5. Indicate on an R-X diagram, the following (select suitable scale, point A at $(0, J\ 0)$.
   (a) Point $R = 1\ \Omega\ jX = +3$
   (b) Point $R = 1, jX = -1$
   (c) Line impedance $AB = 2 + j4$
   (d) Fault resistance at the end of line AB equal to two ohms.
   (e) Mho characteristic with maximum torque angle 53° and radius 3 ohms.
   (f) Plain impedance characteristic to protect 80% of line AB

   Explain the advantages of Mho-characteristic over the plain impedance characteristic. Quantities given refer to secondary side.
6. **Power-Swings.** Explain with the help of neat sketches the phenomenon of power swings in transmission system with particular reference to its influence on distance measurement.

   Describe the blocking features adopted in distance relays to offer selective blocking under power swing conditions.
7. **Lines with series Capacitor.** State the function of series capacitors in long transmission lines. Discuss the difficulties in distance measurement with application of series capacitors. Explain the effect of series capacitor on impedance characteristic drawn on R-X plane. Explain the remedial features provided in distance relay schemes to protect such lines.
8. Explain the following (any two)
   (i) carrier acceleration
   (ii) carrier blocking
   (iii) mho characteristics
   (iv) directional mho characteristics
9. Discuss the errors in distance measurement in double-in-feed lines. State the remedial measures in distance protection schemes for such lines.
10. Explain the requirements of distance protection schemes of long EHV transmission lines. State the merits of static distance relays. Illustrate the features of any static distance relay by means of simplified block-diagram.
11. Explain effect of intermediate infeed from a Teed line on the distance measurement of transmission line.

43-A

Important Assorted Topics and Static Protection Schemes

Insulation, Reliability, Testing
Electrical Noise — Shielding — Guards — Grounding — Over-voltages — Protection — Reliability — Tests for reliability.
Static Protection Schemes
Static protection of Medium Motors and Large Motors — Static Protection of Busbars — Disconnection of Mains Supply by Static Schemes.
Back-up protection, Centrally Coordinated Back-up, protection Signalling
Breaker Back-up — Use of Microprocessor — Computer based centrally coordinated Back-up Programmable Equipment for relaying, protection and control — Principle of centralized back-up — Post fault control — Communication Links for protection signalling — Digital Message System — Fibre Optic Data Transmission.

INSTALLATION, RELIABILITY AND TESTING OF STATIC RELAYS

43.1. COMBATING ELECTRICAL NOISE AND INTERFERENCES

Any disturbing signal which interferes or disturbs the electronic measurement/signal/parameters is electrical noise. All electronic circuits and their installations should be with the noise below acceptable level. This is very important for accurate functioning and reliability of static relay functioning. Conventional electromagnetic relays do not have such a problem. Relaying and control installations for static devices should be designed with particular attention to noise and transient over voltages. The effect of noise and transient over-voltages is two-fold.

(i) error in measurements (ii) maloperation.

The noise can be caused by the following :

— Interfering external signals in the form of electromagnetic radiation or waves, *e.g.* solar waves, radio waves from transmitting stations, electromagnetic waves caused by sudden current changes in a remote electrical circuit, a passing electrical locomotive may cause an error in electrical measurement, a radio voice is distorted by interference from neighbouring station, switching of high voltage line sends a electromagnetic radiation, sparking or corona discharge at a remote point causes disturbance in sensitive voltage measurement.
— Lightning and Switching Surges on primary side of CT's and VT's get reflected on secondary in form of voltage spikes.
— Drifts in electronic apparatus beyond their limit of stability.
— Imperfect connections of fixed wires or connectors leading to minute sparking. Corrosion/wear/imperfection of working joints.
— Device noise depending upon characteristic of resistors, capacitors, semi-conductors as affected by temperature, humidity, loading.

The noise tends to spread throughout an electronic system because of electrical relationship between circuit conductors, enclosures, chassis and ground connections through conductive, capacitive and inductive couplings. Electromagnetic radiation causes voltage gradient between two conductors although not connected physically.

Adjacent conductors are coupled electrostatically. An inherent capacitance exists between, ground, conductors and chassis, shields, enclosures. Thus the voltage change occurring in one conductor causes a change in other conductor, proportional to the capacitance between them and length of conductors in parallel.

Every conductor has a resistance. Change in current produces change in voltage drop, electromagnetic field from parallel conductor induces current and subsequent voltage drop. A sudden change in current in neighbouring conductor produces a voltage spike in the circuit.

Shielding refers to enclosing the conductors or apparatus in enclosure almost completely. Shielding reduces the capacitance between the circuit and outside space. The most effective shield is continuous metalized plastic solid shielding is more effective than braided shielding. Effectiveness of shielding increases with the thickness of the shield and conductivity. Solid copper or silver or aluminium or similar non-magnetic material is effective against a electrostatic and electromagnetic interference. The shield should be insulated from the equipment and equipped with a drain wire for single points grounding.

Grouping several signal conductors within one shield is permissible, if all the signals have same ground point and capacitance between them is acceptable. When several shielded conductors are combined in a cable, each should be covered with insulation.

Placing shielded cable within a metallic conduit is useful. The conduit of good conductivity and thickness is preferable.

Grounding means connecting to earth by a conducting path.

— *Equipment Grounding* : Connecting non-current carrying conductor to earth.

— *Chassis Grounding* : Chassis is used as a reference earth. Chassis may not be connected to earth.

— *Floating Ground* is a reference ground which is not earthed.

— *Signal Ground* is a point within the circuit to which all signals within the circuit are referenced.

— *Uniground or Single point ground.* Single point of electrical system connected to earth to eliminate noise currents.

Signal cables may usually run near each other without interference. However wires carrying a.c. or d.c. power should be separated by at least 10 cable diameters. *Also twisting a pair of leads reduces both inductive and capacitive coupling and interference* (Fig. 43.6.)

43.2. TRANSIENT OVERVOLTAGES IN STATIC RELAYS

During the early period of use of static relays in protection of EHV networks (1960-70), a large number of failures and maloperations of static relays were reported. After investigation, the cause was attributed to high transient overvoltages in relays circuits. The transient overvoltages were measured. Their magnitude was observed to be even of the order of 12 kV, 20 kV peak, on secondary side *i.e.* in relay circuit. After such investigation, necessary research was conducted to find the causes and remedies of transient over-voltages in secondary circuits. These aspects are discussed below :

1. Source of Transient Overvoltages in Static Relay Circuits

There are following three origins of transient overvoltages in static relays circuits connected to the secondaries of CT's and PT's in EHV systems :

1. Transient overvoltages reflected from transient overvoltages in the primary circuits of CT's and VT's. In primary circuits, the overvoltages occur due to lightning, switching, sudden change in circuit conditions, etc. These get reflected to the secondary side.

2. Transient overvoltages generated in control equipment due to breaking of inductive currents in relay circuit, trip circuits etc.

3. Transient overvoltages generated within static relays.

The transient overvoltages of category (1) above, are due to operation of circuit-breakers and isolators. In EHV systems, these overvoltages predominate overvoltages due to lightning. During every switching operation overvoltage occur. The worst cases being operation of unloaded lines by slow operating isolators. The amplitude of such overvoltages can be between 10 kV to 20 kV peak, measured between cable core and earth, when cable is laid on earth and connected to capacitor type voltage transformer. Screened cable or shielded cables, with shield grounded at both the ends are used to reduce to transient voltage to the extent of a few per cent of their prospective value (value, without shields). The frequency of damped sinusoidal oscillations varies widely between 50 kHz to 1 MHz. The source impedance have values between 200 to 300 ohms. The design of circuit-breakers and isolators affect such voltages. A 'train of transients' occurs during the arcing time while opening as well as closing the breaker. The train comprises pulses in the range of 350-400 pulses/second in many cases.

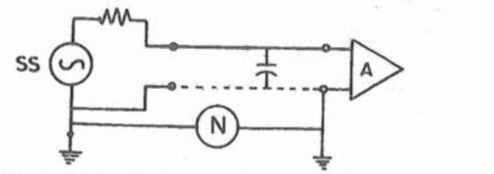
The group (2), mentioned above give transient having steep wave front. Most of the transient overvoltages originating within the control equipment is due to breaking of small inductive currents such as those in auxiliary relays. Such transients have high amplitude and high frequency. A number of restrikes may occur between switching contacts. Transient voltages generated within the relay (group 3 above) have relatively low amplitude and energy. However, they can destroy or disturb certain sensitive components in the static relays.

A usual transistor can be damaged by energy of 10^{-5} to 10^{-3} watts, integrated circuit by energy of 10^{-4} to 10^{-8} watts. Transient overvoltages also arise due to rapid changes in current in wire-wound resistors.

The characteristic of transient voltages include the following :

(*i*) frequency, rate of rise (*ii*) amplitude
(*iii*) energy content (*iv*) source impedance
(*v*) repeat frequency

Fig. 43.1 to 43.5 — Comparison of Shielding, Grounding and Twisting Techniques



SS = Signal source,
A = Apparatus,
G = Ground,
N = Noise Signal,
S = Shield.

Fig. 43.1. Bad method of connection :
Ground return earthed at apparatus end and signal end.
Signal lead and return lead parallel.
Electromagnetic radiation and closed loops cause maximum interference.

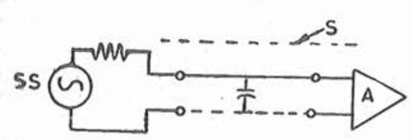


Fig. 43.2. Using single shielded signal lead. Return path by shield grounded at both ends. Shield capacitively coupled to lead, hence can give noise.

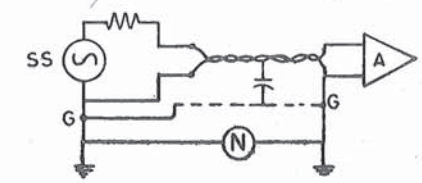


Fig. 43.3. Use of twisted pair of signal lead and return lead improves radiated noise but ground loop capacitive coupling continues.

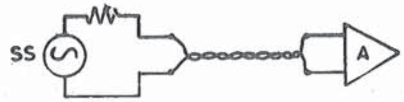


Fig. 43.4. Twisted pair of signal lead and floating apparatus input gives considerable noise immunity.

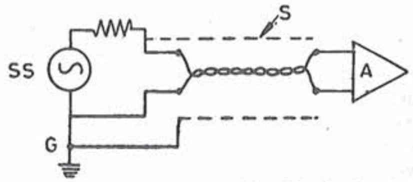


Fig. 43.5. Use of twisted pair of signal lead and return lead, connecting the shield to low side of apparatus floating input reduces shield to lead capacitors. This method is recommended.

43.3. PROTECTION OF STATIC RELAY CIRCUIT

Extensive investigations and analysis of data and experience on electric system circuits show that relay control circuits can be effectively protected against transient and surges by several different methods or techniques.

(*i*) Separation (*ii*) Suppression at source
(*iii*) Suppression by termination (*iv*) Suppression by shielding
(*v*) Suppression by twisting (*vi*) Radial Routing of control cables
(*vii*) Buffers.

Circuit protection by *separation* refers to both physical and electrical techniques. *Physical separation* between quiet and noisy circuits is an effective means of noise control critical circuits. Though mutual capacitance and mutual inductance are logarithmic functions of distance small increases in distance may produce substantial decreases in interaction between circuits.

Routing of control circuits perpendicular to noisy circuits is another effective physical precaution. An example of this would be placing a cable duct run perpendicular to a high-voltages bus. This places any parallel runs between the control circuit and the bus at the maximum practical realizable distance.

Another effective measure in surge control is the grouping of circuits that have comparable sensitivities. Low-energy-level circuits should be grouped together and physically displaced as far as practical from power circuits.

Electrical separation is another useful principle in segregating circuits. In surge control, this appears in the form of inductance discriminatory applied to block conduction of high-frequency transient into protected regions.

Another form of electrical separation is provided by zener diode. It allows conduction, but blocks the flow of current in the other (below the zener voltages level). Also, transformer isolation is an effective method of providing a common mode barrier between segments of a system.

To support transients of surges at the source, either resistor switching or parallel clamping techniques are used.

Isolators and circuit breakers can be equipped with resistors that are inserted during operation of the device to limit the transient voltages to comparatively low values. Economy may occasionally dictate this as a means of restricating the surge level in a sub-station as opposed to other methods.

The surge associated with coil interruption can virtually be eliminated by paralleling the coil with a zener diode. This extends the release time, however, and where this is significant to the application, a varistor may be used instead of the zener diode. The surge permitted by the varistor is higher than that for the zener diode, but its limiting action is satisfactory.

The surge associated with extreme a.c. saturation of a current transformer can also be reduced by a voltage-limiting device across the secondary. Silicon carbide devices have been used for this protective function.

An effective termination that reduces the input impedance at high frequency and has little effect at 50 Hz or on d.c. is a *small capacitor*. It neither forces a higher input energy nor produces heat of its own. A widely used capacitor is a 0.5 mF, 1,500 V d.c. oil-filled type. It limits a 2,500 V, I-megacycle surge with 150-ohm source to less that 35 V. Short leads to the capacitor imperative.

When suppressing transients *shielding methods,* a signal lead shielding with one or more grounds has the effect of increasing the capacitance to ground of the signal lead.

Grounding a shield at both ends allow shield current to flow. Shield current resulting from magnetic induction will tend to cancel the flux that created the shield current. The net effect of the shield on the signal lead is to reduce the noise level. An exception to this is that current flowing in shields not produced by flux linking the signal lead will cause the surge or noise voltage on the signal lead to be higher than it would be if there were no shield.

"Twisting" for surge suppression is achieved by measures that cause the "signal" and "return" leads to occupy essentially the same space, thereby minimizing the effect of differential-mode coupling. Shielded twisted-pair conductors are required for low-energy level circuits routed outside a panel.

As regards radial routing of control cables for surge protection, circuits routed into the switchyard from the control house should not be looped from one piece of apparatus to another in the switchyard with the return conductor in another cable. All supply and return conductors should, in other words, be in a common cable. This is to avoid the large electromagnetic induction possible because of the very large flux loop such an arrangement would produce.

Another effective measure applied to show and desensitize a circuit is a *buffer.* This buffer can accommodate a test source operating at 1 Mhz having 150 ohm source impedance placed directly across the input (differential mode) and having 2,500 V (open circuit) first peak, decaying to 1,250 V in six microsec or more, without the transistor turning on or any element being damaged. It can, with the same results, stand a sustained 7 V d.c. input, or high-level d.c. input voltage of sufficient duration to produce a 4,000 microsec-V product-for example 200 V for 20 ms.

Adequate buffering of low-energy-level circuits greatly decreases the susceptibility of static relays to surge damage or misoperation and, in general, eliminates the need for shielding of circuits inside a relaying panel.

43.4. RECOMMENDED PROTECTION PRACTICES FOR STATIC RELAYING EQUIPMENT*

The recommendations are as follows : They apply particularly to HV and EHV stations utilising static relaying.

1. All current, potential and exposed D.C. leads entering a panel or cabinet shall be terminated by 0.5 microfarad capacitors keeping total capacitor loop lead length as short as possible. A total loop length of 18 inches may be used as a guideline. Thyristor trip circuits must be equipped with TP-2 components (2 winding reactor and zener) or suitable substitutes and a 0.5 microfarad capacitor must be connected between the negative side of the zener and ground.

2. Where low impedance (such as that offered by a zener (diode) exists between an exposed lead and a surge protective capacitor applied to another lead, the capacitor may be omitted from the exposed lead.

3. Circuits entering the panel that are not subject to direct switchyard exposure but are in close proximity to extremely noisy circuits in a cable tray for example, must be treated carefully if they supply low energy level inputs in the panel. The circuit external outgoing and return circuits. The shield should be grounded at both ends.

4. Circuits entering the panel that are subject to direct switchyard exposure that cannot accommodate the 0.5 microfarad capacitor because of the time delay introduced, or for any other

* *Courtesy* : Westinghouse Electric Corporation, U.S.A.

reason, must their surge voltage be controlled by special cable routing or surge generation must be limited at the source to help the surge levels at the panel terminal blocks to the limits stated under (D) below.

5. All cables entering the static relay panel from the switchyard or connected to circuits entering the switchyard shall

(*a*) be shielded (with metallic shield or sheath)

(*b*) have sufficient cross-section in the shield (or metallic sheath) to sustain the maximum 60 hertz current to which it will be subjected to ground fault conditions.

(*c*) have the shield grounded to the common ground mat at both ends of the cable and preferably at intermediate points also. If a common ground mat does not exist between two ends, then means should be taken to assure a low impedance connection between the two ends of the cable. This may be accomplished by connecting the separate mats with one or more cables having sufficient cross-section to handle resulting fault and surge currents.

(*d*) have conductors in pair (outgoing and return conductors) in the same cable. While tri-axial cable affords distinct theoretical advantage for the circuit between a carrier set and tuner (carrier return circuit is grounded at only one point and is eliminated as a possible conduction path for interfering surges), it is felt that its use is not mandatory in EHV stations.

6. Coils of all electromechanical auxiliaries used on the panel must be equipped with a varistor or equivalent surge suppressing means in parallel with the soil.

7. It should be emphasized that the relay designs themselves include zener diodes, capacitors, winding isolation etc. to minimize susceptibility of a static relay to surge damage or misoperation.

8. The fundamental protection philosophy is to (1) provide a low impedance path to ground for high frequency current flow caused by voltages appearing on exposed leads and (2) to minimize the magnitude of these voltages by proper treatment of the loads.

9. The practices outlines here related to static relaying panels and the leads connected to them but apply equally to isolated static devices where surge exposure exists.

10. **Laying of Control, Protection and Measuring Cables.**

The main current in the control cable conductors being low, these cables may be laid in a common duct, without separation. However they should be separated from power cables.

Highly sensitive measuring cables are sometimes laid in separate steel pipes totally away from other cables.

11. **Grounding of Cable Trays, Ducts.**

All the cable trays, racks and metallic ducts should be grounded by connecting at each end to station earth-mat. The adjacent cable trays should be bridged by copper jumpers, to retain continuity of earthing.

43.5. TESTING OF STATIC RELAYS WITH REGARD TO OVER-VOLTAGE TRANSIENTS

The IEEE Power system Relaying Committee has proposed certain tests on static relays as regards their sensitivity to overvoltage transients. British Electric and Allied Manufacturers' Association Ltd. (BEMA), England has issued a publication (No. 219), titled "Recommended Transient Voltage Tests Applicable to Transistorised Relays", proposing an impulse test with limited sources energy. The test consists of subjecting the relay an impulse voltage of 5 kV (1.5 kV) with 1/50 μs wave and energy 0.5 W both in common and transverse modes. Three positive and three negative pulses are applied. Source impedance of impulse generator is 500 ohms.

Static relays should withstand the following design tests :

1. 1500 volts RMS, 60 hertz of 2000 volts d.c. applied between ground and a common point to which all terminals are connected for 1 minute without failure.

2. An input having a volt-time product of at least 4000 microsecond-volts may be applied between energized logic inputs and negative (or positive) without operation (operation being defined as any change of state). An example of this input is 40 volts D.C. applied for 200 microseconds at higher voltages, no less than 65 microseconds' duration is permissible.

3. Surge withstand capability test for 1 MHz applied by a surge generator having an open circuited voltage of 2500 to 3000 volts first peak, decaying to 50% of first peak in 6 microseconds. The surge generator has 150 ohms internal impedance. The surge is applied common mode between signal, current, voltage or power supply leads and chassis. It is also applied differential mode between input logic, output logic or power supply leads and common. The surge is applied at least 50 times per second for not less than 2 seconds without failure, operation or change of calibration.

4. 7 volts positive D.C. sustained between logic circuits inputs and negative without operation. Tests 2, 3 and 4 are applied with the relay energized at 100% voltage and with 75% of nominal CT current.

43.6. RELIABILITY, DEPENDABILITY, SECURITY

Reliability of a product is related with its quality during the total working life. It is usually expressed in terms of the failure rate of individual components of Mean Time Between Failures (MTBF) of the equipment and installation. The ability of protection equipment to operate can be disrupted in three ways :

— Maloperation *i.e.* false tripping in absence of primary fault.

— Incorrect separation or undesirable tripping during a primary fault, *e.g.* back-up protection operates first and trips a circuit-breaker which should not have been tripped. This leads to power failure affecting larger areas.

— Failure to operate (*i.e.* does not trip even on fault when it was supposed to). The back-up protection is provided for this possibility.

The reliability is further expressed in terms of Dependability and Security.

Dependability (Trust worthiness) assures that the protection equipment will operate correctly in the event of a primary fault (trip selectively).

Security assures that the equipment will not operate unless there is a primary fault.

In general the reliability depends on a Design of Protection Scheme, relay and also quality of components, manufacturing technique.

Design Reliability includes apart from the design of the relay itself, the design of complete scheme, other relays, the circuit which form the protection system. The *equipment reliability* is expressed as a probability which can be determined by careful evaluation of the circuit in relation with failure rates of components.

Technical Reliability is subject to external influences and generally declines with time.

Ensuring Higher Design Reliability

A complete protection scheme should be considered. This includes

— CT's , VT's

— Batteries, auxiliary supplies, battery chargers, overload trips.

— All wiring between measuring devices, auxiliary sources, relay and circuit-breaker, auto reclosure and auxiliary relays.

— All main and auxiliary relays.

— All terminals

Communication Channel (PLC or Pilot wires)

Trip circuit

Circuit-breaker, its operating mechanism and control circuit, main current circuit, insulation.

The Application Engineer and Station Designer should have overall concept of the requirements of various components. Each component should be reliable to ensure overall reliability.

Factors affecting the Design Reliability of Complete Protection System

— choice of suitable CT's and VT's with reference to transient conditions
— behaviour of CVT's during transient condition for application to high speed distance relays
— behaviour of d.c. supply unit in protection equipment during battery voltage dip
— behaviour of the protection in the presence of overvoltages, noise, interference, etc.
— behaviour of protection during transients on measuring and control wiring
— behaviour of protection during overages
— arrangements, shielding arrangements.

For most of these influences IEC recommendations are available. The internal voltages in relay are limited by appropriate design features in the relay.

The external factors are taken care of by Station Designer. The induced voltages in secondary circuits must be within specified limits and IEC test voltages.

Ensuring Higher Technical Reliability

The following aspects are considered to ensure technical reliability (which does not depend on design but depends on quality of components as affected by external influences.)

— environmental and operating conditions
— material and components used in the circuit
— failure analysis
— manufacture, testing, quality control
— operating experience.

Environmental and Operating Condition Tests

These include the following :

— Temperature Tests, Climatic Tests, Thermal shock Tests (– 185°C to 200°C), temperature cycling tests (– 185°C to 300°C) carried out as type tests on components, sub-assemblies, complete relay.
— Environmental tests : salt atmosphere or spray (25°C to 71°C) performed as type tests.
— Vibration Tests, shock tests.

Choice of Components

The rigorous acceptance testing of active components of static relays includes 100% acceptance tests on active components (diodes, transistors, IC's) and random testing on other components.

Some tests on electronic components are mentioned in Table 43.1.

Rigorous Tests of Complete Relay*

These include design tests, reliability tests, type tests and routine tests, maintenance and site tests.

Automatic On-line Testing of Protection Scheme

The testing of protection schemes (such as generator protection) comprises the checks on all relays in the protection schemes *viz.* voltage, current, frequency, directional, differential, etc. In each case, the pick-up value of each relay for each phase should be measured. Automatic test sets have been developed for static protection schemes. The test equipment *measures* the pick-up values *regardless of service current* and these values are displayed and printed out digitally. The printed values can be relaxed to control centre for monitoring. Modern microprocessor based static relays have self-checking feature (watch dog).

Table 43.1
Tests on Components, Sub-assemblies, Complete Relays

	Component	*Sub-assembly (Modules)*	*Complete Relay*
Altitude			*
Dew point		*	*
Flammability	*	*	*
Moisture resistance	*	*	*
Resistance to solvents	*		
Salt atmosphere	*	*	
Salt spray			*
Seal, gross leak		*	*
Soldering heat	*	*	
Terminal Strength			
Acceleration	*	*	*
Mechanical shock		*	*
Vibration, fatigue		*	*
Vibration, noise	*	*	*
Vibration, variable	*	*	
Frequency	*	*	*
Seal, fine leak	*		
X-Ray, film	*		
X-Ray, Real Time	*		
Insulation Tests	*	*	*
Maloperation Tests		*	*
Development Tests	*	*	*
Type Tests		*	*
Routine Tests	*	*	*

Section II. SOME STATIC PROTECTION SCHEMES

43.7. STATIC RELAY FOR MOTOR PROTECTION

The introduction of static relay using integrated circuits now allows compact, combined protection relays. A single unit can combine about six functions of motor protection. This results in reduced space, reduced installation time, lower total cost. The relay also gives better characteristic and reduces burden on CT's.

Motor Protection Relay

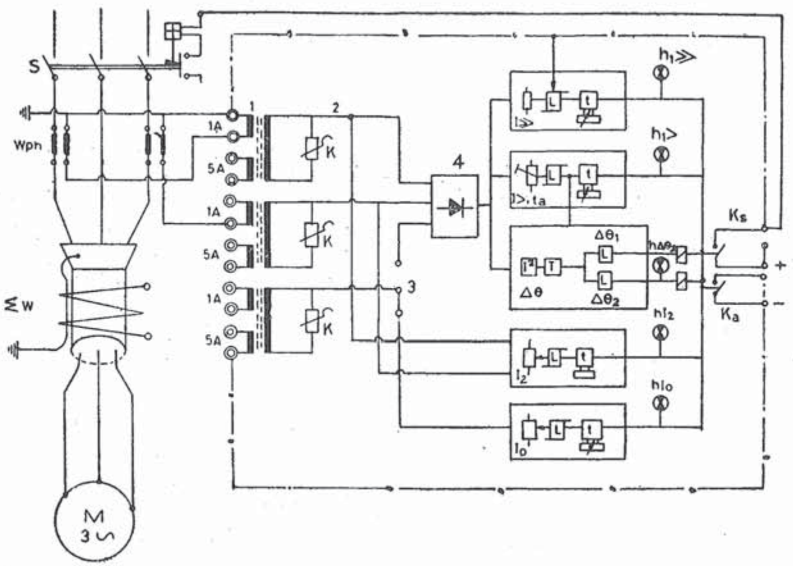
(*Courtesy* : Brown Boveri, Switzerland)

The relay of this type protects three phase induction motors against interphase short-circuits, prolonged starting, locked rotor, overloads, unbalance and earth faults. Similar type of relays are available for protection of over-current and overload protection of transformers and cables. These relays have following features :

— Only two or three phase currents needed as measurement inputs.
— Good match for all kinds of motors due to wide range of adjustments.
— Separate indication for individual function (local and/or remote).

— Two-stage overload protection with thermal facsimile which is retained even if the auxiliary supply fails.
— Can be flush mounted on switchgear or protection panel ; or can be arranged on separate racks.

Ref. Fig. 43.6 giving the block diagram of static motor protection relay for medium, medium large motor. The core balance CT (Σ W) slip over current transformer (Refer Sec. 27.9) is for giving output in terms of zero sequence current ($3I_o = I_R + I_S + I_T$). This output $3I_o$ is useful for sensing earth fault. Due to lower burden of static relay ; cross-section of core of core-balance CT is comparatively less and a compact core balance CT can be used with better accuracy and sensitivity of earth-fault protection (Ref. Sec. 31.7). The two phase CTs (Wph) are installed in the supply connections (generally inside the control panel or switchgear unit). Their secondaries are connected to the input intermediate CT (1) of the Static Relay. The output of intermediate CT's given to rectifier



I_0 = Zero sequence prot. S = Motor circuit-breaker W_{ph} = Phase current transformer
ΣW = Core balance Z.S. CT (Ref. sec. 27.9) M = Asynchronous motor
1 = Input current transformer 2 = Burden of CT adjustable in ten steps k = Setting factor
3 = Selector switch 4 = Rectifier $I >>$ = Short-circuit protection
$I >$ = Protection against prolonged overload t_a = Time lag
$\Delta\theta$ = Overload protection $\Delta\theta_1$ = Warning-stage of overload protection
$\Delta\theta_2$ = Tripping stage of overload protection I_2 = Squaring Element
T = Interactor of Thermal Facsimile (Replica)
I_2 = Unbalance (negative sequence) Protection $h_1 \gg h_2$ etc. = Visual signals
K = Setting K_s = Indicator Contactor (Overload Warning)
K_a = Tripping Contactor L = Level Detector and Trigger.

Fig. 43.6. Circuit and Functional Diagram of a Motor Protection Relay
Courtesy : Brown Boveri.

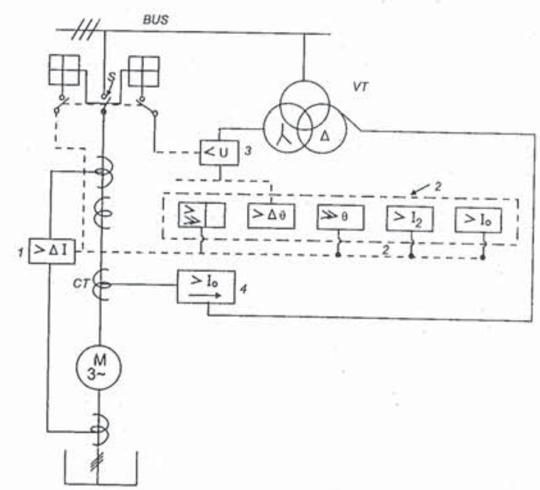
bridge (4).The output of rectifiers is given to the measuring circuit comprising following sub-circuits depending upon requirements.
— short circuit $I \gg$) circuit without time delay
— prolonged starting ($I > t_a$) circuit with time delay
— Overload circuits $\theta_1 \cdot \theta_2$ with warning and tripping stages. The characteristic corresponds to motor heating curve.
— negative phase sequence circuit (I_2) for unbalanced loading
— zero-sequence circuit (I_o) connected to core-balance (slip-over) CT.

Light emitting diodes (LED) are provided for local indication of each function (or floating potential contact with remote indication)

The warning signal closes contactor K_s sounding a local/remote alarm. The tripping is initiated by closing of contractor K_a.

Block diagram of a static relay for large high voltage motor protection is given Fig. 43.7. This incorporates
— Differential relay (1)
— combined overcurrents (> >), overload(>), unbalance ($> I_2$), a earth fault ($> I_o$) relay
— directional earth fault relay $\left(\begin{smallmatrix}> I_0 \\ \longrightarrow\end{smallmatrix}\right)$

All these functions are provided in a single relay unit. Units for several motors can be arranged on one single rack.



1. Differential Relay
2. Combined overcurrent, overload, unbalance, earth-fault Relay
3. Undervoltage Relay
4. Directional Earth-fault Relay
5. Circuit-breaker and other symbols as in Fig. 43.2.

Fig. 43.7. Functional Block Diagram of a large high-voltage Induction Motor Protection Scheme.

43.8. STATIC BUSBAR PROTECTION BASED ON DIRECTIONAL COMPARISON

We will recall, the busbar protection can be based on different principles such as

— Busbar Protection by Over-current Relays. This can be adopted for networks where the in-feed is not clearly defined and where the outgoing feeders to loads are not subject to reverse feed.

— Busbar Protection by Distance Relays of incoming lines

— Busbar protection by Differential Relays

— Busbar Protection by Directional Interlock

The static Busbar Protection schemes have following advantages :

— Modular design. Required modules can be plugged-in accordance with the protection scheme. Hence the design is simple and easy to operate.

— Low burden on Main CT's. Hence problems arising out of CT saturation are reduced.

— Measurement can be independent of CT saturation.

— Intermediate CT's can be decentralised (provided in a separate module with each relay).

Ref. Fig. 43.8, giving functional block-diagram of static busbar protection based on directional comparison.

The direction of currents in all outgoing feeders (II_1, II_2) is compared with the directional of differential current. During internal busbar fault (SC), all these currents flow in the same direction (Towards Busbar in Primary).

If this condition persists for a definite period (or the order of milliseconds) the internal short-circuit is confirmed and the relay trips. Additional conditions for tripping include magnitude of feeder current and their sum. These conditions increase the security of protection.

Ref. Fig. 43.8, the pulse shaper D converts sinusoidal signals into rectangular pulses-D_p converts only positive half cycles and D_N converts only negative half cycles (into rectangular pulses).

F_p and F_n are NOR gates for positive half rectangular pulses and negative half rectangular pulses respectively. The three rectangular signals received by F_n comprise negative half-wave pulses from three D_N elements. These are for out-going feeder II_1 outgoing feeder II_2 and difference between II_1 and II_2 as can be observed from the figure. Let us make truth table for the logic of NOR gate F_n, X being output of F_n.

II_1	II_2	$(II_1 - II_2)$	X
1	0	0	0
0	1	0	0
0	0	1	0
0	0	0	1

From the truth table, NOR gate F_n gives output ($x = 1$) when three inputs II_1, II_2 and $(II_1 - II_2)$ are (0). *i.e.* when three negative half pulses are simultaneously absent (conditions 0).

Similarly NOR Gate F_P gives output ($Y = 1$) when three input positive half, pulses ($II_1, II_2, II_1 - II_2$) are simultaneously absent (condition 0)

The output X of F_n and Y of F_P is given to OR gate G. The truth table of G is as follows :

X	Y	Z
1	0	1
0	1	1
0	0	0

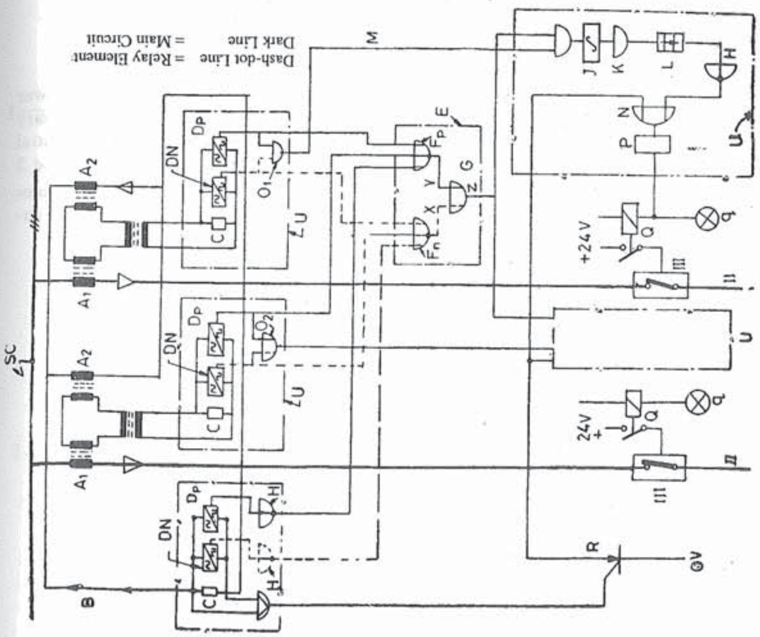


Fig. 43.8. Functional Block-diagram of static Busbar Protection, scheme Based on Directional Comparison.

I = Busbars
II_1, II_2 = Outgoing Feeders
III = Circuit-breakers
A_1 = Main CT
A_2 = Intermediate CT
B = Common Burden
Δ = Direction of Normal Current
Δ = Direction of Intend fault Current
C = Shunt
D = Pulse shaper
D_p = Shaper of Positive half wave
D_N = Shaper of Negative Half wave
E = Central Unit Directional Comparison
F = NOR Gate for the positive half
F_n = NOR Gate for the negative half
G = OR Gate (combination of F_P and F_n)
H = Inverters
J = Integrator (5 ms)
K = Trigger
L = Drop-out Prolongation (Delay Circuit)
M = Tripping Line
N = AND Gate
O_1, O_2 = Tripping Inter-locks
P = Amplifier
Q = Tripping Contactor
q = Trip Indication
R = Trip Release
S = Digital Signal Directional Comparison
S_c = Short-circuit
U = Feeder Measuring Elements.

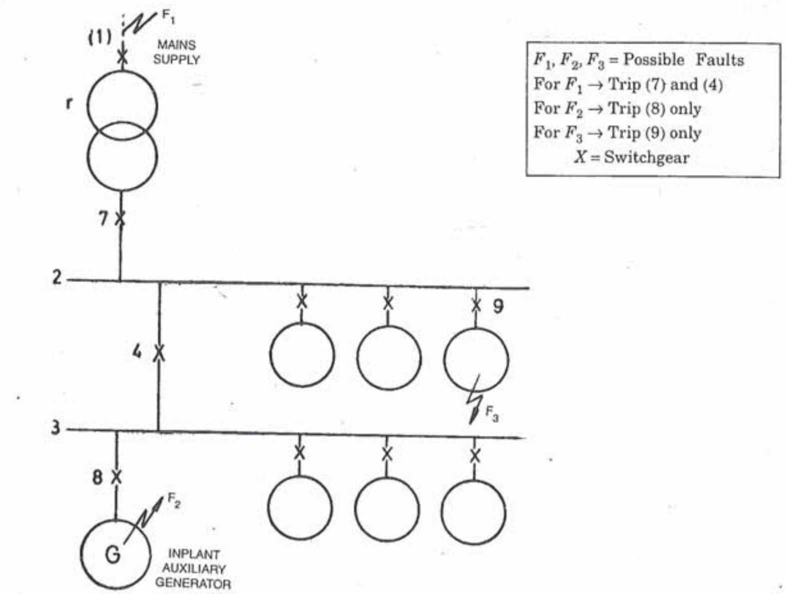
when any of the inputs X or Y are high ($x = 1$ or $y = 1$), the output is high ($Z = 1$). When positive half cycles derived from feeder currents and difference in feeder currents are simultaneously present, the control unit of directional comparison E gives output to trip release R *via* feeder measuring unit U.

AND Gates O_1 and O_2 provide additional interlock conditions *via* measuring element U for trip release R.

43.9. DISCONNECTION OF MAINS SUPPLY FROM INPLANT AUXILIARY SUPPLY DURING SYSTEM FAULTS

(*Courtesy* : Brown Boveri, Switzerland)

Many industrial plants have their inplant generating station and need uninterrupted power for the industrial process. The power is taken from Mains Network as well as inplant auxiliary generator (generally driven by gas turbine). The segregation of essential loads and non-essential loads is illustrated in Fig. 43.9. During system faults (say F_1). The voltage of bus-bars 2 and 3 drops down and the supply of essential loads and non-essential loads is disturbed. Hence, it becomes necessary to disconnect the mains supply very quickly during fault on mains (F_1) by opening circuit-breaker (7) and bus-coupler (4).



1 = Mains
2 = Bus bar for non essential loads
3 = Bus bar for essential loads
4 = Bus coupler

Fig. 43.9. Scheme of mains supply and inplant auxiliary supply for industrial plant.

During a fault (F_2) in generating plant, breaker (8) should trip and (7) should remain closed.

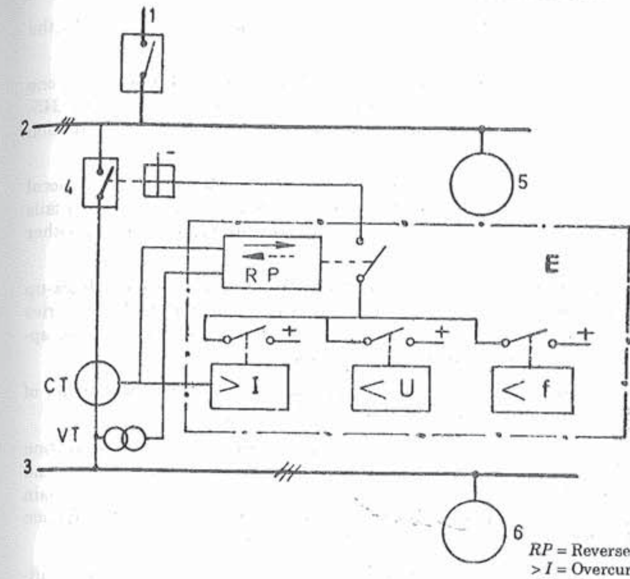
During a short-circuit within the plant (F_3) only faulty part is disconnected without interrupting the mains supply or generator supply.

A protection scheme for quick disconnection of mains supply in the event of fault (F_1) is described here.

Non-essential loads are connected to busbar 2 and essential loads to 3.

The following conditions must be satisfied by the installation:

— Busbar system must be equipped with switchgear and protection for quick disconnection of mains supply which responds to critical conditions in the plant and trips buscoupler.



RP = Reverse power element
$>I$ = Overcurrent element
$<U$ = Undervoltage element, connected to VT
$<f$ = Under-frequency element, connected to VT
All elements in single relay unit E.

Fig. 43.10. Protection scheme for system disconnection for Fig. 43.9 symbols as in Fig. 43.9.

— Enough power should be available from generator G when mains supply is disconnected.

— Enough power should be available from mains, when generator G is disconnected.

The protection scheme has several relays, the main component being a directional power (RP). It is a highly sensitive static relay.

The directional power relay *RP receives input reference voltage from VT via* rectifier bridge and input current from CT *via* another rectifier bridge. The measuring angle of the relay is 60°. This angle gives the best results for short-circuit conditions considering the d.c. component.

The phase angle between rectified outputs of current and voltage are made in positive and negative half waves which makes the measurement very rapid and reliable. Two phase comparison is made per cycle. At 50 Hz the maximum resolution of reed relay contacts is 10 to 15 ms.

The protection also incorporates overcurrents element $>I$, under-voltage element $<U$ and under-frequency element $<f$. *These elements are housed in a single relay (E).*

Section III. BACK-UP PROTECTION, CENTRALLY CO-ORDINATED BACK-UP AND PROTECTION SIGNALLING

43.10. BREAKER BACK-UP LOCAL BACK-UP

The breaker back-up and centrally co-ordinated back-up will be described further in this section.

Breaker back-up protection is employed in installations, where the failure to interrupt a short-circuit, due to breaker failure, could cause serious damage or disturb the stability of the network. Back-up protection provides a safeguard against failure of primary protection. *In breaker back-up* *protection* if faults is not cleared by the circuit-breaker or primary protection, it will cleared by the additional back-up circuit-breaker provided in the same station.

In EHV systems it is now a common practice to provide two different types of protections, one main and other back-up. The cost of EHV circuit-breakers being very high (Rs. 5-15 lakhs per 245-400 kV breaker), it is generally uneconomical to provide a duplicate breaker. Hence more attention is paid to protection scheme.

The protection scheme (generally provided in conjunction with busbar protection) based on local back-up protection, provided with features such that if the circuit-breaker of main protection fails to clear, the protection scheme senses the breaker failure and sends tripping command to another adjacent circuit breaker.

The protection scheme comprises primary protection element, (*A*) and additional back-up protection element (*B*) and complex logic system (Refer Fig. 43.11). The choice of the scheme varies with every application. Accordingly, the wiring of the relay is made for specific application or appropriate relay elements are plugged in to form the complete system.

If both the breakers in the station (for primary and back-up) fails to operate, then breaker of remote back-up provided in other stations may operate and clear the fault.

The breaker back-up protection scheme is generally provided with the bus-bar protection scheme. The principle of protection is that the command is given to the main circuit-breaker and a time lag relay for check. The time lag check relays checks whether the circuit-breaker of main protection has interrupted the current in a period of about 50 to 100 ms. (Time of primary protection say 20 ms to 40 ms and total break-time of circuit breaker 40 to 60 ms.)

If primary protection has been successful (as can be sensed by sensing current through circuit-breaker and CT primary) the back-up breaker does not get tripping command from breaker-back up protection relay. In case the main protection circuit-breaker has failed to interrupt (current has continued to flow), the breaker-back protection sends tripping command (after 50 to 100 ms) to back-up breaker.

The breaker back-up protection scheme with bus-bar system comprise the following items per breaker : (incorporated in block *B* in Fig. 43.11).

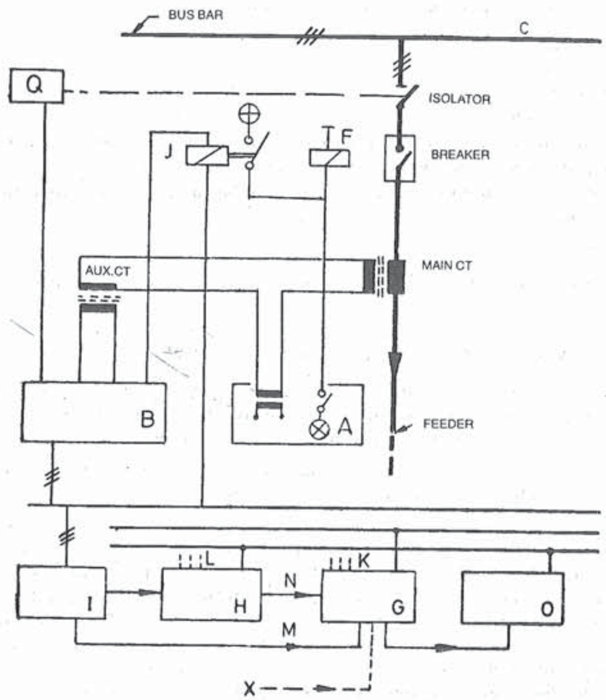
— 3 high speed single-phase current relay elements.
— 1 or more starting elements.
— 1 or more time lag elements.
— 1 or 2 tripping relays.

These elements are suitably arranged to form a complete back-up protection scheme. Logic relations decide as to which circuit-breaker should be tripped. These logic circuit derive inputs from auxiliary CT's in series with the circuit-breaker of primary protection.

Ref. Fig. 43.11 Block *B* contains three adjustable over-currents relays, starting relays for each phase and all three phases, two adjustable timing elements, two outputs for energing the tripping relays. The protective system also contains facility for signalling, monitoring units, intermediate CT, input filters for starting relays and tripping relays besides the main blocks illustrated in the figure.

43.11. USE OF MICRO PROCESSOR FOR LOCAL BACK-UP

It is now a common practice to have two forms of primary protection for transmission lines working on different principles (*e.g.* distance and over-current). It is assumed that at least one protection system will operate on occurrence of a fault. The cost of high voltage circuit-breakers being very high, it may not be economical to duplicate the high voltage circuit breaker even though higher reliability can be achieved by back-up breaker. More attention is being paid to the provision



A = Primary protection element, one for each feeder
B = Breaker back-up protection element, one for each feeder
C = Busbars
D = Tripping line Allocated busbars
E = Blocking or release line
F = Breaker trip coil
G = Logic for release
H = Monitoring module (with fault location facility)
I = Tripping line monitor
J = Tripping contactor
K = Connection between starting contactor and *G*
L = Monitoring connections between each module and *H*
M = Logic connection between *I* and *G*
N = Blocking connection
O = Signal module (output unit for internal and external signal)
P = Signal line
Q = Isolator replica generates logic signals at electronic level, which correspond to position of isolators.

Fig. 43.11. Schematic diagram of static breaker back-up protection scheme. (*Courtesy* : Brown Boveri, Switzerland).

in protection scheme which will operate and clear the fault by tripping the *adjacent breaker* in case of failure of the breaker main protection to trip.

The fault detector devices in the protection scheme are normally simple instantaneous over-current relays but complex logic circuits are associated with these to ensure that correct breakers are tripped under all system operating conditions and provide the necessary security against wrong tripping.

Microprocessors or minicomputers (Ref. Ch. 43-C) are used to advantage for this function to replace the present hard wire logic system. The minicomputer is loaded with a program which takes into consideration various system requirements.

The advantages of programmable processors are the following :

— considerable saving in relay panel space.
— reduction in panel wiring at site.
— reduction in number of multi-core required between plant items and the control room.
— greater ease to change logic to current initial mistakes or to suit subsequent system changes.
— reduction in amount of information which has to be transferred from one department to another during the design and manufacturing stages of logic system
— reduction in overall cost due to reduction in the number of stages and thus time required to provide working system.

Remote Back-up Protection

The remote back-up refers to back-up protection given by protection system in the adjacent station.

43.12. COMPUTER BASED CENTRALLY COORDINATED BACK-UP

Opening of a back-up breaker generally causes loss of power to a larger area and also system disturbance. In centrally co-ordinated back-up protection, the Grid Control Centre (Ref. Ch. 46) receives information from various sub-stations that a fault has not been cleared.

The computer aided control centre takes into account the system conditions at the time of fault land decides which back-up breakers should be opened to clear the fault with minimum system disturbance.

In order to achieve correct back-up breaker operation, it is necessary to transmit a large amount of data from and to individual sub-station if all the analysis of the fault conditions is to be done by the central computer. This would be too complex and prohibitively costly. Instead of sending all the information (Ref. Sec. 46.5) the data which can be processed locally in the sub-station is processed (by the micro-processor based mini-computer) in the sub-station itself and only essential information (data) is telemetered (transmitted to a remote) Grid Control Centre. This information (data) is compared with data received from other sub-station and the program is such that the decision as to which back circuit-breakers should be tripped is taken by computer based Grid Control Centre. This decision is then conveyed to respective sub-station in the form of coded telemetric signal. On receiving these instructions the appropriate back-up breakers are opened. The sequence of tripping of back-up breakers is in accordance with a pre-arranged program.

Smaller mini-computer with their micro-processor (central processing units) is used in individual sub-stations to determine which part of the sub-stations is faulty. The back-up protection scheme (B) in that station (generally incorporated in the busbar protection scheme) has a provision to determine as to which feeder is faulty and to send signal that a particular breaker has not cleared the fault though main protection (A) had instructed that breaker to open. These signals are processed by the mini-computer in that sub-station and relevant data is transmitted to Grid Control Centre. The grid control centre determines which adjacent circuits should be disconnected to clear the fault with least overall disturbance to the system, and also which circuits should be blocked (negative tripping) in order to maintain system stability).

43.13. PROGRAMMABLE EQUIPMENT FOR PROTECTIVE RELAYING MEASURE MENTS AND CONTROL (PPRMC)

In *Hard-Wired electromechanical or static relays* described earlier, the components of the protection system are physically interconnected and are usually for specific purpose (*i.e.* over-current relay protects against over-current and is wired according to its scheme). Hardwire logic is essentially unalterable. Hard-wired relay is set for certain pick-up condition and has certain specific characteristic.

The present trend in power system protection, measurement and control is to use *Programmable* equipment instead of *Hard-wired* equipment. The use of programmable equipment incorporating micro-processor and static digital/analog devices reduces the complexity of the entire protection scheme.

The protection scheme has to perform several complex functions. This includes

— to sense abnormal condition/fault.
— to decide whether to give an alarm or trip command.
— to decide which main circuit-breakers (primary or main protection) should be tripped.
— to decide whether to trip back-up breakers or not ? Which back-up breakers can be tripped with least disturbance ?
— in which sequence Autoreclosure should be carried out ?
— whether breaker should be reclosed or not ?
— how much abnormal condition (say power swings) are permissible that breaker should not trip ?
— what are the conditions at remote station bus ?
— whether remote breakers should be tripped or blocked ?
— what is a sequence of switching in the network ?
— synchronising checks before reclosing ?
— *Monitoring* : checking at periodic intervals, the auxiliary circuits, relay-breaker-CT-VT and other devices to check their operational readiness and health.
— Required fault clearing time of main and back-up breakers.

These complex and multifarious functions are possible with programmable protection schemes in conjunction with static relays and digital logic circuits.

The variables in main primary circuit (current, voltage, power factor, frequency) are given to measurement/protection/control scheme *via* CT/VT/tranducers. Some signals are converted to Digital form in Analogue to Digital converters (A/D)

The entire system has at its centre a large scale integrated circuit (LSI) microprocessor. The microprocessor processes the information by means of built-in static logic circuits, memory and other modules.

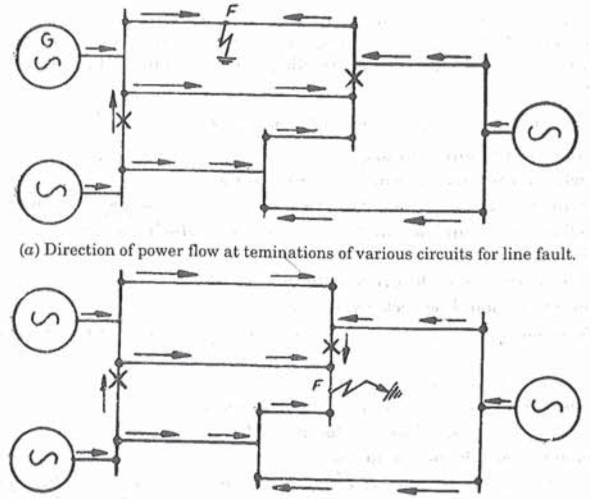
The processing is performed by means of *programmable* microcomputer. The *programmes* are prepared to cater for specific application. These programmes can be prepared to suit local system conditions.

43.14. PRINCIPLE OF CENTRALIZED BACK-UP PROTECTION (CBP)

A real-time on-line computer system is necessary for centralized computer aided back-up protection and post-fault control the basic approach is to substitute logic for measurement.

The faulty circuit in power system is distinguished from healthy circuit by the fact that fault circuit alone has an inflow of fault power at one or more terminations and no out-flow at any termination (Ref. Fig. 43.12).

The central computer is supplied with the data on the directions of (fault) power flow from all circuit-terminations. The computer programme is such that it can determine the faulty circuit by very fast able look-up and then decide which back-up circuit-breakers should be tripped for back-up clearance if one or more of the circuit-breakers of primary (main) protection fail to clear the fault condition within desired time.



(a) Direction of power flow at teminations of various circuits for line fault.

(b) Direction of power flow at terminations of various circuits for busbar fault.

Fig. 43.12. Explaining CBP.

Note. During a fault in a circuit the direction of power flow at the terminations of that circuit is towards the fault F.

Generally, back-up clearance will involve tripping of a section of busbar as only one circuit breaker is provided per feeder for economic reasons. The central computer will then wait for the total break-time of the slowest circuit-breaker in the system plus a suitable safety margin, to service the circuit-breaker trip signals (signal that the circuit-breaker has tripped and cleared the fault). If all such signals arrive, the back-up protection programme will stop; if one or more such signals do not arrive, appropriate trip command will be issued to the relevant out-station.

The trip-command (if any) from central control will be checked for compatibility with the local situation as seen by the out-station before the tripping of back-up circuit-breaker is initiated. The purpose of this check is to prevent false tripping of back-up breaker due to false command from central back-up control station (Grid Control Centre). Generally, outstation can determine/only check whether the particular circuit *may be faulty* or *is faulty* ; and not that *it is faulty*. The last function is determined by central back-up protection. (Protection in outstation might have failed and cannot be relied upon for back-up).

The central computer tables must be continually updated with any change in circuit configuration. Thus the outstation must inform central computer of any circuit-breaker of isolated change of status as a low priority interrupt.

43.15. POST-FAULTY CONTROL (PFC) BY DIGITAL COMPUTERS

Post fault control is necessary after opening of main and back-up circuit-breaker to keep the power system in satisfactory operating condition. Possible actions to be taken include

— load shedding
— generation readjustment
— switching-in of available standby feeders of transformers
— system islanding (splitting)

Central computer can examine several possible post fault conditions before the breaker clears the fault and determines what action may be required to keep system stability with minimum outage. The actions must be pre-programmed on the basis of recent analysis of the system.

The central computer is pre-programmed with tables of specific loads to be shed or switches to be opened corresponding to specific generation/load inbalances. For other aspects, a periodic system security assessment programme is simulates successively all possible contingencies and checks overloads and stability limits, which is pre-assessed off-line. This programme is run periodically or whenever a significant load change occurs, or whenever there is a change in power system configuration. A pre-requisite for this function is that, additionally to the information required by the back-up protection programme, the central computer needs information on busbar voltages, generation levels, circuits watts/VARs flow, etc. These data are scanned at regular intervals (second/minutes) by an existing data loggers and elementary system.

43.16. COMMUNICATION LINKS FOR PROTECTION SIGNALLING

The communication links for protection signalling between out-station and central control station can be one of the following types :

— Pilot wires specially for protection/communication signalling
— Telephone wires
— High frequency carrier channel
— Radio/Microwave channels of very high ultra high frequencies.
— Satellite communication

The communication channel between out-station and central control forms a part of back-up protection scheme.

Digital Message System

Signals are physical representation of a message, and therefore carries the information to be processed. The *Binary signals* can assume only two values either '0' or '1', the '0' value represents not present and '1' value represents present. The logic operations AND, NAND, NOR OR, and the combinations thereof manipulate logic functions in form of binary language of '0' , '1'. A change of signal state of a binary device represents in its message content elementary decision between two possible values 0, 1. In technical terminology, it contain the 'unitbit' called binary digit.

When a varying analogue quantity is to be converted into digital message, it should be converted into digital form in A/D conversion device.

A code is the assignment between individual values of the quantity and the signal states of several binary positions by means of which these values are to be digitally represented.

The analogue circuit quantities or messages are converted into digital messages. These digital messages are in form of 0-1 pulses having certain code. The frequency of signals may be voice frequency or high radio frequency.

43.17. FIBRE OPTIC DATA TRANSMISSION

This technique is being used for machine-tool control or plant process control and power system protection.

The conventional electronic signals are communicated through shielded copper wires of good conductivity. The electrical noise, electromagnetic field disturbances tend to disturb the signals. One method of overcoming this problem is to employ fibre-optic cable for transmitting the control signals fibre-optic cable consists of specially developed glass cable. The light signals can be transmitted through such cable very efficiently and the effect of electrical noise on transmission is completely eliminated.

The transmitter at sending end converts the electrical pulses into light pulses. These light pulses are transmitted through the FO cable. At the receiving end the light signals are converted into electrical signals.

At present silica clad silica optical cables have been developed for working lengths of 40 km before repeaters are necessary. They can handle data rates in excess of 100 M bit/sec.

Development of optical sensors and integrated optics has made a major impact on protection signalling in early 1980's.

Experimental optical link current transformers have been developed the scheme incorporates auxiliary CT's mounted on hollow insulator. The output of auxiliary CT's is given to pulse frequency modulated transmitter. Optoelectric techniques are used for controlling HVDC thyristor valves.

The transmitter drives a gellium-arsenide light emitting diode (LED). Light pulses from the diodes are transmitted through fibre-optical cable to relay room. In this room the light signals received from FO cable are converted into electrical pulses by receivers. The electrical signals are supplied to static relays. Thus the optical system forms a link between outdoor CT and indoor static relay.

43.18. LOCAL BREAKER BACK-UP PROTECTION : BREAKER FAIL PROTECTION ; STUCK-BREAKER PROTECTION

This form of protection has other titles like *Local Breaker Backup Protection, Breaker Fail Protection ; Back-up Tripping Protection.* If a circuit breaker fails to open or clear the fault; the back-up breaker should be operated either 'locally' or 'remote'. The local back-up breaker operates in the same sub-station. The method of achieving local breaker back-up operation is called 'Breaker Fall Protection' of 'Breaker Stuck protection' or 'Back-up Tripping Protection'.

Basic Scheme of Breaker Fall protection is illustrated in Fig. 43.13. As the main protection operates; the breaker fall protection is also initiated. If the main breaker falls to clear the fault, a time delay relay is arranged to operate the required back up breakers so as to clear the fault. The total time required for fault clearance by the back-up breakers depends mainly on the setting of the time delay relay.

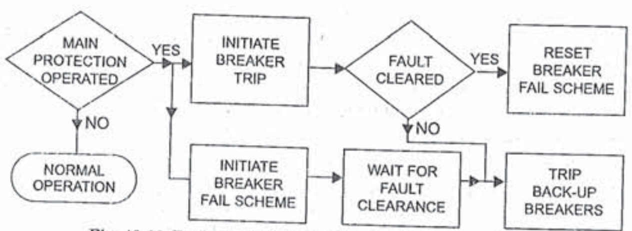


Fig. 43.13. Basic flow diagram of local back-up protection.
Courtesy : GEC measurements, U.K.

Fig. 43.14 illustrates the total time required for clearance by back-up breaker.

Refer Fig. 43.14. The setting of time delay relay in the breaker fail scheme must be longer than the total break time (Circuit breaker time) of the main protection breaker plus reset time of the fault detector relay so that back-up breakers do not operate if the fault detector relay has already reset (*i.e.* the main circuit-breaker has successfully cleared the fault).

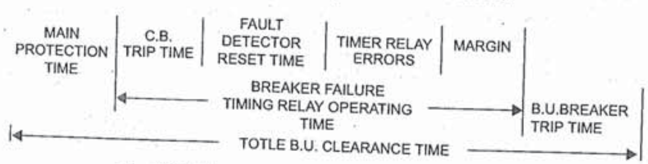


Fig. 43.14. Time components in local breaker back-up.
Courtesy : GEC measurements U.K.

Whether the main breaker has cleared the fault or not is detected by 'an instantaneous over current relay followed by a definite time relay' which together find out whether the main current is still flowing after the tripping signal to trip coils of main circuit-breaker of the faulty feeder.

43.19. UNINTERRUPTED POWER SUPPLY (UPS)

Complex, critical electrical and electronic systems need uninterrupted power supply. Examples of such critical loads include process computers; process control instruments, communication links, relay, boiler flame supply, boiler control, furnace supply, protection circuits, critical alarms etc. For some loads, voltage dips/frequency variations are not allowed. UPS systems provide uninterrupted a.c. power supply to such critical applications.

There are two types of UPS

(*A*) UPS with some delay of several cycles.

(*B*) UPS with time delay less than a fraction of a cycle.

In type *A* above, for a time delay of 4 to 8 cycles, mechanical switches can be used for transferring supply from main to the stand-by generating source.

In type *B* above, there should not be any delay or interruption; hence a continuous or float type UPS system have been illustrated in Figs. 43.15 and 43.16.

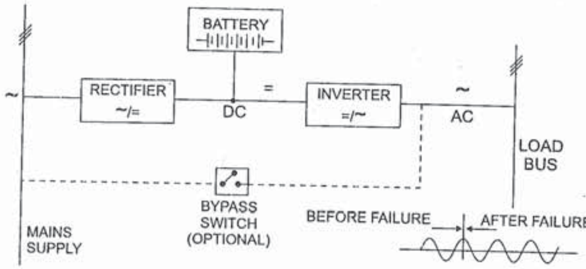


Fig. 43.15. Un-Interruption Power Supply (UPS).

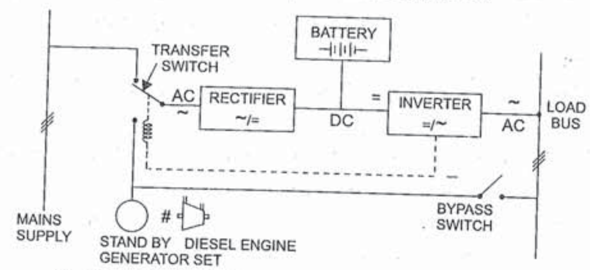


Fig. 43.16. A typical high power UPS with standby generator set.

A solid state UPS is basically composed of the following :

(*a*) Solid State rectifier battery charger.

(*b*) D.C. Storage Battery.

(*c*) Solid State inverter.

(*d*) Solid State (Static) Switch (Optional)

During the normal operation, the a.c. input feeds the rectifier. The rectifier converts a.c. into d.c. and charges the battery. Simultaneously, the rectified supply is inverted to a.c. by the inverter.

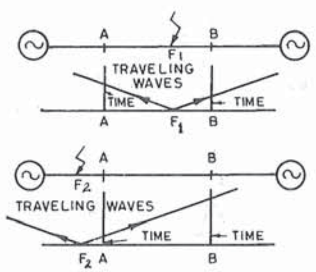
When a.c. supply fails, the battery supply provides the alternative power to the inverter and the continuous uninterrupted a.c. supply is available on the a.c. load side. For a time of 10 to 60 minutes battery can be arranged. For longer power supply duration or for higher capacity standby supply; diesel generator sets or gas-turbine driven generator sets are used. These are brought into circuit automatically when main supply fails.

43.20. DIRECTIONAL WAVE RELAYS FOR FAULT DETECTION AND PROTECTION OF OVERHEAD LINES

The Directional Wave Relays are ultra-fast (2-5 ms) and have been developed during 1980's for protection of overhead lines of any length against phase to phase faults and phase to ground faults. Directional wave relays are also used in conjunction with distance relays for line protection.

The Directional wave relay (DWR) uses the *directional wave detection principle* which detects the direction from which the travelling waves originate. If the point of origin is external to the protected line section the protection blocks and if internal, the protection provides a high speed tripping output which is phase selective.

This principle is illustrated in Fig. 43.17 in terms of the direction of motion of travelling waves generated by a change in the electrical state of the network (*i.e.* fault breaker operation etc.)



F_1 Internal fault for section *AA* F_2 External fault for section *BB*

Fig. 43.17. Principle of Directional Wave Relay (DWR).

Consider protection section A.B.

For internal Fault F_1 the direction of travelling waves originating in F_1 will be $F_1 A$ and $F_1 B$.

The external fault (F_2) the direction of travelling waves will be F_2A and F_2B.

The direction of wave at Point A has reversed.

At point *B*, the time taken by the wave $F_2 B$ is mush lesser than that taken by wave F_2B.

The Directional Wave Relay senses the following :

1. **Direction of Wave** with respect to the protected section relay location.

2. **Amplitude of the Wave** with respect to setting.

In DWR the steady state currents and voltage are suppressed in active and passive filters and only sudden changes are detected. The direction to the fault is established by determining the relative polarity of the sudden changes in voltage ΔU and current ΔI. For external conditions these have the same polarity and for internal conditions the opposite polarity. The directional decision is made in the first 2 to 5 ms after fault incidence and all subsequent information is ignored.

The DWR has two modes of operation.

1. The independent mode determines whether the fault is internal or external by direction and level setting. It is independent of the communication channel and provides ultra high-speed tripping for nearby faults.

2. The more sensitive dependent mode requires information from the remote terminal to establish whether the fault is internal or external in the usual manner of directional comparison and carrier acceleration principles used in distance protection schemes.

In Fig. 43.17, for fault F_1, the DWR at A will detect the internal fault in independent mode and will take tripping decision within 2 to 5 ms. For fault F_2 the DWR at A will remain inoperative, and the DWR at remote terminal B will depend on the carrier acceleration or carrier blocking signal from terminal A. For a fault F_2 very near terminal 'A' the DWR at B cannot precisely determine whether the fault is internal or external. Hence it has to take help of the usual techniques used in carried aided distance protection of long lines. By such combination of the two modes the DWR along with carrier aided distance protection scheme provides fast and selective protection of 100% length of overhead transmission line.

The DWR relay incorporated in Distance protection scheme uses both steady state (50 Hz waves) and transient variations (within milliseconds) but the setting are based on 50 Hz quantities.

Testing : The Directional Wave Relays can be tested by means of special test kit for Dynamic Testing. The tests can be performed on DWR and Distance Protection Scheme.

QUESTIONS

1. Explain the causes of electrical noise in static relays and necessary precautions in installation to eliminate the same.
2. Write short notes on —
   — shielding and earthing
   — uninterrupted power supply (UPS)
   — fibre optical link for data transmission
   — overvoltages in static relays
   — noise in static relays
3. State the merits of static motor protection. Describe a typical static motor protection scheme with the help of a heat block diagram. Describe function of each functional block.
4. Describe principle of a static bus protection based on directional comparison principle.
5. Explain the need for back-protection. Explain principle of breaker back-up protection scheme.
6. Explain the role of centrally co-ordinated breaker back-up in a large power system. Describe the scheme of centrally co-ordinated breaker back-up employing a digital computer.
7. Explain the need of post fault control from central control station. What are the main functions of the post fault control.

43-B

Digital Relays, Microprocessors Based Relays, Fault Recorders and Fault Locators

Three levels : Control centre, Substation, Unit. Functions at each level — Components of Digital Relay, Components of Microprocessor based relays.
Part I Digital Relays. Block diagram — functions of each block — basic processes in Digital Data Processing — Binary system, Word, bits, components.
Part II — Microprocessor based Relay.
Block diagram — functions — Microprocessor — Microcomputer — Functional parts, Architecture, Block diagram or a Distance Relay.
Chapter 43-C — Microprocessor Based Substation Control and Protection

43.21. ENTER MICROPROCESSORS IN PROTECTION TECHNOLOGY

Power Engineers need understanding of basic principles and applications of microprocessor based protection control system in addition to the conventional protection systems.

The microprocessor based protection and control at following hierarchical levels (Fig. 43.18).

Control centre level : Load Control Centre
Substation Level/ Plant Level : Control rooms of Substation, Generating Station, Load Centres.
Unit Level : Individual 'Units' in the substation/generating station/Load centres *e.g.* transformer, busbar, motor transmission line.

These levels are linked by Power Line Carrier Communication channels (PLCC)* and microwave communication channel. The data flows from unit level to upper levels and from upper levels to unit levels *via* the Data Bus. Each level has certain protective, Supervisory/monitoring and control functions.

Before 1980's the protective functions were independent of control and monitoring functions. Monitoring Functions and Control Functions were performed by different systems. The functions of protective relays was limited to sensing the fault/abnormal operating condition and arrange tripping of circuit breaker under main protection and if necessary back-up breakers. The automatic control included Synchronising checks, auto reclosing duty etc.

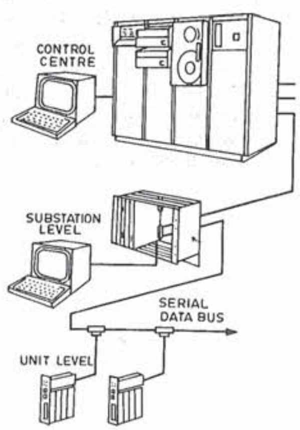


Fig. 43.18. Three levels in microprocessor based Protection, Control Monitoring (PCM) system.
Courtesy : ASEA, Sweden.

* Refer Sec. 46.9 Terms and Definitions.

Digital protective relays, monitoring and control devices in these three levels are in communication by means of power line carrier communication channels (PLCC). (1980-1990)

Changing Scene

With the availability of microprocessor based relays, digital techniques, data transmission facilities microcomputer etc. the functions of supervision, control and protection can be made complementary rather than independent. Functional modules can be incorporated in Combined Protection Control and Monitoring System (CPCM).

In the modular concept of protective and control systems, the required modules are plugged-in to form the desired protection cum control system. The individual level (*e.g.* unit level) has an interface with the next level (*e.g.* substation level) and also has man machine interface. The telecommunication system is used between different hierarchical levels.

This chapter describes the basic components of Digital Relays and Microprocessor based Relays. The Combined Protection Control and Monitoring and Control Systems (CPCM).

PART I
DIGITAL RELAYS

43.22. BLOCK DIAGRAM AND COMPONENTS OF A DIGITAL RELAY *

There are two families of digital relays.

1. Hardwired digital relays incorporating A/D convertors and Digital processing circuits.
2. Programmable digit relays incorporating microprocessors or minicomputer.

Basic components and processes involved in a digital protective relay are illustrated in Block Diagram Fig. 43.19 (*a*) described here as an example.

The three phase AC inputs derived from CTs and VTs are fed to Block 2. Block 2 comprises analog processing compensating circuits. In this block, the measured currents and voltages are developed into a set of quantities required for measurement processing and operation of the relay.

In Block 4 A/D Conversion the phase informations contained in these quantities are converted from the analog signals to representative square wave digital signals.

The equivalent digital signals from Block 4 are fed Block 7 for *digital processing. Block 7 consists of phase comparators, logic gates and other digital circuits required for signal processing. Block 7 also receives other external digital signals from Block 3. These include external data regarding back up breaker and other circuits which have an interface with the protective relay.*

The digital processing carried out in Block 7 is controlled by current and voltage supervision functions carried out in Block 5. *In Microprocessor Based Relays functions of Block 7 and Block 5 are performed by a Microprocessor.*

Block 8 provides an interface between the relay and the circuit-breaker trip coils Block 9 gives indication display on the front face of the relay and is called Man-Machine Interface. In the event of power system disturbance, for which the relay reacts, the events are displayed on Block 9. Signalling contacts enable communication with the peripheral devices like sequence of event recorders, reclosing relays etc. With digital relays there is a provision of fault recorder, fault locator etc.

Block 1 (D.C./D.C. convertor) provides a galvanic separation between the station auxiliary DC system and the protective relay. The time lag relays in Block 6 determine the operating time of the back-up function of the relay and are therefore linked with the Block 7.

Referring to Fig. 43.19 the functions and description of electronic components in a digital relay are summarised in Table 43.2.

[In microprocessor based relay Blocks 7 and 5 are within a microprocessor of the relay]

* The Blocks in Digital Relays, Microprocessor based relays have similarity.

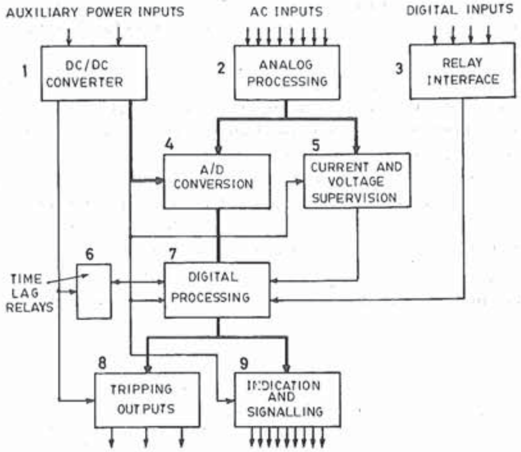


Fig. 43.19. Block diagram of a digital relay.
Courtesy : ASEA, Sweden.

Table 43.2
Summary of Components in a digital protective relays

Block in Fig. 43.19	*Functions*	*Description*
1. D.C./D.C. convertor	Galvanic separation between Auxiliary D.C. supply (Station battery system) and the static relay.	
2. Analog processing, compensating and setting circuits.	3 phase AC inputs include Secondary current of CT, Secondary voltage of VT.	Include different processes required for relay measurement *e.g.* — Amplitude comparison — Zero crossing detection — Phase comparison in sequential logic circuit. — Measurements *e.g.* current or voltage or impedance or direction. — Supervision and control functions by amplitude comparators. — Filtering.
3. Relay Interface with external Digital Signals	To receive external digital inputs and feed to the digital processing block 7.	External digital inputs may include signals from remote terminal, signals regarding back-up protection etc.
7 A/D converter	To convertor analog signals into digital square wave signals	These signals are subsequently fed to the digital processing block 7.
5. Current and voltage supervision	To control digital processes in block 7.	May be included in Block 7 in a Microprocessor.
6. Time-lag relay block.	To determine operating time of back-up relays through block 7.	

Block in Fig. 43.19	*Functions*	*Description*
7. Digital processing block	To process the digital signals received from A/D converter (4) and the Digital Input interface (3) as per required relay logic.	Comprises — Logic circuits for relay operation. — Multiplexers — Encoders, decoders — Memory circuits and other digital electronic circuits.
8. Tripping output.	The trip-command to circuit breakers is given by this block.	The tripping output is generally fed to appropriate auxiliary relay.
9. Indication and signalling	To indicate whether the relay has operated. To provide signals to remote terminals.	In addition, the functions may include display Disturbance recording, Fault recording etc.

43.23. BASIC PRINCIPLES OF DIGITAL RELAYS

Ref. Fig. 43.19. The protective relays receive analog inputs from the CT's and VT's connected in the protected circuit (Block 2). These analog signals are processed in Analog processing unit (Block 2). *The processed analog signals are fed to the analog to digital convertor (A/D converter) (Block 4).*

Digital Signals

Analog signals have continuous faithful wave forms *e.g.* Secondary voltage of a VT, secondary current of a CT.

Digital signals are in form of coded square pulses which represent discrete elements of information (data). In digital system, the signals are in 'binary' form *i.e.* only two discrete values referred to as binary coefficients 0 and 1 or logical values true and false.

The number of binary digits needed to *encode* the various discrete elements of information (data) has a significant influence on the design of a digital system.

The digital system generally operate on groups of 8 or 16 or 32 bits of information atonce. The range of the digital system of encoding the information by a n bit group is 2^n. *Hence digital systems with larger bit operating group can process a wider range of concoded information.*

The earlier digital relays used microprocessors of 8 bit groups. **Some recent digital relays are with 16 bit microprocessor.**

Representation of Digital Information.

The information to be processed may be :

— Textual *e.g.* status of a plant *viz* normal or emergency.
— Numerical *e.g.* value of current, voltage, power etc.
— Logical *e.g.* logical conditions imposed on a relay to operate.

The information usually takes from a sequence of alphabetic characters, punctuating symbols, decimal digits and symbols representing arithmetic operations, logical values and logical operators. The information also includes the spaces which mark the boundaries between various words or quantities.

This form of information is represented in a digital system by codes of binary digits. Since the information must be fed into the input unit, processed in the processor unit and given out by output unit in coded form, there should be possibility of 'encoding' and 'decoding'. Each element of information must have unique representation.

Binary Number System.

Binary digit can take two values (0 or 1) corresponding to ('open' or 'close') and is said to be base 2. Binary numbers are formed by successive powers of binary base. Whole numbers and fractions can be formed by using binary system. For example a decimal number 86 is represented by a binary number 1 0 1 0 110 as follows :

1		0		1		0		1		1		0,		
1×2^6	+	1×2^5	+	1×2^4	+	0×2^3	+	0×2^2	+	1×2^1	+	0×2^0		= 86
645	+	0	+	16	+	0	+	4	+	2	+	0		= 86

To represent 86, binary series requires seven positions, but only two digits 0, 1. The valancy of individual binary position of dual number is obtained by falling powers of base 2.

A Binary number (1 0 1 0 1 1 0)

B 'A' as a relay combination,

1 = close 0 = Open

C 'A' as an amount of binary counter

This can be represented by modern hardware by relay combination and binary counter is shown in Fig. 43.20. The number 86 is represented by binary code (A) by (B) and (C).

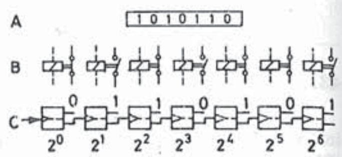


Fig. 43.20. Dial (Binary) number system.

Conversion binary to decimal and vice versa

Simplest method consists of repeated halving of decimal number. Each halving produces a new dual digit which is equal to the remainder which can be 0 or 1 (even or odd number)

Example Conversion Decimal to Binary

Example : 56 →111000

56 : 2 = 28 remainder 0
28 : 2 = 14 remainder 0
14 : 2 = 7 remainder 0 ↑Dual number 111000
7 : 2 = 3 remainder 1
3 : 2 = 1 remainder 1
1 : 2 = 0 remainder 1

Dual number is converted in decimal number by taking highest binary digit and doubling it, adding to second highest binary digit to the result, doubling it again, adding to this the third highest binary digit and so on.

Example : Binary to digital conversion

1 1 1 0 0 0 =

1 × 2	+ 1	= 3
3 × 2	+ 1	= 7
7 × 2	+ 0	= 14
14 × 2	+ 0	= 28
28 × 2	+ 0	= 56
		RESULT

Processing Binary Information

Each element of information within digital protection and control system is represented as a binary code and is stored, transmitted, processed as a set of binary signals '0' - '1' series. Within the digital circuits, the binary signals are processed by digital logic circuits which route the binary signals through appropriate combination of logic gates. Each logic gate implements primitive binary logic which is described mathematically by Boolean Algebra Logic corresponds directly between logical operators and the digital logic gates. Gives principles of Logic circuits. Described logic functions and their applications to digital protective relays.

Boolean Algebra provides a method and a set of rules for logic operations. Basic logic operations NOT, AND, OR and their combinations NAND, NOR etc. are used as building blocks *for forming systematic logic circuits. By using Boolean algebra the logical circuits are manipulated and designed, simplified with mathematical accuracy.*

The logic circuits is formed on the basis of rules from Boolean Algebra and mathematical simplification.

Combination Logic

Digital protective systems have built-in-digital signal processing circuits. The analog inputs are received from secondaries of CT, VTs. Digital signal inputs are received from RTU (Remote Terminals Units) and from other contacts.

Other textual signals are received from the man-machine interface. These data are either in textual numerical or logical. Each discrete information is first converted into digital form to equivalent code in terms of '0' and 1.

In static relays, the *digital signal processing system (Block 7 to Fig. 43.19) is required to produce output signals which are fed to tripping outputs (Block 8) and indication, display signalling unit (Block 9). The signal processing involves logical combinations of input signals. The combination logic functions (Boolean Functions) are implemented using network logic gates in which the signal paths do not form feedback loops. The absence of feed back loops ensures that the output of logic circuit is determined only by logic function of the circuit is determined only by logic function of the circuit and the present set of inputs.* Such a circuit is called 'Combinational logic circuits'.

Combinational logic is used extensively in digital protective relays as illustrated in Fig. 43.19, Static Busbar Protection, Static Distance Protection. It provides many of the logical and arithmetic functions used in digital signal processing and computing systems.

Truth Table

The function of Combinational logic circuits in protective relays can be specified as a Boolean Equation in which the output variable is expressed as a function of input variable. This equation defines the value of output for each combination of input variables. The complete set of inputs and their corresponding output are generally represented in the truth table.

Arithmetic Operations

Arithmetic operations of fundamental nature are performed in

— digital processing systems (Block 7, Fig. 43.19)

— Arithmetic Logic Unit (ALU) within the central processing unit (CPU) of a computer or a microprocessor.

Combination of logic gates can be used to implement arithmetic operations on binary numbers. *Arithmetic addition* is the most fundamental operation in binary digital system.

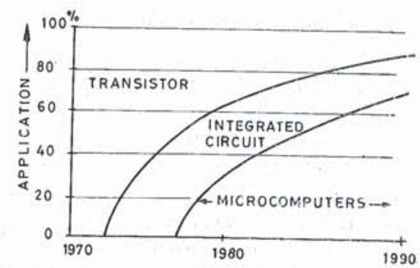


Fig. 43.21. Three generations of technology in components of Static Protection Systems and Control Circuits.

Table 43.4. Digital Circuits and their Functions

Digital Multiplexers.	To produce an output which is a combinational function of input variables.
Encoder and Decoder	If number of inputs is greater than the number of outputs, the combinational logic circuit is called encoder. If the number of inputs is lesser than the number of outputs the combinational logic circuit is called decoder. Encoders and Decoders are used in form of MSI, LSI, VLSL. They are used in CPU of computers and microprocessors.
Sequential Logic Asynchronous and Synchronous	Digital sequential logic circuits and programmable system incorporate these types of logics.
	In synchronous sequential logic, synchronising signal is used to control the instant at which transition occurs in the state of system.
	In Asynchronous sequential logic, the state is determined by the functin of the circuit and the value of the logic signal. External synchronising signal is not used.
Clocked Flip-Flop.	Basic elements in synchronous sequential circuits is Flip-Flop.
Memory function	Memory elements are essential in sequential systems and digital signal processing. Semiconductor read and write memory is very widely used.
Memory device.	It should be possible to uniquely address the memory device that stores a binary digit. It should be possible to read the state of every stored binary digit.
	— ROM Read Only Memory. It is not possible to change the state of binary digits in the ROM. It is nonvolate.
	— RAM Random Access Memory. In this, we can read/write in to the memory.
	Memory is denoted by number of bits *e.g.* 8 bit memory Large arrays of ROM and RAM are used in programmable systems counters.

It is a sequential circuit which can go through specific sequence of states and which perform a state of transition on each occurrence of input. A counter can be used directly to count a number of occurrances of input by converting the series of inputs into a prescribed sequence of states such that at any point the current state or current may be output or read. Counter can also be used to form a coded sequential output.

PART II
MICROPROCESSOR BASED PROTECTIVE RELAYS

43.24. MICROPROCESSOR BASED RELAYS

The microprocessor based relays have become commercially acceptable. They are preferred for complex protection and control systems. In microprocessor based relays the digital processing unit is a **Microprocessor. Most recent protective relays for overcurrent protection, differential protection, distance protection and Substation Protection etc. are with 8 bit or 16 bit microprocessors.**

The basic principles of Digital Relays described with the help of Fig. 43.19 are applicable to microprocessor based relays also.

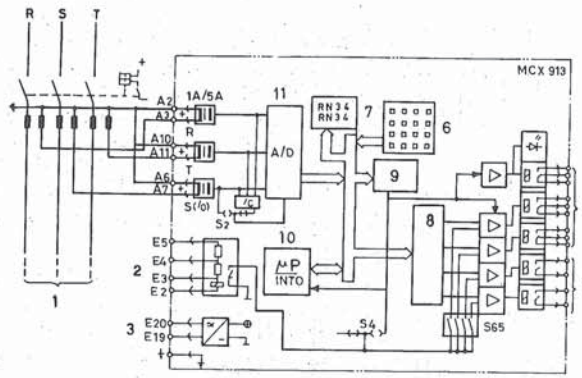
Microprocessor is now used for Protection, fault recording, fault locating, data monitoring and several other functions which were earlier performed by analog or digital systems.

43.25. DESCRIPTION OF A MICROPROCESSOR BASED PROTECTIVE RELAY FOR MOTOR PROTECTION * (*Courtesy* : Brown Boveri, Switzerland.)

Fig. 43.22 gives a block diagram.

The CTs feed current to A/D converter (11). A/D converter gives digital signals to the microprocessor (μP - INT - 0) and software matrix block 8.

* The description is for pinpointing the various special provisions available with a typical microprocessor based protective relays.



1. Protected unit
2. Blocking input
3. Aux. supply 26 to 312 Vdc or 80 to 242 Vac
4. Aux. signalling relays
5. Aux. tripping relays
6. Keypad
7. Display
8. Software matrix
9. Watch dog
10. Microprocessor
11. A/D Converter.

Fig. 43.22. Block-diagram of a Microprocessor based overcurrent relay/overload relay for Motor Protection. (*Courtesy* : Brown Boveri)

The microprocessor (10) performs the digital signal processing.

Protective Functions

In the motor protection relay under description, several conditions are analysed by the microprocessor (11) and the software martix (8). The protective functions in this relay include :

(*i*) Earth fault protection

(*ii*) Negative phase sequence protection (I_2)

(*iii*) Short circuit protection ($I \gg 2$)

(*iv*) Overcurrent protection ($I >$)

(*v*) Protection against low loads ($I <$)

(*vi*) Thermal overload protection ($\Delta\theta$)

(*vii*) Motor starting protection (I-START)

The protective relay has to decide logically the conditions under which the tripping signals are to be given via auxiliary tripping relays (4).

Signalling and trips by Software Martix

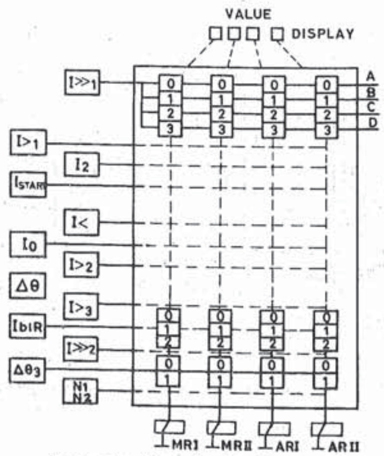
Refer Fig. 43.23. The signalling and tripping logic is provided in the software matrix (Block 8) which gives command to auxiliary tripping relays (4), and auxiliary signalling relays (5).

The software tripping matrix has been shown in Fig. 43.23.

The user is able to freely select those starting and tripping signals that are significant for his plant and can allocate them freely to the various auxiliary relays by means of the software tripping matrix (Fig. 43.23).

Two signalling and two tripping relays are provided. For each relay a number can be used to select one of the four following modes of operation for each protective functions.

— No action (0)	...	Condition A
— Signalling a start	...	Condition B
— Signalling a trip (2)	...	Condition C
— Signalling a trip with self retention (3)	...	Condition D



a no output *b* aux. signalling relay I or II
c aux. tripping relay I or II *d* aux. tripping relay I or II with latching
* This allocation is possible for all protection functions excepting $\Delta\theta_3$ and I_{bLR}

Fig. 43.23. Software tripping matrix in Block 8 of Fig. 43.22.

Signalling of a start : Persists until the particular setting is exceeded.

Signalling of a trip : Appears when the time-lag belonging to the particular protective function has expired or as soon as a set temperature rise or a set number of permissible starts by the motor has been exceeded. Exception : if tripping with self-retention is selected, the trip annunciators only drop out when the reset button has been pressed.

Memory of Tripping value and time run

The memory for the tripping value and time run contains the value of the current and the time-lag of the particular function at the instant the last trip took place. If no trip takes place, the last time run of the particular function will be memorized. The memory for tripping value and time-run is volatile, *i.e.* in the event of failure of the auxiliary supply, its contents are lost.

Self Monitoring

The microprocessor based relay Fig. 43.22 is provided with self monitoring (watchdog) (8). The relay is continuously and comprehensively monitored by the watchdog and test software, any faults which do occur (e.g. failure of components) are detected at once. Thus, without adversely affecting the availability, it is largest possible to dispense with periodical testing of the relay.

Testing Facilities

For periodical testing of the relay one of the test sets may be used. For testing, the active part is withdrawn from its casing and inserted in a test casing wired to the test set. It is also possible to test the relay in its built in state.

Settings and Memories

Settings can be made quickly and at any time *i.e.* even where the relay is in operation. Once values have been set and memorized, they are retained even if the auxiliary supply should fail (memorizing in NOVRAM = Non-/volatile Random Access Memory)

For the parameters of the MCX 91 relays there are two memories.

— Background memory (non volatile, NOVRAM) in it the valid parameters are memorized, *i.e.* the protective relay always operates only with the settings memorized in NOVRAM.

— Foreground memory (volatile)

— when the auxiliary supply is switched on, or with a special command, the parameters from the NOVRAM are copied in the foreground memory. There they can be altered as desired with the "vary" key. The displayed value is always the value in the foreground memory.

43.26. ADVANTAGES OF AND SPECIAL FEATURES OF MICROPROCESSOR BASED PROTECTIVE RELAYS

Compared to the earlier hard wired analog and digital relays, the programmable microprocessor based relays have superior features which include the following :

1. Ability to Combine a large number of protective and monitoring functions in a single relay unit. *e.g.* in Fig. 43.22 the relay unit combines 7 main and 3 auxiliary function.

In the protection schemes of earlier generation separate relay units were necessary for each main function resulting in more number of units, more wiring, lesser reliability.

2. Measured values of variables are processed digitally by microprocessor. The digital processing by microprocessor gives several abilities to the protective relay. These abilities include

— Combinational logic

— Use of on-line processing of variables

— Programmable feature, etc.

3. **High level of Flexibility.** Various protective functions can be freely selected and allocated to the various auxiliary relays by means of software tripping matrix (*e.g.* Fig. 43.23). The same relay can give tripping signals, blocking signals, starting signals, signals to fault recorders etc. *The relay meets the most complex protective and monitoring requirements.*

4. The memory of the relay enables the relay to retain the values of variables responsible for tripping, time taken by relay to operate etc.

The values can be displayed on demand by the operator. Thereby the nature of fault, fault current etc., are precisely known.

5. The relay can *digitally display* values of on the current, voltage etc. by pressing appropriate button on the face. Thereby need of each instrument is eliminated. *Microprocessor design provides precise measurement and compact panel.*

6. *Comprehensive self monitoring self checking feature.* The relay with self monitoring feature can monitor its own circuits continuously and if any internal component has failed, indication is obtained. The relay also indicates functional readiness to operate. In relay with self checking property, the performance can be checked by the operator during periodic maintenance.

7. **Increased Reliability due to self-checking**

Recent Microprocessor based digital relays provide digital sensing and logic Processing. The microprocessor checks itself, the peripheral circuitry, RAM, NOVRAM, EPROM memories and the power supply. In addition, it monitors the AC inputs using A/D converter calibration check inputs. It also monitors LOP (Loss of Potential) and LOI (Loss of Current). The self checking feature improves the reliability of microprocessor based digital relays.

8. **Data Interface Access - Increased Communication ability**

Microprocessor based digital relays can have interface with (communicate with (1) Other Relays (2) Protected equipment (3) Control and protection devices in the substation. By means *via Relay Interface Unit* (Fig. 43.19, Block 3). The data and control commands can be exchanged. The sequence of software events which occur in the processing unit (Fig. 43.19, Block 7) can be stored in the memory and subsequently displayed and obtained in the form of printed output. The periodic maintenance requirements are reduced.

9. **User friendly yet highly capable**

Microprocessor based relays are easy to apply, operate and use. Yet they are highly capable *e.g.* a modern microprocessor relay for transmission line protection has two four digit alphanumerical displays that show up 62 separate settings, seven LEDs and it is easy to access stored data and easy to input new-data.

10. Relay provides Fault designations and informations. The metering display shows three phase voltages, current, load angle. The data is accessible through front panel display. Pre-fault voltage, current and load angle are also displayed when desired. The relays can be hooked to a microprocessor based fault recorder and fault location indicator.

11. **High Speed.** High speed relays Minimum tripping time of 12 millisecond and maximum of 32 millisecond are available for line protection. A typical microprocessor based relay for line protection takes 20 millisec.

43.27. BLOCK DIAGRAM OF A MICROPROCESSOR BASED DISTANCE RELAY FOR PROTECTION OF TRANSMISSION LINE

Refer Fig. 43.24. The Microprocessor (Block 7) is the 'heart' of the protective system. It is a Intel 80 C/96 Microprocessor with a 16 bit microcounter operating at 10 MHz. The program memory (Block 7-1) is in separate easily replaceable EPROM chips. The subsystem (Block 7-2, 7-3) also includes volatile Read-Write memory (RAM) for working storage and Nonvolatile RAM (NOVRAM) for storing the settings and targets when the relay is deenergized.

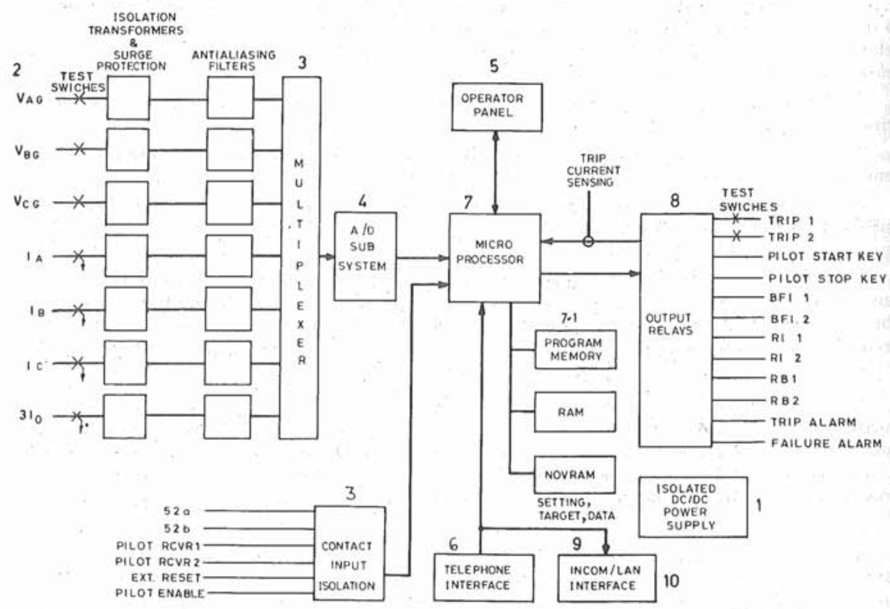


Fig. 43.24. Microprocessor Base Distance Relay.
(*Courtesy* : Westinghouse, USA)

Included on the processor board is the A/D conversion system (Block 4) and a Multiplexer (Block 3). The AC input quantities (Block 2) of 4 currents and 3 voltages are analogue multiplexed to a single sample/hold circuit. The sample/hold output is fed to an A/D subsystem (Block 4) which yields in bits dynamic range. *Each AC input is sampled 8 times per power cycle.* (1/60 sec for 60 Hz)

The filter module (Block 3) contains seven low pass filters which provide anti-aliasing functions and conditioning of incoming AC currents and voltages.

The interconnect module (Block 3) is used for interconnecting with other modules electrically. Located in the interconnecting module are optical isolatops (52A, 52B). External Reset Pilot Enable, Receiver 1, Receiver 2 Inputs)

Block 1 is DC/DC convertor power supply for the communications interface and alarm relays. Power supply provides isolation from station battery system and includes overcurrent and undervoltage protection. A failure alarm relay monitors status and provides loss of power indication. The alarm relay is normally picked up, but will drop when the processor defects a problem on upon loss of DC. The power supply (Block 1) generates DC voltages of – 24, + 5, – 12, + 12 V DC. These are made available for various circuit.

Test switches between Block 2 and 3 provide high quality test and isolation functions and permit convenient entry of current and voltage quantities trip circuits are also wired out through these switches to provide for cut out of trip circuits.

Measurement and Range

The relay provides three zone distance measurement with optional pilots for additional zones. The operating characteristic for each zone is variable mho characteristic for all types of faults.

A single Relay weighing 16 kg and size 19" wide 7" high and 14" deep can perform several functions as mentioned in sec. 43-26 the table.

PART III
MICROPROCESSOR

Microprocessor and Microcomputer

A microprocessor (μP) is a single package containing logic circuits of Central Processing Unit plus various amounts of 'depositary and conduit' logic which surround a central processing unit (CPU). Thus the word 'microprocessor' means a specific electronic logic and packaging. The electronic logic must be equivalent to the central processing unit. The package must be a single chip, packaged as a Dual Line in package (DIP). A chip in electronic language means microscopic electronic circuits created on a tiny silicone piece. The chip is mounted in a Dual In-line package (DIP). The microprocessor has a single chip in a DIP.

In contrast a microcomputer has specific electronic logic incorporated in a variety of packages including several DIPs and additional electronic circuits.

Microcomputer is a product which contains all the functions found in a digital computer.

Microcomputer may have one of the following configurations.

1. One chip microcomputer has a single chip packaged in a single DIP and other electronic circuits. Such a microcomputer is called single chip Microcomputer.
2. Multi-chip microcomputer has two or more chips and other electronic circuits.

Microcomputer must have a central processing unit.

A Microprocessor is remarkably like a Central Processing Unit of minicomputer. Hence, it is generally called Central Processing Unit. However though there is a remarkable similarity between the Microprocessor and a CPU, they are different products.

Microprocessor is a single package containing the processing logic. Adding the memory, interface circuitry and other external devices converts the microprocessor into a microcomputer.

The advanced manufacturing techniques of microelectronics and digital sciences have resulted in the development of microprocessors. The complete 'central processing unit' of a minicomputer is constructed on a single integrated circuit (chip) and is put inside a single package called a microprocessor. The earlier microprocessor built during 1970's were without incorporation of memory in the same chip. Further advances of VLSI (Very Large Scale Integrated Circuits) have resulted in ICs containing CPU and memory units which form the heart of a single chip microprocessor/microcomputer.

Microprocessor is an advanced programmable logic device designed to carry out specific processing function. Microprocessors are used in digital protection systems for processing the digital information.

A Microprocessor has minimum number of components. Once developed, a microprocessor based relay is manufactured into several tens of thousands of units. Therefore extra items are avoided.

Memory Size

The binary digits are combined to form a code which can represent a number. The primary level at which binary digits are grouped within the processor is the most important design characteristic of a microprocessor/minicomputer/computer and is referred as 'word size' An 8-bit microprocessor processes the binary data in eight binary digit units. The memory is organised into 8 bit units.

The memory organised into 8-bit units is visualised as follows :

By common convention the bits of a word are numbered from right (0) for the low order bit) to left (7 for the high order bit).

The following table gives the distinction between microprocessor, minicomputer and computer.

Table 43.5

Type of processor	*Word size —bits*						
Microprocessor and Microcomputer	4,	6,	8*,	12,	16*		
Minicomputers	6,	12,	16@	18,	24	32	64
Large Computers	4,	16,	18,	24,	32@	64@	

* Most common for digital protection systems.
@ Most common for Digital computers.

Byte

An 8-bit data unit is called a byte. A byte is most universally used data unit in computer terminology. It is used when there is no 8-bit data word.

A 16-bit microprocessor will often have memory words interpreted as two bytes.

Memory Addresses

There are subtle differences between the use of memory in a microprocessor and in minicomputer. In a minicomputer memory is simply a sequence of individually addressable RAM words, with address beginning at 0 and ending at some large number which depends on the size of computer memory.

In microprocessor based product for example a microprocessor based relay, program memory is in a separate replaceable EPROM chips.

EPROM means Erasable Programmable Read-Only Memory.

By inserting required EPROM chips, special information that EPROM is to hold is inserted into the micro processor based relay.

An EPROM like PROM holds the information indefinitely once it has been programmed. One can read contents of an EPROM again and again.

RAM (Randon Access Memory) is for working storage. It is generally understood to mean a memory with both read and write capability in which the location can be accessed in any random sequence. In a very simple case, in a 8 bit microprocessor, 8 RAM chips may implement 8-bit read/write memory words with each chip contributing to a word.

RAM chip memory size is commonly described as 'M × N' chip, where M is number of accessible units on a memory chip and N is the number of bits in each addressable unit.

Non-volatile RAM (NOVRAM). Non-volatile RAM (NOVRAM) is used for storing settings and targets when relay is de-energised.

43.28. ARCHITECTURE OF A MICROPROCESSOR

Fig. 43.25 gives a block diagram of a Microprocessor Based Minicomputer.

Microprocessor and Microcomputers are programmable and they perform the digital processing operations as per the program.

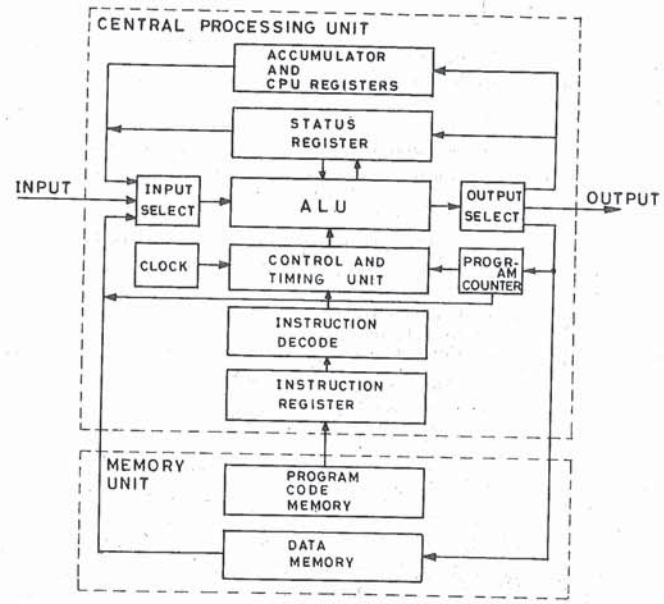


Fig. 43.25. Block diagram of a Microprocessor based Minicomputer. The central Processing Unit corresponds to a microprocessor. Refer Fig. 46.5.

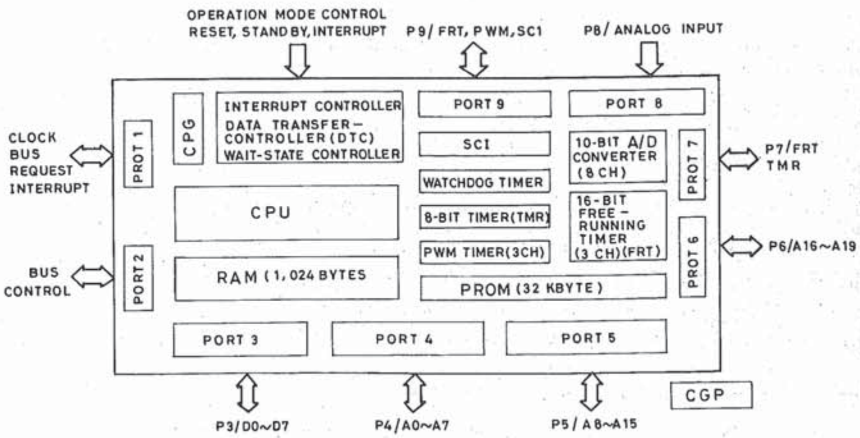


Fig. 43.26. Block diagram of a 16-bit Microprocessor.
Courtesy : Hitachi, Japan.

Table 43.6
Specifications of a 16-Bit Microprocessor*
(Type H8/532 Hitachi)

CPU	16-bit H8/500 CPU
ROM	32 kbytes (PROM/Mask ROM)
RAM	1,024 bytes 8-bit free running timer : 3 channels (3 input capture registers, 6 output compare registers)
Timers	8-bit timer : 1 channel (2 compare registers) PWM timer : 3 channels Watchdog timer : 1 channel
SCI	1 channel (Asynchronous mode/Synchronous mode)
A/D	Resolution : 10 bits, 8 channels (Single mode/scan mode)
INTC	3 external interrupts 19 internal interrupts Priority : 8 levels
DTC	On-chip data transfer controller
WSC	ON-chip wait-state controller
I/O ports	57 input/output ports 8 input ports 84-pin PLCC
Package	84-pin windowed ICC 80-pin OFP
Process	CMOS 1.3 μM

PWM : Pulse width modulation
SCI : Serial communication interface
PLCC : Plastic leaded chip carrier
QFP : Quad flat plastic package.

* Ref. Fig. 43.26 for Block diagram of this Processor.

Central processing unit (CPU) shown in Fig 43.25 is the microprocessor. CPU contains ALU, control and Timing Unit, number of important Registers and Timing clocks etc.

A microprocessor may lack some of the peripherals, but it must have a CPU. The logic of each microprocessor differs widely from the other.

Program are instruction codes which are input to the CPU as means of the sequential operations to be performed. Program is stored in the memory.

CPU Registers fetch the stored data from the memory. The registers are also called **accumulators.** An 8 bit microprocessor has 8 bit accumulator. CPU usually operates on the data contained in register rather than accessing memory words directly.

ALU (Arithmetic Logic Unit). The actual data manipulation within the CPU is handled by the collective logic called ALU. The ALU processes binary data. A 8-bit microprocessor has a ALU which will operate on a 8 binary digits. ALU performs the following functions.

(*i*) Boolean addition (*ii*) Boolean operations
(*iii*) Complement a data (*iv*) Shift a data word one bit, etc.

CPU is built up to perform more complex processing of data.

Control Unit (CPU). The sequence of logic operations of the ALU is determined by the control unit. The CU is in turn is driven by the contents of the instruction register.

Control and Timing Unit. The basic operations of the ALU of the microprocessor or CPU are governed by the control unit (CU) and Timing Unit (TU). The control and Timing Unit gets reference timing signals from external clock and CPU.

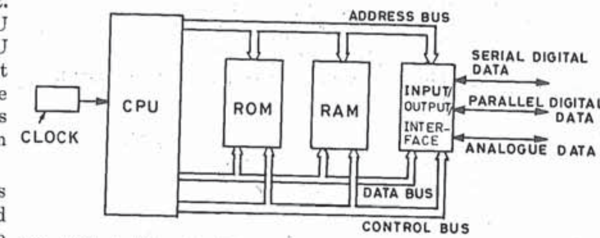


Fig. 43.27. Architecture of System Buses in a Microprocessor based system.
CPU = Central Processing Unit (Microprocessor)
ROM = Read Only Memory
RAM = Random Access Memory (Called Read and Write Memory)

[The data from data lines is placed by RAM is addressed memory word. RAM is able to extract the data from addressed memory word and place it on external system bus data line].

Bus lines are classified into four categories (Fig. 43.27)

(*i*) Address bus
(*ii*) Data bus
(*iii*) Control bus
(*iv*) Clock, power, ground

Bus buffer. Usually the output signals are boosted by appropriate buffer amplifiers before connecting to the system bus lines. Buffer stores the information temporarily during the data transfer. (Fig. 43.28)

Address Bus. One system bus line is provided to every address. Normally more address bus lines are provided than the requirement, some for future requirement.

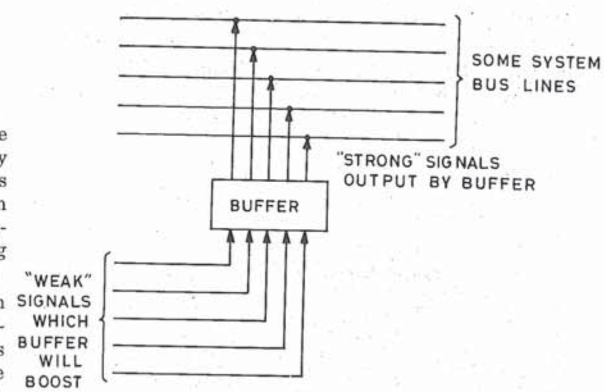


Fig. 43.28. Buffer amplifier weak signals before feeding to bus lines.

Data Bus. System bus line is provided for each data bit of the largest word. More data bus lines are provided, some for future requirement.

Control lines. Separate control line is provided to every control signal that may be output by or input to any device.

Clock, Power , Ground. There will be generally more than one clock signal on a system bus. Also a number of power lines are provided for the various devices.

Random Access Memory (RAM). (Fig. 43.29-A) It is often called read and write memory. A RAM takes off data from data lines of the external system bus and places this data in an addressed memory word. In addition a RAM must be able to extract data from the addressed memory word and places this data on external system data bus lines. Read/write memory is usually implemented a number of RAM chips, with each chip supplying one bit of the data word. Generators control signals necessary to operate various logic systems.

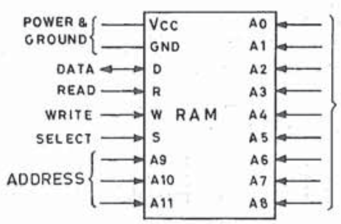


Fig. 43.29-A. RAM - Random Access Memory. Also called Read Write Memory (RWM).

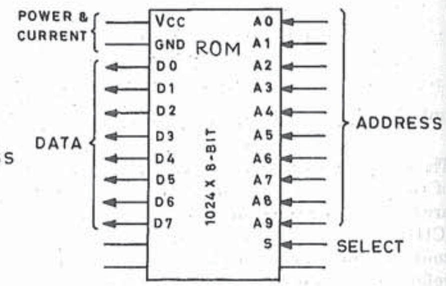


Fig. 43.29-B. A Read Only Memory.

The control unit (CU) is separated from Timing Unit in some microprocessor.

The control and timing unit controls the main operational cycle of the processor and is called the 'Instruction cycle'. The instruction cycle has two phases (1) Instruction fetch and (2) Instruction execution. During the instruction fetch the address of the next instruction is obtained from the program counter unit and transferred to the memory address register.

At the end of instruction fetch the CPU unit will have all the information required to control the instruction execution.

External Bus System

Fig. 43.27 illustrates bus oriented architecture of a microcomputer system. A bus denotes a channel along with data is transferred. It refers to the physical connection of data path. The architecture shown in Fig. 43.26 is preferred in many systems because it provides flexibility and easy expansion.

The Microprocessor (CPU), Read only Memory (ROM) and Read-Write Memory (Random Access Memory - RAM) Clock and many other devices each connect to a group of parallel signal lines which are collectively called as an external bus system.

Physically, the bus system consists of a number of parallel conductors. In todays microcomputers, these conductors are in the form of metal lines etched on a printed circuit card (PCC) *e.g.* There may be 100 parallel lines in an external bus circuit. These lines are assigned to different signals arbitrarity. The buses are not standard and each manufacturer has his own method of routing and naming to the bus system.

ROM in a Dual-in-package pins and signals ROM may have eight data lines for 8 bit word *via* which the contents of the addressed memory are transferred back to CPU.

Fig. 43.27 illustrates a single RAM Dual-In-Line package (DIP) and Fig. 43.26 shows the connections of an RAM, ROM and CPU by means of system buses.

Read Only Memory (ROM) A ROM device requires following input signals :

1. Address of memory words being accessed
2. A read control signal that asks the ROM device when to return the contents of the addressed memory words.
3. Power and ground.

Only output signals of an ROM device are 8 data lines for an 8 bit word through which the contents of the addressed memory word are transferred back to CPU.

ROM devices is built in the form of a Dual-In-Line package (DIP)

Fig. 43.30 shows connections of the ROM and Microprocessor with the bus-lines.

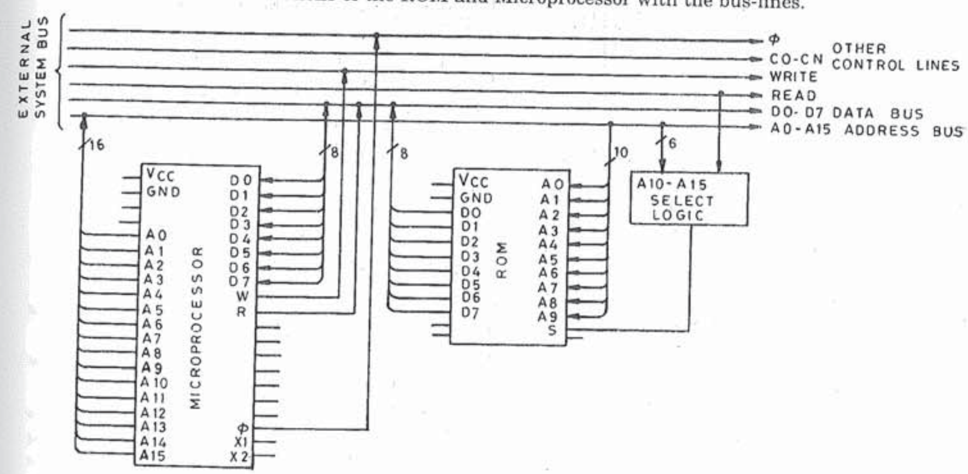


Fig. 43.30. Connections of ROM, Microprocessor with Data Bus, Address Bus, Control lines.

Input/Output. (Fig. 43.31 A, B) The transfer of analog data, digital data, between the CPU/RAM/ROM within the microcomputer and the external system beyond the microcomputer is called input/output and is designated as I/O.

The interface between the microcomputer system and the external logic must be clearly defined. It must have provision to transfer the data and also control signals that identify the events as they occur.

There are many ways by which the data transfer at I/O state takes place between the external system and the microcomputer.

1. **Programmed I/O.** In this case the data transfer between the microcomputer and line external circuit is completely controlled by the microprocessor, or more precisely by the program fed to the microcomputer.

The microcomputer system requires input program based on which it waits for external logic input to place data in some predetermined location. I/O communicates with the operator *via*.Man Machine Interface (MMI).

Fixed Function Programmed Systems. Fixed Function Programmed Systems has a fixed program input and is constrained to perform a prescribed and fixed sequence of instructions. This

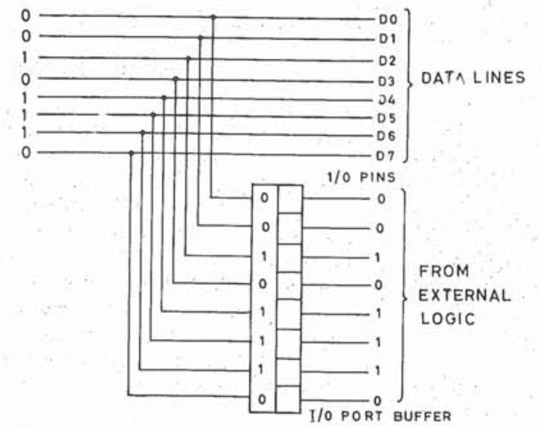


Fig. 43.31. (A). Input/Output, Port Buffer and Data Buses.

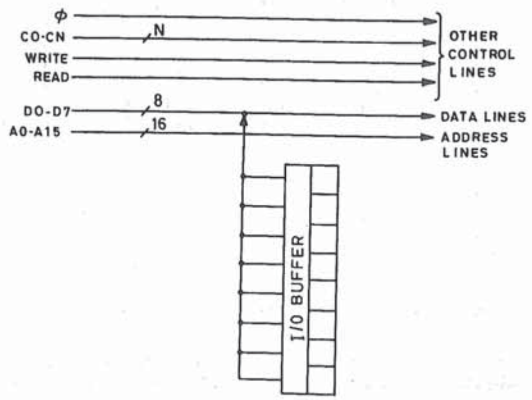


Fig. 43.31 (B). Various bus lines to which I/O Buffer is connected.

type of system does not have a capability of software control to select between two alternative sequences of instruction. The applications function of such system can be altered only by changing the program.

In microprocessor based relays, the fixed programmed system is preferred.

Program Memory is in separate easily replaced EPROM chips. The program memory chip is selected for using the relay for a specific application.

A fixed function programmable relay is forced to execute fixed sequence on instructions based on the programmed logic.

2. **Interrupt I/O.** Interrupts are a means for external logic to force the microcomputer system to suspend whatever it is currently doing in order to attend the needs of external logic. Most microprocessors have control signals *via* external logic which can demand the microprocessor attention. This signal is referred to as an interrupt request. The external logic asks the microprocessor to interrupt whatever it is currently doing in order to service the more immediate task.

3. **Direct Memory Access.** The form of data transfer at I/O stage allows data to move between the microcomputer memory and the external logic without the microprocessor in the data transfer.

High Performance IC Memories.

Microprocessor Unit with high performance are built with fast integrated circuit (IC) memories of following types :

DRAM	Dynamic Random Access Memory
SRAM	Static Random Access Memory
EPROM	Electrically Programmable Read Only Memory
SAM	Serial Access Memory

The microprocessors operated at 20 MHz has memories with access time in the range at 15 ns to 85 ns.

43.29. PROGRAMMING OF MICROPROCESSORS BASED RELAYS

Microprocessor based relays are supplied by the manufacturers for specific applications *e.g.*

— Microprocessor based relay for motor protection
— Microprocessor based relay for transmission line protection
— Microprocessor based relay for generator protection
— Microprocessor system for substation protection and control
— Microprocessor based fault recorder, etc.

The manufacturer furnishes guidelines for selection of the relay with appropriate built-in software for the microprocessor.

A single microprocessor relay has provided several possible combinations of protective functions with a wide range of setting for each function.

The desired protective function and range can be selected by means of '**Mode Selector**'. Mode selector is in several steps. The settings can be made easily in 'User friendly' manner. The programms are provided within the microprocessor by means of the programms module. The mode selection by the operator result in selection of protective function *via* the software matrix built in the relay (*e.g.* blocked, start, trip, signal, self retention etc. illustrated in Fig. 43.21. Block 6.

Disturbance detector detects disturbance in protected circuit and the trip output is possible only if the Microprocessor monitoring interface and Disturbance detector have ensured the presence of fault. Tripping due to malfunction of relay components is prevented.

In some more complex relays the programm is in the form of a separate chip on a EPROM memory. The manufacturer inserts the appropriate program in the relay. In case the application is changed, the program chip is changed.

43.30. SELF-CHECKING AND/OR SELF MONITORING IN MICROPROCESSOR BASED RELAY

The microprocessor based relays are designed for continuous self monitoring and/or automatic self checking.

By self checking/monitoring function the relay is in a position to report locally and remote, the likely malfunctioning/failing of internal component.

Fig. 43.32 illustrates the circuit of continuous monitoring subsystem in a microprocessor based relay. The vital component is a disturbance detector. This detects the disturbance in the protected circuit (transmission line) by measurement of negative sequence currents.

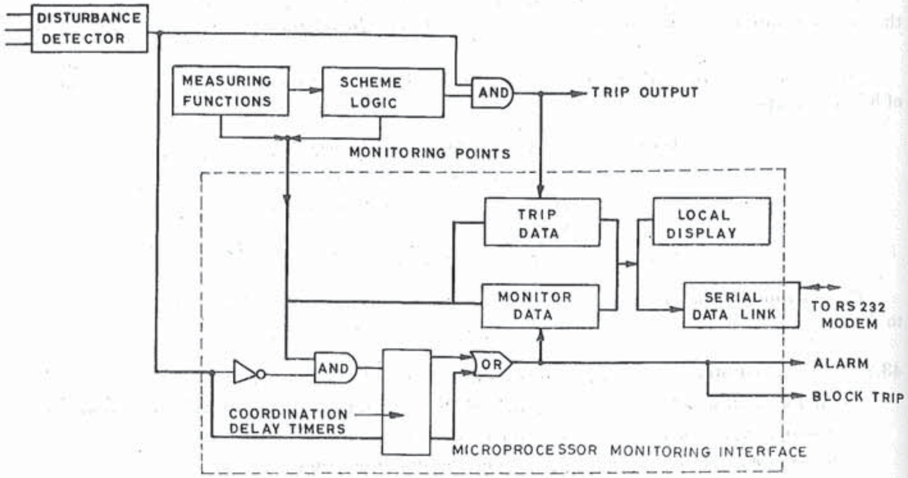


Fig. 43.32. Interface of self-checking of Microprocessor based relay with Disturbance Detector.

If the relay attempts to trip falsely because of malfunction within the relay, but the disturbance detector sees no disturbance in the protected line, the tripping is blocked. Fig. 43.33 shows principle of self checking in a microprocessor based relay. The important circuits which should be checked have been indicated.

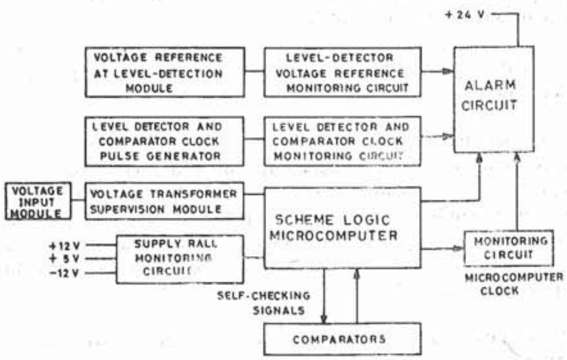


Fig. 43.33. Block diagram of self checking of critical components and circuits in a microprocessor based relay.

Digital relays are designed for continuous self monitoring or automatic self checking or both. There is a considerable difference between the manufacturers and the users regarding the choice between self monitoring and self checking feature.

Analog signals pass through the internal measuring-circuit selector and the A/D converter to the selection logic, together with the 16 units of binary event information added here, the data when passes to the memory, where it is decoded in "1 out of 512" form in a decoding and driver stage.

43.31. ON LINE MICROPROCESSOR BASED FAULT MONITORING

During recent years, fault monitoring systems are being incorporated along with the protective relays. Fig. 43.34 shows a block diagram of a Microprocessor based on line fault monitoring system. It provides for on line fault recording, which means that oscillograms are printed out immediately, on occurrence of a fault without restriction.

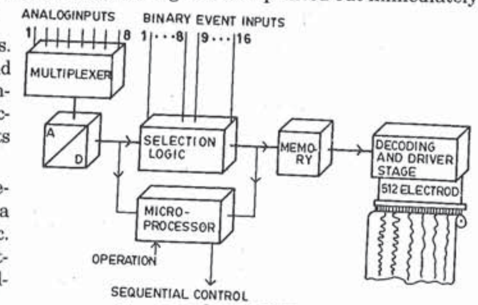


Fig. 43.34. On-line Fault Recorder. (*Courtesy* : Siemens)

Analog inputs are currents and voltages. These are multiplexed in the multiplexer and then converted into digital signals in A/D converter. The digital signals pass through selection logic which mixes in 16 binary events units before the information reaches the memory.

A microprocessor controls the operating sequence. It does not contribute data flow. Data flow is handled by systems hard wired logic. Microprocessor helps in comprehensive operating functions, automatic fault diagonals, recording and operating unit status.

If fault situation arises, the microprocessor activities the chart rotor motor and controls the recording sequence without interrupting the fault monitoring function.

The control system continuously scans all the elements for the inputs of commands (switches and keys) and enable program selection and parameter input by the user. A clock circuit (not shown in Fig. 43.24) is with a permanent lithium battery backup which provides the microprocessor with current time and data and also memory space for storing operating parameters in the event of power failure.

Metalized paper aluminium impregnated paper with a speed of 500 mm/s is used for recording. The current pulses are given by electrodes in 5 μs duration. There are 500 electrodes of 0.2 mm dia. Selected electrodes are activated in a sequence. Pulse sequence ensures recording of sinusoidal functions.

43.32. MICROPROCESSOR BASED FAULT LOCATORS

The distance protective relays for transmission line protects the transmission line from phase faults and ground faults. For permanent fault, the lines-men should reach the fault location and carry out the repair work (*e.g.* replacing procelains, faulty conductor, fallen tower, tree branch, etc.). To carry out these operations quickly the exact location of fault should be known from the terminal substations.

Fault Locator. It is an essential complement to distance protective relay for transmission lines and fault recorder. Fault locators are installed along with distance protection scheme and fault recorders. Fault locator measures and indicates accurately the distance between the substation and the point of fault.

Fault Recorder can also be combined with a fault recorder and printer for recording the distance to the fault and fundamental component of fault current prior to and after the fault.

Fault locator is connected to the secondary CTs and VTs of the line.

Under normal conditions, the fault locator monitors three phase currents and the ground current, voltage input signals continuously. The operation of the fault locator is with following steps (1) Data Collection (2) Starting of fault locator (3) Sorting of Measured Instantaneous values (4) Filtering of Measured signals (5) Determination of type of fault (6) Solution of fault equation (7) Prelocation of results.

The input analog signals are converted into digital signals in A/D converter and are stored in memory for every six cycles continuously.

When a fault occurs, trip circuit from the protective relay initiates the fault locator's calculation program. The prefault sample values and during fault sample values are used for calculating the distance of the fault. The calculation of distance is based on the principle of distance relays. The fault distance is shown as percentage of total line length on two digital front mounted LED display.

Fig. 43.35. illustrates the block diagram of the microprocessor based fault locator.

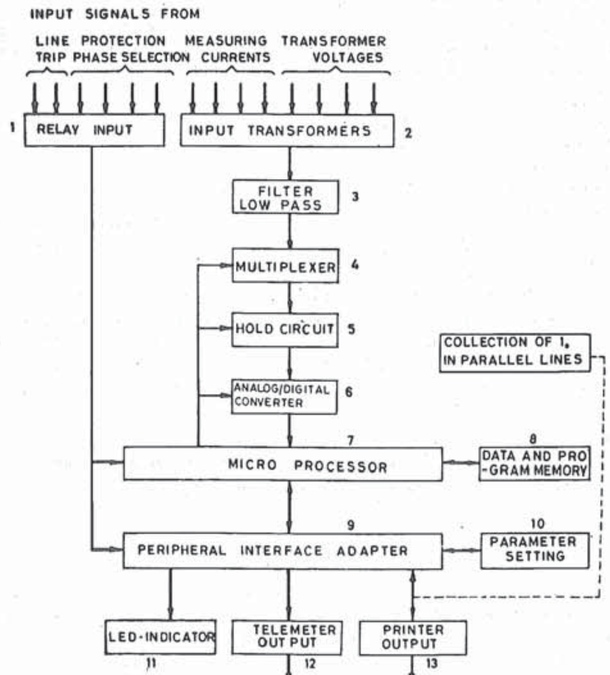


Fig. 43.35. Block diagram of a fault locator. (*Courtesy* : ASEA, Sweden)

Block 1 receives input signals from Line protection *viz* Line trip signals for first and parallel line, phase selection signals which identify the type and faulty phase. The receipt of tripping signal constitutes the starting signal for the fault locator. The measured values received by block 2 from cycles immediately prior to and during the fault are stored in the memory.

Block 2 receive line currents and line voltages from secondaries of CTs and VTs. Block 3 filters the input signals. Block 4 is a Multiplexer which is successive order transmits the signals (measured values) to Block (6) A/D convertor *via* hold circuit (Block 5). The function of the hold circuit is to retain signals for the period of time required by A/D. Converter to converter, the signals to digital form. The rate of measurement is chosen such that 24 measurements are made per cycle on each current and each voltage signal.

The measured digital values are routed through the microprocessor (Block 7) to the correct addresses in the memory capsules (Block 8). In these the values measured during the previous 9 cycles are stored.

Table 43.7. Functions of the Blocks of Fault Locator

Block No.	*Title of Fig. 43.35*	*Function*
1.	Relay Input	— To receive starting signal from distance relay. — Receive signal regarding faulty phases from distance relay — To give starting input to fault locator
2.	Input Unit	To receive signals from CT, VT and to feed to A/D converter *via* Filters.
3.	Low pass Filter	To filter the analog signals
4.	Multiplexer	To send the signals sequencially to A/C convertor.
5.	Hold	To hold the signal for a brief time period before sending to A/D converter.
6.	A/D Converter	To convert analog signal *s* to digital signals.
7.	Microprocessor	Processing of measured digital signals and calculate the fault distance. Feed output to printer, telemeter and LED indicator.
8.	Data and Program Memory.	— To store data for processing — To store programme in memory for instructions to microprocessor
9.	Interface adapter.	Connections between microprocessor and peripherals.
10.	LED Indicator	Indicates Fault Location and percentage of line length.
11.	Telemeter output	Give output data to Remote terminal unit *via* telecommunncation line.
12.	Printer output	— Presents results on printed paper indicating the following : 1. Values of current, voltage in faulted line prior to and during fault. 2. Timing of fault.

The Microprocessor (Block 9) executes the following control and calculating functions :

— Collection of measured values.

— Processes the measured values and calculates the distance between the CT/VT and the fault (proportional to calculated ZL)

— Present the percentage fault distance on the indicator.

— Feeds out calculated distance to the fault on an indicator.

— Returns to normal measuring mode after a line fault.

— Determines the type of a fault when a built in phase selector is used Block 8 constitutes the following Memories of the Fault Locator (FL).

— PROM Programmable Read Only Memory : for the control and calculation programs.

— RAM (Random Access Memory) for storing measured data and apart result during distance determining sequence.

The results are available to the operator in the form of alphanumerical printed output (13) and LED Indication (11). Results can also be transmitted by means of telemeter output (Block 12) to Remote Terminal Unit (RTU). Table 43.4 summarise the functions of various blocks within the fault locator.

43.33. PRINCIPLE OF FAULT DETECTION IN ON LINE DIGITAL RELAYS, FAULT LOCATORS AND FAULT RECORDERS

The 'On Line' protection control and monitoring system is connected to the power system *via* input Module and CTS/VTs.

The current and voltage in the power line are continuously monitored by the CPM system, cycle by cycle.

Measured signals stored in memory and the relationship between different time periods is illustrated. When a starting signal is transmitted to the relay, 9 cycles of information is already stored in the memory. About 2 cycles are stored after receipt of starting signal.

The microprocessor based device (Relay/Recorder/Locator) performs the one-line function as follows.

Input signals are received from secondaries of CTs and VTs. These are converted in digital form in the A/D module.

Sample measurements. Sample measurements are taken for each measured quantity for every cycle of the waveform continuously (*e.g* 24 samples per cycle) Each sample is compared with the corresponding sample of previous cycle (Fig. 43.36). When the power line is healthy sample S_2 of next cycle will have the same value as the previous sample S_1.

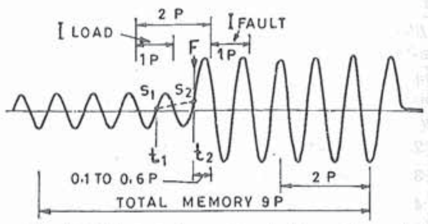


Fig. 43.36. Memory storage in a fault recorders and various microprocessor based relays.

If a fault occurs in the power line during the period S_1 to S_2, the measured value of the sample (S_2) will differ from corresponding value of previous cycle S_1.

If the difference S_2-S_1 is in excess of permitted tolerance, the presence of fault is detected. Thereby the PCM system follows the sub-routine corresponding to a faulty condition immediately and the following actions are taken.

1. Protective relay initiates tripping and autoreclosing actions.
2. Fault recorder gets starting signal from the protective relay and performs the recording of currents and voltages of approximately 9 cycles, which include 2 periods prior to the fault Fp.
3. Fault locator is also initiated and indicates the location of fault in terms of percentage of the length (*e.g.* 40% L).

In the normal conditions, the memory keeps information about currents and voltages for every 9 cycles continuously in the event of a fault the record of 9 cycles is derived from memory by the microprocessor and given to the printer output, telemeter output.

Application of Protection Relays

We now know that the main objectives of Relay Protections are :

— To ensure protection of the apparatus & equipment connected to the system
— Protection of persons and property
— To separate the faulty system immediately from rest of the system so as to facilitate the continued operation of the healthy part of the system.

So far, in previous sections, we have studied the various types of relays & their functions. We shall now give an example of its application in a power plant.

Protection Requirements of a Power Plant

The generator, transformer, Switchgear, feeders & other equipment are provided with protections against all possible electrical faults usual for such networks, the main objectives being to avoid damage to the equipment as well as to avoid unwarranted trippings.

The fault possibilities/abnormal conditions which are normally encountered during the operation of such equipment or system are :-

(*a*) Generator-Transformer Units

— Earth faults in stator and rotor
— Multi-phase faults in stator windings & transformer windings close to terminals
— Single phase ground fault in transformer windings & its terminals

— Inter-turn faults in transformer windings
— External symmetrical & asymmetrical short-circuits
— Pole slipping conditions
— Negative phase sequence currents
— Over-loading of stator windings
— Over-loading of rotor windings
— Breaker failure
— Over-voltage/under voltage conditions
— Sudden energisation of the machine when standstill
— Insulation leakage at HV/LV terminals of Generator Transformers
— Ground fault in generator excitation circuit
— Loss of excitation
— Asynchronous condition of generators
— Under frequency conditions
— Reverse power flow conditions
— Transformer over fluxing
— Incepient Transformer faults
— High oil & winding temperatures.

(*b*) Station Auxiliary, Unit Auxiliary & Excitation transformers

— High temperature of windings
— Over-load
— Multiphase faults in windings & at terminals
— Earth faults
— Under voltage

(*c*) HV, Switchgear

— Multi phase and earth faults in buses & bus-coupler
— Mal-operation of circuit breakers
— Multi phase and earth faults in bus-coupler

(*d*) Shunt Reactor (Where ever Connected)

— Multi phase and earth faults in windings and at terminals
— Mal-operation of circuit breaker
— Oil Level low
— High Winding temperature

(*e*) HV Cables

— Multi phase and earth faults

(*f*) Feeders (Transmission lines)

— Multi phase and earth faults
— Over voltage conditions
— Mal-operation of circuit breakers

The protection system shall identify the above abnormal condition/faults and ensure a fast and selective protection of generators, generator transformers, 420 kV Switchgear equipment, Feeders, Cables and other connected equipment/switchgear with a fast separation of the faulty part & accordingly following electrical protections are provided for each equipment.

Generator & Transformer

87G	Generator Differential
64G1/64G2	95% & 100% Stator Earth Fault
64R*	Rotor Earth-Fault
46G	Negative Phase Sequence Current
37G	Generator Reverse Power
49S	Stator Thermal Over-load
21G	Generator Back-up Distance Protection for external faults
40G	Loss of excitation
78G	Pole slipping
59G	Generator Over-voltage
81 U/O	Under/Over Frequency Protection
27/50G	Dead Machine
60G1, 60G2	Voltage Balance Scheme for VT circuit failure
87T	Generator Transformer Differential
51GT	IDMT O/C Protection for Gen. transformer
64RT	REF Protection for Gen. transformer
51NGT	Gen. Transformer Neutral Grounding Back-up Protection (IDMT O/C relay)
99GT	Generator Transformer Over fluxing
98T	Monitoring of Insulation of HV bushing for Gen. Transformer
59T	Monitoring of Insulation of LV bushing for Gen. Transformer
87GT	Overall Differential Protection for Gen. and Gen. Transformer
50U/51U	Instantaneous and IDMT O/C Protection for UAT.
64RU*	Restricted E/F Protection for UAT
51NGU*	O/C & E/F/Neutral Back up Protection for UAT
50E/51E*	Instantaneous & IDMT O/C Protection for Excitation Transformer.
50EI/51EI*	Instantaneous & IDMT O/C Protection for Independent Excitation system
50S/51S	Instantaneous & IDMT O/C Protection for SAT
64RS*	Restricted E/F Protection for SAT
51NGS*	O/C & E/F/Neutral Back-up Protection for SAT
50Z	Local Breaker Backup Protection
63T*	Buchholz Relay for Gen. Transformer
95G	Split Phase Protection for inter-turn fault

Protections for HV Buses

87AB	Differential main & stand by Protection for each bus bar (High impedance or low impedance)
50Z	Local Breaker Back-up Protection (for bus coupler)

Protections for Shunt Reactor

87R	Differential Protection
50Z	Local Breaker Back Up Protection
64RR	Restricted Earth Fault Protection
21R	Reactor Back Up Distance Protection

Protections for HV Cables for each feeder

85	Differential Protection
67/67(N)	Directional Over current and earth fault back-up protection

Protections for Transmission line

21L1	Line Distance Protection Main-I
21L2	Line Distance Protection Main-II
59L1	Over Voltage Protection
59L2	Over Voltage Protection
79L	Auto Reclose Relay
50Z	Local Breaker Backup Protection

Summary

Microprocessor comprises a Central Processing Unit (CPU) of a digital Computer. A microprocessor is housed in a DIP.

Microprocessor performs digital data processing functions in protective relays. Microprocessor based relays are being increasingly used for busbar protection, line protection, motor protection etc.

Special features of microprocessor based relays are their self-checking properties, multi-function capabilities, memories, facilities for disturbance recording, fault locating, external communication interface, etc.

Microprocessor based relays are becoming commercially successful and they are replacing earlier analog relays.

QUESTIONS

1. Describe by means of a block diagram the various essential components in a Digital Relay (Ref. 43.19).
2. Explain how a decimal number is represented in a Dual (Binary) Code (Fig. 43.20).
3. State the various components in a Microprocessor based Microcomputer (Fig. 43.25*a*).
4. Explain the term 'Microprocessor' and State its functions.
5. Explain the bus system in a Microprocessor based minicomputer (Fig. 43.26). State the functions of
   (*i*) CPU (*ii*) ROM
   (*iii*) RAM (*iv*) Interface
6. State the functions of following components in a Microprocessor based relays.
   (*i*) Buffer (*ii*) Program Memory
   (*iii*) Data Memory (*iv*) ALU
   (*v*) Register (*vi*) Clock
   (*vii*) Control and Timing Unit
7. State and Explain the special features in a Digital Relays as compared with analog relays.
8. Explain the function of Self checking/Monitoring feature in a Microprocessor based Relay.
9. Explain the function of fault by recorder by means of a block diagram.

43-C

Modern Protection System — A Summary

43.34. INTRODUCTION

Electrical Relays made the operation and performance of any electrical installation safe & to a large extent hazard free. The first generation electro-mechanical relays or devices performed their main functions of alarm or trip effectively. However, their utility was limited to those functions only for which they were intended *i.e.* trip & alarm to. It also involved lot of hard wire connections ; Subsequently with the passage of time, Static relays & integrated circuits were introduced for to most of the protective functions.

These static & integrated circuits could were successful in combining few protective relay functions but it did help much in reducing the quantum of cables or in information exchange from the relay to the operator the control room.

The advent of technology has now made it possible to talk to the relays, this has become possible through modern numerical relays. These relays not only perform protection functions, but also provide auto-closing, measurements, disturbance recording & above all communication facilities & software programmable through standard functions and algorithms. They can be integrated with Modern Supervisory & Data Acquisition (SCADA) System.

43.35. NUMERICAL RELAYS

Numerical relays are digital devices designated to carry out protection functions of various electrical equipment such as generator, transformer, transmission lines, motor etc. As opposed to the electro mechanical and static relays which take the inputs from the current and voltage transformers directly, the digital relays/numerical relays take the transduced form of the current and voltage outputs from the current and voltage transformers normally in the range of 0-20 mA or 4-20 mA. The analog signals so taken as inputs are filtered squared and digitized. The protection algorithms take these digitized inputs to perform the calculations necessary to achieve the protection functions for which that particular numerical relay is designed.

Numerical relays are being used for electrical protection functions such as:

— Differential protection
— Overvoltage protection
— Stator earth fault protection
— Negative sequence protection
— Distance protection
— Restricted earth fault protection
— Over current protection
— Thermal overload protection
— Loss of excitation protection
— Over excitation protection etc.

All the protection functions which can be achieved with the static protection relays are achieved by the numerical relays also with the same or better accuracy. The numerical relay achieves a lot many functions such as man-machine communication, connectivity to remote computers, networking etc.

In addition to the above, there are some protection functions, which are achieved with a lot of difficulties using static circuits, and still the final outcome is not quite satisfactory. One example

of such a protection is negative sequence current function. This protection is designed to operate above a particular limit of unbalance in the load connected to a generator. The negative sequence currents result in heating of the rotor of the generator. The analog circuit for this protection requires 120° phase shifting network, which requires sinusoidal currents. In a numerical relay, the negative sequence current is calculated by summing sampled of R, Y and B taken at 0°, 240° and 120° intervals respectively. From this summing, the I_2^2 value is calculated. This value is zero even for non-sinusoidal currents as the three phase currents for the same amplitude to wave shape and also they are phase displaced by 120°.

Advantages of numerical relays

— The output of one current transformer can be used as input to many protection functions.
— The burden on current transformers is substantially reduced due to a very low burden imposed by digital circuits.
— As many functions are done by one numerical relay, a lot of space is saved by eliminating independent relays for each of the functions.
— The settings can be done from a remote computer or the local MMC.
— The service and faulted values of the relays can be accessed either from a remote computer or from the local MMC.
— Selection from a variety of characteristics is possible. This will be useful if one feels the necessity to alter the originally selected curve/characteristics based on operation experience.
— Some of the latest numerical relays share the same hardware for protection of different electrical equipment such as generator, transformer and transmission line. Only the specialized software required for carrying out these protection functions needs to be changed. This helps in reduction of inventory, as most of the modules are interchangeable among the different numerical relays.
— The software can be programmed/modified at site to change the tripping logics such as inclusion of timer, changing of tripping sequence etc. Due to self-supervision feature, internal faults in the relays are detected as and when they occur and as such, there is no necessity of periodical testing of these relays.
— Due to reduction of number of components and also due to the fact that circuits are provided with built in control to prevent mal-functioning, the numerical relays will also increase the security compared to the static relays.
— Recursive algorithms can be achieved easily on a numerical relay. But, precise tuning is required in case of analog circuits.

However, with all the above advantages & convenience they offered, the numerical relays, suffered from one major draw back *i.e.* not understanding & interpreting the language of other relay, if the vendor is different. This problem is referred to as Protocol matching. This problem arised because now a days, the majority of the protection and control equipment is available with vendor specific hard ware-oriented solutions which has given rise to a large number of manufacturer oriented communication Protocols making it in convenient & costlier to make the two systems of different manufacturers to communicate with each other:, even devices belonging to different generations from the same manufacturer cannot communicate with each other & to make them do so involved an appreciable expenditure.

43.36. TRADITIONALLY SEPARATE NETWORKS

Over the years, networks have been developed to respond to the different information flows and control requirements involved in different processes. The usual corporate IT network supports traditional administrative functions and corporate applications, such as human resources, accounting, and procurement. This network is usually based on the Ethernet standard.

The control-level network connects control and monitoring devices, including programmable logic controllers, PC-based controllers, I/O equipment, and human-machine interfaces (HMIs). This network, which has not been Ethernet in the past, requires a router or, in most cases, a gateway to translate application-specific protocols to Ethernet-based protocols. This translation lets information pass between the control network from the field and the corporate network infrastructure.

The device-level network links the field I/O devices, sensors, transducers and actuators, etc. Inter-connectivity between these devices was traditionally achieved with a variety of field buses such as Device Net, Profibus, and Modbus. Each field bus has specific power, cable, and communication requirements, depending on the application it supports. This has lead to a replication of multiple networks in the same space and the need to have multiple sets of spares, skills, and support programs within the same organization.

Instead of using multiple networks architectures, Industrial Ethernet can unite an organisation's administrative, control-level, and device-level networks to run over a single network infrastructure as shown in Fig. 43.39. In an Industrial Ethernet networks, field bus-specific information that is used to control I/O devices and other manufacturing components is embedded into Ethernet frames. Because the technology is based on industry standards rather than on custom or proprietary standards, it is more interoperable with other network equipment and networks.

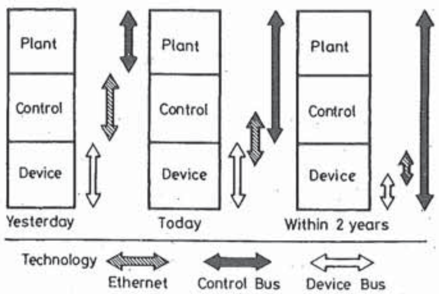


Fig. 43.39. Growth of Ethernet to device level.

43.37. ETHERNET JUST A PHYSICAL LAYER STANDARD

Ethernet has been successfully used in the office automation for many years. It was originally invented by Robert Metcalf at Xerox in 1973 and patented in 1976 and further promoted by Digital and Intel. It is typically used in office local area networks that later evolved into the IEEE 802.3 specification. Today this technology can deliver performance from 10 Mbps (10 BASE-T) to 10 Gbps (10 gigabit Ethernet) on twisted pair copper cables to fibre optics.

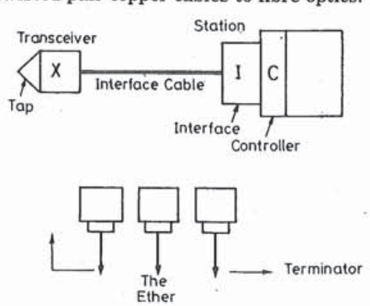


Fig. 43.40. The famous original concept drawing of Ethernet by it's inventor.

The industrial world is now catching onto Ethernet as a supplement to existing field buses. In an Industrial Ethernet network, field bus-specific information that is used to control I/O devices and other manufacturing components are embedded into Ethernet frames. Industrial Ethernet usually requires more robust equipment and a very high level of traffic promotization as compared to traditional Ethernet networks in a corporate data network.

Ethernet is achieving more acceptance in the industrial automation world, but Ethernet in itself is just a physical layer standard and various type of application layer protocols can be used on this medium.

43.38. THE IEC's INITIATIVE

Currently IEC too has the following three distinct standards for network access, protection equipment and tele-control :

— IEC 60870-5-101 Companion standard for basic tele-control tasks.

— IEC 60870-5-103 Companion standard for the informative interface of protection equipment.

— IEC 60870-5-104 Network access for IEC 60870-5-101 using standard transport profiles.

IEC-60870-5-103 standard is generally in the monitoring direction for protective equipment but various manufacturers use the private range of the standard through a few extensions defined by the so-called German VDEW-recommendations for implementing some of the control functions through IEC 60870-5-103. The nonuniformity of using the private range by various manufacturers in their own way makes the products non inter-operable with the products with IEC 60870-5-103 standard.

With a goal to provide uniform standard for inter control center communication and substation to control center communications, a new international standard called IEC 61850 - "Communication Networks and systems in substations" has been developed. This will provide inter operability & free allocations functions between the electronic devices (IEDs) for protection, monitoring, metering, control and automation in substations ; This new standard is expected to provide optimally designed systems in terms of functional performance, cost, availability, expandability and maintenance.

IEC 61850 divides the data into logical groups, viz., protection data, switchgear data (status data), measurement data, supervisory control, power transformer, etc. All the functions performed in a substation are split into small entities, which communicate with each other. These entities or objects called Logical Nodes contain all the function related data and their attributes to be communicated. All the Logical Nodes of a common application are grouped in Logical Devices. This function model has to be a complemented by a physical device model, which describes the common properties of the device. On occurrence of any change of state, IED multicasts a highspeed message called Generic Object Oriented Substation Event (GOOSE) message.

The data model including its services is mapped to a mainstream communication stack consisting of MMS, TCP/IP, and Ethernet.

The IEC 61850 standard is now near its completion. Utilities and manufacturers have been involved in the standardisation work since the beginning, and have taken part in pilot projects and interoperability tests, which have been positive.

IEC61850 is a single, global and future-proof standard for substation communications which safeguards the investment of the end user because the development of the communication network is independent of the development of applications. Besides it provides the benefit of the latest communication technologies for enhancing the performance of the controls and protection system.

Details of IEC 61850 are described separately.

IEC 61850 - Concept, benefits & design

1. Concept

The main goal of IEC 61850 is Interoperability, *i.e.* the ability of Intelligent Electronic Devices (IEDs) from one or several manufacturers to exchange information and to use it to perform the functions in an automation system. 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.

Operational information and configuration information are transferred in client-server mode. Operational information, such as status and control, is standardised and of medium priority. Configuration information, such as file transfer and changing settings, is of low priority. Two further types of message are exchanged under stringent real-time conditions. The first type of message contains one or a few bits of information and is mostly for blocking, release, tripping, indication of position of switchgear in automatic sequences, interlocking, protection as well as for other data exchanges between peer devices. This type of message is called Generic Object-Oriented Substation Event (GOOSE). The other type is for Sampled Values, used for sending streams of analogue data such as current and voltage samples. To attain proper performance, both types of message are mapped directly to the Ethernet; the second layer of the seven-layer communication stack, without going through MMS or TCP/IP.

The Abstract Communication Services Interface facilitates the mapping of the generic data and services to the communication stack. The applications and the stack are thus separated, allowing the communication technology to be upgraded and the existing databases of the applications to be left intact. This feature makes the standard IEC 61850 future-proof.

IEC 61850 also states the engineering process and makes available the Substation Configuration description Language (SCL). The precise descriptions of the IEDs, the substation configuration and other configuration related information can be read by any tool compatible with the standard.

The standard also defines conformance testing of products so that interoperability may be checked, ensuring the successful integration of devices from a variety of manufacturers to form a seamless system.

2. Benefits

Compared to IEC 60870-5-103, DNP3 or proprietary communication protocols, IEC 61850 offers much more benefits to the utilities. Some of these benefits are immediately tangible on the substation automation systems. Other benefits will take time to transpire because:

- Getting the full value of the standard requires
  - accepting new designs e.g. moving away from master-slave to client-server communication,
  - using process bus,
  - new ways of managing assets.
- While the technology starts best on greenfield sites, a large proportion of the projects involve mixing legacy existing devices with new ones, and the benefits due to the new devices can only show themselves to a limited extent.
- Staff often have a natural reluctance in accepting a new technology.
- Not all the advantages of interoperability can be appreciated at the start.

IEC 61850 is applicable within a substation. Work is in progress to extend this method of standardising communication up to the control centres, aiming at seamless data-flows from the processes in the switchyard to the highest control level. The substation data-model is already harmonized with the Common Information Model from IEC 61970. The result of this standardisation will further simplify the specification of substation automation systems.

3. Design

The design stage aims at defining the data flow and infrastructure of the substation automation system.

The underlying Ethernet layer facilitates the design process through the use of mainstream communication technology. For example, Ethernet switches possessing properties such as collision avoidance, optimisation of the messages being transmitted, priority management, are readily available and need no further detailed design, except any additional precautions in the electronics-hostile substation environment. Re-using an existing Ethernet infrastructure also means little new design work. Transferring both real-time data, settings and disturbance files on a common 100 Mbit/s network means fewer systems to deal with. Note that the co-existence of critical and non-critical data on a common network running on other protocols such as RS485 at 64 kbit/s, is impossible without compromising one type of data or another.

Allowing fast peer-to-peer data transfers by means of the multicast messages, Ethernet eliminates physical wiring between devices of most suppliers in substations, for instance, for interlocking and co-ordination of disturbance recorders. This reduces the amount of hardware and also permits adjusting the system easily in the future. For example, changing a database is much simpler than adding wires which sometimes need take voltage insulation into consideration. New automation schemes can be accommodated and would incur little design work.

The availability, or reliability, of master-slave systems from most suppliers depends largely on the availability of the master device. IEC 61850 systems have no master devices. Client-server communication enables redundancy to be built in easily. It improves the flexibility of the system. A new client such as a permanent local voltage regulator for several transformers or a temporary remote monitoring device of a transformer, can be added to the initial design of the system through the same software. Client-server communication leads to better performance, as data are spontaneously sent to the client without the polling from a master device. Data transmission may be initiated by the change in the data value, and the change criteria may be adjusted from remote.

4. Installation and commissioning

The installation and commissioning stage aims at testing the system to make sure it works according to the specifications.

The Ethernet network can be checked by means of standard tools. The Internet Protocol (IP) enables messages to be routed to a remote location where commissioning personnel can view system status and give expert advice. When the system under test spreads over an entire substation, testing staff can plug the Human Machine Interface to any Ethernet switch close to the equipment under test and see simultaneously all the alarms, control points, etc. Likewise, a simulator can be connected to the Ethernet to check the automation functions when the corresponding devices are still not available.

Some built-in features of the standard also directly facilitate commissioning. For instance, when a sensor is not yet in service, the Substitute function can be used to emulate the data it would have given to the IED corresponding to the sensor. The management of the function mode *i.e.* the capability to remotely set a function 'in' or 'off' service, together with the client-server communication, offers the opportunity to progressively commission the system. This means the commissioning of a substation automation system can start before all the equipment is delivered to site.

5. Operation and maintenance

The operation and maintenance stage aims at identifying the possible faults and failures, and at expanding the automation system in accordance with the overall business strategy of the utilities.

Independent of system operations, security can be built easily on communication level into the substation automation system with the aid of commercially available firewalls and routers which hide IP addresses. Operational information can be grouped and access limited to only designated personnel.

A substation automation system compliant with IEC 61850 can be easily extended to include new automation devices, primary equipment, bays or new voltage levels.

Although the management and the rules are yet to be defined, version numbers are mandatory in the SCL and the logical parts of an IED. Being able to keep track of versions of IEDs is vital to the long-term maintenance of the system, and this feature is unavailable in other communication standards.

6. Migration

General. Products compliant with IEC 61850 are available from 2004 onwards, and utilities wishing to

— safeguard investment

— seek a cost-optimised solution over the life-time of the substation

— improve the availability of the substation

are incorporating these products into their systems. The products are mostly introduced into the market step by step. For new substations which can be served by the available IEC 61850 compliant products, only IEC 61850 solutions are expected to be used and in this case, migration is largely irrelevant.

Some new substations may still need to be equipped with non-IEC 61850 devices. Utilities may also integrate IEC 61850 devices into existing substations through gradual replacement of old equipment or the addition of new bays. In these substations, equipment based on other communication standards/protocols needs to function together with IEC 61850 devices until.

Upgrading Devices. If supported by the original design, a device can be upgraded directly, for instance by adding a communication board and upgrading the software to some extent. The parameters would need to be adjusted. This looks attractive but would generally need relatively recent devices. The replacement of the communication system is beneficial only if retrofit or upgrading at the station level is also carried out, and this means some additional engineering work.

For this migration strategy, two options are possible. One option is upgrading all the devices in the substation. The other option is upgrading the devices step-by-step in groups, for example, according to bays. For the second option, the old and new devices would need to function together.

Existing Systems side-by-side with IEC 61850 System. Many existing automation systems already support a number of protocols. The IEC 61850 devices are brought in initially as adding an additional protocol. The IEC 61850 system is gradually expanded and the other non-IEC 61850 devices are phased out. In general, there is a central point to which systems running on different protocols are connected and where protocol conversions take place. To keep the migration costs low, it is important that the protocol conversions are performed only at this point. Special attention shall be paid to distributed automation with real-time constraints because many legacy protocols are unsuitable for handling time-critical data.

In a substation with merely a few devices running on another protocol, the newly incorporated IEC 61850 system would be the dominant system. The existing system would be considered as a subsystem, *i.e.* a data server of the IEC 61850 system. It may support some standard protocols such as DNP3 or IEC 60870-5-101. The existing system is connected to the IEC 61850 system via a gateway that carries out the protocol conversion between the legacy protocol and IEC 61850.

In general, these migration paths are suitable for the following three scenarios:

— The automation system is replaced step by step.

— The substation is extended with additional bays.

— Individual devices are upgraded step by step in groups.

43.39A. Numerical Control & Protection Unit

The numerical control unit (REC 316*4) is a compact multi-functional unit belonging to PANORAMA. It is designed for the control, metering, monitoring, automation and protection functions of MV and HV transmission systems. Simply programmable standard functions from a comprehensive software library and a powerful and last function block language make the unit a user-friendly and extremely flexible terminal.

The control of switching objects is performed with the highest possible supervision and safety. A large selection of protection functions reduces the number of necessary devices in HV bays through the combination of control and backup protection functions in one unit. The integrated autoreclosure function can be utilized by both main protection devices.

The closure of the circuit breaker can be supervised by a synchrocheck function. Motor busbars can be switched on with phase synchronization by a fast switch-over function.

A part from the operating asset protection in cooperation with function block engineered modules using the CAP 316 to tool, the multi-configurable frequency function allows the generation of intelligent load shedding automatic. Automatic network restoration is enabled by integrating the REC 316*4 into a station control system.

For metering the quantities current, voltage real power, apparent power and frequency are available. In addition the transmission of energy counting impulses to the control system is possible. The recording of disturbances switching operations and analog results of protection functions is performed by the integrated disturbance recorder.

The REC 316*4 belongs to the generation of fully numerical control and protection terminals *i.e.* analogue to digital conversion of the input variables takes place immediately after the input transformers and all further processing of the resulting numerical signals is performed by microprocessors and controlled by programs. Resulting numerical processing ensures consistent accuracy and sensitivity throughout its operational life.

REC 316*4 is noted for its process interface, satisfying the highest EMC requirements as well as for the standardized serial interfaces for integrating into a control system. This enables an information exchange both in a vertical direction with systems of higher order and in a horizontal direction between various bay control units.

Because of its compact design, the very few hardware units is needed, its modular software and the integrated continuous self- diagnostic and supervision functions, it ideally fulfills the user's expectations of a modern control and protection terminal at a cost effective price. The availability of a device, *i.e.* the ratio between its mean time in service without failure and the total life, is most certainly its most important characteristic.

The menu-based HMI (Human Machine Interface) and the terminal's small size makes the tasks of connection, configuration and setting simple. A maximum of flexibility, *i.e.* the ability to adapt the protection for application in a particular power system or to coordinate with, or replace units in an existing control and protection scheme, is provided by the extensive library of standard functions and the powerful function block engineering. The free assignment of input and output signals is enabled via the HMI.

The hardware concept for the digital control unit comprises four different plug-in units, a connecting mother PCB and housing (Fig. 43.40A) :

— analog input unit

— 1 to 4 binary input/output units

— connecting mother PCB

— central processing unit

— power supply unit

— housing with connection terminals.

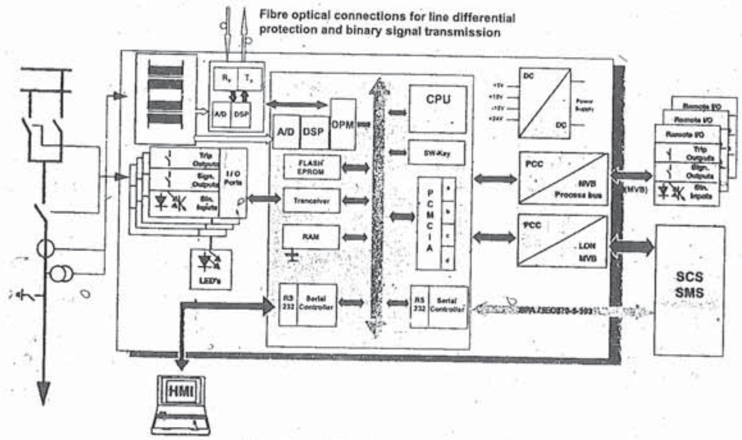


Fig. 43.40A. Hardware platform overview.

In the analog input unit an input transformer provides the electrical and static isolation between the analogue input variables and the internal electronic circuits and adjusts the signals to a suitable level for processing. The input transformer unit can accommodate a maximum of nine input transformers (voltage, protection current or measuring transformer).

Every analog variable is passed through a first order R/C low pass filter on the main CPU unit to eliminate what is referred to as the aliasing effect and to suppress HF inter ferences (Fig. 43.40B). They are then sampled 12 times per period and converted to digital signals. The analog/digital conversion is performed by a 16 Bit converter.

A DSP carries out part of the digital filtering and makes sure that the data for the protection algorithms are available in the memory to the main processor.

The processor core essentially comprises the main microprocessor for the protection algorithms and dual-ported memories (DPMs) for communication between the A/D converters and the main processor. The main processor performs the protection algorithms and controls the local HMI and the interfaces to the station control system. Binary signals from the main processor are relayed to the corresponding inputs of the I/O unit and thus control the auxiliary output relays and the light emitting diode (LED) signals. The main processor unit is equipped with an RS232C serial interface via which among other things the protection settings are made, events are read and the data from the disturbance recorder memory are transferred to a local or remote PC.

On this main processor unit there are two PCC slots and one RS232C interface. These serial interfaces provide remote communication to the station monitoring system (SMS) and station control system (SCS) as well as to the remote I/O's.

It has one to four binary I/O units each. These units are available in three versions :

(*a*) two auxiliary relays with two heavy-duty contacts each, 8 optocoupler inputs and 6 signalling relays.

(*b*) two auxiliary relays with two heavy-duty contacts each, 4 optocoupler inputs and 10 signalling relays.

(*c*) 14 optocoupler inputs and 8 signalling relays.

According to whether one or two I/O units are fitted, there are either 8 LED's or 16 LED's visible on the front of the terminal.

Both analogue and binary input signals are conditioned before being processed by the main processor. As described under hardware above, the analogue signals pass through the sequence input transformers, shunt, low-pass filter (anti-aliasing filter), multiplexer and A/D converter stages and DSP. In their digital form they are then separated by numerical filters into real and apparent components before being applied to the main processor. Binary signals from the optocoupler inputs go straight to the main processor. The actual processing of the signals in relation to the protection algorithms and logic then takes place.

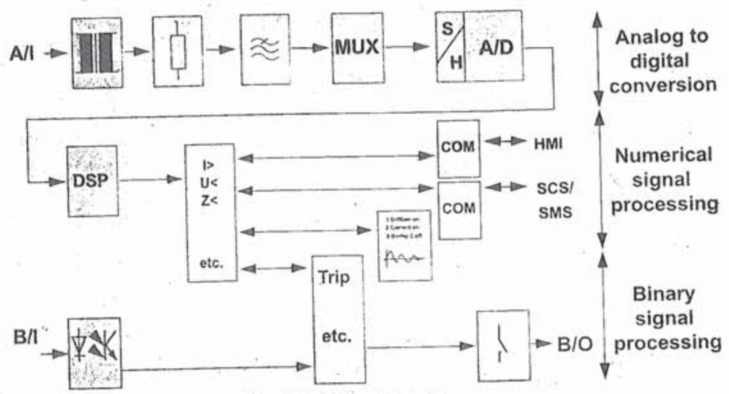


Fig. 43.40B. Signal data flow.

43-D

Microprocessor Based Substation Protection Control and Monitoring

Introduction to Microprocessor based Control, Protection and Monitoring — Two hierachical levels — Substation level, Unit Level, Functions in substation level, Functions in Unit levels — Integrated communication — Summary.

43.39. INTRODUCTION

The basic variable related with the Substation protection, Control and Monitoring include the following :

(*i*) Current (*ii*) Voltage,
(*iii*) Frequency (*iv*) Time,
(*v*) Power Factor, Reactive Power, Real Power, Temperature.

The electrical energy is transferred from large generating station to distant load centres *via* the various substations. In every substation certain measurements, supervision, control and protection functions are necessary. Every substation has a control room. The relay and protection panels and control panels are installed in the control room. The various circuit breakers, tap changes and other devices are controlled by corresponding control-relay panels. In a small independent substation, the supervision and operation for normal service can be carried out by the operator with the aid of analog and digital control systems in the plant. The breakers can be operated by remote control from the control room. During faults and abnormal conditions, the breakers are operated by protective relays automatically. Thus the primary control in substation is of two categories:

1. Normal routine operation by operators command.
2. Automatic operation by action of protective relay and control systems.

Traditionally, the protective system comprising of relays and circuit-breakers was almost independent of control system for tap-changer control, voltage control, data logging, data monitoring and routine operations. This concept is shown in Fig. 26.1 for Circuit-breaker control and Fig. 25.1 for Protective Zone. In traditional substation control the three functions (1) Protection (2) Control (3) Monitoring are not integrated fully. In modern interconnected systems, the functions are interlinked by means of digital processing devices and power carrier communication links (Fig. 43.1).

43.40. EQUIPMENT TO AUTOMATIC CONTROL SUBSTATIONS

The following equipment (either fixed-wired or/and programmable) is used for various tasks in Network Automation.

(*i*) data collection equipment
(*ii*) data transmission telemetric equipment
(*iii*) data monitoring equipment
(*iv*) data processing equipment
(*v*) man/machine interface.

The data (information) regarding various power-system variable is necessary for effective supervision, operation and control. This data can be broadly classified as :

(*i*) data regarding generating plants and power station

(*ii*) data regarding transmitting stations (sub-station)

(*iii*) data regarding conditions of supply region, receiving stations.

The equipment for protection, control and automation are installed in control rooms of :

(*i*) Load Control Centres (*ii*) Transmission substations

(*iii*) Distribution substations (*iv*) Generating Stations.

These control rooms are in communication *via* Power Line carrier communication system (PLCC).

In traditional hard wired systems are relays and circuit breaker operate during abnormal operating conditions. The routine and emergency control functions are performed at individual 'Unit' level systems with the held of substation equipment such as circuit-breaker, tap chargers etc. Control and monitoring functions are performed by separate equipment installed on respective panels. Each substation control room operated almost independently all instructions are received from Control Centre *via* Power Line carrier telephone communication link.

With the present trend and availability of powerful microprocessors a low price, the protection, control and monitoring system in substations have undergone a radical change. The system architecture now includes, microcomputer based digital system control protection and monitoring systems installed in (1) load control centres (2) Substation control Room (3) Generating station control room. The control and protection systems are integrated and there is interaction and information transfer by means of communication channels.

43.41. TWO SUBSYSTEMS IN SUBSTATIONS

The protection control equipment in a substation are to be treated as two sub-systems :

1. Control System 2. Protective System.

For many reasons, it is desirable to have two separate systems as above.

The relay protection system should acquire the data independently, process it, evaluate it and take action to perform protective tasks (tripping).

The different events are reported to the control system as well as protective system. Both the systems must, therefore, co-operate closely with one another.

In modern substation, these functions are realised with relays, static processing devices and micro-computers.

The tasks of protective systems include sensing abnormal condition, annunciation of abnormal condition alarm, automatic tripping, back-up protection protective signalling etc.

The tasks of control and monitoring system in a substation include data collection, scanning event reporting and recording; voltage control, power control, frequency control, other automatic and semi-automatic control etc.

The two systems work in close co-operation.

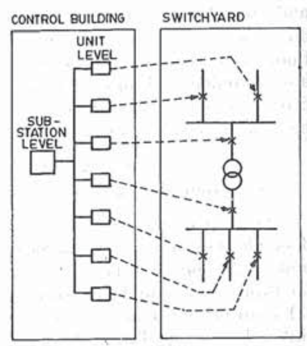


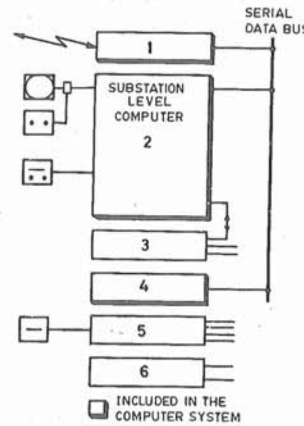
Fig. 43.41. Configuration of protection and control in a substation in two levels.
1. Substation Level 2. Unit Level

43.42. TWO HIERARCHICAL LEVELS IN A SUBSTATION

Two protection and control equipment mentioned above are generally arranged it two hierarchical levels. *From the higher (substation) level, the entire substation is controlled and supervised.*

From the lower (unit) level, the lines, transformers etc. are controlled and supervised. The equipment on unit level is divided into a number of independent units, each controlling one unit. This division improves the operating reliability and simplifies future extensions such as additional lines.

1. Upper level (substation control level)
2. Unit level (Equipment level Transformer, line, busbar, reactor etc.) Also included are,
3. Inter level communication
4. Man-machine interface
5. Interface with load control centre.



1. Remote control adaption
2. Man machine communication, supervision, (Automatic control)
3. Synchronising equipment
4. General Unit
5. Disturbance recorder
6. Busbar protection

Fig. 43.42. Functions in substation level.
(Most functions are stored in substation level computer.)

43.43. SUBSTATION LEVEL (UPPER LEVEL)

The following main functions are arranged in substation level. Automatic functions, supervisory functions. Man-machine communication, Busbar protection.

(*i*) Ordinary man-machine communication system of the substation.

(*ii*) Remote control inter-face.

(*iii*) Synchronising

(*iv*) Disconnector Inter-locking

(*v*) Busbar Protection (Relay Protection) System

(*vi*) Fault annunciation

(*vii*) Automatic Network restoration

(*viii*) Automatic Switching sequences

(*ix*) Load Shedding/Load re-connection

(*x*) Voltage control

(*xi*) Compiling of energy and other reports

(*xii*) Disturbance recording

(*xiii*) Sequential events recording.

Most of these functions are integrated as softwares in the sub-station level computer. This software is of modular-design, which facilitates addition of new functions. Table 43.8 gives the categorywise classification.

Table 43.8
Classification of Function at Substation Level (Upper Level)

Protection	Busbar protection
Automatic functions	Synchronising voltage regulation load, switching, power system restoration sequential operations etc.
Supervision	Fault annunciation, sequential events recording disturbance recording, energy reports, self supervision of the electronic system, fault statistics.
Man-machine Communication.	Operations and indications, interlocking of disconnectors adaption to remote control facilities etc.

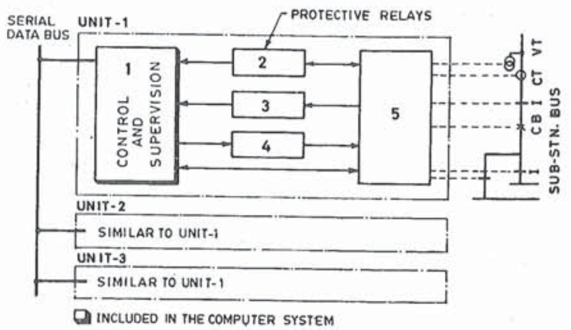


Fig. 43.43. Line Unit Level. Functions stored in programs of unit level microcomputer.

1. Unit level microcomputer, control, supervision of circuit breakers, disconnectors, time-tagging events auto-reclosing etc.
2. Protective Relays 3. Energy Metering 4. Synchronising checks 5. Switchgear Interface

Most of the functions are stored in the substation level computer in the form of software. The software is modularised to facilitate the incorporation of new functions and to simplify future extension of the station. Because of the considerable amount of data to be processed disturbances are registered in a separate unit.

43.43.1. Unit Level

The entire substation is divided into certain 'Units' (Similar to protective zones) which include one or two major equipment such as line, sub-bar section, transformer, etc.

The functions relating to particular unit include the following :

— Line Protection, Breaker Failure Protection, etc.
— Auto reclosing
— Synchronising check
— Energy metering
— Acquisition and time tagging of events
— Acquisition of position indication and measured values
— Execution of commands from substation-level computer
— Back-up control.

Table 43.9 gives categorywise classification.

Table 43.9
Classification of functions of Unit Level

Protection	Line protection, transformer protection, breaker-failure protection, reactor protection etc.
Automation	Auto-reclosing, synchronising checks.
Supervision	Supervision of position of Circuit-breakers, disconnectors, recording of events, energy metering, self-supervision of electronic system fault location on line etc.
Inteface	Switchgear interface, electronic system interface.

Functions which refer to a particular unit are located at unit level. Units are mostly independent of each other. Fault occurring in one unit does not influence other unit control and protection Equipment for each unit is located in a cubicle for that unit.

43.43.2. Inter-level Communication

Information is transferred between the two control levels primarily *via* a serial data bus, where the substation level computer controls the traffic by cyclic boiling the other units connected to the bus. The substation oriented acquisition signals and the serial transmission of information, between the control levels reduces the amount of cabling and terminal blocks.

Table 43.10
Automatic Control Functions in Substations

Auto-reclosing	Single phase or three phase auto-reclosing of line circuit-breakers.
Automatic Synchronising	Check phase sequence, frequency, voltage levels Coincidence of phase voltages and close the circuit-breaker.
Automatic Voltage regulation	Regulate bus voltage by tap-changing and shunt compensation.
Automatic Power restoration	Make attempt for restoration after unsuccessful autoreclosing and after substation blackout.
Sequential operations	Predetermined switching sequences *e.g.* load transfer from one bus to another.
Load shedding	To shed predetermined load when frequency falls. Check for voltage rise.

Table 43.11
Protective function in a substation

1. Detection of fault at the earliest
2. Prevent or minimise damage
3. Disconnect faulty line
4. Detect phase to phase faults and phase to ground fault
5. Overloading protection
6. Overheating prevention
7. Overcurrents prevention
8. Abnormal voltage prevention.

Requirements of Protection and Control Equipment in Substations

The various protection and control functions in a substation have to fulfil certain requirements originating from the power system and the high voltage equipment in the station but they also must fulfil network operation and stability requirements. From the protection and control architecture point of view these main requirements are :

1. **Dependability.** The dependability of a function is the probability that the function will be executed correctly when wanted.

2. **Security.** The security of a function is the probability that the function will not be performed when unwanted.
3. **Degradation withstand capability.** Degradation is the percentage of individual functions that will be inoperative by a single failure in the protection and control system.
4. **Back up Protection.** Principally, the fault clearing ability can not be allowed to be lost. The required degree of dependability in the fault clearing function can be met only with back-up functions. These can be of two types; remote or local.

Remote back-up functions will of then be necessary 'locally' in a station. The transformer over-current protection is often the back-up for the line protection in case of line fault. The totally performed remote back-up requires a separation of the two functions, so that both are not lost simultaneously at a single fault in the protection of control equipment.

43.44. FUNCTIONS PERFORMED BY PROTECTION AND CONTROL EQUIPMENT

The different functions performed by the protection and control equipment in a substation or power station have to be grouped for analysis of the architecture. This grouping of the different functions is not associated directly with a physical separation of the equipment and the function groups will be used only to identify factors that influence the realization of the structure.

The function groups below are used in a typical architecture :

(*i*) Fault clearing functions sub 1

(*ii*) Fault clearing functions sub 2

(*iii*) Emergency control functions

(*iv*) Non-emergency control functions

(*v*) Acquisition of information for analysis

(*vi*) Man/machine communication for service and maintenance.

The function group above are defined as strict groups of functions. Thus, the group will include all components to perform the function. A specific component can be associated with more one group. For the following discussion we have to strictly associate the groups with functions and level out aspects concerning realization and component specification.

An abnormal condition will, after a time develop into a main component fault if no preventive measure is taken. This preventive measure can either restore normal operation or result in a safe status where a part of the system is out of operation.

The fault clearing will separate the faulty part from the system and thus change the status from power system fault condition to a safe condition. The required function for a specific type of station will not be discussed, only their association with the function groups.

Fault clearing functions sub 1

Fault clearing functions sub 2

The fault clearing function include all functions for automatic fault clearing power system faults in the group clearing of line and power system apparatus faults as well as network protection. The group 'fault clearing' include basically the function performed by the protection equipment. The fault clearing functions have to be divided into two groups in cases of redundant (duplicated) protections, which are completely separated. These groups are designated 'Fault clearing function sub 1' and 'Fault clearing function sub 2'.

Emergency control functions

This group includes the functions that manually of automatically perform actions to prevent abnormal power system conditions from developing into a main component fault. The group includes protection, alarm, metering and other functions to detect abnormal conditions as well as manual and automatic control to perform the preventive measures. In case of remotely controlled stations, naturally, a part of the remote control equipment can be associated to this group.

Non Emergency Control functions

This group includes all functions for operation during non-system faults and safe status conditions. Both manual and automatic functions are included for the optimization of operation, voltage and frequency control changing at operation mode as well as other functions related to the non-disturbed operation of the network and station. In this group, manual and automatic functions for restoration of the operation after a disturbance are also included.

Acquisition of information for analysis.

This group contains functions for acquisition, storage, transmission and presentation of information to enable the analysis of network and equipment performance and behaviour both during non-system and system fault conditions. Energy management and measuring functions are also included.

Man/machine communication for service and maintenance.

This group includes the functions that enable supervision testing maintenance of the protection and control equipment as well as functions for the modification of control and protection function and setting values.

43.45. PROTECTION AND CONTROL CONFIGURATION

Integrated or modularized (decentralised) systems

Regardless of the high voltage scheme of a substation, the station can be divided into a number of separately controllable units such as line feeders transformers, busbars operated breakers and isolators. The normal protection and control structure practice is to establish two hierarchical levels for the protection, supervision and control to be provided in a substation.

Integrated equipment (centralised)

Measuring data from distributed measuring transducers are brought to a central computers *via* high-speed communication links. The central computer can perform integrated relaying and control functions.

Modularized equipment (decentralized of Centralized)

Protection and control devices, in principle according to current practice. However with increased capability of information transfer *via* the communication system. With a modularized approach a hierarchy with a unit level and station level is normally adopted.

Unit level

The unit level is related to each unit such as a line transformer, busbar, etc and is at present mainly attributed to protection functions. The protection devices are modularized and normally placed so that they can be physically identified as belonging to a specific unit.

Station level

The control functions, either manual or automatic normally handle functions that concern the overall operation of the substation and handle the communication with remote control centres.

There are functions which can not be clearly allocated to unit or station level, depending on the system design, type of equipment, functional requirements, etc. In practice some of the functions will contain a less well defined structure with a combination of unit and station level functions.

When taking the basic requirements into account, with reference to the required degree of dependability, security and degradation, a modularized approach is advantageous. The consequence of communication speed requirements and interference withstand capability should also naturally be modularized approach to decrease the information flow with the station and to isolate more sensitive equipment further back in the control system from interference. All functions that can be performed at unit level should be kept at this level.