages, vector group, etc., of the transformer are entered in the relay. The relay calculates the full load currents on both the sides and finds out the secondary equivalents. All these calculations are possible to be made by some form of microprocessor within the relay.

When numerical relay is used, CTs on both sides are connected in star only and no ICTs are required to be used. The relay continuously takes the samples of CT secondary currents on both the sides and before feeding these currents to the pilots, the pilot currents are vectorially and arithmetically matched.

$$[I_m] = k [M] [I_n]$$

where,

$[I_m]$ = matrix of the pilot currents

k = constant factor to match the pilot currents arithmetically

$[M]$ = coefficient matrix depending on the vector group to take care of vectorial inherent phase shift of line currents of transformer

$[I_n]$ = matrix of phase currents of R, and B phases available from CT secondaries.

Thus, proper pilot currents are fed to the relay. i_1 is the pilot current on the primary side, i_2 is that on the secondary (and i_3 is the same on the tertiary in case of a three-winding transformer). The relay will calculate the differential current i_{diff} and stabilising current i_{stab} given by,

$$i_{\text{diff}} = i_1 + i_2 + i_3, \text{ i.e., the vectorial sum}$$

and $i_{\text{stab}} = i_1 + i_2 + i_3, \text{ i.e., arithmetic sum}$

If $I_{\text{diff}} > K \times I_{\text{stab}}$, a tripping signal is issued. The characteristic is shown in Fig. 6.20.

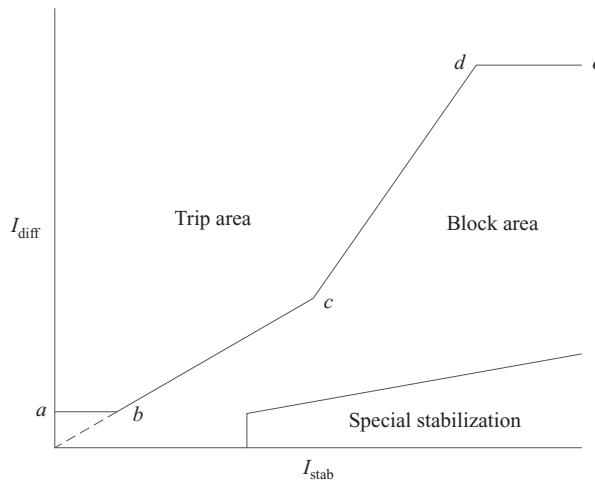


Fig. 6.20 Characteristic of numerical transformer differential relay

A straight horizontal line ab shows the basic setting. Curve bc gives the first slope to take care of CT errors and tap changing. Curve cd causes stronger stabilisation to take care of CT mismatch which occurs for heavy through faults. If I_{diff} is higher than the value given by the portion de , the relay will always issue a trip command and no harmonic restraint or stabilisation is effective. If a bolted three-phase short-circuit occurs, CTs may badly saturate and the operating point may lie in the trip area. The fact that the CT does not saturate during the first cycle is made use of in this case. If, during a first cycle, a point moves in the area defined by special stabilisation and then moves to the trip area in subsequent cycles, the operation can be blocked for a selectable period within which some primary relay may operate avoiding uncalled tripping of differential protection.

The second harmonic stabilisation facility is provided in the relay to avoid unnecessary tripping due to magnetising inrush which occurs while switching ON the transformer. If the second-harmonic content in i_{diff} is more than a preset percentage of fundamental, the relay issues the blocking command.

The fifth-harmonic stabilisation is also generally available in modern numerical relays. This feature takes care of over-excitation of the transformer and avoids possible mal-operation of the relay. If the fifth harmonic content in i_{diff} is more than a certain preset percentage of the fundamental, tripping is blocked. But if heavy overvoltage is found on the primary, it will cause a large magnetising current and iron losses will be very

high. If, in this case, i_{diff} is higher than a certain preset value, blocking is withdrawn and a trip command is issued.

6.10.2 Restricted Earth-fault Protection

The restricted earth-fault protection of a star-connected secondary winding is shown in Fig. 6.21.

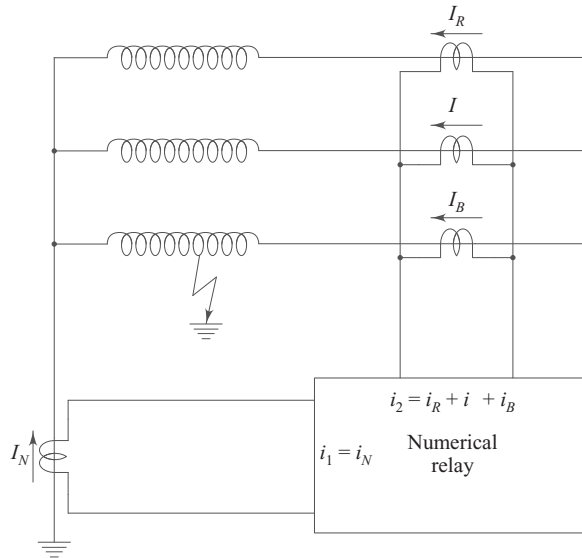


Fig. 6.21 Restricted earth-fault protection

Samples of currents I_R , I , I_B and I_N are taken as seen in secondaries of CTs. The principle is similar to differential protection. The current i_2 will exist only for internal or external earth-fault.

$$i_1 = i_N, \text{ the neutral current}$$

$$i_2 = i_R + i + i_B, \text{ the residual current}$$

Now,

$$I_{\text{ref}} = i_1 + i_2$$

$$I_{\text{stab}} = i_1 + i_2$$

When $i_{\text{ref}} > k \times I_{\text{stab}}$, a tripping command is issued.

6.10.3 Back-up Overcurrent Protection

Back-up overcurrent protection can be provided for line faults. Usually, four standard characteristics are available in modern numerical relays:

1. Normal inverse IDMT characteristic
2. Very inverse IDMT characteristic
3. Extremely inverse IDMT characteristic
4. Long time inverse IDMT characteristic

The facility of 'Switch ON to fault' (SOTF) is provided; i.e., if the fault exists while closing a breaker, the relay trips instantaneously and the associated time delay of the IDMT characteristic is bypassed.

6.10.4 Thermal Overload Protection

Temperature rise in the windings can be calculated by mathematical formula based on current flowing, and thereafter an alarm and/or trip signal can be issued if it exceeds a set limit. Thermal memory is also available in the relay. This gives the option of considering a pre-load temperature rise of the transformer winding.

6.10.5 External Trip Functions

If cooling fans or cooling pumps fail or a Buchholz relay operates, the operation of a Buchholz relay or deenergisation of a fan contactor can be routed through the relay and the relay would issue a trip command. This can be done through the binary input, i.e., (say 110 V) dc voltage can be applied to the designated terminals of the relay through the contact of a Buchholz relay, etc.

6.A.1 APPENDIX I

Information Required for Designing a Protective Scheme with Relay Settings for a Power Transformer

1. Transformer

- (i) MVA rating
- (ii) Nominal transformation ratio
- (iii) Rated primary and secondary voltage
- (iv) Vector group of transformer (i.e., D -11, D -1, etc.)
- (v) Percentage impedance
- (vi) Type of neutral earthing (i.e., effective/non-effective)
- (vii) Value of earthing impedance, if neutral is non-effectively grounded
- (viii) Indoor or outdoor
- (ix) With or without conservator tank
- (x) Zero sequence impedance
- (xi) No-load current
- (xii) Tap-changer details
- (xiii) Overfluxing withstand

2. Current Transformer

- (i) Class of CT
- (ii) Knee Point Voltage (KPV)
- (iii) Magnetising current
- (iv) Secondary resistance
- (v) CT ratio
- (vi) Details of interposing CTs, if used.
- (vii) Accuracy limit factor of CTs used for overcurrent protection
- (viii) Burden (VA rating)

3. Pilot wire resistance for differential protection

4. Type of relays used for overcurrent protection, REF protection, Differential protection, overfluxing protection, etc., and the technical particulars of the relays particularly burden and CT requirements.

5. Potential Transformer

- (i) Voltage ratio
- (ii) VA rating

6. Power-System Particulars

- (i) Network diagram showing the position of transformer
- (ii) Fault level at transformer terminals

REVIEW QUESTIONS

1. Give reasons for the following statements:
 - (i) Large power transformers are protected by both differential and Buchholz relays.
 - (ii) The biased winding of a differential relay cannot avoid unwanted tripping of the relay in case of energising a transformer.
 - (iii) Overfluxing protection of a generator–transformer is a time-delayed protection.
 - (iv) The earth-fault relay used for protection of the h.v. side of a step-down delta-star transformer can be provided with a longer setting than the earth-fault relays on the secondary side.
 - (v) Earth-fault relays employed for protection of the delta winding of a transformer are of instantaneous type while those on the star side have to be time graded.
 - (vi) A Buchholz relay alone cannot be relied upon for the protection of transformers.
2. Enlist incipient faults and suggest the device that will operate in each case.
3. Briefly discuss the problems that arise in the application of differential protection of a power transformer and indicate the solutions employed.
4. Explain why a delta-star power transformer must have the protective CTs connected in star-delta for differential relaying.
5. Explain the phenomenon of magnetising inrush current in power transformers. Describe, with the help of neat diagrams, any one method of preventing tripping of the differential protection due to inrush of magnetising current.
6. Draw a protective scheme of restricted earth-fault protection of a transformer.
7. Why is restraining winding provided in a biased differential relay as applied to the differential protection of a transformer?
8. Make a list of the various protective relays you would use for a generator–transformer unit with the following specifications:

Generator 25 MVA, 6.6 kV, 3 phase, 50 Hz, star-connected with the star point earthed over a grounding transformer and driven by a hydraulic turbine

Transformer 6.6/132 kV, l.v. side delta connected, h.v. side star-connected with the star point earthed solidly

Briefly state the function of each of the relays suggested by you.
9. Restricted earth-fault protection is to be provided to a 5000–kVA, 6.6/11-kV transformer on the h.v. side which is star-connected. Through fault stability is required up to 15 times the full-load current with neutral CT assumed completely saturated. Find out the value of the stabilising resistance required with the following data:

Line and neutral CTs: 300/1 A, CT resistance (secondary): 1 ohm,

Relay pick-up: 0.1 A

Relay resistance: 100 ohm

Lead resistance: 1 ohm

Also suggest the KPV of the CTs to be used for such protection. **(55 ohms, 55 volts)**
10. A 132/66 kV, 20 MVA, YD-11, 3 phase, 50 Hz transformer is connected in delta on the l.v. side and in star (solidly earthed) on the h.v. side. Draw the detailed connection diagram for differential protection of the transformer. If the CTs employed

on the h.v. side have a transformation ratio of 100/1 A, determine the CT ratio on the l.v. side. Suggest the ICT ratio if required. **(200/1 A, 1.732:1 A)**

11. Discuss the factors required to be considered while setting overcurrent and earth-fault relays for transformer protection.
12. Draw a detailed protective scheme for biased differential protection of a 11/132 kV, 150 MVA, DY-I power transformer. Suggest suitable CT ratios. Also suggest the proper ICT for the scheme. **(10000/5 A, 750/1 A, 1:2.597 A)**
13. The following are the particulars of a power transformer:
 - (i) 132/66 kV, 100 MVA, 3 phase
 - (ii) Tap-changer: -7.5 to +10% (in steps of 2.5%) of rated voltage provided on the h.v. side
 - (iii) Percentage impedance: 10%
 - (iv) Vector group: DY-I
 - (v) Magnetising current: 2% of rated current

Select a suitable current transformer of Class 3 including interposing CTs if required. Suggest the settings of a biased differential relay having a setting range as follows:

Basic setting: 10 to 50% (in steps of 10%) of relay rating

Bias setting: 10 to 50% in steps of 10%

Assume suitable relay rating.

(500/1 A, 1000/1 A, 1.732:1, basic setting = 10%, bias setting = 30%)

14. Discuss why an overfluxing protection is required for a generator-transformer stating the causes and consequences of overfluxing.
15. A three-phase, 11/132 kV, 100 MVA, DY-11 power transformer is provided with restricted earth-fault protection scheme for protection against earth-fault in the secondary winding of the transformer. The positive and zero-sequence impedances of the transformer are the same with a value equal to 10%. Draw a detailed scheme of the protection. Determine the suitable CT ratios of the CTs used therein. If the high impedance differential relay (relay resistance = 100 ohms) used in the protection scheme is set at 10% of the CT secondary rating, find out the value of the stabilising resistance required to be connected in series with the relay. Also, suggest the suitable knee point voltage of the CTs used. The star point of the h.v. winding is solidly grounded. Given $R_{CT} < 5$ ohms and R_L (lead resistance) = 2 ohms.

(500/1 amp, 171 ohms, 125 volts)

16. Show why and where are three restraining coils used in a biased differential relay in case of transformer protection.
17. What are the remedies prevalent in manufacturing practices of protective relays to avoid mal-operation of a differential relay when overvoltage occurs on the source side of a power transformer?

MULTIPLE CHOICE QUESTIONS

1. Buchholz relay is most essential for protection against
 - (a) inter-turn fault
 - (b) HT and LT fault
 - (c) earth-fault
 - (d) none of the above
2. The magnetising inrush current in an unloaded transformer is maximum when the switch is closed and the voltage is passing through
 - (a) zero
 - (b) positive maximum
 - (c) negative maximum
 - (d) none of the above
3. The magnetising current in a transformer caused due to overvoltage is rich in
 - (a) 2nd harmonic component
 - (b) 3rd harmonic component
 - (c) 5th harmonic component
 - (d) none of the above
4. The magnetising inrush current in a transformer is rich in
 - (a) 2nd harmonic component
 - (b) 3rd harmonic component
 - (c) 5th harmonic component
 - (d) none of the above
5. Bias setting of transformer differential relay cannot avoid mal-operation due to
 - (a) external fault
 - (b) CT saturation
 - (c) CT mismatching
 - (d) overvoltage on source side of the transformer

Protection of Transmission Lines by Overcurrent Relays

The demand for electrical power generally increases at a faster rate in economically emerging countries. This necessitates installation of transmission lines reaching out to all the areas of the country. Further, the efficiency of transmission should be high when a large bulk of power is to be transmitted over very long distances. It requires extra high voltage ac, ultra high voltage ac and HVDC transmission lines to be erected. The voltage of transmission nowadays has reached 765 kV ac and still higher voltages of transmission are planned. The concept of a national grid requires installing long ultra high voltage ac and HVDC transmission lines between different regional grids of a nation. There are five regional grids currently operational in India, namely, Western, Northern, Southern, Eastern and North-Eastern. Power Grid Corporation of India, Ltd. (PGCIL) is the company involved in transmission expansion planning and implementation.

7

Introduction

These transmission lines are required to be protected by comprehensive and quite involved protective schemes so that the power interruption is reduced to a minimum with regard to the time of interruption and the area affected. The protective scheme must operate fast and selectively before the power system becomes unstable.

It is the usual practice to protect feeders of 11 kV and transmission lines of 66 kV by overcurrent and earth fault relays as the primary (main) protection. Transmission lines of 132 kV and 220 kV are

protected by distance relays as primary protection, and overcurrent and earth fault relays as back-up protection. Lines of 400 kV and beyond use complicated distance relays like quadrilateral relays. The role of overcurrent and earth fault relays as back-up still exists at 132 kV and higher transmission voltage levels. This chapter is dedicated to the elaboration of details for protection of transmission network by overcurrent and ground relays.

7.1 BASIC RADIAL FEEDER

Any transmission system can be subdivided into segments of radial feeders supplying the consumers. Hence our discussion initiates with a single-line diagram of a basic radial feeder as shown in Fig. 7.1.

Referring to Fig. 7.1, power is generated at 11 kV and stepped up by a step-up transformer of 11/132 kV. Power is, then, transmitted at 132 kV to a receiving substation, where voltage is stepped down to 66 kV for

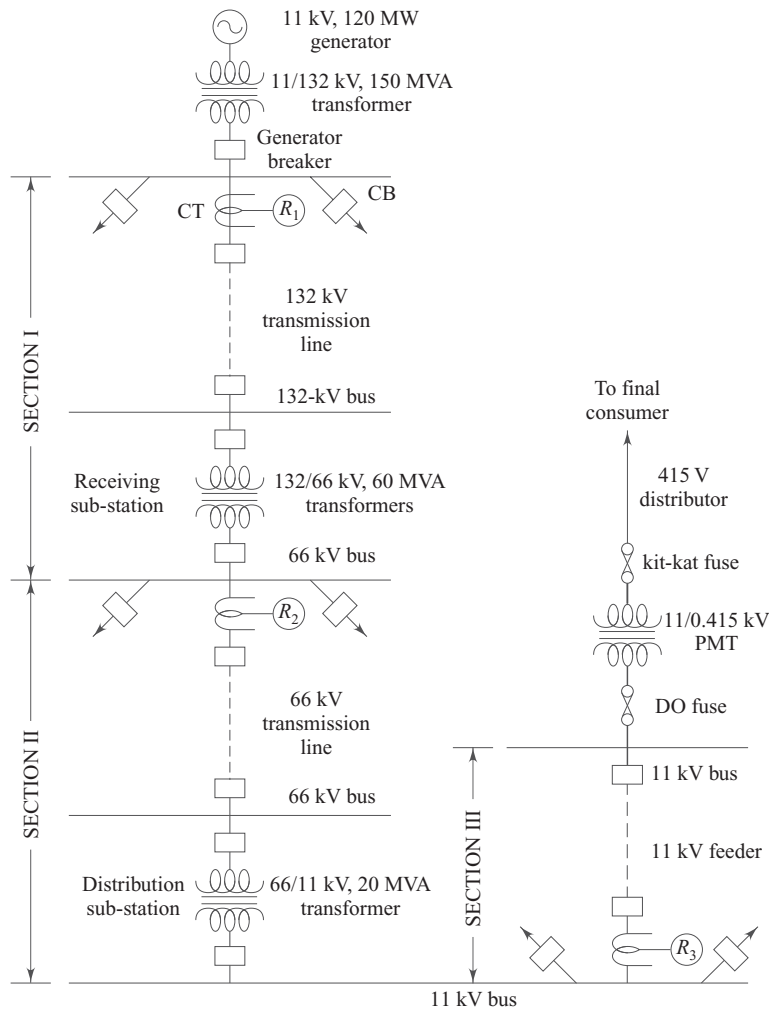


Fig. 7.1 Single-line diagram of a radial feeder

further transmission to a distribution substation. At the distribution substation, voltage is further stepped down to 11 kV for feeding to the distribution system. 11 kV feeders will be terminated at the pole-mounted transformer of 11 kV/415 V. 415 V distributors, in turn, will feed the consumers.

The distributors are protected against faults by kit-kat fuses. The recent practice is to use moulded-case circuit breakers (MCCBs) instead of fuses. The pole-mounted transformer is protected by drop-out fuses. 11 kV feeders, 66 kV and 132 kV transmission lines are protected by overcurrent and earth-fault relays. Current transformers will transform the current at a value suitable for relays. Relays, upon operation when a fault occurs, will signal the circuit breaker for clearing the faults in feeders. Thus, the relay R_3 protects the 11 kV feeder, the relay R_2 protects the 66 kV transmission line and the relay R_1 protects the 132 kV line. When a faulted line is isolated from the remaining healthy system by tripping a breaker, the fault is said to be cleared. 85% of the faults are transient in nature and hence their rectification is not required. Sustained faults are required to be rectified. It is to be noted that relays R_1 , R_2 and R_3 represent a group of relays protecting

all the phases because Fig. 7.1 is a single-line diagram. Two overcurrent and one earth-fault relay scheme of protection, to be discussed later in this chapter, can be used at the relaying point R_3 , whereas three overcurrent and one earth-fault relay scheme has to be used at the relaying points R_1 and R_2 .

In case of faults in the distribution system, kit-kat fuses or MCCBs should operate to isolate the faulty section. If the MCCB or the fuse fails to trip, the relay R_3 in the distribution substation will act as a remote back-up protection to clear the fault. In case of a fault in the 11 kV feeder, the relay R_3 acts as a primary protection and clears the fault and the relay R_2 acts as a back-up in case of failure of switchgear at the relaying point R_3 . Similarly, the 66 kV and 132 kV transmission lines are protected by relays R_2 and R_1 respectively. For the sake of simplicity, the back-up overcurrent relays for protection of power transformers are not shown in Fig. 7.1, however such relays do exist in actual practice.

In Fig. 7.1, the relay R_3 is to be coordinated with the tripping characteristic of the fuse or the MCCB. The setting of the relay R_2 is based on the tripping characteristic of the relay R_3 , and similarly the relay R_1 is to be graded with the relay R_2 . The detailed procedure for deciding the relay settings is discussed later in this chapter.

While deciding relay settings of relays in Fig. 7.1, two important requirements of the protective relaying system (refer Chapter 1, Section 1.8) will be considered; viz., selectivity and speed. Selectivity means the operation of the relay only for the faults in the zone which is assigned to the relay. In the single-line diagram of Fig. 7.2, R_3 must operate for the faults in Section III, R_2 must operate as a main protection for the faults in Section II only and provide a remote back-up for the faults in Section III if the protective system at the relaying point R_3 fails to clear the fault. A similar protection must be offered by the relay R_1 . Speed means the minimum possible time of isolating the faulty section from the healthy system after the instant of fault inception. Thus, a minimum section of the power system should be isolated from the healthy system, as quickly as possible, after the instant of fault inception. Three methods of discrimination are popular to achieve these two important properties of a protective relaying system.

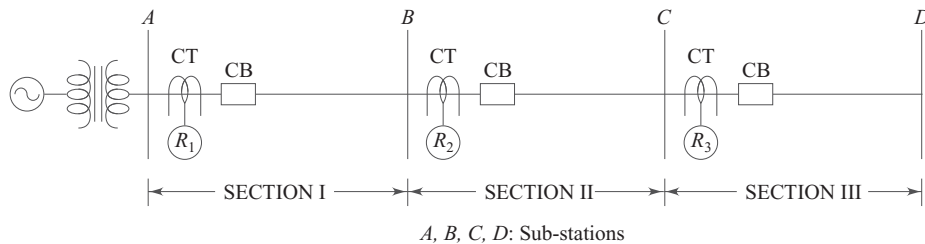


Fig. 7.2 Simplified version of Fig. 7.1

7.2 METHODS OF DISCRIMINATION

The selectivity or discrimination can be achieved by three methods

1. Current discrimination
2. Time discrimination
3. Current-time discrimination

1. Current Discrimination It is obvious that the fault current is maximum for the fault near the power source and goes on decreasing for faults farther to the source. This fact is made use of in the current-discrimination method. When current discrimination is used for obtaining selectivity and speed, relays R_1 , R_2 and R_3 of

Fig. 7.2, being instantaneous overcurrent relays, are adjusted to pick-up at currents progressively decreasing from the source to the remote end of the line as shown in the current-distance characteristic in Fig. 7.3. The relays are set to reach for the faults at the far end of their zone of protection; i.e., the relay R_1 must reach for the fault at the substation B and not beyond that, and so on. If the relay R_1 reaches for the fault beyond the substation B , relays R_1 and R_2 will operate simultaneously which is contrary to the requirement of selectivity.

This method of discrimination suffers from the following disadvantages:

1. It is not practicable to distinguish in fault current magnitudes between faults at F_1 and F_2 (Fig. 7.3), since these two points, in the worst case, could be separated by no more but the path through the circuit breaker. The fault currents, in this case, will differ by only an insignificant amount requiring an unrealistic setting accuracy.
2. The method does not provide remote back-up protection.
3. If the source impedance Z_s (impedance from source to the relaying point) is large compared to the line impedance Z_l (impedance from relaying point to the fault), this method of discrimination fails to discriminate between in-zone faults and external faults. This is because the currents in both these cases will differ by a negligible magnitude. Thus, very short feeder sections cannot be protected by instantaneous overcurrent relays as the maximum possible value of Z_l itself will be very small. Also end-section feeders (like feeder 3 in Fig. 7.3) cannot be protected by instantaneous overcurrent relays; however, the fault current in this feeder may be too small to require instantaneous protection.

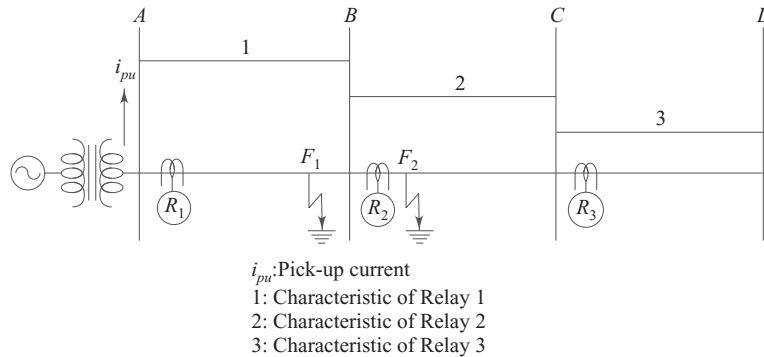


Fig. 7.3 Current discrimination for radial feeder

4. The relaying system does not exploit the short-time fault current withstand capability of the equipment to be protected.
5. It also does not take into account the transient stability limit of the machines. As such, the generators can feed short-circuit power for some time without losing synchronism and the transient fault may vanish during that period.
6. Instantaneous overcurrent relays suffer from the problem of overreach, whereby they would mal-operate for the faults external to their assigned zone. This is explained as follows.

In case of a sudden short-circuit (fault) of a typical series R - L circuit in a power system (Fig. 7.4), the fault current is given by,

$$L \frac{di}{dt} + Ri = e = E_m \sin(\omega t + \theta) \quad (7.1)$$

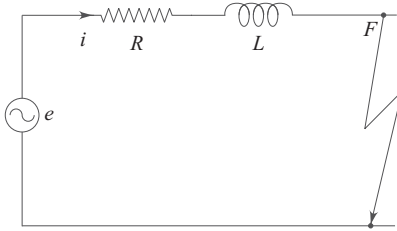


Fig. 7.4 Series R-L circuit

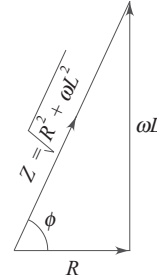


Fig. 7.5 Impedance triangle

The solution of Eq. (7.1) is the sum of the complementary function (transient component) and the particular integral (steady-state component). For obtaining transient component of the fault current,

$$L \frac{di}{dt} + Ri = 0$$

$$\frac{di}{i} = -\frac{R}{L} dt$$

Integrating,

$$\ln i = -\frac{R}{L} t + K$$

$$\ln i = \ln e^{-\frac{R}{L} t} + \ln A \quad \text{where } K = \ln A$$

$$i = A e^{-\frac{R}{L} t} \quad (7.2)$$

Thus, transient component is the exponentially decaying component or dc offset as it is called.

For obtaining PI, try

$$i = C \cos(\omega t + \theta) + D \sin(\omega t + \theta)$$

$$\frac{di}{dt} = -C\omega \sin(\omega t + \theta) + D\omega \cos(\omega t + \theta)$$

Substituting these values in Eq. (7.1),

$$-LC\omega \sin(\omega t + \theta) + LD\omega \cos(\omega t + \theta) + RC \cos(\omega t + \theta) + RD \sin(\omega t + \theta) = E_m \sin(\omega t + \theta)$$

$$\cos(\omega t + \theta) (RC + LD\omega) + \sin(\omega t + \theta) (RD - LC\omega) = E_m \sin(\omega t + \theta)$$

Equating coefficients of like terms,

$$RC + LD\omega = 0 \quad (7.3)$$

$$RD - LC\omega = E_m \quad (7.4)$$

From Eq. 7.3,

$$C = -\frac{LD\omega}{R} \quad (7.5)$$

Substituting this value in Eq. (7.4),

$$RD + \frac{\omega^2 L^2 D}{R} = E_m$$

$$\therefore D \frac{(R^2 + \omega^2 L^2)}{R} = E_m$$

$$\therefore D = \frac{R}{(R^2 + \omega^2 L^2)} E_m \quad (7.6)$$

Using Eq. (7.5),

$$C = -\frac{\omega L}{(R^2 + \omega^2 L^2)} E_m \quad (7.7)$$

Using an impedance triangle given in Fig. 7.5, the values of constants C and D can be rewritten as,

$$C = -\frac{E_m}{Z} \sin \phi \quad (7.8)$$

$$D = \frac{E_m}{Z} \cos \phi \quad (7.9)$$

Thus, the steady-state value of the current can be given by,

$$i = \frac{E_m}{Z} [\sin (\omega t + \theta) \cos \phi - \cos (\omega t + \theta) \sin \phi]$$

$$\text{or} \quad i = \frac{E_m}{Z} \sin (\omega t + \theta - \phi) \quad (7.10)$$

Equation (7.10) suggests that the steady-state component of the fault current is the sinusoidally varying ac component. The steady-state waveforms of e and i are shown in Fig. 7.6. The complete solution for the fault current is the sum of the transient component and the steady-state component, i.e.,

$$i = A e^{(-Rt/L)} + \frac{E_m}{Z} \sin (\omega t + \theta - \phi) \quad (7.11)$$

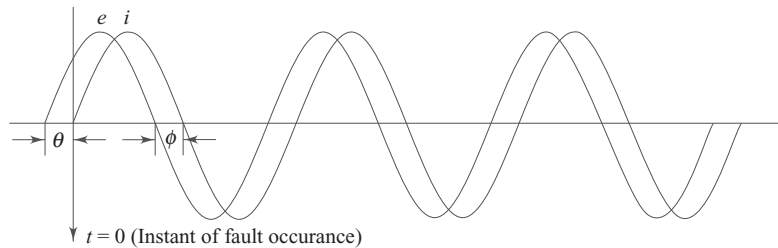


Fig. 7.6 Steady-state waveforms of e and i

Now if the fault occurs at $e = 0$, $\theta = 0$, assume that $R \ll \omega L$, $Z = \omega L$ and $\phi = 90^\circ$. Applying the initial condition, at $t = 0$, $i = 0$, Eq. (7.11) reduces to,

$$0 = A + \frac{E_m}{\omega L} \sin(-90^\circ)$$

$$A = \frac{E_m}{\omega L}$$

Hence, the dc component is the maximum in this case and the current i is given by,

$$i = \frac{E_m}{\omega L} [e^{(-Rt/L)} + \sin (\omega t - 90^\circ)]$$

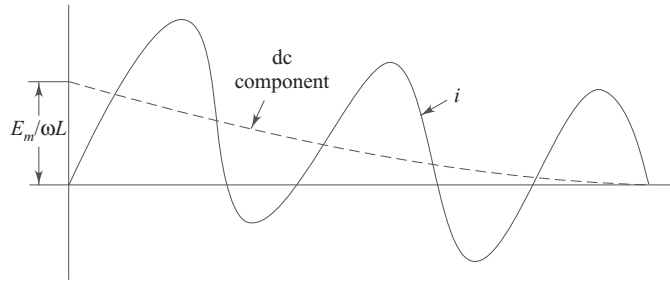


Fig. 7.7 Waveform of fault current (fault occurs when $e = 0$)

The doubling effect in the current waveform is shown in Fig. 7.7. If the fault occurs at $e = E_m$, the conditions will be at $t = 0$, $i = 0$, $\theta = 90^\circ$. Then Eq. (7.11) can be rewritten for initial conditions as,

$$0 = A + \frac{E_m}{\omega L} \sin(90^\circ - 90^\circ)$$

i.e., $A = 0$

This shows that there is no presence of dc component and the waveform of the current i contains a symmetrical steady-state component only as given in Fig. 7.6. For other cases of fault occurrences at the instantaneous value of voltage between 0 and E_m , the dc component does exist having value between 0 and $E_m/\omega L$.

The foregoing discussion clearly indicates that when a fault occurs, the fault current may be asymmetrical in nature. However, if the fault occurs at an instant when $e = E_m$, the asymmetry may not exist. One does not know the instant of fault occurrence, nor could it be predicted. Hence, the protective system has to be designed for the worst condition, i.e., maximum dc offset.

The time-delayed relays are not affected by the asymmetry of the fault current, because the asymmetry would vanish before the time of operation of the relay. The instantaneous relays, on the other hand, are much affected by this transient dc offset component as they are fast in operation (20 to 60 milliseconds). For modern power systems having a high X/R ratio, a dc offset may continue for several cycles.

Referring to Fig. 7.3, it is quite possible that an asymmetric value of the fault current for a fault at F_2 may be more than the symmetric value of the fault current for a fault at F_1 . Hence, with a fault at F_2 , relays R_1 and R_2 will operate simultaneously if the relay R_1 is set for a symmetric fault current for the fault at the end of the section.

In other words, relay R_1 will overreach and Section I will be isolated unnecessarily. It is worthwhile to note here that the relays are always set to pick-up at a current equal to the symmetric value of the fault current for a three-phase fault at 80% of the line section to be protected. This presumes that the relay will not overreach by more than 20%.

It is known that magnitude of fault current with three-phase fault (L-L-L) is more than that with double line fault (L-L). It would be impossible to set the instantaneous overcurrent relays in this regard. If the relay is set for L-L fault at the end of the protected section, it would overreach for triple line fault and if the relay is set for L-L-L fault at the end of the protected section, it would underreach for phase-to-phase fault.

Thus, because of the several problems involved, the method of discrimination by current setting using instantaneous overcurrent relays is not feasible. However, as discussed in the succeeding paragraphs, the instantaneous relays with high settings are used as a supplementary feature to other protective relays.

2. Time Discrimination Time discrimination is used to overcome the difficulties faced by the current-discrimination method. In this method, the relays R_1 , R_2 and R_3 of Fig. 7.2 are definite time overcurrent relays

and are set to operate after times that are progressively decreasing. The pick-up settings are so decided that the relay in one substation will act as a remote back-up to the relay in the next substation away from the source. Thus, the relay R_1 should reach for a phase-phase ($L-L$) fault in the substation C , and so on. This shows that the relay R_1 operates after maximum time delay (Fig. 7.8). Obviously, when there are many line sections in series, the tripping time for a fault near the power source may be dangerously high. This is obviously undesirable because such faults involve large currents and are very destructive if not removed quickly. Thus, the fundamental weakness of time-graded overcurrent relays is the fact that the heaviest fault is cleared the slowest. This difficulty can be overcome by introducing an instantaneous overcurrent element in-built in the definite time unit. In this case, the faults nearer to the relaying point are cleared instantaneously and those away from the relaying point are taken care of by definite time units as shown in Fig. 7.8. The shaded area in Fig. 7.8 shows the saving in time of operation of the relay achieved by employing instantaneous feature. The time of discrimination t_d , between the time of operation of two successive relays is generally set to be equal to 0.25 second as it will be discussed later in this chapter.

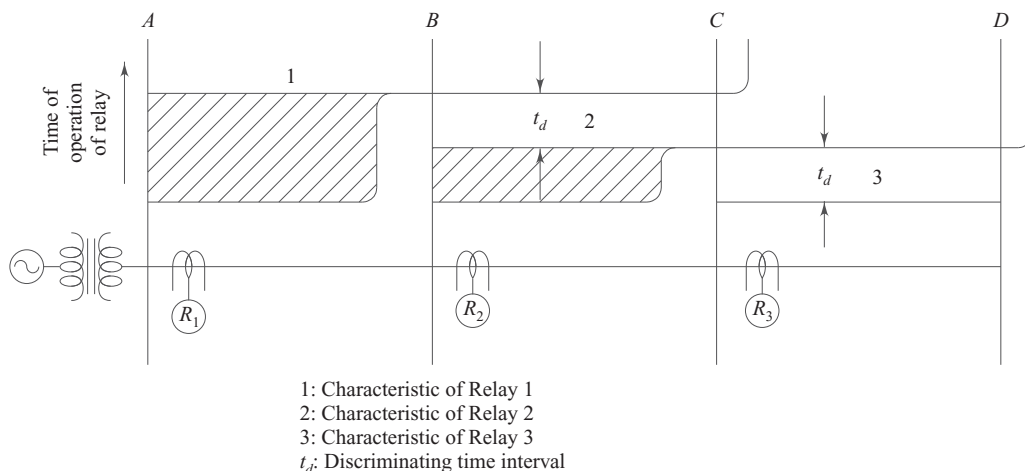


Fig. 7.8 Time discrimination for radial feeder

It is also observed from Fig. 7.8 that the back-up protection is provided by definite time overcurrent relays; i.e., the relay R_1 acts as a main protective relay for faults up to the substation B and as a remote back-up to the relay R_2 for faults beyond the substation B . The definite time overcurrent relays are immune to the ratio of source impedance to load impedance (Z_s/Z_L), i.e., this system of discrimination can be conveniently applied when Z_s is very high compared to Z_L . The problem of uncalled tripping of relays due to overreaching can be solved by setting the in-built instantaneous units to reach up to 80% of the section to be protected (Fig. 7.8). Such a practice will eliminate false tripping of the circuit breaker of the healthy section, even in the case of overreaching of the instantaneous relays, if precautionary measures are taken in designing the instantaneous units to reduce the overreach to minimum possible.

It is very obvious that farther the fault from the source, lesser is the magnitude of the fault current and hence more time can be allowed to clear the fault. Similarly, nearer the location of fault from the power source, the circuit breaker should be tripped faster. This fact is the basis for employing current-time discrimination for obtaining selectivity and speed. In inverse time-current relays, the time of operation of the relay is inversely proportional to the current magnitude. Hence, such relays are used in the current-time method of

discrimination. As this system of discrimination overcomes the demerits of both methods of discrimination described already, it is very widely used in practice.

3. Current-time discrimination The time-distance characteristics of inverse-time overcurrent relays compared with those of definite-time overcurrent relays are shown in Fig. 7.9, which clearly proves that the inverse-time overcurrent relays can provide faster clearing times for the faults near the relaying point than the definite time relays, and still maintain selectivity and back-up protection. The inbuilt instantaneous units attached to inverse time-current relays can further reduce the tripping time for the faults nearer to the relaying point, as is the case with the definite-time relays.

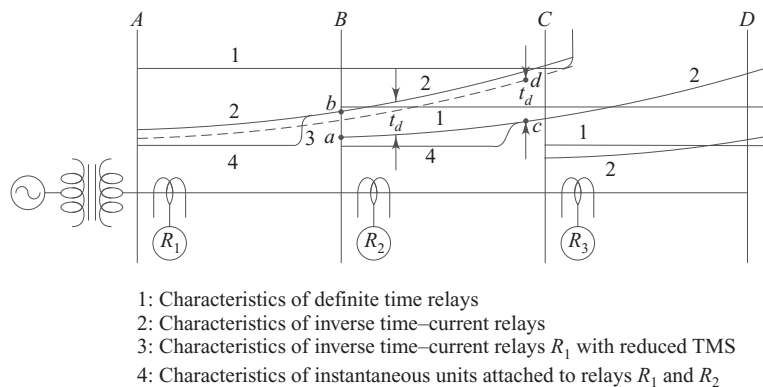


Fig. 7.9 Current-time discrimination for radial feeder

Another advantage that is gained by using instantaneous units, in-built in inverse-time overcurrent relays, can also be seen from Fig. 7.9. Without the instantaneous overcurrent relay at the relaying point 2, the inverse time overcurrent relay at the relaying point 1 would have the characteristic shown by the full line (2) so as to obtain the selective time interval ab with respect to the inverse time relay at the relaying point 2. With instantaneous relay at the relaying point 2, the inverse time relay at 1 need only be selective with the inverse time relay at 2 for the faults at and beyond the point where the instantaneous relay stops operating, as shown by discriminating time interval cd which equals ab . This permits speeding up the relay at the relaying point 1, and hence a lower time setting multiplier can be used for the relay 1 resulting in the characteristic shown by the dashed line (3).

The use of inverse-time overcurrent relays for selective tripping of breakers in a radial feeder is most suitable for radial feeder protection. However, the inverse-time overcurrent relays do suffer from disadvantages explained in the following paragraphs wherein partial or full remedies are also indicated.

1. In inverse-time current relays, the tripping time for very high fault current is very small. This very small time of operation of the relay makes it difficult to decide on the relay settings to enable selective tripping of breakers.

Definite-time overcurrent relays are not subjected to this difficulty because their operating time is independent of the current magnitude. This advantage of a definite-time overcurrent relay provides the solution for addressing the difficulty faced by inverse-time overcurrent relays. An ideal solution is therefore found in a relay which has both the characteristics of a definite-time relay and an inverse-time relay. This means that the relay has inverse time-current characteristics for small currents and practically definite-time characteristic for large overcurrents. Such a characteristic is known as Inverse Definite Minimum Time Lag

(IDMTL or IDMT) characteristic (refer Fig. 2.2, Chapter 2) and the relays are termed as IDMT overcurrent relays.

2. If Z_s is high with respect to Z_1 , the ratio $\frac{Z_s}{Z_s + Z_1}$ is not sufficiently lower than unity to give any appreciable reduction in tripping times. This will occur in the farthest sections of a multisection feeder where Z_s is large as given in Fig. 7.10.

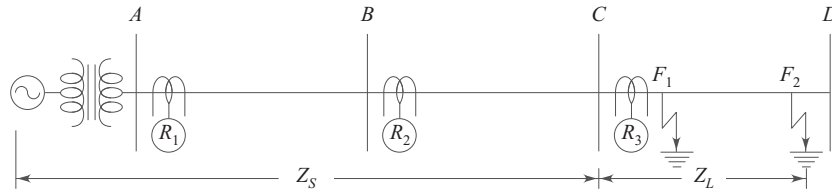


Fig. 7.10 Effect of Z_s/Z_L ratio on performance of inverse time overcurrent relay

For a fault at F_1 ,

$$I_{f1} = \frac{E}{Z_s}$$

where E is the induced emf (ph-n) of generator, and for fault at F_2 ,

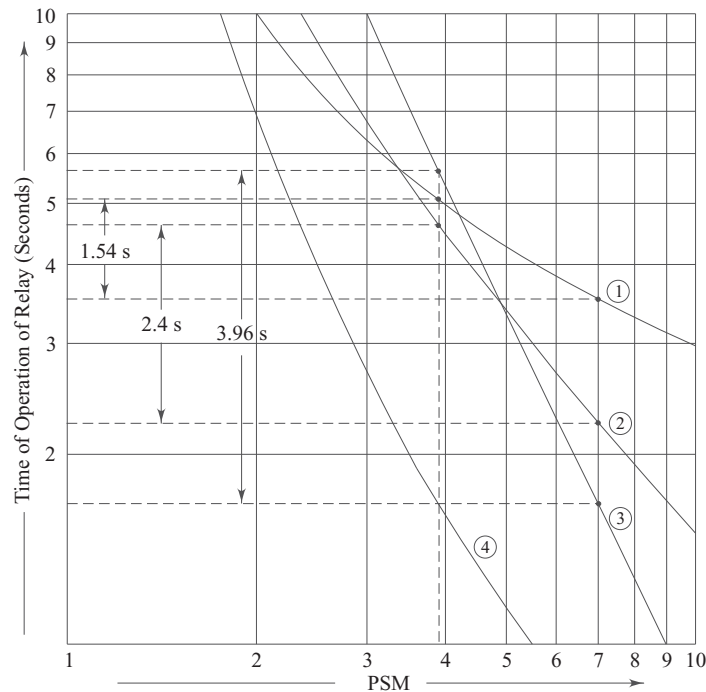
$$I_{f2} = \frac{E}{(Z_s + Z_1)}$$

But since $Z_s \gg Z_1$, there will not be any significant difference between the magnitudes of I_{f1} and I_{f2} . Accordingly, the difference between the tripping times of the relay R_3 for these fault locations will also be insignificant. Therefore, the application of inverse-time overcurrent relay with normal inverse characteristic ($It = K$) will not be justified. The application of such relays is only justified for the ratio $Z_s/Z_1 \geq 2$.

The remedy is to employ a very inverse-time current relays giving steeper characteristic ($I^2t = K$) than that of normal inverse relays. These give more difference in tripping times than do the normal inverse relays for the same difference in fault current magnitudes as shown in Fig. 7.11.

It is clear from Fig. 7.11 that the difference in time of operation of a relay having normal inverse characteristic for two different current magnitudes is 1.54 seconds, whereas the same for a relay having very inverse characteristic for the same current magnitude is 2.4 seconds, providing a better performance of a very inverse-time overcurrent relay. Still higher a performance index can be achieved with the use of an extremely inverse-time overcurrent relay giving a characteristic approximating $I^{3.5}t = K$ as shown in Fig. 7.11. The difference in time of operation for such a relay, in comparison to other characteristics, is shown to be 3.96 seconds in Fig. 7.11.

Another useful advantage gained by the use of a very inverse time overcurrent relay can be understood by referring to Fig. 7.1. The final relay R_3 in Fig. 7.1 is to be graded with the characteristic of a fuse or an MCCB protecting a distributor. As seen from Fig. 7.11, a very inverse-time relay matches much closer to the characteristic of fuse or MCCB. Hence a lower TMS can be selected for the final relay R_3 of Fig. 7.1 and in turn, lower time-setting multipliers for successive relays R_2 and R_1 . Moreover, the time of operation of very inverse relays R_1 , R_2 and R_3 will be less than their normal inverse equivalents even at the same TMS due to more inverseness of the very inverse characteristic than the normal inverse one. This means that faster clearing times can be achieved by the use of very inverse relays. Thus, higher speed of operation of



- 1: Characteristic of normal inverse time-current relay
- 2: Characteristic of very inverse time-current relay
- 3: Characteristic of extremely inverse time-current relay
- 4: Fuse Characteristic or characteristic of MCCB

Fig. 7.11 Characteristics of relays and MCCB

relays can be achieved still maintaining the selectivity between the successive relays and back-up protection. The characteristic of extremely inverse relays matches closest to that of a fuse or an MCCB. Hence, the advantages depicted in the foregoing lines are still more enhanced with the use of extremely inverse relays. Very inverse and extremely inverse relays also have definite minimum time feature.

3. The third problem is due to the variation of generating capacity. Generating capacity will be required to be varied when load varies. Z_s will vary if the generating capacity is varied, becoming larger during a slack load period. This increase in Z_s will not interfere with the selectivity because the time discrimination increases at low current, but it also increase the tripping time and hence defeats the purpose of reducing them.

In case of wider variations in generating conditions, the minimum fault current with minimum generating capacity may be less than the maximum load current with maximum generating capacity. However, the fault current magnitude is less than the feeder capacity, it is harmful because it results in voltage dip and negative and zero sequence currents in case of unsymmetrical faults. This makes it impossible to decide the relay settings, because if the relay is set considering the maximum load current, it will not operate for the fault current with minimum number of generators connected to the bus and if it is set to operate on minimum fault current, it will not allow the system to take its full load current with maximum generating capacity. This problem, however, can be overcome by monitoring the overcurrent relays by undervoltage relays. This

concept forms the basis of distance scheme of protection to be discussed in Chapter 8. One such scheme of protection is suggested in dc control circuit as shown in Fig. 7.12. The relay has two units in-built in one casing; overcurrent unit and an undervoltage unit. The relay will be required to be fed by the line CT and bus PT. The voltage-controlled overcurrent relay discussed in Section 2.9, Chapter 2, instead, can also be used.

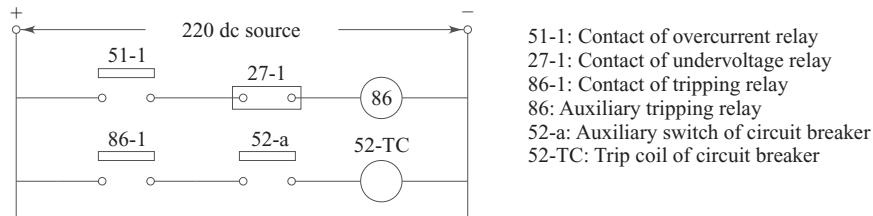


Fig. 7.12 Monitoring of the overcurrent relay by undervoltage relay

In Fig. 7.12, the relays are shown in a de-energised state and the circuit breaker in open condition. In case of no fault, the voltage is normal and hence undervoltage relay remains operated. Therefore, 27-1 will be in open condition rendering it impossible to energise the auxiliary tripping relay even if overcurrent relay operates. Thus, the overcurrent relay can be set for minimum fault current with minimum number of generators connected. The circuit breaker, in this case will not trip for the rated full-load current with maximum generating capacity. In case of fault, voltage drops and undervoltage relay drops off, 27-1 resumes to its normally closed condition and waits for the overcurrent relay to operate. Following the operation of overcurrent relay 51, 51-1 closes, tripping relay gets energised, 86-1 closes and circuit breaker trips as required.

7.3 RULES FOR SETTING THE IDMT RELAYS

7.3.1 Phase Relays

The phase relays are meant for sensing phase faults, i.e., L-L-L and L-L faults (triple line and double line faults).

Plug Settings Plug settings are to be decided considering three rules:

1. The relay shall reach at least up to the end of the next protected zone, e.g., in Fig. 7.9, the relay R_1 shall reach up to the substation C with minimum fault current (for phase relays, this is the phase-to-phase fault at minimum generation). This is required to ensure the back-up protection.
2. The plug-setting must not be less than the maximum normal load including permissible continuous overload unless monitored by undervoltage relay, otherwise the relay will not allow the normal load to be delivered.
3. In estimating the plug-setting, an allowance must be made for the fact that the relay pick-up varies from 1.05 to 1.3 times the plug-settings, as per standards. Let us consider Fig. 7.13 for explanation of this statement.

Let us assume that the rated full-load current of the radial feeder $abcd$ is 200 A. It is felt primarily that all the relays shall be set at a plug-setting equal to 200 A in CT primary terms or 1 A in secondary terms (100% of CT rating or relay rating, as the relay has to be rated for CT secondary rating). This setting, if decided, will interfere with the requirement of selectivity of the protective scheme. This is because a healthy section may unnecessarily trip in certain cases. One possible case is overloading of line-segment cd by 20%, which means

a current passage of 240 A. Now, as per standard, it is quite possible that R_3 picks up at 1.3 times its plug-setting and R_2 at 1.05 times its PS. The pick-up currents of R_2 and R_3 are thus, 210 A and 260 A, respectively. This calculation clearly shows that for the current passage of 240 A, R_2 will pick up and R_3 will not. Hence the line segment bc will be disconnected from the source after expiry of time delay of relay R_2 as per its characteristic, even though TMS of R_2 is higher than that of R_3 . This is exactly contrary to the requirement of a protective system. If the plug-setting of R_2 is so selected that its minimum possible pick-up current is more than or equal to the maximum probable pick-up current of relay R_3 , the problem discussed will be overcome. This, can be shown as follows:

$$\text{PS of } R_2 > (1.3/1.05) \times \text{PS of } R_3$$

For the illustrative Example of Fig. 7.13, plug-setting of $R_2 > 247.62$ A in CT primary terms, i.e., plug-setting of relay R_2 shall be more than or equal to 123.8% of CT rating or relay rating. As the IDMT relays are normally available with the plug settings in the range 50–200% of the relay rating in seven equal steps, i.e., 50–75–100–125–150–175–200 per cent of the relay rating, the plug-setting of the relay R_2 can be safely chosen as 125% of the relay rating (i.e., 1.25 A).

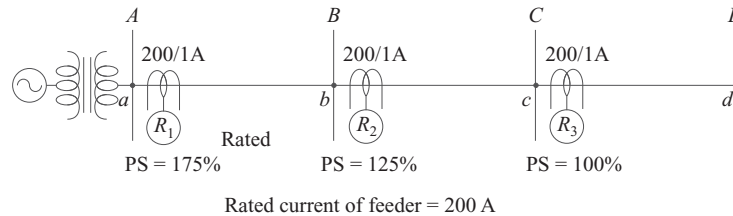


Fig. 7.13 Plug-settings of relays

The plug-setting of the relay R_3 , obviously is 100% of 1 A. The plug setting of the relay R_1 can be, similarly, calculated as follows:

$$\begin{aligned} \text{PS of } R_1 &> (1.3/1.05) \times \text{PS of } R_2 \\ &> 309.52 \text{ A in CT primary terms} \\ &> 154.76\% \text{ of the relay rating} \end{aligned}$$

i.e., plug-setting of R_1 is chosen to be equal to 175%.

It is very obvious that the higher of the two plug-settings offered by the considerations of rules 2 and 3 above shall be adhered to and this value must satisfy the rule 1. Generally, fault currents are large in magnitude and hence there is no difficulty in satisfying the first rule, when the plug-setting is decided by the other two rules. This means that the relay R_1 in Fig. 7.13, will often reach for the faults beyond the substation C when its plug-setting satisfies possible allowable overload and the tolerance in the pick-up value.

Time-setting The time-multiplier setting must be chosen to give the lowest possible time for the relays at the end of the radial feeder. Often, this TMS is decided based on the characteristic of a fuse or an MCCB protecting a distributor. In the preceding sections towards the source, the time multiplier should be chosen to give the desired selective interval from the down-stream relay at maximum fault conditions (for phase relays, this is a three-phase fault just beyond the next relay at maximum generation). In Fig. 7.9, the TMS of R_2 is based on the three-phase fault just after the relaying point of the relay R_3 . For calculating the fault current, one will require the details of impedances in ohms, per unit or per cent impedance of all power transformers, rotating machines and feeder circuits. It is generally sufficient to use machine transient reactance X'_d for such calculations.

The time multiplier setting should allow not only for the time of the breaker but also for the overshoot of the relay and allowable time-errors in the time of operation of successive relays. This statement is explained in Fig. 7.14. Referring to Fig. 7.9, I_f is the fault current for a three-phase fault immediately after the relaying point R_3 . This current value is shown in Fig. 7.14. The characteristic of the relay R_2 must be above that of the relay R_3 , obviously, because of the considerations of the requirement of selectivity. The two characteristics based on the standard time of operations are plotted in Fig. 7.14. Now as per standards, the tolerance allowed between the standard and actual times of operation of IDMT relays is $\pm 7\%$ at currents exceeding four times the plug-setting (this tolerance is $\pm 12\%$ at current values between 2 and 4 times the plug-setting). Considering this tolerance, it is quite probable that the relay R_3 may be slow by 7% and the relay R_2 may be fast by 7%. ab and ef in Fig. 7.14 account for these time-errors. Accordingly, the relay R_3 may operate after the expiry of time given by the ordinate ob instead of oa and the relay R_2 might operate at the end of the time delay oe instead of of , at the fault current I_f . Referring to Fig. 7.9, operation of R_3 does not mean a clearance of fault. The relay R_3 gives signal to the breaker and the breaker starts tripping, its contacts separate, an arc is drawn between the contacts and the arc finally gets quenched. This breaker operation takes a finite time, of the order of 1 cycle to 5 cycles, depending on the type and design of the breaker. The ordinate bc in Fig. 7.14 corresponds to this breaker time. Once the breaker trips, the fault is said to be cleared. But during this time, the disc of the relay R_2 would be rotating at quite a high speed in case of induction-disc type IDMT relay or the static circuitry of R_2 will be counting time in case of a static relay. At the instant of clearance of fault, the disc of the relay R_2 keeps on rotating for a small time due to its moment of inertia. This time is termed as the time of overshoot. If during this time of over-travel, the fixed and moving contacts of the relay R_2 bridge, it will also operate unnecessarily disconnecting line section between substations B and C . The ordinate de represents the time of over-travel of the relay R_2 . As already discussed, points c and d must not coincide, otherwise it will result in unwanted isolation of line section between substations B and C in Fig. 7.9. This means that some time margin cd is to be kept for the factor of safety. Thus, the TMS of the relay R_2 is to be so selected that there remains a total discriminating time margin given by ordinate af at the current I_f . It is a common practice to use a fixed selective interval of 0.25 second (considering 2 cycle breakers) between the successive relays.

Setting of High-Set Instantaneous Unit The high-set instantaneous unit shall be set at the current equivalent to the fault current magnitude for a 3-phase fault at 80% of the line section to be protected.

This assumes overreaching of the instantaneous overcurrent relay by 20%. If data about the relay is available, the relay setting can be done using the following formula.

$$\text{Setting of high-set instantaneous unit} = \frac{100 B}{100 - A}$$

where A = % overreach of the instantaneous overcurrent relay

and B = three-phase symmetrical fault current at the end of a feeder section (in CT secondary A)

If, for example,

$A = 10\%$ and $B = 16 \text{ A}$

$$\text{Setting} = \frac{100 \times 16}{100 - 10} = \frac{1600}{90} = 17.77 \text{ A or } 18 \text{ A can be selected}$$

7.3.2 Ground Relays

The ground relay is meant for sensing ground or earth-faults, i.e., L-g faults. The ground relays may also operate for double line to ground faults, i.e., L-L-g faults.

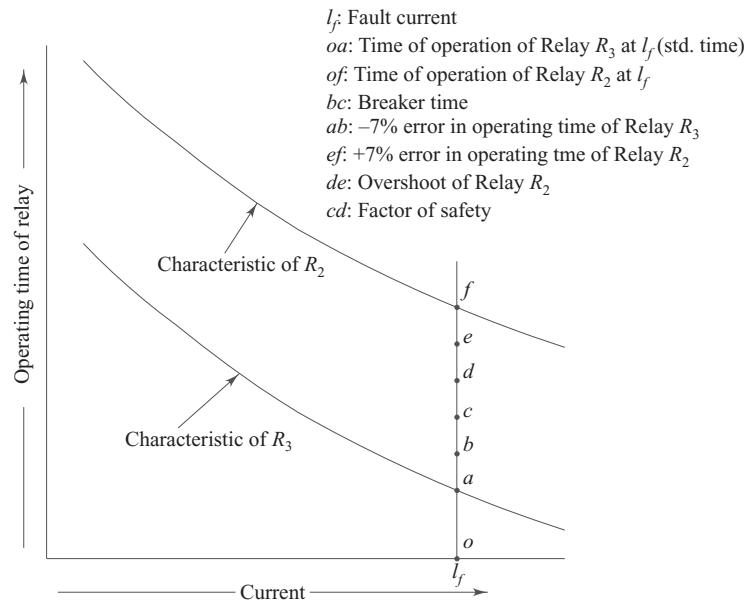


Fig. 7.14 Discriminative time

Plug-Settings Plug-setting of the ground relays is decided based on the following factors:

1. The relay shall reach at least up to the end of the next protected zone, e.g., in Fig. 7.9, the ground relay R_1 shall reach up to the substation C for line to ground fault on the bus-bar of the substation C . While calculating the fault current for this case, it should be noted that the zero sequence current is not reflected in the primary of a delta-star transformer if L-g fault occurs on the star side as it circulates in phase windings connected in delta. Also, earth-fault currents may be very small in magnitude as the current is limited by,
 - (i) zero sequence impedance of the system, which is much larger than the positive or negative sequence impedances,
 - (ii) fault-path resistance which is much larger than that in case of phase faults because arc resistance of flashover path, tower footing resistance and ground resistance are involved in the fault path of a ground fault, and
 - (iii) deliberate impedance connected in the neutral of the system.
2. As only the residual current is passing through the earth-fault relay [refer Fig. 7.15(a)] and because this residual current (three times the zero sequence current) is zero under normal conditions of operation and in case of phase faults (L-L or L-L-L faults), the plug-setting of the earth-fault relay can be made very sensitive (i.e., 10 to 40% of CT secondary rating). If the earth-fault relay is connected in the residual circuit of the three line CTs [Fig. 7.15(a)], the plug-setting of the relay cannot be made extremely sensitive (of the order of 1 to 4% of CT secondary rating). This is because the relay could mal-operate in case of heavy three-phase fault. In such a case, the fault currents in R, and B phases are very high and three line CTs may not faithfully transform the currents to secondary because of probable non-identical saturation characteristics, leading to residual current flow through the ground fault relay. This magnitude of current needs to be considered while deciding the sensitivity (plug-setting) of the relay as the ground fault relay must not operate in case of phase faults because this goes

against relay criteria discussed in Chapter 1. If the ground relay is connected across the secondary of CT, the primary of which is connected to the neutral circuit of the star-connected transformer secondary or generator [Fig. 7.16(a)], the relay can be made sensitive. Also, if such a ground relay is connected across the secondary of a core balance CT, to be discussed later in this chapter [Fig. 7.16(b)], once again the plug setting of the relay can be made extremely sensitive.

Monitoring the ground relay by an undervoltage relay is generally not required. The reason for such a practice is that the zero sequence impedance of the system is very large and it is terminated at the nearest grounded transformer. The residual current, hence, varies mainly with distance to the fault and is less affected by generating conditions.

3. In estimating the plug-setting, an allowance must be made for tolerance in pick-up values as is required to be carried out for phase relays. Once again this is required only if no delta-star transformer is involved in the power circuit between the two relaying points under consideration.
4. While deciding the plug setting for an overcurrent relay, we have not considered the excitation current of a CT. If we neglect the excitation current, there is hardly any error as the excitation current is very small. This can be better appreciated by the following example.

If a relay is connected across the secondary of a CT with a ratio of 500/1 A and if the PS is 100%,
Plug setting = 100% of 1 A = 1 A

If the excitation current is 0.05 A, the relay would pick-up when the CT secondary current exceeds 1.05 A. This means that pick-up occurs when the primary current exceeds 525 A or 105% of 500 A. If excitation current is yet less, the error in pick-up would reduce to even 3% or less which is negligible.

This is not true with ground relays. Referring to Fig. 7.15(a), we assume a CT ratio of 500/1 and an excitation current of 0.05 A for each CT. If the plug setting of relay 64 (ground relay) is 10% of 1 A (setting

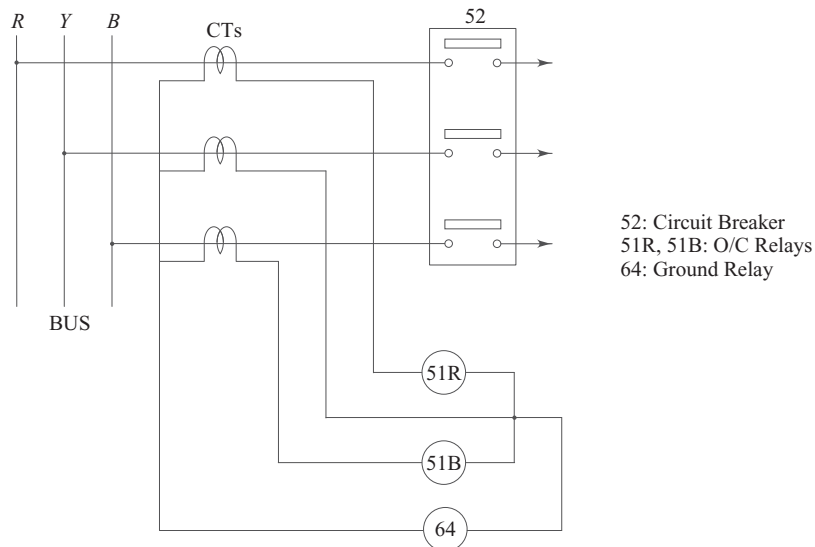


Fig. 7.15(a) Two overcurrent and one earth-fault scheme of protection

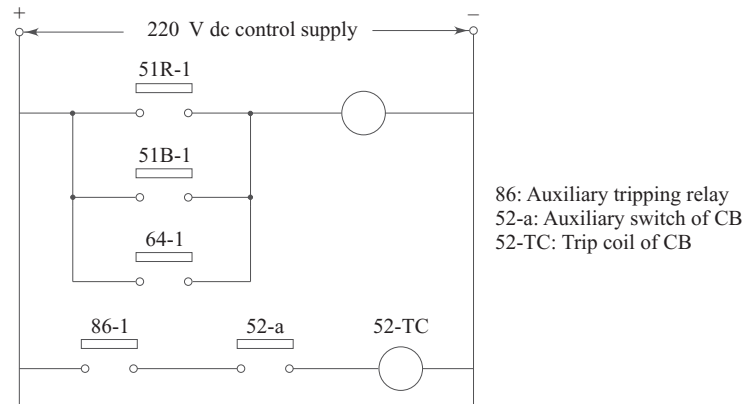


Fig. 7.15(b) DC control circuit of Fig. 7.15(a)

range is 10–40% of 1 A in seven equal steps), the PS will not be 10% of 500 A. There will be a large error due to the excitation current. In other words, sensitivity of a relay will not be 10% in primary terms. This can be appreciated by the following calculation.

PS of a relay = 10% of 1 A = 0.1 A

To inject this current in the relay, current required in CT secondary = $0.1 + 3(0.05) = 0.25$ A

This is because an excitation current of each CT is 0.05 A. So three CTs will consume 0.15 A. Thus, primary equivalent of 0.25 A will be 125 A (CT ratio = 500/1 A). This means that the sensitivity of a relay in primary terms is 25% when the PS is 10%. If the relay is set at 20%, this would mean 175 A in primary terms or 35%. Table 7.1 shows plug setting v/s sensitivity in primary terms.

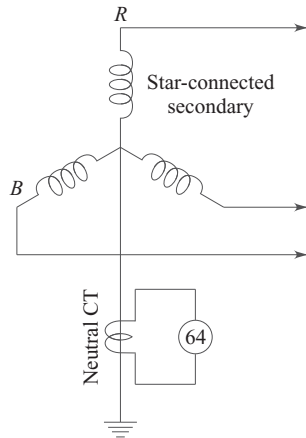
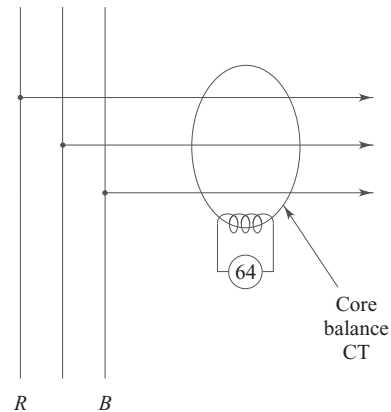
Table 7.1

PS of ground relay of A	Sensitivity in primary terms of 500 A CT ratio 500 1A
5	20
10	25
20	35
40	55
80	95

This proves that it is not worthwhile to select a very high sensitivity (very low PS) unless otherwise required. If the ground relay is connected as shown in Fig. 7.16(a) or 7.16(b), the error in sensitivity of the relay will reduce as there is only one CT. The multiplying factor will be 1 instead of 3.

Time-setting Time-setting is decided in a similar manner as carried out for phase relays, the only difference being the fact that the fault current to be considered is phase to ground fault.

If a delta-star transformer is involved in the power circuit between the relaying points of two successive ground relays, the relay on the primary side of transformer need not be coordinated with that on the star side for earth-fault on the secondary side of the transformer. The relay on the primary side can be set independently. This relay can be made to operate faster than that on secondary of power transformer and can be set to operate even instantaneously if so required.


Fig. 7.16(a) Earth-fault relay connected across neutral CT

Fig. 7.16(b) CBCT connection of an earth-fault relay

While deciding the TMS of ground relays, excitation current of the CTs cannot be neglected as it is not that negligibly small as compared to fault current reproduced in the secondary of a CT. Let us continue the same example which we have considered in Rule 4 of PS of ground relays. We have already seen that if the PS of the relay is 10%, the relay picks up when the primary current (CT ratio = 500/1 A) exceeds 125 A. Now multiples of 125 A are not equal to plug-setting multipliers of the relay; e.g., if the fault current is 250 A, this does not mean PSM equal to 2.

$$I_f = 250 \text{ A}$$

Secondary equivalent of this current, $i_f = 0.5 \text{ A}$

Current through the ground relay (when the relay is connected in residual circuit of three line CTs),

$$\begin{aligned} &= 0.5 - 3(0.05) \\ &= 0.5 - 0.15 = 0.35 \text{ A} \end{aligned}$$

$$\text{PSM of the ground relay} = (0.35/0.1) = 3.5$$

Thus, excitation current of the CT plays a vital role.

7.4 TWO OVERCURRENT AND ONE EARTH FAULT SCHEME FOR PROTECTION OF A FEEDER

In the single-line diagrams of a radial feeder already discussed, it was stated that the relays shown represent a group of relays; e.g., in Fig. 7.9, the relay R_1 means a group of relays. A detailed power circuit or an ac circuit, as it is called, is shown in Fig. 7.15(a). The dc control circuit showing how the breaker can be tripped on fault is shown in Fig. 7.15(b).

As the phase relays (51R and 51B) have to take the CT secondary equivalent of the normal load current of the feeder continuously, the setting range of these relays is 50–200% of the CT secondary current rating. The ground relay 64, does not carry any current in the normal operation and hence its setting range is low (5–20%, 10–40% or 20–80% of CT secondary rating).

In case of phase faults (R- -B, R- , -B or B-R) on the feeder (or transmission line), at least one overcurrent element of the two (51R and 51B) will sense the fault current and will operate as per its characteristic. On

operation of either or both of the two, contact 51R-1 and/or 51B-1 closes energising auxiliary tripping relay 86. The contact 86-1 of this relay will complete the trip circuit and the breaker will trip accordingly. In case of earth-faults (R-g, -g or B-g), the residual current will pass through the earth-fault relay 64 which will operate to trip the circuit breaker. In case of double line to ground faults (R- -g, -B-g or B-R-g), both phase relays and a ground relay will sense the fault, and the tripping of the circuit breaker is initiated by the relay which operates the first. The time of operation of these relays is dependent on the magnitude of fault currents in the lines as well as in the residual path (ground path), the plug setting and time setting of the relays.

The ground relay can be made more sensitive if it is connected in either of the fashion shown by Fig. 7.16(a) and (b) as previously discussed. Figure 7.16(b) shows a core balance CT (CBCT), the core of which encircles all the three phases and the ground relay is connected across the secondary winding of the same. A CBCT can be used for medium voltage networks, e.g., 6.6 kV or 11 kV. For voltages higher than 11 kV (i.e., 66 kV and higher), the leakage flux will not allow construction of CBCT and application of the same.

7.5 THREE OVERCURRENT AND ONE EARTH-FAULT SCHEME OF PROTECTION OF A TRANSFORMER FEEDER

If the relays are protecting a transformer feeder, two overcurrent and one earth-fault scheme of protection will not give adequate protection. Such a case occurs when there is a power transformer between two successive relaying points in the power system. The problem of inadequacy of protection is explained in the following paragraphs.

For a -B fault in Fig. 7.17, the directions and magnitudes of fault currents are as shown. If the -B fault occurs on the secondary side of a transformer having a vector group D -1, the magnitudes of the current will be I_y , $2 I_y$ and I_y in the R, and B lines of primary side respectively.

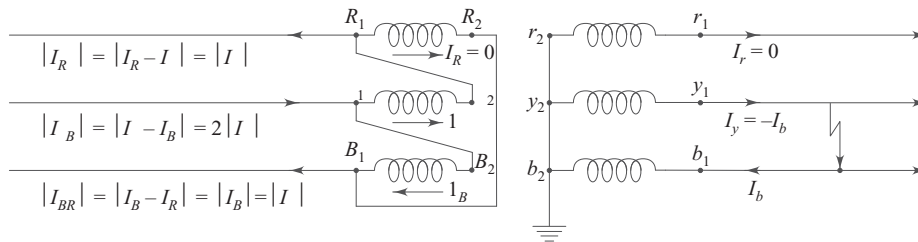


Fig. 7.17 Y-B fault on a transformer feeder

The magnitude of the fault current, thus, is maximum in phase in which there is no overcurrent relay element for the two overcurrent and one earth-fault scheme of protection. The tripping of a circuit breaker, hence, will be delayed because of low current I_y . Thus, two overcurrent and one earth fault scheme of protection renders inadequate protection. Therefore, the element in the phase cannot be saved and one has to connect an overcurrent relay element in the secondary of CT connected in the phase also. This gives three overcurrent and one earth-fault scheme of protection of transformer feeder.

7.6 COMMON PROBLEMS WITH OVERCURRENT RELAYS

Some of the problems met with different types of overcurrent relays have already been discussed in the preceding sections. These are summarised as follows:

1. The instantaneous overcurrent relays and normal inverse-time overcurrent relays are much affected by the ratio of source to fault impedance (Z_s/Z_f).
2. Instantaneous overcurrent relays suffer from the problem of transient overreach.
3. Definite-time overcurrent relays clear the faults near the source after a long time delay if a multi-section long radial feeder is to be protected.
4. The IDMT relays commonly used are affected by variation in generating capacity. In the limiting case, the setting of such relays would be impossible unless they are monitored by undervoltage relays.
5. The overshoot of IDMT overcurrent relays increases the discriminating time margin between the times of operation of successive relays used in a radial feeder. This overshoot is very small in static relays with respect to the electromagnetic ones.

Other problems not addressed so far are discussed as follows.

1. Drop-off to Pick-up Ratio or Resetting Ratio In case of attracted armature-type instantaneous overcurrent relays used for feeder protection, the relay trips a circuit breaker which reduces the current to zero, and hence the reset value is of no consequence. However, if a low-reset relay is used in conjunction with other relays, in such a way that a breaker is not always tripped when the low-reset relay operates, the application should be carefully examined. When the reset value is a low percentage of the pick-up value, there is the possibility that an abnormal condition might cause the relay to pick-up, but a return to normal condition might not return the relay to its normal status, and an undesired operation might result.

2. Resetting Time The time elapsed between the instant of interruption of fault current through relay coil after the relay has operated and the instant the relay establishes the normal condition, in which it was before fault occurrence, is known as the resetting time of the relay.

When fast automatic reclosing of a circuit breaker is involved, the reset time of a relay may be a critical characteristic in obtaining selectivity. If all the relays involved in the power circuit do not have time to reset completely after a circuit breaker has been tripped and before the breaker recloses, and if the short circuit fault that caused tripping still persists when the breaker closes, certain relays may operate too quickly and trip unnecessarily.

The resetting time is smaller in static and numerical relays than the same in case of electromagnetic ones, particularly in case of IDMT relays.

Example 7.1 A single-line diagram of a simple radial feeder is given in Fig. 7.18. Using standard IDMT characteristic (Fig. 2.5), calculate the relay settings of all the phase relays. Assume suitable discrimination time. Relevant data is as follows:

Rated current of the relay = 1 A

Setting range of plug-setting = 50–200% of 1 A in 7 equal steps

Setting of relay R_3 : PS = 75%, TMS = 0.1

Solution Plug-settings PS of the relay $R_2 > (1.3/1.05) \times$ PS of the relay R_3
 $> (1.3/1.05) \times 450$ (in primary terms)
 > 557.14 A (in primary terms)
 $> 92.85\%$ of CT rating

The PS of R_2 is selected as 100% of 1 A as an immediate higher step to 92.85% available is 100%.

Similarly, the PS of R_1 is selected as 75% of 1 A.

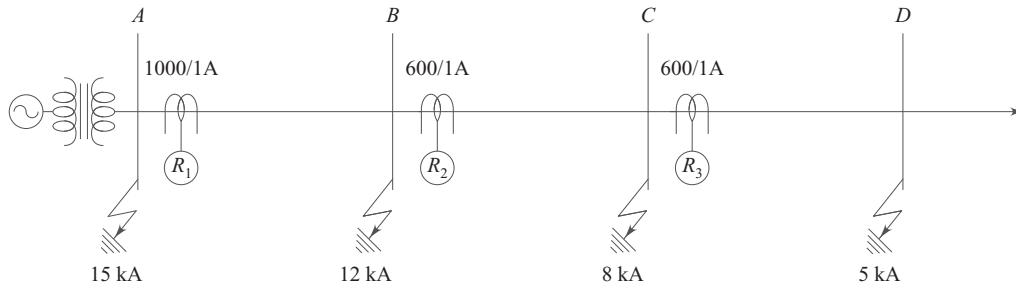


Fig. 7.18 Radial feeder for Example 7.1

Time Settings The relay R_2 is to be graded with the relay R_3 . For this purpose, the fault will have to be considered at the busbar C. This is because the fault current magnitude for a fault after the relaying point R_3 is less than that for a fault at the busbar C by only an insignificant amount (e.g., 0.1% or less).

With a fault current 8 kA (at the busbar C),

$$\text{PSM of } R_3 = \frac{8000}{450} = 17.77$$

The time of operation of the relay can be found out from Fig. 2.5 or more conveniently using the formula (a mathematical approximation) as follows:

$$\begin{aligned} \text{Time of operation of relay } R_3 &= \frac{3}{\log \text{PSM}} \times \text{TMS} \\ &= \frac{3}{\log 17.77} \times 0.1 = 0.24 \text{ s} \end{aligned}$$

The required time of operation of relay R_2 will be 0.49 second considering the time margin of 0.25 second.

PSM of R_2 for the fault current of 8000 A = 13.33

$$\begin{aligned} \text{Time of operation of the relay } R_2 &= \frac{3}{\log \text{PSM}} \times \text{TMS} \\ 0.49 &= \frac{3}{\log 13.33} \times \text{TMS of the relay } R_2 \end{aligned}$$

\therefore TMS of the relay $R_2 = 0.1837$

Therefore, the TMS of R_2 is selected as 0.2 which is an immediate higher figure to 0.1837 in a multiple of 0.05.

For deciding TMS of R_1 , the fault will have to be considered at the bus B.

TMS of R_1 accordingly, can be selected as 0.3.

The results are tabulated as follows:

Table 7.2

RelaySetting	Relays		
	R_3	R_2	R_1
PS (% of 1A)	75	100	75
TMS	0.1	0.2	0.3

Example 7.2 Figure 7.19 shows a single-line diagram of a portion of typical power station. Find out the relay settings of phase relays used therein. Relays used are standard IDMT relays with normal inverse characteristic and a plug-setting range 50–200% of CT secondary rating. The time-multiplier setting of the relay R_4 is given as 0.2. The fault level of a 6.6 kV bus and 415 V bus are 45 kA and 42 kA respectively.

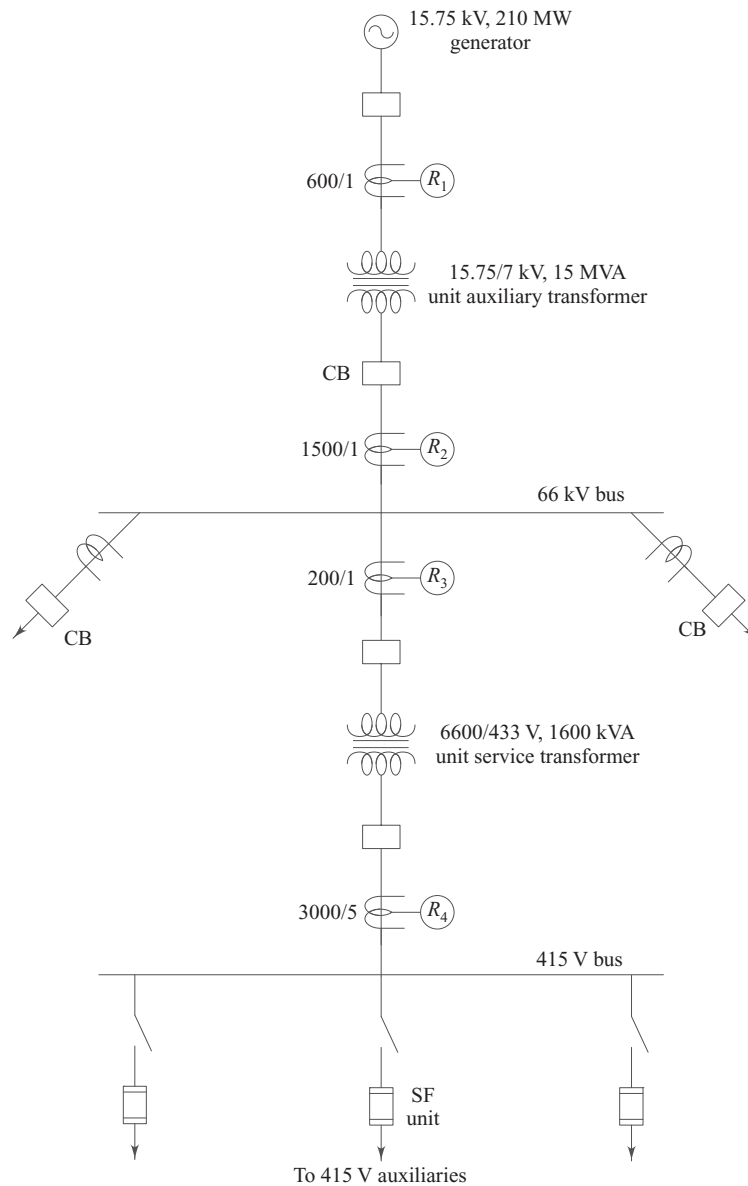


Fig. 7.19 Example 7.2

Solution Plug setting Plug setting of the relay R_4 has to be decided on the basis of the rated secondary current of a unit service transformer (UST). The rated secondary current of UST,

$$\begin{aligned} &= \frac{1600 \times 10^3}{\sqrt{3} \times 433} \\ &= 2133.39 \text{ A} = 71.11\% \text{ of } 3000 \text{ A} \end{aligned}$$

Therefore, PS of the relay R_4 is selected as 75% of the CT rating. A transformation of this current is required to be carried out while finding out the PS of R_3 .

$$\begin{aligned} \text{PS of the relay } R_3 &> \frac{1.3}{1.05} \times \frac{433}{6600} \times 0.75 \times 3000 \\ &> 182.759 \text{ A} > 91.38\% \text{ of } 200 \text{ A} \end{aligned}$$

i.e., PS of R_3 is selected as 100% of the CT rating.

PS of R_2 can be decided with respect to the rated secondary current of the unit auxiliary transformer. Rated secondary current of UAT,

$$\begin{aligned} &= \frac{(15 \times 10^6)}{(\sqrt{3} \times 7 \times 10^3)} \\ &= 1237 \text{ A} = 82.47\% \text{ of } 1500 \text{ A} \end{aligned}$$

Hence, PS of R_2 is selected as 100% of the CT rating

$$\begin{aligned} \text{Finally, PS of the relay } R_1 &> \frac{1.3}{1.05} \times \frac{7}{15.75} \times 1500 \\ &> 825.39 \text{ A} > 137.56\% \text{ of } 600 \text{ A} \end{aligned}$$

Therefore, PS of R_1 can be selected as 150% of its CT rating.

Time Settings The time of operation of relays is tabulated in Table 7.3. One has to understand that time of operation of relays can be calculated by the formula (time of operation = $\frac{3}{\log \text{PSM}} \times \text{TMS}$) only if the PSM is less than or equal to 20.

Beyond a PSM equal to 20, the time of operation of an IDMT relay is constant and is equal to $\frac{3}{\log 20} \times \text{TMS}$

Table 7.3

Relay	Plug setting in CT primary terms A	Fault current kA	PSM	Time of operation at TMS 1.0 seconds	TMS	Time of operation at TMS set seconds
R_1	900	45	22.22	2.3	0.6	1.38
R_2	1500	45	30.00	2.3	0.45	1.035
R_3	200	45	225.0	2.3	0.3	0.69
		42	13.77	2.63	0.3	0.789
R_4	2250	42	18.66	2.36	0.2	0.4721

Example 7.3 Figure 7.20 shows a single-line diagram of a portion of a power system. Bracketed figures give the fault levels on the concerned bus. Relays used are standard IDMT overcurrent relays giving normal inverse characteristic (Fig. 2.5) and they are rated for 1 A with a setting range of 50–200% of 1 A in 7 equal steps. The plug setting and TMS of the relay R_4 are 100% of 1 A and 0.1 respectively. Assuming suitable discrimination time, determine the settings of relays R_1 , R_2 and R_3 .

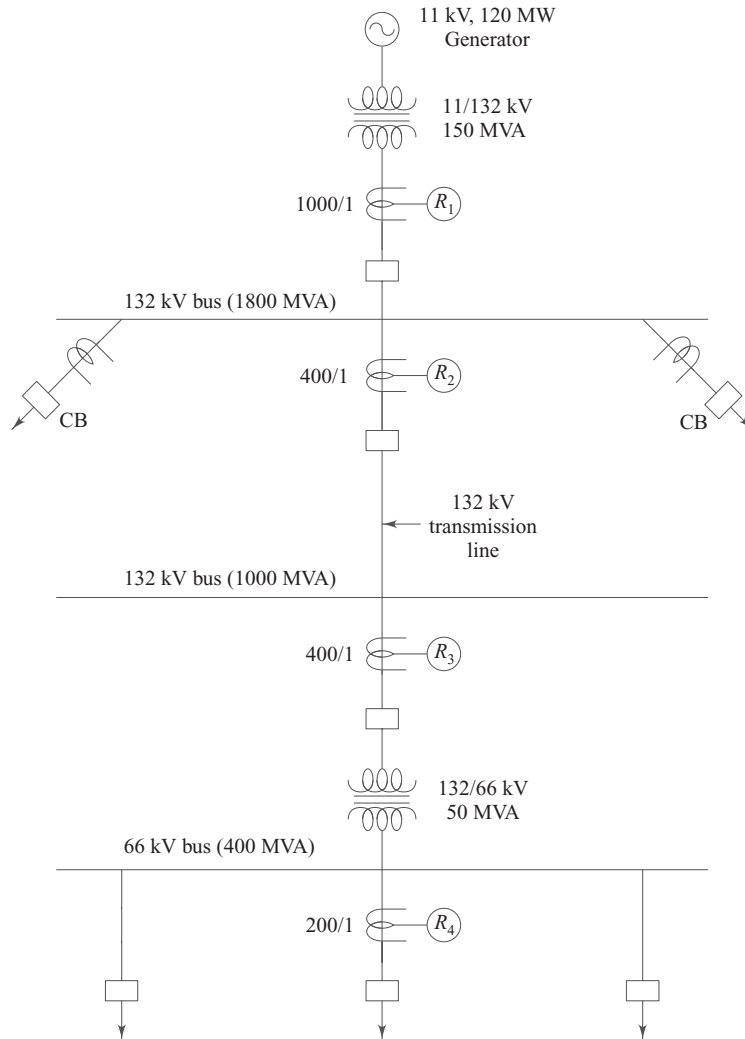


Fig. 7.20 Example 7.3

Solution

$$\begin{aligned}
 \text{PS of the relay } R_3 &> \frac{1.3}{1.05} \times \text{PS of the relay } R_4 \times \frac{66}{132} \\
 &> \frac{1.3}{1.05} \times 200 \times \frac{66}{132} \\
 &> 123.8 \text{ A in CT primary terms}
 \end{aligned}$$

This calculation provides the basis for deciding the plug setting of the relay R_3 from the considerations of tolerance of pick-up variations from 105 to 130% of the plug setting.

But the rated primary current of the 50 MVA transformer is 218.69 A and hence the plug setting of R_3 must be selected as 75% of 1 A.

$$\begin{aligned}
 \text{PS of } R_2 &> (1.3/1.05) \times \text{PS of } R_3 \\
 &> (1.3/1.05) \times 300 \\
 &> 371.42 \text{ A} > 92.85\% \text{ of CT rating}
 \end{aligned}$$

Therefore, PS of R_2 is selected as 100%. The PS of R_1 will depend upon the rated current of the 150 MVA transformer. This will, hence, be 75% of 1 A.

Time settings For grading relay R_3 with R_4 , fault level to be considered is 400 MVA.

I_f with respect to 400 MVA = 3499 A

PSM of relay $R_4 = 3499/200 = 17.5$

Hence time of operation of the relay R_4

$$= \frac{3}{\log 17.5} \times 0.1 = 0.2413 \text{ s}$$

Required time of operation of $R_3 = 0.2413 + 0.25 = 0.4913$...(considering discrimination time of 0.25 sec)

$$\text{PSM of } R_3 = \frac{3499}{300} \times \frac{66}{132} = 5.83$$

Hence, time of operation of the relay R_3

$$0.4913 = \frac{3}{\log 5.83} \times \text{TMS of } R_3$$

\therefore TMS of $R_3 = 0.1254$

TMS selected is 0.15.

Similarly, the relay R_2 is to be graded with the relay R_3 and R_1 is to be coordinated with R_2 . The respective fault levels to be considered are 1000 MVA and 1800 MVA. The final relay settings accordingly are tabulated as given as follows

Table 7.4

Relays	Settings	
	PS of 1 A	TMS
R_1	75%	0.3
R_2	100%	0.25
R_3	75%	0.15
R_4	100%	0.10

Example 7.4 A single-line diagram of a simple radial network is shown in Fig. 7.18. Calculate the relay settings of ground relays R_1 and R_2 , given the PS and TMS of the ground relay R_3 as 10% of 1 A and 0.1, respectively. The relays are normal inverse IDMT relays with a setting range of 10–40% of 1 A in seven equal steps. The fault currents for L-g faults at different buses are given as follows:

Table 7.5

BUS	Fault currents for L g fault in kA
A	5.0
B	3.0
C	1.5
D	1.0

Assume that excitation current of each CT is 0.03 A.

Solution Plug Settings

PS of the relay $R_3 = 10\%$ of 1 A = 0.1 A

For injecting this current through the relay, the CT secondary current will be = $0.1 + 3(0.03) = 0.19$ A

The primary equivalent of 0.19 A will be 114 A.

Therefore,

$$\begin{aligned} \text{PS of the relay } R_2 &> (1.3/1.05) \times \text{PS of the relay } R_3 \\ &> \frac{1.3}{1.05} \times 114 > 141.14 \text{ A (primary)} \\ &> 0.2352 \text{ A (secondary, as CT ratio = 600/1 A)} \end{aligned}$$

For deciding PS, the current through the ground relay R_2 has to be more than $(0.2352 - 0.09)$ A, i.e., 0.1452 A or 14.52% of 1 A.

\therefore PS of $R_2 = 15\%$ of 1 A

Similarly, PS of $R_1 = 10\%$ of 1 A

Time Settings For grading ground relay R_2 with the relay R_3 , fault current to be considered is 1.5 kA or 1500 A.

Secondary equivalent of 1500 A will be (CT ratio = 600/1 A) 2.5 A.

\therefore current through the relay $R_3 = 2.5 - 0.09 = 2.41$ A

$$\text{PSM of the relay } R_3 = \frac{2.41}{0.1} = 24.1$$

Time of operation of the relay $R_3 = 0.23$ s

\therefore required time of operation of the relay $R_2 = 0.48$ s

Current through the ground relay R_2 will also be 2.41 A as CT ratio is the same.

$$\text{PSM of } R_2 = \frac{2.41}{0.15} = 16.06$$

$$\therefore 0.48 = \frac{3}{\log 16.06} \times \text{TMS of the relay } R_2$$

TMS of the relay $R_2 = 0.1929$, i.e., 0.2 is selected

On similar grounds,

TMS of the ground relay $R_1 = 0.35$.

The fault current considered for this calculation is 3 kA.

The final settings are tabulated as follows:

Table 7.6

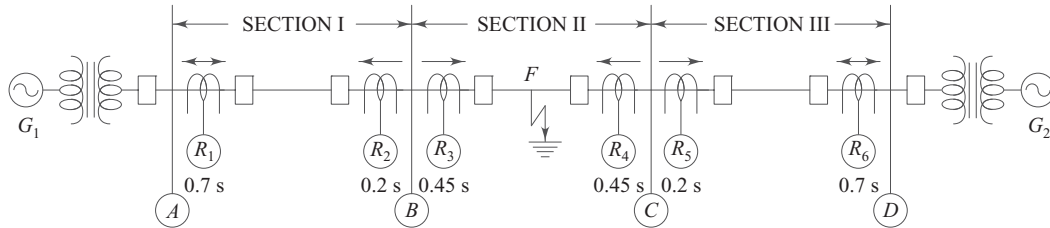
Relays	Settings	
	PS of 1 A	TMS
R_1	10%	0.35
R_2	15%	0.2
R_3	10%	0.1

7.7 DIRECTIONAL PROTECTION

The discussion, so far, has been related to obtaining discriminative operation of relays associated with a simple radial feeder fed from only one end. Such a system, however, fails in maintaining uninterrupted supply

to all load points, as the tripping of a circuit breaker near the source disconnects all the subsequent substations and the loads fed by them. Reference to Fig. 7.9, thus, shows that tripping of breaker at the substation A will result in power interruption for substations B, C and D and the loads fed by them.

The uninterrupted supply at all load points can be guaranteed if the radial feeder is fed from both ends as shown in Fig. 7.21. For a fault at the point F as shown in Fig. 7.21, the section II of the line can be isolated by operation of relays R_3 , R_4 and associated switchgear. The buses A, B, C and D are still kept live and thus continuity of supply to other load points is maintained.



Values below the relays indicate the time of operation of relays for time-discriminative operation

Fig. 7.21 Radial feeder fed from both ends

The setting of the relays for the scheme as shown can be carried out on the time-discrimination principle applied to radial feeders. For this, let us simplify the given network into two radial feeder networks with generation at one end (Fig. 7.22 a and b). Relays R_1 , R_3 and R_5 are along with generator G_1 ; and R_6 , R_4 , R_2 are with G_2 . Allowing for discrimination, the settings are as shown in the figures. Now for a fault at F in Fig. 7.21, relays R_2 and R_5 will operate to isolate section II but buses B and C will also lose supply which goes against the principle of selectivity of protection. The remedy of this situation is the incorporation of directional feature. The fault currents ABF and DCF flow towards the bus for relays R_2 and R_5 and away from the bus

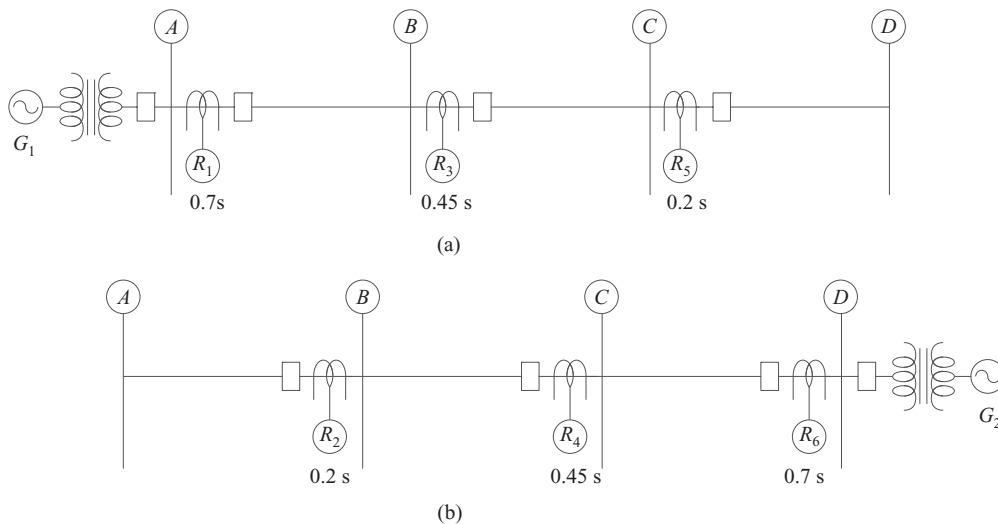


Fig. 7.22 Figure 7.21 split-up into two radial networks

for relays R_3 and R_4 . All these relays are provided with a directional feature whereby they operate only for the direction for which they are meant to operate. The direction of operation is as shown in Fig. 7.21 by an arrowhead. Thus, for a fault at F the operation of relays R_2 and R_5 is restrained because the direction of the fault current is inoperative for both of them while relays R_3 and R_4 will operate after 0.45 second isolating the fault. The relays nearest to the generators R_1 and R_6 in this case, are generally kept non-directional, as shown by double-headed arrows.

Other networks where the directional feature of protection is applied are (a) parallel feeders (Fig. 7.23), and (b) ring main feeders (Fig. 7.24). Referring to Fig. 7.23, only the line CD should trip in case of a fault at the point F as shown and not the line AB . After interruption of the fault, by tripping the line CD due to the operation of R_2 and R_4 , the full load power has to be transferred along the line AB for a short time during which suitable load-shedding measures are taken by the power engineers. However, if the directional feature is not added to the relay R_3 , the relays R_3 , R_4 and R_1 will trip. Operation of the relay R_1 can be delayed but the relay R_3 cannot be delayed with respect to R_4 because in case of a fault in the feeder AB the requirement demands the delayed operation of R_4 with respect to R_3 . Therefore, for satisfying the principle of discrimination for selective operation, relays R_3 and R_4 should be given directional feature as shown by arrowheads in Fig. 7.23. The relays R_1 and R_2 are non-directional overcurrent relays. Relay R_1 is to be graded with the relay R_4 such that the former acts as a backup relay to the latter if the latter fails to clear the faults as at F . Similarly, R_2 is to be coordinated with R_3 .

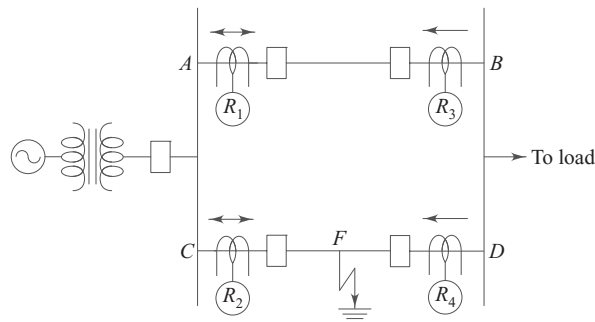


Fig. 7.23 Protection of parallel feeders

Similarly, for a ring main feeder system, a directional feature is provided for the relays as shown in Fig. 7.24. The ring main feeder is actually a special version of a feeder fed from both ends.

It would be interesting to note the requirement of directional feature to be satisfied by the relays for the network as shown in Fig. 7.25. The figure gives an indication that directional control is applied only to those relays where the fault current can flow in both the directions (away and towards the bus). It can be easily seen that fault current will be unidirectional for relays R_1 , R_3 , R_5 and R_7 . The directional control for network as shown in Fig. 7.26 is as shown by arrowheads. In all these networks (Fig. 7.21 to Fig. 7.26), the relays used are directional and non-directional IDMT overcurrent relays.

7.8 DIRECTIONAL RELAY

The directional feature can be achieved by comparing the direction of current flow in the line with reference to the bus voltage. In other words, the directional relay measures the phase angle between voltage and current vectors. This is why the directional relay is a two-quantity relay and a phase comparator relay, i.e., voltage and current both are fed to this relay. Voltage juice of a bus PT and current juice from a line CT are fed to the relay. As such, the protection requirement calls for an AND logic of the fault current and a true direction for

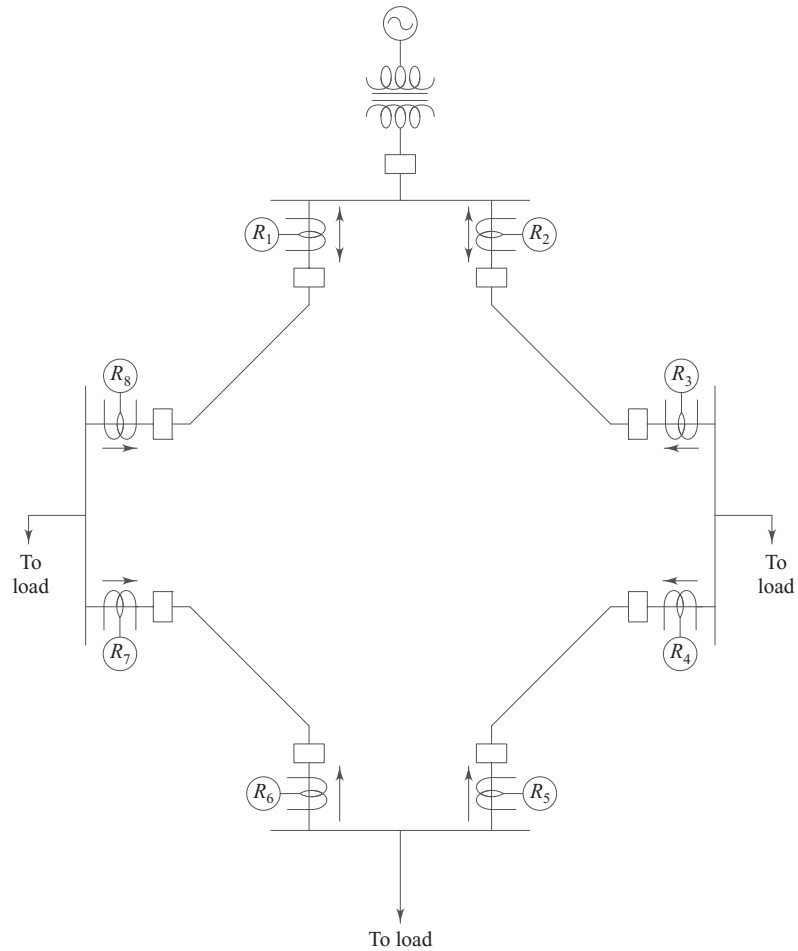


Fig. 7.24 Protection of a ring network

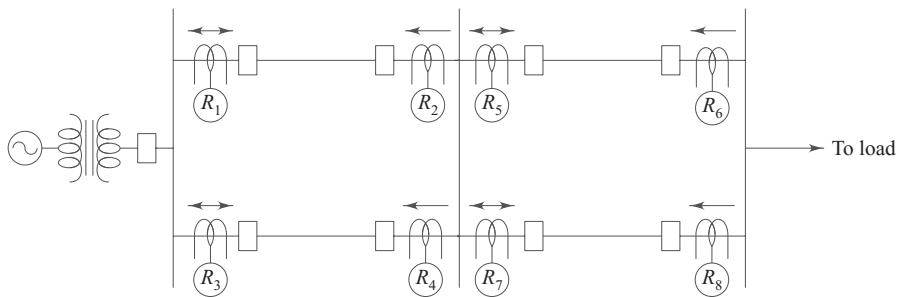


Fig. 7.25 Directional protection for interconnecting tie-lines

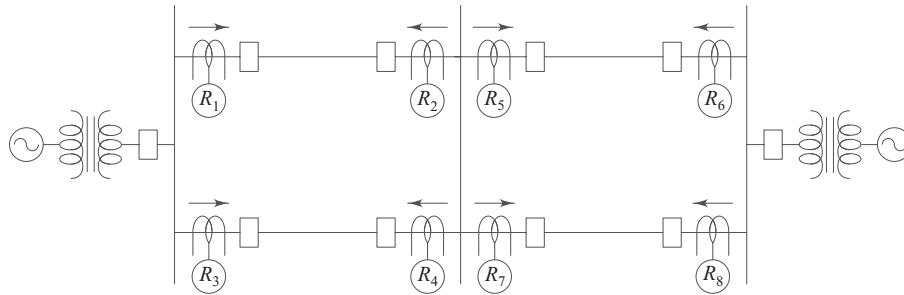


Fig. 7.26 Directional control for relays R_2 , R_4 , R_6 and R_8

the operation. A directional IDMT overcurrent relay is used in directional protection (refer Chapters 2 and 3 for constructional features). Thus, the directional overcurrent relay operates only when the current flowing through the relay is more than its plug setting and also the current flows through the relay in its correct (operative) direction.

7.9 MAXIMUM TORQUE ANGLE

The requirement demands a maximum torque of the directional relay when a fault occurs in the line. The torque is proportional to (refer Chapter 2) $VI \cos(\phi - \theta)$. For maximum torque, $\phi = \theta$. As the power factor angle in operation is normally 70° to 90° , depending on the fault location, the maximum torque angle should also be of the same order to achieve maximum torque. The maximum torque angle of the relay can be set to 30° , 60° or 90° by suitable connections of CTs and PTs in the relaying circuit. As the 90° connection is widely used, it has been discussed here.

Table 7.7 Quantities to be fed to phase relays

Relay	Current	Voltage
R phase relay	I_R	V_B
phase relay	I	V_{BR}
B phase relay	I_B	V_R

The 90° connection is illustrated in Fig. 7.27. The difficulty associated of a reduced torque for certain cases of faults in case of 30° and 60° is eliminated in this connection. In case of an R- fault, the voltage across the R element is V_B and across , is V_{BR} . Thus, appreciable torque is produced in both elements, R and as required. This is because of the fact that the fault voltage is always associated with a non-active phase, e.g., V_R is fed to the B-phase element which is not involved in an R- fault. So, normally in the use of a two-phase and one-earth fault scheme of line protection, a 90° connection is used. It should also be appreciated that an L-L fault (say R- fault) immediately after the relaying point is also cleared as enough torque (enough voltage) is available to both the concerned elements.

In the 90° connection, the polarising voltage lags the unity power-factor position of the faulted current phasor by 90° . In case of a high power factor fault (i.e., when there is considerable resistance in the fault path), the torque produced is very less. So in practice, the effective maximum torque angle is reduced by means of a phase-advancing device in the voltage coil (Fig. 7.28). As can be seen from the phasor diagram, to shift the phasor V_p in phase with the relay current I_r , the voltage V_B has to be shifted or advanced by an angle α . For this purpose, some suitable value of resistance is to be kept in series with the voltage coil. This ensures that maximum torque occurs at an angle $(90^\circ - \alpha)$ or θ .

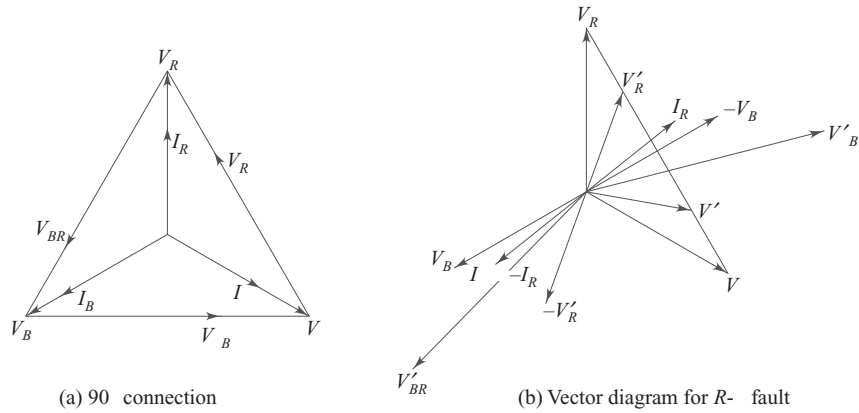
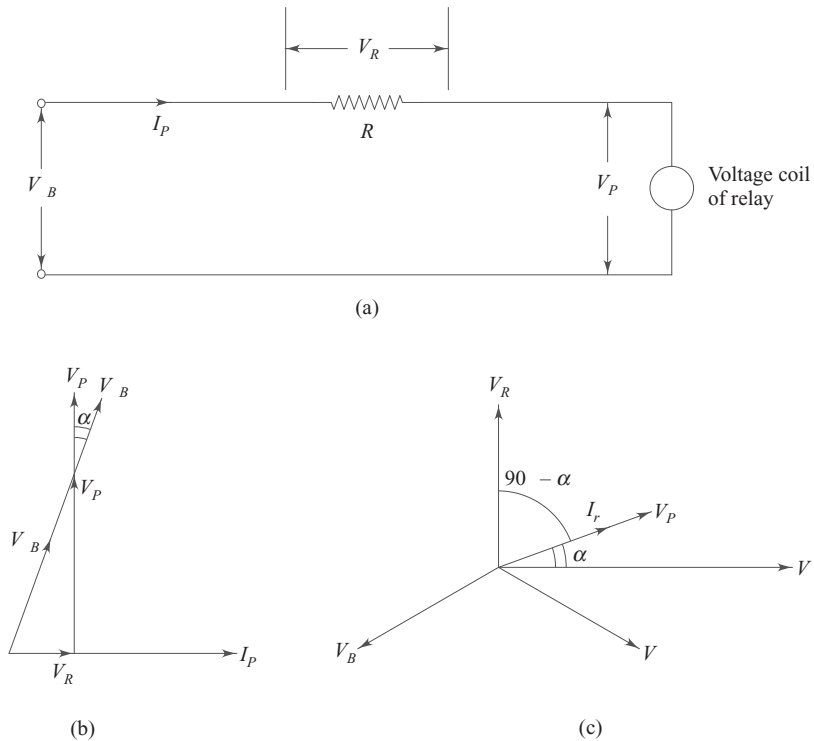


Fig. 7.27 R-Y fault in 90° connection



$$R = r + R'$$

where,

r = Internal resistance of voltage coil of relay

R' = Deliberate resistance added in series with relay voltage coil

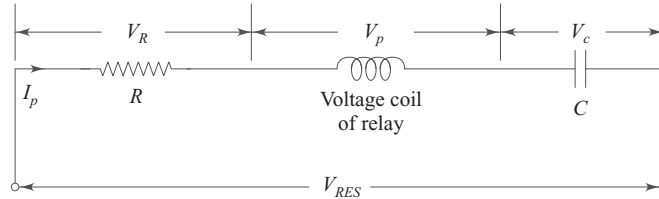
Note: Relay current I_r lags phase current I_R under unity power factor

conditions by an angle $(90 - \alpha)$ or leads polarising voltage V_B by α

Fig. 7.28 Phase advancing in directional relay

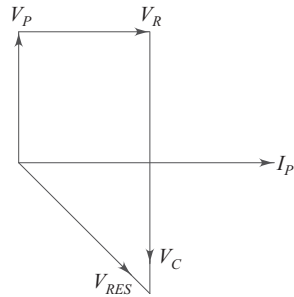
7.10 DIRECTIONAL EARTH-FAULT RELAYS

A directional earth-fault relay element is fed with a residual current and open delta voltage (Fig. 7.30). The residual voltage (i.e., open delta voltage $V_R + V_Y + V_B$) is zero under healthy conditions and during phase faults (L-L-L and L-L). In case of a ground fault (L-g), the residual voltage is equal to depression of voltage in the faulted phase for a solidly earthed system [Fig. 7.29(c)]. This voltage causes the earth fault relay to operate. The voltage coil connections of a directional earth-fault relay are shown in Fig. 7.29(a).

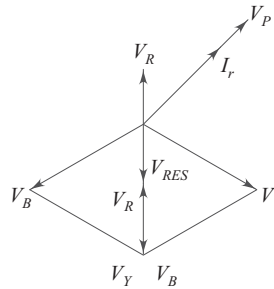


V_{RES} : Residual or polarising voltage of a directional earth-fault relay

(a)



(b)



(c)

Fig. 7.29 (a) Voltage coil connections (b) Vector diagram (c) R-g fault

7.11 DETAILED PROTECTIVE SCHEME OF DIRECTIONAL OVERCURRENT PROTECTION OF A HIGH-VOLTAGE TRANSMISSION LINE

Figure 7.30 shows a detailed ac (power) circuit for protecting a typical 132 kV transmission line using directional overcurrent and earth-fault relays.

Current coils of directional overcurrent relays 67R, 67 and 67B are connected in the secondary of relevant line CTs. The current coil of a directional earth-fault relay of 67N is residually connected. The potential coil of 67R is connected across and B phases of a bus PT secondary. Similarly, 67 is connected across B and R phases, and 67B is connected across R and phases. The phase-advancing resistors (not shown) are in-built with potential connections of relays. The potential coil of a directional earth-fault relay is connected across the open delta of an intermediate voltage transformer (IVT) having a voltage ratio of $110/\sqrt{3} : 110/3$ which will give the voltage $3V_0/3$, i.e., V_0 (zero sequence voltage) across the open delta.

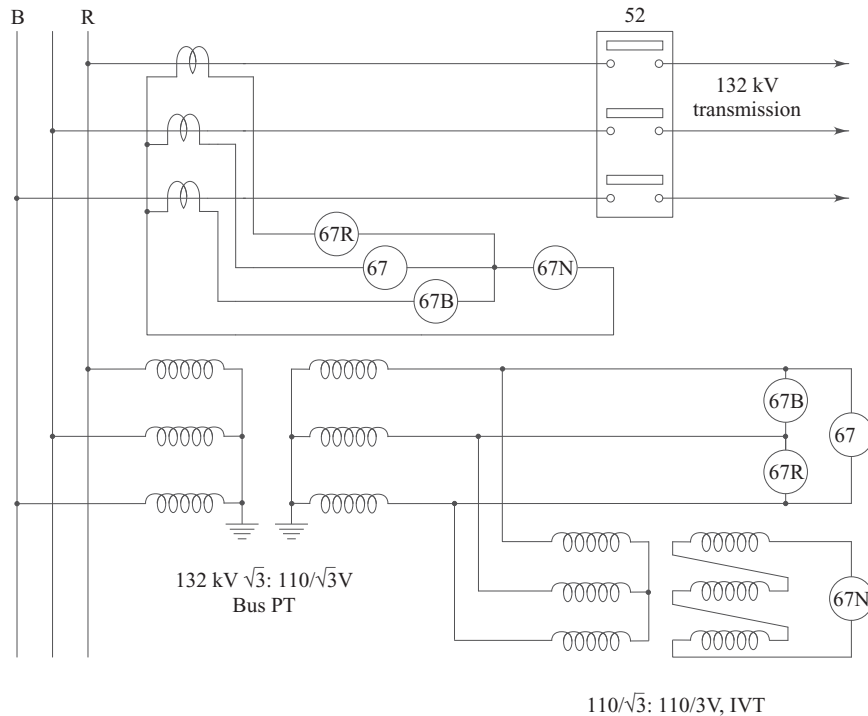
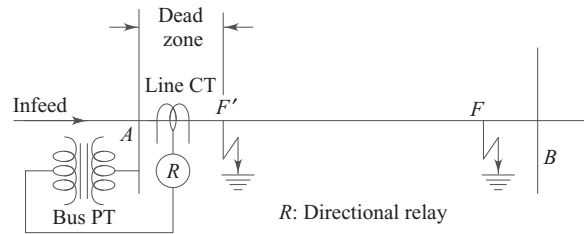


Fig. 7.30 Detailed protective scheme of directional overcurrent protection of line

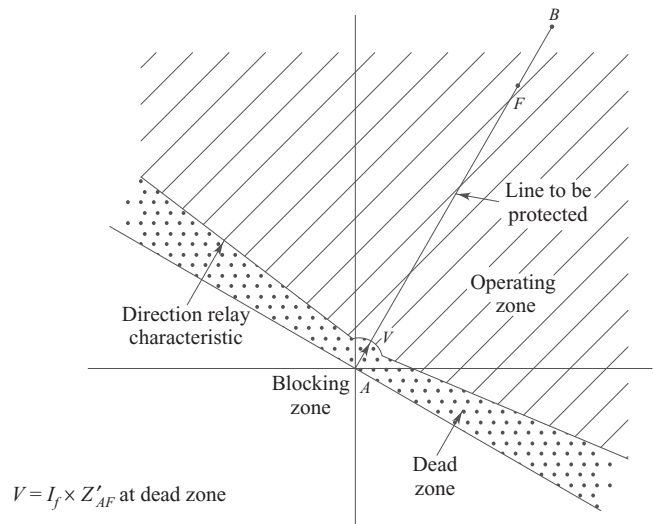
7.12 DEAD ZONE

In case of a fault on a transmission line, the Ph-N voltage available at the relaying point is equal to $I_f \times Z_l$ where I_f is the fault current and Z_l is the impedance from the relaying point to the fault point. If the fault occurs near to the relaying point, the voltage available at the relaying point will be very small, thus producing less torque. If this torque is less than the sum of the frictional torque and spring bias, the relay will fail to operate. This suggests that the relay will sense a fault only beyond a certain minimum distance from the relaying point at which the torque produced from the fault voltage is equal to the frictional torque and spring bias. This minimum distance of the line is known as the dead zone (Fig. 7.31) in which the directional relay scheme fails to perceive the fault. In practice, this minimum voltage is expressed in terms of a percentage of the rated polarising voltage of the relay and is termed the *directional sensitivity*.

Static relays have better directional sensitivity (numerically less) than electromagnetic relays, as they have practically no mechanical friction and no need of restraining spring bias to compensate for. In other words, the dead zone is reduced. In a 90° connection (discussed in Section 7.9) for phase-phase faults, the voltage available is never very small for any location of fault because the polarising voltage fed to the relay is the voltage of the un-faulted phase, e.g., for a -B fault, the A and C relay elements will not suffer from the effect of a dead zone because they will receive the voltages V_{BR} and V_{RY} respectively. Similarly, for faults involving earth, the polarising voltage is never zero. The effect of a dead zone will take place only in case of a bolted three-phase short circuit which occurs because of inadvertent closing of the circuit breaker when the earthing switch is closed which is very rare and can be prevented by suitable interlocks.



(a)



(b)

Fig. 7.31 Dead zone

Example 7.5 Figure 7.32 shows a single line diagram of a ring network. The relays used are directional and non-directional overcurrent relays of the IDMT type. The fault currents fed from both the directions are shown in Fig. 7.32.

Table 7.8 gives the CT ratio and plug settings of relays.

Table 7.8

Relays	CT ratio	Plug setting as % of CT rating
R_1	1000/1	100%
R_2	800/1	75%
R_3	800/1	75%
R_4	500/1	100%
R_5	500/1	100%
R_6	800/1	75%
R_7	800/1	75%
R_8	1000/1	100%

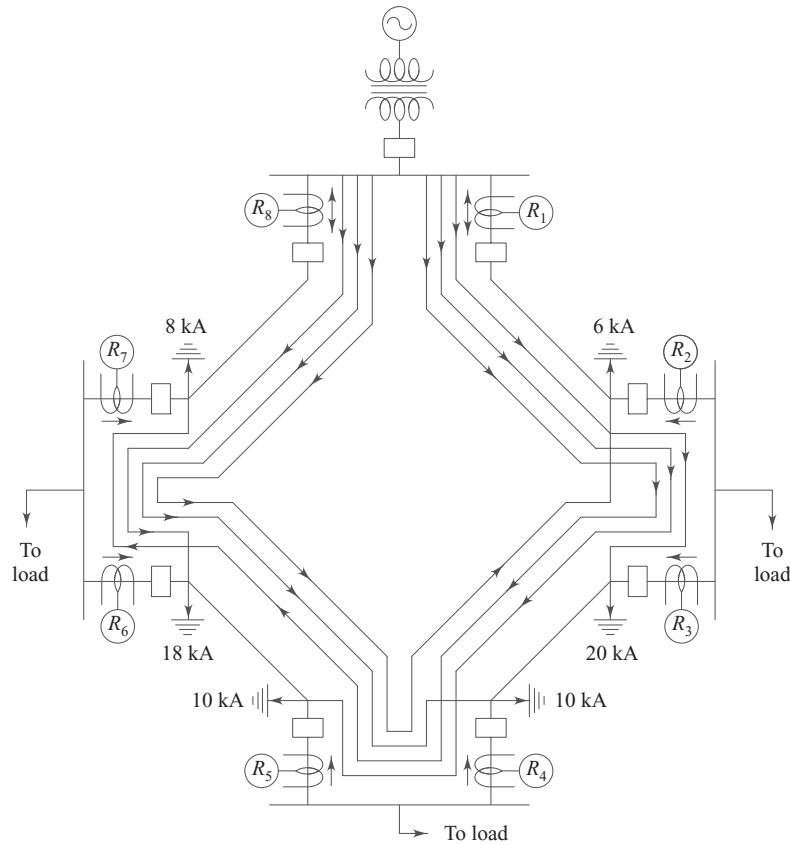


Fig. 7.32 Example 7.5

Show by arrowheads, which relays are required to be directional and which ones are non-directional. Also, determine the time-settings of all the relays. Assume suitable data wherever required.

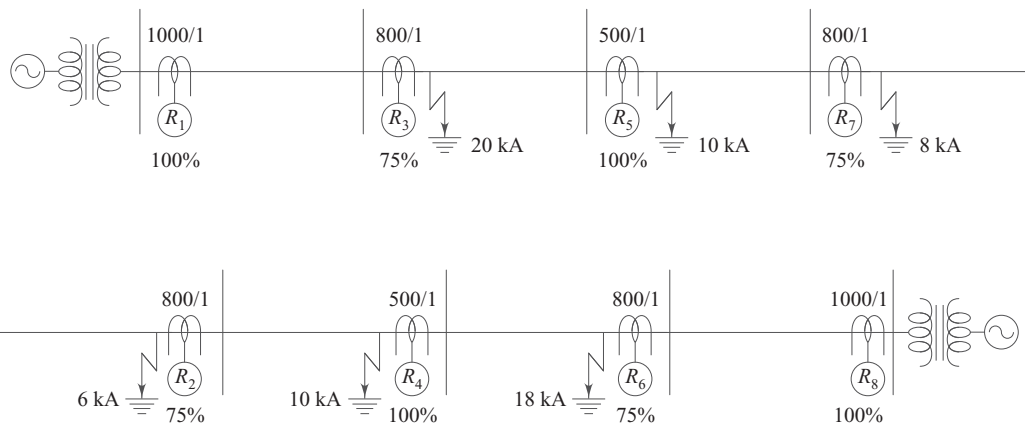


Fig. 7.33 Figure 7.32 split into two radial networks

Solution The directional feature is required for the relay locations where the fault current direction can change. But for R_1 and R_8 , hence, all other relays need be directional as shown by arrowheads in Fig. 7.32.

For finding out TMS of IDMT relays which are operative in each direction of the fault current, we will split the ring network of Fig. 7.32 into two radial networks of Fig. 7.33.

Now assuming the lowest TMS of 0.1 for the last relays R_7 and R_2 , we can calculate TMS of the other relays. Proceeding in this way,

$$\text{PSM of } R_7 \text{ for fault current of } 8 \text{ kA} = 8000 / (0.75 \times 800) = 13.33$$

$$\text{Time of operation of the relay } R_7 = \frac{3}{\log 13.33} \times 0.1 = 0.267 \text{ s}$$

Therefore, required time of operation of the relay $R_5 = 0.517 \text{ s}$
(assuming discriminative margin of 0.25 s between successive relays)

$$\text{Now, PSM of } R_5 \text{ at the fault current of } 8 \text{ kA} = 8000 / 500 = 16.0$$

$$\text{Time of operation of the relay } R_5 = 0.517 = \frac{3}{\log 16} \times \text{TMS of the relay } R_5$$

$$\therefore \text{ TMS of the relay } R_5 = 0.207$$

i.e., TMS of 0.25 is selected. For finding out TMS of R_3 , R_3 and R_5 are required to be graded together for maximum fault current that concerns both. This value is 10 kA.

$$\text{Hence PSM of } R_5 \text{ at } 10 \text{ kA} = 10000 / 500 = 20$$

$$\text{Time of operation of } R_5 \text{ at } 20 \text{ PSM and } 0.25 \text{ TMS} = 2.3 \times 0.25 = 0.575 \text{ s}$$

$$\text{Required time of operation of } R_3 = 0.825 \text{ s}$$

$$\text{PSM of } R_3 \text{ at } 10 \text{ kA} = 10000 / (0.75 \times 800) = 16.66$$

$$\text{Time of operation of the relay } R_3 = 0.825 = \frac{3}{\log 16.66} \times \text{TMS of the relay } R_3$$

$$\therefore \text{ TMS of the relay } R_3 = 0.336$$

i.e., TMS of 0.35 is selected.

Similarly TMS of R_1 (grading it with R_3 for the fault current of 20 kA) can be found to be 0.5. It is to be noted here that for any PSM greater than 20.0, the time of operation of the IDMT relay remains practically constant at 2.3 seconds.

The time settings, accordingly, are calculated for relays R_2 , R_4 , R_6 and R_8 also. All time settings are summarised as follows:

Table 7.9

Relays	TMS	Relays	TMS
R_1	0.5	R_2	0.1
R_3	0.35	R_4	0.2
R_5	0.25	R_6	0.3
R_7	0.1	R_8	0.4

Example 7.6

A portion of the power system is shown by the single-line diagram of Fig. 7.34. The conventional primary and back-up relaying is used for the system using IDMT overcurrent relays of directional and non-directional types (as required) and bus-zone differential relays. In each of the cases listed below, a fault has occurred and circuit breakers have tripped as stated. Indicate the location of fault. Was there any failure of protective relaying? If yes, where was the failure? Assume only one failure at a time. Redraw a single-line diagram showing CT locations taking care of overlapping of the primary protective zones.

Table 7.10

Case	Breakers Tripped
a	4, 5, 6
b	2, 3
c	6, 8
d	4, 5, 8
e	3, 7, 8

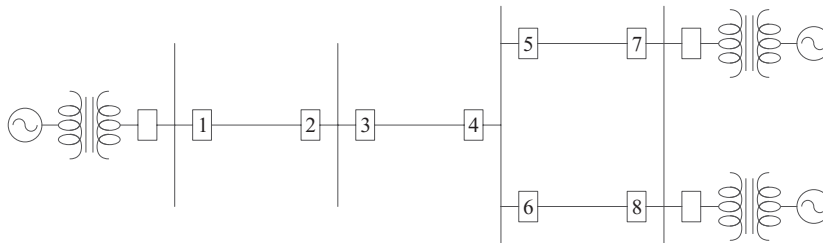


Fig. 7.34 Example 7.6

Solution As the fault current can change its direction for different fault locations at all relay locations, all the relays are directional overcurrent relays as shown in Fig. 7.35. Multicore CTs are used as shown in Fig. 7.35, one core for feeding the directional overcurrent relay and another for feeding the bus differential relay. The overlapping of the line protection zone and the bus zone protection is effected by CT core locations as shown in Fig. 7.35.

Now let us see the first case of fault. Breakers 4, 5 and 6 together can trip only when there is a fault on the bus *C*. Relay 87 will sense the fault and will operate instantaneously. This relay, in turn, will give a signal to all the three breakers 4, 5 and 6. As the correct operation has been resulted, there is no failure of any component of protective relaying at any location. The case is tabulated in Table 7.10 and the fault location is shown in Fig. 7.35.

Similarly in the case b, breakers 2 and 3 have tripped. This is a result of a bus fault on the bus *B*. There is no failure of protective relaying anywhere in this case too.

In the case c, breakers 6 and 8 have tripped because of a line fault as shown by the fault location F_c in Fig. 7.35. Directional overcurrent relays and breakers have correctly tripped. There is no failure of the protective scheme anywhere.

In the case d, breakers 4, 5 and 8 have tripped. Breaker 4 would trip either for a line fault between substations *B* and *C* or due to a bus fault on the bus *C*. But breaker 5 would not operate for the said line fault. Hence it is confirmed that it is a bus fault on the bus *C*. For such a fault, breakers 4, 5 and 6 should have operated but the breaker 6 has failed to trip, hence the fault has been sensed by the relay 67 at the relaying point 8 and breaker 8 has, hence, tripped. This is tabulated in the table below.

In the case e, a little thought would tell us that either there is a bus fault on the bus *C* and the relay 87 of the bus zone *C* has failed to operate, or there is a line fault between substations *B* and *C* or between *C* and *D* (refer table).

In the case f, the fault can be between breakers 1 and 2 or between 3 and 4 or a bus fault at the bus *B* (refer table).

In the case g, breakers 1 and 3 have tripped due to a fault on the bus *B*. Breaker 2 could not operate because of breaker fault.

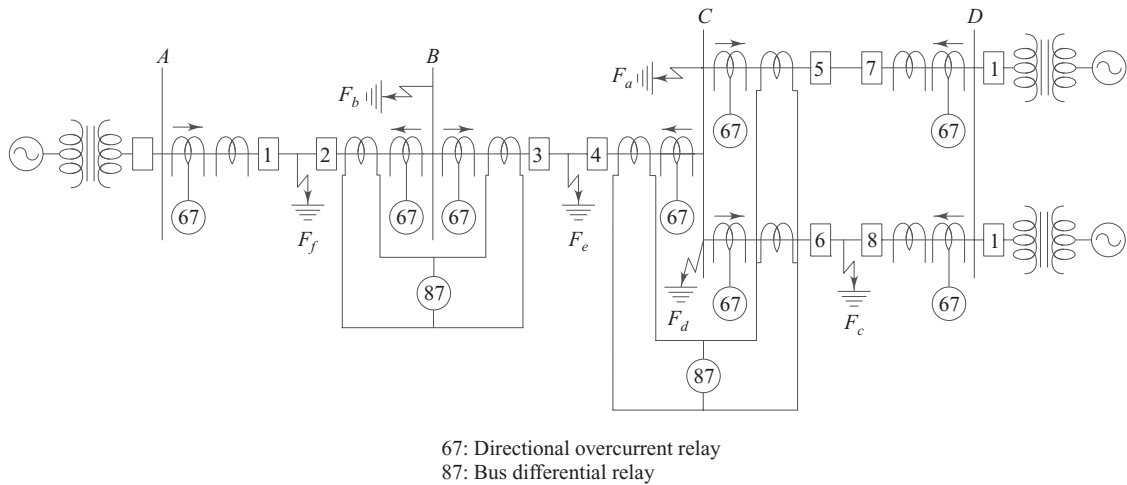


Fig. 7.35 Overlapping of zones for the network of Fig. 7.34

Table 7.11

S. No.	Case	Breakers Tripped	Fault Location	Failure of Relaying
1.	a	4, 5, 6	Bus fault on the bus C	—
2.	b	2, 3	Bus fault on the bus B	—
3.	c	6, 8	Line fault between breakers 6 and 8	—
4.	d	4, 5, 8	Bus fault on the bus C	Breaker 6 failed to trip
5.	e	3, 7, 8	Bus fault on the bus C OR Line fault between breakers 3 and 4 OR Line fault between breakers 5 and 7 OR Line fault between breakers 6 and 8	Relay 87 of the bus C Breaker 4 failed to trip Breaker 5 failed to trip Breaker 6 failed to trip
6.	f	1, 4	Line fault between breakers 1 and 2 OR Line fault between breakers 3 and 4 OR Bus fault at the bus B	Breaker 2 failed to trip Breaker 3 failed to trip Relay 87 of bus zone failed
7.	g	1, 3	Bus fault at the bus B	Breaker 2 failed to trip

Example 7.7 Figure 7.36 shows a single line diagram of a portion of a power system. Bracketed figures show the fault levels at the given buses. Considering a discriminative margin of 0.25 second between successive relays, determine the relay settings of all the relays shown in Fig. 7.36. Enlist the relays to be provided with the directional feature. For which relays is the directional feature not required? The relays used follow standard IDMT characteristic, and the time multiplier settings of the relays R_{10} and R_{11} are set at 0.2.

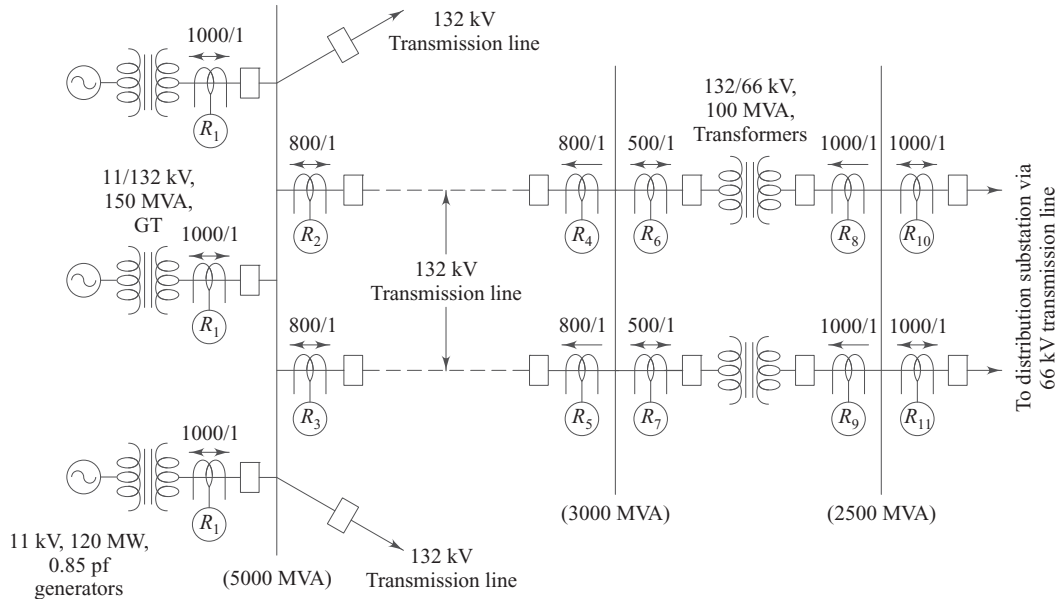


Fig. 7.36 Example 7.7

Solution The possibility of a fault current flowing in both the directions is for relay locations R_4 , R_5 , R_8 and R_9 . Hence these relays are required to be directional. Other relays will be non-directional. First, let us decide the plug-settings of all the relays.

Plug-Settings It is very obvious from the figure that two outgoing lines extending to the distribution substation are fed by two 100-MVA transformers. Assuming both the lines to be identical (as the CT ratio is 1000/1 in both the cases), the maximum current that can flow through each of these lines can be given by

$$\frac{100 \times 10^6}{\sqrt{3} \times 66 \times 10^3} \text{ or } 874.77 \text{ A}$$

i.e., 87.47% of 1000 A. Hence, plug settings of R_{10} and R_{11} can be selected to be 100% as the next available setting to 87% is 100% (50 to 200% in 7 equal steps).

As R_8 and R_9 are directional, the direction of normal flow is the inoperative direction for these relays. Relays R_6 and R_7 are required to be coordinated with R_{10} and R_{11} respectively.

$$\begin{aligned} \text{Hence, PS of the relay } R_6 &> \frac{1.3}{1.05} \times \text{PS of the relay } R_{10} \times \frac{66}{132} \\ &> \frac{1.3}{1.05} \times 1000 \times \frac{66}{132} \\ &> 619.047 \text{ A} \\ &> 123.8\% \text{ of } 500 \text{ A} \end{aligned}$$

Hence PS of R_6 (and R_7) is selected to be 125%.

Now as R_6 backs up R_9 ,

$$\begin{aligned} \text{hence, PS of the relay } R_9 &= \frac{1.05}{1.3} \times \text{PS of the relay } R_6 \times \frac{132}{66} \\ &= \frac{1.05}{1.3} \times 500 \times 1.25 \times \frac{132}{66} \end{aligned}$$

$$\begin{aligned} & 1009.6154 \\ & 100.96\% \text{ of } 1000 \text{ A} \end{aligned}$$

Therefore, PS of R_9 (and R_8) is selected to be 100%.

Now as each of the two transmission lines may be required to take full load current (equivalent to 200 MVA) in case of one of the lines tripping due to fault, PS of R_2 (and R_3)

$$\begin{aligned} & = \frac{200 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 874.77 \text{ A} \\ & = 109.34\% \text{ of } 800 \text{ A} \end{aligned}$$

Hence PS of R_2 and R_3 are selected at 125%.

This has to be confirmed with reference to allowable variation of pick-up,

$$\begin{aligned} \text{i.e., PS of } R_2 & > \frac{1.3}{1.05} \times \text{PS of } R_6 \\ & > \frac{1.3}{1.05} \times 500 \times 1.25 > 773.809 \text{ A} \\ & > 96.72\% \text{ of } 800 \text{ A} \end{aligned}$$

Thus, finally PS of R_2 is required to be selected as 125%.

PS of R_4 (and R_5) on the same line of thinking as that of R_8 and R_9 , can be selected as 100%.

$$\begin{aligned} \text{PS of } R_1 & > \frac{1.3}{1.05} \times \text{PS of } R_2 \\ & > 1238.095 \text{ A} > 123.8\% \text{ of } 1000 \text{ A} \end{aligned}$$

Hence PS of R_1 is selected as 125%.

This PS can be checked with respect to the rated current of a generator-transformer.

$$\begin{aligned} I_{\text{rated}} & = \frac{150 \times 10^6}{\sqrt{3} \times 132 \times 10^3} \\ & = 656.08 \text{ A} = 65.6\% \text{ of } 1000 \text{ A} \end{aligned}$$

Thus, finally PS of R_1 can be selected as 125%.

Time Settings For a 2500 MVA fault level, first R_6 (and R_7) are to be graded with R_{10} and R_{11} .

$$\text{PSM of } R_{10} = \frac{2500 \times 10^6}{\sqrt{3} \times 66 \times 10^3 \times 1000} = 21.86$$

As the value of PSM is greater than 20, the time of operation of the relay R_{10} (and R_{11}) remains constant and equal to 2.3 seconds at TMS = 1.

$$\therefore \text{time of operation of } R_{10} \text{ (at TMS} = 0.2) = 2.3 \times 0.2 = 0.46 \text{ s}$$

Thus, the required time of operation of the relay R_6 (and R_7) is 0.71. As the fault current will equally divide in two paths (transformers are assumed to have same percentage impedance), PSM of R_6

$$= \frac{2500 \times 10^6}{\sqrt{3} \times 132 \times 10^3 \times 500 \times 1.25 \times 2} = 8.747$$

$$\text{Now, time of operation of the relay } R_6 = 0.71 = \frac{3}{\log 8.747} \times \text{TMS of the relay } R_6$$

$$\therefore \text{TMS of the relay } R_6 = 0.223$$

i.e., TMS of R_6 (and R_7) is selected at 0.25.

Now as R_6 backs up R_9 , the time of operation of R_9 has to be 0.25 second less than that of the relay R_6 for a fault level of 2500 MVA.

$$\text{Time of operation of } R_6 = 3.185 \times 0.25 = 0.796 \text{ s}$$

Thus, required time of operation of the relay R_9 (and R_8)

$$0.796 - 0.25 = 0.546 \text{ s}$$

PSM of R_9 (and R_8)

$$= \frac{2500 \times 10^6}{\sqrt{3} \times 66 \times 10^3 \times 1000 \times 2} = 10.93$$

Time of operation of the relay R_9 0.546 s

$$\therefore 0.546 = \frac{3}{\log 10.93} \times \text{TMS of the relay } R_9$$

$$\therefore \text{TMS of the relay } R_9 = \frac{0.546 \times \log 10.93}{3}$$

Therefore, TMS of R_9 (and R_8) is selected as 0.15.

Similarly, R_2 (and R_3) is required to be graded with R_6 (and R_7) for a fault level of 3000 MVA and as R_2 backs up R_5 for a fault level 3000 MVA, R_5 is to be graded with R_2 to find out TMS of R_5 (and R_4). Relay R_1 is to be coordinated with the relay R_2 (and R_3) for fault current equivalent to 5000 MVA. It is to be noted here that a full fault current equivalent to 5000 MVA will pass at the relaying point R_2 , whereas this fault current is divided into three equal paths for the relaying point R_1 . The relay settings are tabulated below.

Table 7.12

Sr. No.	Relays	PS as of CT rating	TMS
1.	R_1	125	0.25
2.	R_2 and R_3	125	0.25
3.	R_4 and R_5	100	0.20
4.	R_6 and R_7	125	0.25
5.	R_8 and R_9	100	0.15
6.	R_{10} and R_{11}	100	0.20

7.13 COORDINATION OF OVERCURRENT RELAYS IN AN INTER-CONNECTED SYSTEM

In preceding sections we have learnt how the overcurrent and earth fault relays can be graded when there is a source only at one end. We have coordinated the overcurrent relays in simple radial and parallel feeder networks fed from one end only. If a parallel feeder is fed from both ends as shown in Fig. 7.37, the relay setting exercise has to be recursive and necessitates computation facilitated by computer software programs.

We are interested in finding out settings of phase relays R_1 to R_4 (setting range is 50–200% of 1 A, in seven equal steps). It is assumed that auxiliaries of the generators are supplied by some external source like diesel generator sets (if there is no such source then about 10% of the generated power would be consumed by the generating plant).

Plug Settings Our initial exercise would be to conduct a load-flow study. In the given network, one would find it very easy to know that the primary of CT feeding R_1 (or R_2) has to feed a load of 100 MW in the worst case (generators feeding the bus B might have tripped due to scheduled or forced outage). It is once again assumed that one of the parallel feeders may trip due to forced outage (fault) and the healthy line may have to take the total load till suitable load shedding is done. Similarly, CT_3 (or CT_4) is required to feed 120 MW in the worst case, as the load is 140 MW but the generation is only 120 MW. All the relays are obviously directional overcurrent relays.

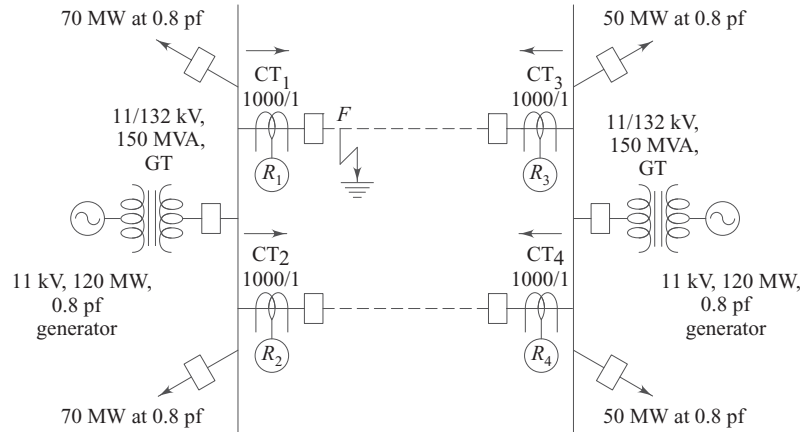


Fig. 7.37 Parallel feeder fed from both the ends

PS of R_1 (or R_2) is hence,

$$= \frac{(100 \times 10^6) \times 100}{(\sqrt{3} \times 132 \times 10^3 \times 0.8 \times 1000)} = 54.67\%$$

Therefore, plug setting of R_1 (or R_2) is selected as 75%.

Similarly, PS of R_3 (or R_4) is 75% based on the load flow of 120 MW.

Time Settings For calculating time settings, fault levels are required to be calculated. For a given network, manual calculations using a scientific calculator can be done if p.u. (or ohmic values) of impedances of generators, transformers and transmission lines are given. Using typical values, the fault currents are calculated as given in Table 7.13.

Table 7.13

CT	Fault currents in the primaries of CTs for a fault at F in Fig. 7.37 in A
CT ₁	4000
CT ₂	1500
CT ₃	1500
CT ₄	1500

The next exercise is to find out primary-backup relay pairs. One can appreciate that there are four pairs in this case. These four pairs are tabulated in Table 7.14.

Table 7.14

Primary Relay	Back up Relay
R_1	R_4
R_2	R_3
R_3	R_2
R_4	R_1

As the network is symmetrical, settings of R_1 and R_2 will be same and those of R_3 and R_4 will be same. For a fault at F , R_4 will back up R_1 .

$$\text{Hence, PSM of } R_1 = \frac{4000}{0.75 \times 1000} = 5.33$$

$$\therefore \text{time of operation of } R_1 = \frac{3}{\log 5.33} \times \text{TMS of } R_1$$

TMS of R_1 can be assumed to be 0.1.

$$\therefore \text{time of operation of } R_1 = 0.412 \text{ s}$$

$$\therefore \text{required time of operation of } R_4 = 0.662 \text{ s}$$

$$\text{PSM of } R_4 = \frac{1500}{0.75 \times 1000} = 2$$

This is because 1500 A flows through primary of CT_4 for a fault at F .

$$\therefore \text{TMS of } R_4 = \frac{0.662 \times \log 2}{3} = 0.066$$

i.e., TMS of R_4 can be selected as 0.1.

Thus, the settings can be tabulated as follows:

Table 7.15

Relays	Settings	
	PS of 1 A	TMS
R_1	75%	0.1
R_2	75%	0.1
R_3	75%	0.1
R_4	75%	0.1

Still, this exercise is not fully addressed. One has to carry out cross checking to confirm that R_1 backs up R_4 with a discriminative margin of 0.25 s when the fault occurs near CT_4 . As the network is symmetrical, the fault current distribution would be similar to the former distribution. Current through the primary of CT_4 will be 4000 A and that through each of the other three CTs will be 1500 A. For these fault currents, it can easily be proved that the discriminative margin between the time of operation of relays R_4 and R_1 will be 0.58 s which will be enough. Thus, this exercise is completed after just one iteration. The network of Fig. 7.37 contains two buses, two lines and four relays. But the networks of state electricity companies/boards typically have 10 to 15 or more buses, 40 to 50 transmission lines and 80 to 100 overcurrent relays. The exercise of load-flow analysis, fault-level calculations and listing the primary-backup pairs will be very tedious. The exercise is very difficult because one has to consider line contingencies and the relay settings are to be decided based on the worst case. Also, several iterations would be required to calculate the TMS of relays so that minimum discrimination margin as required is found between a relay and all its back-up relays. This is possible only through computer programming.

The relay setting exercise for cascaded parallel feeders fed from both ends (Fig. 7.38) is discussed as follows:

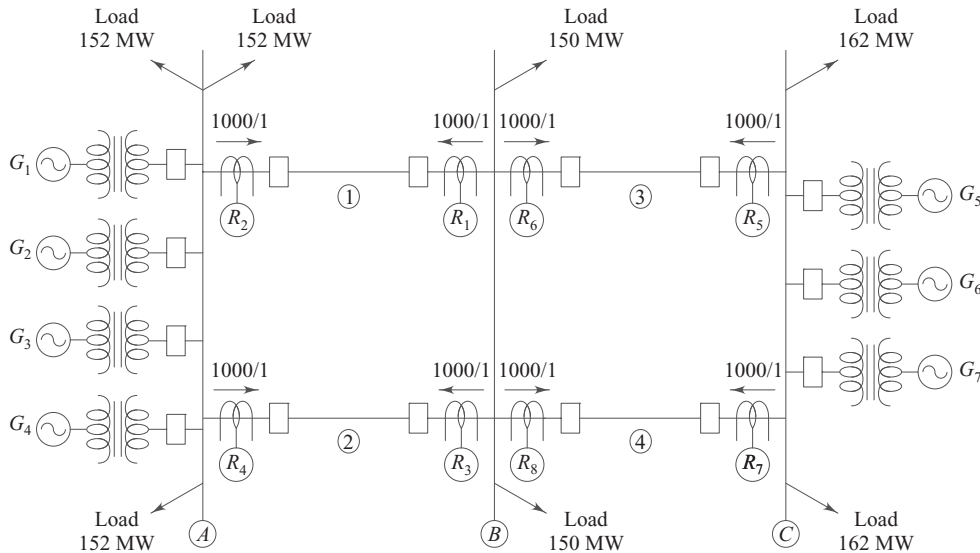


Fig. 7.38 Cascaded parallel feeders fed from both the ends

The data of the network is given in Table 7.16.

Table 7.16

Elements of the network	Ratings	Impedance p.u.
Generators G_1, G_2, G_3 and G_4	210 MW, 15.75 kV, 0.85 p.f.	$j 0.1234817$
Transformers T_1, T_2, T_3 and T_4	250 MVA, 15.75/220 kV	$j 0.056$
Generators G_5, G_6 and G_7	120 MW, 13.8 kV, 0.85 p.f.	$j 0.1971831$
Transformers T_5, T_6 and T_7	150 MVA, 13.8/220 kV	$j 0.100$
Overhead lines 100 km long (assumed)	220 kV	$0.03204 + j 0.08496$

During the development of any algorithm which deals with a network, the programmer has to decide as to how the information of the network should be optionally stored in the computer memory. The storage of the network information becomes tedious for the large network.

One of the structures for representing any network in a computer is the 'linknet' structure. Because of space limitations, this is not discussed here.

The next exercise is to find the primary back-up relay pairs. In a very large network, manual finding of back-up relays to a given primary relay is not possible. If even one back-up relay is missed, it would lead to mal-operation elsewhere in the network. Hence once again, the effective linknet structure is used. Three one-dimensional vectors, namely LIST (bus), NEXT (relay) and FAR (relay) are used in the linknet structure.

Load-flow studies are then required to be carried out to find out the maximum full-load current flowing in each line. Line contingencies are required to be considered in this exercise. Using the data available after load-flow analysis, plug settings of relays can be found out. A typical flow chart for finding out plug settings is given in Fig. 7.39.

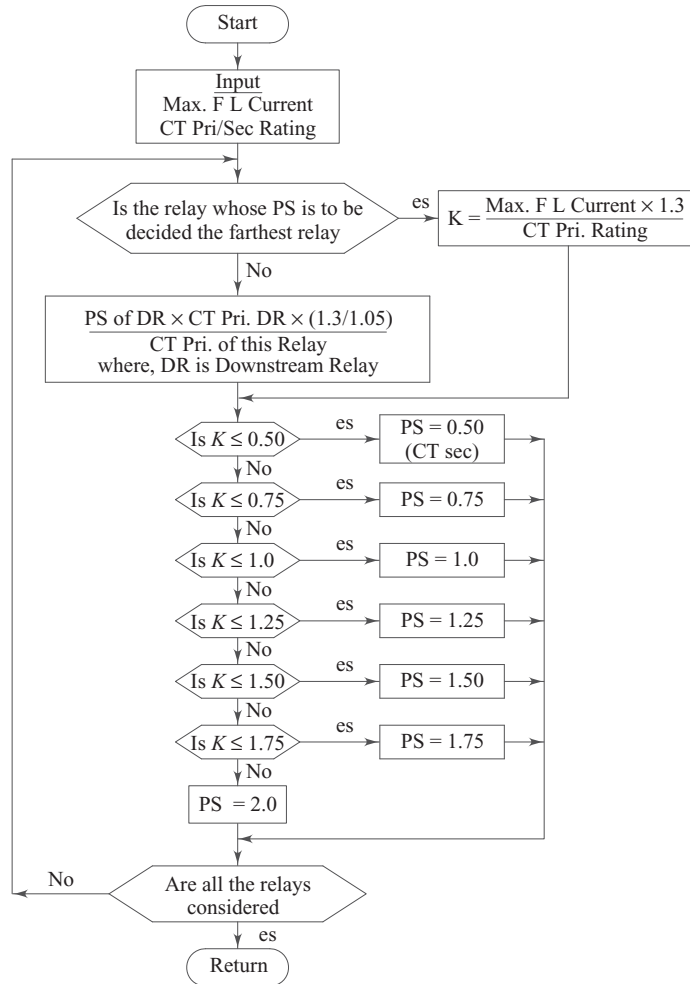
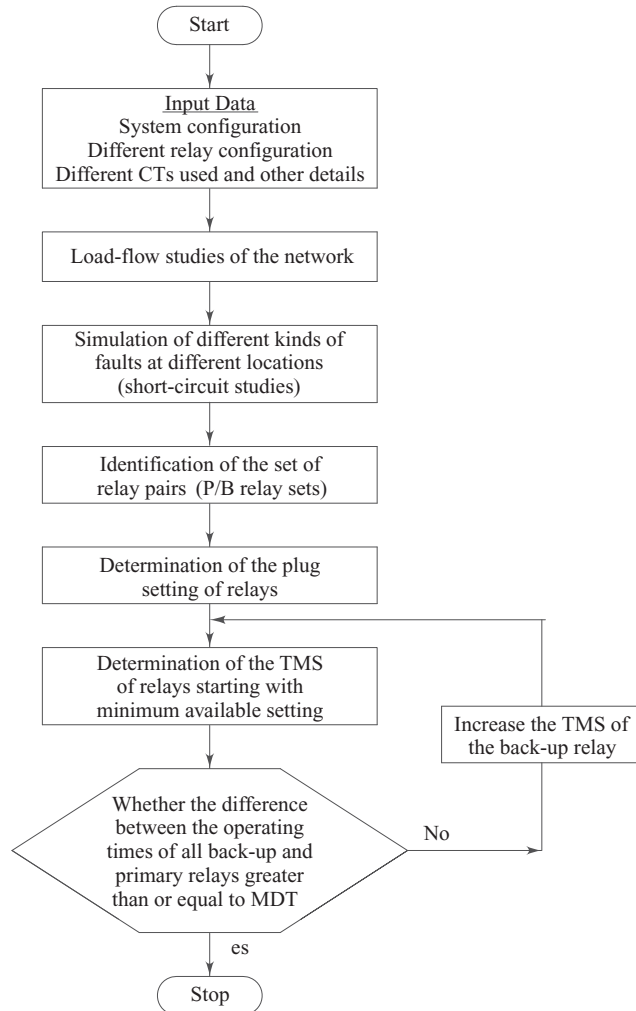


Fig. 7.39 Flow chart for plug-setting determination

Short-circuit (fault) calculations are essential for finding out TMS. Short-circuit studies can be carried out in the bus frame of reference using a bus impedance matrix Z_{bus} or bus admittance matrix Y_{bus} . Line contingencies are once again required to be considered in this exercise. For a given network in Fig. 7.38, 9 line configurations are possible as tabulated in Table 7.17.

Table 7.17 Different line configuration

Line con guration	Description
1	All lines in service
2	Lines 1 and 3 out of service
3	Only line 1 out of service
4	Only line 3 out of service
5	Lines 2 and 4 out of service
6	Only line 2 out of service
7	Only line 4 out of service
8	Lines 1 and 4 out of service
9	Lines 2 and 3 out of service


Fig. 7.40 Generalised flow chart for relay coordination

Finally, the relay coordination exercise can be carried out as shown in the generalised flow chart of Fig. 7.40. The final result of the relay coordination exercise is given in Table 7.18, just for the reader to appreciate how complicated this exercise gets even for a comparatively simple network having three buses, four lines and eight relays. The relays are assumed to be voltage-controlled overcurrent relays in this exercise.

Table 7.18 The result

Primary relay	Back up relay	orst line con guration	Plug setting	TMS
1	7	9	0.50	0.60
1	5	5	0.50	0.60
1	4	7	0.50	0.60
2	3	3	0.75	0.90
3	7	1	0.50	0.60
3	5	8	0.50	0.60
3	2	7	0.50	0.60
4	1	6	0.75	0.90
5	8	1	0.75	0.85
6	7	6	0.50	0.75
6	4	8	0.50	0.75
6	2	5	0.50	0.75
7	6	1	0.75	0.85
8	5	6	0.50	0.95
8	4	2	0.50	0.95
8	2	9	0.50	0.95

7.14 FACILITIES PROVIDED IN MODERN NUMERICAL OVERCURRENT AND EARTH FAULT RELAYS

- 1. Circuit breaker failure protection (CBFP)** If a circuit breaker fails to open after receiving a signal from a relay due to failure of operating mechanism of the breaker or open circuiting of its trip coil, the relay will generate another signal after a small time delay (adjustable from 0.04 s to 0.1 s) to trip an upstream breaker in the power system network.
- 2. Auto-doubling feature** As we have seen in Chapter 6, this chapter and further in Chapter 11, the setting of instantaneous overcurrent relay for a transformer feeder and for a feeder feeding induction motor has to be done beyond the magnetising inrush current of a transformer or beyond the starting current of an induction motor. This implies that a fault with a fault current magnitude less than this magnetising inrush current or induction-motor starting current will be cleared by a time-delayed unit. In modern numerical relays, instantaneous setting is automatically doubled when switching 'ON' a breaker. This allows lower setting of an instantaneous overcurrent relay than the probable magnetic inrush or starting current.
- The relay settings can be automatically changed based on line contingencies of the network due to forced outage. This can be done by applying binary inputs to the relay through auxiliary contacts of the breakers of the network. This is a simple example of adaptive relaying.
- When a relay starts, it generates a start signal which can be used to block the operation of the upstream relay.

Thus, these and many other features have significantly changed the capabilities and options possible for achieving relay coordination.

7.15 LIMITATIONS OF OVERCURRENT RELAYS

1. Z_s/Z_L ratio: The inverse time overcurrent relays and instantaneous overcurrent relays are very prone to Z_s/Z_L ratio. If this ratio is equal to 2.0, these relays cannot be applied. Very inverse and extremely inverse relays are also not immune to this ratio. In the limiting case, one has to apply definite time overcurrent relays which are fully immune to this ratio. But they suffer from the problem of large tripping time for severest fault.
2. In case of varying generating conditions, one has to use voltage controlled overcurrent relays which forms the basis of distance relays.
3. Overcurrent relays achieve selectivity by time-grading. This clearly means that time-setting will progressively increase towards the source. Thus severest faults will be cleared the slowest. The instantaneous relays with high setting can be inbuilt in time-delayed relay, but these suffer from the problem of transient overreach.
4. It is very difficult to calculate relay-setting of overcurrent relays in an interconnected system. Very involved computer softwares are to be used for arriving at relay-settings.

REVIEW QUESTIONS

1. Using standard IDMT relays, calculate the relay settings of the relays R_1 , R_2 and R_3 for the system shown in Fig. 7.41. Plug setting and TMS of the relay R_4 is 100% of CT secondary rating and 0.1, respectively.

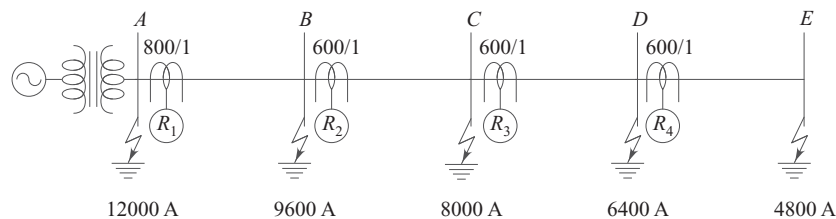


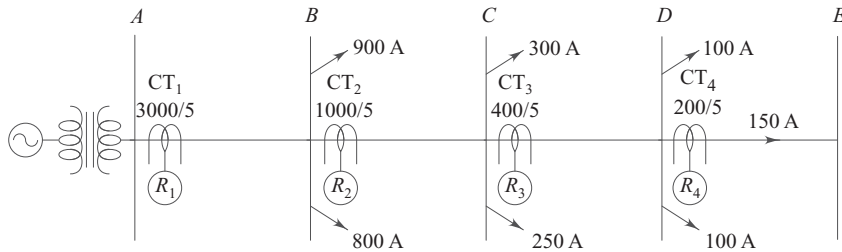
Fig. 7.41 Example 1

(PS of $R_3 = 125\%$, PS of $R_2 = 175\%$, PS of $R_1 = 175\%$, TMS of $R_3 = 0.2$, TMS of $R_2 = 0.25$, TMS of $R_1 = 0.3$)

2. A radial feeder is shown in Fig. 7.42. The CT ratio and maximum and minimum fault currents at various substations A, B, C, D and E are indicated in the table and full-load currents of feeders are indicated in Fig. 7.42. Determine the plug-settings and time-settings of standard IDMT relays used for this feeder protection. TMS of R_4 is set at 0.1. Allow for 10% overload.

Table of Example 2

Fault at substation	A	B	C	D	E
Maximum fault current in A (three-phase fault)	12000	8000	4000	2000	1500
Minimum fault current in A	10000	5000	3000	1100	600

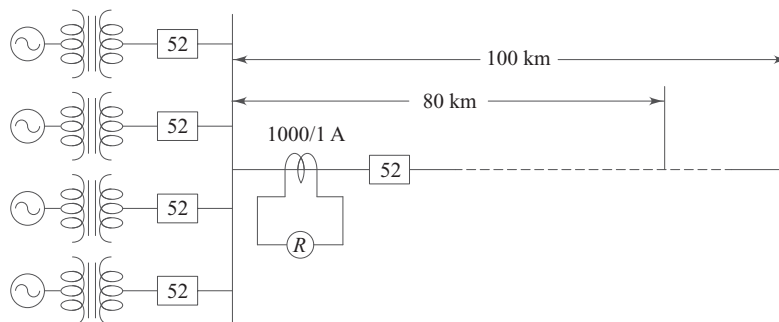

Fig. 7.42 Example 2

(PS of $R_4 = 100\%$, PS of $R_3 = 100\%$, PS of $R_2 = 100\%$, PS of $R_1 = 75\%$ with undervoltage unit, TMS of $R_3 = 0.15$, TMS of $R_2 = 0.15$, TMS of $R_1 = 0.15$)

3. A portion of a power system network is shown in Fig. 7.43, in which a fault occurs at the point X. The fault currents are tabulated in the table.

Table of Example 3

Fault with respect to Generation	Fault currents in kA for	
	L L Fault	L L L g Fault
Minimum generation	5.0	7.5
Maximum generation	6.5	10.0

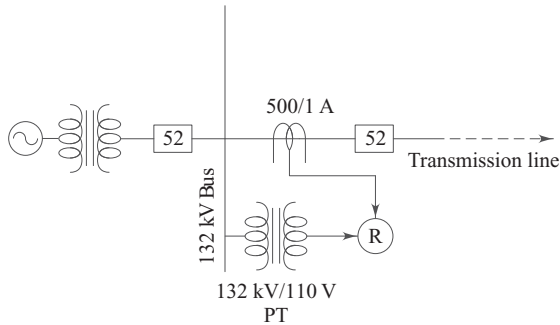
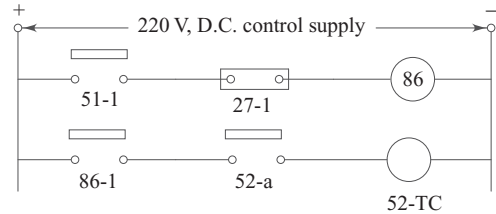

Fig. 7.43 Example 3

The setting range of instantaneous overcurrent relay R is 400–2000% of I A. Suggest the setting as a percentage of I A. **(1000%)**

4. The transmission line of Fig. 7.44 takes maximum full-load current of 600 A. Fault current with minimum generation is 500 A. Suggest the settings of the relays 51 and 27 with respect to Figs 7.44 and 7.45. Also, state the status of all the contacts shown in Fig. 7.45 when the line takes a full-load current of 600 A with no fault.

(PS of the relay 51 = 100%, setting of the relay 27 = 77 V, 51-I will close, 27-I will remain open, 86 is deenergised, 86-I will be open, 52-a will be closed, 52-TC is not energised)

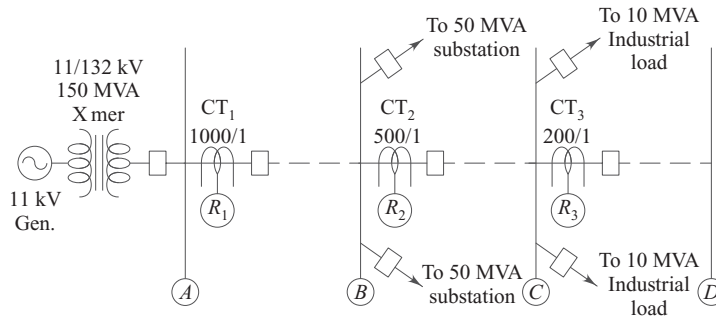
5. Figure 7.46 shows a portion of a power system. Relays R_1 , R_2 and R_3 are standard IDMT relays. Each relay group is wired for a three-overcurrent and one earth-fault protection scheme. The setting range for overcurrent relays is 50–200% of I A in seven equal steps and that for earth-fault relays is 20–80% of I A in seven equal steps. The


Fig. 7.44 Example 4

Fig. 7.45 Example 4

plug settings of earth-fault relays R_1 , R_2 and R_3 are set at 20% each. The time settings of overcurrent and earth fault relays at the relaying point R_3 are set at 0.2 each. Excitation current of each CT is 0.03 A. The fault currents are tabulated below:

Fault at	Fault currents in Ampere		
	<i>L L L Fault</i>	<i>L L Fault</i>	<i>L g Fault</i>
Bus A	1930	1670	1100
Bus B	1600	1390	900
Bus C	1370	1190	800
Bus D	1200	1040	720

Determine the settings of the overcurrent and earth-fault relays R_1 , R_2 and R_3 .

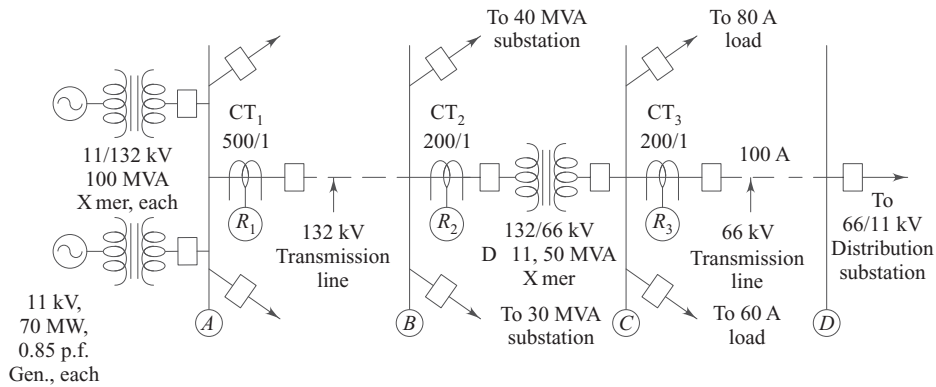

Fig. 7.46 Example 5

(PS of $R_3 = 75\%$, PS of $R_2 = 50\%$, PS of $R_1 = 75\%$, TMS of overcurrent relay $R_2 = 0.25$, TMS of overcurrent relay $R_1 = 0.15$, TMS of earthfault relay $R_2 = 0.25$, TMS of earthfault relay $R_1 = 0.25$)

6. Figure 7.47 shows a single-line diagram of a portion of a power-system network. The fault currents at the different buses are as follows:

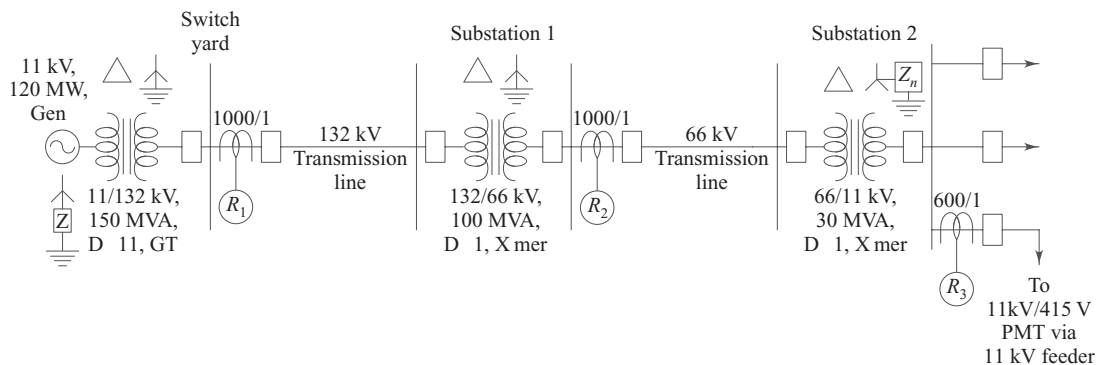
The relays used are IDMT overcurrent relays giving inverse-time characteristic and with high-set instantaneous overcurrent unit. The percentage overreach of instantaneous high-set units of relays is 10%. Considering 10% overload margin, determine the plug settings, TMS and pick-up of high-set units of relays R_1 , R_2 and R_3 .

Bus	Fault current at minimum generation	Fault current at maximum generation
	L L Fault A	L L L g Fault A
A	1200	2000
B	900	1500
C	1000	2000
D	500	1000


Fig. 7.47 Example 6

(PS of IDMT relay $R_3 = 75\%$, PS of IDMT relay $R_2 = 75\%$, PS of IDMT relay $R_1 = 100\%$, Setting of high-set relay $R_3 = 600\%$, Setting of high-set relay $R_2 = 600\%$, Setting of high-set relay $R_1 = 400\%$, TMS of relay R_3 assumed as 0.1, TMS of relay $R_2 = 0.15$, TMS of relay $R_1 = 0.15$)

7. Figure 7.48 shows a single-line diagram of a radial feeder. Draw a detailed ac circuit (three-phase diagram) of the same. If the earth fault relay R_3 is set with a PS of 10% of I A and a TMS of 0.1, find its time of operation for an earth fault immediately after the relaying point R_3 . Relevant data is as follows:
- The sequence impedances of 66/11 kV, 30 MVA, DY-I transformer are $Z_1 = 1$ ohm, $Z_2 = 1$ ohm and $Z_0 = 5$ ohm.
 - Neutral impedance, $Z_n = 10$ ohms.
- (Time of operation of relay $R_3 = 0.338$ s)**


Fig. 7.48 Example 7

8. Figure 7.49 shows a portion of a power system wherein IDMT overcurrent relays giving standard IDMT characteristics are used. If the TMS of R_4 is set at 0.2, determine the plug settings and TMS of other relays of the system. Also, calculate the setting of a high-set instantaneous unit in-built with the relay R_2 . Bracketed values show the fault MVA at locations shown in Fig. 7.49.

(PS of R_4 = 100%, PS of R_3 = 100%, PS of R_2 = 100%, Setting of high-set R_2 = 400%, PS of R_1 = 125%, TMS of R_3 = 0.2, TMS of R_2 = 0.2, TMS of R_1 = 0.25)

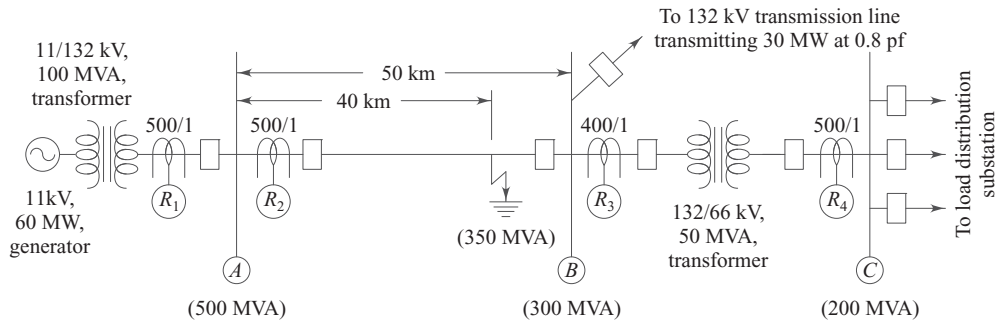


Fig. 7.49 Example 8

9. Figure 7.50 shows a single-line diagram of a part of the power system. The required details are as follows:
Induction Motor = 11 kV, 0.85 p.f., 3-phase, 2000 h.p., efficiency = 90%, overload withstand = 110% of rated current.

Circuit Breaker	Breaking Capacity in MVA
1 and 2	2000
3 and 4	1500
5	40

Determine the settings (plug settings and TMS) of IDMT overcurrent relays R_1 , R_2 , R_3 , R_4 and R_5 . (setting range = 50–200% of CT secondary rating) given that TMS of R_4 and R_5 are set at 0.2 and 0.3 respectively and the high-set instantaneous setting of relays R_5 and R_3 are set at 1000% and 2000% of the CT secondary rating, respectively.

(PS of R_5 = 75%, PS of R_3 = 125%, PS of R_4 = 75%, PS of R_2 = 100%, PS of R_1 = 125%, TMS of R_3 = 0.15, TMS of R_2 = 0.3, TMS of R_1 = 0.25)

10. Figure 7.51 shows a single-line diagram of a radial feeder wherein definite time overcurrent relays are used for protection. The time of operation of the relay R_3 is 0.2 second for the worst fault. Find out the time of operation of relays R_1 and R_2 for the faults in sections I and II respectively.

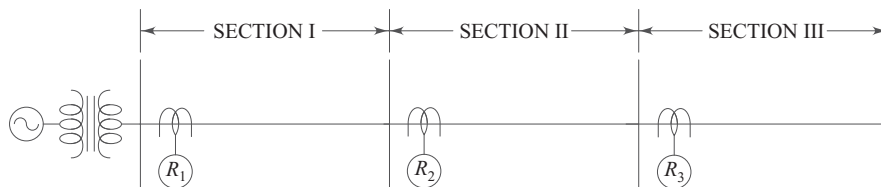


Fig. 7.51 Example 10

(Time of operation of R_3 = 0.2 s, Time of operation of R_2 = 0.45 s, Time of operation of R_1 = 0.7 s)

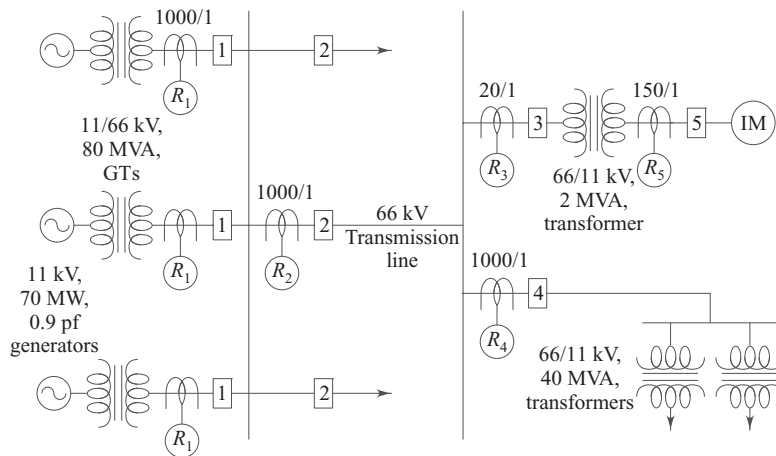


Fig. 7.50 Example 9

11. Figure 7.52 shows a single-line diagram of a portion of a power station. Considering an adequate discrimination margin, determine the relay settings of phase overcurrent relays of IDMT type used therein. Assume that the minimum operating time of relays beyond a PSM equal to 20 is constant at 2.3 seconds at a TMS of 1.0. The fault level at the 6.6 kV bus is 45 kA and that at the 415 V bus is 42 kA.

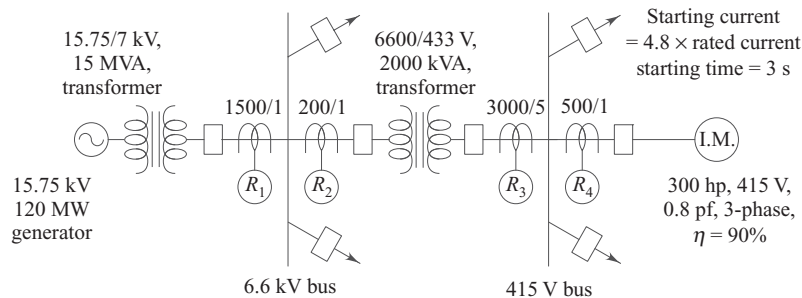


Fig. 7.52 Example 11

(PS of $R_4 = 100\%$, PS of $R_3 = 100\%$, PS of $R_2 = 125\%$, PS of $R_1 = 100\%$, TMS of $R_4 = 0.65$, TMS of $R_3 = 0.7$, TMS of $R_2 = 0.75$, TMS of $R_1 = 0.9$)

12. Figure 7.53 shows a single-line diagram of a power system. Bracketed values give the fault levels on the concerned bus. Relays used are IDMT overcurrent relays. Relays are rated for 1 A with a setting range of 50–200% of 1 A in 7 equal steps each of 25%. Relay R_7 is set at a TMS of 0.25. Assuming a suitable discrimination time, determine the plug-settings and time-settings of all the relays shown in Fig. 7.53.

(PS of $R_7 = 100\%$, PS of R_3 (and R_4) = 150%, PS of R_5 (and R_6) = 100%, PS of R_1 (and R_2) = 200%, TMS of relay R_3 (and R_4) = 0.15, TMS of relay R_5 (and R_6) = 0.1, TMS of relay R_1 (and R_2) = 0.15)

13. Figure 7.54 shows a single-line diagram of a power system. The breaking capacities of breakers are as follows:

Circuit Breakers	Breaking Capacity MVA
1, 2	5000
3, 4, 5, 6	3000
7, 8	2000

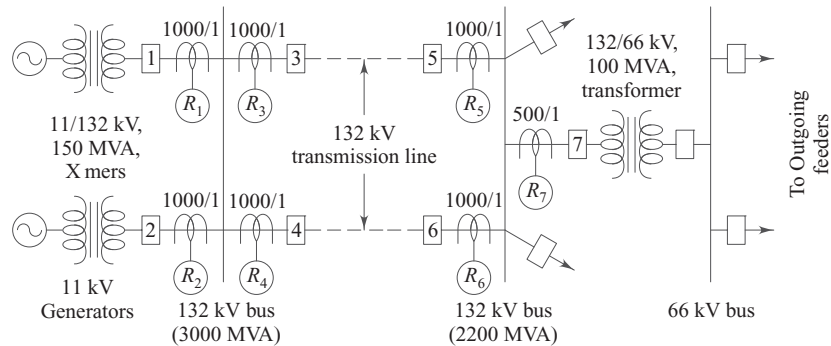


Fig. 7.53 Example 12

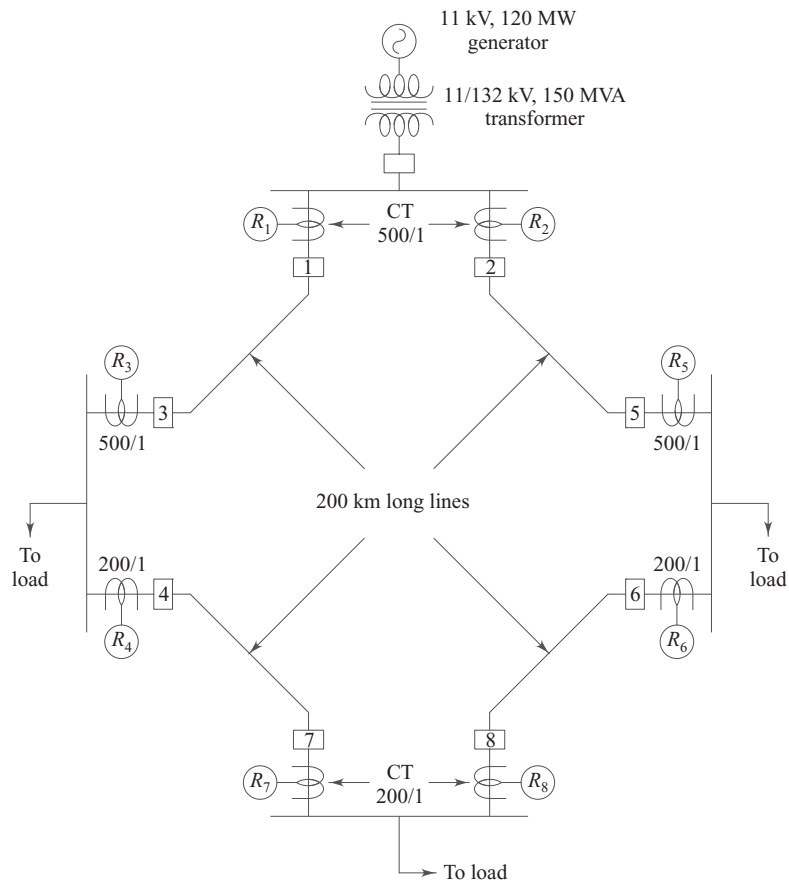


Fig. 7.54 Example 13

The relays used are directional or non-directional IDMT overcurrent relays. The plug-settings of the relays are given as follows:

Relays	Plug setting of CT secondary
R_1	100
R_2	100
R_3	75
R_4	125
R_5	75
R_6	125
R_7	100
R_8	100

Which are the relays requiring directional feature? Given the TMS of relays R_3 and R_5 to be 0.1, determine the TMS of remaining relays shown in Fig. 7.53.

(TMS of R_8 (and R_7) = 0.25, TMS of R_4 (and R_6) = 0.35, TMS of R_1 (and R_2) = 0.5)

14. It is required to change the plug setting of an IDMT overcurrent relay (monitored by undervoltage unit) from 100% to 40% automatically, if the voltage collapses to 70% of the rated normal voltage. With a circuit diagram, show how such a feature can be realised either electromagnetically or statically.
15. Draw the ac circuit (single line diagram) and dc control circuit of the feeder protection using IDMT overcurrent relays monitored by undervoltage relays.
16. Draw a detailed three-phase diagram for protection of transformer feeder wherein IDMT relays are wired on the primary side of a delta-star transformer which feeds a feeder. Also draw a relevant dc control circuit for signaling the breaker.
17. Discuss the rules to be considered while deciding the settings of ground relays used for protection of a transmission line.
18. State and explain the application of very inverse and extremely inverse overcurrent relays.
19. Enumerate different types of problems met with different types of overcurrent relays. Discuss possible solutions and compare these overcurrent relays.
20. Give reasons for the following statements:
 - (i) Relays giving very inverse time-current characteristics are more suitable where the ratio of source impedance to line impedance is large.
 - (ii) Inverse definite minimum time overcurrent relays give better discrimination than inverse-time overcurrent relays.
 - (iii) Overcurrent relays alone are found unsuitable as the main protection of lines with very large variations of load.
 - (iv) Current discrimination in relays cannot be applied where source impedance is large with respect to the line impedance.
 - (v) The earth fault relay used for the protection of the hv. side of a step-down delta-star transformer can be provided with a lower setting than the earth-fault relays on the secondary side.
 - (vi) Ground overcurrent relays can be made more sensitive than phase overcurrent relays. However, their sensitivity is limited if they are connected in the residual circuit of three-line CTs.
 - (vii) Two overcurrent and one earth-fault scheme of protection does not provide adequate protection for transformer feeders.
 - (viii) A directional overcurrent relay will not operate even for a fault current in the operative direction if there is a bolted three-phase short circuit fault at the breaker terminals.
 - (ix) For protection against phase faults, a 90° connection is used in case of directional relays.
 - (x) Directional overcurrent relays are used at the load end of parallel feeders.

21. What are the problems associated with application of instantaneous overcurrent relays for protection of a feeder? What remedies would you suggest to overcome the same?
22. Explain briefly the factors deciding the necessary time interval between successive relays employed for radial feeder protection.
23. Give a classification of overcurrent relays according to their time of operation. State the conditions under which they are employed for feeder protection.
24. What do you understand by IDMT relays? Discuss their use for protection of feeders.
25. Under what conditions are the overcurrent relays to be monitored by undervoltage relays? Why? Draw the dc control circuit for the protection of a feeder by an overcurrent relay monitored by an undervoltage relay.
26. What do you understand by directional sensitivity of a directional relay?
27. Explain the principle of directional relay with the help of an appropriate phasor diagram. Also, explain the significance of maximum torque angle of a directional relay.
28. Explain the 90° connection scheme for directional relays with the help of appropriate circuit diagram and vector diagram.
29. Draw the detailed ac circuit diagram of directional overcurrent and earth-fault protection of a feeder.

MULTIPLE CHOICE QUESTIONS

1. To coordinate overcurrent relays for transmission line protection, the method of discrimination preferred is
 - (a) time discrimination
 - (b) current discrimination
 - (c) current-time discrimination
 - (d) none of the above
2. Zero sequence current is exclusively used for relaying purposes only in the case of
 - (a) phase overcurrent relay
 - (b) phase impedance relay
 - (c) ground overcurrent relay
 - (d) ground impedance relay
3. Overcurrent relays are used as main protection for transmission lines up to
 - (a) 11 kV
 - (b) 66 kV
 - (c) 132 kV
 - (d) 220 kV
4. The maximum torque angle of a directional relay should generally lie between
 - (a) 10° to 30°
 - (b) 30° to 50°
 - (c) 50° to 70°
 - (d) 70° to 90°
5. The time discrimination kept while deciding Time Multiplier Setting (TMS) of overcurrent relay for back-up coordination is based on
 - (a) breaker operating time
 - (b) error in time of operation of relays
 - (c) overshoot of relay
 - (d) all of the above

Protection of Transmission Lines by Distance Relays

In the previous chapter we have already discussed the methods of discrimination for overcurrent relays of different types. We have also discussed the limitations of transmission-line protection using overcurrent relays. The distance relays are not dependent on the Z_0/Z_1 ratio, because they measure only the impedance of the line to be protected by comparing local current with local voltage. The distance relays achieve selectivity on the basis of impedance rather than current and hence can always be set for instantaneous operation in the first zone. Settings for distance relays are relatively easier to carry out.

Because of these advantages, distance relays are applied for long extra-high-voltage transmission lines transmitting power at 132 kV, 220 kV and 400 kV. For 66 kV transmission lines and 11 kV distribution lines, distance protection would not be economically viable and hence overcurrent relays are used. However, overcurrent relays do find their

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Introduction

application as back-up protection relays for extra-high-voltage lines.

As already discussed in Chapter 2, distance relays are supplied with current and voltage juices from line CT and bus PT. Different combinations of current and voltage can render different characteristics such as impedance, ohm, reactance and mho. The distance relays, thus, basically compare local voltage (voltage at relaying point) and local current to measure the impedance from the relaying point to the fault point. As the impedance is proportional to the distance to

the fault point, these relays are termed as distance relays.

The distance measurement can be done either by an amplitude comparator or by a phase comparator. The basic constructional unit representing an amplitude comparator is a balanced beam relay. Similarly, an induction cup relay is a phase comparator. A static phase comparator relay is also discussed in Chapter 3.

8.1 STEPPED DISTANCE CHARACTERISTICS OF A DISTANCE RELAY

The back-up protection is made possible in distance protection by stepped distance characteristics in modern relays. In such a scheme of protection, a distance relay has three zones of protection as shown in Fig. 8.1(a). Due to space limitations in the figure, bus PTs feeding the distance relays are not shown. It is very clear from the figure that each distance relay is designed to be set for three different zones. The first zone covers about 80% of the section to be protected. (The cause for such a practice will be discussed later in this chapter.)

A distance relay operates instantaneously if the fault occurs in the first zone. The second zone covers the first line section plus approximately 50% of the next line section. The same distance relay operates after a preset time delay if the fault occurs in the second zone of protection of the relay. As can be seen in the figure, the relay R_1 would operate in the second zone if the protective relaying equipment fails to clear a fault instantaneously at the relaying point R_3 . No doubt, the full second line section is not covered by the second zone of the relay R_1 . But the relay R_1 does act as a back-up, as the third zone of this relay encompasses the full second-line section.

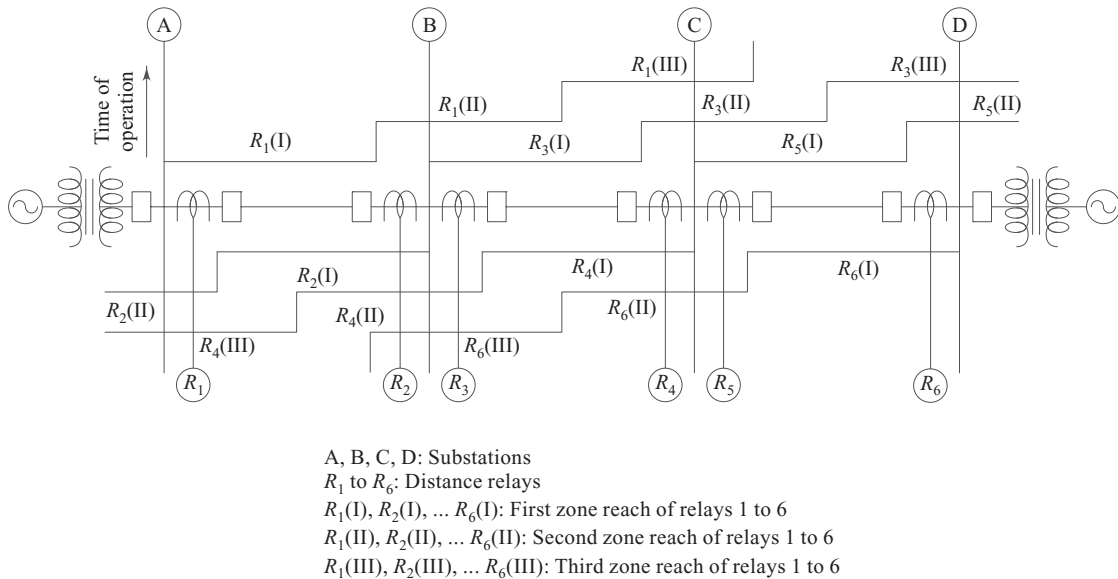


Fig. 8.1(a) Stepped distance characteristics of distance relays

The distance characteristics of a relay (say R_1) are shown in Fig. 8.1(b).

The simplified dc control circuit of a distance protection scheme is shown by Fig. 8.1(c). The directional relay D will not be required in conjunction with mho relay but it is required in conjunction with impedance and reactance relays. Referring to Fig. 8.1(b), if the direction of the fault is correct and the fault is in the first zone, $D-1$ and Z_1-1 close instantaneously energising the trip coil and the tripping relay 86. The seal-in contact 86-1 holds on the trip coil circuit. If the fault lies in the second zone (and not in the first zone), Z_2-1 closes instantaneously. Z_1-1 does not close. Also, as Z_3 encompasses the complete region with diameter AK_3 [refer Fig. 8.1(b)], Z_3-1 will also close instantaneously for the fault in the second-zone energising timer relay T . Closure of T_2-1 after the time delay T_2 completes the trip coil circuit and hence the circuit breaker trips after the time delay T_2 . Similarly, the tripping takes place in the zone 3 after the time delay T_3 . It is very obvious that ohmic settings K_1, K_2 and K_3 as well as time settings T_2 and T_3 are independently adjustable.

8.2 QUANTITIES TO BE FED TO DISTANCE RELAYS

The impedance measurement rendered by a distance relay should be a positive sequence impedance of the transmission line from the relaying point to the fault. It is essential that this measurement should remain unaltered for a given fault occurrence irrespective of the type of fault, i.e., L-L-L-g, L-L-g, L-g or L-L fault.

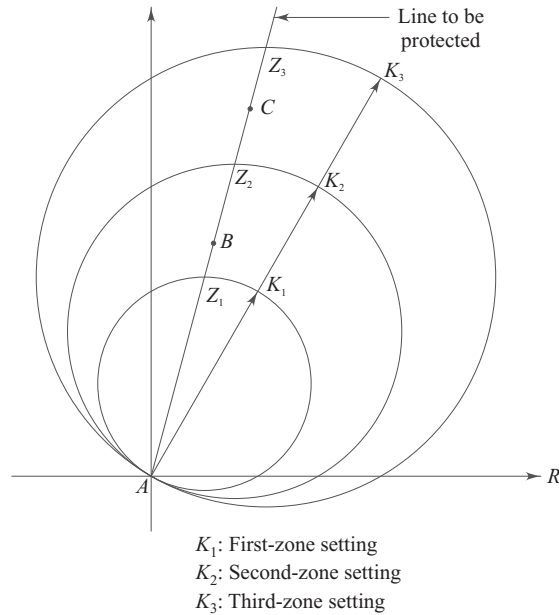


Fig. 8.1(b) Characteristics of mho relays

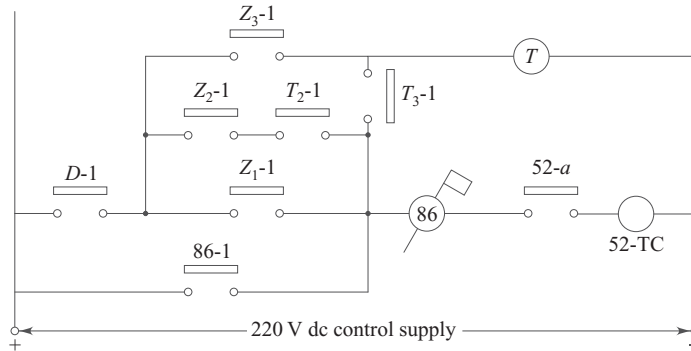


Fig. 8.1(c) Simplified dc control circuit of distance protection scheme

The quantities to be fed to the distance relay for the correct measurement of the impedance are justified in the following paragraphs.

8.2.1 Three-phase Faults

Before proceeding to the analysis of fault conditions, let us brush up the fundamental formulae for the theory of symmetrical components.

$$I_R = I_1 + I_2 + I_0 \quad (8.1)$$

$$I = a^2 I_1 + a I_2 + I_0 \quad (8.2)$$

$$I_B = a I_1 + a^2 I_2 + I_0 \quad (8.3)$$

Similarly,

$$V_R = V_1 + V_2 + V_0 \quad (8.4)$$

$$V = a^2 V_1 + a V_2 + V_0 \quad (8.5)$$

$$V_B = a V_1 + a^2 V_2 + V_0 \quad (8.6)$$

where, suffixes R , and B denote the respective phases, and suffixes 1, 2 and 0 are used for positive, negative and zero sequence components respectively.

Now, in case of a three-phase short circuit,

$$V_R = V = V_B = 0 \quad (8.7)$$

The use of equations (8.4) to (8.6) in Eq. (8.7) will lead to the following results:

$$V_1 = 0, \quad V_2 = 0, \quad V_0 = 0 \quad (8.8)$$

Also, as V_2 and V_0 are zero, I_2 and I_0 will vanish.

$$\text{i.e.,} \quad I_2 = 0, \quad I_0 = 0 \quad (8.9)$$

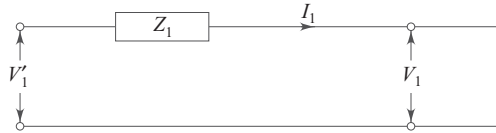


Fig. 8.2 Three-phase fault

The sequence network for such a fault is represented in Fig. 8.2. From Fig. 8.2,

$$V_1 = \text{Positive sequence voltage at the fault point,}$$

$$V'_1 = \text{Positive sequence voltage at the relay location,}$$

$$V'_1 = V_1 + I_1 Z_1 \quad (8.10)$$

If V'_R , V' and V'_B are the phase voltages at the relay location,

$$V'_R = V'_1, \quad V' = a^2 V'_1, \quad V'_B = a V'_1 \quad (8.11)$$

This is because the negative and zero sequence voltage components are absent for three-phase fault. Also, for the same reason, the currents in the three phases will be,

$$I_R = I_1, \quad I = a^2 I_1, \quad I_B = a I_1 \quad (8.12)$$

Substituting the value of V'_1 from Eq. (8.10) in Eq. (8.11) gives,

$$V'_R = V_1 + I_1 Z_1 \quad (8.13)$$

$$V' = a^2 (V_1 + I_1 Z_1) \quad (8.14)$$

$$V'_B = a (V_1 + I_1 Z_1) \quad (8.15)$$

But as $V_1 = 0$ the equations will reduce to,

$$V'_R = I_1 Z_1 \quad (8.16)$$

$$V' = a^2 I_1 Z_1 \quad (8.17)$$

$$V'_B = a I_1 Z_1 \quad (8.18)$$

It can be seen from equations (8.12), (8.16), (8.17) and (8.18) that any one pair of the quantities (i.e., V'_R and I_R , V' and I , V'_B and I_B) available at relay location will give the measurements of positive sequence impedance up to fault point.

This means that

$$\frac{V'_R}{I_R} = \frac{V'}{I} = \frac{V'_B}{I_B} = Z_1 \quad (8.19)$$

However, as we shall see later, the phase quantities used this way do not give the correct impedance measurement in case of other types of faults. Hence quantities V'_R and $(I_R - I)$ are fed to the relay. As such, there are three relays taking care of three types of L-L faults. The other two relays are fed with V'_B and $(I - I_B)$ and V'_{BR} and $(I_B - I_R)$. One can easily check up that all the relays will measure the positive sequence impedance Z_1 in case of a three-phase fault.

8.2.2 Two-phase Faults

In case of a $-B$ fault,

$$V = V_B, \quad I_R = 0, \quad I = -I_B \quad (8.20)$$

Using equations (8.4) to (8.6),

$$\begin{aligned} (V - V_B) &= V_1(a^2 - a) + V_2(a - a^2) = 0 \\ V_1 &= V_2 \end{aligned} \quad (8.21)$$

Similarly, equations (8.1) to (8.3) substituted in Eq. (8.20),

$$\begin{aligned} I_R + I + I_B &= 3I_0 = 0 \\ I_0 &= 0 \end{aligned} \quad (8.22)$$

and

$$\begin{aligned} I_R &= I_1 + I_2 + I_3 = 0 \\ I_1 + I_2 &= 0 \\ I_1 &= -I_2 \end{aligned} \quad (8.23)$$

The sequence network for such a fault is shown in Fig. 8.3. From Fig. 8.3,

$$V'_1 = V_1 + I_1 Z_1, \quad V'_2 = V_2 + I_2 Z_2 \quad (8.24)$$

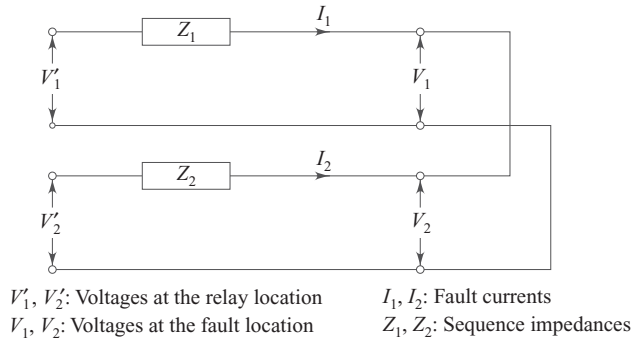


Fig. 8.3 Two-phase fault

As $I_2 = -I_1$ and $V_1 = V_2$ for two-phase fault and $Z_1 = Z_2$ for transmission line,

$$V'_1 = V_1 + I_1 Z_1, \quad V'_2 = V_1 - I_1 Z_1 \quad (8.25)$$

Hence, we can write the equations for the phase voltages at the relay locations

$$V'_R = V'_1 + V'_2 + V'_0$$

$$V' = a^2 V'_1 + a V'_2 + V'_0$$

$$V'_B = a V'_1 + a^2 V'_2 + V'_0$$

But as the zero sequence current and hence zero sequence voltage are absent in two-phase faults,

$$V'_R = V'_1 + V'_2 \quad (8.26)$$

$$V' = a^2 V'_1 + a V'_2 \quad (8.27)$$

$$V'_B = a V'_1 + a^2 V'_2 \quad (8.28)$$

Substituting values of V'_1 and V'_2 in equations (8.26) to (8.28),

$$V'_R = V_1 + I_1 Z_1 + V_1 - I_1 Z_1 = 2V_1 \quad (8.29)$$

$$V' = V_1 (a^2 + a) + I_1 Z_1 (a^2 - a) \quad (8.30)$$

$$V'_B = V_1 (a + a^2) + I_1 Z_1 (a - a^2) \quad (8.31)$$

Similarly,

$$I_R = I_1 + I_2 = 0 \quad (8.32)$$

$$I \quad a^2 I_1 + a I_2 = I_1 (a^2 - a) \quad (8.33)$$

$$I_B \quad a I_1 + a^2 I_2 = I_1 (a - a^2) \quad (8.34)$$

One can appreciate that if the phase quantities (i.e., say V' and I) are fed to the relay, the measurement will not result in Z_1 , the positive sequence impedance. Instead if the line voltage V'_B (i.e., $V' - V'_B$) and delta current (i.e., $I - I_B$) are fed to the relay it will correctly measure the positive sequence as proved below.

$$V'_B = 2I_1 Z_1 (a^2 - a) \quad (8.35)$$

$$I - I_B = 2I_1 (a^2 - a) \quad (8.36)$$

$$V'_B / (I - I_B) = Z_1 \quad (8.37)$$

For R- fault, V'_R and $(I_R - I)$ are fed to a second distance relay. Similarly, B-R fault is taken care of by a third distance relay. In the foregoing analysis, the fault resistance is ignored.

8.2.3 Two-Phase to Ground Faults

For a -B-g fault,

$$V = V_B = 0, I_R = 0 \quad (8.38)$$

$$I_R = I_1 + I_2 + I_0 = 0$$

$$\text{i.e.,} \quad I_1 = -(I_2 + I_0) \quad (8.39)$$

Using equations (8.4) to (8.6),

$$V_1 = V_2 = V_0 \quad (8.40)$$

From a given sequence network of Fig. 8.4,

$$V'_1 = V_1 + I_1 Z_1 \quad (8.41)$$

$$V'_2 = V_2 + I_2 Z_2 = V_1 + I_2 Z_1 \quad (8.42)$$

$$V'_0 = V_0 + I_0 Z_0 = V_1 + I_0 Z_0 \quad (8.43)$$

The voltages and currents at the relay point are as follows:

$$V' = a^2 V'_1 + a V'_2 + V'_0$$

$$V'_B = a V'_1 + a^2 V'_2 + V'_0$$

$$\begin{aligned}
 V'_B &= (V' - V'_B) = V'_1(a^2 - a) + V'_2(a - a^2) \\
 &= (V_1 + I_1 Z_1)(a^2 - a) + (V_2 + I_2 Z_1)(a - a^2) \\
 V'_B &= Z_1(a^2 - a)(I_1 - I_2)
 \end{aligned} \tag{8.44}$$

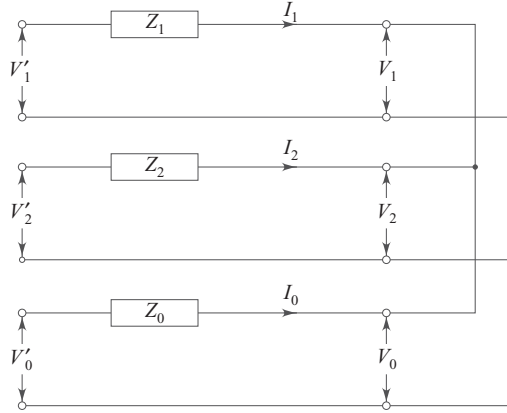


Fig. 8.4 Two-Phase to ground fault

Similarly,

$$\begin{aligned}
 I &= a^2 I_1 + a I_2 + I_0 \\
 I_B &= a I_1 + a^2 I_2 + I_0 \\
 I - I_B &= I_1(a^2 - a) + I_2(a - a^2) \\
 I - I_B &= (a^2 - a)(I_1 - I_2)
 \end{aligned} \tag{8.45}$$

$$\frac{V'_B}{(I - I_B)} = Z_1 \tag{8.46}$$

Thus, it is observed that the same quantities being fed to the relay will take care of an L-L-g fault also. However, should single phase to ground fault occur, the impedance measurement will not be correct (i.e. the relay will not measure positive sequence impedance to the fault) using the same technique.

8.2.4 Single Phase-to-Ground Faults

For R-g fault,

$$V_R = 0, \quad I = 0, \quad I_B = 0 \tag{8.47}$$

Substituting these values in fundamental formulae of equations (8.1) to (8.6), we get,

$$I_1 = I_2 = I_0 \tag{8.48}$$

$$V_1 + V_2 + V_0 = 0 \tag{8.49}$$

With the help of a sequence network shown in Fig. 8.5, the values of the quantities fed to the relay can be derived,

$$\begin{aligned}
 V'_R &= V'_1 + V'_2 + V'_0 \\
 &= (V_1 + I_1 Z_1) + (V_2 + I_2 Z_2) + (V_0 + I_0 Z_0) \\
 &= (V_1 + V_2 + V_0) + I_1 Z_1 + I_2 Z_2 + I_0 Z_0
 \end{aligned}$$

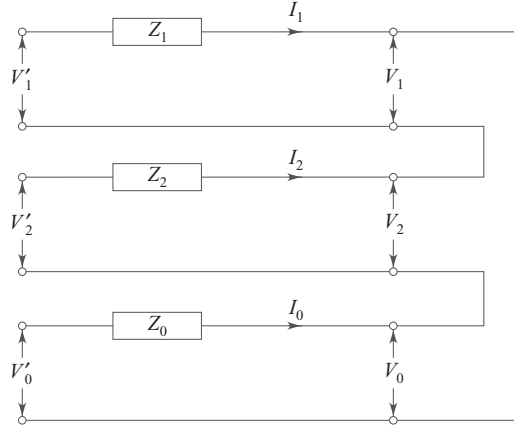


Fig. 8.5 Phase-to-ground fault

Using equations (8.48) and (8.49) and taking $Z_2 = Z_1$ for transmission line,

$$V'_R = 2I_1 Z_1 + I_1 Z_0 \quad (8.50)$$

Similarly,

$$I_R = I_1 + I_2 + I_0 = 3I_1 \quad (8.51)$$

It can be seen that the impedance seen by the relay,

i.e., $(V'_R/I_R) \neq Z_1$

If the relay is supplied with current $I_R + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]$, the measurement will be correct. Thus, current fed to the relay [using equations (8.48) and (8.51)] will be,

$$\begin{aligned} I_R + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right] &= 3I_1 + I_1 \left[\frac{Z_0 - Z_1}{Z_1} \right] \\ &= \frac{(3I_1 Z_1 + I_1 Z_0 - I_1 Z_1)}{Z_1} = \frac{(2I_1 Z_1 + I_1 Z_0)}{Z_1} \end{aligned}$$

Therefore, impedance measured by the relay will be,

$$\frac{V'_R}{I_R + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]} = Z_1$$

$(Z_0 - Z_1)/Z_1$ being known for the section to be protected, the zero sequence current compensation can be given to the relay for the correct measurement. Such three relays will take care of R-g, -g and B-g faults.

The relevant quantities for -g and B-g relays are,

$$V', I + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right] \quad \text{and} \quad V'_B, I_B + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]$$

It is interesting to note that -g and B-g relays will operate for a -B-g fault and they will also measure Z_1 up to the fault.

Thus, six distance relays are required to protect a transmission line against all types of faults. The inputs to these relays are summarised in the following table.

	Relays	Relay's Voltage	Input Current	Faults for which the relay operates
Phase	R-	V_R	$I_R - I$	R- -B, R- , R- -g
	-B	V_B	$I - I_B$	R- -B, -B, -B-g
	B-R	V_{BR}	$I_B - I_R$	R- -B, B-R, B-R-g
Ground	R-g	V_R	$I_R + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]$	R-g, R- -g, B-R-g
	-g	V	$I + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]$	-g, -B-g, R- -g
	B-g	V_B	$I_B + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]$	B-g, B-R-g, -B-g

8.3 PROBLEMS IN DISTANCE MEASUREMENT

1. Direction As we have discussed earlier about the different characteristics, one can easily appreciate that except for a mho relay other distance relays explained so far do not have the directional feature. A mho relay is inherently directional. Other distance relays have to be used in conjunction with a directional relay.

2. Fault Resistance We have discussed that the distance relay measures the impedance of the line to be protected. As the impedance is proportional to the length of the line, we can decide the reach of the relay. Now, when the fault takes place, the impedance involved is that of the line plus the fault impedance. In case of a line-to-ground fault, the fault impedance consists of the resistance of the arc (flashover at line insulator), tower footing resistance and the resistance of the ground. In case of a line-to-line fault, the arc resistance forms the fault impedance.

We will, now, discuss the effect of a fault impedance (or resistance) on different distance characteristics.

As shown in Fig. 8.6, the voltage measured by the relay is V_r instead of V_L because of the drop in the fault resistance.

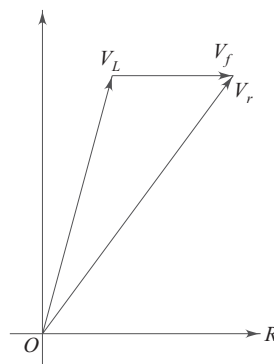


Fig. 8.6 Voltage measured by a relay when fault involves resistance

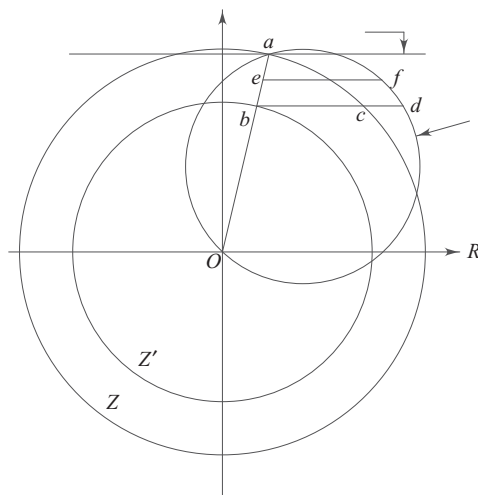
Figure 8.7 shows the effect of fault resistance on impedance, mho and reactance units. If the fault involves the fault resistance equal to bc then the impedance relay reaches up to ob instead of oa . This is very obvious because for the fault anywhere within the line segment ab , the impedance measurement will be out of the impedance circle. This is known as under-reaching of a relay. Higher the fault resistance, the more will be the effect of under-reaching.

The mho unit can incorporate more fault resistance (bd) than the impedance unit for the same under-reach (ab). In other words, for the same fault resistance (ef), the under-reach of a mho relay is reduced (ae).

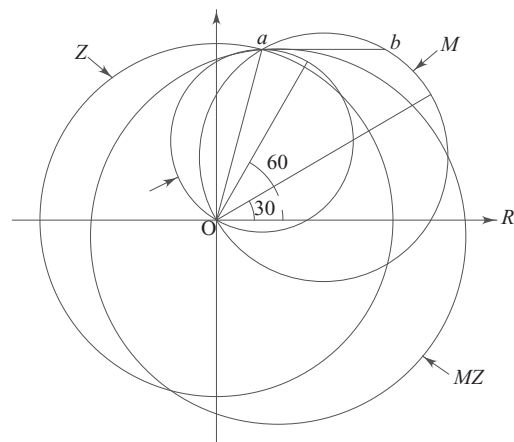
The reactance relay is immune to the fault resistance as it measures only the reactance of the line to be protected.

Based on this discussion, we can conclude that the reactance relay is a good choice for short transmission lines. In case of short lines, the fault impedance (Z_f) is comparable with the line impedance (Z_l), i.e., the effect of Z_f is pronounced.

In case of long lines, however, the fault resistance is negligibly smaller compared to the line impedance, and hence the fault resistance does not cause any problem or does not give rise to any appreciable error. In such a case, the mho relay is a good choice. The modified impedance characteristic (Fig. 8.8) has more tolerance for fault resistance. Similarly, using a modified mho characteristic (mho characteristic with lower characteristic angle) more fault resistance can be incorporated than the standard mho characteristic (characteristic angle 60° to 75°). The area encompassed by such a modified characteristic is so large that the problems of uncalled operation due to power swings and overloads will be frequent, and hence a mho relay with a characteristic angle of 60° to 75° is generally preferred for transmission line protection.



Z' : Reactance characteristic
 Z : Mho characteristic
 Z : Impedance characteristic
 bc : Z underreach due to fault resistance
 oa : Transmission line to be protected
 ab : Underreach of impedance relay
 ae : Underreach of mho relay



Z : Standard impedance characteristic
 MZ : Modified impedance characteristic
 Z : Standard mho characteristic (angle = 60°)
 M : Modified mho characteristic (angle = 30°)

Fig. 8.7 Consequences of fault resistance

Fig. 8.8 Modified impedance and mho characteristics

3. Close-in Faults In case of the faults just after the relay point, the distance relay may fail to operate because of absence of a polarising voltage. Three possible solutions to this problem are

- ultra sensitivity,
- memory action, and
- polarisation with potential from unfaulted phase.

A flashover will always provide at least 3% of normal voltage on overhead lines because of the arc resistance. Considering this fact, the distance relays with a voltage sensitivity of 1% are employed. Any lower value would be beyond the accuracy of the PTs.

The implementation of memory action can remember the voltage before a fault and thus help in use of a memorised polarising voltage to operate the relay. A charged capacitor can be used for this purpose.

None of these three methods is effective in case of a bolted short circuit on the circuit breaker terminals caused by leaving ground switches ON. A control circuit shown in Fig. 8.9 can be useful for such a possibility.

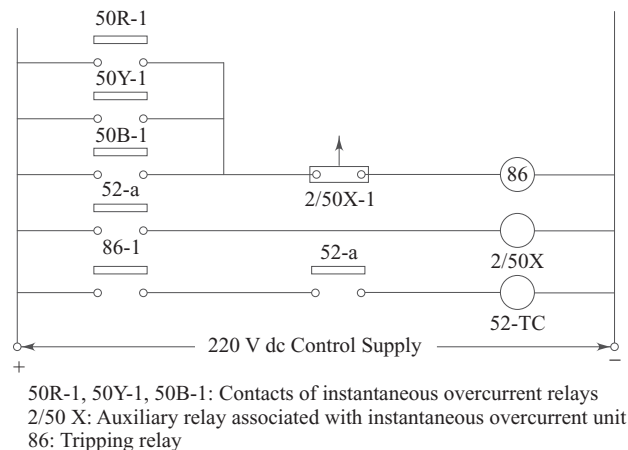


Fig. 8.9 DC control circuit for close-in fault

If the circuit breaker is closed when the earthing switch is inadvertently kept ON, the distance relay will not be able to sense the fault. In such a case, a dc auxiliary relay, 2/50X, which has a time delay (to pick-up) of 4 cycles gets energised due to closure of the 'a' switch (mechanically operated with circuit-breaker operation). The trip circuit is closed for 4 cycles by the contacts of instantaneous overcurrent relays set to operate for close-in faults. After 4 cycles, 2/50X-1 opens to disconnect the trip circuit to let the distance relays take over the function of tripping of the circuit breaker. The tripping due to distance relay operation is not shown in Fig. 8.9.

4. Overloads Figure 8.10 shows the normal load area on the R-X plane. In case of overloads, the operating point *P* moves towards the 3rd zone of the relay. If the point *P* enters the third zone, the relay will operate in the third zone which is not desirable. This would, particularly, happen in the case of long lines. Thus, the limit of setting of the third zone is decided by a possible overload.

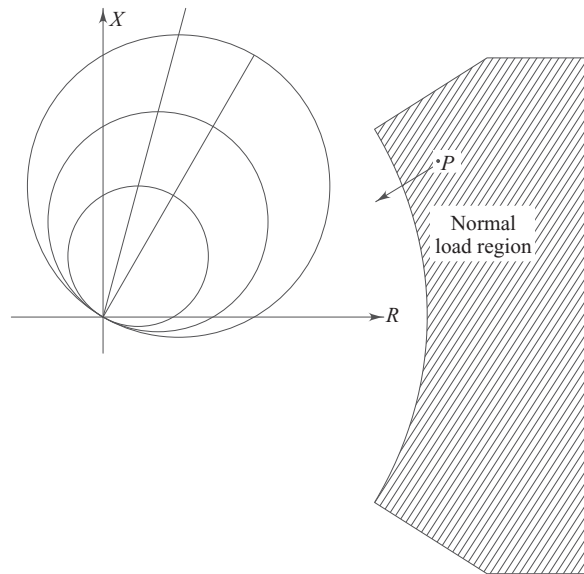


Fig. 8.10 Possibility of mal-operation of distance relay due to overload

It can be appreciated that mho relays are better than impedance relays with reference to the problem of overloads.

5. Power Swings Before we enter into the problem posed by power swings, let us understand as to what a power swing actually is. Basically, the condition of a power swing is posed by out-of-step operation or loss of synchronism between the generators of the power system. The condition can be caused by either a fault on any of the interconnecting tie lines of the system or abrupt disconnection of a transmission line transmitting bulk power.

Consider the single-line diagram of Fig. 8.11, which represents the system by its two-generator equivalent. Figure 8.12 indicates the positive sequence network generally drawn for a three-phase fault. We are interested in studying the response of the relay (as shown in Fig. 8.11) to the loss of synchronism between the two generating sources. Each generating source may be either an actual generator or an equivalent generator representing the group of generators that remain in synchronism.

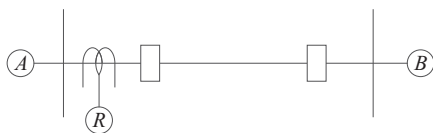


Fig. 8.11 Single-line diagram of a system

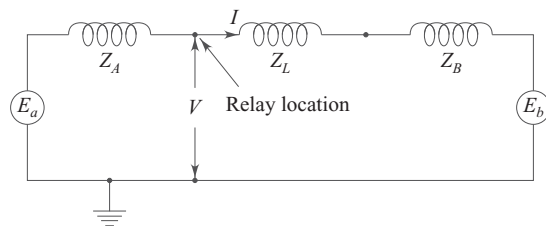


Fig. 8.12 Positive sequence network of Fig. 8.11

The relay current and voltage can be derived as follows:

$$I = \frac{(E_A - E_B)}{(Z_A + Z_L + Z_B)}$$

$$V = (E_A - IZ_A) = E_A - \frac{(E_A - E_B)Z_A}{(Z_A + Z_L + Z_B)}$$

and the impedance seen by the relay,

$$Z = \frac{V}{I} = \frac{E_A (Z_A + Z_L + Z_B)}{(E_A - E_B)} - Z_A$$

If, because of loss of synchronism E_A advances by an angle θ with reference to E_B and if we let the magnitude of E_A be equal to nE_B where n is a scalar,

$$\frac{E_A}{E_A - E_B} = \frac{n(\cos \theta + j \sin \theta)}{n(\cos \theta + j \sin \theta) - 1} = \frac{n(n - \cos \theta - j \sin \theta)}{(n^2 - 2n \cos \theta + 1)}$$

For a special case when $n = 1$,

$$\frac{E_A}{E_A - E_B} = \frac{1}{2} (1 - j \cot(\theta/2))$$

Therefore,

$$Z = \frac{(Z_A + Z_L + Z_B)(1 - j \cot(\theta/2))}{2} - Z_A$$

This value of Z shown on the R-X diagram of Fig. 8.13 is for θ less than 180° . Thus, the point P is on the loss of synchronism characteristic (or power swing locus). It can also be evidently seen that all other points (for different angles θ) will lie on the perpendicular bisector of the line segment AB . Thus, this perpendicular bisector is a power swing locus. The location of P for any angle θ between the generators can be found graphically by drawing a straight line from either the end A or the end B of the line AB at angle $(90^\circ - \theta/2)$ to AB . The point P lies on the intersection of this line with a power swing locus. It will be of interest to note that this angle θ is same as an electrical load angle θ by which the rotor of the generator A slips with reference to that of the generator B .

The preceding paragraphs explain how to draw a swing locus on the R-X diagram for the special case of $n = 1$. For all practical purposes this is enough, perhaps, in order to understand the response of the distance relay to loss of synchronism. However, let us scan through quickly for the general case where n is greater or less than unity.

From the earlier development, it could be gathered that all power swing characteristics are circles with their centres on extensions of the total impedance line AB of Fig. 8.13. The power swing characteristic of Fig. 8.13 is a circle of infinite radius. Figure 8.14 shows three loss of synchronism characteristics for $n > 1$, $n = 1$ and $n < 1$.

The points A, B, P, P' and P'' are on the periphery of a circle because points P, P' and P'' are for the same angle θ by which the generator A has advanced, ahead of the generator B . This fact that P, P' and P'' are the points on the same circle is a geometrical fact as when $APB, AP'B$ and $AP''B$ are all equal to θ and A, B, P, P' and P'' must lie on the periphery of a circle.

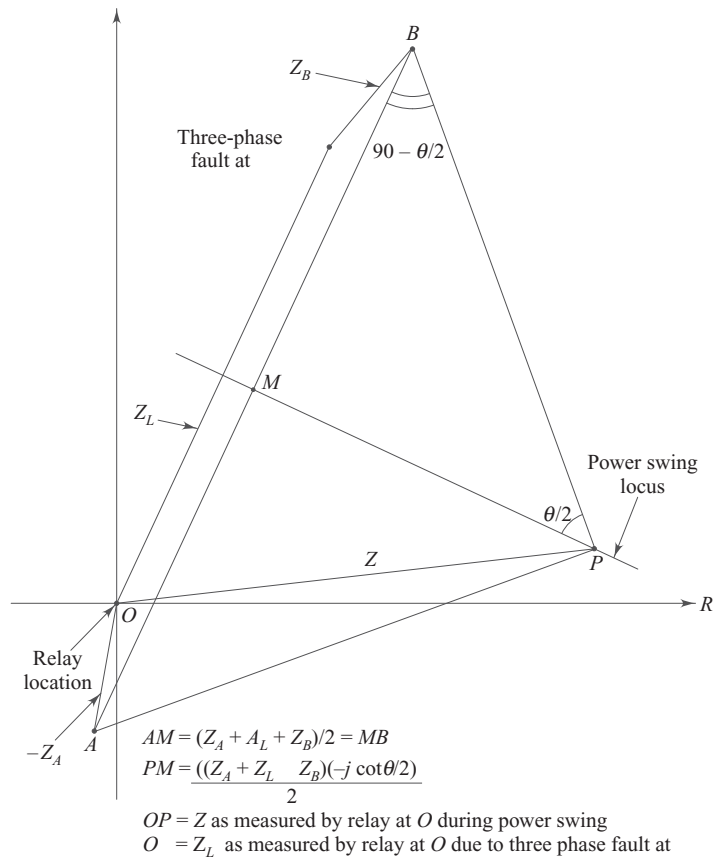


Fig. 8.13 Construction for location of P due to power swing condition

Another interesting aspect of the diagram of Fig. 8.14 is given by the following equations:

$$(P'A \ P'B) = n \quad \text{where } n > 1$$

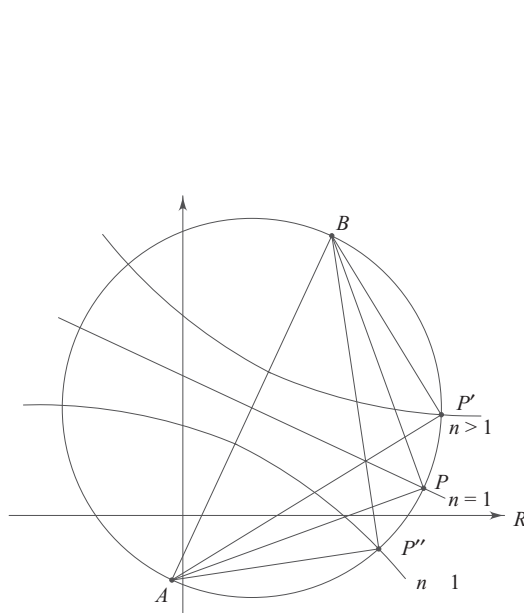
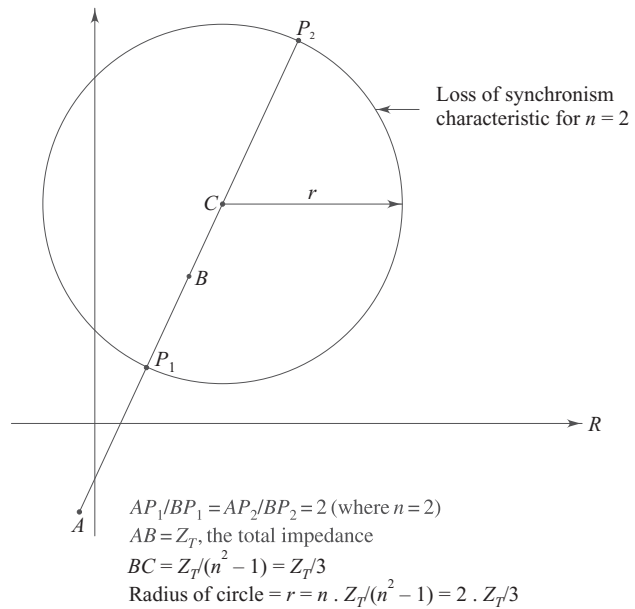
$$(PA/PB) = n \quad \text{where } n = 1$$

$$(P''A/P''B) = n \quad \text{where } n \geq 1$$

This suggests a very simple method by which the loss of synchronism characteristic can be constructed graphically for any value of n . It is only necessary to assume two possible locations of P (as shown by P_1 and P_2 in Fig. 8.15) on the line AB and its extension such that

$$(AP_1/BP_1) = (AP_2/BP_2) = n \quad \text{where } n > 1$$

With this data, it can be mathematically proven that the centre C of a circle representing a power swing locus is at a distance $\frac{Z_T}{(n^2 - 1)}$ from the point B as shown in Fig. 8.15 where Z_T is the total impedance represented by the line AB . The radius of the circle is $\frac{nZ_T}{(n^2 - 1)}$. For $n = 1$, the similar characteristic will be symmetrical to Fig. 8.15 with its centre beyond A . The relevant distances will be as under:


Fig. 8.14 General power swing characteristic

Fig. 8.15 Graphical construction of loss of synchronism characteristic

Radius
$$r = \frac{nZ_T}{(1 - n^2)} \text{ and,}$$

Distance
$$AC = \frac{Z_T}{(1 - n^2)}$$

Now we will understand how such a power swing can be responsible for mal-operation of a distance relay. Consider an interconnected network as shown in Fig. 8.16. For a fault at F as shown, breakers 6 and 7 must trip to isolate the faulty section. This means that distance relays R_6 and R_7 must operate. But meanwhile as the fault current is fed by both the generators G_1 and G_2 , their load angles will increase. As G_2 is nearer to the fault, it will share a larger amount of fault current rather than that shared by G_1 . This gives rise to a power swing. Under this condition, all the relays (R_1 to R_8) of the system will see the impedance continuously decreasing. Thus the point P of Fig. 8.17 moves continuously on the locus of a power swing as shown by the arrowhead. When this point P enters the relay characteristic, the relay will mal-operate until the fault is cleared by breakers 6 and 7. To avoid the mal-operation of other relays (i.e., R_1, R_2, R_3, R_4, R_5 and R_8), some remedy is to be found out.

As can be seen in Fig. 8.17, the reactance relay is most susceptible to a power swing since the area under the characteristic is an operating region. Impedance characteristic is also largely affected by out-of-step condition. The mho characteristic (characteristic angle = 60°) is most immune to power swing compared to all other types of distance relay characteristics. The modified mho relay (characteristic angle = 30°) giving better performance for incorporating the fault resistance, proves to be worse than the standard mho characteristic when we compare them with respect to performance during power swing.

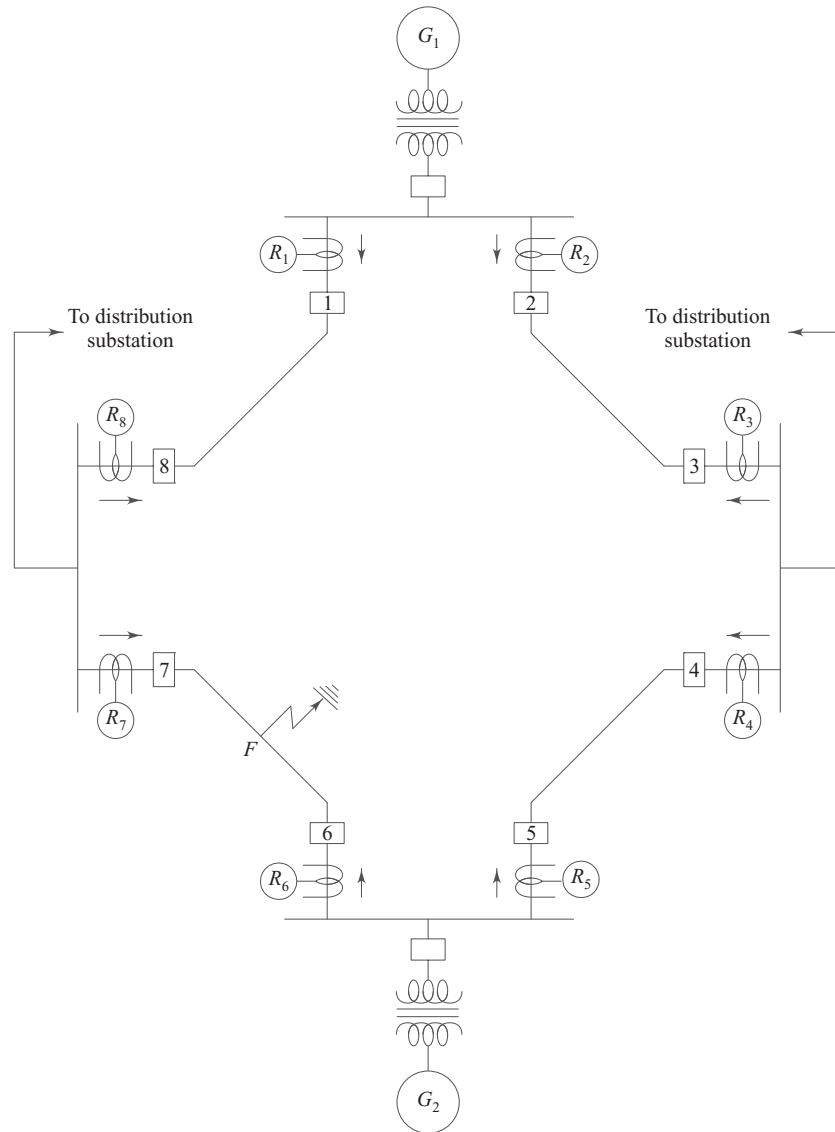


Fig. 8.16 Single-line diagram of an interconnected network

The mho relay, though least affected by power swings, cannot be considered to be fully immune either. An auxiliary offset mho relay can be used in conjunction with a mho relay to bring in out-of-step blocking feature in the distance protection scheme. The scheme is shown in Fig. 8.18(a) and 8.18(b). Point P will move on the locus of power swing comparatively at a slower speed in out-of-step conditions than under the fault conditions.

In case of loss of synchronism, when the point P enters the O characteristic, O operates. Hence O -1 closes. Relay has yet not operated. Closure of O -1 energises the timer auxiliary relay T , which closes its

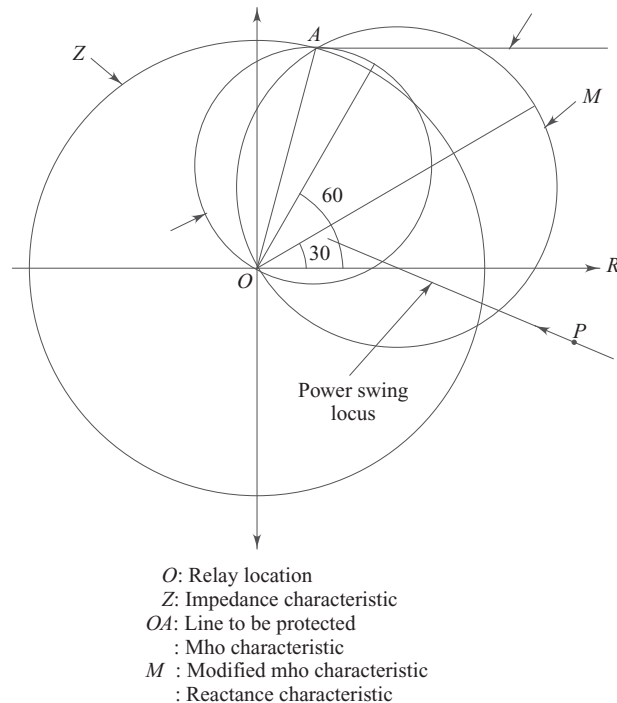


Fig. 8.17 Effect of power swing on different distance relays

contacts after a prescribed time delay. The contact $T-1$ opens. Now even if -1 closes when P enters the characteristic, the timer relay cannot be shorted because the circuit has been disconnected at $T-1$. Contact $T-2$ of the timer relay makes the trip circuit ineffective even if -2 closes. Obviously, the timer T has to time out before P enters the characteristic.

In case of faults that require tripping, $O-1$ and -1 close practically simultaneously because under a fault condition, P will cross both the characteristics simultaneously and hence the timer relay will be short-circuited. Thus, the timer T is made ineffective. Closure of -2 will then complete the trip circuit.

6. Transient Conditions We have already discussed that when a fault occurs, the short-circuit current may be asymmetrical in nature. The asymmetry would eventually die down, depending upon the R ratio of the system. In modern systems having a high R ratio, the dc offset may be present for several cycles. This dc offset may not pose much of a problem for the second and third zone of a distance relay as the relay is designed to operate after a delayed time in these zones. But as the relay operates instantaneously in the first zone, the presence of a dc offset can cause erroneous operation. The distance relay may overreach in the first zone in such a case.

One remedy to this problem of overreaching of a distance relay is to differentiate (or even double differentiate) the input current to the relay so that the dc offset is practically filtered or at least attenuated.

Compensation for overreach is obtained, in practice, by adjusting the relays to operate at 10% to 20% lower impedance than that for which they would otherwise be adjusted. This means that the first zone of the relay extends up to about 80% of the first line section of the line to be protected. The reach of the third zone

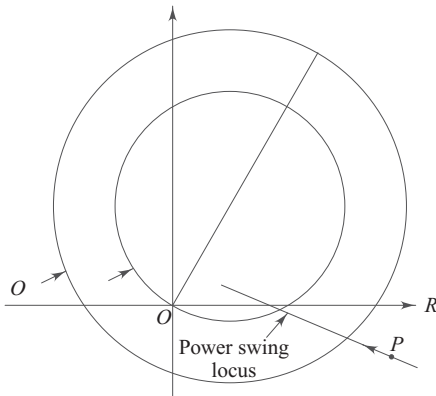


Fig. 8.18(a) Out-of-step blocking in a distance protection scheme

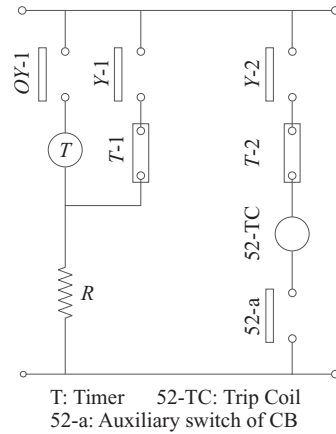


Fig. 8.18(b) DC control circuit for out-of-step blocking

is limited by the other fact already discussed, viz, the problem of erroneous (unfaulted) operation due to overloads and power swings.

7. Loss of Potential due to Blowing of Fuse in the PT circuit When one of the fuses of a PT circuit fails, the voltage supplied to the distance relay coil may drop down causing erroneous operation of the relay. The scheme that takes care of this problem is shown in Fig. 8.19(a) and Fig. 8.19(b).

When the secondary fuses of a PT are healthy, the voltage balance relays (the voltage operated relays) 60R, 60Y and 60B remain in an energised condition because full line-to-neutral voltage is available at their terminals. Hence contacts 60R-1, 60Y-1 and 60B-1 will be in an open condition, keeping the relay 60X in

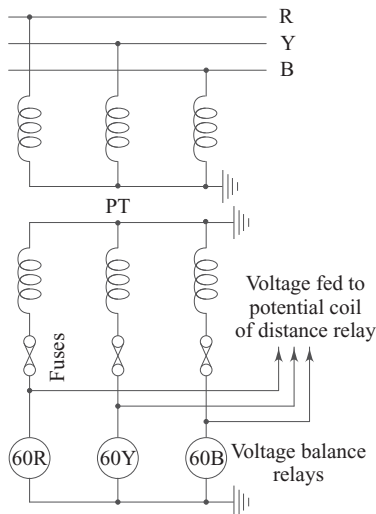


Fig. 8.19(a) AC circuit to avoid mal-operation against PT fuse failure

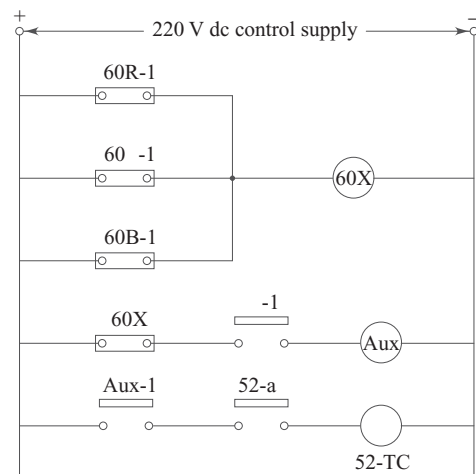


Fig. 8.19(b) DC control circuit of Fig. 8.19(a)

a de-energised condition. In such a case when the fault occurs, closure of -1 causes tripping of the circuit breaker as desired.

Should any one of the PT fuses fail, say in the R-phase, 60R will get de-energised, closings the 60R-1 contact. Closure of 60R-1 energises the 60X relay, and 60X-1 opens making the tripping relay circuit ineffective. Now even though -1 closes, the auxiliary tripping relay will not get energised and hence there will not be any unwanted tripping of the circuit breaker which is what we need.

8. Double Infeed Lines (Bilateral Infeed in Protected Section) When the line to be protected is fed from both the ends, a distance relay may erroneously operate as explained below.

Figure 8.20(a) shows two generators G_A and G_B feeding a tie line AB . A and B are switchyards; 'a' and 'b' are distance relays. The fault occurs at F .

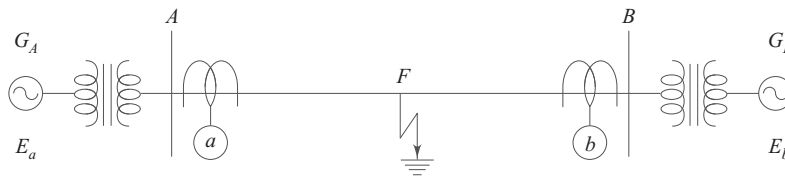


Fig. 8.20(a) Double infeed line

Figure 8.20(b) shows the equivalent circuit of Fig. 8.20(a). I_A and I_B are not in phase. The angle between vectors I_A and I_B is an angle between the bus voltages. Figure 8.20(c) shows the vectorial representation of I_A and I_B .

The mho relay characteristics of relays, a and b are shown in Fig. 8.20(d) and Fig. 8.20(e). The fault at F_1 is seen to be at P , making the relay a overreach. The fault at F_2 is seen to be at Q . Thus the relay b under-reaches. A similar problem will be found while using reactance relays also. The problem can be solved by using ohm relays.

9. Double Circuit Lines When two lines run in parallel, as usually is the case, there will be mutual inductance present, i.e., one line will have its self-inductance plus the mutual reactance because of the other line.

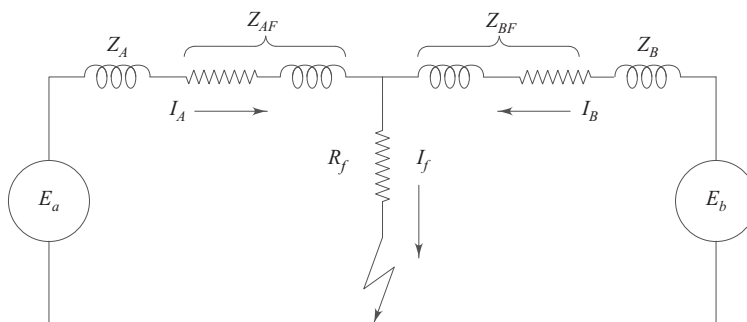


Fig. 8.20(b) Equivalent circuit

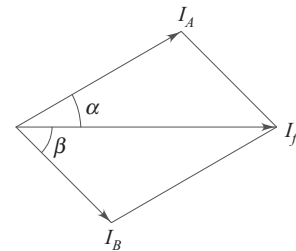
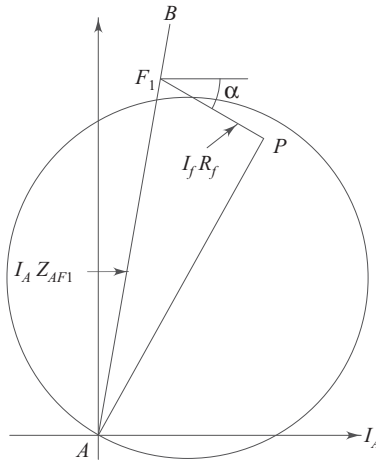
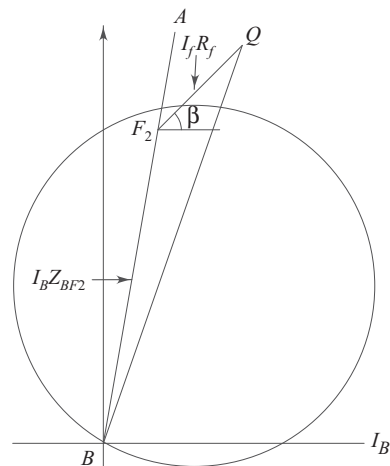


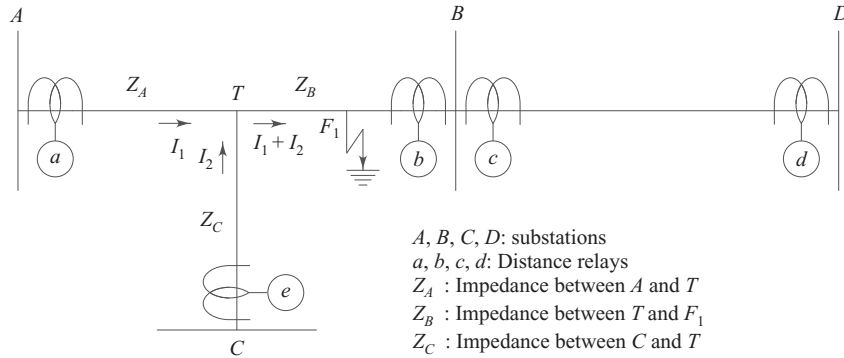
Fig. 8.20(c) Vector of I_A and I_B


Fig. 8.20(d) Overreaching of Relay 'a'

Fig. 8.20(e) Underreaching of Relay 'b'

There will always be a positive sequence, negative sequence and zero sequence mutual reactances during fault condition. The effect of mutual positive and negative sequence reactances will be negligible as the line conductors are generally transposed. But mutual zero sequence reactance between two circuits introduces errors in distance measurement during earth faults L-g and L-L-g.

The solution to such a problem is not within the scope of this book.

10. Teed Lines In the network as shown in Fig. 8.21, the distance measurement will be erroneous. Let us consider the impedance seen by the relay a at the substation A , when a fault occurs at F_1 .


Fig. 8.21 Teed line for fault at F_1

True impedance to fault = $Z_A + Z_B$

In the absence of an intermediate teed line, the relay will measure this impedance. But with the intermediate current infeed I_2 , the apparent impedance seen by the relay becomes,

$$Z_T = Z_A + Z_B + \frac{I_2}{I_1} Z_B$$

This is more than the true impedance ($Z_A + Z_B$), so that the fault appears to be farther away from the actual location. This means that the relay will under-reach.

It is the general practice to adjust the distance relay, to operate on the basis of no intermediate current infeed. The fault at the boundary of the first zone, then, will be cleared after a time delay in the second zone.

11. Effects of Faults on Relays with Un-faulted Phases Let us consider a ϕ -B fault. In this case, the R-unit of the distance protection scheme will also measure some impedance. The impedance measured can be calculated as follows

$$Z_R = \frac{V'_R}{(I_R - I)} = \frac{V'_R - V'}{(I_R - I)}$$

where, V'_R is the voltage across R- lines at the relaying point. Substituting values from equations (8.29) to (8.31),

$$Z_R = \frac{2V_1 - V_1(a^2 + a) + I_1 Z_1(a^2 - a)}{-I_1(a^2 - a)} = \frac{2V_1 + V_1 - I_1 Z_1(a^2 - a)}{-I_1(a^2 - a)} \quad (8.52)$$

where

$$Z_1 = V_1/I_1$$

Similarly,

$$Z_{BR} = \frac{(V'_B - V'_R)}{(I_B - I_R)} = Z_1 + j\sqrt{3} Z_1 \quad (8.53)$$

A plot of these impedances expressed by equations (8.52) and (8.53) on the R-X plane results in Fig. 8.22. It is clear from Fig. 8.22 that if the fault is to occur up to a point P' , R- and B-R units will erroneously operate for ϕ -B fault.

In a similar way one can consider an R-g fault. A ϕ -g unit in this case will measure the impedance Z_g determined as follows:

$$Z_g = \frac{V'}{I + I_0 \left[\frac{Z_0 - Z_1}{Z_1} \right]}$$

$$V' = a^2 V_1 + a V_2 + V_0$$

$$= a^2(V_1 + I_1 Z_1) + a(V_2 + I_2 Z_2) + (V_0 + I_0 Z_0)$$

For an R-g fault,

$$I_1 = I_2 = I_0 \text{ and } V_1 + V_2 + V_0 = 0$$

In transmission line,

$$Z_1 = Z_2$$

$$V' = a^2 V_1 + a V_2 + V_0 + I_1 Z_1(a + a^2) + I_1 Z_0$$

$$= V + I_1 Z_1(a + a^2) + I_1 Z_0$$

and

$$I = a^2 I_1 + a I_2 + I_0$$

$$= I_1 (1 + a + a^2) = 0$$

$$Z_g = \frac{V + I_1 Z_1(a^2 + a) + I_1 Z_0}{I_1((Z_0 - Z_1)/Z_1)} = Z_1 + \frac{V Z_1}{I_1(Z_0 - Z_1)}$$

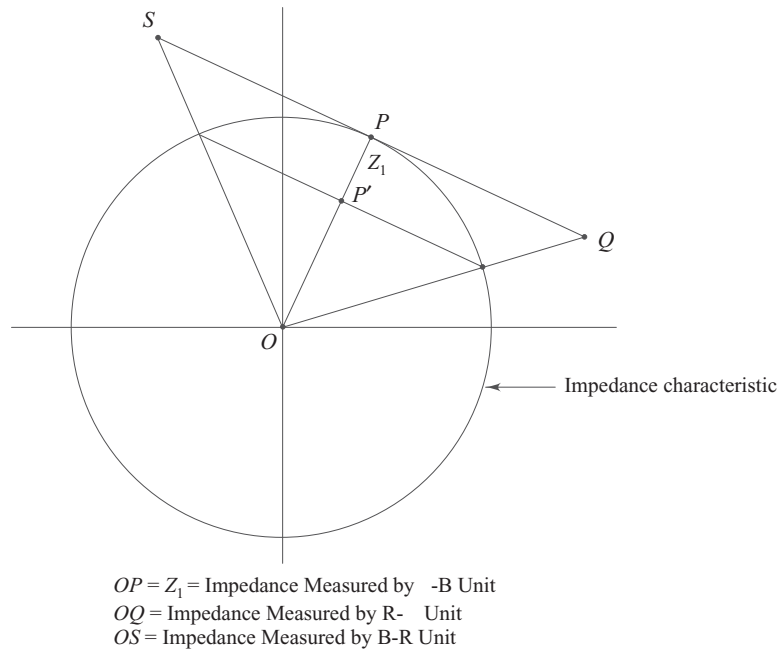


Fig. 8.22 Effect of Y-B fault on R-Y and B-R units

This means that an R-g unit measures more impedance than the actual case.

A similar analysis can be done for the effect of an R-g fault on R-, -B and B-R units. This exercise is left to the readers. In any case, one can prove that for one type of fault in a restricted region, the other five units of a distance scheme may operate erroneously.

If a distance relay giving a limited characteristic in a fault area is used, this problem can be overcome. The quadrilateral characteristic shown in Fig. 8.23 is one such characteristic. The quantities to be fed to such a relay are not within the scope of this book.

12. Effect of a Delta-Wye Transformer between Relay and a Fault Except for the three-phase faults, the presence of a wye-delta or delta-wye transformer between a distance relay and a fault changes the impedance as seen by the distance relay. This is because of the inherent phase shift that occurs in a transformer.

For a three-phase fault, however, the impedance seen by a distance relay would be equal to the impedance from a relay to a transformer plus the impedance of a transformer plus the impedance from the transformer up to the fault. Obviously, all impedances (in ohmic values) are to be expressed in terms of the rated voltage of the transformer on the relay side.

To consider the effect of a two-phase fault, a reference is made to Fig. 8.24.

For a -B fault, the following expressions have already been proved in Section 8.2.2.

$$V_r = 2V_1 \quad (\text{using Eq. 8.29})$$

$$V_y = V_1(a^2 + a) + I_1 Z_1(a^2 - a) \quad (\text{using Eq. 8.30})$$

$$V_b = V_1(a + a^2) + I_1 Z_1(a - a^2) \quad (\text{using Eq. 8.31})$$

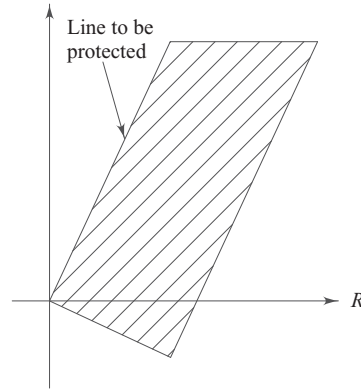


Fig. 8.23 Quadrilateral characteristic

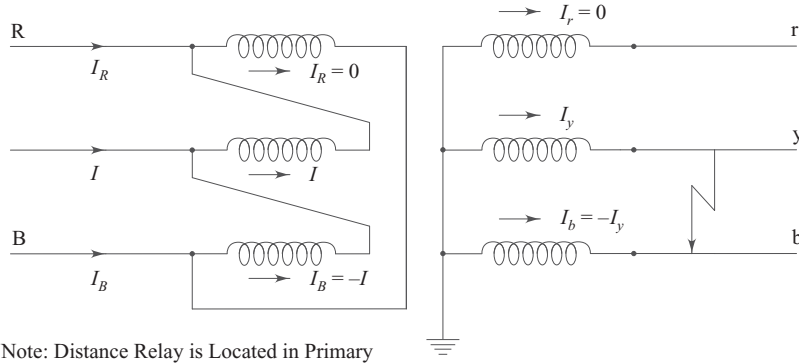


Fig. 8.24 Y-B Fault on the secondary of a DY1 transformer

$$I_r = 0$$

$$I_y = I_1(a^2 - a)$$

(using Eq. 8.33)

$$I_b = I_1(a - a^2)$$

(using Eq. 8.34)

Using the principles of transformation,

$$I_R = 0$$

$$I = KI_y/\sqrt{3} \text{ where } K = \text{nominal transformation ratio}$$

$$I_B = KI_b/\sqrt{3}$$

$$V_R = -\sqrt{3}V_y/K$$

$$V_B = -\sqrt{3}V_b/K$$

$$V_{BR} = -\sqrt{3}V_r/K$$

Applying these relations of -B fault on these equations,

$$I'_R = -I = (-KI_y/\sqrt{3}) = -KI_1(a^2 - a)/\sqrt{3}$$

$$I' = (I - I_B) = 2I = (2KI_1/\sqrt{3}) = 2KI_1(a^2 - a)/\sqrt{3}$$

$$I'_B = I_B = -I = -KI_1(a^2 - a)/\sqrt{3}$$

$$V_R = -\sqrt{3}/K[-V_1 + I_1 Z_1(a^2 - a)]$$

$$V_B = -\sqrt{3}/K[-V_1 + I_1 Z_1(a - a^2)]$$

$$V_{BR} = -2\sqrt{3}V_1/K$$

Impedance seen by an R- relay,

$$Z_R = \frac{V_R}{(I'_R - I')} = 3 \frac{[-V_1 + I_1 Z_1(a^2 - a)]}{[3K^2 I_1(a^2 - a)]}$$

$$= \frac{Z_1}{K^2} - \frac{Z_1}{K^2(a^2 - a)} = \frac{1}{K^2} \left[Z_1 - j \frac{Z_1}{\sqrt{3}} \right]$$

This is shown by the vector OM' in Fig. 8.25.

Similarly, impedance seen by a -B relay,

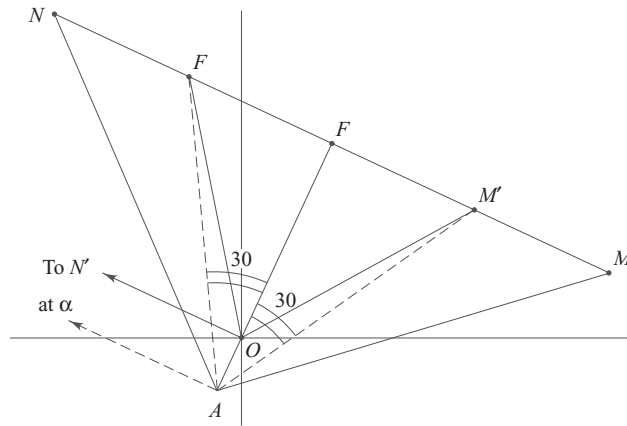
$$Z_B = \frac{1}{K^2} \left[Z_1 + j \frac{Z_1}{\sqrt{3}} \right]$$

This is shown by the vector OF' in Fig. 8.25.

and

$$Z_{BR} = \alpha$$

These relations can be graphically constructed as shown in Fig. 8.25.



OF : Positive sequence impedance of 3-phase fault seen by a relay on the primary
 OM : Impedance due to -B fault seen by R- relay had there been no transformer
 ON : Impedance due to -B fault seen by B-R relay had there been no transformer
 FA : Z_1 : Positive sequence impedance from source to fault
 O : Relay location

Fig. 8.25 Graphical representation of Fig. 8.24

Referring to Fig. 8.25,

$$OF' = Z_B = \frac{1}{K^2} \left[Z_1 + j \frac{Z_1}{\sqrt{3}} \right]$$

$$OM' = Z_R = \frac{1}{K^2} \left[Z_1 - j \frac{Z_1}{\sqrt{3}} \right]$$

$$ON' = \alpha = Z_{BR}$$

Space does not permit the treatment for the case of a phase-to-ground fault when the D transformer exists between a relay and a fault. Similarly, the treatment would get exhaustive if one would like to assess how the ground distance relay would see different types of faults on the other side of a transformer. It is enough to state here that an R-g fault looks like an R-B fault on the delta side of a transformer.

13. Protection of Compensated Lines which use a Series Capacitor First, let us discuss why we should connect a series capacitor in a transmission line. The power transfer capability of a transmission line can be written as

$$P = \frac{V_S V_R \sin \delta}{L}$$

where,

V_S = Sending end voltage

V_R = Receiving end voltage

δ = Angle between two voltage vectors

L = Line reactance

From this equation, the following advantages of series compensation are quite evident.

1. A series compensated capacitor is an effective tool for line reactance compensation. The equivalent line reactance in this case will be $L - C$. 50% compensation is generally used.
2. Increase in transmission capacity.
3. More power can be transferred from one end to another by double circuit (parallel) lines. But, instead, a series-compensated line is cheaper as one can transmit more power through a single line.
4. Better voltage regulation and improved voltage profile is possible at the load end as a series capacitor can supply reactive power during heavy load periods.
5. The stability limit is improved.

Because of these advantages, a series capacitor is usually installed at one of the ends of a transmission line. Figure 8.26(a) below, shows the basic arrangement of a series capacitor bank and its associated protective schemes.

The capacitor must be protected against excessive over-voltages caused by high short-circuit currents. Modern series capacitors are protected by a metal-oxide varistor (MOV) which essentially does not conduct when the voltage across it is below a certain threshold and increasingly conducts if this threshold is exceeded. Thus, a MOV limits the voltage across the capacitor. For reasons of economy, a MOV is frequently protected by a bypass trigger gap which fires if the energy across the MOV reaches its withstand limit. A bypass circuit breaker can be turned ON during a light load period when the series capacitor is not desirable in the network.

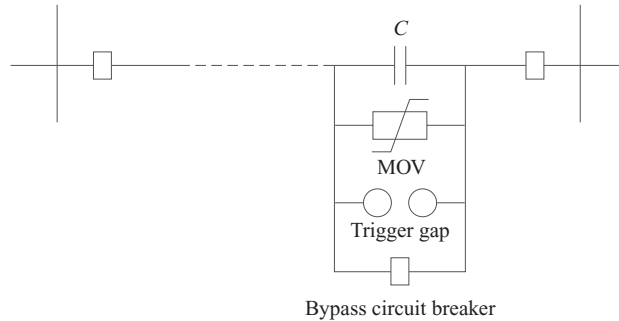


Fig. 8.26(a) Basic arrangement of a series capacitor bank

This series capacitor arrangement adds certain complexities to the application of impedance-based distance relays. Because of the capacitive reactance X_C , the fault after the capacitor looks nearer and thus the relay over-reaches. It is possible to correct the settings of the relay if it is known that the capacitor is always going to be part of the fault circuit. However, during high-current faults, the MOV will conduct and the capacitor will be shorted. The extent to which the MOV will conduct and to what extent the capacitor will conduct depends on the magnitude of the fault current. Thus, the degree of over-reach is highly uncertain. The close-in faults can appear to be faults behind the relay. The locus of impedance seen by a relay is shown in Fig. 8.26(b).

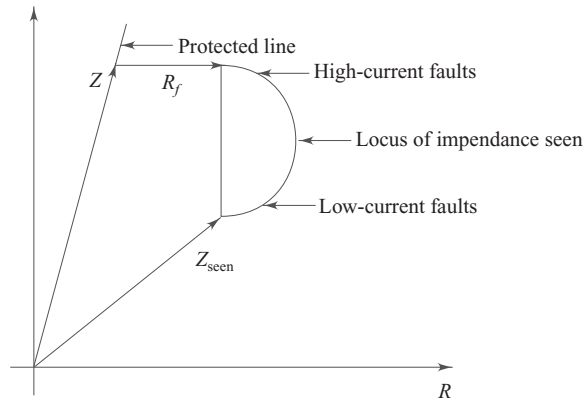


Fig. 8.26(b) Over-reaching of a distance relay due to series compensation

It would be very interesting to know how the distance relay can measure the actual distance to fault in case of low-current faults (as the relay does not practically over-reach in case of high-current faults). This is still a live research topic and is not within the scope of this text.

14. Cross-country Faults Two simultaneous L-g faults occurring on two different phases and at two different locations (say, R-g and -g) are known as cross-country faults. These faults are measured by a distance relay as an R- -g fault at a location between the two fault locations. Hence, for a nearer fault, the relay will under-reach and for the farther fault, the relay will over-reach. This topic is a challenge for researchers.

8.4 SWITCHED AND POLYPHASE DISTANCE RELAYING SCHEMES

Non-switched distance-protection schemes consisting of six measuring elements, discussed in foregoing sections, are very popular particularly on HV and EHV power-system networks. Switched distance schemes, however, are cheaper than full schemes as they consist of fewer components. This scheme finds application in medium-voltage networks where non-switched schemes are economically not viable.

Switched distance protection uses switching networks for connecting the measuring element(s) under fault. For this purpose, the switching network is required to be controlled by fault detectors or starters.

A polyphase distance relaying scheme consists of an element fed by a special combination of signals. The main problem in such a scheme is achieving the discriminative impedance coverage for all fault types. This is the reason why such schemes are not as popular as switched distance schemes.

Switched Distance Protection The principal reason why such schemes are not used for EHV networks is the delay in operation as even Zone-1 distance measurement suffers from the problem of delayed operation. Before the final relay operation, three functions are required to be completed, viz., starting, phase selection and measurement. The non-switched equipment involves only one function, i.e., measurement. With the advent of numerical relays, switched distance protection has become practically possible without time delay and is widely used.

Figure 8.27 shows a simple block schematic of a switched distance scheme using instantaneous overcurrent starting elements. Under fault conditions, say an R-g fault, the red phase-starting element operates and energises the relay followers in the switching networks such that the red-phase compensated current and voltage together with necessary polarising voltage, are applied to the main measuring element. The zone-switching feature enables the scheme to decide two or three zones of protection as already discussed in earlier non-switched schemes.

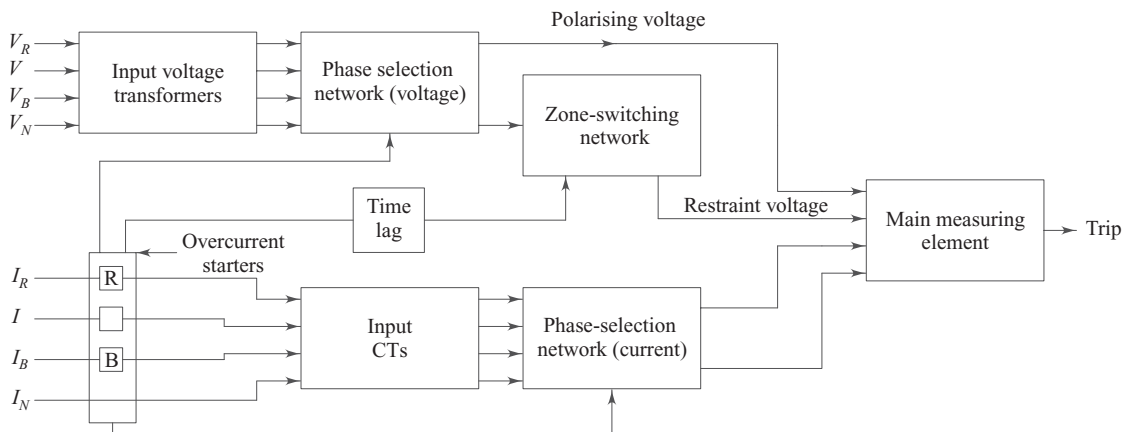


Fig. 8.27 Switched distance scheme using overcurrent starting

The other types of starters used are undervoltage starters, overcurrent starters (monitored by undervoltage) and impedance starters.

Phase-Selection Network Each of the starting elements must energise the follower relays which are connected to form the phase selection network, the function of which is to switch the correct inputs under

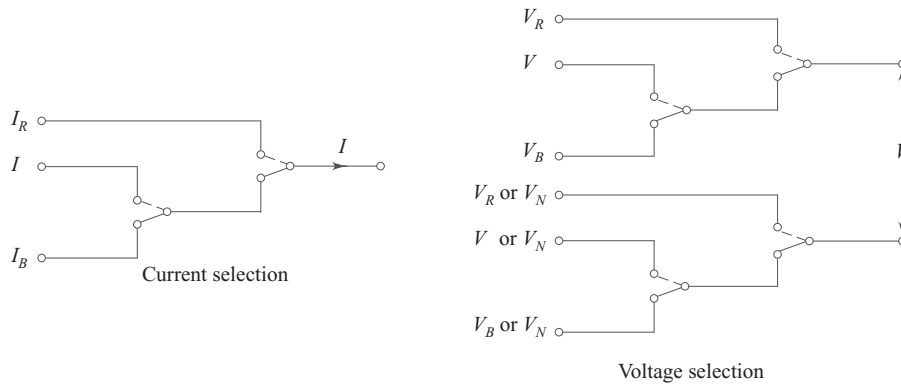


Fig. 8.28 Phase-selection networks

fault conditions to main measuring elements. One typical example of current and voltage switching is shown in Fig. 8.28.

Phase selection based on conventional attracted armature relays including high-speed designs result in a switching time of 5 to 10 milliseconds, whereas encapsulated reed relay switching may give a switching time of the order of just 1 to 2 milliseconds. The recent numerical relays would reduce the number of physical contacts and give an exceptionally high speed of operation.

Impedance Measurement A single mho unit is most common for impedance measurement. However, two elements, one for phase-fault measurement and one for ground faults are also used in certain applications. In the latter case, the two elements may have different characteristics. Mho characteristic is preferable for phase faults whereas reactance characteristic is quite common for earth faults, as an earth fault involves quite a large resistance in the fault path. Phase-selection networks, obviously will be more complex for dual-element schemes.

Example 8.1 Obtain 3 zone settings for (i) a reactance relay, and (ii) a mho relay of 60° MTA from the following data:

CT 400/1 A
PT 132 kV/110 V

Impedance for the first section is $2.5 + j5.0$ ohms (primary) and that for the second section is $3.5 + j7.0$ ohms (primary). The first zone covers 80% of the first section, the second zone covers the first section plus 30% of the second section and the third zone covers the first section plus 120% of the second section.

Solution

$$\begin{aligned} \text{Impedance of first line section} &= 2.5 + j5 \text{ (primary)} \\ &= 5.59 \angle 63.43 \text{ ohms} \\ \text{Impedance of second section} &= 3.5 + j7 \text{ (primary)} \\ &= 7.82 \angle 63.43 \text{ ohms} \\ \text{Impedance of first zone } Z_1 &= 0.8 \times 5.59 \angle 63.43 \text{ ohms} \\ &= 4.472 \angle 63.43 \text{ ohms (primary)} \\ \text{Impedance of second zone } Z_2 &= 5.59 \angle 63.43 + 0.3 \times 7.82 \angle 63.43 \text{ ohms} \\ &= 7.936 \angle 63.43 \text{ ohms (primary)} \end{aligned}$$

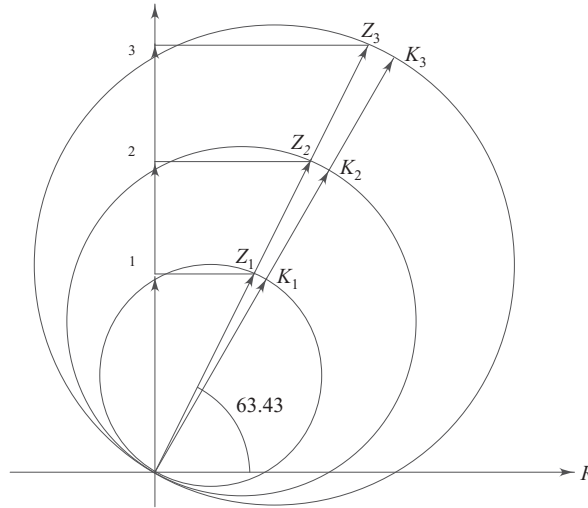


Fig. 8.29 Example 8.1

$$\begin{aligned} \text{Impedance of third zone } Z_3 &= 5.59 \angle 63.43 + 1.2 \times 7.82 \angle 63.43 \text{ ohms} \\ &= 14.97 \angle 63.43 \text{ ohms (primary)} \end{aligned}$$

These impedances are to be transferred to the relay side (i.e., secondary side of CT and PT) because the relay receives transformed juices of current and voltage.

$$\begin{aligned} Z_1 (\text{secondary}) &= (\text{CTR/PTR}) \times Z_1 (\text{primary}) \\ &= \frac{400/1}{132000/110} \times 4.472 \angle 63.43 \\ &= 1.49 \angle 63.43 \text{ ohms} \end{aligned}$$

Similarly,

$$\begin{aligned} Z_2 (\text{secondary}) &= 2.645 \angle 63.43 \text{ ohms} \\ Z_3 (\text{secondary}) &= 5 \angle 63.43 \text{ ohms} \end{aligned}$$

As the reactance relay measures the reactance up to the fault (refer Fig. 8.29),

$$\begin{aligned} x_1 &= Z_1 \sin (63.43^\circ) \\ &= 1.49 \sin (63.43^\circ) = 1.33 \text{ ohms} \\ x_2 &= 2.36 \text{ ohms} \\ x_3 &= 4.47 \text{ ohms} \end{aligned}$$

Now, for the mho relay (refer Fig. 8.29),

$$\begin{aligned} K_1 &= \frac{Z_1}{\cos(\phi - \theta)} \\ &= \frac{1.49}{\cos(63.43^\circ - 60^\circ)} = 1.49 \text{ ohms} \end{aligned}$$

Similarly,

$$\begin{aligned} K_2 &= 2.649 \text{ ohms} \\ K_3 &= 5 \text{ ohms} \end{aligned}$$

Example 8.2 A 220 kV long transmission line has an impedance of $2 + j8$ ohms. Suggest suitable distance relays for its protection and determine the settings of the relays for all the three zones given that

- (i) Zone 1 covers 80% of the line length
- (ii) Zone 2 covers 150% of the line length
- (iii) Zone 3 covers 225% of the line length

Assume

- (a) a fault resistance of 2 ohms while deciding settings, and
- (b) a suitable characteristic angle of the distance relay suggested by you.

Relevant data:

CT ratio = 1000/I A

PT ratio = 220 kV/110 V

Solution As the line to be protected is a long one, mho relays are most suitable. The characteristic angle is taken as 70° , as normally the faulted power factor angle is between 70° and 90° .

Refer Fig. 8.30.

Impedance of line = $2 + j8$ ohms = $8.246 \angle 75.96^\circ$ ohms

$$\begin{aligned} Z_1 &= 0.8 \times 8.246 \angle 75.96^\circ \\ &= 6.597 \angle 75.96^\circ = 1.6 + j6.4 \text{ ohms} \end{aligned}$$

Considering a fault resistance of 2 ohms, Z_1 will be modified.

$$\begin{aligned} Z'_1 &= 2 + j(1.6 + 6.4) \\ &= 3.6 + j6.4 = 7.34 \angle 60.64^\circ \end{aligned}$$

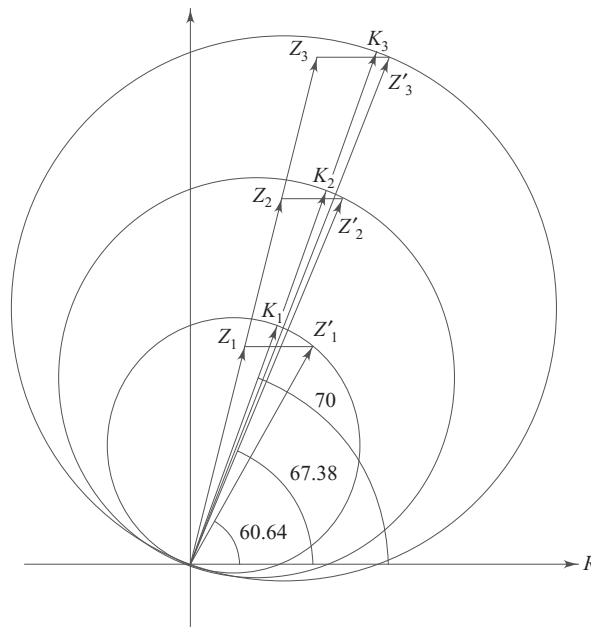


Fig. 8.30 Example 8.2

$$Z'_1 \text{ (secondary)} = (\text{CTR/PTR}) \times Z'_1$$

$$= \frac{1000/1}{220000/110} \times 7.34 \angle 60.64 = 3.67 \angle 60.64 \text{ ohms}$$

$$K_1 = \frac{3.67}{\cos(60.64 - 70)} = 3.72 \text{ ohms}$$

$$Z_2 = 1.5 \times 8.246 \angle 75.96$$

$$= 12.369 \angle 75.96 = 3 + j12 \text{ ohms}$$

Considering a fault resistance of 2 ohms,

$$Z'_2 = 2 + (3 + j12) = 13 \angle 67.38 \text{ ohms}$$

$$Z'_2 \text{ (secondary)} = (\text{CTR/PTR}) \times Z'_2 = 6.5 \angle 67.38 \text{ ohms}$$

$$K_2 = \frac{6.5}{\cos(67.38 - 70)} = 6.51 \text{ ohms}$$

Now,

$$Z_3 = 2.25 \times 8.246 \angle 75.96$$

$$= 18.5535 \angle 75.96 = 4.5 + j18 \text{ ohms}$$

Considering a fault resistance of 2 ohms,

$$Z'_3 = 19.14 \angle 70.145$$

$$Z'_3 \text{ (secondary)} = 9.57 \angle 70.145$$

$$K_3 = \frac{9.57}{\cos(70.145 - 70)} = 9.57 \text{ ohms}$$

Example 8.3 A three-section radial feeder, shown in Fig. 8.31, is to be protected by distance relays. The relevant data is as follows:

Radial Feeder

- | | |
|-----------------------------------|----------------------------------|
| (i) Impedance of Section I | $4 + j16 \text{ ohms (primary)}$ |
| (ii) Impedance of Section II | $3 + j12 \text{ ohms (primary)}$ |
| (iii) Impedance of Section III | $2 + j8 \text{ ohms (primary)}$ |
| (iv) Rated load current of feeder | 1000 A at 0.8 power factor lag |
| (v) Probable overloading | 200% of the rated current |
| (vi) Probable voltage dip | 10% |
| CT ratio | 1000/1 A |
| PT ratio | 132 kV/110 V |

Relay R

- | | |
|---------------------------|-------------------------|
| (i) Transient over-reach | 10% |
| (ii) Characteristic angle | 60° of mho relay |

Determine the settings of zones 1, 2 and 3 of the distance relay R. Also determine the reach of all the three zones, for the line to be protected in terms of percentage of impedance of the first section.

Solution The reach of the zone 3 is restricted by overloading and voltage dip. The load impedance under overload condition and voltage dip of 10% is

$$Z_L = \frac{[(132000/\sqrt{3}) \times 0.9]}{2000 \angle -36.87} \text{ ohms}$$

$$= 34.29 \angle 36.87 \text{ ohms}$$

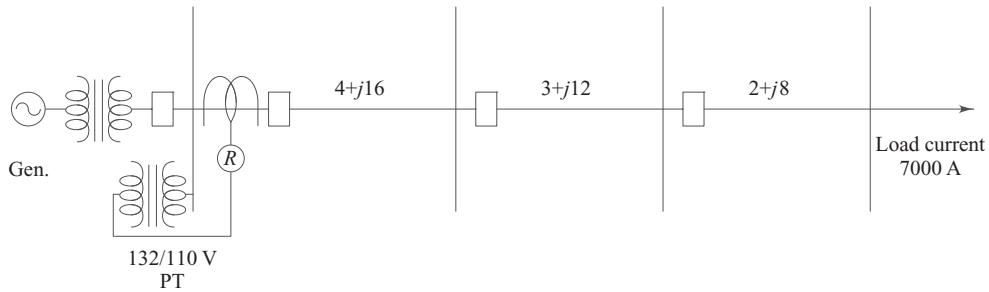


Fig. 8.3I(a) Example 8.3

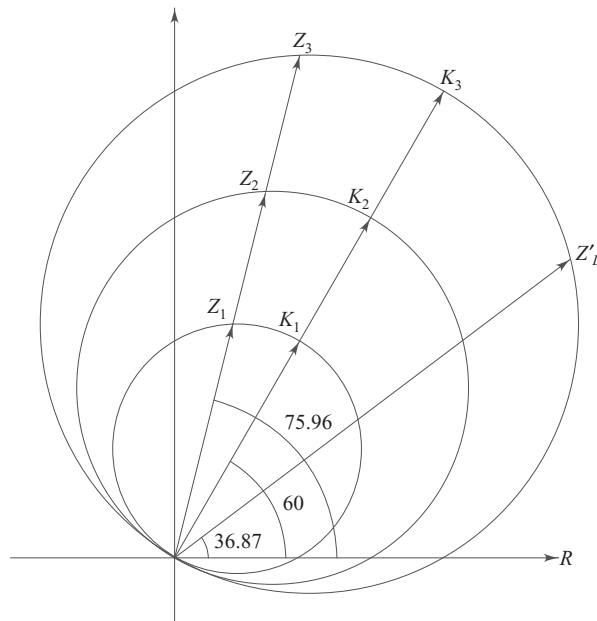


Fig. 8.3I(b) Example 8.3

Considering a 5% margin for relay error,

$$\begin{aligned} Z'_L &= 0.95 \times 34.29 \angle 36.87 \text{ ohms} \\ &= 32.57 \angle 36.87 \text{ ohms} \end{aligned}$$

$$\begin{aligned} Z'_L (\text{secondary}) &= \frac{1000/1}{132000/110} \times 32.57 \angle 36.87 \text{ ohms} \\ &= 27.14 \angle 36.87 \text{ ohms} \end{aligned}$$

Therefore,

$$K_3 = \frac{Z'_L}{\cos(60 - 36.87)} = 29.51 \text{ ohms}$$

$$\begin{aligned} Z_3 &= K_3 \cos(\phi - \theta) \\ &= 29.51 \cos(75.96 - 60) = 28.37 \text{ ohms} \end{aligned}$$

$$\text{Impedance of Section I} = 4 + j16 = 16.49 \angle 75.96$$

Considering 10% over-reach of relay,

$$Z_1 = (1/1.1) \times 16.49 \angle 75.96 \text{ ohms}$$

$$= 15 \angle 75.96 \text{ ohms}$$

$$Z_1 (\text{secondary}) = 12.5 \angle 75.96 \text{ ohms}$$

$$K_1 = \frac{Z_1}{\cos(\phi - \theta)} = 13.0 \text{ ohms}$$

$$\text{Impedance of sections I and II} = 4 + j16 + 3 + j12$$

$$= 28.86 \angle 75.96 \text{ ohms (primary)}$$

$$= 24.05 \angle 75.96 \text{ ohms (secondary)}$$

As Z_3 is more than this figure the relay will cover sections I and section II as required in the zone 3.

Taking impedance of the first section plus 50% of the impedance of the second section for the second zone setting

$$Z_2 = 16.49 \angle 75.96 + 0.5 (3 + j12)$$

$$= 22.67 \angle 75.96 \text{ ohms (primary)}$$

$$Z_2 (\text{secondary}) = 18.89 \angle 75.96 \text{ ohms}$$

$$K_2 = \frac{Z_2}{\cos(\phi - \theta)} = 19.647 \text{ ohms}$$

Determination of the reach of all the three zones, for the line to be protected in terms of percentage impedance of the first section is left as an exercise for the reader.

Example 8.4 Figure 8.32 shows the single-line diagram of a portion of a power system. The relevant data is as follows:

Line	Impedance ohms km	Distance km
L_1	$0.03 + j 0.12$	150
L_2	$0.04 + j 0.16$	100
L_3	$0.05 + j 0.15$	50
L_4	$0.08 + j 0.24$	32
L_5	$0.10 + j 0.30$	25

Mho relay R is with characteristic angle = 60° , Zone 1 setting $K_1 = 14.5$ ohms, Zone 2 setting $K_2 = 160\%$ of K_1 , Zone 3 setting $K_3 = 360\%$ of K_1 , CT ratio of 1000/I and PT ratio of 132 kV/I 10 V is given. Find out in terms of distance in km:

- Zone 1 reach of R from the switchyard A for the line L_1 .
- Zone 2 reach of R from the switchyard B for the line L_2 .

Also find in which zone of relay R, will the faults of lines L_3 , L_4 and L_5 will be cleared? Will the lines L_3 , L_4 and L_5 be fully protected by the relay R?

Solution

$$Z_{L1}/\text{km} = 0.03 + j0.12 \text{ ohm/km} = 0.1237 \angle 75.96 / \text{km}$$

From the data $K_1 = 14.5$ ohms with a characteristic angle of 60°

$$Z_1 = K_1 \times \cos(\phi - \theta) \text{ in secondary terms}$$

$$Z_1 (\text{secondary}) = 14.5 \times \cos(76 - 60) = 13.938 \text{ ohms}$$

$$Z_1 (\text{primary}) = Z_1 (\text{secondary}) \times \text{PTR/CTR}$$

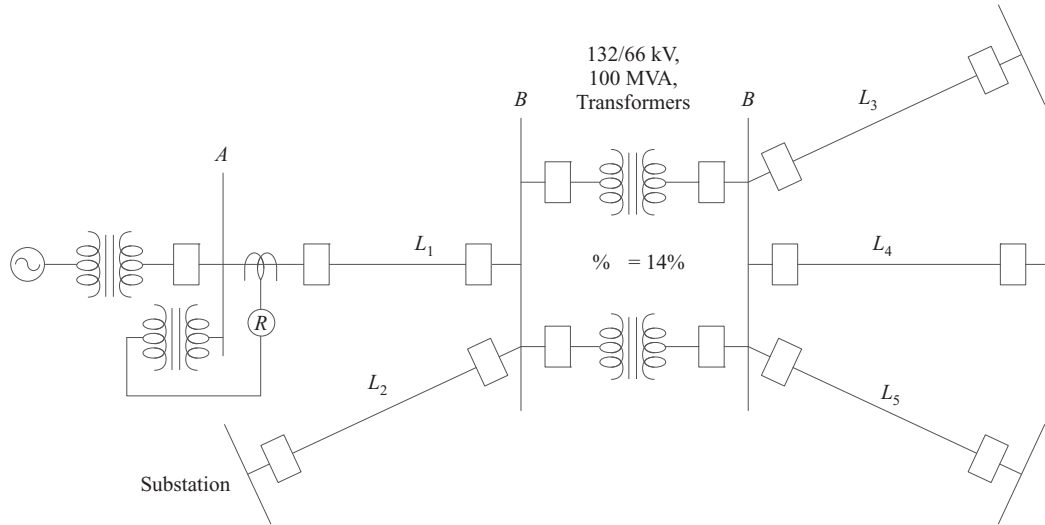


Fig. 8.32 Example 8.4

$$= 13.938 \times \frac{132000/110}{1000/1} = 16.726 \text{ ohms}$$

Thus Z_{L1} reach for $L_1 = Z_1(\text{primary})/(Z_1/\text{km})$
 $= 16.726/0.1237 = 135.2 \text{ km from the switchyard } A$

$$K_2 = 160\% \text{ of } K_1$$

$$= 1.6 \times 14.5 = 23.2 \text{ ohms}$$

$$Z_2(\text{secondary}) = 23.2 \times \cos 16^\circ = 22.3 \text{ ohms}$$

$$Z_2(\text{primary}) = 26.76 \text{ ohms}$$

$$Z_2 - \text{impedance of the line } L_1 = Z_2 - Z_{L1} = 26.76 - 150(0.03 + j0.12) = 8.205 \text{ ohms}$$

$$Z_{L2} = \text{Impedance of the line } L_2$$

$$= 0.04 + j0.16 \text{ ohms/km}$$

$$= 0.1649 \angle 76^\circ / \text{km}$$

Zone 2 reach of the relay R from the substation B for the line L_2

$$= (Z_2 - Z_{L1})/Z_{L2} / \text{km} = 8.205/0.1649 = 49.75 \text{ km}$$

Ohmic value of the reactance of the transformer at the 132 kV base

$$= (132^2 / 100) \times 0.14 = 24.39 \text{ ohms}$$

For two transformers in parallel, reactance of transformers,

$$T = j12.19 \text{ ohms}$$

$$Z_{L1} + T = 150(0.03 + j0.12) + j12.19$$

$$= 4.5 + j30.19 \text{ ohms}$$

$$= 30.52 \angle 81.52^\circ \text{ ohms}$$

Hence, the transformer fault will be seen in the second zone.

$$\begin{aligned}
 K_3 &= 360\% \text{ of } K_1 \\
 &= 3.6 \times 14.5 = 52.2 \text{ ohms} \\
 Z_{L1} + Z_T + Z_{L3} &= 4.5 + j18 + j12.19 + (132/66)^2 (0.05 + j0.15) \times 50 \\
 &= 61.91 \angle 76.45
 \end{aligned}$$

(as the impedance of the line Z_{L3} seen by the relay R is $(132/66)^2$ times the impedance of the line)

$$Z_3(\text{secondary}) = 52.2 \cos(76.45^\circ - 60^\circ) = 50.06 \text{ ohms}$$

$$Z_3(\text{primary}) = 60.07 \text{ ohms}$$

As $Z_3 < (Z_{L1} + Z_T + Z_{L3})$, the line L_3 will not be fully covered by the zone 3. However, the portion of line to be protected will be covered in the zone 3 of the relay.

$$\text{Similarly, } (Z_{L1} + Z_T + Z_{L4}) = 62.66 \angle 76.39 \text{ ohms}$$

Line L_4 also will not be covered fully by the relay R .

In the same manner,

$$(Z_{L1} + Z_T + Z_{L5}) = 61.91 \angle 76.45$$

Line L_5 will also not be covered fully by the relay R .

8.5 LIMITATIONS OF DISTANCE PROTECTION FOR TRANSMISSION LINES

We have discussed quite a few problems of distance measurement in case of faulted transmission lines. One can summarise the main limitations as follows:

1. There are problems of under-reach and over-reach during application of distance relays.
2. It is not possible to distinguish between a fault at the end of a line section to be protected and a fault at just the beginning of a next line section unless time delay is added between the two. Because of this, a full line section can never be protected instantaneously.
3. Consider a line section AB in an interconnected system (Fig. 8.33). When a large bulk of power is being transmitted, a persistent fault not being cleared fast or an abrupt tripping of the line are both equally harmful from the viewpoint of stability of the system. This demands the application of auto-reclosing circuit breakers 1 and 2 at both the ends. Moreover, stability considerations will also demand the simultaneous tripping and closing of both the auto-reclosers. If distance relays are applied at relaying points R_1 and R_2 , this synchronism can be obtained for the fault in the middle 60% of the line if the zone 1 of R_1 and R_2 covers 80% of the line section AB . Should the fault occur in the extreme 20% on either end, the fault will continue to be fed either from A or from B during the auto-reclosing cycle. This will endanger the system stability. Hence, distance relays cannot be applied where auto-reclosers are essentially used.



Fig. 8.33 A double-end fed feeder

REVIEW QUESTIONS

1. Why are distance relays generally preferred to IDMT overcurrent relays for the protection of transmission lines?
2. Give reasons for the following statements:
 - (i) Distance relays cannot be applied for the transmission lines employing auto-reclosing circuit breakers at both the ends of the lines.
 - (ii) Reactance relays are a better choice for short transmission lines whereas mho relays are applied for long lines.
 - (iii) The power swing in a power system may mal-operate a distance relay.
 - (iv) An impedance relay under-reaches in case of a fault incorporating resistance in the fault path, whereas a reactance relay is immune to the fault resistance.
3. What are the limitations that restrict the reach of the first and third zones of a three-zone distance relay?
4. Compare the suitability of the following distance relay schemes for the protection of (a) long transmission lines, and (b) short transmission lines.
 - (i) Mho relays
 - (ii) Reactance relays with mho starting
 - (iii) Plain impedance relays with directional starting
5. Explain the basis of setting three-step distance relays for the first, second and third zones of distance measurement.
6. Discuss the influence of resistance of fault on the protective zone of the distance relays.
7. Show how stepped characteristics employed in distance relays ensure selectivity and back-up protection coupled with fast operation.
8. Discuss over-reach and under-reach in connection with distance relays.
9. Sketch, on the R - X plane, the various characteristics which are usually employed in distance protection. State their advantages and limitations briefly.
10. Discuss the effects of fault resistance and power swings in the performance of distance relays. Explain how these effects are practically neutralised by proper choice of the relay characteristics for the measuring and starting units.
 11. How is the mal-operation of a distance relay due to loss of potential prevented?
 12. Draw a schematic connection diagram for the dc circuit of a distance scheme of protection and explain with its help, the three-step operation of the distance unit.
 13. Draw the dc control circuit for protection against close-in faults.
 14. With appropriate mathematical proof, show that line to ground voltage and compensated currents are supplied as inputs to enable the distance relay to measure the positive sequence impedance from the relay point to the fault point in case of an earth fault.
 15. Give an outline of a comprehensive distance protection scheme built around six relays.
 16. Draw a dc control circuit for an out-of-step blocking of a distance relay.
 17. How many distance protection units are required to protect a transmission line against phase and ground faults? With appropriate mathematical back-up, show how such a relay will measure positive sequence impedance between the relay point and the fault point for an L-L fault.
 18. On the R - X plane, show the impedance vector of a line-section having an impedance of $2 + j5$ ohms. On the same diagram, show the operating characteristics of an impedance relay, a reactance relay and a mho relay, each of which is adjusted to just operate for a dead short circuit at the end of the line section. The characteristic angle for a mho relay is 60° . Find the set impedance K in each case. The CT ratio is 500/1 A and PT ratio is 132 kV/110 V.
(Setting of reactance relay = 2.083 ohms, Setting of mho relay = 2.267 ohms, Setting of impedance relay = 2.244 ohms)
 19. From the following data, determine in terms of secondary ohms, the first zone setting of a reactance relay. Line section AB is to be protected, the positive sequence impedance of which is $3 + j7.5$ ohms (primary).
 CT ratio = 400/1 A
 PT ratio = 132000/110 volt
 The first zone covers 80% of the first line section.

As per the relaying scheme, the second zone protection is obtained for 150% of the line section AB by using reactance characteristic. Both these characteristics are bound by using mho relay of 40° MTA for the third zone protection which covers up to 220% of AB. Find the second and third zone settings too.

$$(X_1 = 2 \text{ ohms}, X_2 = 3.75 \text{ ohms}, K_3 = 6.722 \text{ ohms})$$

20. Draw on an R-X plane, the fault impedance area, i.e., the area which is generated for the fault in the protected line with arc resistance. Suggest how many angle impedance relays would be needed to give an operating characteristic similar to the fault area. Suggest also the logical connection of these relays. Why is the above combination of relays preferred over a mho relay?
21. How many mho units are required to protect a transmission line? Write down, in a tabular form, the quantities to be fed to each of them.
22. Draw the characteristic of a mho relay (characteristic angle = 60°) and reactance relay for protecting a transmission line having an impedance of $4 + j12$ ohms. Calculate the set impedance K in each case. The CT ratio is 500/I A and PT ratio is 132 kV/110 V.
($X = 5.00$ ohms, $K = 5.379$ ohms)
23. A transmission line with an impedance of $3 + j12$ ohms is protected by a distance relay. If a fault resistance of 1 ohm is to be incorporated, calculate the set impedance K for
 - (i) mho relay with a characteristic angle of 60°
 - (ii) ohm relay with a characteristic angle of 60°
 - (iii) impedance relay
 - (iv) reactance relay

The CT ratio is 500/I A and PT ratio is 132 kV/110 V.

$$\begin{aligned} \text{(Setting of reactance relay} &= 5.00 \text{ ohms,} \\ \text{Setting of ohm relay of } 60^\circ \text{ MTA} &= \\ 5.163 \text{ ohms, Setting of impedance relay} &= \\ 5.27 \text{ ohms, Setting of mho relay of } 60^\circ \text{ MTA} &= 5.379 \text{ ohms)} \end{aligned}$$

24. Critically evaluate the performance of a mho distance relay with a special reference to the following problems and suggest the remedies against these problems:
 - (i) Fault resistance
 - (ii) Power swings
 - (iii) Protection of parallel feeders

- (iv) Protection of compensated lines using series capacitance

25. Decide the three zone settings of a mho distance relay R having a characteristic angle of 60° (refer Fig. 8.34).

The required data is as follows:

- (i) 220 kV lines L_1 and L_2
Impedance = $0.015 + j0.06$ ohms/km/ph
Line length = 200 km
- (ii) 132 kV line L_3
Impedance = $0.04 + j0.12$ ohm/km/ph
Line length = 50 km
- (iii) CT ratio = 400/I A
- (iv) PT ratio = 220 kV/110 volts
($K_1 = 2.057$ ohms, $K_2 = 8.033$ ohms, $K_3 = 9.727$ ohms)

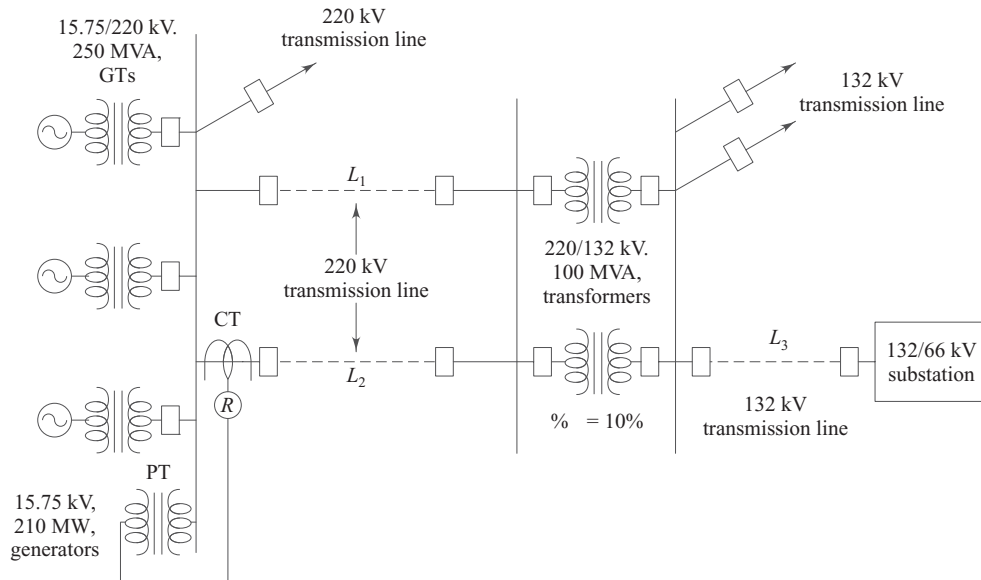
26. Write a short note on the switched distance relaying scheme.
27. Prove that for a Y-B-g fault on a line, the Y-B unit, Y-g unit and B-g unit, correctly measure the positive sequence impedance.
28. Explain how (i) a compensated line using series capacitance, and (ii) a cross-country fault create problem in distance measurement.
29. Compare the impedance characteristic and mho characteristic with characteristic angle θ equal to 60° and 45° with respect to the problem of fault resistance and power swing.
30. Figure 8.35 shows a single-line diagram of a portion of a power system. Relay R is a mho relay with a characteristic angle of 60° . The three zone settings are as follows:

$$\begin{aligned} K_1 &= 3.42 \text{ ohms} \\ K_2 &= 8.02 \text{ ohms} \\ K_3 &= 16.21 \text{ ohms} \end{aligned}$$

Find out,

- (i) the line length covered by the zone 1 of the relay R.
- (ii) the line length of a 220 kV, 200 km long line which will be covered by the zone 2 of the relay R and a parallel feeder that is of 132 kV, and is 100 km long.
- (iii) Coverage of the zone 3 of the relay R.

(The first zone reach of mho relay = 79.75% of the line L_2 , the second zone reach of mho relay = 87% of line L_1 and 19.3% of the line L_3 , the third zone reach of mho relay = full line L_3)


Fig. 8.34

31. Figure 8.36 shows a single-line diagram of a portion of a power system. Relay R is a mho relay with a characteristic angle of 60° . The transient over-reach of the relay R is known to be 10%. Determine the three zone settings of the relay so that the third zone setting backs up all other relays of the power system network shown in the figure. Assume suitable data.

$$(K_1 = 6.5 \text{ ohms}, K_2 = 11.167 \text{ ohms}, K_3 = 15.189 \text{ ohms})$$

32. Figure 8.37 shows a single-line diagram of a portion of a power system. Find out the three zone settings of a mho relay R (characteristic angle $= 60^\circ$).

The impedances of different transmission lines are as follows:

Line	Length km	Impedance km ohms
L_1	200	$0.015 + j0.06$
L_2	200	$0.015 + j0.06$
L_3	50	$0.04 + j0.12$
L_4	60	$0.04 + j0.12$
L_5	40	$0.06 + j0.18$

$$(K_1 = 8.577 \text{ ohms}, K_2 = 16.06 \text{ ohms}, K_3 = 41.62 \text{ ohms})$$

33. Figure 8.38 shows a portion of a power system network. Percentage impedances of transformers are given in the figure. Also, Fig. 8.38 shows the total impedance of 220 kV (150 km long) and 132 kV lines. The percentage over-reach of the mho distance relay R is 10%. Characteristic angle $\theta = 60^\circ$ for the relay.

The settings of the relay are

- Zone 1 = 4.84 ohms (secondary)
- Zone 2 = 20 ohms (secondary)
- Zone 3 = 30 ohms (secondary)

Find

- (i) Reach of the relay R in the zone 1 in terms of km (of 220 kV line)
- (ii) Reach of the relay R in the zone 2.
- (iii) Reach of the relay R in the zone 3. Does the zone 3 cover portion of 11/132 kV generator-transformer?

(First zone reach of mho relay = 134.87 km, second zone reach of mho relay = 42.9 ohms (primary), third zone reach of mho relay = 66.27 ohms (primary), the relay will fully cover the line L_1 , and transformer T_1 .)

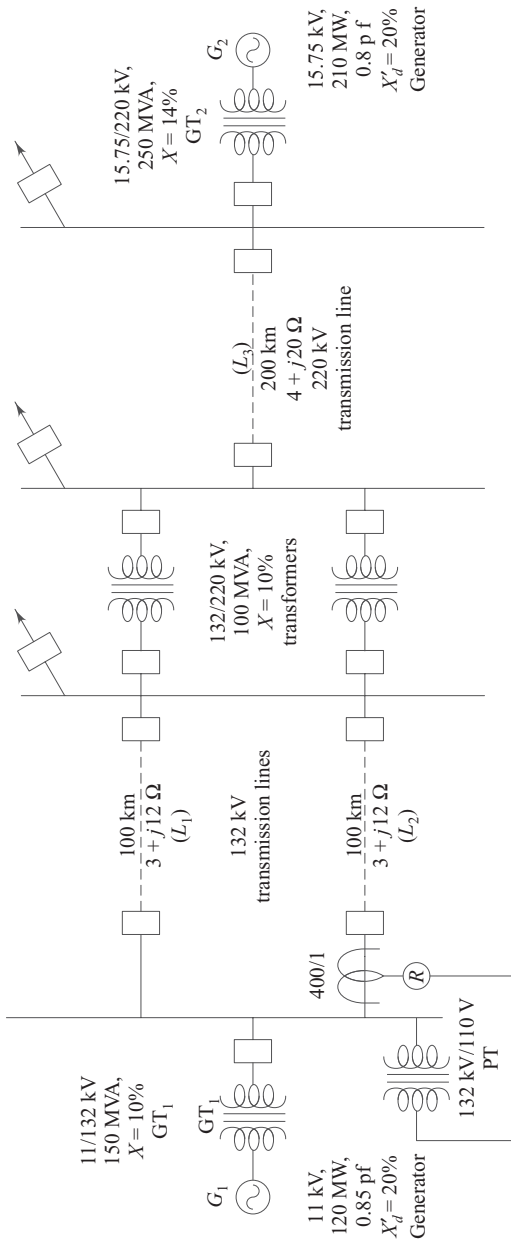


Fig. 8.35

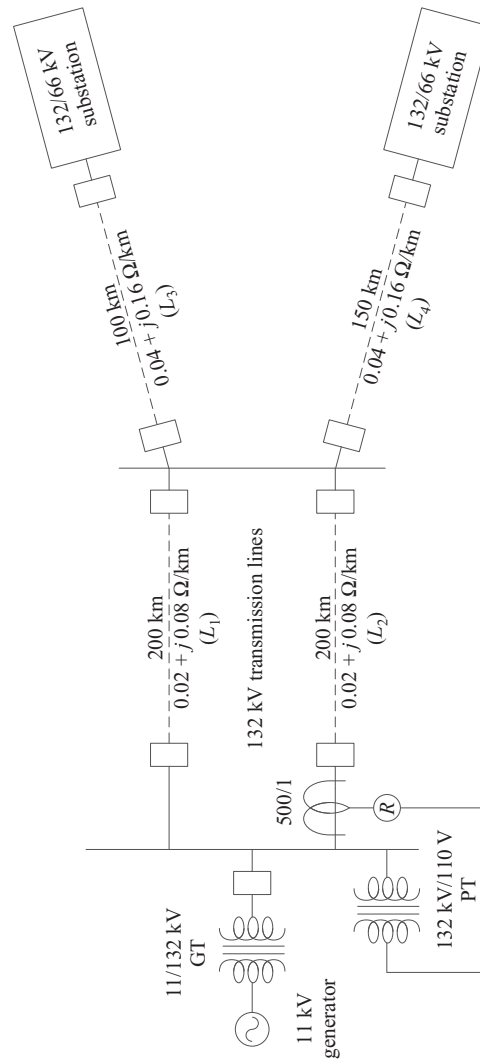


Fig. 8.36

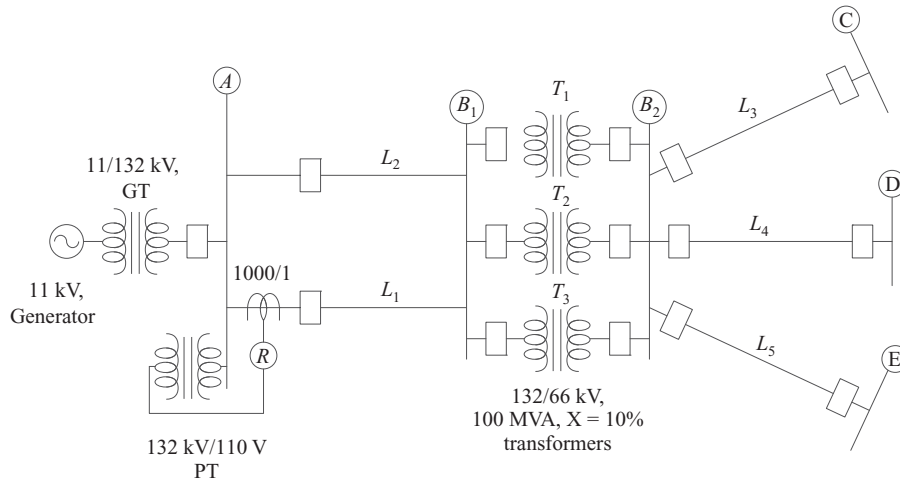


Fig. 8.37

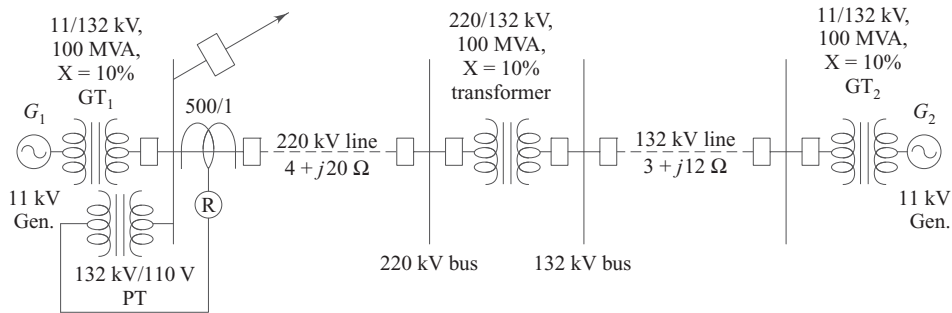


Fig. 8.38

MULTIPLE CHOICE QUESTIONS

- Impedance relaying schemes calculate the impedance using the
 - fundamental component of the post-fault current
 - transient component of the post-fault current
 - fundamental as well as the transient component of the fault current
 - other than the above
- The threshold characteristics of a plane impedance relay in a complex Z -plane is
 - a circle passing through the origin
 - a circle with the centre at the origin
 - a straight line passing through the origin
 - a straight line offset from the origin
- With reference to the problem of power-system swings, for protection of EHV lines
 - mho relays with a characteristic angle of 75° is the best choice
 - mho relays with a characteristic angle of 60° is the best choice
 - reactance relay is the best choice
 - impedance relay is the best choice

4. In case of a short tie line fed at both the ends, for protection
 - (a) reactance relay is the best choice
 - (b) ohm relay is the best choice
 - (c) mho relay is the best choice
 - (d) none of the above
5. A series compensation on transmission line creates a problem in the measurement of distance to fault when
 - (a) the fault is before the series capacitor
 - (b) the fault is a low-current fault
 - (c) MOV has operated and capacitor has been shorted due to a high-current fault
 - (d) bypass circuit breaker has been turned 'ON' during light load period to bypass the series capacitor

Carrier Current Protection of Transmission Lines

The most selective, reliable and fast protection scheme is a unit protection. The differential protection scheme compares the local current with the current at the far end of the line. A distance protection scheme compares the load current with the local voltage. Voltage changes gradually with the location of the fault. Hence, discrimination between two adjacent faults is not that accurate as in differential protection because in the latter case, the current at the far end reverses for a fault beyond the CT provided there. This provides

9

Introduction

an abrupt discontinuity which makes selectivity easy and automatic. The complete line section could be protected instantaneously and auto-reclosures can be easily applied for the transmission line protected by a unit protection scheme. Still, distance relays are widely used because of economic considerations (pilot channels in differential protection are very costly) and the advantage of back-up protection, which is not possible in differential protection. The scope of this chapter is to discuss unit protection schemes (using pilot channels).

9.1 PILOT-WIRE PROTECTION

Pilot-wire protection for transmission lines is a unit type of protection similar to differential protection. A type of interconnecting channel, popularly known as *pilot*, is necessary between the two ends of the transmission line to be protected. These channels are of three types, viz., pilot-wire channel, carrier-current channel or microwave channel.

In a pilot-wire channel, physical wires are to be run from one end to the other. In a carrier channel low-voltage currents at high frequencies, ranging from 30 kHz to 200 kHz, are transmitted along a power-line conductor. A receiver at the other end receives these carrier signals and the ground wire acts as a return conductor.

A microwave pilot is an ultra-high frequency radio system operating above 900 MHz. A pilot-wire channel is generally economical for distances of the order of 10 to 15 kilometres, beyond which a carrier-current pilot usually becomes more economical. Using a microwave pilot, many other services can be rendered which are not technically feasible in a carrier-current pilot.

Circulating-current differential protection discussed in Section 2.11.1 cannot be applied directly for the protection of a transmission line because of the following reasons:

1. It is not possible to maintain the points *A* and *B* (of Fig. 2.12) at the same potential. For achieving this, the relay *R* of Fig. 2.12 is to be installed at some intermediate station midway between the extremes of the line to be protected. This solution is obviously not practical.
2. As the pilots are required to take the rated CT secondary current almost continuously, the pilot wires are required to be of generous cross section. There will be large voltage drops along the pilot wires for the same reason.
3. For a three-phase line, six pilot conductors would be required, one for each phase CT, one for neutral connection and two for the trip circuit.
4. It is quite likely that improper operation of the protective scheme may occur due to CT inaccuracies during heavy VA burden being imposed on them.
5. The charging current between the pilot wires may lead to erroneous operation of the protective scheme.

Howsoever, despite these limitations, we will utilise fundamentals of circulating-current differential protection with certain modifications to apply for pilot wire relaying.

9.2 AC WIRE PILOT RELAYING

9.2.1 Circulating-Current-Type Pilot Relaying

Figure 9.1 shows a practical circuit arrangement for the circulating current type pilot wire protection of a transmission line. A dc directional relay comprising of *OC* and *RC* is being used with rectified ac quantities to get high sensitivity. *OC* is an operating coil and *RC* is a restraining coil. The additional investment of a relay at each end avoids the leads for the tripping circuit to be run along the full length of the line, thereby reducing the complication of wiring and the cost. Conversion of the three-phase and ground currents to a single-phase quantity is achieved by phase-sequence filters. The function of saturating transformers is to limit the magnitude of the voltage impressed on the pilot circuit. The neon lamps suppress the peak of the surge voltages due to switching actions. Isolating transformers at the ends of the pilot isolate the terminal equipment from the pilot circuit against lightning overvoltages.

9.2.2 Opposed Voltage-type Pilot Relaying

Figure 9.2 shows the opposed voltage-type pilot-wire protection. An ac directional-type relay is used at each end. The mixing transformers extract a single-phase quantity for all types of faults. Due to its saturation, it also limits the magnitude of the voltage imposed on the pilot circuit. Moreover, the impedance of the circuit connected across the mixing transformers is sufficiently low to limit the magnitude of peak voltages.

9.3 LIMITATIONS OF AC WIRE PILOT RELAYING

1. If the fault occurs very near to one end and if a very small current flows at the other end, breaker tripping will occur at the end where a high-fault current flows and probably the other breaker may not trip.
2. Charging current between the pilot wires will tend to make the equipment less sensitive to internal faults.

9.4 CARRIER-CURRENT PROTECTION

Carrier-current protection is a unit form of a protection for a transmission line section. When the distance of the pilot is greater than 15 km then a pilot wire proves uneconomical. A carrier current is generally used

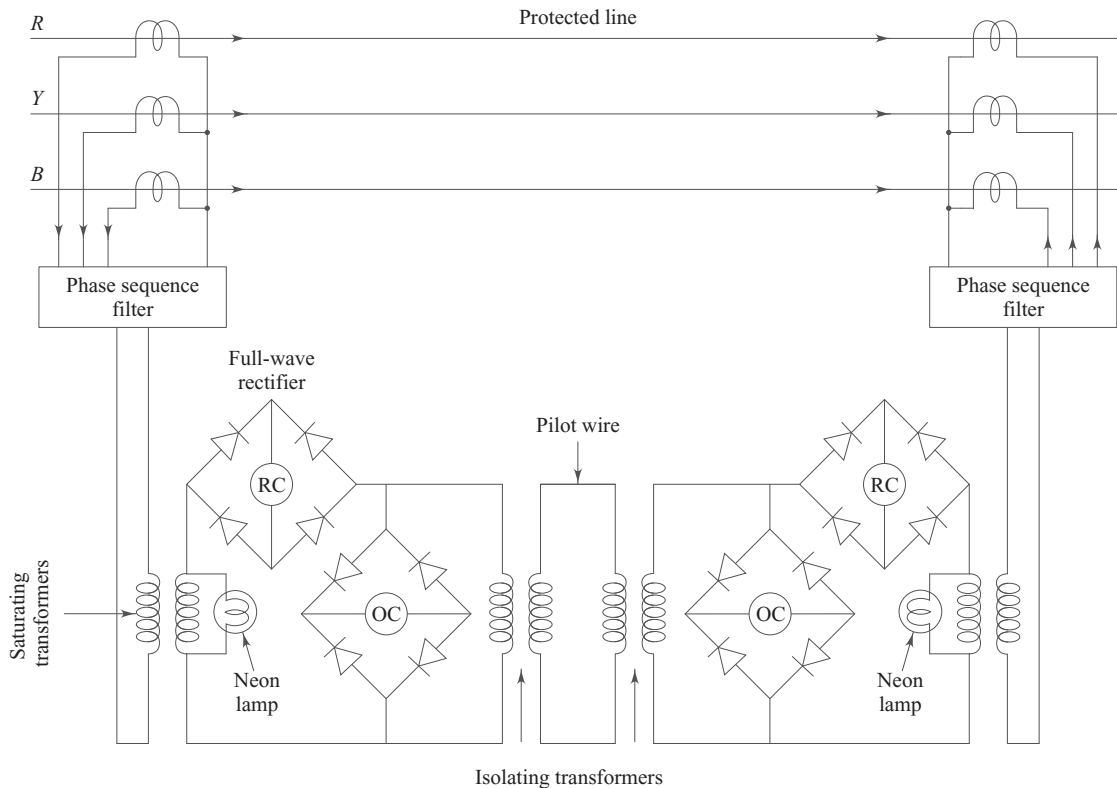


Fig. 9.1 Circulating-current-type pilot relaying

for protecting extra-high-voltage power lines. For lines protected with the distance scheme of protection, the main problem lies in the non-simultaneous opening of circuit breakers at both ends of lines. This can lead to instability of the total power-system network. It also hinders operation where auto-reclosing is employed. Employing a carrier-current scheme instead of a distance scheme, which is a non-unit type of a protective scheme, ensures simultaneous and fast opening of circuit breakers at both ends. The same carrier signal channel in some cases is optimally utilised for communication, supervisory control, relaying and telemetering which justifies the high cost of carrier equipments. Moreover, the coupling capacitors used for carrier signals can be used as potential dividers for local metering purposes.

In carrier-current protection, the role of a carrier signal is either to prevent or to initiate tripping of the relay. When the carrier signal is utilised to block the operation of the relay, the scheme is known as a carrier blocking scheme. When the carrier signal is used to activate tripping, the scheme is called carrier tripping scheme.

Two principles are adopted in carrier-current protection, namely, phase comparison and directional comparison. In phase comparison, the phase angle of current entering at one end is compared with that of current leaving the line section. Under normal conditions or external fault, the phase difference between the two set of currents is zero. In case of an internal fault, the phase angle is 180° which initiates a tripping signal. In directional comparison, the direction of power flow at two ends of the line section is compared. In case of a fault, power flow inwards from both ends of the protected section which initiates the tripping signal.

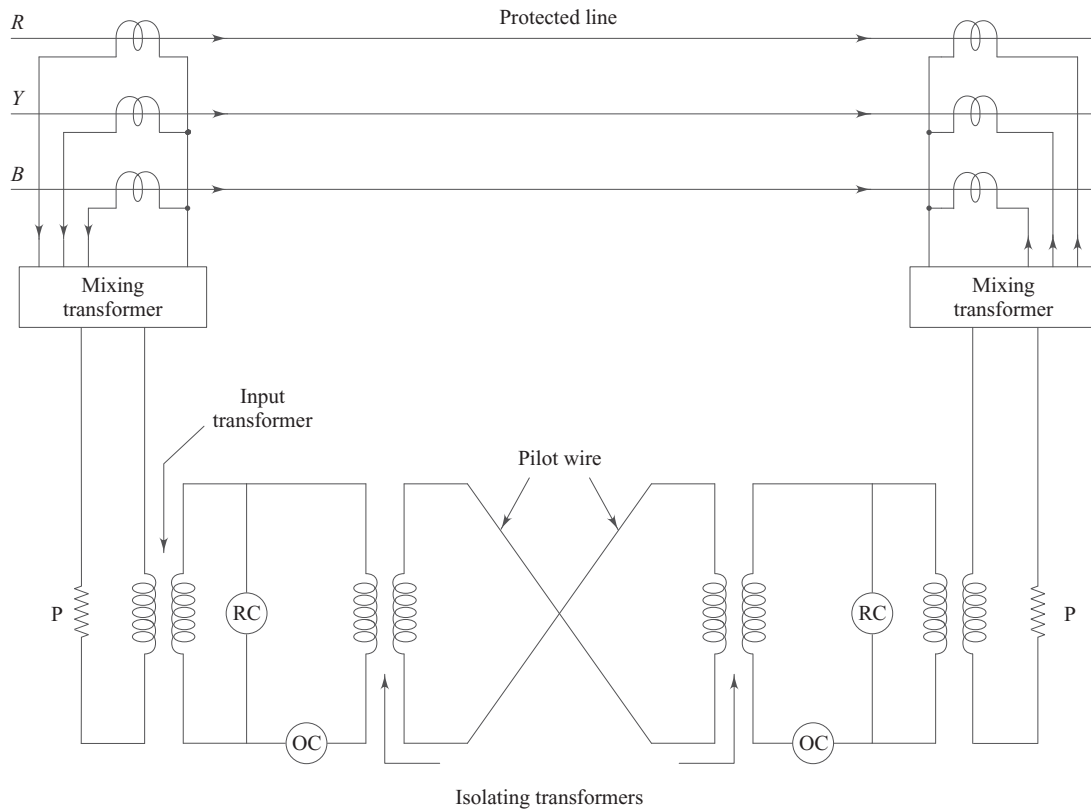


Fig. 9.2 Opposed voltage-type pilot relaying

9.4.1 Phase Comparison of Carrier-Current Protection

The schematic diagram of carrier-current protection is shown in Fig. 9.3. Let us assume that it operates on the principle of a carrier blocking scheme. Each end of the line is provided with identical carrier current equipment. Different equipments are explained as follows:

1. **Coupling Capacitor** The coupling capacitor offers low impedance to carrier frequency but high impedance to power frequency. Through this coupling capacitor the carrier equipment is connected to the transmission line. Thus a coupling capacitor does not allow 50 Hz power frequency currents to enter the carrier equipment but allows carrier frequency signals to enter the carrier equipment. The inductance in series with the coupling capacitor offers low impedance to power frequency current and high impedance to carrier frequency currents. Thus, the transmitter and receiver are insulated from the power line and effectively grounded at power frequency current.
2. **Line Trap Unit** A line trap unit is connected as shown. It is a parallel tuned circuit. It offers a low impedance of less than 0.1 ohm to 50-Hz power frequency signals and a high impedance to carrier frequency signals. Thus, a line trap unit blocks the high-frequency signals from entering the neighbouring line and the carrier currents flow only in the protected line section.

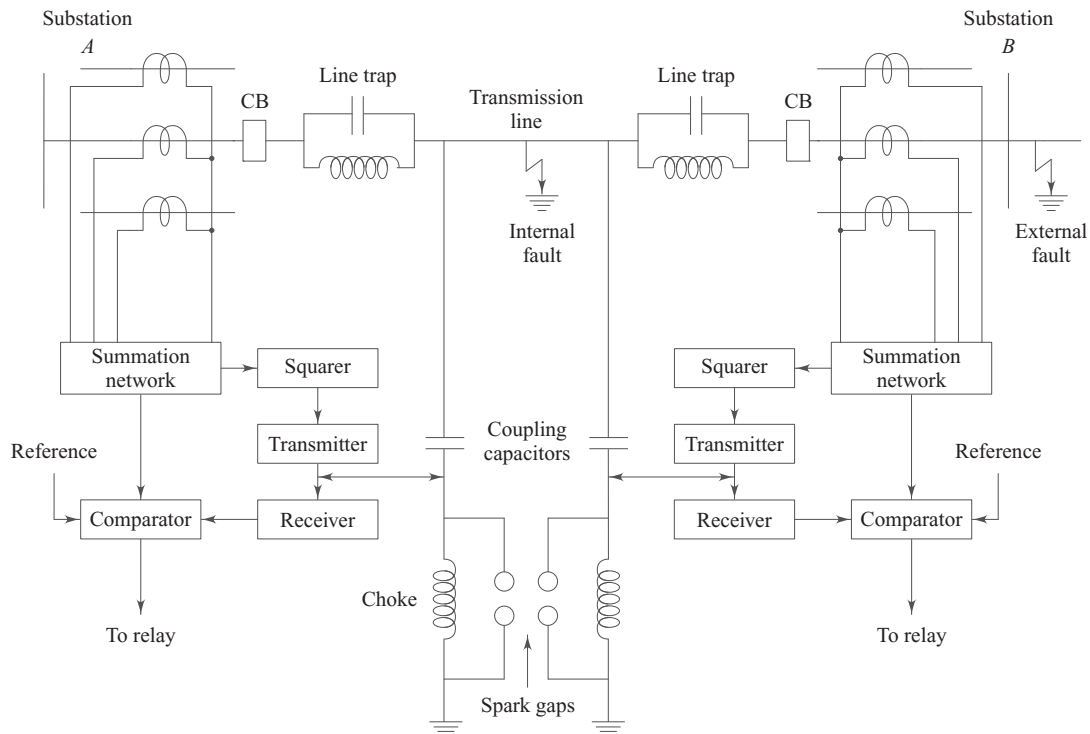


Fig. 9.3 Block diagram of a carrier-current protection scheme

- 3. Protection of Coupling Equipment** To protect the coupling equipment against over-voltages, a spark-gap is used as shown.
- 4. Transmitter Unit** Figure 9.4 gives the general arrangement of a transmitter-and-receiver unit. The oscillator generates the carrier frequencies. The output of the oscillator is provided as an input to the amplifier. The amplifier is essential to compensate for the attenuation of the carrier signal along the transmission path between the transmitter of the local end and the receiver at the remote end.
- 5. Receiver Unit** The block diagram of the receiver unit is shown in Fig. 9.5. The attenuator attenuates the signals to an allowable value. The matching of the impedances of line and receiving unit is done by the matching unit. Rejection of unwanted signals is achieved by a band-pass filter.

During normal conditions, the outputs of the summation network at stations *A* and *B* are 180° out of phase. Thus the carrier signal is transmitted only during the positive half cycle of the network as the squarer clips the negative half. Now refer to Fig. 9.6(a) to Fig. 9.6(d) to understand the transmission of the carrier during an external fault. Figure 9.6(a) shows the waveform output of the summation network at *A*. Figure 9.6(b) shows the carrier signal transmitted by the transmitter at *A*. Figure 9.6(c) shows the output of the summation network at *B*. Figure 9.6(d) shows the carrier signal transmitted by the transmitter at *B*. As the carrier signal is a blocking signal and for the case of an external fault, the carrier is always present, the relay does not trip. In case of an internal fault, the polarity of the network output at *B* is received as shown in Fig. 9.6(e). The carrier signal sent by the transmitter at *B* is shown in Fig. 9.6(f). Thus, it can be seen that during internal

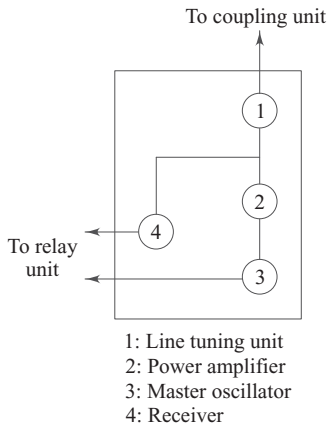


Fig. 9.4 Block diagram of a transmitter unit

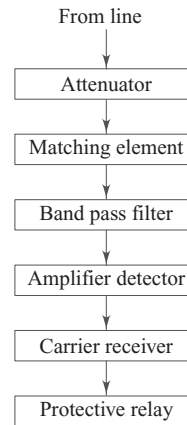


Fig. 9.5 Block diagram of a receiver unit

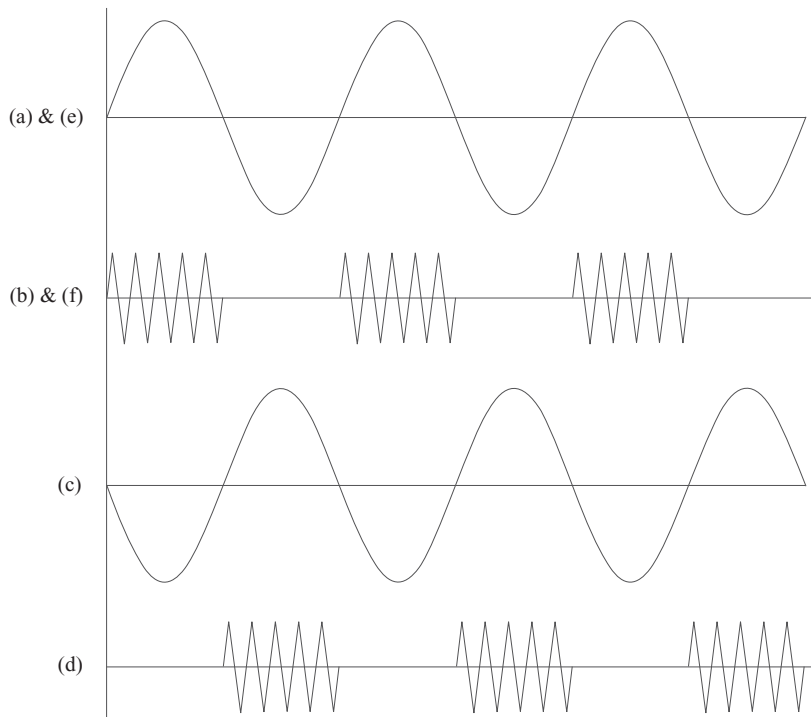


Fig. 9.6 Wave-shapes for external and internal fault conditions

faults carrier signals are present only during one half cycle. Due to the absence of continuous carrier signal in our scheme of carrier blocking, the relay trips.

The phase-comparison scheme of protection is a unit form of protection and hence provides primary protection to the transmission lines. For back-up protection, the conventional three-step distance relays have to be used.

9.4.2 Principles of Carrier-Aided Distance Protection

The signaling channel (which may be obtained by microwave or radio link or voice frequency over pilots, or power line carrier, etc.) is used to transmit information from one end for being evaluated at the other end. There are various methods of evaluation; each method has its own merits and demerits over the other. At least one of these methods is always practicable.

The main difference between the various methods is the manner in which the transmitted signal is utilised. When it is used to trip the breaker, it is known as *transfer tripping*, whereas when it blocks the tripping it is termed *transfer blocking*. In the former method, the setting of the first time step can be made shorter or longer than the length of the protected line section and the signal is utilised to obtain selective tripping, or alternatively the relay may be set in the usual way and the signal prolongs the basic time step of the distance relay at the opposite end.

The Blocking Scheme In this case, the zone 1 of the distance relay extends beyond the principal section, normally 120% of the protected line, so that the distance relay positively covers 100% of the protected line section with maximum under-reach conditions. The tripping command of the protection relay is blocked by the carrier signal for faults in the adjoining line. For this purpose, an additional reverse-looking directional relay is installed with a distance relay on both ends to detect all types of phase and ground faults. For faults in the adjoining line section, this additional relay generates a signal which is transmitted to the other end by the aid of a carrier to prevent tripping.

Figure 9.7(a) shows the time and reach settings of distance relays installed at stations *A* and *B* of a feeder *A-B*, and Fig. 9.7(b) gives a block diagram that is usually used in a blocking scheme.

For fault at F_1 (anywhere in the protected line section) the distance relays at stations *A* and *B* operate, but the fault being in the forward direction, the reverse looking-relays on these stations do not operate. Thus, there would be no blocking signal, i.e., contacts *RR* on both ends remain closed and the fault will be isolated from both stations instantaneously and simultaneously.

For the fault at F_2 , the distance relay at *B* will not pick up, the fault being in the reverse direction. The reverse-looking directional relay will, however, operate at this end to send a blocking signal to the station *A* where the distance relay picks up seeing the fault in forward direction. Because of blocking command at the station *A*, the contact *RR* of the receiver relay opens by a signaling channel and no tripping at station *A* will thus occur.

It must be ensured that the blocking signal from the remote terminal is received before the local distance relay gives a trip command, i.e., for a fault at F_2 , the signal transmitted from the station *B* should be received at the station *A* to open the trip command. In practice, it is always necessary to provide a short time delay to ensure that under all circumstances, the blocking signal is received in time and unwanted tripping for faults in the adjoining section is prevented. The contact of a time-delayed relay is in series with the tripping command. In case of failure of carrier command, mal-tripping can occur, which is a very serious limitation of the blocking scheme.

Inter-Trip Scheme Inter-tripping, which is sometimes known as *transferred tripping* is the controlled tripping of a circuit breaker so as to completely isolate a circuit simultaneously with the tripping of a circuit breaker at the other end. It is applied in two modes, namely *Under reach transfer tripping* and *Over reach transfer tripping*.

In transfer tripping, a signal to the other end is transmitted over a faulty line and to minimise the possibility of a signal being lost in transmission, the following extra precautions are always necessary

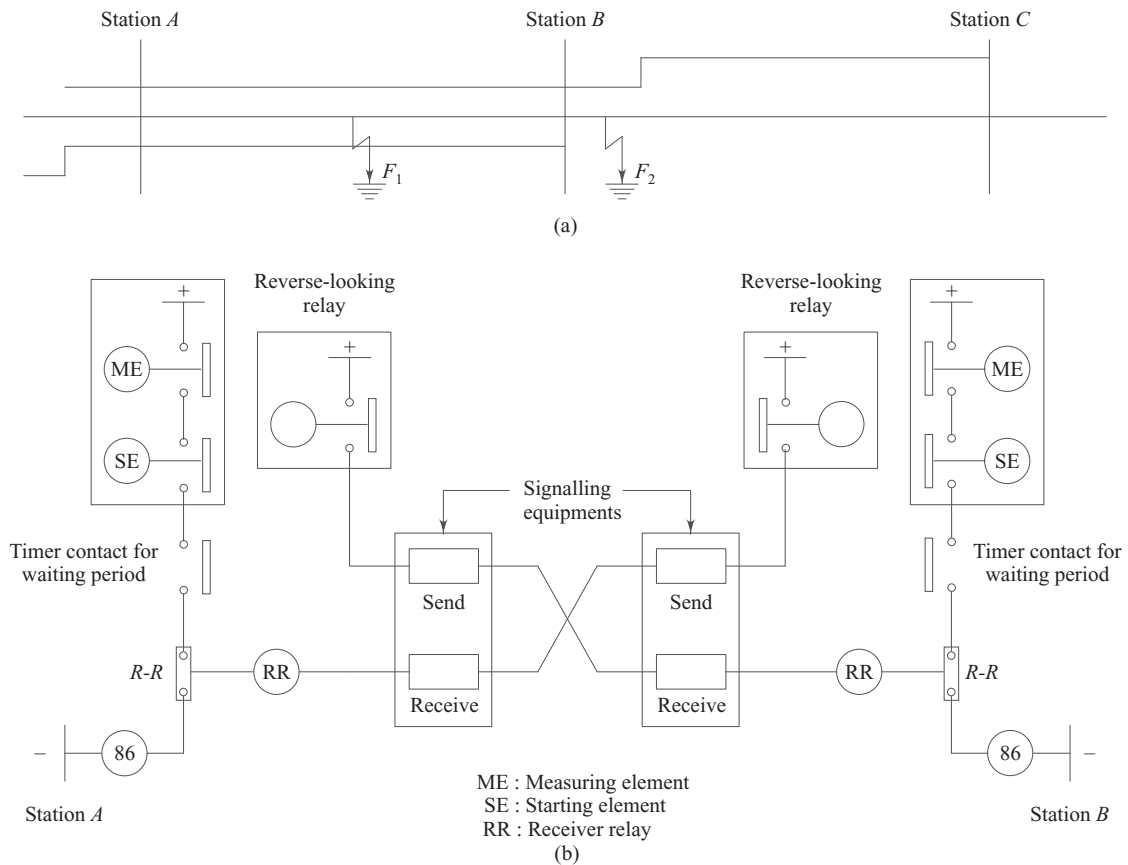


Fig. 9.7 Blocking carrier scheme

- (i) Two-phase coupling has to be invariably employed.
- (ii) In multi-purpose equipment, having voice communication and some superimposed channels, all other applications are disengaged while transmitting the signal to the other end to boost its level.

(I) Under-Reach Transfer Trip Scheme In this case, the distance relay at both ends of a circuit are set in the normal way, i.e., Zone 1 for 80–90% of the protected line section and any fault in the remaining (10–20% of line) section is cleared practically instantaneously by the aid of signaling.

Figure 9.8 shows the time reach setting of distance relays installed at stations *A* and *B* of the line section *A-B*. For fault at F_1 (within the first zone of both relays), both the distance relays pick up instantaneously and clear the fault to isolate a faulty feeder from both ends. Even though the signaling channel does its normal function, yet it has no special role to play in this scenario.

In case of end zone faults, say at F_2 , the distance relay at the station *B* sees the fault in the zone 1, trips its circuit breaker instantaneously and simultaneously gives an inter-tripping carrier signal to the station *A*. With this signal, the protection at the station *A* also effects instantaneous tripping after a small time delay (corresponding to operation of auxiliary relays and transmission time of signal) which is insignificant in comparison to the zone 2 delay. The interlocking NO contact of the starting element is kept in series with trip circuit. Obviously, the impedance reach of the starting element reaches up to the 3rd zone or a little more.

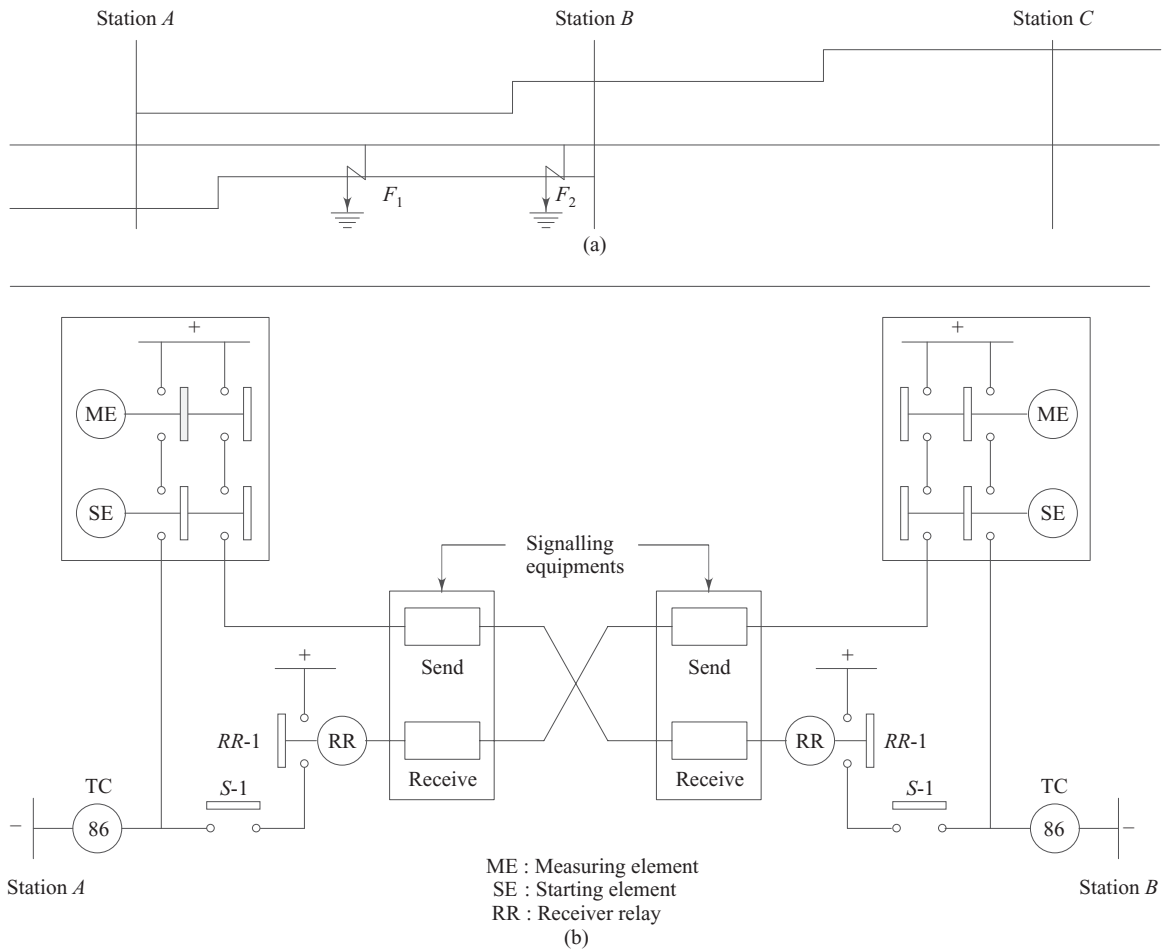


Fig. 9.8 Carrier inter-tripping scheme

The instantaneous tripping at the station *A* can be carried out in the following ways:

When the incoming signal directly trips the circuit breaker, it is termed *direct* under-reach transferred tripping.

When the incoming signal is utilised at the receiving end to trip the circuit breaker after ensuring that the starting element of the local distance relay has operated, it is known as a *Permissive* under-reach transferred tripping (Fig. 9.8 depicts the principle using a block diagram).

When the incoming signal extends the measuring range of the first zone of the distance relay at the receiving end, the arrangement is termed a *carrier acceleration*.

(II) Direct Under-reach Transfer Tripping The receiver relay is seldom used for direct tripping, because of the possibility of an undesired tripping caused by an accidental operation of the signaling channel due to noise frequencies generated by fault or switching surges, etc. One possible method to overcome this drawback is to transmit the tripping command over two separate channels, the contacts of receiving relays being connected in series. For a breaker to trip wrongly, this would mean that both channels would have to

pick up due to a noise signal at the same time, which is highly unlikely. This arrangement will, however, make the signaling channel expensive.

Another method is to use a coded signal; the code word must of course be as short as possible, to avoid transmission time becoming too long. This will require sufficient bandwidth over the carrier scheme.

A direct transfer trip cannot be used when a single-phase auto-reclosure is involved because it requires phase selection at the receiving end. The only way to overcome this limitation would be to employ one channel per phase but this would be too expensive.

(III) Permissive Under-Reach Transfer Tripping In this case, the transmitted command is executed at the receiving end only when the starting element(s) of the local distance relay have already picked up, thus confirming the existence of a fault. By interlocking the received signal with the starting elements of the distance relay, it is possible to ensure that no tripping occurs due to noise on the line being picked up. Thus, both the breakers trip either in basic time or in case of end zone faults in the basic time plus the transmission time, thereby fulfilling the requirement for rapid auto-reclosure.

(IV) Tripping by Carrier Acceleration In 'carrier acceleration', a signal received from the opposite end extends the reach of the zone 1 from, say 80 to 120% of the length of the protected line section. The difference between this and 'under-reach transferred tripping' is that the distance relay is made to perform a new measurement, with the result that a certain extra time lag has to be accepted. On the other hand, there is a better security against unwanted interruptions. With permissive transfer tripping, it is theoretically possible for a noise signal to arrive and also picking up of starters at the same time, resulting in erratic operation which could be avoided in 'carrier acceleration'.

(V) Over-Reach Transfer Trip Scheme As for a 'blocking scheme', the setting of distance relays is so adjusted that their first zone positively covers the main section. But the tripping command is executed only when a permissive signal is received, this signal being given by the first step of the distance relay at the opposite station.

While in case of blocking scheme an 'NC' contact of receiver relay is used in series with the tripping command, in over-reach transferred tripping a 'NO' contact of the receiver relay is operated by the carrier signal from the remote end. In this case, no reverse-looking directional relay is required.

In Fig. 9.9, a fault at F_1 (anywhere in the protected line section) is covered by the first zone of both the distance relays. The tripping command of both the distance relays sends a carrier signal to the opposite end to close the NO contact of the receiver relay, thereby allowing the tripping command to be passed to the trip coil of the circuit breaker.

The fault at F_2 is seen by the distance relay at the station A in the first zone. A carrier signal is sent to close the receiver relay contact at the station B . This does not, however, result in tripping as the distance relay at the station B , seeing the fault in the reverse zone does not pick up. Since the protection at the station B , has not operated, no signal is transmitted from the station B to the station A . The tripping impulse at the station A cannot be passed over to the circuit breaker, even though the local distance relay has operated.

Taking everything into consideration, the tripping times in this mode are longer than 'under-reach' as the transmitted time has to be added to the tripping time for all kinds of fault. Moreover, the failure of a signaling channel will result in the non-isolation of fault. For these reasons, this arrangement is rarely used. But it is used when other methods fail to serve the purpose. This may be the case, for instance, with line containing series capacitors installed in the vicinity of one station. It may be difficult in such a case for the distance relay to determine the direction correctly, especially for those relays on an adjoining or parallel line section. By providing an interlock with relays of opposite station, however, it is possible to avoid unselective interruption of a healthy line.

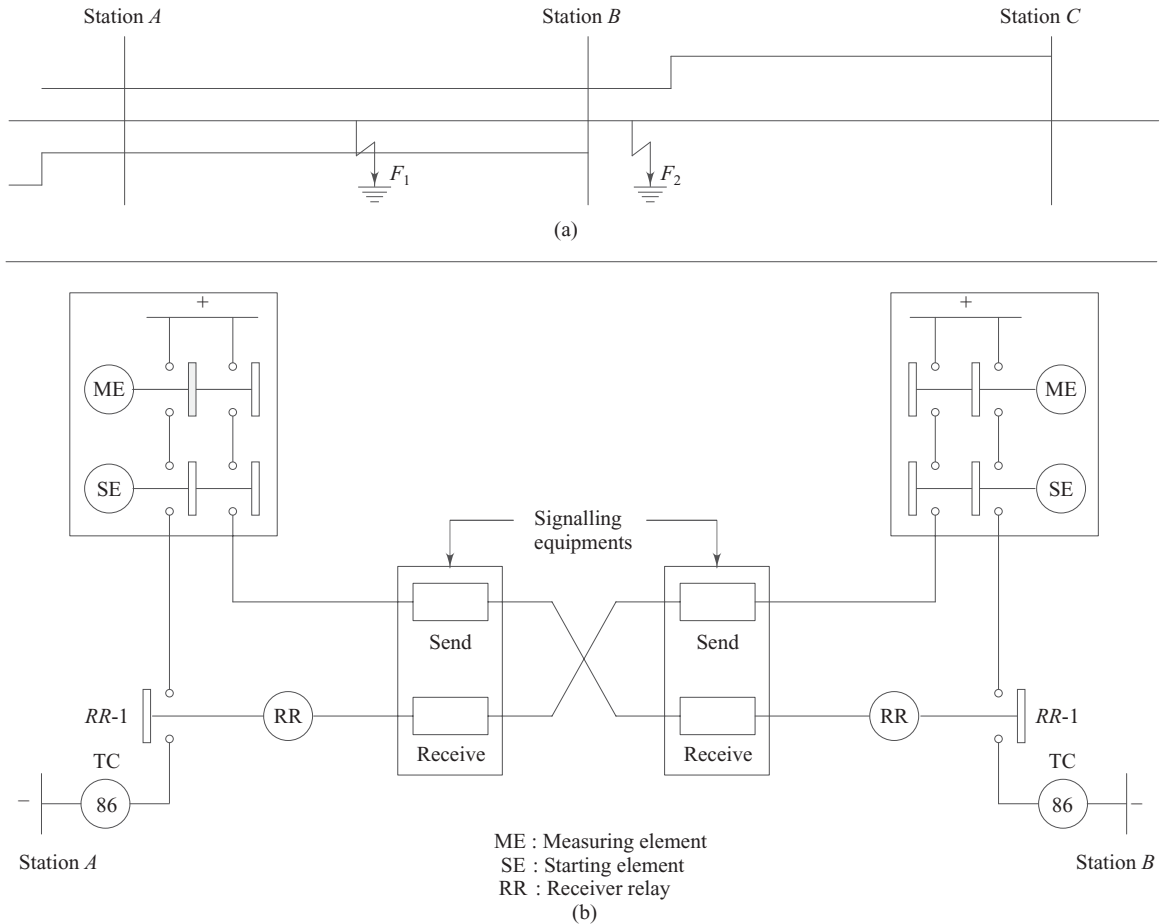


Fig. 9.9 Over-reach transfer trip scheme

Difference between 'Blocking' and 'Transfer Tripping'

- (i) From the signaling point of view, it is obvious that lesser the attenuation in the transmission path, the more reliable the transmission can be for a given length of the feeder, i.e., signal-to-noise ratio can be increased. In the 'transfer-trip' scheme, attenuation due to fault is unpredictable and variable. In the 'blocking scheme', this factor does not exist.
- (ii) The cost of a coupling equipment in the 'transfer scheme' is more than that in the blocking scheme as in the latter case, the signal is always sent on a healthy line and one phase coupling is good enough. The extra money involved in providing a reverse-looking directional relay in case of a 'blocking scheme' compensates to a very good extent, the cost of extra coupling required in the 'trip-transfer' scheme.
- (iii) The major advantage claimed for a transfer trip scheme is the speed, as the intentional time delay needed in a blocking scheme is not necessary here. The time delay in a blocking scheme allows the fault to persist for a longer time.

- (iv) In the event of failure of carrier channel, the behavior of distance relays in various arrangements would be as follows,
- In 'under-reach transfer trip', the relaying will behave in a normal way, i.e., the end zone fault will be cleared after a time delay corresponding to the zone 2 setting.
 - In 'over-reach transfer trip', the distance relay will fail to isolate the fault in the principal section from both ends in the zone 1 and all faults will be cleared after a delay equal to the zone 2 setting.
 - In 'blocking' arrangement, the relaying will operate correctly for a fault in the principal section in the zone 1 but it will erratically operate for close-up faults in adjoining line sections.

REVIEW QUESTIONS

- Describe briefly the functions of a coupling capacitor and line-trap used in carrier current protection of a transmission line.
- Explain the permissive carrier inter-tripping scheme of transmission line protection, with the help of relay characteristics and a dc control circuit.
- With a neat circuit diagram, briefly explain how a unit protection scheme will operate using carrier equipment for transmission line protection.
- What is the demerit of a blocking carrier scheme for protection of a transmission line?
- With a neat circuit diagram explain how a phase-comparison carrier-current protection scheme operates.
- Rewrite the following statement after correcting:
Wire pilot protection is not used for protection of transmission lines because it is a very costly scheme of protection.
- Enumerate different types of carrier-aided distance protection schemes. Briefly explain any one of these schemes.

MULTIPLE CHOICE QUESTIONS

- The frequency of a carrier transmitted by a carrier-current pilot is in the range of
(a) 1 kHz to 10 kHz (b) 10 kHz to 25 kHz (c) 30 kHz to 200 kHz (d) 200 kHz to 500 kHz
- In the case of a carrier-current pilot, the line trap connected at the end of the line consists of
(a) series LC circuit (b) series RLC circuit (c) parallel LC circuit (d) parallel RC circuit
- The unit protection scheme for transmission line provides
(a) primary protection (b) backup (or secondary) protection
(c) simultaneous protection (d) remote protection
- The inductance (choke) in series with the coupling capacitor in PLCC offers
(a) high impedance to power frequency currents (b) low impedance to power frequency currents
(c) high impedance to carrier frequency currents (d) both (b) and (c)
- Over and above transmission line protection, the carrier signal channel can also be utilised for
(a) communication (b) supervisory control (c) telemetering (d) all of the above

Buszone Protection

Clearance of the fault in a busbar would need the tripping of all the breakers of the lines connected to the faulted bus. Hence such a tripping can potentially lead to widespread instability of a power system. This is one of the main reasons for busbar protection being very critical. Two forms of busbar protection are known, viz., unit protection and non-unit protection schemes. Prior to the unit form of protection, the fault at a local bus was cleared by back-up relays at the neighbouring station.

Bus isolation causes widest outage of circuits. Moreover, the occurrence of a bus fault is found to be rare. Therefore, an opinion prevailed that no integrated unit type of bus-fault protection is required. If the back-up protection provided to

10

Introduction

a local bus fault is fast enough then the system can be protected without damage to equipments.

With increasing voltage levels and extensive interconnection, stability of generators becomes an important condition which necessitates faster and reliable operation of relay for a severe bus fault. Further, the danger caused because of an unprotected bus during a bus fault is found to be very severe. Therefore, schemes for busbar protection are implemented to prevent hazards to the system. Care is taken in these schemes to prevent unwanted tripping. By

involving a sectionalised and duplicated busbar system, total interruption of power can be eliminated and at the same time the system is protected.

10.1 PROTECTION REQUIREMENTS

Faults in the busbar can be broadly classified as

- (a) Fault due to insulation failure caused from damaged circuit breakers or insulators
- (b) Arcing and insulator flashover caused by overvoltages
- (c) Faulty handling of switching equipments, especially earthing switch
- (d) Dropping off of metal parts across busbars

Thus the protection provided must possess the following characteristics:

- (i) It should be fast enough to minimise damage and maintain system stability.
- (ii) It should reliably operate on internal faults.
- (iii) It should maintain stability by not operating on external faults which are more likely to occur during the lifetime of the scheme.

- (iv) There should be provision of supervision of associated current transformers which are responsible for providing the actuating juice to the relay in case of a fault.

Experience shows that the majority of faults on busbars and associated switchgear involves earthing. In phase-segregated switchgear, where dividing walls separate the three phases from one another, faults involving earthing only occur naturally. Only human errors (like energisation of a busbar keeping the earth switch closed) can cause a phase fault. But the consequence of a phase-to-phase fault is very severe. Hence, busbars in substations of up to 33 kV (indoor substations) are protected for phase-to-earth fault only, whereas buszone protection in outdoor substations involves protection against all kinds of faults.

10.2 NON-UNIT PROTECTION BY BACK-UP RELAYS

Bus faults cleared by back-up overcurrent, earth-fault and distance protection are usually found to be non-discriminative and slow in operation. The error in the scheme when applied to busbar protection can cause unnecessary tripping when a relay spuriously trips, thereby causing discontinuity of supply. Moreover, it can cause havoc to the equipment if not operated quick enough.

Thus, the philosophy of back-up protection to clear busbar faults can be confined to a radial system at a higher distribution voltage of 11 kV and a lower transmission voltage of up to 66 kV in India, where it becomes economically unviable to implement unit busbar protection schemes.

10.3 UNIT PROTECTION SCHEMES

10.3.1 Frame Earth Protection

This form of protection is normally applied to indoor distribution switchgear. As the name suggests, in this form of unit protection scheme, the complete switchgear framework is lightly grounded through the primary of a current transformer. The framework is usually insulated from the ground by standing it on concrete. Care is to be taken that the frame is connected to the ground through the current transformer only and has no other earth connections. The ohmic value of the grounding resistance of a frame must be above 10 ohms. Use of a large value of resistance might raise the potential of the framework to very high levels which is dangerous from the safety point of view.

Moreover in designing the earthing scheme which incorporates frame earth protection for a busbar, care is to be taken that the earth point for frame and power system neutral is physically connected to the same point. This is to ensure that the earth fault current has no additional path. If additional path is provided then the ground fault current will have alternate path which will cause reduction of sensitivity of relaying scheme.

The scheme is as shown in Fig. 10.1. As seen in Fig. 10.1(a), the second separate earthing line, named cable sheath earth, is shown which is directly connected to the ground. Cables with earthing sheath are connected to this point. For a cable fault involving earth, the earth-fault current should not pass through the relay meant for busbar protection. Thus, a separate earth point for a cable sheath is provided. To prevent spurious operation of the relay, an additional check relay is kept. Referring to dc control circuit of Fig. 10.1(b), the circuit breakers connected to the bus will trip only if permitted by operation of the check relay R_3 (which in turn operates dc auxiliary relay R_4) which will not operate for spurious flow of current through the relay R_1 . If a transformer exists in the infeed, the check relay can be fed from a CT on the transformer's neutral connection. If no neutrals are available then a core balance CT can be fitted around the incoming cable to feed the check relay.

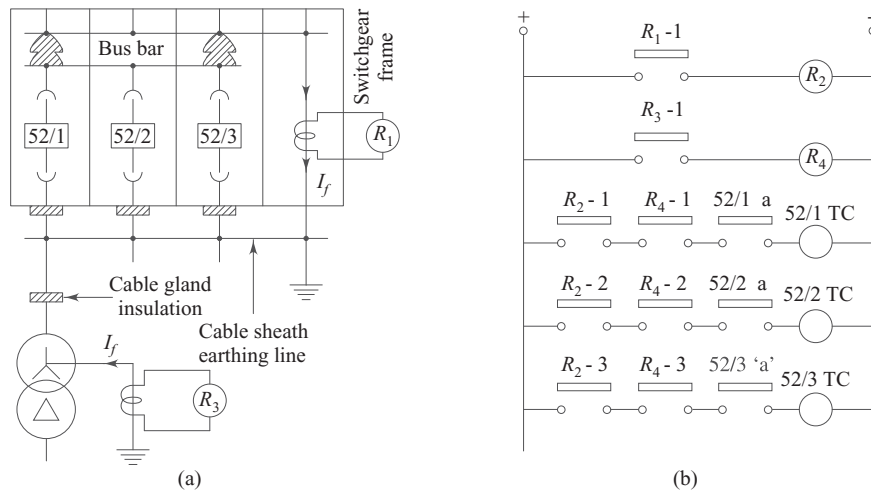


Fig. 10.1 Frame earth busbar protection

10.3.2 Directional Comparison

The guiding principle of working for this type of protection is the fact that during an internal fault, the power will flow towards the bus in all circuits connected to the bus, but during an external fault power will flow towards the bus in all circuits, except the faulted one where power will flow outwards.

Two forms of directional comparison scheme are presented. In the series trip scheme, as shown in Fig. 10.2(a), the directional relays will operate only for the currents flowing towards the bus. In case of an internal fault in the bus, all the three relays will operate energising the tripping relay 86 which in turn will

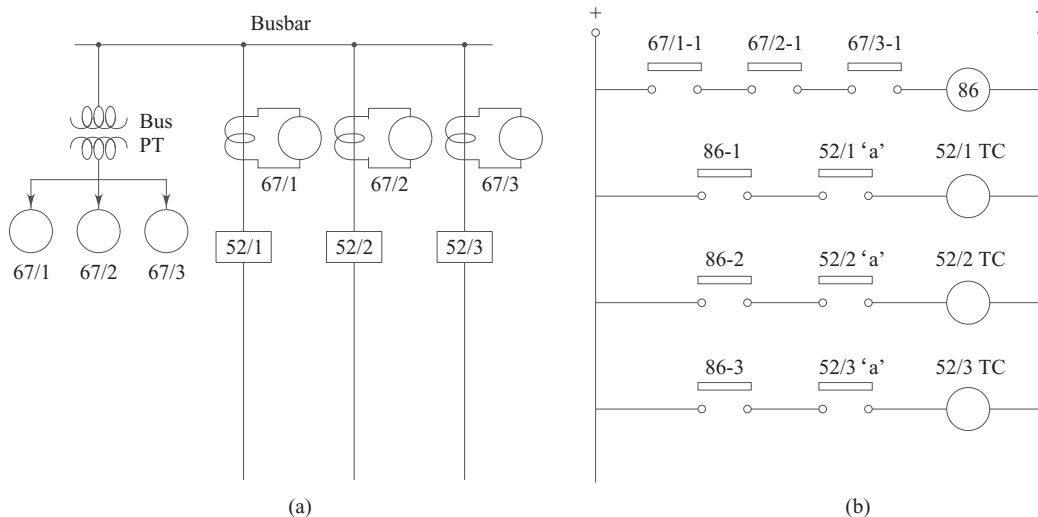


Fig. 10.2 Series trip directional comparison

trip all the breakers as shown in Fig. 10.2(b). In case of an external fault (say on one of the lines) however, the relay connected with the faulted line will not operate, thus blocking the operation of the bus-protection scheme as per the requirement. The disadvantage of the scheme is that because of the dependence of the system on too many series contacts, the reliability of the scheme is reduced. In the blocking scheme, as shown in Fig. 10.3, all the trip contacts of the directional relays are connected in parallel and then to the tripping relay, whereas all the block contacts are paralleled and connected to the blocking relay B . During an internal fault, the blocking relay is de-energised as all circuits feed to the fault, thereby energising the trip circuit. During an external fault, at least one circuit has outgoing power thereby blocking the trip coil from operating.

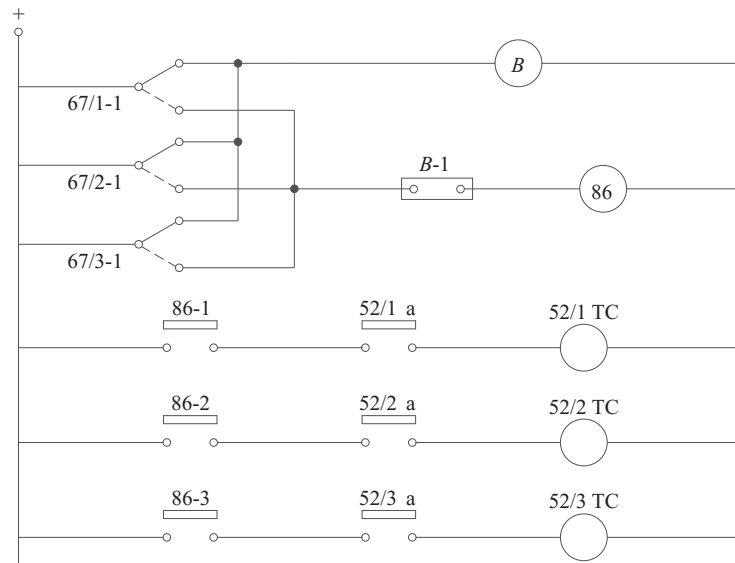


Fig. 10.3 Directional blocking

Note The directional relay contacts are shown for currents flowing away from the bus

10.3.3 Unit Differential Protection Scheme

Circulating-Current Differential Protection The guiding principle of operation of the scheme [Fig. 10.4(a)] is Kirchhoff's current law whereby under normal condition or external fault, currents entering a busbar are equal to the vector sum of currents leaving the busbar. This maintains the relay inoperative because no differential current juice is fed to its operating coil. In case of an internal fault, the vector sum is not equal to zero which actuates the relay to operate.

During an external fault, the CT in the faulted feeder carries a current whose magnetising current equals the sum of the currents in all other CTs. But because of saturation of the CT in the faulted section, the secondary current may not sum up to zero and the relay might mal-operate. Even if care is taken by taking identical CTs with large iron cores to avoid saturation, dc transient conditions which incorporates a decaying component in the total current may trigger a mal-operation if a fast-acting relay is provided. This dc component dies within a few cycles, so if a slow-acting relay like an induction disc relay is used, mal-operation due to dc transient

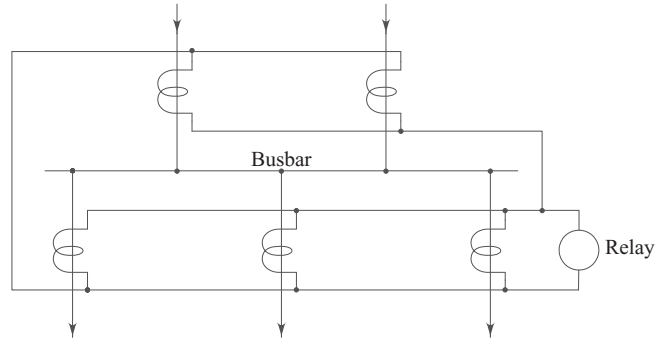


Fig. 10.4(a) Simple busbar differential protection

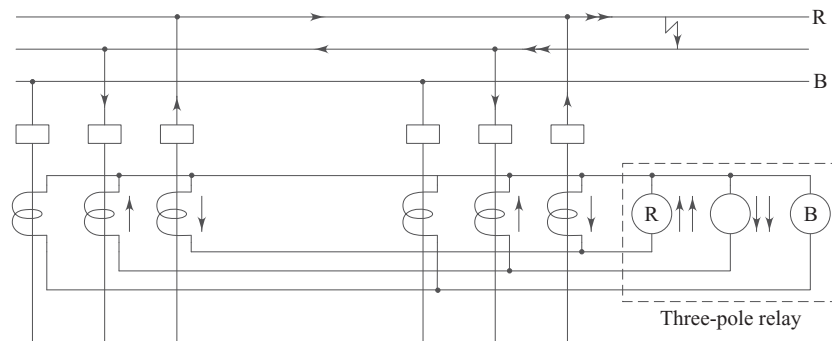


Fig. 10.4(b) Phase fault combined circulating current protection

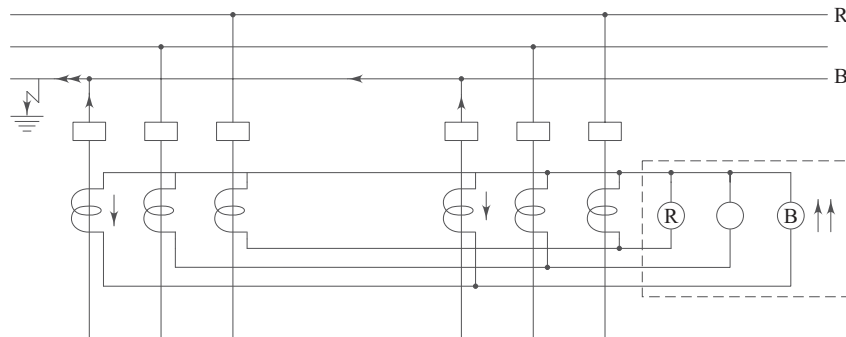


Fig. 10.4(c) Earth fault combined circulating current protection

can be avoided. But this slow operation is unacceptable for a busbar protection. The combined phase and earth-fault scheme of protection [shown in Figures 10.4(b) and (c), respectively] is self-explanatory.

Biased-Percentage Differential Protection To improve upon the mal-operation because of CT saturation on heavy external faults, this solution is used. Here, apart from the operating coil which receives the ac vectorial sum of all currents, a restraining coil is also provided which is energised by the dc scalar sum of all currents (Fig. 10.5). Moreover, stabilising resistance is also provided to offset the effect of transient dc.

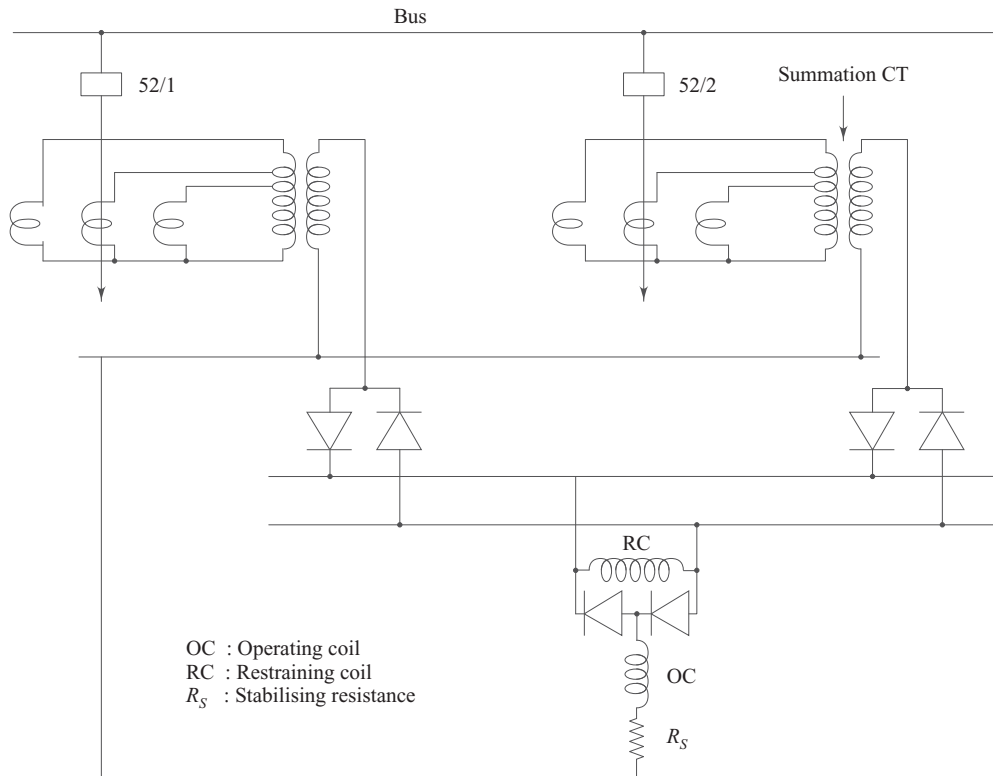


Fig. 10.5 Biased differential protection

High-Impedance Relay or Voltage Comparison The problem of spill current due to CT saturation in case of heavy external fault led to the philosophy of using voltage comparison for the purpose of relaying. For such relays in case of a bus fault, the voltage across the relay will be high which is very near to values of open-circuit voltage of CT secondaries.

This voltage will operate the relay. In case of no fault condition, the relay voltage is zero because it is connected across a voltage of opposite polarity. Even in case of a worst external fault, because of CT saturation, the voltage will be limited to voltage drop in leads from a saturated CT and its secondary winding resistance which is small comparable to the operating threshold voltage of the relay.

The only requirement for such a scheme is low resistance of CT secondary including leads. Stabilising resistors are used to improve upon the saturation characteristics of CTs. Higher value of stabilising resistors reduces the relay current. So magnetising currents, across CTs are forced towards equality for non-identical CTs, i.e. a CT with a higher magnetising current will force an equalising current through the other CT secondary. This will reduce the sensitivity of the relay in case of a fault but proper selection of resistance is found to help operate the relay reliably.

Principle of Operation As shown in Fig. 10.6, it is assumed that CT₂ gets saturated and its magnetising impedance is shorted. Voltage across points AB,

$$V_f = I_f (R_{CT} + R_L)$$

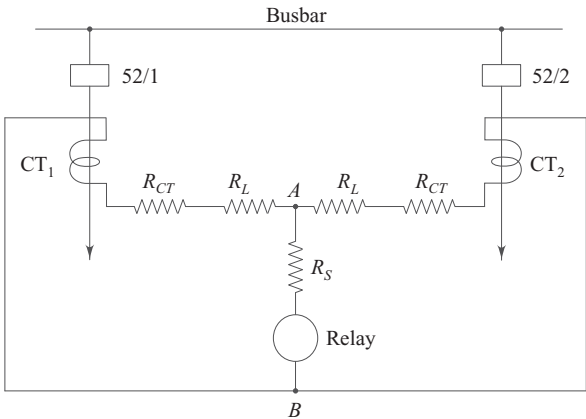


Fig. 10.6 High-impedance differential protection

The current through the relay in this case is

$$I_r = \frac{V_f}{(R_s + R_{\text{relay}})}$$

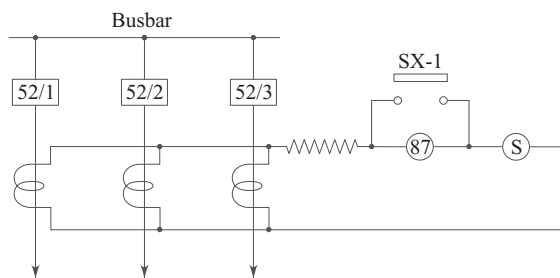
If V_r is the relay operating voltage corresponding to the operating current I_r then R_s can be got by,

$$R_s = \frac{V_f - V_r}{I_r}$$

In case of an internal fault condition, it is necessary that CTs produce sufficient voltage. This can be achieved by keeping the knee-point voltage of a CT larger than a relay setting. Normally, a factor of safety of 2 is kept for the knee-point voltage.

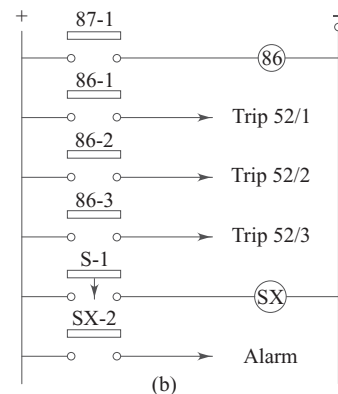
Improvement of High-Impedance Relaying Scheme

(a) *CT Supervision* The accidental opening of a connection of CT secondary (corresponding to perhaps slightly loaded feeder) often results in too low a fault current to activate the relaying circuit in case of an internal fault or mal-operation of the scheme in case of an external fault. The supervisory scheme gives the indication of the status of the CT and also avoids mal-operation as shown in Fig. 10.7.



S: CT supervision relay with low current threshold

(a)



(b)

Fig. 10.7 *CT supervision scheme*

(b) *Using Non-linear Stabilising Resistor and Capacitor* For faster operating times, the schemes as shown in Fig. 10.8 is used. The capacitor renders the relay insensitive to any dc voltage which may be present during the first few cycles. The setting of the relay is done by a non-linear resistor (thyrite). By using this, the current rises more rapidly than the voltage ensuring faster operating speed of the relay.

Because of high impedance of the relay circuit, another thyrite unit is connected in parallel with it to limit the maximum voltage appearing across the insulation of wiring of the panel and associated circuitry. Moreover, the sensitivity of the relay gets improved by the use of these nonlinear resistors.

(c) *Tuned High-Impedance Scheme* For the circuit shown in Fig. 10.9, the vector sum of secondary currents from the CTs of a bus is supplied to an overcurrent relay through a small saturating CT to limit the maximum relay current to a safe value. The capacitance is tuned to the fundamental frequency so as to exclude the dc offset component and transient harmonic current which is rich in higher frequency components.

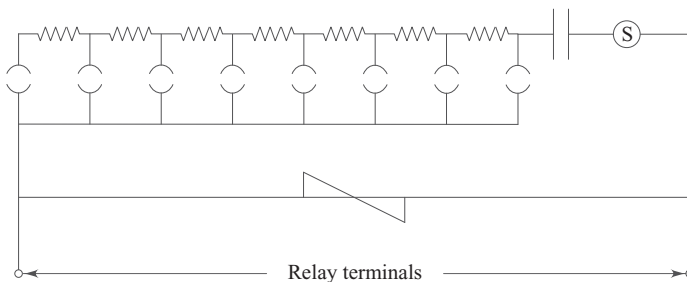


Fig. 10.8 Non-linear pick-up control

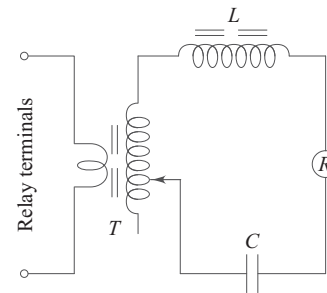


Fig. 10.9 Tuned relay circuit

Split-Bus Protection Scheme The scheme is shown in Fig. 10.10. Here, the overall protection relay O acts as a check relay. The mere operation of the zone A relay or the zone B relay will not trip the respective circuit breaker unless the check relay operates. A bus fault near the circuit breaker 52/S will cause all the circuit breakers to trip. If a fault occurs at F_1 , the fault currents will flow in primaries and secondaries of current transformers as shown in Fig. 10.10(a). It can be appreciated that because of this flow of current, relays O and A will operate but the relay B does not operate. Therefore, the auxiliary relay 86/1 will operate, tripping breakers 52/1 and 52/S. Thus, 52/2 will not operate and half the bus is yet live and feeding the load if connected. Similarly, for a fault at F_2 , breakers 52/2 and 52/S will trip. Continuity of power is, thus, not lost fully.

Double-Bus Arrangement As shown in Fig. 10.11, there are three zones in the double-bus scheme—the zone A on the left side and the zone B on the right side of the sectionalising circuit breaker of the bus 1, while the whole of the bus 2 forms the zone C . Two bus couplers, 52/4 and 52/5, are also provided. Three high-impedance relays A , B and C are provided for the bus-protection scheme along with a fault confirmation differential relay FC . The connection for all CTs is as shown. Overlapping of CT differential connection is provided to all circuit breakers to prevent a dead zone in protection. Interlocking contacts 29/2-1, 29/1-1, 29/3-1 and 29/4-1 associated with respective isolators are provided to enable discrimination of the scheme as can be seen in the following discussion. Under normal conditions, bus couplers 52/4 and 52/5 are kept energised.

Let us assume that isolators 29/2 and 29/4 are closed (therefore, 29/2-1 and 29/4-1 in the ac circuit and 29/2-2 and 29/4-2 in the dc circuit are closed) and power fed to lines L_1 and L_2 are entirely supplied from the bus 1. In this case, for a fault at the point F_1 , circuit breakers 52/1, 52/2 and 52/4 should trip to isolate the fault. As can be seen, the relay A would operate because of differential voltage appearing which forces a

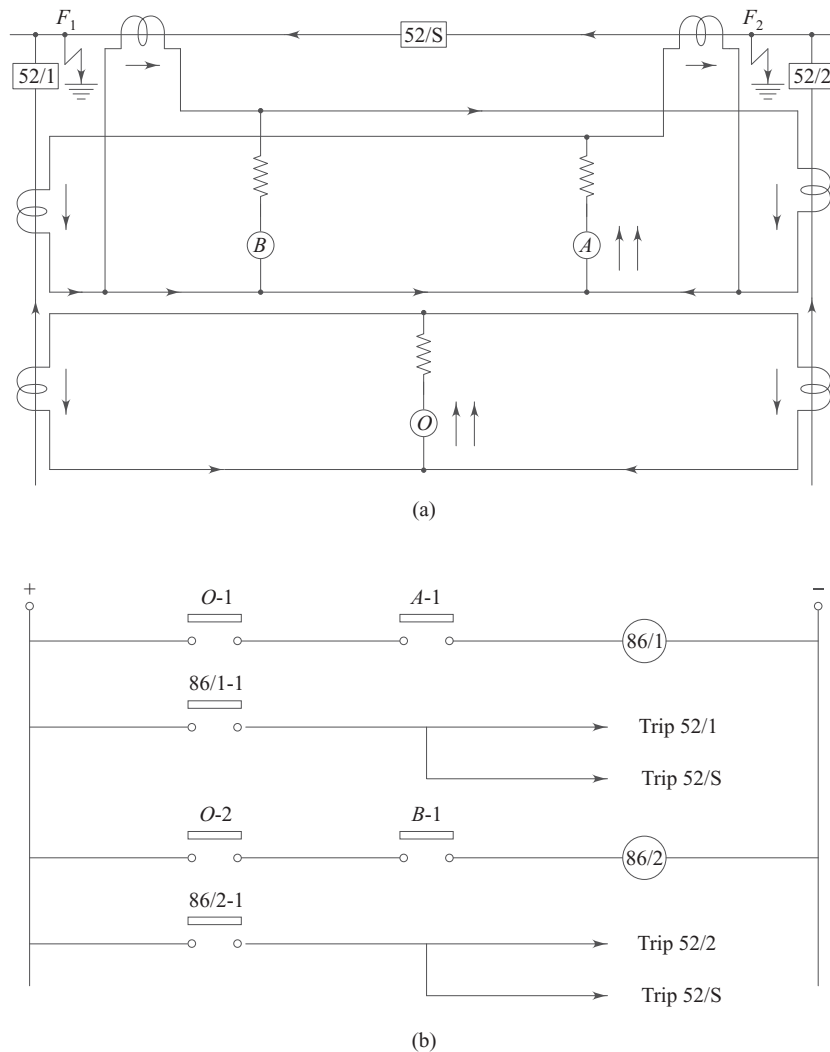


Fig. 10.10 Split-bus protection

current through its operating element. Referring to the dc control circuit, the closing of contacts A-1 with the energising of the relay *A*, in this case, operates tripping relays 86/1, 86/3 and 86/4. The relay FC acts as a fault confirmation relay so that spurious operation of the scheme does not take place. Moreover, as can be seen in the figure, because of too many CTs, the chances of open circuit or short circuit of a CT secondary that can lead to maloperation of the scheme are large. This is avoided by providing a check feature in the form of a fault confirmation relay *FC*.

In a similar manner, the breakers 52/2, 52/3 and 52/5 will open for a fault at F_2 , and for a fault at F_3 (with isolators 29/1 and 29/3 selected) the circuit breakers 52/1, 52/3, 52/4 and 52/5 will trip.

Setting and Selection of a CT for a Practical Scheme The equivalent circuit for an internal fault condition is shown in Fig. 10.12. The primary fault setting can be given by

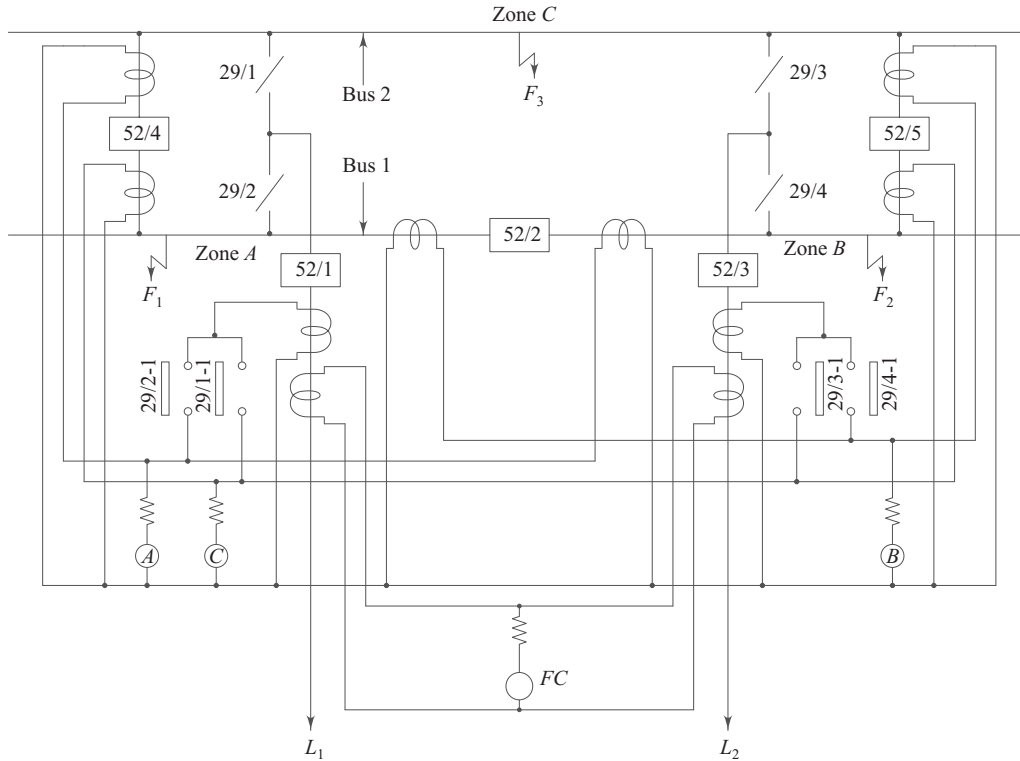


Fig. 10.11(a) Duplicate-bus protection

$$I_f = (n \times I_e + I_r) \times N$$

where,

n = number of CTs in parallel

I_e = exciting current of each CT at the relay setting voltage, V_r

I_r = relay current at setting

N = CT transformation ratio

To determine the magnetising current, two methods are generally used.

- (1) If the manufacturer supplies a curve of I_0 versus secondary voltage, it is easy to determine the I_0 at $1.2 \times V_r$, where 1.2 is the factor of safety.
- (2) Knowing the maximum standardising ratio error E_r and phase difference E , it is easy to calculate the composite error E_c .

$$E_c = \sqrt{E_r^2 + E^2}$$

and

$$i_0 = 1.2 \times V_r \times \frac{E_c}{R_s} \times 100$$

The sensitivity factor is given by

Q = busbar short-circuit current/minimum fault current during external fault

It is usually between 10 and 50.

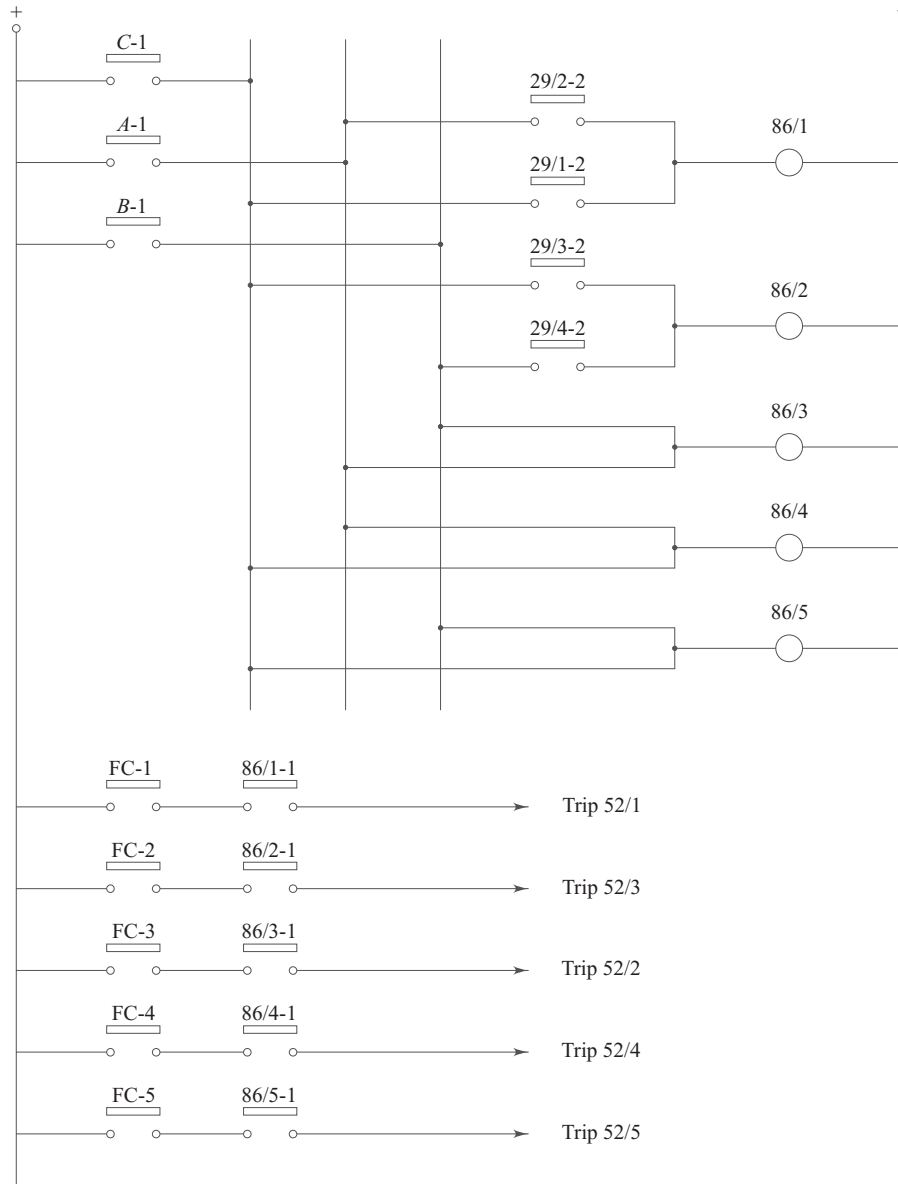


Fig. 10.11(b) A dc control diagram

For calculating stabilising resistor R_s , refer to Fig. 10.13. The voltage across the relay circuit under the worst condition, i.e., in case of a CT getting saturated should be found. This voltage is called stability voltage V_s , across terminals A and B .

$$V_s = I_f \times \frac{(R_L + R_{ct})}{N}$$

The relay must be set such that

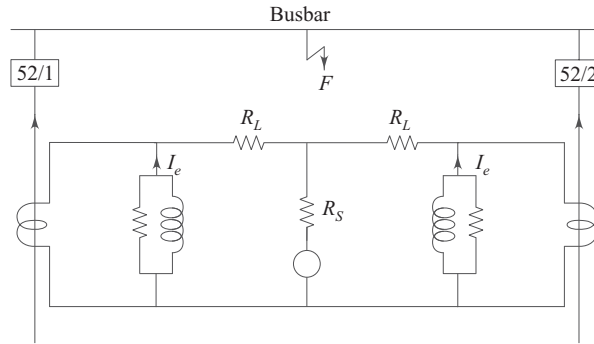


Fig. 10.12 During internal fault

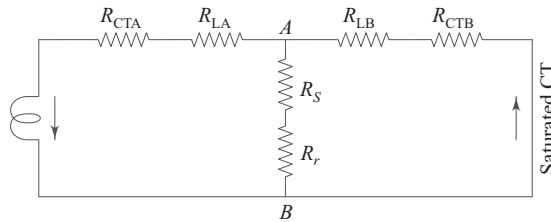


Fig. 10.13 Equivalent circuit

$$I_s \times (R_r + R_s) > V_s$$

$$I_s \times (R_r + R_s) > I_f \times \frac{(R_L + R_{ct})}{N}$$

where

I_s = setting of relay

R_r = resistance of relay coil

R_s = stabilising resistor

R_L = resistance of leads between CT and relay

R_{ct} = secondary resistance of CT

After rearranging we get,

$$R_s > \frac{V_s}{I_s} - R_r$$

Example 10.1 For an arrangement as shown in Fig. 10.13, the data supplied is as follows:

CT ratio: 2000/1

Maximum fault current = 50 kA

$R_{LA} = 2$ ohms, $R_{LB} = 3$ ohms, $R_{ct} = 2.5$ ohms

Relay burden is 0.5 VA.

Relay setting is 50% of 1 A.

Considering the worst condition, i.e., CT on B getting saturated,

$$V_s = I_f \times \frac{(R_{LB} + R_{ct})}{N}$$

$$= 50000 \times \frac{(3 + 2.5)}{2000} = 137.5 \text{ volts}$$

$$R_r = VA/I_s^2$$

$$= 0.5/(0.5 \times 0.5) = 2 \text{ ohms}$$

$$R_s > \frac{V_s}{I_s} - R_r$$

$$> (137.5/0.5) - 2 > 273 \text{ ohms}$$

Choice of Supervision Threshold Setting The supervision relay must be sensitive to unbalance corresponding to a bus current of 10% of the current in the least loaded incoming or outgoing feeder. Normally, while selecting a CT, choose a CT and check its suitability to the characteristics of the busbar. If not compatible, another type is chosen and its suitability reassessed.

10.4 BREAKER BACK-UP PROTECTION

The busbar protection scheme normally includes the function of a circuit-breaker back-up of the individual feeders.

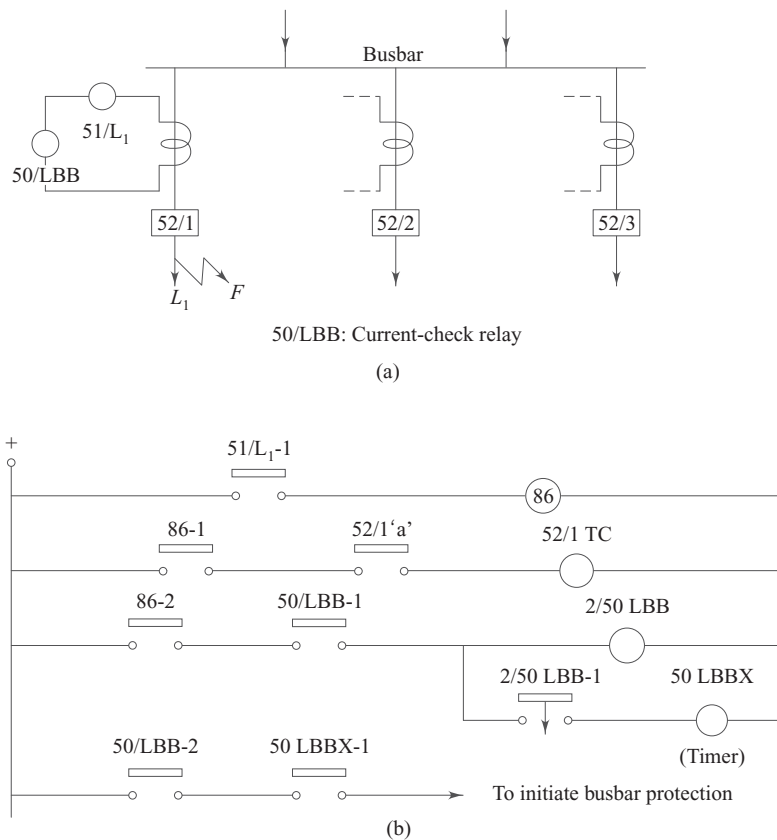


Fig. 10.14 Breaker back-up scheme

Breaker back-up is obtained by paralleling all the relay tripping contacts associated with all the feeders connected to a bus and connecting them to a common timing unit. Thus should any one relay operate and its associated circuit breaker fails, the busbar protection scheme operates after a suitable time delay, whereby the bus itself is tripped clearing the fault of the feeder. For the scheme as shown in Fig. 10.14, there are 3 outgoing feeders from the busbar. For a feeder fault at F , the fault should be sensed by an overcurrent relay $51/L_1$ and the circuit breaker $52/1$ must trip, clearing the fault. In case the circuit breaker does not trip, the un-cleared fault must be cleared by the busbar protection scheme. The current check relay $50LBB$ operates if the current through it exceeds its setting. The current setting of a check relay is discussed in the succeeding paragraph. Referring to the dc control circuit of the scheme, it can be seen that operation of the check relay in conjunction with the operation of the tripping relay 86 (which in any case operates) starts a timer unit $2/50LBB$ which after a suitable time delay initiates a signal for busbar protection by energising the $50LBBX$ and auxiliary relays associated with the breaker back-up protection scheme. The timing diagram of the circuit breaker back-up protection scheme is shown in Fig. 10.15.

The timer setting is derived from the following individual times:

- (i) The minimum local-circuit breaker trip operating time, i.e., either to main arc extinction or to the resistor contact separation, plus
- (ii) The current check supervision relay maximum drop-off time, plus
- (iii) A discriminating margin to allow for scatter of operating times of associated relays and circuit breakers, minus
- (iv) Minimum pick-up time of current check relay.

If the time calculation for fault clearance by back-up method is in excess compared to the allowable maximum then reduction in the discrimination margin may be considered after careful setting of the operation times of the associated circuit breaker and protection relays.

10.4.1 Current Check Relay Setting

The check relay must positively operate for a fault at the farthest end of the protection zone at minimum fault condition.

For a circuit breaker using a resistor breaking, ideally the check relay setting must be above the resistor current of the circuit breaker which enables the relay to reset as soon as the main arc is extinguished. This enables selection of a lower discrimination time. In some designs of circuit breakers, the main contacts interrupt the fault current, but the resistor current continues to flow through the resistor. The check-relay must have a reset, but likelihood of an internal flashover of earthing still persists as the resistor contact is not broken. The resetting of a check relay thereby disables the busbar back-up protection also. To prevent this, it is preferable and a usual practice to keep the current relay setting of not more than two-thirds of the resistor current.

For back-up protection involving an incomer to the bus incorporating a generator, another consideration must be taken while setting the check relay. If the generator's local circuit breaker fails to operate for a non-electrical fault condition like a boiler, turbine, etc., the resultant current drawn from the bus in the reverse direction is relatively small in the period immediately following the circuit-breaker failure. The setting of a check relay for back-up must be sufficiently below this current to ensure relay operation.

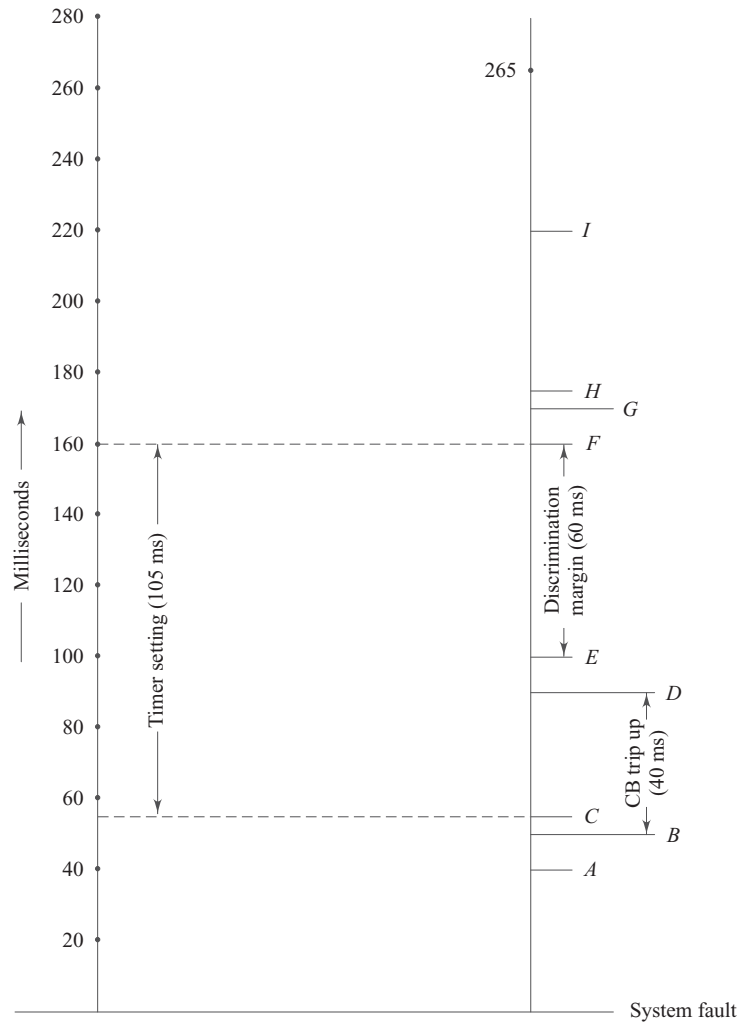


Fig. 10.15 Timing sequence for circuit-breaker back-up

Legends of Fig. 10.15

- A : Circuit protection operation
- B : Circuit breaker trip initiated
- C : Circuit breaker fail timer start, current check relay operate
- D : Circuit-breaker trip complete
- E : Circuit-breaker fail timer stop, current check-relay drop
- F : Circuit-breaker fail timer operation complete, back-up trip initiation
- G : Back-up trip receive relays and current trip-relay operation
- H : Back-up trip receive relays trip-relay operation
- I : Local-circuit breakers trip

REVIEW QUESTIONS

1. What are the various forms of unit and non-unit type of protection schemes for a busbar?
2. Discuss in detail the use of a high-impedance relay used for busbar protection schemes.
3. Write a note on breaker back-up protection.
4. Discuss the necessity and implementation of a check feature in busbar protection.
5. Draw and explain power and control circuit of CT supervision scheme used in bus-zone protection as improvement in a high impedance relaying scheme.
6. What are the problems of unit protection of a bus zone? Suggest the remedies against these problems.
7. Write a short note on 'frame earth protection' for the indoor busbar.

MULTIPLE CHOICE QUESTIONS

1. Bus-zone protection requires
 - (a) some breakers connected to the bus to be tripped
 - (b) only one breaker connected to the bus to be tripped
 - (c) providing alarm for bus-zone fault
 - (d) all breakers connected to the bus to be tripped
2. On occurrence of fault on a bus, double-bus arrangement provides
 - (a) adequate system protection
 - (b) continuity of power
 - (c) both (a) and (b)
 - (d) none of the above
3. The breaker back-up protection is part of bus-zone protection for the purpose of
 - (a) providing protection for fault on the bus
 - (b) providing protection for lightning on the bus
 - (c) providing back-up protection against failure of feeder circuit breaker for fault on the feeder
 - (d) both (a) and (b)
4. To solve the problem of CT saturation due to dc offset (transient) current in case of external fault for bus-zone protection,
 - (a) slow acting induction disc-type relay is suitable
 - (b) high-impedance differential relay is suitable
 - (c) low-impedance differential relay is suitable
 - (d) none of the above
5. In the high-impedance relaying scheme for bus-zone protection, a non-linear resistor is specifically used to
 - (a) make the relay insensitive to any dc voltage
 - (b) ensure stability for external faults and sensitivity for internal faults
 - (c) supervise the CT connections
 - (d) none of the above

Induction Motor Protection

There are many different types and sizes of induction motors used in practice. This chapter deals with protection arrangements for large three-phase induction motors, either of squirrel-cage or wound-rotor type.

Small motors having an output of a few tens of h.p. and rated up to 415 volts can be protected by starters of various kinds having in-built thermal overload relays and no-volt release facility, and very often protection for short circuits can be provided by switch-fuse units. In this chapter, we shall not focus on explaining protective arrangements of small motors as it is assumed that the reader is aware of these practices.

11

Introduction

Large three-phase motors (ranging from 100 h.p. to 5000 h.p. or more) and in the medium-voltage range (of the order of 3.3 kV, 6.6 kV, etc.) are used for running power-station auxiliaries and in large industries such as fertiliser, chemical and petrochemical industries. These motors are controlled by circuit breakers and associated protective relays. Such motors need comprehensive protective arrangements to achieve the desired degree of security and dependability. In the pages to follow, such protective arrangements are discussed. The reader is assumed to have prior knowledge of the principle, construction, equivalent circuit, losses and torque equations of a 3-phase induction motor.

11.1 STARTING OF AN INDUCTION MOTOR

As a protective relay has to accommodate starting transients of an induction motor, let us have a look at the starting phenomena of an induction motor. It is known that just at the instant of starting, the slip 's' is unity. Eq. 11.1 gives the value of the rotor current I_2 at standstill as shown by Fig. 11.1.

$$I_2 = \frac{sE_2}{\sqrt{R_2^2 + (sX_2)^2}} \quad (11.1)$$

Obviously, I_2 and hence I_1 , will be very high (of the order of 4 to 10 times the rated current of the motor). As the motor develops speed during the course of time, the slip decreases and the current I_2 and in turn, the stator current I_1 will reduce and settle down to its rated value. The time for which the starting current passes through the induction motor depends upon the time within which the motor gains the rated speed (or rated slip). In other words, the value of acceleration of the motor decides the starting time. Generally, the starting time is of the order of 5 to 6 seconds but it can be as high as 20 to 30 seconds for motors having loads with high inertia. Figure 11.2 shows the starting characteristic of an induction motor.

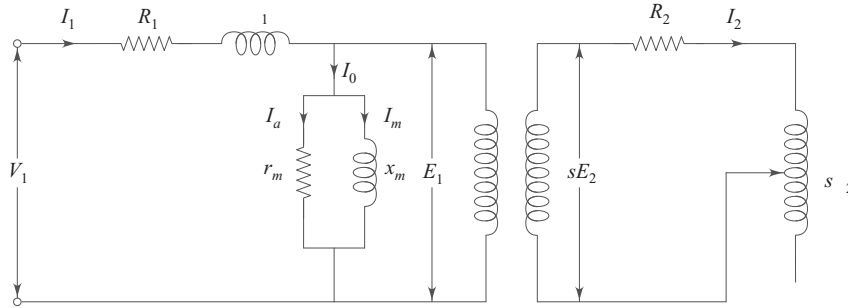


Fig. 11.1 Equivalent circuit of induction motor

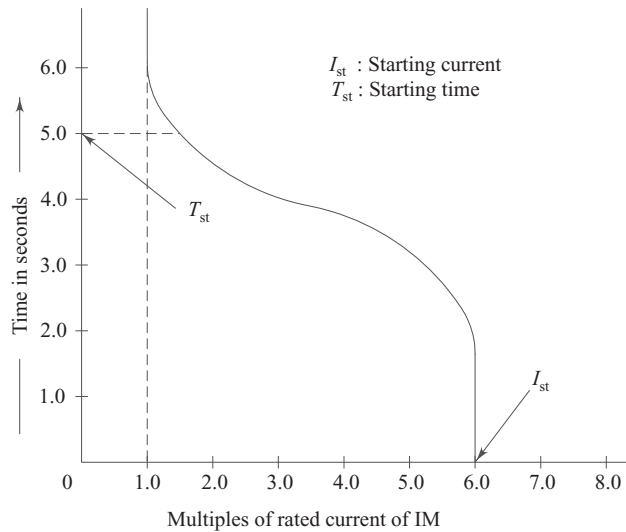


Fig. 11.2 Starting characteristic of induction motor

The high starting current is harmful because it causes a voltage dip. In practice, there will be many consumers at whose premises induction motors are installed. If one of the induction motors draws a high current, the consequent voltage dip causes inconvenience to other consumers, and in many cases, their induction motors may come to a halt. Hence, the methods to control the starting currents have to be employed. For squirrel-cage motors, there are the following two types of starters which are used.

- (i) Star-delta starter
- (ii) Auto-transformer starter

For induction motors, like the ones that are used for driving auxiliaries in power stations in which case voltage dip is not expected to cause inconvenience to consumers, even large induction motors are started direct on the line. This is because voltage is kept constant by an automatic voltage regulator. In this way, there are no means employed to control the starting current.

11.2 FAULTS IN INDUCTION MOTORS

The probable faults in an induction motor can be classified into two broad categories:

1. Stator faults
2. Rotor faults

Short circuits in the stator windings are harmful because they involve high stator currents. Unsymmetrical faults cause unbalance and hence negative sequence currents are generated, and consequently the rotor is heated. Rotor faults generally do not develop in squirrel-cage induction motors. However, such faults are possible in wound-rotor motors. The consequence of such faults is to increase stator currents. Moreover, vibrations are caused in the rotor which may endanger the motor.

11.3 ABNORMALITIES OF INDUCTION MOTORS

The following abnormal conditions are known to exist for an induction motor:

1. Overloading
2. Single phasing
3. Unbalanced currents
4. Reversed phase sequence
5. Under voltage
6. Stalling

These abnormalities are explained as follows:

1. Overloading The load on the induction motor is a mechanical load. Increase in mechanical load will decrease the speed of the motor and hence the slip will increase. Equation (11.1) shows that as slip increases, the rotor current I_2 will increase. That consequently increases the stator current I_1 (refer Fig. 11.1). For a given load, the value of the slip, I_2 and I_1 can be determined. For rated load condition, the rated stator current I_1 will flow through the stator winding. The heat generated due to this current is equal to $I_1^2 R_1 t$, where t is the time for which the current is passed. However, the heat will also be dissipated by radiation due to cooling means employed or due to natural cooling. The generated heat goes on increasing the temperature of the winding and with the increase in temperature, the rate of heat dissipation also increases. As the heat dissipated is proportional to t_d^4 (t_d is equal to the temperature developed minus the ambient temperature), at a particular temperature, the rate of heat generation and the rate of heat dissipation become equal and the temperature settles at this value. This is known as a state of equilibrium. A similar explanation holds true for a rotor circuit also.

Any action of increasing the load (more than the rated load) will increase the slip above the rated slip and the current beyond the rated current (stator and rotor currents). Obviously, with reference to this current (say, stator current), the heat will be generated at a higher rate than the previous case and hence the equilibrium temperature will be higher than the earlier case. The stator or rotor conductors will not be affected in any way due to this increase in temperature but the insulation around these conductors can certainly be affected. The insulation can get deteriorated due to temperature rise and can eventually fail due to thermal breakdown mechanism. The maximum temperature that can be withstood by an insulator without being damaged depends upon the class of insulation used. But, certainly, for any insulator there is a known limit to which the temperature can rise. The reader can now appreciate that with reference to this temperature, there will exist a current beyond which a motor should not be loaded.

Once the motor is overloaded, the insulation will not reach a critical state immediately. The time within which the temperature reaches to a value equal to the maximum allowable limit of an insulator for a given overload is inversely proportional to the square of the current (because heat generated is equal to $I^2 R t$). Thus, different allowable time periods can be derived for different overloads. The curve plotted for maximum

allowable time v/s multiples of the rated stator current is known as the *thermal withstand characteristic* of an induction motor. One such typical curve is shown in Fig. 11.3.

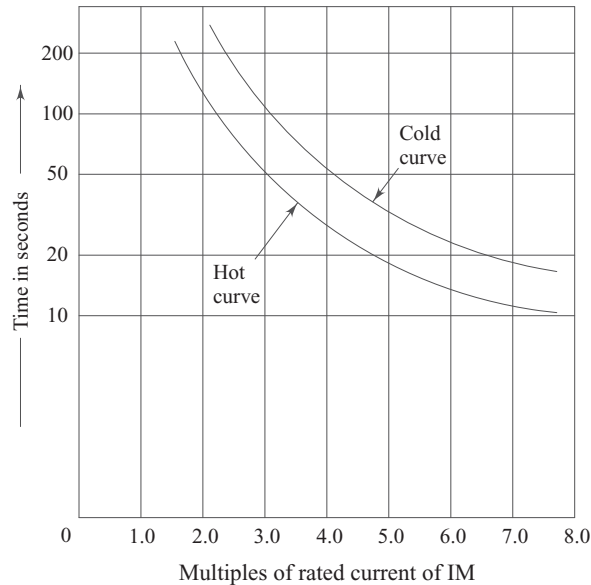


Fig. 11.3 Thermal withstand characteristics of induction motor

It can be easily understood at this juncture that the time within which the temperature rises to a maximum allowable value also depends upon the datum temperature, i.e., the value of the temperature at the instant of overloading. If the motor is overloaded in a cold condition (i.e., from standstill), the time ordinate of Fig. 11.3 will, naturally, be higher than when the motor is overloaded to the same extent (same stator current as former case) from a hot condition (i.e., from the rated condition). Accordingly, there will be two almost parallel curves, one known as *cold curve* and other as *hot curve*, as depicted in Fig. 11.3.

The torque–slip curve of the induction motor is shown in Fig. 11.4. In this curve the portion *oa* is a stable region and *ab* is an unstable one. This is obvious as when the motor is operating at the slip below *oa*, any increase in the load torque will increase the slip giving a higher torque to cope up with the demand. If the motor is operating at the slip given by *oa* and if additional load is thrown on the motor, the slip will increase causing a decrease in the torque developed. As the load torque is more, the motor will start decelerating continuously increasing the slip and decreasing the torque until finally the motor comes to a standstill.

With reference to Fig. 11.4, it can be concluded that for any overload which develops slip beyond the point *a'*, the motor will be operating in an unstable region. In this condition the motor is said to be *stalling*, about which we will discuss later in this section.

2. Single Phasing In case one phase conductor develops an open-circuit fault or in the case of one pole of a circuit breaker (controlling induction motor) not making contact while an induction motor is running, a condition known as *single phasing* develops. If the motor is loaded to its rated full load, it will draw excessive currents on single phasing. The windings are overheated and hence insulation may be damaged.

Single phasing causes unbalanced currents also. The negative sequence component of this unbalanced current causes the rotor to overheat. This is because the rotating magnetic field produced due to the negative

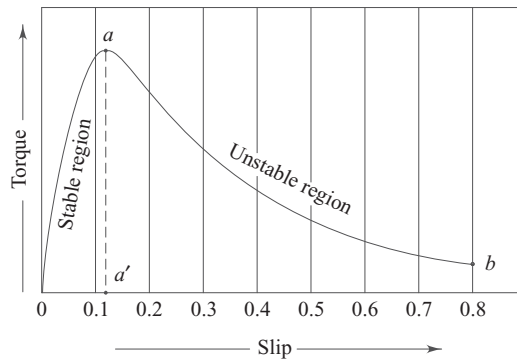


Fig. 11.4 Torque-slip curve

phase sequence current rotates at synchronous speed in the opposite direction to the actual rotor movement. Hence, the slip, for this component, has a value nearly equal to 2. The frequency f_r will be nearly double the supply frequency ($f_r = 2f_s$) and hence the iron losses in the rotor will increase to a very large extent. (These are generally neglected in normal condition, f_r being small). The flow of negative sequence current increases the rotor copper losses also. The total effect is the overheating of the rotor due to losses generating heat in the rotor.

For large motors, the protection against single phasing by thermal overload relay, considering positive sequence currents alone would prove inadequate as the effect of negative sequence currents cannot be fully taken into account by such a protective arrangement. The effect of negative sequence currents is explained at length in the following paragraphs.

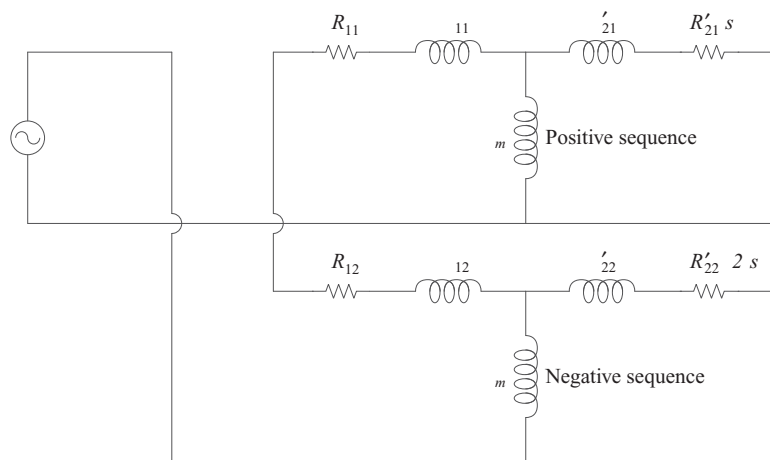


Fig. 11.5 Equivalent circuit of induction motor on single phasing

The equivalent circuit of an induction motor in single-phasing condition is shown in Fig. 11.5 in which,

$R_{11} + j_{11}$ = Positive sequence impedance, per phase of stator

$R'_{21} + j'_{21}$ = Positive sequence impedance, per phase of rotor, as referred to stator

$R_{12} + j_{12}$ = Negative sequence impedance, per phase of stator

$R'_{22} + j'_{22}$ = Negative sequence impedance, per phase of rotor, as referred to stator

Neglecting magnetising inductance, the positive sequence impedance,

$$Z_1 = \left[R_{11} + \frac{R'_{21}}{s} \right] + j[X_{11} + X'_{21}]$$

At stand-still when $s = 1$,

$$Z_1 = [R_{11} + R'_{21}] + j[X_{11} + X'_{21}]$$

The negative sequence impedance,

$$Z_2 = \left[R_{21} + \frac{R'_{22}}{2-s} \right] + j[X_{12} + X'_{22}]$$

At standstill when $s = 1$,

$$Z_2 = [R_{12} + R'_{22}] + j[X_{12} + X'_{22}]$$

Under normal running speed when s is small,

$$Z_2 = \left[R_{12} + \frac{R'_{22}}{2} \right] + j[X_{12} + X'_{22}]$$

Under normal running condition $s = 0.02$ to 0.03 and hence R'_{21}/s will be about 10 times the reactance term and will be the dominant factor. In an induction motor, the value of resistance is usually small as compared to the reactance. So it can be assumed that positive sequence impedance at standstill will be equal to the negative sequence impedance under running condition.

$$\text{i.e., } [R_{12} + R'_{21}]^2 + [X_{11} + X'_{21}]^2 = \left[R_{12} + \frac{R'_{22}}{2} \right]^2 + [X_{12} + X'_{22}]^2 \quad (11.2)$$

Moreover, under balanced condition,

$$\begin{aligned} \frac{I_{\text{start}}}{I_{\text{run}}} &= \frac{E/Z_1 \text{ (at standstill)}}{E/Z_1 \text{ (running condition)}} \\ &= \frac{Z_1 \text{ (running)}}{Z_1 \text{ (standstill)}} \\ &= \frac{(R_{11} + (R'_{21}/s))^2 + (X_{11} + X'_{21})^2}{(R_{11} + R'_{21})^2 + (X_{11} + X'_{21})^2} \end{aligned}$$

Using Eq. 11.2,

$$\begin{aligned} \frac{I_{\text{start}}}{I_{\text{run}}} &= \frac{(R_{11} + (R'_{21}/s))^2 + (X_{11} + X'_{21})^2}{(R_{12} + R'_{22}/2)^2 + (X_{12} + X'_{22})^2} \\ &= \frac{Z_1 \text{ (running)}}{Z_2 \text{ (running)}} \end{aligned}$$

Now, negative sequence current,

$$I_{12} = \frac{V_2}{Z_2} = V_2 \frac{I_{\text{start}}}{I_{\text{run}}} \cdot \frac{1}{Z_1}$$

or

$$I_{12} \propto V_2 \frac{I_{\text{start}}}{I_{\text{run}}}$$

Thus, if $I_{\text{start}}/I_{\text{run}} = 6/1$ (which is the case for most of the induction motors) then 5% negative sequence voltage V_2 , would result in 30% of negative sequence component of current. Thus, the effect of increase in the negative sequence current is six times the effect of a similar increase in the positive sequence current due to thermal overload. Hence, it is evident that special protection arrangement is to be provided for protection against single phasing.

3. Unbalanced Currents Single phasing is the worst and a particular case of unbalanced currents. However, it has been treated here at the start as it is a common condition encountered in practice.

Voltage unbalance causes unbalanced currents and hence negative sequence currents which we have already discussed. Unbalanced voltage will cause negative sequence voltage to be developed, and the negative sequence currents generated will be approximately six times the negative sequence voltage. Unbalanced voltage and hence unbalanced current can be caused by unsymmetrical fault within the motor or such a fault on the feeder for the motor.

4. Reversed Phase Sequence If the phase sequence in the supply circuit of an induction motor is reversed, only the negative sequence currents are taken by the motor and the motor will run in the opposite direction when started. The loads like fans or pumps cannot be run in the other direction than the one for which they are meant to run. Hence, the reverse rotation would cause damage to the load.

5. Under Voltage If the voltage drops when the motor is running at the full rated load, the current taken by the motor increases. This is because the power to be delivered remains constant and the voltage is reduced from the normal rated voltage. The effect of an increased motor current can cause damage to the insulation of the motor windings as has been discussed earlier.

6. Stalling The induction motor is said to be stalling when it is operated in the region *ab* of the torque-slip curve of Fig. 11.4. When a heavy load is thrown on the motor abruptly, the motor can stall. If there is a heavy load on the motor at the time of starting, the motor cannot start and the rotor gets blocked. In such a condition, the motor is said to be stalling. Moreover, the rotor of the induction motor may be locked because of gear drive jamming or bearing failure.

Under the condition of stalling or locked rotor, the speed of the rotor will be very small or most often zero. Consequently, the motor will draw very high currents of the order of 15 to 20 times the rated current.

It is known that for a given load, the speed of the induction motor is known. With an increase in the load, the speed will decrease and settle down at a lower steady-state value. If the load is abruptly increased, the rotor speed, because of its inertia, falls below the steady-state speed with respect to the applied load. The speed, hence, will vary around the steady-state value. The magnitude of variations and time to reach the steady-state value depends upon the magnitude and rate of increase of load. If the increase in the load is gradual, the thermal overload protection is enough. But when a large load is suddenly increased, the consequent variations will give rise to mechanical stresses on the parts of the rotor and electrical stresses on insulation of windings due to variations of currents. Moreover, if the transient stability limit of the induction motor is crossed because of abrupt large overloading, the motor might operate in the unstable region *ab* (Fig. 11.4) and may not, perhaps, regain synchronism (stable slip). This out-of-step operation of an induction motor is termed as a stalling condition. Hence, a separate protection against such stalling condition is required for large motors.

11.4 PROTECTION OF SMALL INDUCTION MOTORS

The low-voltage induction motors of a capacity of few tens of h.p. can be termed as small motors. As has already been explained, all the abnormalities (but for reversed phase sequence) and faults give rise to flow of

high stator and rotor currents. Hence, the protection against overloads and short-circuit will be enough for small motors. Separate protections against different abnormalities and faults, however necessary, cannot be economically justified for small motors. Fuses can be used for protection against short-circuits. HRC (High Rupturing Capacity) fuses may be used whenever necessary. Thermal relay can be used to protect the motor against different abnormalities. In-built thermal elements are generally provided in all types of induction motor starters. Voltage-operated single-phasing preventors are popular in actual field practices as they are economically viable for the small motors.

11.5 PROTECTION OF LARGE INDUCTION MOTORS

The size, cost and importance of large, medium-voltage, three-phase induction motors used in industries demand complex protective arrangements. The design of a modern motor-protection relay must be adequate to cater for the protection needs of the vast range of motor designs in service. In addition, relays may offer options such as circuit-breaker condition monitoring as an aid to maintenance. The following sub-sections discuss how protection may be applied for each of the possible fault conditions for the motor.

11.5.1 Thermal Overload Protection

It has already been discussed that every induction motor has a certain time limit during which it can withstand a given overload. This time limit, no doubt, is dependent upon the class of insulation used. Figure 11.3 shows a typical thermal withstand characteristic of an induction motor.

It is evident that the motor should be disconnected from the supply before it reaches the respective time limit for a given overload.

However, disconnecting the motor much in advance from the given limit is also undesirable because, in this case, the thermal overload capability of the motor is not fully exploited. Therefore, a relay, the characteristics of which matches closely with the thermal withstand characteristics of the motor, would be the best choice. None of the overcurrent relays can be used here because they cannot be coordinated with the thermal withstand characteristics of a motor. A thermal relay (refer Chapter 2) can be used for protection of an induction motor against thermal overloads. Obviously, a selection of the most suitable thermal relay has to be made for better protection. Thermal relays having different time constants, which decide the shape of relay characteristics, are available in the market. Similar to the thermal characteristics of the motor, the thermal relay also gives two characteristic curves, one hot and another cold. The way in which the thermal relay characteristics are coordinated with that of the induction motor is shown in Fig. 11.6.

It is to be remembered that curves 3 and 4 of Fig. 11.6 are drawn in terms of a CT primary current as the relay is fed through a CT. The ordinates of curves 3 and 4 give the time of operation of the thermal relay for a given CT primary current (in terms of multiples of rated current of the motor) when the relay is in hot and cold condition respectively.

While selecting a thermal relay for thermal overload protection of an induction motor, it is to be assured that the relay shall not operate when the motor is started. This can happen, particularly, when motors having high inertia and, in turn, long accelerating times (starting times) are started in hot condition. In such a case, the relay is to be so selected that the hot characteristics of the relay should not overlap with the starting characteristics of the motor. If such overlap occurs as shown in Fig. 11.7, the motor cannot be started in the hot condition. In such a case, the operation of the thermal relay can be inhibited during the starting of the induction motor. Relays having this inhibiting facility are also available in the market. However, the demerit of such a facility is that adequate protection is not provided for an unhealthy start. The remedy is to use a microprocessor/DSP based comprehensive relay for protection of the induction motor.

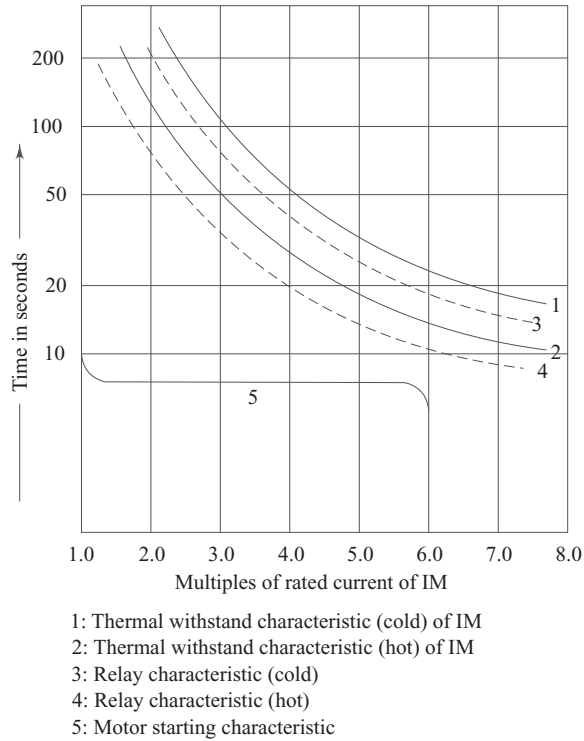


Fig. 11.6 Coordination of characteristics of IM and relay

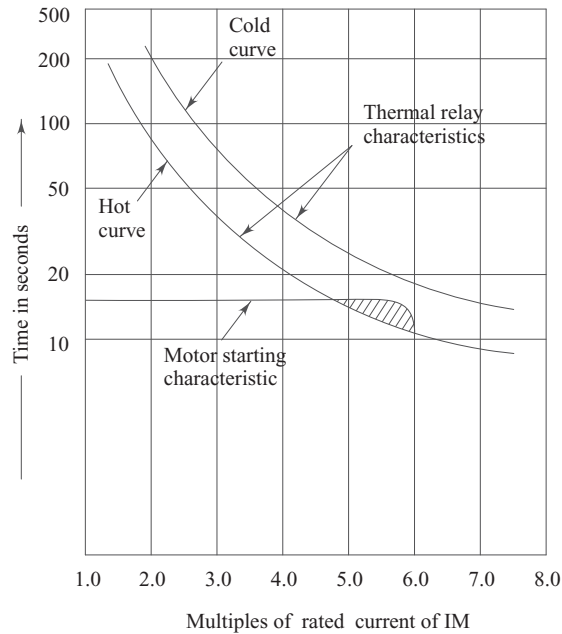


Fig. 11.7 Incorrect selection of a thermal relay

Relay Settings The thermal relay has the following settings.

Time Constant Normally, relays with a fixed time constant are available in the market. A customer can ask for the required time constant. However, a few curves (normally 3 to 5) having different time constants can be offered by the same relay in certain versions.

Tripping Temperature Some relay manufacturers give an adjustment of the temperature at which tripping is desired. Normally, this adjustment is in terms of temperature rise.

Current Adjustment This is normally in terms of the percentage of the rated current of relay.

For deciding settings of thermal relay, we take a typical example with the following data:

1. The Induction Motor

- (i) Rating = 1200 kW
- (ii) Rated current = 132 A
- (iii) Rated voltage = 6.6 kV
- (iv) Accelerating time = 5.5 sec
- (v) Thermal withstand characteristics of motor curves 1 and 2 (Fig. 11.6)
- (vi) Starting current = six times the rated current
- (vii) Permissible overload = 110% of rated current (continuous)

2. CT 150/1 A

3. The Relay

- (i) Relay rated current = 1 A
- (ii) Setting range = 70 to 130% of 1 A
- (iii) Pick-up = 105% of setting

Setting

Rated current I_R of motor = 132 A

Therefore, CT secondary equivalent of rated current,

$$i_R = 132/150 = 0.88 \text{ A}$$

Allowing for 110% of overload and considering that the relay picks up at 105% of its setting, the setting (I_{th}) of a thermal relay,

$$I_{th} = 0.88 \times (1.1/1.05) = 0.922 \text{ A}$$

i.e., setting of 90% of 1 A can be selected.

After drawing the thermal withstand characteristics and starting characteristics of an induction motor, a suitable time constant of the relay can be selected by drawing its characteristics on the same graph with similar scale, as shown in Fig. 11.6.

11.5.2 Short-Circuit Protection

Short-circuit protection is required to be applied during two possible abnormal conditions of motor operation:

1. Electric short circuits due to phase faults in motor windings because of insulation failure
2. Blocking of rotor The rotor does not start rotating because of heavy load at starting or due to bearing failure or gear drive jamming

In both these conditions the current drawn by the motor will be very high and the motor should be isolated from the supply instantaneously, as the electrodynamic forces created would deshape and destruct the motor if it is not isolated from supply within a maximum limit of 3 cycles.

An instantaneous overcurrent relay can be used for protecting the motor against such conditions.

Obviously, the relay should be set to pick-up a little above the maximum starting current. Generally, a pick-up setting equal to a value of the starting current at 75% of the rated voltage can be selected.

In the typical example of induction-motor data of previous section, if we use an instantaneous relay (having a setting range of 400 – 2000% of 1 A) for short-circuit protection; its setting can be as follows:

The starting current at 75% of rated voltage,

$$I_{\text{stm}} = (6 \times 132)/0.75 = 1056 \text{ A}$$

The secondary equivalent of this current (CT ratio 150/1 A)

$$i_{\text{stm}} = 1056/150 = 7.04 \text{ A}$$

i.e., the setting of 750% of 1 A can be selected.

11.5.3 Negative-Phase Sequence Protection

Under the abnormal operating conditions of single phasing, voltage unbalance and reversed phase sequence explained in Section 11.3, the negative-phase sequence currents are generated. As has already been discussed, the negative-phase sequence currents heat up the rotor abnormally and hence separate protective arrangement is required to protect an induction motor against such abnormalities.

In actual field practices, there are two strategies prevalent for this purpose. One practice uses a definite-time overcurrent relay which responds to negative-phase sequence current of the stator (I_{12}). Time delay is of the order of 6 to 10 cycles. This small time delay avoids mal-operation of the relay during starting. During first 4 to 8 cycles, the starting current is 15 to 20 times the rated current. This current may not be faithfully reproduced by three line CTs. Thus for this small time, there can be a current unbalance seen by the relay. The pick-up of definite time overcurrent relay is normally set at 50% of the starting current of an induction motor. In the typical example of induction-motor data of Section 11.5.1, if a definite time overcurrent relay responding to I_{12} having setting range of 200 – 600% of 1 A is used, its setting can be decided as follows:

50% of starting current of the motor,

$$I_{\text{st}}/2 = (6 \times 132)/2 = 396 \text{ A}$$

Secondary equivalent,

$$i_{\text{st}}/2 = 2.64 \text{ A}$$

i.e., the relay can be set at 250%. The relay with such a high setting should be used in a protective system employing a thermal element which also takes care of negative-phase sequence currents (refer Section 11.6.1).

Another practice uses a relay which has characteristics of $(I_{12})^2 t = \text{constant}$. This is a better practice as the tripping time of the relay is inversely proportional to the square of the negative-phase sequence current of the stator, and as the consequence of the negative-phase sequence current involves heating, the heating characteristics of rotor insulation closely matches with such inverse characteristics. Normally, such a relay has a setting range of 20 – 80% of the relay rating. The setting is based on Z_2/Z_1 ratio.

In both these practices, the line CTs (Fig. 11.8) will supply the input signals to the relay and the negative sequence filter will take out the negative phase sequence current components from the input current. This current can, then be fed to an $I^2 t$ relay or a definite time overcurrent relay, whichever is the case.

11.5.4 Protection against Stalling

It has been explained in Section 11.5.2 that when the rotor of the motor is fully blocked, a subsequent high stator current will operate the instantaneous overcurrent relay and the motor will be isolated from the supply instantaneously. However, in certain cases such as abrupt heavy overloading, the motor may not fully stop running but speed variations may be found around a lower steady-state speed. If these variations are within safer limits with respect to electrical and mechanical stresses on the motor insulation and rotor parts respectively, and the rotor has not lost synchronism, certain time is needed to elapse for the motor to gain a steady and stable state. This time is called the *safe stalling time*. The motor may regain synchronism and become stable during this time and it will then be not required to trip.

Even if the abrupt loading is too large, the motor will not stop immediately when running, because it will operate in an unstable region *ab* of Fig. 11.4 and hence will come to halt after a certain time.

In such cases, the motor is not required to be tripped immediately but the protection arrangement can be made to wait for a time equal to the safe stalling time of the motor and then trip the motor if the situation still persists.

The protective scheme employs a definite time overcurrent relay (Chapter 2) the contacts of which trip the circuit breaker (controlling the motor) through a centrifugal speed switch (Fig. 11.8). The time setting will depend upon the safe stalling time of the motor. The centrifugal switch is used as an interlock in the dc control circuit (Fig. 11.8) because the trip coil of the circuit breaker (controlling the motor) is required to be energised only under conditions of stalling. Under these conditions, the speed of the motor will drop considerably from the normal rated speed, and hence the speed switch will close allowing the circuit breaker to open if the stalling relay (definite time overcurrent relay) has operated. In case of gradual overloading, however, the thermal overload relay should take care. The tripping of the circuit breaker, in this case, due to operation of stalling relay will be blocked because of interlock of centrifugal speed switch.

Relay Settings For deciding the relay setting of a stalling relay that is used for protection against stalling, certain additional data of induction motor is required over and above the data given in Section 11.5.1. This typical data is as follows:

1. Safe stalling time of induction motor

- (i) Hot condition = 12.7 s
- (ii) Cold condition = 22 s

2. Locked rotor relay (stalling relay)

- (i) Current-setting range = 150–600% of 1 A
- (ii) Time-setting range = 6 to 60 s

Setting The general practice is to set the current equal to 1/3 of the starting current.

$$I_{st} = 6 \times 132 = 792 \text{ A}$$

$$I_{st}/3 = 264 \text{ A}$$

The secondary equivalent,

$$i_{st}/3 = 1.76 \text{ A}$$

Hence, a setting of 175% can be selected.

The time setting of the relay, obviously, has to be higher than the accelerating time which is 5.5 seconds in this case. However, the setting must be less than the safe stalling time under the hot conditions. Hence, the time setting can be selected as 10 seconds.

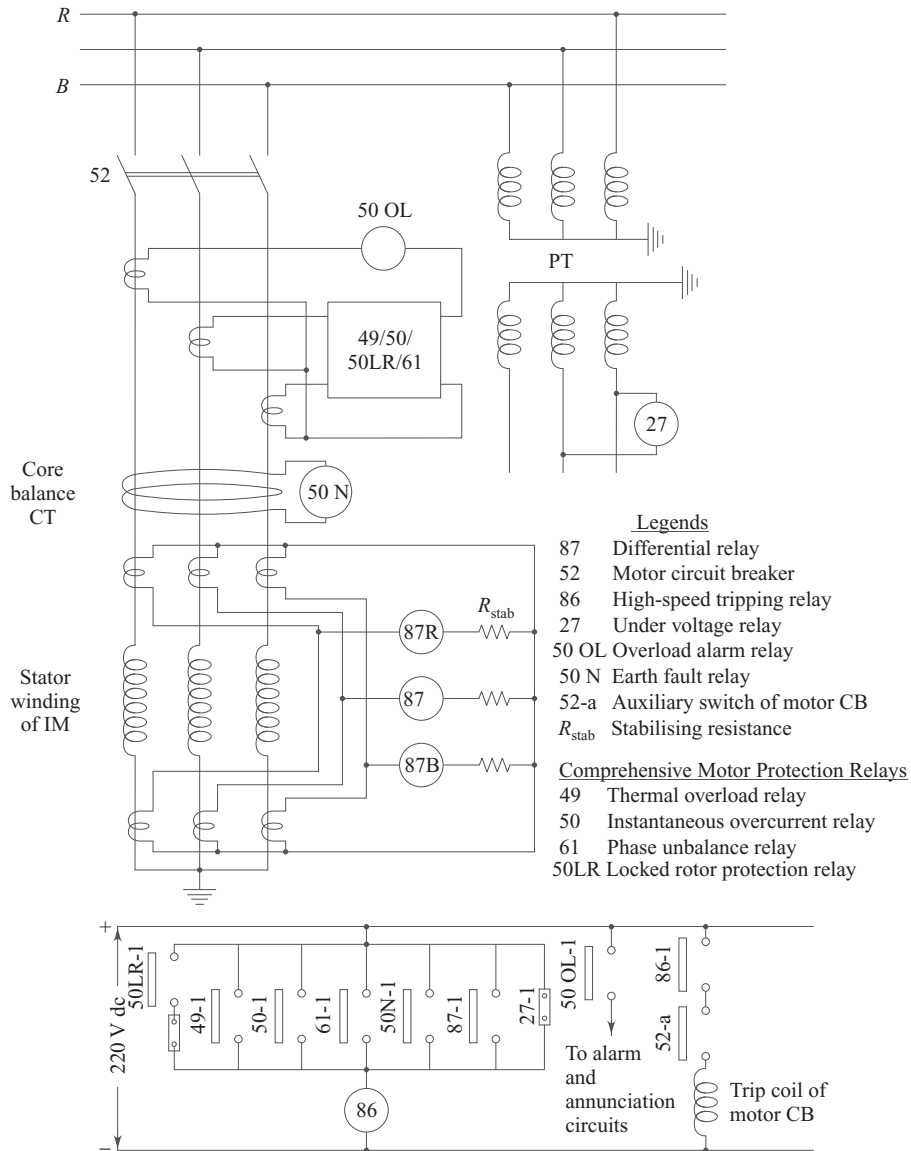


Fig. 11.8 Induction motor-protection scheme

So often high inertia motors have a long starting time and the safe stalling time is less than the starting time. It becomes difficult to set the stalling relay in such a case, without causing mal-operation during a healthy start. Certain additional arrangement, in which the stalling relay is made ineffective only during starting, can be made at the risk of no protection during unhealthy start.

11.5.5 Earth-Fault Protection

Earth-fault protection for a motor operating on earthed neutral system is provided by means of a simple instantaneous relay having a setting of approximately 20% of full-load current of motor. The relay can be wired in the residual circuit of 3 line CTs.

In such a scheme, operation of the relay due to CT saturation during initial high starting current should be avoided. This can be achieved by increasing the voltage setting of the relay by inserting a stabilising resistance in series with it.

Still more sensitive protection can be provided against earth faults in the motor if a core balance CT is available. An earth-fault relay in the secondary of core balance CT (Fig. 11.8) can be as sensitive as 3–10% of rated current. The setting, however, will depend on the minimum possible ground fault current.

When a motor operates on an unearthed neutral system, a neutral displacement-type voltage operated relay has to be applied.

11.5.6 Differential Protection

We have seen in Section 11.5.2 that the protection against the phase fault in the stator winding of an induction motor can be provided by an instantaneous overcurrent relay. Such a relay has to be set at a current higher than the starting current of the motor. The starting current of slip-ring induction motors can be limited to about 1.25 times the full-load current by means of resistance in the rotor circuit. Hence, an overcurrent relay can be set to about 1.4–1.6 times the full-load current. But in a squirrel-cage induction motor, in which the starting current is of the order of 4 to 10 times the rated current, the instantaneous relay has to be set above this value. With such a higher setting of the relay, the fault current for certain fault location must be less than the pick-up value of the relay. This can happen in case of a phase-to-phase fault near the neutral point of the star-connected motor. Since such faults are not cleared by instantaneous relays, one has to wait for either the thermal relay or negative sequence relay to clear the fault.

The most sensitive and quick protection for all phase faults in the motor is the circulating current differential protection. The possible mal-operation due to CT saturation and CT errors can be avoided by the use of stabilising resistance in series with the relay as already explained in Chapter 5. For motors above 1500 h.p., the differential protection scheme (Fig. 11.8) is employed.

11.5.7 Overload Alarm

For large motors, it is the general practice to provide the facility to sound an alarm when the motor is overloaded. Therefore, actions can be taken by reducing the load before the decision to trip the motor is taken in case of a sustained overload. A definite time overcurrent relay can be used for this purpose. The pick-up setting can be equal to 70–90% of the setting of the thermal overload unit and the time setting can be 25 to 60 seconds depending upon the thermal overload relay characteristics.

11.5.8 Under-voltage Protection

One of the reasons for employing under-voltage protection for a group of motors as in the case of power station auxiliary motors is to ensure that the motor circuit breakers are tripped on a complete loss of supply, so that when the supply is restored, the unit auxiliary transformer is not overloaded by simultaneous starting of all motors. This is particularly important for ac motors. In power stations, the simultaneous starting of a large bank of motors would probably overload and result in the tripping of feeding transformer.

Another reason why the under-voltage protection is required, is clear from Section 11.3 wherein it has been explained that the consequence of under-voltage is the increase of stator current.

All the protective schemes discussed in Sections 11.5.1 to 11.5.8 are shown in Fig. 11.8.

11.6 NUMERICAL MOTOR-PROTECTION RELAY (Courtesy Areva T & D Ltd.)

A modern numerical motor-protection relay is designed to offer a wider range of functions and more user-related possibilities for motor protection, supervision and control. The numerical relay can perform a full range of motor-protection functions based on load current such as thermal overload, short-circuit, excessive start time, locked rotor, unbalance, earth fault, loss of load, etc. The optional monitoring of temperature sensors or of thermistors provides continuous monitoring of the temperature inside the motor.

11.6.1 Thermal Overload Protection

The numerical motor protection relay produces a thermal image of the motor from the positive and negative sequence components of the currents consumed by the motor, in such a way as to take into account the thermal effects created in the stator and in the rotor. The negative sequence component of currents consumed in the stator generates large amplitude of eddy currents in the rotor, which create a substantial temperature rise in the rotor winding. The composition carried out by the relay results in an equivalent thermal current I_{eq} , the image of the temperature rise caused by the current in the motor. The current I_{eq} is calculated according to the following formula:

$$I_{eq} = \sqrt{I_1^2 + K_e I_2^2}$$

where,

K_e = negative sequence current recognition factor (0 to 10 in steps of 1)

K_e can be set at I_{st}/I_R for a given motor

where I_{st} = starting current of the motor

I_R = normal rated full-load current

Starting from this equivalent thermal current, the thermal state of the motor θ is calculated after every 5 cycles (every 100 ms for a 50 Hz system) by the relay according to the formula,

$$\theta_{i+1} = (I_{eq}/I_\theta)^2 \cdot [1 - e^{(-t/\tau)}] + [\theta_i \cdot e^{(-t/\tau)}]$$

in which

I_θ = thermal overload current threshold

θ_i = value of the thermal state calculated previously (5 cycles earlier, so 100 ms for a 50 Hz system, 83.3 ms for a 60 Hz system)

τ = time constant of the motor

As a function of the operating conditions of the motor, the relay uses one of the following three thermal time constants:

1. The thermal time constant τ_{e1} which is applied when the equivalent thermal current I_{eq} lies between 0 to $2.I_\theta$, that is, when the motor is running (normal load or overload conditions)
2. The starting time constant τ_{e2} which is applied when the equivalent thermal current I_{eq} is greater than $2.I_\theta$, that is, when the motor is in the starting phase or locked-rotor condition
3. The cooling time constant τ_r which is applied when the motor is shut down; in this case, the motor no longer consumes current and the value of the thermal state θ therefore decreases as time passes according to the formula given as follows:

$$\theta_{i+1} = \theta_i \cdot e^{(-t/\tau_r)}$$

A thermal overload signal is generated when the value of the thermal state θ reaches 100%.

Function Inhibiting Thermal Tripping during a Start This function permits inhibition of the thermal-tripping information during the starting stage. It may be necessary to use this function for some motors with temperature rise characteristics in a starting condition very different from those in a locked-rotor condition.

If the user brings this function into service, this inhibition is activated as soon as the starting time delay begins. On expiry of the starting time delay, this inhibition is deactivated.

When this function is activated, that is, during the motor-starting phase, the value of the thermal state θ calculated cannot exceed 90%. This means that thermal tripping cannot take place under any circumstances. At the end of the time allowed for starting, the value of the thermal state is authorised to exceed 90%.

Function of the Thermal Image Influenced by Ambient Temperature When the ambient temperature exceeds 40 °C, the admissible motor current diminishes with respect to its rated current. A setting of the protection parameters which is suitable under normal temperature conditions is no longer suitable when the ambient temperature rises above 40 °C.

The numerical relay offers the possibility of taking into account this necessary derating of motors. The thermal image can be modified by the ambient temperature measurement.

When this function is brought into service by the user, if the ambient temperature rises above 40 °C, the value of the thermal threshold I_θ is automatically modified to adapt the motor protection to the external temperature conditions.

The rules for the ambient temperature measurement influencing the thermal image are as follows:

1. For an ambient temperature lower than or equal to 40 °C, the thermal image is not modified.
2. For an ambient temperature between 40 °C and 65 °C, the thermal threshold I_θ is modified by a multiplying coefficient in compliance with the following formula.
 Multiplying coefficient = $1 - (\text{ambient temperature in } ^\circ\text{C} - 40)/100$
3. For a temperature greater than or equal to 65 °C, the thermal threshold I_θ is modified by a multiplying coefficient of 0.75.

Table 11.1 gives the relationship between temperature measurement and the influence on the thermal image.

Table 11.1

Ambient temperature °C	40 °C	45 °C	50 °C	55 °C	60 °C	65 °C
I_θ	1.00	0.95	0.90	0.85	0.80	0.75

Thermal Alarm Function The purpose of this function is to produce an alarm signal indicating that the thermal state θ of the motor has exceeded an adjustable threshold. Corrective action can thus be taken before thermal tripping occurs.

Thermal Start Inhibition Function This function makes it possible to inhibit a start on a hot motor, or not, as a function of its thermal state. When this function has been adjusted in service by the user, a further start is inhibited for the motor as long as its thermal state θ is higher than an adjustable threshold. It is then necessary to wait until the motor cools down. When the value of the thermal state θ falls below the threshold, the starting of the motor is authorised.

11.6.2 Excessive Start Time

This function protects the motor if the starting period lasts too long. A motor may fail to accelerate from rest due to many reasons like single phasing, low voltage supply, excessive load torque, bearing or gear drive problems, etc. Due to any of the above reasons, the motor will draw large currents from the supply that can increase its temperature to an extremely high value and finally will create damage to the motor.

To provide protection to the motor against this condition, this scheme uses a starting current threshold and a starting time delay. This threshold and this time delay can be adjusted to allow the starting current to pass for a specified time duration. If the starting current will pass for more duration than the specified time, this protection scheme will trip the motor.

This function is activated as soon as the numerical relay detects a start that may be sensed by detection of the closure of the auxiliary contact of the contactor or the circuit breaker of the motor. It is deactivated on expiry of the starting current time delay.

11.6.3 Number of Starts Limitation

Any motor has a restriction on the number of starts that are allowed in a defined period without exceeding the temperature. Starting should be blocked if the permitted number of starts is exceeded.

This protection scheme of a numerical relay allows the number of motor start-ups over a given period of time. This scheme uses the following adjustable parameters:

- Monitoring period (T_{ref})
- Number of hot starts limit
- Number of cold starts limit
- Start inhibit time delay

Each time the motor start is detected, the T_{ref} time delay is initiated and the number of starts registered by the counter corresponding to the temperature of the motor (hot or cold) is incremented by one. At the end of this time delay, the counter will be decremented by one.

Each time the motor is stopped, the relay establishes whether either of the two counters has been reached. If this is established, start inhibit signal will be generated for a length of time equal to T_{stop} . At the end of time T_{stop} , this signal drops out and it is possible to start the motor again.

11.6.4 Minimum Time between Two Starts

To allow the motor to cool down between two starts, a time delay may be specified between consecutive starts (again distinguishing between hot and cold starts).

This time delay is initiated on detection of the motor start-up by the relay. When the motor stops, if the '*minimum time between two starts*' time delay has not finished, the *start inhibit* signal is generated until the end of the specified time delay.

11.6.5 Earth-Fault Protection

One of the most common faults of a motor is an earth fault. The type and sensitivity of protection provided depends largely on the system earthing. However, it is common to provide both instantaneous and time-delayed relay elements to cater for major and slowly developing faults, respectively.

Earth faults create a zero phase-sequence current which is measured either by a relay connected in residual circuit of the three line CTs or by a relay connected across winding of a CBCT, the core of which surrounds the three conductors (usually a three-core cable).

The numerical relay provides two independent earth-current thresholds (I_{e1} and I_{e2}) with their associated time delays (t_1 and t_2) enabled by the operator to configure for an alarm threshold and a tripping threshold. The setting thresholds are expressed as a function of the residual current. For each earth-current threshold, time-delayed or instantaneous operation settings are available.

11.6.6 Unbalance Protection

The unbalance protection scheme is based on the measurement of the negative sequence component of the current.

Two negative sequence overcurrent thresholds are available:

1. One of them, $I_2 >$, is associated with a definite time delay
2. The other, $I_2 >>$, is associated with inverse time characteristic.

The user can use the threshold $I_2 >$ to detect the inversion or loss of a phase, or to give an unbalance alarm.

The threshold $I_2 >>$ has an inverse time characteristic which enables it to allow slight instantaneous unbalance to pass whilst more substantial unbalances will be detected more quickly. This inverse time characteristic permits selective clearance of external two-phase faults which appear on the system.

Unbalance protection is also applied to a feeder supplying a large motor or a group of small motors, where there is a possibility of one of the feeder phase opening as a result of a loose connection, a fuse failure or a similar case.

11.6.7 Stalling

The condition of stalling of the motor may occur at the time of starting or running state of the motor. With respect to these two conditions, the motor is protected through the following ways:

(a) Protection against Stalling at Start This function, which makes it possible to detect stalling condition of the motor at the time of starting, is activated only during the starting period that is during the course of the starting time delay (T_{start}).

It uses a speed signal from the motor and safe stalling time delay (T_{stall}). On detection of a start, this function is activated and the time delay provided for safe stalling (T_{stall}) begins. At the end of this time delay, the motor should gain the required speed. If the speed of the motor is not sufficient then it means there is a condition of stalling, so the relay trips the motor.

(b) Protection against Stalling at Running This function, which makes it possible to detect stalling while the motor is running, is activated immediately after the starting time delay (T_{start}).

It uses the stalled rotor current threshold (I_{stall}) with its associated time delay T_{stall} . The relay detects the overcurrent caused by stalling and generates a tripping signal and information that the rotor has stalled while the motor is running if the phase current exceeds the threshold I_{stall} for a length of time greater than T_{stall} .

11.6.8 Loss of Load

This function, which makes it possible to detect a loss of load (for example, the draining of a pump or breakage of a conveyor belt), uses definite time undercurrent protection.

The following are the parameters required to be set

- (i) undercurrent threshold
- (ii) time delay associated with undercurrent threshold
- (iii) the inhibit start time delay

Once the motor is started, this function is activated at the end of the inhibit time delay (T_{inhibit}). This time delay T_{inhibit} is useful for motors to start at no-load and increased load to its full-load capacity gradually at the end of starting.

When the motor is running (and after expiry of the inhibit time delay), if the value of one of the phase currents consumed by the motor is lower than the threshold setting for a period greater than or equal to the set time delay, the relay will generate a loss of load signal.

11.6.9 Protection against Temperature Rise

This function is intended to detect abnormal temperature rise of the motor by direct temperature monitoring. This is achieved by monitoring temperature using RTDs (Resistance Temperature Detectors) or thermistors.

An alarm signal is generated by the relay, if the temperature measured exceeds the programmed alarm threshold for a period of time equal to the time delay associated with this threshold.

A tripping signal is generated if the temperature measured exceeds the programmed tripping threshold for a period of time equal to the time delay associated with this threshold.

The RTDs can be located

- (i) at the stator windings (protection of the stator, indirect protection of the rotor, detection of failure of the cooling system),
- (ii) at the mechanical bearings (to detect failure of the lubrication), and
- (iii) outside the motor (ambient temperature measurement), at the same level as that of the entry of cooling air.

11.6.10 Functions of a Numerical Relay

- (a) **Programmable Scheme Logics** A modern numerical relay can achieve up to 4 logical equations by combining the internal and external information. These equations make it possible to define logical AND/OR expressions which can be associated with time-delays. These logical schemes result in savings in external relaying and in relay/process interactivity.
- (b) **Measurements** A modern numerical relay provides continuous measurements of a large amount of electrical data as well as information about the status of the motor.
- (c) **Analog Output** An optional analog output is available in a modern numerical relay. Certain information and measurement values can be driven through a current loop towards a PLC.
- (d) **Trip Statistics** A modern numerical relay provides the user with trip statistics for every protection function. The user can thus keep track of the number of trips, which have taken place as well as their origin.
- (e) **Switchgear Monitoring** The safety maintenance of the switchgear is provided by monitoring the summarised contact breaking duty, the number of switching operations as well as by controlling the opening time. In the case of an abnormality or the overflow of a pre-settable threshold, the relay will generate an alarm signal.
- (f) **Event Records** The last 75 status changes are recorded by a modern numerical relay in a non-volatile memory. This covers all the status changes on the logic inputs and outputs, the modification of one or more parameters, the alarm signals or the operation of one of the output contacts. Event logging is recorded with a time tag accuracy of 1 ms.

- (g) **Fault Records** Nowadays, a numerical relay records typically the last 5 faults. The recording of the fault values associated with oscillography functions and trip statistics will enable the user to understand the origin of faults and to eliminate them.
- (h) **Oscillography** Typically, 5 oscillographic recordings, each of three seconds, can be stored by a recent numerical relay. The oscillography data can be uploaded via the communication network or via the RS232 port.

REVIEW QUESTIONS

- Enumerate the abnormal conditions of an induction motor. Also write the causes and consequences of it.
- What are the factors required to be considered while deciding thermal overload protection of a large induction motor? Explain your answer with relevant characteristics.
- What are the causes and consequences of stalling of an induction motor? Describe the protection scheme of protecting a large induction motor against stalling.
- Explain different schemes for earth-fault protection of an induction motor.
- An induction motor with the following particulars is to be protected against (i) overload, and (ii) short circuit.

Rated output	500 kW
Rated power factor	0.85
Rated voltage	6600 volts
Efficiency	90%
Permissible continuous overload	110% of rated current
Starting current	5 times rated output

Which type of relay do you suggest for aforesaid protections? Suggest a suitable CT ratio of the CT feeding the relays used, and calculate the current setting.

(Thermal overload relay setting = 80%, Instantaneous overcurrent relay setting = 550%, CT ratio = 75/1 A)

- Following is the data for an induction motor:
- | | |
|-------------------|-----------------------|
| Rated voltage | 6.6 kV |
| Rated power | 250 kW |
| Rated current | 27.5 A |
| Accelerating time | 11 s |
| Starting current | 6 times rated current |

Safe stalling time

Hot	20 seconds
Cold	50 seconds
CT ratio	30/1 A
PT ratio	6.6 kV/110 volts

Suggest the types of relays to be used for

- Short-circuit protection
- Stalling protection
- NPS protection
- Under-voltage protection

Suggest the suitable settings of these relays.

(Instantaneous overcurrent relay setting = 750%, Definite time overcurrent relay setting = 180% with time setting of 15 seconds, overcurrent relay setting = 275% with time-delay of 10 cycles, Under-voltage relay setting = 70%)

- The following are the details of a large three-phase induction motor:
 - Input = 1250 kW
 - Rated voltage = 6.6 kV
 - Rated power factor = 0.8
 - Starting current = 5 times rated current
 - Starting time = 8 seconds
 - Continuous overload = 110% of rated current

Suggest a suitable CT ratio for protection of induction motor. If the setting range of a thermal overload relay (used for thermal overload protection) is 70–130% of CT secondary rating in steps of 5%, suggest a suitable setting of the relay. Also, suggest a suitable setting of an instantaneous relay (used for short-circuit protection) if the setting range is 400–2000% of CT secondary rating in steps of 50%.

Standard CT primary currents are given as follows: 50, 100, 150, 200, 300, 500, 800, 1000 A

(CT ratio = 150/1 A, thermal overload relay setting = 95%, instantaneous overcurrent relay setting = 650%)

8. The details of a large 3-phase induction motor are as follows:

Output	1200 kW.
Efficiency	90%
p.f.	0.8
Rated voltage	6.6 kV

Starting time

At 100% voltage	10 seconds
At 80% voltage	15 seconds

Hot relay characteristic overlaps starting characteristic

Starting current	6 times rated current of induction motor
Safe stalling time	20 seconds
Safe stalling current	$(1/3) \times$ starting current of induction motor
Permissible continuous overload withstand	110% of rated current
Negative sequence impedance Z_2	20%
Positive sequence impedance Z_1	80%
CT ratio	200/1 A
Range of thermal overload relay	70–130% of 1 A in steps of 5%
Range of instantaneous overcurrent relay	400–2000% of 1 A in steps of 50%
Range of negative phase sequence current relay	10–40% of 1 A in seven equal steps. Relay gives very inverse characteristic ($I_2^2 t = K$)
Range of stalling relay	150–600% in steps of 30%
Range of definite time overcurrent relay for overload alarm	70–100% of thermal relay setting in steps of 5%.
Time setting	2.5–25 seconds
Setting range of under-voltage relay	70–110% of rated voltage (110 V) (instantaneous)
Thermal limitation (inhibition) setting	3–4–5–6 times relay rating

Timer setting for thermal limitation feature 2.5–25 seconds

Suggest the relay settings for thermal overload relay, thermal limitation feature with timer setting, instantaneous overcurrent relay, NPS current relay, stalling relay with timer setting, setting of overload alarm relay with timer setting and setting of undervoltage relay.

(Thermal trip setting of 75%, thermal alarm setting of 70%, instantaneous overcurrent relay setting = 600%, NPS overcurrent relay setting = 25%, definite time overcurrent relay setting = 150% with time setting of 17.5 seconds, undervoltage relay setting = 70%, Thermal limitation setting = 6 A)

9. The following is the data for a three-phase, 50 Hz, induction motor:

Rated power input	400 kW
Rated power factor	0.8
Rated voltage	6.6 kV
Continuous overload withstand	110% of rated current
Starting current	5.5 times rated current
Starting time	6 seconds
Safe stalling time	12 seconds
Safe stalling current	2 times rated current

Suggest the suitable ratio of CT feeding a relay. Calculate the relay setting of (a) a relay for overload protection (setting range 70–130% of relay setting in steps of 5%), (b) a relay for protection against stalling of the induction motor (setting range 150–600% of relay rating, time setting 3–30 seconds) and (c) a relay for short-circuit protection. Name the type of the relay used in each case.

(Thermal overload relay setting = 90%, instantaneous overcurrent relay setting = 650%, definite time overcurrent relay setting = 180% with time setting of 9 seconds)

10. Briefly explain any one method of protecting a large induction motor against single phasing. What do you understand by delayed start? What protective measures are taken in the modern comprehensive motor protection relays against this eventuality?
11. What is the difference in achieving the thermal overload protection by a modern numerical relay and by an electromechanical relay?

12. Explain in detail about the following types of protections provided for an induction motor by a modern numerical relay:
 - (i) Unbalanced protection
 - (ii) Protection against stalling
 - (iii) Loss of load
 - (iv) Protection against temperature rise
13. Enumerate the functions provided by a modern numerical relay used for protection of an induction motor.

MULTIPLE CHOICE QUESTIONS

1. The starting current of an induction motor is generally of the order of
 - (a) 1 to 2 times the rated current of the motor
 - (b) 2 to 4 times the rated current of the motor
 - (c) 4 to 10 times the rated current of the motor
 - (d) 10 to 15 times the rated current of the motor
2. For large induction motors, to detect single-phasing condition
 - (a) the relay shall depend on positive sequence current measurement
 - (b) the relay shall depend on negative sequence current measurement
 - (c) the relay shall depend on zero sequence current measurement
 - (d) no special protection is required
3. For thermal overload relay setting, the relay characteristic has to be coordinated with
 - (a) thermal withstand curve of induction motor
 - (b) starting characteristic of induction motor
 - (c) none of the above
 - (d) both (a) and (b)
4. For more sensitive earth-fault protection of an induction motor
 - (a) an instantaneous relay shall be connected in the residual circuit of 3 line CTs
 - (b) an instantaneous relay shall be connected in the secondary of a core balance CT
 - (c) differential protection shall be provided
 - (d) inverse time overcurrent relay shall be provided
5. Negative phase sequence currents are generated in an induction motor during abnormality of
 - (a) single phasing condition only
 - (b) voltage unbalance condition only
 - (c) reversed phase sequence condition only
 - (d) all of above (a), (b) and (c)

Testing, Commissioning and Maintenance of Relays

Relays are the crux around which all the protection systems for various electrical equipments depend upon. Reliable operation of the relay, under conditions of abnormality, saves the costly power-system equipments from damage. Regular and systematic operation of a relay

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has to be checked and verified, since during the lifetime of a relay the actual number of times it has to operate upon is significantly small. There are basically three forms of testing that each relay has to undergo during its lifetime. They are (1) Acceptance tests, (2) Type tests, and (3) Routine or Periodic tests.

Introduction

12.1 ACCEPTANCE TESTS

Acceptance tests are those tests which are to be performed by the manufacturer to satisfy the customer's demand as per their specification. These tests are carried out by the manufacturer in the presence of the customer at a standard laboratory.

12.2 TYPE TESTS

Before any relay is purchased by the user in India, it has to undergo all the following tests carried out by the manufacturer under the standards of IS 3231-1968.

- (a) Operating or pick-up value test
- (b) Reset value or drop-off value test
- (c) Operating time test
- (d) Resetting time test
- (e) Insulation test
- (f) Temperature rise test

- (g) Contact capacity test
- (h) Volt-Ampere test
- (i) Overload test
- (j) Mechanical test

Some Special Tests

- (a) Distance setting test
- (b) Stability test
- (c) Sensitivity test
- (d) Voltage variation test
- (e) Ageing for thermal relay
- (f) Overshoot test
- (g) Impulse voltage test
- (h) Damp heat test
- (i) Shock test
- (j) Vibration test

(a) Operating Value Test The operating quantity whether it is current, voltage, frequency, etc., of the relay is changed towards its set value and the value at which the relay unit just operates is noted. Initially, care must be taken that the value of the operating quantity is such that the relay is completely reset. Generally, the pick-up value must be within 90% to 130% of the declared nameplate value. For over and under-voltage relay, the permissible value should be around $\pm 5\%$ of the declared value.

(b) Reset Value Test In this test, the operating value is adjusted such that the relay remains operated. Then the actuating quantity is changed towards a value when the relay just fails to operate. This value is the reset value and is normally expressed as a percentage of the nominal set value of the relay.

(c) Operating Time Test The time interval between the energisation of the relay and the operation of its contacts is the operating time. For a single-input instantaneous relay, several sets of readings must be taken and the average operating time chosen. For IDMT relays the operating times are taken for PSMs 2, 5, 10 and 20. Also, the times for different TMSs for the above PSMs have to be determined. As per IS for the highest TMS and PSM between 2 to 4, the permissible deviation from the declared time should be within 12.5%, and within 7.5% for PSM between 4 to 20. For all other TMSs, the test is carried at PSM 10, for all plug settings and the allowable error is 7.5% limited to a maximum of 0.1 second. In case of definite time relays, the permissible error in operating time is $\pm 5\%$ limited to 0.1 second.

(d) Reset Time Test The reset time is defined as the time taken by the trip contacts of a relay to return it from its energised position to de-energised condition. In this test, the relay is kept in the operated condition. The energising quantity is removed suddenly and the time taken for the relay contacts to completely return to its un-operated condition is noted.

(e) Insulation Test All relays have to undergo this test whereby the safety of insulation between coils, contacts and casing is checked. Test voltage obtained from an H.V. testing set is applied between

- (i) All current-carrying terminals connected together and the casing of the relay
- (ii) The contact terminals shorted together and other coil terminals
- (iii) Between set of 'NO' and 'NC' contacts held open externally by operating the relay mechanically

The voltage applied must be sinusoidal and should be applied gradually. The voltage equal to 2 kV ac is to be applied for one minute during which insulation should not fail.

- (f) **Temperature Rise Test** This test must be carried out on all relays. The current-operated relay must be energised for its setting current or rated current whichever is lower, while voltage-operated relay should be energised at 110% of its rated voltage. The test is carried until the circuits attain a final steady temperature, as measured by a thermometer. The above test must be carried out at an ambient temperature not exceeding 40⁰ C. The insulation should withstand a temperature rise as per its class of insulation.
- (g) **Contact Capacity Test** For the contacts of a relay meant for heavy duty (viz., for actuating the trip circuit of a breaker), it is required that the maximum VA capacity that it can successfully make, break or carry continuously has to be determined. Both making and breaking capacities are to be determined by dc and ac sources with resistive loading. Moreover, the breaking capacity has to be further determined for an inductive load having p.f. (0.4±0.1) lag for ac and time constant of (40±5) milliseconds. The relay has to undergo repeated make and break operations, 100 times in succession with time interval not less than 30 seconds between 2 immediate operations.
- (h) **Volt–Ampere Burden Test** To carry out this test, the relay must be energised at its rated current or voltage and the voltage drop across or the current flowing through the coil has to be measured. The product of rated quantity (current/voltage) and noted quantity (voltage/current) gives the VA burden.
- (i) **Overload Test** This test is applicable to all current-operated relays. In this test, at the highest time setting a current of 20 times the setting current is injected. Three such operations are made in quick succession for instantaneous relays and at intervals for time lag relays.
For a thermal relay, 8 times the setting current is injected at the highest time setting and the test as above is carried. For a voltage-operated relay, 115% rated voltage is applied during the operating time of the highest time setting.
In case of relays having current and voltage coils, 20 times the setting current is passed at highest time setting with a rated voltage across the voltage coil.
The temperature rise of the relay after undergoing this test must not exceed 200 C.
- (j) **Mechanical Endurance Test** All relays having a mechanical moving system must undergo this test. It is carried out at the highest time setting and largest plug setting of a relay. The relay coil is energised at twice the current setting for current-operated relays and at the operating voltage setting for voltage-operated relays. 500 repeated operations are carried out. After the test, all mechanical assemblies of the relay must be in sound order.

12.2.1 Special Tests

Apart from the above-mentioned type tests, some tests, which specially apply to specific relays are discussed herewith.

- (a) **Distance Setting** The following tests are to be performed specially for distance relays.
 - (i) Verification of polar characteristic
 - (ii) Accuracy versus range test
 - (iii) Verification of time settings for different zones
- (b) **Stability Test** It is performed on relays which possess restraining or polarising features. The purpose of this test is to determine whether relays mal-operate or not when the polarising feature is adequate.

- (i) **Voltage or Current Unbalance Relays** Voltage unbalance, current unbalance, negative sequence relays of both voltage and current type are tested for stability test. Current unbalance relays should not operate for balanced phase currents up to 7–8 times of the rated current. Voltage unbalance should not mal-operate for balanced three-phase voltages up to 125% of the rated voltage.
- (ii) **Current Differential Relay**
- (iii) **Directional Relays** For directional and reverse power relays, stability test has to be carried by applying a rated voltage and 20 times the rated current, where it should remain inoperative. The relay should also not operate when 15 times the rated current is passed suddenly through the current coil with no voltage applied to the voltage coil.
- (c) **Directional Test** Directional relays have to undergo the following two tests:
 - (i) Sensitivity test
 - (ii) Quadrature test
- (d) **Voltage Variation Test** Frequency sensitive relays, whose operating coils are energised by voltage, must be tested by changing energising voltage keeping the frequency constant. The error in frequency setting must not exceed $\pm 0.5\%$ for a voltage variation of $\pm 10\%$ from its rated value.

In voltage operated definite-time-lag relays, the operating time should be within $\pm 7.5\%$ of the rated operating time or within ± 0.15 seconds, whichever is more, when the relay is energised by a varying voltage between 80% to 110% of the rated value.
- (e) **Overshoot Test** This test is carried out for time-lag relays. A current of 20 times the current setting at the highest time setting is passed for a time duration of 0.1 seconds less than the actual time of operation of relay. The relay under test must not operate to pass this test.
- (f) **Impulse Voltage Test** This test is recommended for static relays. A high-voltage surge of short duration without much oscillation is applied and the components of the relay must withstand it to pass this test.
- (g) **Shock Test** In this test the relay is subjected to a very heavy impact, up to 400 g. The test is used in the design stage of a prototype of relay. If the shock resistance is less, the designer improves upon the design with the aid of inertia, resonance and friction equations obtained by the test.
- (h) **Vibration Test** It is carried out to determine if natural resonance of any part of the relay occurs at any multiple of system frequency. The resonance may result in undesirable contact closing or loosening of assembly and result in damage.

12.2.2 Installation (Commissioning) Test

Commissioning tests are done to verify that the equipment has not been damaged during transit. It is done to ensure that the relay has been correctly installed and the characteristics are as per the standards.

Some of the initial examinations on the relay at site are checking of terminal tightness, check of ferrule numbers, insulation resistance test and examination of auxiliary test. Secondary injection tests are then conducted to verify the calibration of a relay. Thereafter, CTs are checked for their polarity, and a primary injection test is conducted to confirm that the CTs are correctly wired to the installed relays. The tripping and closing of the relay is checked and all the annunciations, indication and alarm conditional status are verified. A checklist of the tests is as follows:

Preliminary Tests

- (a) Damages like loosened plates, broken parts, etc.
- (b) Iron fillings in air gap of magnets removed
- (c) Mechanical moving assembly inspected
- (d) Ratings and specifications checked

Electrical Tests

- (a) Insulation resistance test
- (b) Pick-up value test
- (c) Drop-out value test
- (d) Timing
- (e) Polarity checking
- (f) Directional sensitivity
- (g) Flag indication and annunciation

Maintenance Test Periodic maintenance of the relay is an absolute necessity. The programme for periodic maintenance has to be checked out distinctly. The frequency of the test will, however, vary widely with the type of equipment. Certain items are continuously tested, while others may be tested once in a year. A typical schedule has been suggested as follows:

(a) Continuously checking

- Pilot supervision
- Trip circuit supervision
- Relay voltage supervision
- Battery emf supervision
- Busbar CT supervision

(b) Daily

- All flags and semaphores

(c) Monthly

- Earthing resistance

(d) Yearly

- Checking and calibrating operating levels, sensitivity, tripping angle, etc.
- Secondary injection test on more complex relays
- Insulation resistance test
- Inspection of gas and oil actuated relays

It is very important to keep records of the routine maintenance test reports. The relay mostly stays non-operative and yet it is required to operate with accuracy and in a fully discriminative manner when demanded. The fault record and fault liability of each equipment has to be carefully preserved. The keyword should be "Prevention is better than cure".

12.2.3 Classification based on Test Equipments

Test equipments are required to inject electrical quantities into the relay for the purpose of testing. Based on the method of injection, the tests can be classified as follows:

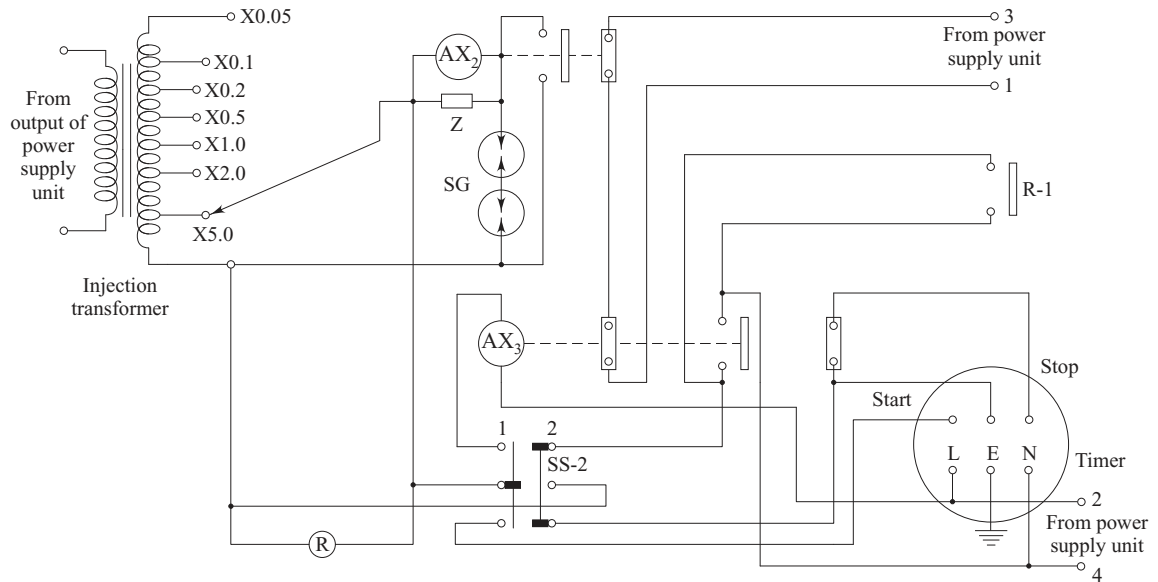


Fig. 12.1(b) Injection transformer unit of overcurrent relay test-set (Courtesy:Areva T & D.Ltd.)

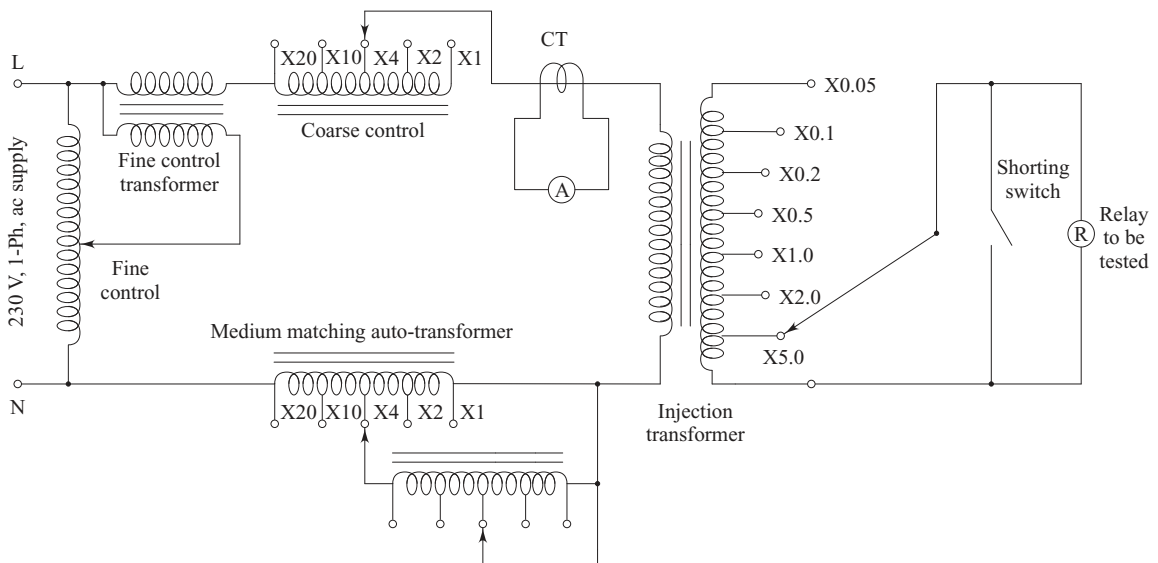


Fig. 12.1(c) Equivalent circuit of Fig. 12.1(a) and (b)

Nowadays, overcurrent relay test sets are available in the market, which generally use a tapped non-saturating reactor to suppress the harmonics so that a good waveform can be obtained with minimum power dissipation. The circuits of one such test equipment [Courtesy Areva T&D Ltd.] are given in Fig. 12.1(a) and (b). The equipment is formed of a power supply unit [Fig. 12.1(a)] and an injection transformer unit [Fig. 12.1(b)]. The whole arrangement is such that the current drawn from the supply mains is comparatively quite small.

Figure 12.1(c) is a simplified equivalent circuit of Figs 12.1(a) and 12.1(b). The circuit arrangement is such that the current injected to the relay is the multiplication of ammeter reading, coarse current multiplier and injection transformer ratio. Medium and fine control helps for adjustment of required current with highest precision. The push button PB is required to be kept pressed during testing. This is because the test set is not continuously rated for high current. The test current is immediately interrupted by a contactor when the relay under test operates (through contact of auxiliary relay AX_3). Relay AX_2 is an overvoltage relay. If the secondary of the injection transformer gets open-circuited, its insulation may be damaged, because of the overvoltage produced. Before this happens, the spark gap SG sparks over at this overvoltage and the relay AX_2 gets energised. The 'NC' contact of AX_2 disconnects the injection transformer from the supply mains. Auxiliary relay AX_1 is used for initiating the operation of contactor and to avoid chattering of the contactor when the relay under test operates. The relay coil can be shorted by a selector switch SS_2 so that the test current can be comfortably adjusted. Removal of shorting link gives the start pulse to a digital timer and operation of the relay under test gives the stop pulse to the timer (through the contact of AX_3). Thus time of operation of relay at any current can be measured and time-current characteristic can be confirmed.

For experiments to be conducted in laboratory of educational institutes, a low-cost test-set is developed by the authors. The output cannot be guaranteed to be perfectly harmonic-free, but for demonstrating to the students it serves its purpose. The pictorial view of this test-set at BVM Engineering College is shown in Fig. 12.2.

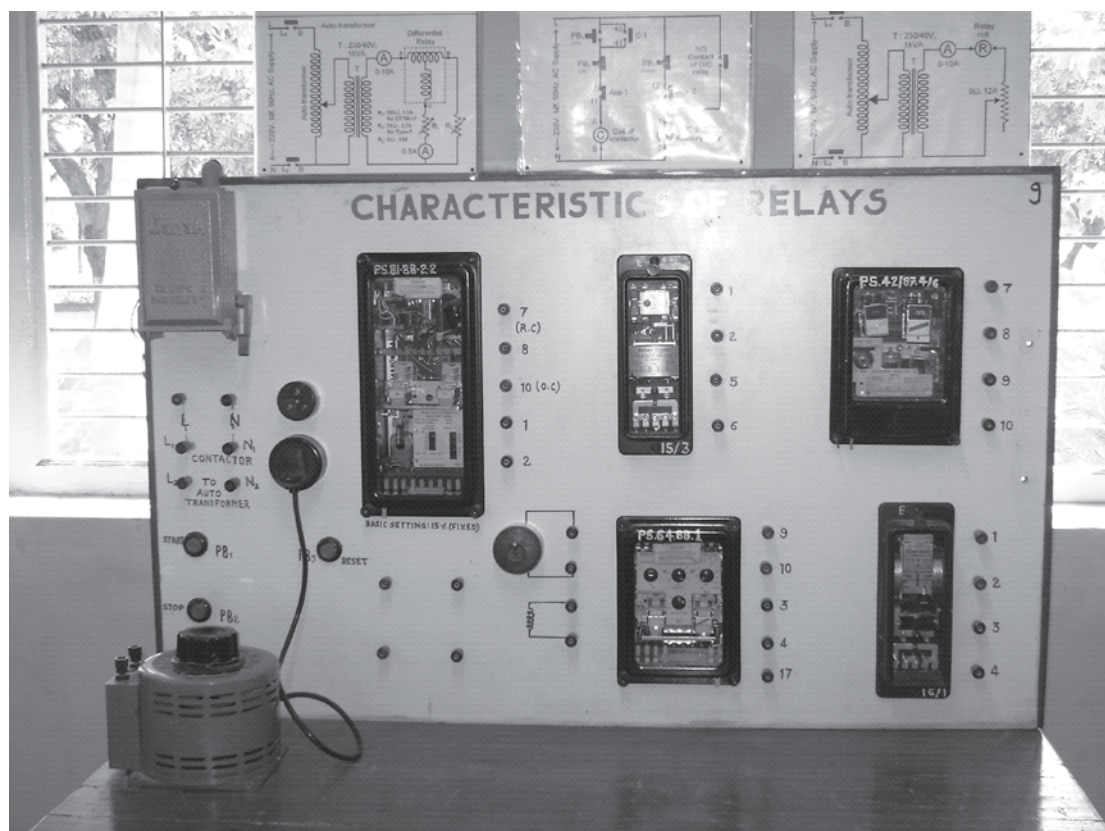


Fig. 12.2 Pictorial view of low-cost test set at BVM engineering college

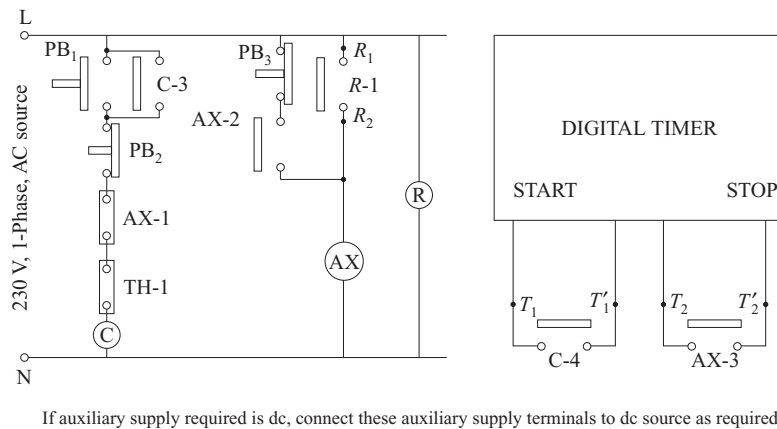


Fig. 12.3 Control circuit for characteristics of overcurrent, thermal, overvoltage and differential relays

For testing an instantaneous overcurrent relay, definite time overcurrent relay, IDMT relays giving normal inverse, very inverse or extremely inverse characteristics and thermal relay, the circuit as given in Fig. 12.4 can be permanently wired. For convenience in adjustment of current, a shorting switch (not shown in figure) across C_1 - C_2 can be provided. The auxiliary contact $C-4$ of contactor C gives the start pulse to the timer and 'NO' contact ($AX-3$) of auxiliary relay AX gives the stop pulse (Fig. 12.3). Control circuit (Fig. 12.3) shows that the contactor trips (through $AX-1$) when the relay under test operates. Contact $AX-2$ avoids chattering of the contactor when the relay operates. A current of up to 100 A can be injected for a short duration of time (few seconds) using such a set.

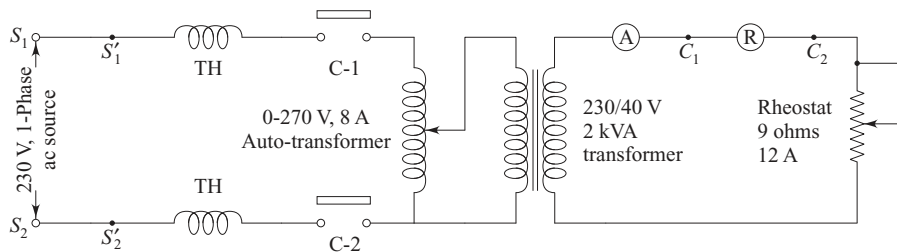


Fig. 12.4 Circuit diagram for obtaining characteristics of overcurrent relays

12.3.2 Overvoltage Relays

Overvoltage relays giving different characteristics are available in the market. These are instantaneous overvoltage relays, definite time overvoltage relays and inverse time overvoltage relays. For testing such relays, the circuit as shown in Fig. 12.5 can be used. The control circuit is same as given in Fig. 12.3. Undervoltage relays also can be tested using the same circuit arrangement.

12.3.3 Directional Relays

A directional relay is a phase comparator relay. Its characteristic is a polar characteristic. The characteristic is to be drawn on the R - plane. The circuit arrangement as shown in Fig. 12.6 can be used for the purpose. It is comfortable to shift the phase angle of voltage with reference to the current as voltage coil of the relay

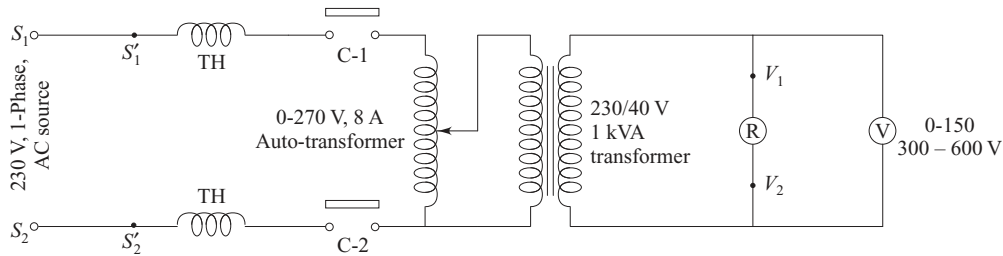


Fig. 12.5 Circuit diagram for obtaining characteristic of overvoltage relay

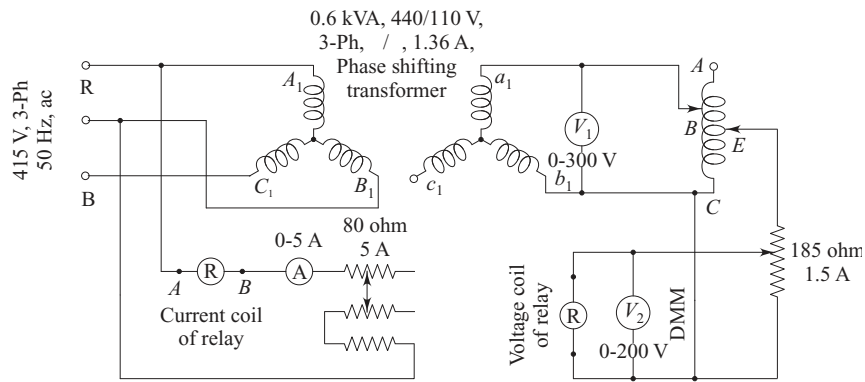


Fig. 12.6 Circuit arrangement for obtaining characteristic of directional relay

draws only few milliamperes, and hence the phase shifter of a smaller capacity can be used. The relay shown in Fig. 12.6 is a 5-A relay with a polarising voltage of 110 volts. An auto-transformer and rheostat as potentiometric arrangement are used for adjusting voltage injected to the relay. The voltage is required to be changed from about 0.5 volt to 110 volts.

If the MTA of the relay is 45° lag, the MT line will be at an angle of 45° lead with reference to the current vector plotted on the positive $-axis$ quadrants. This means that zero torque angles will be voltage vector lagging the current by 45° and leading the current by 135° . When the voltage vector lies in the blocking zone (Fig. 12.7), torque is negative as given by the equation.

$$T = K \times V \times I \times \cos (\Phi - \theta)$$

where,

$$\theta = -45^\circ$$

$$\Phi = +45^\circ \text{ and } -135^\circ$$

Here, angles are referred to using the conventional method (i.e., current with respect to voltage). For all angles between voltage and current lying in the positive torque region (trip zone), different minimum voltages will be required just to make the relay operative. The arrowheads of these voltage vectors when joined by a line, give the characteristic of a directional relay. The region between zero torque line (Fig. 12.7) and characteristic line is said to be the dead zone. The voltage required to make the relay just operative at the MT line gives the directional sensitivity. Normally, this sensitivity is expressed as a percentage of polarising voltage.

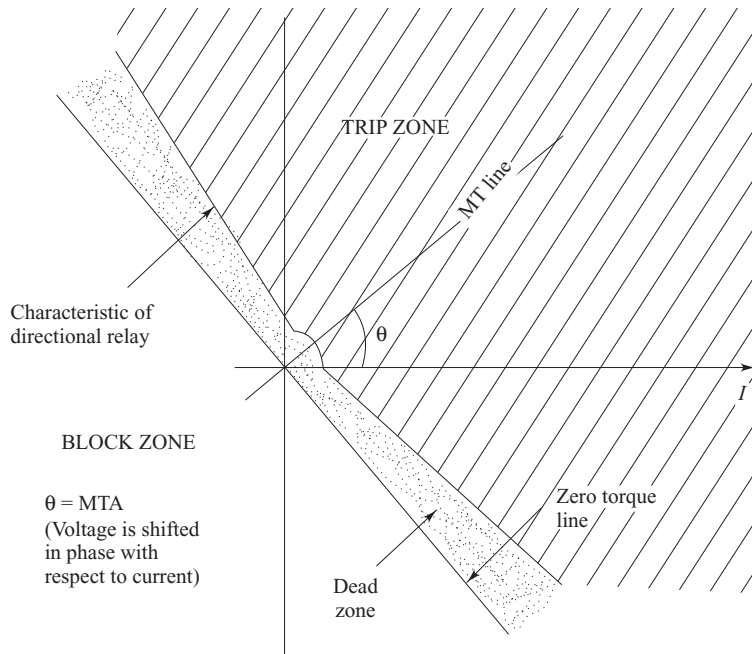


Fig. 12.7 Typical characteristic of directional relay

12.3.4 Biased Differential Relays

Two tests are to be carried out on biased differential relay for confirming its characteristic, viz., checking its basic setting (or sensitivity threshold) and check for bias setting. The circuit arrangement as shown in Fig. 12.8 can be used for both the checks. Suitably rated rheostats shall be used. The control circuit is the same as that given in Fig. 12.3.

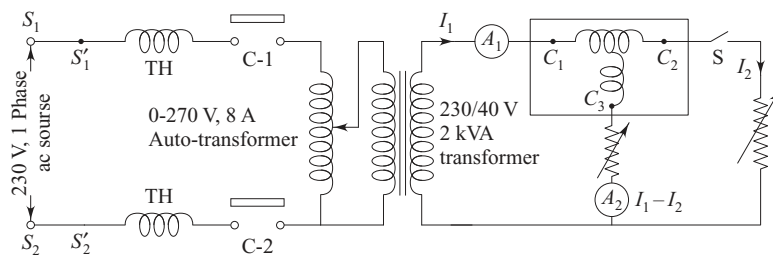


Fig. 12.8 Characteristics of differential relays

Check for Basic Setting Keep the switch S OFF and make the contactor 'ON'. Gradually increase the voltage using the auto-transformer. The relay must operate when current $I_1 - I_2$ (shown by the ammeter A_2) just exceeds basic setting. The condition of bias setting is satisfied as a pick-up ratio,

$$\frac{I_1 - I_2}{(I_1 + I_2)/2} = \frac{I_1}{I_1/2} = 2 \text{ or } 200\%.$$

because $I_2 = 0$. The bias setting available in relays ranges from 10–50%.

Check for Bias Setting Now keeping the switch S 'ON', and making contactor 'ON', gradually change the currents I_1 , I_2 and $I_1 - I_2$ by adjusting the auto-transformer and the variable rheostats. I_1 is given by the ammeter A_1 and $I_1 - I_2$ is given by the ammeter A_2 from which I_2 can be calculated. Values of I_1 , I_2 and $I_1 - I_2$ are to be noted when the relay just operates. The ratio $\frac{I_1 - I_2}{(I_1 + I_2)/2}$ must be equal to or a little more than the bias setting.

12.3.5 Synchro-check Relays, Underfrequency Relays and Overfluxing Relays

Synchro-check relays are used for interconnecting two grids at the appropriate and correct instant. They are also used for synchronising the generator with the infinite bus. A synchro-check relay will allow the breaker to be made 'ON' if the synchronising conditions are satisfied. Synchro-check relays allow the synchronising if

- (i) the phase-angle between the voltages of the infinite bus and generator (or incoming grid) is within $\pm 15^\circ$ (or in certain relays within $\pm 30^\circ$)
- (ii) the frequency of incoming machine (or grid) is within the tolerance (as specified by manufacturers) of frequency of the infinite bus, and
- (iii) the voltage of the incoming machine (or grid) is within the tolerance (as specified by manufacturer) of voltage of the infinite bus.

For testing synchro-check relays, a circuit arrangement of Fig. 12.9 can be used. Two alternators can be run by their prime-movers. The prime-movers are dc motors. The speed of the motors (and hence generators) can be altered by varying armature resistance and field resistance. The voltage of the generator can be varied by adjusting the resistance of the generator field circuit. The phase angle between instantaneous voltages of both the machines can be measured by a synchroscope. The relay operation is sensed by sounding a buzzer when the conditions depicted above are satisfied. While checking one condition, other conditions should be kept constant. When the difference of voltage magnitude of two machines at which synchro-check relay operates is to be checked, the frequency of two machines must be kept constant. For checking frequency difference, voltage magnitudes must be kept constant. While checking phase-angle difference, the voltage and frequency both must be maintained constant.

Under-frequency relay operates or drops off when frequency falls below a pre-set value. One machine is sufficient for testing under-frequency relay. Frequency can be easily changed in a laboratory set-up of Fig. 12.9 (only one machine out of the two is to be used) and operation of the relay checked.

For testing over-fluxing relay, V/f ratio is to be changed. Using one machine out of the two as shown in Fig. 12.9, the voltage and frequency both are so varied that V/f ratio is just above the pre-set ratio. The operation of the relay is sensed by sounding a buzzer. The time-delay can be checked by a timer (not shown in the circuit).

12.3.6 Negative-Phase Sequence Current Relays

There are several versions available for negative-phase sequence relays. One version of the NPS current relay is tested by supplying the phase currents I_R and I only as at balance,

$$I_R + I + I_B = 0$$

For such a relay, a test circuit as shown in Fig. 12.10 can be used. The magnitude of current to be injected can be found out by analysis as follows:

$$I_2 = 1/3(I_R + a^2 I + a I_B)$$

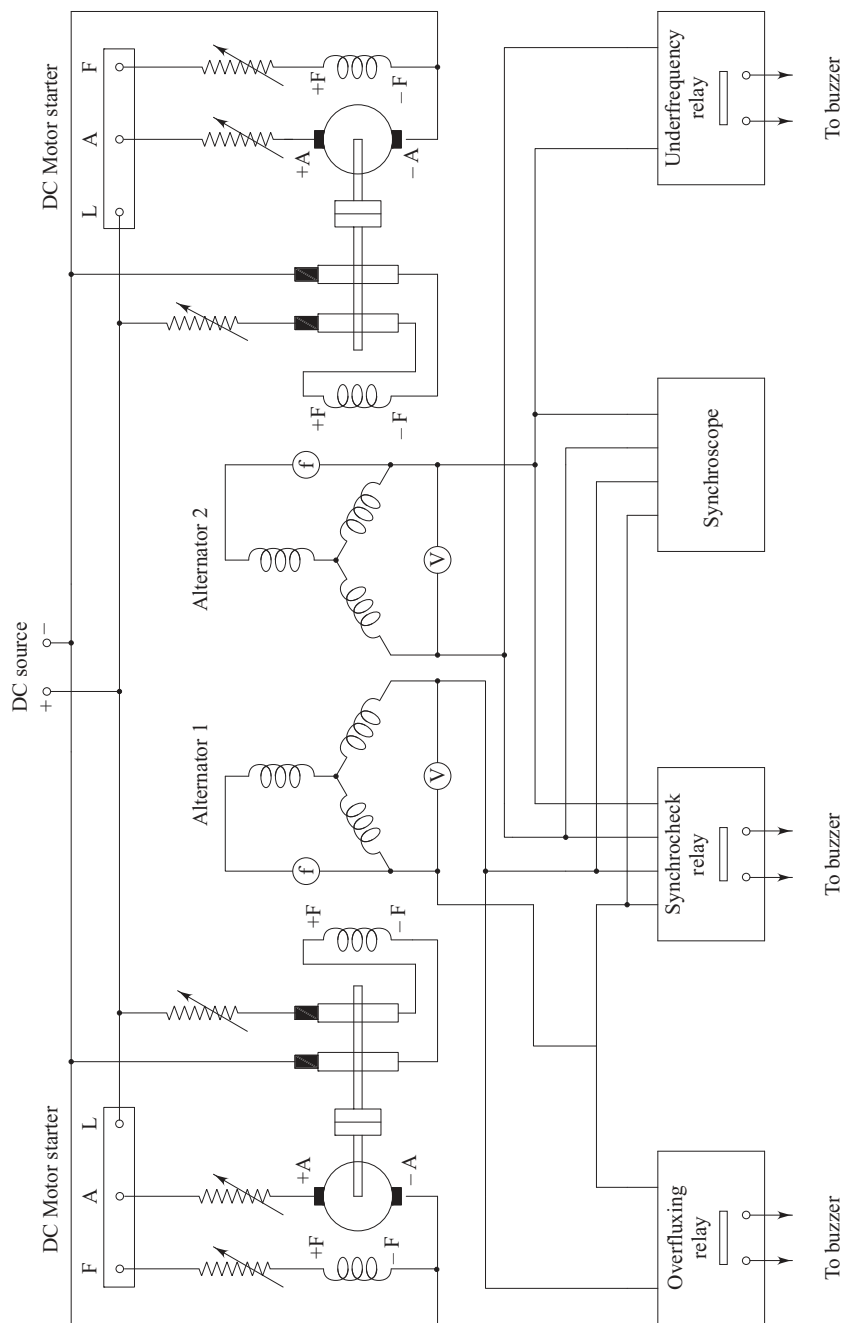


Fig. 12.9 *Circuit arrangement for testing overfluxing, under-frequency and synchrocheck relays*

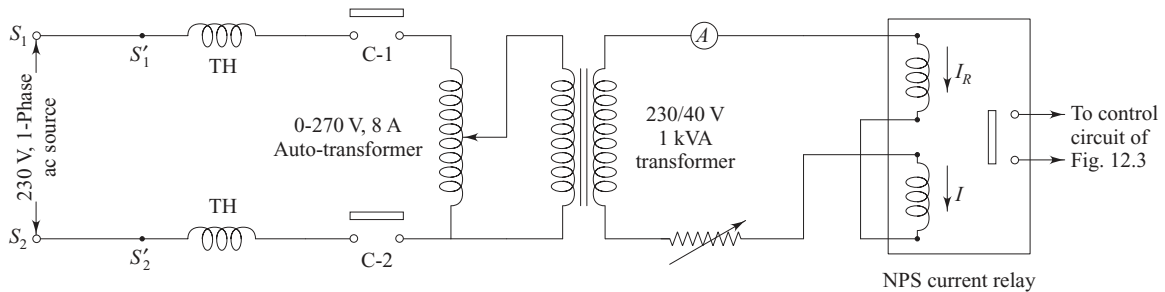


Fig. 12.10 Test circuit for testing NPS current relay

Referring to Fig. 12.10,

$$I_B = 0, I = -I_R = -I$$

Thus

$$I_2 = (1/3) \times I \times (1 - a^2) = (1/3) \times I \times (\sqrt{3} \angle 30^\circ) = (1/\sqrt{3}) \angle 30^\circ$$

With reference to magnitude, the current to be injected,

$$I = \sqrt{3} I_2$$

For a 1 A relay ($I_n = 1A$) and $I_2/I_n = 0.6$,

$$I = \sqrt{3} \times 0.6 \times 1A = 1.04 A$$

Thus by injecting this current of 1.04 A, we can check the time of operation for $I_2/I_n = 0.6$. For measuring time and for contactor control, the circuit of Fig. 12.3 can be used.

In another version of an NPS current relay, current juices of three line CTs are processed to filter negative-phase sequence current. For such a case, three-phase supply is to be used and the phase sequence is to be intentionally reversed (R-B-). Ammeters can be placed in all the three phases as shown in Fig. 12.11. The NPS current v/s time of operation can be directly measured (using control circuit 12.3), as the ammeter reads 100% NPS current. While testing, rheostats should be so adjusted that $I_R = I = I_B$ and $I_N = 0$. In this case R, and B currents are balanced negative-phase sequence currents.

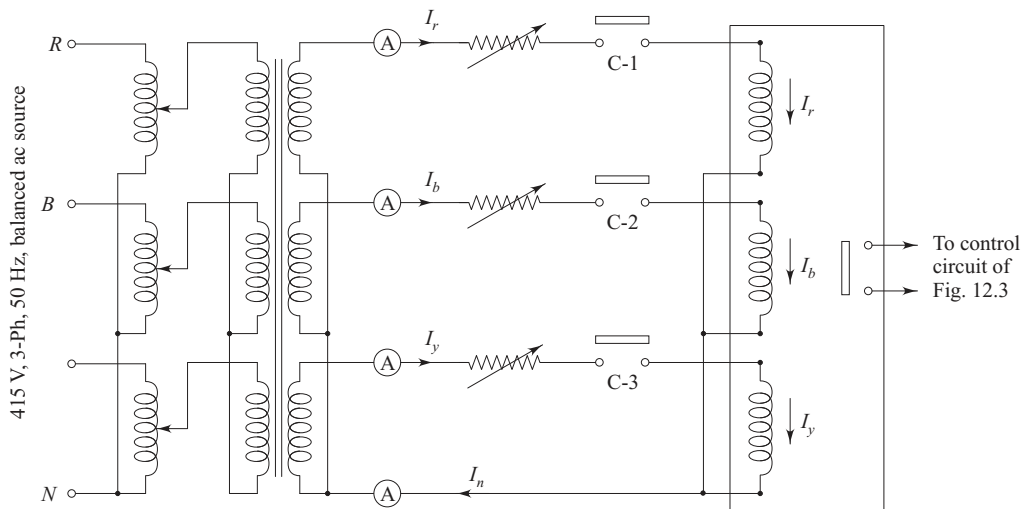


Fig. 12.11 3-phase test circuit for testing NPS current relay

12.3.7 Zero-Sequence Voltage-Measurement Relays

Zero-sequence voltage-measuring relays are used for detection of an earth-fault in a non-effectively grounded system. Both the versions, definite time and inverse time are available. The test circuit for testing such a relay is given in Fig. 12.12. Time measurement circuit is same as that of Fig. 12.3. If the relay as shown in Fig. 12.12 is fed with three phase voltages V_R , V and V_B , under normal conditions $V_R + V + V_B = 0$. Hence the output signal at the open delta connected secondaries of the three input transformers is zero. Thus the relay does not operate. In case of an earth-fault, $V_R + V + V_B = 3V_0$. This zero sequence voltage is fed to the measuring circuit of the relay and the relay finally operates at the end of the set time or time as per relay characteristic.

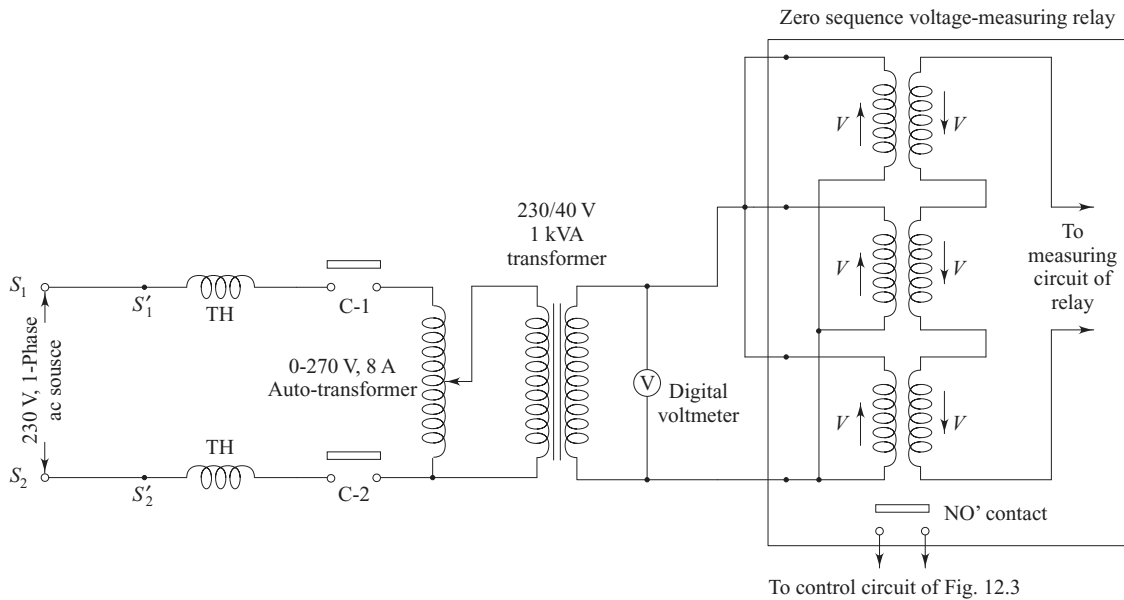


Fig. 12.12 Test circuit for testing zero sequence voltage measuring relay

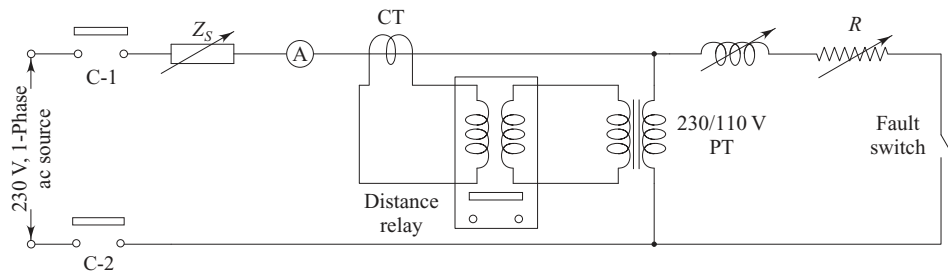


Fig. 12.13 Principle of testing a distance relay

In Fig. 12.12, single-phase voltage is fed to primaries of all the three input transformers in parallel. Thus the voltage fed to relay measuring circuit is three times the voltage read by the digital voltmeter. The relay operation and its characteristic can be tested by measuring the voltage at which the relay picks up and the time of its operation (measured by timer of Fig. 12.3).

The test set-up is shown in Fig. 12.14. The test bench consists of the following:

1. Contactor C, with manual closing and adjustable time-delayed automatic opening. The relay under test with given setting should operate or restrain within this time lag.
 2. Source impedance Z_s , which is a variable air-cored inductive reactance to simulate the source side reactance of the actual power system network.
 3. Current transformers to inject the required current to the relay under test. These CTs have adjustable ratios.
 4. Switch S_1 is controlled by a point-on-wave switching arrangement. The relay under test can be fed suddenly by fault current and/or voltage by closing the primary circuit by the switch S_1 . The sudden closure simulating inception of a fault is made effective through a controlled thyristor switch. The thyristors are tuned on at any pre-set instant of current waveform. The duration of current flow through primary circuit can be regulated by an adjustable timer operated contactor C, which breaks the current at the end of the pre-set time.
 5. Variable X_L and variable R simulate the fault impedance.
 6. S_2 is a fault switch.
 7. Shunt resistors Sh are provided to connect the CRO across them. As the transient behavior of the relay under test is to be checked, good recording arrangement (either storage oscilloscope or oscillograph with photographic attachment) is indispensable.
 8. X_n and R_n represent neutral impedance.
 9. The relative phase displacement between the test current and test voltage is created with the help of phase shifter PS, which supplies a variable ratio PT.
 10. The current juices are fed to the relay by CTs and potential juices by PTs.
- Thus the dynamic behavior of the instantaneous relays can be studied using this test bench.

12.5 REQUIREMENTS FOR TESTING OF STATIC RELAYS

Transient voltages of short duration but of relatively high peak values may influence the relay circuit(s). These transient voltages can be generated by any sudden change of circuit condition, such as closing a switch in the auxiliary circuit or operating a line circuit breaker or isolator and can also be generated by switching within the relay itself. They can be transmitted to the relay through conductors; capacitive, inductive or magnetic coupling; or through earth paths. The transient voltage may appear across the relay circuit terminals, between circuits and earth or between normally isolated circuits. To cover different field conditions, three levels of test voltage, namely, Class I, Class II and Class III have been specified. There may be sources of generation that will produce voltages higher than 5 kV at the relay. These should be reduced at the source of generation to the level of voltage appropriate to the class declared by the manufacturer of the relay.

The static relays shall conform to IS 3231-1965 in addition to the requirements laid down in the standard (IS 8686-1977).

Test Voltage Classes

Class	Impulse Voltage withstand Test	High Frequency Disturbance Test
I	Zero	Zero
II	1 kV peak	(a) Longitudinal mode 1 kV peak value of first half cycle (b) Transverse mode 2.5 kV peak value of first half cycle
III	5 kV peak	(a) Longitudinal mode 2.5 kV peak value of first half cycle (b) Transverse mode 1 kV peak value of first half cycle

12.6 RECOMMENDED APPLICATION OF TEST VOLTAGE CLASSES

Class I (No Test 0 kV) Relays of this class are exempted from the transient voltage test. Where a relay is used as part of a protective equipment, it is not necessary to apply a withstand test voltage to the relay since the equipment will be tested in accordance with its own class.

Class II (Test with 1 kV) Relays or relay circuits with a Class II test voltage level may be used where

- (a) the auxiliary circuits (power supply circuits) of the relay are connected to a voltage supply used exclusively for the power supply of static relays. If the leads are short, and in the absence of switching on other circuits connected to the supply, the levels of transient voltage on the supply leads is low (below 1 kV);
- (b) the input energising circuits of the relays are not connected directly to the current transformers and/or voltage transformers or where good screening and earthing is employed on the connecting leads;
- (c) the output circuits are connected to a load by short lead lengths; and
- (d) normally no voltage test is required but an extra high security is needed.

Class III (Test with 5 kV) Relays or relay circuits with a Class III test voltage level may be used where

- (a) the auxiliary energising circuits (power supply circuits) of the relay are connected to station batteries. Due to long lead lengths, longitudinal transient voltages of a relatively high value may appear on the supply leads and transverse voltages may arise from switching in other circuits connected to the same battery or supply source;
- (b) the input energising circuits of the relays are not connected directly to the current transformers and/or voltage transformers or where long lead lengths are involved and no effective screening and earthing is employed;
- (c) the output circuits are connected to a load by short lead lengths with the result that longitudinal transient voltages of a relatively high value may appear at the output terminals; and
- (d) normally a lower test voltage, mentioned in the previous section, is sufficient but an extra high security is required.

A relay may have different test voltage classes for its input energising circuits, auxiliary energising circuits and output circuits.

12.7 TESTS

12.7.1 Impulse Voltage Withstand Test

An impulse voltage withstand test is performed to determine whether the relay and its individual components will withstand high voltage surges of short duration without damage.

For the withstand test, the impulse voltage is an aperiodic transient voltage without appreciable oscillations.

Test-Circuit Conditions

(a) Impulse waveform	This shall be the standard 1.2/50 μ s impulse as specified in IS 2071 (Part II) – 1974 and having the following tolerances: Voltage rise time = ± 30 per cent Voltage fall time = ± 20 per cent
(b) Source impedance	500 ohms with a tolerance of ± 10 per cent

(c) Source energy	0.5 J with a tolerance of ± 10 per cent
(d) Standard value of test voltage	As specified in 12.5 for the appropriate class. The test voltage levels are the voltages at the output of the test circuit before the relay is connected to the test circuit terminals.
(e) Test-voltage tolerance	+0 –10 per cent
(f) Impulse generator circuit	The recommended standard test circuit is shown in Fig. 12.15. The test leads shall not be longer than 2 m.

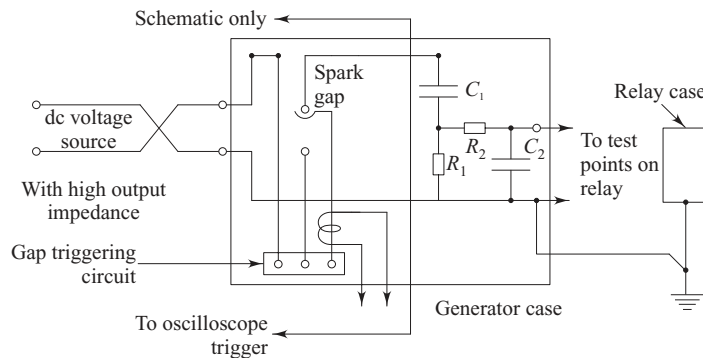


Fig. 12.15 Circuit for impulse generator

Table of Fig. 12.15

Component	Test Condition	
	5kV	1kV
R_1	1800 ohms	180 ohms
R_2	500 ohms	500 ohms
C_1	0.035 μF	0.6 μF
C_2	0.0008 μF	0.0008 μF

Test Procedure

1. Impulse test shall be regarded as a type test only.
2. Three positive and three negative impulses shall be applied at intervals of not less than 5 seconds.
3. The impulse test shall be carried out as follows to the appropriate points of the circuit under test which are accessible from outside the case, the other circuits and the accessible metal parts of the relay intended to be earthed being connected together and to earth
 - (a) between all terminals connected together and earth,
 - (b) between all independent circuits of the relay with the terminals of each independent circuit connected together, and
 - (c) between all independent circuits of the same circuit except contact circuits.

It is not always necessary to carry out the impulse voltage withstand test between open metallic contacts. The requirement should be agreed between manufacturer and user, and the manufacturer should assign to the contact circuit a test-voltage class. Where energising circuits (inputs and auxiliary) and output circuits of different test voltage classes are present on the same relay test as given above, the test is carried out at the assigned class voltage of the circuit. All other tests are carried out at the highest class voltage assigned to any circuit within the relay.

4. The test shall be carried out with all energising and auxiliary energising quantities disconnected from the relay.

Criteria for Acceptance

1. After the test, the relay shall still comply with all relevant performance requirements specified in IS 3231–1965. A flashover (capacitance discharge) is not necessarily a criteria of failure as this may occur in a position that does no damage and the manufacturer shall decide whether or not to eliminate the cause, provided other criteria of acceptance are met.
2. The impulse test is designed as a type test and should not normally be made on production relays. Since repeated stressing may reduce the performance and/or life, any impulse tests, which are carried out after the relays leave the manufacturer's works should be limited to a maximum of 60 per cent of the class voltage assigned by the manufacturer.

12.7.2 High-Frequency Disturbance Test

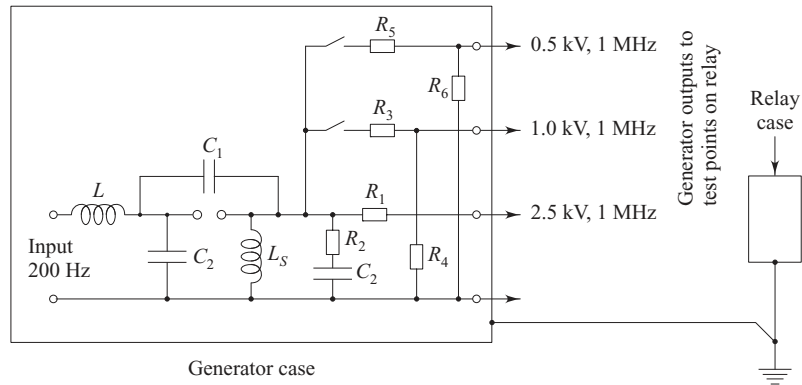
The high-frequency disturbance test is recommended in order to determine whether a relay will operate in a faulty manner when specified high-frequency transients, which are representative of practical system conditions, are applied to a fully energised relay.

Test-Circuit Conditions

(a) Waveform	A damped oscillatory wave with the envelope decaying to 50 per cent of peak value at the end of 3 to 6 cycles.
(b) Frequency	1.0 MHz with a tolerance of ± 10 per cent
(c) Source impedance	200 ohms with a tolerance of ± 10 per cent
(d) Repetition rate	The test wave is supplied to the relay under test at a repetitive rate of 400 per second.
(e) Duration of test	2 seconds with a tolerance of $+10$ per cent -0
(f) Standard value of test voltage	As specified in 12.5 for the appropriate class. The test-voltage levels are the voltages at the output of the test circuit before the relay to be tested is connected to the test-circuit terminals.
(g) Test voltage tolerance	$+0$ per cent -10
(h) Impulse generator circuit	The recommended standard test circuits are shown in Figs 12.16, 12.17 and 12.18. The test leads shall not be longer than 2 m.

Table of Fig. 12.16

$L = 26 \text{ H}$	$C_s = 4 \text{ nF}$	$R_2 = 100 \Omega$	$R_5 = 1000 \Omega$
$C_1 = 20 \text{ nF}$	$C_2 = 80 \text{ pF}$	$R_3 = 500 \Omega$	$R_6 = 250 \Omega$
$L_s = 6.3 \text{ nF}$	$R_1 = 200 \Omega$	$R_4 = 333.3 \Omega$	



Note 1 - The UHF filter $R_2 C_2$ is optional as determined by experiment.
 Note 2 - If oscilloscope is connected in circuit for checking output parameters, it should be switched out of circuit when applying test to the relay for safety reasons.

Fig. 12.16 Circuit for damped oscillatory wave generator

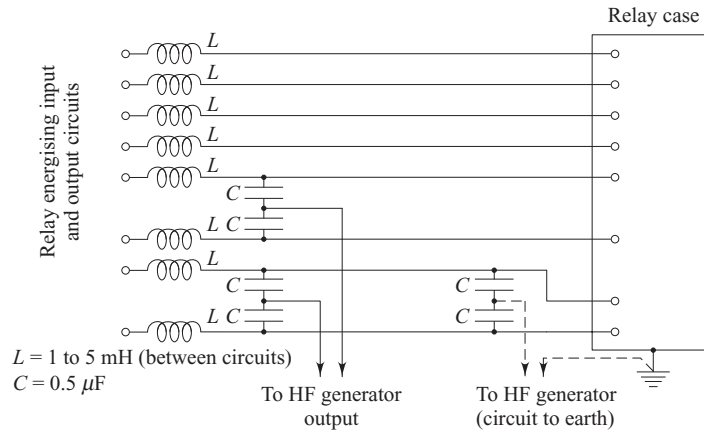


Fig. 12.17 Coupling circuit for HF disturbance test-longitudinal mode

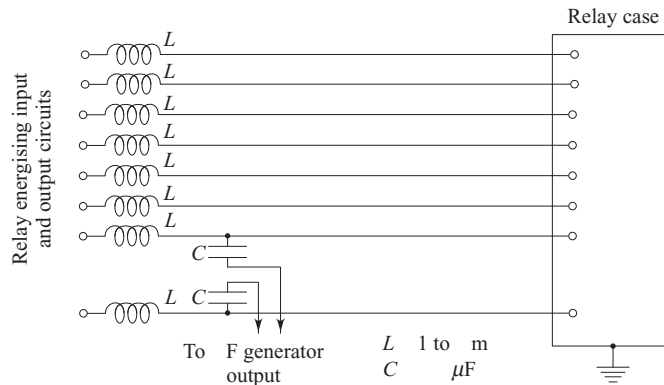


Fig. 12.18 Coupling circuit for HF disturbance test-transverse mode

Test Procedure

1. Disturbance test shall be regarded as a type test only.
2. The test shall be carried out with the relay under reference conditions.
3. The test shall be carried out with the following values of energising quantities (auxiliary and input) applied to the appropriate circuits

(a) Auxiliary energising quantity(ies)	Rated value(s)
(b) Input energising quantity(ies)	<i>For all or nothing relays</i> zero and rated values. <i>For measuring relay</i> rated value where appropriate (for example, frequency relays) or value(s) corresponding to setting value of the characteristic quantity as specified.

4. For measuring relays, the test shall be carried out at both below and above the operating value of the characteristic quantity.
5. The test shall be carried out as follows at the appropriate points accessible from outside the relay case with the cover in position, and the accessible metal parts of the relay being earthed
 - (a) between each set of input terminals and earth (longitudinal),
 - (b) between all independent circuits of the relay (longitudinal), and
 - (c) between terminals of the same circuit where applicable (transverse).

The test as given above is not for metallic contact circuits but should be applied to semiconductor output circuits. Where energising circuits (input and auxiliary) and output circuits of different test voltage classes are present on the same relay, the test given above is carried out at the assigned class voltage of the circuit. All other tests are carried out at the highest class voltage assigned to any circuit within the relay.

6. The test shall be carried out and the effect checked across one set of test points at the same time.
7. The test shall be carried out for a period of 2 seconds except for relays with an operating time greater than 2 seconds. It is recommended that the test be carried out with a time setting nearest to 2 seconds. Where the minimum time setting is greater than 2 seconds, it may be convenient to extend the period of application of the disturbing signal to cover this minimum time.
8. The variation due to the effect of the disturbance test should be declared by the manufacturer.

Criteria for Acceptance

1. When the characteristic quantity is set at a value equal to the claimed variation below the operating value of the characteristic quantity, the relay shall not operate during the disturbing period.
2. When the characteristic quantity is set at a value equal to the claimed variation above the operating value of the characteristic quantity, the relay shall comply with the declared performance specification and shall not disengage during the disturbing period.
3. After the test, the relay shall still comply with all relevant performance requirements specified in IS 3231-1965.

Environmental Tests The environmental tests are under consideration. For the time being, such tests shall be subject to agreement between the manufacturer and the purchaser.

MULTIPLE CHOICE QUESTIONS

1. Acceptance tests for relays are those tests which are
 - (a) performed after relays reach the customer's premises
 - (b) not compulsory to be performed
 - (c) carried out by the manufacturer
 - (d) carried out by the manufacturer in the presence of the customer at a standard laboratory
2. As per IS, for IDMT relays for the highest TMS and PSM between 4 to 20, the permissible deviation from the declared time by the manufacturer shall be within
 - (a) 12.5%
 - (b) 7.5%
 - (c) 10.5%
 - (d) 4%
3. The directional relay characteristic is
 - (a) drawn on a log-log graph paper
 - (b) drawn on a semilog graph paper
 - (c) a polar curve drawn on a normal graph paper
 - (d) plotted between voltage and current fed to a directional relay
4. The switch S used in the circuit for testing of a biased differential relay is kept open to check
 - (a) bias setting of the relay
 - (b) basic setting of the relay
 - (c) continuity of the relay
 - (d) none of the above
5. The circuit arrangement used for testing of under-frequency, overfluxing and synchrocheck relays consists of
 - (a) an open-delta secondary of a 3-phase transformer
 - (b) a 3-phase phase shifting transformer
 - (c) a single-phase auto-transformer
 - (d) two identical 3-phase alternators with their prime-movers

Protective Current and Potential Transformers

Current transformers and potential transformers are used for proportionately reducing currents and voltages respectively to values suitable to be fed to protective relays.

In all transformers, part of the primary ampere-turns (AT) produces magnetic flux, which induces the voltage on the secondary whereas the remaining primary ampere-turns balance the secondary ampere-turns.

13

In current transformers the impedance of the secondary burden is very low so that magnetising ATs are very small and the secondary ATs are less by about 1% of the primary AT.

In potential transformers the secondary impedance is very high so that the magnetising ATs are large compared with the secondary ATs but the secondary voltage is within 1% of the primary voltage (corrected for turns ratio).

Introduction

13.1 EQUIVALENT CIRCUIT AND VECTOR DIAGRAM OF A CT

Figure 13.1 shows an equivalent circuit of a CT. The primary winding of a current transformer is connected in series with the power circuit. The power-system impedance governs the current passing through the primary winding of the current transformer. The secondary current is dependent on the primary current and it will not be affected by change of the burden over a considerable range.

Figure 13.2 shows the vector diagram from which ratio and phase angle errors can be evaluated. The ratio and phase angle errors can be calculated easily if the magnetising characteristics and the burden are known.

13.2 CONSTRUCTION OF CURRENT TRANSFORMERS

Current transformers can be classified into two major types, the single-turn (bar) primary and the multi-turn (wound) primary.

In the former type, the primary conductor may form part of the CT assembly. The primary conductor, in this case, must be suitably insulated to withstand system voltage to earth where it passes through the CT core and secondary windings. The majority of single-turn primary CTs makes use of an insulated conductor

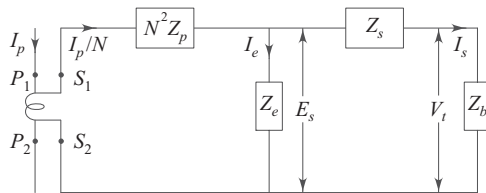


Fig. 13.1 *Equivalent circuit of a CT*

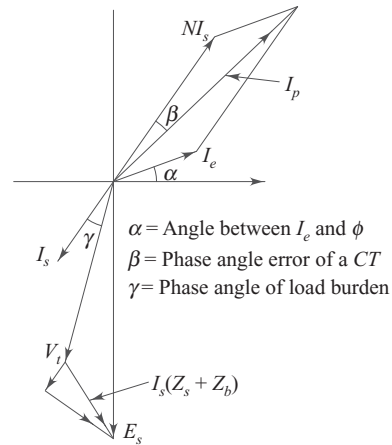


Fig. 13.2 Vector diagram of a CT

provided as part of other equipment such as bushings of switchgear or power transformers, and the CT is merely a ring core with a toroidally wound secondary winding.

Wound primary CTs have the primary and secondary windings arranged concentrically, the secondary winding being the inner winding.

The core is manufactured from hot-rolled silicon-steel stampings or, using recent techniques, from cold-rolled grain-oriented silicon steel or from nickel-iron alloy. Cores are assembled from E, I, L or C stampings. Cores of grain-oriented materials should be arranged as far as possible with the flux direction along the dipoles of the grain.

Primary windings of wound primary current transformers, usually, are of edge-wound copper strips. Insulation (to earth) for such transformers may be cast resin (for 12 kV designs). Secondary windings are usually wound from round cross-sectional enameled copper wire.

In high-voltage applications, separately mounted post-type CTs suitable for outdoor service, are frequently required for use in conjunction with air-blast or SF₆ circuit breakers. There are three forms of construction as shown in Figs 13.3(a), 13.3(b) and 13.3(c). In the CTs of the type shown in Fig. 13.3(a), the cores and secondary windings are contained in an earthed tank at the base of a porcelain insulator and the leads of the fully insulated primary windings are taken up to the top helmet. In the CTs of the type described by Fig. 13.3(b), the cores and windings are mounted midway inside the porcelain housing, with half of the major insulation on the primary windings and the other half on the secondary windings and cores. In the third type [Fig. 13.3(c)], the cores and secondary windings are housed in a live tank and the earthed secondary leads are brought down to the insulator. The major insulation may be wholly on the secondary windings and cores or partially on the primary conductor. This form of construction is particularly suitable for applications where high primary currents are involved. This form of construction eases the problems of heavy electrodynamic forces.

The major insulation of such current transformers is usually oil-impregnated paper with interleaved stress-control foils. The arrangement as shown in Figs 13.3(a), (b) and (c) contain a porcelain housing in which a mixture of a specially manufactured insulating quartz powder and oil is filled. SF₆ insulated CTs are also popular.

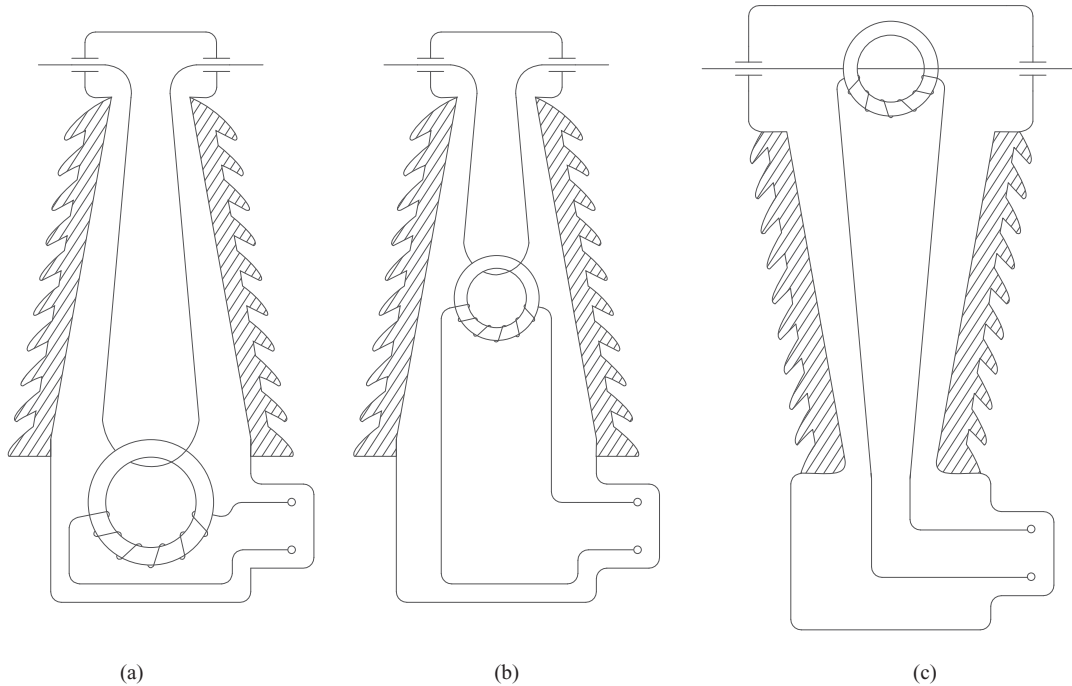


Fig. 13.3 Different constructions of high-voltage CTs

13.3 MAGNETISATION CURVE OF A CT (CT SATURATION CHARACTERISTIC)

Saturation characteristic is a plot of open-circuit voltage v/s excitation current of a CT. This curve is a very important tool for deciding whether a CT is suitable for a given application. The ratio error can also be checked using this curve. The curve can be experimentally obtained using a test set-up as shown in Fig. 13.4.

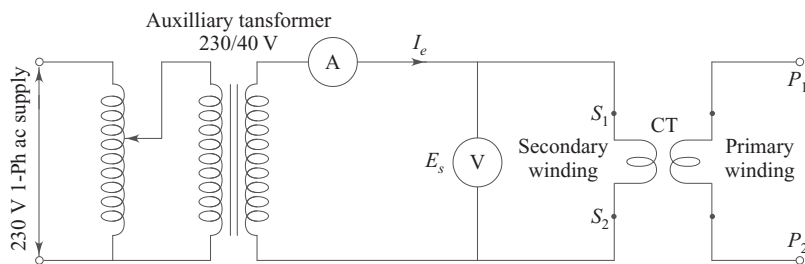


Fig. 13.4 Test set-up for obtaining CT magnetisation curve

The voltage should be gradually increased and ample number of readings for the exciting current I_e and the corresponding value of the open-circuit voltage E_s should be taken. Care should be taken to see that I_e times E_s does not exceed the rated burden of the CT. The plot of E_s v/s I_e will be as shown in Fig. 13.5. The initial non-linear region OA is due to the fact that small ampere-turns supplied is used for exciting the core (for producing flux). Hence, the CT does not reproduce the primary current on the secondary side faithfully when it operates in the region OA . Thus, at a very small percentage of the primary rated current, the CT ratio error is

large. Region AB of the curve is linear in which the CT should be operated. In the further knee region, the CT again behaves non-linearly. Point K is known as the 'knee-point' and is defined as the point at which an increase of 10% in the open-circuit voltage results in an increase of 50% in the exciting current.

The excitation characteristic of a CT depends upon the cross-sectional area and length of the magnetic path of the core, the number of turns in the windings and the magnetic characteristics of the core material. Figure 13.6 shows typical magnetisation curves for three core materials commonly employed in current transformers, viz.,

- (a) hot-rolled non-oriented silicon steel,
- (b) cold-rolled oriented silicon steel, and
- (c) nickel-iron core.

It will be seen that at low densities (a) has the lowest permeability and (c) has the highest permeability, whereas (b) has extraordinarily high flux densities. If a core of cold-rolled silicon steel is used, the accuracy would be reasonably good, up to 10 to 15 times the rated current. However, it does not produce accuracy as good as the CT with nickel-iron core for currents equal to and below five times the rated current.

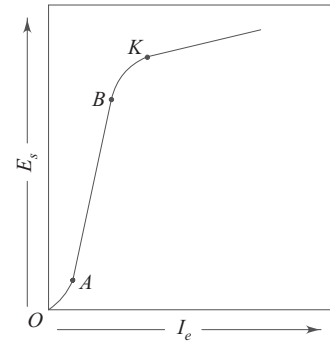
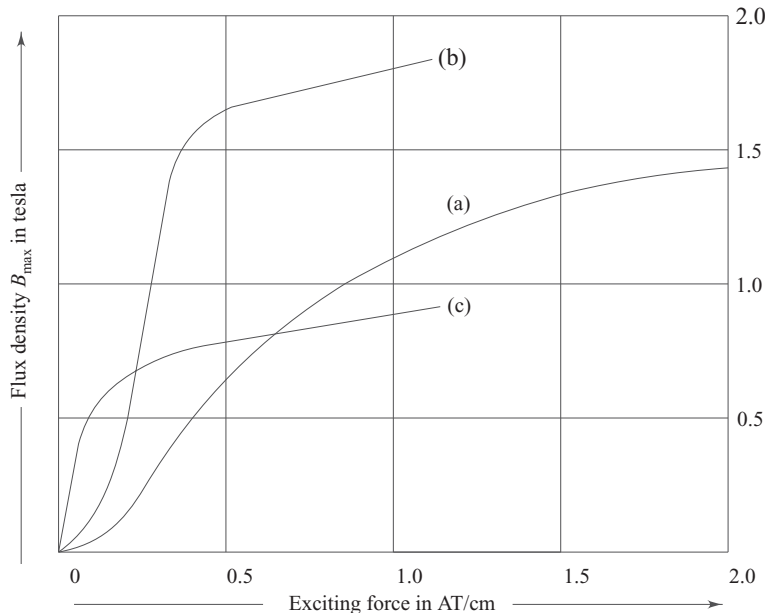


Fig. 13.5 Saturation characteristic of a CT



- (a): Hot-rolled non-oriented silicon steel (for protection)
- (b): Cold-rolled oriented silicon steel (for protection)
- (c): Nickel-iron (80% nickel) (for measurement)

Fig. 13.6 Typical magnetisation curves

13.4 DIFFERENCE BETWEEN CT CORES USED FOR MEASUREMENT AND THOSE USED FOR PROTECTIVE RELAYS

When a CT is required to step down the primary current to a value suitable for ammeters or current coils of wattmeters, energymeters, etc., two basic requirements are to be satisfied.

- (i) The error of the CT should be 0.5% or 1.0%, i.e., it should transform the current with good accuracy. Otherwise, the measurement will be incorrect. Particularly in wattmeters if the CT and PT both have a 5% error, the cumulative error may be as high as 10%.
- (ii) The CT must not faithfully transform the fault current as otherwise the measuring instrument will be damaged.

The nickel-iron cores are used in CTs used for measurement. The cross-sectional area of the core is normally small. Saturation flux density is less. When the primary current exceeds the rated primary current, the core will saturate and the secondary current, hence, will be limited to a value that will not endanger the instruments.

When a CT is used for feeding protective relays, faithful reproduction of primary current right up to maximum possible fault current is an essential requirement, because otherwise the relays will get wrong information leading to delayed operation or even non-operation. For this requirement to be satisfied, cores of cold-rolled grain-oriented silicon steel are used for protective CTs. Moreover, cross-sectional area of core is large; CT cores have high knee-point voltage. A CT must not saturate for the worst possible fault current. Accuracy is not as important as metering CTs, and errors up to 10% are tolerable. It is rarely necessary to determine phase-angle error of a CT used for relaying purposes. One reason is that the load on the secondary of a CT is generally of such highly lagging power factor that the reversed secondary current is practically in phase with the exciting current. Hence the effect of the exciting current on the phase-angle accuracy is negligible. Furthermore, most relaying applications can tolerate this phase-angle error which for metering purposes would be unacceptable.

13.5 CT ERRORS

13.5.1 Errors due to Magnetising Current

It is known that

$$I_p = N \times I_s + I_e$$

I_e is a function of the core flux ϕ , which is proportional to E_s , the secondary emf. Since this E_s drives the secondary current through the secondary burden, I_e is proportional to $(Z_s + Z_b)$. Hence, the CT error is a direct function of the total CT secondary burden. This error is smaller at currents and fluxes below the magnetic saturation level of the core. Hence, the impedance of the relay and the secondary leads should be kept low enough such that the secondary voltage does not cause the CT core to saturate even at high fault currents.

Saturation can be avoided either by increasing the cross-section of the iron cores of the CT or by reducing the burden. The burden on the CT is due to resistance of the relay, the CT secondary and the leads. The lead burden can be reduced by using a lower secondary current rating. For example, when the control room is far from the switchyard (of the order of 1 to 1.5 km), the CT secondary current should be 1 A.

13.5.2 Effect of Saturation

When the CT saturates, there is no induced emf, because of which the secondary current is zero. This leads to wrong zero crossing. Hence, a phase-comparator relay would mal-operate. Moreover, for an inductive load,

the amplitude of the secondary current is also reduced which gives rise to a large ratio error. For an inductive load, with respect to Fig. 13.2 the angle γ will increase which will increase I_p , thus, resulting in a large ratio error.

13.5.3 Effect of Remanance in Iron Core

The CT core may saturate prematurely at currents well below the normal saturation level due to presence of the residual flux. Cold-rolled silicon steel, which is favoured because of its high saturation flux density, suffers from high residual flux.

Since the circuit breakers tend to interrupt the current as it passes through zero, the amount of residual flux left in the CT core depends upon the phase angle of the secondary burden. With a purely inductive burden, the voltage will be the maximum at the instant of current zero and the flux will be zero. Hence, there will be no residual flux. With a purely resistive burden, the voltage will be zero and hence the flux will be the maximum at the instant of current zero. This will result in maximum flux.

Most electromagnetic relays impose a burden impedance with a phase angle of about 60° lag, so that the residual flux is approximately 50% of its maximum value; whereas static relays impose a resistive burden, and hence the maximum remanance will be present in the CT used. This may give rise to inaccurate operation of the relay.

The investigations have shown that the decay of the flux is negligible after the first 30 seconds, and therefore high residual flux densities can remain indefinitely in spite of the demagnetising effect of the ac flux due to the load current.

13.6 CALCULATION OF CT ACCURACY

Referring to Fig. 13.1, I_p/N is the primary current referred to the secondary. Part of this current is used in exciting the core and the remainder is the secondary current. The relation between I_e (secondary excitation current) and E_s (secondary excitation voltage) is shown in Fig. 13.5. The total burden impedance is composed of the effective resistance and the leakage reactance of the secondary winding, lead burden and the impedance of the load. The primary winding impedance Z_p , does not affect the ratio of a CT

If the curve as given in Fig. 13.5 is available for a given CT and the impedance of a secondary winding of the CT is known, the ratio error can be determined for any burden. The procedure for calculating the ratio error is described as follows:

1. Assume a magnitude of secondary current, e.g., for a 1000/5 A CT, one can start assuming secondary currents like 1, 2, 3, 4, 5, 6, 10, 15, 20, 30 A and so on, upto the value of the secondary current up to which the accuracy calculation is desired.
2. E_s is equal to $I_s(Z_s + Z_b)$. Z_b consists of a lead burden and a load burden. The lead burden is practically resistive, whereas the power factor of a load burden depends upon the type of the relay. If the application is known, the actual vector addition of the lead and load impedances can be done. Otherwise one can make arithmetic additions.

Similarly, the secondary impedance of a CT (Z_s) may be assumed to be the dc resistance. The secondary leakage reactance is a variable quantity depending upon the construction of the CT and on the degree of saturation of the CT core. For the CTs with a completely distributed secondary winding, the secondary leakage reactance is so small that it can be ignored. For the CTs where the secondary winding is not distributed, leakage flux cannot be omitted. Also, even though the total secondary winding may be completely well distributed, tapped positions (in multi-ratio CT) of this winding may not be well distributed.

3. For this value of E_s , the secondary excitation current I_e is read from the curve of Fig. 13.5.
4. Adding I_e to I_s gives I_p/N . It should be noted that adding I_s arithmetically to I_e may give a ratio error slightly higher than the actual value.
5. I_p/N is to be multiplied by N (marked or nameplate ratio of the CT) to give I_p . This value of I_p will produce the assumed value of I_s .
6. The ratio correction factor will be $I_p/N I_s$. The ratio correction factor is defined as that factor by which the marked ratio of a CT must be multiplied to get the true ratio. The ratio correction factor is always greater than unity.

By assuming several values of I_s and obtaining the ratio correction factor for each, the ratio-correction-factor curve (Fig. 13.7) can be plotted for a given load burden. Usually, a family of such curves (not shown in the figure) can be provided by a manufacturer for different values of the load burden.

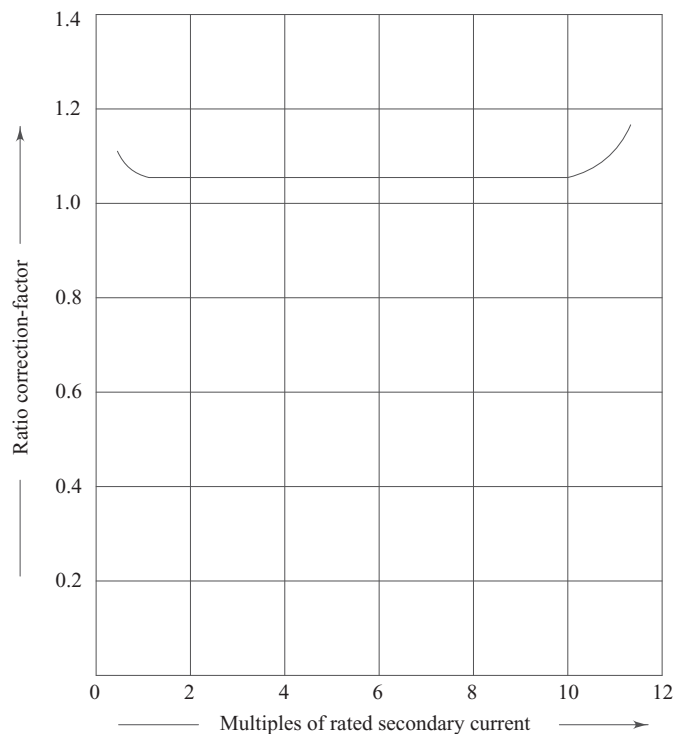


Fig. 13.7 Ratio-correction factor curve of a CT

This method of calculation of CT accuracy gives realistic results up to a ratio error of 10% or less (ratio correction factor = 1.10). When the ratio error appreciably exceeds this value, the waveform of the secondary excitation current and hence of the secondary current is distorted because of saturation of the CT core.

13.7 FACTORS TO BE CONSIDERED WHILE SELECTING A CT

The following factors are to be considered while selecting a CT for a given application.

13.7.1 Accuracy Class

CT accuracy is defined in terms of departure from the true ratio. It is expressed as

$$\% \text{ error} = (NI_s - I_p)/I_p \times 100$$

The accuracy varies with the secondary burden and is also dependent upon the saturation flux density of the core.

For many relays, an accuracy of $\pm 10\%$ to $\pm 15\%$ is acceptable. For example, in case of IDMT overcurrent relays, the accuracy is less important, particularly at high currents as the time of operation of the relay is practically constant. On the other hand, with distance and differential relays, a CT accuracy of $\pm 3\%$ to $\pm 5\%$ is desirable.

CT errors can also be expressed in terms of composite error.

$$\text{Composite error} = 100/I_p \sqrt{1/T \int_0^T (N \times i_s - i_p)^2 dt}$$

where,

I_p = rms value of rated primary current

i_s, i_p = instantaneous values of rated secondary and primary currents, respectively

T = time period of one cycle in seconds

CT accuracy classes are symbolised by classes 5P, 10P, 15P, etc., where the number indicates a composite error and letter *P* means a protective class CT.

13.7.2 Rated Secondary Current

When the lead resistance is large (i.e., the CT is far from a relay, e.g., protecting a transformer which is about 0.5 to 1 km away from the control room), a rated secondary current of 1 A is used. For indoor applications (e.g., for protecting a generator), secondary ratings of 5 A are preferred. This selection has a reference to the burden. For instance, if the CT is required to supply relays taking 10 VA through a lead resistance of 0.1 ohm, the total burden at 5 A is $(10 + 5^2 \times 0.1)$ or 12.5 VA. If, however, the lead resistance, due to long distance between the CT and the relays is 2 ohms, the total burden requirement will be $(10 + 5^2 \times 2)$ or 60 VA. Such a CT will be excessively large and expensive. By using a 1 A secondary rating, the burden requirement reduces to $(10 + 1^2 \times 2)$ or 12 VA, which can be provided by a CT of reasonable size and cost.

A 1-A CT secondary current, however, should not be used indiscriminately particularly with CTs having high primary current as they require an increased number of secondary turns, increase in dimension and cost. Moreover, the problem of increased transient and secondary open-circuit voltages is pronounced in such CTs.

While using interposing CTs also, the burden imposed by these CTs on the main CTs should be accounted for.

13.7.3 Accuracy Limit Factor

Protective CTs are required to faithfully transform maximum possible fault currents. This value of the fault current can be calculated by assuming a three-phase bolted short-circuit immediately following a CT location. Accuracy Limit Factor (ALF) is given by

$$\text{ALF} = \text{Maximum Fault Current} / \text{Rated Primary Current}$$

A CT is so often specified as 15 VA, 5P10 where 15 VA denotes burden, 5 denotes composite error and 10 is the ALF.

13.7.4 Short-Time Current Rating of the Transformer

Short-time current is the maximum fault current that a CT can withstand for a short duration of time. This current is to be decided by the following factors:

1. The rms value of the fault current for a short time period
2. The duration for which fault current may persist
3. Peak asymmetric value of the fault current
4. Transient voltage at the instant of fault occurrence and the instant of extinction of arc by a circuit breaker

The first two factors constitute the thermal limit. The more the fault current and greater is the time period specified; the larger will be the primary conductor cross-section.

The peak value of the asymmetric fault current imposes the mechanical limit. The electrodynamic force produced depends upon this peak value, the number of primary turns and the configuration of the coil. For this reason, a single turn primary winding with a coil configuration as shown in Fig. 13.3(c) makes a mechanically stronger CT. Lower the class of accuracy, the burden and ALF, the stronger the transformer can be made mechanically. Conversely, the higher the burden, the better the accuracy requirement and higher ALF, larger will be the size of the CT. The CT in this case will be little difficult to construct and will be more costly.

With reference to transient voltages generated, a bar primary is preferred. Also, the graded insulation is used on the primary conductor with reference to open-circuit secondary voltage. A 1000/5 A CT is preferred over a 1000/1 A CT as in the second case, higher peak voltages are produced when the secondary is open circuited.

13.7.5 Knee-Point Voltage

The requirement for knee-point voltage is different for different types of protective relays. This will be discussed later. Generally speaking, the knee-point voltage should not be less than the maximum voltage induced in the secondary with the highest fault current.

13.7.6 Burden

The burden of measuring instruments such as ammeter, current coils of wattmeter, energymeter, p.f. meter, etc., is approximately 5 VA each for a 5 A secondary rating of the CT. The burden of protective relays is always specified by the relay manufacturer.

The burden of a control cable (2.5 mm^2) is around 20 VA for a 5 A secondary rating and about 1 VA for 1 A secondary rating, for a 100 metre length.

13.8 PROBLEMS ENCOUNTERED IN CT

There are certain problems to be considered while applying the CTs for protection.

13.8.1 Open-Circuit Secondary Voltage

In the introduction of a current transformer, it is discussed that the emf induced in the secondary winding is that required to drive the secondary current through the load impedance and the excitation is provided by a small difference between the primary and the secondary AT. With the secondary winding open-circuited, there are no secondary ATs to oppose those due to primary current and the whole of the primary ATs are used to produce an exciting flux. The core, hence, gets saturated on each half-wave of the current. Typical flux and induced emf wave shapes for these open-circuited secondary conditions are shown in Fig. 13.8. The figure

clarifies that a peaky shape of the induced emf E_s is found because of higher rate of change of flux at zero crossing of the current I_p .

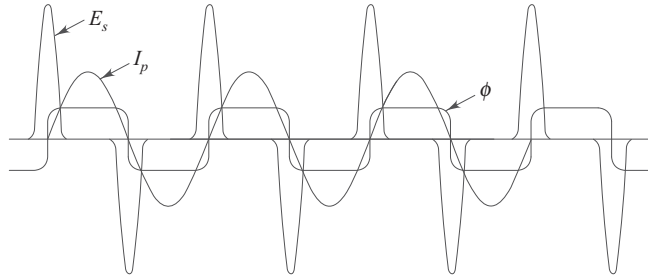


Fig. 13.8 Wave shapes of CT primary current I_p , core flux ϕ and CT secondary emf E_s under the condition of open-circuited secondary

With the rated primary current and 5 A CT secondary rating, this value may not be much harmful in a measuring CT, but for a 2000/1 A protective CT with a large core-section, the peak value of E_s might reach a value of many kilovolts. Moreover, under the fault condition even higher peaks are encountered. Such high voltages are not only harmful to the CT secondary insulation and insulation of the control cable but also pose danger to the operating technical staff.

When the relays and ammeters are removed, an arrangement is to be provided both by the relay manufacturer or instrument manufacturer such that the CT secondary is automatically short-circuited to prevent the problem of high peaks of induced emf.

13.8.2 DC CT Saturation

When a fault occurs in a power system, the fault current generally contains a transient dc component. The reproduction of such an asymmetric primary current is shown in Fig. 13.9. The flux induced because of the dc component rises to a value approximately equal to X/R times the peak ac flux if no dc component were present. No doubt, this rise is transient in nature but it nevertheless saturates the CT core. The reproduction of the primary current in secondary is not faithful and certain relays may mal-operate because of this behavior of the CT.

It can be seen that if the relays operate within half a cycle, the dc CT saturation materially does not affect the performance of the protective scheme; else the protective scheme has to wait for the dc offset to die down fully. For this reason, the modern trend in an interconnected system is to use the microcomputer-based relays as discussed in Chapter 4.

Linear Couplers Linear couplers are toroidal CTs with non-ferrous cores usually of air or plastic. The absence of iron eliminates ratio and phase-angle error due to saturation at high current (as there is practically no saturation in linear couplers). The problem of dc CT saturation is also not there with these CTs. The power output is small compared with that of an iron-cored CT, but it is adequate for any static relay. In low-voltage switchgear where the distance between phase conductors is small, the error is produced due to interference of adjacent conductor (proximity effect). Hence linear couplers are not recommended for low-voltage switchgear.

13.9 CT REQUIREMENTS FOR DIFFERENT PROTECTIVE SCHEMES

The CT requirements for major protective schemes will now be discussed.

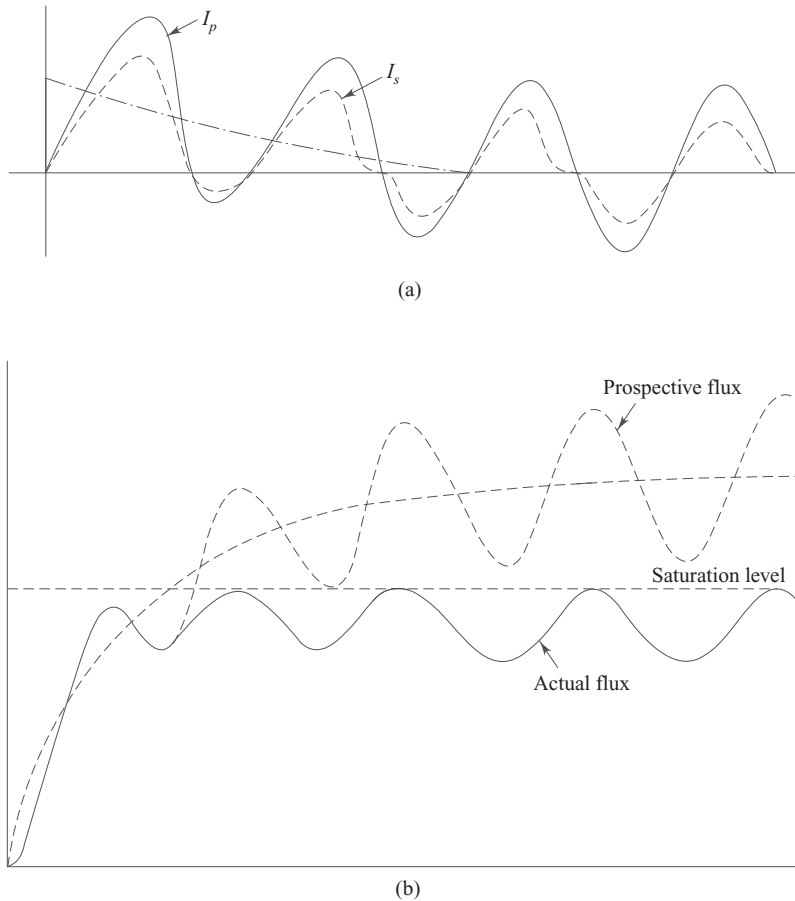


Fig. 13.9 DC CT saturation

13.9.1 Overcurrent and Earth-fault Protection

IDMT overcurrent and earth-fault relays can give correct performance only if they get the true information of the fault current. For this purpose, it is imperative that CTs feeding these relays transform faithfully up to the maximum possible fault current. This is possible if the total burden in VA at rated current of the secondary circuit is sufficiently below the output capability of the transformer. Thus, the rated burden of the CT and ALF are important factors for CTs to be used for overcurrent and earth-fault protection.

The burden of overcurrent relays usually does not create any problem, but the burden of earth-fault relays produces problems worth paying attention. An earth-fault relay, similar in design to the overcurrent relay with a burden (at 100% set current) of 3 VA, if set at 20%, would impose a burden equivalent to $(100/20)^2 \times 3$ or 75 VA at rated current.

Similarly, the primary setting of an overcurrent relay can be calculated on the basis of CT ratio but not for an earth-fault relay. For example, if an overcurrent relay is set at 75% and connected across 1000/1 A CT, the relay will pick-up when primary current exceeds 750 A. But a similar calculation is not true for an earth-fault relay, connected in residual circuit of three line CTs of 1000/1 A ratio. If it is set at 20%, it will certainly not pick-up when primary earth-fault current exceeds 200 A. This is because the secondary equivalent current has

to supply the excitation of the three line CTs. The effective setting of an earth-fault relay (20–80% of 5 A) is calculated and tabulated in Table 13.1. For calculating the coil voltage, a relay burden of 3 VA is assumed. The exciting current for this coil voltage can be read from a typical excitation characteristic of a CT (not shown). Table 13.1 shows that at 20% setting of the earth-fault relay, the primary (CTR 1000/5 A) earth-fault current at which the relay picks up is 380 A (38% of 1000 A). This analysis also reveals that a lower setting has to be applied very cautiously. Also, a 20% setting in a 20–80% range and 10–40% range does not mean the same impedance of a relay. Therefore, a higher setting range is generally suitable for most applications unless it is really very necessary to go for lower setting ranges.

Table 13.1

Relay plug setting %	I_s (A)	Coil voltage at setting (volts)	Exciting current I_e (A)	$3I_e$ for 3 CTs (A)	Effective setting (A)	$I_s + 3I_e$ %
20	1.0	3.0	0.3	0.9	1.9	38
30	1.5	2.0	0.24	0.72	2.22	44.4
40	2.0	1.5	0.22	0.66	2.66	53.2
50	2.5	1.2	0.19	0.57	3.07	61.4
60	3.0	1.0	0.17	0.51	3.51	70.2
70	3.5	0.86	0.16	0.48	3.98	79.6
80	4.0	0.75	0.15	0.45	4.45	89.0

When time-grading is done for an earth-fault relay, once again similar problems are faced. While reading the relay curve of time v/s PSM, one can read in terms of primary PSM as far as phase relays are concerned. This is not true in case of earth-fault relays. This is because the excitation curve of a CT is non-linear. Non-linearity exists below and near to plug-setting (ankle-point region of CT saturation characteristic) and also beyond knee-point (saturation region).

Referring to calculations of Table 13.1, at 20% setting, an earth-fault relay picks up effectively beyond 1.9 A. This does not mean that 3.8 A means a PSM equal to 2, and so on. The CT may actually improve in performance with increased primary current and with an input current several times greater than the primary setting. The PSM applied to the relay is appreciably greater than the multiple of primary current setting causing a shorter operating time than might be otherwise expected. Therefore, large discrimination margins should be allowed while coordinating successive earth-fault relays.

13.9.2 Differential Protection

CT requirement for differential protection scheme calls for two considerations—*in-zone sensitivity* and *external fault stability*.

For stability consideration to be met, knee-point voltage of the CTs used must be higher than (or must not be less than) the voltage across the relay operating circuit, i.e.,

$$V_k > 2 i_f (R_{ct} + R_l) \quad (13.1)$$

where,

V_k = knee-point voltage

i_f = secondary equivalent of maximum fault current

R_{ct} = resistance of CT secondary winding

R_l = lead resistance

Both the sets of the CTs used in such a protective scheme should be identical.

The knee-point voltage requirement is often expressed in terms of relay rating rather than the fault current.

The CT secondary rating and relay rating have to be same. Moreover, CT primary rating is normally matched with maximum load current of the circuit where the CT is installed. Considering maximum possible fault current to be $20 I_l$ (where I_l is the maximum load current),

$$2 i_f = 2 \times 20 \times i_l \quad \text{where } i_l \text{ is the secondary reproduction of } I_l \\ \leq 40 \times I_r$$

Hence Eq. 13.1 becomes

$$V_k > 40 \times I_r (R_{ct} + R_l)$$

where, I_r = relay rating

13.9.3 Distance Protection Scheme

The knee-point voltage recommended by M/s Areva T & D Ltd., is as follows

$$\text{For earth-faults} \quad V_k > X/R i_f (R_{ct} + R_l + 2/I_r^2 + R_r)$$

$$\text{For phase faults} \quad V_k > X/R i_f (R_{ct} + R_l + 1/I_r^2 + R_r)$$

where,

R_r = relay resistance

X/R = primary X/R ratio for a fault at the end of the first zone

i_f = secondary equivalent of maximum fault current for a fault at the end of the first zone

Other terms are known.

13.10 SPECIFICATIONS OF A CURRENT TRANSFORMER

While floating a tender enquiry, before a purchase the following items need to be specified.

1. *Type* Pedestal mounted, Bushing CT, Oil-filled, SF₆ filled or natural cooled, etc.
2. *Installation* Outdoor/Indoor
3. *Standards* (i) IS 2705
(ii) IS 4201
4. *Rated Maximum Voltage* With reference to system voltage, the following standard maximum rated voltages are known:

System Voltage (kV)	Rated Maximum Voltage (kV)
6.6	7.2
11.0	12.5
66.0	72.5
132.0	145.0
220.0	245.0
400.0	420.0

5. *Frequency* 50 Hz in India
6. *Number of phases* Usually single unit per phase is used
7. *Rated Continuous Current (Primary)* 10, 15, 20, 30, 50, 75, 100, 150, 200, 300, 500, 750, 1000, 1500, 2000, 3000, 5000, 7500, 10000 A

8. *Rated Secondary Current* 1 A or 5 A
9. *Rated Short-Time* It is recommended in IS 4201 (application guide for CT)
10. *Rated Dynamic Current* Usually 2.5 times that given at Item 9
11. *Insulation Level* Refer Table 13.2

Table 13.2

Rated maximum voltage (kV)	One minute power frequency withstand voltage		Impulse withstand (1.2/50 μ sec) voltage	
	Full Insulation (kV)	Reduced Insulation (kV)	Full Insulation (kV)	Reduced Insulation (kV)
7.2	20	—	60	—
12.5	35	—	75	—
72.5	140	—	325	—
145.0	275	230	650	550
245.0	460	395 360	1050	900 825
420	—	680 630	—	1550 1425

Full insulation values are intended for CTs for use on non-effectively grounded systems. Reduced insulation values are intended for CTs for use on systems having effectively earthed neutral.

12. *Minimum Creepage Distance* Total ____ mm
Protected ____ mm
13. *Flashover Voltage of the insulator*
14. *Service*
 - (i) Overcurrent and earth-fault protection
 - (ii) Bus zone protection
 - (iii) Distance protection
 - (iv) Differential protection
 - (v) Metering
15. *Rated CT Ratio*
16. *Accuracy Class*
 - (i) Class PS for differential, bus-zone and distance protection
 - (ii) Class 5P20 (typical) for overcurrent and earth-fault protection
 - (iii) Class 0.5 for metering core

As such, the primary winding is common and the CT has more than one core, each being used for different services. Each core can have an independent ratio, accuracy class, etc.

17. *Output Burden*
18. *Accuracy Limit Factor*

19. *Instrument Security Factor*
20. *Knee-Point Voltage*
21. *Exciting current in mA at*
 - (i) Knee-point voltage
 - (ii) 50% knee-point voltage
 - (iii) 25% knee-point voltage
22. *CT secondary resistance in ohms*
23. *Magnetisation curve, ratio and phase angle error curves and ratio correction factor curve at normal burden from 0.25 to 20 times rated current shall be demanded.*
24. *Tests*

I. Type Tests

- (i) Verification of terminal markings and polarity
- (ii) HV power frequency test on primary winding
- (iii) HV power frequency test on secondary winding
- (iv) Overvoltage inter-turn test
- (v) Error measurement
- (vi) Short-time current test
- (vii) Temperature rise test
- (viii) Impulse withstand test

II. Routine Tests (i) to (v) above

III. Special Tests

The following tests shall be carried out by mutual agreement between the purchaser and manufacturer.

- (i) HV power frequency wet withstand voltage test
- (ii) Commissioning tests
(HV dry withstand of the primary winding insulation at site)
- (iii) Partial discharge test
- (iv) Measurement of
 - (a) Knee-point voltage
 - (b) Exciting current
 - (c) Secondary winding resistance
- (v) Turns ratio test

For detailed procedure of these tests, the reader should refer to IS 2705 or the latest version thereof.

13.11 EQUIVALENT CIRCUIT OF A PT

Figure 13.10 shows an equivalent circuit of a PT. Figure 13.11 gives the vector diagram from which ratio and phase angle errors can be read.

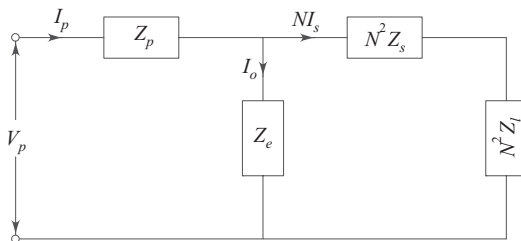


Fig. 13.10 Equivalent circuit of a PT

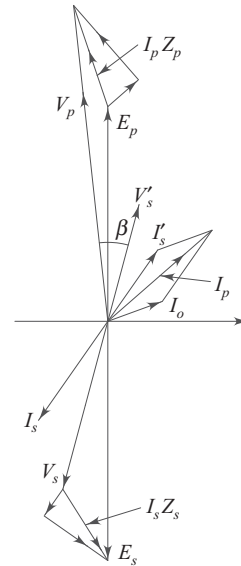


Fig. 13.11 Vector diagram of a PT

13.12 CONSTRUCTION OF POTENTIAL TRANSFORMER

There are basically the following two types of PTs:

- (i) Electromagnetic PT
- (ii) Capacitor Voltage Transformer (CVT)

Electromagnetic PT For lower voltages, up to 3.3 kV, a dry-type PT with varnish impregnated and tapped windings are generally used. For higher voltages, the core and windings are immersed in oil. The development of synthetic resin, however, has made possible HV PTs which are smaller in size and comparatively have no maintenance requirements. SF_6 gas-insulated PTs have also been introduced. A five-limbed type three-phase electromagnetic PT construction is shown in Fig. 13.12.

The conventional PT having a single primary winding becomes bulky and expensive for system voltages beyond 132 kV. In such a case, a cascade-connected PT is used. Because the primary winding is in several stages, the insulation level of each stage gets reduced, e.g., for a 6-stage cascaded PT of 400 kV rating, the insulation required per stage is about 66 kV only.

In a CVT, capacitor voltage divider is formed.

13.13 CAPACITOR VOLTAGE TRANSFORMER

At 132 kV and beyond, CVTs may be more economical than electromagnetic PTs. Moreover the HV capacitor of a CVT can also serve as coupling capacitor of a carrier equipment. Figure 13.13 shows the basic circuit of a CVT.

The primary voltage V_p is applied across the capacitive potential divider comprising C_1 and C_2 and the voltage V_{c2} is fed to the primary winding of a transformer T through a tuning inductor L which resonates approximately with $C_1 + C_2$ at the system frequency. The transformer T is often provided with taps to adjust the exact ratio required. The taps may also be provided on L to arrive at the exact tuning. V_{c2} could reach

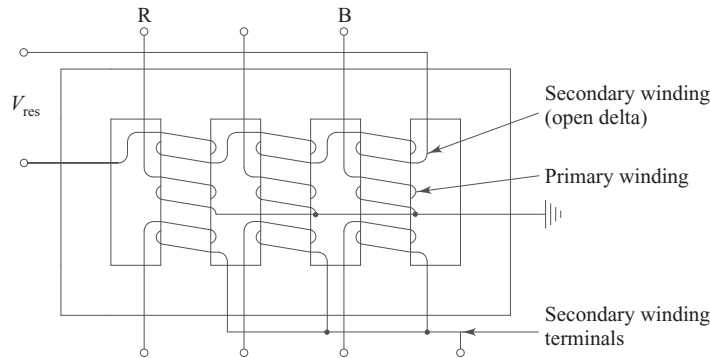


Fig. 13.12 Five-limbed three-Phase PT

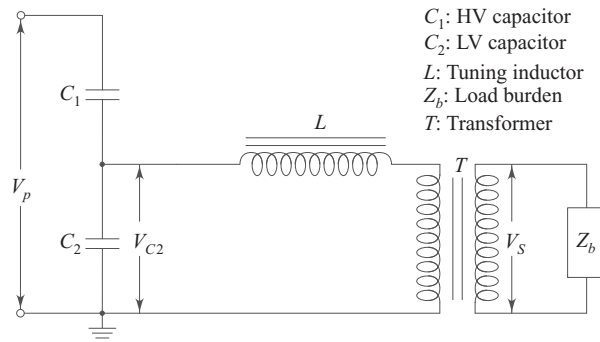


Fig. 13.13 Basic circuit of a CVT

a very high value in the event of the secondary terminals being short-circuited. V_{c2} is, however, limited by providing spark gaps connected across C_2 (not shown in Figure) or by using a saturable inductor L which saturates at currents above the rated value.

Advantages of CVT

1. Simple design and easy installation.
2. The impedance of the meter or relay coil Z_b is seen as $N_T^2 Z_b$ (where N_T is the ratio of the primary to the secondary turns of the transformer T). Thus the burden does not load the capacitive potential divider.
3. It can be used for metering, protection, power-line carrier communication and carrier current protection.

The transient performance of the CVT is not good compared to that of an electromagnetic PT. This is because when a fault occurs, the secondary voltage does not immediately fall to the fault value but goes through a decaying oscillation. For high-speed protection, transient oscillations should be minimum. Hence, cascaded electromagnetic PT is preferred to CVT.

Another problem of a CVT is the ferro-resonance effect. Owing to the non-linear nature of the exciting impedance Z_c of the transformer T , oscillation may be initiated by transients in the supply voltage. These oscillations will result in a rise in output voltage up to 25% to 50% above the normal value. Transformer T should have a large core to minimise this ferro-resonance effect. To avoid saturation, an air-gap can be

provided in the core of the transformer T . Therefore, often a suitable damping resistance is connected across the secondary winding of a transformer to damp the oscillations.

13.14 SPECIFICATIONS OF VOLTAGE TRANSFORMER

While floating the tender enquiry, the following items are required to be specified for PTs.

1. *Service* Metering and protection
2. *Type* Pedestal mounted, oil immersed or dry type, natural cooled
3. *Installation* Outdoor or Indoor
4. *Specification* I.S. 3156 (Part I, II and III)
5. *Rated Voltage* (see in CTs)
6. *Rated Frequency* 50 Hz in India
7. *Number of Phases* Generally 3 single-phase units are used
8. *Insulation* (see in CTs)
9. *Maximum Temperature Rise*
10. *Overvoltage Factor* (i) Continuous 1.1
(ii) For 30 second 1.5
11. *One minute dry and wet power frequency voltages* (see in CTs)
12. *1.2/50 μ s impulse withstand voltage test as in CTs*
13. *Minimum Creepage Distance*
14. *Rated Transformation Ratio*
15. *Rated Output in VA*

The burden imposed by voltmeter, voltage coils of wattmeter, energymeter, power factor meter, kVAh and kVARh meters, frequency meters, etc., is about 5 VA each (110 V secondary rating) and that of recording meters is about 7.5 VA each. The burden imposed by relays is specified by relay manufacturers.

16. *Accuracy*
17. *Tests*
 - I. Type Tests
 - (i) Temperature rise test
 - (ii) Lightning impulse test (1.2/50 μ s)
 - (iii) Switching impulse test (250/2500 μ s) for PTs of voltage rating 420 kV and above
 - (iv) HV power frequency wet withstand test on outdoor PTs up to and including a voltage rating of 245 kV
 - (v) Determination of errors
Additional type tests for CVTs
 - (vi) Ferro-resonance test
 - (vii) Transient resonance test
 - (viii) Verification of accuracy
By mutual agreement between the purchaser and the manufacturer, the following more type tests can be conducted.
 - (ix) Chopped lightning impulse test

(x) Short-circuit withstand capacity test

II. Routine Tests

(i) Verification of terminal marking and polarity

(ii) Power frequency dry withstand test on primary winding

(iii) Power frequency dry withstand test on secondary winding

(iv) Partial discharge measurement (not in CVT)

(v) Determination of errors

Additional routine tests for CVT

(vi) Power frequency withstand test on capacitive potential divider

(vii) Power frequency withstand test on electromagnetic transformer

(viii) Verification of accuracy

For detailed procedures of these tests IS 3156 should be referred.

REVIEW QUESTIONS

1. A 6.6 kV generating station contains 4 generators, each rated at 10 MVA and having a reactance of 30%. Each of these is connected to a 6.6/66 kV, 10 MVA transformer with 10% reactance. The units so formed are connected to a busbar, which feeds a number of feeders. If the protective current transformers on the feeders have each a transformation ratio of 150/5 A and if saturation occurs at a secondary voltage of 100 volts, determine the maximum permissible impedance burden on each CT secondary (**3.43 Ω**)
2. Define knee-point voltage of a CT and discuss its significance.
3. Discuss the effects of dc offset on the performance of (i) CT, and (ii) linear coupler.
4. Why should the secondary winding of a CT installed in a substation not be open-circuited?
5. What is a linear coupler? Show that in a linear coupler, the relative effect of dc transients is reduced while that of harmonics is increased.
6. Discuss the effect of saturation on the performance of protective CTs.
7. What are the special features of the protective CTs as compared to metering CTs?
8. Give reasons:
 - (i) Linear couplers reduce the effect of primary transients on the operation of relays.
 - (ii) Separate CTs (cores) have to be provided for measurement and protection.
9. Describe the open-circuit test on a CT and explain its significance.
10. What is meant by 'burden' and 'composite error' of a CT?
11. How is the saturation curve of a CT determined? Explain the importance of this curve in the selection of CTs for protection.
12. A CT of ratio 300/5 is installed at a point in a power system at which the fault level is 2400 A. The knee-point voltage of the CT is 140 volts. Determine the maximum permissible impedance burden on the secondary and the corresponding VA. (**3.5 Ω , 87.5 VA**)
13. A small power plant consists of three 5 MVA, 6.6 kV, 3-phase, 50 Hz alternators with 20% reactance, each connected to a common busbar. The busbar supplies a number of feeders, on each of which are installed CTs with details as follows:
 - (a) CT ratio = 600/5 A
 - (b) CT secondary resistance = 0.8 ohm
 - (c) Burden impedance = 1.2 ohms
 Neglecting the lead burden and assuming that no generating source exists at the far ends of the feeders, specify
 - (i) the secondary voltage up to which the CTs should not saturate (knee-point voltage)
 - (ii) accuracy limit factor
 - (iii) rated burden of the CT
 (**108.8 V, 15, 50 VA**)
14. The maximum load current and fault current on a feeder are 87 A and 1290 A, respectively. Specify
 - (i) CT ratio,
 - (ii) accuracy limit factor,

- (iii) accuracy class, and
- (iv) rated short-time current of a protective CT to be installed on the feeder.

(100/1 A, 15, 5P15, 1290 A for 3 seconds)

15. Figure 13.14 shows a single-line diagram for protection of a 220/66 kV, 100 MVA transformer. Find out the

- (i) CT ratio of all the CTs,
- (ii) accuracy limit factor of CT₁, and
- (iii) knee-point voltage of CT₂ and CT₃.

Assume $R_{ct} < 5$ ohms and $R_l < 1.5$ ohms.

(CT ratio for CT₁ and CT₂ = 300/1 A, CT ratio for CT₃ = 1000/1 A, ALF = 10, KPV = 113.7 V)

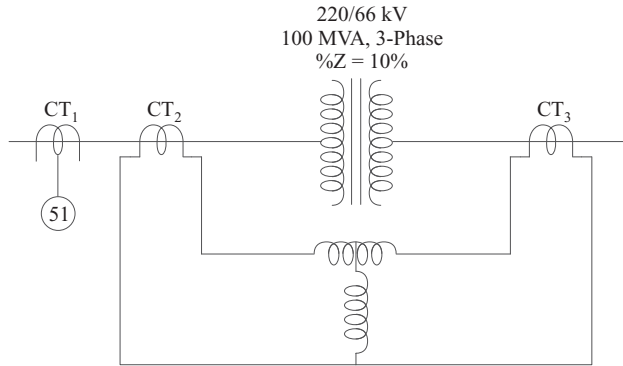


Fig. 13.14 Example 15

MULTIPLE CHOICE QUESTIONS

- In comparison to the knee-point voltage (KPV) of a measuring CT used to feed current to a 1 A meter, the KPV of a protective CT used to feed current to a 1 A relay shall be
 - (a) equal
 - (b) lower
 - (c) higher
 - (d) double
- The material preferred as core of protective CTs is
 - (a) nickel-iron
 - (b) hot-rolled non-oriented silicon steel
 - (c) cold-rolled oriented silicon steel
 - (d) none of the above
- The additional type test required to be preferred for a CVT as compared to an electromagnetic PT is
 - (a) temperature rise test
 - (b) ferro-resonance test
 - (c) lightning impulse test
 - (d) HV power frequency wet withstand test
- For a differential protection scheme, to fulfill the requirement of stability against external faults, it is necessary to have
 - (a) $KPV > I_f(R_{CT} + R_L)$
 - (b) $KPV = 2I_f(R_{CT} + R_L)$
 - (c) $KPV > 2I_f(R_{CT} + R_L)$
 - (d) $KPV < 2I_f(R_{CT} + R_L)$

where,

I_f = secondary equivalent of maximum fault current

R_{CT} = resistance of CT secondary winding

R_L = lead resistance

KPV = Knee-Point Voltage

- The CT saturation characteristic is the curve of
 - (a) open-circuit voltage versus exciting current
 - (b) secondary voltage versus load current
 - (c) secondary voltage versus primary voltage
 - (d) ratio correction factor versus multiples of rated secondary current

Circuit Breaking Fundamentals

All electrical devices used for making and breaking the electrical circuits are grouped under the term '*Electrical Switchgear*'. Thus protective relays, off-load switches, load-breaking switches, isolators,

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fuses, circuit breakers and control panels can all be grouped under electrical switchgear. In this chapter we will learn about circuit-breaking fundamentals.

Introduction

14.1 FUNCTIONS OF CIRCUIT BREAKERS

Circuit breakers are designed to carry out the following functions:

- (1) They must be capable of closing on and carrying full-load currents at rated power factors continuously.
- (2) They must be capable of successfully and rapidly interrupting the heavy short-circuit currents at a very low power factor.
- (3) With their contacts open, the gap must withstand the steady-state power frequency system voltage continuously and transient high-frequency voltage for a short duration of time.
- (4) They must be capable of carrying out making duty, i.e., closing on to a circuit in which a fault exists and immediately reopening to clear the fault.
- (5) They must be capable of carrying currents of short-circuit magnitudes until the fault is cleared by another breaker or by a fuse nearest to the point of fault.
- (6) They must be capable of successfully interrupting quite small currents such as transformer magnetising currents or line and cable charging currents.
- (7) They must be capable of withstanding the effects of arcing of the contacts and electromagnetic forces produced due to high currents (actually there is an opening tendency of the contacts due to these high currents; the contacts may get deteriorated if this opening tendency is not prevented). Also, they must

be capable of withstanding thermal conditions because of passage of current which may be 2 to 10 times (or more) the rated current of the breaker.

14.2 TYPES OF CIRCUIT BREAKERS

The most important duty that the circuit breaker is supposed to carry out is arc extinction while clearing short circuits. The following circuit breakers evolved as the technology progressed.

1. **Air-Break Circuit Breakers** These are the breakers usually used for up to 415 volt applications and currents ranging from around 100 to 4000 A. Breaking capacities up to 80 kA are recorded. They have in-built thermal overload release and high-speed (instantaneous) operation on short circuits. They are available with many functions such as shunt trip, remote trip, undervoltage release, etc. The arc quenching is done by lengthening, splitting and cooling the arc. Moulded case circuit breakers (MCCBs) are the latest version of air-break circuit breakers.
2. **Bulk Oil-Volume Circuit Breakers** These have become obsolete today. But they do find their existence at older substation installations. Normally, beyond 66 kV, these breakers are not preferred. As the name suggests, oil is used as the insulating and arc-quenching medium. Generally, such circuit breakers receive the signal from the relays to operate. As oil is a hydrocarbon organic chemical material, its decomposition on arcing will generate hydrogen, which is an insulating gas and a thermally highly conductive gas. This is an important phenomenon leading to quenching of arc in bulk-oil circuit breakers. Other factors responsible for arc quenching are turbulence of oil due to arcing and cool oil rushing in an ionised medium.
3. **Minimum Oil Volume Circuit Breakers (MOCB)** The basic difference in these breakers and bulk oil-volume circuit breakers is a separate arc chamber. The oil used for a quenching medium is filled in an arc chamber, whereas oil used in an insulating column of a porcelain container is separate. This reduces the bulk of oil to be deteriorated due to arcing. In both these types, many methods of self-blast arc quenching mechanisms are used.
4. **Air Blast Circuit Breakers** The dielectric strength of pressurised air is many times more than that of air at normal temperature and pressure. This fact coupled with the arc extinction using forced air (forced blast mechanism) made this circuit breaker very popular. It started replacing MOCB too. The designs of up to 735 kV are developed in air-blast circuit breakers.
5. **SF₆ (Sulphur Hexafluoride) Circuit Breakers** The extraordinarily high rate of recovery of dielectric strength made these breakers even more popular than air-blast circuit breakers. SF₆ circuit breakers are available in a wide voltage range ranging from 6.6 kV to 735 kV and beyond.
6. **Vacuum Circuit Breakers** This is the most modern and recent technology of circuit breaking, but unfortunately restricted up to 33 kV rating.

In Chapter 15 to follow, we will study the constructional details, performance, operation and relative merits and demerits of these breakers.

Important topics related to short-circuit current testing and high-voltage testing of circuit breakers cannot be avoided. Last but not the least, the ratings and specifications of these circuit breakers for their procurement in field practices have also to be known. These topics will be dealt with in Chapter 16.

During opening of any switch or circuit breaker or contactor, generation of an arc discharge is inevitable. Hence, we will begin our discussion with the theory of arc formation, methods of arc quenching and other difficult duties the circuit breaker is supposed to perform.

14.3 FUNDAMENTALS OF CIRCUIT BREAKING

For any kind of circuit breaker, ultimately the gas is going to be formed between the two electrodes (i.e., contacts) when the contacts separate out. Even when the gas between the two electrodes is not applied with electric field (electric potential), the gas does conduct a low current. Because of natural ionisation (attributable to radioactive radiations on the earth, cosmic rays and ultraviolet rays from the sun's spectrum, etc.), some molecules (or atoms) are ionised (i.e., a free electron gets detached from the atom leaving behind a positively charged particle usually known as a hole). This ionisation is insufficient to break down the gaseous medium between the two electrodes as the process of recombination (merging of free electron with positively charged particle) also is going on continuously along with natural ionisation. Also, no directional transport of free charges can occur because of the random nature of motion of free charges.

If, however a difference of potential is applied across the two electrodes (two contacts in case of a circuit breaker) placed in a gaseous insulating medium, it produces a directional movement of free charges (due to natural ionisation) and gives rise to a flow of leakage current. With an electric field applied for such a condition, the following equation is valid.

$$2n_0 = n_1 + n_2 \quad (14.1)$$

where,

n_0 = number of free electrons

= number of free positive ions too

n_1 = number of charges (positive and negative) neutralised by recombination in the inter-electrode space, and

n_2 = number of charges (of both signs) neutralised at the corresponding electrodes.

The number of charges n_2 determines the magnitude of leakage current.

$$\text{i.e.,} \quad I = n_2 \quad (14.2)$$

where I = charge

In a weak field (i.e., low voltage) n_2 is very small. The leakage current in such a case is directly proportional to the applied voltage (i.e., Ohm's law is followed). This is shown by the portion oa in Fig.14.1.

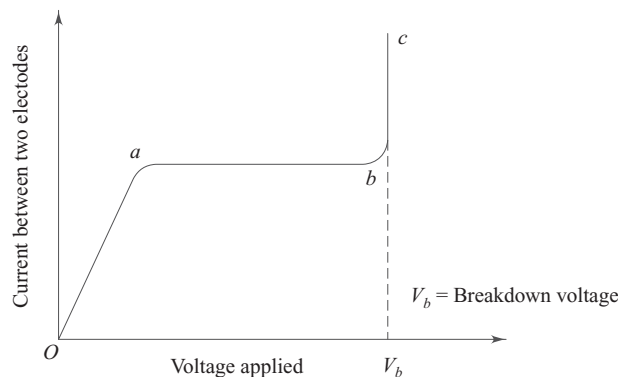


Fig. 14.1 Breakdown voltage

As the electric field is intensified (more voltage is applied), the chances of recombination are gradually reduced and at a particular voltage, all charges reach the electrodes and no recombination takes place in

the inter-electrode space. All charges due to natural ionisation reach the electrodes. In this case the leakage current is determined by Eq. (14.2) only; hence the current remains constant even with increase in voltage (portion *ab* of Fig. 14.1).

At a very high field intensity, the free charges acquire such a high velocity that when they collide with a neutral atom, an electron is knocked out from the atom. This process rises exponentially with geometric progression and hence the voltage remains constant and a very high current passes between the two electrodes (as many as a million charges are produced and reach the electrodes). The gas is no more an insulator now and becomes conducting. This is known as breakdown of the gas (portion *bc* of Fig. 14.1). The current in this case can be limited by external impedance only. This is true for both dc and ac types of voltages, as the free charges travel at roughly the velocity of light and hence the anode and cathode are always formed even for a small period in case of ac fields. Thus in circuit breaking, we come across this breakdown voltage and the insulating medium between the contacts becomes conducting. We have to see to it that the medium acquires its insulating properties as fast as possible to enable the circuit breaker to be successfully applied in the modern interconnected power system network.

14.4 THE GASEOUS DISCHARGES

1. **Decay Discharge** This occurs in a gas at a small gas pressure (less than atmospheric). Numbers of atoms or molecules per unit volume are less and hence the discharge current, when the gas breaks down, cannot acquire a high value. This discharge covers the full inter-electrode space. Tubelights and day light lamps are typical examples of this type of discharges.
2. **Spark Discharge** This is formed in the gas at a sufficiently high pressure (atmospheric or more) but the power of the source is low or the voltage is applied to the gap intermittently or for a small time. Thus, the spark discharge encompasses the volume between two electrodes intermittently and not continuously. Such a discharge takes place between two contacts of a simple switch (found in households) or in case of a circuit breaker when it is interrupting a rated load current at comparatively high power factors.
3. **Arc Discharge** This is the next step during spark discharge when gas pressure and power of source are both larger. The numbers of charges available are quite large and collision ionisations do occur. A continuous canal of bright arc is formed. The temperature at the centre of this arc is of the order of 9000 C while the same at the periphery of the arc is of the order of 2000 C. Because of this high temperature, thermal ionisation also intensifies the arc. The arc would be self-sustaining unless otherwise quenched by some external means. When a high-voltage circuit breaker clears the fault, the formation of arc discharge is inevitable. The different construction and technique, which will be discussed further in this chapter, is only for explaining the process of arc-quenching.
4. **Corona Discharge** When an electric field between the two contacts is not uniform but dense near one electrode and scarce near another electrode, corona discharge takes place. This is a unique type of discharge as the inter-electrode gap does not break down but break down of the gap is limited to a small envelope around one of the electrodes where the field is concentrated. This discharge mechanism is useful to understand as it helps in deciding the material of the electrode, the smoothness of the electrode and the profile of the electrode. If one electrode (i.e., contact of a circuit breaker) is of a smaller diameter than another, corona discharge can take place. If the surfaces of the contacts are not rounded off but cornered, corona can occur. If the surface is not smooth but rough with pitting on the contacts, there can occur a concentration of field leading to corona. The corona discharge is

harmful for contact material as well as insulating medium. Gaseous insulating medium would regain its insulating properties once the voltage collapses. Liquid insulating material like oil would partially regain the insulating properties but keeps on deteriorating with the passage of each corona discharge because of decomposition of oil into hydrogen and carbon (carbon is a conducting medium). The material of electrode also plays a vital role as the liberation energy (the energy required to knock out an electron from the surface of the electrode, i.e., contact) is different for different materials. The alloys of very high liberation energy have been discovered by metallurgists in recent times.

14.5 IONISATION PROCESS IN A GASEOUS INSULATING MEDIUM

In order to ionise a neutral molecule, i.e., to remove an electron from it, it is necessary to expend a finite amount of energy. This is called energy of ionisation, w_i . There are various ways by which an atom can be ionised.

1. Ionisation by Collision If a particle of mass m moving with a velocity v collides with a neutral atom, kinetic energy of the moving particle can bring about the act of ionisation if the following inequality holds good:

$$(1/2)mv^2 > w_i$$

2. Photo Ionisation When energy is imparted to a neutral atom, an electron may jump from a lower orbit to a higher orbit. This is known as excited state of an atom. The atom can remain in such a meta-stable state for a period of the order of 10^{-6} to 10^{-8} seconds. When it returns to its original stable state, the energy which was expended is released in the form of a quantum of light or in the form of a wave of different frequencies. Such an energy is termed *photon*. Also, when a positive particle recombines with an electron in a gaseous volume, a *photon* is generated.

In order that the action of radiation (photon) having a frequency f , of wavelength $\lambda = c/f$ (where c is the velocity of light), on a gas may cause ionisation of the gas, it is necessary to fulfill the condition

$$(h \times f) > w_i \quad \text{or} \quad \lambda < \frac{c \times h}{w_i}$$

where h = quantum constant

Thus, photons of short wavelengths can bring about the ionisation of a gaseous volume.

3. Thermal Ionisation According to the kinetic theory of gases, molecules of gases move with all possible velocities. At higher temperature, velocity increases and the probability of ionisation is more. This is the basis for thermal ionisation.

4. Ionisation on the Surface of Electrodes The electron can appear in a gas by way of emission from the cathode. Liberation of this electron needs a certain amount of energy, called *energy of liberation*, which is required to be expended. This energy is different for different electrode materials. This energy can be imparted in four different ways.

- (i) By heating the cathode, the electron can be liberated from the surface of electrode, called thermionic emission
- (ii) By bombardment of the surface of the metal by particles which possess sufficient energy
- (iii) By irradiating the cathode surface by short wave radiation
- (iv) By superposition of a strong electric field

In circuit breakers, the item (iv) above initiates the arc discharge, which afterwards gets intensified by all other processes described above. It is necessary to establish some mechanism or process, called *de ionisation* or *decay process*.

14.6 DECAY PROCESS

There are three main processes:

- (a) Recombination
- (b) Attachment or negative-ion formation
- (c) Diffusion

All the practical methods used for de-ionisation are basically using one or more of the above processes. The principal methods used are described as follows:

1. Reduction of Velocity of Charged Particles If the gas pressure is increased, the mean free path (the distance of travel of a charged particle before collision) of a charged particle gets reduced. Hence, collision takes place before the charged particle can acquire a velocity enough to gather kinetic energy more than the ionisation energy. Hence collision cannot result in ionisation. Thus, chances of recombination are greatly increased and the gas gets de-ionised. Arc discharge gets quenched in this case. Air-blast circuit breakers use air at high pressure (9 kg/cm^2 to 16 kg/cm^2) to increase the dielectric strength of air and to increase the rate at which dielectric strength gets recovered.

2. Use of Vacuum In vacuum medium, the mean free path of the charged particles is so long (longer than the inter-electrode space) that the charged particles acquire enough velocity to result in ionising collision. But as this collision takes place at the surface of the electrode, the probability of ionisation can be reduced by using electrode material that has high liberation energy. Vacuum circuit-breaker technology uses this principle.

3. Use of Electronegative Gas SF_6 (sulphur hexafluoride) is a gas which has an inherent property of electronegativity. The molecules of SF_6 have affinity towards electrons. The electrons are attached to these molecules forming negative ions. The velocity of negative ions is 100 times less than that of electrons. Thus as the kinetic energy gets reduced, the chances of ionising collisions is reduced to a negligibly small value. In an SF_6 circuit breaker, for this reason, the rate of recovery of dielectric strength is very high.

4. Use of Self-Blast or Forced Blast Principle If the charged particles are diffused from a region of high concentration of charges to a comparatively less dense region of charged particles, the probability of recombination gets largely increased. The arc-control devices in oil-filled circuit breakers and other types of circuit breakers use this principle of diffusion. These are known as self-blast circuit breakers. In air-blast circuit breakers and SF_6 circuit breakers, air and SF_6 respectively are used at higher pressure. The forced blast of gas is applied on the highly dense ionised medium to diffuse the charged particles far away into the region where charged particles are practically absent.

5. Cooling The temperature of the core of the arc discharge is very high, in the range of $9000 - 15000^\circ \text{C}$. If the arc current is reduced, this temperature can be reduced. The intensity of thermal ionisation gets reduced and arc discharge can be quenched. Arc current can be reduced by lengthening the arc using horns. The arc extinction can be made even faster by directing the arc discharge into a cooler medium (and hence suppressing thermal ionisation). Splitters can be used for this purpose.

6. Uniform Electric Field By avoiding electric field stress concentration and by trying to make the electric field as uniform as possible, the arc can be more easily extinguished. For this purpose, cornered surfaces in

the construction of the contacts of circuit breakers should be avoided and surfaces should also be as smooth as possible. The contacts should be changed when they become heavily pitted following several breaking and making operations.

14.7 QUENCHING OF AC ARC

It is well known that when a sudden short circuit occurs in a power system, the fault current can be represented as,

$$i = \frac{E_m}{\omega L} \left[e^{-\frac{Rt}{L}} + \sin(\omega t - \phi) \right]$$

This is the case when a fault occurs at the instantaneous value of voltage zero. The wave shape is as shown in Fig. 14.2.

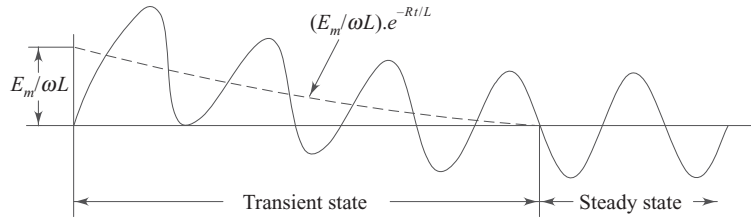


Fig. 14.2 Wave shape of fault current

$\frac{E_m}{\omega L} e^{-\frac{Rt}{L}}$ is also known as transient component or dc offset. A sinusoidal ac wave is superimposed on this dc offset. If the fault occurs at an instantaneous voltage equal to V_{\max} , there would no dc offset and the fault current will just be a steady-state sinusoidal fault current given by,

$$i = \frac{E_m}{\omega L} \sin(\omega t - \phi)$$

When such a fault current is to be interrupted, high voltage is developed across the contacts of a circuit breaker when the arc due to this fault current is quenched. This fact is discussed in the following paragraphs.

The equivalent single-phase circuit for any power system can be approximated as shown in Fig. 14.3. The loop equation for the above circuit can be written as,

$$v = Ri + L \frac{di}{dt} + \frac{1}{C} \int i dt \quad (14.3)$$

where, $v = E_m \sin(\omega t)$

Neglecting R and solving for complementary function or transient solution,

$$\left[LD^2 + \frac{1}{C} \right] i = 0 \quad \text{where } D = \frac{d}{dt}$$

$$\text{or} \quad D = \pm \frac{j}{\sqrt{CL}}$$

Hence, the solution will be,

$$i = Ae^{\frac{jt}{\sqrt{LC}}} + Be^{-\frac{jt}{\sqrt{LC}}}$$

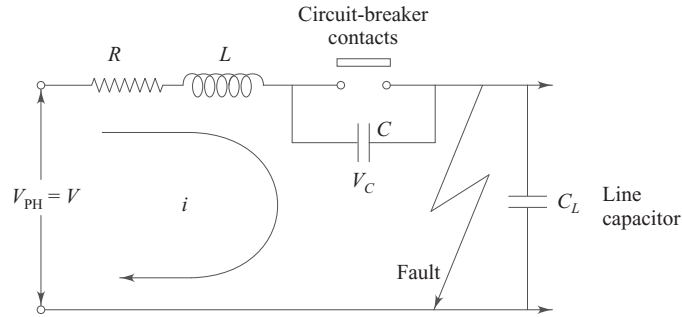


Fig. 14.3 Equivalent single-phase version of any portion of a power system

The oscillogram for current and voltage are shown in Fig. 14.4.

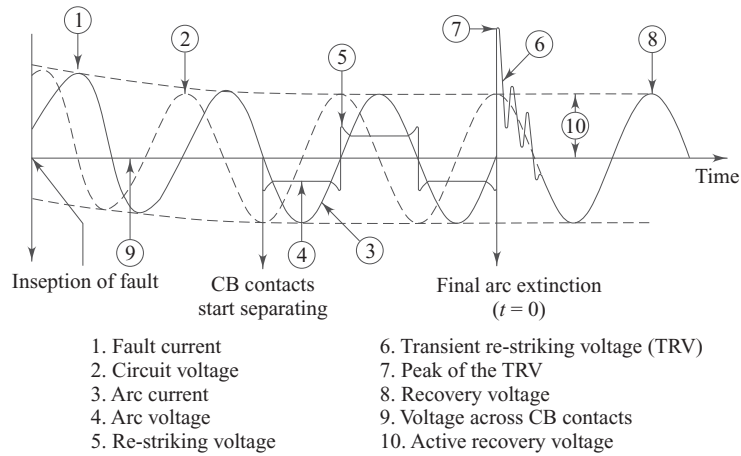


Fig. 14.4 Oscillogram of voltage and current at the time of arc extinction

At $t = 0$ (at the instant of arc extinction), $i = 0$

$$\therefore 0 = A + B$$

$$\therefore A = -B$$

$$i = A \left[e^{\frac{jt}{\sqrt{LC}}} - e^{-\frac{jt}{\sqrt{LC}}} \right] = k \sin(t/\sqrt{LC})$$

$$\therefore \frac{di}{dt} = \frac{k}{\sqrt{LC}} \cos(t/\sqrt{LC})$$

$$\text{At } t = 0, \quad \frac{di}{dt} = \frac{k}{\sqrt{LC}}$$

Using Eq. (14.3), at $t = 0$,

$$L \frac{di}{dt} + \frac{1}{C} \int i dt = v \quad \dots (\text{neglecting } R)$$

$$\text{But at } t = 0, \quad V_c = \frac{1}{C} \int i dt = 0$$

where V_c = voltage across circuit breaker

$$\begin{aligned}
 \therefore L \frac{di}{dt} &= v \\
 \therefore \frac{di}{dt} &= \frac{v}{L} \\
 \therefore \frac{k}{\sqrt{LC}} &= \frac{v}{L} \\
 \therefore k &= v \sqrt{\frac{C}{L}} \\
 \therefore i &= v \sqrt{\frac{C}{L}} \sin(t/\sqrt{LC}) \\
 \therefore V_c &= \text{voltage across circuit breaker} \\
 &= \frac{1}{C} \int i \, dt = \frac{1}{C} \times v \sqrt{\frac{C}{L}} \int \sin(t/\sqrt{LC}) \, dt \\
 &= \frac{1}{C} \times v \sqrt{\frac{C}{L}} \times \sqrt{LC} [-\cos(t/\sqrt{LC})] + k' = [-v \cos(t/\sqrt{LC})] + k'
 \end{aligned}$$

At the instant of arc extinction, when $t = 0$, $V_c = 0$.

$$0 = -v + k'$$

$$\therefore k' = v$$

$$\therefore V_c = v(1 - \cos(t/\sqrt{LC})) \quad (14.4)$$

Thus a transient voltage (V_c) is superimposed on steady-state phase to neutral voltage as given by Eq. 14.4. The frequency of this transient voltage is known as natural frequency (f_n) given by,

$$f_n = \frac{1}{2\pi\sqrt{LC}}$$

The maximum voltage of this transient voltage ($V_{c\max}$) is given by,

$$V_{c\max} = 2v \quad \text{at } t = \pi\sqrt{LC}$$

i.e., two times the peak of phase to neutral voltage will appear across circuit-breaker contacts. The insulation of the circuit breaker should be able to withstand this voltage.

This discussion leads to certain definitions or understanding certain terms as follows:

1. Re-striking Voltage As the arc energy tends to zero at the current zero, the arc tries to get quenched. If the dielectric strength of the insulating medium between the contacts of the circuit breaker has not built up and hence if it breaks down, the arc re-strikes. The voltage peak at this instant (shown as No. 5 in Fig. 14.4) is known as the re-striking voltage.

2. Arc Voltage As the arc is resistive, the arc voltage is in phase with the arc current (nearly fault current if this arc has no means to reduce the fault current). This arc voltage (No. 4 in Fig. 14.4) is shown exaggerated in Fig. 14.4. It is actually very small. The voltage across the circuit-breaker contacts when the circuit breaker was closed was obviously zero (as shown by No. 9 in Fig. 14.4).

3. Transient Re-striking Voltage (TRV) The high-frequency voltage across circuit-breaker contacts immediately after arc extinction is known as TRV (shown by No. 6 of Fig. 14.4). Its peak is shown by No. 7 in Fig. 14.4.

4. Recovery Voltage Power frequency steady-state voltage across circuit breaker contacts after arc extinction is known as recovery voltage (shown by No. 8 in Fig. 14.4).

5. Active Recovery Voltage The instantaneous value of recovery voltage at the instant of arc extinction is known as active recovery voltage (shown by No. 10 in Fig. 14.4).

14.8 ARC INTERRUPTION THEORIES

14.8.1 Slepian's Theory

Looking at the oscillogram of Fig. 14.4, it is seen that the arc tries to get quenched at each current zero. Slepian advanced a theory to explain this in 1928. At each current zero, there is a race between the rate of rise of the re-striking voltage (RRRV) and the rate at which the dielectric strength of insulating medium recovers.

If the rate of rise of the re-striking voltage (RRRV) is more than the rate at which the dielectric strength recovers, the arc re-strikes and is not quenched.

However, if the rate at which the dielectric strength recovers is higher than RRRV, the arc is quenched. No doubt, at this instant, the contact gap is stressed by a very high voltage as already shown in Section 14.7.

This theory suffers from the following demerits:

1. It cannot answer how to calculate the rate at which the dielectric strength recovers.
2. It does not consider energy relations in the arc extinction.

14.8.2 Cassie's Theory

Cassie's theorem can be expressed as follows:

At current zero, when no current is flowing there is no power input to the arc gap. Post-arc conductivity continues for a while in the gap and then ceases so that the arc is said to be extinguished. Somewhere in between these two instants (actual current zero and post-arc current) however, the power input will pass through a maximum. If this maximum value exceeds the power loss from the arc column, the column will heat up, arc conductivity will increase and the arc is re-struck. If there are better means for carrying away the power loss in the arc at the current near zero, the arc can be quenched.

Summarising, the arc extinction can be obtained at current zero by building up dielectric strength of the insulating medium rapidly and by quickly dissipating (or carrying away) the energy (in the form of heat) fed into the arc. The arc extinction in a circuit breaker is influenced by many factors such as

1. Speed of contact
2. Material of contact
3. The pattern of flow of the quenching medium
4. Magnitude of the arc current
5. Energy liberated during arcing
6. RRRV
7. Rate at which the dielectric strength recovers
8. Power factor of the circuit at the instant of arc extinction
9. Type of fault

14.9 FACTORS AFFECTING RRRV, RE-STRIKING VOLTAGE AND RECOVERY VOLTAGE

14.9.1 Effect of Power Factor of Circuit

Referring to Fig. 14.4, it shows that higher the power factor, less will be the voltage (active recovery voltage) at the instant of current zero. Hence, the voltage stresses in the circuit-breaker contact gap will decrease. This is the reason why a circuit breaker will find it easier to interrupt the load current. In this case, current is also comparatively less with respect to the fault current (and hence the arc intensity is less) and because power factor is around 0.8, the voltage stress across the contact gap will be less. The peak of the re-striking voltage is also less and RRRV will also reduce as the natural frequency of the transient re-striking voltage will be less which we shall see in the section on *Resistance Switching*.

On the other hand, clearing short-circuit currents (where the power factor is ranging from 0.1 to 0.3 or even less) of very high magnitudes is a case of very severe duty for the circuit breaker. Similarly, quenching of low magnitudes of currents for an unloaded transformer or capacitive currents of a long unloaded transmission line is a very difficult duty for the circuit breaker. In these cases, however, the current is low, the power factor being approximately zero, the active recovery voltage is the peak of the circuit voltage. This will be discussed at length later.

Break time is the time elapsed between the instant when the circuit breaker receives the signal from the tripping relay and the instant of actual arc extinction. This is composed of the pre-arcing time and arcing time. For slow-acting circuit breakers with a break-time of 5 cycles, heavy voltage stresses are not exerted. This is because the arc gets lengthened, cooled and in many cases split into multiple arcs by arc splitters during the arc interruption. Lengthening and cooling both decrease the conductivity of the arc and increase the resistance of arc. Thus, at the instant of arc extinction, the inherent arc resistance is added to the circuit inductance and resistance. This makes the circuit-breaker duty easier with respect to voltage stress. Such slow-acting circuit breakers were used in old days when fault levels were low. But in a modern power system, the circuit breaker duty becomes difficult from the point of view of electro-dynamic stresses and contact deterioration due to heavy current passing for a longer time. The problems of heat dissipation also demand improvements in circuit-breaker design. The circuit-breaker failures were also observed for slow-acting circuit breakers. Last but not the least, there is a problem of power-system instability, if the fault current is allowed to persist for a longer duration of time. Thus, fast-acting circuit breakers (two cycles or even one cycle) became the need as the time called for that. In case of a fast-acting circuit breaker, dielectric strength of contact gap recovers so fast that no arc resistance can develop and hence a heavy voltage stress is applied across the contact gap. Insertion of deliberate resistance between the contact gap is the solution to this problem. We will discuss this a little later.

14.9.2 Types of Faults

The faults can be categorised into two broad groups:

A Those involving earth

1. L-L-L-g
2. L-L-g
3. L-g

B Those which do not involve earth

1. L-L-L
2. L-L

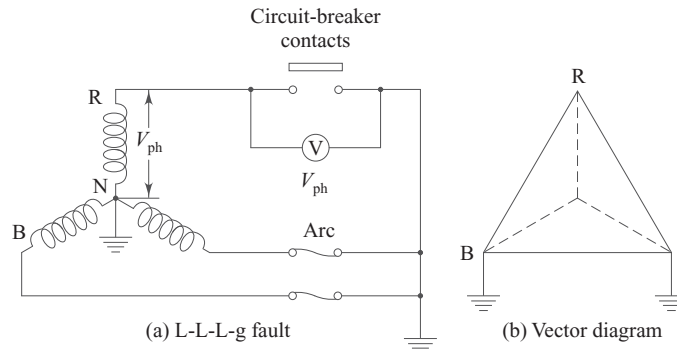


Fig. 14.5 L-L-L-g fault

Any fault involving earth in an earthed system will not pose a serious threat to the circuit breaker, because when the circuit breaker opens, there will be only phase-to-earth voltage appearing across the circuit breaker contacts as shown in Fig. 14.5(a).

It should be remembered at this juncture that though the contacts of a circuit breaker for all the phases open simultaneously, the arc is not extinguished at all three pairs of contacts simultaneously, as the arc is extinguished always at the current zero and the current in R, and B phases do not pass through zero simultaneously.

Now, if the fault or the system itself is not earthed, the voltage across the circuit breaker contacts in which the arc is first extinguished will be higher than V_{ph} . It will be 1.5 times the phase voltage for a three-phase fault and 1.732 times the phase voltage for line-to-line fault. This is demonstrated in Fig. 14.6(a) and (b).

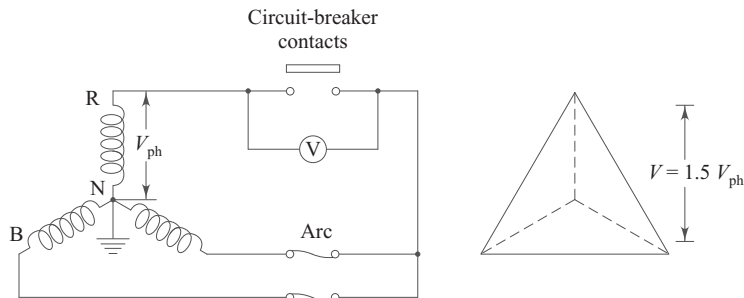


Fig. 14.6(a) L-L-L fault in an earthed system

This can be demonstrated in a very simple but effective laboratory experiment designed by the authors at BVM Engineering College, Vallabh Vidyanagar, Gujarat, India. The experimental circuit to simulate various types of faulty conditions is shown in Fig. 14.7. As our aim is to observe the voltage across the circuit-breaker contact, current magnitude is not that important. Hence, current is suppressed by using 185Ω rheostats. Switches S_1 , S_2 and S_3 represent circuit-breaker contacts and it can also be used for creating faults. Switch S_4 decides whether the fault is grounded or not. Switch S_5 is used either to connect the system neutral to earth or to isolate the neutral from earth. The experimental procedure is as follows:

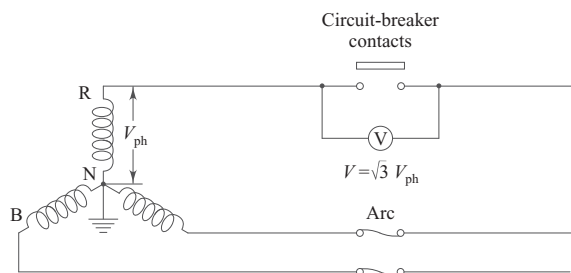


Fig. 14.6(b) L-L fault in an earthed system

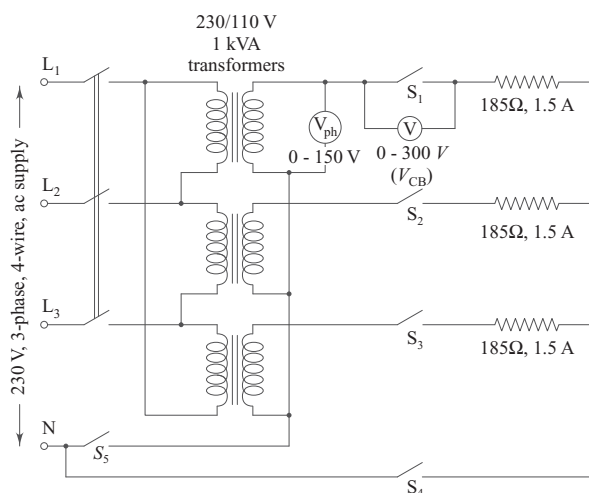


Fig. 14.7 Experimental circuit

Procedure

1. Connect the circuit.
2. Simulate different faults with the given circuit arrangement.
3. Observe the phase voltage (V_{ph}) and the voltage across the circuit-breaker contacts (V) and note them down.
4. Calculate the ground constant (or overvoltage factor).

$$\text{Ground constant or overvoltage factor} = \frac{\text{Voltage across circuit-breaker contacts}}{\text{System phase-to-earth voltage}}$$

Observations

Part I System neutral and fault both grounded

Sr No	Type of fault	V_{ph} (volts)	V_{CB} (volts) Measured	V_{CB} (volts) Theoretical	Ground constant V_{CB}/V_{ph}
1.	L-L-L-g	110	110	110	1.0
2.	L-L-g	110	110	110	1.0
3.	L-g	110	110	110	1.0

Part 2 Neutral grounded but fault ungrounded

Sr No.	Type of fault	V_{ph} (volts)	V_{CB} (volts) Measured	V_{CB} (volts) Theoretical	Ground constant V_{CB}/V_{ph}
1.	L-L-L	110	110×1.5	110×1.5	1.5
2.	L-L	110	$110 \times \sqrt{3}$	$110 \times \sqrt{3}$	$\sqrt{3}$

Part 3 Fault grounded but system ungrounded

Sr No.	Type of fault	V_{ph} (volts)	V_{CB} (volts) Measured	V_{CB} (volts) Theoretical	Ground constant V_{CB}/V_{ph}
1.	L-L-L-g	110	110×1.5	110×1.5	1.5
2.	L-L-g	110	$110 \times \sqrt{3}$	$110 \times \sqrt{3}$	$\sqrt{3}$

No doubt, the steady-state rms value of the voltage can only be observed in such an experiment. The transient value will be as tabulated in Table 14.1.

Table 14.1

Sr No.	Type of fault	Ph N voltage of the system (p)	RMS value of voltage across CB contacts (m)	Active recovery voltage $\sqrt{2} \times m$	Peak of the re striking voltage (n)	Transient ground constant (n/p)
1.	L-L-L-g	V	V	$\sqrt{2}V$	$2\sqrt{2}V$	2.8
2.	L-L-L	V	$1.5V$	$\sqrt{2}V \times 1.5$	$2\sqrt{2}V \times 1.5$	4.2
3.	L-L-g	V	V	$\sqrt{2}V$	$2\sqrt{2}V$	2.8
4.	L-L	V	$\sqrt{3}V$	$\sqrt{2} \times \sqrt{3}V$	$2\sqrt{2} \times \sqrt{3}V$	4.84
5.	L-g	V	V	$\sqrt{2}V$	$2\sqrt{2}V$	2.8

It is assumed that the condition experienced is extreme, i.e., no resistance in the circuit and power factor is zero lagging. The worst condition shown is across the circuit-breaker contact in which the arc is cleared first. It is also assumed that system neutral is also grounded, which is normally the case in all EHV and UHV networks.

Table 14.1 suggests that the worst of the voltage stress occurs across circuit breaker contact gap when an L-L fault occurs. If a slight asymmetry in the voltage wave is considered, this voltage can be as bad as six times the phase-to-neutral system voltage.

14.9.3 Effect of Asymmetry of Short-Circuit Current

In most practical cases, the current in at least one phase will be asymmetrical to some degree and the waveform will include major and minor loops as shown in Fig. 14.8.

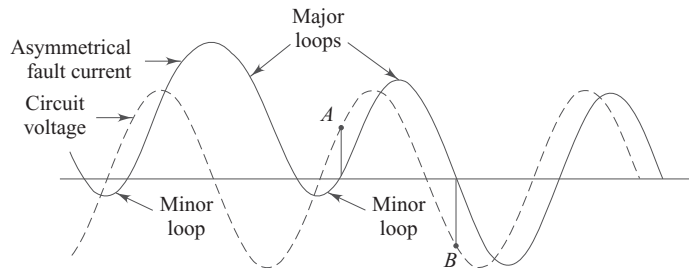


Fig. 14.8 Effect of asymmetry of short-circuit current

Assuming again a low power-factor condition, it will be seen that the instantaneous recovery voltage will depend upon whether the interruption follows a minor loop (as shown at *A*) or a major loop (as shown at *B*). In either case, however, it will be less than the peak associated with the symmetrical current. Attention may also be drawn to the fact that the peak current in a major loop is higher than that in a symmetrical loop, and also that there is increase in time between zero crossings in the major loop. The higher values of peak current must be taken into account in determining the electromagnetic forces which the breaker (operating mechanism of breaker) must withstand and the mechanical strength of an arc-control device must be related to this condition.

14.9.4 Effect of Shunt Capacitance

If the capacitance is shunted to the circuit-breaker contacts, the wave shape of the arc current and the capacitive current would be as shown in Fig. 14.9. The capacitance may be either natural capacitance of the system or a capacitance deliberately added to improve the performance of the circuit breaker and to improve the system power factor. As the short-circuit current diminishes towards zero value, the resistance of the arc path increases and hence some current gets diverted away from the arc through the shunt capacitance. The arc current thus reduces faster and reaches the zero value at *A* instead of *B*. The voltage across the contacts increases up to *A*, which is a turning point. After this, there is no current through the arc, but the entire current passes through the capacitance. As this current decreases, capacitance gets charged at a lower rate. The voltage across the contacts increases slowly up to *B*, and then as the current changes direction it decreases and swings over to the other side.

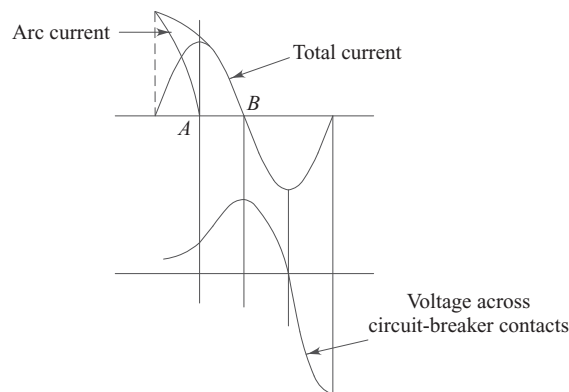


Fig. 14.9 Effect of shunt capacitance

Now, larger the capacitance in parallel with the circuit-breaker contacts, lower will be the voltage at the turning point and lower will also be the maximum rate of rise of voltage and hence smaller will be the swing of the voltage. This reduces the swing factor. It is for this reason that a circuit breaker which fails in a power system with overhead lines can still successfully deal with an equal or even larger short-circuit MVA in cable networks of the same voltage.

14.9.5 Short Line Fault or Kilometric Fault

This type of fault produces conditions of extreme severity. This discovery arose out of a number of unexplained failures of otherwise fully capable circuit breaker action, and investigations showed that these failures were associated with fault occurring on a transmission line at the point very close to the line side terminal of the

circuit breaker, i.e., at a distance in the range of 1 to 8 km. The investigations also showed that the re-striking voltage transient across the circuit breaker was of multiple frequencies with a very steep RRRV to the initial peak, and that this transient was the summation of two voltages, one at the supply-side terminal of the breaker and the other at the line-side terminal. At the supply-side terminal is the normal re-striking voltage transient as discussed previously, while that at the line-side terminal is a high-frequency saw-toothed transient, the maximum amplitude of which is at the terminal side and decays to zero at the fault point. These are shown in Fig. 14.10.

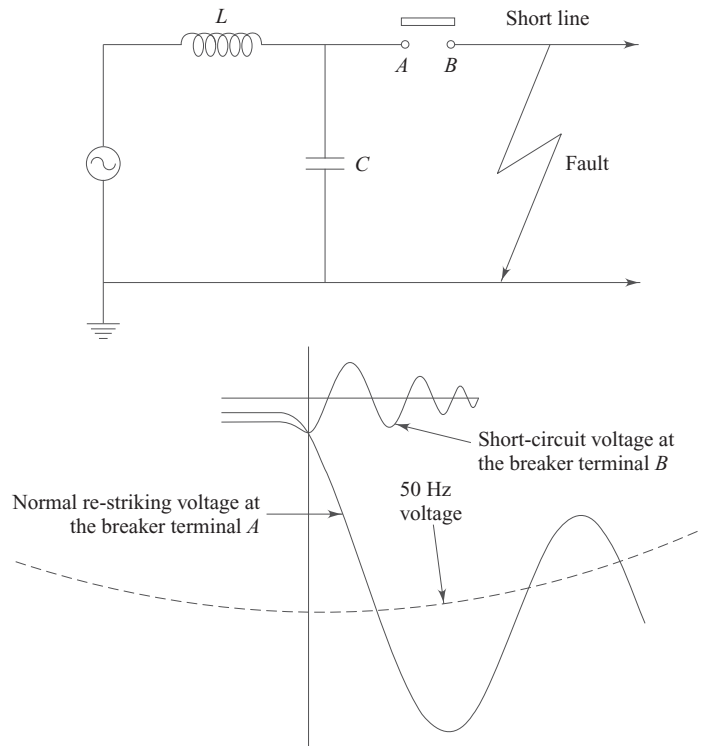


Fig. 14.10 Short-line fault

It is seen that the first peak of the resultant re-striking voltage transient is very close to the dielectric recovery curve and produces a post-zero current which is much greater than that which could be produced by the supply-side transient alone. There is therefore appreciable power input to the post zero arc and air-blast circuit breakers are particularly sensitive to this kind of fault because of their inability to absorb a large power input into the post-zero arc.

The amplitude of the saw-toothed transient at the line-side terminal will be dependent on the fault current, which will naturally be at its maximum value at points near the power source. Beyond about 8 km, the impedance of the transmission line reduces the fault current sufficiently to ease the nature of the transient and the duty of the breaker.

Since the problems of short line faults have been recognised, facilities have been introduced in test plants whereby the conditions can be simulated and the test made to prove the ability of a circuit breaker to deal with such faults.

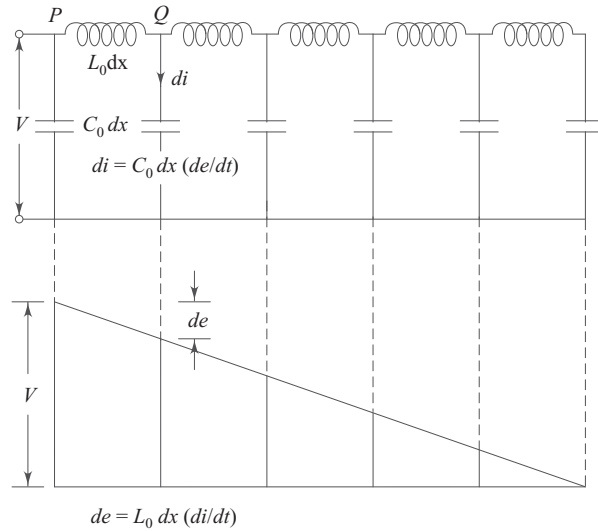


Fig. 14.11 Representation of single-phase line

Now let us consider a single phase line (Fig. 14.11)

$$\text{Inductance} = L_0 \text{ henry/km}$$

$$\text{Capacitance} = C_0 \text{ f/km}$$

The capacitance element of the circuit-breaker terminal is at potential V , the active recovery voltage. Between P and Q there is a voltage drop of $L_0 dx \frac{di}{dt}$ where $\frac{di}{dt}$ is the rate of change of current at current zero at which the interruption takes place. Hence, after the interruption there is a voltage drop of $L_0 dx \frac{di}{dt}$.

$$\therefore de = L_0 dx \frac{di}{dt} = L_0 di \frac{dx}{dt}$$

$$\therefore de = v L_0 di \quad (14.5)$$

If 'di' be the current flowing out of a condenser element,

$$\therefore di = C_0 dx \frac{de}{dt} = C_0 de \frac{dx}{dt}$$

$$\therefore di = v C_0 de \quad (14.6)$$

where v = the velocity at which a charge is propagated.

Dividing Eq. (14.5) by (14.6),

$$\frac{de}{di} = \frac{L_0}{C_0} \frac{di}{de}$$

$$\therefore \left[\frac{de}{di} \right]^2 = \frac{L_0}{C_0}$$

$$\therefore \frac{de}{di} = \sqrt{\frac{L_0}{C_0}} = Z \quad (14.7)$$

$$\therefore de = Z di$$

$$\therefore e = i Z$$

where Z = natural impedance of line

Whatever has been discussed here for one element holds good for the other elements so that the voltage of each element goes on falling. The process is extended over all the elements. The last capacitance element discharges over the last inductance element and attains a zero value. A traveling wave is thus created and travels with a velocity (v) given by,

$$v = \frac{de}{di} \times \frac{1}{L_0} \quad \text{from Eq. (14.5)}$$

$$= \sqrt{\frac{L_0}{C_0}} \times \frac{1}{L_0} \quad \text{from Eq. (14.7)}$$

$$\therefore v = \frac{1}{\sqrt{L_0 C_0}} = \text{velocity of propagation}$$

$$\begin{aligned} \text{RRRV} &= \frac{de}{dt} = Z \frac{di}{dt} \\ &= \sqrt{\frac{L_0}{C_0}} \frac{d}{dt} (\sqrt{2} I_{sc} \sin \omega t) \end{aligned}$$

$$\text{where } i = I_{scm} \sin \omega t = \sqrt{2} I_{sc} \sin \omega t$$

$$\therefore \text{RRRV} = \sqrt{\frac{L_0}{C_0}} (\sqrt{2} I_{sc} \omega \cos \omega t)$$

At $t = 0$, where interruption occurs,

$$\begin{aligned} \frac{de}{dt} &= \sqrt{\frac{L_0}{C_0}} (\sqrt{2} I_{sc} \omega) \\ &= \frac{1}{\sqrt{L_0 C_0}} (\sqrt{2} I_{sc} \omega L_0) \end{aligned}$$

$$\text{Thus, RRRV} \propto I_{sc}, \quad (14.8)$$

$$e = i Z = \sqrt{\frac{L_0}{C_0}} \times i$$

$$\begin{aligned} \sqrt{\frac{L_0}{C_0}} (\sqrt{2} I_{sc} \sin \omega t) &= v L_0 (\sqrt{2} I_{sc} \sin \omega t) \\ &= 2l \omega L_0 (\sqrt{2} I_{sc} \sin \omega t) = 2l x_0 (\sqrt{2} I_{sc} \sin \omega t) \\ E_{\max} &= 2l x_0 \sqrt{2} I_{sc}. \end{aligned}$$

Thus maximum value of the re-striking voltage,

$$E_{\max} \propto l I_{sc} \quad (14.9)$$

From Eqs (14.8) and (14.9), it is clear that

- (i) if the fault occurs immediately after the circuit breaker, the short-circuit current is large, while the maximum value of re-striking voltage, E_m , is small as length is small; the amplitude is thus quite low
- (ii) if the fault is far from the circuit breaker, the fault current is small and hence RRRV is small, although E_m is large

- (iii) when the fault is at a short distance from the circuit breaker, both RRRV and E_m have considerable value and hence the possibility of failure is maximum. Such a fault is known as *kilometric fault* or *short line fault*.

The Factor of Severity The severity of fault for the circuit breaker can be approximately represented by the severity factor F . The factors which determine the severity of fault are the short-circuit current, RRRV and amplitude of the re-striking voltage.

$$F = K I_{sc}^3 l \quad (14.10)$$

If $I_{sc \max}$ be the short-circuit current for a fault immediately after the circuit breaker then for a system in Fig. 14.12,

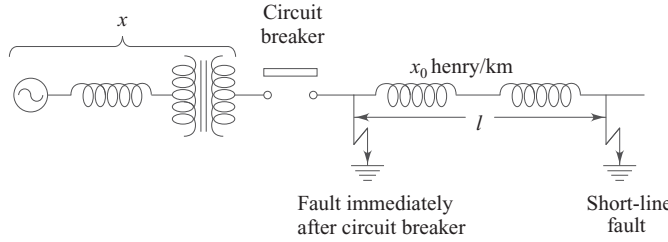


Fig. 14.12 System for locating severest fault

$$I_{sc \max} = E/x \quad (14.11)$$

For a fault at a distance l ,

$$I_{sc} = \frac{E}{x + l x_0} \quad (14.12)$$

$$\therefore (I_{sc} x) + (I_{sc} l x_0) = E$$

$$\therefore l = \frac{E - I_{sc} x}{I_{sc} x_0} = \frac{E}{I_{sc} x_0} - \frac{x}{x_0}$$

From Eq. (14.10),

$$F = k \left[I_{sc}^3 \frac{E}{I_{sc} x_0} - \frac{x}{x_0} \right] = k \left[\frac{E I_{sc}^2}{x_0} - \frac{I_{sc}^3 x}{x_0} \right]$$

From a maximum value of F ,

$$\frac{dF}{dI_{sc}} = 0$$

$$\therefore \frac{2E}{x_0} I_{sc} - \frac{3x}{x_0} I_{sc}^2 = 0$$

$$\therefore \frac{2E}{x_0} I_{sc} = \frac{3x}{x_0} I_{sc}^2$$

$$\therefore I_{sc} = (2/3) \times (E/x)$$

$$\therefore I_{sc} = (2/3) I_{sc \max}$$

Hence the severe-most condition for the circuit breaker occurs at a fault in which the short-circuit current equals 2/3 of the short-circuit current for a fault at the circuit breaker.

The Danger Zone The variation of the severity factor with a fault distance from the circuit breaker is shown in Fig. 14.13.

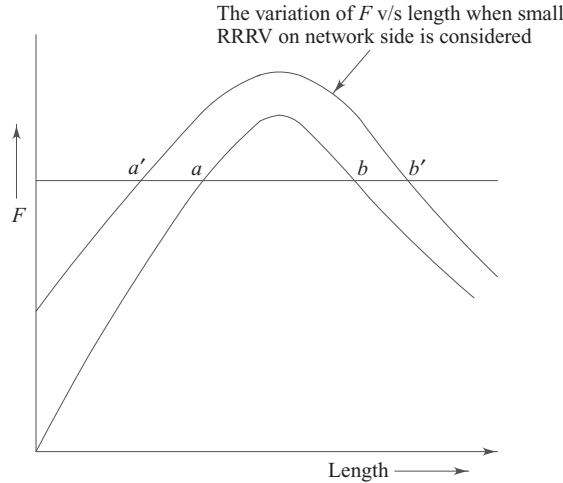


Fig. 14.13 Variation of severity factor

When the small rate of rise of the re-striking voltage on the network side is also taken into account, the variation becomes that as shown. In this case the maximum value is obtained when $I_{sc} = (3/4) I_{sc \max}$.

If the circuit breaker is chosen to suit the conditions for a fault at the circuit breaker itself, the conditions between points of intersection a and b would be too severe for it and this region would constitute the danger zone for the circuit breaker. Obviously, the circuit breaker should be chosen so as to withstand the highest factor of severity.

For overhead lines, the velocity of propagation v , has a value typically of 3×10^5 km/s and x_0 to be 0.4 ohm/km, while for cables, v has a value of 1.5×10^5 km/s and x_0 negligible. Hence the problem of kilometric fault occurs in overhead lines rather than in cable networks.

In medium-voltage networks, the short-circuit currents are generally heavier and the number of short circuits per year per 100 km are larger than the networks of higher voltages. The kilometric fault assumes more severe proportions in such networks (11 to 132 kV).

Illustrative Example Consider the network as shown in Fig. 14.14. It is required to find the distance from the circuit breaker at which a short circuit is to occur for maximum severity factor.

$$I_{sc} = \frac{E}{x + lx_0} = \frac{E/x}{\left[1 + \frac{lx_0}{x}\right]}$$

$$= \frac{I_{sc \max}}{\left[1 + \frac{lx_0}{x}\right]}$$

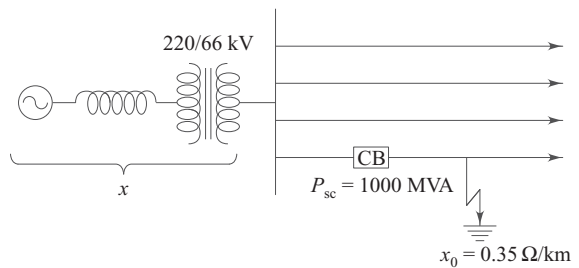


Fig. 14.14

But maximum F will be when $I_{sc} = (3/4)I_{sc\max}$

$$\begin{aligned} \therefore (3/4) I_{sc\max} &= \frac{I_{sc\max}}{\left[1 + \frac{lx_0}{x}\right]} \\ \therefore (3/4) \left[1 + \frac{lx_0}{x}\right] &= 1 \\ \therefore \left[1 + \frac{lx_0}{x}\right] &= (4/3) \\ \therefore \left[\frac{lx_0}{x}\right] &= (1/3) \\ \therefore l &= \left[\frac{x}{3x_0}\right] \end{aligned} \quad (14.13)$$

If P_{sc} be the rated fault MVA of the circuit breaker chosen on the basis of a fault immediately after the circuit breaker,

$$P_{sc} = (\sqrt{3} \times kV \times I) \text{ MVA}$$

where I is in kA

$$\begin{aligned} \therefore P_{sc} &= \frac{(\sqrt{3} \times E_L \times E_L)}{\sqrt{3}x} \quad \text{as } I = \frac{E_L}{\sqrt{3}x} \\ \therefore P_{sc} &= \frac{E_L^2}{x} \\ \therefore x &= \frac{E_L^2}{P_{sc}} \end{aligned}$$

Using Eq. (14.13),

$$l = \frac{E_L^2}{3P_{sc}x_0} \quad (14.14)$$

From Eq.(14.14),

$$l = \frac{66^2}{(3 \times 1000 \times 0.35)} = 4.15 \text{ km}$$

14.9.6 Current Chopping (Interruption of Small Inductive Currents)

While interrupting small inductive currents, such as no-load current of transformers, the arc path is ionised by the low current and it may reach a zero value before natural zero. This phenomenon is known as *current chopping*. The magnetic energy present in the inductance of the circuit is converted into electrostatic energy, the capacitance of the system being charged.

The magnetic energy in the inductance, $m = (1/2)LI^2$ is suddenly dissipated into the capacitance.

$$\begin{aligned} \therefore m &= c = (1/2) CV^2 \\ \therefore (1/2) LI^2 &= (1/2) CV^2 \\ \therefore V &= \sqrt{L/C} I \end{aligned}$$

This voltage is impressed on a power frequency voltage and can damage insulation of the transformer itself or of some other equipment.

Consider a disconnection of a 110/33 kV, 20 MVA transformer.

$$\text{Rated current} = \frac{20 \times 10^6}{\sqrt{3} \times 110 \times 10^3} = 105 \text{ A}$$

No-load magnetising current was found to be 2 A.

$$x_0 = \frac{110 \times 10^3}{\sqrt{3} \times 2} = 31.7 \times 10^3 \text{ ohms}$$

$$\therefore L_0 = \frac{x_0}{2\pi f} = 101 \text{ henry}$$

Assuming the current to be interrupted at peak value, $\sqrt{2} \times 2 = 2.82 \text{ A}$, with a system capacitance to be 5000 pF between phase to ground.

$$V = \sqrt{L/C} I$$

$$= 2.82 \sqrt{\frac{101}{5000 \times 10^{-12}}} = 400 \text{ kV}$$

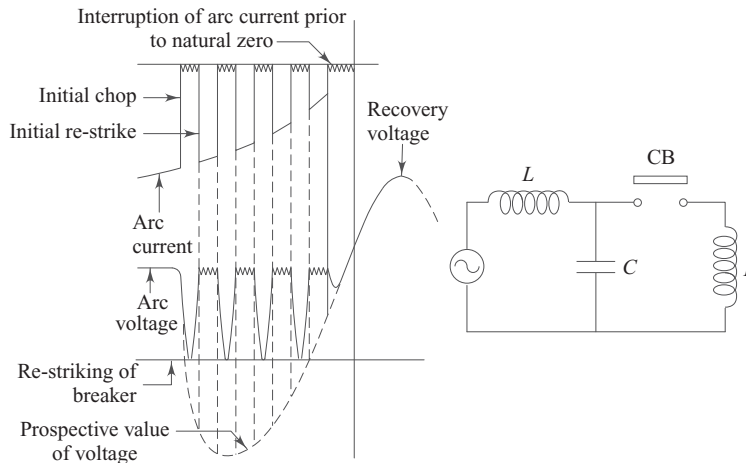


Fig. 14.15 Current-chopping phenomenon

This voltage can easily impair the transformer insulation. Fortunately, the breaker is usually able to relieve the insulation by re-striking at some point on the rising chop voltage. Just how far the voltage may rise before re-strike depends upon various factors. For example, the lower the rate of rise of this voltage, the more time there is for de-ionisation of the breaker gap, and correspondingly, a high overvoltage may be reached. Similarly, the effectiveness of the de-ionising means will influence the re-striking voltage. Such a re-strike draws the energy out from the capacitance and the voltage thereafter collapses (see Fig. 14.15). If the de-ionising force is still in action, however, a second chop takes place. This time, the chopped current is rather less than the previous value and hence also the RRRV is somewhat slower. This may give the gap a chance to become further de-ionised than earlier and a higher re-striking voltage may result. This is not shown in the figure. Successive chops may occur as shown until the final chop brings the current to a zero prematurely with no further re-striking since the gap is now in advanced stage of de-ionisation. Such a small current

breaking is very difficult and it takes more time for self-blast breakers like breakers provided with arc-control devices. This is because the arc intensity being very low, the gas pressure within the arc-control device is also very low. This does not facilitate the arc to be quenched faster. However, this will not also give rise to large overvoltages.

On the other hand, for forced blast breakers like air-blast circuit breaker and SF_6 circuit breaker, where the pressure of the gas is independent of the current to be interrupted, the phenomenon of current chopping is quite predominant. For vacuum circuit breaker also, current chopping is a problem.

14.9.7 Interruption of Capacitive Currents

The examples of interrupting capacitive currents are while opening up the unloaded line or while disconnecting the static capacitor bank. Let us examine the circuit shown in Fig. 14.16.

The charging currents are easily interrupted closer to its passing through zero (point a , Fig. 14.17). The opening of the circuit leaves a charge trapped in the capacitance.

The voltage across the circuit-breaker contacts V_{CB} is equal to the difference between V and V_C . Its initial value is zero (point a). But half a cycle later when V reverses, V_{CB} reaches twice the normal peak value (point b). At this instant or even earlier, it is possible that the arc re-strikes because the electrical strength between the contacts of the circuit breaker may not have attained a sufficiently high value. This will re-close the circuit and V_C will oscillate with a high frequency about the supply voltage V . At this moment, the supply voltage is at its negative peak (point 2), therefore a high-frequency oscillation will occur between $+1$ and -3 times the peak value of the supply voltage. At the instant when the arc is re-struck, recovery voltage is zero (point c'). If we assume that at the first zero of high-frequency current, an arc extinction takes place (point c), the voltage across the capacitance gets trapped at $-3V_m$. Due to this, V_{CB} reaches the point c and starts to increase up to the point d . If at this instant, a re-strike occurs again, a high frequency oscillation of V_C about the supply voltage (point 3) will take place between -3 to $+5$ times its peak value. Several repetitions of the re-striking cycle can theoretically increase the voltage across the capacitance to exceedingly high values (at a rate of nearly twice the peak value of the supply voltage per half cycle). Fortunately, however, practical

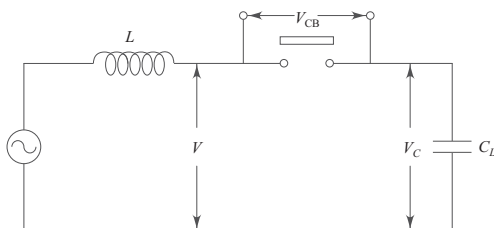


Fig. 14.16

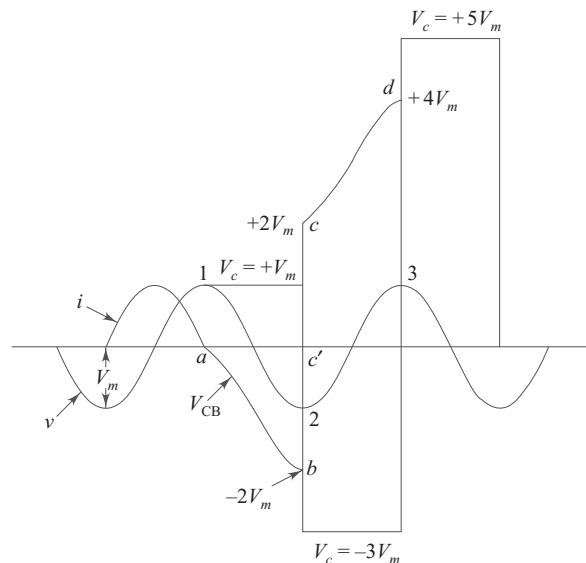


Fig. 14.17

factors like leakage reduce the severity of the problem. The leakage cannot be avoided and hence the voltage on the line falls sensibly from its maximum. Even so, in some cases voltages 2.5 times the normal peak have been observed on the line and 3.5 times across the circuit breaker.

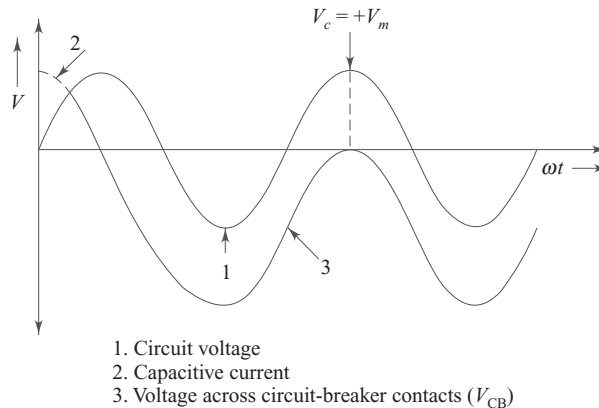


Fig. 14.18

If the re-strike free circuit breaker (like SF_6 and vacuum) is used, the voltage across circuit-breaker contacts will be as given by Fig. 14.18. Obviously, V_C will not remain constant at $+V_m$, as it will exponentially decay because of leakage through the surface of the insulator etc. But for quite a few cycles, V_{CB} will be a power frequency overvoltage of twice the magnitude with respect to the circuit voltage. This may be, in certain cases, worse than higher transient voltage. Therefore, re-strike free circuit breakers have to be designed to withstand this power frequency overvoltage to prevent the thermal failure of contact gap medium.

14.10 RESISTANCE SWITCHING

A deliberate connection of a resistance in parallel with the contact space (arc) is called *resistance switching*. Resistance switching is resorted to in circuit breakers having high post-zero resistance of contact space (air-blast circuit breaker, SF_6 circuit breaker, vacuum circuit breaker, oil circuit breaker with arc-control devices). By employing resistance switching, the frequency of the re-striking voltage is reduced and RRRV is reduced. The resistance also diverts the part of the arc current. The peak of the re-striking voltage is reduced and arc intensity is also reduced.

In the plain-break oil circuit breaker, the post-zero resistance of the contact space is low, hence resistance switching is not necessary. However, the resistance switching assists the circuit breaker in interrupting low magnetising currents and capacitive currents.

Resistance switching is a method to overcome the effect of overvoltages due to current chopping. In an air-blast circuit breaker, the pressure of air used for arc extinction is independent of the current to be interrupted. For low current interruption, the pressure is rather high and the current is chopped up before natural current zero. In vacuum circuit breaker, the current is cut off almost at the instant of contact separation. Therefore, severe voltages are developed across the contacts. These voltages may be large enough to cause spark-over outside the interrupter or the severe voltage transients are set up in the system causing damage to the insulation. Hence, some provision should be available to discharge these voltages. Resistance switching provides this provision.

A circuit breaker in which the dielectric strength of the contact space grows at a slower rate, the problem of re-striking voltage disturbance and current chopping is less severe because the gap would breakdown and absorb the magnetic energy in successive re-strikes.

During the case of interrupting small capacitive currents, if a suitable resistance is connected across the circuit breaker contacts, the charge on the capacitance would not be trapped, as the capacitance would discharge through the resistance.

Referring to Eq. (14.3) and for finding a transient solution,

$$\left[D^2 + \frac{R}{L}D + \frac{1}{LC} \right] i = 0$$

The complementary function of the above equation would be

$$\left[D^2 + \frac{R}{L}D + \frac{1}{LC} \right] = 0$$

$$D = -\frac{R}{2L} \pm \sqrt{\frac{R^2}{4L^2} - \frac{1}{LC}}$$

∴

$$\therefore \text{the roots are } -\frac{R}{2L} + j\sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}}$$

$$\text{and } -\frac{R}{2L} - j\sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}}$$

It can be expected that

(i) if $R < \sqrt{\frac{4L}{C}}$

$$\text{The term } \sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}} = \sqrt{\frac{1}{LC}}$$

$$\text{And hence natural frequency } f_n = \frac{1}{2\pi\sqrt{LC}}$$

The re-striking voltage would be undamped, which is the case we have already discussed.

$$(ii) \text{ if } \frac{R^2}{4L^2} = \frac{1}{LC}$$

$$\therefore R^2 = 4 \frac{L}{C}$$

$$\therefore R = 2\sqrt{\frac{L}{C}}$$

The re-striking transient would be critically damped out and amplitude would just be equal to the active recovery voltage.

(iii) if $R < 2\sqrt{\frac{L}{C}}$, the re-striking transient would be damped, the maximum amplitude would be reduced compared to the undamped case. Hence this would be the case of underdamped oscillations.

(iv) if $R > 2\sqrt{\frac{L}{C}}$, this would be the case of overdamped re-striking transient. In practice, this is the value of the resistance used by all circuit breakers where resistance switching is employed.

The complete transient solution will be given by,

$$i = e^{-at} (Ae^{jbt} + Be^{-jbt})$$

where $a = \frac{R}{2L}$ and $b = \sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}}$

At $t = 0, i = 0$

$$\begin{aligned} \therefore A + B &= 0 \quad \text{therefore } B = -A \\ \therefore i &= Ae^{-at}(e^{jbt} - e^{-jbt}) \\ \therefore i &= ke^{-at} \sin bt \\ \therefore \frac{di}{dt} &= kbe^{-at} \cos bt + (-a)e^{-at} \sin bt \\ \therefore \text{At } t = 0, \frac{di}{dt} &= kb \end{aligned} \tag{14.15}$$

From the original equation (Eq. 14.3),

$$L \frac{di}{dt} + \frac{1}{C} \int i dt + iR = v$$

At $t = 0, \quad \frac{1}{C} \int i dt = V_c = 0, i = 0.$

$$\begin{aligned} \therefore L \frac{di}{dt} &= v \\ \therefore \frac{di}{dt} &= \frac{v}{L} \end{aligned} \tag{14.16}$$

Comparing Eqs (14.15) and (14.16),

$$\begin{aligned} kb &= \frac{v}{L} \\ \therefore k &= \frac{v}{Lb} \\ V_c &= \frac{1}{C} \int i dt = \frac{1}{C} \int k(e^{-at} \sin bt) dt \\ &= \frac{v}{LCb} \int (e^{-at} \sin bt) dt \end{aligned}$$

Now $\int (e^{-at} \sin bt) dt$

$$\begin{aligned} &= \frac{-(e^{-at} \cos bt)}{b} - \int (-ae^{-at}) \frac{(-\cos bt)}{b} dt \\ &= \frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b} \int (e^{-at} \cos bt) dt \\ &= \frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b} \left[\frac{(e^{-at} \sin bt)}{b} - \int \frac{(-ae^{-at}) \sin bt}{b} dt \right] \\ &= \frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b} \left[\frac{(e^{-at} \sin bt)}{b} + \frac{a}{b} \int (e^{-at} \sin bt) dt \right] \end{aligned}$$

$$= \frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b^2} (e^{-at} \sin bt) - \frac{a^2}{b^2} \int (e^{-at} \sin bt) dt$$

$$\therefore \left[1 + \frac{a^2}{b^2} \right] \int (e^{-at} \sin bt) dt = \frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b^2} (e^{-at} \sin bt)$$

$$\therefore \int (e^{-at} \sin bt) dt = \frac{\left[\frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b^2} (e^{-at} \sin bt) \right]}{\left[1 + \frac{a^2}{b^2} \right]}$$

$$\therefore V_c = \frac{v}{LCb} \frac{\left[\frac{-(e^{-at} \cos bt)}{b} - \frac{a}{b^2} (e^{-at} \sin bt) \right]}{\left[1 + \frac{a^2}{b^2} \right]} + k'$$

At $t = 0$, $V_c = 0$

$$\therefore 0 = - \frac{\left[\frac{v}{LCb} \right] \left[\frac{1}{b} + 0 \right]}{\left[1 + \frac{a^2}{b^2} \right]} + k'$$

$$\therefore k' = \frac{\left[\frac{v}{LCb} \right] \left[\frac{1}{b} \right]}{\left[1 + \frac{a^2}{b^2} \right]}$$

$$= \left[\frac{v}{LCb} \right] \left[\frac{1}{b} \right] \left[\frac{b^2}{a^2 + b^2} \right] = \frac{v}{LC(a^2 + b^2)}$$

$$\therefore V_c = \frac{v}{LC} \left[\frac{1}{(a^2 + b^2)} - \frac{(e^{-at} \cos bt) + \left(\frac{a}{b} \right) (e^{-at} \sin bt)}{(a^2 + b^2)} \right]$$

$$\therefore V_c = \frac{v}{LC} \left[\frac{1 - (e^{-at} \cos bt) - \left(\frac{a}{b} \right) (e^{-at} \sin bt)}{(a^2 + b^2)} \right]$$

Now
$$a^2 + b^2 = \frac{R^2}{4L^2} + \frac{1}{LC} - \frac{R^2}{4L^2} = \frac{1}{LC}$$

$$\therefore V_c = v \left[1 - \frac{e^{-at}}{b} (b \cos bt + a \sin bt) \right]$$

Here
$$\omega = 2\pi f_n = b$$

$$\therefore f_n = \frac{1}{2\pi} \sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}}$$

Thus with R neglected, there will be large RRRV, high natural frequency and the peak of re-striking voltage will be twice the active recovery voltage V as proved previously.

$$\text{But if } R = 2\sqrt{\frac{L}{C}}$$

$$f_n = \frac{1}{2\pi} \sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}}$$

which will be less than the case with R neglected, RRRV reduced and peak value attained by re-striking voltage reduced and damped at the lower value than double.

$$\text{Now if } R = 2\sqrt{\frac{L}{C}}$$

$$f_n = \frac{1}{2\pi} \sqrt{\frac{1}{LC} - \frac{R^2}{4L^2}} = 0$$

i.e., there is no re-striking transient at all,

$$b = 0, a = \frac{R}{2L}$$

$$V_c = v$$

$$V_{c\max} = v, \text{ as shown in Fig. 14.19.}$$

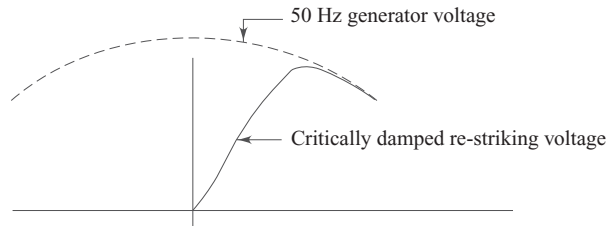


Fig. 14.19

Thus it can be clearly seen from the derived expressions that by including the shunt resistor across the circuit breaker, the oscillatory wave shape of the restriking voltage changes into a periodic one. By doing so even for larger faults, though the dielectric strength of the gap increases less slowly, the arc gets extinguished. Thus, the rupturing capacity of the circuit breaker is increased by including shunt resistance.

Figure 14.20(a) illustrates the typical relationship of RRRV of ABCB with the natural frequency of oscillation, for both cases of with and without shunt resistors. The increase of breaking capacity of ABCB with the natural frequency of oscillation, with inclusion of shunt resistors in comparison to without shunt resistors is shown in Fig. 14.20(b). The effect of shunt resistor on the RRRV and breaking capacity follows as per the expressions derived earlier.

Either linear or non-linear resistors can be used. Non-linear resistors are especially suitable from space and reliability considerations. An approximate idea of the value of a shunt resistor to perform various duties can be given as follows:

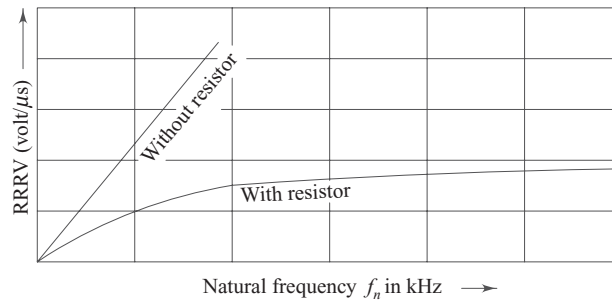


Fig. 14.20(a) Effect of shunt resistor on RRRV

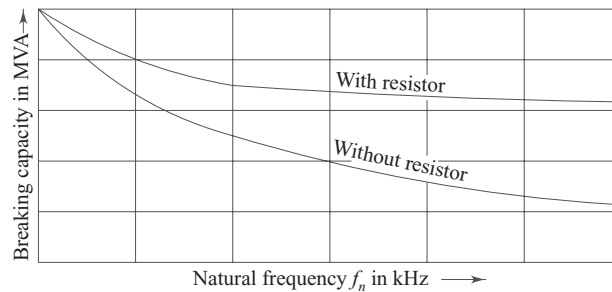


Fig. 14.20(b) Effect of shunt resistor on breaking capacity

- (i) To equalise voltage distribution across two or more breaks, high values (10000 to 100000 ohms) are required.
- (ii) To suppress overvoltages due to current chopping—10000 to 20000 ohms.
- (iii) To avoid damage when switching capacitive currents—2000 to 5000 ohms.
- (iv) To control RRRV—1000 to 2000 ohms for oil circuit breaker and 50 to 100 ohms for medium-voltage air blast circuit breaker

The higher values, (i) and (ii), may be non-linear resistors. The low values of resistors (iv) would require impracticably large non-linear units and hence wire-wound linear resistances are used for this purpose.

14.11 QUENCHING OF DC ARC

Let,

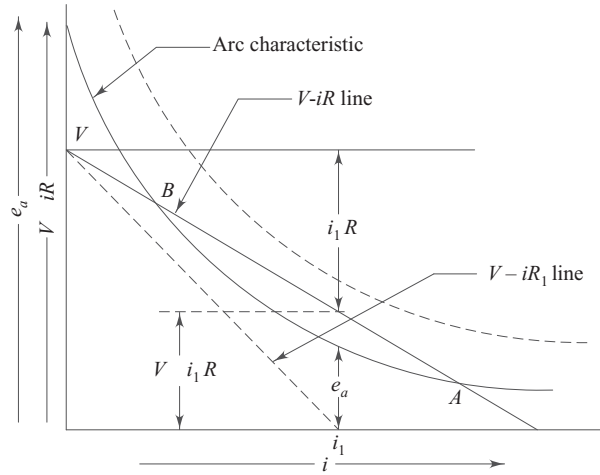
V = emf of the circuit

i = current through the arc

R = circuit resistance

The arc characteristic and the straight line $V - iR$ are plotted in Fig. 14.21.

As shown, A and B are the points of intersection for the two characteristics. At points between A and B , the arc voltage available for the arc is greater than required. At A and B it is just equal to the voltage required. A is a stable point and B is an unstable one. At A any change in the current causes a change in $V - iR$, i.e., if current decreases, the arc voltage available is greater than that required. Hence the arc is maintained, intensified and current increases again to a value back to A . At B , an increase in current would cause e_a required to fall faster than increase in iR thus bringing about further increase till the point A is reached. A decrease in current

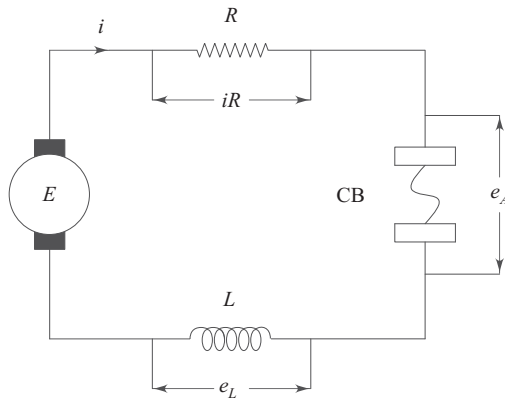

Fig. 14.21

causes e_a to rise faster than the fall in iR , thus causing a further decrease till zero value is reached, ultimately quenching the arc. While at A , the increase in current would cause e_a required to be higher than the available, arc resistance will hence increase and current will reduce back corresponding to the point A .

If the arc length is increased, the arc characteristic is shifted upwards and hence there may be no points of intersection between this and $V - iR$ line. In other words, the voltage available is never sufficient to maintain the arc current and it is quenched. The arc characteristic can also be shifted upwards by helping the process of de-ionisation which can be carried out by either blowing the arc or by cooling it. Instead of increasing the separation, the same effect can be obtained by increasing the external resistance in the circuit as shown in the $(V - iR_1)$ characteristic.

14.11.1 Effect of Circuit Inductance

Consider the circuit as given in Fig. 14.22.


Fig. 14.22

In Fig. 14.23, the curve CD is $E - iR$, and the curve PQ is the arc characteristic.

It is obvious that higher the di/dt , shorter is the arcing time; but with higher di/dt , arc-extinction voltage increases. Generally, a compromise is made between the arcing time and the arc-extinction voltage. Further details of HVDC circuit breakers are given in Section 15.2 in the next chapter.

REVIEW QUESTIONS

1. Explain how an arc is initiated in a circuit breaker.
2. Explain Slepian's theory of arc interruption and discuss its limitations. How does the energy-balance theory explain the process of arc extinction?
3. What are the factors to be considered while selecting the circuit breaker, given an application?
4. Which circuit breaker will you select for an arc-furnace duty of 11 kV and if the number of operations envisaged are at least 39 times a day?
5. In connection with circuit breakers, explain the significance of RRRV, TRV, recovery voltage and active recovery voltage.
6. Giving reasons, suggest a suitable type of circuit breaker for the following application:
220 kV, 7500 MVA circuit breaker for an overhead line. State the salient features of the circuit breaker suggested.
7. What is resistance switching? Prove, with derivation, that the re-striking voltage can be reduced by incorporating resistance switching in an air-blast circuit breaker.
8. Explain 'successive re-strikes' and 'current chopping' as applied to the interruption of capacitive and low-inductive currents respectively. How does the resistance help in such conditions?
9. Give reasons for the following statements:
 - (i) A self-blast circuit breaker takes a longer time to interrupt a small inductive current than a forced-blast circuit breaker.
 - (ii) Faults on a feeder at a small distance from the circuit breaker installed on it are likely to be more dangerous than close-in faults.
 - (iii) A resistor in parallel with circuit-breaker contacts may be used to control RRRV.
 - (iv) Self-blast circuit breakers often find it difficult to interrupt small inductive currents, while in forced-blast circuit breakers, chopping is likely to occur when dealing with such currents.
 - (v) A circuit breaker can deal with a higher short circuit MVA in a cable network than in an overhead system.
 - (vi) A circuit breaker finds it easier to interrupt asymmetrical fault currents than the symmetrical fault currents of the same rms value.
 - (vii) Interruption of fault current at zero power-factor lagging represents a more difficult condition for a circuit breaker than the interruption of load current at 0.8 power factor lag.
 - (viii) While clearing short circuit, worst possible overvoltage across circuit-breaker contacts can be approximately 6 times phase to neutral voltage of the system.
 - (ix) Use of re-strike free circuit breaker can reduce the overvoltage factor when capacitive currents are interrupted.
10. A 3-phase, 132/66 kV substation has a number of outgoing feeders on the 66 kV side, each served by a circuit breaker and each having a reactance of 0.35 ohm/ph/km. The fault level on the 66 kV side is 800 MVA. Calculate the value of the short-circuit current and estimate the maximum voltage across the circuit-breaker contacts for a fault on the feeder at a distance of 10 km from the circuit breaker, situated in that feeder. **(4259.93 A, 107.777 kV)**
11. A substation has a large number of feeders connected to its bus-bar, each being protected by a circuit breaker. Derive expressions for RRRV and the maximum voltage across the circuit breaker contacts in terms of fault current, feeder parameters and distance of the faults from circuit breaker. Also derive the condition for maximum severity for the circuit breaker.
The fault level of a certain 132/66 kV substation is 500 MVA on the 66 kV side. It serves a large number of feeders, each having a reactance of 0.33 ohms/phase/km. Determine the distance from the

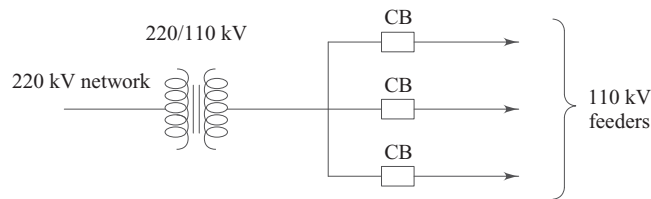


Fig. 14.25

substation of a location on a feeder, a fault at which would cause the circuit breaker installed on the feeder to experience the severe-most condition neglecting resistance. **(13.2 km)**

12. Explain the terms 'severity factor' and 'kilometric fault'.

A 132/66 kV substation supplies a large number of feeders on the 66 kV side. The equivalent reactance of the source side referred to the 66 kV side is 1.5 ohms/phase and inductance of each is 1.1 mH/km/phase. Determine a point on a feeder at which the severity factor is maximum. Also, find the severity factor (i) at the start of the feeder, and (ii) at a distance of 50 km from the start, in terms of maximum value. Neglect resistances.

(2.17 km, 0, 3.9658%)

13. A 66 kV, 3-phase feeder is protected by a 250 MVA circuit breaker installed at the substation. If the feeder has an inductance of 1 mH/km, determine the point on the feeder, a fault at which, would cause a severity factor at the circuit breaker to be maximum. Assume that the circuit breaker is selected so as to be just capable of dealing with the maximum short-circuit current. Neglect resistance. **(27.74 km)**

14. Derive an expression for the distance of the fault from the circuit breaker which causes the severe-most conditions for the circuit breaker.

A 132/66 kV substation has large number of feeders going out from the 66 kV bus. Each of these feeders has a reactance/phase of 0.3 ohms/km, and the source reactance including that of the transformer is 4.5 ohms, referred to the 66 kV side. Estimate the distance of a point on the line, a fault at which would cause the maximum severity factor at the circuit breaker. Determine also the value of this severity factor. Neglect resistances.

(7.5 km, $1.34927 \times 10^{12} \text{K}$)

15. Figure 14.25 shows a 220/110 kV, 50 Hz substation supplying a number of feeders on the 110 kV side. The equivalent reactance of the transformer and

the 220 kV network referred to the 110-kV side is 25 ohms. The 110 kV feeders have an inductance of 1.3 mH/km/phase. Determine on the feeder at which the factor of severity is maximum. Calculate also the factors of severity for three-phase symmetrical faults at (a) the start, and (b) the far end of a 100 km, 110 kV feeder, in terms of the maximum value. Neglect resistances.

(30.63 km, severity factor at start = 0, severity factor at 100 km = 60.43% of maximum value)

16. A 220/33 kV substation has a number of feeders on the 33 kV side. The source impedance is 6 ohms/phase. Determine whether a three-phase symmetrical fault on a feeder that is 2 km from the circuit breaker installed on the feeder would be more severe than a similar fault at 6 km. Also, find the distance on the feeder from the substation, a symmetrical fault at which would be severe-most for the circuit breaker. Neglect resistances. The reactance of feeders is 1 mH/ph/km.

(Fault at 6 km is more severe, maximum severity is at a distance of 9.55 km)

17. Find out the natural frequency of transient overvoltage when circuit breaker is opened on fault. Assume $L = 0.5$ henry and $C = 5000$ pF. What will be the natural frequency if a deliberate resistance of 10 k Ω is added across circuit-breaker contacts?

(3183 Hz, 2756.64 Hz)

18. Find out the overvoltage factor due to maximum overvoltage produced while interrupting a no-load current of 220/400 kV, 350 MVA transformer. Assume (a) 400 kV side to be the load side, (b) phase-to-neutral capacitance of the system to be 5000 pF, and (c) no-load magnetising current to be 1% of rated current.

(1218.18 kV)

19. What is the peak value of the power frequency overvoltage across contacts of a circuit breaker when an unloaded 400 kV transmission line is switched off?

(1131.37 kV)

20. Find out the maximum probable value of the voltage produced when an unloaded 220/66 kV, 250 MVA, three-phase transformer is disconnected from the 220 kV, 50 Hz source. Assume the no-load current to be 1% of the rated current and capacitance between the phase and ground to be 5000 pF.
(1029.95 kV)
21. Describe the phenomenon of extinction of arc in a dc circuit breaker. Why is it easier to quench an ac arc than a dc arc?

MULTIPLE CHOICE QUESTIONS

1. The arc extinction in a circuit breaker is influenced by
 - (a) magnitude of arc current only
 - (b) RRRV only
 - (c) rate of rise of dielectric strength of medium only
 - (d) all of the above factors
2. The most severe voltage stress occurs across the circuit breakers for
 - (a) L-L fault
 - (b) L-L-g fault
 - (c) L-L-L fault
 - (d) L-g fault
3. The most severe condition with reference to kilometric (short-line fault) for a circuit breaker is when the ratio of fault current to the short-circuit current for fault at the circuit-breaker terminals is
 - (a) 1/3
 - (b) 1/2
 - (c) 2/3
 - (d) 1
4. Current-chopping phenomenon in a circuit breaker is associated with
 - (a) capacitive current
 - (b) small inductive current
 - (c) resistance switching
 - (d) short-line faults
5. The value of resistance used for resistance switching with the circuit breaker having high post-zero resistance is typically
 - (a) $R \ll L$
 - (b) $\frac{R^2}{4L^2} = \frac{1}{LC}$
 - (c) $R < 2\sqrt{\frac{L}{C}}$
 - (d) $R > 2\sqrt{\frac{L}{C}}$

where L is the series inductance and C is the shunt capacitance at the circuit-breaker contacts.

Electrical Switchgear

In this chapter the details of high-voltage circuit breakers, isolators and low-voltage switchgear like fuses, miniature circuit breakers and earth leakage circuit breakers are explained. A generic common term 'electrical switchgear' can be used for these devices. The constructional aspects, working principle, applications and comparative merits and demerits are the significant features described here. The main factors responsible for the arc-extinction process in a circuit breaker are the rate of rise of recovery voltage and the rate of gain of dielectric strength of the arc-quenching medium. The different materials used for contacts of a circuit breaker are as follows:

1. Copper
2. Copper Beryllium (Cu-Be)
3. Copper Cadmium (Cu-Cd)
4. Copper Chromium (Cu-Cr)
5. Copper Tungsten (Cu-W)
6. Silver-Cadmium Oxide (Ag-Cd-O)
7. Silver Tin Oxide and Silver Zinc Oxide (Ag-Sn-O₂ and Ag-Zn-O)
8. Silver Tungsten (Ag-W)
9. Silver Tungsten Carbide (Ag-W-C)

Before 1950, copper contacts were widely used in circuit breakers and contactors. But the problem with copper contacts is due to the oxide (CuO₂) that is formed during switching operations. This oxide is a poor conductor of electricity. The

15

Introduction

build-up of an oxide layer renders the contacts useless. One of the solutions is to use silver plating over the contacts, which stops the oxide formation. But the arc burns off the silver plating during the current-interruption period due to the very high heat developed during that time. So silver-plated copper contacts can be used as the main contacts where the heat production is comparatively low with respect to the arcing contacts (arcing contacts are used to dissipate most of the arc energy through it).

Cu-Be is used primarily for contact springs, where the beryllium content is about 1.5 to 2.5%. This alloy has a lower conductivity than copper (15 to 25% of copper). Also, the material is much stronger structurally. Cu-Cd contains 1.5 to 2.0% cadmium. The strength of this material is 1.5 to 2 times that of copper. The conductivity reduces by about 8 to 25% with respect to copper. Cu-Cr is the strongest available alloy, which can be used as a backing material for silver contacts. The chromium content is 0.3 to 1.2%. Cu-W is made by the sintering process. The tungsten content can be 20 to 80%. The conductivity ranges from 30 to 50% of copper. Cu-W contacts are used as arcing contacts. Ag-Cd-O is a much harder material than silver. It has more resisting power against the welding process. Cd-O gas is dissociated in the arc. This helps in early arc quenching. Ag-W, Ag-W-C and Ag-Ni contacts have low contact resistance, low change in contact resistivity when it is used with a high number of switching operations, and low erosion rate.

15.1 HIGH-VOLTAGE AC CIRCUIT BREAKERS

In this section, the constructional mechanism and working of various types of ac circuit breakers are explained. Based on the type of medium and arc-quenching mechanism used, several types of circuit breakers have been developed and are being used in practice. The names of the circuit breakers are given based on the medium used inside the circuit breaker for contact separation and arc extinction.

15.1.1 Air-Break Circuit Breakers

The air-break circuit breakers are available in the range of 415 volts to 11 kV rating, the rated continuous current ranging from 100 to 4000 A and breaking current capacity up to 80000 A. As the name suggests, the insulation between the two contacts is air at normal temperature and pressure. The operating mechanism can be pneumatic, solenoid-operated or spring-operated. In case of a spring-operated mechanism, the spring is to be charged by an induction motor (motor-operated spring mechanism). The performance and cost of the breaker is mainly decided by its breaking capacity. While breaking the fault currents, large electro-dynamic forces are produced, not only due to high current but also due to asymmetry of the fault current. These electro-dynamic forces act on the operating mechanism and because of these forces, there is a tendency for contact opening. This may deteriorate the contact surfaces. Immediately after the fault current is interrupted, large high-frequency voltage transients are produced across the contacts. The magnitude of these transients and RRRV depend upon the type of the fault and the location of the fault as already discussed in Chapter 14. Both of these, high voltage and high current, decide the breaking capacity (i.e., the capacity of the breaker to deal with high currents without being damaged).

Figure 15.1 shows the constructional mechanism of one pole of an air-break circuit breaker. The main contacts carry the normal current without giving a high millivolt drop, and the contacts must be made with enough pressure because there could be an opening tendency even when the rated current is carried by the breaker, particularly for breakers with higher current ratings. The main contacts are made of copper cadmium alloys. The arcing contacts are made up of heat-resistant material like copper tungsten, or silver tungsten.

While opening, the main contacts open first and there is negligible arcing at the main contact tips as a parallel path is available through the arcing contacts. This is because of the compression spring. While making, the arcing contacts are made first and the main contacts are made following it. This can be clearly seen from Fig. 15.1. The making duty of the breaker is much more difficult than the breaking duty. When the circuit breaker is closed onto a fault there can be arcing at the contact tips and the current would be very high (2.5 to 2.8 times the symmetrical breaking current).

The arc produced while making or breaking the fault current is highly intense. The temperature in the arc varies from 6000°C at the periphery of the arc to as large as 15000°C at the core of the arc. Because of this reason special arcing contacts are used. The main contact material would be otherwise burnt off or the contact welding may result. As shown in Fig. 15.1, the arc that is struck on the arcing contact tips immediately travels onto the arc runners because of thermal and electromagnetic forces. As the arc runners have a horn-type shape, the arc is lengthened which increases the arc resistance, reduces the intensity of the arc and moves the arc into comparatively a cooler area. This helps in the de-ionising process. When the voltage across the arc is less than that is required to maintain the arc, it may be quenched. Further help in quenching is provided by arc splitters.

There are two alternatives prevalent for arc splitting:

1. Conducting arc splitters
2. Insulating arc splitters

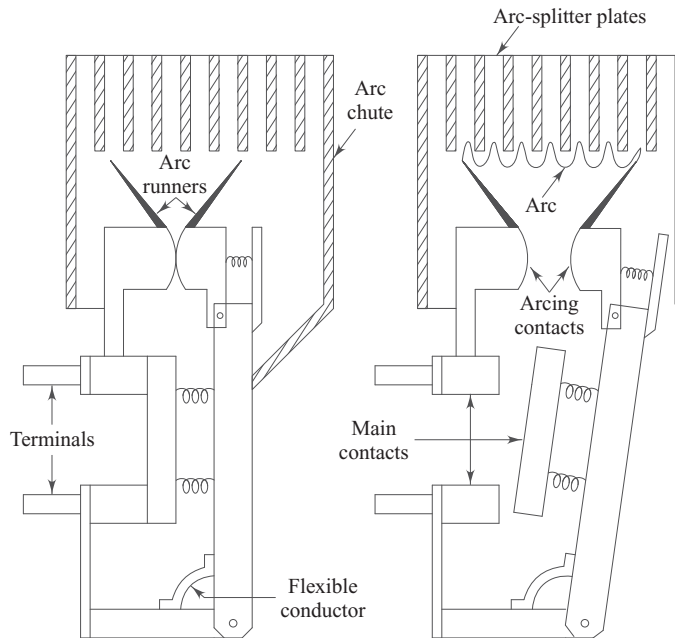


Fig. 15.1 Constructional mechanism of air-break circuit breaker

In the case of conducting arc splitters, the conduction of heat of arc onto the surfaces of arc splitters helps in faster heat dissipation. In case of insulating arc splitters, the arc is split into many smaller arcs and lengthened further. This gives rise to faster arc quenching. Thus arc is quenched by lengthening, splitting and cooling processes. Also, the inherent resistance of the arc reduces the peak of the re-striking voltage and RRRV (Rate of Rise of Re-striking Voltage), thereby increasing the breaking capacity of the breaker.

15.1.2 Bulk-Oil Circuit Breaker

As the name suggests, this type of circuit breaker uses insulating oil as the arc-quenching medium. The same oil serves the purpose of insulating the live parts from ground (tank). The oil has dielectric strength approximately seven times that of air at normal temperature and pressure. Hence the use of oil will reduce the breaker size considerably.

As shown in Fig. 15.2(a), the oil is filled in the earthed tank. The live conductors enter into the tank through high-voltage bushings. These bushings are hollow porcelain containers. The live conductor passes through the centre of the bushings. The mixture of quartz powder and oil is filled between the live conductor and inner surface of the bushing. The complete arrangement properly insulates the high-voltage conductor from the ground, maintaining the even distribution of electric field intensity in the area of high-voltage stresses. In most of these arrangements, the current transformers are mounted inside the bushings.

The control arm receives the opening signal and the contacts are detached, i.e., the moving contact is separated from the fixed contact. At the instant of separation, the arc is struck between the moving and fixed contacts [Fig. 15.2(b)]. Because of the heat of the arc, the oil gets decomposed into hydrogen and carbon, as the oil is basically hydrocarbon. Hydrogen has two important properties. It acts as a coolant and it has a good dielectric strength. Because of cooling action, the thermal ionisation process is curbed and, therefore, it helps in arc quenching. As the hydrogen has high dielectric strength, the contact gap recovers the dielectric strength

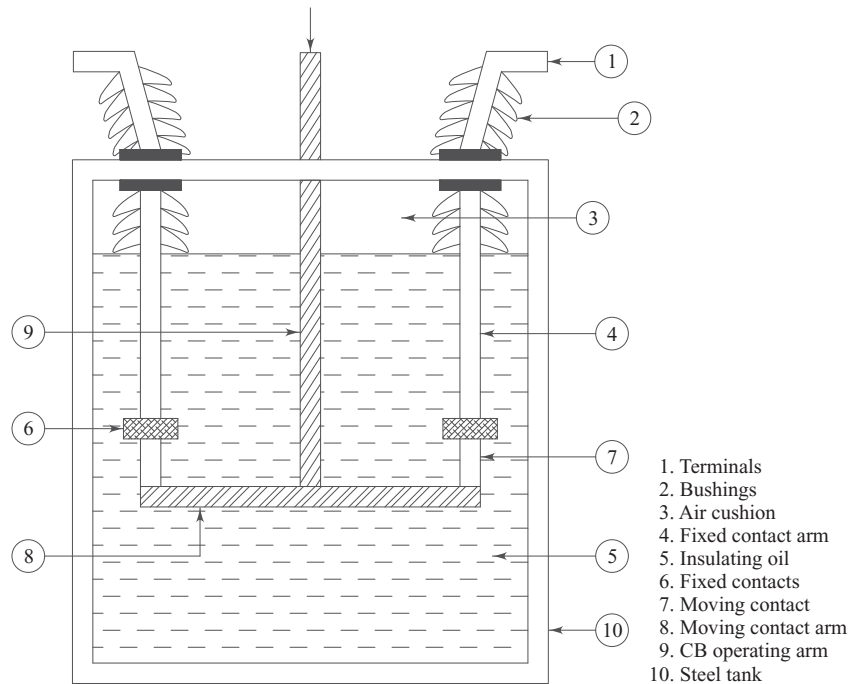


Fig. 15.2(a) Schematic diagram of bulk-oil circuit breaker

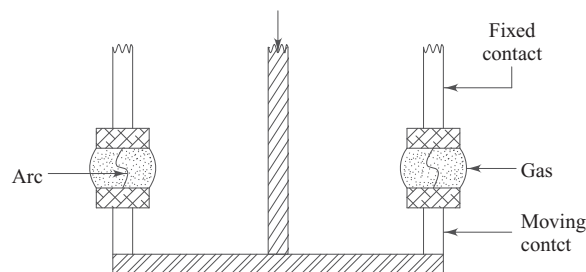


Fig. 15.2(b) Opening of bulk-oil circuit breaker

at a faster rate. At the instant of production of arc, as the current is large, a violent turbulence occurs at the contact gap. This also helps to quench the arc. The disadvantage is that there is no pressure developed in the contact gap. This results in comparatively slower arc quenching than in the case of breakers equipped with high gas pressure between the contact gap. The carbon that is produced due to decomposition of oil is a good conductor of electricity; hence it reduces the dielectric strength of the oil. Also as carbon is not soluble in oil, the carbon content in the oil depends upon the number of arcing (number of switching). This is the reason why the oil circuit breakers are not suitable when the switching frequencies are large.

Another disadvantage of oil is that the dielectric strength of oil deteriorates severely if the moisture permeates the oil. Another demerit is the high inflammability of oil. Typically, once in every three months, the oil in the oil circuit breaker is required to be filtered to remove carbon content, moisture and dissolved gases to build up the dielectric strength. Frequent maintenance of contact surface is also required.

Arc control device is fitted in oil circuit breaker to overcome the limitation of low breaker time.

Arc Control Devices Arc control device is a cylindrical structure manufactured from resin-bounded fibre glass (insulating material). The fixed contact assembly is within the arc control device. The moving contacts are made with the fixed contacts within this device. When the opening command is received, the moving contacts are separated from the fixed contacts as shown by the arrow in Fig. 15.2(c). The oil, due to the arc that is struck between fixed and moving contacts, gets converted into gas (Fig. 15.2(d)). The pressure is generated because the gas needs more volume but this is not available. In third stage (Fig. 15.2(e)), the moving contact comes out of arc control device. The pressurised trapped gas therefore comes out with high velocity. This will result in blast effect on the arc, due to which the arc gets lengthened and quenched fast. The breaker time of the order of 2 cycles is technically feasible as against 5 cycles for plain break oil circuit breakers. Such circuit breaker that is fitted with arc control device is called self blast circuit breaker because the blast is created by arc current itself. The pressure of the gas, therefore, depends on the magnitude of the arc current. Therefore, these circuit breakers will quench the arc rapidly in case of heavy faults because of production of higher gas pressure at these high currents. But on the other hand, such circuit breakers find it difficult to quench the arc produced due to interruption of low inductive or capacitive currents. Because in such cases, the pressure developed within arc control device is so small that there is practically no blast effect when the moving contact comes out of arc control device and hence arc persists for comparatively longer time. Resistance switching arrangement (not shown in fig.) is also provided when arc control device is fitted.

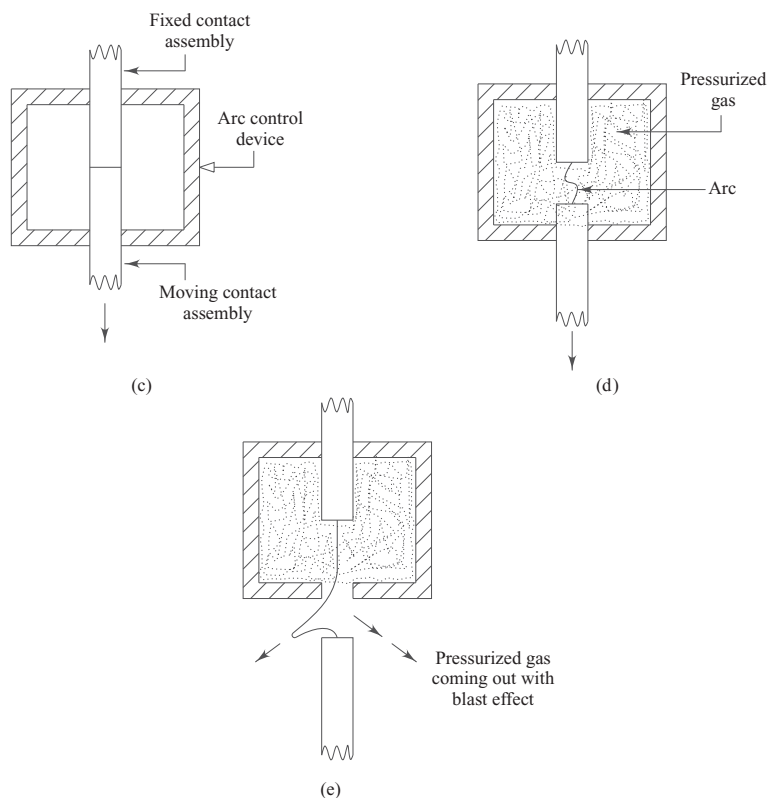


Fig. 15.2(c), (d), (e) Opening sequence of arc control device

15.1.3 Minimum Oil-Circuit Breaker

In a bulk-oil circuit breaker, the tank is at earth potential and the necessary clearances for the system voltage must be obtained in oil. In the minimum oil-volume circuit breaker, the tank is a tube of insulating material held between metal end caps. As these caps are terminals for the external circuit, the tank is live. This assembly (known as interrupter assembly) has therefore to be supported on one or more insulators suitable for system voltage and impulse level.

As shown in Fig. 15.3, the oil used in the circuit-breaking compartment (arc-interruption chamber) is segregated from that used for insulation purposes, the latter is never contaminated by the former.

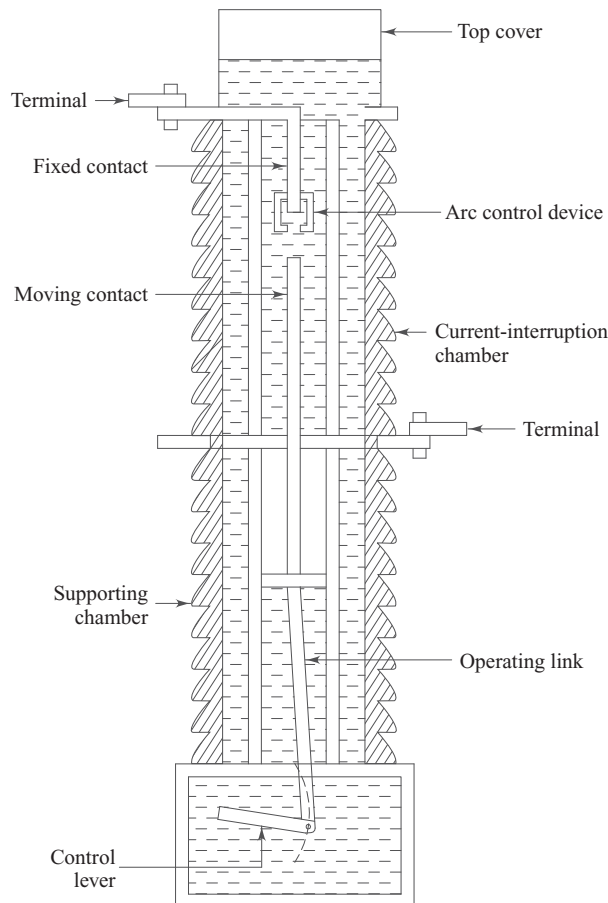


Fig. 15.3 Schematic diagram of minimum-oil circuit breaker

Arcing under oil causes carbonisation and sludging and in any oil circuit breaker, replacement and/or purification of oil is essential from time to time. Requirement of small quantity of oil (and hence the smaller size) is an advantage of a minimum-oil circuit breaker over a bulk-oil circuit breaker. However, it is a disadvantage with reference to the frequent maintenance requirements. As the quantity of oil is small, carbonisation and sludging is more, in case of frequent switching.

15.1.4 Air-Blast Circuit Breaker

Figure 15.4 shows the principle of arc extinction in an air-blast circuit breaker. The moving contact is making a firm contact with a fixed one due to pressure of the compression spring as shown in Fig. 15.4. When the trip command is received, the valve between the pressurised air tank and the arc chamber opens out allowing high-pressure air to rush into the arc chamber. Pressurised air does two functions. Firstly, it is part of the pneumatic operating mechanism. The pressurised air works against the spring pressure and pushes the moving contact as shown in Fig. 15.4(b), bringing in the separation between the two contacts. Secondly, it works as an arc-quenching medium. The arc that is struck between the moving and fixed contact due to separation is elongated and quenched very fast because of high pressure of air. Also, as pressurised air has much more dielectric strength than air at normal temperature and pressure, the high overvoltages (between the two contacts) can be withstood by the pressurised air medium immediately following the arc extinction. The ionised arc products are vented through the vents shown in Fig. 15.4.

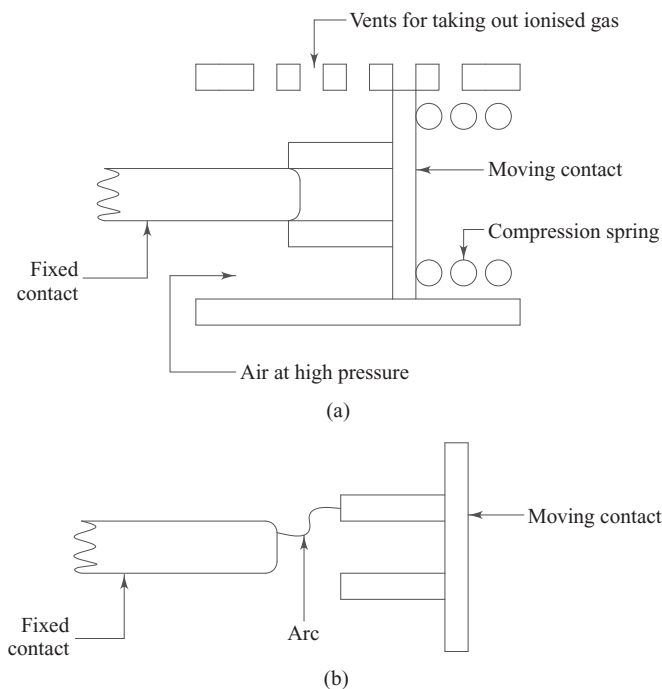


Fig. 15.4 Principle of arc quenching

To carry high normal currents continuously, each pole has three current paths in parallel, typically as shown in Fig. 15.5. From this figure, it is seen that the two outer paths contain a pair of parallel current chambers 'S' and the isolating switches 'T'. The middle path consists of three arcing chambers L_1 , L_2 , L_3 and 'K', the resistance current breaking chamber.

On receipt of a trip command, the four load-bearing contacts 'S' open first leaving the full current carried by the central path. The contacts at L_1 , L_2 and L_3 now open to interrupt the current through a blast of air at a pressure ranging from 9 to 16 kg/cm² (this varies from one design to another). As the resistors are in parallel, fast arc quenching is facilitated. This is followed by opening of contacts 'K' to interrupt the resistor current, which is a very simple interruption. Finally, isolator blades 'T' opens out and contacts S, L_1 , L_2 , L_3 and K

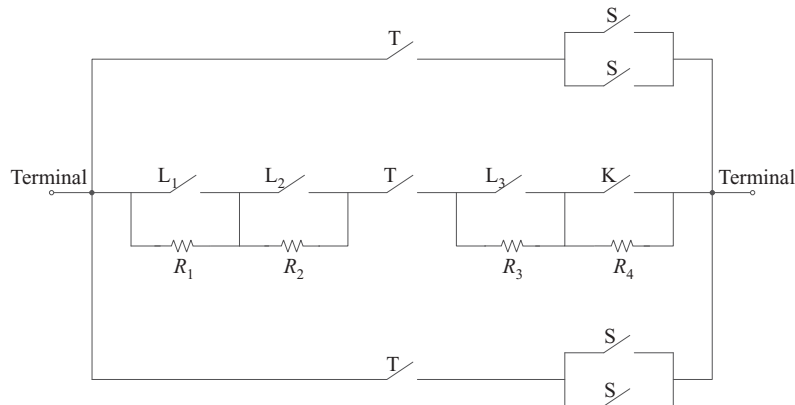


Fig. 15.5 Parallel current paths for a pole

re-close. Isolation is guaranteed by 'T'. Actually on stoppage of pressurised air being fed to the chambers S, L and K, these contacts will automatically re-close because of spring pressure. This is required as maintenance of high pressure in load bearing chambers and arc chambers is not possible. Due to the leakages, air will leak. For high-pressure maintenance, the air compressors are continuously required to be run which is very costly.



Fig. 15.6 Equivalent circuit of ABCB

After the arc is quenched, the isolating switch shown in the equivalent circuit diagram (Fig. 15.6) will open out. Obviously, there will be no arcing at the contact tips of the isolating switch as it opens at no load. The required clearance is guaranteed by this isolating switch. The valve feeding air to arc chamber is now closed restoring air pressure in the arc chamber to atmospheric value. Hence the moving contact will touch the fixed contact due to pressure of compression spring. The reverse process will happen on receiving the closing command.

Travel Velocity Curve of ABCB For the forced-blast circuit breaker designs, it has a feature that there is a critical gap length for a given blast condition at which the interrupting capacity is maximum. If the gap length is less than this critical value then the arc re-strikes may occur due to overvoltages at the instant of arc extinction leading to reduction in breaking capacity. If the gap length is more, the air pressure might have reduced by the time the arc is quenched. This reduces the dielectric strength of the medium bringing in the reduction of the rupturing capacity of the breaker. Figure 15.7 shows the typical travel-velocity curve of ABCBs. If the moving contact travels fast as shown in the curve 1, the arc gets quenched probably at first current zero when the critical gap is reached. The slower contact velocity shown by the curve 2 is not desirable. In this case, the arc gets quenched at 5th or 6th current zero and by this time the air pressure would have reduced giving rise to the possible re-strike. This suggests that the critical gap length and velocity of contacts both are important factors for improving the breaking capacity of a breaker.

In the case of provision of isolating switch, the travel velocity curve is as shown in Fig. 15.8. Here, 3 shows the curve for the moving contact. In this case, moving contact separates and when the separation is

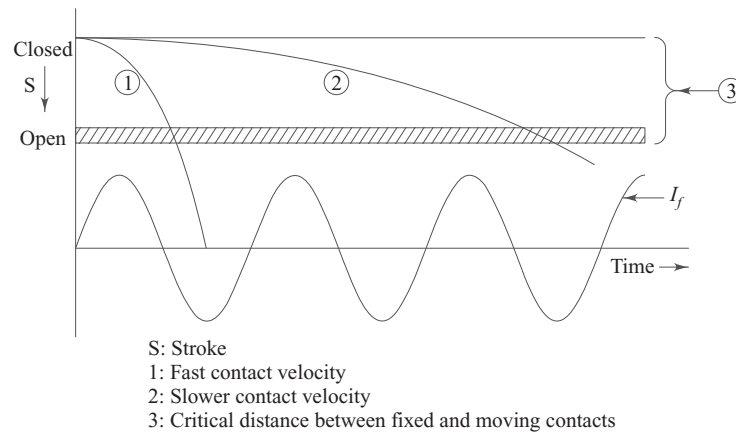


Fig. 15.7 Travel velocity curve of ABCB

equal to the critical length, the moving contact holds. The arc is then quenched and the isolator starts opening out. On full opening of the isolator (curve 4), the moving contact re-closes with the fixed contact as shown by the curve 3.

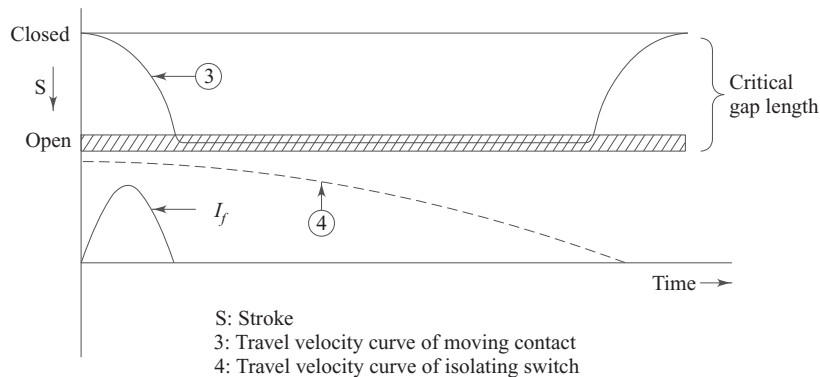


Fig. 15.8 Travel velocity curve of ABCB with isolating switch

Figure 15.9 shows the schematic diagram of one pole of an air-blast circuit breaker having two breaks per pole. When the circuit breaker is carrying the current, the main contacts are firmly closed because of compression spring pressing the moving contact onto the fixed contact.

Arcing contacts are normally open. When the tripping command is received, the valve (not shown in the figure) is opened and pressurised air rushes from the air receiver (there is an individual receiver for each breaker at the bottom of the breaker) to the arc chamber as shown in the figure. Because of air pressure, arcing contacts close first and the main contacts then open out. This opening is brought about by pressing the moving contacts against the force of the spring. The arc struck across the main contacts is quenched by axial flow of air. The current now passes through the resistor column and hence the arc struck across the arcing contacts is easily quenched. The isolating switch (not shown in the figure) is now opened as a part of the operating sequence and then the air valve is closed. The main contacts will now close because of spring pressure and arcing contacts will open out, the opening of the breaker being guaranteed by the isolating

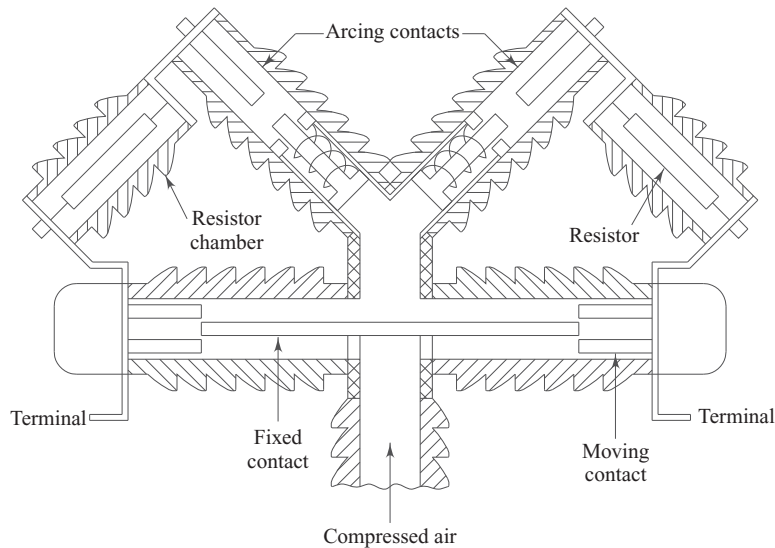


Fig. 15.9 Schematic diagram of air-blast circuit breaker

switch. The forced-blast principle used in the breaker deals with interruption of low magnetising currents and low capacitive currents easier than the self-blast principle used in an *OCB* fitted with arc control devices. Fresh air can be used for every arcing and hence this breaker is suitable for repeated operations. Designs of up to 735 kV, 10000 MVA exist in practice.

For equalising voltage distribution across the breaks in multi-break circuit breakers, the capacitors are connected across each break as shown in Fig. 15.10. The value of a capacitor is so selected that when the breaker is in open condition, this shunt capacitor current plays a predominant role and equalises the voltage across each break.

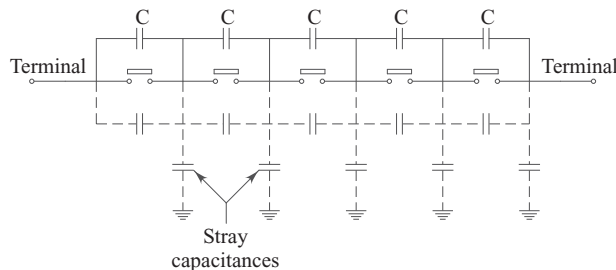


Fig. 15.10 Voltage distribution in a multi-break circuit breaker

The demerits of air-blast circuit breakers are given as follows:

1. An air-blast circuit breaker is noisy in operation.
2. *ABCs* require costly compression plants.
3. *ABCs* are not suitable for polluted atmospheres, coastal areas and moist areas.
4. It is not desirable to use *ABCs* in areas like petrochemical plants, fertiliser plants, mines, etc.

5. ABCBs suffer from a problem of current chopping that gives rise to heavy overvoltages that may result in re-strike of an arc.
6. ABCBs cannot be used as auto-reclosures as auto-reclosing would require large receiver tanks; otherwise the air pressure may not be sufficient and the dielectric strength would reduce resulting in arc re-strike.

15.1.5 Sulphur Hexafluoride (SF₆) Circuit Breakers

SF₆ circuit breakers have emerged as very popular circuit breakers because of their excellent rate of recovery of dielectric strength. Actually, all new installations now use SF₆ breakers for voltage rating ranging from 11 kV (or even 6.6 kV) to as high as 735 kV. Air-blast circuit breakers are becoming obsolete slowly. SF₆ enclosed indoor metal-clad switchgears are also very popularly used. Before discussing different designs of SF₆ breakers, we will initiate our studies with the properties of SF₆.

Physical Properties of SF₆ Gas

1. It does not have any colour as well as odour.
2. The gas starts liquefying at 10°C at a gas pressure of 15 kg/cm². Hence this gas cannot be used at a pressure higher than 15 kg/cm². However, over the ranges of pressures and temperatures required to provide high dielectric strength and arc extinctions, there is no risk of liquefaction.
3. The gas is non-toxic. However, decomposition of SF₆ under electrical discharges forms lower order fluorides (SF₂ and SF₄). These products are toxic and corrosive to many insulating and conducting materials.
4. It is a heavy gas. Its density is 5 times that of air at 20°C and atmospheric pressure.
5. It is a non-inflammable gas.
6. The heat transferability of SF₆ is about 2 to 2.5 times that of air at the same pressure. This property reduces the size of the breaker.
7. One of the important properties of the insulating medium is the time constant. It is the time lapsed between the instant of current zero and the instant at which the arc between the contacts extinguishes totally. As SF₆ is electronegative, the arc time constant of an SF₆ circuit breaker is very low. Thus, the rate of recovery of dielectric strength is higher resulting in high rupturing capacity of the breaker.

Chemical Properties of SF₆ Gas

1. SF₆ is stable up to 500°C. However, while considering the SF₆ gas in a dielectric application, it should be noted that the ingredients of SF₆ compound, i.e., fluoride and sulphur present a serious chemical corrosivity problems if SF₆ is degraded.
2. The gas is generally accepted to be inert to the more common metals and insulating materials used in electrical equipment such as copper, steel and aluminum. This increases the life expectancy of the SF₆ breaker. Also, maintenance requirements are reduced. However, presence of moisture is harmful for SF₆. In presence of moisture, hydrogen fluoride is formed during arcing. This can attack on the metallic and insulating structures in the circuit breaker.
3. During the arc-interruption process, SF₆ gets decomposed to some extent into SF₂ and SF₄. These products are toxic and corrosive. However, most of the decomposed products recombine on cooling to form the original gas. To prevent damage, filters comprising of activated alumina (Al₂O₃) are used to remove the remaining products.
4. Moisture content in the gas, due to influx from atmosphere, poses a serious problem in SF₆ circuit breaker. Quite a few failures have occurred as a consequence of moisture content.

Dielectric Properties of SF_6

1. Dielectric strength as a function of pressure is shown in Fig. 15.11. It is seen that at normal temperature and pressure, the dielectric strength of SF_6 is about 2.35 times that of air. At 3 kg/cm^2 , the dielectric strength of SF_6 is more than that of transformer oil.
2. Rough electrode surfaces reduce the breakdown voltage in SF_6 medium.
3. SF_6 not only possesses a high dielectric strength, but also due to its electronegative property, the electrons are attached to SF_6 molecules. This property increases the recovery of dielectric strength at a very fast rate. Therefore, arc-interrupting capability of SF_6 breakers is very high.

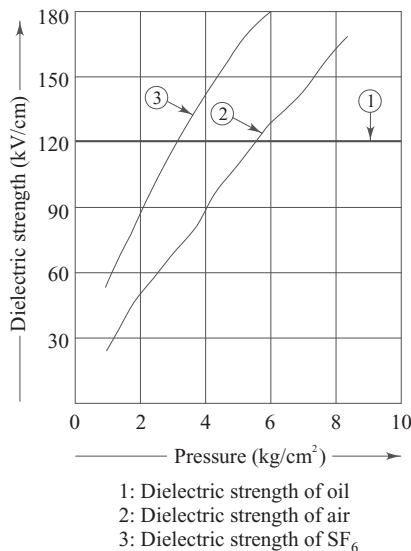


Fig. 15.11 Dielectric strength of SF_6

Closed-System Double-Pressure Type SF_6 Circuit Breaker This type of breakers are used up to voltage levels of 33 kV. As shown in Fig. 15.12, this type of SF_6 breaker uses the double-pressure gas system. SF_6 gas is used not only as an insulating medium and arc-quenching medium but also as a drive for opening and closing the contacts.

When a trip command is received, the electromagnetically operated trip valve will open so that high-pressure gas flows into the bottom part of the interrupter unit forcing a piston carrying the moving contact upwards to the open position shown in Fig. 15.13. The gas flows through nozzles of moulded plastic inlet in the fixed contact so that gas is directed against the arc, de-ionising the break at current zero and establishing a high dielectric strength at the break. The gas passes into the upper part of the interrupter unit and is discharged into the low-pressure tank. This causes rise in pressure in this tank which through a pressure switch, starts up the compressor to return the excess gas to the high-pressure tank via the filter, thus restoring the normal condition of the double-pressure system. To close the breaker, the closing valve is opened, admitting high-pressure gas above the piston.

Dead-Tank SF_6 Circuit Breaker This type of breaker is used up to voltage levels of 132 kV. A typical 132 kV dead tank SF_6 circuit breaker is illustrated in Fig. 15.14. The fixed contacts comprise a set of current-carrying fingers and an arcing probe. With the breaker in the closed position, the fingers make contact round

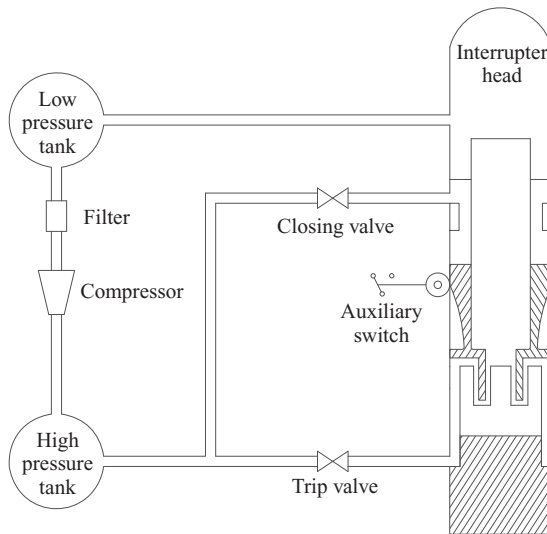


Fig. 15.12 Closed-system double-pressure type SF_6 circuit breaker

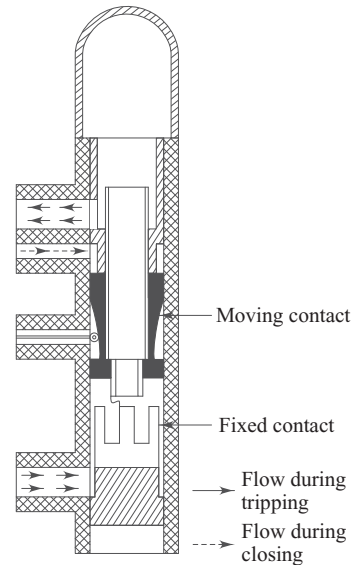


Fig. 15.13 Interrupter unit for closed-system double-pressure type SF_6 CB

the circumference of the moving contact which has the arcing probe, enclosed within its hollow end. The contacts are surrounded by interrupting nozzles and a blast shield which controls the arc displacement and the movement of the hot gas.

The moving contact takes the form of hollow nozzles sliding in the second set of spring-loaded fingers. Side vents in the moving contact let the high-pressure gas into the main tank. As soon as the moving contact is withdrawn from the fixed finger contacts, an arc is drawn between the arcing probe and the inside of the moving nozzle. It is extended and attenuated as the contact moves further apart, controlled by the nozzle and the blast shield and finally extinguished by the gas flow from the high-pressure to low-pressure systems.

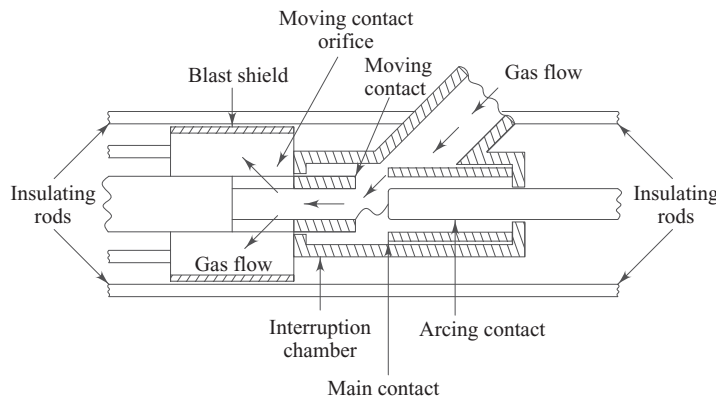
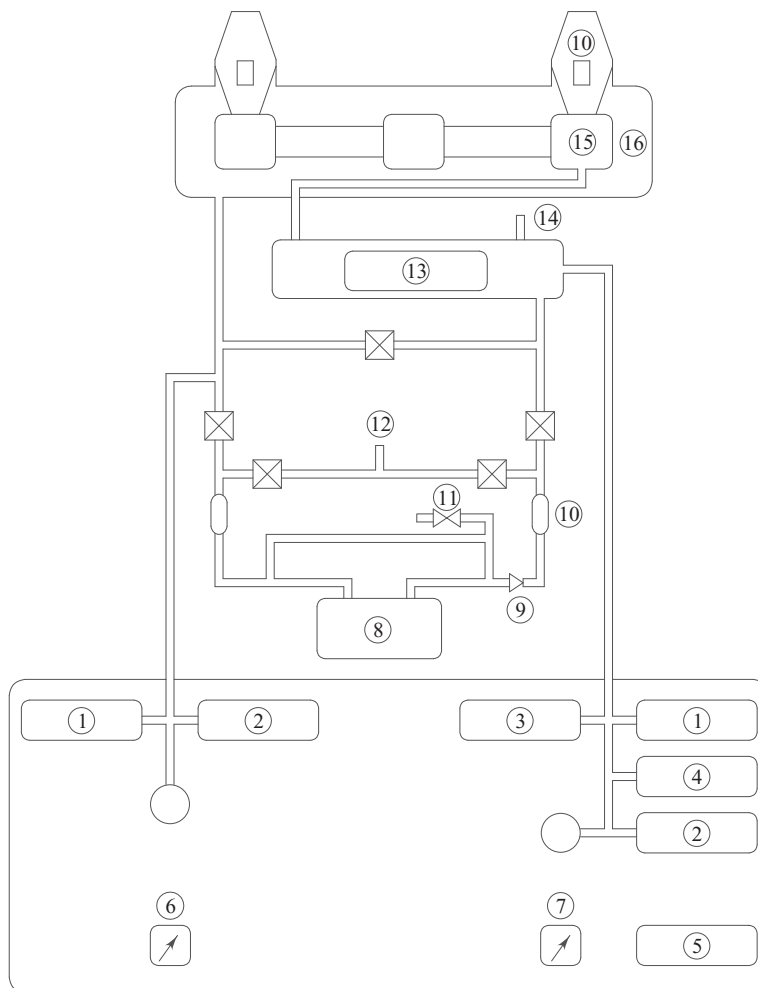


Fig. 15.14 Dead-tank SF_6 circuit breaker (up to 132 kV)

The schematic diagram of the closed-circuit gas system used in the SF_6 circuit breakers is shown in Fig. 15.15. Since the gas is under high pressure, considerable care has to be taken to prevent gas leakage at joints, etc., and therefore perfect sealing is essential. Both the high-and low-pressure systems are fitted with low-pressure sealing alarms and a set of lock-out switches to give warning of any pressure drops which could reduce the dielectric strength of the breaker and endanger the arc-quenching ability. If the danger limit is reached, the safety devices immobilise the breaker. Over-riding safety devices ensure that a control-circuit fault cannot permit the compressor to build up excessive pressure in the high-pressure reservoir or continue to pump the gas into the atmosphere in the event of a major leak.

In the design under discussion, the high-pressure gas is at 15 bars while the low-pressure gas is at 3 bars, both at 20°C . To prevent liquefaction of the gas at low temperatures, a heater is fitted in the high-pressure reservoir, thermostatically controlled to switch on when the ambient temperature falls below 16°C . To minimise heat losses, the reservoir is lagged.



Legends of Fig. 15.15

1. Low-pressure alarm
2. Low-pressure lock out
3. Compressor ON/OFF
4. High-pressure alarm
5. Low-temperature alarm
6. High-pressure system
7. Low-pressure system
8. Compressor
9. Non-return valve
10. Filter
11. Relief valve
12. Service connection
13. Heaters
14. Fusible plug
15. Internal high pressure reservoir
16. Low-pressure tank

Fig. 15.15 Closed-circuit gas system in SF_6 circuit breaker

Live Tank SF₆ Circuit Breaker This type of circuit breaker using the live tank principle can be built for a range of voltages between 110 kV and 765 kV. A breaker based on this principle is illustrated schematically in Fig. 15.16. Two break interrupters per support column are employed, the required ratings being obtained using one or multiple columns with all the breaks per pole connected in series.

In this design, a high-pressure SF₆ intermediate receiver is formed by the dome above the column which is charged with a gas from a main high pressure storage tank at the breaker through feed pipes through the hollow support insulator. The low-pressure system consists of the interrupter units, the distributor head and the hollow support insulator. The pressures employed are 18 bars and 2 bars for high and low-pressure systems respectively.

The blast valve is located at the base of the intermediate receiver and is obtained as the breaker is tripped, releasing a blast of high-pressure gas into the arc in both the interrupter units via the blast tubes. It can be seen from Fig. 15.16(a) that a part of the gas after passing through the arcing region, flows to the right directly into the low pressure system, while the remaining gas passes into the buffer compartment on the left, where it gets cooled and later returned to the low-pressure system, as shown in Fig. 15.16(b). Similar to other designs, the restoration of the pressure differential between the low-and high-pressure systems after each operation is achieved by pumping excess gas from the low to high-pressure system via filters with a compressor.

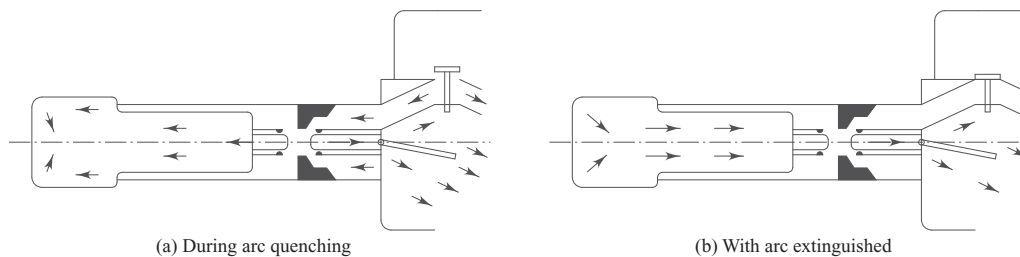


Fig. 15.16 Schematic diagram of interrupter unit

Puffer Type SF₆ Circuit Breaker This type of breakers are used up to a voltage level of 765 kV. Instead of the conventional two-pressure system having a closed-gas circuit for arc quenching, the puffer-type circuit breakers employ a single-pressure system. Apart from being simple in design, this system proves to be economical as it saves about 40% items in the components required by the two pressure system. The compressor required in the two-pressure system is not needed here and hence the installation time is less and thus the problems of maintenance are also lesser.

Figure 15.17 shows one pole of 245 kV puffer-type circuit breaker. Figure 15.18 illustrates schematically the puffer-type technique in an arc extinguish chamber. The operation is demonstrated in Fig. 15.19. In Fig. 15.19(a), which is for the closed position of the circuit breaker, the current flows through the fixed contact fingers (1), the cylinder (3), and tube (4), the fixed contacts (2) and supports for the fixed contact (8). The contact fingers (1) and the supporting part (8) are connected to the pole terminals.

In Fig. 15.19(b), when the cylinder (3) moves away from the finger (1), the current flows through the arcing rod (6), the arcing fingers (5), the tube (4), the fixed contacts (2) and the fixed contact supporting part (8). Simultaneously, the shift of the cylinder (3) in relation to the fixed contact supporting part (8) which acts as a piston, gradually compresses the gas inside the cylinder while the rod (6) blocks the opening of the nozzle (7).

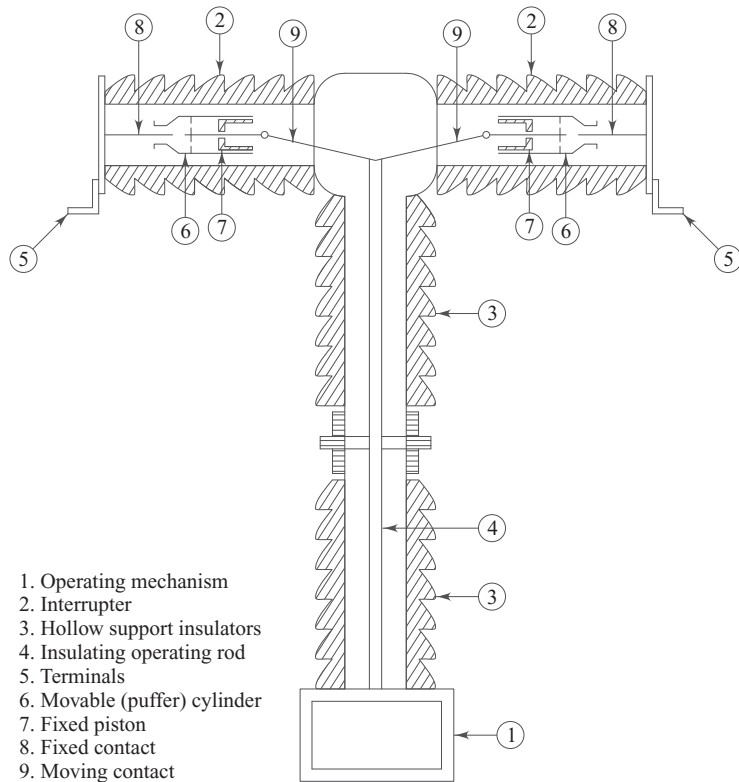


Fig. 15.17 Construction of one pole of a 245 kV puffer-type SF_6 circuit breaker

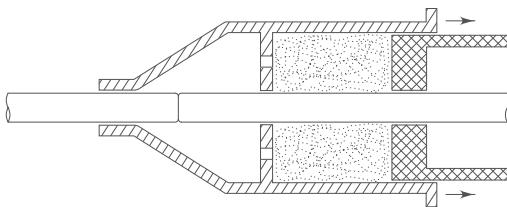


Fig. 15.18(a) Breaker in closed position

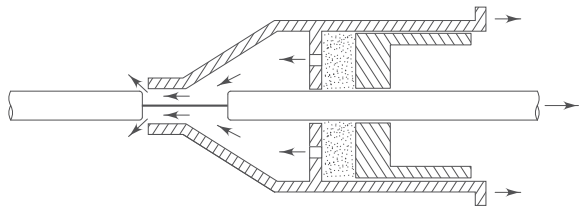


Fig. 15.18(b) Breaker with contacts separated, puffer action in progress

In Fig. 15.19(c), when the arcing fingers (5) leave the rod (6), an arc strikes between them. However, as the rod (6) no longer blocks the opening of the nozzle (7), the compressed gas is directed on to the arc to extinguish it. Figure 15.19(d) shows the final open position after extinction of the arc.

One of the chief advantages of this type of circuit breaker is the control obtained over the blow out. At the beginning of the compression process occurring during the contact separation, there is only a relatively low pressure in the nozzle space and the switching arcs caused by the load currents or no load currents of transformers generally of the order of only few amperes are blown out gently. This prevents the problem of current chopping and consequent overvoltages. During severe short circuit, on the other hand, the plasma-jet

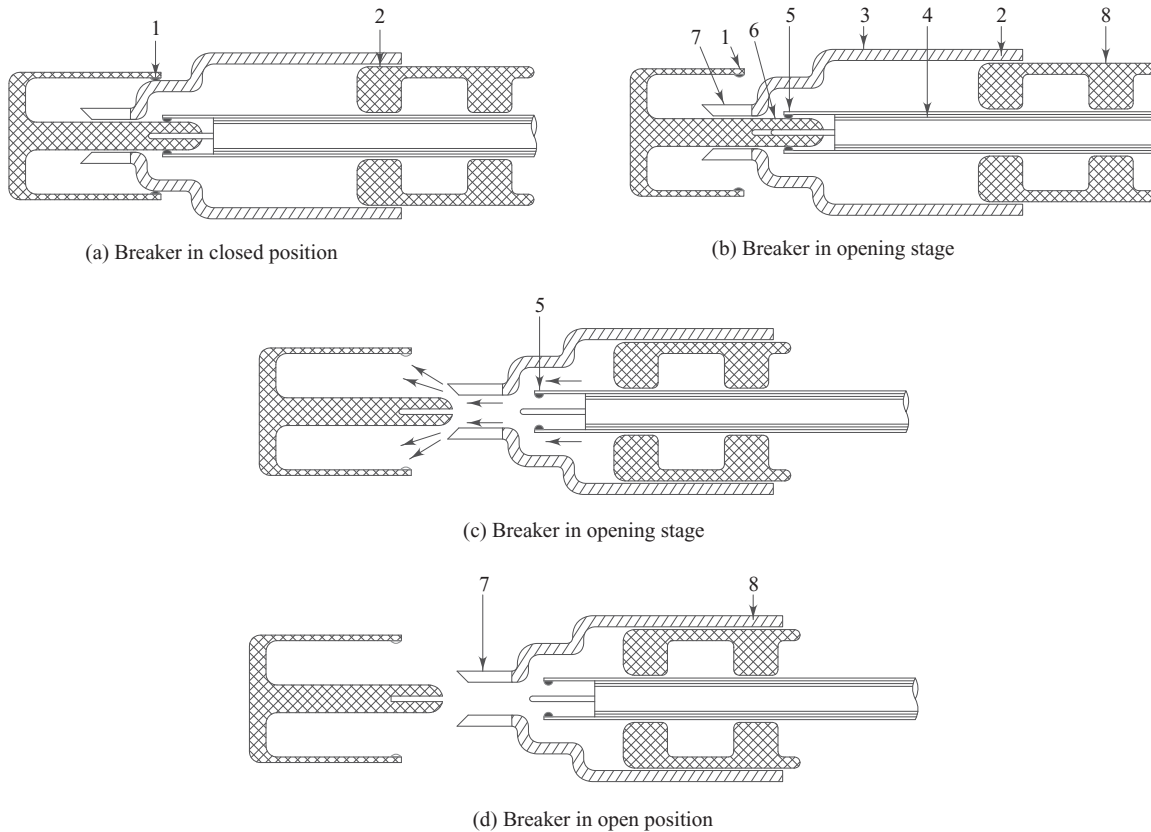


Fig. 15.19 Stage-wise operation of a puffer-type circuit breaker

pressure partially blocks the cross section of the nozzle and reduces the quantity of the gas flowing out. In this case, the nozzle pressure during the peak of the current builds up to higher than when small currents are to be interrupted. At current-zero instant of the short-circuit current, when the plasma jet pressure decreases, a particularly intense flow of the quenching medium occurs. In other words, the breaker has a quenching intensity that adjusts itself with the current to be interrupted.

Advantages of SF_6 Circuit Breaker

1. The size of an SF_6 circuit breaker is smaller than that of an air-blast circuit breaker of the same rating. This is mainly because of the fact that the dielectric strength of SF_6 gas being high, the necessary clearance is small.
2. The non-inflammable and chemically stable nature of the gas is useful for fire safety. Moreover, the products of decomposition are not explosive. Thus, chances of fire or explosion are eliminated.
3. Since the same gas is re-circulated in the circuit, the requirement of SF_6 gas is small in the long run.
4. The operation of the breaker is noiseless unlike an *ABC*B.
5. The sealed construction provides total protection against environmental influences such as pollution, air pressure, rain, fog, etc.
6. The breaker has rapid fault-clearing capability and also the ability to interrupt low and high-fault currents, magnetising and capacitive currents and short line faults.

7. Owing to the low contact erosion in SF_6 and almost negligible decomposition of the gases in the arc, the breaker can be operated for several years without having to be opened for the purpose of overhauling. This development has enabled taking us one step forward towards the development of a maintenance-free breaker.
8. No overvoltage problems arise since the arc is extinguished at natural current zero without current chopping.
9. The breakers are suitable for very high voltages and breaking capacities.
10. SF_6 breakers can be very comfortably used as auto-reclosures.

Disadvantages of SF_6 Circuit Breakers

1. The special constructional requirements lead to the difficulties of sealing. Special materials have to be used in construction.
2. Leakage of gas may occur if joints are not perfect.
3. Entry of moisture in the gas system makes SF_6 circuit breakers vulnerable to failure. In the past, some cases of such failures have been noticed.
4. The arc products are toxic if present in high concentration in the air.

15.1.6 Vacuum Circuit Breaker

Vacuum circuit breaker is a very important development in circuit-breaker technology. Vacuum is a good dielectric medium. These circuit breakers are generally being used for applications below 66 kV.

When two current-carrying contacts are separated in the vacuum module, an arc is drawn between them. An intensely hot spot or spots are created at the instant of contact separation from which metal vapour shoots off. The amount of vapour is proportional to the rate of vapour emission from the electrodes, hence to the arc current. With the alternating current arc, the current decreases during a portion of the wave and tends to zero soon. After natural zero, the remaining metal vapour condenses, the dielectric strength builds up rapidly and re-striking of arc is prevented. This principle is used in vacuum circuit breakers.

Break-down Phenomenon in Vacuum The voltage-withstand capacity of vacuum is much larger compared to other insulating mediums like oil, SF_6 (1 bar) and air (1 bar) as can be seen from Fig. 15.20. Referring to the ideal paschen curve of Fig. 15.21, it can be seen that the gap breakdown voltage with respect to gap length

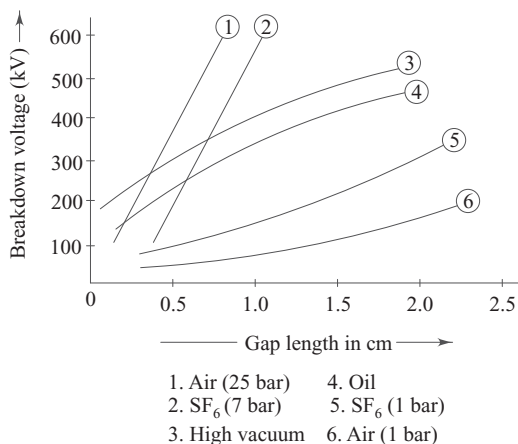


Fig. 15.20 Comparison of breakdown strength of different insulating mediums

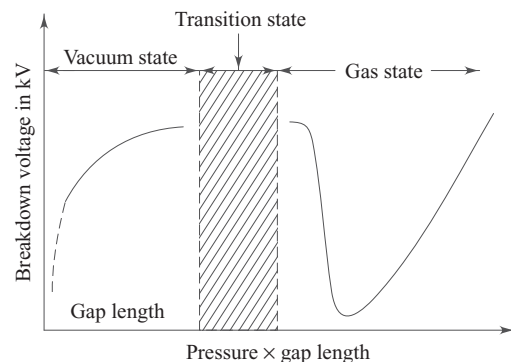


Fig. 15.21 Change in breakdown voltage in vacuum for change in gap length

decreases with lower pressure reaching a minimum value after which it rises rapidly. This can be explained as follows.

When the mean free path of the gas is of similar order as the dimension of the tube, the breakdown depends more strongly on the condition of the electrode surface rather than the properties of the gas.

In case of very high vacuum, the mean free path of the gas is very large compared to the gap of the electrodes which means there are very few electrons that have the probability of collision with other slow-moving molecules. Thus, in this region, the breakdown depends much on the gap length.

Subsequent vacuum breakdown depends on the effects of arc products and the surface of the contact. For highly smooth and polished electrode surfaces, the breakdown strength is large. But if roughened surfaces result due to arcing then it can affect the breakdown voltage of the breaker.

Problem of Current Chopping and its remedy When the contacts are separated, during one part of an ac power cycle, an arc will be drawn between the contacts, which will sustain for the remainder of the half cycle. As the current approaches near zero, the arc is quenched before the natural current zero. This is known as current chopping.

To prevent current chopping, sometimes a copper–bismuth alloy is used in which the bismuth is interspersed with the copper in order to act as a vaporising material during current interruption. Bismuth is located at a large distance away from the contact point to sustain the vapour clouds for the current to reach its zero point and avoids current chopping.

Construction of Vacuum Circuit Breakers Vacuum switchgear comprises mainly of vacuum contactors and vacuum power interrupters. The vacuum interrupter is a power device, capable of dealing with tens of kilo-amperes and must not be confused with a vacuum contactor which is generally rated for only small currents, of the order of a few hundred amperes. The contactor may look same as the interrupter but it is vastly different in design, manufacture and performance. Duties of a contactor demands something like ten million mechanical operations which is normally 1000 times more than that in an interrupter, but deals only with $1/10^{\text{th}}$ or even less of the fault current that the interrupter is expected to deal with. The contactor, in fact, operates at a much slower speed and over a shorter stroke; and its contact material and geometry are different from those of the interrupter, although the degree of vacuum used is of the same order in both the cases. However, greater care is required during manufacturing of the interrupter to ensure absolute cleanliness.

In both vacuum contactors and interrupters, the main contacts are sealed in a ceramic bottle commonly known as vacuum switch or vacuum bottle. Even though different designs of vacuum switches have been developed by various manufacturers of vacuum switchgear, all these designs are functionally identical, the difference being mainly with respect to contact geometry and material. A schematic diagram of a vacuum switch is shown in Fig. 15.22. The outer envelope, which is made of glass or ceramic, contains a pair of contacts. These electrodes are fixed on the two flanges, which in turn, are sealed to the envelope. The fixed contact stem is either brazed to the flange or made as an integral part of the flange. The moving contact stem is connected to the second flange through a metal bellows which provides the necessary movement for the moving contact rod as well as the hermetic sealing against the atmosphere. The switches are sealed off at a pressure of 10^{-7} torr or less, after special processing to outgaze the contacts and other parts.

When the contacts separate, arcing occurs between them and metal vapour is produced. In order to prevent these metallic particles reaching the envelope and reducing the breakdown voltage level between the contacts, a sputter shield is provided around the contacts to collect these particles.

There is no significant difference between the switches used in vacuum contactors and interrupters except that the switches used in the latter have larger size and more complicated contact geometry since they are required to handle large values of current.

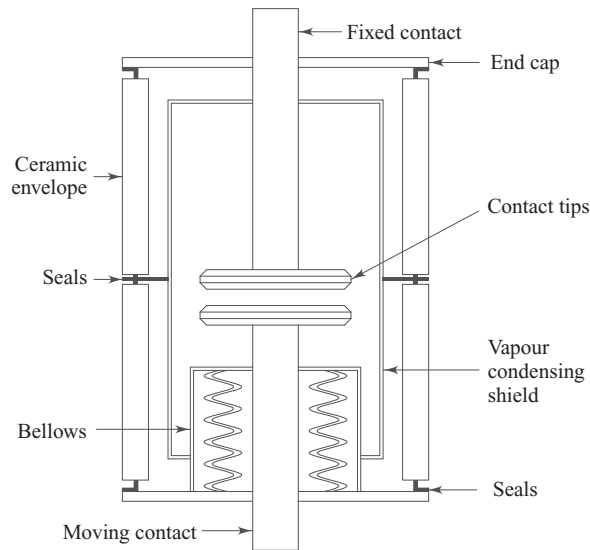


Fig. 15.22 Constructional view of a vacuum interrupter

Applications of Vacuum Circuit Breakers The vacuum circuit breakers are effectively used for capacitor bank switching. The switching of a capacitor is difficult for the oil-circuit breakers. The quick interruption of the capacitor bank current and recovery voltage build-up across the contacts of the breaker during the capacitor switching operation may cause re-strike, which can lead to overvoltages on the system and possible damage to circuit breaker or other equipments. Oscillographic study with vacuum switches has shown that the arc extinction behaviour with leading power factor at current zero is same as that for lagging power-factor loads. They can also be used for auto re-closing duties on overhead line systems which are subjected to outage resulting from lightning, etc. Advantage can be taken due to the short operating time of the vacuum circuit breaker, which in conjunction with the instantaneous static overcurrent relay can give an overall clearance time less than 40 milliseconds during phase-to-phase faults.

Switching substation transformer banks and protecting them against faults is an application suited for a vacuum circuit breaker. A vacuum circuit breaker with lower interruption rating can be used for transformer differential protection. In such cases, the vacuum contactors can be used in conjunction with high power-up fuses or may be permitted to sustain the fault until the remote breaker can trip, thereby preventing destruction of more expensive breakers at the expense of lower-cost vacuum type.

If an actuator is installed to close the vacuum interrupter rather than open it, the mechanism can be used for high-speed grounding. Because of short contact travels and low mass, the grounding can be done just enough to limit fault damage or maintain system stability.

Vacuum circuit breakers can also be used for on-load tap changing applications. Generally, on-load tap changing is done using arcing contact under oil. However, this has the disadvantage of producing contaminating arc products in the surrounding insulating medium. This results in high maintenance cost and long servicing down time. Arc-free switching under oil can be accomplished in on-load tap changing with the use of vacuum interrupters. Current is interrupted within the vacuum interrupter and a vacuum contact is switched to its new position without drawing any external arc.

The rate of recovery of high vacuum is very fast, for example $1 \text{ kV}/\mu\text{s}$ while interrupting a current of 100 A. This very fast recovery characteristic is because of the fact that the vaporised metal between the inter-electrode space diffuses rapidly as there is no gas molecule because of high vacuum. This helps in very quick build-up of the dielectric strength following arc interruption. This capability of vacuum device is particularly useful for certain severe fault clearing requirements, e.g., short line fault that is near a transformer.

Vacuum circuit breaker can be safely used with its all advantages in medium voltage switchgears at power stations.

Advantages of Vacuum Circuit Breakers Vacuum circuit breakers have the following merits over other types of circuit breakers.

1. Vacuum has better insulating properties as compared to air and oil.
2. At the time of opening of the contacts in vacuum, the dielectric strength between the contacts builds up at a rate of about 10 to 20 times higher than the circuit breakers using air or oil as medium. This recovery characteristic of vacuum ensures the arc interruption at the first current zero.
3. Vacuum circuit breakers are more efficient.
4. They are compact and occupy lesser space.
5. They are economical.
6. The average service life of vacuum circuit breakers is longer.
7. The maintenance problems are very less.
8. Over the years, they have already proved their reliability due to excellent performance.
9. Due to the above advantages, they have already replaced the oil circuit breakers in the power utilities and industries. The financial support for this upgrading is many times provided by various government funding agencies under the modernisation or removal of obsolescence drive.

15.2 HIGH-VOLTAGE DC (HVDC) CIRCUIT BREAKERS

Perhaps the most remarkable new technical development in electric power systems during the last few decades has been the direct current transmission. This has happened because of the need to transmit bulk power over ever-increasing distances where the limits of high-voltage alternating current transmissions are coming into sight. DC transmission has several advantages over ac transmission. They are as follows:

1. Absence of line charging current
2. Absence of kVAR
3. Lower cost of transmission system
4. Lower losses
5. Greater reliability
6. Higher stability
7. Possible use of earth return conductor
8. Absence of skin effect

In spite of these advantages, the use of high-voltage direct current transmission has been limited because of some technical difficulties. The great limitation is the difficulty in breaking large dc currents at high voltage. In the case of alternating current, the current goes through zero value twice every cycle. AC circuit breakers exploit this property to interrupt the current, and the problem of re-striking after a current zero for ac circuit breakers thereby reduces. DC circuit breakers do not have this natural advantage and, therefore, currents have to be forced to zero from the short circuit value by some means.

In simple point-to-point transmission, such as all the schemes in operation at present, the lack of dc circuit breakers has not been felt much because the protection against faults on dc lines or in the converters is provided by means of grid control of converters backed by switchgear on the ac side. Fault interruption through the medium of grids of the converters is considered to be the most effective method, even superior to the use of a circuit breaker. In view of the size and complexity of the terminal stations, it has been considered satisfactory to deliver power in bulk from the point of generation to one or two points in the receiving system and to use the local ac system for more widespread distribution. However, the future application may not be restricted to this simple arrangement only, but it will be necessary to have parallel lines, branches and even interconnected network systems. A fault could occur in any part of this interconnected system and, therefore, dc circuit breakers capable of load switching and interruptions of faults will be needed. Of course, one may argue that under such circumstances, the faulted line section can be switched out by suppressing the voltage of the whole system to zero by means of converter grid control, for a time sufficient to allow a quick acting isolator to disconnect the faulted section and immediately raising the voltage back to normal by de-blocking. Relays can easily perform these functions. The time for this whole sequence of events would be approximately equal to that now required for rapid re-closure of ac circuit breakers.

15.2.1 Problems and Approaches for HVDC Circuit Breakers

Design requirements, both electrical and mechanical, are in some ways quite different for HVDC circuit breakers than for corresponding ac breakers. Fortunately, what is most needed is not a circuit breaker for interrupting short-circuit currents, since fault currents can be limited by grid control to the magnitude of the rated currents, but rather a switch capable of interrupting load currents in circuits at high potential with respect to ground. With such switches, the transmission lines could be switched into or out of an un-faulted network without reducing the voltage down.

The HVDC circuit breaker should be capable of clearing reliably within about 0.03 second and without unduly high overvoltages, direct currents of 1-3 kA at rated voltages of 400–1200 kV in a highly inductive circuit. Of course, all these should be achieved through economically viable design.

This problem has attracted attention for a number of years and many proposals have been made. Most of them fall into the following two categories

1. The arc is greatly extended and some efficient method of cooling, say by gas blast or oil blast is used to obtain a large voltage gradient in the arc, which leads to an interruption of the current. The energy to be dissipated in such cases is taken care off by the cooling medium.
2. The current is artificially brought to zero by superimposing on the direct current an oscillation from an additional circuit. The interruption can then take place on similar lines as ac circuits. The energy to be dissipated in such cases is taken up by the additional capacitances or other energy absorbers.

15.3 ISOLATORS

When carrying out inspection or repair in a substation installation, it is essential to disconnect the unit or the section on which the work is to be done from all other live parts of the installation. For this purpose, the make or break in the circuit should be clearly visible. This function is carried out by an isolator. It can be used to open the circuit either when negligible current is interrupted (or established) or when no significant change in voltage across the terminals of each pole of the isolator will result following the operation.

15.3.1 Classification

Based on the type of construction, the types of isolators are classified as

1. Three-post, centre-post rotating, double-break type.

2. Two-post, single-break type (horizontal operation and vertical operation)
3. Pantograph type.

In the first type, the centre post carries the moving arm with the contacts assembled at the extremities. The moving contacts are engaged with the fixed contacts on the outer fixed insulator posts, as shown in Fig. 15.23.

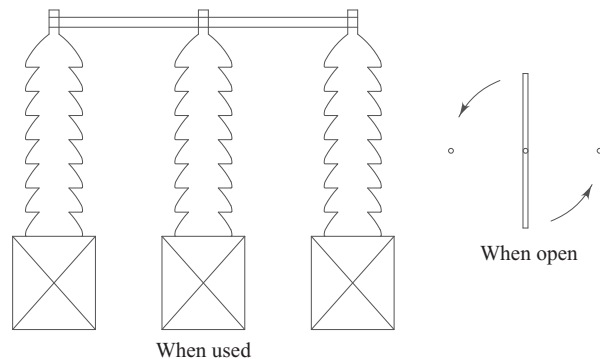


Fig. 15.23 Three-post, centre-post rotating, double-break type isolator

In the second type, there are two arms with contacts mounted at the end of each arm, as shown in Fig. 15.24.

In the third type, while closing, the linkages of the pantograph are brought nearer by rotating the insulator column. In the closed position, the pantograph gets closed on the overhead section of the bus giving a grip. The current is carried by the upper bus-bar to the lower bus-bar through the conducting arms of the pantograph. While opening, the insulator column is rotated so that the pantograph blades collapse in the vertical plane and get detached from the bus. Pantograph isolators cover less floor area.

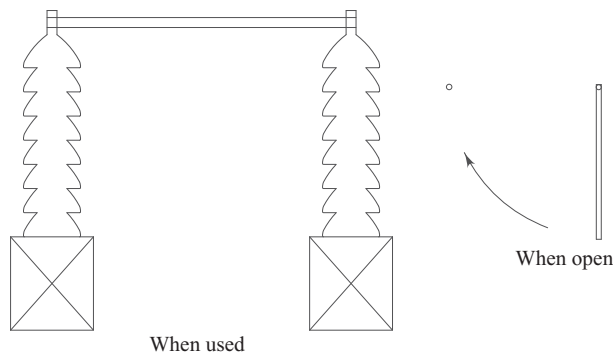


Fig. 15.24 Two-post, single-break type isolator

The operating mechanism can be manual, electrical or pneumatic. The operation can be either local or remote. The isolators are also provided with several auxiliary contacts (NO and NC) that could be used for several purposes like semaphore indication in the control room, interlocking and other control requirements.

15.3.2 Interlocking

The incorrect operation of an isolator may exceedingly be harmful towards the installations in the substation. Also, it may prove to be fatal to the operating person if the operation is local. To avoid incorrect operation, the following interlocking requirements are to be provided.

1. The isolator cannot be opened unless the associated breaker is locked in the open position.
2. The earthing switch shall close only when the isolator is open.
3. The line isolator shall close only when the corresponding circuit breaker and the earthing switch are open.
4. The circuit breaker shall close only after all the isolators associated with it have been closed.
5. A bus-selector isolator of any bay in a double-bus arrangement shall close only when
 - (i) the circuit breaker of the corresponding bay is open
 - (ii) the other bus isolator of that bay is open
6. When the bus-selector isolator of any bay is closed in a double-bus arrangement, the other shall close only when the bus coupler and both its isolators are closed.
7. The isolators of the bus coupler shall operate only when the bus coupler is open.
8. The bypass isolator of the feeder shall close when the feeder circuit breaker and its adjoining isolators are closed.
9. The bypass isolator can be closed manually irrespective of whether the feeder circuit breaker and its isolators are open or closed.

Mechanical Interlocking This is achieved by providing certain common keys to a number of locks and trapping the keys as required.

Mechanical interlocking for a single-bus arrangement is shown in Fig. 15.25. When the feeder circuit breaker and its associated isolators are closed and earthing switch is open, the key K_1 is trapped in the lock of the circuit-breaker operating mechanism and the key K_2 is trapped in the lock of the isolator as shown. Now for the opening operation, one has to switch the circuit breaker off. Rotate the key K_1 which will be released. Remove and insert it in the isolator 1 and rotate. The isolator can, now, be opened. Key K_1 is free and it can be inserted in the isolator 2. By rotating the key, the isolator can be opened. Key K_2 can now be rotated and removed. Insert the key K_2 in the earthing switch and rotate. The earthing switch can now be operated to close. Key K_2 is trapped in the earthing switch now.

The interlocking arrangement for the double-bus arrangement could be achieved in a similar manner.

Electrical Interlocking It generally consists of an electromagnetic coil with a plunger as shown in Fig. 15.26. It is very clear from the figure that the isolator can be opened only if the associated circuit breaker is open. If the isolator

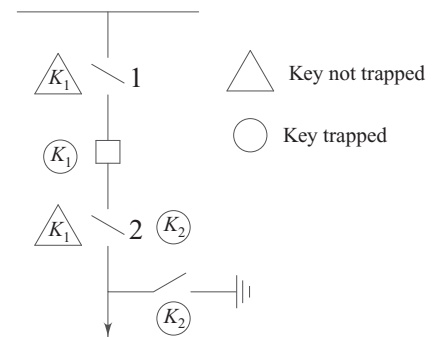


Fig. 15.25 Mechanical-interlocking scheme

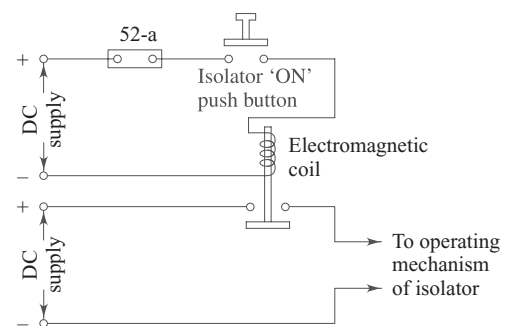


Fig. 15.26 Electrical interlocking scheme

mechanism is manual, the plunger of the coil latches the operating handle when the coil is in a de-energised condition. The handle is free only when the latch is removed if the coil is energised. In case of a pneumatic mechanism, the plunger operates the pneumatic valve when the coil is energised.

15.3.3 Specifications of Isolators

The following particulars are required to be demanded from the manufacturer while procuring the isolators:

1. *Type* Constructional classification
2. *Installation* Outdoor/Indoor
3. *Design ambient temperature* Ambient temperature at the site of installation is to be specified.
4. *Number of poles* 1 or 3
5. *Rated voltage of isolator* The following standard voltage ratings are available in market.

Table 15.1

System voltage kV	Voltage rating of isolator kV
6.6	7.2
11	12.5
66	72.5
132	145
220	245
400	420

6. *Rated continuous current* The standard ratings available are 200, 400, 630, 800, 1250, 1600, 2000, 2500, 3150, 4000 and 5000 A.
7. *Rated frequency* In India, it is 50 Hz.
8. *Rated short time current*
 - (i) Current to be calculated for the three-phase fault at the point of installation of the isolator
 - (ii) Short time of 3 seconds.

This means that the isolator shall be capable to withstand short-circuit current for three seconds.
9. *Rated peak short circuit current* This is 2.5 times the value calculated as per item 8 above. This is because the current at the time of fault can be of this order because of asymmetry in the current wave shape.
10. *One minute power frequency withstand voltage*
 - (i) Between each pole and earth.
 - (ii) Across the isolating distance
 - (iii) Power-frequency withstand voltage across the isolating distance of an isolator is about 110% of that between pole and earth. This is because of the fact that the flashover should occur between pole and earth and not across the isolating distance when the isolator is open, if at all flashover occurs due to overvoltages. This is required to avoid damage of the substation equipment due to flashover across isolating distance.
11. *1.2/50 μ s impulse withstand voltage*
 - (i) Between each pole and earth
 - (ii) Across the isolating distance

Table 15.2

Rated isolator voltage kV	Impulse withstand voltage kV peak		Power frequency withstand voltage kV	
	Pole to earth	Across isolating distance	Pole to earth	Across isolating distance
7.2	60	70	27	35
12.5	75	85	35	45
72.5	325	375	140	190
145	550	630	230	310
245	900	1035	395	535

12. Permissible temperature rise of current carrying parts not more than 60°C.
13. *Clearance* The recognised minimum clearances are given in the following tables. This assumes an altitude not exceeding 1000 m, to be increased by 3% for each 300 m higher than this. Atmospheric pollution by smoke, chemical fumes, salt laden spray, etc., may require larger clearances to be provided. The clearances to be provided also depend on a number of conditions such as whether a system is exposed or non-exposed to external overvoltages or whether the system is effectively or non-effectively earthed.

Table 15.3 Clearances for open and enclosed indoor isolators and bus-bars

Rated isolator voltage kV	Minimum clearance to earth in air		Minimum clearance between phases in air	
	Open mm	Enclosed mm	Open mm	Enclosed mm
0.415	19	16	26	19
0.6	26	19	32	19
7.2	64	64	89	89
12.5	77	127	127	127

Table 15.4 Clearances for outdoor isolators and bus-bars for non-effectively earthed systems of 66 kV and above

Rated voltage kV	Minimum clearance to earth in air mm	Minimum clearance between phases in air mm
72.5	685	786
145	1270	1473
245	2082	2368

Table 15.5 Clearances for outdoor isolators and bus-bars for effectively earthed systems of 110 kV and above

Rated voltage kV	Minimum clearance to earth in air mm	Minimum clearance between phases in air mm
145	1068	1219
245	1770	2029

14. *Minimum creepage distance of insulators*

- (i) Total
- (ii) Protected

15. Rated pressure of compressed air for pneumatically operated isolators
16. Control supply voltage for electrically operated isolators
17. *Control* Remote/local
18. *Operating mechanism* Manual/electrical/pneumatic
19. *Auxiliary contacts* NO or NC
20. *Contacts* Power contacts shall be heavy duty, self-aligning, high-pressure type and made of hard-drawn electrolytic copper
21. Interlocks
22. *Tests* The following type tests and routine tests are required to be performed on isolators.
 - Type tests*
 - (i) Impulse voltage withstand
 - (ii) Power-frequency withstand voltage (dry and wet)
 - (iii) Temperature rise test
 - (iv) Milli-volt drop test
 - (v) Short-circuit current withstand for 3 seconds
 - (vi) Operation test
 - (vii) Mechanical endurance test
 - Routine tests*
 - (i) Power-frequency withstand test (dry)
 - (ii) Operation test
 - (iii) Milli-volt drop test

15.4 FUSES

A fuse is a device that by the fusing of one or more of its components, opens the circuit in which it is inserted and breaks the current when this exceeds a given value for a sufficient time. The function of a fuse is to carry the normal current without overheating but when the current exceeds its normal value, it rapidly heats up to melting point and disconnects the circuit protected by it. The fuse is the complete device consisting of a fuse holder (which comprises a fuse base and fuse carrier) and a fuse link. A fuse link is a device comprising of a fuse element or several fuse elements connected in parallel enclosed in a cartridge usually filled with an arc-extinguishing medium and connected to terminals. The fuse link is the part of a fuse which requires replacing after the fuse has operated. The fuse is used as a protective device for protection of electrical equipment. It prevents overheating and consequent failure of insulation of electrical apparatus.

15.4.1 Advantages of Fuses

1. Operating time of the fuse is much smaller than that of the circuit breaker, for interrupting very large currents. The fuse operates in less than 5 milliseconds while interrupting large currents. Serious overheating and electromagnetic or electrodynamic forces in the system can thus be avoided.
2. The fuse does the function, viz., detection and interruption of current unlike a circuit breaker which can only interrupt the fault current and requires elaborate equipment for detection of fault current (i.e., relays, current transformer, etc.). The low-voltage air circuit breakers and moulded-case circuit breakers are, however, fitted with thermal and electromagnetic releases.
3. The sealed cartridge fuses are silent in operation and do not emit flame.

4. Fuse is the cheapest form of protection.
5. Fuse requires no maintenance.

15.4.2 Disadvantages of Fuses

1. It takes longer time to replace a fuse than to reclose a circuit breaker. This drawback is often exaggerated, especially with modern cartridge fuses, some of which can be replaced quite quickly. It may, in practice, take longer to trace a blown fuse, if it is not fitted with an indicating device, than to replace it. Usually far more time is consumed in checking the faulty circuit; hence this disadvantage of more time in replacement loses its significance.
2. The fuse gives comparatively poor protection against small overcurrents. A circuit breaker can be set to trip on as little as 5% overcurrent while the semi-enclosed fuse has a fusing factor (ratio of minimum fusing current to the rated current) of about 1.75. A modern cartridge fuse can, however, be obtained with fusing factor as low as 1.25. The values lower than 1.25 are not recommended if unwanted blowing of fuse-element due to momentary system abnormalities is to be avoided.

15.4.3 Desirable Characteristics of Fuse Elements

The fuse element should have the following desirable characteristics:

1. Low melting point, e.g., tin, lead
2. High conductivity, e.g., silver, copper
3. Free from deterioration due to oxidation, e.g., silver
4. Low cost, e.g., lead, tin, copper

The above discussion reveals that no material possesses all the characteristics together. For instance, lead has a low melting point but it has a high specific resistance and is liable to oxidation. Similarly, copper has high conductivity and low cost but oxidises rapidly. Therefore, a compromise is required while selecting the material for a fuse.

15.4.4 Fuse Element Materials

It has been determined practically that silver is a quite satisfactory material for fuse wires because silver oxide formed as a result of oxidation is unstable and there is no deterioration of the material when used in dry air and it remains bright, but when the air is moist and contains hydrogen sulphide, the silver surface is attacked and a layer of silver sulphide is formed at the top which shields the metal from further attack. Further reasons for using silver despite its high costs are as follows:

1. The coefficient of expansion of silver is so small that no critical fatigue occurs. Therefore, the fuse element can carry the rated current continuously for a long time.
2. The conductivity of silver is very high. Therefore, for a given rating of fuse element, the mass of silver metal required is smaller than that of other materials. This minimises the problem of clearing the mass of vaporised material set free of fusion and thus permits fast operating speed.
3. Due to comparatively low specific heat, silver fusible elements can be raised from normal temperature to vaporisation quicker than other fusible elements. Moreover, the resistance of silver increases abruptly as the melting temperature is raised, thus making the transition from melting to vaporisation almost instantaneous. Consequently, operation becomes very much faster at the higher currents.
4. Silver vaporises at a temperature much lower than the one at which its vapour will readily ionise. Therefore, when an arc is formed through the vaporised portion of the element, the arc path has high resistance. As a result, short-circuit current is quickly interrupted.

The following table gives melting point and conductivity of some materials used as a fuse element.

Table 15.6

<i>Metal</i>	<i>Melting point $^{\circ}F$</i>	<i>Specific resistance $\mu\Omega \text{ cm}$</i>
Aluminum	240	2.86
Copper	2000	1.72
Lead	624	21.00
Silver	1830	1.64
Tin	463	11.3
Zinc	787	6.1

15.4.5 Types of Fuses

In general, fuses may be classified into (1) low-voltage fuses, and (2) high-voltage fuses depending upon the voltage rating of their applications. They are enlisted as per this classification.

Table 15.7 *Classification of Fuses*

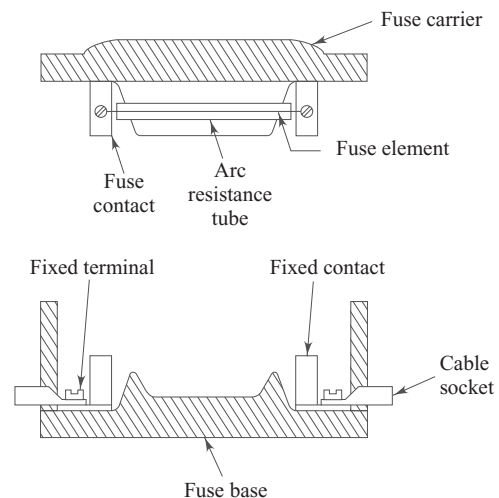
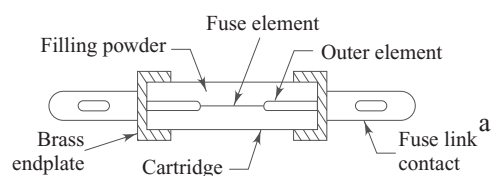
<i>Low Voltage Fuses</i>	<i>High Voltage Fuses</i>
1. Semi-enclosed rewirable fuse (kit-kat fuse)	1. Expulsion fuse
2. High rupturing capacity (HRC) cartridge fuse	2. Drop-out fuse (DO fuse)
3. D-Type cartridge fuse	3. Liquid-quenched fuse

The constructional features of different types of fuses are explained as follows:

Semi-enclosed Rewirable Fuse (Kit-Kat Fuse) The semi-enclosed fuse shown in Fig. 15.27 consists of a base, a carrier, the fuse element and some form of protection, such as an arc resistant tube, to limit the emission of flame. This is a low-voltage fuse used for domestic applications. To strike a balance between cost and performance, the material used for fuse element is tinned copper. The fusing factor is about 1.75.

High Rupturing Capacity (HRC) Cartridge Fuse The primary limitation of low and uncertain breaking capacity of semi-enclosed rewirable fuses is overcome in HRC cartridge fuse (Fig. 15.28). It consists of a heat-resisting ceramic body having metal end caps to which is welded a silver current-carrying element. The space within the body surrounding the element is completely packed with a filling powder. The filling material may be chalk, plaster of Paris, quartz or marble dust and acts as an arc-quenching and cooling medium.

Under normal load conditions, the fuse element is at temperature below its melting point. Therefore, it carries the normal overcurrent without overheating. When a fault occurs, the current increases and the fuse element melts before the fault current reaches its first peak. The heat produced in the


Fig. 15.27 *Semi-enclosed fuse*

Fig. 15.28 *HRC Cartridge fuse*

process vaporises the melted silver element. The chemical reaction between the silver vapour and the filling powder results in the formation of a high resistance substance which helps in quenching the arc.

D-Type Cartridge Fuse The typical fuse comprises a fuse base, an adapter ring, a cartridge and a fuse cap. The cartridge is pushed in the fuse cap. The cap is screwed on the fuse base. While completing the screwing the cartridge tip touches the conductor and the circuit between the two terminals is completed through the fuse link.

Expulsion Fuse The expulsion fuse, shown in Fig. 15.29, consists of a tube of insulating material into which the element is inserted. When the element melts and arcing takes place, the resultant gas pressure causes the arc to be blown out of the ends of the tube and thus be extinguished. In certain designs, this process is assisted by lining the interior of the tube with a material such as boric acid which produces gas when heated by the air. In order to accelerate the process of arc extinction, the element is held under spring tension and when the element melts, the spring rapidly separates the two sections.

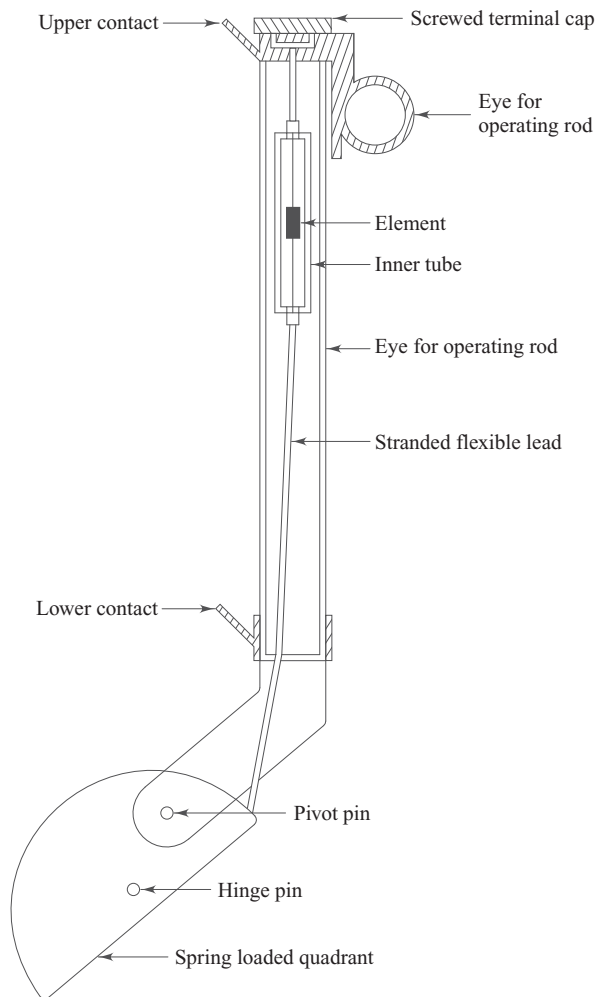


Fig. 15.29 Expulsion fuse

The operation of the expulsion fuse is violent, especially with large fault currents, and it is usually pole-mounted out of doors.

The expulsion fuse is not manufactured for lower voltages such as 415 V, but is essentially a high-voltage fuse for use on systems of up to 33 kV. It is used for the protection of overhead line networks.

Drop-out Fuse (DO Fuse) The DO fuse (Fig. 15.30) is used for protection of distribution-pole-mounted transformers. They are placed on the HV side of the distribution transformers. The fuse element is covered by a hollow ceramic tube for protection against atmospheric effects. The fuse element will melt down when the current exceeds the HV current rating of this transformer. Thereafter, the tube falls down due to its own weight and thereby helps in quenching the arc. The voltage ratings for DO fuses range from 11 kV to 33 kV.

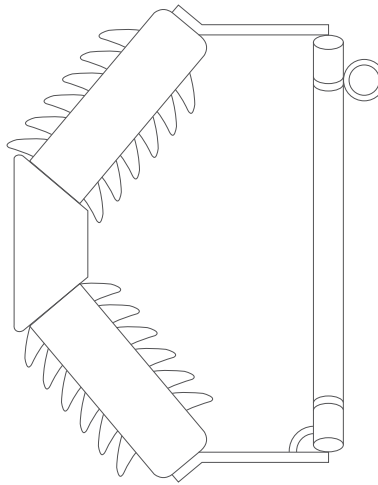


Fig. 15.30 DO Fuse

Liquid-Quenched Fuse These fuses are filled with carbon tetrachloride and have the widest range of application to HV systems. They may be used for circuits up to 100 A rated current on systems of up to 132 kV and may have breaking capacities of the order of 6100 A.

Referring to Fig. 15.31, it consists of a glass tube filled with carbon tetrachloride solution and sealed at both ends with brass caps. The fuse wire is sealed at one end of the tube and the other end of the wire is held by a strong phosphor bronze helical spring fixed at the other end of the glass tube. When the current exceeds the prescribed limit, the fuse wire blows out. As the fuse wire melts, the spring retracts a part of it through a baffle (or liquid detector) and draws it well into the liquid. The small quantity of gas generated at the point of fusion forces some part of the liquid into the passage through the baffle and then it effectively extinguishes the arc.

15.4.6 Mechanism of Fuse Operation

When a fuse is blown by a current, not much larger than the minimum fusing current so that the melting time is measured in minutes, the

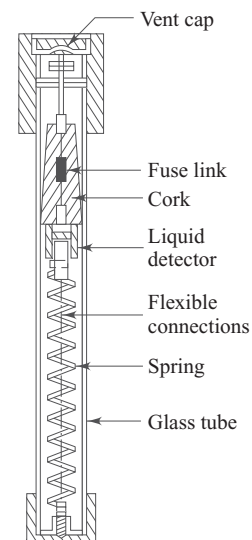


Fig. 15.31 Liquid-quenched fuse

temperature distribution along the element is not uniform with the hottest point being near the center. It is at this point that melting occurs first, giving rise to a short arc. The arc-quenching hence, takes a longer time, than for clearing large currents.

When a fuse is subjected to a very large overcurrent (short-circuit current), the element is heated so rapidly that the temperature distribution along the element is uniform and hence the whole element gives rise to a long arc which is quenched fast. The current is actually interrupted before the peak is reached.

15.4.7 Fuse Characteristic

Figure 15.32 shows a single-line diagram of fuse protecting electrical equipment. Now, if the equipment is rated for 10 A and if it can withstand continuous overload of say 25%, there will be no damage to the insulation of electrical appliance for 12.5 A of current. If the current increases beyond this value, the heat generated will increase which will then result in higher temperature rise. No doubt, as the heat generated is a function of time, a specified time will elapse before the temperature reaches a point equal to the withstand temperature of the insulation of equipment. Also, as heat generated is proportional to $I^2 Rt$, there is a time required for reaching the withstand temperature for a given current. For higher currents, obviously this time will be less. A characteristic drawn for this time v/s current is known as thermal withstand characteristic of electrical apparatus. Figure 15.33 shows such a characteristic (Curve 1).

It is obvious that the fuse must operate before the withstand temperature of the insulating material is reached. Thus, the fuse characteristic shall be below the thermal withstand curve of equipment. It is also equally important that the fuse must not operate very early than the specified time. This is because the fuse should exploit the thermal overload capability of the equipment.

For very large overcurrents (short-circuit current), however, it is not only the thermal damage that needs to be considered but also possible damage due to electrodynamic stresses must also be taken into account. Such forces can distort and deshape the equipment and therefore damages cannot be repaired if a large current flows for more than 3 to 5 cycles. The fuse, in such a case operates within the time of the order of 5 milliseconds, thereby avoiding irreparable damage to the equipment. Curve 2 in Fig. 15.33 shows a fuse

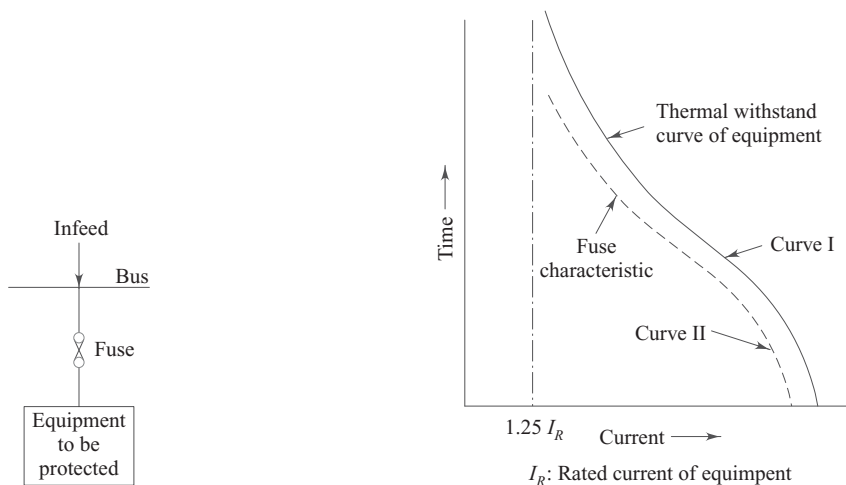


Fig. 15.32 Single-line diagram of fuse

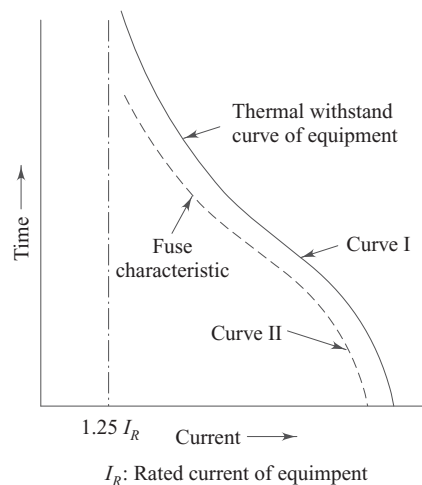


Fig. 15.33 Fuse characteristic

characteristic which is a plot of operating time of fuse v/s current. It is so often plotted for multiples of fuse rating.

15.4.8 Discrimination between Two Fuses

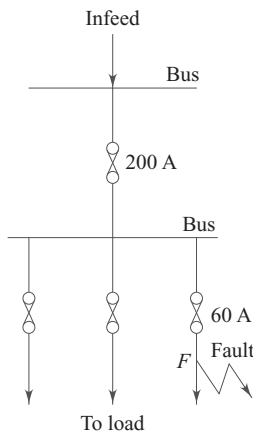


Fig. 15.34

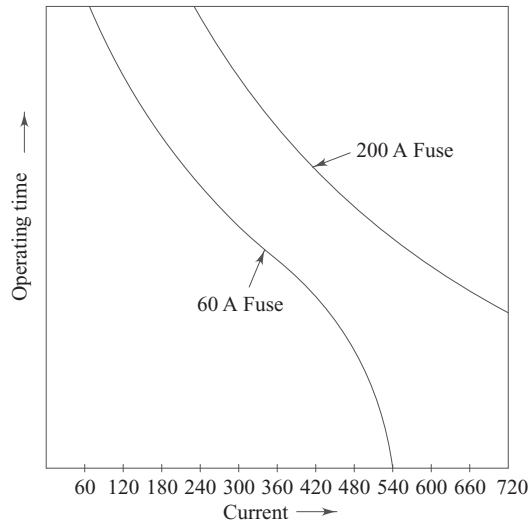


Fig. 15.35

Figure 15.34 shows a single-line diagram of a distribution network. It is very clear from the figure that a 60 A fuse must operate for the fault at F. A 200 A fuse should act as a back-up in case of failure of the 60 A fuse. The characteristic of two fuses have to be coordinated as shown in Fig. 15.35.

15.4.9 Discrimination between a Fuse and an Overcurrent Relay

Figure 15.36 shows a single-line diagram of an 11 kV feeder supplying a pole-mounted transformer. The drop-out fuse is for the protection of transformer only. Hence, the overcurrent relay has to be coordinated with the kit-kat fuse. The characteristic of both the relay and fuse are plotted in Fig. 15.37 considering the transformation ratio.

15.4.10 Fuse for Motor Protection

Induction motors are widely used as drives in industries. The fuse used for such a motor protection has to be selected with great care. Generally, HRC fuses are used for induction-motor protection in industries.

Figure 15.38 shows how the fuse for motor protection can be selected. Induction motor takes large current while starting. The starting current is as large as six times the rated current if the motor is started direct online. The accelerating time may vary from 4 seconds to even 30 seconds depending upon the inertia of the load on the motor. The fuse must not blow during starting. Hence, the fuse characteristic must lie between the starting characteristic and thermal withstand characteristic of the motor.

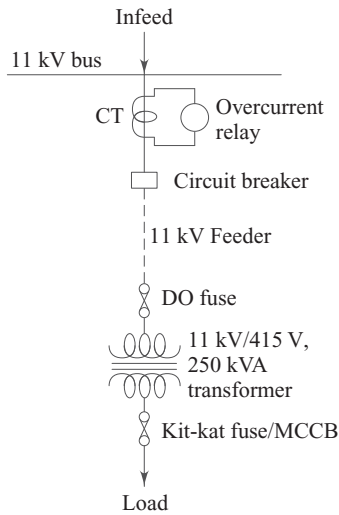


Fig. 15.36

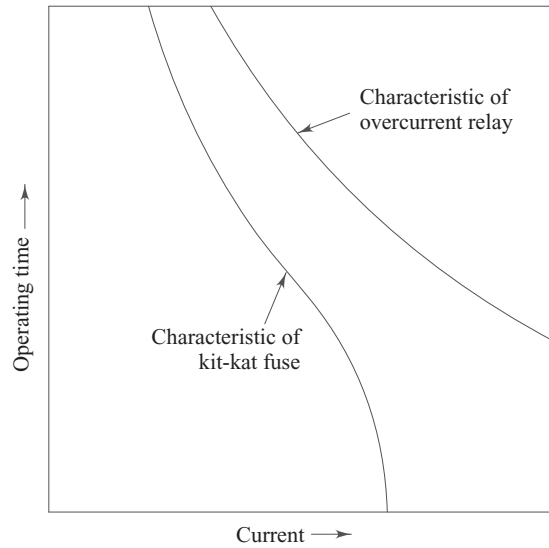


Fig. 15.37

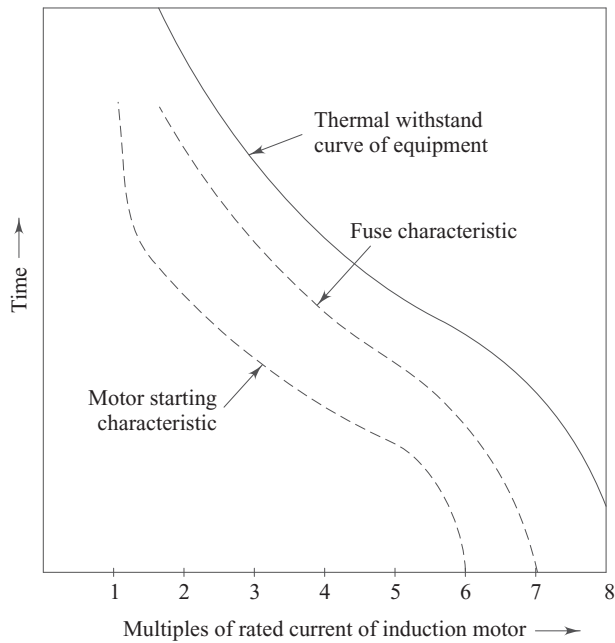


Fig. 15.38

15.4.11 Categories of Duty of Fuses

Every fuse is assigned for one or more of five categories given in Table 15.8.

Table 15.8

<i>Category of duty</i>	<i>Prospective current of test circuit A</i>	<i>Power factor lagging of test circuit not greater than</i>	<i>Time constant L R of dc test circuit not less than</i>
ac ₁ and dc ₁	1000	0.6	0.003
ac ₂ and dc ₂	4000	0.4	0.004
ac ₃ and dc ₃	16500	0.3	0.01
ac ₄ and dc ₄	33000	0.3	0.01
ac ₅	46000	0.15	—

AC and DC denote whether the fuse is suitable for use in ac circuit or dc circuit. The prospective current of the test circuit should not be greater than the breaking capacity rating of the fuse.

15.4.12 Selection of Fuse Links

The problem of selection of fuse links is not as simple as one may imagine. An improper blowing out of fuse (when it is not required) may look to be insignificant but it may result in interruption of power, stoppage of continuous process industries or loss of production. The fuse should not operate during temporary permissible overloads or switching surges. The following factors should be considered carefully before selecting a fuse:

1. Normal current of the equipment to be protected
2. Permissible continuous overloads
3. Starting current of induction motor/dc motor.
4. Whether steady load or fluctuating load—fluctuating loads are those in which peak of comparatively short duration occur.

For overload protection of steady loads, fuses with a fusing factor of 1.25 are preferred. The fuse of the rated current equal to normal current of the equipment or the next higher rating must be selected. For fluctuating loads, the fuse should not blow under transient overloads. For such a feature, the current–time characteristic of the fuse should always be above the transient current characteristic of load, with enough margin. Hence it is necessary, so often, to select a fuse of rated current higher than normal current of the circuit. Further, a fuse with a fusing factor of 1.75 may be suitable. During switching of transformers, fluorescent lighting, capacitor, etc., a current in-rush takes place. The fuse selected for protection of such apparatus should not blow during switching.

5. Peak prospective current and desired cut-off value
6. Breaking capacity required based on fault calculations
7. Category of duty required
8. Discrimination required

15.4.13 Specification of Fuse Link

The following specifications should be considered:

1. Voltage rating of the fuse
2. Frequency, in ac application
3. Application, whether ac or dc

4. Current rating
5. Minimum fusing current
6. Breaking capacity
7. Characteristic required
8. Type of fuse
9. Fuse element material
10. One minute power frequency overvoltage withstands
11. Temperature rise
12. Indication if required
13. Application
 - (i) Transformer protection
 - (ii) Lighting protection
 - (iii) Capacitor protection
 - (iv) Fluorescent light protection
 - (v) Motor protection
14. Whether steady load or fluctuating load
15. Category of duty
16. Confirmation with relevant IS

15.5 MINIATURE CIRCUIT BREAKERS

Miniature circuit breakers are the latest development in circuit-breaker technology, particularly for low currents, 440 V applications. For high-current rating, moulded-case circuit breakers (MCCBs) are used. The MCBs can replace fuses in many applications like house-wiring, and commercial and industrial applications.

When a fuse blows, it has to be replaced; while in case of an MCB one has just to switch it ON when it becomes off due to fault current or overload. Also, for fuses there are chances of a person replacing higher capacity of a fuse wire which will endanger the equipment which the fuse is protecting. In case of MCBs, such a difficulty is absent because an MCB is a sealed unit and there is nothing to be replaced when it switches off on fault. An MCB has comparatively better defined characteristics in comparison with a fuse. MCBs can be well coordinated with fuses, induction motors and characteristics of overcurrent relays for protection of a feeder.

An MCB cover is moulded using thermo-setting powder having high dielectric strength. Inside the cover, an MCB contains a current-carrying conductor, flexible cord, current-carrying bimetal, contacts, arc chute, tripping mechanism, instantaneous electromagnetic tripping arrangement, etc.

The conductor is made up of copper and takes different forms like a coil for instantaneous electromagnetic tripping arrangement, flexible cord (wherever required) and flat or round conductor. The bimetal also carries the current and if the current crosses the rated value, the bimetal, because of the temperature developed by the heating, bends and actuates the tripping mechanism leading the MCB to trip. The tripping mechanism is trip-free which means that unless the fault is cleared, the cannot be made 'ON'.

The contacts are of silver, silver-tungsten or copper-tungsten depending on short circuit capacity. An arc chute is used for splitting the arc, so that arc is cooled, split, lengthened and quenched fast.

Instantaneous tripping arrangement is so adjusted that the electromagnetic attracting force generated by a coil of the conductor is not enough to attract an armature (which is responsible for actuating the tripping mechanism) at lower currents at which a thermal bimetallic tripping action works, e.g., a bimetal will actuate the tripping mechanism for up to say 40 A for a 5 A MCB. Beyond this current, the electromagnetic attracting force increases to a value which attracts the armature, which in turn actuates the tripping mechanism and hence the MCB trips instantaneously (i.e., within 3 cycles).

MCBs are available in single-pole, double-pole, three-pole or four-pole versions.

15.5.1 Rating (Specifications) of MCB

1. *Number of poles* 1, 2, 3 or 4
2. *Rated voltage* 240/415 V
3. *Rated current* The current ratings available are 0.5, 1, 2, 6, 10, 16, 25, 32, 40 and 63 A.
4. *Rated frequency* 50 Hz
5. *Rated short circuit breaking capacity* The MCB is capable of complying with a prescribed test-duty cycle at the prescribed voltage and power factor. The MCBs with short-circuit breaking capacity of 3 kA, 9 kA and even 25 kA are available in the market.
6. *Category of duty* (Refer Table 15.9).
Operating sequence shall be B-2-MB-2-MB,
where B = Break
MB = Make-Break
2 = 2 minutes
7. *Tripping factor* The ratio of minimum value of overcurrent at which the MCB will trip to the current rating.

Table 15.9

<i>Category of Duty</i>	<i>Prospective current of test ckt A</i>	<i>Power factor of test ckt</i>
M1	1000	0.85-0.9
M1.5	1500	0.8-0.85
M2	2000	0.75-0.8
M3	3000	-do-
M4	4000	-do-
M6	6000	-do-
M9	9000	0.55-0.6

15.5.2 Time–Current Characteristic

The MCB shall have a fixed non-adjustable time–current characteristic. The tripping factor shall not exceed

1. 1.5 for a rating up to and including 10 A
2. 1.35 for rating above 10 A

The operating time shall fulfill the requirements mentioned in IS 8828-1978.

15.6 EARTH LEAKAGE CIRCUIT BREAKERS

Current operated Earth Leakage Circuit Breakers (ELCBs) or Residual Current Circuit Breakers (RCCBs) primarily intend to give protection by automatic disconnection of supply against the risk of dangerous and possibly lethal electric shocks. The ELCBs interrupt the circuit within a fraction of a heartbeat providing protection against dangerous contact voltages. They also produce a high degree of protection against earth faults and shocks.

15.6.1 Protection against Direct Contact

The risk of electrocution by direct contact exists in the following cases:

1. When the insulation of the wiring and/or electrical equipment or their leads is damaged
2. The earth wire is interrupted or is interchanged by mistake with the phase wire
3. Contact with live wire accidentally, as during maintenance

In case of direct contact, irrespective of the neutral system, since the earth-leakage current will always be equal to the current passing through the human body, an ELCB with a high sensitivity of 30 mA should be used.

15.6.2 Protection against Indirect Contact

Protection of individuals against electrocution due to contact with a 'live' metal part of a machinery or an appliance is possible by using an earth leakage circuit breaker, provided the chassis and metalwork of the appliance are earthed.

International standards have defined the maximum contact voltages which can be maintained without endangering the user:

$V_L \leq 12$ volts for wet chassis/enclosures

$V_L \leq 25$ volts for wet factory/workshop or commercial premises and building sites, etc.

$V_L \leq 50$ volts for dry residential, industrial or commercial premises

In order to prevent an earth-leakage current which may result in build up of dangerous contact voltages, it is needed to install an ELCB with a sensitivity rating corresponding to the two parameters:

1. Resistance to earth, R_m
2. Maximum allowed contact voltage, V_L

In all but a few installations, an ELCB with a 30 mA sensitivity will provide adequate protection. A 10 mA sensitivity ELCB while preferable, may cause nuisance tripping in some cases due to leakages in the installations itself.

15.6.3 Operating Principle and Features of ELCB

Earth-Leakage Circuit Breakers are current-operated devices which operate on the principle of measurement of differential (residual) current using a core balance current transformer and tripping a switching device through an electromagnetic tripping relay. Figure 15.39 shows internal connections of an ELCB for 1-phase and 3-phase applications. The outstanding features and advantages of the ELCB are as follows:

1. ELCB, a truly current-operated device, can operate at a nominal voltage less than 10 volts. ELCBs are totally independent of the mains voltage for tripping and provide a highly reliable protection.
2. ELCBs trip in the event of opening of the neutral wire due to any reason and are provided with neutral advance mechanism (neutral opens after phases and closes before) which ensures complete discharge of line inductance/capacitance.

3. The mechanism is trip-free ensuring that the ELCB cannot be reclosed/reset if the earth-leakage/fault persists.
4. ELCBs have a high repeat tripping accuracy of less than 5% of the operating current.
5. They have a very long operational life of over 20,000 operations.
6. ELCBs are capable of withstanding starting inrush currents of motors of up to 4/8 times the rated current.
7. The ELCBs have excellent short-circuit withstand capacity ensuring that there is no damage to the device itself, till the back-up protection fuse or another overcurrent device clears the fault.
8. A test push button is provided to check the correct operation of the unit.

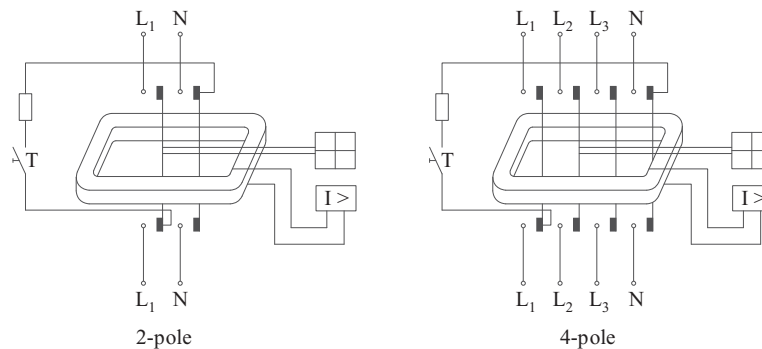


Fig. 15.39 Internal connection of an ELCB

REVIEW QUESTIONS

1. Write a detailed note on the construction, operation and use of an air-break circuit breaker.
2. Explain the role played by arc runners and arc splitters in an air-break circuit breaker.
3. Why are circuit breakers provided with arcing contacts in addition to main contacts?
4. Differentiate clearly between the following:
 - (i) Self-blast and forced-blast circuit breakers
 - (ii) Air-break and air-blast circuit breakers
 - (iii) Recovery voltage and active recovery voltage
 - (iv) Circuit breakers and isolators
 - (v) Vacuum contactors and vacuum interrupters
5. Write a short note on contact materials used in circuit breakers.
6. Write a short note on arc-control devices in case of oil-circuit breakers.
7. Draw a neat cross-sectional view of a bulk-oil circuit breaker employing an arc-control device and explain its arc-quenching mechanism.
8. Why cannot an oil circuit breaker be used for repeated operations?
9. Why is the potential distribution over the contacts of a multi-break circuit breaker not uniform? Explain how this distribution can be improved.
10. Discuss the advantages and disadvantages of oil as an arc-quenching medium.
11. Write a short note on the construction and working of a minimum-oil circuit breaker.
12. Compare minimum-oil circuit breaker and bulk-oil circuit breaker.
13. Write a short note on the following:
 - (i) Merits of SF₆ gas as an insulating and arc-quenching medium
 - (ii) Properties of SF₆ gas
14. Explain why SF₆ circuit breakers are considered 'maintenance-free' breakers?
15. Explain the principle of a puffer-type SF₆ circuit breaker.

16. Would you prefer an air-blast circuit breaker or an SF_6 circuit breaker for modern high-voltage substations? Why?
17. Give a brief description of the auxiliaries required for air-blast circuit breakers.
18. Compare oil, air and SF_6 as arc-quenching media.
19. Compare minimum-oil circuit breakers with air-blast circuit breakers.
20. What is the effect of quick automatic re-closing on the performance of oil circuit breakers and air-blast circuit breakers?
21. Give reasons for the following statements:
 - (i) Large air-storage tanks have to be installed for air-blast circuit breakers used for quick automatic re-closing.
 - (ii) SF_6 circuit breakers are smaller in size than oil circuit breakers of the same ratings.
22. In Fig. 15.40, it is required that breakers B_1 and B_2 both can be closed only when sectionalising breaker SB is open, and SB can be closed only if B_1 or B_2 are off. Draw the interlocking control circuit for the above-mentioned requirements.

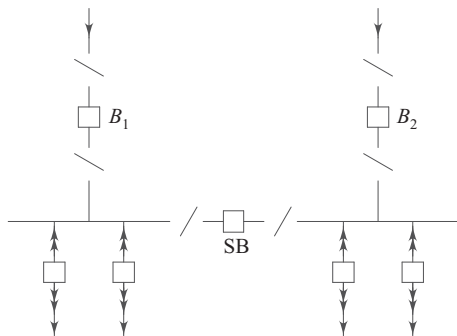


Fig. 15.40

23. It is required that when a bus-selection isolator of any bay is closed in a double-bus arrangement, the other shall close when the bus coupler and both

its isolators are closed. Assume that bus selection isolators are operated electrically from remote control. Draw the interlocking control circuit for these requirements.

24. Why are pantograph-type circuit isolators preferred in 400 kV substations?
25. Draw the circuits showing the arrangements of mechanical and electrical interlocking of an isolator with its associated breaker.
26. It is required that the breaker should not close if the associated isolators are open. Draw the circuit showing an electrical interlock for this purpose.
27. Explain the process of arc extinction in high vacuum.
28. Discuss the merits of a vacuum interrupter and the problems involved.
29. Describe the process of current sustenance and interruption in vacuum. How is the process affected by choice of contact material?
30. Compare SF_6 and vacuum circuit breakers.
31. Discuss the desirable characteristics of fuse elements. In this regard, which are the different materials suitable for fuse elements?
32. Which are different types of fuses for LV applications? Explain them.
33. Explain the various fuses used for HV applications.
34. Describe the principles of discrimination between
 - (i) two fuses
 - (ii) a fuse and an overcurrent relay
35. Explain the selection criteria of a fuse for induction-motor protection.
36. Explain the constructional mechanism of a miniature circuit breaker.
37. What are the advantages of the MCB as compared to the fuse?
38. What do you mean by ELCB? What is its function and operating principle?
39. Explain the main features of an ELCB.

MULTIPLE CHOICE QUESTIONS

1. The recovery of dielectric strength after arc interruption in SF_6 circuit breakers is very fast due to the
 - (a) non-toxic property of SF_6 gas
 - (b) non-inflammable property of SF_6 gas
 - (c) inert nature of SF_6 gas
 - (d) electronegative property of SF_6 gas
2. Vacuum circuit breakers are used for applications of up to a voltage level of
 - (a) 132 kV
 - (b) 220 kV
 - (c) 66 kV
 - (d) 400 kV

3. The circuit breaker preferred in recent times for voltage levels of 132 kV to 765 kV is a/an
 - (a) vacuum circuit breaker
 - (b) minimum-oil circuit breaker
 - (c) air-blast circuit breaker
 - (d) SF_6 circuit breaker
4. The most suitable circuit breaker for having auto-reclosure is a/an
 - (a) minimum-oil circuit breaker
 - (b) air-blast circuit breaker
 - (c) vacuum circuit breaker
 - (d) SF_6 circuit breaker
5. With reference to criteria of occupying lesser floor area, the isolator preferred is of
 - (a) three-post, centre-post rotating, double-break type
 - (b) pantograph type
 - (c) two-post, single-break type
 - (d) none of the above

Short-Circuit Testing of Circuit Breakers

16

It is very essential to know the procedures required to prove the capability of circuit breakers to perform their functions during short circuits, interruption of low magnetising currents, interruption of capacitive currents, interrupting

short-line fault currents, etc., before they are installed and commissioned for actual field practice. To understand the professional aspects, let us first look at the specification details of a circuit breaker.

Introduction

16.1 SPECIFICATIONS OF A CIRCUIT BREAKER

- | | |
|--|---|
| 1. <i>Installation</i> | Outdoor/Indoor |
| 2. <i>Types of the breaker</i> | ABCB/MOCB/OCB/SF ₆ CB/ VCB |
| 3. <i>Number of poles</i> | |
| 4. <i>Rated voltage</i> | Same as those of isolators |
| 5. <i>Rated continuous current</i> | The standard values are 400, 630, 800, 1250, 1600, 2000, 2500, 3150 and 4000 A |
| 6. <i>Short circuit breaking current</i> | This has to be calculated for the given system and for the fault immediately after the circuit breaker. The standard values are 8, 10, 12.5, 16, 20, 25, 31.5, 40, 50, 63, 80 and 100 kA. Percentage dc component is also to be specified as per IS 2516. |
| 7. <i>Short time current</i> | Same as breaking current for one second. |
| 8. <i>Making capacity</i> | 2.5 × breaking capacity |
| 9. <i>Operating duty</i> | O-T-CO-T'-CO |

- O* Opening operation
- CO* Closing operation followed by the opening operation immediately, without any intentional time delay
- T* 3 minutes for the circuit breaker without auto re-closing
0.3 sec for auto re-closers
- T'* 3 minutes

10. Total break time

11. Make time

12. *Line charging breaking current*

The standard values are as follows

System voltage <i>kV</i>	Line charging breaking current <i>A</i>
66	10
132	50
220	125
400	400

13. Cable charging breaking current

14. Small inductive breaking current

15. *1.2 50 s impulse withstand* Same as that for isolator.

16. Switching surge withstand

17. One minute power frequency withstand (dry and wet)

18. *Spacing* Same as isolators.

19. *Creepage distance* Same as isolators.

20. Details of bushing CT, if provided.

21. Auxiliary contacts

22. Auxiliary power requirement

23. Interlocking

24. Pre-insertion resistors

(i) Pre-insertion time

(ii) Capable of carrying short circuit current

(iii) Ohmic value

25. Tests

T e tests

(i) Short-circuit test (breaking and making capacity both) as per test duty

(ii) Short-time current test

(iii) Temperature rise test

(iv) Operation test

(v) Mechanical endurance test

(vi) Impulse withstand

(vii) Power frequency overvoltage withstand (dry and wet).

utine test

- (i) Operation test
 - (ii) Milli-volt drop test
 - (iii) One-minute power frequency withstand test (dry)
26. *Operating mechanism* Pneumatic/Electrical
- (i) Compressed air pressure
 - (ii) Auxiliary voltage

16.2 BASIC SHORT-CIRCUIT TESTING PLANT

On occurrence of a short circuit, not only the circuit breaker under test but also all associated equipments of a short-circuit testing plant have to withstand electrodynamic stresses and thermal conditions which arise due to the passage of a fault current. Major test equipments are generators, resistors, reactors, bus-bars, isolating switches, master breaker, connectors, cables, cable terminations, current transformers, series overload coils, etc.

A short-circuit test plant is shown in a very simple form in Fig. 16.1. Power for the short circuit test is derived from a generator. This generator has specially braced windings and the stator has low reactance in order to give maximum short-circuit current. The stator windings are arranged to have two windings per phase with a terminal arrangement permitting the windings to be connected in parallel delta or star and series delta or star, thus providing four nominal voltages, viz., 6.6, 11, 13.2 or 22 kV. To minimise the mechanical shock transmitted to the foundation due to short-circuit oscillating torque, the machine has to be mounted on a resilient base.

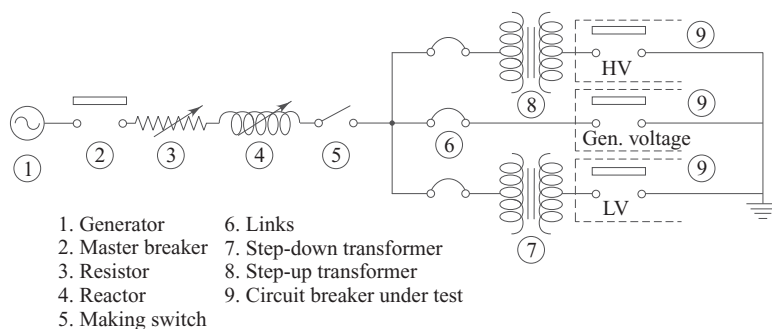


Fig. 16.1 Basic set-up for short-circuit testing

The generator is generally motor-driven. Just before the short circuit, the motor is disconnected from the mains, since otherwise the reflection of the short-circuit load on to the mains would be excessive. The energy for the short circuit comes from the kinetic energy of the generator rotor. An alternative is to use a slip-ring motor and the external resistances are inserted in the rotor circuit at the instant of the short circuit. No doubt, these procedures result in the diminishing speed of the generator and consequently a decrement in voltage, which has to be compensated by boosting the generator field excitation during the period of test by some arrangement such as automatic voltage regulator.

The master or back-up circuit breaker has to perform as suggested by its name. The possibility of failure of the circuit breaker under test cannot be ignored. Also, during research testing, it is often required to test until

failure occurs. Therefore, failure has to be cleared by the master circuit breaker which is set to open after a predetermined time after the initiation of short circuit. This breaker must have a breaking capacity more than the short circuit MVA rating of the generator.

Next in line, resistors and reactors are installed. Resistors are used for control of power factor so that it is in accordance with IS requirements; and the reactors are used to control the test-current magnitude. Tapings in both will help to choose the required values.

After this, the making switch is installed. It is a vital item in the circuit and is always a specially designed piece of apparatus. When carrying out a break test on the circuit breaker under test, the latter and the master breaker will both be closed and the short circuit will be established by closing the making switch. The breaker under test should clear this short-circuit current. The making switch must be capable of closing at high speed on to fault currents of high peak magnitude without pre-arcing as the contacts approach the 'touch' position. Accurate control of its closing instant is necessary so that it can be closed at any selected point on the supply voltage wave, thereby controlling the degree of asymmetry in the short-circuit current at fault inception. This is known as 'point-on-wave-switching' and is achieved with the help of electronic circuits.

When a circuit breaker under test is to be assessed for making capacity, i.e., to be closed on fault, the master breaker and making switch both are closed first and the breaker under test is closed afterwards to establish short circuit and then to clear it.

From the outgoing terminals of the making switch, connections are taken to the test bays, either directly for testing at the available generator voltage or via step-up or step-down transformers for tests at higher or lower voltages respectively. These transformers are specially designed for the duties involved and the repeated short circuits to which they will be subjected.

Four auxiliary items of importance in short-circuit tests are given as follows:

1. An Electro-Magnetic Oscillograph (EMO) for recording power frequency quantities
2. A Cathode Ray Oscillograph (CRO) for recording voltages transient in nature, e.g., re-striking voltages whose frequency of oscillation is beyond the response of the EMO. Such a CRO should better be storage oscilloscope and/or a high-speed camera attached with polaroid film attachment for permanent record and giving the certificate to the customer.
3. A time sequence controller
4. A point-on-wave switching arrangement

The data recorded on an EMO will include the following:

1. The short-circuit current of each phase
2. The voltage across each pole of the circuit breaker before, during and after the short circuit
3. In an oil circuit breaker, the pressure of oil
4. In an air-blast circuit breaker, the air pressure or in an SF₆ circuit breaker, the pressure of gas
5. The current in the closing coil and trip coil circuit
6. The generator voltage

In make-break test, short circuit is made by closing the circuit breaker under test and then the short-circuit current is interrupted by the breaker under test. So oscillographic records are not very different. The TRV, peak of the re-striking voltage and the natural frequency of oscillation of TRV can be known from the high-frequency records of the CRO.

The values of the current like ac component, dc component and % dc component can be measured from the oscillograph. Further, % dc component, rms symmetrical breaking current and rms asymmetrical breaking current can also be calculated.

16.3 SHORT-TIME WITHSTAND CAPACITY TEST

When the breaking and making capacity tests are being carried out, a major effect is the electrodynamic and electromagnetic stresses that are generated. But during short-time withstand test, the circuit breaker under test has to withstand both electromagnetic and thermal effects. In the breaking test, the circuit breaker interrupts the current by receiving a signal from, say, instantaneous overcurrent relay (or by any other mechanism) immediately. The short-time withstand test is designed to check the ability of the circuit breaker to carry high fault currents while the fault is being cleared elsewhere. Two time ratings are generally specified, viz., 3 seconds and 1 second. When the ratio of symmetrical breaking current to the rated normal current is 40 or less, the 3-seconds rating is chosen. When this ratio is over 40, the one-second rating is acceptable. The current equal to the rated symmetrical breaking current is passed for this short time in a short-time withstand test. The current is interrupted by the master breaker in this case.

Whatever has been discussed up to this point is known as direct testing, which requires a complete three-phase circuit. However, with the ever-increasing fault levels of modern power systems, the provision of the generator and other test apparatus would be prohibitive in terms of capital cost. Therefore, it becomes essential to resort to the other economic methods.

16.4 SINGLE-PHASE TESTING

One method of assessing the breaker capacity of a three-phase circuit breaker where plant limitations prevail is that of single-phase testing on one pole of a three-phase breaker. When testing by this method, it should be noted that the phase recovery voltage is 1.5 times the phase voltage. This is because, in a three-phase circuit breaker, when the first pole clears the short circuit, the voltage across breaker contacts in this pole is 1.5 times the phase-to-neutral voltage. Such single-phase testing demands a total plant MVA equal to only 50% of that required for three-phase testing for the same breaking capacity.

16.5 UNIT TESTING

Another method of testing is one which can be applied to many high-voltage and extra-high-voltage circuit breakers which use a number of identical interrupter heads operating in series per pole, e.g., the air-blast type. For designs of this type, what is known as 'unit' testing is employed in which the interrupter head is tested at full-rated breaking (and/or making) current as per operating duty and at a voltage equal to the full-rated voltage reduced in the proportion to the number of interrupter heads used in the complete pole of the breaker. From such unit tests coupled with supplementary part tests on a complete breaker pole (a) at full voltage with reduced current, and (b) with full current with reduced voltage, the breaking capacity of the breaker as a whole can be determined. The validity of this method depends upon the assumption that there is equal voltage distribution between the multiple breaks of a breaker.

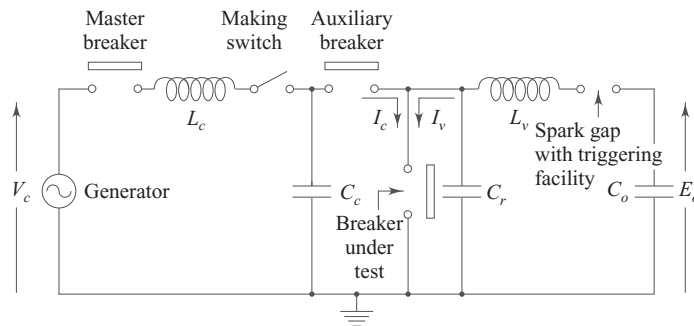
The high power test plants can test up to 5000 MVA. This means that a 35000 MVA circuit breaker rated at 400 kV would require 8 interrupter heads per pole. Present SF₆ circuit-breaker designs have very few circuit breaker interrupter heads per pole. The testing of such a circuit breaker would become impossible by test plants, as otherwise the cost of the test plant would be prohibitively large. Hence, the alternative test method is sought for, known as synthetic testing of circuit breakers.

16.6 SYNTHETIC TESTING

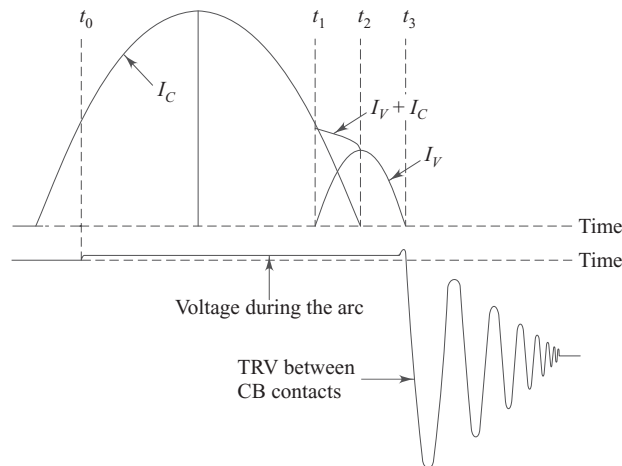
This method uses two sources of power. One, to supply the short-circuit current at reduced voltage and another, a high-voltage power source comprising a large capacitor bank to inject a high voltage across the breaker contacts to simulate the full re-striking voltage.

One method of synthetic testing is known as the *parallel current injection method* in which the voltage circuit is effectively connected in parallel with the current circuit. The other is the *series current method* in which a voltage circuit is effectively connected in series with the current circuit. The parallel-current injection method is usually preferred. It is suitable for testing with TRV (Transient Re-striking Voltage) of 1.0 kHz and above. For frequencies below this the series current method is used.

Figure 16.2(a) shows the circuit used in the parallel injection method. A generator supplies the current to the test breaker at reduced voltage. The use of the resistor, reactor, master breaker and make switch are same as the conventional direct testing method. An auxiliary breaker isolates the current and voltage circuits. Capacitor C_c eases the duty of the auxiliary breaker. The voltage circuit comprises a source capacitor C_o charged from the separate dc source in series with a triggered spark gap and an inductor L_v ; the whole arrangement being connected in parallel with the capacitor C_r , which controls the frequency of TRV. The operation of this testing circuit is explained as follows.



(a) Test set-up



(b) Typical waveforms

Fig. 16.2 Synthetic testing—parallel-current injection method

The current circuit is set to give the required power frequency current, the make switch being open and the auxiliary breaker, master breaker and breaker under test all closed. The source capacitor C_O is charged to a value appropriate to the required test voltage. The make switch is closed at the instant as per requirement of the dc component. The current I_c flows through a series circuit of the auxiliary and test breakers. The auxiliary and test breakers open at a predetermined time and arcing commences in both. As shown in Fig. 16.2(b), the triggered spark gap is fired at time t_1 and the current I_v flows from the voltage source through the test breaker. When the power frequency current reaches to zero at time t_2 , the auxiliary breaker interrupts current I_c , leaving current I_v flowing alone from the voltage source through the test breaker. At time t_3 , I_v reaches zero and the test breaker attempts to interrupt the same. Should interruption occur, capacitor C_r will be charged from C_O through L_v causing TRV to appear across the test breaker. If the test breaker re-ignites, the current from the high-voltage circuit will be re-established through the test breaker. No doubt, the test does not exactly simulate the conditions of direct test as (i) the reactance in the voltage circuit may have different characteristics than that of generator of current circuit, and (ii) C_O in the voltage circuit will lose some charge in the cycle of operation, due to its leakage resistance.

Using the synthetic-testing method, the power requirement in the test plant is reduced by 5 to 10 times. For testing the ability of the circuit breaker to interrupt the small inductive current and to check that chopping or re-striking does not occur, a transformer or reactor can be provided in a test plant. For checking the ability of the interrupting low-capacitive current, a bank of capacitors can be provided in a test plant. When using synthetic-test methods, it is not possible to conduct make duties or duties involving make-break tests as realistically as direct testing.

Figure 16.3 shows how the circuit breaker can be tested to confirm its ability to clear severest short line faults. Figure 16.3 depicts an artificial line in which the surge impedance can be adjusted to give desired fractional value. It is a ladder network, which usually represents an equivalent length of line up to 6.5–8 km. The values of inductance and capacitance correspond to those of actual lines. The only difference is that in an actual line, the capacitance and inductance are distributed uniformly throughout the line.

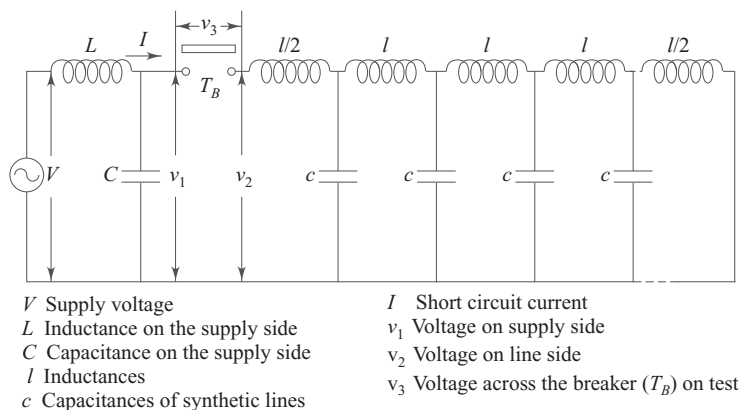


Fig. 16.3 Synthetic line for short-line fault tests (ladder network)

In this chapter, we have discussed briefly about short-circuit testing of circuit breakers. As these short-circuit testing facilities are costly, they are generally installed and made available by test and research centres. In India, Central Power Research Institute (CPRI), Bangalore, has the short-circuit testing facilities for circuit breakers. Some of the manufacturers also have the facilities for testing. Technical visit and/or industrial training by students provide practical exposure to such testing of electrical switchgear.

REVIEW QUESTIONS

- Select a circuit breaker for the following application.
6.6 kV, 650 MVA (breaking capacity) breaker. Number of operations envisaged are about ten per day. It is supposed to be connected to primary of 6600/433 V, 2000 kVA transformer. Justify your choice and prepare the specifications for the breaker.
- Why is making capacity required for a breaker more than symmetrical breaking capacity? Why is it generally taken as 2.5 times the breaking capacity?
- Suggest the type of circuit breaker to be used for each of the following applications:
 - Circuit breaker for the high-voltage arc furnace
 - 415 volts circuit breaker for industrial application (load current = 1000 A)
- Figure 16.4 shows a 132/66 kV power transformer (% $Z = 14\%$) fed from an infinite bus.

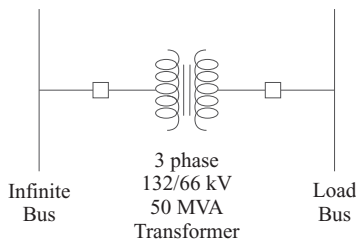


Fig. 16.4

If the 66 kV bus is a load bus, specify for the breaker X.

- rated continuous current
- breaking capacity in MVA

MULTIPLE CHOICE QUESTIONS

- Which of the following tests is not a routine test?
 - One-minute power frequency withstand test
 - Operation test
 - Short-time current test
 - Milli-volt drop test
- The highest magnitude of current for a circuit breaker shall be that of
 - breaking capacity
 - short-time current
 - rated continuous current
 - making capacity
- The impulse voltage waveform utilised for performing impulse test on a circuit breaker has a specification of
 - 1.2/50 μ s
 - 1.3/40 μ s
 - 1.2/500 μ s
 - 1.5/20 μ s
- making capacity in kA (peak) specify for the breaker Y
- low inductive breaking current.
- A circuit breaker controls a three-phase, 1000 kW, 6.6 kV, 0.8 p.f. induction motor. Suggest a suitable circuit breaker and specify
 - continuous current rating
 - symmetrical breaking capacity in MVA if current for a three-phase fault at motor terminals is 10 kA
 - making capacity
 - short time rating.
- An 11 kV, 200 MVA (breaking capacity) SF_6 circuit breaker is to be sent for repair. If a 22 kV, 200 MVA, SF_6 circuit breaker can be spared as replacement, would you recommend it to get replaced? Why?
- Draw the basic short-circuit testing plant for a circuit breaker.
- What do you mean by 'point-on-wave switching' for short-circuit test of a circuit breaker?
- Which four auxiliary items are important for short-circuit tests of a circuit breaker?
- Explain the single-phase testing method for testing a breaker.
- What are the advantages of unit testing of a breaker?
- What do you mean by synthetic testing w.r.t. testing of a breaker?
- Explain the parallel-current injection method of synthetic testing of a circuit breaker.
- Explain the arrangement to test a circuit breaker for short-line faults.

4. The synthetic testing method for breaking capacity test of circuit breaker is preferred because
 - (a) the results are as accurate as direct test
 - (b) the power requirement in the synthetic test plant is reduced by 5 to 10 times, hence cost of testing reduces
 - (c) the results are more accurate than the direct test
 - (d) none of the above
5. The parallel-current injection method for synthetic testing of a circuit breaker is suitable for
 - (a) Transient Recovery Voltage (TRV) of frequency less than 1 kHz
 - (b) Transient Recovery Voltage (TRV) of frequency equal to 1 kHz
 - (c) Transient Recovery Voltage (TRV) of frequency 1 kHz and above
 - (d) Transient Recovery Voltage (TRV) of frequency equal to 50 Hz

Lightning Overvoltage Protection

Lightning strokes on transmission lines are classified into two groups—the direct strokes and the induced strokes as shown in Fig. 17.1. When a thunder cloud directly discharges on a transmission line, it is called a direct stroke. This is the severest form of a stroke. However, direct strokes are rare and mostly induced strokes take place.

Direct Lightning Strokes

Type A Stroke Due to atmospheric conditions, the clouds get charged and further induce a charge on the nearby earthed objects like transmission towers, lines, high buildings, etc. The non-uniform field configuration is formed by these two electrodes, i.e., the topmost part of the building or transmission tower or line and a cloud is similar to that of the point-plane electrode geometry. Hence, the electrostatic stresses at the topmost point will be very high and so the surrounding air gets ionised. The dielectric withstand capacity of this ionised air reduces drastically. As

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Introduction

a result, a direct lightning stroke occurs which is called *Type A stroke*. Protection against this stroke can be provided by placing a lightning conductor on the top of a building. The charge will be discharged to the earth through this conductor as its other end is earthed at the bottom of the building.

Type B Stroke To understand the phenomenon of the *Type B stroke*, let us take a case of three clouds, *P*, *Q*, and *R* in the atmosphere as shown in Fig. 17.2. The clouds *P* and *R* are positively charged and the cloud *Q* is negatively charged.

The negative charge on the cloud *Q* acts as a binding force for the positively charged cloud *R*. Eventually, the positively charged cloud *P* moves nearer to the cloud *Q* and a lightning stroke occurs from *P* to *Q*. Thus, the charge on the cloud *R* is released and can discharge instantaneously on any nearby earthed object like a transmission line. As this stroke occurs without any time-lag, there is no scope for providing protection against it.

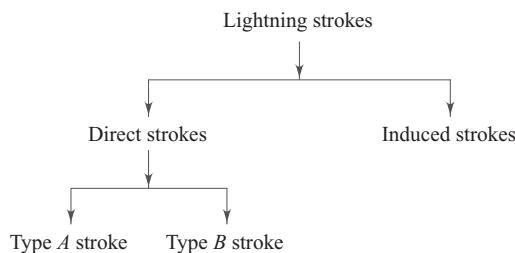


Fig. 17.1 Classification of lightning strokes

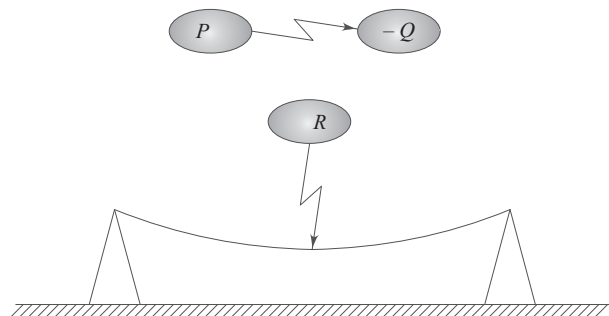


Fig. 17.2 Lightning stroke of type 'B'

When the lightning stroke falls on a conductor, a large amount of overvoltage surge waves travel on both the sides of the transmission line. It can damage the insulators on the poles or towers coming in the path of travel. If the stroke is distant from the generating station or the substation, the energy will be dissipated in the impedance of the line. Thus chances and severity of the damage to the generating station or the substation will reduce. But if the stroke is near then its intensity will be sufficiently high to damage the equipments in the generating station or the substation. Hence, protection against such overvoltages is necessary.

Occasionally, when a direct lightning stroke falls on a tower, the tower has to carry the large impulse currents. If the tower footing resistance is not low, the potential of the tower steeply rises to a high value with reference to the line. Hence a flashover may take place along the insulator strings. This phenomenon is known as 'back flashover'.

Induced Lightning Strokes An induced lightning stroke is depicted in Fig. 17.3. The cloud nearby to the transmission line is positively charged and due to electrostatic induction, the portion of the line under the cloud becomes negatively charged. The portion of the line away from the cloud will be positively charged. The negative charge remains bounded due to the oppositely charged cloud but the positive charge on the far ends of the line slowly leaks through the insulators, metallic parts, etc. Eventually, it may so happen that the positive charge on the cloud is neutralised by the negative charge of a closely passing cloud. Alternatively, the positively charged cloud may often discharge to some nearby earthed object. In both these cases, the bound charge on the line becomes free and travels in both the directions in the form of overvoltage waves. The wave fronts of these high magnitude overvoltage waves are steep enough to damage the equipment attached with the line. Hence, overvoltage protection for such induced lightning strokes is essential.

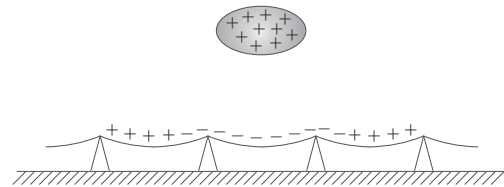


Fig. 17.3 Induced lightning stroke

17.1 SPECIFICATIONS OF A LIGHTNING STROKE

A lightning stroke is associated by a wave traveling along both the sides of the line from the point of strike. The typical shape of this wave is as shown in Fig. 17.4. The specifications of lightning are the amplitude of the voltages and currents, the rate of rise and the wave shapes of the lightning voltages and currents.

The wave is defined by two parts. The first is the *wave front*. The time (t_1) taken to reach to peak voltage, V_p , is defined as the front time. The second part is known as *wave tail*. The time (t_2) taken to reach half the peak value of the voltage ($V_p/2$) is known as tail time.

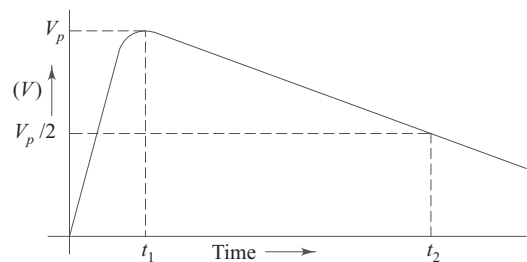


Fig. 17.4 Impulse wave shape for lightning

As the wave travels along the line, its front is modified by the inductance of the line and the distributed capacitances to earth. It may be further modified by the capacitances of bushings, insulators, etc., which the wave encounters on its journey, thus reducing the steepness of the wave front. Thus the overvoltage gets attenuated.

Another point to be considered is that when the traveling wave reaches a point where there is a change in value of surge impedance of the line, a reflection of the wave will occur, the reflection being whole or partial depending on the amount of change in the surge impedance. The intensity of voltage, at the point of reflection will therefore be more, even double, depending upon the nature of reflection.

The oscillograms of the lightning current indicate that the lightning current is very high initially and has short front times in the range of $10 \mu\text{s}$. The low current portion follows next and lasts for a longer duration in the range of milliseconds. Although this last portion is low in magnitude, it can cause thermal damage to insulation owing to its longer duration. Time taken to reach the peak value and the rate of rise are also important. Based on practical data, it can be concluded that 50% of lightning stroke currents have a rate of rise higher than $7.5 \text{ kA}/\mu\text{s}$. Only for 10% of lightning strokes, it is more than $25 \text{ kA}/\mu\text{s}$.

Actual measurements of lightning overvoltages reveal that a maximum voltage of 5000 kV occurs on the transmission lines. But, in general the lightning strokes give rise to overvoltages of not more than 1000 kV on the transmission lines. The wave-front time ranges from 0.8 to $10 \mu\text{s}$ and the tail times are generally between 20 to $100 \mu\text{s}$. The typical value of rate of rise of voltage is about $1 \text{ MV}/\mu\text{s}$.

17.2 PROTECTION AGAINST LIGHTNING OVERVOLTAGES

Protection of transmission lines against lightning overvoltages is done by suitable line design, providing ground wires and using surge diverters.

Overvoltages due to lightning strokes can be avoided or minimised in practice by

1. Shielding the overhead lines by using ground wires above the phase wires
2. Using ground rods
3. Using counter-poise wires
4. Use of lightning arresters or surge diverters

17.2.1 Lightning Protection using Shielding Wires or Ground Wires

Referring to Fig. 17.5, a ground wire is a conductor run parallel to the main conductor of the transmission line, supported on the same tower and earthed at every equally and regularly spaced towers. It is run above the main conductor of the line. The ground wire shields the transmission-line conductor from induced charges, from clouds as well as from a lightning discharge. The effective protection given by the ground wire depends on the height of the ground wire above the ground and the shielding angle, θ_s , as shown in Fig. 17.5. The shielding angle of 30° is considered adequate for a tower height of 30 metres or less.

If a positively charged cloud is assumed to be above the line, it indicates a negative charge on the portion below it, i.e., the transmission line. With the ground wire present, both the ground wire and the line conductor get the induced charge. But the ground wire is earthed at regular intervals, and as such, the induced charge is drained off.

Moreover, the potential difference between the ground wire and the cloud and that between the ground wire and the transmission line wire will be in the inverse ratio of their respective capacitances. This is discussed as follows.

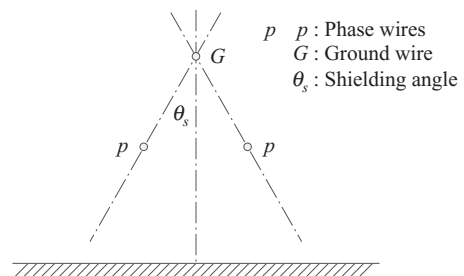


Fig. 17.5 Shielding of line conductor

Referring to Fig. 17.6,

$$V_1 = \frac{i}{\omega C_1}, \text{ the voltage to which the ground wire is stressed}$$

and

$$V_2 = \frac{i}{\omega C_2}, \text{ the voltage to which the phase wire is stressed}$$

As the phase wire is insulated by porcelain insulators and as the distance between the phase wire and ground is very small compared to the distance between the ground wire and cloud,

$C_2 \gg C_1$, considering air as a dielectric medium between the cloud and the line

$$\therefore V_1 \gg V_2$$

Thus, the electric stress due to lightning is largely taken care off by the ground wire, reducing the electric stress on the phase wire with respect to ground to a very small value. Thus, the overvoltage on the phase wire is minimised. Stress concentration never occurs on ground wires as the electric charges leak to the ground.

When the lightning strikes, it falls either on the tower or on the ground wire. The lightning current and charge can flow to the ground through three possible paths. The first path is through the tower metal frame to ground. The second and third paths are through the ground wire in both the directions. As all three paths are leading to the ground, the current will be divided in these paths. Hence, the instantaneous magnitude of voltage to which the tower top can rise, is reduced considerably. Let us have a closer look at this tower-top instantaneous voltage with the help of Fig. 17.7.

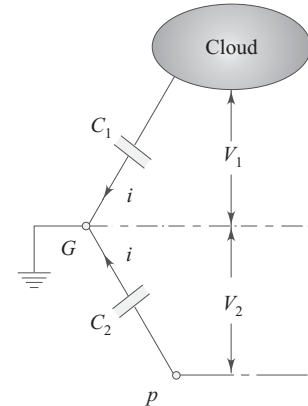


Fig. 17.6 Reduction of electric stress

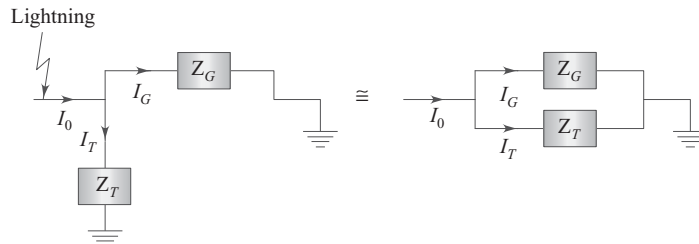


Fig. 17.7 Significance of tower footing resistance

$$V_T = I_T Z_T$$

where,

V_T = instantaneous magnitude of voltage at tower top

Z_T = surge impedance of the tower

Z_G = surge impedance of the ground wire

I_0 = lightning current

I_G = lightning current through the ground wire path

I_T = lightning current through tower path

The equation given above can be further simplified by using division of current in parallel paths as shown below.

$$V_T = I_T Z_T = \frac{I_0 \cdot Z_G}{Z_T + Z_G} \cdot Z_T$$

$$\therefore V_T = \frac{I_0 Z_T}{1 + \frac{Z_T}{Z_G}}$$

Thus, it can be concluded that V_T is greatly dependent on the surge impedance of the tower which is nothing but the effective tower footing resistance. So, the final conclusion is that the use of ground wire must be supported by the reduction in the effective tower-footing resistance. This can be achieved by the use of driving ground rods and counter-poise wires connected to the tower-bottom foundation.

17.2.2 Use of Ground Rods

The ground rods are made up of galvanised iron or copper-bearing steel to prevent corrosion. The diameter of a rod is 15 mm. There are a number of rods each of 2.5 to 3 metre length driven into the ground to form a mesh. The purpose of the ground rods connected to the legs of the tower is to reduce the tower footing resistance. The type of soil also affects the configuration of ground rods. For soils that are hard, the rods have to be driven down to a greater depth. The design of the ground rods depends on the requirement of the value of the effective tower-footing resistance. By using 10 rods of 4 m length and a spacing of 5 m, a value of 10 Ω may be achieved for the effective tower-footing resistance.

17.2.3 Use of Counter-poise Wires

This is an alternative method for reducing the effective tower footing resistance. In this method, the wires are placed inside the ground at a depth of 0.5 to 1.0 m, running parallel to the transmission line conductors. Of course, these wires are connected to the tower legs. The length of these wires may be from 50 to 100 m. In this method, depth does not affect the value of the tower-footing resistance. The wires are laid at a sufficient depth so that the theft of wires can be prevented. To reduce the effective tower-footing resistance, it is necessary to use a large number of parallel wires than a single wire. With this method of counter-poise wires, the effective tower-footing resistance may be reduced to as low as 25 Ω . The only problem is the difficulty in laying counter-poise wires as compared to ground or driven rods. However, with the modern development in erection techniques, it may be easier to lay counter-poise wires.

17.2.4 Use of Lightning Arresters or Surge Diverters

To be really effective, a surge diverter should reduce the crest of the surge voltage and at the same time absorb the transient energy to an extent sufficient to prevent reflection. Also, it should be noted that the surge diverter should provide a path of low impedance, only when a traveling wave of surge reaches it, neither before nor after it.

The lightning arrester should have the following characteristics:

1. The lightning arrester should not absorb any current during the normal operation, but during overvoltages it must provide an easy path to earth.
2. The impulse spark-over voltage of the arrester must safeguard the insulation of the terminal apparatus.

3. The diverter must be capable of carrying the discharge current for a short duration without being damaged.
4. The arrester must, after discharge, cease to carry any current, i.e., it must seal-in itself.
5. After operation, the arrester must be in a condition to accept and deal with ensuing surges i.e., there must be no failure of the arrester itself.

Figure 17.8 shows the functioning of a simple lightning arrester. The successive stages of operation are shown diagrammatically.

In Fig. (a), the front of the wave approaches the diverter which is protecting the terminal equipment (not shown), connected to the line to the left of the diverter. By (b), the surge has reached the diverter and in about $0.25 \mu\text{s}$, the voltage has reached a value sufficient (V) to break down the spark gaps. During (c), the surge current flows to earth. As the voltage applied increases, and just as rapidly, the resistance of the element decreases, thus permitting further surge energy to discharge, and so limiting the voltage impressed on the terminal apparatus to a safe value. At (d), the front of the wave is shown approaching and during (e) the tail of the wave passing the arrester, and in consequence the current through the arrester decreases while the resistance increases, reaching a stage when the current flow is interrupted by the spark gaps, thus sealing the diverter as shown by (f). This entire operation takes place in a matter of microseconds, typically $30 \mu\text{s}$.

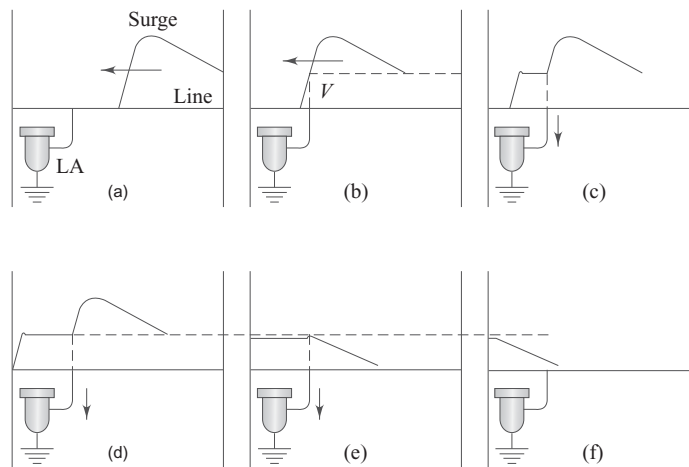


Fig. 17.8 Functioning of a lightning arrester

17.3 DIFFERENT TYPES OF LIGHTNING ARRESTERS USED IN PRACTICE

The overhead transmission lines and connected apparatus, viz., transformers, switchgears and other apparatus are subjected to overvoltages due to lightning discharges caused by atmospheric disturbances and switching overvoltages due to switching operations. These overvoltages act across the insulation and as the time taken by these voltages to rise to their peak values is very small, very severe voltage stresses are imposed on insulation of transformer windings, circuit breakers, bushings and other equipment. The lightning arrester discharges these overvoltages to earth.

Different types of lightning arresters (LA) used in practice are

1. Rod-gap LA
2. Sphere-gap LA

3. Horn-gap type LA
4. Modified horn-gap LA
5. Expulsion-type LA
6. Lead-oxide type LA
7. Thyrite-type LA
8. Valve-type LA
9. Metal-Oxide Surge Arrester (MOSA) or Gapless LA

Overvoltage protection started from the use of simple rod gaps. But the gap was not capable of preventing power frequency voltages (following the overvoltages) to earth due to ionisation of air within gaps. Also, climatic conditions and heat produced by the arc were major problems. This led to the development of sphere gaps. In sphere gaps, the arc was automatically extinguished by hot air traveling upwards. In spite of this design, the arc might be maintained after the surge has been discharged and may interrupt the system by operation of circuit breakers. Some modifications were made to the gaps resulting in the development of the horn-gap arrester. Severe problems of pitting and corrosion of horns are observed, which results in alteration to the settings of the lightning arrester. Also, this lightning arrester could cause dangerous conditions by reflecting the surge wave. Also, for low-voltage lines, the gap being very small, possibilities of accidental discharges were increased. Moreover, in such arresters there are problems of chopping of an impulse wave. This chopped wave may prove to be worse than original lightning or switching surge. The quenching of arc is improved in the modified horn-gap arresters and expulsion arresters. The development of arresters with series gaps and non-linear resistor blocks was the next step. Finally, with the advent of metal-oxide surge arresters (MOSA), which do not require such series gaps, most of the disadvantages of the earlier arresters were removed. They are also known as gapless lightning arresters. The working principles of the main lightning arresters are explained in the following sub-sections.

17.3.1 Thyrite Lightning Arrester

Thyrite is a mixture of a certain type of clay and carborandum. It has a non-linear property which at lower voltages acts as a non-conducting or insulating material and at higher voltages acts as a good conductor. The resistance offered by thyrite is voltage dependent. Whenever the voltage is doubled, the resistance decreases so as to pass more current through it. Hence, during a lightning surge, it allows the current through it to the earth. Once the surge has passed away, the thyrite regains its original resistance value at normal voltages without any permanent chemical changes. The basic cells of thyrite are used inside this type of lightning arrester.

A thyrite lightning arrester consists of a number of discs stacked one above the other and electrically in series with air gaps in the series-gap unit. The discs and series-gap units are assembled inside a wet-process porcelain container. At the top and bottom, there are two aluminum castings. These castings are cemented to the porcelain container. The discs are kept in position by the spring underneath the top cap casting. The cap of the casting is connected to the line by a terminal at the top. The bottom case is connected to earth.

During surge, the gap spark-over and the thyrite discs offer relatively low resistance to the flow of surge current. After the surge disappears, the discs regain their original high resistance and the series gap together with this high resistance do not allow any flow of current under the normal operating conditions.

17.3.2 Valve-Type Lightning Arrester

A valve-type lightning arrester consists of a divided spark gap in series with a nonlinear resistor (made of silicon carbide). The index in the nonlinear volt-A characteristics ($I = KV^n$) for silicon carbide valve blocks lies between $n = 4$ to 5 . Due to the limited nonlinearity of the silicon carbide elements, the current at normal

line to ground voltage would be high, if the silicon carbide blocks are used without the series gap. Hence, the arresters with silicon carbide elements must have the series spark gaps.

The gaps are housed in an arc chamber made of glass-bonded mica. This material has a very high arc resistance, dielectric strength and mechanical strength. The electrodes made of brass are riveted to the arc chamber. The magnetic coil wound on an insulated former is connected in series with the gaps. The coil is designed to carry power follow current and is bypassed by means of the air gap. The gaps are shunted by means of nonlinear voltage-grading resistors for achieving linear voltage distribution across the entire arrester. The electrical circuit for such an arrangement is shown in Fig. 17.9.

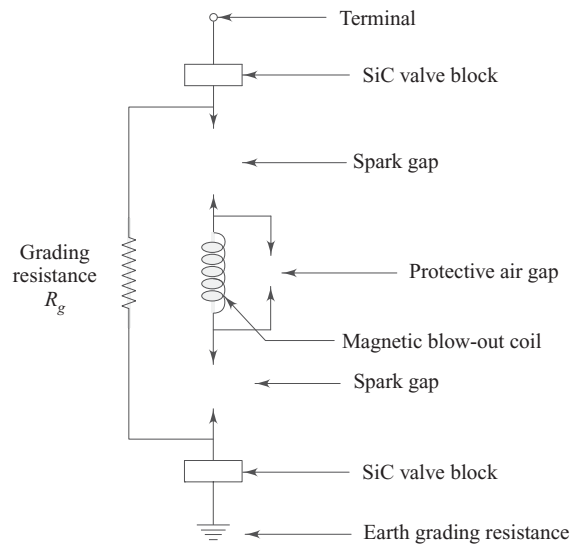


Fig. 17.9 Electrical circuit of a valve-type lightning arrester

When the system voltage increases abnormally, higher than the spark-over voltage of the arrester, the series gaps spark over. The lightning current flows to earth through the series gaps. The high-voltage transient current does not flow through the magnetic coil, as the coil offers a high impedance path for steep wave fronts. This means that the presence of the coil does not hamper the protective characteristics of the arrester. After the lightning current discharges, the power follow current flows through the coil, due to its low impedance at power frequency. The magnetic field set up by the coil due to this current exerts a force on the arc in the arc chamber and the arc is elongated and its resistance gets increased.

Therefore, the voltage necessary to maintain the arc increases. Hence when the instantaneous ac voltage falls to less than this value, the arc is extinguished, much before the voltage zero. The added advantage for using a magnetic coil is that it reduces the power-follow current. During the flow of the lightning discharge current, the nonlinear silicon-carbide elements limit the voltage drop across the arrester to a value far below the basic insulation level (BIL) of the equipment to be protected because of its nonlinear VI characteristic ($I = KV^n$). Under the normal operating conditions, silicon-carbide valve blocks offer high impedance and series gaps insulate the line from ground.

The spark-gaps in the valve arresters are most significant as they perform the following tasks:

1. To isolate the circuit from ground against maximum line to ground voltage under normal system conditions

2. To spark-over at a value well below the withstand level of the equipment to be protected
3. To interrupt the follow current and return to a non-conducting condition immediately

Several gaps are to be connected in series in order to interrupt the follow current effectively and efficiently. The higher the voltage of an arrester, the greater the number of gaps required. Stray capacitance between the gaps and ground capacitance unbalance the power-frequency voltage distribution between the gaps and so the power frequency spark-over voltage of the arrester gets reduced. To counteract this, nonlinear grading resistors are used in parallel with the gaps for the uniform distribution of power-frequency voltage. In addition, an external grading ring on h.v. arresters (above 66 kV) may be provided for maintaining uniform voltage distribution across the arrester units, for impulse voltages.

It is important that the grading resistors should have a considerably stable value during its operation in the power system over the years. This is because of the fact that the arrester is always energised. To comply with this demand, the nonlinear grading resistors are subjected to rigorous high-voltage pulse tests and endurance tests to make sure that their values will not change with time.

The nonlinear resistors used in valve blocks are the essential part of the arrester. These resistors are moulded and sintered silicon-carbide blocks metalised at both ends with aluminum. The cylindrical surfaces are coated with special epoxy paints to eliminate flashover. These valve blocks possess nonlinear voltage–current characteristic and offer very high resistance for power frequency currents and very low resistance for large surge currents.

The nonlinear resistors or valve blocks perform the following important tasks:

1. Limits the magnitude of discharge voltage, while discharging the transient current, to a value well below the withstand level of the protected apparatus
2. To discharge the energy associated with transient currents
3. To limit the power-follow current through the arrester to a value that the spark gap can consistently interrupt

17.3.3 Limitations of Valve-Type Lightning Arresters

In the valve-type lightning arrester, the series gap is the weakest link. Some difficulties while using these arresters are discussed below. The most severe issue is the effect of pollution. The worst conditions encountered have been in the coastal areas where contamination has taken the form of salt-fog deposits on the insulator surface. Various types of agricultural sprays that settle on the surface of the insulator have also shown that they are electrically conductive. The smoke, chemical fumes and deposits from industrial areas worsen the problem. The contamination on the arrester housing acts mainly in three ways.

1. The most well-known effect is *external ashover*. If the type and the amount of the contamination are severe enough, the leakage current increases to the extent that surface insulation breaks down completely causing flashover.
2. Leakage current produces corona because small current areas are created on the insulation surface.
3. The arrester is subjected to another effect of contamination—a disruption of gap voltage gradient—and the arrester may spark over at normal power frequency voltages.

Figure 17.10(a) represents the circuit details of an arrester when the porcelain surface is clean and dry. R_g is a voltage-grading resistor. The leakage current can be neglected since the porcelain surface is clean and dry. The voltage distribution across the gap structure remains uniform as the gap grading current I_g is high compared to the stray capacitance current I_{cs} . C_s does not vary widely and remains more or less constant for all the gaps.

Figure 17.10(b) represents a similar arrester with the porcelain surface contaminated. The resistance R is the resistance of the leakage path through the contaminants. Due to the non-uniform resistance of the contaminant path caused by the fluctuations of the contamination resistivity, the voltage distribution across the housing is also disrupted. The stray capacitance of each gap shown as C_{s1} , C_{s2} , C_{s3} etc., also varies widely and this makes the voltage across the gap structure highly nonuniform tending to reduce the power frequency spark-over voltage. There may then be a risk of repeated spark-overs of the arrester due to overvoltages which may be harmless. Such spark-overs may threaten the service reliability of the arresters. Further, the performance of the arrester may be adversely affected by the fact that it may not be able to reseal itself after discharging a lightning current. Also, consideration must be given to the fact that the reduced spark-over voltages of the gaps due to contamination must be overcome by providing a higher rating of arresters, thereby sacrificing the protective margin and economy.

Thus, the conventional gapped arresters suffer from spark-over voltage variations, low energy-discharge capability and possible erroneous operation due to housing contamination. These difficulties led to the development of the gapless arrester, where the gap is replaced by zinc oxide blocks.

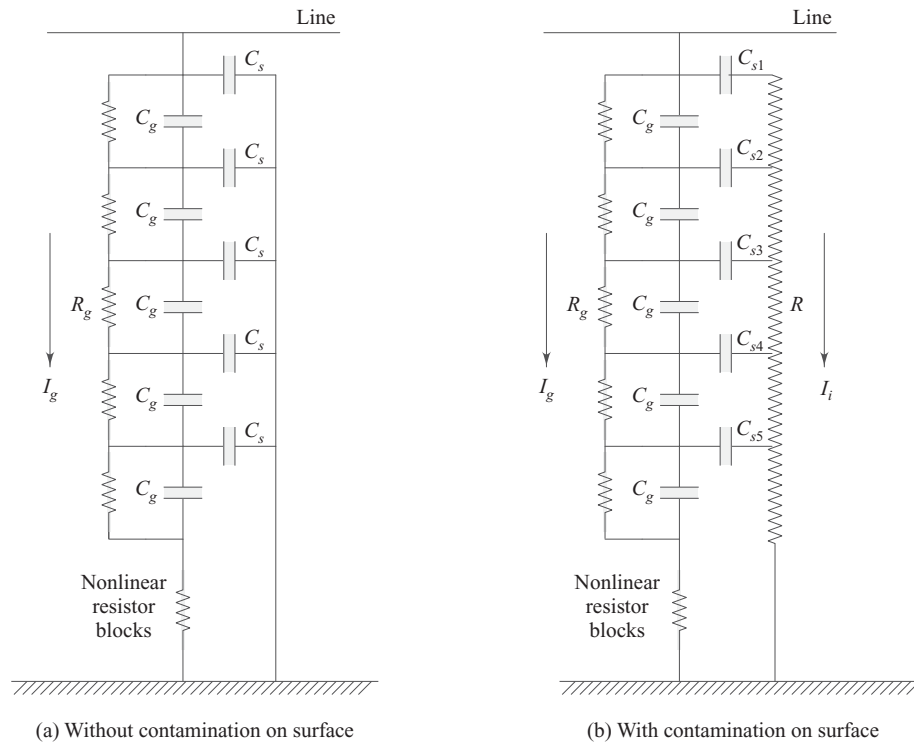


Fig. 17.10 Circuit details for Valve-Type lightning arrester

17.3.4 V-I Characteristics for SiC and Metal Oxide

The metal oxide (ZnO) element has an exceptionally high nonlinear V-I characteristics (Fig. 17.11).

When the voltage increases by 100%, current increases from 5 mA to 10 kA, value of nonlinear index n varies from 25 to 30 in the nonlinear V - I characteristics ($I = KV^n$) for metal oxide blocks as against $n = 4$ to 5 for silicon carbide blocks used in valve-type arresters. This clearly shows the superiority of MOSA.

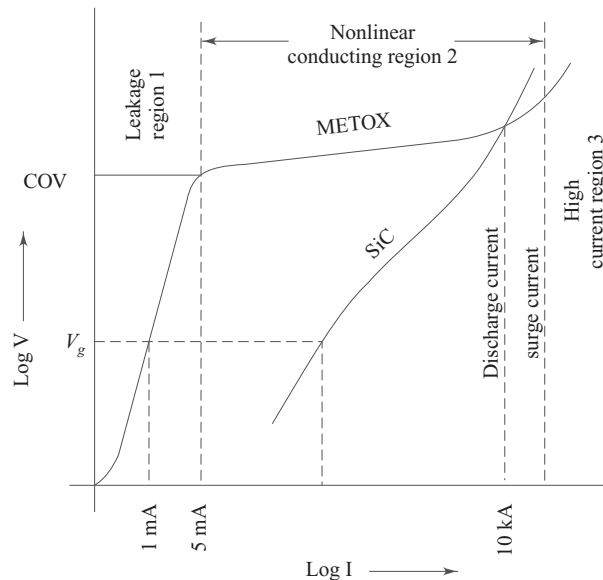


Fig. 17.11 V-I Characteristics for SiC and METOX

The working of MOSA can be briefly explained in the following three stages:

1. METOX elements enter into conduction at a specific voltage level above the arrester rating.
2. Clamps the voltage during conduction period of surge currents
3. Ceases to conduct at very nearly the voltage at which the conduction had started

The excellent nonlinear characteristic of the zinc-oxide element keeps the current at normal line to ground voltage in the milliamperere range. Hence, no spark gaps are required to isolate the live terminal from earth.

Referring to Fig. 17.11, in the region 1, the METOX composition will appear to be a ceramic capacitor, with capacitance and resistive currents as symbolically represented in Fig. 17.12.

As such, very little current, of the order of few milliamperes, will flow in this region mainly being determined by the dielectric constant and cross-sectional area. However, if a certain voltage stress level is exceeded, the device, then crosses over (region 2) and exhibits very high nonlinear resistive characteristics. Finally, in the high-current region 3, the device loses nonlinearity due to linear resistance of zinc grains. The region 1 performs the function of spark gaps of a conventional arrester, while the region 2 limits the discharge voltage for surge currents.

There being no follow current [Fig. 17.13(a)], the metal-oxide arrester conducts only the current required to reduce the surge voltage to the arrester protective level and therefore dissipates only the energies associated with the surges. Examination of Fig. 17.13(a) clearly shows that as there is no power frequency follow-up current in MOSA, it has very high energy discharge capabilities. MOSA has the speed of the order of nanoseconds, i.e., it absorbs the incoming surges without any time delay.

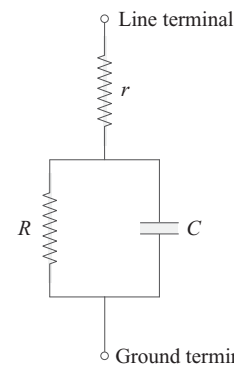


Fig. 17.12 Symbolic representation of METOX element

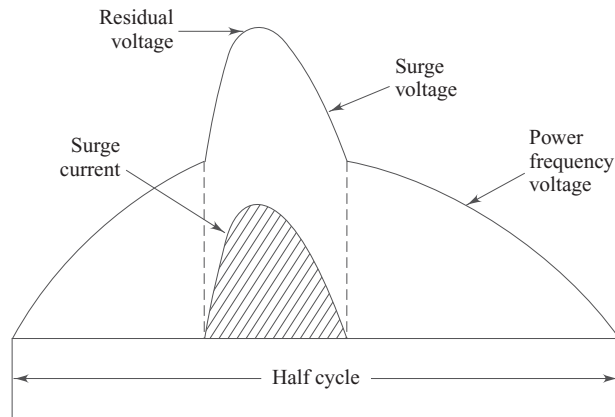


Fig. 17.13(a) Surge current and voltage waveform in MOSA

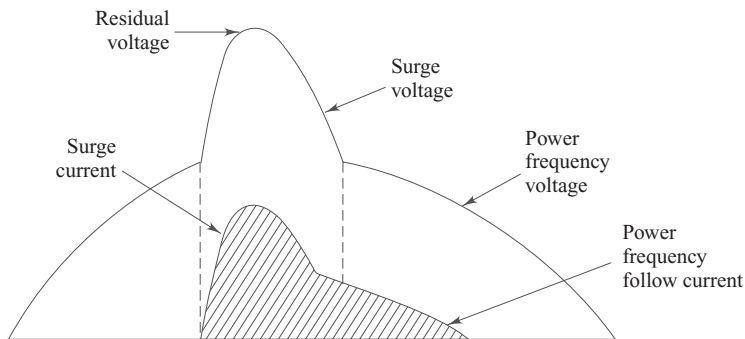


Fig. 17.13(b) Surge current, power frequency follow current and voltage wave forms in valve-type lightning arrester

17.3.5 Gapless Lightning Arresters (Metal Oxide Surge Arresters)

The problems associated with gapped designs, namely spark-over voltage variations, low energy discharge capability and possible erroneous operation due to housing contamination, are totally eliminated in gapless lightning arresters.

METOX elements are continuously stressed as there are no series gaps to isolate the elements from the voltage stresses. This continuous exposure to normal and harmless overvoltages as well as temperature stresses due to higher ambient temperature causes a drift in the leakage region of the $V-I$ characteristics of the METOX element, causing increased watt-loss, as shown in Fig. 17.14.

The condition is accelerated with increased voltage stresses and ambient temperature. In the limiting case, the current would increase so rapidly with time that the device eventually 'runs away' thermally and ends its useful life. Accelerated life tests are conducted at an elevated temperature of 115 °C for the satisfactory operation of MOSA during actual field applications.

In the remote event of arrester failure to limit and interrupt the power-frequency follow currents in gapped arresters or thermal run away in the case of MOSA, a fault will be established through the arrester and a full-system short-circuit current will pass through it. Due to the fault current through the failed arrester, gases are generated and the internal pressure increases tremendously which results in violent explosion of the arrester. To safeguard the life of adjacent equipment and personnel, the high-pressure gases are vented out through

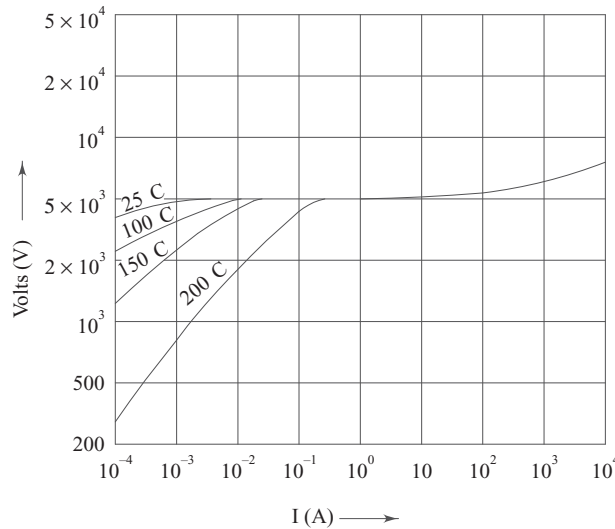


Fig. 17.14 V-I Characteristics of the METOX Element

the pressure-relief arrangement provided in all arresters. Due to rapid pressure build-up, associated with high fault currents, pressure release diaphragm provided in the relief arrangement bursts through and the high-pressure ionised gases are vented out through the exhaust port, thus reducing the pressure inside the arrester housing and preventing the shattering of the porcelain housing.

17.4 OVERVOLTAGE FACTORS

A wider knowledge of the magnitude of the lightning and internal overvoltages has justified downward revision of the insulation requirements in recent years. Further, the availability of non-restriking circuit breakers, circuit breakers with the provision of pre-insertion resistors, lightning arresters with improved characteristics, the ever-increasing short-circuit power in the networks and the provision of busbar protection against earth-faults in EHV stations have made it possible to limit the severity of switching overvoltages to an overvoltage factor of 2.5 for lines operating at 220 kV and to a value of about 2 for lines at 400 kV. The power-frequency overvoltage factor has been reduced to a value of 1.3 for 220 kV and a value of 1.5 for 400 kV.

17.5 CHOICE OF INSULATION LEVEL FOR TRANSMISSION LINE

Insulation requirements are a function of lightning and switching surges and power frequency overvoltages. The number of insulators, swing angle, effects of weather, phase spacing and clearance to tower and to ground wires affect tower dimensions and insulation costs as well as the outage rate. Economy and practicability of design demand that the insulation strength be kept to a minimum and should reasonably afford adequate protection. One has to strike an economic balance between the chances of failure and the cost of greater insulation strength.

It has long been recognised that as higher system voltage levels are adopted, internal overvoltages rather than lightning overvoltages would be the governing criterion. It does not, of course, follow that lightning overvoltages can be ignored. If tower footing resistances are acceptably low and ground wires are properly located, the insulation which is adequate for internal overvoltages, provides satisfactory lightning protection

also. In general, it can be said that lightning overvoltages determine the insulation level of insulations up to 66 kV lines, switching overvoltages for lines in the range of 66 kV to 220 kV and power frequency overvoltages for lines above 220 kV.

The string insulation must be sufficient to prevent a flashover from the stationary overvoltages and the switching surges, taking into account all the local unfavourable circumstances (rain, dust, insulator pollution, etc.) which decrease the flashover voltage. Some additional multiplying factors are therefore allowed to account for contaminated, nonstandard atmospheric conditions, polluted insulation surfaces, etc. These factors influence the value of normal frequency flashover voltages more than that of an impulse flashover voltage. Further, it is the usual practice to allow for some safety margin for unforeseen or unpredictable conditions. The various overvoltage factors along with their values normally applicable to EHV lines are given in Tables 17.1 and 17.2 below.

Table 17.1 Overvoltage factors for switching surges

1.	Maximum operative voltage	1.1 for 220 kV 1.05 for 400 kV
2.	Crest factor	1.414
3.	Switching surges	2.5 for 220 kV 2.0 for 400 kV
4.	Impulse flashover voltage / switching surges strength	1.15
5.	Impulse withstand voltage / Impulse flashover overvoltage	1.15
6.	Contaminated surface, nonstandard atmosphere etc.	1.1
7.	Overall safety margin	1.15

∴ positive impulse withstand voltage (crest $1/50 \mu\text{s}$)

$$= V_{pn} \times 1.1 \times 1.414 \times 2.5 \times 1.15 \times 1.15 \times 1.1 \times 1.15$$

$$= 6.5 V_{pn} \text{ for lines at 220 kV}$$

and

$$V_{pn} \times 1.05 \times 1.414 \times 2.0 \times 1.15 \times 1.1 \times 1.15 \times 1.15$$

$$= 5.0 V_{pn} \text{ for lines at 400 kV}$$

where, V_{pn} is the phase-to-neutral voltage

Table 17.2 Overvoltage factors for power frequency overvoltages

1.	Maximum operative voltage	1.1 for 220 kV 1.05 for 400 kV
2.	Overvoltage factor	1.3 for 220 kV 1.5 for 400 kV
3.	Withstand / flashover voltage	1.15
4.	Nonstandard, contaminated surface etc.	1.20
5.	Overall safety margin	1.50

∴ 50 Hz wet withstand voltage (rms)

$$= V_{pn} \times 1.1 \times 1.3 \times 1.15 \times 1.2 \times 1.5$$

$$= 3.0 V_{pn} \text{ for lines at 220 kV}$$

and

$$V_{pn} \times 1.05 \times 1.5 \times 1.15 \times 1.2 \times 1.5 \\ = 3.3 V_{pn} \text{ for lines at 400 kV}$$

where, V_{pn} is the phase-to-neutral voltage.

It is a good practice to make an allowance for one or two extra insulator discs to take care of the possibility of an insulator unit in the string becoming defective and also for hot line maintenance, over and above those required to withstand the above overvoltage.

17.6 INSULATION COORDINATION

Insulation coordination is the proper matching of insulation of transmission lines and other equipment with the characteristics of protective devices so that the surges entering the station are conducted to ground through the protective devices without damaging the insulation. The present practice is to locate the lightning arresters as close as possible to the transformer which is the costliest equipment in the substation. The lowest insulation is therefore chosen for the transformer which is governed by the characteristics of the lightning arrester.

An insulation coordination scheme for a substation covers the following parameters:

1. Protective characteristics of lightning arrester
2. Transformer Basic Impulse Level (BIL)
3. Impulse levels for circuit breakers, disconnecting switches (isolators), busbars, supports and other apparatus at the terminals

17.6.1 Protective Characteristics of Lightning Arresters

The important settings to be selected for the protective characteristics of a lightning arrester are the voltage rating and the discharge-current capacity. Arrester rating must equal or exceed the maximum permissible rms power-frequency voltage applied between its terminals under normal or abnormal conditions of operations, including fault conditions. On EHV transmission systems with effectively earthed neutrals, the voltage between phases and earth under faulty conditions does not generally exceed 75–80% of the highest phase to phase system voltage. The arrester voltage rating is therefore based on 75–80% of the maximum system voltage. 10 kA arresters are generally used for 220 kV and 400 kV systems. Protection level of the lightning arrester should be decided by knowing the BIL of the transformer.

17.6.2 BIL of Transformers

The BIL of a transformer can be decided by referring to relevant IS specification. To coordinate the arrester protective level with impulse withstand strength of the transformer, a margin in terms of ratio (generally taken as 1.2) between the insulation withstand strength (BIL) and impulse protective level of the lightning arrester has to be maintained.

17.6.3 Insulation Levels for other Substation Equipments

The insulation strength of the remaining substation equipment (circuit breakers, isolators, busbar supports, CT, PT, etc.) is kept generally greater than the selected BIL of the transformer to provide the equipment with as good protection and is economically justified. Hence this insulation strength is kept generally 10% higher than the BIL of the transformer. This presumes that the lightning arresters are located very near to the transformer terminals. In case additional lightning arresters are applied elsewhere in the substation, lower

BILs for circuit breakers, etc., can be permitted. The problem is therefore, essentially that of an economic balance between reduction in BIL of equipment and increased cost due to additional arresters.

Insulation level across the open poles of the isolating switches is kept about 10–15% higher than that provided between the poles and the earth, so that in the event of a surge at an open isolating switch, the flashover should pass to earth and not across open poles or between poles.

17.7 INSULATION COORDINATION SCHEME FOR 132 KV SUBSTATION

1. Nominal system voltage = 132 kV
2. Highest system voltage = $1.1 \times 132 = 145$ kV
3. Highest system voltage to ground = $\frac{145}{\sqrt{3}} = 83.8$ kV
4. Arrester voltage rating = 80% of 145 kV = 116 kV
 \therefore a surge diverter of 123 kV rating can be selected.

BIL of transformer = 550 kV peak

Power-frequency withstand voltage of transformer = 230 kV (rms)

Arrester protective level

$$\frac{\text{Transformer BIL}}{\text{Arrester protective level}} = 1.2$$

$$\therefore \text{arrester protective level} = \frac{\text{Transformer BIL}}{1.2} = 458 \text{ kV peak}$$

So an arrester protective level of 443 kV is selected.

BIL of other apparatus = 110% of 550 kV peak = 605 kV peak

\therefore BIL of other apparatus is selected at 650 kV peak.

Power-frequency withstand voltage of other apparatus = 110% of 230 kV = 253 kV

\therefore withstand strength of 275 kV (rms) is selected.

Insulation level across open poles of insulator = 110% of 650 kV = 715 kV

\therefore 750 kV is selected.

Similarly, a power frequency withstand strength of 325 kV (rms) is selected.

Based on the same principles, insulation coordination schemes for 220 kV system and 400 kV systems are tabulated in Tables 17.3 and 17.4 respectively.

Table 17.3 Insulation coordination scheme for a 220 kV system

1.	Arrester voltage rating	196 kV (rms)	
2.	Arrester protective level	715 kV	
3.	Transformer	900 kV _p	395 kV
4.	Other apparatus	1050 kV _p	460 kV
5.	Across open poles of isolators	1175 kV _p	520 kV
		Impulse voltage withstand (BIL)	Power-frequency withstand voltage (rms)

Table 17.4 Insulation coordination scheme for a 400 kV system

1.	Arrester voltage rating	336 kV (rms)	
2.	Arrester protective level	1200 kV	
3.	Transformer	1425 kV _p	630 kV
4.	Other apparatus	1550 kV _p	680 kV
5.	Across open poles of isolators	1780 kV _p	780 kV
		Impulse voltage withstand (BIL)	Power frequency withstand voltage (rms)

REVIEW QUESTIONS

- Enumerate the functions of the following components of a valve-type lightning arrester.
 - Spark-gaps
 - SiC valve blocks
 - Magnetic blow-out coil
 - Grading resistance
- Why is the performance of MOSA superior to conventional gapped arresters? Support your answer by showing characteristics and oscillographs.
- Giving detailed procedure and reasoning, decide insulation levels of the equipments of a 220 kV substation.
- Give reasons for the following:
 - The lightning arrester, after discharge, must seal-in itself.
 - The valve-type lightning arrester may fail in coastal areas.
 - The accelerated life tests are conducted at elevated temperature on a gapless zinc-oxide lightning arrester for its satisfactory applications.
 - The lightning arresters are installed as near as possible to the power transformer in a substation.
 - Direct lightning stroke of type 'B' cannot be channelised through a lightning conductor.
 - A ground wire, if properly grounded using ground rods or counter-poise wires, acts as a protection against lightning strokes on transmission lines.
 - The spark gaps are not required in metal-oxide gapless lightning arresters.
 - The zinc-oxide type of lightning arresters have high energy discharge capabilities.
 - Insulation level of the transformers is decided to be the least in a substation.
 - The BIL of CT/PT, circuit breakers, isolators, etc., is fixed at a value of 10% higher than that of a transformer.
 - BIL across open poles of an isolator is planned to be 10% higher than that between line and earth.
- Explain, briefly, with a neat circuit diagram, the function of a valve-type lightning arrester for protecting electrical equipment against overvoltages.
- How will an induced lightning stroke develop traveling waves in the transmission line network? State and explain the methods to protect the line from lightning strokes.
- What are the limitations of a valve-type lightning arrester? How are these limitations overcome in a gapless metal-oxide lightning arrester?
- What are the requirements of a good lightning arrester?
- What is the peak value of the power-frequency overvoltage across contacts of a circuit breaker when an unloaded 400 kV transmission line is switched off?
- What is the probable cause of failure of a gapless lightning arrester? What is the remedy to avoid such a failure?
- Find out the voltage rating of a lightning arrester used at the entry of a 400 kV transmission line in a substation.

MULTIPLE CHOICE QUESTIONS

1. Most of the times, the lightning stroke occurring practically is a/an
 - (a) direct lightning stroke
 - (b) induced lightning stroke
 - (c) lightning stroke of type A
 - (d) lightning stroke of type B
2. The angle between the phase wires and the ground wire used for lightning protection on the towers is generally
 - (a) 45°
 - (b) 60°
 - (c) 30°
 - (d) 90°
3. The nonlinearity index n for silicon-carbide block in a valve-type lightning arrester in the equation $I = KV^n$ is generally between
 - (a) 7 to 8
 - (b) 5 to 6
 - (c) 3 to 4
 - (d) 4 to 5
4. A series spark-gap unit is not essential in
 - (a) thyrite type lightning arrester
 - (b) valve-type lightning arrester
 - (c) metal-oxide surge arrester
 - (d) none of the above
5. Based on the principles of insulation coordination in a substation, the lowest insulation strength is provided for a/an
 - (a) circuit breaker
 - (b) isolator
 - (c) bus-bar
 - (d) transformer