



IEEE Guide for Protective Relay Applications to Distribution Lines

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IEEE Power and Energy Society

Developed by the
Power System Relaying Committee

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Developed by the

Power System Relaying Committee
of the
IEEE Power and Energy Society

Approved 3 December 2020

IEEE SA Standards Board

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Abstract: A review of generally accepted applications and coordination of protection for power system distribution lines is presented. The advantages and disadvantages of schemes presently being used in protecting distribution lines are examined in this guide. Identification of problems with the methods used in distribution line protection and the solutions for those problems is included.

Keywords: coordination, distribution, faults, IEEE C37.230™, protection, reclosing, sensitivity

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Introduction

This introduction is not part of IEEE Std C37.230-2020, IEEE Guide for Protective Relay Applications to Distribution Lines.

This guide compiles information on the application considerations of protective relays to power distribution lines. This guide presents a review of generally accepted distribution line protection schemes. Its purpose is to describe various schemes to assist relay engineers in selecting the most appropriate scheme for a particular installation. It is intended for engineers who have a basic knowledge of power system protection. This is an application guide and does not cover all of the protective requirements of all distribution line configurations in every situation. Additional reading material is suggested so the reader can evaluate the protection for the individual application.

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IEEE Guide for Protective Relay Applications to Distribution Lines

1. Overview

This guide is divided into ~~seven~~ eight clauses. Clause 1 provides the scope and purpose of this guide. Clause 2 ~~lists referenced documents that are indispensable when applying this guide. Clause 3~~ provides definitions that are not found in other standards. Clause ~~3~~ 4 gives an explanation of distribution fundamentals. Clause ~~4~~ 5 discusses system configuration and components. Clause ~~5~~ 6 explains the characteristics of protective schemes. Criteria and examples are discussed in Clause ~~6~~ 7, including margins and ~~common~~ normal considerations. Clause ~~7~~ 8 has several special applications and considerations for distribution line protection.

This guide also contains two annexes. Annex A provides the bibliography, and Annex B contains a glossary of terms defined in other IEEE standards.

1.1 Scope

~~The scope of~~ This guide discusses ~~is to discuss~~ the application and coordination of protection ~~of for~~ radial power-system distribution lines. It includes the descriptions of the fundamentals, line configurations, and schemes. In addition to these, this guide identifies ~~the scope includes~~ ~~identification of~~ problems with the methods used in distribution line protection and the solutions to ~~for~~ those problems.

1.2 Purpose

This guide educates and provides information on distribution protection schemes to utility engineers, consultants, educators, and manufacturers. The guide examines the advantages and disadvantages of schemes presently used in protecting distribution lines. This provides the user with the rationale for determining the best approach for protecting an electric power distribution system.

1.3 Word usage

The word *shall* indicates mandatory requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted (shall equals is required to).^{1,2}

The word *should* indicates that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others; or that a certain course of action is preferred but not necessarily required (should equals is recommended that).

The word *may* is used to indicate a course of action permissible within the limits of the standard (may equals is permitted to).

The word *can* is used for statements of possibility and capability, whether material, physical, or causal (can equals is able to).

2. Normative references

~~The following referenced documents are indispensable for the application of this guide (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.~~

¹The use of the word *must* is deprecated and shall not be used when stating mandatory requirements, *must* is used only to describe unavoidable situations.

²The use of *will* is deprecated and shall not be used when stating mandatory requirements, *will* is only used in statements of fact.

2. Definitions, acronyms, and abbreviations

2.1 Definitions

For the purposes of this [document guide](#), the following terms and definitions apply. The ~~Authoritative Dictionary of IEEE Standards~~ [Dictionary Online Terms \[B29\]](#) should be [consulted](#) ~~referenced~~ for terms not defined in this clause.³

distributed energy resource (DER): Source of electric power that is not directly connected to a bulk power transmission system. DERs include both generators and energy storage technologies.

~~**3.1 distributed resources (DRs):** Power sources such as generators, photovoltaic units, fuel cells, etc., connected on distribution circuits and dispersed throughout the utility distribution system.~~

distribution automation: A technique used to limit the outage duration and restore service to customers through fault location identification and automatic switching.

interrupting medium: The material used to facilitate the interruption of the arc during opening of a switching device.

polarizing voltage: The input voltage to a relay that provides a reference for establishing the direction of the operating current.

sympathetic tripping: The ~~phenomenom~~ [phenomena](#) where an ~~unfaulted~~ interrupting device [on an unfaulted circuit](#) trips for a fault on a nearby circuit, usually caused by current inrush on the device after the faulted feeder's interrupting device opens and the system voltage returns to normal.

varmetric relays: Relays that respond to the quadrature (imaginary) component current compared to the polarizing voltage.

wattmetric relays: Relays that respond to the in-phase (real) component current as compared to the polarizing voltage.

³[IEEE Standards Dictionary Online is available at: http://dictionary.ieee.org. An IEEE Account is required for access to the dictionary, and one can be created at no charge on the dictionary sign-in page.](#)

2.2 Acronyms and abbreviations

AMI automated metering infrastructure

BIL basic insulation level

CT current transformer

CIS customer information system

DA distribution automation

DER distributed energy resource

DMS distribution management systems

FLISR fault location, isolation, and service restoration

FDIR fault detection, isolation, and restoration

GIS geographic information system

OMS outage management system

PSAT modern powertrain system analysis toolkit

SCADA supervisory control and data acquisition

SF₆ sulfur hexafluoride

VT voltage transformer

Xfmr transformer

Z_f fault impedance

3. Fundamentals

3.1 Fault characteristics

3.1.1 Type and calculation

Faults commonly occur on overhead and underground electric distribution systems ~~with regularity~~.

It is not feasible to design distribution systems to eliminate the possibility of faults from occurring.

Faults can be caused by a number of sources including the following:

- Equipment failure
- Weather (such as wind, lightning, extreme temperature, and precipitation)
- ~~— Forestry contact~~
- Public contact (such as vandalism, vehicle accidents, ~~including pole and overhead contacts~~ and underground dig-ins)
- Vegetation
- Wildlife

Some ~~Most~~ faults are temporary in nature. Common causes of temporary faults are wildlife, wind, and lightning. Some faults are permanent in nature, such as those caused by equipment failures or dig-ins.

- ~~— Animal contact~~
- ~~— Vandalism~~
- ~~— Vehicle accidents~~

When faults occur, they can present hazards to the general public and utility personnel⁷ and can cause damage to distribution facilities. Protective systems are applied to detect ~~sense~~ short-circuit conditions (faults), clear faults in a timely fashion, and limit the effects to the smallest practical portion of the distribution system.

Different types of faults can occur on distribution systems. The design of the grounding configuration of a given distribution system such as a three-wire ungrounded or four-wire effectively grounded system determines the short-circuit characteristics associated with different types of faults. Fault types commonly experienced include the following:

- Three-phase
- Phase-to-phase
- Phase-to-ground~~or single line to ground~~
- Two-phase-to-ground

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.

An understanding of the type of grounding system and type of fault assists ~~must be understood~~ in the modeling ~~order to model~~ and calculating of ~~calculate~~ fault currents, as well as in the application of ~~and to apply~~ protective systems that identifies ~~will sense~~ and operates ~~operate~~ for detectable fault conditions involving ground. ~~There~~ Three classes of grounding systems are used. They include ungrounded, impedance (resistance or reactance) grounded, and effectively (or solidly) grounded. Current and voltage characteristics during fault conditions will ~~differ from non-faulted conditions, and will~~ vary depending on the grounding system utilized.

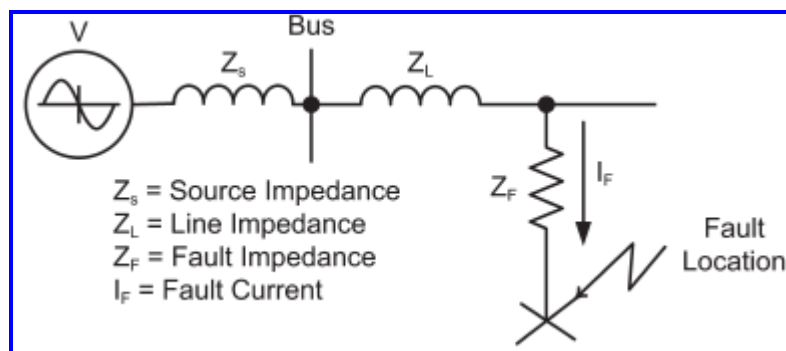
The consideration of fault impedance helps optimize low-level relay settings ~~should be considered.~~

Some faults will be solid, such as the case when a broken phase conductor contacts a neutral wire; some will have an arc whose resistance varies with the arc length, such as an insulation flashover; and other faults involve ~~a~~-specific fault impedance, such as the case of a tree limb contacting an overhead circuit. Fault impedance is typically more of a consideration for faults involving ground, or at lower distribution voltages. In addition, the types of faults that may occur at a given location on a distribution system are defined by the number of phases (one, two, or three) involved in contributing to the fault current ~~in place.~~

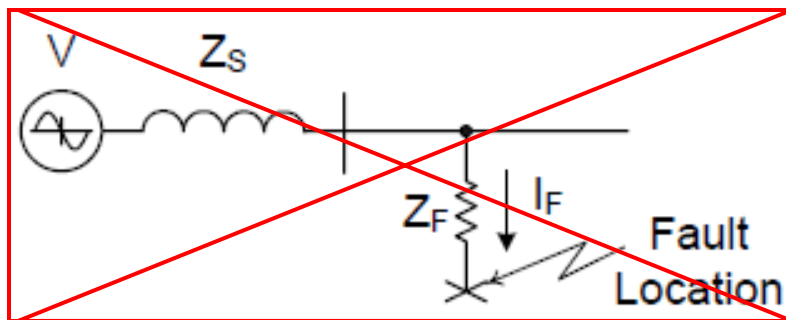
Calculations of the system fault currents used to select, apply, and set protective devices for use on distribution systems are typically accomplished through the use of the symmetrical components methodology. Symmetrical components are a mathematical tool used to calculate the effects of balanced and unbalanced fault conditions on three-phase distribution systems. 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 'sequence components'" ~~for various types of fault conditions.~~ These studies ~~A fault study should be performed to~~ obtain these characteristics at various nodes ~~levels at each node~~ of the circuit. The currents can then be used to select and apply protective devices such as relays, reclosers, and fuses. In the application of overcurrent protective equipment to distribution systems, it is important to know the minimum as well as the maximum fault current levels. Various cases are typically modeled ~~in order~~ to calculate maximum and minimum fault currents.

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

For a radial system, maximum fault current levels are influenced by low-source impedances at maximum generation conditions and zero fault impedance. Minimum fault-current levels are influenced by high-source impedances during times of minimum generation and nonzero fault impedance (Figure 1 5-14). These conditions are calculated for three-phase, phase-to-phase, and phase line-to-line, and line ~~double-line~~ to-ground faults. Normally, fault current decreases as the fault resistance increases. However, there are some cases ~~actual circuits~~ where the current magnitude in one phase of a phase-to-phase ~~double-line~~ to-ground fault will increase when going from a zero to a non-zero value of fault impedance (see *Electrical Distribution-System Protection* [B13 B12]).⁴



(New)



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Figure 1—Fault on radial system

⁴The numbers in brackets correspond to those of the bibliography in Annex A.

It is common in fault studies to use nominal system voltages with no distinction between circuit loading conditions that produce maximum and minimum voltages. Also, it is assumed that loads are not modeled. In most distribution applications, the substation transformer impedance is much larger than the generation- source impedance supplying it. For this reason, the maximum and minimum generation source impedances are often assumed to be equal. In locations served by parallel transformers, minimum fault currents occur with only one transformer in service. In radial systems, the positive-sequence source impedance is the sum of the positive-sequence impedances of all system components from the distribution substation low-voltage (LV) bus up to and including the generator. The negative-sequence source impedance is defined in a similar fashion. The zero-sequence source impedance is usually not the sum of the component zero-sequence impedances because the typical delta winding of the ~~effect-of-the~~ transformer causes a discontinuity in the zero-sequence network connections.

3.1.2 High-impedance faults

Fault impedance (Z_f) is the impedance involved in the fault (see *Electrical Distribution-System Protection* [B13 B12]). Z_f is different than positive- (Z_1) or zero-sequence (Z_0) impedances, which are system characteristics. Z_f is the complex ~~an~~ impedance, ~~resistive or reactive~~, between the faulted power system phase conductor(s) or between phase conductors and ground. Z_f is not earth resistivity or the mutual impedance between an overhead conductor and a conducting ground plane. Z_f depends on the fault type and the environment. A phase-to-phase ~~line-to-line~~ fault on an overhead circuit caused by a dry tree branch can be a high-impedance fault, and ground is not involved at all. A fallen conductor can cause a low Z_f value if the conductor drops into a stream or ground water, or it can cause a high Z_f value if it drops onto a dry pavement.

Z_f can vary over ~~is also a~~ time ~~variable~~. A fault may begin as a high-impedance fault and progress to a low-impedance fault. Conversely, a fault may start out with some fault impedance that increases to infinity if the fault is self-clearing, or if the flow of fault current into the contacted material causes changes in that material which increases its impedance.

A small percentage of ground faults have very large impedance to ground. They are comparable to load impedances and consequently have very little fault current, typically less than 50 A. 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. The IEEE Power System Relaying Committee working group on High Impedance Fault Detection Technology [B33] defines high-impedance faults as those that “do not produce enough fault current to be detectable by conventional overcurrent relays or fuses.” Protection engineers and researchers have been challenged for a long time to develop a suitable technique for detecting high-impedance faults with a reasonable degree of reliability and security.

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 a surface in the case of conductor snapping and falling. High-impedance faults can also be multiphase faults, for example, a tree limb making contact with two phase conductors. The majority of high-impedance faults involve a ground path, such as conductor snapping and falling on a surface, which can pose risks to life. It is difficult to determine the frequency of high-impedance fault occurrences because utilities’ record-keeping practices do not normally track these events. Some of the statistics from a survey of many utilities in different countries are reported in the CIGRE Working Group B5.94 Report [B10].

Generally speaking, in the protection world, a relay detects a fault and trips a circuit breaker. However, high-impedance fault detection is a much different situation. To detect any type of fault, there needs to be a difference in the measurements before and after the fault. Reliability of high-impedance fault detection requires both dependability and security. Dependability of detection is the ability of the detection method to detect all high-impedance faults. Security reflects the ability of the detection method to not falsely identify a normal situation as a high-impedance fault. High dependability forces lower security, and vice versa. Higher dependability is a target, but security is also very important as outages that affect critical loads such as traffic control and hospitals can create a public hazard.

The tripping level of conventional ground overcurrent relays are adjusted to values that are above the neutral imbalance on the grid to avoid unwanted trips. The pickup levels may conflict with the values chosen when applying high-impedance fault detection methods. Consequently, some high-impedance ground faults cannot be detected since they produce low levels of fault current and cannot be differentiated from the load current.

In the 1970s, research began in the USA on the characteristics of the waveforms of arcing faults. In the mid-1990s, one of the first commercially available relays based on the use of the harmonic content of the current waves for detecting arcing faults was developed. Other devices were launched in the mid-2000s that use multiple algorithms, using harmonics and inter-harmonics of the current waveforms. These products have been tested in the field by various utilities for several years. They are being implemented at a slower pace than previously anticipated due to some misoperation (Adamiak et al. [B4], Carpenter et al. [B9], Das and Kunsman [B15], Depew et al. [B17], Hou [B29], and Russell et al. [B73]).

~~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. Examples of this condition include a dry tree limb contacting two phase conductors, or the case of a conductor breaking and contacting asphalt or concrete pavement. These conditions, typically referred to as high impedance faults, present a challenge to the protection specialist in application of protective devices to sense and clear faults. Conventional overcurrent and distance protection cannot reliably detect this type of fault. Special protection is necessary for this type of fault, which is beyond the scope of this guide. In the last decade, there have been technological advancements in the development of protective and monitoring devices specifically designed to sense high impedance faults. Evaluation of the trade-offs between security and dependability of these devices is continuing.~~

3.2 Load characteristics

Line protection devices are not typically intended to operate during normal or abnormal 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.

~~It is important to have the knowledge of load characteristics at various points in a power system for various studies such as load flow, short circuit, stability, and electromagnetic transients as explained in “System load dynamics simulation effects and determination of load constants” [B30], “Representation of loads” [B11], “Incorporation of load modeling in load flow studies” [B17], and “A fault locator for radial subtransmission and distribution lines” [B14]. Complex models to represent the load exist; however, the main problem to include adequate representation of loads is obtaining proper data for use in a model.~~

~~Although frequency dependant load models have been proposed in various works such as “Representation of loads” [B11], “Incorporation of load modeling in load flow studies” [B17], and “The influence of load characteristics on power system performance—A C.E.G.B. viewpoint” [B63], it is difficult to obtain data from field tests for these models. It is almost impossible to obtain permission from grid control to isolate a part of the system and vary frequency over a wide range to measure load frequency characteristics at various load points. In a large interconnected system, the frequency usually does not vary over a wide range.~~

3.3 Harmonics ~~and transients~~

~~4.3.1 Harmonics and their effect on distribution line protection~~

A harmonic is defined as a sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency (see IEEE Std 519™-1993 [B58 B38]). In other words, a harmonic is a sinusoidal waveform that has a frequency equal to an integer multiple of the fundamental frequency. ~~For 60 Hz power systems, harmonics will be integer multiples of 60 Hz, which can be expressed another way, as follows in Equation (1):~~

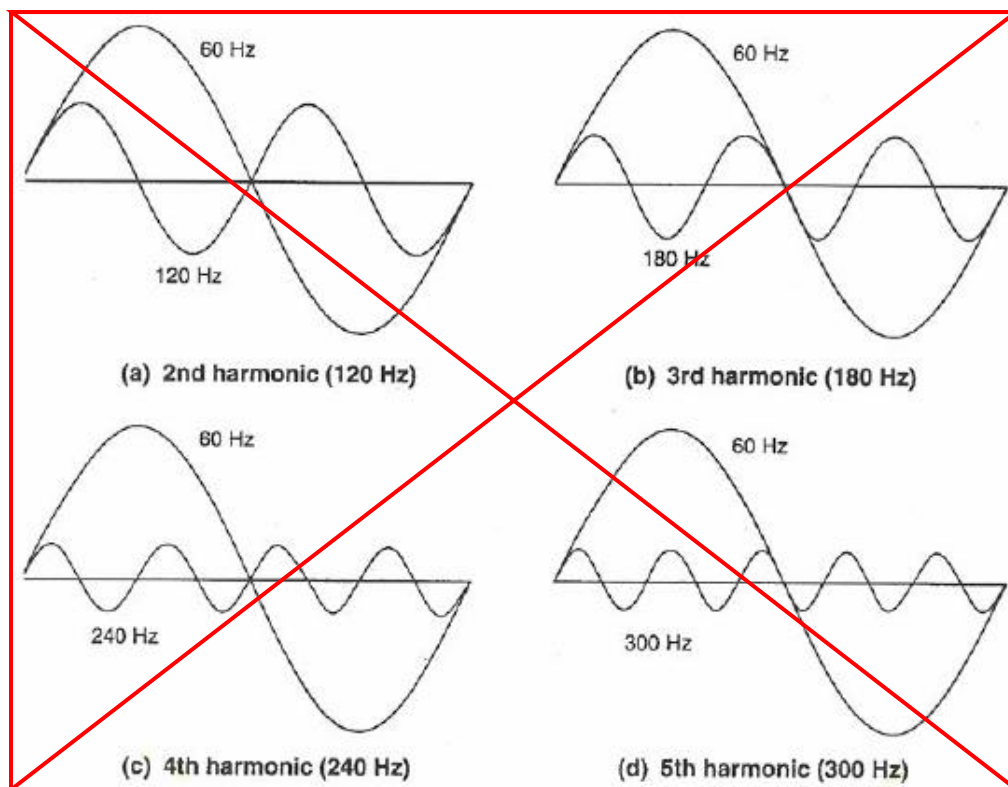
$$f_h = n \times 60 \text{ Hz} \quad (4)$$

where

f_h — is the harmonic frequency

n — is the harmonic number

A 60 Hz waveform and its second, third, fourth, and fifth harmonics are shown in Figure 4-1.



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Figure 4-1 Second, third, fourth, and fifth harmonics with a 60 Hz sinusoid from IEEE Std 141TM-1993 (IEEE Red BookTM) [B35]

Nonlinear loads and power electronic devices are the largest source of the harmonics that appear in power systems. Some typical devices that inject harmonics into the power system are identified in *Electric Power Quality* [B27] as follows:

- Single-phase static and rotating ac/dc converters

- ~~Three-phase static ac/dc converters~~
- ~~High phase-order static converters~~
- ~~Battery chargers~~
- ~~Electric arc furnaces~~
- ~~Fluorescent lighting~~
- ~~Pulse modulated devices~~
- ~~Adjustable speed motor drives~~
- ~~Transformers~~

~~Other power electronic devices such as diodes, silicon-controlled rectifiers (SCRs), gate turn-off (GTO) thyristors, and insulated gate bipolar transistors (IGBTs) chop the supply waveforms. This chopping effect produces non-sinusoidal waveforms, which contain harmonics. The harmonic producing device will act as a current source and inject harmonic current back into the system. This is counter intuitive since we typically think of loads as absorbing power.~~

~~Like fundamental frequency currents, harmonic currents tend to flow towards the path of least impedance. This causes them to show up in the most unexpected places such as power system neutrals. Other problems such as series and parallel resonance can occur, but those problems will not be addressed in this guide.~~

The effect of harmonic currents on power system protection can be analyzed using symmetrical components. Assuming a balanced three-phase power system, harmonic quantities can be considered in terms similar to symmetrical components. However, a fundamental difference between the harmonic components and the symmetrical components is the frequency of the signal. Symmetrical components, as commonly used, are of fundamental frequency, while harmonic components have frequencies that are integer multiples of the fundamental frequency. Table 4-1 lists a few lower order harmonics and their corresponding similarity with a sequence component (see IEEE Std 141TM-1993 (*IEEE Red Book*) [B56 B35] and Concordia “~~Representation of loads~~” [B11]).

Table 1—Similarity between a harmonic quantity and a sequence component

Order	Sequence	Order	Sequence	Order	Sequence
1	Positive	6	Zero	11	Negative
2	Negative	7	Positive	12	Zero
3	Zero	8	Negative	13	Positive
4	Positive	9	Zero	14	Negative
5	Negative	10	Positive	15	Zero

The similarity between a sequence component and ~~with~~ any harmonic component can be found by further developing Table 4-1. For example, the 16th harmonic would be similar to the positive sequence; the 17th harmonic would be similar to the negative sequence, and so on.

Thinking of harmonics in terms of symmetrical ~~sequence~~ components can aid the protection engineer in analyzing how harmonics might affect protection devices. For example, all harmonics divisible by three or *triplens* are similar to zero-sequence quantities and are thus capable of affecting ground relays if the relays do ~~are~~ not operate based on ~~tuned to~~ the fundamental frequency. ~~Negative sequence harmonics may cause erroneous operation of negative sequence responding elements if those elements are not tuned to the 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 ~~should be considered~~. If harmonic distortion is great, the total rms current can be significantly greater than the fundamental frequency component alone.

The true RMS current can be found by using Equation (2) as follows:

$$\text{RMS} = \sqrt{\sum_{n=1}^{\infty} i_n^2} \quad (2)$$

(Deleted)

where

i — is the RMS value of a particular harmonic current

n — is the harmonic number

~~It should be noted that~~ Harmonics associated with the acceptable distortion levels set forth in IEEE Std 519-1993 [B58 B38] do not present a significant threat to the proper operation of protective relays. Furthermore, harmonic currents tend to affect electromechanical relays more severely than modern microprocessor-based relays. Most of these microprocessor relays employ 60 Hz filters in their protection algorithms and are practically immune to the effects of harmonics.

~~4.3.2 Effect of transients on distribution line protection~~

~~Distribution line protective relays can be negatively affected by power transients, and their effect should always be evaluated when applying settings. For example, if a large capacitor bank is installed at the substation bus, "close in" faults can cause large capacitor discharge currents to flow resulting in the possible misoperation of instantaneous over-current relays. Additional examples of transients are transformer energization inrush and system switching. Typically, time over-current relays are not affected by transients since the transient will be dampened out much faster than the relay operating time.~~

3.4 Interrupting ratings

When circuit breakers, reclosers, and fuses are called ~~on~~ upon to interrupt a fault, it is imperative that their interrupt rating is not exceeded. The interrupt rating is the maximum symmetrical current that the device is capable of interrupting and is provided by the manufacturer.

When applied to reclosers and [circuit](#) breakers, the [interrupting](#) ~~interrupt~~ current rating must be greater than the maximum expected symmetrical fault current at the device's point of application, ~~or possible damage can occur for a fault.~~ The X/R ratio at that location must be equal to or less than that at which the [device](#) ~~recloser~~ is tested, at the maximum interrupting current, during the operating duty test [for the same reason](#). No uprating for symmetrical fault currents occurring at X/R ratios less than these maximums for which the recloser is tested [are](#) ~~should be~~ allowed. [The maximum available interrupting ratings for reclosers are typically less than those of circuit breakers, and therefore, their use may not be suitable for distribution systems with higher maximum available fault currents \(IEEE Std C37.60™-2012 \[B41\]\).](#)

~~Typically, reclosers are rated up to 20 kA. Circuit breakers are rated up to 63 kA for distribution applications.~~

4. System configuration and components

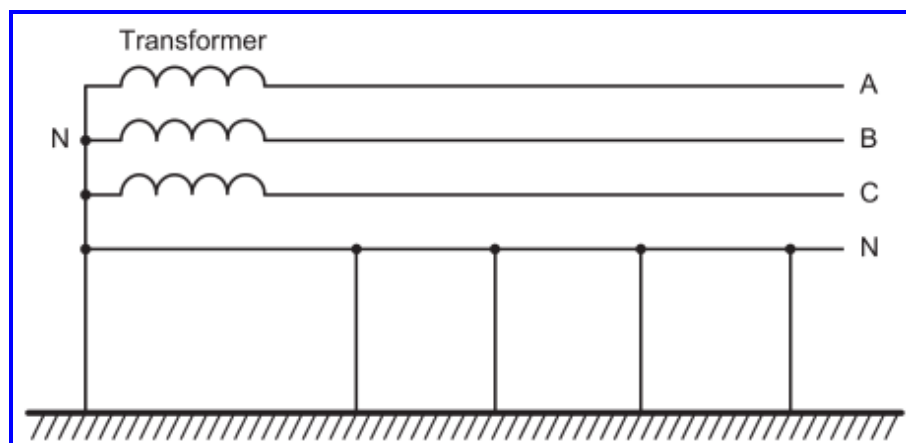
4.1 System

4.1.1 Neutral treatment

~~As mentioned in 4.1.1, there are~~ Three main methods of system grounding [are](#) used around the world. The methods are solidly grounded, ungrounded, and impedance grounded. 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 is not important during normal operation, if all the loads are connected phase-to-phase. However, during single-phase-to-ground faults, operational and safety aspects strongly depend on the grounding method chosen (see [Kojovic \[B63\]](#) and [Lakervi and Holmes \[B64\]](#) ~~“Roundup: System grounding” [B52] and Electricity Distribution Network Design [B55]~~).

4.1.1.1 Multi-grounded system

Multi-grounded systems have a neutral wire that is grounded at multiple locations along the length of the feeder (Figure 2). This is commonly referred to as a four-wire system supplied by a wye-grounded source. This is the most widely used method in the U.S. and is also used in some developing countries. It provides power for single-phase and three-phase loads and is cost-effective for rural areas where single-phase loads are widely scattered. Phase-to-ground faults do not excessively affect voltage magnitudes on the other two unfaulted phases because the neutral is solidly grounded; however, it ~~and~~ shifts slightly since the grounding resistance in real-life applications cannot be zero. Ground fault currents may be high, but the majority of fault current returns to the source through the neutral conductor, not through ground, which limits touch and step voltages within acceptable ranges (IEEE Std 80™-2000 [B55]). Ground fault currents depend on the system voltage, parameters of the feeder on which the fault occurs, and the grounding resistance. A system is considered effectively grounded if the voltage rise on the unfaulted phases does not exceed 35% of nominal voltage (see IEEE Std C62.92.4™-2014 [B54]).⁴ Ground fault protection is typically provided by ground overcurrent relays set more sensitively than phase overcurrent relays, depending on the load unbalance as explained in 4.1.3.1 5.1.1.2.



(New)

Figure 2—Four-wire multigrounded system

⁴~~Information on references can be found in Clause 2.~~

Advantages of a multi-grounded system include ~~systems are that~~ the following:

- Overvoltages during ground faults are low. ~~and~~
- Protection is simple and inexpensive.
- The detection and isolation of ground faults can be accomplished with time overcurrent protection devices such as fuses or reclosers.

Disadvantage of multi-grounded systems include the following: ~~are that the circuit should be quickly interrupted~~

- Shorter interrupting times are needed when ground faults occur to prevent the high fault currents from causing excessive damage, ~~to prevent damage~~ to unfaulted circuit components, as well as ~~and~~ to minimize the duration of voltage dip to customers connected to the faulted phase.

4.1.1.2 Ungrounded system

Ungrounded systems (Figure 3 5-1) are still widely used. Since the neutral is not grounded, it can freely shift. Under normal conditions and balanced loads, phase-to-ground voltages are equal in magnitude and 120° apart. Therefore, there is no voltage difference between neutral and ground. In the case of a phase-to-ground fault (Phase C in Figure 4 5-2), the fault current will flow from the source to the fault location and returns through the stray capacitance-to-ground of the two unfaulted phases of that feeder and the unfaulted phases of all other feeders connected to the same power transformer. Therefore, ground fault current magnitudes depend not only on the faulted feeder parameters, but also on the size (i.e., stray capacitance) of the rest of the system. ~~Magnitudes can be approximately calculated from Equation (3) (as shown in Figure 5-3).~~

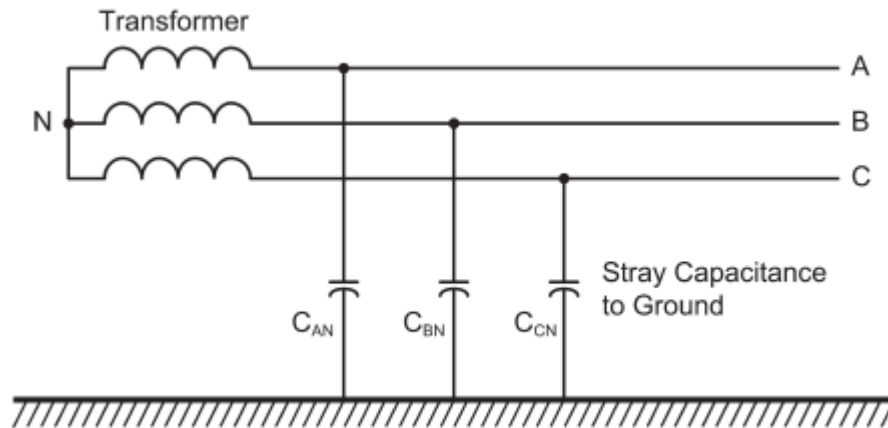


Figure 3—Ungrounded system

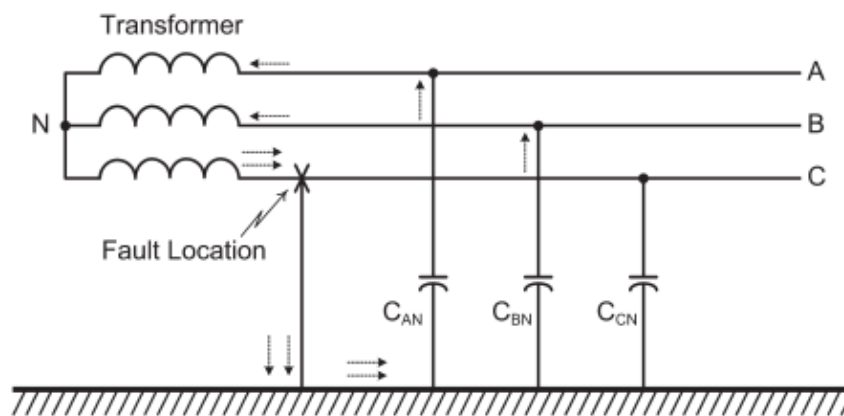


Figure 4—Ground fault in ungrounded system

$$\begin{aligned}
 C_{AN} &= C_{BN} = C_{CN} = C && \text{(phase-to-ground capacitance of each phase)} \\
 |V_{AN}| &= |V_{BN}| = |V_{CN}| = V_{PH} && \text{(phase-to-ground voltages)} \\
 I_A &= j\omega C V_{CA} \\
 I_B &= -j\omega C V_{BC} \\
 I_f &= |\vec{I}_A + \vec{I}_B| = 3\omega C V_{PH} && \text{(fault current)}
 \end{aligned}
 \tag{3}$$

(Deleted)

where

ω —is equal to $2\pi f$ rad/s

Ground faults also cause phase-to-ground voltage rise on the unfaulted phases (A and B in Figure 4 5-3) approaching $\sqrt{3} \times$ nominal. The insulation level of feeders ~~is~~ ~~should be~~ designed to accommodate this voltage increase, which ~~can be~~ ~~is~~ a disadvantage due to increased investment. However, when system expansion increases the fault current through the stray capacitance, a neutral may be added, converting it to a grounded system. Grounding the system ~~This~~ can be accomplished by grounding the neutral of the transformer, either solidly or through an impedance, or by installing a grounding transformer. If the solidly grounded method is used, the same feeders can then transfer more power by increasing the system voltage. For example, feeders of an existing ~~15 40~~ kV system can be energized at ~~25 20~~ kV, since they are already designed for this higher voltage, allowing transfer ~~of two times~~ more power. This has been implemented in some countries in Europe.

Effective ground fault protection for ungrounded systems is provided by directional overcurrent relays that use residual voltage or neutral current for polarization and residual current from the faulted feeder, as described in 7.14 8.15. Phase difference between residual voltage and residual current is approximately 90° (Figure 5-3).

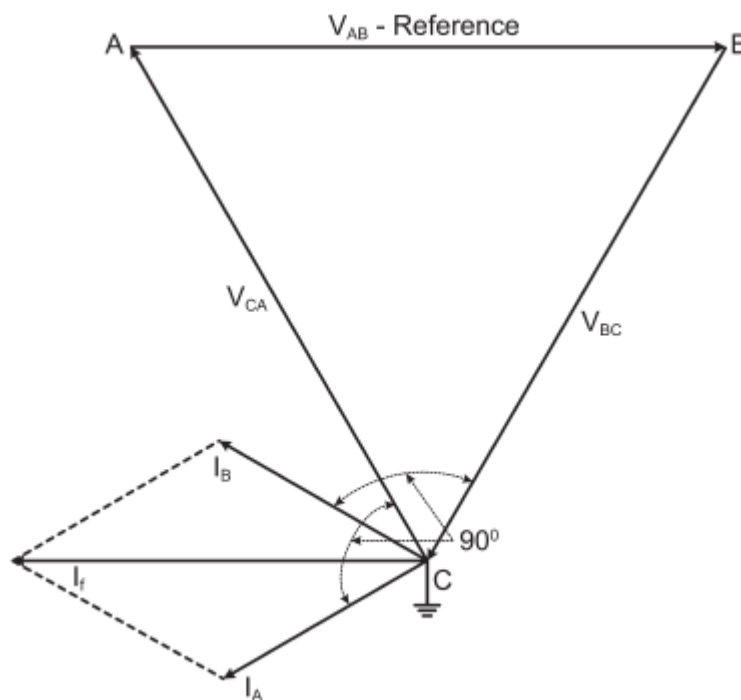


Figure 5— Voltage and ground fault currents in ungrounded system

The ungrounded system can operate for a prolonged time with a ground fault, and the arc can self-extinguish. This is an advantage for reliable operation, but also poses a personnel safety hazard. Relays ~~are~~ ~~should be~~ applied to detect the condition and alert the operators so that the fault can be located and repaired in a timely manner.

Advantages ~~A disadvantage~~ of ~~the~~ ungrounded systems include the following: ~~system is that~~

- Fault current arcs can often self-extinguish.
- System can continue to operate with a single ground fault.

Disadvantages of ungrounded systems include the following:

- Fault current arcs cannot self-extinguish when capacitive currents become high.
- ~~Also,~~ Intermittent arcing can occur and develop high-frequency oscillations that can cause overvoltage escalation of several times rated voltage. ~~There will be fundamental frequency voltage rises on healthy phases;~~
- Voltage rise occurs on unfaulted phases during phase-to-ground fault.
- ~~therefore~~ Single-phase-to-ground faults can develop into phase-phase faults. ~~;~~
- Operating with a single-phase-to-ground fault can yield high fault currents similar to solidly uni-grounded systems in the case of a second phase-to-ground fault.

See 7.14 for methods of detecting ground faults on ungrounded systems.

4.1.1.3 Uni-grounded system

Uni-grounded systems are solidly grounded only at the substation. This can be a three-wire system, with no neutral conductor (Figure 6-5-4) or a four-wire system with an insulated neutral. [Similar to multigrounded systems](#), ground fault currents can be as high as phase-fault currents (or even higher) at the substation but will typically be lower than phase fault currents further outside the substation. In a uni-grounded system, ground fault currents flow back to the source through earth. A very high voltage between the faulted point and the reference ground (V_g) can occur. Part of this voltage represents hazardous voltages defined as touch (V_{touch}) and step (V_{step}) voltages that are dangerous for humans and animals. [Additional details on step and touch and grounding system design can be found in IEEE Std 80™-2000 \[B55\].](#)

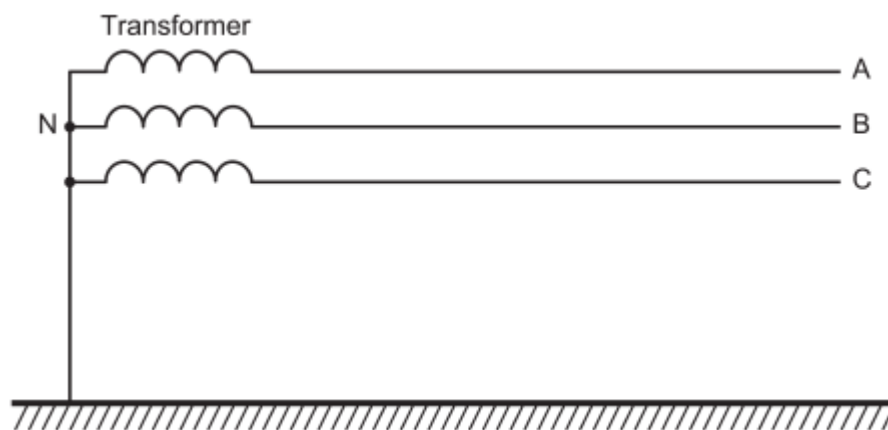


Figure 6—Solidly uni-grounded system

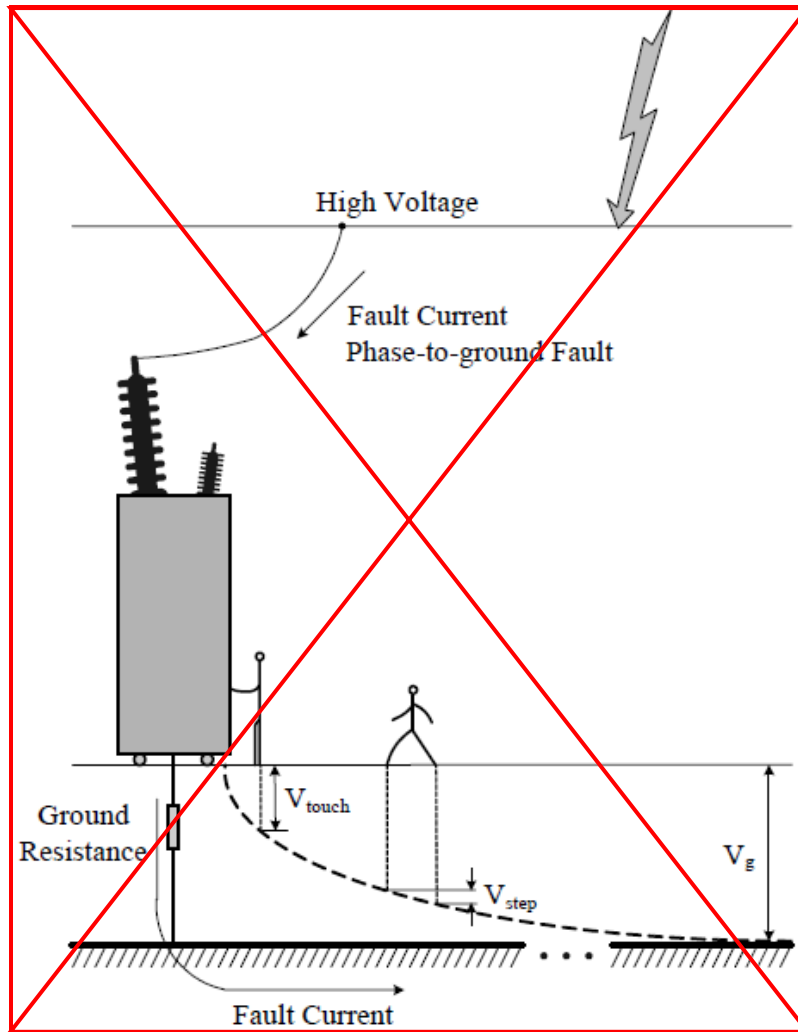
Advantages [of uni-grounded systems include the following:](#) ~~are that~~

- Overvoltages [on unfaulted phases](#) are small, ~~(usually below 1.4 p.u.) and.~~
- Intermittent arc voltages are avoided.
- ~~Because the~~ Transformer windings near the neutral do not see high voltages even during ground faults, which ~~this~~ permits a ~~is~~ less expensive graded insulation of the entire winding.

Disadvantages of uni-grounded systems include the following:

— Grounding study is needed to evaluate and address ground and step potentials.

~~A disadvantage is that extensive analysis is needed to design an effective grounding system.~~



~~(Deleted)~~

~~Figure 5-5—Touch and step voltages for a substation transformer~~

4.1.1.4 Resonant-grounded system

Resonant-grounded systems are most often applied in Europe. In this method, the [substation](#) transformer neutral is grounded through a reactance, also known as a Petersen coil (Figure [7 5-6](#)). The reactance is resonantly tuned to the fundamental frequency with the stray capacitance of all feeders connected to the same transformer. The value of reactance is approximately determined by Equation ([1 4](#)). In the case of a ground fault (C phase- to-ground fault in Figure [8 5-7](#)), if properly tuned, the neutral reactor and the system stray capacitance will cause the same amount of fault current to flow in opposite directions through the point of fault, canceling each other. Figure [8 and Figure 9 illustrate](#) ~~5-7-illustrates~~ fault current contribution by the system stray capacitance (solid-line arrows) and by the neutral reactor (dashed-line arrows). Since it is impossible to entirely match values for the neutral reactor with the system stray capacitance, a small amount of ground fault current will flow through the fault, but the majority of current will return to the source through the reactor. Small mismatches between the reactance and system capacitance (below 25%) will not create protection problems.

Advantages of a resonant-grounded system include the following:

- Ground fault currents are small.
- Arcs are self-extinguished.
- Touch and step voltages are small.
- The need for maintenance of the switches is reduced.
- For a [phase single-line](#)-to-ground fault on the system, it is possible to operate for a [period](#) ~~space~~ of several hours, even when the fault persists, [increasing reliability](#).
- The self-extinguishing effect exerted by the compensation reduces the possibility of a single-[phase line](#)-to-ground fault developing into a multi-phase fault. Intermittent ground faults are avoided.

Disadvantages of a resonant-grounded system include the following:

- ~~— Phase-to-ground voltages can be high due to resonance.~~
- In protection systems using traditional technology, the reliability and sensitivity of the relays is reduced.
- The difficulty of locating faults is increased.
- Arrester protective levels are higher.
- Insulation may need to be increased due to neutral shifting during transients.
- It is not effective in case of arcing cable faults.
- Cables can produce repetitive and harmful restrikes.
- Tuning can be difficult to adjust for varying system configurations such as those associated with distribution systems. During a single-phase line-to-ground fault, the phase line-to-ground voltages of each unfaulted phase increase by a factor approaching $\sqrt{3}$. Due to economic considerations, this limits implementation of this type of grounding to lower voltage systems, since line-to-line voltage rated insulation would be required.
- The increased voltage experienced raises the probability of simultaneous ground faults developing due to increases in weak points in the system.

The first two drawbacks are being overcome with the development of new fault detection and protection technologies (see [Leitloff et al. \[B65\]](#)). ~~“Detection of resistive single-phase earth faults in a compensated power distribution system” [B57], “Le traitement du point neutre dans les réseaux de moyenne tension” [B26], and “Détection de défauts à la terre très résistants sur les réseaux compensés” [B16]~~. Due to the last two drawbacks, in order to make it possible to adopt the resonant grounding system, a preliminary analysis will have to be made of effects that the voltage surges in sound phases might have on insulation in the electrical system. To prevent any harmful effects, it will be necessary to ascertain the weak points in the system and also to check that all equipment has been designed to support new voltage demands. [See 7.13 for methods of detecting ground faults on resonant-grounded systems.](#)

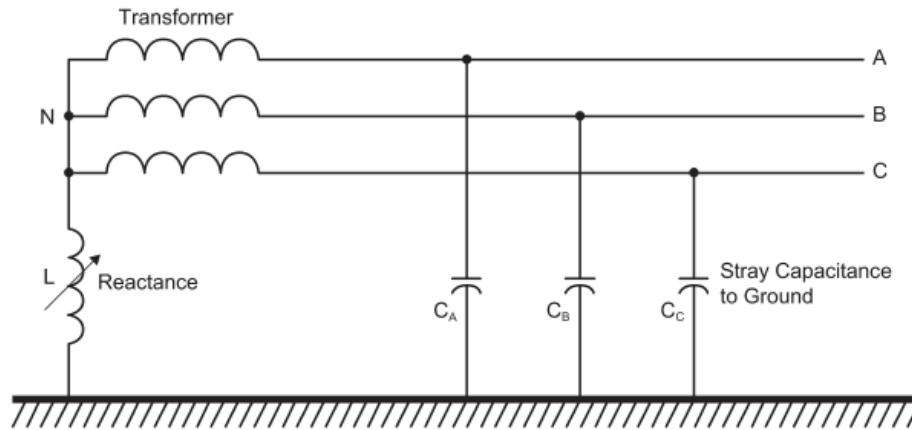


Figure 7—Resonant-grounded system

$$\begin{aligned}
 |I_L| &= |\vec{I}_A + \vec{I}_B| \\
 I_L &= \frac{V_{PH}}{\omega L} = 3\omega C V_{PH} \\
 L &= \frac{1}{3\omega^2 C}
 \end{aligned} \tag{1}$$

where

L is the inductance of the Pederson coil

C is the total stray capacitance to ground of the system

ω is the $2\pi f$ and f is the system nominal frequency

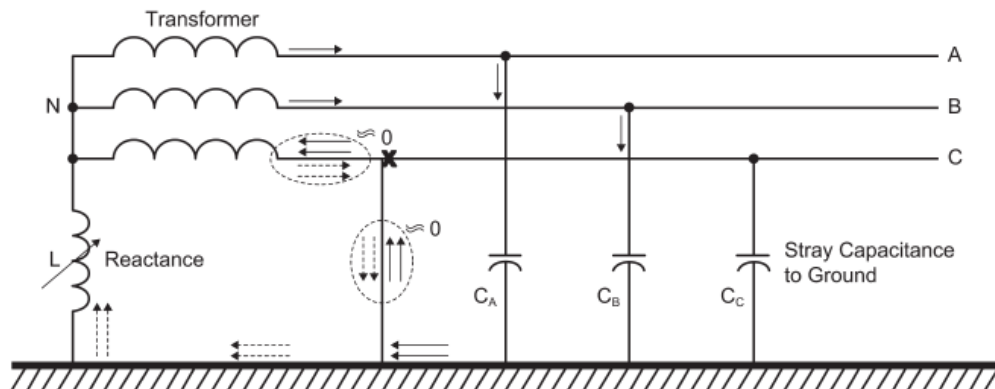


Figure 8—Ground fault in resonant-grounded system

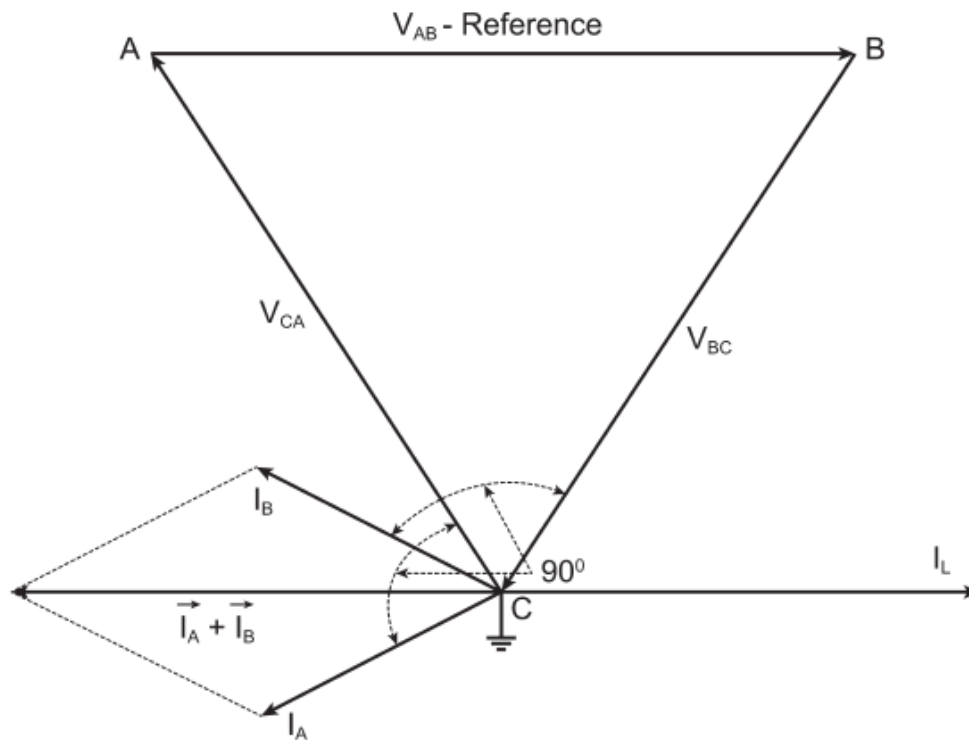


Figure 9— Voltages and ground fault currents in resonant-grounded system

4.1.1.5 Resistive- and reactive ~~Resonant~~-grounded system

To limit ground fault currents, and reduce dynamic and thermal stress on equipment (particularly [substation](#) transformers), resistors or reactors are installed from the [substation](#) transformer's neutral to ground (Figure [10 5-9](#)). However, this grounding method causes the neutral voltage to increase during ground faults. For a 40% reduction in ground- fault current using a resistor compared [with a](#) ~~to~~ fault current without a resistor, the neutral voltage increases to 80% of the phase voltage.

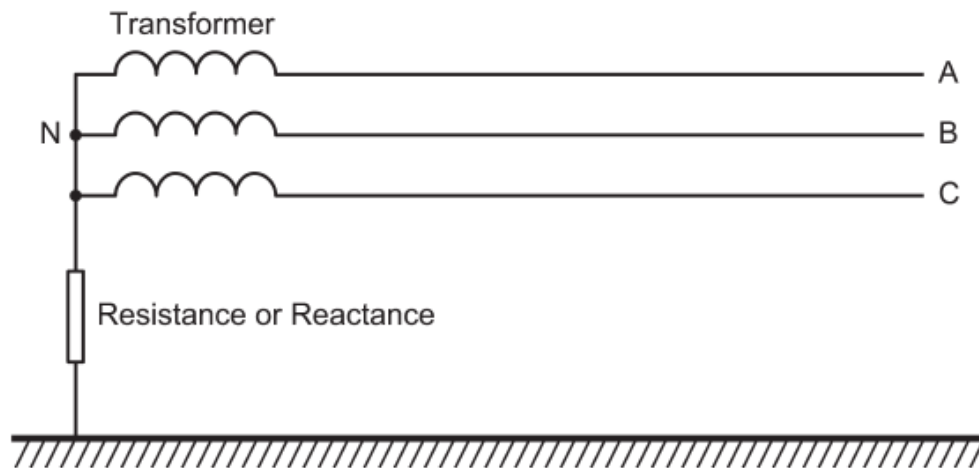


Figure 10— Resistively or reactively grounded system

For this type of neutral grounding, resistors or reactors are used to reduce ground fault currents to acceptable levels, but not to entirely (almost zero current) eliminate it as with resonant-tuned systems.

Advantages of resistive or reactive grounded systems include the following:

- Ground fault currents, touch, and step voltages are reduced.
- Overvoltages are smaller compared to ungrounded systems [depending on the size of the neutral resistor or reactor](#).
- Intermittent arc voltages are avoided.

Some disadvantages of these systems include the following:

- The use of neutral resistance or reactance increases neutral voltages during ground faults and requires higher insulation of the transformer neutral.
- Overvoltages can be high when higher resistance values are used.

Table 2 ~~5-4~~ presents comparative results of the impact of different transformer neutral treatments on a typical distribution system during phase-to-ground faults. Figure 11 ~~5-10~~ shows a 12.47 kV feeder supplying power to a 5 MVA constant impedance, delta connected load. The source voltage was increased 5% to obtain 0.99 p.u. voltage at the load. A ground fault on phase C, with a fault resistance of 1 Ω , was simulated. For different load types and connections, the results will be different.

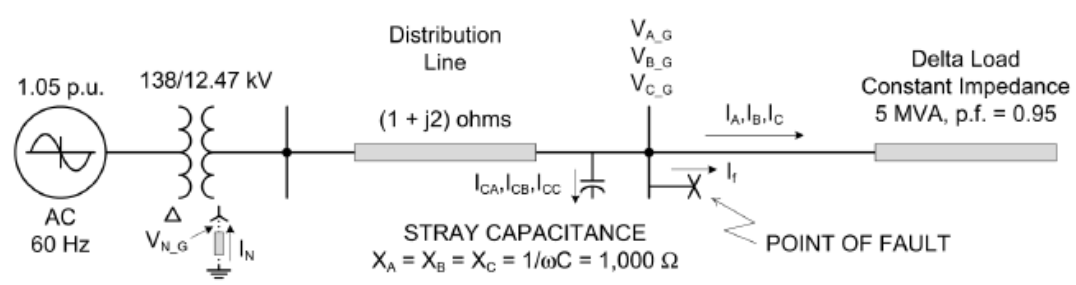


Figure 11 – ~~A~~ Typical distribution system with a radial feeder

Table 2—System voltages and currents during single-phase-to-ground faults for different neutral treatments ([refer to Figure 11](#))

Voltages and currents		Normal operation	Single-phase-to-ground fault with neutral impedance				
			Solidly grounded	Ungrounded	Resonant grounded	Resistor grounded	Reactor grounded
			0.1 Ω	10 000 Ω	1000/3 Ω	10 Ω	10 Ω
Voltage at fault	V_{AG} [V]	7159	7276	12 430	12 400	10 480	11 610
	V_{BG} [V]	7163	7252	12 480	12 400	11 860	10 580
	V_{CG} [V]	7161	2062	22	0	578	542
Load currents	I_A [A]	230	114	231	230	212	198
	I_B [A]	230	223	231	230	238	219
	I_C [A]	230	190	230	230	213	226
Xformer neutral	V_{NG} [V]	0	207	7197	7141	5795	5601
	I_N [A]	0	2067	0	21.4	579	560
Fault current	I_f [A]	0	2062	22	0	578	542
Capacitive currents	I_{CA} [A]	7.2	7.3	12.4	12.4	10.5	11.6
	I_{CB} [A]	7.2	7.3	12.5	12.4	11.9	10.6
	I_{CC} [A]	7.2	2.1	0	0	0.6	0.5

(New)

Neutral impedance (Ω)		Normal operation	Single-phase-to-ground fault (refer to Figure 5-10)				
			Solidly grounded	Ungrounded	Resonant grounded	Resistor grounded	Reactor grounded
			0.1 Ω	10 000 Ω	1 000/3 Ω	10 Ω	10 Ω
Voltage at fault	V_{AG} [V]	7 159	7 276	12 430	12 400	10 480	11 610
	V_{BG} [V]	7 163	7 252	12 480	12 400	11 860	10 580
	V_{CG} [V]	7 161	2 062	22	0	578	542
Load currents	I_A [A]	230	114	231	230	212	198
	I_B [A]	230	223	231	230	238	219
	I_C [A]	230	190	230	230	213	226
Xformer neutral	V_{NG} [V]	0	207	7 197	7 141	5 795	5 601
	I_N [A]	0	2 067	0	21.4	579	560
Fault current	I_f [A]	0	2 062	22	0	578	542
Capacitive currents	I_{cA} [A]	7.2	7.3	12.4	12.4	10.5	11.6
	I_{cB} [A]	7.2	7.3	12.5	12.4	11.9	10.6
	I_{cC} [A]	7.2	2.1	0	0	0.6	0.5

(Deleted)

5.1.2.1 Methods for calculating source impedance

Depending on the information available, several methods for calculating source impedance may be used:

If a short-circuit study was performed and the per-unit values of fault current for a three-phase fault (I_{f3ph}), line-to-line fault (I_{fph-ph}), and line-to-ground fault (I_{fph-G}) at the high-voltage (HV) bus of the distribution substation were determined, symmetrical components Z_{s1} , Z_{s2} , and Z_{s0} of source impedances at the HV bus can be found from Equation (5), Equation (6), and Equation (7), as follows:

$$Z_{s1} = \frac{V_{l-n}}{I_{f3ph}} - Z_f \quad (5)$$

$$Z_{s2} = \frac{j\sqrt{3}V_{l-n}}{I_{fph-ph}} - Z_{s1} - Z_f \quad (6)$$

$$Z_{s0} = \frac{3V_{l-n}}{I_{fph-G}} - Z_{s1} - Z_{s2} - 3Z_f \quad (7)$$

(Deleted)

Knowing that transmission lines and transformers have $Z_1 = Z_2$ and assuming $Z_f = 0$, then for single- and three-phase faults, the source impedances Z_{S1} , Z_{S2} , and Z_{S0} can be calculated using Equation (8), Equation (9), and Equation (10) as follows:

$$\begin{aligned} Z_{S1} &= \frac{V_{l-n}}{I_{f_{3ph}}} & (8) \\ Z_{S2} &= Z_{S1} & (9) \\ Z_{S0} &= \frac{3V_{l-n}}{I_{f_{ph-G}}} - 2Z_{S1} & (10) \end{aligned}$$

(Deleted)

The Z_{S1} , Z_{S2} , and Z_{S0} values obtained from the Equation (8), Equation (9), and Equation (10) are HV bus values and have to be appropriately combined with the per-unit symmetrical components of the substation transformer to obtain the source symmetrical components at the LV side of the substation.

If only the three-phase fault kVA available at the HV bus is given, then the value for Z_{S1} magnitude is calculated by converting the fault kVA to a per-unit fault current magnitude, using Equation (11) and assuming a nominal system voltage if the actual line-to-line value of V at the HV bus is unknown. The per-unit magnitude of Z_{S1} can also be found from Equation (11) as follows:

$$|Z_{S1}| = \frac{V^2}{\frac{kVA_{3ph(FAULT)}}{kVA_B}} = \frac{V^2}{kVA_{3ph(FAULT_{pu})}} \quad (11)$$

(Deleted)

where

$|Z_{S1}|$ — is the magnitude of positive sequence source impedance (per unit)

V — is the line-to-line voltage at the substation HV bus (per unit)

$kVA_{3ph(FAULT)}$ — is the available three-phase fault kilovolt-ampere

kVA_B — is the base kilovolt-ampere

$kVA_{3ph(FAULT_{pu})}$ — is the three-phase fault kilovolt-ampere (per unit)

4.1.2 Bus configurations

The 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 installed for metropolitan service where the importance of maintaining continuity of service justifies a high capital expenditure.~~

~~Bus configuration for distribution buses may differ radically from the layout of transmission buses. In some metropolitan developments supplying underground cable systems, segregated phase layouts are employed to secure the maximum of reliability in operation (see *Electrical Transmission and Distribution Reference Book* [B2]).~~

Bus configurations play an important role in determining adequate settings for feeder breakers. Feeder breakers are set to coordinate with the upstream and downstream relays and devices to improve selectivity of protection tripping. The bus configuration will determine which relays require consideration for coordination. The figures following are some commonly used distribution ~~substation bus arrangements and a description of the protective relay issues that these bus~~ arrangements. For a detailed discussion of the protection schemes for substation buses, see IEEE Std C37.234TM-2009 [B50] create.

Figure ~~5-12~~ shows a substation with a fused transformer, transformer low side secondary breaker (T), and three feeder breakers (F). The transformer low side secondary breaker provides bus protection and backup for the feeder breakers. The protection on the feeder breakers coordinates with ~~Overcurrent relays on~~ the transformer low side secondary breaker should be set below the ~~transformer damage curve. Overcurrent relays on the feeder breakers should be set to coordinate with the transformer secondary~~ relays and with downstream devices on the feeder to avoid additional tripping. For a detailed discussion on the protection requirements for transformers see IEEE Std C37.91TM-2008[B43]. ~~In this substation, there are two sets of relay curves to coordinate between the primary fuse and devices on the feeder. In some installations, the secondary breaker is omitted; then bus protection and feeder backup protection should be provided by the transformer fuse.~~