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A Tutorial for Distribution Protective Relay Applications

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Presented Before the
31st Annual Western Protective Relay Conference
October 19th – 21st, 2004
Spokane, Washington USA

Abstract

This paper is a tutorial covering relay applications in distribution networks. For relay engineers, projects involving distribution systems take up the majority of their time. In many cases, attrition has robbed them of their mentors, leaving a void in experience that is difficult to fill. This paper provides help in understanding the various methods used to protect equipment in distribution systems as well as some ideas for better practices.

Introduction

Protection and control of distribution networks is an often neglected topic at conferences such as this. Transmission line, generation, and bus protection often dominate the agenda. Distribution system protection is often taken for granted, as if the skills needed were bestowed upon us at birth. To make things more difficult, the gap is widening in the experience level of utility engineers. The young and inexperienced engineer is being expected to do design and applications on distribution systems with little help from their peers. Thus the art and science of protection and control of distribution systems is becoming a lost art.

The majority of faults in a power system occur on distribution lines. All regulating agencies have strict performance criteria for outage duration and frequency. With the advent of sophisticated numerical relays much more in the way of protection and control can be accomplished. Therefore it is important that today's relay engineer be schooled in traditional techniques, and also understand the new technology present in modern relays.

Many texts have been written on the subject of distribution protection. The reference list at the end of this paper gives credit to the giants. We will not attempt to reinvent the wheel so to speak, but will offer by way of this paper a primer on the subject. Basic feeder protection strategy is introduced, and Industry trends will be discussed. This allows the reader to see what has or has not been working for utilities. Also, a step-by-step procedure for substation and feeder coordination that has worked for decades will be presented. This set of "rules" serves a standard for a top-ten electric utility company. Finally, some new protection and control methods made possible by new technologies will be discussed.

Basic Design Criteria

Although not strictly associated with distribution systems, a discussion of the basic protection problem is warranted. Four design criteria are essential to any well-designed and efficient protection system. Some of the criteria counter balances each other and others are difficult to measure. Thus the beautiful problem that all relay engineers confront, how to balance the necessary compromises on the basis of comparative risk, while attempting to satisfy the design criteria. This is the "art and science" of protective relaying. The four design criteria are:

Reliability

System reliability consists of two elements: dependability *and* security. Dependability is the degree of certainty that a system will operate correctly to a given input. Security is the degree to which a system will *not* operate to a false set of inputs. These two aspects of reliability tend to counter each other. Increasing security tends to decrease dependability and visa versa.

Dependability can be checked in the laboratory by subjecting the relay system to simulated faults. Security, however, is much more difficult to check. A true test of security would have to measure response to an infinite variety of transients and false trouble in the power system. The balance of these in a distribution system is essential to obtain low outage durations.

Speed

Relays that could anticipate a fault would be ideal. The development of faster relays must always be measured against the increased probability of false operations. Time is an excellent criterion for distinguishing between real and counterfeit trouble. In distribution systems, time is a tool used extensively in device coordination and certain control functions.

Simplicity

Simplicity in a protective relay system is a strong indication of good design. Simplicity of design improves system reliability because there are fewer elements to malfunction. Due to the varied skill level of personnel who contact distribution relay systems, simplicity is a highly desirable attribute.

Performance vs. Economics

Discreet relays that have a clearly defined zone of protection provide good selectivity but cost more than multi-function devices. High-speed relays also cost more, but are not generally needed in distribution systems. Local backup of feeder relays is also costly and is loosing favor with utilities. All of these factors play in to the generally accepted practice of using multifunction relays without local backup. This method is clearly the most economical approach, but gives up ground in reliability.

Table 1 is presented to bring out some figures regarding correct relay operations based on actual utility statistics.

Correct and desired	92.2%
Correct but undesired	5.3%
Wrong tripping operations	2.1%
Failure to trip	0.4%

Table 1. Relay Operations

Typical Distribution System Defined

Figure 1 illustrates a typical utility radial distribution system. The major components that are of interest to the relay engineer are shown. The equipment that is to be protected is the transformer, bus, and lines. Other equipment such as substation capacitors or reactors may also have the need for a protection system.

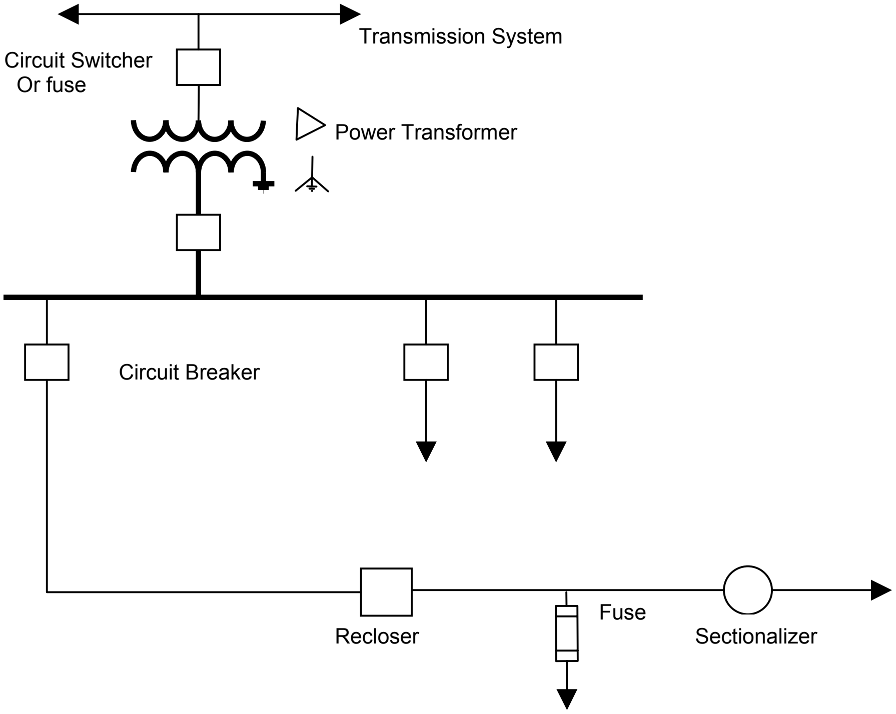


Figure 1. Typical Radial Distribution System

Voltage Class
Distribution systems are characterized by nominal operating voltage. This is expressed in kV, and ranges from 2.5 to 50kV. Original primary distribution voltages were generally limited to 14kV, but increases in load densities in recent years has forced utilities to limit expansion of lines below 15kV and begin to convert sub-transmission voltages (15-50kV) to primary distribution. Figure shows the percentage of various voltage classes used by U.S. utilities for primary distribution.

Voltage Class	U.S. Utilities
5 kV	6%
15 kV	62%
25 kV	20%
35 kV	12%

Figure 2. Primary Distribution Voltage Class Among U.S. Utilities

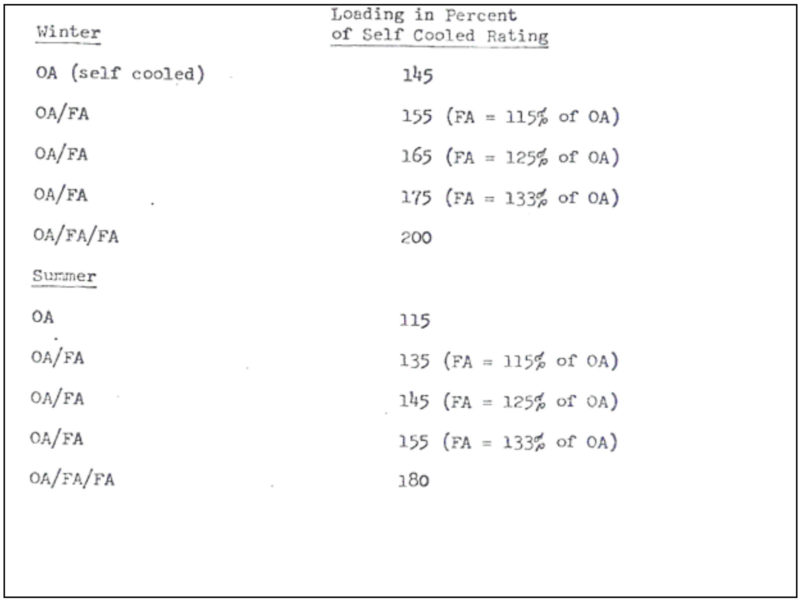
Types of Faults
Faults on distribution systems can be temporary or permanent. Temporary faults are those that burn clear or are successfully cleared by a temporary interruption of circuit voltage. On overhead lines 85% or more are temporary ground faults. Permanent faults are those that cannot be cleared by circuit opening, and are usually caused by equipment failure or cable rupture.

Transformers

Transformers are classified as distribution or power. Power transformers are those generally rated above 500 kVA. The transformer ratings that are most common in distribution substations are discussed below.

Power and Voltage Ratings of Transformers:

Most transformers in substations are liquid filled. Ratings in KVA or MVA will be at the self-cooled rating at a specified permissible temperature rise. The standard average temperature rise for modern liquid-filled banks is 65º C at an ambient of 30º C. Typical MVA ratings are 10/12 OA/FA, 15/20/25 OA/FA/FOA. OA = Oil-immersed, self-cooled; OA/FA = Oil-immersed, self-cooled / forced-air-cooled; OA/FA/FOA = Oil-immersed, self-cooled / forced-air-cooled / forced-oil cooled. Typical permissible maximum loadings for substation transformers are shown in figure 3. This particular utility company has winter peaking loads. The maximum permissible load value is necessary for determining fuse size or overcurrent relay pickup selection.



Winter	Loading in Percent of Self Cooled Rating
OA (self cooled)	145
OA/FA	155 (FA = 115% of OA)
OA/FA	165 (FA = 125% of OA)
OA/FA	175 (FA = 133% of OA)
OA/FA/FA	200
Summer	
OA	115
OA/FA	135 (FA = 115% of OA)
OA/FA	145 (FA = 125% of OA)
OA/FA	155 (FA = 133% of OA)
OA/FA/FA	180

Figure 3. Permissible Maximum Loadings for Substation Transformers. (Courtesy of PacifiCorp)

Voltage Taps:

Most modern power transformers for substation use have integral load tap changers (LTC) attached to their tanks. The LTC automatically changes the tap position on the transformer in response to varying load conditions. LTCs generally have a range of ± 10% of nominal voltage in 16 steps. The existence of an LTC in the transformer zone of protection must be accounted for when applying differential relays.

Impedance:

The impedance voltage of a transformer is the voltage required to circulate rated current through one of the windings while the other is short-circuited. Impedance voltage is normally expressed as a percentage of the rated voltage of the winding that is not shorted, at the OA rating of that winding. The percent impedance is a limiting factor in through fault magnitude, which determines the transformers ability to withstand the stresses of external faults. The transformer impedance is usually much higher than the source impedance. A quick check of the maximum fault current can be performed as follows.

$$\textbf{Max 3-phase fault (per unit)} = \frac{1}{Z}$$

Example1. Maximum Through Fault Current

Given: 15 MVA, 115 / 12.5 kV, 9.0% Z, 3-phase transformer
Find: The maximum through fault current.
Solution:

$$I_f \text{ p/u} = \frac{1}{0.90} = 11.1 \text{ p/u}$$

$$I_{12.5\text{kV base}} = \frac{15000}{\sqrt{3} \times 12.5} = 692 \text{ Amps}$$

$$I_f = 11.1 \times 692 = \mathbf{7698\ Amps}$$

Thus given an ideal source, the maximum fault current that can be expected on the 12.5 kV substation equipment is 7698 Amps.

Circuit Breakers

The main fault interrupting device in a substation (transmission or distribution) is the power circuit breaker. Circuit breakers have many ratings, with the rated short circuit current and rated interrupting time, of most interest to relay engineers. The available fault current of the particular installation must be less than the rated short circuit current of the breaker. Also, the interrupting time of the breaker has to be considered when coordinating with down-stream overcurrent devices. Typical ratings for a 15kV class breaker are 20kA rms or more for short circuit current, and 3-5 cycles for interrupting time.

Power circuit breakers can be either freestanding (outdoor) or enclosed in switchgear (indoor). Freestanding breakers are discrete devices that are mounted on concrete pads installed in substations that have exposed overhead bus. Indoor breakers are installed in metal enclosed switchgear. Generally, switchgear applications are less costly than outdoor installations. But the risk of catastrophic failure of metal enclosed switchgear is much higher than in outdoor breaker applications.

Circuit Switchers

Circuit switchers are a free standing outdoor fault interrupting switching device. They are used to protect the substation power transformer primary when used with protective relays. The circuit switcher started replacing fuses in substations about 20 years ago, and is the preferred device for primary voltage rating above 69kV and 15MVA for many utility companies.

The main advantage of using of a circuit switcher over a fuse is for single line to ground through faults. These are the most common faults that a distribution transformer is subjected to, and present a challenge for power fuses. This is because for delta-wye transformer banks, ground current as seen by the primary is only 58% of the reflected value of a low side fault. As a result, the fuse, which only "sees" high-side current, reacts slower than it would for a similar 3-phase fault on the same bus. In many cases the clear times of the shifted fuse curve encroach on the transformer damage curve, causing loss of life to the transformer. Note that the frequent fault curves are lower than the infrequent fault curve shown in Figure 4. Atypical fuse sized for a category III transformer may not adequately protect the bank for a low side ground fault.

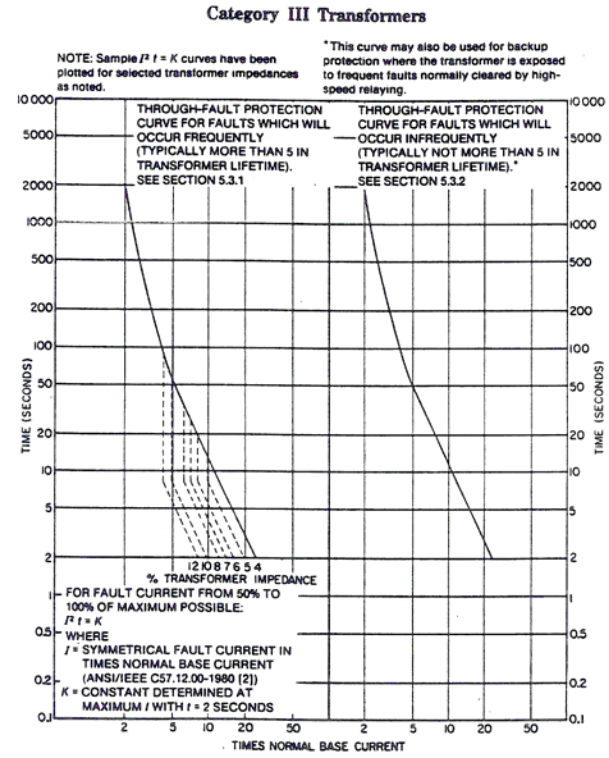


Figure 4. Recommended Duration Limits for Category III (5 - 30 MVA) Transformers (From IEEE/ANSI C57.109-1985)

Overhead Lines

Overhead lines make up much of the utility distribution system. The main concern for relay engineers is to keep the conductors from being damaged, while maintaining service continuity. To do this, the interruption times for various faults must be kept faster than the time required to bring the conductor to a temperature that will cause damaging annealing. Service continuity is maintained by various control and protection schemes (auto reclosing, fuse saving etc.) that are dealt with in more detail later in this text. Figure 5 shows the conductor annealing characteristics for ACSR.

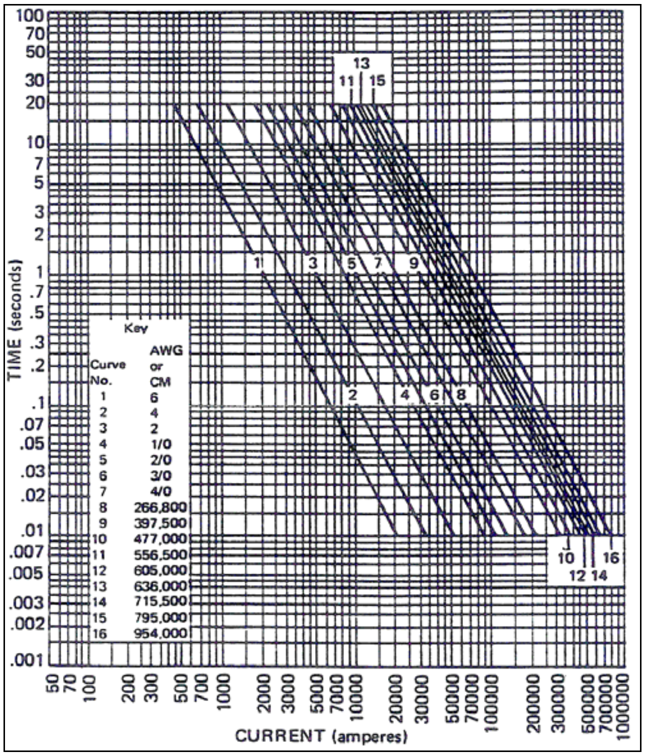


Figure 5. Conductor Annealing Curve for ACSR
(Courtesy of Alcoa Conductor Products Company)

System Modeling

System modeling is an arduous task often left up to the relay engineer. In many cases, existing electrical distribution system models only consist of positive sequence impedances. This is because system planning engineers are often most interested in loads and load flow, not short circuit analysis. The relay engineer needs negative and zero sequence impedances for his or her work, and therefore must complete the distribution system model.

Overhead line resistance and reactance are generally found in tables that are derived from the conductor properties. Impedances for three phase circuits are affected by conductor spacing, tower design, cable diameter, and cable material. For a given conductor, the series inductive reactance is given as

$$X_L = X_a + X_d$$

The two inductances $X_a + X_d$ can be read from standard tables as long as the equivalent distance (D_{eq}) for the given tower is known. Utilities usually have tables of equivalent distances for their most common tower and pole configurations. Figure 6 shows the X_L for ACSR.

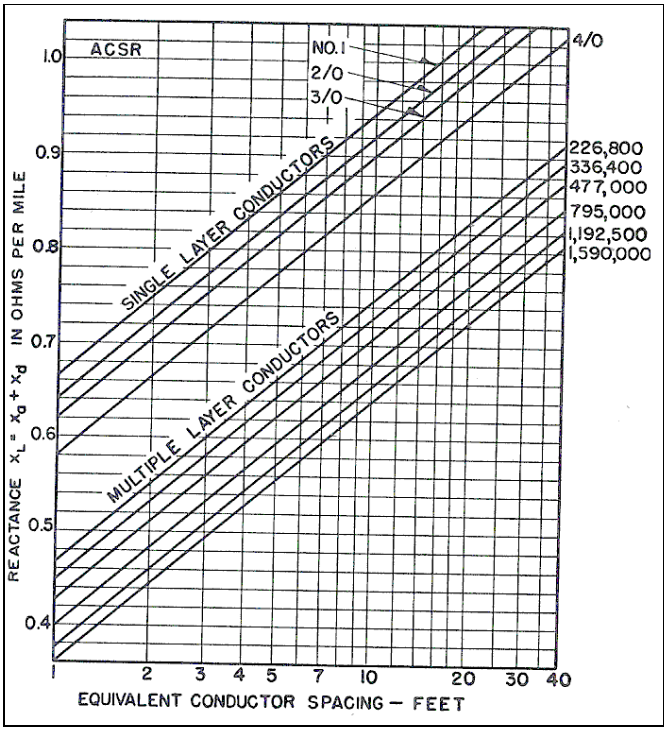


Figure 6. Series Inductance of ACSR
(From "Electrical Transmission and Distribution Reference Book", Westinghouse Electric Corporation)

Positive and negative sequence impedances are equal, and derived by the methods described above. Zero sequence impedance (Z_0) is a more inexact number that depends on many factors. Using certain approximations and assumptions, a practical method has been developed. The fundamental equation for Z_0 is

$$Z_0 = x_a + r_e + j(x_a + x_e - 2x_d)$$

The additional constants, x_e and r_e, can be found in standard tables for a given frequency and earth resitivity. Often the resitivity is not known, so 100 meter-Ohms is assumed.

<u>Underground Cables</u>
Underground cable makes up a small percentage of a utility distribution network. Typically, the only place where the relay engineer will find underground cables is on substation feeder getaways and in high-density urban power distribution systems.

Faults on cables tend to permanent, as opposed to those on overhead lines. As a result, protection of the cable is usually the only consideration. Service continuity is almost always lost after a cable fault. Impedance characteristics are also quite different for cables. Impedance coupling tends to be capacitive due to the dielectric effect of the insulation. This is not of great concern to relay engineers, but must be accounted for when modeling the system for short circuit analysis.

Reclosers

An automatic circuit recloser is a self-contained device with the necessary intelligence to sense current and to trip and reclose automatically. If the fault should become permanent, the recloser will lock-out after a pre-set number of operations, or “shots”. Traditional reclosers are single pole or three-pole with hydraulic or electronic operators. They typically have oil or vacuum interrupters.

Modern automatic circuit reclosers are three-phase devices that can operate three-pole or single-pole. They have their own integrally mounted control device, instrument transformers, and battery. Their operators are magnetic, so that they are rated for many more operations than traditional oil-type reclosers. They generally have slower interrupting times and lower rated short circuit current than do breakers. However, in recent years the short circuit rating and voltage ratings of reclosers has approached that of circuit breakers. As a result, reclosers have begun to replace circuit breakers as primary feeder interrupting devices in substations with overhead bus work. Reclosers can be as little as one third the cost of a breaker, and they include all of their own protection and control apparatus. However, reclosers generally have a lower duty cycle, making maintenance intervals more frequent.

Sectionalizers

Sectionalizers are usually single-pole devices which do not have fault interrupting capabilities. They are used to open a feeder circuit after a permanent fault. The sectionalizer is operated by an integrator that is operated by the fault current pulses caused by automatic reclosing of an upstream breaker or recloser. The integrator counts the number of pulses and breaks the circuit after the count has exceeded the setting.

Fuses

Fuses are usually used to protect taps off of a main feeder trunk. They use a metallic link that responds to the heat produced by current flow. When the current through the link exceeds a certain value for a certain amount of time, the fuse link melts, opening the circuit. After having interrupted an overcurrent, it is renewed by the replacement of its current-responsive element. The time-current relationship is defined by curves supplied by the various fuse manufacturers. The fuse curves show a range of time-current values representing the “total clearing” tine and the “minimum melting” time.

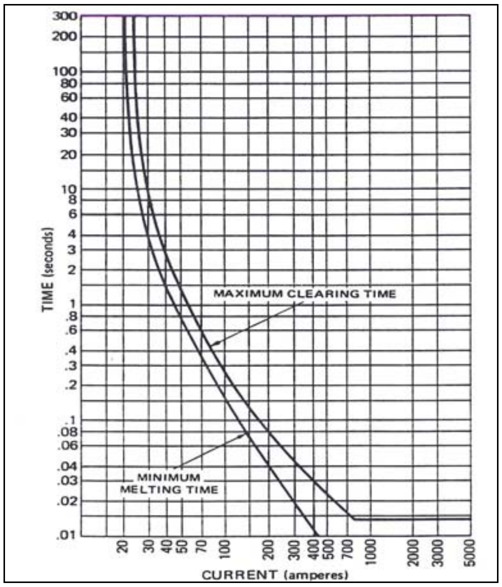


Figure 7. Time Current Curve (TCC) for Typical Distribution Fuse Link

Basic Relay Units for Distribution Systems

Distribution power systems should be designed so that the protective relays operate to sense and isolate faults quickly to limit the extent and duration of an outage. The basic relay units and their operating characteristics are discussed below. Keep in mind that this is a subset of all relay types, intended for application on utility distribution substations and networks.

Time Overcurrent Relay (51)

By far the most common relay type used in distribution systems in the time overcurrent (TOC) relay. The TOC relay is designed to give a time-delayed tripping characteristic which follows a set time-current curve (TCC). The curves associated with this time delay follow loose standards, but are generally as follows.

- Inverse
- Very Inverse
- Extremely Inverse
- Short Time Inverse
- Long Time Inverse

The following graphic shows a comparison of these curve shapes.

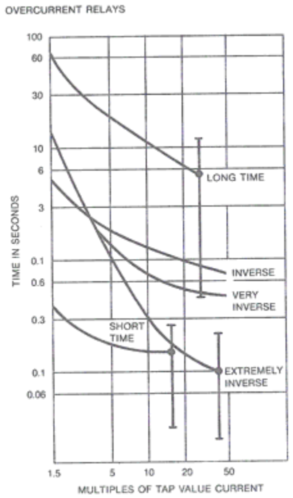


Figure 8. Comparison of Typical Curve Shapes for TOC Relays
(From ANSI/IEEE Std 242-1986)

In addition to the shape of the TCC, an associated “time dial” (TD) setting is required. The time dial is just a family of the same curves, adjusted for time. Figure 9 shows the time dials 1 through 10 for a typical Very Inverse TCC.

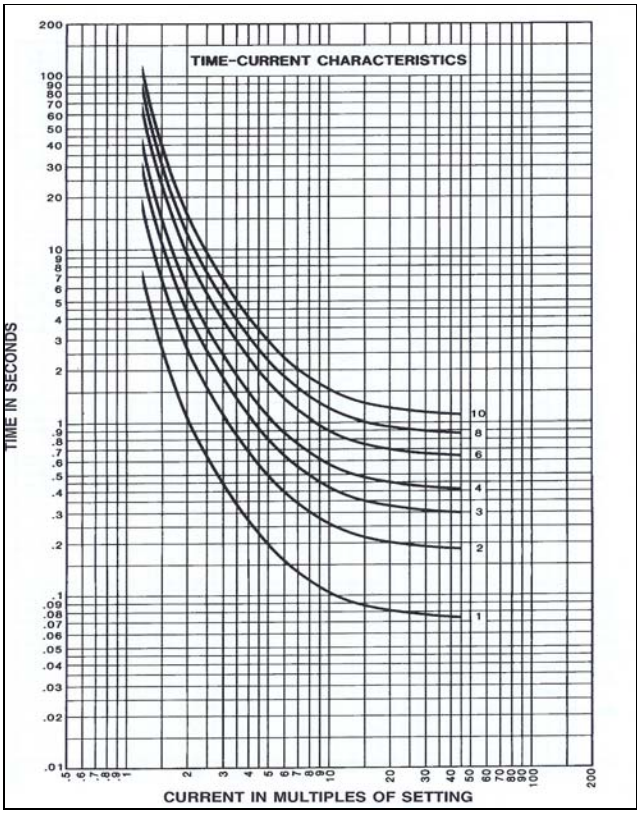


Figure 9. Very Inverse TCC
(Courtesy of ABB Inc)

In addition to curve selection and time dial, time overcurrent relays also have a “pickup” setting. This is the current value at which the relay begins timing. The pickup is set to accommodate maximum loads on a particular piece of equipment, and is discussed in length later in this text. In the above curve the current value is shown as a multiple of the pickup current value. So for a pickup of 4.0 AMPS, the point on the horizontal axis representing 1 per unit would actually be 4.0 Amps. Multiplying this times the current transformer turns ratio would yield the actual primary current for this point on the curve.

Example 2: Determine the trip time for an overcurrent value of 1,500Amps
Given: Very Inverse TCC, Pickup = 3.0 Amps, Time Dial = 2, CT ratio = 600 / 5
Find: The trip time corresponding to this overcurrent.
Solution:

CT Turns ratio = $\frac{600}{5}$ = 120 Turns

Relay current = $\frac{1500 Amps}{120 turns}$ = 12.5 Amps

Multiples of pickup setting = $\frac{12.5 Amps}{3.0 Amps}$ = 4.17 X pickup

Find the point on the TCC corresponding to 4.17 times pickup on the horizontal axis, and read the trip time on the vertical axis:
Trip Time = 0.63 seconds

To obtain a representation of ground current in a circuit, the overcurrent relays are often connected in a “residual” configuration:

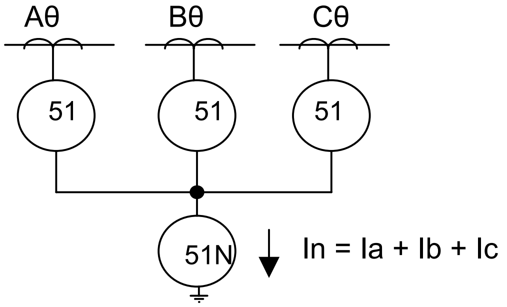


Figure 10. Residual Connection for Overcurrent Relays

The current flowing in the neutral relay (51N) is the sum of the phase currents, and is equivalent to the ground current in a multi-grounded distribution system.

Instantaneous Overcurrent Relay (50)
Instantaneous tripping relays operate for an overcurrent above their setting with *no intentional* time delay. They are used for high-speed operation for close-n faults, and to clear temporary faults without operating other time overcurrent devices that are located in other parts of the system.

Differential Relay (87)

Differential relays have many applications in power systems. The general principle is the same for all situations, but we will only focus on differential relays applied to distribution substation transformers.

This fundamental technique is illustrated in Figure 11. The basic principle is that the *current flowing into the relay must equal the current flowing out of the rely.* In the illustration, the relay tripping is based on the operating current (Io). It can be seen that

$$\mathbf{Io = I_1 + I_2}$$

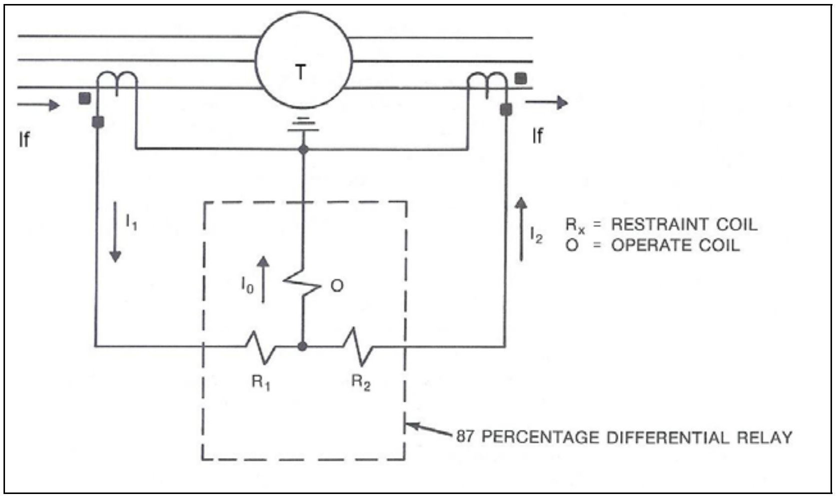


Figure 11. Differential Relay Principle

The most common transformer configuration in a distribution substation is the high-side delta, and low-side wye. Therefore, the voltage and current are not equal across the high and low side of a transformer differing by both magnitude and angle. Standard winding wiring practices have the high-side delta leading the low-side wye by 30º.

To make them the same as far as the differential relay is concerned, the secondary currents are divided by a "tap" setting. Also, the CT connections must be opposite that of the transformer to cancel out the angle difference of a wye-delta connection across the transformer. This will be discussed in detail later in the text.

The CTs that measure the differential current are not perfect devices. Therefore, the relay needs to be de-sensitized the for high magnitude through faults to increase security. The percentage differential relay is used to account for the CT irregularities. Figure 12 illustrates the principle.

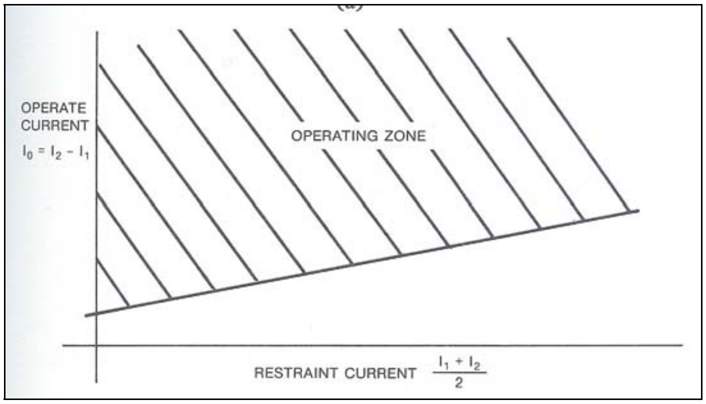


Figure 12. Percent Differential Characteristic
(From ANSI/IEEE Std 242-1986)

It can be seen that for external faults, that the greater the magnitude of restraint current the more operate current is necessary to trip the relay. This feature adds security to the design, which is usually weighted more heavily than reliability for distribution power transformers.

Automatic Reclosing Relay (79)

The automatic reclosing relay will close the associated circuit breaker after a variety of conditions have been met. Generally, the breaker will be closed a set number of times, with an set time delay between closures. The basic settings for a reclosing relay are:

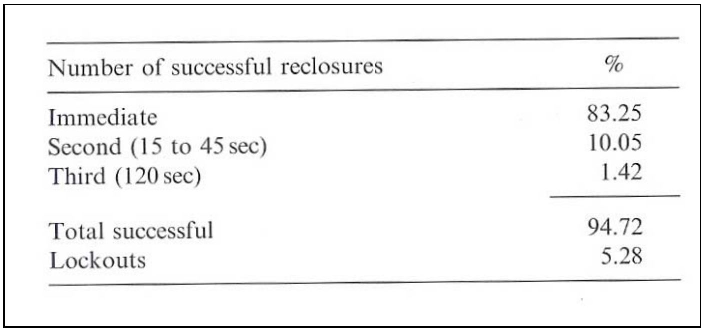
- Number of shots. This is the number of reclosures that the relay will attempt.
- Open Interval Time. This is the time that the breaker is programmed to remain open between reclose attempts. There is usually a different setting for each shot.
- Reset Time. This is the amount of time allotted for a reclosing event. If, for example, a reclosing relay is programmed for two shots and a third fault occurs before the reset time, the circuit breaker will be "locked" open by the reclosing relay.

Certain precautions should be observed when deciding on a particular reclosing sequence. If a generator is on or near the feeder, reclosing should not be attempted. The generator can be severely damaged by the electrical and mechanical forces that occur due to the loss of synchronism with the system. The generator must be given time to get off line before any attempt is made to close the breaker. Modern reclosing relays can check the line to make sure that it is dead, and if not can even check synchronism before closing the breaker.

The substation transformer can be subjected to severe mechanical stresses for high magnitude close-in faults. These stresses produce a motion between the windings and core that shorten transformer life. Minimizing the number of reclose attempts can have a positive effect on transformer life.

Some modern relays are flexible enough to change their number of programmed shots depending on the type and magnitude of a fault. For example, the reclose sequence can be locked out or reduced if the fault is close-in or 3-phase. This is an excellent strategy as most temporary faults are single line to ground with at least some fault impedance. For example a falling tree branch has significant fault impedance and can be transient.

Multiple-shot reclosing relays are warranted on distribution circuits with significant tree exposure, where faults caused by flying debris can outage a line. A fault and trip for this transient type of event would result in a customer outage if not for automatic reclosing. A typical utility experience on a feeder with high storm activity is as follows:



Number of successful reclosures	%
Immediate	83.25
Second (15 to 45 sec)	10.05
Third (120 sec)	1.42
Total successful	94.72
Lockouts	5.28

Figure 13. Successful First Reclose Attempts

The data shows a high success rate for first reclose attempts, but the incremental benefit is less for subsequent attempts.

Some utilities use what's commonly refereed to as a "fuse saving" scheme. In this application, instantaneous tripping units are set very low so that they will operate for any phase or ground fault on a feeder. Typical settings are:

50P = 1.0 times 51P setting
50N = 1.0 times 51N setting

The strategy is to trip the substation feeder breaker before the tap fuses, and then high-speed reclose. If successful, the temporary fault is cleared and full service is restored. If, on the other hand, the fault persists beyond the first reclose attempt, the 50 and 50N elements are turned off to allow the fuse closest to the fault to trip. This is accomplished by switching the tripping element to a 51 or 51N and coordinating it with the fuse curve.

After the time delayed trip, the relay is usually programmed to remain open for 5 – 15 seconds, and then close again. Some utilities even go to third attempt, commonly holding the breaker open for 30 – 45 seconds before closing. This is commonly referred to as a "0-5-30" or a "0-15-45" sequence.

In recent years utilities have begun to move away from the three-shot reclose sequence in favor of improving transformer life. The following data from a survey illustrates the trend.

Number of Reclosing Attempts Programmed

	5 & 15kv	25 & 35kv
1 shot:	8%	10%
2 shots:	33%	50%
3 shots:	52%	30%
4 shots:	9%	8%

Figure 14. Number of Reclose Attempts by Various Utilities

Frequency Relay (81)

Frequency relays operate for measured frequencies above (81O) or below (81U) a predetermined set point. They have many applications, but we will only be interested here in underfrequency load shedding schemes.

The objective of load shedding is to balance generation and load. The rapid frequency plunges that accompany severe overloads would require an impossibly fast response from a generator governor. To stop these severe drops it is necessary to intentionally and automatically disconnect a portion of the load that is equal to or greater than the overload. After the frequency excursion has been stabilized, it is possible to restore the disconnected loads in small increments. The following figure illustrates the behavior of frequency during automatic load shedding.

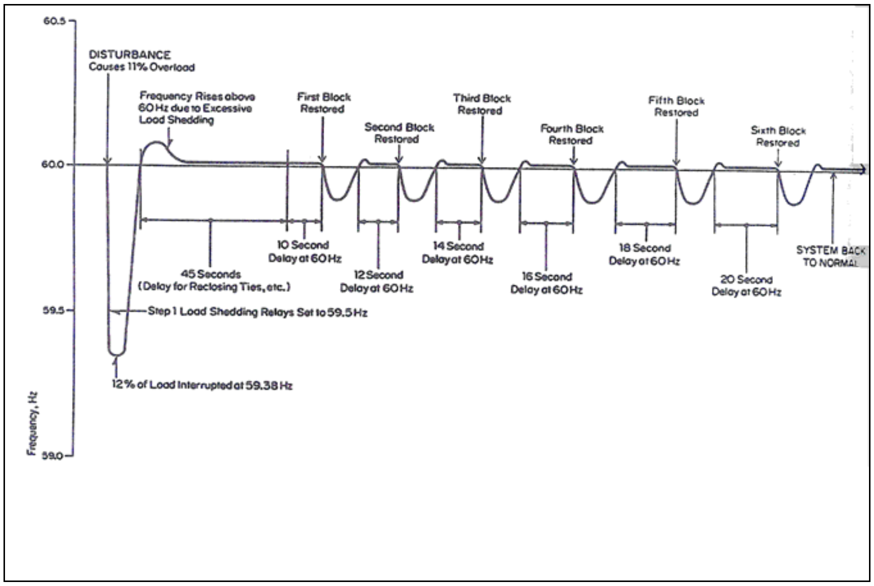


Figure 15. Frequency Behavior During a System Overload
(From "Applied Protective Relaying Theory and Application", 2nd ed, W.A. Elmore)

Frequency relays used in automatic load shedding schemes are usually installed in distribution substations. Since the amount of the overload cannot be measured at the inception of an event, the load is dropped in increments until the frequency is stabilized. The location and amount of load that can be shed is usually determined by planning engineers. The relay engineer generally just needs to know if load shedding will be employed at a the location under design, and the set points for initiation of the scheme.

In general, the restoration of shed load is left up to the discretion of system operators. Frequency relays, however, have been used to either supervise manual or automatic restoration of loads.

Most modern multi-function feeder relays have the ability to provide at least two set points for load shedding and restoration. The settings are quite minimal, consisting of:

- 81U-1 and 81U-2 to initiate load shedding
- 81U-1TD and 81U-2TD to allow different time delays for each frequency step
- 81R – and 8R-2 for load restoration, and
- 81R-1TD and 81R-2TD to allow time for the system frequency to stabilize during restoration.

The nine Reliability Councils across the US have adopted their own guidelines for the amount of load to be shed and at what frequencies. The figure below is the recommended practices for the Western Electricity Coordinating Council (WECC).

Load Shedding Block	% of customer load dropped	pickup (Hz)	tripping time
1	5.3	59.1	-
2	5.9	58.9	-
3	6.5	58.7	-
4	6.7	58.5	-
5	6.7	58.3	-
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 sec
	1.7	59.5	30 sec
	2.0	59.5	1 min
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 sec
	1.7	60.7	5 sec
	2.3	60.9	0.25 sec

Figure 16.

WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan

Protection and Coordination of Equipment

The basic problem of confronting relay engineers in a distribution system is to combine maximum speed of tripping with minimum system disconnection. This is called selective tripping, or simply "coordination". Coordination is done by comparing the TCC of two devices at a time, and marinating a time clearance between them. Consider the simple radial system below:

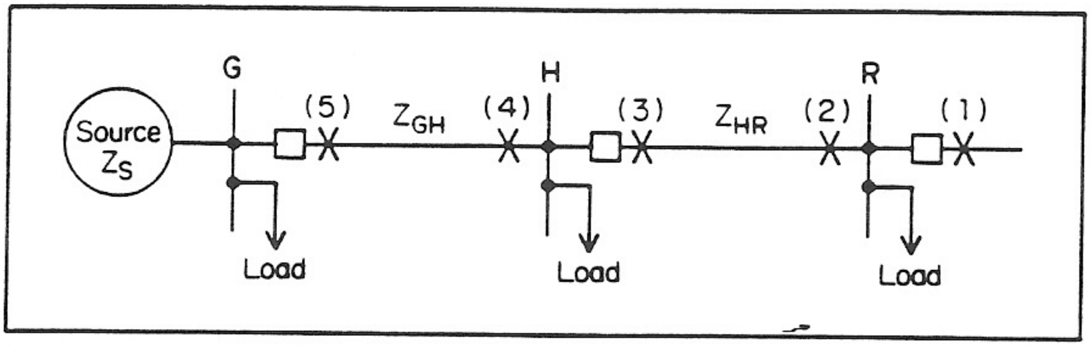


Figure 17. Example Radial System
(From "Applied Protective Relaying Theory and Application", 2nd ed, W.A. Elmore)

Consider, for example, a fault at (3). For this fault, both the relays at bus G and bus H will see the resulting current. It is desirable that the relay at bus H trip for this incident, and the relay at bus G restrains (does not trip). The two relays are coordinated if their two curves are separated for the same fault by a coordination time interval (CTI). The CTI is a safety margin allowing for breaker times and relay impulse times, and is usually in the range of 0.2 to 0.5 seconds. For most distribution applications, a CTI of 0.3 seconds provides security, while allowing enough distance in the coordination plots to fit in 3-4 curves. The figure below illustrates the CTI principle.

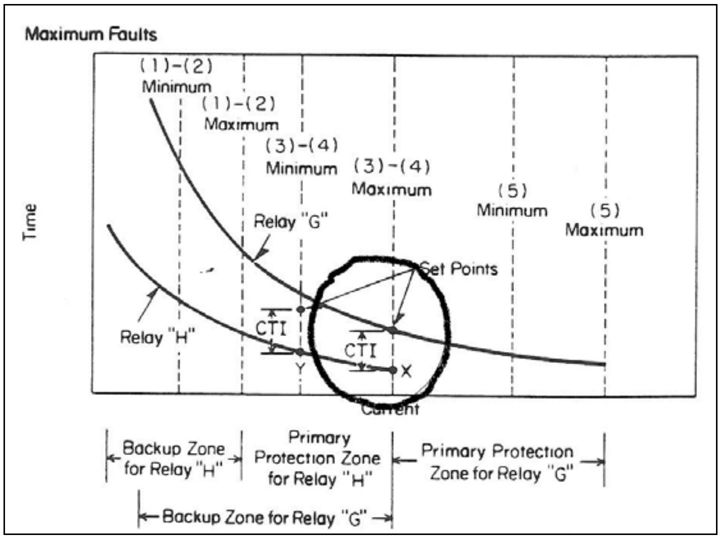


Figure 18. Coordination Time Interval
(from "Applied Protective Relaying Theory and Application", 2nd ed, W.A. Elmore)

Transformers
Generally, substation trans formers at 34.5 – 69kV are protected on their high sides by fuses. The following procedure should be used to properly size a transformer fuse.

Example 3
Given: 12/16/20 MVA transformer, 8% Z, 69 – 12.5 kV
Find: The appropriate power fuse, and plot it on a TCC graph.

Solution:
The OA rated load current for this bank is given by

$$I_{OA} = \frac{12{,}000}{\sqrt{3} \times 69} = 100 \text{ Amps}$$

The fuse must accommodate the maximum load allowed for the bank. Referring to Figure 3, it can be seen that this is the winter rating = 200% of I_{OA}.

$$I_L = 2 \times 100 = 200 \text{Amps}$$

Select a fuse size that will accommodate 200 Amps of load, plus a suitable safety margin; and adequately protect the transformer for low-side ground faults. An S&C 125E fuse is chosen for this application. Note the 600 second total clearing point is about 265 Amps. Note that the left most damage curve has been shifted for line-to-ground faults.

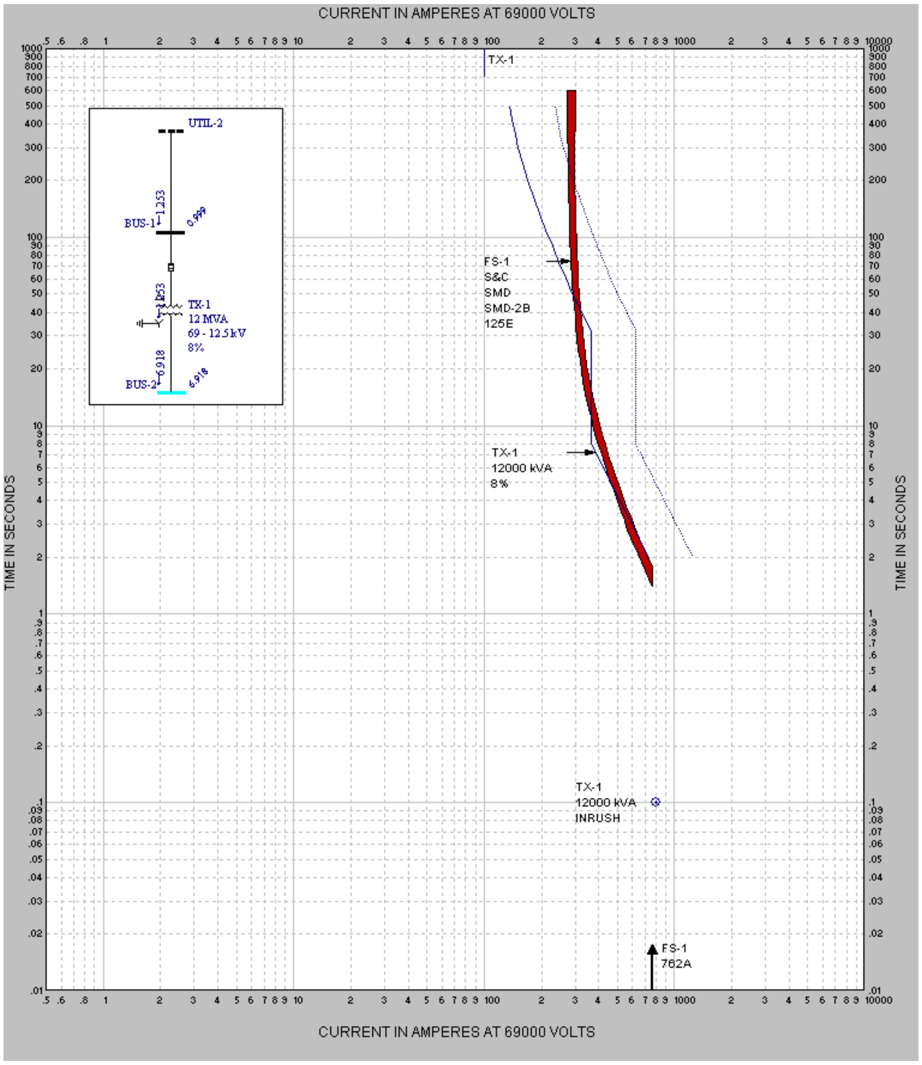


Figure 19. Ground Fault Coordination for 69 kV Transformer
(Courtesy of ESA Inc.)

Now consider the one line shown below:

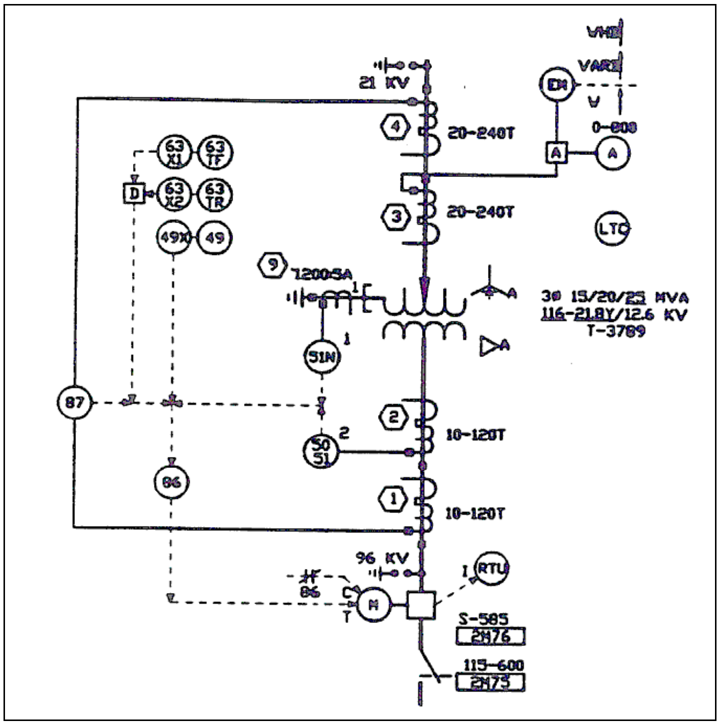
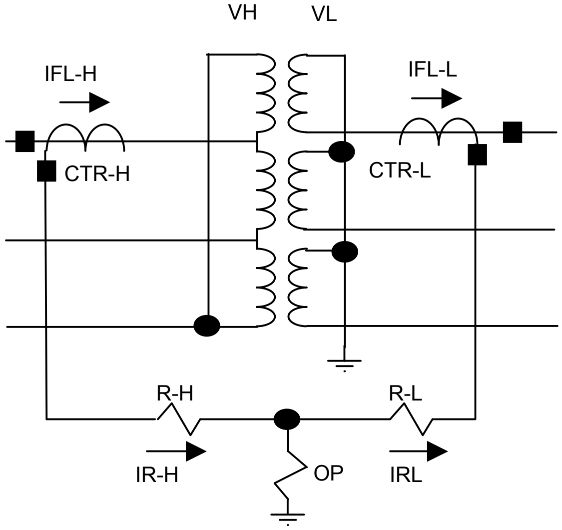


Figure 20. Typical Distribution Transformer Protection (Courtesy of PacifiCorp)

This substation transformer is protected by Differential (87T), two sets of 3-pase overcurrent relays (50/51), one ground overcurrent relay (51N), sudden pressure relays for both the transformer and LTC, and an over temperature relay (49). The trips for all protective relays go to a hand-reset lockout relay (86). The interrupting device is on the high side only, and is a circuit switcher design. The bushing CTs on the high side are C800, and the low side are C400. The protection shown is generally considered as adequate by most utilities.

Example 4.
Given the Transformer in the above oneline:
Find: Settings for the differential relay (87T) and the overcurrent relays (51P, 50P, 51N) and plot on a TCC diagram.
Solution:



To determine the tap settings, any current flowing through the transformer can be used. It is convenient here to use the force-cooled rating;:

$I_{FL\text{-}H} = \frac{25{,}000}{\sqrt{3} \times 115}$ = 125.5 Amps $I_{OA\text{-}H} = \frac{15{,}000}{\sqrt{3} \times 115}$ = 75.3 Amps

$I_{FL\text{-}L} = \frac{25{,}000}{\sqrt{3} \times 12.5}$ = 1155 Amps $I_{OA\text{-}L} = \frac{15{,}000}{\sqrt{3} \times 12.5}$ = 692.8 Amps

Now determine the tap settings for the differential elements.
A compromise between full-tap and lower tap ratios must be arrived at before selecting the CT ratios. Choosing full ratio for both high and low side produces about 5% CT mismatch, which is relatively high. Choosing full ratio on the low side, and 60 turns on the high side is a good compromise. The mismatch is below 1% for this configuration (the actual calculation is done later in the text).

The effective accuracy class should be checked for avoidance of CT saturation. The effective accuracy class of the high side CT, assuming C800 CTs is:

$$800 \times \frac{300}{600} = 400$$

This should work well for this common transformer in terms of CT saturation. A saturation calculation can be performed, but is generally unnecessary for this size of distribution transformer in this application.

$\therefore$ CTR-H = 60T, and CTR-L = 400T.

Connect CT-H in wye, and CT-L in delta. This will cancel out the 30º phase shift and eliminate any zero sequence current in the 87T that will flow during a ground fault on the low-side. Care must be taken that the delta configuration of the transformer is exactly replicated for the delta connected CTs. Deltas can be connected so that they produce either a +30ºshift or a -30º shift, so make sure the proper connection is used.

Now determine the secondary relay currents for the differential circuit. Use the maximum load current for this calculation.

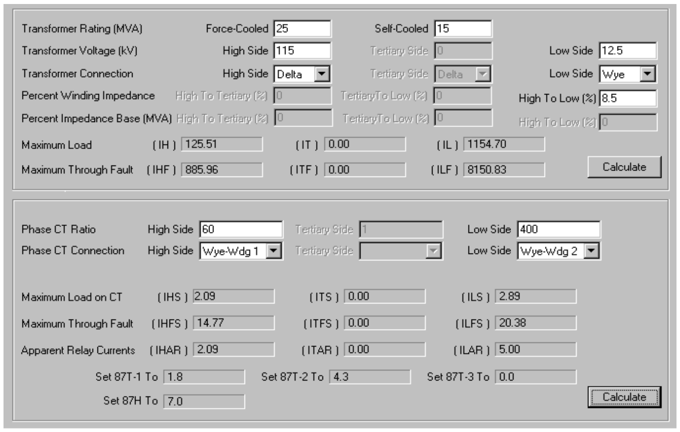
$I_{R\text{-}H} = \frac{125.5}{60}$ = 2.09 A $I_{R\text{-}L} = \frac{1155}{400} x\sqrt{3}$ = 5.00 A

The ratio of low to high side relay currents is $\frac{5.00}{2.09}$ = 2.39. Any ratio of available taps that is close to 2.39 should be chosen.

Choose Tap-H = 1.8, and Tap-L = 4.3, the ratio then is $\frac{4.3}{1.8}$ = 2.39

It can be seen that CT mismatch (CTM) is negligible for this combination of taps.

Some modern relays have a tap calculator built into their setting software packages. The following figure shows such an example.



Transformer Rating (MVA)	Force-Cooled	25	Self-Cooled	15		
Transformer Voltage (kV)	High Side	115	Tertiary Side	0	Low Side	12.5
Transformer Connection	High Side	Delta	Tertiary Side	Delta	Low Side	Wye
Percent Winding Impedance	High To Tertiary (%)	0	TertiaryTo Low (%)	0	High To Low (%)	8.5
Percent Impedance Base (MVA)	High To Tertiary (%)	0	TertiaryTo Low (%)	0	High To Low (%)	0
Maximum Load	(IH)	125.51	(IT)	0.00	(IL)	1154.70
Maximum Through Fault	(IHF)	885.96	(ITF)	0.00	(ILF)	8150.83

Phase CT Ratio	High Side	60	Tertiary Side	1	Low Side	400
Phase CT Connection	High Side	Wye-Wdg 1	Tertiary Side		Low Side	Wye-Wdg 2
Maximum Load on CT	(IHS)	2.09	(ITS)	0.00	(ILS)	2.89
Maximum Through Fault	(IHFS)	14.77	(ITFS)	0.00	(ILFS)	20.38
Apparent Relay Currents	(IHAR)	2.09	(ITAR)	0.00	(ILAR)	5.00
	Set 87T-1 To	1.8	Set 87T-2 To	4.3	Set 87T-3 To	0.0
	Set 87H To	7.0				

Figure 21. Tap Calculating Software
(Courtesy of ABB Inc.)

Now set the high-side phase overcurrent backup relays. As mentioned earlier, most utilities don't have local backup for feeder relays. The pickup should be set at 2½ to 3 times I_{OA} to accommodate maximum loading.

$$51P = 2.5 \text{ x } \frac{75.3Amps}{120Turns} = 1.57 \text{ Amps}$$

The time dial should be set so that it crosses the maximum 3-phase fault current at about one second. This gives good protection for the transformer, while allowing plenty of room to coordinate other relay and fuses.

Very Inverse curve selection
TD = 2.8 (solved graphically),

Instantaneous elements can be set to give high-speed clearing of bushing faults and provide backup for high magnitude internal faults. The setting should be 125% of the maximum 3-phase low side bus fault.

$$I_{pickup} = \frac{886Amps}{120turns} \times 1.25 = 9.22 \text{ Amps; } \quad 50P = \frac{9.22}{1.57} = 5.9 \textit{ Times Tap Setting}$$

The ground relay pick is set higher than the maximum expected unbalance current. Since this is usually not known, a value close to the full load current will give reasonably fast tripping and coordinate with feeder protection.

I_{OA} = 693 Amps $\therefore$ round up to 720 Amps

$$51N = \frac{720Amps}{240Turns} = 3.0$$

The time dial needs to be set higher than the feeder relays and still give good backup coverage for lower magnitude ground faults.
Select the Very Inverse curve

TD = 4.0 (solved graphically)

The transformer coordination is now complete. The TCC plot is shown below.

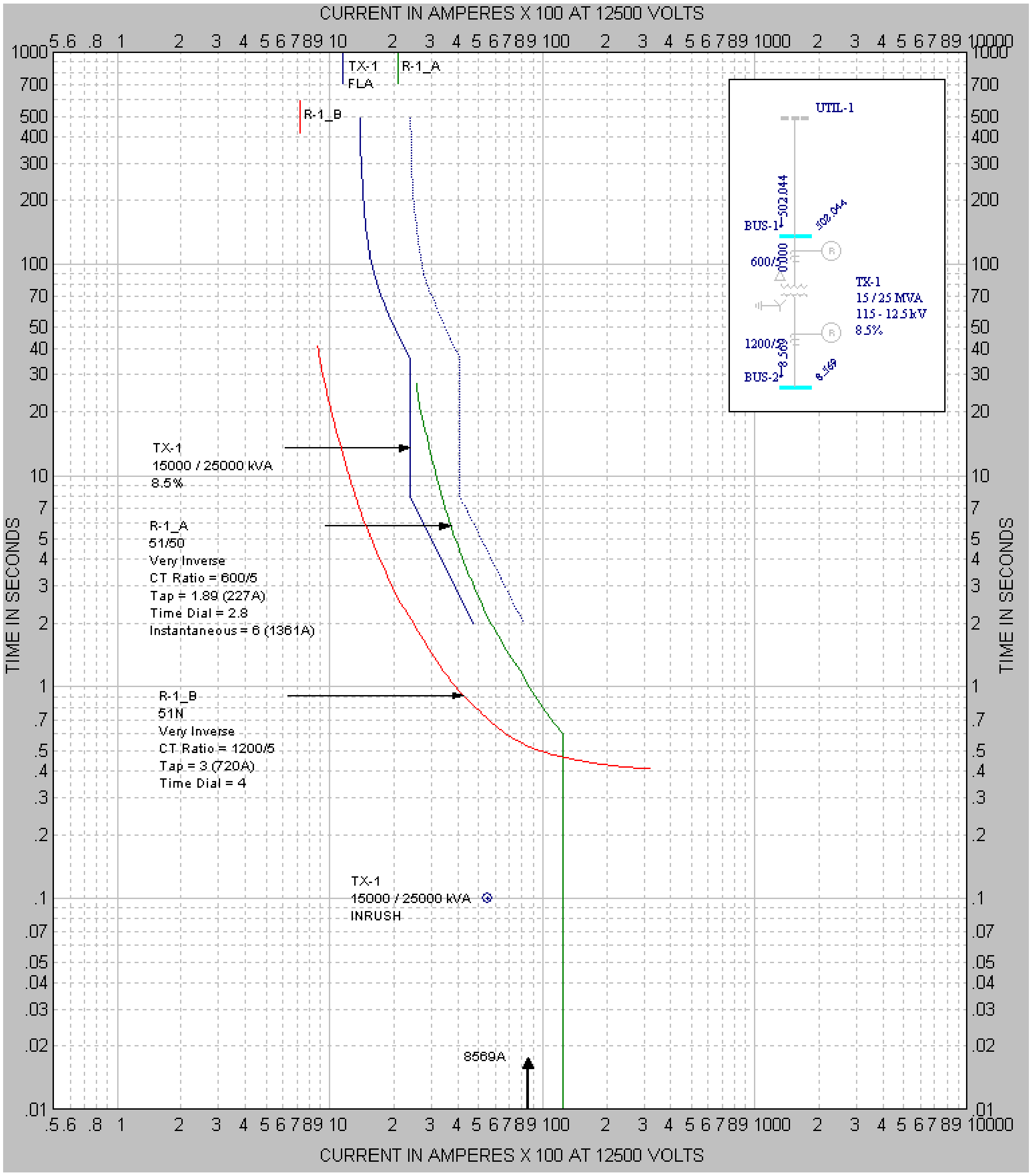


Figure 22. Solution to Example 4
(Courtesy of ESA Inc.)

A modern multifunction relay has several advantages to the discrete function solution just shown. However, there are several additional settings that are in need of consideration. These settings have a high degree of flexibility, making the relay system less secure. For distribution applications, security is of high importance, and great care must be taken to maintain a secure protection system.

- The CTs can be connected in wye instead of delta. This will allow the same set of CTs to be used for the 87, 51, and metering functions. Of course the relay must be set to cancel out phase and magnitude differences. From example 4 using delta CTs we have:
  $I_{R-L} = \frac{1386}{400} x\sqrt{3}$ = 6.00 A
  For wye connected CTs we have:
  $I_{R-L} = \frac{1386}{400}$ = 3.47 A $\angle -30°$

  Care must be taken to set the Phase Compensation setting to +30°, and the relay must internally multiply the relay current by a factor of $\sqrt{3}$ to be equal to the high side current. The tap ration remains the same.

- The amount of harmonic restraint usually needs to be set in the modern relay. Harmonic restraint is needed on distribution substation transformers to block the 87T element from tripping for magnetizing inrush current during energization. This current only shows up in the second harmonic, so restraining for 2^{nd} harmonic only is the preferred method for distribution banks. Unfortunately, the amount of 2^{nd} harmonic current varies with the transformer saturation density and the switching point on the voltage wave. Also, modern transformers have less 2^{nd} harmonic available than older units. Reasonably secure settings are as follows:

  Harmonic Restraint = 2^{nd} only
  Percent of Fundamental = 9%

  Some relays have a “cross blocking” feature that restrains the 87T from tripping if any one or more phase is over the percent of fundamental setting and the operating current is exceeded. This feature, when enabled, gives additional security to the protection system.

- The shape of the percentage differential function can also be chosen. Some common settings are the slope, and minimum operating current. Also, some relays can emulate traditional electromechanical characteristics. If this is a possibility, then using one of these tried and true characteristics adds security.

  Percent Differential Characteristic = Electromechanical Emulation (HU, BDD or other). Otherwise make sure that the minimum operate current is at least 0.3 per unit.

  The percent slope setting depends on the mismatch between high and low side relay currents. This is caused by CT mismatch, CT error, and the LTC voltage taps. The modern relays can easily match the CTs within 1%, making the presence of an LTC the main issue. The LTC is ±10%, making the total mismatch no more than 10% to 15%. For a the typical LTC transformer shown in this example, a slope of 25% will provide good security.

Example 5.
Consider the typical feeder 1-line below:

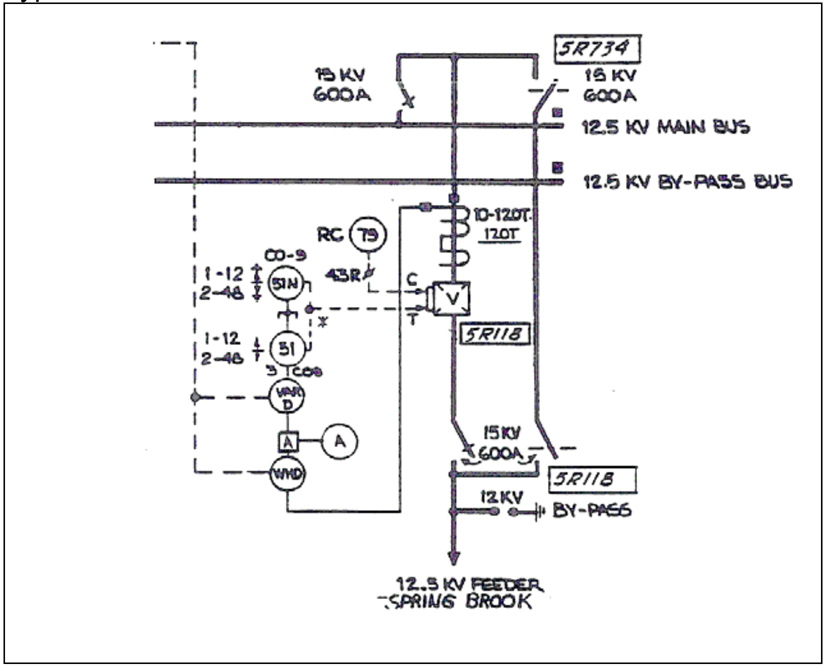


Figure 23. Typical Substation Feeder
(Courtesy of PacifiCorp)

Find:
Settings for 50/51 and 50N/51N relays, assuming a fuse saving reclosing scheme. Plot the results with the previous transformer solution.
Solution:
Fist select the pickup setting, or "tap". The 51P should be set high enough to accommodate the maximum expected feeder load. Generally 150% of maximum expected load is sufficient. The breaker in this example is rated at 600 Amps. Most utilities won't load this breaker above 480 Amps, so use this as a reference.

51P = 150% of max load, = $\frac{480}{120} \times 1.5$ = 6.0 Amps

The 50P unit needs to operate for a minimum phase fault at the end of the feeder. If this value is not known, the 50P can safely be set to 1X the 51P setting.

50P = 6.0 Amps
The time dial setting must coordinate with the first downstream overcurrent device. For this example, assume a 140T fuse.

TD = 1.0 (solved graphically)

The 51N pickup can be set low enough to see a fault at the end of the line, but above the maximum expected unbalance. The amount of unbalance is usually unknown, so a good secure setting is 100% of maximum load.

$$51N \geq \frac{480 Amps}{120 turns} = 4.0 \text{ Amps}$$

The 50N can also be set 1X 51N = 4.0 Amps

The 51N Time Dial also needs to coordinate with the 140T fuse:

51N Time Dial = 2.0 (solved graphically). The complete TCC plot is show below (note that the 51N pickup was adjusted to 4.4 Amps to better coordinate with the 140T).

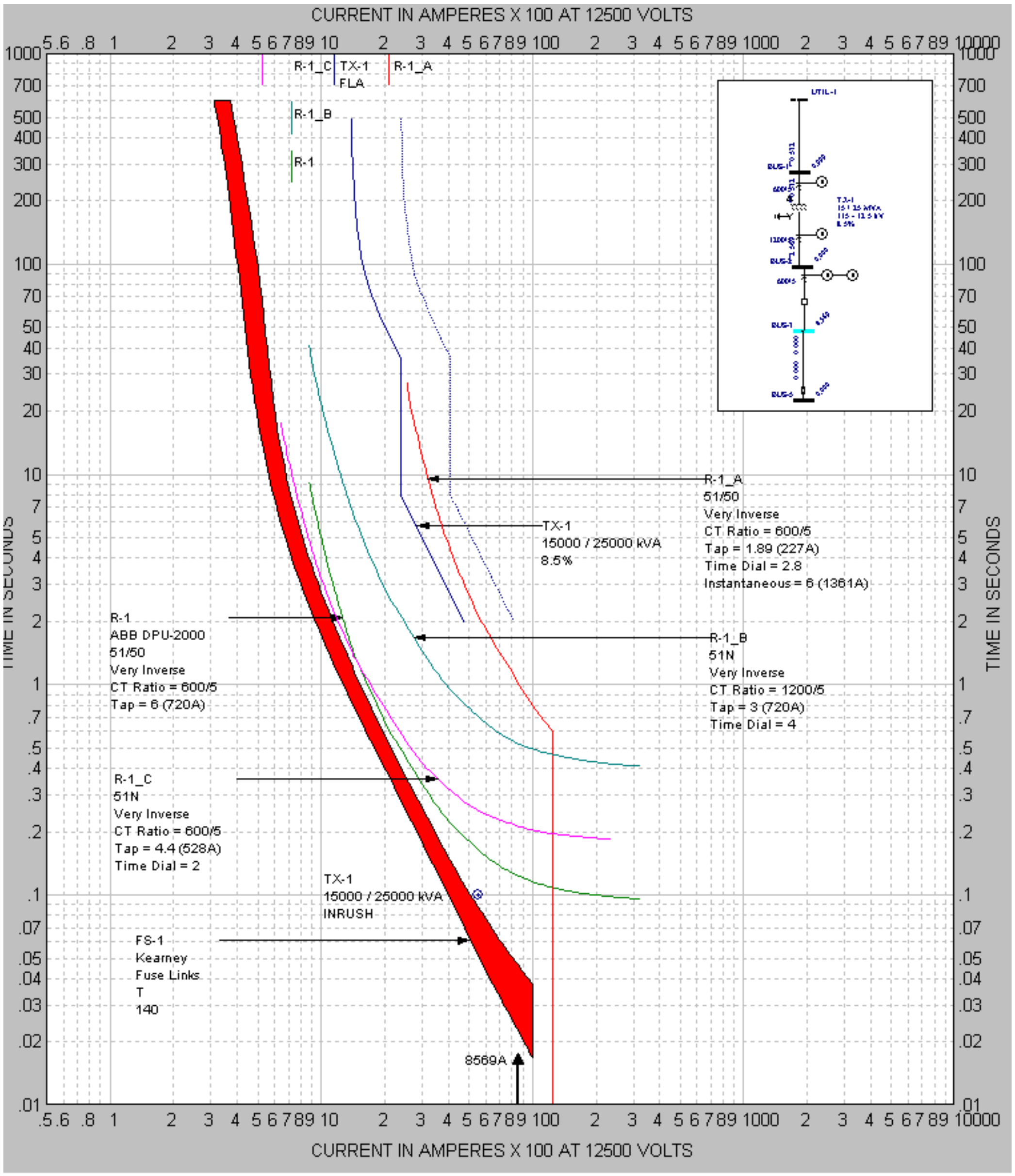


Figure 24. Complete Feeder TCC Plot

Special Protection and Control Applications

Modern multi-function microprocessor based relays allow the relay engineer to be more creative in his approach to distribution protection. This section describes some Special applications that are fairly common and easily implemented.

Cold Load Pickup

Feeders that have been disconnected for a period of time will experience a current surge caused by loads attempting to come online simultaneously. Such loads are air conditioners, resistance heaters, and motors. The inrush current form these loads can cause low set instantaneous overcurrent elements to trip unnecessarily. This undesirable operation is called “cold load pickup”.

Traditional relay schemes have dealt with cold load pickup by disabling the 50 and 50N elements for a period of time, often up to several minutes. This is puts the line protection at risk for this time. Modern relays can deal with this issue in a more comprehensive way.

Instead of completely disabling the instantaneous protection, the relay can be made to change the 50P and 50N settings to higher pickup points. This way, high-speed tripping is maintained for a large percentage of the feeder, while accommodating the temporary load increase. The settings will return to normal when he current has dropped to a predefined level, or a timer has expired. The following scheme was developed by a large NW utility for their cold load application.

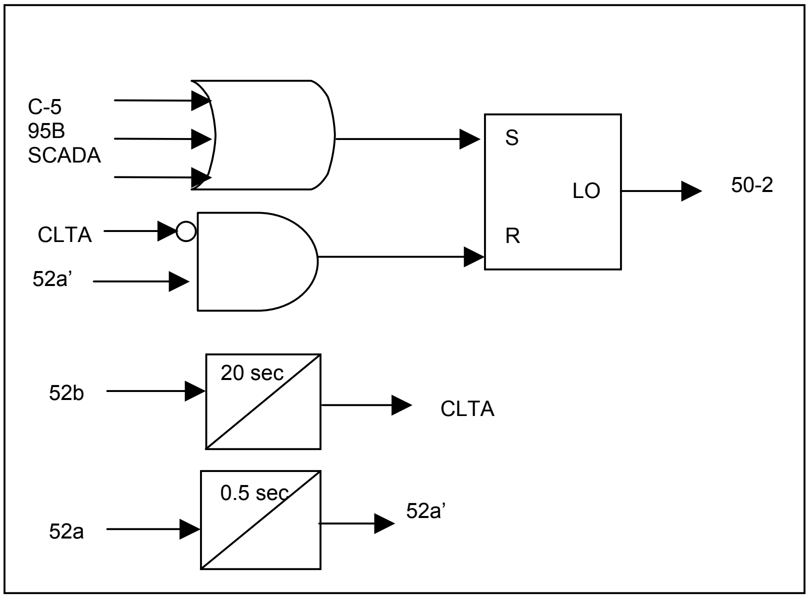


Figure 25. Cold Load Pickup
(Courtesy of Portland General Electric)

The cold load setting (50-2) is enabled by the activation of a pushbutton (C-5), an external switch (95B), or a SCADA command. The settings return to normal when the cold load timer (CLTA) goes low, and the breaker is closed. 52a’ is needed to avoid a race on the AND condition. The cold load timer starts when the breaker is closed by control switch action.

SCADA Control

Basic SCADA in a distribution substation consists of just a few analog, control, and digital points. This information is typically gathered by transducers, meters, or auxiliary relays. Then the auxiliary devices transfer the information to a remote terminal unit (RTU) via wiring. From the RTU the data is transmitted to the master SCADA terminal with a communication link. This whole process is rather slow, taking as much as 1-5 seconds for updates at the master station.

Typical information required by the SCADA master is

- Metering: Amps, Watt-hours, Watt peak demand, VAR peak demand.
- Control: Breaker open and close, LTC raise and lower.
- Status: Breaker position.

Newer protective relays now have the SCADA communication protocol resident in them, making the use of hard-wiring to the RTU obsolete. Additionally, much more data is now available by simply configuring the point list in the relay. Control is also much easier and more economical because expensive auxiliary control switches can be eliminated.

Negative Sequence Overcurrent Protection

As mentioned earlier, phase overcurrent pickup settings must be set above maximum load current, but ground relays can be set below load current. This means that for 3-phase and phase-phase faults the relay will trip slower than it would for ground faults. With the use of negative a sequence (46) element, the same higher speed fault clearing can be achieved for phase-phase faults.

We know that both positive and negative sequence current appear in phase-phase faults. Analysis shows that

$$I2 = \frac{\sqrt{3}}{3} \times Ip$$

$I2 =$ Negative Sequence fault current

$Ip =$ The phase fault current for a line-line fault

Thus a negative sequence overcurrent element set to $\frac{\sqrt{3}}{3} \times$ the phase pickup setting will have the same sensitivity to phase-phase faults.

Coordination then becomes very easy. Consider the negative sequence overcurrent element as an "equivalent" phase overcurrent element. Choose the pickup, time dial, and curve type for this equivalent element to coordinate with the nearest down stream phase device. Remember, the actual relay setting will be $\frac{\sqrt{3}}{3} \times$ the pickup used for the coordination plot.

LTC Cutout

Load tap changers raise and lower voltage for varying load conditions. During faults, the voltage at the substation bus is depressed. It is therefore desirable to block the LTC from raising the voltage during a fault condition.

Modern relays can do this function very easily. Most relays have a logic bit that asserts during the reclose sequence. This bit can be mapped to an auxiliary output to prevent the LTC from raising the voltage unnecessarily.

Instantaneous Trip Disable

During storms flying tree limbs and debris can come into contact with distribution lines. This will cause a momentary service interruption. The circuit will then reclose automatically, re-establishing service. During severe storms however, the frequency of temporary faults can be such that the maximum reclose attempt setting is exceeded, causing the feeder relay to lock out. The lockout can only be cleared, and service restored, by operator intervention.

The culprit of this scenario are the 50P and 50N relay elements. Remember that they are used in fuse saving schemes, and are set very close to the 51P and 51N pickup settings. They must be temporarily disable to prevent them from initiating multiple reclose sequences. Modern relays can easily do this by either blocking the 50P and 50N, or can switch to an alternate “storm” setting group.

Breaker Failure Protection

Modern relays have the ability to detect a failed breaker and then trip a backup device. The schemes used vary greatly, and in many cases the user can create their own. Typical settings for relays that have built-in breaker failure protection are:

- Separate trip and re-rip timers with both pickup and dropout settings.
- External breaker failure initiate (BFI) starter.
- Settable phase and neutral overcurrent thresholds

Ground Trip Disable

Unbalance load current can flow in the CT neutral during manual switching operations on the distribution line. This current is caused by the non-simultaneous making and breaking action of the switch. In these instances, the lower set 50N elements can pickup and trip, causing a service interruption. To prevent this, modern relays adapt the scheme to either block the ground elements, or raise the setting above the unbalance current.

Hot Line Tagging

Linemen are often asked to perform work on energized distribution lines. During this time, the line is said to be “tagged” out. Tagging is a procedure that calls for the tag to not be removed by anyone other than the lineman who placed it. This is sometimes called “hotline hold”, or “one-shot mode”. The relay functions under the tag condition are also altered. Typically one or more of the following conditions need to be met:

- All breaker close operations (reclosing, manual, SCADA) are disallowed.
- The “tag” state must be visible at all times, including during loss of control power. This is usually accomplished by a mechanical target.
- The state of the tagging relay must not be lost by recycling of control power.

Many modern relays have the ability to handle the above requirements, and even allow the user to create their own custom scheme. Some relays even have the states visible on their front panels

Low Magnitude Permanent Faults

Low magnitude permanent faults are troublesome on feeders with fuse saving schemes. The reclosing relay can enter into a continuous cycle of trips and recloses if the fault magnitude is low enough that the 51N time delay is longer than the open time interval settings. For example, a fault just above the 51N pickup setting can persist almost indefinitely. If the fault duration lasts beyond the reset timer setting, the entire reclose cycle will start over.

This scenario can be prevented by modern microprocessor relays. Many of them have the ability to re-insert a low-set 50N element just before the reset timer expires. The reclosing relay will then be able to lock out the feeder breaker if a fault is not cleared before the reset timer expires. This stops the relay from resetting and starting the reclose sequence over again.

AC Breaker Closing

It is possible to have an entire array of substation breakers open and locked out during an outage of the transmission system. If AC voltage is used for feeder breaker closing, and a DC powered multi-function relay is used for feeder protection, the following scenario can occur.

Assume a permanent fault on the transmission line upstream of a distribution substation. The breakers at each end of the line will operate, causing the line to go dead. If the line has reclosing enabled, the breakers will close into the fault, causing the motor loads on the distribution system to attempt to re-start. The current surge associated with this cold-load start can be higher than the low-set 50 elements on the feeder relays, causing those breakers to trip. The overcurrent trip looks like a temporary fault to the feeder relays, and reclosing will be attempted. If the transmission fault is permanent, by the time the feeder relay attempts their reclose, the transmission line will be locked out. The loss of AC resulting from this will signal an unsuccessful reclose attempt in the feeder relay logic, locking out the reclosing function. After the transmission system is restored, the system operators will discover that multiple feeder breakers are locked open, extending the outage.

This can be prevented if the relay is programmed to suspend the open interval and reset timers until the AC has returned. This way, the reclose sequence will pick up where it left off and close the breakers after their open interval timers expire.

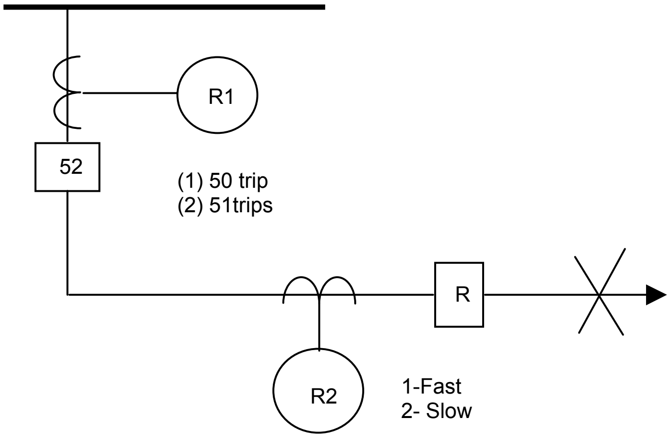
High Magnitude Close-in “Faults

As was discussed earlier, utilities have begun to reconsider how many reclose shots are programmed into feeder relays. At issue is balance between reducing customer outages, and shortening the life of the substation transformer. The trend is reduce the number of shots for high magnitude faults, but allow the relay to complete the reclosing sequence for other faults.

Modern relays can accommodate this philosophy because they typically have several overcurrent elements. The pickups of these elements can be programmed to limit the reclosing relay in the event of a high magnitude close-in fault. A low-set element can still be used for the fuse saving scheme (typically 3-shots), but if the fault current exceeds a high-set element, the reclosing relay will either lock out or attempt fewer shots.

<u>Zone Sequence Coordination</u>

Consider the following breaker – recloser coordination example:



Coordination can be lost between the substation breaker and downstream recloser for a fault beyond the recloser. Assume that the both the recloser and feeder relay are programmed for a 3-shot fuse saving scheme. Therefore the feeder relay has a low-set 50 element programmed for the first reclose, and 51 elements for the remaining two. The recloser in turn is set for one "fast" operation, and two "slow" operations. The 50 and the fast curves are coordinated so that the recloser will operate first for a downstream fault. Also, the 51 elements of the feeder relay are coordinated with the slow recloser curves. The problem scenario is as follows:

1. A fault occurs downstream from the recloser
2. The recloser trips on its "fast" curve, and the feeder relay restrains as it should.
3. The recloser closes into the fault, and starts timing on its "slow" curve.
4. The feeder relay sees this fault, and trips on its 50-1 setting.
5. The result is a mis-coordination between devices, causing an unnecessary outage.

This situation can be avoided by using what's called "zone sequence coordination" (ZSC). With ZSC enabled, correct operation is achieved.

1. A fault occurs downstream from the recloser
2. The recloser trips on its "fast" curve, and the feeder relay restrains as it should.
3. With ZSC enabled, the feeder relay increments its own reclosing sequence to the second step, bypassing the 50-1 trip state.
4. The recloser closes into the fault, and starts timing on its "slow" curve.
5. The feeder relay sees this fault, and is also timing on its 51 curve.
6. The recloser and feeder breaker continue with this process until the recloser locks out. The feeder breaker remains closed throughout the sequence, limiting the outage to the customers downstream of the recloser.

Conclusion

Distribution protection is performed in many different ways, none of which are intrinsically right or wrong. Utility companies tend to have guidelines, some more defined than others. When grey areas in protection philosophy are uncovered, the answer tends to be “that’s the way we’ve always done it!”

The author has attempted to provide information that is helpful to utility relay engineers who are engaging in feeder protection. Obviously, the subject is not covered completely here, but a the most common feeder protection problems are dealt with in a simple and time-proven method. New and evolving methods of feeder protection are discussed which are applicable to engineers using modern relay technology. The reader should consult the bibliography for a complete list of references when problems not covered here are encountered.

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Acknowledgments

1. Thanks to PacifiCorp for the use of their Distribution Protection Standards.
2. Easy Power Inc. for the use of their software to produce the TCC plots.
3. Portland General Electric for the use of their cold load application.

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