INDUSTRIAL POWER SYSTEMS

Industrial power systems vary considerably in size, complexity, nature of loads served, and process requirements. A 500 kVA outdoor pad-mounted transformer in a radial feed arrangement connected to a lineup of low voltage motor control center serving induction motor loads, with peak demand limited to 400 kVA can be classed as an industrial distribution system. Conversely, Fig. 1 shows 13.8 kV distribution for a large industrial distribution system. Four utility tie transformers of 30/50 MVA each, and six plant generators having a total installed capacity of 270 MVA, serve a running load of 190 MVA. The excess power generated is supplied into the utility's system. Full-stream production can be sustained on forced or maintenance outage of one or more generators or utility tie transformers. While size is one aspect, an industrial distribution system is designed for the specific requirement of loads and processes. These requirements vary from industry to industry, yet the considerations of simplicity, capability of expansion, ease of maintenance, reliability, and safety are applicable to all systems.

PLANNING AND DESIGN

Load Survey

The major loads, their types, relevance to processes, and their locations are identified. Based upon the load survey, maximum demand, peak load, demand factor, load factor, and diversity factor can be ascertained. Experience shows that loads grow and a five- to ten-year projected forecast is necessary. Lack of planning leads to early retirement, due to inadequate ratings and overloads, which could have been avoided at incremental cost in the initial design phase.

Load Types

The loads can be divided into various categories, with respect to power quality requirements and processes. Some loads will tolerate a shutdown without seriously affecting the process, while the essential loads, like auxiliaries of a generator or boiler plant, must keep running under normal and contingency operating conditions. These are essential to sustain operation and to reduce downtime, to bring the processes on line after a planned or forced shutdown. A different distribution strategy, that is, double-ended substations, parallel running transformers, or automatic transfer schemes without load dropping, may be required for these loads. Electronic equipment, instruments, digital controls, PLCs, and data-processing equipment require conditioned power (see Power Quality section).

Voltage Levels

In the United States, common primary voltages of distribution are three-phase 13.8, 4.16, and 2.4 kV, respectively. The low-voltage levels are three-phase 600 V and 480 V. Three-phase four-wire 480 V, and single-phase 120/240 V systems are used for lighting installations. The American National Standards Institute (ANSI) defines systems rated $\geq$1000 and $<$100,000 V as medium voltage. Load magnitude, short-circuit ratings, voltage drops, utilization equipment availability as a function of voltage ratings, and economic considerations govern the choice. For large distribution systems, two medium-voltage levels and one or two low-voltage levels are common.

Plant Generation

Industrial plant generation can be a viable and economical alternative for some plants using recovery boilers, waste heat boilers, and process steam, that is, petrochemical and paper and pulp industries. In a noncondensing turbine cycle, high-pressure steam is introduced into the turbine and extracted for process use at one or more than one lower pressures. A coupled generator uses the energy released, and this heat-recovery cycle is called a "topping" cycle. In a "bottoming" process, waste heat from an exothermic process, that is, a furnace or kiln, is run through an expander turbine to generate electric power. Typical of power that can be generated per unit of heat energy delivered to process is 200 to 300 kWh per million kJ net heat supplied to process. A better power quality can be ensured from plant generators, as compared with utility power supply received over long transmission lines that are subjected to greater fault exposure and lightning.

Utility Service

The load requirements, maximum demand usage, projected load growth, and contingency load demand when one or more plant generators are out of service are the basic data for negotiating a contract with the power supply company. Other data and considerations are:

- Load power factor and its planned improvement
- Space for utility's substation and right-of-way for transmission lines
- Protective relaying and coordination
- Considerations of stability of plant generators operating in synchronism with utility; short-circuit duties
- Service reliability and redundant power supply arrangements

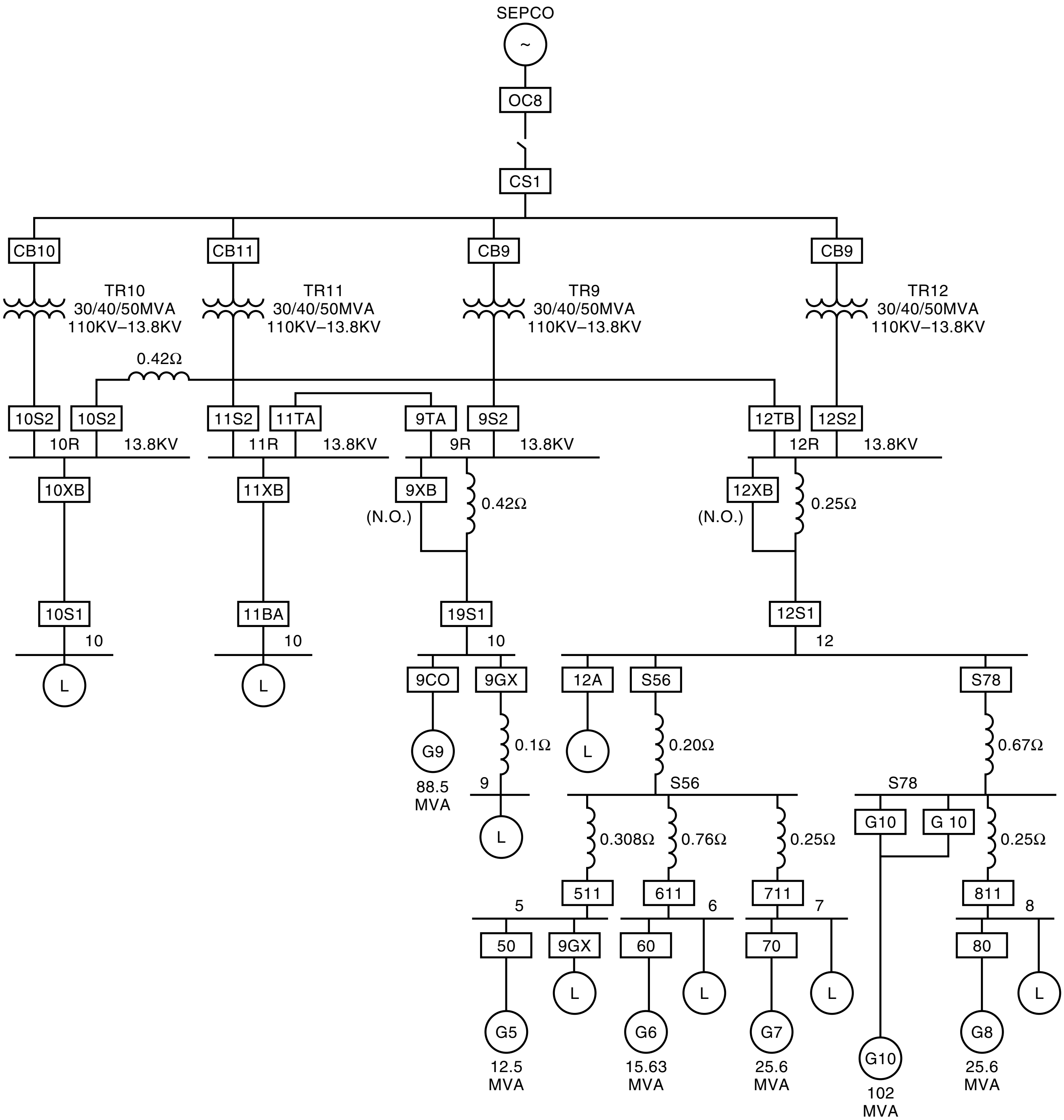


Figure 1. 13.8 kV distribution for a large industrial system (courtesy Union Camp Corporation, Savannah, Georgia).

- Bus-connections, duplicate feeders and transformers
- Starting impact of large motors
- Expected power quality and harmonic analysis

The lead time for the availability of power may be 18 to 30 months. The power supply voltages are 34.5, 69,115, 138, and 230 kV, respectively, using dedicated substations.

Single-Line Diagram

Single-line diagram shows bus arrangement, interconnections, major ratings of equipment, switching and interrupting devices, and connections to unit substations and motor control equipment. Figure 1 is an example of a single-line diagram of distribution at 13.8 kV. It is usual to develop and evaluate three to four configurations, based upon the results of the power system studies, and adopt the one that best meets the present and future load requirements.

Environmental Concerns

Electrical equipment in industrial plants may be required to operate under condition of high ambient temperatures, humidity, vibrations, exposure to corrosive atmosphere, chemical fumes, and gases. Where the equipment cannot be provided in environmentally conditioned rooms and is required to be field mounted, special enclosures and constructional features are used. These include insulated bus bars, humidity controllers, stainless steel housings and hardware, anticorrosive paints, larger electrical creepages and clearances between phases and phase to ground, and higher Basic Insulation Levels (BIL).

Hazardous Locations

Electrical and electronic equipment and wiring at all voltage levels, in locations where fire or explosion hazards exist, are tested and certified for such usage by Underwriters Laboratories Inc. (UL) in the United States. According to the NEC (National Electric Code, National Fire Protection Association), the hazardous areas are classified as follows:

1. Class I locations, where flammable gases and vapors are present in the air in sufficient quantities to produce explosive and ignitable mixtures: Depending upon the flash point of the gases, these are divided into groups A, B, C, and D. Class I locations are subdivided into Division I and Division II areas. Division I areas are those where the ignitable concentrates exist under (a) normal operation, (b) maintenance or repair or leakage, (c) breakdown or faulty operation of the processes. In Division II areas, such flammable gases are confined within closed systems or containers and ignitable concentrations are prevented by positive ventilation. Areas next to Class I Division I are classified as Division II areas.
2. Class II locations are hazardous due to presence of combustible dust. Class II groups are E, F, and G. These locations are also divided into Divisions I and II.
3. Class III locations are hazardous because of the presence of easily ignitible fibers and flyings.

A classification based upon zones (zones 0, 1, and 2), consistent with the International Electrotechnical Commission (IEC) is included in the NEC. The recognized protection techniques are: explosion proof, dust-ignition proof, and purged and pressurized apparatus; intrinsically safe systems; nonincendive circuits and components; oil immersed and hermetically sealed apparatus.

Safety

Safety of life and preservation of property are two major factors in the design of an electrical system. The following eight criteria may be laid down:

1. The installation should meet the requirements of the NEC, the Occupational Safety and Health Association (OSHA) and the National Electric Safety Code (NESC). The equipment must conform to ANSI, the Institute of Electrical and Electronic Engineers (IEEE), UL, and the National Electrical Manufacturer's Association (NEMA), all of which have published standards or equivalent acceptable standards for prevalent industrial practices.
2. All switching devices must be applied within their short-circuit ratings, and should have ample margins in these ratings for future load growth.
3. All electrical components, i.e., transformers, cables, and switchgear lineups, must have current ratings to carry their peak load demands. Intermittent and short-time duty cycles can be converted into equivalent continuous current ratings.
4. All off-load switching devices must be properly interlocked with their current interrupting counterparts. All switching conditions, which can route power over more than one alternate circuit, should have similar interlocks.
5. Protective relaying system should ensure safety, security, and selectivity, minimizing the area of shutdown and preventing nuisance trips.
6. An adequate grounding system designed for the ground fault currents involved is a safety requirement. The "step," "touch," and "transfer" potentials in a properly designed system are controlled to safe limits.
7. The system should be designed so that maintenance work on a part of installation can be carried out while the adjacent systems are powered up. This requires certain safety and work clearances to be maintained in indoor and outdoor installations.
8. Assess to electrical rooms should be limited, and danger signs and warning plates posted. Emergency lighting, escape routes, firefighting equipment, containment and handling of liquid-filled transformer spills, surveillance systems, a work force aware of safety standards and trained in plant operation, maintenance, and emergency operations are other key safety factors.

RELIABILITY

System reliability assessment, and evaluation methods based upon probability theory, which allow reliability of a proposed system to be assessed quantitatively, are finding wide application. Alternative system designs, redundancy, impact on cost of changes, service reliability, protection and switching, and system-maintenance policy can be quantitatively studied, using reliability evaluation methods, and system reliability indexes can be computed. The two basic system-reliability indexes are the load interruption frequency and expected duration of load interruption events. These can be used to compute other indexes, that is, total expected average interruption time per year, system availability or unavailability at the load supply point, expected energy demanded, but unsupplied, per year.

Data for Reliability Evaluations

Data needed will depend upon the nature of the system being studied and the details of the study. Usually, data on individual system components and the times required to do various

Table 1. Reliability Data from IEEE Reliability Survey of Industrial Plants

Equipment Category	Failure Rate per Year, λ	Hours of Downtime per Failure, r	Forced Hours of Downtime per Year, $\lambda.r$
Protective relays	0.0002	5.0	0.0010
Metalclad drawout circuit breakers			
0–600 V	0.0027	4.0	0.0108
Above 600 V	0.0036	83.1*	0.2992
Above 600 V	0.0036	2.1**	0.0076
Power cables (1000 circuit feet)			
0–600 V	0.00141	10.5	0.0148
601–15,000 V, conduit above ground	0.00613	26.5*	0.1624
601–15,000 V, conduit below ground	0.00613	19.0**	0.1165
Cable terminations			
0–600 V, above ground	0.0001	3.8	0.0004
601–15,000 V, conduit below ground	0.0003	25.0	0.0075
Disconnect switches enclosed	0.0061	3.6	0.0220
Transformers			
601–15,000 V	0.0030	342.0*	1.0260
601–15,000 V	0.0030	130.0**	0.3900
Switchgear bus—bare			
0–600 V (connected to 7 breakers)	0.0024	24.0	0.0576
0–600 V (connected to 5 breakers)	0.0017	24.0	0.0408
Switchgear bus—insulated			
601–15,000 V (connected to one breaker)	0.0034	26.8	0.0911
601–15,000 V (connected to two breakers)	0.0068	26.8	0.1822

* Repair failed unit.
** Replace with spare.

switching operations will be required. System component data required are as follows:

- Failure rates or forced outage rates associated with various modes of component failure. Table 1 shows data from the IEEE reliability survey of industrial plants.
- Expected average time to repair or replace a component
- Scheduled maintenance outage rate of the component
- Expected duration of a schedule outage event

Switching time data needed include expected times to open and close a breaker, disconnect or throw-over switch, replace a fuse link, as well as performing emergency operations, such as installing jumpers.

Method of Evaluation. The service reliability requirements of the loads and processes supplied is assessed to decide a proper definition of service interruption, that is, it is not only the total collapse of voltage, but also a voltage sag, which may cause a shutdown.

A failure modes and effects analysis (FMEA) is carried out. The FMEA for power distribution systems means listing all component outage events or combinations of component outages that result in an interruption of service at the load point being studied. Component outages are categorized as

- Forced outages and failures
- Scheduled or maintenance outages
- Overload outages

Component failure can be categorized by physical mode or type of failure. Table 2 shows failure modes of circuit breakers.

Computation of the quantitative reliability indexes can proceed, once the minimal cut sets of the system have been found. The first step is to compute the frequency, expected duration, and expected downtime of each minimal cut set. Approximate expressions for frequency and expected duration of the most commonly considered interruption events associated with first, second, and third-order cut sets for forced outages are given in Table 3.

Table 2. Failure Mode of Circuit Breakers, Percentage of Total Failures in Each Failure Mode

Failure Characteristics	Percentage of Total Failures, All Voltages
Back-up protective equipment required, failed while opening	9
Other circuit breaker failures:	
Damaged while successfully opening	7
Failed while in service	32
Failed to close when it should	5
Damaged while closing	2
Opened when it shouldn't	42
Failed during testing or maintenance	1
Damage discovered during testing or maintenance	1
Other	1
Total Percentage	100

Table 3. Frequency and Expected Duration Expressions for Interruptions Associated with Forced Outages Only

Minimum cut-sets	f_{cs}	r_{cs}
First-order minimum cut-set	λ_1	r_1
Second-order minimal cut-set	$\lambda_i\lambda_j(r_i + r_j)$	$r_i r_j/(r_i + r_j)$
Third-order minimal cut-set	$\lambda_i\lambda_j\lambda_k\ (r_i r_j + r_i r_k + r_j r_k)$	$r_i r_j r_k/(r_i r_j + r_i\ r_k + r_j r_k)$

f_s = Interruption frequency
$= \sum_{\text{min cut-sets}} f_{csi}$
r_s = Expected interruption duration
$= \sum_{\text{min cut-sets}} f_{csi} r_{csi}/f_s$
$f_s r_s$ = total interruption time over time period
Symbols:
f_{cs} = Frequency of cut set event
r_{cs} = Expected duration of cut set event
λ_i = Forced outage rate of ith component
r_i = Expected repair or replacement time of ith component

REACTIVE POWER FLOW AND COMPENSATION

Reactive power loading and losses reduce the active power handling capability of electrical equipment rated on a kVA basis. Voltage swings in an electrical distribution system occur mainly due to changes in the reactive power flow over inductive elements, and the voltage problems can compound when reactive power flow occurs over heavily loaded active power circuits. The X/R ratio may be 7 to 40 and, thus, the inductance prevails. Most power supply companies penalize users for a low power factor in the form of a kVA demand charge. Thus, control of the reactive power flow is imperative for

- Voltage control, commonly called V-Q control
- Efficient utilization of installed equipment kVA ratings
- Reduction of kVA demand charges
- Reduction of the system losses

Reactive Power Characteristics of Equipment

Induction Motors. The reactive power demand varies with rating and speed, from 0.35 kvar/hp to 0.6 kvar/hp. At lower speeds, the stator windings have considerable leakage flux and reactive power demand increases.

Drive Systems. The dc drive systems absorb reactive power from power supply systems; kVA remaining constant over the entire speed range. Thus, at low speeds, the reactive power component is high. The reactive power demand of dc drive systems is 0.6 to 0.8 kvar/hp, while ac drive systems can maintain a high power factor, depending upon the drive system topology. An induction motor with pulse width modulation (PWM) inverter can maintain a power factor close to unity, while load commutated inverter (LCI) for a synchronous motor has a low power factor, due to phase control.

Arc Furnaces. In the beginning of the melting cycle of an arc furnace, the power into the furnace is mostly reactive, with large swings in furnace current between short-circuit level and near zero. The operating power factor in the stable arc region is low, about 0.7. Shunt capacitor filters are normally provided for harmonic and reactive power control.

Synchronous Motors. An overexcited synchronous motor is a source of reactive power, and can be rated to operate at 0.8 power factor leading on a continuous basis. The "V" curve of the motor is a relation between the excitation current and motor load, and there are two values of excitation current for a certain load, one in the lagging region and the other in the leading region. Type of excitation control influences the stability, voltage control, and reactive power supply characteristics.

Synchronous Condensers. These have large synchronous reactance and field windings develop zero power factor leading currents, with least possible expenditure in active power losses. At 100% excitation, full-load leading kvar is obtained and, at approximately 30% of the excitation current, it falls to a minimum value corresponding to losses. The lagging var is usually limited to $\frac{1}{3}$ of maximum leading var rating to prevent loss of synchronism on a system disturbance.

Synchronous Generators. Figure 2 shows the reactive power capability of a synchronous generator, rated at 0.85 power factor. At a reduced power load, a generator will produce more reactive power and, on a short-time basis, the reactive power output can be increased, which will increase the field winding temperature rise. The reactive power output of a generator decreases and increases inversely with the system voltage and, thus, it has a stabilizing effect on the system voltage.

Transformers and Reactors. Depending upon the reactance and reactive power flow, a considerable amount of reactive power will be lost in the system reactance. 70 Mvar at the input terminals of a 0.76 Ω reactor results in a 50 Mvar output, 20 Mvar is lost in the reactor, and a voltage drop of 28% occurs due to reactive power flow. This relation of reactive power loss through the inductance and voltage drop is nonlinear.

Power Capacitors. These can be switched with induction motors or applied in banks at unit substations and at main distribution buses. When switched with induction motors, the self-excitation and generation of overvoltages should be avoided, by limiting the size of the capacitors, so that it does not exceed the no-load kvar of the motor:

$$C_{\text{kvar}} < \sqrt{3}VI_0 \sin\theta_0 \tag{1}$$

Where C_{kvar} is the three-phase kvar of the capacitor and V, I_0, and θ_0 are the line-to-line voltage, no-load current, and no-load power factor angle, respectively. Manufacturers publish data on the maximum size of power capacitor that can be switched with their motors. Motor data to size the power capacitor according to Eq. (1) are generally not available to the user. In the presence of capacitors, self-excitation of motor on disconnection from the supply system is prolonged, and the motor residual emf decays at a slower rate. Thus there is a greater possibility of subjecting the motor to an out-of-phase transfer of power on rapid reconnection to power supply system, and reclosing transients will be of higher magnitude. Therefore, capacitors should not be applied to motors requiring fast reswitching, plugging, or reversing duties.

The kvar rating of a capacitor decreases with the square of voltage:

$$\text{kvar}_{v2} = \text{kvar}_{v1}\left(\frac{V_2}{V_1}\right)^2 \tag{2}$$

where kvar_{v1} is at voltage V_1 and kvar_{v2} is at voltage V_2. Thus on a voltage dip, the kvar decreases, which further reduces the voltage. This destabilizing effect of power capacitors is reverse of the stabilizing effect of synchronous generators.

Static var Compensators (SVC). A static var compensator provides continuously controllable leading and lagging reactive power from capacitors and reactors. The applications are for load compensation of large arc furnaces, rolling mills, voltage and flicker control, and stability improvement of transmission lines. Fast response time of $\frac{1}{2}$ cycle or less is possible. A SVC may consist of thyristor-controlled reactors (TCR), connected in parallel with a fixed or variable thyristor-controlled capacitor bank. Alternatively, fixed reactors with thyristor-controlled capacitors are used. Figure 3 shows a fixed capacitor and controlled reactor (FC-TCR) scheme. Some large (200 Mvar) SVCs have been connected to arc furnace installations for voltage flicker control. Due to randomness of load variations in an arc furnace, a closed-loop control is essential to achieve response times of less than a cycle.

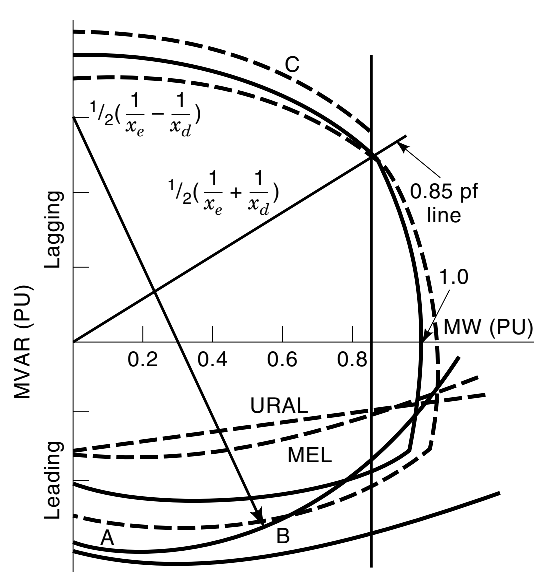


Figure 2. Reactive power characteristics of a synchronous generator with superimposed stability limit curves. (a) without fast regulators, (b) with a fast regulator, (c) overload reactive capability for short-time duration of 20 minutes. Dotted reactive capability curve is for operation at higher than rated voltage. URAL and MEL are under excited reactive-amp limit and minimum excitation limit, respectively.

Implementation Strategies. An analysis to decide the location and type of reactive power compensating devices in a distribution system requires estimation or measurement of the reactive power requirements. Load flow studies to investigate the normal and contingency power flows and voltage profiles throughout the distribution system are the primary analytical tools. The calculated depressions in voltages and reactive power flows in certain sections of the distribution will point to the possible locations of compensating devices. Reduction of system reactance to reduce losses (which will also improve stability) and "stiffening" of the distribution system, by duplicating the feeders and parallel running transformers, have large cost impacts, but may be necessary occasionally. Redistribution of the loads and relocation of the reactive power sources, such as, generators, condensers, or power capacitors, can be evaluated.

VOLTAGE REGULATION

The Electrical apparatus and machines have a certain maximum and minimum operating voltage range in which the normal operation is maintained. Beyond these voltage limits, the operating characteristics may be seriously affected, and the continuity of processes may be lost. The voltage problems in the power supply system are passed on to the industrial distribution systems directly, and affect the industrial consumers. Percentage change in voltage from no load to full load is called *voltage regulation* and, within the plant distribution, it mainly depends on reactive power flow. Consider flow of active and reactive power $P + jQ$ in an element of a distribution system.

$$P + jQ = V_r e^{-j\theta}[(V_s - V_r e^{j\theta})(g + jb)] \tag{3}$$

where V_s and V_r are the sending end and receiving end voltages, g and b are line conductance and susceptance, and θ the phase angle difference between the voltages. If receiving end load demand changes by a factor $\Delta P + \Delta Q$ and the resistance is neglected, it can be shown that, at the load node:

$$\Delta P = \frac{\partial P}{\partial \theta}\Delta_\theta + \frac{\partial P}{\partial V}\Delta_v \tag{4}$$

$$\Delta Q = \frac{\partial Q}{\partial \theta}\Delta_\theta + \frac{\partial Q}{\partial V}\Delta_v \tag{5}$$

With the constraint that the first term of Eq. (4) is much larger than the second term and the first term of Eq. (5) is much smaller than the second term, the active power demand change ΔP through a mainly reactive element of a power sys-

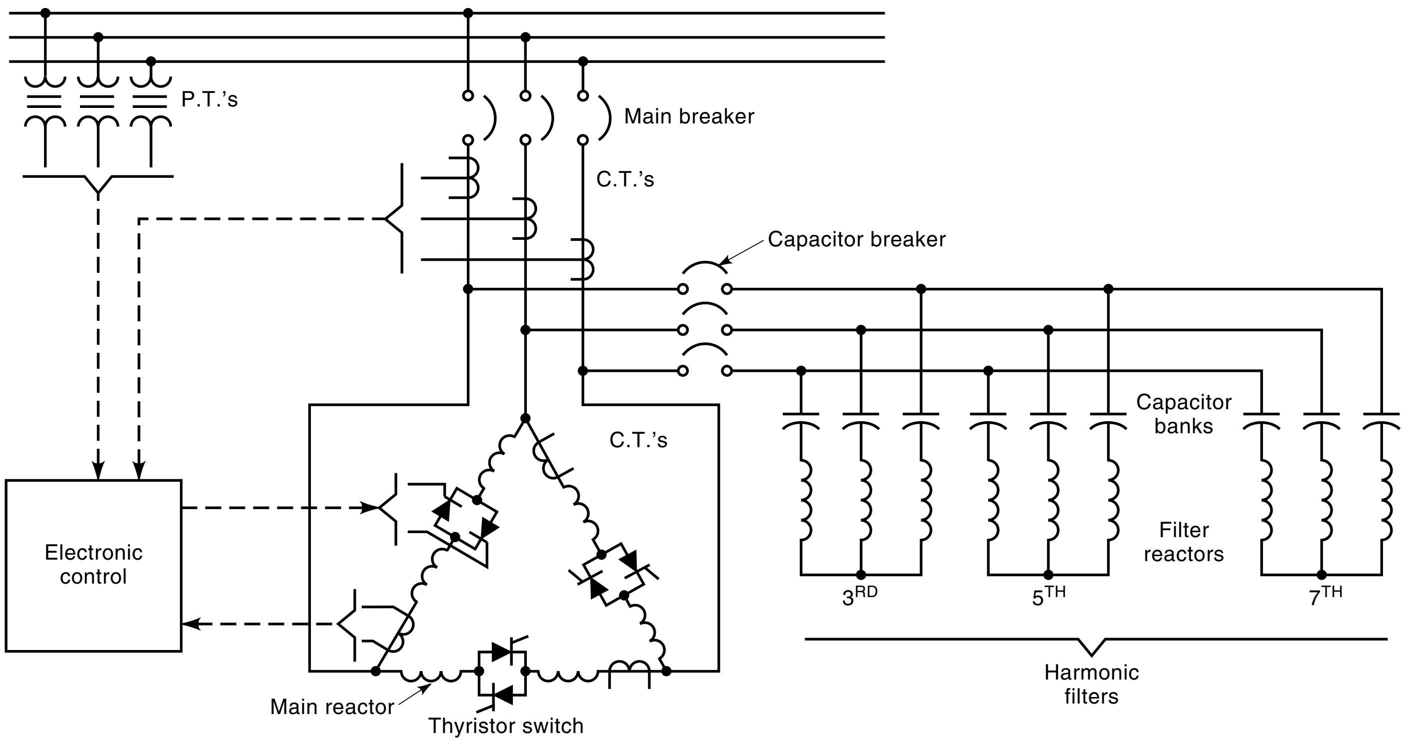


Figure 3. A fixed capacitor and controlled reactor (FC-TCR) static var compensator. Capacitors applied as filters.

tem requires an incremental change in the phase angle Δ_θ between sending and receiving end voltages. A reactive power change ΔQ, on the other hand, requires an incremental change in the scalar voltage between sending and receiving end voltages, Δ_v.

The elimination of θ in Eq. (3) yields the dynamic voltage equation:

$$V_r^4 + V_r^2(2QX - V_s^2) + X^2(P^2 + Q^2) = 0 \quad (6)$$

where X is the line reactance. This equation is plotted in Fig. 4, and shows that there is a critical reactance X_c, below which there are two operating voltages, one in the stable region and another in the unstable region. For a system reactance close to the critical reactance, system instability can occur for a small positive excursion in the power demand.

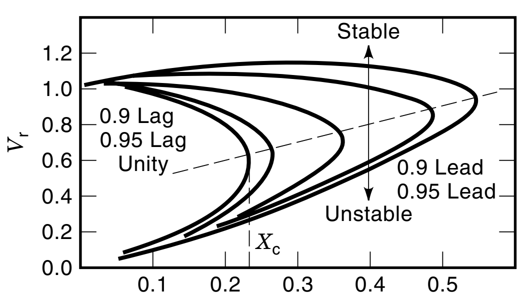


Figure 4. Receiving end voltage versus system reactance for different power factors. Stable and unstable zones for reactance less than the critical reactance.

Voltage-Regulating Devices

Transformer On-Load Taps Changers (OLTC). Transformer on-load taps can be provided to adjust voltage in steps of $\frac{5}{8}\%$ up to $\pm 20\%$ of the nominal, generally 10%. Though the transformer losses slightly vary as the transformer impedance changes with tap changing, yet tap adjustment directly affects the voltage, and does not result in additional reactive power generation or consumption in the transformer itself. The reactive power flow in the distribution system itself may change, due to voltage change. The step down transformers in a utility's substation, when provided with on-load taps, can compensate for utility system sustained voltage drops. The response time is slow, about one second and, thus, voltage dips due to a fault cannot be corrected. A load tap changer may employ oil-immersed reversing, selector, and by-pass switches with vacuum interrupters.

Voltage Regulators. These provide phase angle and voltage control, based upon Eqs. (4) and (5) and consist of shunt exciting winding on the source side and a tapped series winding on the load side. A series in-phase voltage into the loop circulates a quadrature current, and a quadrature series voltage results in currents lagging approximately by 90° of the circulating in-phase currents.

Capacitive Reactive Power Generating Devices. Overexcited synchronous motors and generators, synchronous condensers, power capacitors and SVCs are voltage regulating devices too, each having a different voltage-regulating characteristic.

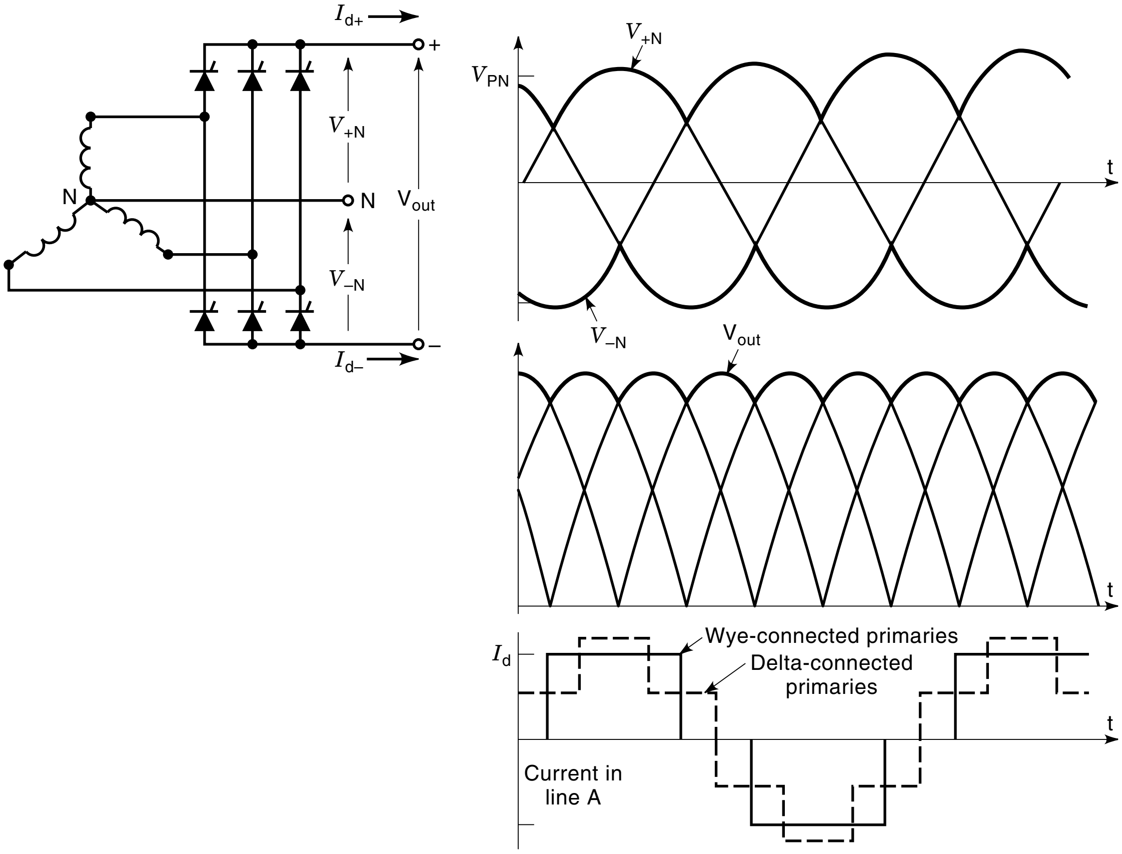


Figure 5. ac line-current waveforms for a three-phase, six-pulse rectifier circuit.

HARMONICS

A harmonic is a sinusoidal component of a periodic wave or quantity, having a frequency that is an integral multiple of the fundamental frequency. The harmonics of a distorted waveform can be represented by a Fourier series. For application on digital computers, discrete Fourier transform is used. Fast Fourier Transform (FFT) is useful at high sampling rates, and to reduce the number of computations.

Harmonic Sources

Nonlinear drive system loads are the major harmonic sources. The characteristic harmonics are nontriple odd harmonics and are given by:

$$h = kq \pm 1 \tag{7}$$

where h is the order of harmonic, k is any integer, and q is the pulse number which is the total number of successive nonsimultaneous commutations occurring within a converter circuit during each cycle, when operating without phase control. Thus, a three-phase, six-pulse bridge circuit, which is mostly used for adjustable speed drives (ASD), will produce 5th, 7th, 11th, 13th, . . . harmonics. Figure 5 shows the ac line-current waveforms for this circuit. The theoretical magnitude of the maximum harmonic current is given by $I_h = I/h$, where I is the fundamental current, and I_h is the harmonic current. Thus, maximum 5th harmonic current is 20% of the fundamental current. This assumes instant current transfer on commutation; in practice, the reactance in the circuit will cause current transfer to be more gradual. The theoretical and typical values are shown in Table 4.

Arc furnaces produce both even and odd harmonics. The spectrum of harmonics during heating and melting cycles varies. Harmonic currents during starting are many times higher than the melting cycle harmonic currents. Other sources of harmonics are (a) current transformers' saturation under fault conditions, which produces harmonics in the secondary circuits and may cause improper operation of protective devices; (b) overexcitation of power transformers due to high V/f (voltage over frequency) ratio, which produces harmonics; the inrush current of a transformer contains decaying dc com-

Table 4. Harmonic Order and Current Magnitude in Per Unit of Fundamental for Six-Pulse Converters

Harmonic Order	5th	7th	11th	13th	17th	19th	23rd	25th
Theoretical value	0.200	0.143	0.091	0.077	0.059	0.053	0.043	0.40
Typical value	0.175	0.111	0.045	0.029	0.015	0.010	0.009	0.008

ponent, 2nd, 3rd, 4th, and higher harmonics; (c) switching power supplies of data-processing equipment that can overload the supply system neutral circuits with third harmonic currents; (e) improperly applied power capacitors, which may increase harmonic distortion and cause resonance problems.

Effects of Harmonics

Transformers and Reactors. Determining a transformer load capability in nonsinusoidal environment considers added winding eddy-current loss due to harmonics in the region of greatest flux density and then arriving at a derating factor, so that total I^2R loss and stray loss does not exceed the total loss under rated frequency conditions. This derating factor is given by:

$$I_{\max}(pu) = \sqrt{\frac{P_{\text{L-RR}}(pu)}{1 + \left[\left(\sum_{h=1}^{h=h_{\max}} f_h^2 h^2 \Big/ \sum_{h=1}^{h=h_{\max}} f_h^2\right) P_{\text{EC-R}}(pu)\right]}} \quad (8)$$

where $I_{\max}(pu)$ is the derating factor, $P_{\text{LL-R}}(pu)$ is maximum load-loss density and $P_{\text{EC-R}}$ is the maximum eddy-loss density. The expression within small parentheses in the denominator of Eq. (8) is UL "K" factor. A transformer supplying a 6-pulse converter, harmonics limited to typical values shown in Table 4 will have a K factor of 2.81.

Cables. The flow of nonsinusoidal current in a conductor causes additional heating, due to skin effect and proximity effect. The ratio of ac resistance to dc resistance is:

$$R_{\text{ac}}/R_{\text{dc}} = 1 + Y_{\text{cs}} + Y_{\text{cP}} \quad (9)$$

where Y_{cs} is the component of resistance due to skin effect and Y_{cp} is the component of resistance due to proximity effect.

Rotating Machinery. Harmonics may excite complex vibration modes involving structural resonances in rotor elements and flexing of turbine buckets. High mechanical responses may be developed if the frequency of the coupled mode is close to the frequency of an electrical stimulus. The 5th, 11th, 17th . . . harmonics are backward rotating, while 7th, 13th, 19th . . . are forward rotating. These produce pulsating torques and heating. The synchronous generators' continuous unbalanced current capability is limited to 5% to 10%, and I_2^2t (where I_2 is the negative sequence current expressed in per unit stator current, and t is time duration in s) is limited to 10 to 30, depending upon the size and construction. Negative sequence currents due to harmonics can cause these limits to be exceeded.

Communication Interference. Magnetic and electrostatic couplings between electrical power circuits can cause communication interference. Depending upon the magnitude of induced current or voltage, this may produce induced line noise, interference with power line carrier systems and relay malfunctions. *IT*-product is a product of harmonic current and Telephone Influence Factor, which gives a frequency-dependent weighting. *IT* guide lines for converter installations and Tie (supply lines) divide these into three categories. Category I has *IT*-product up to 10,000, and this is most unlikely to cause interference. Category II levels are 10,000 to 50,000, and these might cause interference. Category III has levels >50,000, and these will probably cause interference. The interference between power distribution cables and twisted and shielded pair telephone cables is usually low.

Table 5. Harmonic Voltage Limits for Power Producers (Public Utilities or Cogenerators)

	Harmonic Distortion in % at PCC		
Voltage	2.3–69 kV	69–138 kV	>138 kV
Maximum for individual harmonic	3.0	1.5	1.0
Total harmonic distortion (THD)	5.0	2.5	1.5

Harmonic Measurements

The equipment used for making automated on-line harmonic measurements consists of a harmonic analyzer, a computer-based system controller, a mass storage device, instrument transformers and signal conditioners. Generally, the instrument transformers provided in the power distribution for metering purposes are used as input transducers. Signal conditioners should give a flat frequency response; these convert the voltage or current signal from the transducers to input levels of the analyzers. Harmonic analyzers use FFT; typical measurements up to 2.5 kHz are found adequate. The sampling rate must be chosen high above the Nyquist rate to avoid aliasing.

Harmonic Limitation

The harmonic voltage and current distortion limits specified in ANSI standards are shown in Tables 5 and 6. The harmonic voltage and current distortion factors are:

$$\text{THD}_I = \left[\left(\sum_{h=2}^{h=\max} I_{\text{h}}^2\right) \Big/ I_{\text{f}}^2\right]^{1/2} \quad (11)$$

$$\text{THD}_v = \left[\left(\sum_{h=2}^{h=\max} v_{\text{h}}^2\right) \Big/ v_{\text{f}}^2\right]^{1/2} \quad (10)$$

Table 6 lists the harmonic current limits based upon the size of the user's distribution system with respect to the power system to which he is connected. The ratio $I_{\text{se}}/I_{\text{L}}$ is the short-circuit current available at the point of coupling (PCC) to the nominal fundamental load current. As the size of the load decreases with respect to the size of the system, the larger is the percentage of harmonic current a user is allowed to inject into the utility system. Table 5 specifies the quality of voltage that the utility must furnish to the user and lists the voltage distortion that is acceptable from a utility to the user.

Harmonic Resonance

When power capacitors are used for voltage or reactive power control, there is a certain frequency at which these are in parallel resonance with the power system reactance. This fre-

Table 6. Harmonic Current Limits for Nonlinear Loads at the Point-of-Common-Coupling with Other Loads at Voltages of 2.4 to 69 kV

	Maximum Harmonic Current Distortion in % of Fundamental					
	Harmonic Order (odd harmonics)					
I_{sc}/I_L	<11	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 < h$	THD
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20–50	7.0	3.5	2.5	1.0	0.5	8.0
50–100	10.0	4.5	4.0	1.5	0.7	12.0
100–1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Even harmonics are limited to 25% of the odd harmonic limits above.
* All power-generation equipment is limited to these values of current distortion, regardless of I_{sc}/I_L
Where I_{sc} = maximum short-circuit current at PCC
I_L = maximum load current (fundamental frequency) at PCC
For PCCs from 69 to 138 kV, the limits are 50% of the limits above. A case-by-case evaluation is required for PCCs of 138 kV and above.

quency can be approximately calculated by the expression:

$$f_p = f_1\sqrt{X_c/X_{sc}} \tag{12}$$

where f_1 is the fundamental frequency, X_c is the reactance of the capacitor in per unit and X_{sc} is the short-circuit reactance of power system in per unit. Parallel resonance is a high impedance to the current at resonant frequency, while series resonance is a low impedance. If a parallel resonant circuit is excited at a load-generated harmonic that coincides with its resonance frequency, large oscillating currents circulate between the system inductance and the capacitive reactance of the capacitors leading to magnification of harmonic currents. This overloads system components and increases the harmonic distortion factors.

Harmonic Reduction and Filtering. Harmonics can be reduced by phase multiplication Figure 5 shows the ac current waveform with two types of rectifier transformer connections, delta–delta connected and delta–wye connected. If the two transformers are similarly loaded, an analysis of the supply system current waveform results in the same harmonics as in Table 4, but 5th, 7th, 17th, and 19th harmonics are 180° out of phase, thereby canceling each other. This has the same effect as that of a 12-pulse rectifier system. Due to imperfect transformer phase shift, impedance unbalances, and unequal phase-retard angles of thyristors, complete cancellation does not occur. Residual harmonics are 10% to 20%.

Harmonic reduction through passive filters is commonly employed. Table 7 shows various types of passive filters and their characteristics. A band-pass or single-tuned passive filter is most commonly used, and acts a low impedance path to harmonics at its tuned frequency. The quality factor is given by the expression:

$$Q = \frac{\sqrt{L/C}}{R} = \frac{X_{Lr}}{R} = \frac{X_{Cr}}{R} \tag{13}$$

Passband is given at a frequency at which filter impedance is $\sqrt{2}R$. The concept can be extended to double-pass filters, tuned to two different frequencies. A composite filter may have two or more single-tuned sections, with a high-pass filter for higher harmonics. A high-pass filter has a low impedance above a corner frequency, though this minimum impedance is always higher than that of a single-tuned filter at its notch frequency. Shunting of all system harmonics through one high-pass filter will increase fundamental frequency loadings. A high-pass filter by itself is rarely used.

Passive filters have limitations, that is, a change in the system switching condition or short-circuit level changes the parallel resonance peak and the filter loading. The ideal solution of harmonic control by incorporating harmonic compensating circuitry in the harmonic producing equipment itself, so that no harmonics are generated, has not come of age. Third harmonic current-injection, magnetic flux compensation, and dc ripple-injection methods for harmonic current control have been proposed. However, practical systems have not been extensively developed, although some systems are presently available.

When power capacitors are used for filter applications, the following loading limits should not be exceeded:

$$\text{kvar}(pu) \le 1.35 = \sum_{h=1}^{h=\max} (V_h I_h) \tag{14}$$

$$V_s \le 1.2\sqrt{2} = \sqrt{2}\sum_{h=1}^{h=\max} V_h \tag{15}$$

$$I_{rms} \le 1.8 = \left[\sum_{h=1}^{h=\max} I_h^2\right]^{1/2} \tag{16}$$

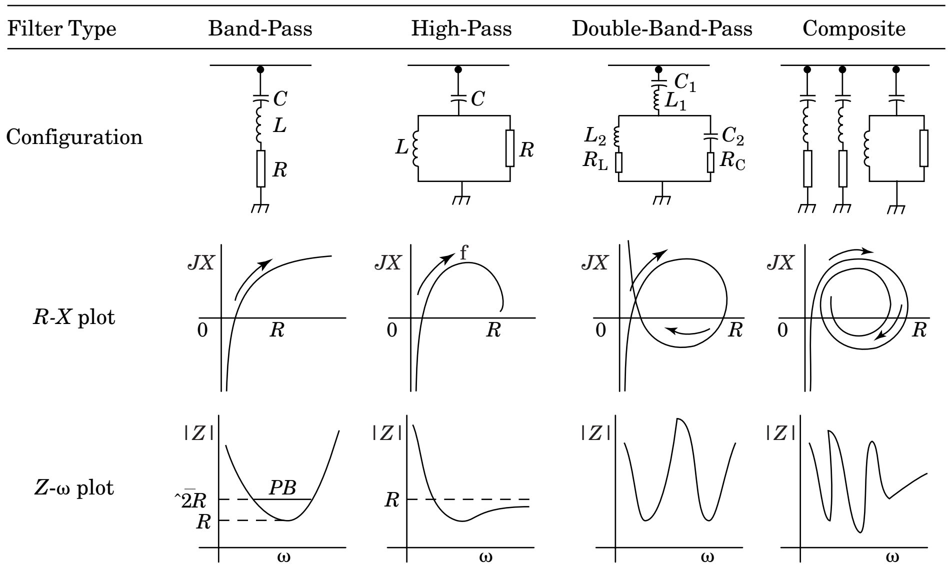
$$V_{rms} \le 1.1 = \left[\sum_{h=1}^{h=\max} V_h^2\right]^{1/2} \tag{17}$$

V_s is the sum of randomly occurring peaks of harmonic voltages which for conservatism can be considered cophasial, I_h is harmonic current, and V_h is harmonic voltage.

POWER QUALITY

Many industrial processes require a higher quality of power. Electronic means of control are becoming increasingly common and adjustable speed drives communicate with programmable logic controllers (PLCs) to control many aspects of pro-

Table 7. Passive Harmonic Filters, Configuration, *R-X* and *Z*-ω Plots



cess behavior. PLCs use a "ladder-type" logic instead of a programming language. Graphical users' interfaces (GUI), networked to different types of equipment, permit simultaneous controls. Many processes are highly integrated and power quality variations in one section of process impact the overall production.

Power Quality Problems. Power quality problems include voltage sags and swells, high-frequency line-to line surges, steep wavefronts or spikes caused by switching of loads and circuits, harmonic distortions and outright power interruptions, which may extend over prolonged periods. An impulse is a unidirectional pulse of less than 10 ms in duration. A voltage sag is reduction in nominal voltage for more than 0.01 s and less than 2.5 s. A swell is an increase in nominal voltage for more than 0.01 s and less than 2.5 s. Low and high voltages are reduction and increase in voltage for more than 2.5 s. All these events are observable. A problem that is not easily detected is common mode electrical noise, which occurs on all conductors of an electrical circuit at the same time. It can also occur in short bursts of random time and duration. A typical case is arcing on the brushes and commutator of a motor, which induces high-frequency current and voltage in the power circuit. Common mode noise can cause a system shutdown because of corruption of signal transmissions. Figure 6 shows the scatter plot of voltage sags in the United States.

The first step in identifying the power quality problems and their impact on the processes is to distinguish which characteristic is likely to cause equipment to misoperate or shut down. Methods of characterizing rms disturbances for calculations of performance indices have been developed. The most important parameter, in terms of its impact on sensitive industrial equipment, is the minimum voltage magnitude. Index of voltage sag performance measures the frequency of occurrence of rms variations below a specified threshold. A recommended method of summarizing expected voltage sag performance, in terms of magnitude and duration, is shown

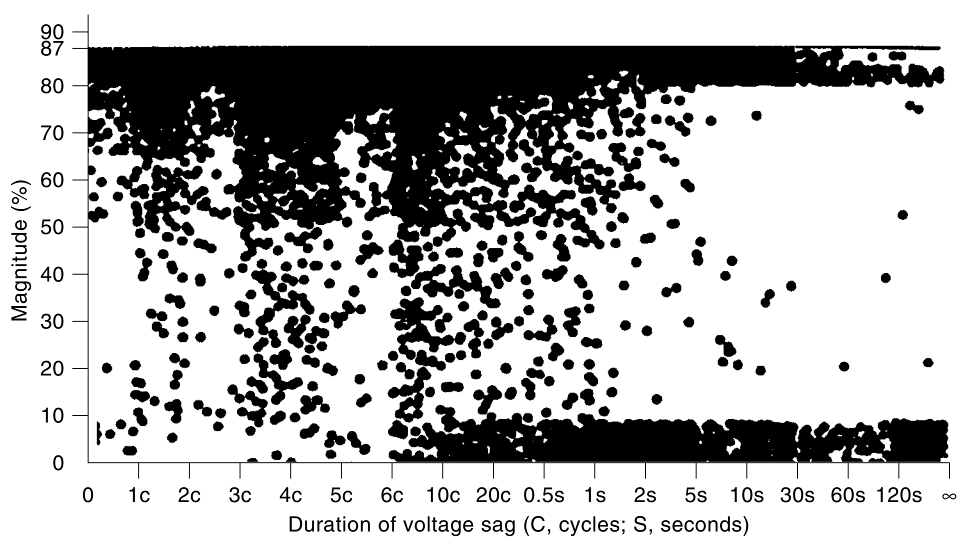


Figure 6. Scatter plot of voltage sags in the United States.

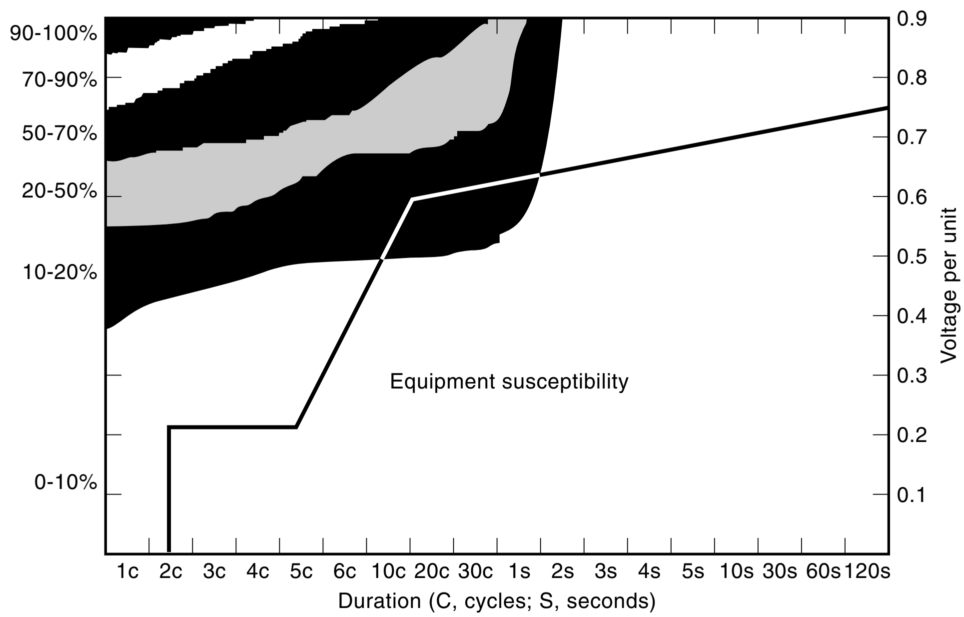


Figure 7. Voltage sag performance contour plots with superimposed equipment susceptibility characteristics.

in Fig. 7. This presents the performance as a series of constant supply sag performance contours, similar to a topographical contour map, which can be compared directly with a plot of equipment sensitivity. This permits expected numbers of shutdowns to be directly estimated.

The performance features of various types of power conditioning equipment are shown in Table 8. A shielded isolation transformer provides common mode noise isolation. Fiber-optic cables and electro-optical isolation at interfaces are the best methods. An uninterruptable power supply system (UPS) consists of a front-end rectifier, the output of which is floated in parallel with a storage battery and a following inverter. Static by-pass switches, redundant rectifiers, and inverters reduce the mean time between failure (MTBF) and improve availability. Low-voltage static switches up to 4000 A are available, and will transfer power to an alternate source without load dropping. Medium-voltage static switches have recently become available.

Voltage Flicker. Voltage flicker phenomena can be divided into two categories, cyclic and noncyclic. Cyclic flicker occurs from periodic fluctuations, such as may be caused by an arc furnace or a reciprocating compressor. Noncyclic flicker corresponds to occasional voltage fluctuations, such as may be caused by operation of a welder. Percentage voltage flicker is defined by:

$$\%\text{voltageflicker} = \frac{\text{rms voltage of modulating wave}}{\text{average rms voltage}} \tag{18}$$

On-site field tests with equipment that accurately captures the multiple frequencies aid in measuring existing voltage flicker. Voltage variations are in the range of 0.5% to 6%, which may vary in frequency from 10/s to 1/h. Static var controllers have been extensively used for control of voltage flicker.

ENERGY MANAGEMENT

Energy costs are growing at an average of 8% to 10% per year and kVA demand charges are increasing. An energy-monitoring system collects, profiles, and analyzes energy usage, and generates energy usage trends and graphic displays. Based upon the information provided, specific actions can be taken. It consists of three components:

1. Electronic full-function meter blocks, protective relays, trip units, and PLC input/output (I/O) interfaces with communication facilities: These devices are installed on medium- and low-voltage circuit breakers, motor control centers, adjustable frequency drives, and transfer switches, and may operate on multitasking operating systems, VMS®, UNIX® or Windows®.
2. Data concentrator, PLC, or computer workstations that receive the data from field devices on communication network, RS-422/485 interfaces, Ethernet, telephone modems, or fiber optics.
3. Multiuser software and host computing facilities.

An energy-management system goes a step further to control multiple pieces of equipment, and can be integrated with energy-monitoring system. A computerized energy-management system has three hierarchial tiers: process control, supervisory control, and planning. Basic energy-management strategies include:

- Equipment scheduling
- Optimized start/stop
- Duty cycling
- Peak shaving and demand limiting

Demand Control. In an instantaneous demand controller, action is initiated when instantaneous demand exceeds the established set point. In an ideal-rate controller, ultimate demand is prescribed, and a slope is established to define when usage indicates that the demand will be exceeded. A converging rate controller works on an accumulated usage curve. Microcomputer systems continuously monitor the demand, based upon one or another type of controllers, and determine if the specified demand will be exceeded.

Table 8. Performance Features of Various Types of Power Conditioning Equipment

Power Quality Condition		A	B	C	D	E	F	G	H	I
Transient voltage surge	Common mode	▒	□	■	▒	■	■	▒	▒	□
	Normal mode	▒	□	□	▒	■	■	▒	■	□
Noise	Common mode	□	▒	■	▒	■	■	▒	▒	□
	Normal mode	□	▒	▒	▒	■	■	▒	■	□
Notches		□	□	▒	□	■	■	□	■	□
Voltage distortion		□	□	□	□	▒	■	□	▒	□
Sag		□	□	□	▒	▒	▒	▒	■	□
Swell		□	□	□	▒	■	■	▒	■	□
Undervoltage		□	□	□	■	■	■	▒	▒	□
Overvoltage		□	□	□	■	■	■	▒	▒	□
Momentary interruption		□	□	□	□	□	▒	■	■	□
Long-term interruption		□	□	□	□	□	□	□	□	■
Frequency variation		□	□	□	□	□	□	▒	■	▒

Power Conditioning Technology: A–I

■ It is reasonable to expect that indicated condition will be corrected.

▒ The indicated condition may or may not be corrected, due to significant variations in power conditioning product performance.

□ The indicated condition is not corrected.

A = Transient voltage surge suppressor
B = EMI/RFI filter
C = Isolation transformer
D = Electronic voltage regulator
E = Ferroresonant voltage regulator
F = Motor generator
G = Standby power system
H = Uninterruptable power supply
I = Standby engine generator

Avoiding Investments. Based upon the real-time power flows throughout the distribution system and customized graphic screens for each plant, energy-handling capability in each section of distribution can be established. A reallocation and distribution of loads may be possible to relieve the overloaded sections, without adding to the capital equipment cost.

Switching and Operating Strategies. Overloads in progress that can cause a process shutdown can be averted by diverting the excess load flow or load shedding of the affected section. The cause of the trip and fault current waveform can be captured. This saves diagnostic and repair time, and helps to get the process back on line quickly.

Maintenance Data. Preventive-maintenance schedules can be developed from the real-time electrical and mechanical usage. Equipment identifiers and alarms indicate when preventive maintenance is required.

Energy-Conservation Opportunities

A key element of the energy-management process is identification of energy-conservation opportunities (ECO), a broader concept than mere energy conservation. Energy-saving methods include: (a) housekeeping measures, better maintenance and operation, and improving electricity demand management; (b) equipment and process modifications, that is, use of more efficient equipment and processes and retrofitting the existing systems; (c) better use of equipment achieved by carefully examining the production processes, schedules, and operating practices; and (d) reduction of losses in building shell, that is, by better insulation.

Lighting Systems. Proper control of lighting systems is one of the most effective ways to save lighting energy. Automatic control systems permit programmed operation of lighting systems. The switching function can be activated by a time clock, photocell, presence detector, or a programmable controller. Optimizing electrical energy is inherent in lighting design tailored to meet the requirements of color correction and visual tasks involved. Optimization also embraces required illumination level, type of lighting fixtures selected for the task, and their maintenance requirements. Table 9 shows energy requirements for four major types of lighting systems. The efficiency of fluorescent and HID lamp systems can be improved further by electronic ballasts. These lower the internal losses and increase the lighting efficiency by operating at frequencies above 20 kHz.

High-Efficiency Motors and Transformers. Motors may account for 70% of the energy consumed in an industrial plant. High-efficiency motors have 3% to 8% higher efficiencies, and are higher in cost from 15% to 25% of the standard motor costs. Evaluating investments that account for time value of money are necessary. Generally, the cost of energy savings will justify additional investments and retrofitting the existing installations.

Adjustable Speed Drives. Approximately 65% of the energy in industrial plants is used for fans, pumps, blowers, and compressors. Typical operation may be as low as 40% of the design values. A variable-speed drive system, as compared with a constant-speed motor with an output control valve, will conserve energy on two accounts; (a) power savings achieved by elimination of head loss in the control valve itself, and (b) reduction in the power required in the drive motor when flow requirements are reduced.

TRANSIENT STABILITY

A system is stable under a specified set of upset conditions and perturbations, if all its synchronous machines remain in step. Classical transient stability model considered that the stability is decided in the first swing. It modeled constant generator field winding flux linkage, neglected damping, assumed constant mechanical power, and represented loads as passive elements. These concepts have much changed due to the advent of fast excitation systems and governors. Transient stability studies performed now consider response characteristics of control equipment, excitation systems, governing, and dynamic models of loads are used.

The most immediate hazards of asynchronous operation of a power system are the high transient mechanical torques and currents. To prevent these damages, synchronous generators and motors are equipped with out-of-step and pull-out protection. An unstable system results in more frequent process interruptions. Disturbances that produce instability in industrial distributions are short-circuits, loss of generation or a utility tie, starting of large motors, and abrupt loading of generators. A three-phase short-circuit is the largest disturbance. The voltage at the point of short-circuit is reduced to zero, and elsewhere in the system it depends upon system impedances and flow of short-circuit currents. This reduced system voltage acts like a throttle to the flow of power from the generators to the motors, accelerating the generators, and slowing down the motors initially. The incident impact is distributed unevenly among various machines according to their share of synchronizing power in the overall synchronizing power brought into play by the disturbance. Rigid machines with high synchronizing power take a larger impact, and the softer machine a correspondingly smaller impact. Under this impact, every machine is retarded or accelerated:

$$\alpha = \frac{\nu^2}{\omega}\Delta\partial \tag{19}$$

where ν is the natural frequency of oscillation of the machine, $\omega = 2\pi f$, and $\Delta\partial$ is the change in the torque angle. ν is given by:

$$\nu = \sqrt{\frac{\omega P_s}{T_a P_0}} \tag{20}$$

where P_0 and P_s are the rated power and synchronizing power and T_a the acceleration time constant, given by:

$$T_a = \left[\frac{\pi}{30}\right]^2 \frac{n_0^2 WR^2}{P_0} \tag{21}$$

where WR^2 is moment of inertia in kg/m^2. Thus the initial retardation of various machines differ, if their natural frequencies differ. The synchronizing forces cause all machines to strive for some mean retardation. Under this retardation, after decay of oscillations, the softer machines with a high moment of inertia are more retarded than these were under initial impact and are loaded to a higher degree. This increased power is taken from the inertia of the rotating masses, and the torque angle changes further. Ultimate value is reached after a series of damped oscillations with overswings. Figure 8 illustrates the softer machines of smaller natural frequency going out of step. As the size of plant generators in an industrial distribution system is much smaller, compared with the utility's system, this illustrates the problem of keeping these machines in synchronism with the utility, and preventing a system separation on a disturbance.

Factors Affecting Stability

Excitation Systems. The excitation systems affect stability. An excitation system voltage response ratio is defined in

Table 9. Energy Requirements for Four Major Lighting Systems, for an Area of 930 m^2

Lighting System	Fluorescent	High-Pressure Sodium (400 W)	Metal Halide (400 W)	Mercury (400 W)	Incandescent (1000 W)
No. of fixtures	73	40	65	118	70
Power requirement	33.2 kW	19 kW	30 kW	52 kW	70 kW
% of HPS power required	175%	100%	158%	274%	368%

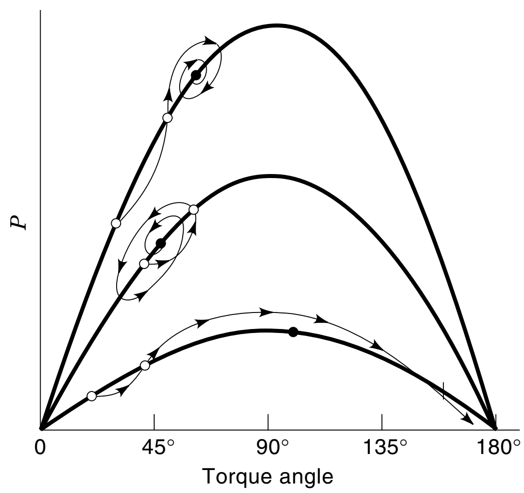


Figure 8. Transient stability of a multi-machine system and instability of softer machines on a disturbance.

ANSI as the numerical value obtained in volts per second, measured during first half-second interval. Following a severe power disturbance, the maximum torque angle swing will peak in approximately 0.4 to 0.7 s, and a fast excitation system must act within this time to affect transient stability considerations. A fast response system has a response ratio of 0.1 s or less. Excitation systems are classified under three different types:

1. Type ST1 and ST2 excitation systems, in which excitation power is supplied through static controlled rectifiers. ST1 represents all systems in which excitation power is supplied through a transformer from generator terminals. ST2 type is a compound exciter, in which excitation power is supplied from a phasor combination of terminal voltage and current.
2. Type AC excitation systems use an alternator and either stationary or rotating rectifiers to produce the field excitation. AC1 represents field-controlled alternator rectifier systems and incorporates an alternator main exciter with noncontrolled rectifiers and feedback from exciter field current. AC2 represents a high initial response field-controlled alternator-rectifier excitation system. AC3 is much like AC1, the exciter employs self-excitation. AC4 type represents an alternator-supplied controlled-rectifier excitation system.
3. Type DC excitation systems use a direct current generator with a commutator as the excitation source. DC1 is a field-controlled commutator exciter with continuously acting voltage regulator. DC2 is also a field-controlled commutator exciter, with continuously acting regulators, having supplies obtained from generator or auxiliary bus voltage. DC3 represents noncontinuously acting regulators.

Figure 9(a) shows a brushless excitation system with a permanent magnet generator (PMG), and Fig. 9(b) shows a block control circuit diagram of type AC1 exciter.

Industrial generators are directly connected to the load buses. A fault close to the generator will drive the bus voltage to low values and, when the excitation power is derived from it, the stability will be jeopardized. A brushless system and a compound static excitation system will tend to maintain the excitation and improve stability.

Other Factors Affecting Stability.

1. The greater the impedance between the machines, the smaller will be the impact required to drive them out of step. A lower impedance, however, increases the short-circuit duties on the switching devices. Economics and requirements of a physical layout further dictate how far reducing the impedances in an industrial distribution is practical.
2. Stability can be enhanced by increasing the inertia of the mechanical systems and using machines of low transient reactance and short-circuit ratio. These design parameters are sometimes hard to alter.
3. System protection and faster fault clearance times offer the best prospects for improving the stability of the power system. Instantaneous and differential protection will isolate the severe faults within one to one-and-a-half cycles. Medium-voltage circuit breakers used in industrial distribution have five cycle interrupting time (opening time plus contact parting time). The total fault clearance time is the relay operating time plus the breaker interrupting time.

Power System Stabilizer. Power system stabilizers are used to damp local-machine system oscillations. In high-response excitation systems and with large regulator gains, negative damping is introduced into the machine torque-speed loop, and oscillations of 1 to 2 Hz may become negatively damped. Inter-area oscillations are normally of much lower frequency. The use of power system stabilizers for industrial generators is limited.

SYSTEM ANALYSIS

Power system studies are required for short-circuit, load flow, large motor starting, stability, reliability, harmonic analysis, switching transients, and relay coordination. In addition analysis of power quality problems, failure analysis, cable ampacity calculations in special configurations and grounding grid design studies may be required. The analysis required for a distribution system will depend upon the size, power requirements, nature of the processes, and plant generation facilities, if provided. Each analysis has a specific purpose, and all the studies are rarely required.

A host of data is required for each type of study, though some data are common to the various types of studies and some are specific to a particular study. Trends are toward an integrated common data base, which communicates with editors and data libraries. Manufacturers' data can be directly entered, and provide a convenient resource for the data editors, which can model transformers, motors, transmission lines, generators, and transform data to per-unit quantities.

Short-Circuit Studies

A three-phase (balanced) short-circuit calculation for comparison with the switching equipment capability is the most common type of calculation for industrial distribution systems. In certain cases, magnitudes of single-line-to-ground or double-line-to-ground fault currents can exceed three-phase short-circuit currents. These include faults near solidly grounded synchronous machines, delta–wye transformer connection, with wye winding neutral solidly grounded, grounded wye-delta tertiary autotransformers and grounded wye, three-winding transformers. Assembling an impedance diagram to correctly model the impedances of the various network components is the starting piont of the study. Passive system elements like transformers and reactors remain time invariant, and to model the decaying short-circuit current contributed by dynamic loads (induction and synchronous motors) and generators, multiplying factors shown in Table 10 are used, depending upon the type of calculation involved. This means that a constant mmf behind a transient reactance, which is increased to model the machine under fault conditions, has

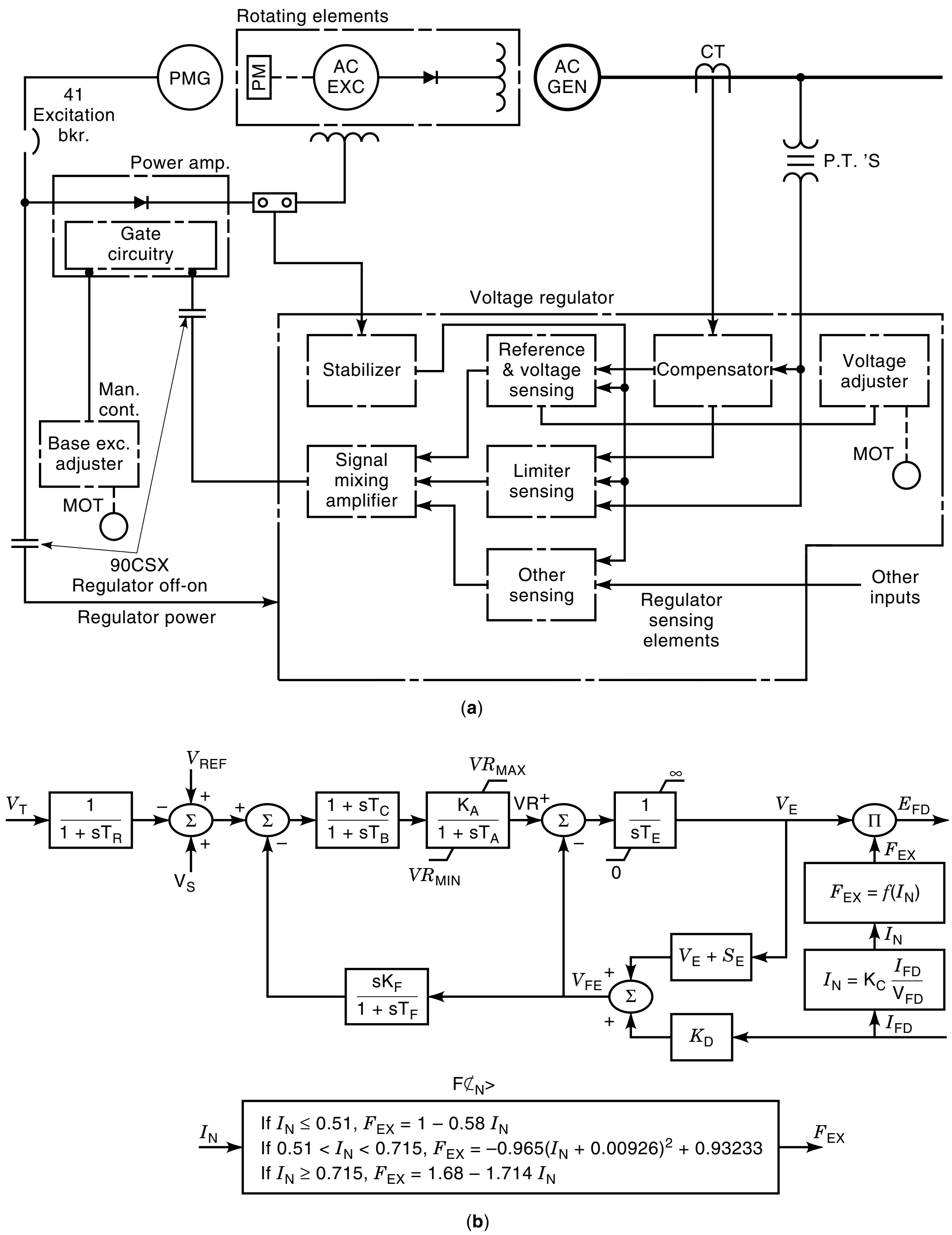


Figure 9. (a) Brushless excitation system; (b) block control-circuit diagram of AC1 excitation system.

Table 10. Multiplying Factors for Dynamic Loads and Generators for Various Types of Short-Circuit Calculations

Type of Calculation	Generators*	Synchronous Motor	Large Induction Motor	Induction Motor $\geq$ 50 hp	Induction Motor $<$ 50 hp
First cycle fault duties for evaluation of high- and medium-voltage breakers and fused contactors	$R + jX''_d$	$R + jX''_d$	$R + jX''$	$1.2(R + jX'')$	∞
Interrupting fault duties for evaluation of high- and medium-voltage circuit breakers	$R + jX''_d$	$1.5(R + jX''_d)$	$1.5(R + jX'')$	$3(R + jX'')$	∞
First cycle fault duties for low-voltage circuit breakers or multi-voltage level systems	$R + jX''_d$	$R + jX''_d$	$R + jX''$	$1.2(R + jX'')$	$1.67(R + jX'')$

* Applicable to all turbine generators; all hydrogenerators with amortisseur windings; all condensers. For hydrogenerators without amortisseur, the factor is $0.75R + 0.75jX'_d$.
X''_d is the rated voltage saturated subtransient reactance of synchronous generators and motors.
X'' is the locked rotor reactance of induction motors.
X'_d is the rated voltage saturated transient reactance of hydrogenerators without amortisseur windings.
A large induction motor is one that is >1000 hp at ≤1800 rev/min or >250 hp at 3600 rev/min.

the same effect as the decrease in emf resulting from the trapped flux in the machine. The prefault load currents are neglected.

The computer solution is arrived by a solution of the matrix equation:

$$I = VZ^{-1} \tag{22}$$

The diagonal elements of the Z matrix contain self or Thevenin impedances, while off-diagonal elements are transfer impedances. Z matrix is a sparse matrix.

While a complex impedance calculation is normally carried out to calculate the fault point impedance, separate reactance and resistance networks are constructed to find the fault point X/R ratio. The first cycle rms asymmetrical currents do not require any special consideration for the local and remote sources. For interrupting duty calculations, appropriate multiplying factors from the ANSI curves, shown in Fig. 10, are applied. Usually, all utility sources are considered remote, and any local generator that supplies less than 40% of its terminal fault current is also considered remote. A weighted factor calculated from curves, depending upon the local and remote fault current contributions, is applied for comparison of the calculated short-circuit currents with the breaker ratings. If there is no local generation, then no ac decrement (NACD) current is set to zero. Before 1964, the circuit breakers were rated in ANSI on an 8-cycle symmetrical "total" basis, that is, considering the asymmetricity and the dc offset at the time of contact parting. Present standard ratings are based upon symmetrical rms basis alone.

Load-Flow Studies

Planning, design, and operation of power systems require load flow calculations to analyze the steady-state (quiescent) performance of the power system under various operating conditions and to study the effect of changes in the system configuration. A more important consideration is study of operation under contingency conditions. A plant generator or a tie line may be out of service, due to a forced outage or maintenance, and full-load operations may be required to be sustained without loss of production. A sudden outage of a source may force power flow through alternative paths of higher impedance, which may result in transient voltage drops large enough to cause voltage instability and widespread shutdowns. Modern power systems are complex, and have many branches in series or parallel, over which the power can flow. Slide rule calculations of the power-flow conditions are virtually impossible. Dynamic load-flow models are used to simulate real-time load flow by utilities in automatic supervisory control and data acquisition (SCADA) systems. For industrial plants, static load-flow analysis is adequate. The load models should be carefully constructed, as dynamic loads behave differently under a voltage sag.

Load-Flow Solution Methods

Iterative Gauss-Seidel. The voltage at kth bus is given by:

$$V_k = \frac{1}{Y_{kk}}\left[\frac{P_k - jQ_k}{V_k^*} - \sum_{i=1}^{i=n} Y_{ki}V_i\right] \qquad \text{for } i \neq k \tag{23}$$

where n = number of buses, V_k and Y_{kk} are complex voltage and admittance, respectively, and V_k^* is the complex conjugate of V_k. The problem of load flow is that neither the voltage nor the current at a bus is known, though the applied load models are known. A "swing" bus is assumed with a series impedance to model the utility's system. The concept of the swing bus is like an infinite bus, and no load or generation can be connected to it. Voltages at all other buses can be assumed, equal to the rated per unit voltage. Using these values, the voltage at kth bus is calculated and the corrected values substituted in Eq. (23). The process is continued for the specified iterations and is repeated for other buses. The convergence of the Gauss-Seidel iteration algorithm is asymptotic, that is, a particular bus voltage is reached in smaller and smaller increments. The rate of convergence can be increased by applying accelerating multiplying factors in the range of 1.2 to 1.8.

Newton–Raphson Method. Small changes in the power flow ΔP give rise to small changes in bus voltages ΔV. A linearized approximation to the power changes as a function of voltage changes is given by:

$$\Delta V = J^{-1}\Delta P \tag{24}$$

where ΔV and ΔP are n column matrices corresponding to n buses and $n \times n$ matrix J is called Jacobian. It consists of partial derivatives, $\partial P_1/\partial V_1$, $\partial P_1/\partial V_2$, . . . $\partial P_1/\partial V_n$, (row 1).

The convergences in Newton–Raphson technique is not asymptotic. It is rapid for first few iterations and slows down as

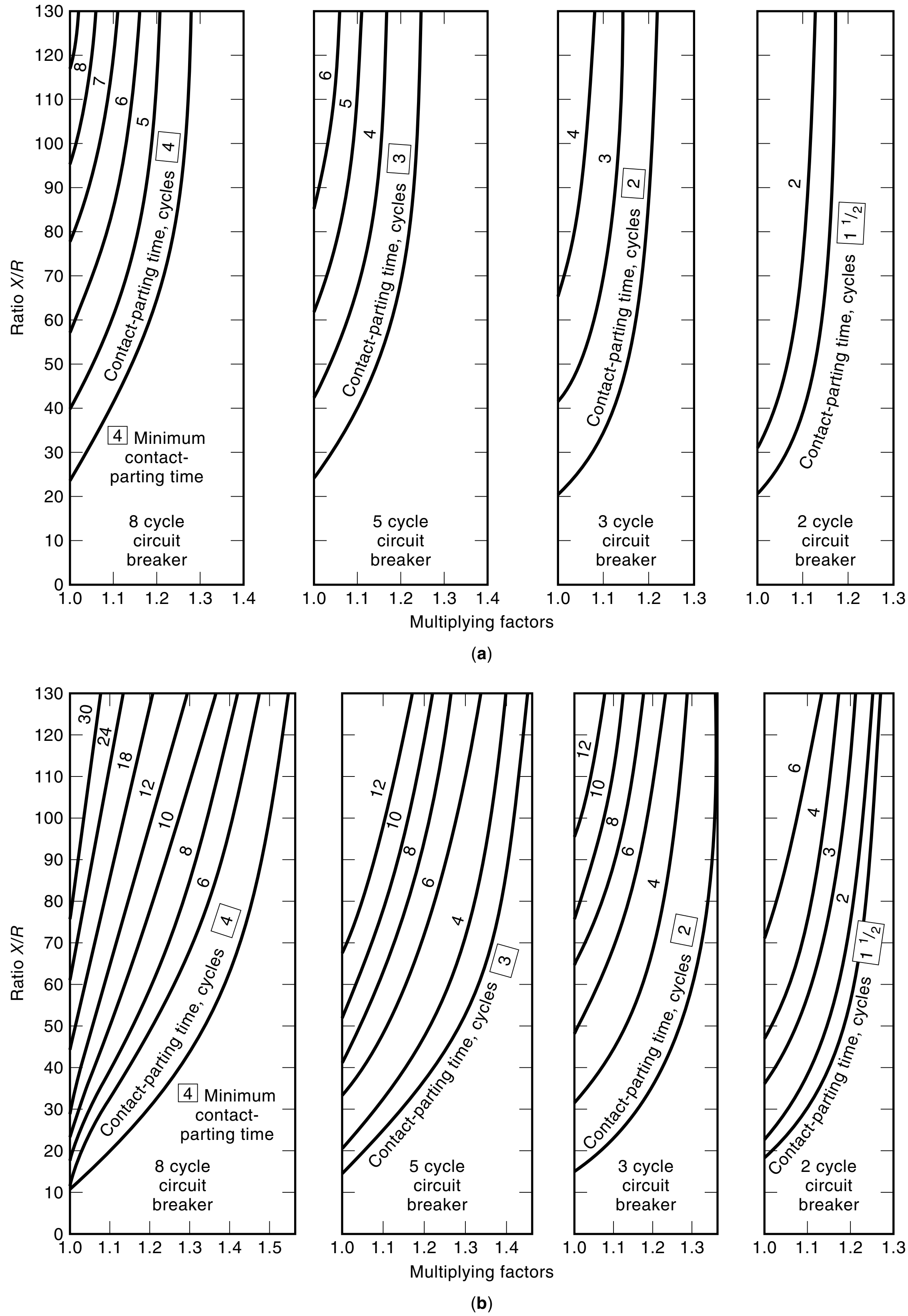


Figure 10. (a) Multiplying factors for three-phase faults fed predominantly from generators; (b) multiplying factors for three-phase and line-to-ground faults fed predominantly from generators (remote).

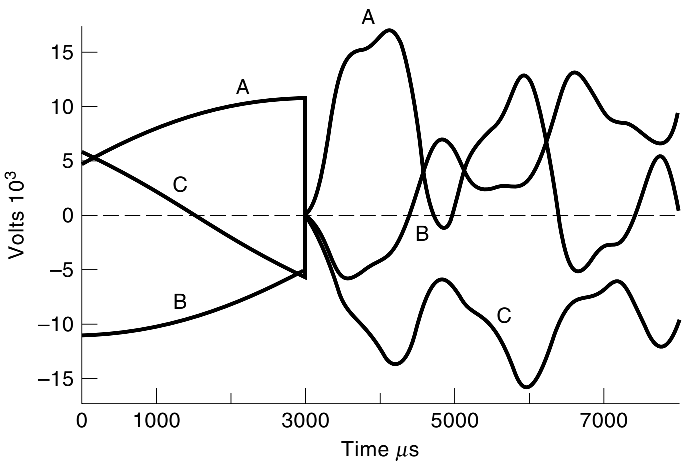


Figure 11. Voltage transients on switching of a 7.5 Mvar capacitor bank at a 13.8 kV bus, switched at crest of phase A voltage, with no initial residual charge.

the convergence is reached. An approximation to the Newton–Raphson method is obtained by observing that, for small change in magnitude of bus voltage, the real power does not change appreciably. Similarly, for a small change in bus voltage phase angle, the reactive power does not change very much. These concepts form the basis of P–Q decoupling or decoupled load flow. The convergence in each method of load flow is not the same, and a most appropriate solution technique must be chosen for a study problem. The Gauss–Seidel method will not converge if negative impedances (as may be required for modeling of three-winding transformers or duplex-reactors) are present. Decoupled method will not converge when the resistance elements exceed the reactance, as may be the case in low-voltage distributions. Newton–Raphson method is prone to failure if given a poor starting voltage estimate.

Switching Transient Studies

Analytical techniques of differential equations and Laplace transforms have been employed to study transients. Switching transients due to capacitor banks in the industrial systems and close to the utility interconnections have known to cause interference and shutdown of the sensitive drive loads. Most studies for industrial distribution system are concentrated on capacitor switching transients. Analog methods are Transient Network Analyzers (TNA), which are made of scaled-down power system component models, interconnected to represent the system under study. Electromagnetic Transient Program (EMTP) is a software package that can be used for single-phase and three-phase networks to calculate electromagnetic switching transients. The versatility of the EMTP program is that each power system component can be modeled from basic building blocks, lumped resistances, reactances and capacitances, nonlinear elements, time-varying elements, variety of switches, and current and voltage sources. Figure 11 shows the voltage transient on switching a 7.5 Mvar capacitor bank on a 13.8 kV bus.

SWITCHGEAR AND MOTOR CONTROL EQUIPMENT

Switchgear is a general term, covering switching and interrupting devices and their combination with associated controls, instruments, metering, protective, and regulating devices. The metal-clad construction is characterized by a drawout and removable main switching and interrupting device. A mechanism for moving it physically between connected and disconnected positions with self-aligning and self-coupling disconnecting devices and disconnectable control wiring connections is provided. Major parts of the primary circuit, that is, disconnecting device, voltage transformers, buses, and control power transformers are completely enclosed by grounded metal barriers that have no intentional openings between compartments. Automatic shutters cover primary elements when primary circuit element is in the disconnected, test, or removed position. Primary bus conductors and connections are covered with insulating material throughout. Mechanical interlocks are provided, and instruments, meters, relays, and control wiring are isolated by grounded metal barriers from all primary circuit elements. Metal-clad construction is available in indoor or outdoor aisleless walk-in-designs for medium voltages up to 38 kV. A number of switching devices are assembled together in one-high or two-high construction, to form a continuous line-up. Figure 12 shows 38 kV metal-clad switchgear assembly in a one-high construction, using vacuum circuit breakers. For higher voltages, individual outdoor circuit breakers are in use. Metal-clad switchgear is metal-enclosed, but not all metal-enclosed switchgear can be correctly designated as metal-clad.

Station-type cubical switchgear is metal-clad power switchgear, characterized by a stationary type interrupting device, mechanically interlocked with a gang-operated primary isolating switch. Primary bus conductors and connections are bare.

Vacuum and SF_6 (sulfa-hexafluoride gas) circuit breakers have replaced air, oil, and air-blast designs at voltage up to 38 kV. A circuit breaker must be selected for the continuous and short-circuit duties involved. Table 11 shows ANSI preferred ratings of indoor oilless medium-voltage breakers rated

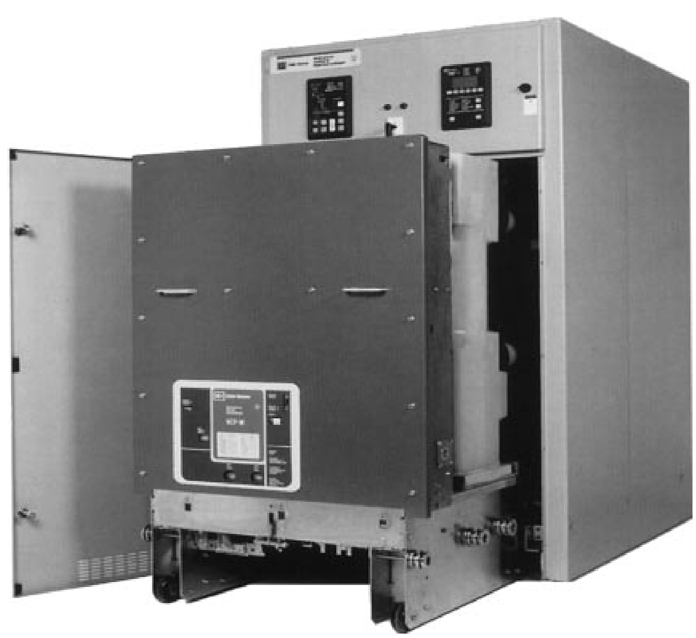


Figure 12. 38 kV metal-clad switchgear with vacuum circuit breakers in one-high construction (courtesy Cutler Hammer Inc.).

Table 11. Preferred Ratings for Indoor Oilless Circuit Breakers (ANSI)*

Rated Max. Voltage	Rated Voltage Range Factor K	Rated Continuous Current at 60 Hz, Amperes rms	Rated Short-Circuit Current at Rated Max Voltage, kA, rms	Rated Interrupting Time	Rated Max. Voltage Divided by K kV, rms	Max. Sym. Int. Capability and Short-Time Current kA, rms	Close and Latching Capability, 2.7 K Times Short-Circuit Current kA Crest
4.76	1.36	1200	8.8	5	3.5	12	32
4.76	1.24	1200,2000	29	5	3.85	36	97
4.76	1.19	1200,2000,3000	41	5	4.0	49	132
8.25	1.25	1200,2000	33	5	6.6	41	111
15.0	1.30	1200,2000	18	5	11.5	23	62
15.0	1.30	1200,2000	28	5	11.5	36	97
15.0	1.30	1200,2000,3000	37	5	11.5	48	130
38.0	1.65	1200,2000,3000	21	5	23.0	35	95
38.0	1.0	1200,3000	40	5	38.0	40	108

* Transient recovery voltage values of these circuit breakers are not yet standardized in ANSI/IEEE standards. However, the rated permissible tripping delay time is 2 s.

on a 5-cycle symmetrical basis. The transient recovery voltage parameters are not standardized for these breakers.

Metal-enclosed medium-voltage interrupter switchgear consists of power fuses, selector switches, control instrumentation, and metering. This type of switchgear is in use for the primary fuse protection of unit substation transformers. The power fuses may be replaced with electronic fuses, which have built-in current transformer and electonic sensing logic, plus a fusible element. These provide tailored time-current characteristics (TCC), not affected by fuse aging and deterioration.

Special Switching Applications. For capacitance switching, a 15 kV 1200 A general-purpose breaker, rated at short-circuit current of 33 kA, has an ANSI-rated highest line switching current of 2 A, up to the maximum rated voltage and a shunt capacitor switching current of 250 A. Back-to-back capacitor switching current rating or cable switching applications are not established for general purpose breakers. A similarly rated "definite purpose" breaker has an isolated shunt capacitor or cable or back-to-back capacitor switching current of 630 A, the peak inrush current limited to 15 kA, and frequency to 2000 Hz. In some applications, particularly on generator buses, more than 100% asymmetricity may be obtained, and precautions should be taken to protect breakers from opening where normal current zeros are not obtained. The voltage stresses under out-of-step switching and capacitor switching exceed those for terminal faults. A special circuit breaker or the one rated for higher voltage is sometimes required for out-of-phase switching.

Low-Voltage Switchgear. Low-voltage circuit breakers are classified as follows:

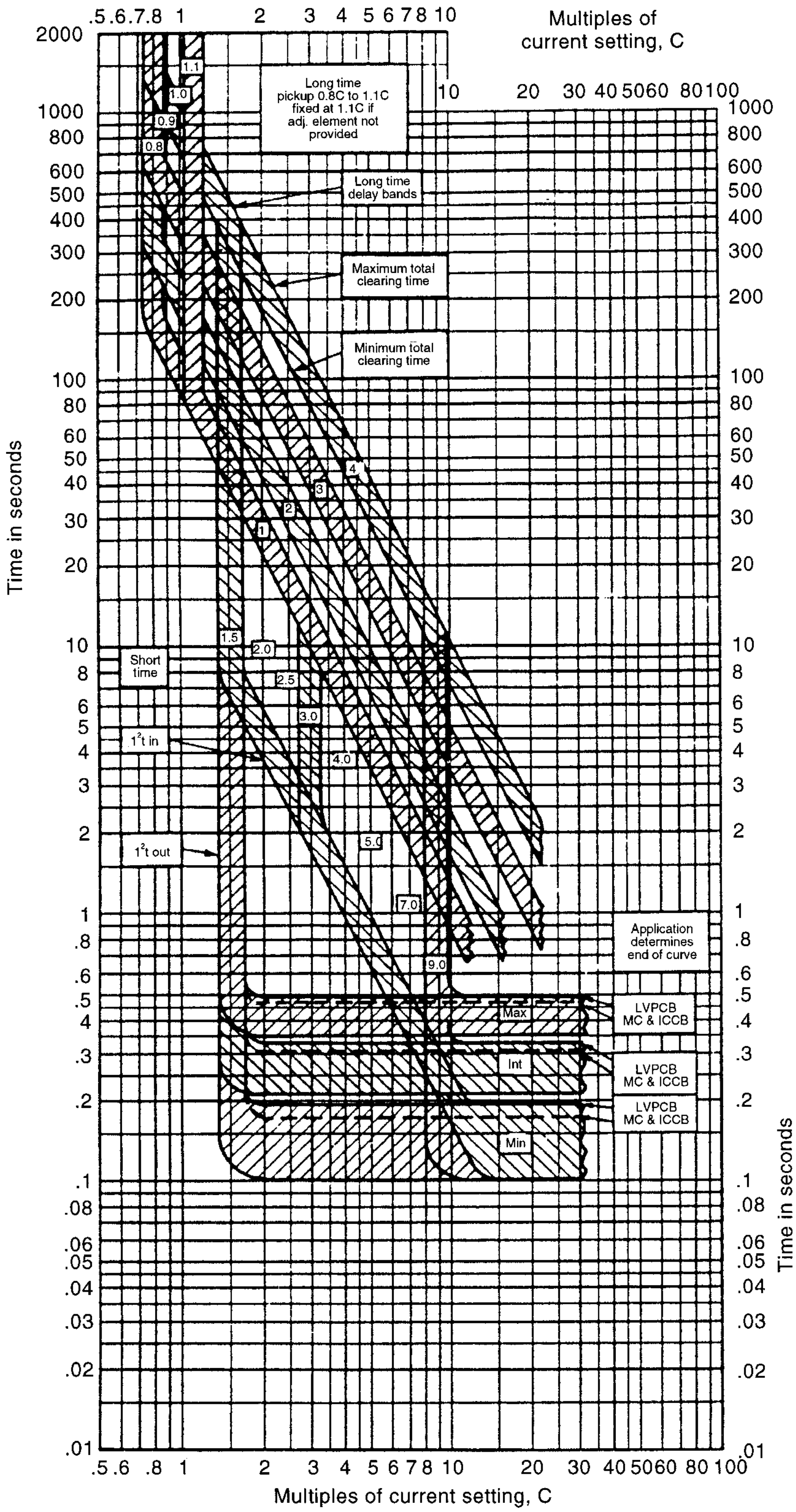
- Molded-case circuit breakers (MCCB)
- Insulated-case circuit breakers (ICCB)
- Low-voltage power circuit breakers (LVPCB)

MCCBs have current-carrying parts, mechanism and trip devices completely contained within a molded case of insulating material. Available in a wide range, from 15 A to 6000 A frames with various interrupting ratings, these are nonmaintainable. Virtually all MCCBs interrupt fast enough to limit the amount of prospective fault current and some are fast enough to be classified as current-limiting type. An MCCB rated for continuous operation at 100% must be thus tested, according to UL requirements. MCCBs that are not 100% rated are capable of operation in an enclosure at their rated maximum temperature at 80% of their free-air current rating.

ICCBs are hybrids between power and molded case circuit breakers, are fast in interruption, but are not of current-limiting type. These may use electronic trip devices, have short-time ratings and ground fault sensing, and employ stored-energy mechanisms similar to those designed for LVPCBs.

LVPCBs are used primarily in drawout metal-enclosed switchgear, are field maintainable, and are largest in physical size. These use a variety of trip units. Figure 13 shows the time current characteristics of a microprocessor-based rms-sensing trip programmer. It has adjustable long-time pickup current level, long-time delay bands, adjustable short-time pickup and delay bands, I^2t ramp function, and adjustable instantaneous settings. Removable current rating plugs may extend the range of application with fixed-current sensors. The ground fault function can be set at a certain percentage of phase fault pickup.

Application of low-voltage breakers should consider voltage, current, and interrupting ratings, temperature rise inside the enclosures, temperature rating of cables and terminals, humidity, altitude, nonlinear loads, and coordination. Load-side circuit breakers of lower interrupting rating, less than the available short-circuit current, can be employed with "series rated" devices. A specific upstream breaker or fuse is tested for such applications. A series combination should not use different manufacturers' circuit breakers or other devices which have not been specifically tested and UL listed for series rating.



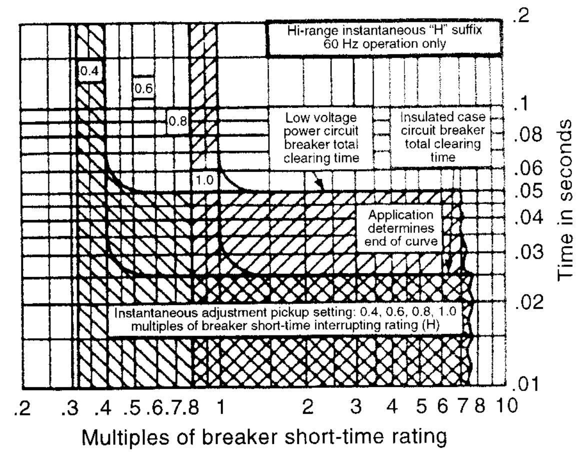


Figure 13. A microprocessor-based trip programmer for LVPCBs, ICCBs, and MCCBs (courtesy General Electric).

Instantaneous-trip circuit breakers (motor circuit protectors) provide adjustable short-circuit protection, but no overload protection. These cannot be used for branch circuit protection, and are primarily used in combination with motor starters, to provide short-circuit protection.

Current-limiting fuses can be integrally mounted with low-voltage circuit breakers for short-circuit protection of high-level short-circuit systems. Ideally, their application should be so coordinated that the breaker trip device clears all overcurrents and low-level fault currents and fuses take over at high-level fault currents and trip all three poles of the circuit breaker to avoid single-phasing.

Molded-case switches with magnetic trip elements do not provide overcurrent protection, but they include a preset nonadjustable magnetic trip element, which serves to protect the switch against damaging effects of high-level fault currents.

Medium-Voltage Motor Controls

Medium-voltage industrial motor controls recognized by NEMA are Class E controls. Class E1 controls use a contactor or a circuit breaker, which acts as a motor switch and also provides fault protection. 50 MVA interrupting rating is the maximum listed for this type of control. Circuit breaker type of controls for interrupting ratings higher than 50 MVA and voltages greater than 5 kV are classified as power switchgear assemblies. NEMA type E2 control is the most popular in the industry and incorporates "R" rated current limiting fuses, which are coordinated with the contactors, raising the interrupting ratings to 350 MVA at 4 kV. Vacuum contactors have replaced air break designs and with an available maximum rating of 800 A, motors up to 5500 hp at 4.16 kV and 3000 hp at 2.4 kV can be controlled with E2 controls. Motor contactors with fuses may be fixed-mounted, with a line-side interlocked disconnect switch, or these may be in a roll-out design. For larger motors and 13.8 kV motors, power circuit breakers are used.

Low-Voltage Motor Controls

A motor control center is a floor-mounted assembly of one or more enclosed vertical sections, with a horizontal bus and principally containing combination motor control units, which includes circuit disconnecting means, branch circuit overcurrent protection, and a magnetic motor controller with associated auxiliary devices. NEMA classification of low-voltage motor control centers is Class I and Class II. Class I assemblies do not include inter-wiring and interlocks between units or to remotely mounted devices. Class II motor control centers include these features. NEMA type wirings are A, B, and C, and these pertain to no terminal blocks or location of terminal blocks and control and interlock wiring methods. Motor branch circuits supplying individual motors must carry 125% of the motor full-load current. NEMA controller sizes 1 through 9 provide control of motors in nonreversing, reversing, plugging, and jogging duty cycles, that is, a size 9 controller has a continuous current rating of 2250 A and a locked rotor current rating of 10,000 A at 480 V for jogging duty.

Solid-state reduced-voltage starters use forward and reverse connected thyristors in each phase, with current sensing control logic and overload protection. The "soft start" reduces inrush current and finds application on "weak" supply systems to control the motor starting voltage drops. The starting torque per ampere of line current is, however, less than some types of magnetic reduced voltage starters.

PROTECTIVE RELAYING

Protection of Transformers

NEC specifies maximum settings of transformer primary and secondary overcurrent devices. In supervised locations, where conditions of maintenance and supervision ensure that qualified persons will monitor and service the installation, providing only primary protection is permissible. For transformers over 600 V and rated impedance not more than 6%, the maximum settings on primary protective devices are 250% of the transformer full-load current for the fuses and 300% for electronically operated fuses or circuit breakers. For transformers of 600 V or less, these primary protective devices should be set at no more than 125% of the transformer full-load current. Higher primary settings are permissible when both primary and secondary protective devices are provided.

"E" rated power fuses are extensively used for transformer primary protection at medium voltage. Fuses rated 100 E or less open in 300 s at current levels of 200% to 240% of their E ratings. Fuses rated above 100 E open in 600 s at a current level between 220% to 264% of their E ratings. The E rating also reflects 2 : 1 minimum melting current versus continuous current ratio, which is a design feature of power fuses. E rated fuses can be expulsion type or current-limiting type. Application of a fuse should consider inrush current of the transformer; 8 to 14 times the transformer full-load current for a duration of 0.1 s and 25 times the full-load current for a duration of 0.01 s; transformer overload, enclosure temperature, and the available short-circuit currents. Another consideration is to protect the transformer so that it is not damaged for a through-fault condition. Depending upon the ratings, ANSI divides liquid-immersed transformers into four categories, with respect to through-fault withstand capability. Category I (5 to 500 kVA single-phase and 15 to 500 kVA three-phase), Category II (501 to 1677 kVA single-phase and 501 to 5000 kVA three-phase), Category III (1668 to 10,000 kVA single-phase and 5001 to 30,000 kVA three-phase), and Category IV (above 10,000 kVA single-phase and 30,000 kVA three-phase). Figure 14 shows through-fault withstand characteristics for liquid-immersed Category II transformers. Through-fault protection should consider: (a) type of secondary fault and transformer winding connection, and (b) transformer secondary grounding system. A line-to-ground fault on the secondary of a delta–wye connected transformer, with wye neutral solidly grounded will result in 58% of the short-circuit current in two phases serving the primary windings, while a phase-to-phase fault results in approximately 116% of the short-circuit current in one primary phase on a per unit basis.

Primary protection of the transformers employing current limiting fuses is available in transformer sizes up to 5 MVA at 13.8 kV, 3 MVA at 4.16 kV, and 1.5 MVA at 2.4 kV. UL listing of indoor transformers with less-flammable liquids for indoor installation is based upon limitation of let-through fault energy by current limiting fuses. Phase fault and ground fault differential protection with harmonic restraint may be provided for transformers of 10 MVA and larger. Apart from relay protection, additional protective devices include winding

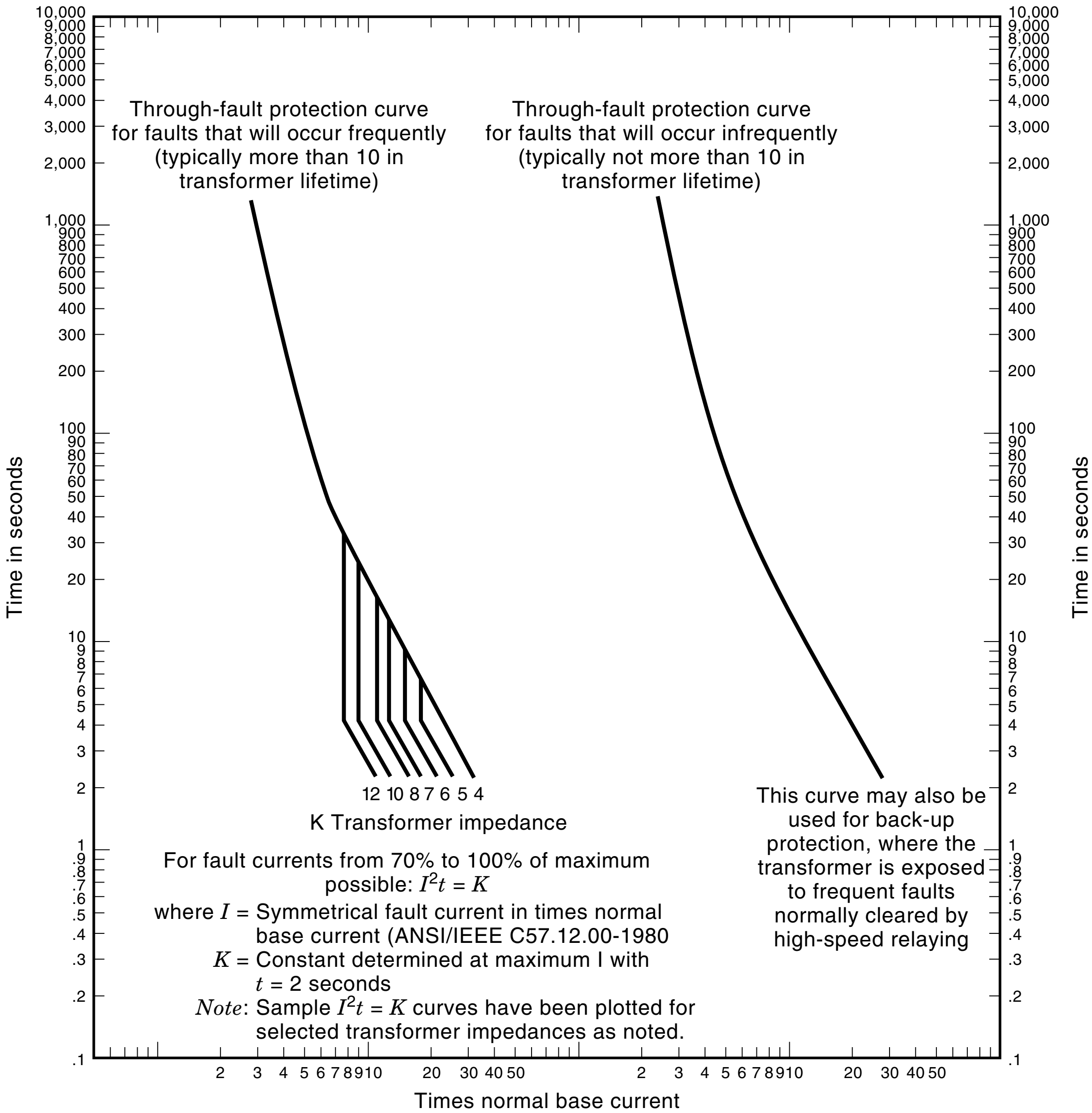


Figure 14. Through-fault withstand characteristics of liquid-immersed Category II transformers.

temperature alarms and trips, low liquid level and temperature alarms, and sudden fault-pressure relays, generally provided for transformers of 5 MVA and above.

Protection of Motors

A motor should be protected for the following conditions of abnormal operation and short-circuit:

- Sustained overloads
- High short-circuit currents due to phase faults
- Ground fault currents. A sustained ground fault current as low as 5 A can cause considerable damage to the windings and even the iron core at the point of fault.
- Negative sequence currents and loss of a phase
- Over temperature in bearings, windings, and air passages, normally detected through resistance temperature detectors (RTD) of copper, nickel, or platinum
- Protection against locked rotor conditions and frequent starts, more than that for which the motor is designed. A locked rotor condition is more severe than a starting condition, because the currents induced in the locked rotor are at supply frequency and heat dissipation is restricted at standstill.
- Protection against loss of the load and load jam
- Synchronizing, pull-out, and field winding protection for synchronous motors

Multifunction static relays have replaced earlier discrete electromagnetic devices for medium-voltage motor protection. These create a thermal replica of the motor windings, based upon the input current, voltage, and winding temperature. The effect of the negative sequence currents for heating in the rotor is simulated by equation:

$$I^2 = I_1^2 + KI_2^2 \tag{25}$$

K can be as high as 6, and the relay "learns" based upon the motor parameters.

For low-voltage motors, bimetallic elements are still in use, though more motors are being protected with solid-state modules incorporating adjustable thermal time-current characteristics, unbalance detection, and locked rotor protection.

Protection of Cables, Bus Bars and Reactors

Phase overcurrent and ground fault time delay and instantaneous relays are the primary protective devices. Low-voltage conductors, other than flexible cords and fixture wires, are protected against overloads in accordance with their ampacity. For conductors over 600 V nominal long time trip setting of a breaker or minimum trip setting of an electronic fuse should not exceed six times the conductor ampacity, and for fuses it should not exceed three times their ampacity. Unit protection for important circuits, feeders, and reactor ties is provided by high impedance differential relays. Depending upon the available through-fault currents, the current transformer requirements may preclude application of these relays for long feeder lengths. For circuit lengths exceeding 600 m, pilot wire differential relays using metallic conductors or fiber-optic interfaces or charge-coupled differential systems are in use.

SURGE PROTECTION

Overvoltages are generated due to lightning or generated in the power system itself due to operation of current limiting fuses, restrikes in breakers, load dropping, and switching of capacitor banks. All the internally generated overvoltages are classified as "switching" generated. These overvoltages, whether transient, short-time, or steady state, stress the insulation system and can cause premature aging and breakdowns.

Lightning is a major source of overvoltage, and an industrial distribution connected to a utility's system through overhead transmission lines becomes exposed to these voltages. A direct lightning stroke current is a steep-fronted waveform, which travels in either direction from the stricken point. Surge current recordings show that 13.5% times the currents exceed 20 kA, with a reasonable probability of discharge currents reaching 40 kA. A distributed-constant transmission line can be considered as an infinite number of elemental inductances each shunted by capacitance. Assuming a lossless line exchange of electromagnetic energy $\frac{1}{2}LI^2$, and capacitive energy $\frac{1}{2}CE^2$, takes place in every elemental section of the propagating wave and surge impedance is given by:

$$Z_0 = EI = \sqrt{L/C} \tag{26}$$

At a discontinuity in the medium, that is, a change in the surge impedance, the voltages of the reflected wave and of the refracted wave, which is the sum of the incident and reflected wave, are given by:

$$V_{\mathrm{rf}} = E(Z_2 - Z_1)/(Z_2 + Z_1) \tag{27}$$

$$V_{\mathrm{rr}} = 2EZ_2/(Z_2 + Z_1) \tag{28}$$

where V_{rf} is the reflected voltage wave, and V_{rr} is the refracted wave. These expressions show a doubling of current at the short-circuited line and doubling of voltage on the open circuited line. A traveling voltage wave encountering a junction of higher surge impedances in series, for example, a series of transformers in a radial system of distribution, can have its voltage magnitude elevated more than twice the voltage magnitude of the initial wave.

Insulation Tests

The insulation tests for electrical equipment are one min power frequency high potential test, 1 min dry, and 10 s wet power frequency tests (for exposed insulation, i.e., transformer bushings), 1.2/50 μs full wave voltage impulse test (BIL) and switching surge test. The 1.2/50 designation means that a voltage wave increases from virtual 0 V to its crest value in 1.2 μs and declines to one-half value in 50 μs. For chopped wave test, a 1.2/50 wave is increased 10% to 15% and is chopped by a suitable gap after a certain minimum time to flash over. Typical test values for transformers are shown in Table 12. The impulse voltages for switching surges are slow-fronted. Gapless surge arresters are tested, with surges having wavefront times of 45 to 60 μs. Table 12 shows the peak of the switching surge for switching surge test on transformers. In a front-of-wave (FOW) test, the impulse voltage is raised so that it is chopped on the wave front. This test is useful to check the inter-turn insulation strength. Rotating machines have relatively low impulse strength and no standardized BIL ratings, though these have standardized high-potential test values. Insulation coordination is a process of correlation of the equipment insulation strength, with expected overvoltages and with the characteristics of surge-protection devices.

Surge Arresters

Surge arresters can be classified as gap-type and gapless type. Internally designed gaps are used in silicon carbide arresters, so that elements of low resistance can be used which can withstand continuously the system voltage. Metal oxide (zinc) valve elements were introduced in 1970s and have a much greater nonlinearity. These can withstand system rated voltage continuously, without a series gap. The arrester characteristics can be expressed by a so-called α equation:

$$I = KV^{\alpha} \tag{29}$$

α is 10 for silicon carbide arresters and 50 for metal oxide arresters, I is the current through the arrester elements, V is the resulting voltage drop through the valve elements, and K is a constant. Discharge voltages on silicon carbide arresters for steep-fronted voltages waves, as compared with zinc oxide gapless arresters, are higher by 15% to 20%.

Classification of valve type arresters based upon "classifying" lightning impulse and switching surge current divides them into following four classes: (1) station class, (2) intermediate class, (3) distribution class heavy duty and normal duty, and (4) secondary. High discharge currents may be encountered in presence of power capacitors, and these calculations require simulations of the system and arrester characteristics on digital computers. Durability, discharge capability, and protective level primarily determine the class of arrester selected. Three categories of protective voltage level characteristics are recognized:

Table 12. Impulse Test Levels for Liquid-Immersed Transformers

Insulation Class and Nominal Bushing Rating	Windings: Hi-Pot Tests	Windings: Chopped Wave, Minimum Time to Flashover		Windings: BIL Full Wave (1.2/50)	Windings: Switching Surge Level	Bushing Withstand Voltages: 60-Cycle 1 Min Dry	Bushing Withstand Voltages: 60-Cycle 10 s Wet	Bushing Withstand Voltages: BIL Impulse Full Wave
kV (rms)	kV (rms)	kV (crest)	μs	kV (crest)	kV (crest)	kV (rms)	kV (rms)	kV (crest)
1.2	10	54 (36)	1.5 (1)	45 (30)	20	15 (10)	13 (6)	45 (30)
2.5	15	69 (54)	1.5 (1.25)	60 (45)	35	21 (15)	20 (13)	60 (45)
5.0	19	88 (69)	1.6 (1.5)	75 (60)	38	27 (21)	24 (20)	75 (60)
8.7	26	110 (88)	1.8 (1.6)	95 (75)	55	35 (27)	30 (24)	95 (75)
15.0	34	130 (110)	2.0 (1.8)	110 (95)	75	50 (35)	45 (30)	110 (95)
25.0	50	175	3.0	150	100	70	70 (60)	150
34.5	70	230	3.0	200	140	95	95	200
46.0	95	290	3.0	250	190	120	120	250
69.0	140	400	3.0	350	280	175	175	350
92.0	185	520	3.0	450	375	225	190	450
115.0	230	630	3.0	550	460	280	230	550
138.0	275	750	3.0	650	540	335	275	650
161.0	325	865	3.0	750	620	385	315	750

Values in parentheses are for distribution transformers, instrument transformers, constant-current transformers, step-and-induction-voltage regulators, and cable potheads of distribution cables. The switching surge levels shown are applicable to power transformers and not distribution transformers.

1. Front of wave (FOW) protective level is defined as the higher of (a) crest discharge voltage resulting from a current wave through the arrester of lightening impulse classifying current magnitude with a rate of rise high enough to produce arrester crest voltage in 0.5 μs or, (b) gap sparkover voltage on similar waveshapes. The lightning impulse classifying currents ranges between 1.5 kA to 20 kA, depending upon the arrester class and voltage rating.
2. Lightning protective level (LPL), also referred to as the discharge voltage (IR) of the arrester, is the voltage that appears across the arrester when a standard 8/20 μs current wave is conducted through the arrester.
3. Switching impulse protective level (SPL) is defined as the higher of (a) the discharge voltage with a current wave through the arrester of switching impulse classifying current and a time of actual current crest of 30 to 2000 μs, or (b) gap sparkover on similar wave shapes.

The degree of protection is measured by the protective ratio. Three protective ratios in common use are:

1. PR_{L1} = CWW/FOW
2. PR_{L2} = BIL/LPL
3. PR_S = BSL/SPL

where CWW, BIL, and BSL are chopped wave withstand, basic insulation level, and basic switching surge level of the equipment being protected, and FOW, LPL, and SPL are as defined above.

Arrester maximum fundamental frequency operating voltage must exceed the expected maximum continuous overvoltage (MCOV) imposed by the system. An arrester must also withstand anticipated temporary overvoltages (TOV). A high-resistance grounded system may be operated for long period of times, with a phase-to-ground fault with complete displacement of neutral. The voltage to ground on the unfaulted phases will rise to line-to-line voltage, that is, by a factor of $\sqrt{3}$. A shielded substation will have less severe surges, as compared with an unshielded substation, resulting in better protective levels. The separation effects must be considered. The voltage at the protected equipment will be higher than at the arrester terminals, due to Ldi/dt of the connecting leads.

Rotating Machine Protection

Surge capacitors paralleled with surge arresters are provided in the line-side terminal box of motors of 1000 hp and above. Due to large capacitance coupling between winding conductors of each coil and grounded iron core, the end turns of the terminal coil in a motor are overstressed on an incident voltage wave. The rate of rise of fast voltage transient will be attenuated by the charging rate of a surge capacitor.

Secondary Surge Protection

With the proliferation of electronic equipment, secondary surge protection has gained momentum. Transient voltage surge suppression (TVSS) is required at low-voltage transformer secondaries, feeders to sensitive equipment, instrumentation loops, input power circuits to computers, data highways, and telephone cable circuits. Hybrid circuits with series and parallel elementls are used. In a series hybrid circuit, the primary component may consist of a high-energy discharge device, that is, a gas tube or silicon avalanche diodes, a series reactor, which delays the rapidly rising voltage waveform, and a secondary load-side component. A voltage clamping ratio of 2 can be obtained under ANSI Category C installations, with a response time of 5 ns under ANSI bi-wave test applications.

GROUNDING

System Grounding

System grounding refers to the electrical connection between the phase conductors and ground, and dictates the manner in which the neutral points of wye-connected transformers and generators or artificially derived neutral systems through delta-wye or zig-zag transformers are grounded.

Solid Grounding. In a solidly grounded system, there is no intentional impedance between the system neutral and ground. These systems meet the requirements of an "effectively grounded" system, in which ratio X_0/X_1 is positive and less than 3.0 and ratio R_0/X_0 is less than 1, where X_1, X_0 and R_0 are the positive-sequence reactance, zero-sequence reactance, and zero-sequence resistance, respectively. The coefficient of grounding (COG), defined as a ratio of E_{Lg}/E_{LL} in percentage, where E_{Lg} is the highest rms voltage on an unfaulted phase, at a selected location, during a fault effecting one or more phases to ground and E_{LL} is the rms phase-to-phase power frequency voltage obtained at that location with the fault removed. Though these systems provide effective control of overvoltages, which become impressed on or are self-generated in the power system by insulation breakdowns and restriking faults, these give the highest arc-fault current and consequent damage, and require immediate isolation of the faulty section.

The limits of the acceptable damage to material for arc-fault currents of 3000 to 26,000 A in 480 V systems have been set in NEMA by the following equation:

$$V_D = K_s 250 I_r = K_s (I)^{1.5} t \ (\text{mm})^3 \tag{30}$$

where K_s is the burning rate of material in mm^3/As$^{1.5}$, V_D is acceptable damage to material in mm^3, I_r is the rated current, t is time duration in s, I is the arc-fault current, and K_s depends upon material type and is given by:

$$\begin{aligned} K_s &= 11.80 \times 10^{-3} \text{ for copper} \\ &= 24.91 \times 10^{-3} \text{ for aluminum} \\ &= 10.81 \times 10^{-3} \text{ for steel} \end{aligned}$$

Due to high arc-fault damage and interruption of processes, the solidly grounded systems are not in much use in the industrial distribution systems. However, ac circuits of less than 50 V and circuits of 50 to 1000 V for supplying premises wiring systems and single-phase 120/240 V control circuits must be solidly grounded, according to NEC.

Low-Resistance Grounding. An impedance grounded system has a resistance or reactance connected in the neutral circuit to ground. Reactance or "resonant" grounded systems are not used in industrial installations. In a low-resistance grounded system, the resistance in the neutral circuit is so chosen that the ground fault is limited to approximately full-load current or lower, typically 200 to 400 A. Though the arc fault damage is reduced, and these systems provide effective control to safe levels of the overvoltages generated in the system by resonant capacitive-inductive couplings and restricking ground faults, yet the ground fault cannot be allowed to be sustained and selective tripping must be provided. For a ground fault current limited to 400 A, the pick-up sensitivity of modern ground fault devices of 5 A or even lower protects approximately 98.75% of the transformer and motor windings. The incidence of ground fault toward the neutral decreases as square of the winding turns. Medium-voltage distribution systems in industrial distributions are commonly low resistance grounded.

Ungrounded Systems. In an ungrounded system, there is no intentional connection to ground, except through potential transformers or metering devices of high impedance. In reality, an ungrounded system is coupled to ground through distributed phase capacitances. It is difficult to assign X_0/X_1 and R_0/X_0 values for ungrounded systems. The ratio X_0/X_1 is negative, and may vary from low to high values and COG may approach 120%. These systems provide no effective control of transient and steady-state voltages above ground. A possibility of resonance with high-voltage generation, approaching five times or more of the system voltage exists for values of X_0/X_1 between 0 and -40. For the first phase-to-ground fault, the continuity of operations can be sustained, though unfaulted phases have $\sqrt{3}$ times the normal line-to-ground voltage. All unremoved faults, thus, put greater than normal voltage on system insulation and increased level of conductor and motor insulation is required. The grounding practices in the industry are withdrawing from this method of grounding.

High-Resistance Grounded. In a high-resistance grounded system, the charging current due to distributive phase capacitance to ground under a phase-to-ground fault is made equal to or less than the current through the resistor, that is, $I_r \geq I_c$, where I_r is the current through the grounding resistor due to neutral displacement on a phase-to-ground fault and I_c is the distributed phase capacitance current. Thus the total ground fault current is $\sqrt{2}I_c$. This controls the overvoltages due to resonant inductive-capacitive couplings and the overvoltages due to arcing-type faults. Continuity of operations can be sustained with a single-line-to-ground fault, though no phase-to-neutral loads can be served. Fault detection, isolation, and alarm can be provided through neutral connected voltage relays. A "pulsing type" of grounding and detection system monitors the system ground and, on occurrence, of a ground fault, a cycle-timer shorts-out a portion of the grounding resistor at a frequency of approximately 20 min^{-1}. The ground fault current pulsates and the fault point can be localized by a portable clip-on-type current-sensing device. Selective tripping and isolation is possible, using specially designed core balance current transformers and sensitive relays, pickup sensitivity of 100 mA or lower. Low-voltage distribution systems in industrial plants are often high resistance grounded.

Equipment Grounding

The equipment ground refers to the system of grounding conductors and buses by which all non-current-carrying metallic structures in an industrial installation are interconnected and grounded. The purpose is to maintain a low potential difference between metallic members, minimizing the possibility of electrical shock to personnel, and to provide paths for the ground current for protective devices to operate selectively. Equipment and tanks handling solvents, dusty materials, or other inflammable products, may accumulate a static charge, and, therefore, grounding is essential to provide a discharge path and prevent fire hazards.

Lightning protection grounding is concerned with conducting the discharge currents originating in the atmosphere cloud formations to earth. The current in the direct discharge may be as high as 200 kA, rising at a steep rate of 10 kA/μs. The protection consists of air terminals (lightning rods), cross and down conductors, which form a Faraday's cage. The down

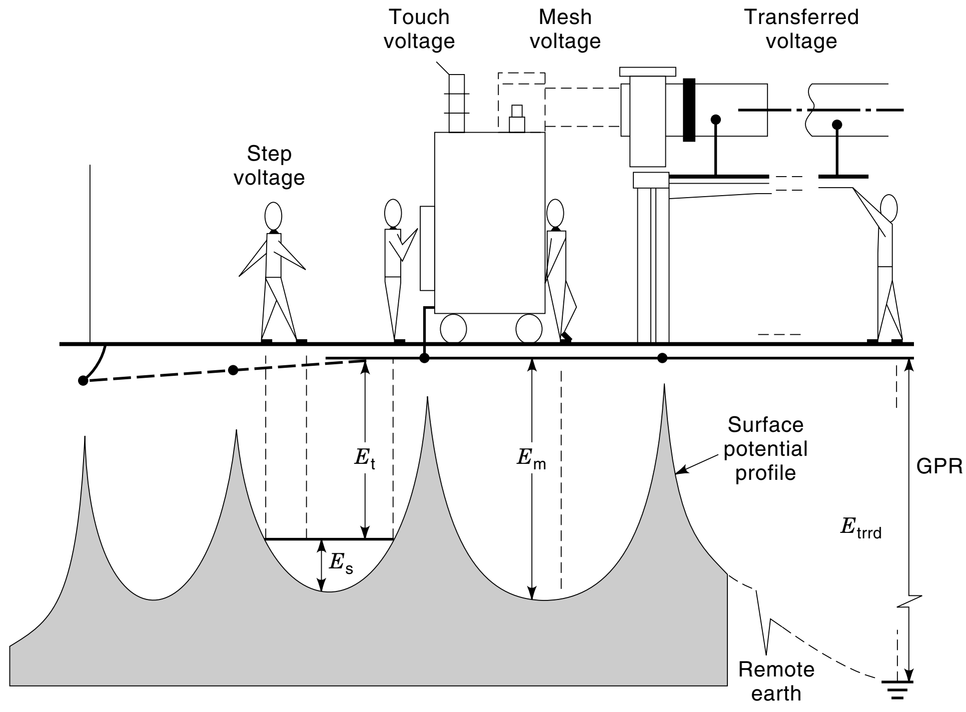


Figure 15. Transfer potential E_{trrd} to remote ground. E_s, E_t and E_m are step, touch, and mesh potentials, respectively, and GPR is ground potential rise.

conductors must have adequate current-carrying capacity and present the least possible impedance to earth. The dynamic devices for lightning protection consist of emission ionization streamers and use radioactive sources. These produce a rising air stream, which acts as an extended air terminal.

Grounding of computer systems and sensitive electronic equipment requires special precautions so as not to create "noise" in the ground couplings. A signal reference grid may be used, which may consist of a large sheet of copper foil installed under the computer, or a copper mesh laid on the subfloor. All computer units are bonded to this grid besides equipment grounding conductors.

Utility Substation Grounding

Most industrial systems will have a utility substation, which may be served from high-voltage transmission lines up to 230 kV. As the plant distribution systems are impedance grounded, the maximum ground fault current giving rise to ground potential rise (GPR) occurs for a fault in the utility's incoming service. GPR is given by $I_G R_G$, where I_G is the current returning through grid to earth and R_G is the grid resistance. All the available ground fault current does not give rise to GPR and a split factor is applicable, depending upon the number of sky wires, tower footing resistance, soil resistivity, connections to grounding conductors, and remote and local grounds. A potential problem for such a fault scenario can be the transfer potential, illustrated in Fig. 15. The GPR is transferred to a remote ground through metallic couplings, that is, cable sheaths. A plant grounding grid, however, covers a large area, and is principally composed of steel reinforcing bars in concrete footings and foundations, ground electrodes, and ground conductors, all interconnected together. The ground safety is, thus, based upon creating an equipotential surface throughout the work area, and the utility substation grid is bonded with the plant grounding system. Transfer potentials are, therefore, not a problem, though special situations require careful evaluations.

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