Introduction to Protective Device Coordination Analysis

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Introduction to Protective Device Coordination Analysis

General

Electrical power systems must be designed to serve a variety of loads safely and reliably. Effective control of short-circuit current, or fault current as it is commonly called, is a major consideration when designing coordinated power system protection. In order to fully understand the nature of fault current as it is applied to electrical power system design, it is necessary to make distinctions among the various types of current available, normal as well as abnormal. It is also important to differentiate between the paths which the various types of current will take. Both types of current and current path, as well as current magnitude, will affect the selection and application of overcurrent protective devices.

Normal current

Normal, or load, current may be defined as the current specifically designed to be drawn by a load under normal, operating conditions. Depending upon the nature of the load, the value of normal current may vary from a low level to a full-load level. Motors offer a good example. Normal motor current varies from low values (under light loading) to medium values (under medium loading) to maximum values (under maximum loading). Maximum load current is called full load current and is included on the motor nameplate as FLA (Full-Load Amperes). Normal current, therefore, may vary from low values to FLA values. Additionally, normal current flows only in the normal circuit path. The normal circuit path includes the phase and neutral conductors. It does not include equipment grounding conductors.

Overload current

Overload current is greater in magnitude than full-load current and flows only in the normal circuit path. It is commonly caused by overloaded equipment, single-phasing, or low line voltage, and thus is considered to be an abnormal current. Some overload currents, such as motor starting currents, are only temporary, however, and are treated as normal currents. Motor starting current is a function of the motor design and may be as much as twenty times full-load current in extreme cases. Motor starting current is called locked-rotor current and is included on the motor nameplate as LRA (Locked-Rotor Amperes). Overload current, then, is greater in magnitude than full-load amperes but less than locked-rotor amperes and flows only in the normal circuit path.

Short-circuit current

Short-circuit current is greater than locked-rotor current and may range upwards of thousands of amperes. The maximum value is limited by the maximum short-circuit current available on the system at the fault point. Short-circuit current may be further classified as bolted or arcing.

- Bolted short-circuit current. Bolted short-circuit current results from phase conductors becoming solidly connected together. This may occur from improper connections or metal objects becoming lodged between phases. Obviously, large amounts of short-circuit current will flow into a bolted fault.

- Arcing short-circuit current. Arcing short-circuit current results from phase conductors making less than solid contact. This condition may result from loose connections or insulation failure. When this happens, an arc is necessary to sustain current flow through the loose connection. Since the arc presents impedance to the flow of current, smaller amounts of current will flow into an arcing fault than will flow into a bolted fault.

- Failure classifications. Short-circuit currents, whether bolted or arcing, will involve two or more phase conductors. Line-to-line faults involve two-phase conductors (A-B, B-C, C-A) while three-phase faults involve all three phases (A-B-C). Although three-phase bolted short-circuits rarely occur in practice, short-circuit studies have traditionally been based upon the calculation of three-phase, bolted short-circuit current. Modern personal computers and associated software have made the calculation of all types of fault currents easier to accomplish.

Ground-fault current

Ground-fault current consists of any current which flows outside the normal circuit path. A ground-fault condition then, results in current flow in the equipment grounding conductor for low-voltage systems. In medium- and high-voltage systems, ground-fault current may return to the source through the earth. Ground-fault protection of medium-voltage and high-voltage systems has been applied successfully for years using ground current relays. Ground-fault protection of low-voltage systems is a considerable problem because of the presence and nature of low-level arcing ground faults. Ground-fault current on low-voltage systems may be classified as leakage, bolted, or arcing.

- Leakage ground-fault current. Leakage ground-fault current is the low magnitude current (milliampere range) associated with portable tools and appliances. It is caused by insulation failure, and is a serious shock hazard. Personnel protection is accomplished by using ground-fault circuit interrupters (GFCI) in the form of GFCI-receptacles or GFCI-circuit-breakers.

- Bolted ground-fault current. Bolted ground-fault current results when phase conductors become solidly connected to ground (i.e., the equipment grounding conductor or to a grounded metallic object). Bolted ground-fault current may equal or even exceed three-phase, bolted short-circuit current if the system is solidly grounded. Equipment protection is accomplished by using standard phase and ground overcurrent devices depending upon system voltage levels.

- Arcing ground-fault current. Arcing ground-fault current results from a less than solid connection between phase conductors and ground. Because an arc is necessary to sustain current flow through the connection, the magnitude of arcing ground-fault current will be less than that of bolted ground-fault current. Depending upon the arc impedance, arcing ground-fault current may be as low as several amperes (low-level) or as high as 20-38 percent of three-phase, bolted short-circuit current (high level) on a 480V system. Considerable research has been conducted in the area of arcing ground-fault current magnitudes on low voltage systems. Some designers use the 38 percent value while others use the 20 percent figure. NEMA PB2.2 applies ground-fault damage curves instead of performing a calculation. Equipment protection is accomplished by using ground-fault protective (GFP) devices. Due to ionization of the air, arcing ground faults may escalate into phase-to-phase or three-phase faults.

Sources of short-circuit current

All sources of short-circuit current and the impedances of these sources must be considered when designing coordinated power system protection.

- Synchronous generators. When a short-circuit occurs downstream of a synchronous generator, the generator may continue to produce output voltage and current if the field excitation is maintained and the prime mover continues turning the generator at synchronous speed. The flow of short-circuit current from the generator into the fault is limited only by the generator impedance and downstream circuit impedances. The magnitude of generator fault current depends on the armature and field characteristics, the time duration of the fault, and the load on the generator. The ability of a generator to supply current during a fault is a function of the excitation system.

- Some generator excitation systems do not have the ability to sustain short-circuit current. The magnitude of fault current is determined by the generator reactance, and, for such systems, can be essentially zero in 1.0 to 1.5 seconds.

- Static exciters derive excitation voltage from the generator terminals. Since static exciters do not sustain short-circuit current, protective devices on the system will not operate properly, or at all. Static exciters, therefore, are not recommended. Static exciters with current boost should be specified for applications requiring static excitation.

- Round-rotor generators with brushless exciters, typically above 10 MVA, can sustain short-circuit current for several seconds. Salient-pole generators less than 10 MVA, also with brushless exciters, will typically sustain short-circuit current at 300 percent of generator full load amperes.

- Synchronous motors. When a short-circuit occurs upstream of a synchronous motor, the system voltage goes to zero, and the motor begins losing speed. As the motor slows down, the inertia of the load is actually turning the motor and causing it to act like a generator. The synchronous motor has a dc field winding, like a generator, and actually delivers short-circuit current into the fault until the motor completely stops. As with a generator, the short-circuit current is limited only by the synchronous motor impedance and the circuit impedance between the motor and the fault.

- Induction motors. With one slight difference, a short-circuit upstream of an induction motor produces the same effect as with a synchronous motor. Since the induction motor has no dc field winding, there is no sustained field current in the rotor to provide flux as is the case with a synchronous machine. Consequently, the short-circuit current decays very quickly.

- Supply transformers. Supply transformers are not sources of short-circuit current. Transformers merely deliver short-circuit current from the utility generators to the fault point. In the process, transformers change the voltage and current magnitudes. Transformer impedances will also limit the amount of short-circuit current from the utility generators. Standard tolerance on impedance is plus or minus 7.5 percent for two-winding transformers and plus or minus 10 percent for three-winding transformers. The minus tolerance should be used for short circuit studies and the plus tolerance for load flow and voltage regulation studies.

Time variation of short-circuit current

Since short-circuit current from rotating machines varies with time, it is convenient to express machine impedance (inductive reactance) as a variable value. This variable reactance will allow calculation of short-circuit current from a rotating machine at any instant in time. For the purpose of simplification, three values of reactance are assigned to rotating machines for the purpose of calculating short-circuit current at three specified times following the occurrence of a fault. These three values are called subtransient, transient, and synchronous reactances.

- Subtransient reactance (Xd”). Subtransient reactance is a value used to determine the short-circuit current during the first few cycles after a short-circuit occurs. This is the short-circuit current value to be used in all short-circuit studies.

- Transient reactance (Xd’). Transient reactance is a value used to determine the short-circuit current from the first few cycles up to about 30 cycles after the short-circuit occurs (depending upon the design of the machine). This value is often used in voltage regulation studies.

- Synchronous reactance (Xd). Synchronous reactance is a value used to determine the short-circuit current when the steady state condition has been reached. Steady state is reached several seconds after the short-circuit occurs. This value is often used to determine the setting of generator backup overcurrent relays.

Symmetrical and asymmetrical short-circuit currents

"Symmetrical" and "asymmetrical” are terms used to describe the symmetry of the short-circuit current waveform around the zero axis. If a short-circuit occurs in an inductive reactive circuit at the peak of the voltage waveform, the resulting short-circuit current will be totally symmetrical. If a short-circuit, in the same circuit, occurs at the zero of the voltage waveform, the resulting short-circuit current will be totally asymmetrical. If a short-circuit, in the same circuit, occurs at some time between the zero and peak of the voltage waveform, the resulting short-circuit current will be partially asymmetrical. The amount of offset or asymmetry depends on the point when the fault occurs. In circuits containing both resistance and inductive reactance, the amount of asymmetry will vary between the same limits as before. However, the X/R ratio (ratio of inductive reactance to resistance looking upstream from the fault point) will determine the rate of decay of the DC component. As X/R increases, the rate of decay decreases. Interrupting current ratings may have to be derated for high X/R values. Practically speaking, most all short-circuit currents are partially asymmetrical during the first few cycles after a short-circuit occurs. Modern personal computers can now be used to easily calculate symmetrical and asymmetrical current values at various times after a fault. Low-voltage protective devices are rated on a symmetrical basis but tested on an asymmetrical basis. Medium-voltage switchgear has a momentary and an interrupting rating. The momentary rating is the short-circuit duty during the first cycle after a fault, and de- fines the equipment's ability to close and latch against worst-case mechanical stresses. The interrupting rating is the short-circuit duty as the equipment contacts part, and is expressed in symmetrical amperes or MVA. Medium-voltage fuses have interrupting ratings expressed in symmetrical amperes.

Overcurrent protection devices

General

Design of power system protection requires the proper application motor of overload relays, fuses, circuit breakers, protective relays, and other special purpose overcurrent protective devices. This chapter provides detailed information about various protective devices, illustrates their time-current characteristics, and identifies information required to design coordinated power system protection.

Motor overload relays

- Thermal overload relays. The most common overcurrent protective device is the thermal overload relay associated with motor starting contactors. In both low-voltage and medium-voltage motor circuits, thermal overload relays detect motor overcurrents by converting the current to heat via a resistive element. Thermal overload relays are simple, rugged, inexpensive, and provide very effective motor running overcurrent protection. Also, if the motor and overload element are located in the same ambient, the thermal overload relay is responsive to changes in ambient temperature. The relay trip current is reduced in a high ambient and increased in a low ambient. The curves level off at about 10 to 20 times full-load current, since an upstream short-circuit device, such as a fuse or circuit breaker, will protect the motor circuit above these magnitudes of current. The thermal overload relay, therefore, combines with the short-circuit device to provide total over-current protection (overload and short-circuit) for the motor circuit.

- Melting alloy type overload relays, as the name implies, upon the circuit when heat is sufficient to melt a metallic alloy. These devices may be reset manually after a few minutes is allowed for the motor to cool and the alloy to solidify.

- Bimetallic type overload relays open the circuit when heat is sufficient to cause a bimetallic element to bend out of shape, thus parting a set of contacts. Bimetallic relays are normally used on automatic reset, although they can be used either manually or automatically.

- Standard, slow, and quick-trip (fast) relays are available. Standard units should be used for motor starting times up to about 7 seconds. Slow units should be used for motor starting times in the 8-12 second range, and fast units should be used on special-purpose motors, such as hermetically sealed and submersible pump motors which have very fast starting times.

- Ambient temperature — compensated overload relays should be used when the motor is located in a nearly-constant ambient and the thermal overload device is located in a varying ambient.

- Magnetic current overload relays. Basically, magnetic current relays are solenoids. These relays operate magnetically in response to an over-current. When the relay operates, a plunger is pulled upward into the coil until it is stopped by an insulated trip pin which operates a set of contacts. Magnetic relays are unaffected by changes in ambient temperature. Magnetic current relays may be used to protect motors with long starting times or unusual duty cycles, but are not an alternative for thermal relays.

Information required for coordination. The following motor and relay information is required for a coordination study:

- Motor full-load amperes rating from the motor nameplate.
- Overload relay ampere rating selected in accordance with NFPA 70.
- Overload relay time-current characteristic curves.
- Motor locked rotor amperes and starting time.
- Locked rotor ampere damage time for medium-voltage motors.

Fuses

A fuse is a non-adjustable, direct acting, single-phase device that responds to both the magnitude and duration of current flowing through it. Fuses may be time delay or non-time delay, current-limiting or non-current-limiting, low-voltage or high-voltage.

Information required for coordination. The following fuse information is required for a coordination study:

- Fuse continuous current rating.
- Fuse time-current characteristic curves.
- Fuse interrupting-current rating.
- UL classification and time delay characteristics.

Motor short-circuit protectors (MSCP)

Motor short-circuit protectors are current-limiting, fuse-like devices designed specifically for use in switch-type, combination motor controllers. UL considers MSCPs to be components of motor controllers rather than fuses. Therefore, MSCPs are marked by letter designations (A-Y) instead of ampere ratings and may not be used as fuses. MSCPs may be used in motor circuits provided the MSCP is part of a combination motor controller with overload relays and is sized not greater than 1,300 percent of motor FLA (NFPA 70). This relatively new arrangement (first recognized by NFPA 70-1971), provides short-circuit protection, overload protection, motor control, and disconnecting means all in one assembly. MSCPs provide excellent short-circuit protection for motor circuits as well as ease of selection.

Circuit breakers

A circuit breaker is a device that allows automatic opening of a circuit in response to overcurrent, and also manual opening and closing of a circuit. Low-voltage power circuit breakers have, for years, been equipped with electromechanical trip devices. Modern, solid-state devices, however, are rapidly replacing electromechanical trips. Solid-state trips are more accessible, easier to calibrate, and are virtually unaffected by vibration, temperature, altitude, and duty-cycle. Furthermore, solid-state devices are easy to coordinate, and provide closer, more improved protection over electromechanical units. Still, electromechanical units have their applications. Industrial plants with harsh environments, such as steel mills and ammunition plants, may demand the more rugged electromechanical devices. Today, molded-case circuit breakers are being equipped with solid-state trip units to obtain more complex tripping characteristics. Surface-mount, or integrated-circuit, technology is allowing very sophisticated molded-case circuit breakers to be constructed in small frame sizes. Most low-voltage power circuit breakers are also being equipped with solid-state trip units. New microprocessor-based circuit breakers are now available that offer true RMS current sensing. The increased use of switching-mode power supplies for computer systems and other harmonic-generating, non-linear loads created the need for true RMS sensing, which is a major advantage over peak-sensing trip units.

- Low-voltage circuit breakers. Low-voltage circuit breakers are classified as molded-case circuit breakers or power circuit breakers. A molded-case circuit breaker is an integral unit enclosed in an insulated housing. A power circuit breaker is designed for use on circuits rated 1000 Vac and 3000 Vdc and below, excluding molded-case circuit breakers.

- Low-voltage circuit breaker trip units may be of the electromechanical (thermal-magnetic or mechanical dashpot) or solid-state electronic type. Low-voltage circuit breakers may include a number of trip unit characteristics. Circuit breaker curves are represented as "bands." The bands indicate minimum and maximum operating times for specific overcurrents.

- Long-time pick-up allows fine tuning of the continuous current rating. Typical settings range from 50 percent-100 percent of circuit breaker sensor current rating.

- Long-time delay varies the tripping time under sustained overcurrent and allows momentary overloads. Three to six bands are typically available.

- Short-time pick-up controls the amount of high-level current that can be carried for short periods of time without tripping and allows downstream devices to clear faults without tripping upstream devices. Typical settings range from 1.5 to 9 times long-time pick-up setting.

- Short-time delay is used with short-time pick-up to improve selectivity. It provides time delay to allow the circuit breaker to trip at the selected short-time pick-up current. Three bands (minimum, intermediate, and maximum) are typically available.

- Short-time I-t switch introduces a ramp function into the short-time characteristic curve to improve coordination with downstream devices whose characteristic curves overlap the circuit breaker characteristic curve.

- Instantaneous pick-up establishes the tripping current level with no intentional time delay. Typical settings range from 1.5 to 9 times Long time pick-up setting.

- Ground-fault pick-up establishes ground fault tripping current level and may incorporate the I-t function. Ground-fault pick-up is typically adjustable from 20 percent to 100 percent of sensor rating. Ground-fault pick-up should never be set above 1200 A in accordance with NFPA 70.

- Ground-fault delay incorporates time delay for coordination. Three to six time delay bands are typically available. Ground-fault delay should not exceed one second for ground-fault currents greater than 3000 A in accordance with NFPA 70.

- Specifications should detail only those functions that are necessary on a particular project.

- The continuous current rating may be fixed or adjustable.

- Molded-case breakers with solid-state trips and power breakers normally have adjustable long-time and short-time functions.

- Power breakers may or may not have the instantaneous function.

- Most molded-case circuit breakers, especially in the smaller sizes, are not provided with long-time adjustments, short-time functions, or ground-fault functions.

- The inverse-time (or thermal-magnetic) circuit breaker contains a thermal and a magnetic element in series and is similar in operation to time delay fuses. This circuit breaker will trip thermally in response to overload currents and magnetically in response to short-circuit currents. Magnetic tripping is instantaneous while thermal tripping exhibits an inverse-time characteristic (i.e., the circuit breaker operating characteristics of time and current are inversely proportional). Inverse-time circuit breakers have three basic current ratings: trip rating, frame rating, and interrupting rating. Trip rating is the minimum continuous current magnitude required to trip the circuit breaker thermally. The frame rating identifies a particular group of circuit breakers and corresponds to the largest trip rating within the group. Each group consists of physically interchangeable circuit breakers with different trip ratings. Although NEMA recognizes other frame ratings in addition to those listed in table 3-2, these are the most common ones supplied by manufacturers. The interrupting rating describes the short-circuit withstand capability of a circuit breaker.

- The instantaneous-trip circuit breaker is nothing more than an inverse-time circuit breaker with the thermal element removed and is similar in operation to the non-time delay fuse. This circuit breaker is often referred to by other names, such as, magnetic circuit breaker, magnetic-only circuit breaker, or motor circuit breaker. Instantaneous-trip circuit breakers may be used in motor circuits, but only if adjustable, and if part of a circuit breaker type, combination motor controller with overload relays. Such an arrangement is called a Motor Circuit Protector (MCP) and provides short-circuit protection (circuit breaker magnetic element), overload protection (overload relays), motor control, and disconnecting means all in one assembly. Instantaneous-trip circuit breakers have frame and interrupting ratings but do not have trip ratings. They do have an instantaneous current rating which, for motor circuits, must be adjustable and not exceed 1,300 percent of the motor FLA (NFPA 70). MCPs provide excellent motor circuit protection and ease of specification, and should be considered for installations with numerous motors where MCCs would be specified.

- A current-limiting circuit breaker does not employ a fusible element. When operating within its current-limiting range, a current-limiting circuit breaker limits the let-through I-t to a value less than the I-t of the quarter cycle of the symmetrical current. Current-limiting circuit breakers employ single and double break contact arrangements as well as commutation systems to limit the let-through current to satisfy the fundamental definition of current-limitation without the use of the fuses. Current-limiting circuit breakers can be reset and service restored in the same manner as conventional circuit breakers even after clearing maximum level fault currents. Manufacturers of current-limiting circuit breakers publish peak let through current (I) and energy (I-t) curves.

- Integrally fused circuit breakers employ current limiters which are similar to conventional current-limiting fuses but are designed for specific performance with the circuit breaker. Integrally fused circuit breakers also include overload and low level fault protection. This protection is coordinated so that, unless a severe fault occurs, the current limiter is not affected and replacement is not required. Current limiters are generally located within the molded case circuit breaker frame. An interlock is provided which ensures the opening of the circuit breaker contacts before the limiter cover can be removed. Single phasing is eliminated by the simultaneous opening of all circuit breaker poles. Many circuit breakers employ mechanical interlocks to prohibit the circuit breaker from closing with a missing current limiter. The continuous ampere rating of integrally fused circuit breakers is selected in the same manner as for conventional circuit breakers. The selection of the individual limiters should be made in strict accordance with the manufacturer's published literature to achieve the desired level of circuit protection.

- A molded-case circuit breaker can be applied in a system where fault current may exceed its rating if it is connected in series on the load side of an acceptable molded-case circuit breaker. Such an application is called cascade system operation. The upstream breaker must be rated for maximum available fault current and both breakers must be tested and UL certified for a series rating. Cascade operation depends upon both breakers opening at the same time, and upon the fact that the upstream breaker will always open. Since molded-case circuit breaker contacts are designed to "blow open" on high short-circuit currents, failure of the upstream breaker to operate is not a concern. Since low-voltage power breakers are not designed to "blow open," power breakers should not be applied in cascade. Individual components within a cascade system should not be replaced since the entire system is UL approved. Individual components are not UL approved. Additionally, individual components should be from the same manufacturer as the cascade system. By virtue of the design, this approach does not provide a coordinated system.

- Medium-voltage circuit breakers. ANSI defines medium-voltage as 1000V or more, but less than 100kV. Switching a medium-voltage circuit involves either opening or closing a set of contacts mechanically. When closing the contacts, the applied mechanical force must be greater than the forces which oppose the closing action. An arc is created when the contacts are opened, which must be extinguished. Medium-voltage circuit breakers are classified according to the medium (oil, air, vacuum, or SF) in which their contacts are immersed. Normally, metal clad, drawout switchgear is used at medium-voltages up to 15kV. Air-magnetic, vacuum, and SF -filled-interrupter circuit breakers are available in drawout switchgear. Oil circuit breakers are used outdoors, as individual units, and thus are not available in drawout switchgear mounting.

- Medium-voltage air circuit breakers are either of the air-magnetic type or of the air-blast type. Due to cost and size restrictions, air-blast breakers are not normally used in medium-voltage drawout switchgear construction. In recent years, most medium-voltage drawout switchgear employed air-magnetic breakers. However, due to cost, size, and noise limitations, vacuum and SF6 circuit breakers are replacing air circuit breakers in medium-voltage drawout switchgear.

- The contacts of vacuum circuit breakers are hermetically-sealed in a vacuum chamber or “bottle”. Vacuum interrupters are much smaller and quieter than air circuit breakers, and require no arc chutes. Vacuum circuit breakers in drawout switchgear mounting are available in a variety of continuous current and MVA ratings at 5kV to 15kV.

- Sulfur hexafluoride, SF, is a non-flammable, nontoxic, colorless, and odorless gas, which has long been used in high-voltage circuit breakers. Now, SF -filled-interrupter circuit breakers are available in drawout switchgear for 5kV and 15kV applications. Like vacuum interrupters, the circuit breaker contacts are immersed in a hermetically-sealed bottle filled with SF gas. SF circuit breakers in drawout switchgear mounting are available in a variety of continuous current and MVA ratings.

- EMI/RFI considerations. With today's increasing use of sensitive, solid-state devices, the effects of Electro-Magnetic Interference (EMI) and Radio-Frequency Interference (RFI) must be considered. Solid-state devices, due to their many advantages, are rapidly replacing the rugged electromechanical devices previously used. One disadvantage of solid-state devices, however, is their sensitivity to power source anomalies and electrostatic and electromagnetic fields. Recent developments in the design and packaging of solid-state devices have incorporated effective shielding techniques. However, the designer must still evaluate the environment and ensure that additional shielding is not required.

In formation needed for coordination. The following circuit breaker information is required for a coordination study:

- Circuit breaker continuous current and frame rating.

- Circuit breaker interrupting rating.

- Circuit breaker time-current characteristic curves.

- Circuit breaker ratings. To meet UL requirements, molded case circuit breakers are designed, built and calibrated for use in a 40 degrees C (104 degrees F) ambient temperature. Time-current characteristic trip curves are drawn from actual test data. When applied at ambient temperatures other than 40 degrees C, frequencies other than 60 Hz, or other extreme conditions, the circuit performance characteristics of the breaker may be affected. In these cases, the current carrying capacity and/or trip characteristics of the breaker may vary. Therefore, the breaker must be rerated.

- Since thermal-magnetic circuit breakers are temperature sensitive devices, their rated continuous current carrying capacity is based on a UL specified 40 degrees C (104 degrees F) calibration temperature. When applied at temperatures other than 40 degrees C it is necessary to determine the breaker's actual current carrying capacity under those conditions. By properly applying manufacturer’s ambient rerating curves, a circuit breaker’s current carrying capacity at various temperatures can be predicted.

- Application of thermal-magnetic circuit breakers at frequencies above 60 Hz requires that special consideration be given to the effects of high frequency on the circuit breaker characteristics. Thermal and magnetic operation must be treated separately.

- At frequencies below 60 Hz the thermal rerating of thermal-magnetic circuit breakers is negligible. However, at frequencies above 60 Hz, thermal rerating may be required. One of the most common higher frequency applications is at 400 Hz. Manufacturer's rerating curves are available.

- At frequencies above 60 Hz, tests indicate that it takes more current to magnetically trip a circuit breaker than is required at 60 Hz. At frequencies above 60 Hz, the interrupting capacity of thermal-magnetic breakers is less than the 60 Hz interrupting capacity.

- When applying thermal-magnetic circuit breakers at high altitudes, both current and voltage adjustments are required. Current rerating is required because of the reduced cooling effects of the thinner air present in high altitude applications. Voltage rerating is necessary because of the reduced dielectric strength of the air.

- Trip curves provide complete time-current characteristics of circuit breakers when applied on AC systems only. When applying thermal-magnetic circuit breakers on DC systems, the circuit breaker's thermal characteristics normally remain unchanged, but the manufacturer should be consulted to be certain. The magnetic portion of the curve, on the other hand, requires a multiplier to determine an equivalent DC trip range. This is necessary because time-current curves are drawn using RMS values of AC current, while DC current is measured in peak amperes. Additionally, the X/R ratio of the system as seen by the circuit breaker will affect its DC rating. When a circuit breaker opens a DC circuit, the inductance in the system will try to make the current continue to flow across the open circuit breaker contacts. This action results in the circuit breaker having to be derated. Furthermore, some circuit breakers require the AC waveform to pass through a current zero to open the circuit. Since DC does not have current zeros, the circuit breaker must be derated. For DC applications the manufacturer should be contacted for derating requirements.

- System X/R ratio. Normally, the system X/R ratio need not be considered when applying circuit breakers. Circuit breakers are tested to cover most applications. There are several specific applications, however, where high system X/R ratios may push short-circuit currents to 80 percent of the short-circuit current rating of standard circuit breakers. These applications are listed below.

- Local generation greater than 500kVA at circuit breaker voltage.

- Dry-type transformers, 1.0 MVA and above.

- All transformer types, 2.5 MVA and above.

- Network systems.

- Transformers with impedances greater than values listed in the ANSI C57 series.

- Current-limiting reactors in source circuits at circuit breaker voltage.

- Current-limiting busway in source circuits at circuit breaker voltage. If the system X/R ratio is known, multiplying factors from various references can be used to determine the circuit breaker short-circuit current rating. If the system X/R ratio is unknown, the maximum X/R ratio of 20 may be assumed and the appropriate multiplying factor used.

- Circuit breaker application. Molded-case circuit breakers, power circuit breakers, and insulated-case circuit breakers should be applied as follows:

- Molded-case circuit breakers have traditionally been used in panel boards or load centres where they were fixed-mounted and accessible. Low-voltage power circuit breakers, on the other hand, were traditionally used in industrial plants and installed in metal-enclosed assemblies. All power circuit breakers are now of the drawout-type construction, mounted in metal clad switchgear. Therefore, molded-case breakers should be used in fixed mountings, and power breakers should be used where drawout mountings are employed.

- Since power breakers were traditionally used in metal-enclosed assemblies, they were rated for 100 percent continuous duty within the assembly. On the other hand, molded case breakers were traditionally used in open air. When used in a metal enclosure, molded-case breakers had to be derated to 80% of continuous rating. Molded-case breakers are now available at 100 percent rating when installed in an enclosure.

- Power breakers have traditionally been applied where selectivity was very important, thus requiring high short-time ratings to allow downstream devices to clear the fault. Molded-case breakers were, instead, designed for very fast operations. Fast opening contacts under high short-circuit current conditions resulted in molded-case breakers having higher interrupting ratings than power breakers.

- An insulated-case circuit breaker is somewhat of a hybrid circuit breaker which incorporates advantages of both the molded-case and power circuit breaker. However, an insulated-case breaker is not a power breaker, and should not be applied as such. Insulated-case breakers are not designed and tested to the same standards as power breakers. An insulated-case breaker is essentially a higher capability molded-case breaker. All commercially available insulated-case breakers are 100% rated.

- Molded-case or insulated-case breakers should be used in noncritical, small load applications with high interrupting requirements. Power breakers should be used in critical applications where continuity of service is a requirement.

Protective relays

Protective relays are classified according to their function, and there are a wide variety of protective relays available. The overcurrent relay, for example, monitors current and operates when the current magnitude exceeds a pre-set value.

- Overcurrent relay. The most common relay for short-circuit protection is the overcurrent relay. These relays are much more sophisticated than the simple thermal overload relays discussed previously for motor applications, and have a wide range of adjustments available. Electromagnetic attraction relays may be AC or DC devices and are used for instantaneous tripping. Electromagnetic induction relays are AC only devices. Electromagnetic attraction and induction relays, like all electromechanical devices, are simple, rugged, reliable, and have been used successfully for years. However, solid-state electronic relays are rapidly replacing the electromechanical types. Solid-state relays require less panel space and exhibit better dynamic performance and seismic-withstand capability. Additionally, solid-state overcurrent relays are faster, have more precisely-defined operating characteristics, and exhibit no significant over-travel. As in the case of circuit breakers, electromechanical relays will continue to find applications in harsh environments. Overcurrent relays have a variety of tap and time dial settings.

- Relay device function numbers. Protective relays have been assigned function numbers by IEEE that are used extensively to specify protective relays.

- Instrument transformers. Protective relays will always be associated with medium-voltage and high-voltage circuits, involving large current magnitudes. Therefore, current transformers (CT) are required to isolate the relay from line voltages and to transform the line current to a level matching the relay rating. CTs are normally rated 5A on the secondary with a primary rating corresponding to the requirements of the system. Potential or voltage transformers (VT) are single-phase devices, usually rated 120V on the secondary with primary rating matched to the system voltage.

- CT burden is the load connected to the secondary terminals. Burden may be expressed as volt-amperes and power factor at a specified current, or it may be expressed as impedance. The burden differentiates the CT load from the primary circuit load.

- Residually-connected CTs are widely used in medium-voltage systems, while core-balanced CT's form the basis of several low-voltage ground-fault protective schemes. Relays connected to core-balance CTs can be made very sensitive. However, core-balanced CTs are subject to saturation from unbalanced inrush currents or through faults not involving ground. High magnitude short-circuit currents may also saturate core-balance CTs thus preventing relay operation.

- EMI/RFI With today's increasing use of sensitive, solid-state devices, the effects of Electro-Magnetic Interference (EMI) and Radio-Frequency Interference (RFI) must be considered. Solid-state devices, due to their many advantages, are rapidly replacing the rugged electromechanical devices previously used. One disadvantage of solid-state devices, however, is their sensitivity to power source anomalies and electrostatic and electromagnetic fields. Recent developments in the design and packaging of solid-state devices have incorporated effective shielding techniques. However, the designer must still evaluate the environment and ensure that additional shielding is not required.

- New developments. Microprocessor-based relays are also becoming available which provide multiple relay functions as well as metering, fault event recording, and self-testing in a single enclosure. This system requires fewer connections and less panel space than individual relays and associated peripherals.

Automatic reclosing devices

Automatic reclosing schemes should not be applied where the load being protected is a transformer or cable, since faults in these types of loads are usually not transient in nature. Automatic reclosing schemes applied to permanent faults in transformer or cable loads may result in equipment damage and personnel hazards. Additionally, automatic re-closing schemes should be guarded against in motor circuits. If the system voltage is restored out of phase, the motor windings, shaft, and drive couplings may be damaged. Furthermore, reclosers should be applied only on aerial distribution systems.

Protective Device Coordination

Where there are two or more series protective devices between the fault point and the power supply, these devices must be coordinated to insure that the device nearest the fault point will operate first. The other upstream devices must be designed to operate in sequence to provide back-up protection, if any device fails to respond. This is called selective coordination. To meet this requirement, protective devices must be rated or set to operate on minimum overcurrent, in minimum time, and still be selective with other devices on the system. When the above objectives are fulfilled, maximum protection to equipment, production, and personnel will be accomplished. As will be seen later in this chapter, protection and coordination are often in direct opposition with each other. Protection may have to be sacrificed for coordination, and vice versa. It is the responsibility of the electrical engineer to design for optimum coordination and protection.

The coordination study

A coordination study consists of the selection or setting of all series protective devices from the load upstream to the power supply. In selecting or setting these protective devices, a comparison is made of the operating times of all the devices in response to various levels of overcurrent. The objective, of course, is to design a selectively coordinated electrical power system. A new or revised coordination study should be made when the available short-circuit current from the power supply is increased; when new large loads are added or existing equipment is replaced with larger equipment; when a fault shuts down a large part of the system; or when protective devices are upgraded.

- Time-current characteristic curves. Time is plotted on the vertical axis and current is plotted on the horizontal axis of all time-current characteristic curves. Log-log type graph paper is used to cover a wide range of times and currents. Characteristic curves are arranged so that the area below and to the left of the curves indicate points of "no operation," and the area above and to the right of the curves indicate points of "operation." The procedure involved in applying characteristic curves to a coordination study is to select or set the various protective devices so that the characteristic curves located on a composite time-current graph from left to right with no overlapping of curves. The result is a set of coordinated curves on one composite time-current graph.

- Data required for the coordination study.

The following data is required for a coordination study.

- Single-line diagram of the system under study.

- System voltage levels.

- Incoming power supply data.

- Impedance and MVA data.

- X/R ratio.

- Existing protection including relay device numbers and settings, CT ratios, and time-current characteristic curves.

- Generator ratings and impedance data.

- Transformer ratings and impedance data.

- Data on system under study.

- Transformer ratings and impedance data.

- Motor ratings and impedance data.

- Protective devices ratings including momentary and interrupting duty as applicable.

- Time-current characteristic curves for protective devices.

- CT ratios, excitation curves, and winding resistance.

- Thermal (I-t) curves for cables and rotating machines.

- Conductor sizes and approximate lengths.

- Short-circuit and load current data.

- Maximum and minimum momentary (first cycle) short-circuit currents at major buses.

- Maximum and minimum interrupting duty (5 cycles and above) short-circuit currents at major buses. The exact value of ground-fault current (especially arcing ground-fault current) is impossible to calculate. Methods are available for estimating ground-fault current.

- Estimated maximum and minimum arcing and bolted ground-fault currents at major buses.

- Maximum load currents.

- Motor starting currents and starting times.

- Transformer protection points.

Coordination procedure

The following procedure should be followed when conducting a coordination study:

- Select a convenient voltage base and convert all ampere values to this common base. Normally, the lowest system voltage will be chosen, but this may not always be the case.

- Indicate short-circuit currents on the horizontal axis of the log-log graph.

- Indicate largest (or worst case) load ampacities on the horizontal axis. This is usually a motor and should include FLA and LRA values.

- Specify protection points. These include magnetizing inrush point and NFPA 70 limits for certain large transformers.

- Indicate protective relay pick-up ranges.

- Starting with the largest (or worst case) load at the lowest voltage level, plot the curve for this device on the extreme left side of the log-log graph. Although the maximum short-circuit current on the system will establish the upper limit of curves plotted to the right of the first and succeeding devices, the number of curves plotted on a single sheet should be limited to about five to avoid confusion.

- Using the overlay principle, trace the curves for all protective devices on a composite graph, selecting ratings or settings that will provide over-current protection and ensure no overlapping of curves.

- Coordination time intervals. When plotting coordination curves, certain time intervals must be maintained between the curves of various protective devices in order to ensure correct sequential operation of the devices. These intervals are required because relays have over-travel and curve tolerances, certain fuses have damage characteristics, and circuit breakers have certain speeds of operation. Sometimes these intervals are called margins.

- Coordination can be easily achieved with low voltage current-limiting fuses that have fast response times. Manufacturer's time current curves and selectivity ratio guides are used for both overload and short-circuit conditions, precluding the need for calculating time intervals. For relays, the time interval is usually 0.3-0.4 seconds. This interval is measured between relays in series either at the instantaneous setting of the load side feeder circuit breaker relay or the maximum short-circuit current, which can flow through both devices simultaneously, whichever is the lower value of current. The interval consists of the following components:

- Circuit breaker opening 0.08 seconds time (5 cycles).

- Relay over-travel - 0.10 seconds

- Safety factor for CT satu-0.22 seconds ration, setting errors, contact gap, etc.

- This safety factor may be decreased by field testing relays to eliminate setting errors. This involves calibrating the relays to the coordination curves and adjusting time dials to achieve specific operating times. A 0.355 seconds margin is widely used in field-tested systems employing very inverse and extremely inverse time overcurrent relays.

- When solid-state relays are used, over-travel is eliminated and the time may be reduced by the amount included for over-travel. For systems using induction disk relays, a decrease of the time interval may be made by employing an overcurrent relay with a special high-dropout instantaneous element set at approximately the same pickup as the time element with its contact wired in series with the main relay contact. This eliminates over-travel in the relay so equipped. The time interval often used on carefully calibrated systems with high-dropout instantaneous relays is 0.25 seconds.

- When coordinating relays with downstream fuses, the circuit opening time does not exist for the fuse and the interval may be reduced accordingly. The total clearing time of the fuse should be used for coordination purposes. The time margin between the fuse total clearing curve and the upstream relay curve could be as low as 0.1 second where clearing times below 1 second are involved.

- When low-voltage circuit breakers equipped with direct-acting trip units are coordinated with relayed circuit breakers, the coordination time interval is usually regarded as 0.3 seconds. This interval may be decreased to a shorter time as explained previously for relay-to-relay coordination.

- When coordinating circuit breakers equipped with direct-acting trip units, the characteristics curves should not overlap. In general only a slight separation is planned between the different characteristics curves. This lack of a specified time margin is explained by the incorporation of all the variables plus the circuit breaker operating times for these devices within the band of the device characteristic curve.

- Delta-wye transformers. When protecting a delta-wye transformer, an additional 16% current margin over margins mentioned previously should be used between the primary and secondary protective device characteristic curves. This helps maintain selectivity for secondary phase-to-phase faults since the per-unit primary current in one phase for this type of fault is 16 percent greater than the per-unit secondary current which flows for a secondary three-phase fault.

Low-voltage coordination involves selecting feeder-breaker, tie-breaker, main-breaker, and transformer fuse ratings and settings that provide optimum protection of equipment while maintaining selective coordination among the low-voltage, protective devices. Total system coordination with upstream medium-voltage and primary protective devices must also be incorporated.

Ground-fault coordination

Most of the concern about ground-fault protection and coordination, today, centres on low-voltage systems where low-level arcing faults are a considerable problem. The phenomena of arcing faults began in the 1950's with the advent of large capacity 480Y/277V solidly-grounded systems. Medium-and high-voltage grounded systems don't experience the arcing ground fault problem common to low-voltage systems, and have employed ground current relays for years. Currently, there are three methods for achieving low-voltage arcing ground-fault protection.

- Method 1. The non-selective, single-zone method applies ground-fault protection only at the main service disconnect. This is minimum protection as required by NFPA 70, and is required only on 480Y/277V services rated 1000A or more. Non-selective, single-zone ground-fault protection may be difficult to coordinate with additional ground-fault protection at downstream levels may have to be considered even though not required by NFPA 70.

- Method 2. The selective, time-coordinated method applies ground-fault protection at additional levels downstream of the main service disconnect. Coordination is achieved by intentional time-delays to separate the various levels. This method achieves the coordination that Method 1 does not, but protection is sacrificed by inclusion of the time-delays. Additionally, Method 2 costs more than Method 1.

- Method 3. The selective, zone-coordinated method, applies ground-fault protection at downstream levels like Method 2 does, but includes a restraining signal which can override the time-delay. Coordination and protection are both maximized by the application of this system of restraining signals by allowing each level to communicate with other levels. This method, of course, costs more than the other methods, and should be considered only for special purpose applications.

- Government facilities. Except for special installations requiring precise ground-fault protection and coordination, government facilities should incorporate ground-fault protection in accordance with NFPA 70 only.

Coordination requirements

The primary purpose of the coordination procedure is to select the proper ratings and settings for the protective devices on an electrical distribution system. These ratings and settings should be selected so that pick-up currents and time delays allow the system to ignore transient overloads, but operate the protective device closest to the fault when a fault does occur. Proper selection of ratings and settings of protective devices requires knowledge of NFPA 70 requirements for protection of motors, transformers, and cables as well as knowledge of ANSI C57.12 requirements for transformer withstand limits.

NFPA 70 transformer limits. NFPA 70 specifies the maximum overcurrent setting for transformer protective devices. Fuse ratings are permitted to be lower than circuit breaker ratings due to the differences in operating characteristics in the overload region.

- ANSI C57.12 withstand point. At current levels greater than 600 percent of full-load, transformer withstand can be approximated by $I\text{-}t^2$ through-fault curves which have replaced the old, familiar ANSI C57.12 withstand point.

- Magnetizing inrush. Transformer primary protective devices must be rated or set below the withstand limit but above the magnetizing- and load-inrush currents that occur during transformer energization. In-rush current magnitudes and durations vary among transformer manufacturers, but 8 to 12 times full-load current for 0.1 second are commonly used for coordination purposes.

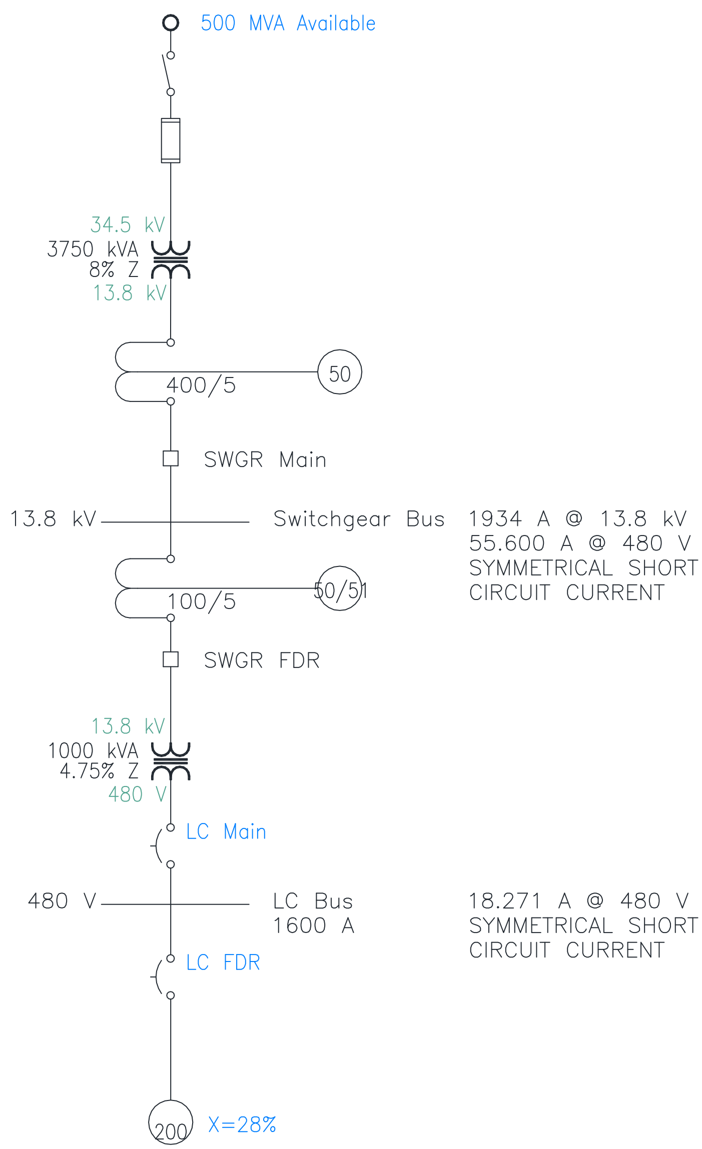
Maintenance, testing, and calibration

Preventive maintenance should not be confused with breakdown maintenance, which is not maintenance at all, but is really repair. Preventive maintenance involves a scheduled program for cleaning, tightening, lubricating, inspecting, and testing devices and equipment. The purpose is to identify and correct problem areas before troubles arise. Maintenance, testing, and calibration procedures vary with the type of equipment, the environment, frequency of operation, and other factors. While procedures may vary, certain initial field tests and inspection areas should always be addressed. Control power and control circuits should be tested for correct operation. Protective devices should be inspected, calibrated, and proper settings incorporated. Grounding connections should be verified, instrument transformers should be tested for proper polarity and operation, and ground-fault protection systems should be performance tested.

Example of phase coordination

This paragraph, in conjunction with the referenced figures, outlines a step-by-step procedure for conducting a phase coordination study. The example includes primary protection (34.5kV), medium-voltage protection (13.8kV), low-voltage overcurrent protection (480V), and low-voltage ground-fault protection. The procedures developed in this example may be applied to any electrical distribution system regardless of the complexity or simplicity. Short-circuit current calculating procedures are not covered.

- Single-line diagram. Draw the single-line diagram of the system under study. Include voltage levels, incoming power supply data, and other information as outlined in this chapter. Figure below shows the single-line diagram for the electrical system considered by this example.



Short-circuit and load currents. Short-circuit and load currents must be determined and included on the appropriate time-current coordination curves or entered into the computer plotting program.

$$I_{sym} \text{ at LC Bus} = 18{,}271\text{ A}$$
$$I_{sym} \text{ at LC Bus} = 27{,}691\text{ A}$$
$$I_{sym} \text{ at SWGR Bus} = 55{,}600\text{ A}$$
$$I_{sym} \text{ at SWGR Bus} = 88{,}960\text{ A}$$

- Assume that motor kVA is approximately equal to motor horsepower. This is a widely used and valid assumption for large motors. Also, for simplicity assume motor voltage is 480V, although it may actually be 460V. Motor examples using 460V ratings are covered in other examples. Calculate motor full load amperes (FLA) and motor locked-rotor amperes (LRA) as shown below:

$$Motor_{FLA} = (kVA)/(1.73*kV) = 200/(1.73)(0.480) = 241\text{ A}$$
$$Motor_{LRA(SYM)} = (FLA)/Xd" = 241/0.28 = 861\text{ A}$$
$$Motor_{LRA(ASYM)} = (Motor_{LRA(SYM)})(1.6) = 861*1.6 = 1378\text{ A}$$

- Determine maximum and minimum short-circuit currents and express the currents on a common base voltage. The base voltage for this example was selected to be 480V.

Asymmetrical current is important because all instantaneous devices see the asymmetrical current. If the coordination study is being completed manually, short-circuit current values are normally shown on the current axis to remind the designer about the short-circuit current limits. For computer plotting programs, short-circuit current values, along with other data, are entered directly into the computer. The computer keeps track of all current limits, thereby simplifying the coordination procedures.

- Protection points. Determine NFPA 70 limits and transformer inrush points for transformers T1 and T2. Equations below illustrate the required calculations.

$$T1_{FLA}=(kVA)(1.73)(kV)=(3750)/(1.73)(0.48)=4511\ A$$
$$T1_{3X}=(T1_{FLA})(3)=13{,}533\ A$$
$$T2_{FLA}=(kVA)/(1.73)(kV)=1000/(1.73)(0.48)-1203\ A$$
$$T2_{6X}=(T2_{FLA})(6)=7218\ A$$
$$T1I_{NRUSH}=12(T1_{FLA})=(12)(4511)=54{,}132\ A \text{ for } 0.1 \text{ second}$$
$$T2_{INRUSH}=(8)(T2_{FLA})=(8)(1203)=9624\ A \text{ for } 0.1 \text{ second}$$

- Plot the transformer through-fault protection curves and inrush points on the time-current curves. Transformer primary protection should always be below the through-fault curve to protect the transformer, but above the inrush point to prevent operating the protective device when the transformer is energized. Long-time rating or setting of the transformer primary protective device should he above FLA but less than the NFPA 70 limit.

- Load center (LC) feeder circuit breaker characteristics. Although NFPA 70 will allow the LC FDR device to be set at 250 percent of FLA, or 600A, it is obvious from the characteristic curves that a lower setting, and thus better protection, can be used. Computer plotting programs allow the designer to interactively select, compare, and reselect (if necessary) curves of a wide range of protective devices. The settings shown below were selected for this example.

- Long-time pick-up=400A.

- Instantaneous pick-up=10X or 4000A. The instantaneous curve is truncated at the maximum short-circuit current seen at this point in the system (27,691A). The 10X value was selected because it is representative of commercially-available circuit breakers. As will be seen from the time-current curves, instantaneous and other settings are flexible and dependent upon many circuit variables.

- Separate overload protection not greater than 125 percent of motor nameplate amperes in accordance with NFPA 70.

- LC MAIN circuit breaker characteristics. The long-time pick-up was set at 1600A to obtain full capacity from the 1600A LC bus. The LC MAIN can be set as high as 250 percent of the full-load amperes of T2 since T2 has both primary and secondary protection. The following settings were selected for the LC MAIN:

- Long-time pick-up = 1600A.
- Long-time delay=minimum.
- Short-time pick-up=7X or 11,200A
- Short-time delay=minimum. The short-time curve is truncated at the maximum short-circuit current seen at this point in the system (18,271A).
- Instantaneous pick-up=NONE, since it is impossible to coordinate the instantaneous curves for the two series devices, LC MAIN and LC FDR. If LC MAIN has an instantaneous element, it should be set high to coordinate with the LC FDR as much as possible.

- Switchgear feeder circuit breaker and relay characteristics. In this example, a 100/5A current transformer is used. On a 480V base a relay tap setting of IA will result in a primary current value of:

$$(1A)\frac{100A}{5A}\frac{13{,}800V}{480V} = (1A)(20)(28.75) = 575A$$

Other tap settings will result in the following primary currents:

(2A)(20)(28.75)=1150 A
(3A)(20)(28.75)=1725 A
(4A)(20)(28.75)=2300 A
(5A)(20)(28.75)=2875 A
(6A)(20)(28.75)=3450 A
(7A)(20)(28.75)=4025 A
(8A)(20)(28.75)=4600 A
(9A)(20)(28.75)=5175 A
(10A)(20)(28.75)=5750 A
(12A)(20)(28.75)=6900 A

The relay tap setting must be higher than the LC MAIN or 1600A, but less than the T2 NFPA 70 limit (6X), or 7200A. Allowing an additional 16 percent current margin in addition to standard margins between the primary and secondary protective devices of the delta-wye transformer, select an appropriate pick-up (tap setting) for the SWGR FDR relay. Line up the relay "1" vertical line with the selected tap setting previously sketched at the top of the curves. Select both tap and time-dial settings which result in the optimum protection and coordination. Remember that the relay curve must be below the T2 through-fault protection curve in addition to complying with the inrush point and NFPA 70 limits. For computer plotting programs each tap and time dial setting can be viewed on the CRT workstation screen and the optimum setting selected. The settings listed below were selected for the SWGR FDR relay.

- Tap (pick-up) =8A

- Time dial = 3

- Instantaneous 60X or 34,500A on a 480V base, which is less than the symmetrical short-circuit current at the SWGR bus. Maximum short-circuit current seen by the instantaneous device will be I_{asym} or 88,960A. Asymmetrical current must be considered since all instantaneous devices will see asymmetrical current.

- Switchgear main circuit breaker and relay characteristics. Allowing a convenient margin between the SWGR FDR and the SWGR MAIN, select appropriate tap and time dial settings for the SWGR MAIN relay. The following settings were selected:

- Tap (pick-up) =2

- Time dial=6

- Instantaneous=NONE, since instantaneous curves for the SWGR MAIN and SWGR FDR will not coordinate. Maximum short-circuit current seen at this point in the system will be I_{sym} or 55,600A.

- The SWGR FDR, which is also the primary have to be reduced or a different relay characteristic protection for transformer T2, intersects with the used to maintain coordination. In the final analysis, T2 Thru-Fault curve. The settings for this device complete coordination may not be achievable. The LC MAIN and IC FDR settings coordination using reduced settings and solid state must also be reduced to maintain coordination.

Conclusion

The increased popularity of the computer and its availability in most engineering facilities has resulted in liberating the design engineer from the tedious task of manually drawing coordination curves, thereby allowing him or her to be free to design. The engineer is still needed to make those critical judgment decisions and to establish the criteria that should not be left to a computer. With state-of-the-art coordination software, the engineer is no longer required to struggle with the mundane tasks of manually drawing curves and tabulating results.