

IEEE Guide for Determining the Maximum Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault

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**IEEE Guide for Determining the
Maximum Electric Power Station
Ground Potential Rise and Induced
Voltage from a Power Fault**

Sponsor
**Transmission Systems Committee
of the
IEEE Communications Society**

Approved June 14, 1978
IEEE Standards Board

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American National Standards Institute

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Foreword

(This Foreword is not a part of IEEE Std 367-1979, IEEE Guide for Determining the Maximum Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault.)

Telecommunications engineers often have difficulty in understanding the determination of the magnitude of power station ground potential rise or induced voltage, or both. This guide was developed primarily to provide calculation methods in order to determine the protection requirements for wire line communications facilities serving electric power stations.

In order that realistic values may be used in specifying the rating of communications protective devices, the application of mitigating or reduction factors to maximum or worst case values is discussed. The guide also provides information relative to the time requirements, both interruptible and noninterruptible, for signal channels, particularly those involved on critical circuits such as protective relaying.

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IEEE Guide for Determining the Maximum Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault

1. Scope

Difficulties are experienced by telecommunication and protective relay engineers in determining the maximum power station ground potential rise, or induced voltages, or both. Suitably rated protective devices are required for personnel safety and for the protection and continuity of service of wire line telecommunication facilities entering electrical power stations, or otherwise exposed to the influence of electrical power circuits. This guide provides guidance for the calculation of these maximum voltages and for the acceptance of values lower than maximum, as well as the time requirements of communication channels where protective relaying is involved.

2. Introduction

2.1 Telecommunication Circuits. These enter power stations to provide a variety of services. The most important are channels for protective relaying if provided. Whenever line-to-ground faults involving a particular power station occur, the station ground potential rise or induced voltage, or both, appears between the telecommunication circuits and station ground. To protect telecommunication circuits and provide the required reliability in carrying out their functions, the magnitudes of these abnormal voltages must be determined.

2.2 Power Station Ground Potential Rise. This is essentially the product of the power station ground grid impedance to remote earth and that portion of fault current that flows through

it. There are many factors that should be understood by protection engineers in their equipment designs. These include:

(1) Ground resistance measurements and potential gradients in the earth (see IEEE Std 81-1962, Recommended Guide for Measuring Ground Resistance and Potential Gradients in the Earth)

(2) Power system fault currents; magnitudes, division due to multiple return paths, duration and degree of asymmetry (described in Section 4)

(3) Methods of calculation of induced voltages, shielding, etc (described in Section 5).

2.3 High Magnitude Fault Current. Because of the availability of higher fault MVA, high-magnitude currents are quite common wherever faults occur on power systems. Many faults are quite complex in nature and determining the distribution of return currents is sometimes a formidable problem.

2.4 Faults on Power Systems. These may occur at any point on a line or in the power generating, switching or distribution stations and each has different characteristics. Faults can be line-to-ground, phase-to-phase, two-phase-to-ground, or three-phase and can progress from one to the other. They can theoretically be initiated at any point on the current waveform. The resulting ground potential rise can be minimal or disastrously high. Theoretical values as high as 25 kV rms are possible but under unusual circumstances. The waveform can vary from the symmetrical to the completely offset as described in Section 4.

2.5 Division of Fault Current. There are many factors controlling the division of fault current. These are described in Section 4.

2.6 The Types of Wire Line Telecommunication Services Usually Requested for Electric Power Stations. These are:

(1) All metallic circuits between terminals for direct current and alternating current signals, including audio tone, which can be interrupted prior to, during or after power system faults, (noncritical channels)

(2) Nonmetallic (for example, audio tone) circuits that can be interrupted prior to, during or after, power system faults, or both (noncritical channels)

(3) All metallic circuits between terminals for direct current and alternating current signals, including audio tone, which cannot be interrupted (critical channels)

(4) Nonmetallic (for example, audio tone) circuits which cannot be interrupted (critical channels)

These types of services may have various requirements regarding time and fidelity of output versus input, etc.

A “noninterruptible” telecommunication channel usually implies that the channel be uninterrupted prior to, during, and immediately following the power fault. This guide provides guidance for the time requirements of telecommunication channels relative to the various classes of power system communications including protective relaying channels, prior to, during and after the fault or circuit breaker operation.

2.7 Voltage Resulting from Power System Operation. Surges or transients produced by power system operation, such as breaker operation or capacitor tap changing, etc, often result in relatively high-magnitude short-duration voltages being induced into telecommunication cables. This guide does not treat these phenomena.

2.8 Additional Discussions. This guide considers:

(1) The various types of power transmission and distribution systems with respect to fault currents and fault current distribution

(2) The nature of the faults and their determination using symmetrical component techniques

(3) The characteristics (resistances, induc-

tances and capacitances) of the power system and related time constants

(4) The buildup duration and decay of both symmetric and asymmetric fault currents

(5) The determination of maximum values of ground potential rise and longitudinal induction, and their summation and duration under varying conditions

(6) The application of probability and mitigating factors to provide more realistic and acceptable values consistent with required reliability and safety which could affect economic decisions and tradeoffs

(7) The time requirements for telecommunication channels when used for protective relaying

(8) The effects of HVDC, telluric or auroral currents, or all, as well as dc power system neutral currents which can affect wire line facilities or protective devices

3. Definitions

The following are the definitions of terms peculiar to this guide.

area (volt time area). The area under a curve plotted with voltage versus time (or current versus time) between changes in polarity. This value is a measure of the cumulated flux in a transformer core only up to the first zero crossing and will not necessarily be indicative of the total degree of transformer core steel saturation. The volt time area that is generally of concern consists of the net accumulated volt time area that occurs during a certain number of power frequency cycles of the ground potential rise (GPR). The area is a function of the magnitude and decay rate of the dc offset.

auroral. Electrical voltages and currents on or around the earth due to emission of particle energy from the sun. (See **susceptibility**.)

dc offset. The difference between the symmetrical current wave and the actual current wave during a power system transient condition. Mathematically, the actual fault current can be broken into two parts, a symmetrical alternating component and a unidirectional (dc) component, either or both with decreasing magnitudes (usually both). The unidirectional component can be of either polarity, but will

not change polarity, and will disappear at some predetermined rate.

dc offset factor. The ratio of the peak fault current to the peak symmetrical value.

earth resistivity. A measurement of the electrical resistance of a unit volume of soil. The commonly used unit of measure is the ohm-meter which refers to the resistance measured between opposite faces of a cubic meter of soil.

inducing current. The current that would flow in a single conductor electric supply line with ground return to give the same value of induced voltage in a telecommunication line (at a particular separation) as the vectorial sum of all voltages induced by the various currents in the inductive exposure as a result of a line-to-ground fault.

longitudinal voltage. A voltage acting in series with the longitudinal circuit.

mutual impedance. The ratio of the total induced open-circuit voltage on the disturbed circuit to the disturbing electric supply system phase current with the effects of all conductors taken into account.

per unit (PU). The reference unit, established as a calculating convenience, for expressing all power system electrical parameters on a common reference base. One per unit (PU) is 100 percent of the base chosen. The PU system in power systems engineering is used to obtain a better comparison of the performance of the power system elements of different ratings, similar to the decibel system used for equating the losses and levels of different telecommunication systems.

solar induced currents (SIC). Spurious, quasi-direct currents flowing in grounded power systems or telecommunication cables caused by earth potential differences due to geomagnetic storms resulting from the particle emission of solar flares erupting from the surface of the sun. (See *auroral*.)

subtransient reactance. The reactance of a generator at the initiation of a fault. This reactance is used for the initial calculation of the initial symmetrical fault current. The current continuously decreases but it is assumed to be steady at this value as a first step, lasting approximately 0.05 s after a suddenly applied fault.

susceptibility. The property of an equipment which describes its capability to function acceptably when subjected to unwanted electromagnetic energy.

synchronous reactance. The steady state reactance of a generator during fault conditions used to calculate the steady state fault current. The current so calculated excludes the effect of the automatic voltage regulator or governor.

telluric. Currents circulating in the earth or in conductors connecting two grounded points due to voltages in the earth.

transient reactance. The reactance of a generator between the subtransient and synchronous states. This reactance is used for the calculation of the symmetrical fault current during the period between the subtransient and steady states. The current decreases continuously during this period but is assumed to be steady at this value for approximately 0.25 s.

X/R Ratio. The ratio of system inductive reactance to resistance. It is proportional to the L/R ratio or time constant, and is, therefore, indicative of the rate of decay of any dc offset. A large X/R ratio corresponds to a large time constant and a slow rate of decay.

4. Electrical Power Station Ground Potential Rise (GPR)

4.1 Statement of the Problem. In order to determine the maximum voltage and voltage as a function of time that a station ground grid may attain relative to a remote ground point, hereafter called GPR for ground potential rise, consideration should be given to the following:

(1) The complete data on the power system impedances, currents and voltages for power system faults

(2) The location of the worst possible fault as far as protection of the communication equipment and facilities is concerned

(3) The duration and waveform (area) of the voltages and currents for the worst case fault

(4) The ground impedance at the power station grounding grid and at the remote locations of fault current flow, including the earth resistivity between these points

4.2 Calculation of the GPR

4.2.1 When a ground fault occurs, the fault current returns to the power system ground sources through the earth and also through alternate paths such as neutral conductors, shield wires, messenger, counterpoise and metallic cable shields. The ground sources are the grounded wye-connected windings of power transformers. The GPR is equal to the product of the station ground grid resistance (actually impedance) and that portion of the total fault current which flows through it. The GPR may also be equal to the product of the alternate path impedance and that portion of the fault current which flows through it, but this is usually more difficult to evaluate and is usually neglected. The area to be determined is in volt-second for the duration of the fault.

4.2.2 Since the station ground grid impedance is needed to calculate the GPR, the ground grid impedance must be obtained without the connections to the alternate paths, for example, neutral conductors, shield wires, messengers, counterpoise and metallic cable shields.

4.2.3 A study is made of various ground faults in order to determine the one with the highest GPR voltage and volt-second area (see 4.5.4). The station ground grid impedance should be included in the calculations and tends to limit the fault current as well as to produce the GPR.

4.2.4 In the study under 4.2.3, the power system generators are usually represented by their subtransient reactances. As the time progresses until fault clearing, their reactances increase to their transient values and possibly to the steady state synchronous reactances. This change can be neglected in most cases and the initial subtransient reactance retained. All significant impedances should be included, such as for transmission lines.

4.2.5 The initial magnitude of the dc offset can be calculated as a function of the voltage magnitude at the time the fault is initiated. The highest dc offset occurs when the change in current, from just before fault initiation to just after fault initiation, is maximum. Since the alternating current cannot change state instantaneously due to the inductance of the circuit, initially, the dc offset counterbalances the change in alternating current. The offset then decreases to zero at a rate determined

from the reactance-resistance ratio (X/R) of the power circuit at the fault. With a highly inductive circuit the maximum offset will occur when the fault is close to voltage zero, a condition which is most unlikely. Also, a highly inductive circuit will have a prolonged offset.

4.2.6 There are four possible combinations of circumstances involving power faults which should be considered in calculating the maximum GPR. Fig 1 relates to the GPR at the local ground source as follows:

(1) Where the ground fault involves the local ground grid and the fault current from the remote ground source predominates, the remote source produces the GPR. This could also occur without a *local ground* source. (Fig 1A)

(2) Where the ground fault is to remote ground (that is, far enough away so that there is no mutual impedance between the fault location and the local station ground grid) and the fault current from the local source predominates, the local source produces the GPR. This could also occur without a *remote ground* source. (Fig 1B)

(3) Where the ground fault is to the local ground grid, the fault current from the local ground source predominates (Fig 1C) and the remote source produces the GPR. This also occurs without a local ground source.

(4) Where the ground fault is to remote ground and the fault current from the remote ground current source predominates (Fig 1D), the local source produces the GPR. This also could occur without a remote ground source.

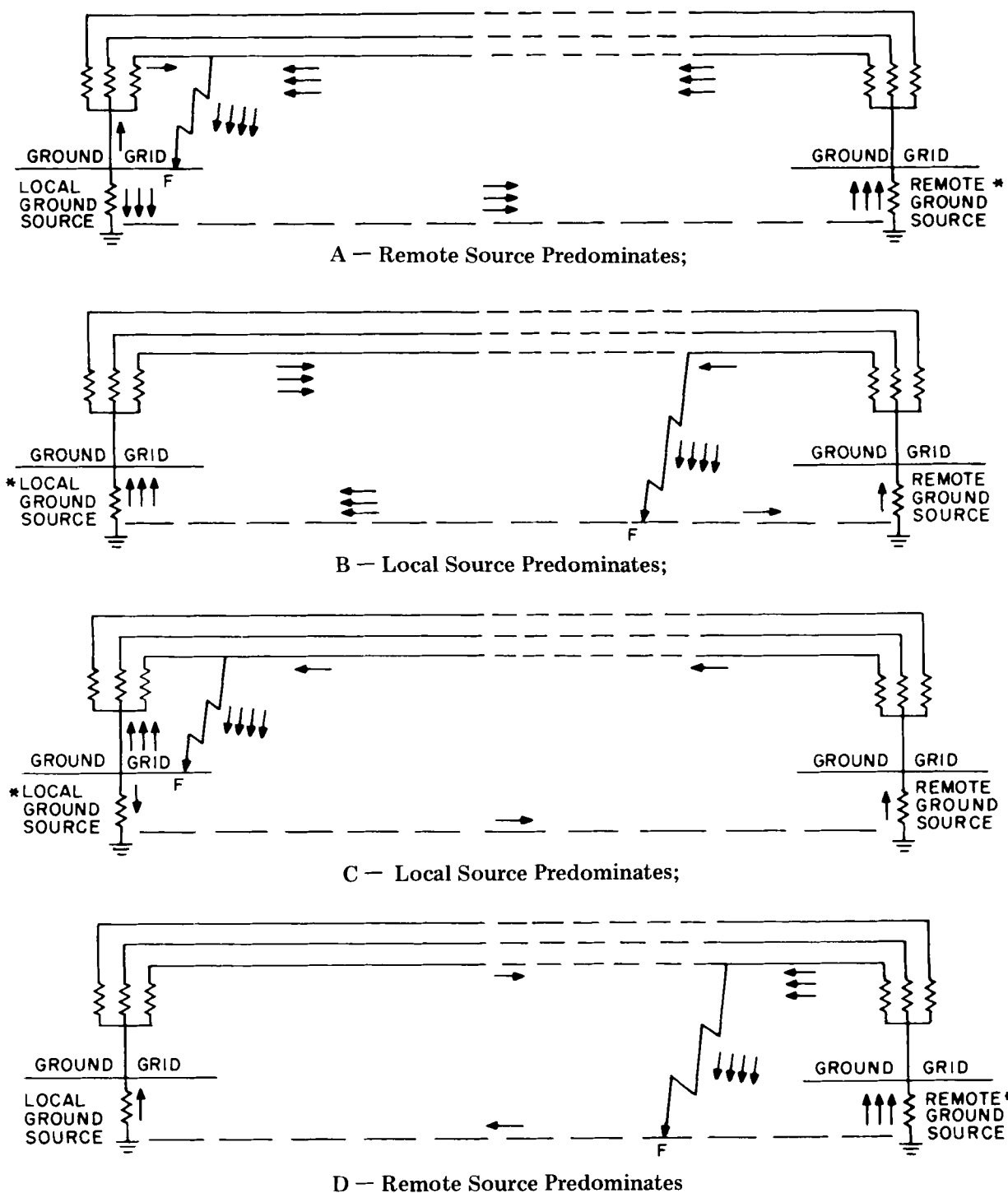
NOTE: Either 4.2.6.1 or 4.2.6.2 will produce the largest GPR, and normally both must be calculated at each voltage level to determine the maximum GPR at a particular station.

4.3 Duration of the Fault and its Relationship to Communication Requirements for Power System Protection

4.3.1 The duration of the fault currents and resulting voltages depends upon the power system protective relay scheme and its equipment as well as the power system layout and equipment. The relaying scheme may employ wire line communication facilities.

4.3.2 The time required to clear a fault usually falls into one of the following categories:

(1) Lightning surges that are cleared by arresters on the power circuits and require no circuit breakers to be opened. The communication service is protected by its own lightning



NOTE: For simplicity, a single line with only two ground sources is illustrated.

Fig 1
Different Combinations of GPR Occurring at the Local Ground Source

arresters or high speed devices and no communication is necessary.

(2) The voltage breakdown of power system insulation that requires circuit breakers to open or fuses to melt. The fault can be cleared by

(a) *Normal* operation for all voltage classes when fault clearing time may be from 0.05 s to 1 s, or more. Communication by wire line facilities is often used to attain a time interval of 0.05 to 0.15 s.

(b) *Abnormal* operation is when fault clearing time is increased due to a failure of some switching equipment or its control. Wire line facilities are often used as part of this backup tripping scheme with or without being a part of the normal tripping. The maximum time is rarely, if ever, over 3 s in situations having a high GPR. A noninterruptible wire line facility is essential in this type of operation.

4.3.3 The calculation of the fault currents and voltages should include their changes or decrements for the duration of the fault as expected from the normal tripping time or abnormal tripping time if backup protection involves wire line facilities. In some limited cases the communication channel can be discontinued momentarily after the tripping signals have been received. There is one type of relay protection (phase comparison) that must have continuous communication as long as the fault exists.

4.4 Extraordinary Possibilities

4.4.1 There is the extremely rare possibility that a single phase-to-ground fault may develop into a two-phase-to-ground fault at the critical time necessary to yield the worst possible GPR both in terms of magnitude of voltage and duration.

4.4.2 In many locations a transmission line having a higher voltage than exists in the substation being studied is nearby. Should this external source of high voltage be applied to the substation, the normal fault current and resulting GPR may be exceeded.

4.4.3 Telluric currents due to auroral phenomena will produce a dc GPR at an unpredictable voltage, time, or location.

4.4.4 There are combinations of circumstances and multiple faults which will produce currents and voltages higher than those calculated on a single contingency basis.

4.5 Example of a GPR Calculation and Area Calculation

4.5.1 Introduction. The following is an example of a GPR calculation with the power system having a voltage of 115 kV and an arrangement shown in Fig 1A and described in 4.2.6.1. For simplicity the contribution of fault current from the local source is neglected in the calculations and only that portion of the fault current which creates GPR is considered. There are no overhead ground wires. The remote ground source equivalent fault impedance and the line fault impedance is given in per unit on a 100 MVA base. The local source station ground resistance is given as 1.5 Ω .

4.5.1.1 Impedance of Power System

Source $Z_1 = 0.01 + j0.05$ PU on 100 MVA base

$$Z_2 = 0.01 + j0.05$$

$$Z_0 = 0.02 + j0.08$$

Line $Z_1 = 0.03 + j0.19$

$$Z_2 = 0.03 + j0.19$$

$$Z_0 = 0.18 + j0.67$$

Station ground resistance $R_s = 1.5 \Omega$

$$\text{base ohms} = \frac{115^2}{100} = 132.25$$

$$R_s = \frac{1.5}{132.25} = 0.011342 \text{ PU}$$

The value to be inserted in the sequence network is 3×0.011342 or 0.034 PU.

Therefore,

$$\begin{aligned} Z_{\text{Total}} &= Z_1 + Z_2 + Z_0 + 3R_s \text{ (in PU)} \\ &= 0.314 + j 1.23 \text{ PU.} \end{aligned}$$

4.5.2 Calculations to be Performed

4.5.2.1 Calculate the peak current for phase-to-ground fault at 115 kV in the substation yard. (See 4.5.3.)

4.5.2.2 Calculate the area under the current curve as illustrated for the interval to first zero crossing. (See 4.5.4.)

4.5.2.3 Calculate the GPR and voltage curve area. (See 4.5.5.)

4.5.2.4 Calculate the peak current for a single-phase-to-ground fault followed by a two-phase-to-ground fault. (See 4.5.6.)

4.5.2.5 Calculate the area under the current curve to first zero crossing. (See 4.5.7.)

4.5.2.6 Calculate the GPR and voltage curve area. (See 4.5.8.)

NOTE: For the general case, only that portion of the fault current returning through the substation ground resistance with respect to reference ground should be considered.

4.5.3 Calculating Peak Current (4.5.2.1)

The base current for a 100 MVA, 115 kV transformer bank is 502 amperes per phase. The symmetrical fault current in the one faulted phase and ground, assuming no change in the source impedance with time and with the substation ground resistance included, is three times the base current divided by $Z_1 + Z_2 + Z_0 + 3R_s$, [1]¹.

$$I_G = \frac{3(502)}{0.314 + j1.23}$$

$$= \frac{1506}{1.269 \angle 75.68}$$

$$= 1186 \text{ A rms steady state.}$$

4.5.3.1 The peak of the steady state current is $\sqrt{2}(1186) = 1677 \text{ A}$. This fault current lags its corresponding phase voltage by 75.68° . When the voltage is approaching zero and is only 14.32° away, the current will be maximum. If a phase-to-ground fault occurs at that instant then there will be a dc offset equal to 1677 A and of opposite polarity. The net current will be zero, assuming no prefault current. The dc offset will decrease exponentially from this instant with no change in polarity. When the alternating current has reversed its polarity and approximately one-half cycle later, the total fault current will be maximum.

$$i = i_{ac} + i_{dc} = I \left[\sin \left(377t - \frac{\pi}{2} \right) + e^{\left(\frac{-t}{T} \right)} \right]$$

for 60 Hz

where

- i = instantaneous total fault current
- I = peak symmetrical current = 1677 A
- t = time from start of fault or $t = 0$ is 90° before i_{ac} is zero. At maximum current $t = 0.00833 \text{ s}$
- T = time constant
- $= \frac{X}{377R}$ for 60 Hz = 0.01039

¹Numbers in brackets correspond to those of the Bibliography, Section 9 of this guide.

NOTE: $X/R = \tan 75.68^\circ$ or

$$X/R = \frac{1.23}{0.314} = 3.9171.$$

R = resistance of the system to the point of fault

X = reactance of the system to the point of fault

$$\text{At peak } i_{ac} = 1677 \sin [377(0.004167)]$$

$$= 1677 \sin 1.57 = 1677 \text{ A}$$

At one-half cycle after the fault starts,

$$i_{ac} = 1677 \sin [377(0.008333 - 0.004167)]$$

$$= 1677 \text{ A.}$$

$$i_{dc} = 1677 e^{\left(\frac{-0.008333}{0.01039} \right)} = 1677 (0.44842)$$

$$= 752 \text{ A}$$

$$i = 1677 + 752 = 2429 \text{ ampere peak}$$

4.5.4 Calculating the Area (4.5.2.2).

4.5.4.1 The area under the current waveform may be of importance for iron core devices since the flux reversal is delayed to give the effect of a lower frequency. This area can be calculated as the sum of three parts, the dc offset, the sine wave above the axis and the sine wave below the axis. The time between zero crossings of the total fault current is the time between the start of the fault and the next time that $i_{dc} = -i_{ac}$, and is best determined by trial and error. Each area is described as follows:

Let the ac wave be given by the equation

$$i_{ac} = -I \cos 377t$$

where the angle $377t$ is given in radians. Then at $t = 0$ the current is maximum, and is negative. At the first ac current zero crossing, $t = 0.004167$.

$$i_{ac} = -I \cos (1.5708) = -I \cos 90^\circ = 0,$$

but

$$i_{dc} = I e^{\left(\frac{-t}{T} \right)}$$

$$= I e^{\left(\frac{-0.004167}{0.01039} \right)}$$

$$= I e^{-0.40103}$$

$$= I (0.670) \text{ assumed to be positive.}$$

At the second ac zero crossing

$$i_{ac} = -I \cos 377 (0.0125)$$

$$= -I \cos 4.7125$$

$$= -I \cos 270^\circ = 0$$

but

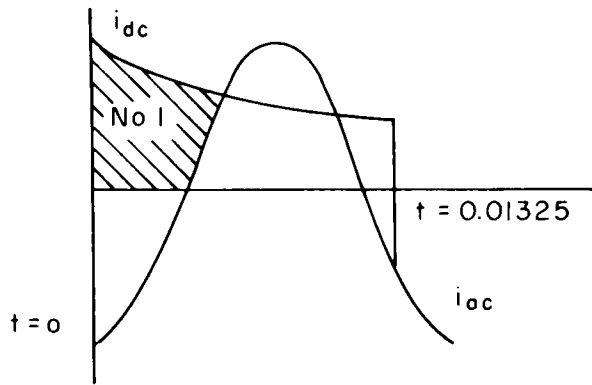


Fig 2
Area No 1

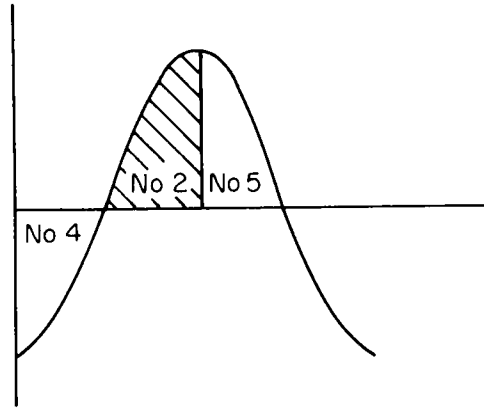


Fig 3
Area No 2

$$\begin{aligned} i_{dc} &= I e^{\left(\frac{-0.0125}{0.01039}\right)} \\ &= I e^{-1.203} \\ &= I (0.300) \end{aligned}$$

At $t = 0.01325095$ we find the ac and the dc are equal and opposite.

$$\begin{aligned} i_{ac} &= -I \cos 377t \\ &= -I \cos 4.9956 \\ &= -I (0.27932) \end{aligned}$$

$$\begin{aligned} i_{dc} &= I e^{\left(\frac{-0.01325095}{0.01039}\right)} \\ &= I e^{-1.275356} \\ &= +I (0.27932). \end{aligned}$$

$$\begin{aligned} \text{The area No 1} &= I \int_0^{t_1} e^{\left(\frac{-t}{T}\right)} dt \\ &= I \left[-T e^{\left(\frac{-t}{T}\right)} \right]_0^{t_1} \\ &= 1677 [0.01039 (1 - 0.27932)] \\ &= 12.56 \text{ A}\cdot\text{s} \end{aligned}$$

where

$$\begin{aligned} t_1 &= 0.01325095 \\ T &= 0.01029 \text{ (see Fig 2).} \end{aligned}$$

$$\begin{aligned} \text{Area No 2} &= I \int_0^{\pi/2} \sin 377t \, dt \\ &= \frac{I}{377} \left[-\cos 377t \right]_0^{0.004167} \\ &= -\frac{1677}{377} [(\cos 90^\circ) - 1] \\ &= 4.448 \text{ A}\cdot\text{s (see Fig 3).} \end{aligned}$$

For area No 3 the time is $t = 0.01325095 - 0.0125$.

$$\begin{aligned} \text{Area No 3} &= -\frac{1677}{377} \left[-\cos 377t \right]_0^{0.00075095} \\ &= 4.448 (\cos 0.28311 - 1) \\ &= -0.1771 \text{ (see Fig 4).} \end{aligned}$$

$$\begin{aligned} \text{Total total area} &= +12.56 \\ &\quad + 4.448 \\ &\quad - 0.177 \\ &\quad + 16.83 \text{ A}\cdot\text{s}. \end{aligned}$$

The normal one-half cycle area is twice No 2 area = 8.896 A·s.

4.5.4.2 Areas No 4 and No 5 cancel each other.

4.5.5 The Resultant GPR (4.5.3.2). Based on the peak currents, this will be:

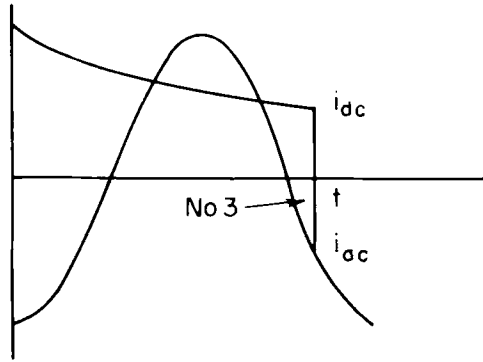


Fig 4
Area No 3

- (1) 1.5 (1186 A) (station ground resistance) = 1779 V, rms symmetrical
- (2) $\sqrt{2}$ (1779 V) = 2515 V, peak symmetrical
- (3) 1.5 (2429 A) = 3643 V, peak with dc offset.

4.5.6 Calculating the Peak Current. This will be done for a single phase-to-ground fault followed by a two-phase-to-ground fault.

NOTE: Calculations are rounded off to two significant decimal places.

4.5.6.1 First, it is necessary to determine the steady state two-phase-to-ground fault using phases B and C, with phase A the reference for angles.

$$\begin{aligned}
 I_0 &= \frac{-Z_2 (502) \angle 0}{Z_0 Z_1 + Z_1 Z_2 + Z_2 Z_0} \\
 &= \frac{0.2433 \angle 80.53 (502) \angle 180}{0.4410 \angle 154.26} \\
 &= 277 \angle 106.27 \\
 I_1 &= \frac{(Z_0 + Z_2) (502) \angle 0}{0.4410 \angle 154.26} \\
 &= \frac{1.027 \angle 74.53 (502) \angle 0}{0.4410 \angle 154.26} = 1169 \angle 280.27 \\
 I_2 &= \frac{-Z_0 (502) \angle 0}{0.4410 \angle 154.26} \\
 &= \frac{0.7857 \angle 72.67 (502) \angle 180}{0.4410 \angle 154.26} = 894 \angle 92.42
 \end{aligned}$$

$$\begin{aligned}
 I_B &= I_0 + 1 \angle 240 I_1 + 1 \angle 120 I_2 \\
 &= 1882 \angle 176.81 \text{ ampere rms symmetrical} \\
 &= 2662 \text{ ampere peak} \\
 I_C &= I_0 + 1 \angle 120 I_1 + 1 \angle 240 I_2 \\
 &= 1786 \angle 22.85 \text{ ampere rms symmetrical} \\
 &= 2626 \text{ ampere peak} \\
 I_G &= 3I_0 = I_B + I_C \\
 &= 831 \angle 106.27 \text{ ampere in ground}
 \end{aligned}$$

The angle between I_B and I_C is 153.96° .

4.5.6.2 Should the initial fault be phase B to ground at the time which yields the maximum dc offset, and then followed by a phase C involvement after 0.007128 s or the time phase B travels 153.96° , the result can be shown as in Fig 5.

NOTE: For simplicity of representation, the old $I_{B \text{ ac}}$ is considered to be in phase with the new $I_{B \text{ ac}}$.

The dc decrement of phase B until the start of phase C fault is calculated first.

$$\frac{t}{T_B} = \frac{0.007128}{0.01039} = 0.686,$$

and

$$e^{-0.686} = 0.5036,$$

then

$$i_{Bdc} = 1677 (0.5036) = 845 \text{ A.}$$

The ac component of phase B when phase C starts is $-1677 \cos 153.96 = 1507 \text{ A}$. Then the total phase B current = $845 + 1507 = 2352 \text{ A}$.

From the two-phase-to-ground calculation, phase B should be $\sqrt{2} (1882) \cos 153.96 = 2391$ when phase C is maximum, but is actually 2352. Therefore, the new phase B_{dc} component is -39 . To obtain its decrement, evaluate the X/R ratio for the new phase B current using the angle between E_B and I_B :

$$\tan (240 - 176.81) = \tan 63.19^\circ = 1.979,$$

then

$$T_B = \frac{1.979}{377} = 0.0052488.$$

The X/R ratio for the phase C is determined by the angle between E_C and I_C :

$$\tan (120 - 22.85) = \tan 97.15 = 7.9718$$

then

$$T_C = \frac{7.9718}{377} = 0.021145.$$

By trial and error we find that the maximum ground current for this problem appears after I_B and I_C have rotated 85° or at 0.0039356 s after their position when I_C started.

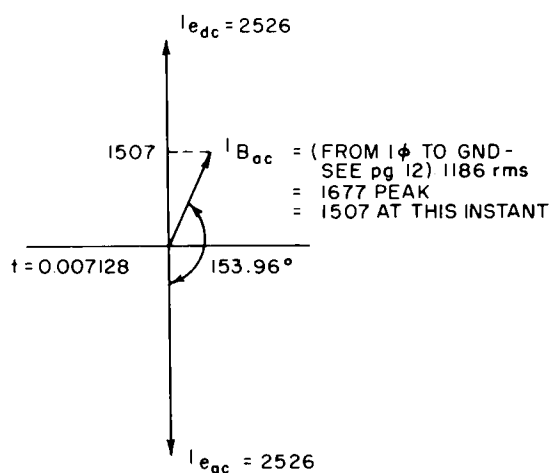
To determine the total fault current, we must evaluate the two components of each phase current. (See Fig 6.)

$$I_{C_{ac}} \text{ component} = 2526 \sin(-90 + 85) = -220 \text{ A.}$$

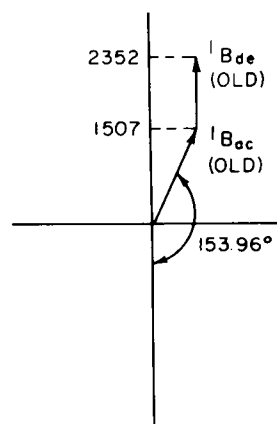
For the $I_{C_{dc}}$ component find

$$\frac{t}{T_C} = \frac{0.0039356}{0.021145} = 0.18612,$$

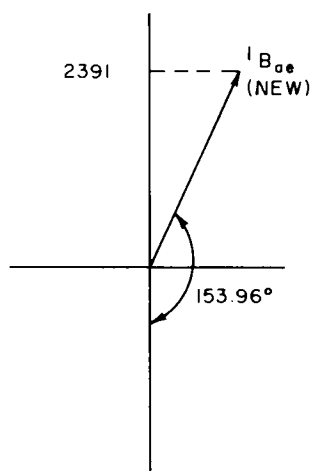
Fig 5
Graphical Representations of Peak Currents



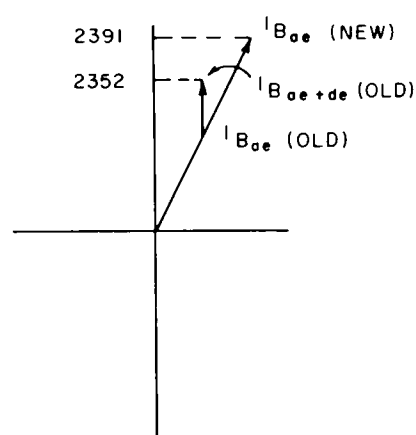
A



B



C



D