RELAY PROTECTION

Discoveries in the field of electrical sciences by Galvani, Volta, Oersted, Ohm, and Ampere were related to direct current (dc) systems. Since dc current was the basis of developed theories, application and utilization of electricity began with direct current. Electric lighting and power transmission began in 1882 by generating direct current from dynamos at the first electric central station in the world, the Pearl Street Station in New York City built by Thomas Edison. It supplied a dc current at 110 V through underground cables to an area of about 1.6 km (1 mile) in radius. However, dc power transmission had a limited range of delivery beyond its point of generation.

Alternate current (ac) power transmission eliminated the distance limitations of dc power transmission. Development of iron core transformers by three Hungarian engineers in 1885 based on Faraday's theory of electromagnetic induction in 1831, and polyphase circuits made high voltage power transmission possible. In the meantime polyphase induction machines gained popularity in industrial applications.

The first single-phase ac transmission of electricity in the United States took place in 1889 between Oregon City and Portland. Electric power was transmitted over a distance of 21 km (13 m) at 4 kV level to Portland, proving Nikola Tesla's transmission theory to be valid. This event marked industry's acceptance of ac power delivery that is currently in use worldwide.

Today's electric power system consists of large and small generating stations, transformers, transmission lines, distribution lines, reactors, capacitors, and induction motors. Most of the time a power system operates in its normal mode of operation. The term *normal operation* implies that there are no equipment failures or human errors in operating the system. However, natural events such as lightning, wind, ice, earthquake, fire, explosions, falling trees, flying objects, physical contact by animals or humans, contamination, and personnel errors can result in short circuits (1). Short circuits, also known as faults, will change the status of a power system from a normal state to an *abnormal* state.

PROTECTIVE RELAYS

Protective relays are in wide use throughout power systems to detect abnormal modes of operation. The Institute of Electrical and Electronic Engineers (IEEE) defines a *relay* as "an electric device that is designed to interpret input conditions in a prescribed manner and after specified conditions are met to respond to cause contact operation or similar abrupt change in associated control circuits." Also, the IEEE defines a *protective relay* as "a relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action" (2).

Protective relays are relatively small electromechanical, solid-state, or computer (microprocessor-based) devices connected throughout the power systems to sense the abnormal modes of operation. They receive their input signals from the power system through instrument transformers. The instrument transformers consist of voltage transformers (VTs), coupling capacitor voltage transformers (CCVTs), and current transformers (CTs).

Voltage transformers step down the power system voltages to significantly lower voltages. Standard voltage transformers' secondary voltage is rated for 115 V or 120 V line-to-line. Coupling capacitor voltage transformers are less expensive than the voltage transformers at 34.5 kV and higher system voltages. The coupling capacitor voltage transformer is a string of capacitors connected in series to the high voltage system. The capacitors form a voltage divider, and a tap provides a reduced voltage in the range of 1 kV to 4 kV. The tap is connected to a voltage transformer which steps down the primary voltage to 115 V or 120 V line-to-line. Current transformers step power system currents down to a few amperes. Standard CT secondary current is rated for 1 A or 5 A. In the United States, the secondary current of CTs is rated for 5 A (3).

During an abnormal mode of operation, a relay identifies the problem quickly and initiates circuit breaker tripping to isolate the faulty component. Consequently, a minimum amount of the circuit is disconnected and a high level of service continuity is achieved. It is important to note that protective relays do not prevent failures. However, they mitigate undesirable effects of faults and failures, and minimize failed equipment damage.

Well designed protective relay equipment have high levels of:

1. Reliability: degree of certainty that relay systems perform correctly.
2. Speed: fast operating times to minimize damage (50 ms for high-speed relays).
3. Sensitivity: operating reliably with the least tendency of incorrect operation.
4. Selectivity: removal of minimum amount of equipment from service.
5. Economics: maximum protection at minimum cost. The estimated cost of protective relays and their associated circuits is about 10% of the total station facility investment.

A secondary function of protective relays is to provide information regarding the location and type of failure. This information assists in locating and repairing faulty equipment. It also provides a means for assessing the effectiveness of a protection scheme based on the level of damage that occurred (4).

RELAY HARDWARE

Depending on the manufacturing technology, a basic relay unit belongs to one of the three categories of electromechanical, solid-state, and computer (microprocessor-based) relays (4,5).

Electromechanical Relays

Early relays of 1900s utilized electromechanical concepts in establishing a relay response to close and/or open a set of contacts. Electromechanical relays are divided into the two categories of electromagnetic attraction and induction relays.

Electromagnetic attraction relays, such as plunger or hinged armature relays, have cylindrical coils and magnetic structures. The applied voltage or current to the coil establishes a magnetic force which is proportional to the square of the current in the coil. If the applied voltage or current is greater than the pickup value, the magnetic force moves the plunger upward or attracts the armature. Since no intentional time delay is introduced, the plunger and hinged armature relay operation is instantaneous. The response time of these relays is typically less than 50 ms.

Electromagnetic induction relays operate based on principles similar to a single-phase induction motor. They are classified as induction disc or induction cup relays. The induction disk relay utilizes the same concept as a watt-hour meter, and a current through a coil produces a flux. A shading ring at the pole face, or a second coil and its associated current, produce the second flux. Fluxes piercing a movable disk create eddy currents which act on the fluxes to produce opposing forces. Forces acting on the disk produce torque. The disk rotates to close a set of contacts originally held open by a restraining force, provided that the operating force is greater than the restraining force. Induction disk relays are time delay units, and the delay is adjusted by a time dial which controls contact separation. The range of the operating time is typically a fraction of a second to tens of seconds.

The induction cup relay design is also based on the single phase induction motor concept. The unit consists of a stator and a rotor. The stator is similar to the salient pole stator of an induction motor, and the rotor is made of a thin-walled aluminum cylinder (cup). Two out-of-phase fluxes are produced by the two coils on the stator, and they cause the rotation of a cup that was held stationary by a restraining force. The cup movement is limited to a few degrees. Consequently, this relay operates almost instantaneously with no intentional time delay.

Solid-State Relays

Transistors and semiconductor devices reached their maturity stages in the early 1960s. Consequently they were utilized to develop relays with more sophistication and complexities to suffice the needs of growing power systems. Solid-state relays do not have an armature or other moving elements. The desired response is achieved by electronic, solid-state, magnetic, or other components without mechanical motion. Today's solid-state relays use low-power components such as diodes, transistors, and silicon-controlled rectifiers.

Although the early designs of solid-state relays suffered a few failures in the harsh environment of a substation, their superior features attracted some attention. Early solid-state relay failures were due to overcurrents, overvoltages, and extreme temperature and humidity in electric power substations. In addition, solid-state relays required independent power supplies. Consequently, the reliability of these relays for protecting power system equipment was questioned in the early days. However their improved sensitivity, faster speed, repeatability of operation within smaller tolerances, the expectation of lower maintenance, smaller size, and lower cost challenged the existing electromechanical relays.

Solid-state relays consist of analog and digital circuits. The analog circuits are measuring or fault-sensing circuits. The digital circuit shapes the relay logic to determine whether the relay should operate or not. Solid-state relays utilize power system voltages and currents to establish a trip decision. Current is converted to a voltage internally. The relay utilizes this voltage to generate a trip/no trip command.

Computer Relays

In the late 1960s, George D. Rockefeller conceptualized the idea of a digital computer to perform many of the power system protective relay functions in a substation. The digital computer is responsible for detecting a fault, locating the fault, and initiating the opening of appropriate circuit breakers. Not only is the digital computer responsible for faults within the station, but also it performs the functions that protect lines leaving the substation.

Although the concept of power system protection by digital computers received a considerable amount of attention, the performance of all of the substation protection functions by one digital computer was considered to be risky and expensive. Failure of the digital computer would leave the entire substation and lines connected to the substation unprotected. In addition, digital computers of the 1960s were expensive and could not perform required high speed relaying functions. Evolution of computers, including lower cost, and research in the field of power system protection resulted in development of microprocessor-based relays by the early 1980s. However, these relays are responsible for a single protective function rather than protection of the entire substation.

Filters process power system currents and voltages from current and voltage transformers and convert them to digital form by an analog-to-digital converter. The sampling clock provides the pulses at frequencies of 8 to 64 times the nominal fundamental frequency of power systems. Digital algorithms of the microprocessor operate on these signals and produce a digital output signal (6). Figure 1 shows the typical functional block diagram of a computer relay.

Computer relays provide many features which are not available in electromechanical or solid-state relays. Digital algorithms make it possible to pinpoint fault location with high accuracies. Control functions that were previously wired externally to a relay can now be accomplished by using the programmable logic software in microprocessor based relays. Microprocessor-based relays also have self-diagnostic capability and issue a warning of relay malfunction, thus reducing relay testing efforts. Communication capability of these relays makes it possible to interrogate the relay from the central engineering office and obtain fault or metering information. These relays have analog and digital output signals for local and remote display for use by power system operators. In addition, relay settings can be changed from the central engineering office because of the communication capabilities of the microprocessor-based relay systems.

POWER SYSTEM ZONE OF PROTECTION PHILOSOPHY

The philosophy in applying protective relays to power systems is to divide a power system into zones of protection for lines, transformers, buses, generators, motors, and so on. Figure 2 shows the standard zones of protection based on the CT locations for a typical power system.

In the following sections the protective schemes utilized for protection of lines, substation buses, transformers, generators, capacitors, reactors, and motors are discussed. An overview of the adaptive relaying concept in its infancy state is also provided.

LINE PROTECTION

Although utilitywide standards for protection of ac power lines are not in existence, they are typically classified based on their voltage level. Distribution circuits transmit power to the final user at voltage levels of 2.4 kV to 34.5 kV. Subtransmission circuits transmit power to distribution substations at operating voltages in the range of 13.8 kV to 138 kV.

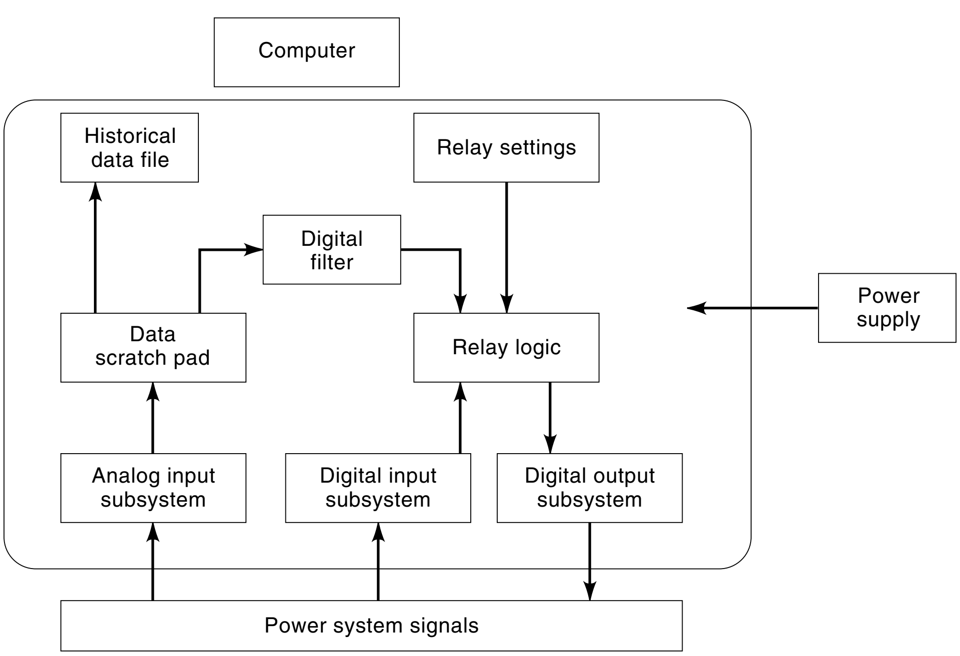

Figure 1. Functional block diagram of a computer relay specifying the internal components.

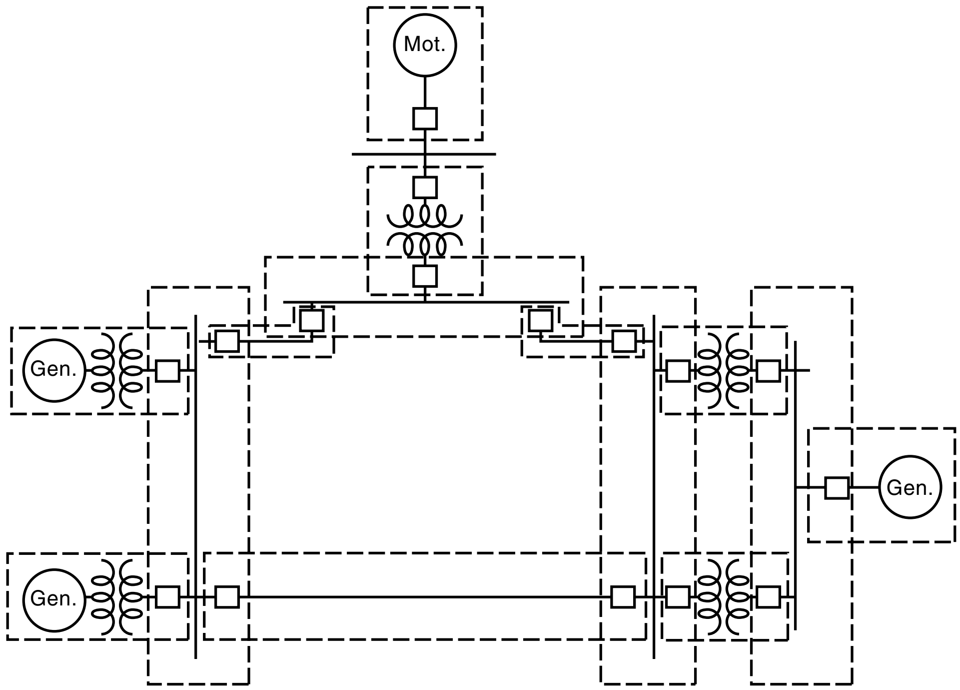

Figure 2. Zones of protection for a power system based on CT locations throughout the system.

Transmission circuits of 69 kV to 765 kV transmit power between interconnected systems and provide power to the wholesale outlets. Transmission lines are further divided into three categories based on their operating voltages:

1. High voltage (HV): 69 kV to 230 kV
2. Extra high voltage (EHV): 345 kV to 765 kV
3. Ultra high voltage (UHV): above 765 kV

Since most faults in a power system occur on the lines due to the wide use of overhead construction, line protection has received a considerable amount of attention. Commonly applied protective schemes utilize instantaneous overcurrent, time overcurrent, directional, distance, and pilot relays. Factors such as operating voltage, type of circuit (overhead lines, cable, single line, parallel lines), importance and function of the line (lines feeding vital loads and effects of their outage on service continuity), and coordination and matching requirements (compatibility with the adjoining lines, protective devices), all influence the final decision of the protection scheme.

Most of the radial distribution and subtransmission feeders are protected with instantaneous and time overcurrent relays. The majority of line faults can be detected by the overcurrent relays, since in most cases fault current is higher than load current by orders of magnitude. Overcurrent relays are set such that they will not respond to load or overload conditions. However, fault current initiates a relay operation (contact opening or closing), and subsequently results in a circuit breaker operation.

From a complexity and cost standpoint, this is the simplest and cheapest relay type that is available for line protection. These relays provide protection against phase-to-phase and phase-to-ground faults. Figure 3 shows a radial feeder consisting of four line sections. Instantaneous and time overcurrent relays at circuit breakers 1, 2, 3, and 4 control the operation of their respective circuit breaker.

A time overcurrent relay at circuit breaker 1 provides primary protection for line section 1. The time overcurrent relay at circuit breaker 2 provides primary protection for line section 2, and backup protection for line section 1. Similarly, the time overcurrent relay at circuit breaker 3 provides primary protection for line section 3, and backup protection for line section 2. Backup protection provides the necessary protection in case of primary relay or circuit breaker failures.

Setting of a series of time overcurrent relays start at the point farthest from the generating sources. For the distribu-

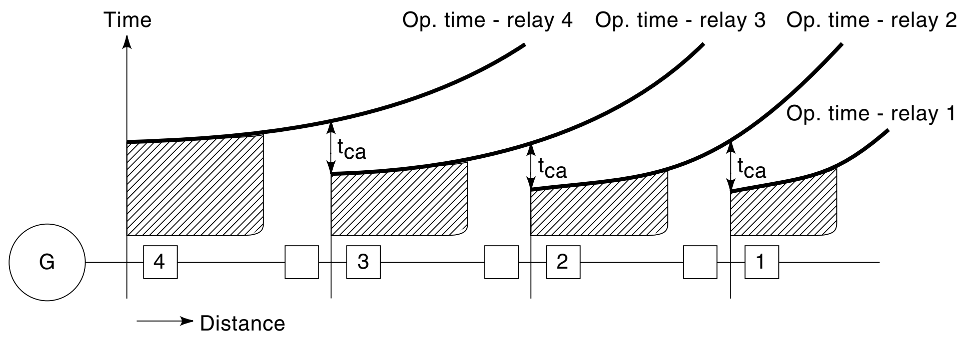

Figure 3. Instantaneous and time overcurrent relay operating characteristics as applied to a radial feeder.

tion circuit of Fig. 3, it starts with the relay at circuit breaker 1. The relay's current-tap-setting is chosen based on the minimum detectable fault current. For the phase relays, the minimum detectable fault current is due to a phase-to-phase fault at the far end of the line section. The calculated minimum fault current is divided by the CT turns ratio to provide the current seen by the relay. This current is also divided by a safety factor to ensure relay operation for unforeseen operating conditions. Finally, the current-tap-setting of the relay is set based on this value. Maximum relay sensitivity is obtained by ensuring that the selected current-tap-setting is above the overload condition on a line section. Unless coordination with fuses or reclosers is required, the lowest available time dial (1/2) is chosen for this relay to achieve fast operating times.

Since the relay at circuit breaker 2 should act as a backup relay for the relay of line section 1, its current-tap-setting can be chosen to be equal to the current-tap-setting of relay 1. Often the current-tap-setting of this relay is set slightly higher in order to avoid loss of coordination at light fault currents. Time dial setting of relay 2 requires coordination between the operating times of relays 1 and 2. The value of three-phase fault current at a location immediately to the right of circuit breaker 1 is used to determine the operating time of relay 1. A coordinating time interval is added to the operating time of relay 1 to compute the operating time of relay 2. The coordinating time consists of the operating time of circuit breaker 1, relay over-travel time, and a safety factor. The time dial of relay 2 is chosen based on the previously calculated value of maximum fault current and the computed operating time of relay 2.

Relays are coordinated in pairs. Consequently the previous procedure is repeated for calculation of the current-tap-setting and time dial of relays at circuit breakers 3 and 4. However, the fault location is moved one line section closer to the generating source for each step of the relay coordination. The relay at circuit breaker 3 should coordinate with relay at circuit breaker 2, and the relay at circuit breaker 4 should coordinate with the one of circuit breaker 3.

The operating time as a function of fault distance from the generating source is shown in Fig. 3. Although the previous procedure results in well-coordinated relays, it suffers from disadvantage of long operating times for fault locations close to the source. To overcome this, instantaneous overcurrent relays are often applied to provide high speed primary protection. These relays are set to pick up under maximum fault current conditions for three-phase faults somewhat short of the end of the line. Their operating time is typically within one cycle, and they usually cover 80% of each line section. The current-tap-setting of the instantaneous relays are based on a three-phase fault current at the far end of the line section multiplied by the inverse of the line coverage percentage. The reduction in operating times by instantaneous relays for faults within the operating regions of line sections 1, 2, 3, and 4 is shown in Fig. 3. The shaded areas of the figure illustrate the improvement in tripping time obtained by application of the instantaneous relays.

The ground fault protection of the distribution and subtransmission circuits is also accomplished by instantaneous and time overcurrent relays. They are set to operate faster and with more sensitivity for ground faults, because in a balanced system load current is not sensed by the ground relays.

Nonradial or looped distribution and subtransmission feeder protection require utilization of directional relays in addition to instantaneous and time overcurrent relays. Figure 4 shows a looped circuit.

The purpose of a directional relay is to prevent tripping of the protected line section, unless the fault current flow is into the section. This simplifies the selectivity problem between adjoining system elements. In Fig. 4, the arrows show the tripping direction of the relays. Relays at circuit breakers 5 and e are nondirectional. Directional overcurrent relays used for phase protection require a current or a voltage source (or both for some) for polarization and establishing directional reference.

Although application of directional overcurrent relays can remedy the selectivity problem from the application standpoint, it is very difficult to apply these relays satisfactorily for nonradial feeders. For the looped circuit of Fig. 4, the loop is broken by opening circuit breaker e. Then the current-tap-settings and the time dials of relays 1, 2, 3, 4, and 5 are chosen based on the previously described procedure. Then circuit breaker e is closed and circuit breaker 5 is opened. Now the current-tap-settings and time dials of relays a, b, c, d, and e are selected similarly. This completes the relay setting task for a simple loop circuit. However, the relay setting and coordination task for multiloop circuits is considerably more challenging and requires many iterations.

Fault current is high on high voltage transmission circuits and should be cleared rapidly to minimize damage and maintain system stability. Distance relays perform this function satisfactorily. Phase distance relays are used in place of directional overcurrent relays for protection of transmission circuits. Distance relays provide greater instantaneous tripping coverage and sensitivity.

Although distance relays are more complex and more expensive than overcurrent relays, setting their calculation and coordination is much easier. Knowledge of transmission lines' positive sequence impedance is the only requirement for setting distance relays. Another advantage of the distance relaying scheme is that changes in the generating capacity or system configuration do not affect application of distance relays. Also, extensive short circuit studies and fault current level calculations are not required for their application.

Distance relays measure complex impedance between relay and the fault location. In other words, $Z = V/I$, where V and I are voltage and current phasors, respectively. If the impedance Z falls within the relay operating characteristic (for example inside a circle) it initiates a relay operation. The operating characteristic of a mho relay, generally utilized for transmission line protection, is shown in Fig. 5. For a fault in the protected line section, impedance to the fault is the ratio between voltage and current supplied to the relay. In this

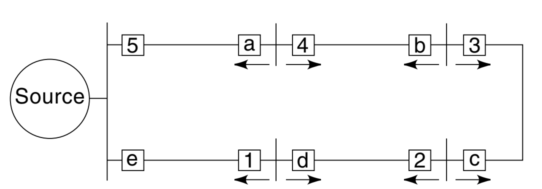

Figure 4. A looped (nonradial) circuit requiring directional relays for proper operation and coordination.

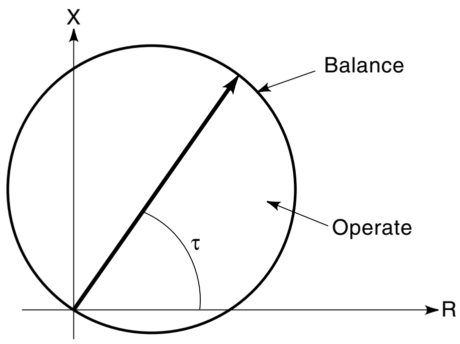

Figure 5. Operating characteristic of a mho relay. An operating point inside the circle will initiate a line tripping action.

manner, the relay can also provide information about the actual fault location.

Figure 6 shows the application of distance relays for phase fault protection. Phase-to-ground faults are typically cleared by directional time overcurrent relays, although ground distance relays are also available. Mho relays are inherently directional, and Fig. 6 illustrates how a step distance relaying scheme is applied for protection of transmission lines. Step distance relays include three steps of protection, with each step reaching a fixed distance and operating in a set time. The relay at circuit breaker 1 is set with a zone 1 reach of 80% to 90% of the line length. The zone 1 relay operates with no intentional time delay. The zone 2 relay setting at circuit breaker 1 extends beyond the end of the line by 10% to 20% to ensure that it operates for all faults in the end of the protected line. A fixed time delay of 0.2 s to 0.4 s is incorporated in the second trip zone circuit to allow zone 1 of the adjoining line to operate first and clear an internal fault within its zone of protection. Zone 3 reach is usually the sum of the protected line impedance plus 120% to 150% of the length of the longest of the next line. The time delay for zone 3 should be greater than the time delay of zone 2, and it can be as long as 1 s. The zone 3 step distance relay functions as a remote backup relay for the primary relays of the adjoining line.

Pilot relays are also used for protection of transmission lines. Pilot relays are strictly primary relays and do not provide backup protection. Pilot relaying schemes employ a communication channel in conjunction with the protective relays to clear a fault within 100% of a line in a very short time. Fast determination of fault location permits simultaneous high speed tripping of all terminal circuit breakers which are feeding the fault. This minimizes damage and allows successful high speed automatic reclosing of the tripped line.

The basic types of pilot communication channels in use are wire line, power line carrier, and microwave. The wire line method utilizes a twisted pair of copper wire for communication between the two ends of the line. Current versions of this technology use a fiber-optic link in place of the metallic conductor. The main application of this scheme is for short transmission lines 16 km to 48 km (10 miles to 30 miles) where application of distance relays might be difficult.

In power line carrier schemes, the protected transmission line is also the communication channel. A high frequency signal of 30 kHz to 200 kHz is superimposed on the 60 Hz transmission line for the purpose of communication. Figure 7 shows the power line carrier scheme with line traps to filter out high frequency signal at the end of the line, coupling capacitors and radio frequency (RF) chokes for connecting high frequency signal to the high voltage transmission line, and the transmitter/receiver system. For this scheme distance relays and directional overcurrent relays control blocking or tripping action of circuit breakers.

A microwave channel consists of a radio frequency signal employing very short wavelengths (2 GHz to 23 GHz) for point-to-point communications. Microwave dishes and repeaters are often needed for their application. Federal Communications Commission (FCC) approval is required for application of microwave channels.

A variety of protective relaying schemes have been developed for transmission line protection by utilizing a pilot relaying concept. They fall into the two categories of blocking and tripping schemes. For blocking schemes, when a signal is received from a remote terminal, tripping is not permitted (blocked) at the local terminal. For tripping schemes, when a signal is received from a remote terminal, tripping occurs at the local terminal. Typical examples of blocking schemes are directional comparison and phase comparison. Direct underreaching transfer trip, permissive underreaching transfer trip, and permissive overreaching transfer trip are examples of the tripping scheme.

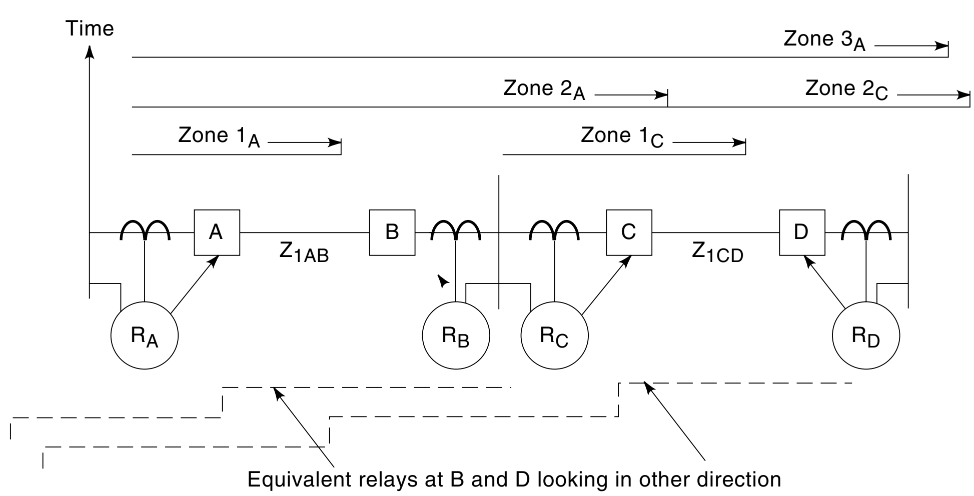

Figure 6. Step distance relaying method for line protection showing the line coverage of each zone of protection.

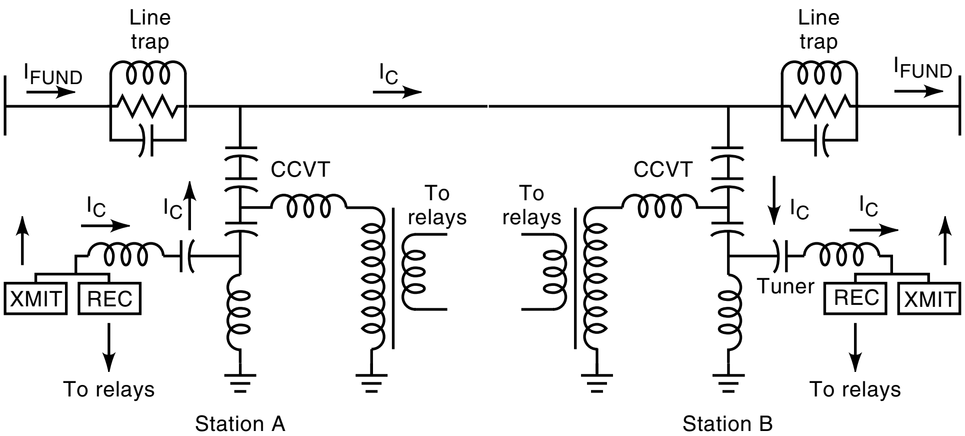

Figure 7. Power line carrier scheme utilizing the transmission line as a communication channel. Transmitters and receivers are connected to the transmission line via CCVTs.

SUBSTATION BUS PROTECTION

A substation bus is an important element in a power system. Transmission lines, transformers, generators, and loads are connected to a substation bus, and consequences of a bus fault can be significant. Therefore, high speed bus protection is necessary to limit damage, preserve system stability, and maintain service continuity.

Differential protection is the most popular, sensitive, and reliable method for substation bus protection. Figure 8 shows the basic configuration of a current differential relaying scheme. When two currents at the secondary of current transformers are equal, the relay operating element does not sense a significant current. However, an internal fault upsets this current balance, and current through relay initiates opening of associated circuit breakers.

Since external faults close to a bus can potentially saturate a current transformer and result in an incorrect bus trip, high impedance differential relays can be utilized to remedy the CT saturation problem. Also, linear couplers (air core voltage transformers) are used to eliminate the impact of CT saturation on bus protection.

TRANSFORMER PROTECTION

The schemes utilized for protection of transformers are dependent on the MVA rating of transformers. Transformers

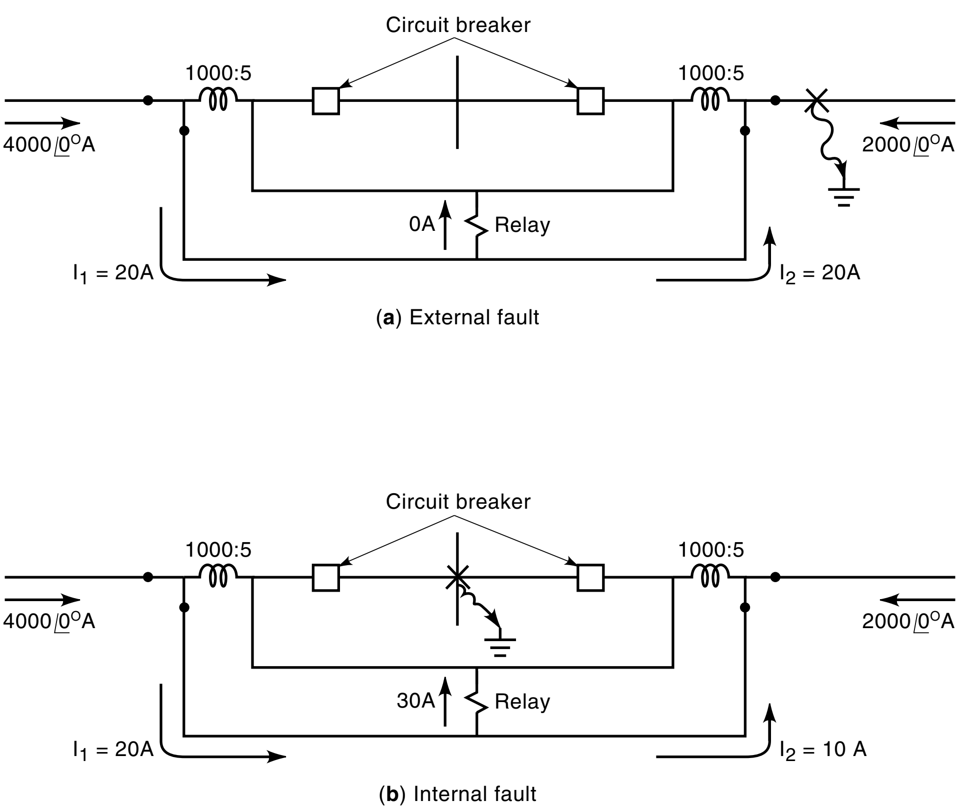

Figure 8. Current differential relaying scheme showing currents at the secondary side of CTs. Current through the relay operating coil is 0 A for an external fault. Current through the relay operating coil is 30 A for an internal fault.

rated below 2.5 MVA are protected by fuses. Transformers with a rating of 2.5 MVA to 10 MVA are typically protected by time overcurrent relays. The harmonic restraint percentage differential relaying scheme is utilized for protection of large transformers rated at 10 MVA and above. Also, sudden pressure and temperature relays are often applied for protection of these large transformers.

Since large transformers are located in substations, transformer terminals are readily accessible for the measurement of current in and out of a power transformer. Currents are compared after the turns ratio factor is taken into consideration, by utilizing current transformers with appropriate turns ratios and adequate relay tap selection. A considerable difference between these currents indicates the existence of an internal fault. No significant difference between currents rules out the possibility of an internal transformer fault.

For delta-wye connected transformers, a 30° phase shift is compensated by connecting the current transformers on the wye-side of the transformer in a delta configuration, and current transformers at delta-side in a wye configuration.

Additionally, at the time of transformer energization, magnetizing inrush current is seen by the relay as an internal fault and may cause it to trip. To remedy this problem, harmonics of this current are filtered and utilized to restrain insecure operation of the relay. A relay utilizing this technique is called a *harmonic restraint current differential relay.*

GENERATOR PROTECTION

Protection of turbine-generators against short circuits and abnormal operating conditions is extremely important, although the failure frequency of synchronous generators is relatively low. Fault currents at the machine terminals can be high and damages can be costly and time consuming to repair. Consequently, abnormal conditions should be identified and isolated quickly.

A synchronous generator is protected from the following faults and abnormal modes of operation:

1. Stator short circuits
2. Loss of excitation
3. Motoring
4. Unbalanced currents
5. Inadvertent energization
6. Overload and overheating
7. Overspeed
8. Out-of-step
9. Subsynchronous oscillations

Stator protection against internal short circuits requires considerable attention. An internal fault starts as a ground in a stator winding and develops into a fault involving more than one phase. Differential protection is the best method for detecting multiphase faults. In this scheme, phase currents on each side of the machine winding (neutral and high voltage ends) are compared. Existence of a considerable difference in the currents initiates relay operation.

The method utilized for grounding a generator affects the performance of differential relaying scheme for ground faults. Generator and step-up transformer installations with a high resistance grounding through a distribution transformer limits single-phase-to-ground fault currents at the terminal of generators to 10 A or less to minimize damage. Unfortunately, high resistance grounding deteriorates the performance of differential relays to a level that single-phase-to-ground faults are no longer detectable. An overvoltage relay in the grounded neutral provides sensitive protection against single-phase-to-ground faults. A time delay is necessary to coordinate this relay with other overlapping relays in the power system.

Loss of excitation can occur as a consequence of a number of failures in the excitation system. During this period, voltage and current variations are observed at the machine terminal. When the reactive power starts to flow into the machine, the impedance locus ($Z = V/I$) moves into the negative X region of the R–X diagram. Loss-of-excitation protection consisting of one or two distance relays looking into the generator are utilized to detect this abnormality, since the impedance locus eventually penetrates inside the operating characteristics (circles) of relays.

A turbine-generator is protected against reversal of power flow into the generator. In fact, the synchronous generator operates as a synchronous motor by absorbing real power from the system, while reactive power may flow in or out of the machine. A reverse power flow relay is used to detect this abnormal operating condition. A relay can detect reverse power flows as small as 0.2% and as large as 3% of the machines' ratings, depending on the type of the prime-mover.

Asymmetrical faults due to failure of equipment external to the machines or unbalanced loads can cause severe heating in synchronous machines. The negative sequence current is induced in the rotor. These currents flow in the surface of the rotor forging, nonmagnetic wedges, and retaining rings leading to excessive heat and possible metal melting. American National Standards Institute (ANSI) standards define permissible negative sequence current in per unit of machine rated current and its time duration. An overcurrent relay in conjunction with a negative sequence current filter is utilized to protect turbine-generators against current unbalances.

Inadvertent energizations of turbine-generators have occurred in the past. Inadvertent energization results from closing of the generator main, or station service breaker, with the machine at standstill. Full voltage energization of a machine applies a torque to the machine shaft which can cause mechanical damage to the shaft or associated bearings. Typical relaying schemes applied for protection against the inadvertent energization are:

1. Directional overcurrent relays
2. Pole disagreement relays
3. Frequency-supervised overcurrent relays
4. Voltage-supervised overcurrent relays
5. Distance relays

Large generators are equipped with resistance temperature detectors (RTDs). RTDs provide temperature information to indicators or relays. Relays can detect abnormally high operating temperatures due to overload conditions and initiate contact closing for alarm.

When a generator operating under load is separated from a power system by action of circuit breakers, the unbalance between input mechanical power and output electrical power causes acceleration of the generator rotor. A transducer converting speed to a voltage, as a part of the governor system, is used to control the speed. An overfrequency relay can be used to supplement the governor action.

Abnormal operating conditions such as faults and other system disturbances may cause loss of synchronism (out-of-step condition) between areas within a power system. The asynchronous areas should be separated prior to collapse of the power system. With the present EHV system, it is necessary to trip a generator when the electrical center appears inside the generator during the loss of synchronism. A distance relay in conjunction with two blinders are used to initiate generator tripping when a separation angle of about 120 degrees is detected.

If a generator is connected to a power system with nearby series compensated lines (series capacitors), it is possible for torsional modes of vibration of the shaft to coincide with a resonant frequency of the electrical network. Consequently, subsynchronous frequency current oscillations occur in the system which can twist and damage the shaft of a turbine-generator. Monitoring and protective devices are designed to detect such conditions and trip a turbine-generator before extensive damage is done.

SHUNT REACTOR AND CAPACITOR PROTECTION

Shunt reactors and capacitors are used throughout the power system for control of system voltages. Shunt reactors are used for EHV lines, long HV lines, and HV cables to compensate for line charging capacitance. Typically a reactor is directly connected to the line by a disconnect switch, or it is connected to the tertiary winding of a transformer bank.

In case of a direct connection of reactor with the line, a reactor fault requires all line breakers to open. Local line relay recognizes a reactor fault and initiates local breaker tripping. However, the remote terminal relay may have difficulty detecting a reactor fault. Consequently, separate reactor relays might be necessary with the capability to activate a transfer trip signal, via a communication channel, to the remote line terminal.

When the reactor is connected to the tertiary of a transformer bank, primary and secondary side breakers should be opened for a reactor fault. The tertiary of the transformer can be included in the transformer bank differential zone. However, separate reactor relays are recommended.

Shunt reactors are separately protected by overcurrent or current differential relays. Additionally, rate-of-rise of pressure protection for reactors which are immersed by oil in a tank may be utilized.

Shunt capacitors are used throughout power systems to compensate for the reactive power consumption of inductive loads. The reactive power compensation effectively reduces the feeder current magnitude, and thus raises bus voltage magnitude. Shunt capacitor bank failures can occur from a fault between the breaker and capacitor bank or overcurrent conditions of individual capacitor units (cans).

To detect faults between the breaker and a capacitor bank, an overcurrent relaying scheme is utilized to trip the breakers. Time overcurrent relays are used for fault detection, and it should be noted that instantaneous overcurrent relays might pickup at the energization of the capacitor banks because of large inrush currents. Therefore, they are not recommended for protection of capacitor banks.

For protection against an individual capacitor unit failure, manufacturers provide individual capacitor unit fuses. Fuses blow for currents greater than 125% to 135% of the rated capacitor current. However, loss of one or more units can result in an overvoltage across other individual capacitor units of that phase. This can be detected by measuring neutral-to-ground current by a CT or the voltage by a VT. An overcurrent or overvoltage relay in the secondary circuitry of the CT or VT, respectively, can be utilized to detect this unbalanced condition and trip the capacitor bank breakers.

MOTOR PROTECTION

Electrical motors should be protected against abnormal operating conditions. Typical motor abnormalities are:

1. Winding faults and overloads
2. Supply voltage loss or reduction
3. Phase reversal
4. Phase unbalance
5. Out-of-step operation for synchronous motors
6. Loss-of-excitation for synchronous motors

In application of protective relays to electrical motors, the cost and extent of protective relays must be weighed against damages that a motor can suffer. Protective relays are often applied to larger electrical motors which are connected to 2.4 kV to 13.8 kV systems through circuit breakers. Low voltage motors are protected by fuses.

Motor thermal capability curves have a time inverse characteristic and they are used for determining temperature endurance of the insulation. A time overcurrent relay with its characteristic fitted under thermal capability curve of the motor is chosen for protection against winding faults and overloads. Often this protective method is augmented by a high set instantaneous trip above the starting current of the motor for winding faults. Figure 9 shows the thermal capability curve of a motor and the applied protective measure.

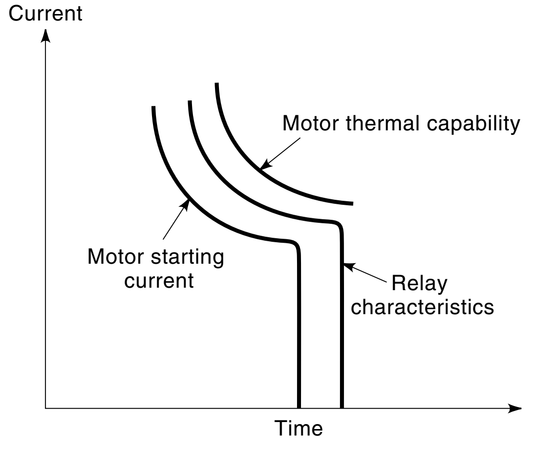

Figure 9. Overload, locked-rotor, and fault protection of induction motors.

For detection of winding faults, current differential relaying (although more expensive) is applied to motors rated above 1.12 MW (1500 hp). Sensitivity of this relay is independent of starting current and dc offset due to asymmetrical current transients.

On starting, large inrush current of the motor will cause a voltage drop at its terminals. This affects the torque applied to the mechanical load, and prevents the motor from reaching rated speed. Consequently, motors must be disconnected when severe low voltage conditions occur. Time-delayed undervoltage relays are applied to protect motors against persistent undervoltage conditions.

Starting a motor in reverse direction can be undesirable. In this case, a reverse phase relay is applied to detect reverse rotation by examining the sequence of positive rotation of current of the three phases. Detection of an ACB rather than an ABC rotation by the reverse phase relay trips the motor.

Similar to protection of generators, a negative sequence filter in conjunction with an overcurrent relay is used to detect phase unbalance and protect motors against prolonged contribution to external unbalances. Out-of-step and loss-of-excitation protection for synchronous motors are similar to the protective functions of a synchronous generator.

ADAPTIVE RELAYING

Although protective relays should quickly detect all system abnormalities and faults, other considerations might detract from this primary objective. In general, a relay system is designed to achieve the highest levels of reliability, speed, sensitivity, selectivity, and economics. Since it is impractical to satisfy all requirements simultaneously, compromises are made in application of protective relay systems.

For example, a typical conflicting set of objectives are embedded in the reliability of a relay system. The dependability and security of a relay system establish its reliability. *Dependability* is a measure of relay system to perform properly in removing system faults, and *security* is a measure of the least operating tendency of a relay system in order to avoid an incorrect trip action.

With conventional relays, protective system design is either biased toward dependability or security. Therefore, highest levels of dependability and security not being achieved at the same time leads to a relay system design which is far from optimum, and performance degradation becomes even more transparent when network topology changes. Contributing factors to the existing compromises are mainly due to:

1. Evolving relaying philosophies over the years
2. Designs heavily relying on electromechanical relay technology
3. Limitations in use of local variables, such as current or voltage, as the relay input

Major weaknesses are the inadequacy of electromechanical relay hardware and its limited capability in adapting to the changing environment of a power system. However, this weakness can be overcome by utilizing state-of-the-art technology in the field of power system protection. Microprocessor-based relays are programmable devices with extensive logic, memory, data transfer, communication, and reporting capabilities. These features of microprocessor-based relays can be used to develop relaying schemes capable of adapting to the changing environment of a power system.

Adaptive relaying is defined by Arun G. Phadke in 1988 as: "A protection philosophy which permits and seeks to make adjustments to various protection functions in order to make them more attuned to prevailing power system conditions" (7–8). The adaptive relaying concept considers the fact that the status of a power system can change. Thus, settings or characteristics of relays should change on-line to accommodate power system changes.

Microprocessor-based relays can certainly accommodate requirements of adaptive relaying concepts. However, this concept poses new challenges in developing algorithms that allow proper adaptability to changes in system conditions. Additionally, since a power system is highly integrated, it is not possible to detect all system loading and topological changes at a local bus within the power system. Therefore, systemwide communication capability may become the fundamental requirement for many adaptive relaying functions.

It should be noted that this concept is not totally new. Existing time overcurrent relays adapt their operating times to fault current magnitudes. Directional relays adapt to direction of fault currents. Harmonic restraint current differential relays adapt to the difference between energizing a transformer and faults within a transformer. However, adaptive capability of these relays is very limited.

An IEEE working group of the substation protection subcommittee recently documented the results of a survey and provided analysis of responses to the feasibility of adaptive protection and control (9). Identified application areas for adaptive relays are:

1. Operating time as a function of distance to the fault
2. Mutual coupling compensation of ground impedance protection
3. High source impedance ratio changing
4. Remote-end open breaker detection for high-speed sequential tripping
5. Load flow compensation
6. Speed of operation change based upon fault type
7. Multiterminal distance relay coverage
8. Variable breaker failure timing
9. Permissive reclosing
10. Adaptive reclosing
11. Sympathy trip response
12. Adaptive synchronism check angle for reclosing
13. Proactive load shedding
14. Adaptive transformer differential protection
15. Voltage change supervision of differential unit
16. Bus protection restraint for arrester applications

Recent research in the area of adaptive relaying is discussed in Ref. 10.

SUMMARY

Highly reliable and efficient power systems are protected against equipment failures and faults by proper application of protective relays. Based on CT locations, zones of protection are established for transmission lines, subtransmission lines, distribution lines, buses, transformers, generators, shunt reactors, shunt capacitors, and motors. Electromechanical, solid-state, or computer (microprocessor-based) relays are used to detect abnormalities in each zone of protection. In case of an abnormality, relays initiate tripping of the associated circuit breakers.

Today, most of the existing protection systems are such that they accommodate limited changes in a power system. This is accomplished by a compromise in relay settings. In the future, adaptive relays will make adjustments to settings or characteristics of relays to increase their accuracy of detection, and thus enhance performance of power systems and continuity of service to users.

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RELIABILITY. See STRESS-STRENGTH RELATIONS.
RELIABILITY ANALYSIS. See RELIABILITY OF REDUNDANT AND FAULT-TOLERANT SYSTEMS.
RELIABILITY, BAYESIAN INFERENCE. See BAYESIAN INFERENCE IN RELIABILITY.
RELIABILITY, COMPUTER. See COMPUTER EVALUATION.
RELIABILITY, DESIGN FOR MICROELECTRONICS. See DESIGN FOR MICROELECTRONICS RELIABILITY.