Distribution Feeder Principles

Introduction

Electrical distribution is the final stage in the delivery of electricity to end users. The distribution system's network carries electricity from the transmission system and delivers it to consumers. Since the transmission system is typically rated from 130kV up to 700kV, substation step-down transformers are used to bring the voltage levels down to under 50kV levels for distribution to consumers.
As the distribution system is rated up to 50kV many large industrial end users will be fed at these voltage levels and will supply their own on-site substation that will step-down the voltage to more useful voltage levels for their facility.

For consumer consumption various step-down transformers and pole mounted transformers will be located in the geographical region that will supply electricity for consumer use.

The purpose of Distribution Systems

With power generating stations being remote to urban centers, it's required that the generated voltage be to stepped up to higher voltage levels for transmission in order to reduce the electrical losses in the overhead transmission lines. By transmitting the electricity at high voltage levels, this reduces the transmission line losses and makes the transmissions line more efficient.

Since transmission voltage levels cannot be used by consumers it is required to step-down the transmission voltage to more usable voltages.

The transmission power lines will enter a distribution substation where the voltage will be stepped down to distribution levels where it will be distributed for use by industrial, commercial and residential customers.

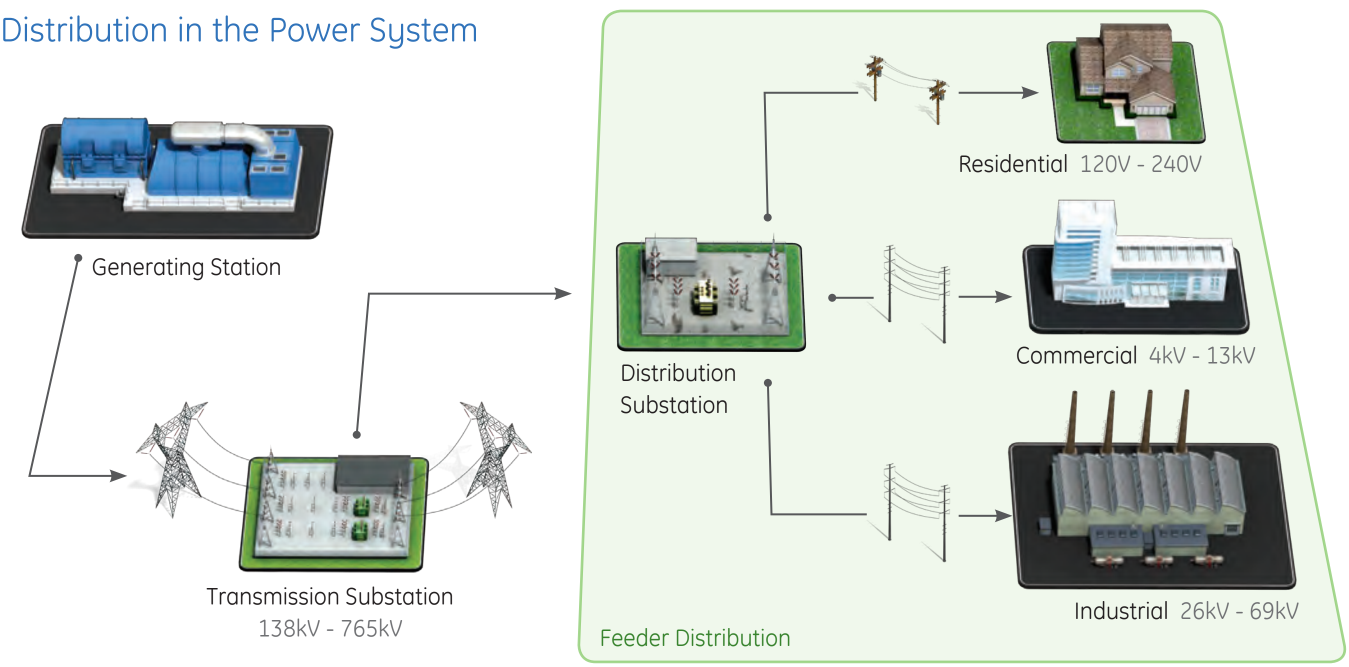
As the distribution network will typically be rated at no greater than 50kV, this voltage will be distributed to geographical area's where connection to industrial and commercial customers will be achieved. It is most common to find that industrial and large commercial customers are connected to the grid at this distribution level. It is then the responsibility of the industrial or commercial customer to employ their own on-site substation that will step-down the distribution voltage to levels that are required within the facility.

Residential consumers are typically supplied from overhead or underground feeders emanating from utility-owned substations.

Pole mounted transformers are typically used in older residential neighborhoods and rural areas. Pole mounted transformers will be limited in the number of customers they supply in order to minimize the interruption time should a fault occur. Connection from the pole mounted transformer is made to each home.

In newer developed areas, residential and commercial distribution is done via underground services Distribution feeders use underground cables and padmount transformers for the final service connection to each home or business.

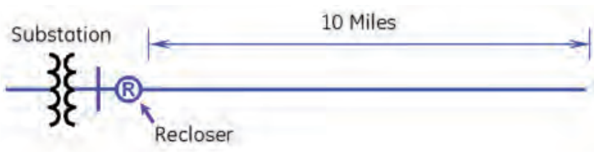
Distribution in the Power System



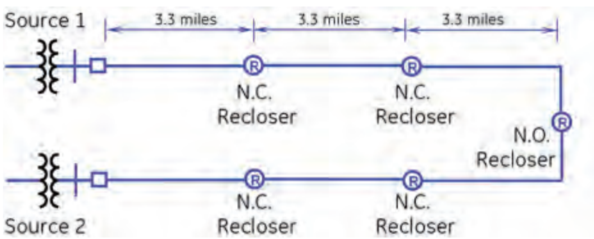
Distribution System Configurations

Distribution networks are typically of two types, radial or networked. A radial feeder leaves the station and passes through the service area with no normal connection to any other supply. This is typical of long rural lines with isolated load areas.

A networked system, having multiple connections to other points of supply, is generally found in more urban areas. These points of connection are normally open but allow various configurations by the operating utility by closing and opening switches. Operation of these switches may be by remote control from a control centre or by a lineman. The benefit of the networked model is that in the event of a fault or required maintenance a small area of network can be isolated and the remainder kept on supply.



Radial Network



Interconnected Network

Within these networks there may be a mix of overhead lines utilizing traditional utility poles and wires and, increasingly, underground construction with cables and indoor or cabinet substations. Underground distribution, however, is significantly more expensive than overhead construction and therefore often co-located with other utility lines in what are called common utility ducts.

Distribution feeders emanating from a substation are generally controlled by a circuit breaker which will open when a fault is detected. Automatic Circuit Reclosers may be installed to further segregate the feeder thus minimizing the impact of faults.

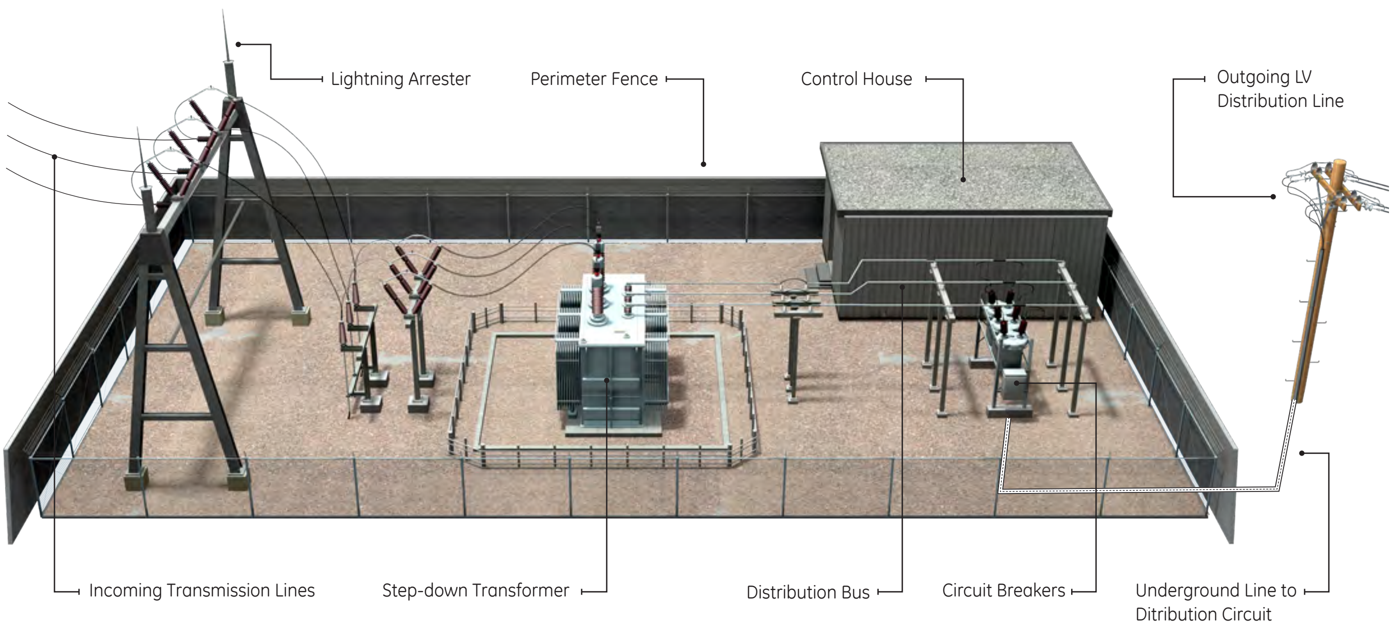
Abnormal Conditions

Common distribution system faults occur on above ground distribution lines. In most cases these faults are caused by trees coming in contact with a distribution lines, or rodents coming in contact with phase connections. Usually, these faults can be cleared by the system, quickly restoring power with the use of auto-reclosers.

Fault conditions can also be caused by the contamination of connections and insulators. When the insulation in the connection degrades, the insulation properties are lost and may cause a flashover between phases or to ground. Common causes of insulation failure is salt, air pollution, water, and ice.

System transformer faults can also interrupt the distribution system. As transformers become older and insulating material degragades from age, overload conditions, weather, etc. this may also cause a fault in the system.

Typical Distribution Substation



Feeder Protection

Introduction

Faults occurring on overhead and underground distribution feeders caused by various sources including:

- Faulty equipment
- Environmental induced faults: wind, lightning, ice, snow-storm, sag due to extreme temperature, salt spray
- Falling tree limbs
- Animal contacts
- People induced including: pole and overhead contacts and underground digging

Faults occurring in the distribution system must be sensed quickly and immediately isolated to prevent hazards to the general public and utility personnel. Protective relays are used to sense short circuit conditions caused by faults in distribution protection schemes and the use of proper schemes and settings can help to maximize sensitivity and selectivity.

Some permanent faults can be equipment failures or cables cut or short-circuited by excavation equipment. The type of grounding of the distribution system affects the voltage and current characteristics during a fault. Proper protection strategies should be employed to make dependability an utmost criterion.

Basic feeder protection principles are well-known. Phase and ground overcurrent functions reliably detect most faults. Reclosing is often applied to restore service following temporary faults on overhead circuits. Security is maintained through time and pickup coordination between overcurrent devices that may operate for a specific fault event. The challenge in feeder protection is reliable operation during unusual fault events such as high impedance ground faults and adjacent feeder faults. A key advantage of microprocessor based feeder relays is the ability to protect against these unusual faults, while improving the operation of the distribution system through flexibility, programmability, and communications. The following applications illustrate ways that GE Multilin products can improve feeder protection and system reliability.

High Impedance (Hi-Z) Fault Detection

Arcing and downed distribution conductors, although not necessarily of immediate concern from an equipment damage point of view, do pose a safety threat from a personnel and property perspective. An energized downed conductor can cause fires, injuries, and even fatalities. Traditional protection devices typically do not detect the fault current levels resulting from these fault conditions. Distribution protection engineers are being challenged with the detection of these high impedance (Hi-Z) faults. The ability to detect Hi-Z faults

has been a topic of research and development for over 30 years. The IEEE Power System Relay Committee's working group on High Impedance Fault Detection Technology defines Hi-Z faults as those that "do not produce enough fault current to be detectable by conventional overcurrent relays or fuses". As such, it should be noted that whereas traditional protection is designed to protect the power system, Hi-Z protection is primarily focused on the protection of property and the safety of personnel .

High impedance faults can be caused by a number of events, including:

- Broken conductor laying on the ground (Downed Conductor)
- Broken pole allowing line to contact ground or other surface
- Broken pole or tree limb causing primary conductor to sag
- Contact with tree limb or other objects
- Contaminated or failing equipment (insulators, transformers, conductors, etc.)

Common Misconceptions

There are many misconceptions about Hi-Z faults and a lack of understanding of high impedance fault phenomena may lead to injuries and fatalities. The following table lists a few of the common misconceptions about Hi-Z faults.

Importance of Hi-Z detection:

- If not detected and isolated, live Downed Conductors can be fatal to public and lines crewmen
- Hi-Z faults often arc and can be a significant fire hazard.
- Detect failing insulation before complete device failure, which can lead to power outages and loss of production.
- Inability to detect Hi-Z can cost utilities liabilities and customer service issues

Misconceptions	Reality
Properly set overcurrent protection will trip and clear all faults.	Hi-Z faults often draw less current (10 – 100 amps) than the minimum allowable overcurrent pickup setting, making overcurrent protection impossible.
Sensitive ground protection typically used to detect low ground current, will clear Hi-Z faults.	Hi-Z faults can occur where the primary conductor remains intact while in contact with ground through a high fault impedance. No change in the primary current means no change in neutral current to be detected.
Over time, the fault current will increase and cause overcurrent protection to operate.	In most cases, the fault current decreases as the arcing heats the contact surface and the fault impedance actually increases (moisture evaporates, sand fuses). Overcurrent protection seldom operates after first minute.
Faults always clear on my system.	Operations staffs believe the Hi-Z fault rate is low, but many line crews report many downed conductors are still energized when they arrive on scene.

Table 1: Misconceptions about Hi-Z faults.

The GE Multilin Hi-Z Solution

The Hi-Z element in the F60 provides reliable detection of faults caused by downed conductors and high impedance arcing faults. This unique, field proven algorithm incorporates a signature-based expert pattern recognition system developed at Texas A&M University. Harmonic energy levels in the arcing current are used for HiZ fault detection and a sophisticated expert system assures security and dependability for detection of Hi-Z faults. This algorithm has shown a success rate in detecting downed conductors of almost 90% based on actual in-service utility data.

Key benefits of Hi-Z detection using the F60:

- Reliable detection of faults caused by downed conductors, high impedance arcing faults
- Allows for fast response to hazardous situations
- Dependable and secure operation
- Easy retrofit to existing F60 installations through addition of a single module

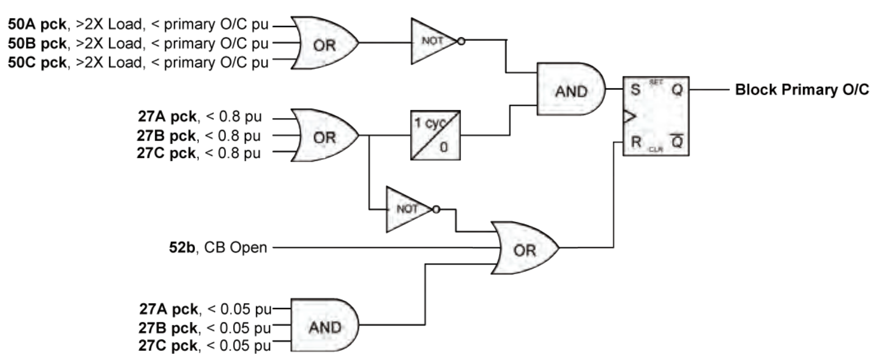


Figure 2a. System undervoltage sympathy trip blocking logic.

Sympathy Feeder Trip Prevention

Feeder sympathy trips may be defined as incorrect operation of a feeder relay for faults in other areas of the power system or abnormal operating conditions. The likelihood of a sympathy trip is dependent on the system configuration, the types of loads on the circuits, system grounding configuration and protective relay settings. There are many possible causes for sympathy trip. One cause is a system undervoltage, resulting in higher load currents to serve constant VA devices such as large motors. Another cause is adjacent circuit ground faults and adjacent intercircuit coupling.

System undervoltage sympathy trips

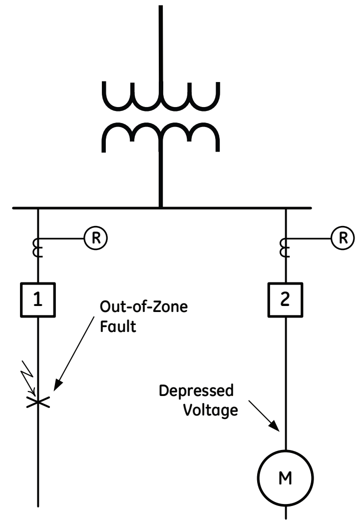


Figure 2. System undervoltage sympathetic trip.

This type of sympathy trip occurs when a fault occurs on an adjacent feeder depresses the system voltage at the distribution bus (Figure 2). Motors run at a constant VA, and demand a larger current if the voltage decreases. The system voltage drops nearly instantly with the occurrence of the out of zone fault, however the load current ramps up at slower rate to serve the constant VA loads and may grow considerably as motors stall and draw locked rotor current. With motor loads of sufficient size, the increased load current may appear as on overcurrent condition on unfaulted feeder circuit connected to the bus.

GE Multilin feeder relays can easily prevent sympathy feeder trips by employing a blocking logic. The blocking logic uses phase undervoltage and phase overcurrent elements in the logic to discriminate between an out-of-zone fault and fault on the protected feeder (Figure 2). The pick up of an undervoltage elements indicates a fault is occurring somewhere on the system. If the fault is on the protected feeder, then the overcurrent element will also pick up near instantly. If the definite time overcurrent element does not pick up in one cycle, then this logic (Figure 2a) indicates a condition where a sympathy trip may occur, and blocks the primary instantaneous overcurrent elements. The sympathy trip block logic is removed when the system voltage returns to nominal. Additional logic is used to prevent operation of the scheme for open breaker conditions.

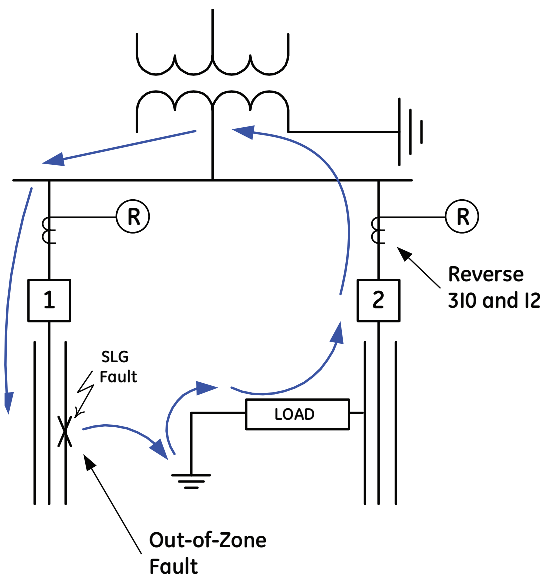


Figure 3. Load unbalance sympathy trip

Load unbalance sympathy trips

Sympathy trips due intercircuit current coupling are dependent on the system configuration, system grounding, soil resistivity, and load configuration. Figure 3 illustrates a typical intercircuit current coupling event. A phase-to-ground fault occurs on one circuit. One possible return path, depending on grounding and soil conditions, is through a grounded loads on the unfaulted circuit. This causes the relay on the unfaulted circuit to detect zero-sequence and negative-sequence current due to the fault on the adjacent circuit, and this current may be high enough to operate the relay.

The solution to this situation is easily implemented in GE Multilin feeder relays. Desensitizing the relay when an out-of-zone fault exists will prevent operation. Ground and negative sequence directional overcurrent elements operating in the reverse direction from the protected feeder determine an out-of-zone fault and can be used to supervise primary overcurrent protection elements.

Pilot Protection for Distribution Networks

Distribution systems are networked to maintain a high level of reliability for critical areas or loads. Networked distribution systems have similar protection challenges to transmission systems in terms of identifying the fault location to correctly isolate the fault.

One very reliable method of protecting networked distribution feeders is to use pilot protection schemes on the feeder, based on directional overcurrent elements and inter-relay communications. One implementation uses a permissive over-reaching transfer trip (POTT) scheme as the primary system (Figure 4), and a time-delayed directional comparison blocking (DCB) scheme (Figure 5) as the backup. The DCB scheme will operate correctly even when the feeder is temporarily operated radially.

The operation of POTT and DCB schemes is well known from transmission protection. The challenge in implementing these schemes in distribution protection is in communications, as inter-relay communications is rarely part of the distribution system. GE Multilin relays meet this challenge through the use of IEC61850 GOOSE messaging or Direct I/O communications built directly into one of the Universal Relays.

Either IEC61850 GOOSE or Direct I/O securely transmits digital status points between processing these messages exactly the same as contact inputs and outputs. The POTT scheme illustrated sends the permissive signal from one relay to the other using either one of these communications methods, and also sends Direct Transfer Trip (DTT) command using the same method. The DCB sends the blocking signal, and DTT command, via Direct I/O.

Direct I/O is highly reliable, both in performance and communications media. The performance is continuously monitored using a 32-bit CRC to verify bit error rates and package reception, and by routinely

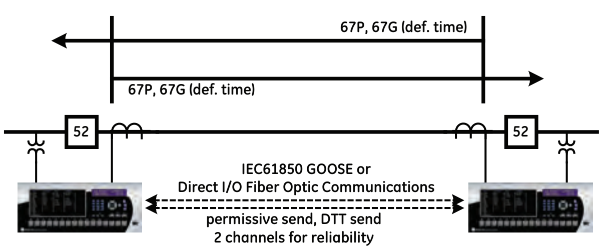


Figure 4. Pilot Protection for Distribution Networks example 1.

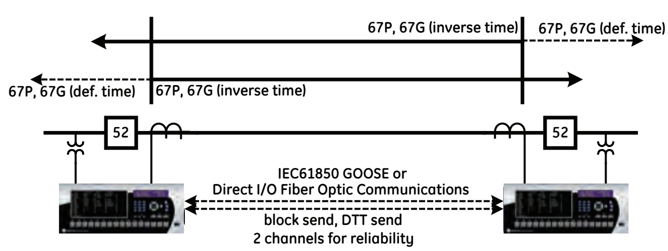


Figure 5. Pilot Protection for Distribution Networks example 2.

sending integrity messages. An individual relay can support single-channel or dual-channel Direct I/O communications for point-to-point communications, dual point-to-point communications, or ring communications between up to 16 relays without the use of a communications hub or other ancillary equipment.

Dynamic Setting groups change

Electric power distribution changes hourly to seasonally due to various reasons, including:

- Scheduled switching
- Emergency switching for repairs
- Breaker maintenance
- Seasonal load changes and transfers
- Transformer inrush
- Motor starting currents

The effect of such change produces:

- Major changes in load current
- Changes in unbalance levels
- Variations in fault levels
- Coordination problems
- Increased fault duty on conductors and equipment

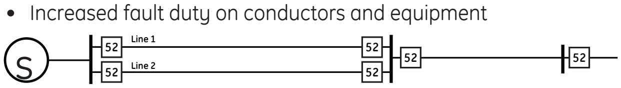


Figure 6. Parallel feeders

It is important that the protective relay provides sensitive settings under such conditions to provide secure and dependable protection. The ability to have several relay settings groups that can be dynamically activated manually or automatically to meet the needs of the system is one of the most powerful features of most microprocessor based relays. When system conditions change, relay settings are changed instantly. There is no need to compromise a setting to fit two or more different system conditions. Switchgear status can be used to modify protection settings by switching to appropriate setting groups to maximize dependability. The setting groups can be changed in GE Multilin relays via communication ports, digital inputs actual system measurements using logic decisions.

One such application where a dynamic setting group change is required is illustrated in the following example.

During normal operation, both lines are in service and carry a portion of the load. The time and instantaneous overcurrent elements are coordinated with the downstream relays according to the system conditions. When line 2 goes out of service the entire load current is carried by line 1 and the time and instantaneous overcurrent settings have to be changed due to the change in system conditions to achieve proper coordination. With multiple settings groups this can be easily achieved by examining the status of the line breakers to switch the settings groups accordingly.

Cold Load Pick-up

A cold load condition can be caused by a prolonged feeder outage. Upon the return of the power to thee load, the circuit will experience inrush current into connected transformers, starting currents into motors, and simultaneous demand from many loads as the normal load diversity has been lost. During the cold load pickup condition, the feeder current can be above the pickup setting of some protection elements, so this feature can be used to prevent the tripping that would otherwise be caused by the normal settings. Without historical data on a particular feeder, some utilities assume an initial cold load current of about 500% of normal load, decaying to 300% after 1 second, 200% after 2 seconds, and 150% after 3 seconds. There are two methods of initiating the operation of this feature. The first initiation method is intended to automatically respond to a loss of the source to the feeder, by detecting that all phase currents have declined to zero for some time. When zero current on all phases has been detected, a timer is started. This timer is set to an interval after which it is expected the normal load diversity will have been lost, so setting groups are not changed for short duration outages. After the delay interval, cold load pick up setting are used. A second initiation method can use a digital input, including breaker status or SCADA commands.

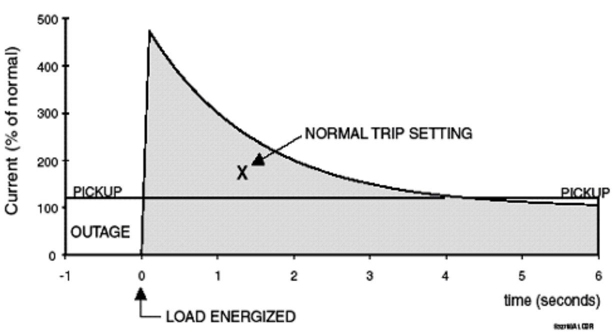


Figure 7. Dynamic cold load pickup.

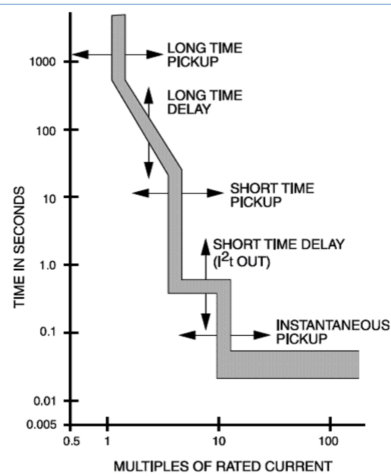


Figure 8. Custom Overcurrent Curves Maximize Sensitivity and Corrdination

Custom Overcurrent Curves Maximize Sensitivity and Coordination

A typical TOC curve for a thermal-magnetic MCCB (Molded Case Circuit Breaker) is depicted in Figure 8 and 9. This particular curve is for a 600 A frame in ratings of 125 A to 600 A at the typical rated operating temperature of 40 °C. The operating time varies inversely with current level. The shaded band covers manufacturing tolerances and other variables of a typical installation. The shown curve can be conveniently separated into three regions:

- Long-time . . . in which opening is timed in minutes up to a maximum of 1 hour or 2 hour—depending on the circuit breaker size and the degree of overcurrent—to provide an inverse-time characteristic. The provided time delay allows intermittent or cyclical loads above the pickup current to be carried without causing an interruption. It trips on sustained overcurrent to protect conductors and other equipment.
- Short-time . . . in which opening is timed in seconds or tenths of seconds. Overcurrent might be in the range expected in the case of a motor locked rotor or an arcing ground fault. Time delay in this region allows for starting and inrush transient currents or for selective coordination with supply-side or load-side devices.
- Instantaneous . . . in which opening is not intentionally delayed and is timed in milliseconds. Typical operation is a result of short circuit from a bolted fault.

Attempts to employ standard IEEE and IEC overcurrent curves to provide protection over this MCCB would result in lack of coordination or unnecessarily slow clearing times. The Flexcurves™ of GE Multilin relays allows building custom overcurrent curve characteristics to suit application like this to achieve proper coordination with a downstream MCCB.

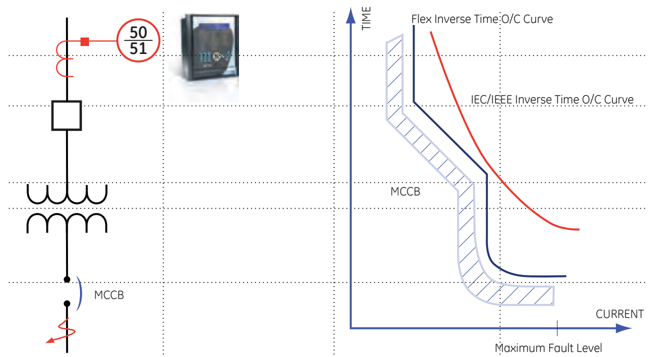


Figure 9. Typical TCC curve example.

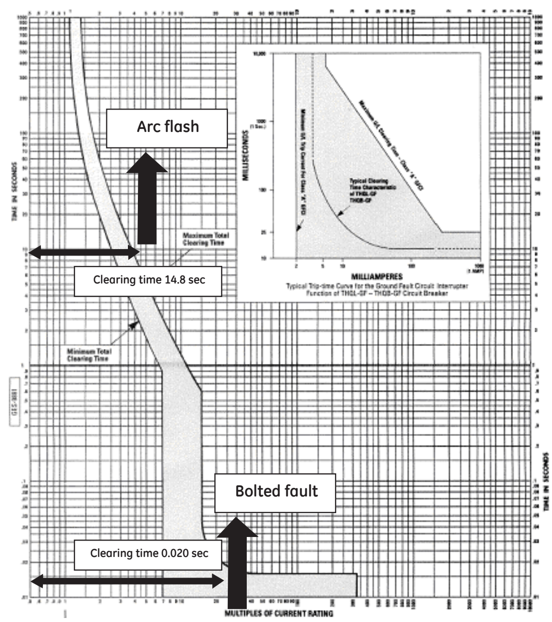


Figure 10. Circuit Breaker Tripping Curve

Arc-flash mitigation using feeder protection system

Arc flash in industrial and utility distribution systems can cause severe damage to equipment and personnel. When arcing occurs, the pressure generated by the sudden increase in the temperature (approximately 30,000°F) is strong enough to break off the metal cabinet door. The plasma emitted from the arc incidents of high energy is very dangerous.

Since an arcing fault must travel through air, its fault current is usually lower than that of bolted fault or close-in fault currents. Figure 10 shows Circuit Breaker Tripping Curve and clearance times for bolted faults and arcing faults. As shown in Figure 10, the smaller value of the arcing fault current can significantly delay the fault clearing time of the protection system and result in increased flash damage.

As arc flash hazards are recognized, investments in personnel protection are required. Although the amount of energy released in an arc-flash may be greater for higher voltage installations

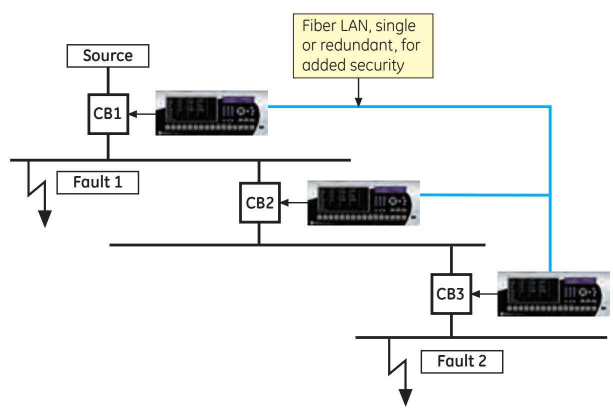


Figure 11. Reverse zone interlocking protection - By using the IEC61850 GOOSE or hi-speed direct I/O capability blocking signal can be transferred upstream, allowing minimal coordination delays. Fast clearance can be provided for Fault 1 and still maintain coordination for Fault 2.

found in some large industrial facilities and utility power plants and substations, the sheer volume of low voltage equipment in commercial and smaller industrial facilities means that these installations account for the greatest number of electrical safety incidents. Many industries and regulatory agencies are currently showing interest in mitigating arc-flash energy and reduce personnel safety hazards.

In the recent years many techniques have been proposed to mitigate arc-flash hazards using microprocessor based protective relays. As far as the installations with legacy protective relays are concerned, they are only left with a single expensive incomplete option to reduce arc-flash hazards. To clear the fault quickly as possible coordination studies of the particular system needs to be revised to tighten up the coordination time settings between Time Over Current relays.

GE Multilin's leading edge protection and control products such as F60, F35 and F650 relays can be used to provide advanced arc flash mitigation solutions that are easy to implement. Key benefits of these solutions are:

- Improved personnel safety
- Increase production uptime
- Easy and cost-effective implementation
- Reduce damage to the facility and decreased cost of repair or replacement

Hi-speed Interlocking Schemes

Figures 11 shows examples of typical distribution configurations that can be used to provide advance arc-flash mitigation using F60, F35 and F650 protective relay systems. The built-in peer to peer communication capabilities in these relays allow hi-speed data exchange between relays without the use of a communications hub or other ancillary equipment. By using the IEC61850 GOOSE or hi-speed Direct I/O capability, Interlocked protection can be provided to protect buses. Fast clearance can be achieved for a feeder Fault 2 during maintenance and still maintain coordination for fault 1 during normal operation. If the blocking signal from feeder is not received within given time delay then the main breaker will trip the bus. Another method of reducing arc flash hazards is to use a maintenance mode scheme. During the maintenance mode the relay protecting the potential arc flash hazard zone will have its settings changed to instantaneous from coordinated time over current. Although coordination is sacrificed during the maintenance interval, the clearing time is greatly reduced.

Key advantages of Hi-speed Tripping Schemes:

- Fast clearance (2-3 cycles)
- Sensitivity and security not compromised during normal operation.
- Easy implementation using existing F60, F35, F650 using IEC61850 or Direct I/O
- Reduced wiring and commissioning cost

Fast arc-flash detection using pressure, heat and light sensors

Arcing generates heat, sudden pressure and light. Sensors that are capable of detecting above parameters can be integrated with F60 and F35 relays to provide fast and secure arc flash detection. Disturbance Detector (50DD) in the F60 & F35 relays is a fast and sensitive current element that will respond to minor system disturbance. Industrial grade sensors along with 50DD element in the UR can be used to detect arc-flash fault. The sensors can be suitably placed in various cubicles or drawers inside the switchboards. These sensors are connected to a junction box (Figure 13), which will be wired to the UR F60 or F35 that controls the main breaker. During the scheduled maintenance, relays in the switchyard can be switched to maintenance mode. During the maintenance mode the relay settings will be changed to instantaneous from coordinated time overcurrent. FlexLogic™ can be used to develop an arc detection system (Figure 12) to rapidly trip the breaker if the light/pressure/heat sensor asserts and the relay's sensitive disturbance detector asserts.

Figure 13 shows a typical dual incomer configuration. The Universal Relay event report can be used to trigger events for traceability and waveforms can be captured for in-depth analysis.

Key advantages of fast arc-flash detection using sensors:

- Fast clearance
- Sensitive detection than other techniques
- Cost-effective - Reduced wiring and commissioning cost
- Traceability using event report.

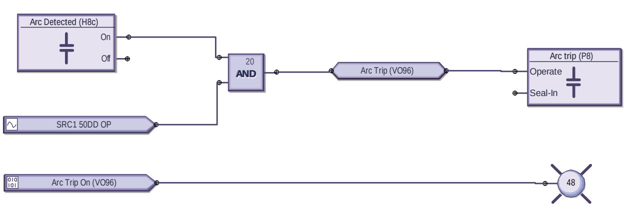


Figure 12. Fast and secure arc flash detection.

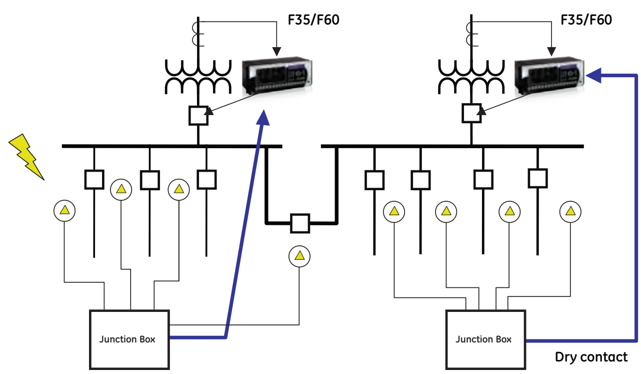


Figure 13. Dual incomer configuration with sensors and junction box.

On-line Breaker Monitoring

With today's emphasis on reducing maintenance spending, industrials and utilities are being pressured to reduce their overhaul and maintenance costs, which represent a significant portion of the overall operating costs. One way to accomplish this is by extending the interval between maintenance cycles and doing less maintenance, or performing maintenance based on equipment condition rather than elapsed time. The present trend for scheduled maintenance, which is usually based on equipment type, elapsed time, equipment maintenance history, or number of operations, is being directed more towards Reliability Centered Maintenance (RCM) programs based on the criticality of the assert to the system, maintenance history and diagnostic technologies available to identify problems or indications when maintenance is required. This approach provides guidance to staff to target maintenance on the most critical apparatus.

Legacy protective relays can only provide number of breaker operations and I^2t. This data is not adequate to monitor a breaker and to identify performance variation, developing circuit breaker problems or decide on RCM maintenance.

GE Multilin' s leading technology products from the Universal Relay and 650 families of products can be used to measure additional key parameters from the circuit breakers and process them using the Flexlogic™ to derive breaker health conditions.

- Arc duration — A good indication of dielectric condition
- Maximum Fault Current — Each operation, by phase
- Contact interrupting duty — Accumulated I^2T per phase
- Latch health indication – Trip command to "52a" opening
- Balance of mechanism health – Trip command to "52b" closing
- Number of Operations Alarm
- Real time data availability – Immediate detection of impeding problem immediately.
- Visible record available, using waveform capture of breaker operations.

Key advantages of On-line Breaker Monitoring:

- Reduce costs by postponing unnecessary maintenance — with confidence that breakers are operating within normal wear limits.
- Detect breaker problems in order to schedule just-in-time maintenance to prevent malfunction or failure.
- Implement a predictive Reliability Centered Maintenance (RCM) Program based on historical intelligence continuously gathered in real time.
- Extend the operational life of older oil-type circuit breakers.
- Better power system reliability.

CT Saturation in Industrial Applications

In metal-clad switchgear and MCC applications, current transformers are often selected based on size limitations and full load current. The result is that CTs in these applications are severely underrated, with the available fault current potentially hundreds of times larger than the CT primary (e.g. 50 kA short circuit capacity on a 50:5 C10 CT). When subjected with these large fault currents a CT will saturate severely, passing only a small fraction of the ratio current with the end result being a potential loss of coordination with upstream protection. Relays using Fourier-like measurements (such as cosine filters) are affected by this problem, but products using true RMS measurements, like GE Multilin relays, are unaffected.

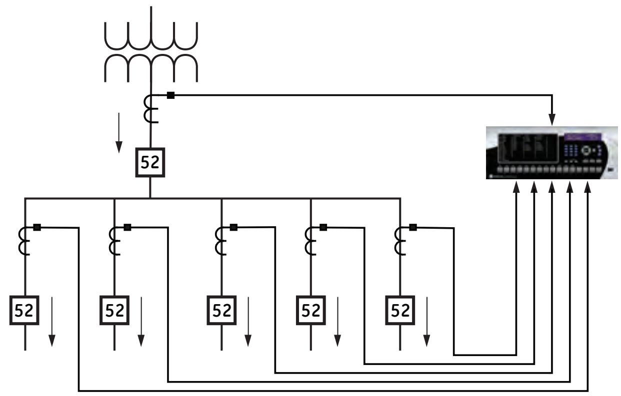


Figure 14. Multiple Feeder Protection and Control.