C37.230-2020 Summary Paper

IEEE C37.230-2020, “IEEE Guide for Protective Relay Applications to Distribution Lines” Summary Paper

D46 Working Group of Line Protection Subcommittee of IEEE PSRC

Chair: Brian Boysen
Vice Chair: Christopher Walker

Members and Contributors

Patrick Carroll
Juan Gers
Muhammad Hamid
Wayne Hartmann
Jack Jester
Joshua Lamb
Raluca Lascu
Bruce Mackie
Madhab Paudel
Qun Qiu
Gregory Ryan
Prasad Shrawane

***Abstract*— This paper provides a summary of IEEE C37.230-2020, "IEEE Guide for Protective Relay Applications to Distribution Lines". This paper provides a very high-level summary of some of the main topics covered in the Guide. Refer to the Guide for additional topics, details, tables, figures, examples, and reference material related to protective relay applications to distribution lines.**

Keywords*— *coordination, distribution, faults, protection, reclosing, sensitivity

I. INTRODUCTION

IEEE C37.230-2007 was revised to correct errors and address additional distribution line protection related topics. For example, new sections were added to address distribution line protection impacts on and/or interaction with arc flash hazards and fault locating while other sections were expanded to include new protection concepts such as partial range fuse saving and coordination bands.

The revised Guide begins with a discussion of distribution fundamentals, line configurations and schemes. Advantages and disadvantages to some schemes are listed. Solutions to identified problems are discussed. The Guide also includes protection criteria and provides useful examples for illustrative purposes. This Guide will provide the user the rationale for determining the best approach for protecting a radial electric power distribution system.

The Guide contains a number of figures and graphs to aid in the understanding of the protection concepts explained in the text. Tables illustrating calculation results are also included to further clarify some key concepts.

The Guide has several key clauses, including: fundamentals, system configuration and components, protective schemes, criteria and examples, and special applications. The special applications clause includes important topics that were not addressed in other sections of the Guide.

II. FUNDAMENTALS

Clause 3 of the Guide discusses the fundamentals of the various types of faults that can occur on distribution systems. Understanding the nature of these faults and the fault's impedance are important in determining the protective device application. In some cases, the fault impedance will limit the fault current to values that are not detectable or that are comparable to load current values. This clause also discusses load characteristics and harmonics. The importance of the interruption rating of circuit breakers, reclosers and fuses is also discussed.

Some faults are temporary in nature. Common causes of temporary faults are wildlife contact, conductor movement from wind and flashovers from lightning. Some faults are permanent, such as those caused by equipment failures or dig-ins. Often, on distribution systems, faults can evolve from one type to another, such as a phase-to-ground fault flashing over and involving another phase. In some cases, the fault current magnitude will change through the course of the fault event as a fault arc is established or the item initiating the fault burns away. Simultaneous faults involving different distribution circuits, sometimes of different voltages or phase relationships, can also occur.

Calculations of the system fault currents used to select, apply, and set protective devices on distribution systems are typically accomplished through the use of the symmetrical components methodology. Most fault studies utilizing symmetrical components are performed through the use of computers and software tools that allow protection specialists to model three-phase power system impedance characteristics, and calculate short circuit currents or 'symmetrical components' for various types of fault conditions. These currents can then be used to select and apply protective devices such as relays, reclosers, and fuses.

For radially designed and operated distribution circuits the maximum available fault current is at the substation bus or feeder source. In some cases, maximum fault current levels are limited by specifying a minimum allowable substation transformer impedance or adding line reactors in order to apply equipment with lower short-circuit interrupting capability. Due to the effects of the impedance of the line conductors, fault currents decrease with distance from the substation source.

A small percentage of ground faults have a very large impedance to ground. High impedance faults generally result when an energized primary conductor makes electrical contact with a quasi-insulated object such as a tree, a pole with very high impedance grounding, or in the case of conductor breaking and falling, surfaces such as paved roads, sand, and dried leaves. These fault impedances are comparable to load impedances and consequently have very little fault current, typically less than 50 Amps. High impedance faults may not pose imminent danger to power system equipment; however, high impedance faults can be a considerable threat to humans and property. Protection engineers and researchers have been challenged to develop a suitable technique for detecting high impedance faults with a reasonable degree of dependability and security.

Distribution line protection devices are not typically intended to operate during normal or abnormally high loading conditions. An understanding of the load characteristics at various points in the distribution system is beneficial when setting distribution line protection devices to prevent unintended operations on load conditions.

A harmonic is a sinusoidal waveform that has a frequency equal to an integer multiple of a fundamental frequency. Protective devices such as fuses and traditional electromechanical overcurrent relays monitor an unfiltered current, and thus respond to the total RMS value of the current. When high harmonic distortion is present, the effect of harmonics can have an impact on these devices. Harmonics associated with the acceptable distortion levels set forth in IEEE Std 519 do not present a significant threat to the proper operation of protective relays. Furthermore, harmonic currents tend to affect electromechanical and solid- state relays more severely than modern microprocessor-based relays. Most microprocessor relays employ filters for the fundamental frequency of the power system in their protection algorithms and are practically immune to the effects of harmonics.

III. System configuration and components

Clause 4 of the Guide discusses the three main methods of system grounding, describes various bus configuration designs, discusses neutral / ground CTs and transformer connections that allow for a zero sequence path, highlights the impact on relaying on distribution line and transformers, and discusses distribution protection devices and instrument transformers. The major change is to remove the Fault Studies and Fault Impedance sections which are discussed in the Fundamentals section in Clause 3 of the Guide.

A. Methods of System Grounding

There are three main methods of system grounding used around the world, which are solidly grounded, ungrounded and impedance grounded. Each type of grounding method is described in significant detail in the Guide. For example: the solidly grounded method can be uni-grounded or multi-grounded; impedance grounded can be resistive grounded, reactive grounded or resonant grounded. The grounding method used greatly affects operational aspects, especially during single-phase-to-ground faults.

B. Bus Configurations

Bus configuration designs take into consideration requirements such as load characteristics, the necessity for maintaining continuity of service, flexibility of operation, maintenance, and cost. The designs vary from the simplest single-circuit layout to the involved duplicate systems sometimes installed for metropolitan service. Along with each bus description, relay setting criteria and coordination considerations are discussed.

C. Neutral / Ground CTs and Transformer Ground Connections

The change in ground current sensitivity when using residual current compared to using current from a CT connected in the neutral of a four-wire system is discussed. One of the differences is that residually connected CTs can cause nuisance operations due to errors arising from CT saturation and unmatched characteristics.

When a ground reference is needed, for example, with a substation feeder bus sourced from a delta connected transformer winding, additional transformers are commonly used to provide the ground source. Zigzag and grounded-wye with a closed delta connection are two commonly used grounding transformer arrangements. Although the zigzag transformer connection is more widely used to provide a ground source, both have been used successfully. Both arrangements have the ability to provide high positive sequence impedance while providing a low zero sequence impedance path. The level of available fault current can be controlled by adding a resistor between the primary neutral and ground of the grounding transformer.

D. Distribution Lines and Transformers

The required coordination of distribution system overcurrent protective relays with the conductor damage curve is also discussed. The concern of overheating insulated power cables that can lead to damage to their dielectric, sheath, extruded jacket, splices, and PVC conduit systems is considered. Parameters to consider in the evaluation are the available fault current, relay time-current curve, conductor I^2t curve, and effects of reclosing.

The coordination of the feeder circuits with the source transformer are reviewed including the consideration of the transformer damage curve. Information on the winding configuration and impedance of the source transformers are also addressed. The protection of line distribution transformers is also briefly discussed.

E. Protective Devices

Relays are defined as “devices that respond to signals from sensors (voltage, current, temperature, etc.), and operate contacts based upon predetermined criteria’. Relays are used for many purposes from operating breaker trip and close coils to controlling the operation of lockout and timing devices.

A recloser is defined as a “protective device that combines the sensing, relaying, fault interrupting and reclosing functions in one integrated unit”. Reclosers are generally installed in substations or along a feeder to provide fault detection, isolation, and service restoration.

The simplest form of overcurrent protection is provided by a fuse. Clause 4 of the Guide explores the differences between the two fundamental types of fuses most often used in distribution systems, which are expulsion and current limiting fuses.

F. Instrument Transformers

Instrument transformers, both voltage and current transformers, are used to provide reduced magnitudes of available primary voltages and currents that can be safely used in relays and at the same time provide isolation from the primary system. When three voltage transformers are used they are generally connected wye and provide three phase-to-phase and phase-to-neutral voltages. The open delta VT connection is also commonly used and it provides three phase-to-phase voltage measurements using two VTs. CTs used for feeder relaying are generally located on the bus side of a distribution substation feeder circuit breaker when used for primary feeder protection. By connecting the relay at this location the breaker is able to isolate all faults that are detected beyond the location of the breaker.

The accuracy and ratings of current transformers are discussed. Current transformer saturation in general and as a result of the DC component of an asymmetrical fault current is also discussed in Clause 4 of the Guide. Examples of CTs exhibiting saturation and DC offset are provided.

IV. Protective Schemes

Clause 5 of the Guide describes various protection schemes. This includes overcurrent protection, fuse saving / fuse blowing, and voltage schemes. The most significant change to this clause was to expand the Fuse Saving section to include partial range fuse blowing schemes.

A. Overcurrent Protection Schemes

Overcurrent protection is the simplest scheme used to protect distribution lines. There are three types of overcurrent relays applied on distribution systems:

1) Phase overcurrent

2) Ground overcurrent

3) Negative sequence overcurrent

These relays can be directional or non-directional depending on relay type, system configuration, and protection requirements. For radial distribution, non-directional overcurrent relays are more common.

Phase overcurrent relays respond to line currents. They must have minimum response or pickup settings greater than the expected maximum of their feeder load current. This current may be as high as the maximum load capability of the line.

Other factors to consider when calculating the pickup setting are the cold load characteristics of the feeder and any significant transformer magnetizing inrush current. Cold load pickup settings are generally required to be greater than pickup settings used for normal feeder loads.

To avoid misoperation, the phase overcurrent relay pickup settings are generally 1.5 to 3.0 times the maximum expected feeder load current. The maximum expected feeder load is determined by factors such as cold load pickup, abnormal system configuration, connection/disconnection of distributed energy resources and equipment current ratings.

Ground overcurrent relay pickup must be greater than the zero-sequence current unbalance expected on the feeder. The level of this unbalance current depends on the type of grounding used on the distribution circuit. For ungrounded, high impedance grounded, and uni-grounded systems the normal unbalance current will be very low. For multi-grounded systems, which is the most common system used in North America, much of the distribution load consist of single phase loads which are connected phase to neutral, so it is usual to have higher levels of residual or zero sequence current flowing in the feeder.

Coordination with downstream fuses should be looked at carefully. The fuse must carry maximum phase current and may operate slower than the feeder breaker ground relay for a low-current ground fault. To avoid coordination problems, it is often the practice to set ground relay pickup time-current settings identical to phase relays and give up added sensitivity for ground faults.

On systems where the majority of the loads are single phase and connected phase-to-neutral, some utilities are implementing single phase tripping at the substation and on pole-mounted fault interrupters. With single phase tripping, only the phase involved in the fault is de-energized. Refer to the guide for specific discussion on when single phase tripping may be used.

Similar to ground overcurrent relays, negative sequence relays can be set below load current levels and be set more sensitively than phase overcurrent relays for phase-to-phase fault detection. In many applications, phase overcurrent relay pickup settings can be higher allowing more feeder load capability. Negative sequence relays can also be applied to detect open phase conditions and low side phase-to-ground faults on delta-grounded wye transformers.

The ability to detect ground faults on the low side of delta-grounded wye transformers allows the feeder relays to protect numerous tapped delta-wye transformers at the source, saving the cost of local protection if one chooses to do so.

Negative sequence current caused by feeder load unbalance must be considered when setting negative sequence relays. Transformer magnetizing inrush, cold load pickup, and expected maximum feeder loads are to be considered as well when calculating relay settings.

B. Fuse Saving /Blowing Schemes

Overcurrent protection schemes for distribution feeders generally fall into three categories;

1) Fuse saving schemes

2) Partial-range fuse saving schemes

3) Fuse blowing schemes

Distribution fuses require physical replacement after a fault clearing operation. This results in extended outage time to the customer and added expense to replace the fuse. In a fuse saving scheme, breakers or reclosers are set such that they trip before the fuse operates and then automatically reclose. After one or two operations on the “fast” curves, the next trip is set such that the fuse will operate first to clear the persistent fault before the breaker or recloser trips again. This provides one or two opportunities for a temporary fault to be cleared before the fuse is allowed to operate. Application of fuse saving schemes is only applicable to in-line or tap fuses. Care should be taken to consider that transformer fuses are not included in the fuse saving scheme as transformer faults are usually permanent and should be cleared immediately with the transformer fuse to limit further transformer damage or damage to other equipment.

Conventional fuse saving schemes, as described previously, are occasionally unable to save the fuse due to the level of fault current experienced by both the upstream recloser and the fuse. In these instances, the fuse is not saved, and all customers served by the upstream recloser or circuit-breaker experience an unnecessary momentary interruption.

This combined operation of the upstream recloser and downstream fuse at higher fault levels can be avoided by limiting the response of the fast clearing curve to only levels where it coordinates with the fuse as shown in Figure 1. This current limiting function can be accomplished by developing protection logic using today’s modern microprocessor-based protection relays or controls. The shape of the fast fuse saving curve can be designed to conform to the specified fuse curve as closely as possible, thus minimizing interference with smaller downstream transformer fuses. Ideally, a fast fuse saving tripping response occurs when the fault can be cleared before the downstream fuse begins to melt. If the fuse cannot be saved, then tripping using the slow curve rather than the fast fuse saving protection is desirable.

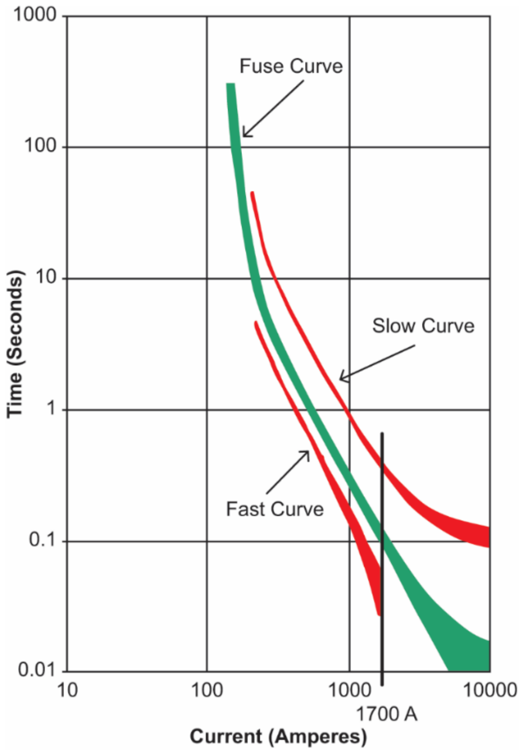

Figure 1 Time-current curve showing partial-range fuse saving scheme

Faults which are permanent and do not self-clear (such as underground cable faults) could be protected using a fuse blowing scheme. Here only a slow recloser curve is used that allows sufficient time for fuse operation to occur prior to response by the main feeder recloser or breaker.

C. Voltage Scheme

Voltage sensing relays are used in a wide variety of applications. Some of these are to protect equipment (e.g. power transformers) from damage, determine if a supply source is healthy or not (i.e. source transfer schemes), detect ground faults on normally ungrounded systems, supervise automatic or manual closing of circuit breakers, determine whether a single breaker pole is open or closed undesirably, detect unbalanced voltage due to a blown fuse, protect renewable sources connected to a feeder, and supervise or restrain overcurrent elements for fault detection near generation sources.

The voltage elements can be over or under voltage depending on the specific application. Overvoltage elements assert when the measured voltage goes above a predetermined threshold. Conversely, undervoltage elements assert when the measured voltage drops below a predetermined threshold. Voltage elements can be connected or programmed to measure either phase-to-phase or phase-to-ground voltage. Phase-to-ground connections are usually preferred since phase-to-phase quantities can then be calculated. If only one or two VTs are to be used then phase-to-phase connections are generally preferred. It is important to verify that the VTs are rated for phase-to-phase operation.

Positive-, negative-, and zero-sequence voltage quantities are frequently used for protection and control purposes. Positive-sequence voltage provides three-phase voltage measurement information under balanced system conditions. Negative-sequence voltage has been widely used for detection of a loss of phase, or to detect a blown fuse. Zero-sequence voltage is used for ground fault detection. Zero-sequence voltage can be calculated from three-phase, four-wire connected VTs or measured directly from the wye-broken delta connection. Refer to the guide for specific connections and examples.

V. CRITERIA AND EXAMPLES

Clause 6 of the Guide discusses protection criteria. This includes discussion on protection reach / sensitivity, overcurrent coordination, protection device clearing times, reclosing, and cold load pickup considerations. Changes of note include adding a section on overcurrent coordination bands, moving Fuse Saving to Clause 5 of the Guide (Protective Schemes), and moving Adaptive Relaying to Clause 7 of the Guide (Special Applications).

A. Reach / Sensitivity

Typically, at least one fault detecting device is to be set to operate for phase-to-phase or three-phase faults on the distribution line. Since the source impedance to the origin of the distribution line can vary in most situations, the maximum reasonable source impedance is normally used. Using this maximum source impedance and the impedance of the distribution line, the expected currents for a phase-to-phase fault at the most remote location can be calculated. The phase-to-phase fault current will be 0.87 times the three-phase fault at the same location. A margin can be applied to account for unforeseen operating conditions such as arc resistance, fault impedance and CT error.

If the relay being used to detect phase-to-phase and three-phase fault conditions is a phase overcurrent relay, its pickup value is set higher than the maximum load current for the feeder. The maximum load current is not just the maximum steady state load current, it also includes the cold load pickup current.

Although it is desirable to have at least one fault detecting device operate for any phase-to-ground fault on the distribution line, it is not always possible to accomplish this because the amount of resistance in the fault can range from zero to almost infinity. It is not unusual for the amount of fault resistance to change if a fault is not detected for a period of time.

It is impossible to detect all ground faults and not cause tripping due to unbalanced load currents. Therefore, some common methods for designing the ground fault detection system for a feeder include: establishing a fault resistance target value, establishing a maximum clearing time for ground faults with zero fault resistance, or setting the overcurrent relay pickup to some fraction of the bolted fault current at the end of the protection zone.

Being able to detect faults and still being able to carry the load current in many cases cannot be achieved with only protection devices at the substation. Locating fault sensing and interrupting devices out on the distribution line at some distance from the substation will reduce the amount of fault detection coverage that needs to be provided from the substation. Most distribution lines do not have single point loads but have the loads distributed along the length of the line, so these remote fault sensing devices will not be required to permit as much load current to flow as the protection back at the substation. The distribution feeder configuration most often will not be a single line, but a series of line branches with a structure resembling a tree. To sectionalize and to minimize the number of customers disconnected for a fault, fault-interrupting devices can be installed at the branching locations.

To achieve the desired results of sectionalizing the faulted branches of the distribution feeder, while keeping the unfaulted parts energized, requires the time coordination of the protective devices, which are operating in series. By delaying the operation of the device closest to the source the more remote device can time out and clear the fault. In this type of arrangement, the device closer to the source will back up the failure of the remote device.

B. Coordination

Most of the devices applied to protect distribution lines have inverse time characteristics. This is true for fuses, time overcurrent relays and reclosers. To time coordinate overcurrent devices, a critical condition to check is the response of the two devices for a fault condition that produces the maximum current through the remote device. By comparing the response of both devices for the same fault condition one can determine if the desired coordination will occur. The remote device is expected to detect and clear the fault before the device closer to the source times out.

One method of coordinating inverse time-current protection elements relies upon plotting the single, nominal, time-current characteristic (TCC) curves of series devices and ensuring they are minimally separated by a Coordinating Time Interval (CTI) time-value. CTI values are frequently based on historical coordination experiences and will often be uniform when coordinating protection elements of like manufacture, i.e., electromechanical vs microprocessor.

Another approach to coordinating series inverse time-current protection elements is to develop minimum and maximum time-current response curves or bands for each series device. Much like the CTI method, these time-response bands account for the effects of the minimum and maximum primary current sensing (CT) error, the overcurrent element’s minimum and maximum current measurement and time-response tolerances, and include the total fault-clearing time of the associated fault-interrupter. After these time-current tolerance-response bands are developed for each series device, coordination is achieved by simply ensuring these bands do not touch one another for an appropriate level of fault current.

The guide also discusses methods for coordinating phase overcurrent elements with downstream phase and ground overcurrent elements and overcurrent coordination through transformers.

C. Clearing Time

Long fault clearing times will adversely impact the power quality of the customers whose services are electrically close to the fault location, but are not actually interrupted. Customer equipment may be designed to conform to published standards concerning the ability of the equipment to properly operate during the voltage sag or swell due to a distribution system fault. These standards may provide the relaying engineer some insight into the impact that long fault clearing times may have on a customer. For power quality issues, and minimizing human exposure and equipment damage issues, the line faults are expected to be cleared as fast as possible. By setting the device closest to the fault location to operate as fast as possible the two issues of speed of fault clearing and coordination for selectivity can reach an acceptable balance.

D. Reclosing

After tripping in response to a fault, a reclosing relay or controller automatically closes the interrupting device based on a predetermined sequence. Automatic reclosing is applied because the majority of faults on overhead distribution systems are temporary in nature. These feeders can be effectively restored after de-energizing the fault long enough to allow the fault arc to extinguish and the gases to de-ionize.

Reclosing schemes will usually incorporate several reclosing attempts. The speed and number of reclosing attempts is determined by individual utilities. Some utilities may use one fast and one or two time-delayed attempts. The first reclose time, combined with the device operating time, is determined to allow enough time for the arc to de-ionize. If there is a Distributed Energy Resource (DER) downline of the reclosing device, provisions are made to coordinate the disconnection of the DER prior to the feeder reclosing to restore the line. Subsequent reclosing attempts may have longer delays.

E. Cold Load Pickup

Usually when a distribution circuit is restored after an extended outage the power draw is greater than the power draw before the outage. This phenomenon is referred to as cold load pickup. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. The inrush portion of the cold load pickup can be substantial in magnitude but short in duration and will be a factor for energization of the circuit after a short outage as well after an extended outage. The guide explains the cause of Cold Load Pickup and methods for addressing this challenge.

VI. SPECIAL APPLICATIONS

Clause 7 of the Guide discusses special applications. This includes simultaneous or inter-circuit feeder faults, loop schemes, underfrequency load shedding, undervoltage load shedding, adaptive relaying schemes, distributed energy resources (DERs), communication assisted protection applications, multiple source configurations, directional overcurrent protection, impacts of motor loads, breaker failure, single phase tripping, ground fault detection / protection, arc flash protection, and fault locating. The 2020 revision added new sections on protection considerations for arc flash protection and undervoltage load shedding while also revising other sections of the Guide.

A. Simultaneous or Inter-circuit Feeder Faults

Often adjacent circuits exit a substation in close proximity or even share common structures. Faults of sufficient duration may evolve to the point where multiple circuits are involved. This is especially true if instantaneous relaying is not applied. The consequence of this situation is that the circuits will share portions of the total fault current which will affect relay coordination. The single point source detects the entire fault current for the entire duration. Each circuit protection device only sees a portion of the fault current only for the time that the particular device is closed. The Guide discusses how to address coordination of these types of circuits.

B. Loop Schemes

Loop schemes may be used to improve system reliability by creating a looped feeder with a normally open point on the feeder loop. When faults occur sectionalizing reclosers and the normally open tie recloser may operate based on system conditions thus restoring un-faulted portions of the looped feeder and increasing reliability.

C. Underfrequency Load Shedding

The objective of underfrequency load shedding is to arrest system-wide frequency decay after a disturbance to the system. If the frequency is decaying rapidly, the objective of the underfrequency load-shed scheme is to quickly drop sufficient load automatically to balance load with generation. An underfrequency load shed can be accomplished using electro-mechanical, solid state, or microprocessor relays. These relays can then be set to shed load based on a fixed frequency or rate-of-change of frequency depending on the type of relay being used. Additionally, multiple steps of load shed can be implemented. Load may then be restored as system recovery allows, either automatically or more typically via manual operation.

D. Undervoltage Load Shedding

The objective of undervoltage load shedding is to unload a system that is on the verge of collapse due to a shortage of reactive or real power support. An undervoltage condition may cause inductive motor loads to stall thus creating a potential for insufficient reactive resources, large load loss, and cascading events. Either a time-delayed undervoltage set point can be used or a slope permissive undervoltage load shedding scheme (SPUVLS) can be applied.

E. Adaptive Relaying Schemes

Adaptive relaying is defined as making automatic real-time adjustments to power system protection schemes. Microprocessor based protection relays with multiple settings groups provide the capability to adapt protection settings, control schemes, reclosing schemes, and protection elements by changing settings groups and tripping matrices automatically based on changing system conditions. The relays adapt based on decisions made by internal logic, by analog quantities that they measure, by communication with other relays or intelligent electronic devices (IEDs), and/or by monitoring the status of switches and/or circuit breakers.

F. Distributed Energy Resources

Distributed energy resources (DERs) are typically generation sources operating in parallel with the distribution electric power system. When DER is integrated on radial or networked power systems originally designed to only serve load, modification of the feeder protection may be required. Thus, the main issues for DER and utility distribution system protective relaying are Protective Device Coordination, Islanding, and Grounding with each discussed in the guide.

G. Communication Assisted Protection Applications

Relay communications channels for distribution circuit protection have been successfully implemented via direct connection to fiber optic cables, leased telephone circuits, and point-to-point radio. Selection of the communications channel and medium and various applications are discussed in the guide including direct transfer trip, trip and restore protection schemes, and closed loop distribution systems communication based protection schemes.

H. Multiple Source Configurations

If the line is a two or three terminal line, a line with DER, a line where a line switch may be closed to energize a second source, or a line networked with other adjacent stations on the low voltage side; a single group of protection settings may be inadequate. Through the use of settings groups, various line switching configurations may be accommodated. SCADA or distribution automation systems may be used to automate the settings group changes.

I. Directional Overcurrent Protection

Directional overcurrent relays discern the direction of current flow to a fault, thereby permitting overcurrent relay operation for faults in one direction, and blocking relay operation for faults in the reverse direction. They are most commonly applied on networked circuits, or distribution circuits with DER. Directional overcurrent protection is used where relay schemes have different sensitivity or operate time for faults in one direction compared with the reverse direction.

J. Motors (Effects of Unbalance)

The effect of three phase motor unbalance on distribution line protection depends on the percentage of motor load compared to the total load and the type of motor connection. Typically, the percentage is a small portion and thus can be neglected. The motor unbalance is typically created due to a blown fuse or bad connector. An induction motor will increase loading of the connected phases by a factor of 1.73 p.u. and create a significant amount of negative sequence current when the one phase is disconnected.

K. Breaker Failure

Breaker failure relays, applied to distribution feeder circuits, can improve dependability by clearing feeder faults during a breaker failure condition. In particular, microprocessor-based feeder protection relays that include breaker failure elements allow the application of breaker failure protection at low cost. Various breaker failure protection schemes are discussed in the guide including re-tripping, tripping additional breakers, and backup relaying.

L. Single-Phase Tripping

With the increasing interest in power quality and minimizing interruptions, single-phase tripping offers an alternative to three-phase tripping when the loads are mostly if not all single phase. Rather than tripping all three phases for a single phase-to-ground fault, the protective device can trip only the phase that has experienced the fault. This can be accomplished in the reclosing cycle as well as the lockout. Customers connected to the other two phases do not experience a service interruption due to the fault. Drawbacks are discussed in the guide due to three phase connected loads including capacitor banks, motor loads, and transformer banks.

M. Methods of Detecting Ground Faults

1 Resonant Grounded Systems

There are two methods commonly used to selectively detect ground faults in resonant-grounded systems and discussed in the guide. One method is to use the zero-sequence impedance and measure a negative or positive power flow to determine the location of a fault via the use of a wattmetric element. A second method uses incremental conductance and may be applied where the sensitivity of the wattmetric element is inhibited by the standing unbalance of the power system.

2 Ungrounded Systems

There are two methods commonly used to selectively detect ground faults on ungrounded systems. Varmetric relays are applied on isolated neutral systems, where wattmetric relays are applied on compensated neutral systems. Both methods use a component of the residual current that is perpendicular to the direction of the system displacement voltage. Therefore, these methods require the use of three voltage transformers connected wye-grounded to provide displacement voltage to the relay. The differences of these methods are discussed in the guide.

N. Arc Flash Hazards

Arc flash hazards may exist when employees are working on or near exposed energized equipment. When arc flash hazards are determined to exist, incident energy calculations are to be performed to determine the size of the hazard by using working distances, arc gaps, fault clearing time, and short circuit current data. Levels of personal protective equipment can then be determined based on these calculations, and if necessary, clearing times may be shortened to decrease the incident energy. The Guide discusses methods for developing and evaluating line protection settings to provide protection against arc flash hazards.

O. Locating Faults on Distribution Lines

Determining the location of a fault on a distribution line is challenging because of the unique topology of each system and several other factors including system grounding, lateral connections, and impedance discontinuities. Fault location has been performed by traditional technologies (restoration through switching, reclosing, fuse operations, customer calls, downed wires, relay targets, dc thumping of underground circuits); observant technologies (local detection with communications feedback, intelligent metering with communications, faulted circuit indicators or FCIs, fault recorders, etc.); and advanced technologies (protective devices, distributed intelligent devices with communications); or some combination of these where the latter two typically include the capability to support SCADA communication.

VII. Conclusion

This summary paper has only provided a very high-level summary of some of the main topics covered in the IEEE C37.230-2020. The Guide contains a number of figures, tables, and graphs which aid in the understanding of the protection concepts outlined in the summary paper. Refer to the Guide for additional topics, details, tables, figures, examples, and reference material related to protective relay applications to distribution lines.