**CHAPTER-1**

**INTRODUCTION**

**1.1Radial Feeder Protection**

Overhead lines or cables which are used to distribute the load to the customers they interconnect the distribution substations. This is an electrical supply line, either overhead or underground, which runs from the substation, through various paths, ending with the transformers. It is a distribution circuit, usually less than 69,000 volts, which carries power from the substation with the loads**.**

The modern age has come to depend heavily upon continuous and reliable availability of electricity and a high quality of electricity too. Computer and telecommunication networks, railway networks, banking and continuous power industries are a few applications that just cannot function without highly reliable power source. No power system cannot be designed in such a way that they would never fail. So, protection is required for proper working.

Power distribution systems are that portion of electrical systems that connects customers to the source of bulk power (such as distribution substation). Radial distribution systems are characterized by having only one path for power to flow from the source to each customer. A typical distribution system consists of several substations which each includes one or more feeders. A three-phase primary feeder extends away from a substation, and there are many lateral feeders (three-phase, two-phase or single-phase) extending away from the primary feeder. There are loads, transformers, shunt capacitor banks, and protective devices in a distribution feeder. There are a large number of components in distribution systems and these components age over time. Further most distribution systems are overhead systems, which are easily affected by weather, animals, etc.

 These two reasons make faults in distribution systems inevitable. To reduce operating cost and outage time, fast and accurate fault location is necessary. The need to analyze protection schemes has resulted in the development of protection coordination programs.

**1.1.1** **Protection schemes can be divided into two major groupings:**

(i) Unit schemes

(ii) Non-unit scheme

**(i)Unit Scheme**

Unit type schemes protect a specific area of the system, i.e., a transformer, transmission line, generator or bus bar.

•The most obvious example of unit protection schemes is based on Kirchoff’s current law – the sum of the currents entering an area of the system must be zero. Any deviation from this must indicate an abnormal current path. In these schemes, the effects of any disturbance or operating condition outside the area of interest are totally ignored and the protection must be designed to be stable above the maximum possible fault current that could flow through the protected area.

**(II)Non Unit Scheme**

•The non-unit schemes, while also intended to protect specific areas, have no fixed boundaries. As well as protecting their own designated areas, the protective zones can overlap into other areas. While this can be very beneficial for back up purposes, there can be a tendency for too great an area to be isolated if a fault is detected by different non unit schemes.

•The most simple of these schemes measures current and incorporates an inverse time characteristic into the protection operation to allow protection nearer to the fault to operate first.

**1.2** [**Feeders**](http://www.elec-toolbox.com/basicdef.htm) **over Current Protection**

Feeder are conductors which carry electric power from the service equipment (or generator switchboard) to the over current devices for groups of branch circuits or load centers supplying various loads.



Fig. 1.1 Typical Distribution Feeder Over current Protection

Figure 1.1 is a one-line diagram of a typical four wire, radial distribution feeder circuit and the Over current devices used for protection of various parts of the feeder. Radial means there are no other sources of power or fault current on the feeder other than the source substation. The ultimate loading capability of these circuits may range from 10 to 25 MVA for voltages of 12.5 to 34.5 kV. The circuit leaves the substation through a power circuit breaker or reclosers, device 52, with instantaneous and time over current protection, devices 50/51, applied for phase and ground fault detection. Along the circuit are fused lateral taps to various-sized customers or main line pole top reclosers where fault current detection or coordination is beyond the limits of the substation protection. All over current devices on the distribution feeder are time coordinated so that the one closest to the fault will trip the fastest, except for systems using .fuse saving philosophy. In fuse saving. a low instantaneous over current element, device 50L, will be set to detect or see faults on much of the feeder length without regard to time coordination. After one or two reclosers of the circuit breaker, the 50L element will be removed from service by the reclosing relay, device 79, which controls the time sequence of the reclosing cycle.

“**Sub feeders**” originate at a distribution center other than the service equipment or generator switchboard and supply one or more other distribution panel boards, branch circuit panel boards, or branch circuits. Code rules on feeders also apply to sub feeders.

**1.3 Radial Protection**

Whole of the power system can be subdivided in to number of radial feeders fed from oneend. Generally such radial feeders are protected by over current and earth fault relaysused as primary relays for 11 kV and 66 kV lines. For lines of voltage rating beyond 66kV, distance protection is applied as a primary protection whereas over current and earthfault relays are used as back up relays.A simplified radial feeder network without transformers (in actual practice transformersdo exist at substations) is shown in single line diagram of fig. 1.2 below.

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Fig. 1.2 A Typical Radial Transmission Line

If the fault occurs in distribution network, fuse should isolate the faulty section. Should the fuse fail, relay R3 shall give back-up protection. Relays R1, R2, and R3 act as primary relays for faults in section I, section II, and section III respectively. If fault in section III is not cleared by relaying scheme at relaying point R3, relay R2 will act as a back-up.

Similarly back-up protection is provided by relay R1 for faults in section II. A, B, C and D are substations in fig. 1.2. Generally Inverse time over current relays with Definite Minimum Time feature (IDMT relays) are used in practice. There are many types of such relays available in relay market, viz. normal inverse relays, very inverse relays and extremely inverse relays. The characteristics of these relays are shown in fig. 1.3. The other types of o/c relays are 3 second relay and 1.3 second relay. This means the time of operation of the relay is either 3 or 1.3 second at Plug Setting Multiplier (PSM) equal to 10. Long time inverse relays are used for o/c cum overload application. Voltage restrains o/c relays have their own Application.

**1.4 Parallel Feeder Protection**

In power systems, power is also fed by parallel feeders. A simplified single-line diagram of parallel feeder network (without transformers) is shown in fig.

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Fig 1.3 Parallel feeder network

Let the settings be done according to this criterion. Now, for the fault at F2, it is required that relay R4 operate and relay R3 operates to provide backup. This fact requires that relay R3 should operate later than R4. But the relay settings are not satisfying this condition. Hence by using simple IDMT o/c relays it is impossible to fulfill both the criteria. Relay R4 operates as the directional criterion is satisfied. Hence for fault at F2, R2 and R4 operate and if R4 fails to operate R1 provide the backup. Relays operate on similar lines for fault at F1.

**1.5 Power System Protection**

Power system protection is the process of making the production, transmission, and consumption of electrical energy as safe as possible from the effects of failures and events that place the power system at risk. It is cost prohibitive to make power systems 100 percent safe or 100 percent reliable. Risk assessments are necessary for determining acceptable levels of danger from injury or cost resulting from damage. Protective relays are electronic or electromechanical devices that are designed to protect equipment and limit injury caused by electrical failures. Unless otherwise noted, the generic term relay will be synonymous with the term protective relay throughout this text. Relays are only one part of power system protection, because protection practices must be designed into all aspects of power system facilities. Protective relays cannot prevent faults; they can only limit the damage caused by faults. A fault is any condition that causes abnormal operation for the power system or equipment serving the power system. Faults include but are not limited to: short- or low-impedance circuits, open circuits, power swings, over voltages, elevated temperature, off-nominal frequency operation.

Power system protection must determine from measurements of currents and/or voltages whether the power system is operating correctly. Three elements are critical for protective relays to be effective: measurements, data processing, and control. Figure 1.2 shows a typical application of relays to a power system. This example system contains a single source that is connected to bus S through a step-up transformer, two transmission lines that connect bus S to bus R, and a load that is connected to bus R through a step-down transformer.

Breakers A through F provide the control to isolate faulted sections of the power system. Breaker F would not be required for this example except that customer-owned generation is becoming more common and a load can change to a source. The current transformers attached to the relays at strategic points in the power system provide the necessary instrumentation for relays to determine the presence of faults. Voltage instrumentation for protection systems may also be required, depending on the relaying scheme used. Any number of relay devices may use any single-voltage or current instrumentation device. It is important that the load or burden the relay devices create does not adversely affect the quality or accuracy of the measurements by these or other devices.



Fig. 1.4 Power System Single-Line Diagram

**1.6 Radial Line Protection**

A fault tree, tailored to a particular failure of interest, models only the part of the system that Influences the probability of that particular failure. The failure of interest is called the Top Event. A given system may have more than one top event that merits investigation. Figure 1.5 shows a protective system consisting of a circuit breaker, a CT, a relay, a battery, and associated control wiring. The fault tree in this figure helps us analyze the chance that the protective system will not clear a fault.



Fig. 1.5 Radial Line

The Top Event is a box containing a description of the failure event of interest. This description usually includes the event that occurred and the maximum tolerable delay for successful operation. For example, our top event here is “Protection Fails to Clear Fault in the Prescribed Time.” We assume the power system is faulted and we assume the protection system is intended to detect and isolate the fault in question in a very short time, usually a few cycles. We wish to know the probability that the protection system will fail to clear the fault in the prescribed time limitation.

Electrical power distribution systems are that portion of electrical systems that connects customers to the source of bulk power (such as distribution substation). Radial distribution systems are characterized by having only one path for power to flow from the source to each customer. A typical distribution system consists of several substations which each includes one or more feeders. A three-phase primary feeder extends away from a substation, and there are many lateral feeders (three-phase, two-phase or single-phase) extending away from the primary feeder. There are loads, transformers, shunt capacitor banks, and protective devices in a distribution feeder. There are a large number of components in distribution systems and these components age over time. Further most distribution systems are overhead systems, which are easily affected by weather, animals, etc. These two reasons make faults in distribution systems inevitable. To reduce operating cost and outage time, fast and accurate fault location is necessary.

Compared with transmission systems, distribution systems have some unique characteristics: unbalanced loads, non-homogeneity of lines, and frequent switching operations. Because of these characteristics, it is difficult to apply the fault location approaches developed for transmission systems to distribution systems. There are methods to locate faults in a distribution system based on impedance calculation, relay and CB operations, and knowledge-based techniques. These methods only use one criterion to identify the possible fault location. Hence the accuracy of these methods is limited. A paper proposed a method to locate faults according to fault distance calculations, and to prune down and rank several possible fault locations by integrating the information about protective device operations. The process of deciding the operated protective device was through observations and was not implemented automatically by a program. The method used probabilistic modeling method to deal with the uncertainties of fault location calculation, but it did not take into account of the uncertainty in the process of deciding the operated protective device.

Protective devices are used in distribution systems to minimize the duration of a fault and isolate the affected areas of a fault. Commonly used protective devices in distribution systems are fuses, reclosers, and circuit breakers, which are usually controlled by relays. Their function will be discussed separately.

## 1.6.1 Fuses

Fuses are over current protective devices and can operate only once. They use a metallic element that melts when overload current passes through them. The metallic element must be replaced before a fuse can be used again. A fuse is designed to blow within a specific time for a given value of over current. It has two TCC curves: the minimum-melt (MM) curve and the total-clearing (TC) curve. MM curve represents the relationship between the over current value and the minimum time needed to melt the fuse; TC curve is the relationship between the over current value and the maximum time to melt the fuse.

The advantage of fuses is their low cost. It only needs a small investment to install them. The disadvantage is that they are one-time operating devices. When a fault happens, even a temporary fault, they will blow and interrupt power supply. However, most faults (80-95%) on distribution and transmission lines are temporary faults. Using too many fuses will jeopardize the continuity of power supply; hence reclosing devices like reclosers are used.

## 1.6.2 Circuit breaker / relay combination

Usually CBs’ operation are controlled by relays and their characteristics are determined by over current relays and reclosing relays. Over current relays have two types: instantaneous trip relays, which operate instantaneously when currents are larger than the setting, and inverse time relays, which have inverse, very inverse, or extremely inverse time-current characteristics. Generally the relay used to open CBs is the second type. CBs can operate once or reclose several times.

## 1.6.3 Reclosers

Reclosers are over current devices that automatically trip and reclose a preset number of times to clear temporary faults and isolate permanent faults. Recluses also have two types of TCC curves: instantaneous curve (also called fast curve) and time-delay curve (also called slow curve). The operation sequence of reclosers can vary. The sequence can be two instantaneous operations followed by two time-delay operations (2F+2S), one instantaneous operation plus three time-delay operations (1F+3S), one instantaneous operation and two time-delay operations (1F+2S), etc. Usually the number of operations is set at three or four (up to five times is typical).

The advantage of reclosers is that they clear temporary faults before they lock out. This improves the continuity of power supply significantly. The shortcoming of Recloses is they are more costly than fuses.

**1.7 Feeder Protection**

**1.7.1 Cold Load Pickup**

Whenever service has been interrupted to a distribution feeder for 20 minutes or more, it may be extremely difficult to re-energize the load without causing protective relays to operate. The reason for this is the flow of abnormally high inrush current resulting from the loss of load diversity. High inrush currents are caused by:

1. Magnetizing inrush currents to transformers and motors,

2. Current to raise the temperatures of lamp filaments and heater elements, and

3. motor-starting current.

Figure 1.2 shows the inrush current for the first five seconds to a feeder which has been de-energized for 15 minutes. The inrush current, due to magnetizing iron and raising filament and heater elements temperatures, is very high but of such a short duration as to be no problem. However, motor-starting currents may cause the inrush current to remain sufficiently high to initiate operation of protective relays. The inrush current in Fig. 1.2 is above 200 percent for almost two seconds. The magnitude of the inrush current is closely related to load diversity, but quite difficult to determine accurately because of the variation of load between feeders. If refrigerators and deep freeze units run five minutes out of every 20, then all diversity would be lost on outages exceeding m20 minutes.

A feeder relay setting of 200 to 400 percent of full load is considered reasonable. However, unless precautions are taken, this setting may be too low to prevent relay disoperation on inrush following an outage. Increasing this setting may restrict feeder coverage or prevent a reasonable setting of fuses and relays on the source side of this relay.

A satisfactory solution to this problem is the use of the extremely inverse relay. Figure 1.3 shows three over current relays which will ride over cold-load inrush. However, the extremely inverse curve is superior in that substantially faster fault-clearing time is achieved at the high-current levels.

This figure, for the purpose of comparison, shows each characteristic with a pickup setting of 200 percent peak load and a five-second time delay at 300-percent peak load to comply with the requirements for re-energizing feeders. It is evident that the more inverse the characteristic, the more suitable the relay is for feeder short-circuit protection. The relay operating time, and hence, the duration of the fault can be appreciably decreased by using a more inverse relay. Comparing the inverse characteristic shows that the extremely inverse characteristic gives from 30-cycles faster operation at high currents to as much as 70-cycles faster at lower currents.

Feeders and sub feeders must be capable in carrying the amount of current required by the load, plus any current that may be required in the future.

Selection of the size of a feeder depends upon the size and nature of the known load as computed from the branch circuits, the unknown but anticipated future loads and the voltage drop. Because feeders & sub feeders are inherently carrying heavy or high ampere loads, most electrical fires originate in these circuits. [Electrical fires](http://www.cdc.gov/nasd/docs/d000801-d000900/d000818/d000818.html) usually don’t happen after one or two weeks from the time of energization. They usually happen after several years of operation where loads are added indiscriminately and capacities of feeder cables went overloaded, unnoticed.

**1.7.2 Coordination between Feeder Breakers and the Secondary Breaker**

Coordination between feeder breakers and the transformer secondary breaker requires the total clearing time of the feeder breaker (relay time plus breaker interrupting time) to be less than the relay time of the main secondary breaker by a margin which allows 0.1 seconds for electromechanical relay over travel plus a 0.1 to 0.3-second factor of safety. This margin should be maintained at all values of current through the maximum fault currents available at the secondary bus.



Fig.1.6 Breaker Trip Circuit

**1.8 Fault Selective Feeder Relaying**

The reclosing relay recloses its associated feeder breaker at preset intervals after the breaker has been tripped by over current relays. A recent survey indicates that approximately 70 percent of the faults on overhead lines are non persistent. Little or no physical damage results if these faults are promptly cleared by the operation of relays and circuit breakers. Reclosing the feeder breaker restores the feeder to service with a minimum of outage time. If any reclosers of the breaker are successful, the reclosing relay resets to its normal position. However, if the fault is persistent, the reclosing relay recloses the breaker a preset number of times and then goes to the lockout position.

The reclosing relay can provide immediate initial reclosers plus three time delay reclosers. The immediate initial reclosers and/or one or more of the time-delay reclosers can be made inoperative as required. The intervals between time delay reclosers are independently adjustable. The primary advantage of immediate initial reclosing is that service is restored so quickly for the majority of interruptions that the customer does not realize that service has been interrupted. The primary objection is that certain industrial customers cannot live with immediate initial reclosing. The operating times of the over current relays at each end of the tie feeder will be different due to unequal fault-current magnitudes. For this reason, the breakers at each end will trip and reclose at different times and the feeder circuit may not be de-energized until both breakers trip again.

The majority of utilities use a three-shot reclosing cycle with either three time delay reclosers or an immediate initial reclosers followed by two time-delay reclosers. In general, the interval between reclosers is 15 seconds or longer, with the intervals progressively increasing (e.g., a 15-30-45second cycle), giving an over-all time of 90 seconds. Fault-selective feeder relaying allows the feeder breaker to clear non-persistent faults on the entire feeder, even beyond sectionalizing or branch fuses, without blowing the 10 fuses. In the event of a persistent fault beyond a fuse, the fuse will blow to isolate the faulty section. Operating engineers report reductions of 65 to 85 percent in fuse blowing on non-persistent faults through the use of this method of relaying. The success of fault-selective feeder relaying depends on proper coordination between the branch-circuit fuses and the feeder-breaker over current relays.

The feeder breaker, when tripped instantaneously, must clear the fault before the fuse is damaged. Therefore, the breaker-interrupting time plus, the operating time of the relay-instantaneous attachment must be less than 75 percent of the fuse minimum-melting current at the maximum fault current available at the fuse location. In turn, the fuse must clear the fault before the breaker trips on time delay for subsequent operations.

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Fig.1.7 One line Diagram of typical feeder circuit protected by fault-selective feeder relaying

**CHAPTER-2**

**APPLICATION**

The main purpose of the radial feeder protection function is to provide tripping at the ends of radial feeders with passive load or with weak end in feed. To obtain this tripping, the function must be included within the protection terminal at the load weak end in feed end.

1. The feeder protection relay is used in applications requiring directional phase over current, directional short-circuit and directional earth-fault protection.
2. The relay is used for the over current and earth-fault protection of in feeders and bus bars in distribution substations provided with multiple in feeders supplied via power transformers from the same high-voltage bus bar system.
3. The relays are also applied for the selective short-circuit and earth-fault protection of parallel multiple feeders between substations and for feeder protection in ring-type and meshed distribution networks.

**2.1 Features**

* Provides tripping at ends of radial feeders
* with passive loads or weak end in feed conditions
* Fast tripping with communications system,
* or time delayed tripping without communications
* system or on communications system
* failure
* Phase selective operation for fast tripping,
* Selectable for delayed tripping.
* Three-phase over current protection with two directional stages and one non-directional high-set stage.
* Two-stage directional earth-fault protection or alternatively three-stage residual voltage protection.
* Four heavy-duty relays for CB control and five relays for signalling purposes.
* Double-pole or single-pole circuit breaker control.

**2.2 Functionality**

The function performs the phase selection using the measured voltages. Each phase voltage is compared to the opposite phase voltage. A phase is deemed to have a fault if its phase voltage drops below a settable percentage of the opposite phase-phase voltage. The phase-phase voltages include memory. This memory function has a settable time constant. The function has built-in logic for fast tripping as well as time delayed tripping. The voltage-based phase selection is used for both the fast and the delayed tripping. To get fast tripping, scheme communication is required. Delayed tripping does not require scheme communication.

It is possible to permit delayed tripping only on failure of the communications channel by blocking the delayed tripping logic with a communications channel healthy input signal. On receipt of the communications signal, phase selective outputs for fast tripping are given based on the phase in which the phase selection function has operated. For delayed tripping, the single-pole and three-pole delays are separately and independently settable. Furthermore, it is possible to enable or disable three-pole delayed tripping. It is also possible to select either single-pole delayed tripping or three-pole delayed tripping for single-phase faults. Three-pole delayed tripping for single-phase faults is also dependent on the selection to enable or disable three-pole tripping. The voltage used is appropriate for the shorter distance and varies from 2,300 to about 35,000 volts depending on utility standard practice, distance, and load to be served. Distribution circuits are fed from a [transformer](http://en.wikipedia.org/wiki/Transformer) located in an [electrical substation](http://en.wikipedia.org/wiki/Electrical_substation), where the voltage is reduced from the high values used for power transmission. Only large consumers are fed directly from distribution voltages; most utility customers are connected to a transformer, which reduces the distribution voltage to the relatively low voltage used by lighting and interior wiring systems.

For single-phase faults, it is possible to include a residual current check in the tripping logic. Three-pole tripping is always selected for phase selection on more than one phase. Three-phase tripping will also occur if the residual current exceeds the set level during fuse failure for a time longer than the three-pole trip delay time. The radial feeder protection function also includes logic which provides outputs that are specifically intended for starting the automatic reclosers.

**2.3 Technical Data**



Table no. 2.1 Radial feeder Protection Function

**2.4 Important Elements for Power System Protection**

**2.4.1 Switch Gear**

The Consists of mainly bulk oil, circuit breaker, minimum oil circuit breaker, circuit breaker, air blast circuit breaker and vacuum circuit breaker etc. Different operating mechanisms such as solenoid, spring, pneumatic, hydraulic etc. are employed in Circuit Breaker. Circuit Breaker is the main part of protection system in power system it automatically isolate the faulty portion of the system by opening its contacts.

**2.4.2 Protective Gear**

Consists of mainly power system protection relays like current relays, voltage relays, impedance relays, power relays, frequency relays, etc. based on operating parameter, definite time relays, inverse time relays, stepped relays etc. as per operating characteristic, logic wise such as differential relays, over fluxing relays etc. During fault the protection relay gives trip signal to the associated circuit breaker for opening its contacts.

### 2.4.3 Station Battery

### All the circuit breakers of electrical power system are DC (Direct Current) operated. Because DC power can be stored in battery and if situation comes when total failure of incoming power occurs, still the circuit breakers can be operated for restoring the situation by the power of storage battery. Hence the battery is another essential item of the power system. Some time it is referred as the heart of the electrical substation. A Substation battery or simply a Station battery containing a number of cells accumulate energy during the period of availability of A.C supply and discharge at the time when relays operate so that relevant circuit breaker is tripped.

**CHAPTER-3**

 **RECENT SENARIO**

The modern distribution system begins as the primary circuit leaves the sub-station and ends as the secondary service enters the customer's meter socket by way of a [service drop](http://en.wikipedia.org/wiki/Service_drop). Distribution circuits serve many customers. The voltage used is appropriate for the shorter distance and varies from 2,300 to about 35,000 volts depending on utility standard practice, distance, and load to be served. Distribution circuits are fed from a [transformer](http://en.wikipedia.org/wiki/Transformer) located in an [electrical substation](http://en.wikipedia.org/wiki/Electrical_substation), where the voltage is reduced from the high values used for power transmission. Only large consumers are fed directly from distribution voltages; most utility customers are connected to a transformer, which reduces the distribution voltage to the relatively low voltage used by lighting and interior wiring systems. The transformer may be pole-mounted or set on the ground in a protective enclosure. In rural areas a pole-mount transformer may serve only one customer, but in more built-up areas multiple customers may be connected. In very dense city areas, a [secondary network](http://en.wikipedia.org/w/index.php?title=Secondary_network&action=edit&redlink=1) may be formed with many transformers feeding into a common bus at the utilization voltage.

However, multiple connections between the utility ground and customer ground can lead to [stray voltage](http://en.wikipedia.org/wiki/Stray_voltage) problems; customer piping, swimming pools or other equipment may develop objectionable voltages. These problems may be difficult to resolve since they often originate from places other than the customer's premises.

**Power System Safety**

**3.1.1 Public Safety**

Relays are designed to de energize faulted sections as quickly as possible, based on the premise that the longer the power system operates in a faulted condition, the greater the chance that people will be harmed and / or equipment damaged. Instead, designers use physical separation and insulation to prevent direct contact. Still, the faster a faulted system element can be detected, isolated, and de energized, the lower the probability that anyone will encounter hazardous voltages.

**3.1.2 Equipment Protection**

The primary function of power system protection is to limit damage to power system apparatus. Whether the fault or abnormal condition exposes the equipment to excessive voltages or excessive currents, shorter fault times will limit the amount of stress or damage that occurs. The challenge for protective relays is to extract information from the voltage and current instrumentation that indicates that equipment is operating incorrectly.

**3.1.3 Power Quality**

The factors measured to determine the quality of power are voltage amplitude, frequency, and Waveform purity. Voltage amplitude quality takes into account persistent RMS value, flicker, and intermittent dips and peaks, as well as momentary and long-term outages. Frequency changes at most a few hundredths of a hertz, unless the power system has lost generation control. Induction motors have the most sensitivity to power system frequency. Waveform purity is largely a function of harmonic content and is predominantly influenced by load.

The quality of electrical power is an issue for loads that are sensitive to momentary outages and harmonics. In the past, when loads were primarily resistive and inductive, harmonics were either inconsequential or nonexistent. Also, momentary outages had little effect on residential customers. Commercial and industrial customers compensated for momentary outages either with multiple feeds from the utility power sources or with local generation.

**3.2 Protection System Management**

**3.2.1 Protection Quality**

There are four primary causes of protection system failures: instrumentation distortion, control failures, relay equipment failures, and incorrect relay settings. Instrumentation distortion is usually caused by saturation from excessive inputs or remnant flux. Breaker failures or faults in the dc controls can cause control failures. Relay equipment reliability depends on design and manufacturing processes. In addition to overlapping zones of protection, both redundant and backup protection increase reliability for critical applications. Improper settings render relay systems useless. Hence protection systems designers must know which relay is best suited for a particular application and how to set the relay parameters to obtain the proper selectivity and sensitivity.

**3.2.2 Continuous Improvement**

Power systems are not static networks. Transmission lines and generators are continuously put into or taken out of service. Each change in the network potentially affects the operations of protective relays. Protection engineers must decide how to alter the relay settings to compensate for a change in the power network configuration. Many modern computer based relays allow multiple setting which can be automatically selected depending on system conditions.

**3.2.3 Economics of Protection**

Plant equipment represents a significant investment to electric utilities. A representative utility that has a significant amount of hydro-based generation show that 50 percent of the plant investment is allocated to production, 14 percent to transmission, and27 percent to distribution. In actual year-2000 dollars for a moderately sized utility, the investment in transmission and distribution alone is over one billion dollars. The cost of protection equipment is but a very small part of this investment.

**3.2.4 Capital Expense**

A rule of thumb is an installed cost of $30,000 per terminal end regardless of relay type. If the relaying scheme includes pilot protection, the cost of the communications is an additional expense.

**3.2.5 Operating Costs**

Operating costs for relays are not the same as operating costs for protection systems. The former includes the costs of servicing and maintenance. Electromechanical and solid-state relays (also called static relays) require regular testing to determine their functionality. This means personnel must go to the substation and take the relay out of service during testing and calibration. If power system network changes require new relay settings, then personnel must again go to the substation to make appropriate modifications and tests. The expense of this human power adds to the operating costs of relays.

**3.2.6 Lifetime Costs**

Lifetime costs include the purchase price, the cost of installation, and the operation of the protection system. The cost of protection must be justified by the value of potential losses from decreased revenue or damaged equipment. As greater demand is placed upon power systems, the cost of over tripping (tripping when not needed) is becoming as important as under tripping (slow tripping or not tripping when needed). Proper protection requires a balance between speed and security, based on the needs of the system.

**3.2.7 Backup Protection**

The two most common types of redundancy are dual and parallel redundancy. Dual redundancy is where two identical units are operated with identical inputs. The outputs are placed in parallel for added reliability or in series for added security. Parallel redundancy uses two units of different design but the two units are functionally equivalent. They may or may not use the same inputs but the outputs are connected as they are in dual redundancy.

**3.3 Fault Tree Construction**

A fault tree, tailored to a particular failure of interest, models only the part of the system that in fluencies the probability of that particular failure. The failure of interest is called the Top Event. A given system may have more than one top event that merits investigation. The fault tree in this figure helps us analyze the chance that the protective system will not clear a fault. This description usually includes the event that occurred and the maximum tolerable delay for successful operation. For example, our top event here is “Protection Fails to Clear Fault in the Prescribed Time.” We assume the power system is faulted and we assume the protection system is intended to detect and isolate the fault in question in a very short time, usually a few cycles. We wish to know the probability that the protection system will fail to clear the fault in the prescribed time limitation.

Let us improve the system by adding a redundant relay. The fault tree of Figure 3.1 contains an AND gate. This AND gate shows that both protective relays must fail for the event “Relays Fail to Trip” to occur. Our failure rate for the relays taken together is 0.001·0.001 = 0.000001. The sum implied by the OR gate is 0.0202. The reliability improvement in this case is small, because failures other than those of the relay dominate the system.



Fig.3.1 Fault for Radial Line Protection



Fig.3.2 Fault Tree for Radial Line Protection with Relays

**CHAPTER-4**

**CONCLUSION AND FUTURE SCOPE**

To verify fault location, modules and distribution feeder is modelled to generate data such as fault currents, voltages, equipment parameters, protective device settings and phase distribution of line sections.

When Distributed Generation is added to circuit, a savings in initial cost of protective relaying, engineering design, installation time plus conservation of physical space for mounting equipment and periodic maintenance will be realized if a multifunction protection package with both current and voltage inputs is already in place for feeder protection. The additional protective elements available in these will solve the protection issues addressed, regardless of the size or number of DG.s added to circuit.

With the increasing loads, voltages and short-circuit duty of distribution substation feeders, distribution over current protection has become more important today Power systems that have evolved in the 20th century consist of generation plants, transmission facilities, distribution lines, and customer loads, all connected through complex electrical networks. In the United States, electrical energy is generated and distributed by a combination of private and public utilities that operate in interconnected grids, commonly called power pools, for reliability and marketing. Elsewhere in the world, generation is tied to load through national or privatized grids. Either way, power flows according to electrical network theory.

Interconnection improves the reliability of each pool member utility because loss of generation is usually quickly made up from other utilities. However, interconnection also increases the complexity of power networks. Power pool reliability is a function of the reliability of the transmission in the individual members. Protection security and dependability is significant in determining the reliability of electrical service for both individual utilities and the interconnected power system pool.

**APPENDIX;**

**Functions and Definitions**

The devices in the switching equipments are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear.

1. CONTROL POWER TRANSFORMER is a transformer which serves as the source of a-c control power for operating a-c devices.
2. BUS-TIE CIRCUIT BREAKER serves to connect buses or bus sections together.
3. A-C UNDERVOLTAGE RELAY is one which functions on a given value of single phase a-c under voltage.
4. TRANSFER DEVICE is a manually operated device which transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
5. SHORT-CIRCUIT SELECTIVE RELAY is one which functions instantaneously on an excessive value of current or on an excessive rate of current rise, indicating a fault in the apparatus or circuit being protected.
6. A-C OVERCURRENT RELAY is one which functions when the current in an a-c circuit exceeds a given value.
7. A-C CIRCUIT BREAKER is one whose principal function is usually to interrupt short-circuit or fault currents.
8. A-C POWER DIRECTIONAL OR A-C POWER DIRECTIONAL OVERCURRENT RELAYis one which functions on a desired value of power flow in a given direction or on a desired value of over current with a-c power flow in a given direction.
9. PHASE-ANGLE MEASURING RELAY is one which functions at a pre-determined phase angle between voltage and current.

The above numbers are used to designate device functions on all types of manual and automatic switchgear, with exceptions as follows:

FEEDERS - A similar series of numbers starting. With is used for the functions which apply to automatic reclosing feeders.

**REFERENCES**

1. WWW.SLIDESHARE.COM
2. WWW.WIKIPEDIA .COM
3. A textbook on Calculational fault location for electrical distribution networks.
4. WWW.GOOGLE.COM