

An American National Standard

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



Published by
The Institute of Electrical and Electronics Engineers, Inc



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Std 367-1987
(Revision of IEEE
Std 367-1979)**

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

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

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Foreword

(This Foreword is not a part of ANSI/IEEE Std 367-1987, IEEE Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault.)

Wire-line telecommunication facilities serving electric power stations often require that extraordinary protection measures be taken to protect against the effects of fault-produced ground potential rise (GPR) or induced voltages, or both. In the presence of a hostile electromagnetic environment, suitably rated protection equipment is required at the power station for personnel safety, for the protection of the serving telecommunication facilities, and to help ensure the desired continuity of telecommunication transmission at times of power system faults. There is a fundamental need, therefore, to determine the appropriate values of fault-produced GPR and induction, including considerations of their probability and duration, to be used in developing the specifications and ratings for the protection equipment to be used in any given application.

This guide provides information for the determination of the appropriate values of fault-produced power station GPR and induction for use in the design of protection systems. Included are:

- (1) The determination of the appropriate value of fault current to be used in the GPR calculation;
- (2) Taking into account the waveform, probability, and duration of the fault current;
- (3) The determination of inducing currents, the mutual impedance between power and telephone facilities, and shield factors;
- (4) The vectorial summation of GPR and induction;
- (5) Considerations regarding the power station GPR zone of influence;
- (6) Communications channel time requirements for noninterruptible services.

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1. Scope

Difficulties are experienced by telecommunication, protection, and relay engineers in determining the “appropriate” values of power station ground potential rise (GPR) or the longitudinally induced voltages (LI) into wire-line telecommunications facilities (or both) including their probability, waveform, and duration, which are to be used in developing the specifications for systems and component protection.

Suitably rated protection devices are required for personnel safety and for the protection and continuity of service for wire-line facilities that either enter electric power stations or that are otherwise exposed to the influence of high-voltage electric power circuits. (See ANSI/IEEE Std 487-1980 [5].¹)

This standard provides guidance for the calculation of these interfering voltages and guidance for their appropriate reduction from worst-case values for use in wire-line telecommunication protection design. Information is also included for the determination of

(1) The fault current and earth return current levels; their probability, waveform, and duration; and the impedance to remote earthing points used in these GPR and LI calculations as well as the effective X/R ratio.

(2) The zone of influence of the power station GPR.

(3) The calculation of the inducing currents, the mutual impedance between power and wire-line telecommunication facilities, and shield factors.

(4) The channel time requirements for wire-line telecommunication facilities where noninterruptible channels are required for protective relaying, etc.

¹The numbers in brackets correspond to those of the references listed in Section 4.

2. Introduction

2.1 Wire-Line Telecommunication Circuits. Wire-line telecommunication circuits, which enter an electric power station, provide telecommunication channels for a wide variety of services. The most important services are channels used for protective relaying, usually considered as noninterruptible. Whenever faults involving a particular power station occur, any resulting station ground potential rise (GPR) or longitudinally induced voltage (LI), or both, appear between the telecommunication circuits and station ground. Other wire-line telecommunication circuits that merely pass through the zone of influence of the power station are also subject to similar interference; however, their reliability requirements may or may not be the same. The magnitudes, waveform, and duration of the abnormal interfering voltages must be accurately determined to protect wire-line telecommunications circuits entering or passing through

2.2 Faults on Power Systems. Power system faults can occur at any point on a power line or in any type of power station at any voltage level. Each location has different fault characteristics. Faults can be single line-to-ground (L-G), phase-to-phase, open-phase, double line-to-ground (2L-G), or three-phase and can progress from one to the other. These faults can theoretically be initiated at any point on the voltage or current waveform and the resulting fault currents can attain values even higher than 100 kA. The resulting GPR or LI, or both, on adjacent telecommunication facilities can be minimal or quite high. Values of GPR as high as 25 kV rms are possible under unusual circumstances; however, the usual values are less than 10 kV. The waveform of the GPR voltage can vary from the symmetrical to the completely offset, as described in Section 4. The decay time of the direct-current component (dc offset) of the fault current may have a duration of several cycles.

Fault-current studies should be re-evaluated at least every five years and more often, if required, due to the ever-increasing MVA capacity or configuration of these power systems.

2.3 Power Station Ground Impedance to Remote Earth. The power station ground grid impedance to remote earth, Z_{SGT} , is required in the determination of the inducing current and is used in both GPR and LI calculations.

The total power station ground grid impedance to remote earth, Z_{SGT} , is the total impedance between the power station ground and remote earth and consists of the parallel combination of

- (1) Power station ground grid impedance itself, Z_{SG} .
- (2) Combined impedance, Z_L , of all high-voltage (HV) and low-voltage (LV) ladder networks. These ladder networks are composed of overhead ground wires or neutrals with multiple tower or pole footing grounds.
- (3) Incidental impedances, Z_i —rails, pipes, etc.

The total power station ground grid impedance, Z_{SGT} , can be obtained by either of two methods: Calculations based on measurement of earth resistivity only (Method A); determinations based upon direct measurements (Method B).

The choice of method will depend upon a variety of circumstances as discussed in the following.

Method A. Several mathematical models and computer methods are used by power utilities to derive the station ground grid impedance, Z_{SG} . For example, a formula derived from the ANSI/IEEE Std 80-1986 [3], Eq 39, and good for homogenous earth where the depth of burial is less than 0.25 m, is

$$Z_{SG} = \rho \left(\frac{1}{4r} + \frac{1}{L} \right) \quad (\text{ohms})$$

where

- ρ = earth resistivity, in ohm-meters (obtained by field measurements)
- r = equivalent radius of a power station ground grid (radius of a circle having the same area as the station ground grid), in meters
- L = total length of buried horizontal ground conductors, in meters

In GPR studies, calculations of the impedance of all connected overhead ground wire/tower ladder networks are required.

The impedance of a ladder for sufficiently long lines is

$$Z_L = \frac{Z_s}{2} + \sqrt{\frac{Z_s^2}{4} + Z_s Z_p}$$

Z_s = per span self-impedance of the overhead ground wire, in ohms

Z_p = tower/pole footing impedance, in ohms

The third component, Z_i —incidental grounds, is not amenable to calculation and is omitted in this method because it can be changed without knowledge of the power utility. This omission results in an estimate of GPR that errs in a conservative (that is, a higher GPR) direction.

Method B. Determination based upon direct measurement. The total station ground impedance, Z_{SGT} , can be measured with the station in its operational state (all normally externally grounded metallic conductors connected). Such

conductors include ladder network impedance, Z_L , and incidental grounds, Z_i , (for example, metallic water, gas, sewer lines, and others).

Since these connections exist when the power station is operational and since they increase the effective area of the ground grid and reduce its impedance to remote earth, they should be in place when the impedance measurement is made. Power utilities generally measure the grid impedance immediately after a new grid is constructed but before any intentional ground connections are made. This measurement is useful to check the grid against its design objective, but in itself would not be the correct value to use for GPR calculations.

The fall-of-potential method of measurement, described in the ANSI/IEEE Std 81-1983 [4], is appropriate for the measurement of the magnitude and phase of the impedance to earth of large grids. Refinements of this method using modern instrumentation are described in several IEEE publications (see references).

If, subsequent to the measurement, any of the incidental connections should be removed, measurements must be repeated.

2.3.1 Evaluations and Applications of Methods A and B

(1) *Accuracy.* Both methods require measurements, and the accuracy of each depends upon the completeness and care with which such measurements are made. Method A requires only measurements of ρ (earth resistivity). In areas of homogeneous soils a single measurement in the near vicinity of an existing or proposed station is usually all that is required; however, some utilities require that several measurements be made. In nonhomogeneous soils, where ρ may vary markedly with both horizontal displacement and depth, multiple measurements are required to adequately categorize ρ in the area of interest. This requirement is particularly true in the calculation of Z_L for long transmission lines that traverse varying terrains. Method B, on the other hand, requires measurement at an existing station with the test conductors extending outward to points beyond the influence of the station ground grid (including overhead ground wires, neutrals, and incidental grounds). Care must be exercised so that coupling between these extended ground conductors and the test leads does not introduce measurement errors.

(2) *Applications.* Method A is the only way to predict the GPR of electric power stations that have not yet been built. This method is particularly accurate for stations with relatively uncomplicated and singular grid structures. In nonhomogeneous soil earth areas, multiple measurements of earth resistivity are required to ensure accuracy. More complicated ground structures or situations require increasingly complex calculations to the point that stations with two or more interconnected grids may be beyond the present calculating capabilities of some power utilities.

Method B can only be used on existing stations and is particularly useful for extremely complicated stations such as those which have multiple interconnected ground grids. This method is a practical way to determine the Z_{SGT} of older stations where growth and modifications have resulted in complex ground structures or where corrosion may have reduced the effectiveness of the grounding structure. Method B ignores the effects of coupling between fault-current-carrying conductors and overhead ground wires or other grounded conductors resulting in errors in the conservative (higher GPR) direction, unless the phase

conductors are used for current injection. Similarly, the test voltages used in Method B are usually too low to flashover the insulators of insulated overhead ground wires; hence, the resulting GPR values will be higher (more conservative) where insulated overhead ground wire systems are in place because such conductors do not form part of the measured circuit.

As discussed in a later section of this guide, the determination of the location of a line fault producing the worst GPR requires many of the same calculations as are used in Method A, so that Method A may be preferable including the determination of worst-case line fault locations.

With the wide variation of conditions at different power stations, no one method of determining Z_{SGT} is best for all stations. Each power utility or substation owner should choose the method or methods best suited to its needs and capabilities. Larger power utilities, having more specialized engineering staffs and adequate computer capabilities, may routinely use Method A supplemented by Method B for special situations. Smaller power utilities and private substation owners may find that Method B is more suitable considering their staff and equipments. The relative costs of obtaining accurate measurements in Method B, of purchasing and operating the necessary computers for Method A, and of purchasing and operating any resulting telecommunication protection equipment are all important considerations.

2.4 Establishing Net Fault Current Values. Power utilities, in their calculations of zero-sequence fault currents, usually do not take into account the conductive effects of the transmission and distribution line grounding network impedances (comprising overhead ground wires, neutrals, transmission tower and distribution pole footing impedances, counterpoises, and station ground impedances).

The net fault currents should be recalculated by including the effects of the impedances of power line ladder networks, incidental paths (pipes, rails, etc), telecommunications cable grounds, station ground impedance, and a judicious value of fault impedance.

Additional reduction of the induced voltages caused by the net fault current can be achieved by application of various shielding mechanisms available.

Care should be taken in recalculating positive sequence fault currents to include phase shifts in certain transformer windings. Substantial reduction of the net fault current can thus be achieved. The amount of reduction will depend on earth resistivity, tower/pole footing impedances, type and material of overhead ground wire or neutral conductors, span length, transmission or distribution line length, and whether or not overhead ground wire(s) are connected to the station ground grid and whether or not counterpoises and bonds are present.

2.5 Division of Fault Current. Generally, fault current will, at the point of fault, divide between the metallic return paths and earth. The metallic return paths will include overhead ground wires, neutrals, counterpoises, bonds, station ground grids, commonly grounded telecommunication circuits, and incidental grounds such as rail and metallic pipes.

There are many factors controlling the division of power system fault current

into its several paths, and calculations are usually quite complex. The determination of an accurate division of fault current requires knowledge of the earth return path impedance and the ground system including all other return path impedances, as will be shown in Section 5.

2.6 Calculating the Inducing Current. The purpose for calculating inducing current flowing in each transmission or distribution circuit connected to the power station under study is twofold:

- (1) To determine the amount of fault current induced in each overhead ground wire or neutral. These currents do not cause any GPR.
- (2) To determine the amount of voltage induction in nearby telecommunication circuit.

The inducing current which is used to determine the shielding action of overhead ground wires is also used to determine the longitudinally induced voltage in telecommunication networks.

NOTE: The terms "overhead ground wire(s)," "shield wire(s)," "static wire(s)," or "skywire(s)" are synonymous.

2.7 Ground Potential Rise (GPR). This is essentially the product of:

- (1) The total ground grid impedance (Z_{SGT}) at the power system fundamental frequency to a true or remote earthing point (must be outside the zone of influence of the GPR), and
- (2) The total net fault current that flows through the ground grid impedance.

These values should be determined by the electric power utility; reference can be made to ANSI/IEEE Std 80-1986 [3] and ANSI/IEEE Std 81-1983 [4].

2.8 Sources of Fault and Inducing Current Information and Impedance to Remote Earth Information and Related Responsibilities of Power Utilities and Serving Telecommunication Utilities. In some power utilities the necessary fault current information can be obtained from a system planning or protective relaying group. The group responsible for the determination of station ground grid impedance will usually be different from the group responsible for determining an overall impedance to a remote earthing point including any telecommunications cable shields. Serving telecommunication utilities may be involved in this latter determination. In any event, the power utility is essentially responsible for assessing the validity of these parameters and to judge the assessment of the assumed or "appropriate" net fault current value to be used in the GPR calculation, its waveform and duration, and the magnitude of the inducing current. The responsibility for assessing the magnitude of the GPR, induced voltage, and their sum is that of the power utility with the cooperation of the associated telecommunication utility.

Since the electric power utility system originates the fault-produced interfering voltages into the wire-line telecommunications facilities serving the power station, the power utility is responsible for the accurate determination of GPR and induced voltage by considering

- (1) The impedance of the power station ground grid to remote earth.
- (2) The earth return fault current (its waveform and duration) that flows through the grid and produces the GPR.

- (3) The effective X/R ratio of the power system at the fault location.
- (4) The extent of the power station zone of influence along the route of the serving telecommunications cable.
- (5) Fault current values and maps of the relevant power feed routes as required by a serving telecommunications utility for the computation of fault-produced induction on the serving telecommunications cables.
- (6) The required non-interruptible channel time should be the responsibility of the power utility relay engineer.

Since the telecommunications facilities extend into the power station to provide telecommunications service, the power utility or substation owner should advise a serving telecommunications utility of the fault-produced environment. This provision of fault-related data applies even to those cases in which the power utility or substation owner, rather than the serving telecommunications utility, provides the telecommunications protection equipment at the power station.

The telecommunications company and the power utility should cooperate closely in determining the sum of the GPR and induced voltage. Obviously a great deal of cooperation and trust should exist between the power utility or substation owner and the serving telecommunication company representatives, as well as with individuals within these organizations, in order to satisfactorily determine the nature of the hostile environment of the power station.

2.9 Transient Voltages Resulting from Power System Operation. Surges or transients, either unidirectional or oscillatory, usually having fast rise times, are produced by power system switching operations. These stem from switching operations involving breakers, transformer tap changes, capacitors, etc, and often result in relatively high-magnitude, short-duration voltages being induced into telecommunication wires or cables. This guide is confined to the fundamental frequency and its dc offset and does not discuss surges or transients. The lower level of harmonics, however, is included.

2.10 Types of Wire-Line Telecommunication Circuits Usually Requested for Electric Power Stations as Defined by Power Utilities

- (1) All metallic circuits between terminals for dc and ac signals, including audio tone, that 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 dc and ac signals, including audio tone, that cannot be interrupted (critical channels).
- (4) Nonmetallic (for example, audio tone) circuits that 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 document provides guidance for the time requirements of telecommuni-

cation channels relative to the various classes of power system telecommunications including protective relaying channels prior to, during, and after the fault or circuit breaker operation.

To some degree the assumed "appropriate" values of interfering voltages may well be influenced by the reliability requirements.

2.11 Service Types and Performance Objectives for Telecommunications Services Provided at Power Stations as Defined in ANSI/IEEE Std 487-1980 [5]. Wire-line telecommunication services into electric power stations are classified into four major types according to the following definitions:

Type 1. Services requiring either dc transmission or ac and dc transmission used for

(a) Basic exchange telephone service, private line, or both; voice telephone service; etc.

(b) Teletypewriter, telemetering, supervisory control, etc.

Type 2. Private line services, requiring ac or dc transmission, or both, used for pilot wire protective relaying, or dc tripping.

Type 3. Private line services requiring ac-only transmission used for telemetering, supervisory control, data, any noncritical audio tone applications, etc.

Type 4. Private line services requiring ac-only transmission used for audio tone protective relaying.

Interruptions or outages due to the effects of power system faults can be minimized through the installation and maintenance of special protection systems that are designed to operate in the fault-produced, electrical environment (GPR and longitudinal induction) at electric power stations. Because of the critical need for service continuity during power system faults on certain types of telecommunication service provided to power stations, a system of optional "service performance objective classifications," for the purpose of this guide, has been established for all types of telecommunication services provided to power stations.² These objectives, with respect to the effects of power system faults, fall into three classifications. They are

(1) *Class A.* Noninterruptible service performance (must function before, during, and after the power fault condition).

(2) *Class B.* Self-restoring interruptible service performance (must function before and after the power fault condition).

(3) *Class C.* Interruptible service performance (can tolerate a station visit to restore service).

2.12 Summary of Introduction. This guide considers the following:

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

(2) The nature (that is, type and location) of the faults and discusses their determination using symmetrical component techniques.

² Refer to ANSI/IEEE Std 487-1980 [5].

- (3) The characteristics (impedances, inductances, and capacitances) of the power system and related time constants.
- (4) The characteristics (impedance, susceptibility, etc) of the affected wire-line telecommunication systems.
- (5) The determination of the value of impedance to remote or true earth.
- (6) The determination of appropriate values of GPR and LI and their summation and duration under varying conditions.
- (7) 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.
- (8) The *zone of influence* of the GPR.
- (9) The rise, duration, and decay of both symmetric and asymmetric fault currents.
- (10) The time requirements for telecommunication channels when used for protective relaying.
- (11) The effects of high-voltage, direct-current (HVDC), telluric, or auroral currents, or all, as well as dc power system neutral currents that can affect wire-line facilities or protective devices.
- (12) A few typical examples of GPR and induced voltage calculations.

3. Definitions

The following are definitions of terms peculiar to this guide:

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

direct-current (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 during its decay period, and will reach zero at some predetermined time.

direct-current (dc) offset factor. The ratio of the peak asymmetrical fault current to the peak symmetrical value.

earth resistivity. A measurement of the electrical impedance of a unit volume of soil. The commonly used unit is the ohm-meter ($\Omega \cdot \text{m}$) which refers to the impedance measured between opposite faces of a cubic meter of soil.

inducing current. The current that would flow in a single conductor of an 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 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 effect of all conductors taken into account.

per unit system (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% 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 telecommunications systems.

solar induced currents (SIC). Spurious, quasidirect currents flowing in grounded power differences due to geomagnetic storms resulting from the particle emission of solar flares erupting from the surface of the sun. *See: auroral effects* (also known as geomagnetically induced currents [GIC]).

subtransient reactance. The reactance of a generator at the initiation of a fault. This reactance is used for the 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 that describes its capability to function acceptably when subjected to unwanted interfering 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 effects. 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 the system inductive reactance to impedance. It is proportioned to the L/R 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, whereas a small X/R ratio indicates a small time constant and a fast rate of decay of the dc offset.

effective X/R ratio. The value of X/R obtained by the reducing effects of the terminal X/R on the transmission line X/R .

volt-time area. The area under a curve plotted with voltage versus time (or current versus time) with areas of positive and negative polarities added algebraically. 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.

4. References

The following publications shall be used in conjunction with this standard:

- [1] ANSI/IEEE C37.90-1978, IEEE Standard Relays and Relay Systems Associated with Electric Power Apparatus.³
- [2] ANSI/IEEE C37.93-1987, IEEE Guide for Protective Relay Applications of Audio Tones Over Telephone Channels.
- [3] ANSI/IEEE Std 80-1986, IEEE Guide for Safety in AC Substation Grounding.
- [4] ANSI/IEEE Std 81-1983, IEEE Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System.
- [5] ANSI/IEEE Std 487-1980, IEEE Guide for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations.
- [6] BODLE, D. W. *Earth Potential Distributions Associated with Power Grounding Structures*, AIEE Paper No CP62-205 (unpublished paper), 1962 Winter Meeting.
- [7] CARSON, J. R. Wave Propagation in Overhead Wires with Ground Return, *Bell Systems Technical Journal*, Oct 1926, pp 539–554.
- [8] CCITT (International Telegraph and Telephone Consultative Committee) Study Group V. *The Electromagnetic Field Due to a Line Source Above a Uniform Earth of Finite Conductivity*, COM V, No 30-E, Aug 1982.
- [9] CIGRE—Study Committee 36 on Interference, Working Group 02, Volume 108, Paris, 1986.
- [10] National Electric Light Association and the Bell Telephone System, Joint Subcommittee on Development and Research. *Coupling Factors for Ground-Return Circuits—General Considerations and Methods of Calculations*, Engineering Report No 14, Vol II, Apr 1932.

³ ANSI/IEEE publications can be obtained from the Sales Department, American National Standards Institute, 1430 Broadway, New York, NY 10018, or from the Service Center, Institute of Electrical and Electronics Engineers, 445 Hoes Lane, PO Box 1331, Piscataway, NJ 08855-1331.

- [11] OLSEN, R. G. and JAFFA, K. C. Electromagnetic Coupling from Power Lines and Magnetic Field Safety Analysis, *IEEE Transactions on Power Apparatus and Systems*, Vol PAS-103, No 12, Dec 1984, pp 3595–3607.
- [12] OLSEN, R. G. and PANKASKIE, T. A. On the Exact, Carson and Image Theories for Wires at or Above the Earth's Interface, *IEEE Transactions on Power Apparatus and Systems*, Vol PAS-102, Apr 1983, pp 769–778.
- [13] PARKER, Jr., J. C. Hand Held Calculator Program for Evaluating External Mutual Impedance, *Bell Laboratories Technical Memorandum*, Feb 1980.

5. Electrical Power Station Ground Potential Rise (GPR)

5.1 Statement of the Problem. In order to determine the value of 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, alternate return paths such as overhead ground wire, water pipes, rails, etc.
- (2) The fault locations that produce the worst combination of GPR and induction.
- (3) The duration and waveform (dc offset) of the voltages and currents for the case of the worst fault.

NOTE: This assumes an evaluation of the assumed point on the voltage or current waveform for fault initiation.

- (4) The ground grid impedance at the power station ground grid with respect to remote earth, and the impedance with respect to remote earth at the remote fault location.
- (5) The calculation of appropriate fault current values, due to the conductive effects of grounding.
- (6) The calculation of the GPR, induced voltages, and their sum.
- (7) The reduction of GPR and induced voltage due to shielding effects of transmission line conductors, overhead ground wires, and telecommunication cable shields.

5.2 Determination of Appropriate Symmetrical GPR

5.2.1 When a ground fault occurs, the zero-sequence fault current returns to the power system ground sources through the earth and also through alternate paths such as neutral conductors, unfaulted phases, overhead ground wires, messengers, counterpoises, and metallic cable shields. The ground sources are the grounded wye-connected windings of power transformers, generator grounds,

shunt capacitors, frequency changers, etc. The GPR is equal to the product of the station ground grid impedance and that portion of the total fault current that flows through it. Also, the GPR is equal to the product of the alternate path impedance and that portion of the conductively coupled fault current that flows through it. The volt-time area of GPR to be determined is given in volt-seconds for the duration of the fault.

5.2.2 Since the station ground grid impedance to remote earth is needed to calculate the GPR, the ground grid impedance must be obtained either by the calculation or measurement methods described in 2.3.

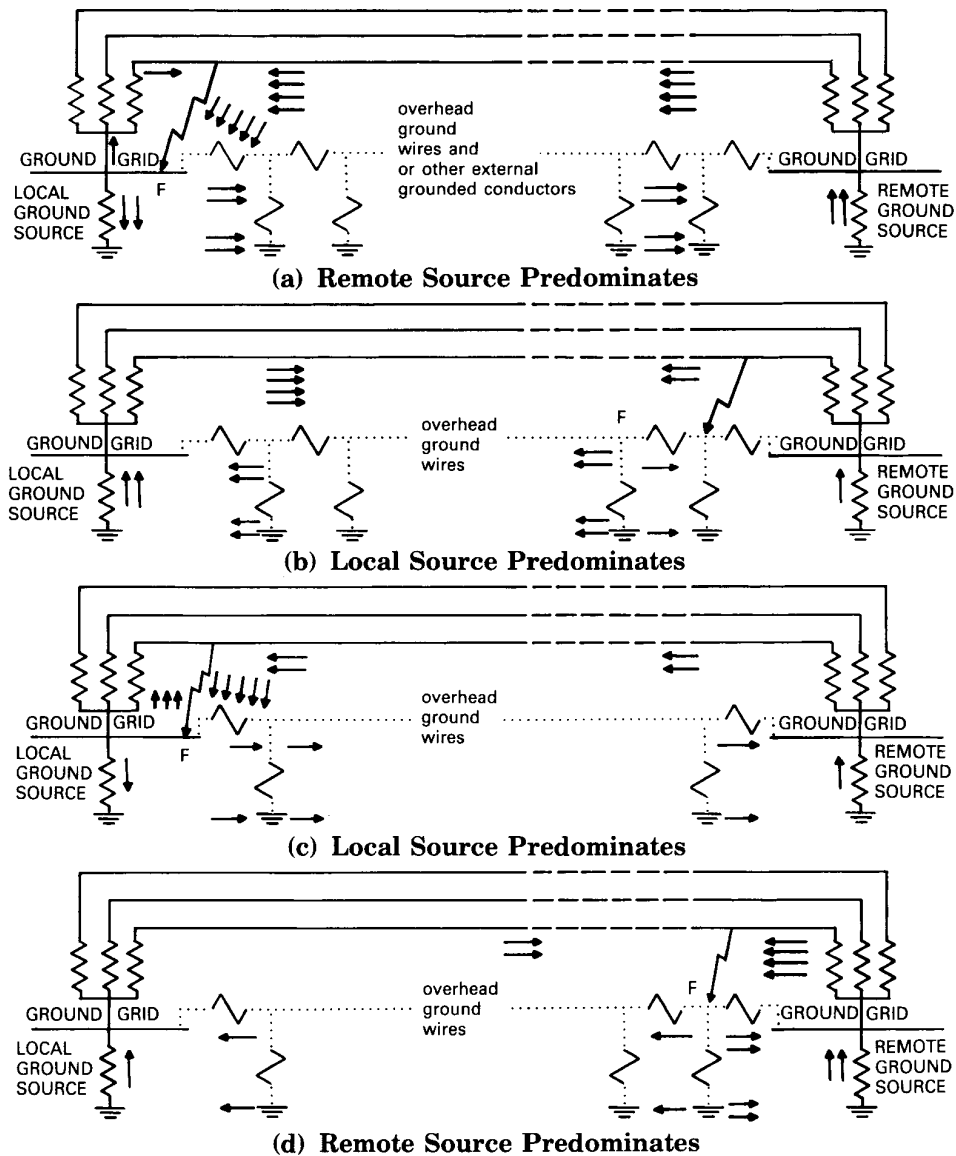
5.2.3 A study is made of various ground faults in order to determine that the one that produces the highest GPR and volt-second area (see 5.5.4). The station ground grid impedance as well as power overhead ground wire and telecommunication grounding networks tend to limit the fault current and should be included in the calculations.

5.2.4 In the study of 5.2.3, 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.

5.2.5 The initial magnitude of the dc offset should 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 dc offset then decreases to zero at a rate determined from the effective reactance-impedance ratio (X/R_{eff}) of the power circuit at the fault. With a highly inductive circuit the maximum dc offset will occur when the fault is initiated close to voltage zero, a condition that is most unlikely for faults resulting from insulation breakdown. Also, a highly inductive circuit will have a prolonged dc offset. For the application of a multiplication factor for dc offset, refer to Section 10.

5.2.6 There are four possible combinations of circumstances involving power faults that should be considered in determining the worst-case GPR at a power station. With reference to Fig 1, four different ground fault conditions causing GPR at the local power station (local ground source) will be described. For simplicity, a single-circuit three-phase power line with two ground sources is illustrated. A ground source at a power station is a component that can supply current to a fault and to which current returns by way of the earth and all available metallic conducting paths. Ground sources include wye-connected transformers with grounded neutrals, grounded autotransformers, and grounded generators.

(1) Figure 1(a) illustrates the situation involving a fault to the local ground grid where the remote source provides a greater amount of fault current than the local source (the remote source "predominates"). In this case, the current supplied by the local source simply circulates on the metallic grid (it does not flow into the earth), therefore not producing any GPR. However, the relatively large current from the remote source returns to that source by way of the earth



NOTES: (1) For simplicity, a single line with only two ground sources is illustrated.
 (2) Overhead ground wires can be insulated from the towers, resulting in different values.
 (3) F—fault location.

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

and all available metallic conductors, thereby producing a relatively large GPR at the local power station.

(2) Figure 1(b) illustrates the situation involving a line fault to remote earth (the fault location is outside the zone of influence of the local power station) where the local source provides a greater amount of fault current than the remote source (the local source "predominates"). In this case, the fault currents return to their respective sources by way of the earth and all available conductors. Since the local source supplies the high fault current, the GPR produced at the local power station will be relatively large.

(3) Figure 1(c) illustrates the situation involving a fault to the local ground grid where the local ground source provides a greater amount of fault current than the remote source (the local source "predominates"). The current supplied by the local source does not flow into the earth and does not produce any GPR. The relatively small current from the remote source returns to that source by way of the earth and all variable metallic conductors, thereby producing a relatively small GPR at the local station.

(4) Figure 1(d) illustrates the situation involving a line fault to remote earth where the remote source provides a greater amount of fault current than the local source (the remote source "predominates"). The fault currents return to their respective sources by way of the earth and all available conductors. However, since the local source provides a relatively small current, this GPR produced at the local power station will be relatively small.

NOTES: (1) In the above examples, the cases described in 5.2.6 (1) and 5.2.6 (2) resulted in the largest GPRs at the local power station. However, all four fault conditions must be evaluated to determine the worst-case GPR at the power station of interest.

(2) Figure 1 shows a typical system in which the externally grounded metallic conductors (including overhead ground wires) are indicated by dotted lines. Overhead ground wire systems are constructed in various configurations and may be either directly bonded to the transmission line towers or may be insulated from the towers. In addition, overhead ground wire systems may be directly connected to the station ground grid or may be terminated one or more spans out from the station. The externally grounded metallic conductors, including grounded wires, provide an alternate path for the fault current, reducing the earth return portion of the total fault current to as little as 40% or less of the total fault current.

(3) Power stations without ground sources (for example, switchyards with transformers having only delta connections) do not experience GPR from line faults occurring off the station grid when the power line overhead ground wire is not connected to the station ground grid. However, such stations do experience a GPR if a fault occurs directly to the grid, system connections on the other end permitting, for example, the transformer at the other end has a grounded winding.

5.2.7 Determination of the Worst-Fault Location. A complex power station may have a large number of rights-of-way (R-O-W) with multicircuit power lines on each R-O-W. These circuits may be operated at a different voltage levels.

A fault current study for a line-to-ground (L-G) fault at each transformer bus voltage level should be produced. Each fault current study should be examined as follows:

(1) If the vectorial sum of all zero-sequence fault current contributions to the bus fault from all transmission and distribution lines entering the station under study is greater than the sum of all current contributions from all grounded sources at that station (including generators, grounded transformers, shunt ca-

capitors, frequency changers, etc), then at the voltage level for which the fault current study is presently being examined, the bus fault will usually produce a worse GPR than the line fault.

(2) If the reverse is true, that is, the vectorial sum of the line contributions is smaller than the local ground source current sum, the line fault will produce a greater GPR. This is because the local ground current—which in the bus fault case merely circulates through the faulted transformer winding, the station ground bus, and the fault impedance (if included)—will, in the case of the line fault, return partially through the station ground impedance adding to the GPR caused previously by the line current contribution.

Having determined the worst-fault location (bus versus out on the line), to pick up that fault current study that shows the highest fault current is not appropriate. Variances between grounding networks of lines with the various voltage levels may, for instance, cause the study showing lower zero-sequence fault currents to result in a GPR greater than that caused by the higher currents. Instead, all faults should be investigated for fault locations as determined above.

5.2.8 Determination of the Worst-Fault Type. Basically, three types of faults should be investigated:

(1) *Line-to-Ground Faults (L-G).* These are predominant in terms of frequency of occurrence. Zero-sequence and positive-sequence currents will be required. In practice, GPR is a function of zero-sequence currents *only*, but positive-sequence currents are required to determine magnitudes of the individual zero-sequence currents flowing in each phase of the faulted circuit.

(2) *Three-Phase Faults.* Producing positive-sequence (balanced) currents discussed above in (1).

(3) *Double Line-to-Ground Faults (2L-G).* These are statistically less frequent than L-G faults but could produce zero-sequence currents far exceeding those produced by L-G faults. Theoretically this is because of different connections of sequence networks during these faults. For a L-G fault, the positive-, negative-, and zero-sequence networks are connected in series and driven by the prefault voltage source; whereas, for a 2L-G fault, positive-sequence impedance is connected in series with the parallel combination of zero- and negative-sequence impedances, with less overall impedance in the path of the fault current. (For instance, many high MVA autotransformers may be added to power stations. These could have their primary-to-secondary, or primary-to-tertiary, zero-sequence reactance ratios so high, that their primary current is small compared with the tertiary [ground] current. In addition to this, if more such transformers are added to the station, the resulting tertiary currents will be very large due to further paralleling of reactances.)

If X_1 and X_0 are positive- and zero-sequence reactances, respectively, of the system impedance at the point of fault and $X_1 < X_0$, the 2L-G fault will result in higher zero-sequence fault currents, often twice as high as the L-G fault currents calculated at the same fault location. An economical comparison should be made before protection of telecommunications facilities is designed. The GPR produced by 2L-G faults is not normally considered due to its low probability.

For an overview of the frequency of occurrence of different types of faults as

a function of voltage levels on which they occur and other parameters, see reference [9].

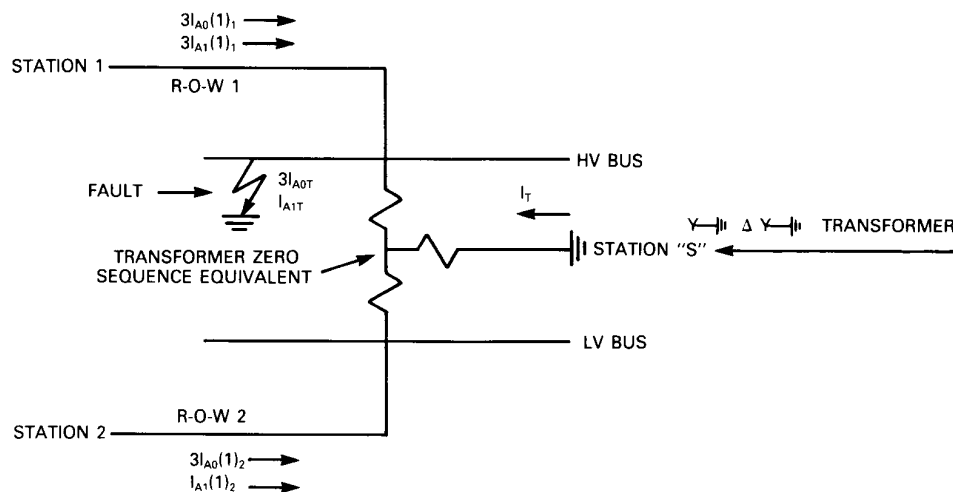
5.2.9 Notes on Modelling of Ladder Networks of Long and Short Lines.

As will become clear later, GPR work requires modelling of transmission and multigrounded distribution line grounding networks. This becomes important when determining the amount of fault current carried away from the fault by the line's grounding network, conductively, by first calculating its impedance to remote earth. This determines the amount of the GPR-causing current.

A modified transmission line theory can be used by modelling the ladder networks by the distributed parameter method. Care must be taken in correcting the classical hyperbolic transmission line equations due to the fact that the series (overhead ground wire self-impedance) and shunt (tower footing impedance) components of the overhead ground wire-tower ladder network are indeed very discrete components. This modification should enable one to transform these discrete components into a set of distributed ladder network parameters. This, however, can only be done with lines sufficiently long. If the line is short, one must resort to the nodal and mesh analysis which may require considerable computing time, particularly with large R-O-Ws with a multitude of lines and overhead ground wires. The presence of counterpoises and bonds can be extremely complicating, but should be considered.

5.2.10 HV Bus Fault GPR. By simulating the L-G and three-phase bus faults, power utilities can generally calculate resulting zero- and positive-sequence fault currents as shown in Fig 2,

Fig 2
L-G and Three-Phase Fault Simulation



where

- $3I_{A0}(J)_r$ = zero-sequence current in the J th circuit on the r th R-O-W
 $I_{A1}(J)_r$ = positive-sequence currents in the J th circuit on the r th R-O-W
 $3I_{A0T}$ = total zero-sequence fault current
 I_{A1T} = total positive-sequence fault current
 I_T = transformer neutral, generator, etc, current

and

$$\sum_r \left(\sum_J 3I_{A0}(J)_r \right) + I_T = 3I_{A0T} \quad (\text{Eq 1})$$

$$\sum_r \left(\sum_J 3I_{A1}(J)_r \right) = I_{A1T} \quad (\text{Eq 2})$$

NOTE: The fault currents shown in Fig 2 are the per circuit (as opposed to per phase) quantities; that is, all three-phase currents are concentrated in a single equivalent conductor and, in the case of zero-sequence currents, include the inductive effect of ground wires. To account for the conductive effects of the presence of overhead ground wires, station ground impedance, incidental ground path impedances, and phase wire zero-sequence impedances, the total zero-sequence current ($3I_{A0T}$) must be reduced accordingly. A new circuit, valid for electrically long lines, is formed as shown in Fig 3.

then

- V_p = prefault voltage
 Z_c = zero-sequence self-impedance of the phase conductor, between the source and fault locations
 Z_{SG} = station ground impedance
 $Z_{\infty T}$ = parallel combination of impedance of all ladder networks Z_L and the incidental impedances Z_i
 Z_{sy} = system impedance
 Z_a = fault impedance

The system impedance (Z_{sy}) is the impedance seen between the fault terminals, as determined by the power utility in fault calculations, and includes the zero-sequence impedances of lines, transformers, etc.

The new zero-sequence fault current ($3I_{A0N}$) resulting from Fig 3 includes the conductive effects of grounding. This new interfering current, however, must be further reduced by the amount it induces into the overhead ground wires of the tower (or pole) line that carries the faulted circuit. Because of the unequal spacings between the phase wires and neutrals and because each phase carries different currents both in amplitude and phase (faulted phase, generally, depending on the corresponding positive-sequence current, carries the current toward the fault location, whereas the remaining two unfaulted phases generally carry currents away from the fault location), unequal currents are induced in the overhead ground wires from each phase of the faulted circuit. Overhead ground wire currents induced from the faulted phase will act as a shield, but those induced from the unfaulted phases will subtract from the shielding current and act as an "antishield," as depicted in Fig 4.

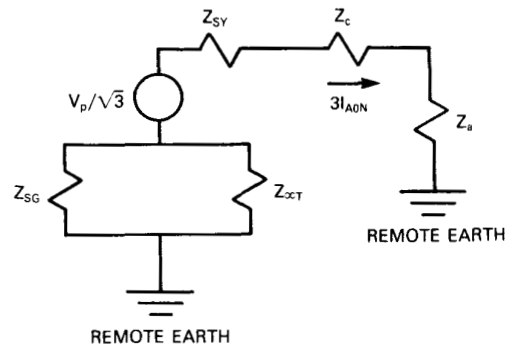


Fig 3
Circuit for Total Zero-Sequence Current ($3I_{A0T}$) Reduction

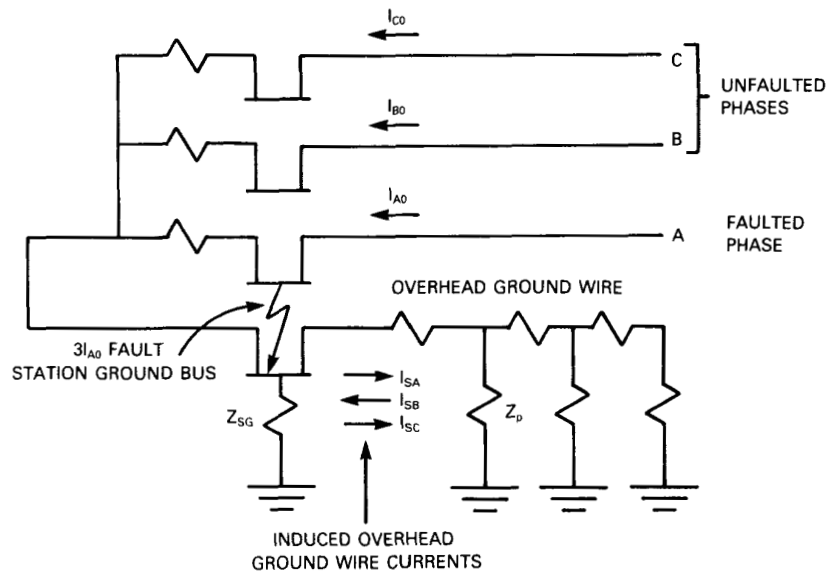


Fig 4
Power Line Shielding

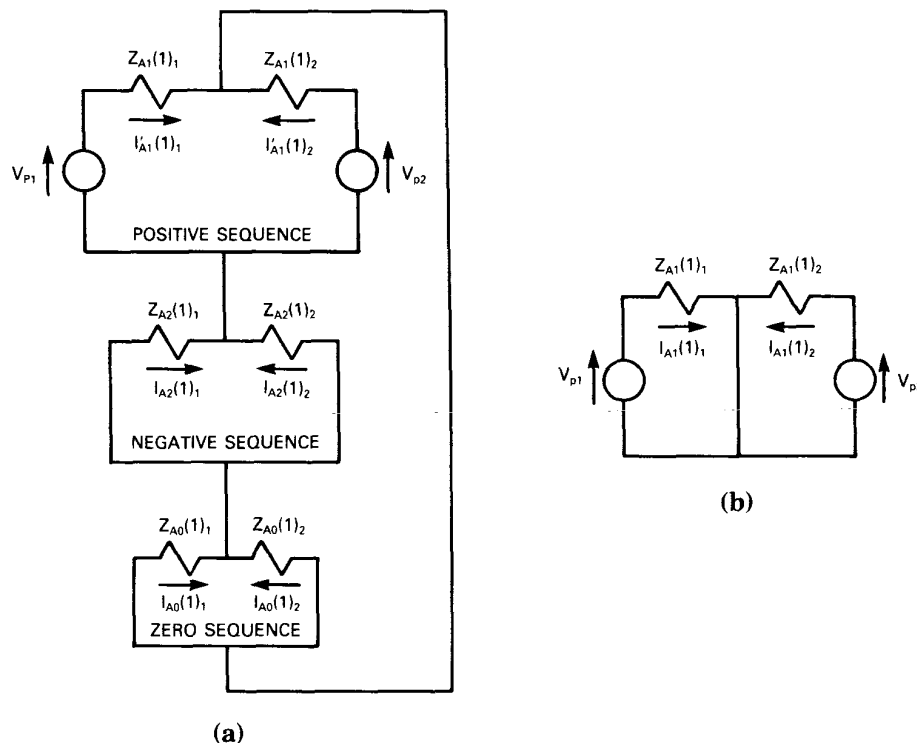
Similar shielding or antishielding will be produced by unfaulted circuits of the faulted tower line and unfaulted tower lines with their circuits on the same R-O-W, depending on their terminal connections in relation to the faulted circuits. Since the induced overhead ground wire current(s) does not enter ground but stays in the overhead ground wire, therefore causing no GPR, the determination of shielding or antishielding currents is important. Also, telecommunication cable sheaths and messenger strands may act as shields if strategically grounded.

Because of the foregoing conclusion, the per circuit fault quantities must be broken down into their respective per phase equivalents, and induction into the overhead ground wire(s) calculated separately from each phase.

Limiting the analysis to two single-circuit tower lines extending in two directions from station S (as in Fig 2) on two R-O-W's (1 and 2), the phase current will be determined as shown in Fig 5.

Positive-sequence currents in Fig 5(b) are coincidental with those in Fig 2, and their source is the three-phase fault study done by the power utility. The

Fig 5
Circuit for L-G and Three-Phase Fault Analysis



positive-sequence currents in Fig 5(a) have a superscript (') because these currents differ from those in Fig 5(b) since the voltage sources V_{p1} and V_{p2} drive two different circuits, 5(a) and 5(b).

Here

$$I_{A'1}(1)_1 = \frac{I_{A1}(1)_1}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} \quad (\text{Eq 3})$$

and

$$I_{A'1}(1)_2 = \frac{I_{A1}(1)_2}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} \quad (\text{Eq 4})$$

Then, assuming positive-sequence currents equal negative-sequence currents, the phase currents in circuit 1 on R-O-W 1 are:

$$I_A(1)_1 = I_{A0}(1)_1 + I_{A'1}(1)_1 + I_{A2}(1)_1 \quad (\text{Eq 5})$$

$$I_B(1)_1 = I_{A0}(1)_1 + a^2 I_{A'1}(1)_1 + a I_{A2}(1)_1 \quad (\text{Eq 6})$$

$$I_C(1)_1 = I_{A0}(1)_1 + a I_{A'1}(1)_1 + a^2 I_{A2}(1)_1 \quad (\text{Eq 7})$$

where a is the complex operator ($1/\sqrt{120^\circ}$), and

$$a + a = -1 \quad (\text{Eq 8})$$

Similarly, for the circuit on the R-O-W 2

$$I_A(1)_2 = I_{A0}(1)_2 + I_{A'1}(1)_2 + I_{A2}(1)_2 \quad (\text{Eq 9})$$

$$I_B(1)_2 = I_{A0}(1)_2 + a^2 I_{A'1}(1)_2 + a I_{A2}(1)_2 \quad (\text{Eq 10})$$

$$I_C(1)_2 = I_{A0}(1)_2 + a I_{A'1}(1)_2 + a^2 I_{A2}(1)_2 \quad (\text{Eq 11})$$

Substituting the expression for $I_{A'1}(1)_1$ and $I_{A'1}(1)_2$, currents in the faulted phases of both circuits are obtained:

$$I_A(1)_1 = \frac{2I_{A1}(1)_1}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} + \frac{3I_{A0}(1)_1}{3} \quad (\text{Eq 12})$$

$$I_A(1)_2 = \frac{2I_{A1}(1)_2}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} + \frac{3I_{A0}(1)_2}{3} \quad (\text{Eq 13})$$

Currents in the unfaulted phases are

$$I_B(1)_1 = I_C(1)_1 = \frac{3I_{A0}(1)_1}{3} - \frac{I_{A1}(1)_1}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} \quad (\text{Eq 14})$$

$$I_B(1)_2 = I_C(1)_2 = \frac{3I_{A0}(1)_2}{3} - \frac{I_{A1}(1)_2}{I_{A1T}} \cdot \frac{3I_{A0T}}{3} \quad (\text{Eq 15})$$

Next, mutual impedances between overhead ground wire(s) and each phase conductor on the faulted R-O-W should be obtained by the use of the simplified form of Carson's equation [7]:

$$Z_m = 0.00159f + j0.004657f \log_{10} \frac{2160 \sqrt{\frac{\rho}{f}}}{d_{ab}} \quad (\Omega/\text{mi}) \quad (\text{Eq 16})$$

where

f = frequency, in hertz

ρ = earth resistivity, in ohm-meters

d_{ab} = distance between each phase and overhead ground wire(s), in feet

NOTE: See 6.3.2 for additional information.

Self-impedance of each overhead ground wire is calculated as follows:

$$Z_s = r_c + 0.00159f + j0.004657f \log_{10} \frac{2160 \sqrt{\frac{\rho}{f}}}{\text{GMR}} \quad (\Omega/\text{mi}) \quad (\text{Eq 17})$$

where

r_c = conductor impedance, in ohms/mile

GMR = geometric mean radius of the conductor, in feet

The total zero-sequence current induced in each overhead ground wire (I_{sk}) is the sum of the products of each phase current and the coupling factor r ,

where

$$r = \frac{Z_m}{Z_s} \quad \begin{matrix} (Z_m = \Omega/\text{mi}) \\ (Z_s = \Omega/\text{mi}) \end{matrix} \quad (\text{Eq 18})$$

Conversely, for the current I_G flowing in the earth due to induction, the coupling factor $(1 - r)$ is

$$(1 - r) = 1 - \frac{Z_m}{Z_s} \quad (\text{Eq 19})$$

To assess the conductive effects, Z_∞ must be determined next. Z_∞ is defined as an impedance looking into an overhead ground wire-tower (or neutral pole) ladder network from the fault terminals. The determination of Z_∞ is complex and can be done by either discrete or distributed parameter methods. In the case of one electrically long line conforming to the inequality,

$$L \sqrt{Z_s Z_p} > 2 \quad (\text{Eq 20})$$

where

L = length of the line, in miles

Z_s = series impedance of the overhead ground wires, in ohms/span

Z_p = tower (pole) footing impedance, in ohms/span

then

$$Z_{\infty} = \frac{Z_s}{2} + \sqrt{\frac{Z_s^2}{4} + Z_s Z_p} \quad (\text{Eq 21})$$

In this example, two such ladder network impedances, $Z_{\infty 1}$ and $Z_{\infty 2}$, are paralleled to obtain $Z_{\infty T}$ as in Fig 3. In the final analysis, the following situation applies (Fig 6):

In Fig 6 it can be seen that for the fault on the HV bus (the situation is reversible) the transformer ground current I_T circulates through the faulted winding and the fault itself. For simplicity it can be assumed that it does not enter ground. The GPR causing zero-sequence current I_{GPR} is

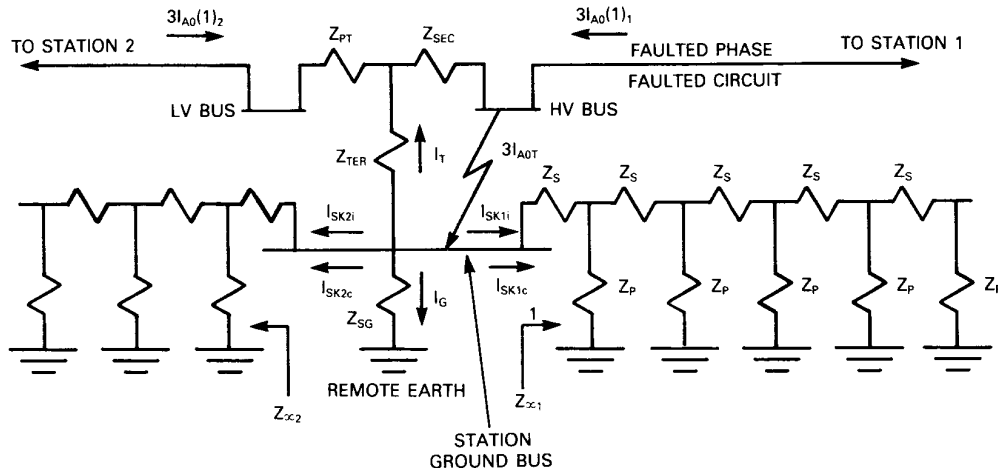
$$I_{GPR} = I_G + I_{SK1c} I_{SK2c} \quad (\text{Eq 22})$$

and also

$$I_{GPR} = 3I_{A0T} - (I_{SK1i} + I_T)$$

This current will enter the following impedance combination:

Fig 6
Complete Faulted Circuit



$$I_{SKi} = I_{SK1i} + I_{SK2i}$$

I_{SK1i} and I_{SK2i} = induced overhead ground wire fault currents (do not enter ground)

$$I_{SKc} = I_{SK1c} + I_{SK2c}$$

I_{SK1c} and I_{SK2c} = conducted overhead ground wire fault currents (do not enter grounding network)

$$3I_{A0T} = (I_{SK1i} + I_{SK1c}) + (I_{SK2i} + I_{SK2c}) + I_G + I_T$$

$$3I_{A0(1)_1} = I_{SK1i} + I_{SK1c}$$

$$3I_{A0(1)_2} = I_{SK2i} + I_{SK2c}$$

$$Z_{GPR} = Z_{SG} \parallel \left(\frac{Z_{x1} \cdot Z_{x2}}{Z_{x1} + Z_{x2}} \right) \quad (\text{Eq 23})$$

and the GPR is then

$$GPR = I_{GPR} \cdot Z_{GPR} \quad (\text{Eq 24})$$

5.2.11 Low Side Bus and Line Fault GPR. Theoretically, LV faults can be handled in precisely the same manner as the HV faults. All differences between HV and LV side construction (transformer connections, line conductors, length, pole footing impedance, etc) will reflect in the calculation of zero- and positive-sequence LV L-G and balanced fault currents. As opposed to HV systems, which usually carry overhead ground wires, some LV lines, delta or wye connected, carry no neutrals.

When neutrals are present on LV systems, LV bus fault calculations follow the same method described in 5.2.10 and LV line faults will be the same as HV line fault calculations, to be described later.

When neutrals are not present on LV system, both LV bus and line fault GPR can be calculated using simplified method shown in 5.2.10. For a LV bus fault, Z_L will consist of the parallel combination of impedances-to-remote earth of all HV overhead ground wire-tower ladder networks only. The rest of the method still applies.

For LV line faults, assuming a radial LV line, a single fault infeed can be assumed if no generation exists on the load side of the line. This assumption is correct for most cases but it should be pointed out that, for instance, a large induction motor can become a zero-sequence current generator at the instant of the fault, due to the inertia of the rotor and the mechanical load. If this can be neglected, though, the worst fault then occurs outside and near the station. The HV bus fault method is then modified by inserting, in series with Z_s , the self-impedance of the faulted phase conductor, and inserting a faulted pole footing impedance in series with Z_a in Fig 3.

The methods described above can be used for hand calculation and estimation purposes only.

For a more complicated network, that is, high number of rights-of-way, circuits, transformers, ground sources, and short lines such as could be found between generating and switching stations, hand calculations cannot be used for either exact or approximate solutions; a computer program must be used. In such a program, the theoretical approach should include the effect of other forms of grounding, such as rails, pipes, etc; the effect of the length of lines; the effect of positive-sequence current phase shift in certain transformer windings; etc. For the theoretical basis of such a program, see [7].

5.2.12 HV Line Fault GPR. The preceding theory is a simplified one. It can, however, be used with confidence to obtain results within some 10–30% of true figures, for estimating purposes.

The present topic is, by contrast, much more complicated not only by the complexity of the problem itself, but also by the vast amount of data input required. No hand calculation methods exist.

When a particular L-G HV bus fault current study indicates that the worst fault is the line fault, there is no easy way to determine the exact location of that fault. The only definite condition is that the fault will be at any one tower carrying circuit(s) connected to the bus at the same voltage level for which the aforementioned bus fault current study was produced. This necessitates placing a fault at *each* tower for *each* circuit of *each* tower line of *each* R-O-W carrying such circuit(s) and calculating the GPR at the station under study for each of these faults. Because of the tremendous multitude of line faults to be examined (for complex stations with a number of R-O-Ws and long lines, the number of faults to be examined may reach into the hundreds), to ask the utility's planning section for so many fault current studies would be impractical. A selective computer program calculating GPR for line faults at all voltage levels must contain its own short-circuit subprogram. *Both* positive- and zero-sequence short-circuit current study sets will be required.

The system to be analyzed is modelled as a network consisting of left and right voltage sources with impedances between them. The faulted R-O-W is the path followed by the faulted circuit. A fault is defined to occur at a transmission tower between a left source and a right source. Ground currents will then flow through the ground network made up of overhead ground wires, towers, counterpoises, and bond conductors. Because of inductive effects, all unfaulted circuits along the faulted R-O-W are also affected by the fault. The ground currents and the conductor currents are calculated using symmetrical components. This technique requires calculation or knowledge of the sequence impedances in the system under study. It is not, obviously, within the scope of this document to provide the basis for a computer program capable of doing this. See [7] for this information.

5.2.13 Example 1: HV Bus Fault and LV Bus and Line Fault

5.2.13.1 System Data. The station with $Z_{SG} = 0.5 \Omega$ shown in Fig 8 has three R-O-Ws entering it:

(1) R-O-W 1 carries a single circuit 230 kV transmission line with conductor configuration, as shown in Fig 7. The following data apply:

(a) Phase conductors: 1307.4 AS28/19

$$R + jX = 0.0797 + j0.3720 \Omega/\text{mi}$$

$$\text{diameter} = 1.34 \text{ in}$$

(b) Overhead ground wires: 7 AWG No8

$$R + jX = 2.354 + j.644 \Omega/\text{mi}$$

$$\text{diameter} = 0.385 \text{ in}$$

(c) Tower footing impedance: 80Ω

(d) Earth resistivity: $1000 \Omega \cdot \text{m}$

(e) Average span: 1014 ft

(f) Line length: 7 mi

(2) R-O-W 2 data is the same as for R-O-W 1. Line length: 5 mi

(3) R-O-W 3 carries a three-phase 44 kV delta-connected circuit. In Figs 8 and 9, two fault current studies—one for the 230 kV and the other for the 44 kV bus—fault currents are shown. Both L-G and symmetrical fault currents were calculated. The future fault condition is assumed.

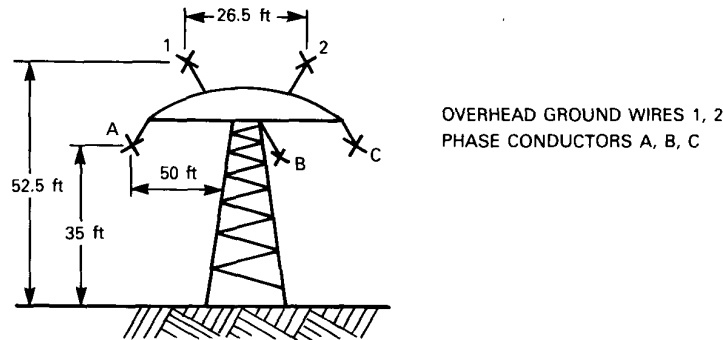


Fig 7
R-O-W 1 Conductor Configuration

5.2.13.2 Worst-Fault Location Determination. In Fig 8(a) (230 kV bus fault L-G study) note that in comparing the sum of all transmission and distribution line zero-sequence fault currents ($I = 995.7 - j4967.7$ A), and the sum of all local ground currents ($I = -15.6 - j2076.4$ A), the line current contribution is higher. This indicates that for GPR purposes, the bus fault is the worst case. In Figure 10(a) (44 kV bus L-G fault), all zero-sequence fault currents will originate from the local source, that is, the line fault will be the worst case.

5.2.13.3 Worst-Fault Type. From Figs 8(a) and 8(b), zero-sequence system reactance as seen from the fault terminal is $X_0 = 0.03348$ pu (per unit), and the similar positive-sequence reactance is $X_1 = 0.04057$ pu.

A 2L-G fault will therefore produce higher zero-sequence fault currents than a L-G fault. However, as mentioned earlier, a 2L-G fault seldom evolves and so, for the purpose of this example, a L-G fault will be studied.

5.2.13.4 GPR Calculations

5.2.13.4.1 230 kV Bus Fault

(1) *R-O-W 1.* From Fig 8(a), the zero-sequence fault current contribution is:

$$3I_{A0(1)} = 413.8 - j1851.5 \text{ A}$$

Total zero-sequence fault current is:

$$3I_{A0T} = 980 - j7044 \text{ A}$$

Positive-sequence fault current contribution is:

$$I_{A1(1)} = 1.694 - j9.802 \text{ pu based on prefault voltage of } 1.04545$$

$$+ j0 \text{ (base kV} = 220.00 \text{ kV)}$$

Total positive-sequence fault current is:

$$I_{A1T} = 2.87 - j25.44 \text{ pu}$$

Mutual impedances between each phase conductor and overhead ground wire 1 are:

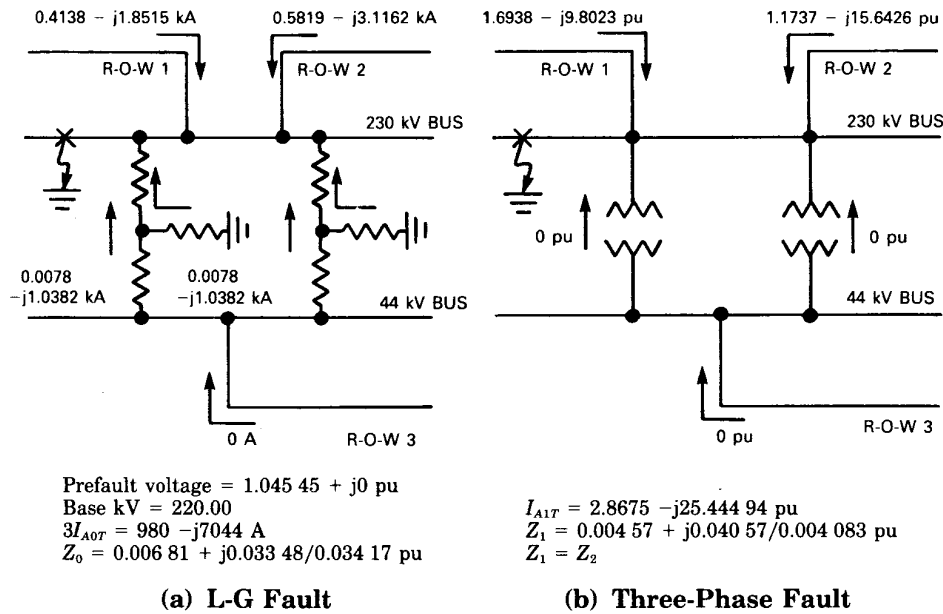


Fig 8
230 kV Bus Fault

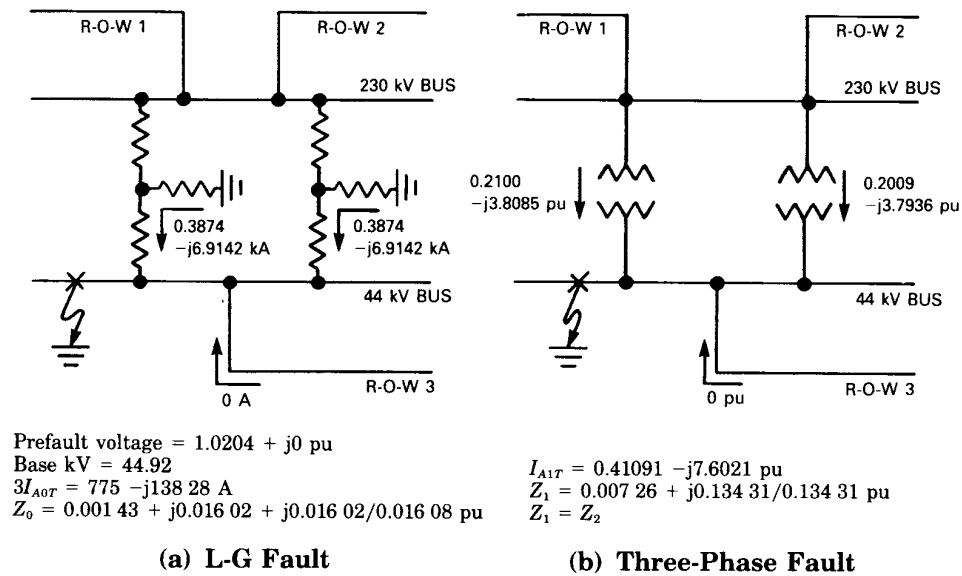


Fig 9
44 kV Bus Fault

Conductor A: $0.0939 + j0.706 \Omega/\text{mi}$

Conductor A: $0.0941 + j0.741 \Omega/\text{mi}$

Conductor C: $0.0941 + j0.736 \Omega/\text{mi}$

Because of symmetry, the same mutual impedances apply to overhead ground wire 2.

Self-impedances of overhead ground wires 1 and 2 are:

Overhead ground wire 1: $2.448 + j1.748 \Omega/\text{mi}$

Overhead ground wire 2: $2.448 + j1.748 \Omega/\text{mi}$

Phase conductor currents (Eqs 5–7 and 12):

$I_A(1)_1 = 13.060 + j287.362 \text{ A}$ —unfaulted phase

$I_B(1)_1 = 13.060 + j287.362 \text{ A}$ —unfaulted phase

$I_C(1)_1 = 387.681 - j2426.224 \text{ A}$ —faulted phase

An intelligent choice of the faulted phase must be made to obtain the worst condition.

Generally, the phase farthest from the overhead ground wire (or neutral) should be faulted. This implies a lower mutual impedance between the phase and neutral, causing lower shielding current in the neutral forcing more current into the ground. Since phase C is faulted, zero-sequence fault current, $I_C(1)_1$, flows in it toward this fault. Currents in the two unfaulted phases A and B are smaller and generally flow in the direction opposite to that of the faulted phase, that is, away from the fault, providing a shielding action and ultimately reducing the GPR. However, in some cases the reverse may be true, thereby producing antishielding. The induced overhead ground wire currents are calculated as Eq 18:

$I_{SK}(1)_1 = -224.57 + j222.288 \text{ A}$

$I_{SK}(2)_1 = -336.383 + j248.635 \text{ A}$

Since the induced overhead ground wire current flows in the direction opposite to that of the faulted phase, it provides shielding action as well. The ratio of overhead ground wire to line current (shielding factor) is calculated as $(-0.030904 - j0.024471)$.

Inequality (Eq 20) shows that the line becomes electrically infinite after the 31st span. Therefore, Eq 21 can be used and will result in a overhead ground wire-tower ladder network impedance of $Z_x(1) = 4.9536 + j2.0716 \Omega$.

(2) R-O-W 2. Similar to R-O-W 1 calculations:

$3I_{A0}(1)_2 = 581.9 - j3116.2 \text{ A}$

$I_{A1}(1)_2 = 1.774 - j15.64 \text{ pu}$

Mutual impedances between each phase conductor and overhead ground wires 1 and 2 are the same for R-O-W 1. The same is true for the $Z_{\infty}(2)$. Phase conductor currents are calculated as:

$$I_A(1)_2 = -7.919 + j404.735 \text{ A}$$

$$I_B(1)_2 = -7.919 + j404.735 \text{ A}$$

$$I_C(1)_2 = 597.737 - j3925.671 \text{ A}$$

The induced overhead ground wire currents are:

$$I_{SK}(1)_2 = -398.117 + j390.386 \text{ A}$$

$$I_{SK}(1)_2 = -544.745 + j432.182 \text{ A}$$

The ratio of overhead ground wire to line current is $(-0.309\ 67 - j0.244\ 74)$ and the number of spans required for the electrically infinite overhead ground wire-tower ladder network is 31. The residual fault current I_{GPR} (Eq 22) can be shown to be $I_{GPR} = -528.12 - j3674.21 \text{ A}$ and GPR (Eq 24) will be 1580.88 V where $Z_{GPR} = 0.43 + j0.03 \ \Omega$ calculated with $Z_{SG} = 0.5 \ \Omega$.

5.2.13.4.2 44 kV Bus Fault. All of the 44 kV bus fault, $3I_{A0T}$, is generated locally, resulting in a negligible GPR.

5.2.13.4.3 44 kV Line Fault. Because the R-O-W 3 carries a 3 wire (no neutral) circuit, the circuit of Fig 10 can be used to calculate the 44 kV line fault as follows:

- (1) Prefault Voltage $V_p = 46\ 000 \text{ V}$

NOTE: The prefault voltage is higher than the operating voltage of 44 kV because the neutral voltage undergoes a shift during the initiation of the fault.

- (2) 44 kV line zero-sequence current contribution [Fig 10(a)] is $3I_{A0}(1)_3 = 0 \text{ A}$.

The low side (LS) transformer contribution is $I_T = 855 - j16\ 911 \text{ A}$; the total low side fault current is $3I_{A0T} = 855 - j16\ 911 \text{ A}$; and the 230 kV zero-sequence current contribution is $I_N = 0 \text{ A}$. The system impedance at the faulted 44 kV (bus) terminal is $Z_S = 0.11 + j1.91 \ \Omega$. The calculated LS line fault GPR is 5620.64 V. As a matter of interest, the fault impedance, Z_a (Fig 3), of $5 \ \Omega$ will reduce the GPR to 1929.2 V and illustrates the need to include the appropriate value of the fault impedance in some cases.

5.2.14 Example 2: HV Line Fault

5.2.14.1 System Data. The generating station (Fig 10) has three voltage levels:

- (1) R-O-W 1 has a tower-line carrying a single 230 kV circuit with 795.0 ACSR 26/7 conductors and two 3/8 steel overhead ground wires. The tower-footing impedance is $79.57 \ \Omega$ and the average span is 924 ft. Earth resistivity, assumed uniform, is $1000 \ \Omega \cdot \text{m}$.

- (2) R-O-W 2 has a tower-line carrying four 230 kV circuits with 795.0 ACSR 26/7 conductors and four 3/8 steel overhead ground wires. The average span and the earth resistivity are the same as in R-O-W 1.

- (3) The 44 kV bus is connected to the 230 kV bus by means of a $\Delta = Y_{\text{ground}}$ connected transformer. A 3-wire (no neutral) 44 kV circuit is on R-O-W 3.

(4) 13.8 kV is the generation voltage level.

5.2.14.2 Worst-Fault Location Determination

(1) *230 kV Fault.* Fig 10(a), the vectorial sum of all transmission and distribution line contributions for the 230 kV bus fault is I_L .

$$I_L = \sum_r \sum_J (3I_{A0}(J)r) = 3I_{A0T} = 356.9 - j1133.3 \text{ A}$$

Local ground sources contribute

$$I_T = 591.1 - j7580.7 \text{ A}$$

Because $I_T > I_L$, the greatest GPR will be caused by a fault occurring along one of the four HV lines. The 230 kV bus fault will produce less GPR than the line fault.

(2) *44 kV Fault.* As seen in Fig 10(a), the station 230/44 kV transformer has a delta-connected secondary. Assuming a delta-connected primary at the station to which the 44 kV line is connected (at the other end), zero-sequence fault currents are negligible. The only impedance-to-ground is due to capacitive coupling, that is, line charging currents will flow, which implies that both 44 kV bus and line faults will produce an insignificant GPR at the station under study.

(3) *13.8 kV Fault.* Essentially all the 13.8 kV fault current generated circulates locally; therefore, no appreciable GPR will be developed due to the L-G fault at the generator terminals.

5.2.14.3 Worst-Fault Type. From Fig 10(a) and 10(b), for the 230 kV faults, the positive-sequence system reactance as seen from the fault terminals is $X_1 = 0.03408 \text{ pu}$ and zero-sequence reactance is $X_0 = 0.02518$.

Because $X_1 > X_0$, a double line-to-ground fault will cause a higher zero-sequence fault current resulting in a greater GPR than a single L-G fault. However, we will limit ourselves to a single L-G fault in this example.

5.2.14.4 GPR Calculations. As mentioned earlier this calculation is complex and will not be shown here.

A sample of a computer program output is shown in Fig 11.

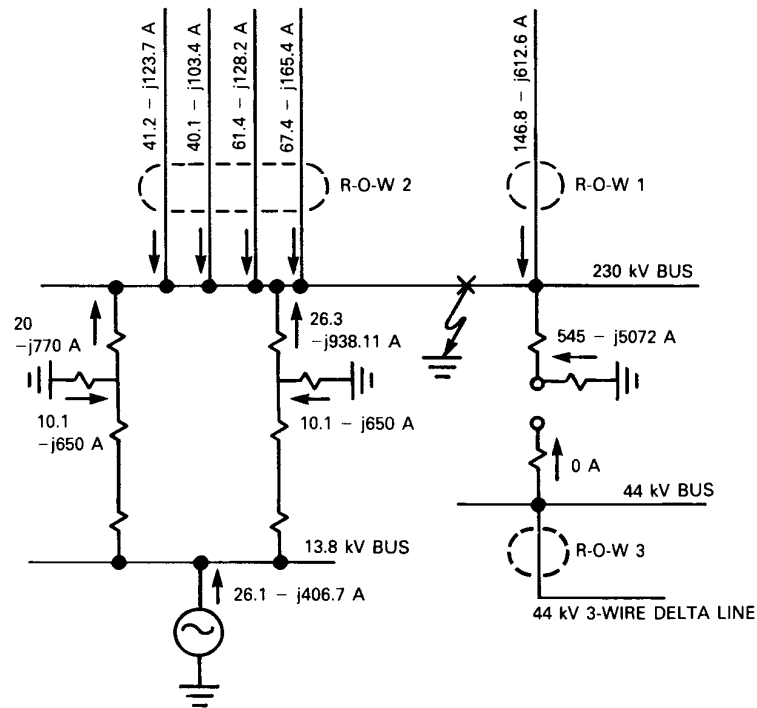
Left station GPR versus tower number, as counted from the left station, is shown in Fig 12 and is seen peaking for the fault occurring on the thirtieth tower out of the left station, at 2216.965 V.

5.3 Duration of the Fault and its Relationship to Wire-Line Telecommunication Requirements for Power System Protection.

5.3.1 The duration of the fault currents and resulting interfering voltages depends upon the power system protective relay scheme and its equipment as well as the power system layout and equipment. The relaying schemes often employ wire-line telecommunication facilities.

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

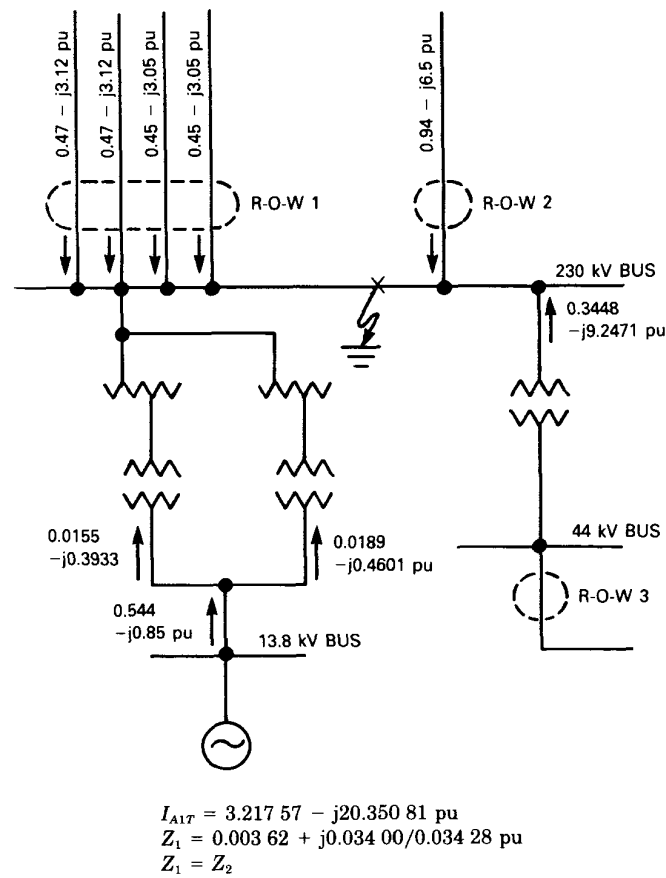
- (1) Lightning surges that are cleared by arresters on the power circuits in less than half a cycle require no circuit breakers to open and no fuses to melt. When rapid clearing takes place no power system telecommunication is necessary to clear this fault.



prefault voltage = $1.04545 + j0$ pu
base • kV = 220.00
 $3I_{A0T} = 948 - j8714$ A
 $Z_0 = 0.00295 + j0.02518/0.02555$ pu

(a) L-G Fault

Fig 10
230 kV Bus Fault



(b) Three-Phase Fault

Fig 10 (continued)

From Left Station	Left Station Ground Resistance	Right Station Ground Resistance	Ground Current from Left Station	Ground Current from Right Station	Skywire Current from Left	Skywire Current from Right	Faulted Tower Current from Left	Faulted Tower Current from Right
Tower	L Res	R Res	L Ig	R Ig	Max L Iskwire	Max R Iskwire	IT1	IT2
1	1.000	1.000	1057.450	435.603	3355.020	391.797	69.018	.000
1	0.500	0.500	1230.460	506.631	3392.419	356.077	63.996	.000
2	1.000	1.000	667.482	443.967	3095.051	591.347	109.798	.000
2	0.500	0.500	776.396	516.409	3100.512	566.984	106.911	.000
5	1.000	1.000	426.452	468.129	2510.236	380.940	190.726	.000
5	0.500	0.500	496.037	544.514	2505.393	985.201	191.699	.000
8	1.000	1.000	1050.195	491.035	2166.461	1135.743	232.181	.000
8	0.500	0.500	1221.556	571.159	2154.902	1196.713	234.482	.000
12	1.000	1.000	1617.079	519.809	1901.428	1300.497	255.396	.000
12	0.500	0.500	1890.932	604.719	1999.775	1912.195	257.842	.000
15	1.000	1.000	1882.202	540.435	1779.510	1325.923	260.495	.000
15	0.500	0.500	2189.322	628.618	1769.961	1335.929	262.598	.000
16	1.000	1.000	1947.792	547.099	1747.486	1327.927	260.978	.000
16	0.500	0.500	2265.602	636.369	1738.723	1337.254	262.841	.000
17	1.000	1.000	2003.913	553.674	1719.599	1327.717	260.903	.000
17	0.500	0.500	2330.892	664.020	1710.607	1336.331	262.623	.000
18	1.000	1.000	2051.594	560.172	1692.302	1325.706	260.361	.000
18	0.500	0.500	2306.354	651.575	1685.076	1333.620	262.038	.000
19	1.000	1.000	2091.729	566.599	1669.200	1322.265	259.625	.000
19	0.500	0.500	2453.036	659.039	1661.694	1329.450	261.162	.000
20	1.000	1.000	2125.121	572.929	1645.937	1317.691	259.656	.000
20	0.500	0.500	2471.879	666.414	1640.106	1924.270	260.059	.000
25	1.000	1.000	2214.006	603.607	1553.872	1294.921	251.747	.000
25	0.500	0.500	2575.266	702.099	1550.695	1239.795	252.599	.000
30	1.000	1.000	2216.965	632.829	1481.320	1246.225	242.571	.000
30	0.500	0.500	2579.709	736.098	1479.725	1249.349	244.045	.000
40	1.000	1.000	2106.869	689.022	1366.106	1172.829	227.924	.000
40	0.500	0.500	2450.647	800.297	1365.807	1173.363	228.056	.000
50	1.000	1.000	1949.651	740.318	1275.204	1111.865	214.742	.000
50	0.500	0.500	2267.777	861.117	1275.202	1111.958	214.771	.000

Fig 11
A Sample Computer Program Output

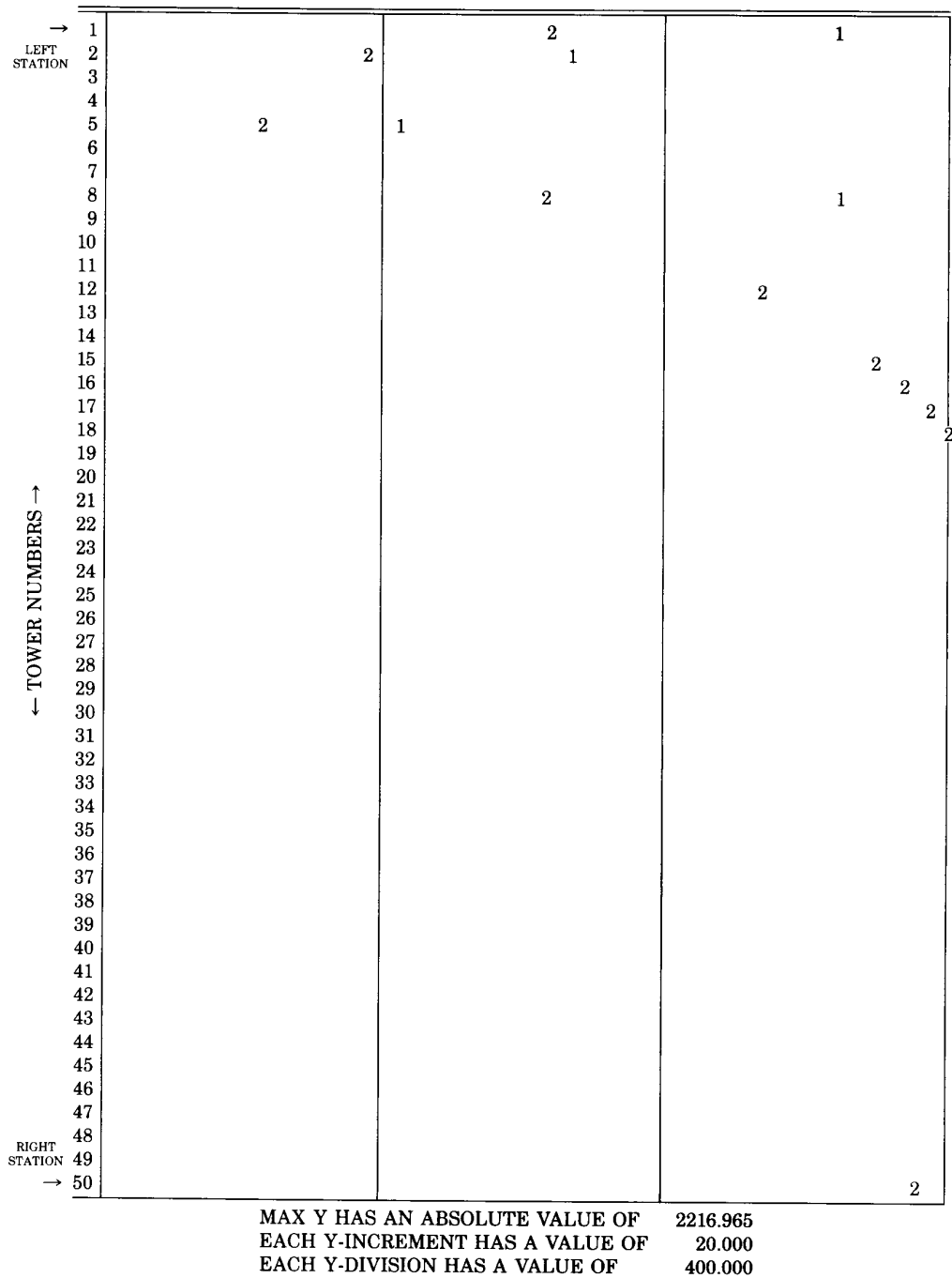


Fig 12
Left Station Potential Versus Tower Numbers