

PACIFIC POWER & LIGHT COMPANY
INTERNAL CORRESPONDENCE

SUBJECT:

Portland, Oregon
November 21, 1978TO: R. C. Birkes - 800
L. M. Stinson - 800
J. L. Mitseff - 800

SUBJECT: Fifth Annual Western Protective Relay Conference

The WSU Protective Relay Conference was held this year in Sacramento. I represented, singularly, Pacific Power in the general meetings and in the first planning session for next year's conference. Sacramento was selected this year to emphasize that this was a "Western" not a "Northwest" conference. Little additional attendance appeared from the Southern area over that received when the meeting was held in Spokane, so the consensus is that the meeting will remain permanently in Spokane. I would like to see Pacific show a little more financial support of our regional meetings (send more people) if possible. I find that in our work there is a return in motivation as well as in the area of knowledge when one can communicate with other engineers of similar work specialty.

The papers presented this year can be grouped in six categories as follows:

1. SYSTEM CONTROL AND DESIGNSix Phase Fault Computations and Relaying Methods

- Lyle L. Gleason
Seattle City Light (retired), Seattle, WA
- F. Robert Bergseth
University of Washington, Seattle, WA

Pacific Northwest Stability Controls for Light Load - Heavy Import Conditions

- Carson Taylor
Bonneville Power Administration, Portland, OR

These two papers are both of direct interest. The first describes stability limits and relay and control additions to live with potential instabilities at times of large system power transfers. The second paper describes an extremely innovative design development for increasing voltage (and power) rating for a dual-circuit single-tower configuration.

2. TRANSMISSION PROTECTION - EHVMICA 500 kV Protection - A Segregated Phase Comparison System with Special Features for High Tower Footing Resistance

- Maurice J. Lefrancois
B. C. Hydro & Power Authority, Vancouver, BC, Canada

The Development and Operation of an Ultra High Speed Relaying System for EHV Transmission Lines

- Jules Estergalyos
Bonneville Power Administration, Portland, OR

Ultra High Speed Transmission Relay

- L. Matele, Vasteras, Sweden
- John Linders, Strongsville, OH
ASEA, Inc.

The MICA project paper is the result of a Canadian-Westinghouse proposal for a project very similar to Pacific's Midpoint-Malin 500 line which included single-pole relaying. Apparently, a more sophisticated and complete offering was presented by the Canadian-Westinghouse firm than that offered Pacific by the Newark team.

The ultra-high speed development by ASEA for BPA was presented and is a significant development in the speed area. I dislike (fear!) indiscriminate application of relatively insecure (but fast) relaying systems so as to make relatively small incremental increases in intertie schedules. I think industry guidelines need be set before regional or national ones are dictated.

3. UTILITY MANAGEMENT

Corporate Economic Modeling Encourages Relay Standardization

- C. P. Dalpiaz & D. T. Norman
Utah Power & Light Co., Salt Lake City, UT

Utah Power & Light again seems to be out front in innovation, first with their model line, then development of state-of-the-art computerized dispatch, now in the extent their financial model has been extrapolated within the company. The result has been not only altered work methods but also a complete new set of standard designs for substation meter and relay control panels. Standardization to the last washer is accomplished through design, specification, and purchase via two manufacturers.

4. TRANSMISSION RELAYS - GENERAL

Logic Concepts - New Transmission Line Relaying System

- W. A. Elmore
Westinghouse Electric Corp., Newark, NJ

Breaker Failure Relaying

- W. A. Elmore & H. J. Li
Westinghouse Electric Corp., Newark, NJ

New Concepts in Ground Relaying for Transmission Lines

- L. E. Goff, W. C. New, J. B. Williams
General Electric Co., Philadelphia, PA

Transient Response of Distance Relays

- C. A. Mathews
General Electric Co., Philadelphia, PA

R. C. Birkes
L. M. Stinson
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- 4 -

November 21, 1978

LOON LAKE TOUR

Loon Lake Power Plant

The Loon Lake MVA Power Plant is built 1000 feet underground. It is approximately 85 miles east of Sacramento with a reference point 15 miles west of Lake Tahoe.

The Loon Lake tour was very interesting and worth seeing mostly as it is uniquely a totally buried facility (almost).

D. E. Franzel
D. E. Franzel

DEF/1h

Dave Franzen

STABILITY CONTROLS
FOR
PACIFIC NORTHWEST HEAVY IMPORT CONDITIONS

Carson W. Taylor
Bonneville Power Administration
Portland, Oregon

Abstract - New transient instability patterns have evolved within the Pacific Northwest and the western North American interconnection. Increased use of hydro generation for peaking and development of base loaded coal-fired generation in the Rocky Mountain states contribute to reduced stability levels throughout the western interconnection during light load conditions.

New transient stability controls discussed include direct tripping of 2800 MW of aluminum reduction plant load, HVDC fast power changes, and generator dropping. Revisions to the Pacific Northwest underfrequency load shedding program are described. The importance of various protective relays in the transient stability of large power systems is emphasized.

Presented at Washington State University's Fifth Annual Western Protective Relay Conference, Sacramento, California, October 16-18, 1978.

INTRODUCTION

Since the Pacific 500 kV AC Intertie was energized in the late 1960's, stability of this Intertie has been of principal concern to the western interconnection. Until recently, the Pacific Northwest was primarily an exporting region and transient stability enhancement measures such as a 1400 MW dynamic brake¹, 1-cycle circuit breakers², and ultra-high-speed relays^{3,4} were developed to allow heavy north to south AC Intertie power schedules.

Following AC Intertie instability, several control measures have been used to prevent further breakups in parallel, but weaker, transmission paths from the Pacific Northwest to the Pacific Southwest through the Rocky Mountain States. These measures include hydro generator dropping in the Northwest and controlled separations. Controlled separations of Arizona and the Pacific Southwest from Utah and Colorado is by a transfer trip signal based on AC Intertie opening or by a local rate of power change relay. Separation of Utah from Idaho and Wyoming is by an out-of-step relay.

Due to several factors, new Pacific Northwest (and western interconnection) stability problems are more complicated and of a different nature. Development of coal-fired generation in the Rocky Mountain States with low stability levels to Pacific Northwest and Pacific Southwest load centers have recently contributed to several widespread system breakups. The low stability levels are due to inadequate transmission capabilities caused by economic and environmental pressures on utilities and reduced series capacitor compensation due to subsynchronous resonance considerations.

Another factor which changes the nature of stability problems is the increasing tendency to use hydro and oil-fired generation for peaking. During light load conditions, heavy imports to the Northwest from the Southwest, the Rocky Mountain States, and British Columbia are likely. The reduced rotating inertia and the reduced generator voltage support in the Lower Columbia area (northern end of AC Intertie) and Middle Snake area (eastern end of Idaho-Northwest interconnections) due to the light loads reduce stability levels. These conditions first became apparent in 1977 as a result of drought related adverse hydro conditions. However, the heavy import, light load critical conditions are likely during the late summer and fall in future years.

Figure 1 shows a simplified interchange diagram for the western interchange. Most of the interconnections shown have relatively low transient stability levels and the Montana, Idaho, and Wyoming areas are vulnerable to internal breakups. Note that, although California may be exporting around 2000 MW to the Northwest, they can be net importers.

SCENARIOS FOR ISLANDING OF THE PACIFIC NORTHWEST POWER SYSTEM

Transient stability simulations together with recent operating experience have revealed probable scenarios for islanding of the Northwest as a region during heavy import, light load conditions. Various contingencies of fairly high probability can result in instability of eastern (Rocky Mountain states) interconnections and the AC Intertie. Instability of heavily loaded remote hydro generation in British Columbia is possible following islanding of the Northwest together with British Columbia.

Initiating events which could lead to Northwest islanding include loss of a large generating plant (over about 800 MW) in the Northwest or British Columbia, loss of the Pacific AC or HVDC Intertie, or opening of key transmission lines in the Rocky Mountain states. The interconnections between the Northwest and eastern systems are often loaded close to steady-state stability limits and stability levels are generally lower on these lines than on the AC Intertie.

Islanding of the Northwest would result in a large-generation load unbalance with reduced rotating inertia due to the heavy import, light load conditions. System frequency decay rate would therefore be quite high. High speed underfrequency load shedding would be required to prevent underfrequency tripping of thermal generating plants. The Centralia plant trips instantaneously at 57.8 Hz, while the Trojan plants trips instantaneously at 57.7 Hz and at 58.0 Hz with 1.2 second delay.

The ultimate result of islanding with the inadequate load shedding presently installed could be a regional blackout. Following islanding, abnormal voltages exist and, considering the voltage sensitivity of loads, analysis shows an alternative outcome might be sustained operation at low voltage, high current, and near normal frequency. A potential for considerable equipment damage exists.

As an example of the above scenarios, frequency deviation for simulated loss of 1100 MW at the Trojan Nuclear Plant is shown on Figure 2. Northwest stability with Montana, Idaho, and the Southwest is lost at 120, 170, and 220 cycles, respectively. This results in a Northwest generation deficit of about 3500 MW. Following islanding, 2500 MW of aluminum plant load is tripped by the AC Intertie load tripping control described below. An additional 800 MW of existing high speed load shedding occurs between 260 and 240 cycles. At about 284 cycles, the G. M. Shrum hydro plant (2200 MW) loses stability. At 377 cycles, the Centralia steam plant (1200 MW) is tripped by underfrequency relay set at 57.8 Hz. Induction disc underfrequency relays with sensitive settings would begin to operate after 360 cycles but were not represented in the simulations.

CONTROL MEASURES TO PREVENT TRANSIENT INSTABILITY

Several control measures have either been implemented or have been proposed for transient stability enhancement during Northwest heavy import conditions. These include revision of underfrequency load shedding, aluminum plant load tripping prior to underfrequency conditions, HVDC fast power changes, and generator dropping in systems that are accelerating.

Underfrequency Load Shedding

Load shedding is not a stability control but is a mitigation effort following instability resulting in islanding. Until recently the Northwest has not experienced underfrequency conditions requiring load shedding. In the fall of 1977, coincident with drought related heavy imports, it was realized that the Northwest Power Pool (NWPP) load shedding program was inadequate. The widely used induction disc underfrequency relays were too slow to coordinate with the thermal plant underfrequency relays for the high frequency decay rates expected.

The NWPP load shedding program is currently being revised with widespread replacement of the slow relays with high speed underfrequency relays. The planned load shedding schedule will shed up to 60 percent of total load uniformly between about 58.7 Hz and 59.3 Hz. Either 0.1 Hz or 0.2 Hz intervals between load shedding steps will be used.

Direct Load Tripping

Since fairly high probability contingencies can lead to islanding of the Northwest, it is desirable (within cost constraints) to employ stability enhancement control measures to avoid abnormal frequency conditions. This is particularly important prior to completion of load shedding program revisions.

Last fall, BPA implemented controls for high speed tripping of up to 2800 MW of aluminum reduction plant load immediately following opening of the AC Intertie with south to north power flow. This prevents rapid deceleration of Northwest generation and instability of eastern interconnections leading to islanding.

Further analysis indicated a number of other contingencies for which load tripping is necessary to avoid islanding. The load tripping is now being extended to cover the following events.

1. Loss of the Trojan nuclear plant.
2. Loss of over 800 MW of generation in British Columbia. This loss is detected by a sudden real power change on the two Custer-Ingledow 500 kV lines (BPA-BC Hydro interchange point) along with sudden real power changes at the G. M. Shrum or Mica hydro plants.

3. Loss of the HVDC intertie loaded above about 800 MW.
4. A breakup in the Rocky Mountain states resulting in loss of imports to the Northwest. This is detected by an out-of-step relay at Hot Springs Substation and is armed when the AC Intertie is loaded above about 1200 MW south to north. This relay will provide some backup to maintain AC Intertie stability for failure of the three above load tripping controls.

Figure 3 shows voltage rises accompanying islanding and aluminum plant load tripping for the loss of Trojan simulation described above. Because of the voltage sensitivity of remaining loads, these voltage rises reduce the effectiveness of direct load tripping or underfrequency load shedding. Assume, for example, constant current loads (load increase proportion to first power of voltage increase). Then with 10,000 MW of remaining load, a 10 percent voltage increase would result in an 1000 MW load increase. If 2000 MW of load was tripped, the effective value would initially be only 1000 MW. In some cases the voltages immediately following the direct load tripping can be as high as 1.3 pu. Voltage regulators reduce overvoltages within about half a second.

HVDC Fast Power Change

For opening of the parallel Pacific AC Intertie, a fast power change capability of about 700 MW on the Pacific HVDC Intertie is planned. When HVDC power schedules allow the 700 MW of unused capacity, this capability will reduce the amount of load tripping following AC Intertie opening.

Generator Dropping

Aluminum plant load tripping is effective in preventing AC Intertie instability but less effective in stabilizing interconnections with the Rocky Mountain states (eastern systems). Since the eastern systems are exporting to the Northwest with generators accelerating during disturbances, generator dropping in the eastern systems can have a stabilizing effect. For opening of the Bridger-Borah 345 kV line loaded at 581 MW, Figure 4 shows the effect on rotor swings of dropping one unit at Colstrip and one unit at Jim Bridger 68 cycles after the line opening. The generator dropping could be initiated by out-of-step relays located near swing centers in Montana and Idaho. Fairly sensitive relay settings are required to insure fast enough generator dropping. Faster tripping would reduce the severity of the rotor swings. For disturbances originating within the Northwest, generator dropping could provide backup for load tripping. For many disturbances originating within the eastern systems, generator dropping could prevent a widespread breakup where the units proposed for dropping might be lost in any case.

There are no plans at present to implement this generator dropping. Although dropping of steam generation is much more costly than dropping of hydro generation, controls presently exist for dropping a number of large steam units in the western interconnection. Most of the generation dropping is for loss of transmission lines integrating the generation to the transmission grid.

THE IMPORTANCE OF PROTECTIVE RELAYING IN TRANSIENT STABILITY OF POWER SYSTEMS

Analyses of breakups and blackouts reveal the key role of various types of protective relays. For example, the 1965 Northeast blackout was triggered by a zone 3 distance relay operating on overload. Apparently the August 7, 1977 breakup in the Rocky Mountain states was also triggered by an undesirable zone 3 operation. The 1977 New York City blackout and other breakups have been due to undesirable operation of generator loss of excitation relays.^{5,6} Voltage relay supervision of the loss of⁷ excitation relays would have prevented the New York City blackout.

Because of the importance of protective relays, they should be incorporated in transient stability simulations to a much greater extent than they generally are at the present time. This will involve data gathering efforts and close cooperation between relay and planning engineers. In addition to more accurate simulations, relay modeling greatly facilitates analysis of simulation results of large scale power systems. Rather than studying numerous plots of various variables, a quick scan of relay operations and consequential switching will often suffice.

A few of the more important protective relays are discussed below and related to Northwest heavy import simulation results:

Distance Relays

Line protection distance relays are the normal means for system separation when stability is lost. For the unstable simulations discussed above and for recent system breakups, 30-40 lines relay due to out-of-step conditions. Most of these lines are in the Rocky Mountain states.

Automatic reclosing of lines tripped by distance relays is generally undesirable during breakups. It may be feasible and desirable to automatically block reclosing on lines prone to tripping during breakups based on type of relay operation (allow reclosing only for ground faults).

As discussed above, zone 3 relays operating on overload can trigger a breakup. For this reason and for economics, BPA stopped applying zone 3 relays for main grid protection about 1970. This was justified by the low probability of multiphase faults and the use of redundant primary relaying along with breaker failure relaying.

In typical BPA transient stability simulations, distance relaying is represented on over 100 transmission lines. In addition, if distance relays are not represented explicitly, the BPA program can represent distance relays on a default basis. Typical settings are assumed and the default option is computationally efficient. Lines with phase comparison relay, out-of-step relays, etc, must be represented explicitly. For 230 kV and higher lines, the default representation assumes communication channels so that simultaneous zone 2 operation at each end of the line will trip the line.

Out-of-step Relaying

Out-of-step relaying is actually a stability control rather than protective relaying. A fairly large number of out-of-step tripping and out-of-step blocking controls are installed throughout the western interconnection. These controls should, of course, be represented in stability programs.

Regarding out-of-step blocking and related protective relaying, the prevention of asynchronous operation following instability is important. Asynchronous operation can result in equipment damage due to overheating or shaft fatigue. Some interesting simulation results pertaining to possible asynchronous operation are outlined below:

1. Several lines in the western interconnection have out-of-step blocking relays which block all tripping. Although this prevents tripping on stable swings, it tends to prevent separation for instability. Simulation results for unstable cases indicated that the swing trajectories for the slip cycles following the first swing moved very rapidly through the concentric impedance characteristics and out-of-step would not be detected. Line tripping may then occur on the first slip cycle. Circuit breaker out-of-step switching duty may be very severe.
2. In a number of simulations, asynchronous operation resulted due to swings passing through transformers or lines protected by phase comparison relaying. The subsequent slip cycles were fast enough that distance relays might not operate even if the swing center shifted to a line protected by distance relays (especially true if the swing trajectory was close to the relay balance point).
3. In the loss of Trojan simulation, a swing center was almost exactly at the Kelly Lake British Columbia 500 kV bus with the trajectory being inside the distance relays looking either north or south for only a few milliseconds. Subsequent slip cycles were much faster and asynchronous operation between G. M. Shrum and the Northwest was sustained.

Undervoltage Relays

The importance of load models, particularly the voltage sensitivity of loads, in transient stability programs is generally recognized. Equally important, however, is protective relaying applied to large individual loads. Figure 5 shows severe voltage dips for the loss of Trojan simulation. How much load would be dropped due to a-c contactor type protection? How much of the load would be protected by much slower induction disc undervoltage relays? Clearly, proper tripping of large loads due to undervoltage is an area for improvement of transient stability simulations.

CONCLUSIONS

Evolving power system characteristics due to technical, economic, and environmental factors present challenges in maintaining transient stability for high probability initiating disturbances. New stability controls, including direct tripping of large loads, are described. These controls can prevent islanding of the Northwest as a region with very large generation-load unbalances. Various protective relays are shown to be critical in the transient stability of large power systems. There is a need to expand representation of protective relays in transient stability simulations.

REFERENCES

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- [2] R. O. Berglund, W. A. Mittelstadt, M. L. Shelton, P. Barkan, C. G. Dewey, and K. M. Skreiner, "One-Cycle Fault Interruption at 500 kV: System Benefits and Breaker Design," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-93 pp. 1240-1251, September/October 1974.
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- [5] IEEE Committee Report, "Loss-of-Field Relay Operations During System Disturbances," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-94, pp. 1464-1472 September/October 1975.
- [6] G. L. Wilson, P. Zarakas, "Anatomy of a Blackout," IEEE Spectrum, pp. 39-46, February 1978.
- [7] R. H. Park, "Hardware and Software for System Protection," IEEE Spectrum, pp. 40-45, May 1978.

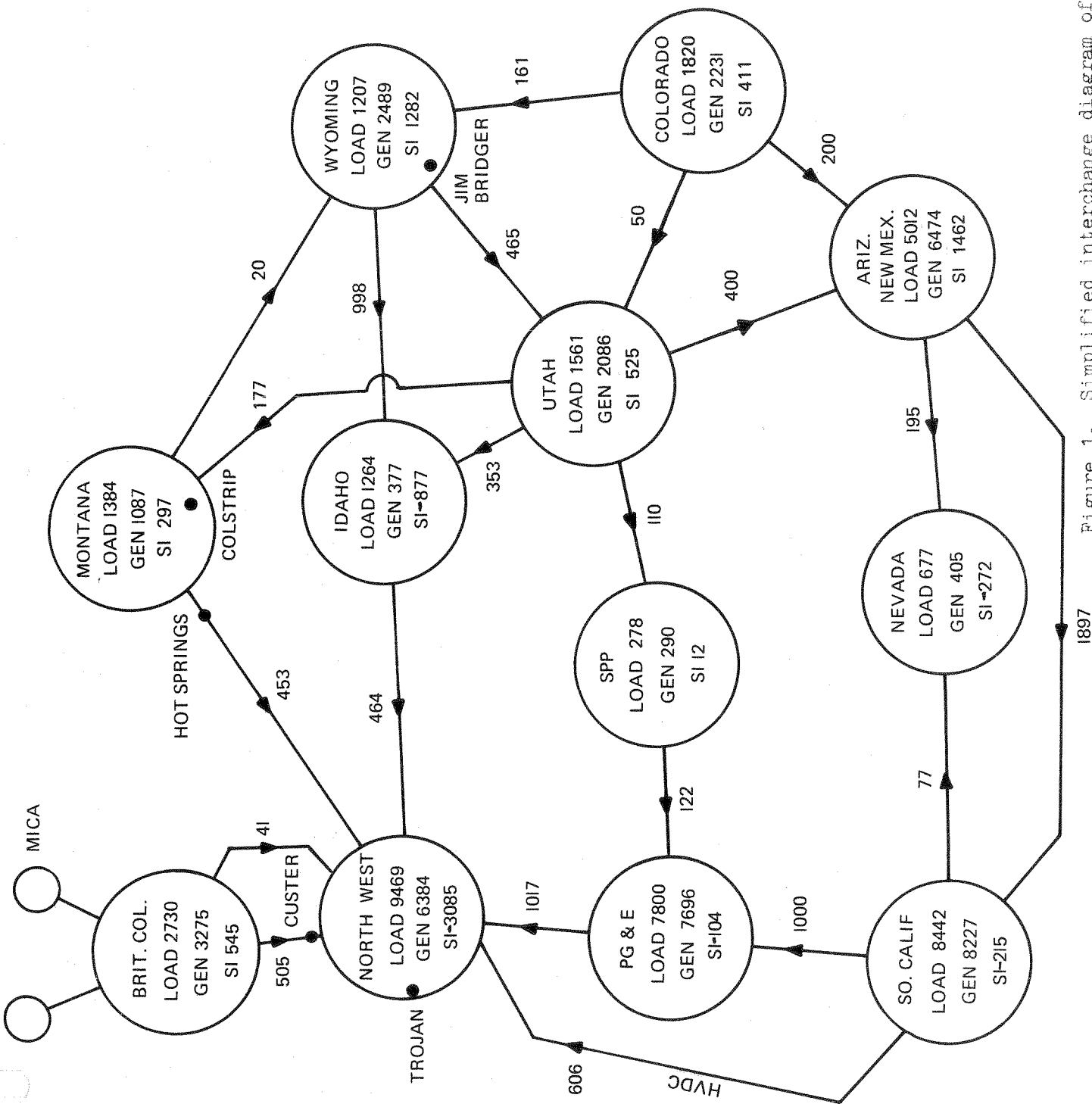


Figure 1. Simplified interchange diagram of western interconnection for heavy Northwest import during light load. Many of the interconnections have low stability levels.

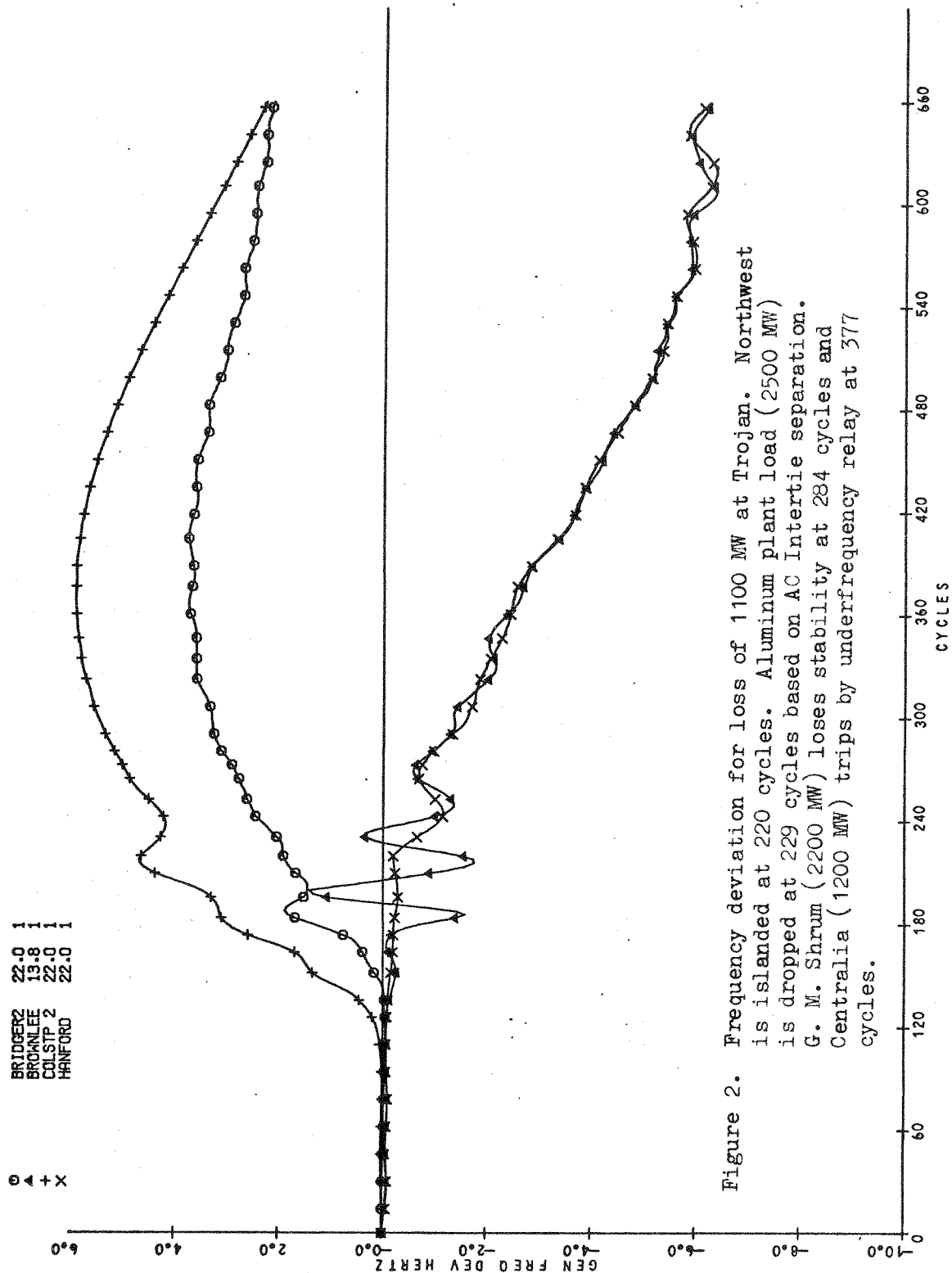


Figure 2. Frequency deviation for loss of 1100 MW at Trojan. Northwest is islanded at 220 cycles. Aluminum plant load (2500 MW) is dropped at 229 cycles based on AC Intertie separation. G. M. Shrum (2200 MW) loses stability at 284 cycles and Centralia (1200 MW) trips by underfrequency relay at 377 cycles.

SNOWHSH 230.0
 JOHN DRY 500.0
 ROSS 230.0

+
 +
 +

BUS VOLTAGE PU

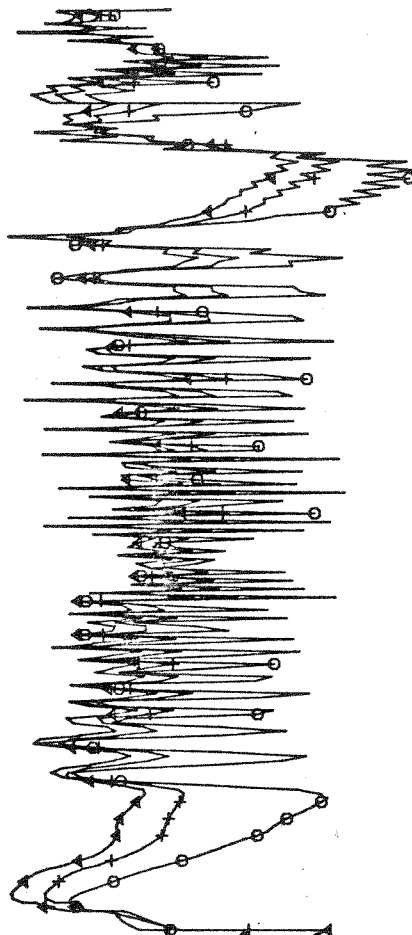


Figure 3. Voltage for loss of 1100 MW at Trojan. Note voltage rises due to islanding at 220 cycles and 2500 MW of load tripping at 229 cycles. G. M. Shrum loses stability at about 284 cycles but incomplete separation results in asynchronous operation (high frequencies after 300 cycles).

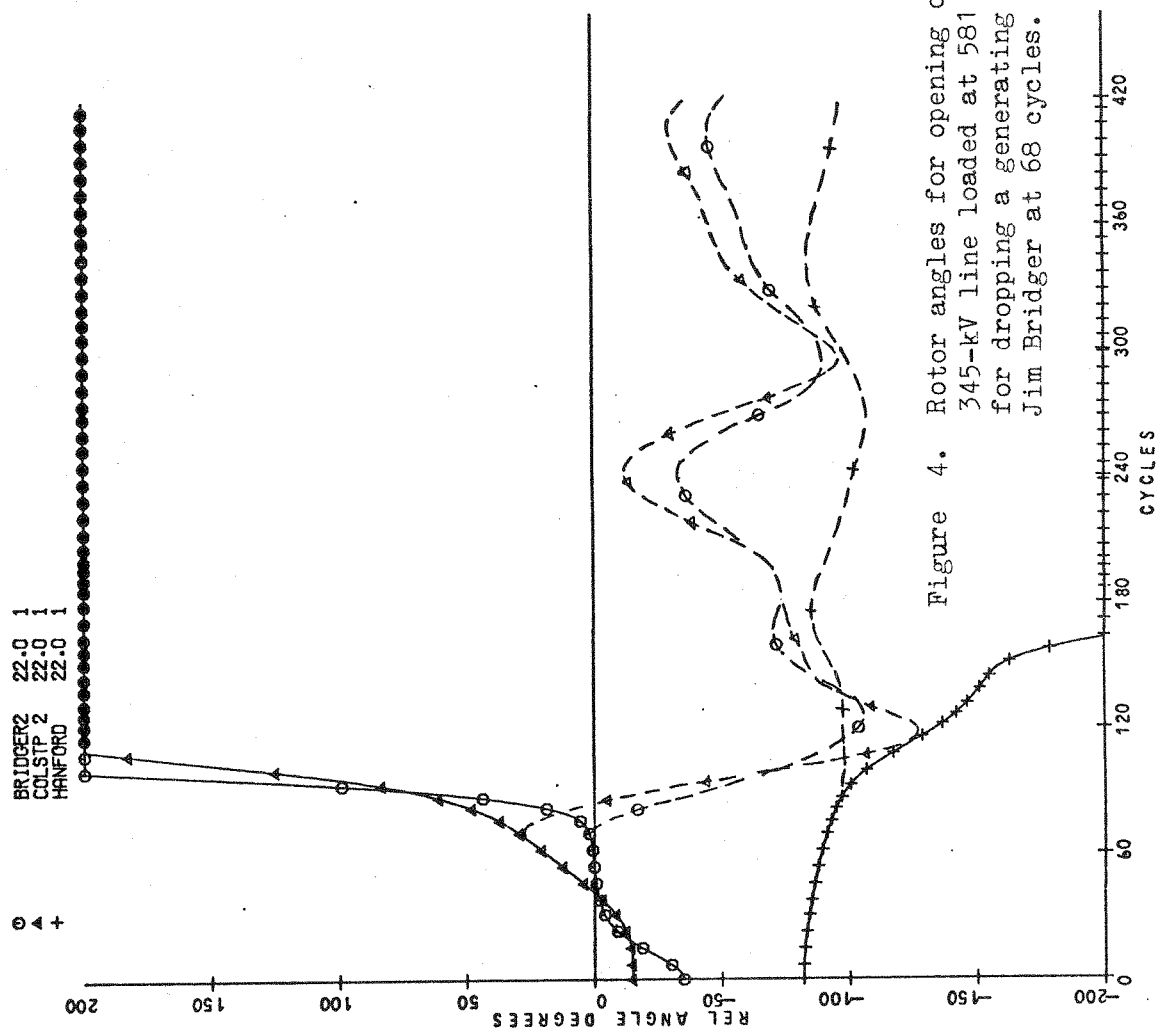


Figure 4. Rotor angles for opening of the Bridger-Borah 345-kV line loaded at 581 MW. Dashed lines are for dropping a generating unit at Colstrip and Jim Bridger at 68 cycles.

BOISE LD 138.0
 BUTTE MT 100.0
 GT FALLS 100.0

0.4 +

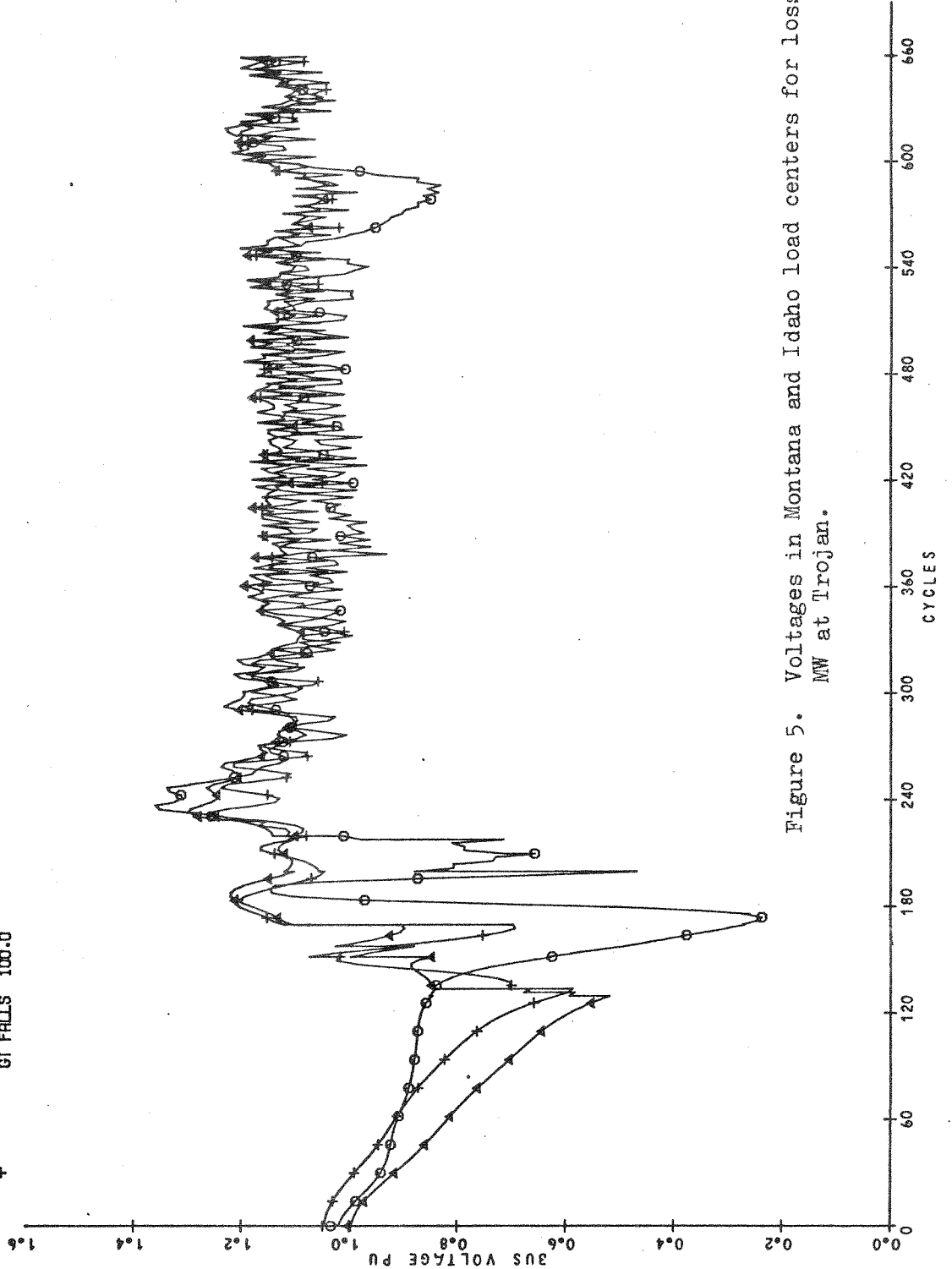


Figure 5. Voltages in Montana and Idaho load centers for loss of 1100 MW at Trojan.

— Mica 500 kV Protection —
A Segregated Phase Comparison System
With Special Features for High Tower Footing Resistance

By:
Maurice J. Lefrançois, P. Eng.
British Columbia Hydro and Power Authority
Vancouver, British Columbia, Canada

Presented To:
Western Protective Relay Conference
October 16-18, 1978
Sacramento, California

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Forward

The object of this presentation is to tell you about the transmission line protection chosen for what we call our Mica 500 kV system.

First we will give you a brief description of the Mica 500 kV system and how it relates to the total B. C. Hydro system. We shall then outline the requirements for the protection system.

Following will then be a brief description and review of the basic system chosen; a Westinghouse SPCU (Segregated Phase Comparison System). For those already familiar with this system we ask you to bear through the brief review we wish to give before going on to discuss the more unique supplementary features.

We will then discuss the supplementary features incorporated with the SPCU system to give us adequate performance under conditions of high tower footing resistance, weak source conditions and blinding due to load.

An analysis of performance with particularly high tower footing resistances will be given.

The Mica System

(Refer to Figure 1 and 2)

The Mica 500 kV transmission system is designed to tie the Mica generation to the main load center in the B. C. Lower Mainland.

The Mica Generating Station now has four 457 MVA units and will ultimately have a total of six units.

The 500 kV transmission system consists of two circuits from Mica to an intermediate switching and transformation station at Nicola. From Nicola we have two circuits to the Lower Mainland, one terminating at Ingledow and the other at Meridian. The total transmission distance from Mica to the Lower Mainland is in the order of 340 miles. All line sections are completely transposed. It is to be noted that except for very short distances from the terminal stations these lines do not have the benefit of overhead ground conductors.

Series capacitors are planned for some later stage of development. These will be no greater than 50% compensation and would be installed near the midpoint of the Mica-Nicola circuits and at near the 1/3 point from the Nicola terminal of the Nicola-Lower Mainland circuits.

Shunt reactors have been installed at both terminals of the Mica-Nicola circuits and at the Nicola terminal of the Nicola-Lower Mainland circuits. These reactor installations consist of three star connected 45 MVAR reactors with the neutral end grounded through a 1000 ohm neutral

reactor. The neutral reactor functions to reduce the secondary arc current and the secondary recovery voltage during the open pole period in a single pole trip and reclose operation.

The staging in the system commissioning is to be noted. This was as follows:

- 1) 5L81 (Nicola-Ingledow) - 1976
- 2) 5L71 (Mica-Nicola) and first units at Mica - 1976
- 3) 5L82 (Nicola-Meridian) and more units at Mica - 1977
- 4) 5L72 (Mica-Nicola) - 1978

Protection System Requirements

The basic requirements for the protection of the four Mica system 500 kV circuits were to be as follows:

Reliability - To assure reliability two separate sets of protection were required - primary and standby. Consistent with this the primary and standby protection each connect to separate C.T. secondary windings. The circuit breakers are equipped with primary and standby trip coils.

Speed - The objective was to achieve 4 cycle clearing times for the total length of the line. This includes 2 cycle breaker time leaving 2 cycles for the relaying (including communications channel delay). Note that under some conditions of reduced fault current we can expect longer clearing times.

Sensitivity - The protection was required to detect all faults including:

- An open conductor with one end on the ground
- Faults with no (or very weak) positive sequence source behind one bus, i.e. in the early stages of the Mica system when only circuit 5L81 (Nicola-Ingledow) was in service Nicola was a very weak source.

- Faults with very high ground resistance.

Because of the lack of overhead ground conductors and the geological conditions the tower footing resistance for many line sections is very high. Relay performance under these conditions is discussed in a later section.

Selectivity - The protection system was to be capable of single pole trip and reclose on single line to ground faults and three pole tripping and reclosing on multi-phase faults. The single pole reclose time set at 40 cycles is not supervised. For the three pole operation reclose is set at 60 or 80 cycles. On the Mica-Nicola circuits we reclose at Mica if the parallel line is in service as determined by parallel line current supervision followed by reclosing at Nicola on restoration of line potential. On the Nicola-Lower Mainland circuits we reclose at Ingledow or Meridian followed by reclosing at Nicola on restoration of line potential if the parallel line to the Lower Mainland is in service as determined by parallel line current supervision.

Basic Relaying Scheme

The basic scheme chosen was a Westinghouse SPCU (Segregated Phase Comparison System). The basic features of this scheme will be briefly reviewed in this section.

To cater for the particular requirements and the extreme fault conditions of the Mica 500 kV transmission system, Westinghouse incorporated significant supplementary features in the protection package and these are discussed in the following section.

The system adopted comprises two identical SPCU systems, primary and standby each made up of four subsystems (A, B, C and N). Basically, during a fault each current is compared in phase relation with the remote current. This is done on a phase by phase basis. For this there is a SPCU relay for each phase and for the neutral currents.

Looking at the basic SPCU logic we will first review the functions of some of the main components following: (refer to Figure 3).

CD - (Change Detector) is designed to give a minimum 50 msec output for a sudden current change (magnitude or angular shift).

It arms the local comparison AND and allows transmission by keying off guard.

I_L - Overcurrent Unit is to enable the comparison AND. It is set with pickup above line charging current so as to prevent operation on line energizing.

ISW - Provides for square wave keying derived from the current.

Sensitivity is ≈ 7.4 ms pulse at $\approx .18$ amps (≈ 7.4 ms pulse at $\approx .12$ amps in neutral subsystem).

ISWP and ISWN - Provides positive and negative local square waves derived from the current. This is used for the comparison AND.

I_E - At very low currents I_E indicates open breaker conditions and will provide continuous keying to the remote terminal.

F.V. - (Frequency Verifier) checks the time between adjacent zero crossings to be at least 5 milliseconds. It will block the comparison AND for high frequency components which can occur due to line charging of shunt capacitance. This can occur during line energizing or on external fault clearing.

I_H - This is a high set overcurrent element which will trip directly.

Coincidence Timers - To provide added security when comparing the local and remote currents we must have comparison AND output (coincidence) for 3 milliseconds. We choose to operate in the two count mode so that we must have either two 3 millisecond comparisons or one 5 millisecond comparison.

The SPCU system is inherently designed for comparison on both positive and negative half cycles (dual comparer). However, to save on

channel requirements we have elected to use two state tones and operate in a single comparer mode (refer to Figure 4). This means that on a system comparing on positive half cycles we key the tone transmitter to the trip state on the positive half cycle and let it return to guard on the negative half cycle. This guard inherently blocks the comparison AND during alternate half cycles. For our system the primary phase subsystems compare on the positive half cycle and the standby phase subsystem compares on the negative half cycle. The primary neutral subsystem compares on the negative half cycle and the standby on the positive half cycle. When both the primary and standby protection systems are in service we then effectively have a dual comparer mode of operation which can advance tripping by half a cycle.

We will look at the typical sequence of events on the primary phase subsystem for an internal fault (Refer to Figure 5). At the remote terminal the CD operates on the current change and allows alternating square wave keying of the tone transmitter. At the local end this keying is received but delayed by the channel time of ≈ 8 msec. At the local terminal the CD and the I_L operate to enable the comparison AND. The ISWP at the local terminal (which is following the local current) is delayed by the LDT (local delay timer) set to compensate for the channel delay of the keying received from the remote terminal. In the case illustrated in the attached figure we will obtain ≈ 7 milliseconds of coincidence during the first cycle after fault inception. Relay trip output will occur after 5 milliseconds of coincidence. For the case illustrated this trip output is ≈ 25 milliseconds after fault inception.

Looking briefly at the neutral subsystem (refer to Figure 6) we find it similar to the phase subsystem previously described except for the following:

- There is no requirement for a CD to arm the comparison AND
- Instead the I_L unit serves to arm the comparison AND as well as allow transmission of trip keying. The I_L unit can be set relatively sensitive since normally there is little neutral current.
- The I_E function which was applicable to the phase subsystem is not applicable to the neutral subsystem. This means that the neutral subsystem cannot operate for a single line to ground fault occurring when one terminal is open.
- The coincidence timer in the neutral subsystem is set for 4 milliseconds. Note that the phase subsystem coincidence timer is set at 3 milliseconds. This is because the phase subsystem is subject to greater misalignment caused by such effects as load current for high impedance ground faults.

The main disadvantage of the basic SPCU is the requirement for a separate tone channel for each primary and standby subsystem (A, B, C and N) for a total of eight per transmission circuit for our system.

The main advantages of the basic SPCU are as follows:

- 1) The major problems of future series compensated lines are solved
 - low frequency oscillations during faults
 - phase impedance unbalance due to gap flashing
- 2) High Speed Operation due to angle diversity between phases for multi-phase faults and the elimination of filters in the phase comparison circuit.
- 3) Redundancy in that A, B, C and N back each other up.
- 4) Inherent phase selection.
- 5) Has the advantages of current only relays
 - no problems with mutual induction
 - no problems with loss of potential
 - correct relaying for close in three phase faults

Supplementary Features

The basic SPCU system described in the preceding section will cater for tripping on multiphase or single line to ground faults provided either a phase comparison can take place or the I_H element (high set overcurrent element) operates. To cater for single phase tripping on single line to ground faults the SPCU phase subsystem on the faulted phase must operate to give us phase discrimination. The sensitivity of the phase subsystem is limited by the I_L (overcurrent arming unit typically set at approximately 360 A on the Mica system) set to override line charging current. The neutral subsystem has a more sensitive I_L setting (set at 200 amps on the Mica system) but it cannot by itself identify the faulted phase.

For SLG faults it is necessary to achieve adequate sensitivity and phase selection under conditions of particularly high ground resistance. To this end the basic SPCU protection has to be supplemented. The supplementary features are discussed in this section as follows:

- 1) $\emptyset$ ITT (Phase Identified Transfer Trip) (Refer to Figure 7):

This serves to

communicate the identity of the faulted phase to the remote terminal. The $\emptyset$ ITT is sent from a terminal whenever that terminal has detected an internal fault and has identified the faulted phase.

Keying of $\emptyset$ ITT is accomplished by keying both the primary and standby tones of the particular phase to continuous trip for a minimum of

60 milliseconds. At the receiving end the ØITT is recognized upon receipt of simultaneous trip on primary and standby tones for 4 milliseconds. The four millisecond time is to override possible overlap due to channel jitter which can exist between the primary and standby trip keying during normal square wave keying. In the event that a channel is out then receipt of continuous trip on one channel for 25 milliseconds will also give the ØITT function. Note that continuous trip on primary channel gives ØITT for that primary subsystem and similarly continuous trip on the standby channel gives ØITT for that standby subsystem. Under normal keying, continuous trip keying (caused by DC offset) with no SPCU trip is cut off after 20 milliseconds and the 25 milliseconds for single channel ØITT is set to coordinate with this.

2) TTN (Transfer Trip Neutral) (Refer to Figure 8): This serves to communicate to the remote terminal that an internal fault has been detected. It is required by the neutral logic if there is no operation or a delayed operation of the neutral SPCU at the remote terminal. It is initiated from a terminal at the same time as the ØITT.

At the sending terminal both the primary and standby neutral subsystems are keyed to continuous trip for a minimum of 60 milliseconds.

At the receiving end (similarly to that for ØITT) the TTN is recognized upon receipt of simultaneous trip on primary and standby tones for 4 milliseconds or receipt of continuous trip for 25 milliseconds on one channel in the event that a channel is out.

The TTN function could be derived directly from the ØITT logic. However, for the event that either primary or standby tone is out of service for the particular phase resulting in the slower (25 millisecond timer) ØITT then the TTN with two tone channels (primary and standby) will be derived more quickly (4 milliseconds). This could mean faster tripping.

3) 3Io Fault Detector: This is a sensitive, non directional overcurrent detector. It supervises tripping initiated by ØITT plus TTN.

4) ISW Neutral System Return Keying Circuit (Refer to Figure 9):

In the basic phase comparison scheme, keying of the neutral tone channel requires that the neutral current be above the setting of I_{LN} (overcurrent arming unit).

For a high ground resistance fault at one terminal with weak infeed from the other terminal there may not be sufficient current at the weak infeed terminal to operate I_{LN} and allow channel keying even though there is sufficient current to operate the ISW.

The ISW return keying circuit at the weak terminal provides for ISW keying upon receipt of neutral keying from the remote terminal provided the local I_{LN} is not picked up. This will allow the remote terminal to complete its neutral phase comparison.

There will be no neutral phase comparison at the weak terminal since I_{LN} will not pick up to enable the comparison AND.

5) Phase Selectors (Refer to Figure 10): The phase selector relay is another means of locally identifying the faulted phase during a single line to ground fault.

The phase selector relay we apply operates on the basis that for an idealized single line to ground fault the negative and zero sequence current components in the faulted phase are coincident with one another. It also accounts for the fact that in practice these components could be separated by an angular shift in excess of 30° . This angular shift can be due to local resistive shunt load.

As illustrated in Figure 10 for a phase A-G fault with 0° shift between the negative and zero sequence current components there is 180° coincidence between components in A phase and 60° coincidence in B and C phases. For phase A-G fault with 30° shift between the negative and zero sequence current components there is 150° coincidence between components in A phase, 30° coincidence in B phase and 90° coincidence in C phase.

The phase selector relays measure the coincidence time between the negative and zero sequence components to determine the faulted phase. For the Mica system this coincidence timer is set at 5 milliseconds (108°) and would correctly select the faulted phase for the cases illustrated in Figure 10.

For terminals with a weak positive sequence and hence negative sequence source behind them the angular shift between the negative and zero sequence current components can become excessive leading to incorrect phase selections.

For this reason the phase selectors at Nicola were initially disconnected until three 500 kV lines were terminated into Nicola.

6) Ground Backup Trip (Refer to Figure 11): For faults with very low current flow it is possible that there will be no phase identification at either terminal, and that only the SPCU N subsystem will effect a comparison (detect an internal fault). After a time delay the SPCU N trip output will operate the ground backup trip timer to achieve three pole tripping.

The ground backup trip timer has to be set to coordinate with the maximum time in which a SPCU N trip would occur under fault conditions for which there is phase identification. For a trip on N SPCU COMP + $\emptyset$ ITT the SPCU N could be maintained in the order of 150 milliseconds before resetting. We, therefore, require a time delay of approximately 180 milliseconds on the ground backup timer.

With the supplementary features described above there are several trip options available for single line to ground fault. These are illustrated on Figure 12 and are as follows:

$\emptyset$ SPCU I_H - where the local current is sufficiently high to operate this high set overcurrent element

$\emptyset$ SPCU COMP - where there is sufficient current at both terminals to effect a successful phase comparison

NSPCU I_H + $\emptyset$ SELECT or NSPCU COMP + $\emptyset$ SELECT - where there is not sufficient

current for phase comparison on the phase subsystem but there is sufficient current for a neutral phase comparison and for phase selection.

NSPCU I_H + $\emptyset$ ITT or NSPCU COMP + $\emptyset$ ITT - where there is not sufficient current for phase comparison on the phase subsystem but there is sufficient current for a neutral phase comparison and where the remote terminal having identified the faulted phase keys a $\emptyset$ ITT signal.

TTN + $\emptyset$ ITT + 3IoFD - where there is not sufficient current for phase comparisons on either the phase or neutral subsystems and the phase selectors do not operate due to inadequate current and where the remote terminal having identified the faulted phase keys $\emptyset$ ITT and TTN.

TTN + $\emptyset$ SELECT - this trip option is essentially redundant.

However, for the case where one incoming channel has failed and we have to rely on single channel $\emptyset$ ITT (25 msec) then it could be faster than waiting for tripping via TTN + $\emptyset$ ITT + 3IoFD.

For phase to phase faults with a weak positive sequence source behind a terminal there may be inadequate current at the weak terminal for phase comparison in all of the faulted phases. We may also have the combined effect of a weak positive sequence source and load current result in adequate current for phase comparison in one phase and inadequate current in the other phase due to blinding by the load current. For these cases the basic SPCU system has to be supplemented as described following:

1) WSD (Weak Source Detector) (Refer to Figures 13 and 14): The

WSD is essential for phase to phase faults where current at the weak terminal is inadequate for phase comparison on all faulted phases. It will also function for the case where there is adequate current in only one of the faulted phases.

The WSD consists of two elements ΔV and ΔI . The ΔV element measures the voltage in one phase minus the voltage in an adjacent phase (i.e. $V_A - V_B$, measures phase to phase voltage) and has an adjustable dropout setting. The ΔI element measures the current in one phase minus the current in an adjacent phase (i.e. $I_A - I_B$) and also has an adjustable dropout setting.

The principle of the weak source detector is based on the fact that for a phase to phase fault;

— ΔV approaches zero between the two faulted phases close to the point of fault. ΔV at the line terminal increases as the fault is further away from that terminal. Normally the ΔV elements will see a voltage magnitude equal to normal phase to phase operating voltage.

— ΔI between two faulted phases adopts a value of twice the fault current for a fault at the weak terminal and considering resistive load at that terminal. A low ΔI signifies a weak source.

Operation of the WSD results when both ΔV and ΔI drop out. The WSD must be set for operation as follows:

a) At the weak source for all internal phase to phase or three phase faults for which there would not be adequate current to enable keying by the SPCU I_{SW} (square wave keying element).

b) At the strong terminal for external faults behind the terminal. This setting must be coordinated with the weak terminal to ensure that if the weak terminal can operate for a fault behind the strong source then the strong terminal will also operate.

WSD must not operate as follows:

- a) at weak terminal for fault behind it
- b) at strong terminal for a fault toward the weak source

WSD will perform the following functions on operation (drop out of ΔV and ΔI).

a) At weak terminal it will key the tone transmitter to continuous trip to enable phase comparison at the strong terminal and subsequent tripping at that terminal. The weak terminal will then trip on receipt of direct transfer trip (as described in 2) following) or by a ΔV conversion to three pole tripping (as described in 3) following).

b) At the strong terminal if the WSD operates this indicates a fault behind the strong source and the WSD will block the comparison AND.

For the Mica system Nicola is considered a weak source for the event of only one 500 kV circuit into the Nicola bus and weak positive sequence source behind the Nicola bus.

2) DTT (Direct Transfer Trip) (Refer to Figure 15): A DTT signal is keyed to the remote terminal whenever a three pole trip is initiated by the line protection. The receipt of DTT at a terminal results in three pole tripping.

The tone channels used for the DTT function are the same channels which are also used for shunt reactor transfer trip function and for breaker failure function.

As an example of the usefulness of this function let's refer to the WSD operation described in 1) above. (Refer to Figure 16). For an

internal phase to phase fault where there is inadequate current at the weak terminal for $\emptyset$ SPCU COMP, the WSD for the two faulted phases at the weak terminal keys to the strong terminal. The strong terminal is thus able to complete a comparison on the two faulted phases and trip three pole. The strong terminal keys DTT to the weak terminal. At the weak terminal where no phase comparison has occurred three pole tripping will occur on receipt of DTT.

3) Undervoltage Three Pole Trip (Refer to Figure 17): For the phase to phase fault where one phase has adequate current for a phase SPCU operation and the other phase is blinded by load current, the WSD previously described can serve to ensure operation on both phases. However, for these cases there will be a reduced phase to phase voltage which is detected by the ΔV element of the WSD package described in 1) preceding. Under these conditions where there is one SPCU phase trip and a ΔV operation (ΔV dropout), what would be a single pole trip is converted to a 3 pole trip. For this case the undervoltage three pole trip would likely achieve fault clearing from both terminals somewhat faster than if we were relying on the WSD operation.

With the above described supplementary features the trip option for phase to phase faults are as follows: (Refer to Figure 18).

2 $\emptyset$ SPCU I_H - where the local current is sufficiently high to operate both faulted phase high set overcurrent elements.

2Ø SPCU COMP - where phase comparison has been effected on both faulted phases.

1Ø SPCU COMP + ΔV - where only one phase was able to complete a comparison and the other phase due to too low a current at the weak terminal did not operate then the ΔV element effected a conversion to 3 pole trip.

Received DTT - where the remote terminal line protection has initiated a 3 pole trip a DTT is transmitted to the opposite terminal.

For failure of communications channels (Refer to Figure 19):

We have one set of channel independent protection at each terminal. This consists of an impedance relay (21L) for phase faults and a non directional overcurrent relay for ground faults.

Normally this protection is delayed via a long time delay timer, set at 2 seconds.

In the event of a tone channel failure occurring in both the primary and the standby SPCU phase comparison tones, the backup protection reverts to a short time set at 0.1 seconds.

Note that for some very high resistance ground faults where there is inadequate current to effect a neutral system comparison the backup ground relay can serve to provide for three phase tripping. This is illustrated in the next section analyzing performance with high tower footing resistances.

Performance Analysis with High Tower Footing Resistances

As mentioned previously the B. C. Hydro 500 kV transmission lines are not equipped with overhead ground conductors or counterpoise (except for very short distances out of the terminal stations). In addition the soil and rock conditions for much of the lines are such as to make for particularly high tower footing resistances.

Note that for the Mica system counterpoise conductors were added to supplement the grounding only for limited sections where the tower footing resistances would be too high for successful relaying of ground faults.

Because of this these lines are subject to a high number of single line to ground faults caused by lightning and the ground fault currents are of considerably reduced magnitude such as to make relaying particularly difficult.

All the Mica circuits are subject to this problem. However, let us examine 5L82 in some detail as to the performance of the protection for high resistance ground faults.

The tower footing resistance profile for 5L82 is illustrated in Figure 20. It is observed that the ground resistance ranges up to 775 ohms nearer the Meridian terminal.

We will examine ground faults at three different locations on 5L82 and analyze the relay performance we expect for these particular faults. The analysis will be done on the basis of normal system prefault conditions with all four Mica 500 kV circuits in service and four generators on the bus at Mica.

For a fault at A (149 miles from the Nicola terminal and 5.4 miles from the Meridian terminal) the tower footing resistance is 550 ohms (refer to Figure 21).

For this fault (neglecting system impedance) the fault current distribution follows:

3Io Total - 525 A Primary = 1.31 A Secondary with 2000/5 CT's

3Io Meridian = 511 A Primary = 1.28 A Secondary

3Io Nicola - 14 A Primary = .04 A Secondary

Relay settings are as follows for both Meridian and Nicola:

I_{H0} - 3600 A I_{HN} 2400 A

I_{L0} - 360 A I_{LN} 200 A

Backup CO-9 Pickup 200 A 1 Time Dial trips via timer set at 2 seconds.

From the foregoing it can be seen that at Meridian there would be adequate current for the I_{L0} and I_{LN} elements to operate, and arm the phase comparison logic. However, at the Nicola terminal there is inadequate current for this and nor is there enough current for return keying of the neutral subsystem (since the ISW unit has a sensitivity requiring approximately .12 A to provide a 7.4 millisecond pulse). Fault clearing will have to rely on the CO-9 backup protection with the following sequence and approximate times:

At Meridian CO-9 time	.8 seconds
-----------------------	------------

Backup timer	2.0 seconds
--------------	-------------

Direct Transfer Trip Meridian to Nicola	.02 seconds
---	-------------

Nicola Breaker Time	<u>.03</u> seconds
---------------------	--------------------

Total Clearing Time	2.85 seconds
---------------------	--------------

For this fault with a resistance of 550 ohms our planners indicate a stability limit in the order of 8 seconds.

For a fault at B (127 miles from the Nicola terminal and 27.4 miles from the Meridian terminal) the tower footing resistance is 775 ohms (refer to Figure 22).

For this fault the fault current distribution follows:

3Io Total - 372 A Primary = .93 A Secondary with 2000/5 CT's

3Io Meridian = 301 A Primary = .75 A Secondary

3Io Nicola = 71 A Primary = .18 A Secondary

Relay settings are as indicated for fault A

With 301 A at Meridian there is adequate current for ILN to operate, arm the phase comparison logic and key square wave pulses to Nicola. Nicola with .18 A (secondary current) has adequate current for ISW neutral current return keying so that neutral subsystem phase comparison can take place at Meridian. There is also adequate current at Meridian for faulted phase selection. Meridian will trip via;

N SPCU COMP + Ø SELECT

With tripping at Meridian the current at Nicola increases to 360 A. ILN will then operate.

We will assume Nicola trips via;

N SPCU COMP + ØITT

Other trip paths then also available to Nicola are;

N SPCU COMP + Ø SELECT

TTN + ØITT + 3IoFD

TTN + Ø SELECT

Ø SPCU COMP (Possibly)

The following sequence and approximate times can be expected;

At Meridian N SPCU COMP + Ø SELECT	2~
Breaker Time	2~
At Nicola N SPCU COMP + ØITT	1~
Breaker Time	<u>2~</u>
Total Clearing Time	7~

For a fault at C (25 miles from the Nicola terminal and 129.4 miles from the Meridian terminal) the tower footing resistance is 150 ohms (refer to Figure 23).

For this fault the fault current distribution follows:

3Io total = 1925 A

3Io Meridian = 408 A

3Io Nicola = 1517 A

Relay settings are as indicated for fault A.

With the above currents this is adequate for faulted phase subsystem and neutral subsystem comparison at both terminals.

The trip sequence and approximate times for both terminals can be expected as follows:

Ø SPCU COMP	1~
Breaker Time	<u>2~</u>
	3~

Examining the requirements for single pole operation it is recognized that the minimum current requirements are that there be sufficient current at one terminal for I_{LN} to operate. For our system

the I_{LN} elements are set at 200 A so in our analysis we are looking for 250 A to positively ensure operation. At the other terminal we require at least sufficient current for I_{SW} neutral current return keying. The I_{SW} neutral unit requires approximately .12 A to provide a 7.4 millisecond pulse. With our 2000/5 CT's this translates to 48 A primary. In our analysis we are then looking for 50 A to ensure successful comparison via I_{SW} neutral current return keying.

Based on the above, for 5L82 we have plotted the locus for the maximum tower footing resistance which will allow for single pole operation. Referring to Figure 24 it can be seen that despite the exceptionally high tower footing resistances we can expect single pole relay operation for the entire line except for some faults close to Meridian. For these faults we have to rely on the CO-9 backup protection to effect three pole tripping.

Conclusion

This paper has described the approach we have taken on a part of our 500 kV system to meet our particular requirements and conditions. These included a requirement for single pole operation accompanied with high tower footing resistance and weak source conditions.

Our choice has been the basic Westinghouse SPCU system with the supplementary features described. We are not suggesting that other available protection systems would not also meet our requirements.

We hope that the information presented may be of use to others faced with similar requirements.

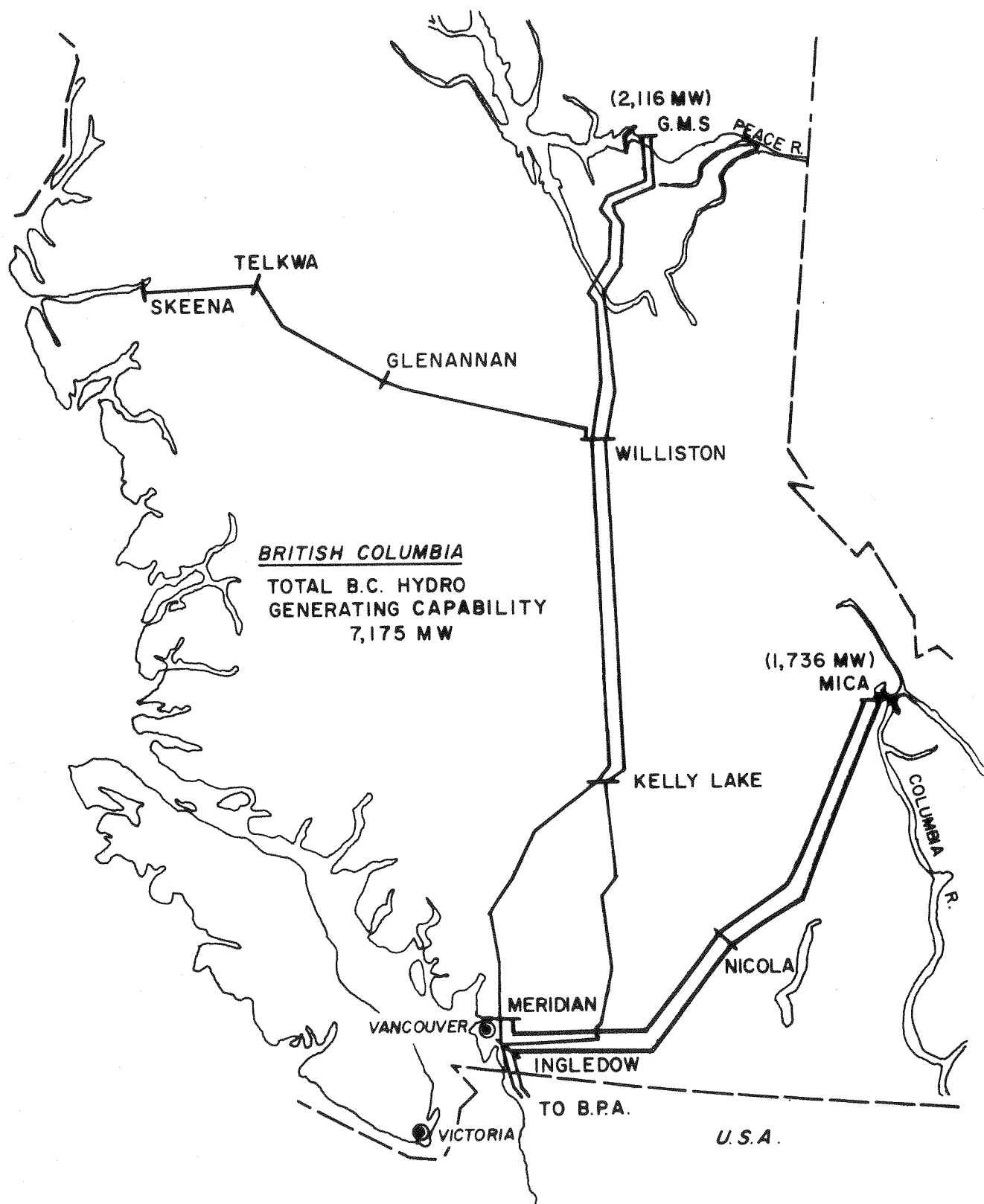
Acknowledgement

The author wishes to acknowledge the developmental work of Westinghouse Canada Ltd. in the adoption of the supplementary features to the basic SPCU scheme to meet B. C. Hydro requirements.

The author also expresses appreciation to A. B. Webb and B. J. Burk of the B. C. Hydro System Protection Section for their advice in this presentation.

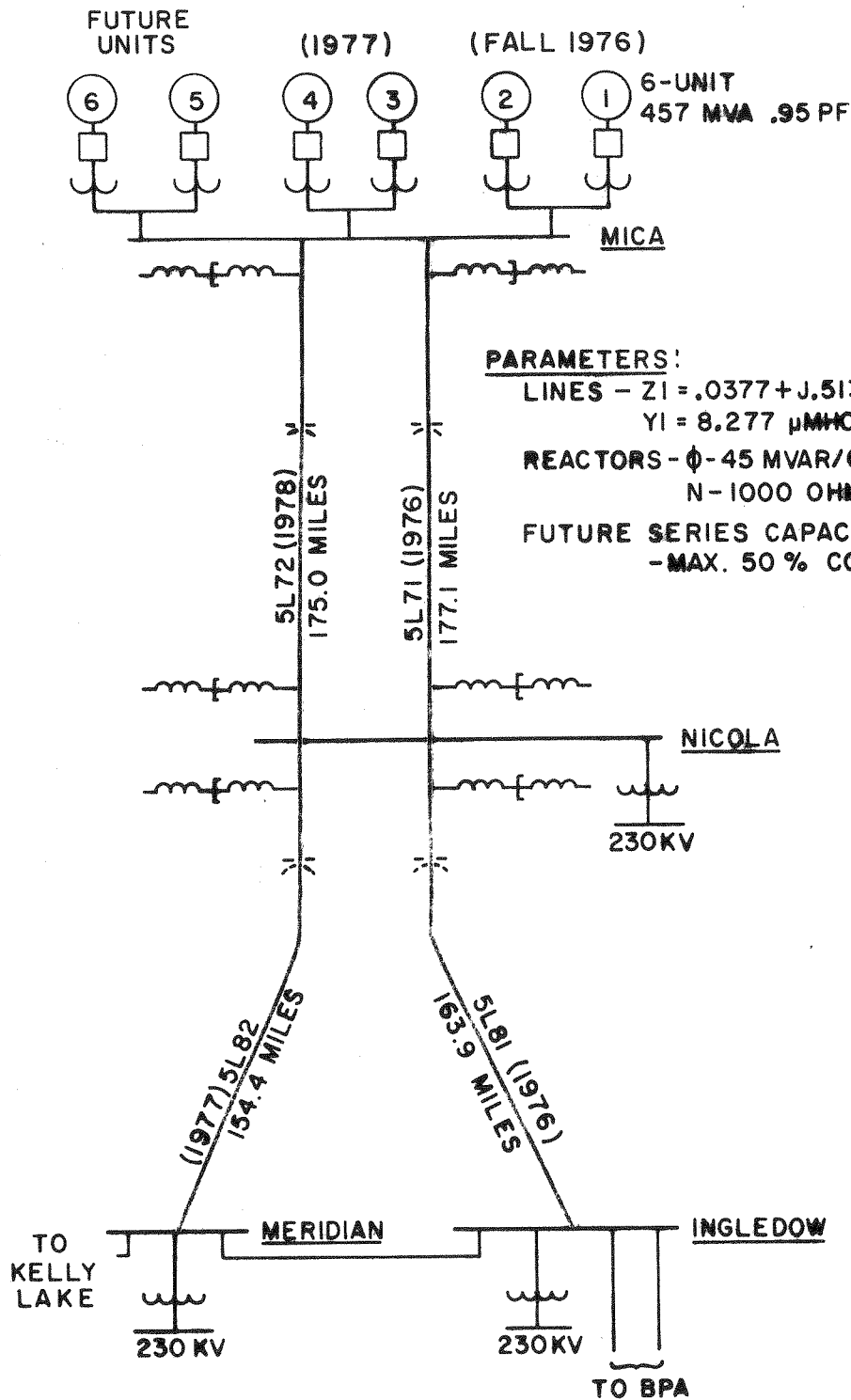
References

- SPCU Single Pole Trip and Reclose Protection System for Use with Audio Tones - Westinghouse Canada Ltd. I.L.40-201.41
- The SPCU Segregated Phase Comparison Relay for Use with DIT-4 Audio Tones - Westinghouse Electric Corporation I.L. 41-955A
- A New Relaying System to Protect Series Compensated Lines by W. L. Hinman and R. W. Gonnarn, Westinghouse Electric Corporation



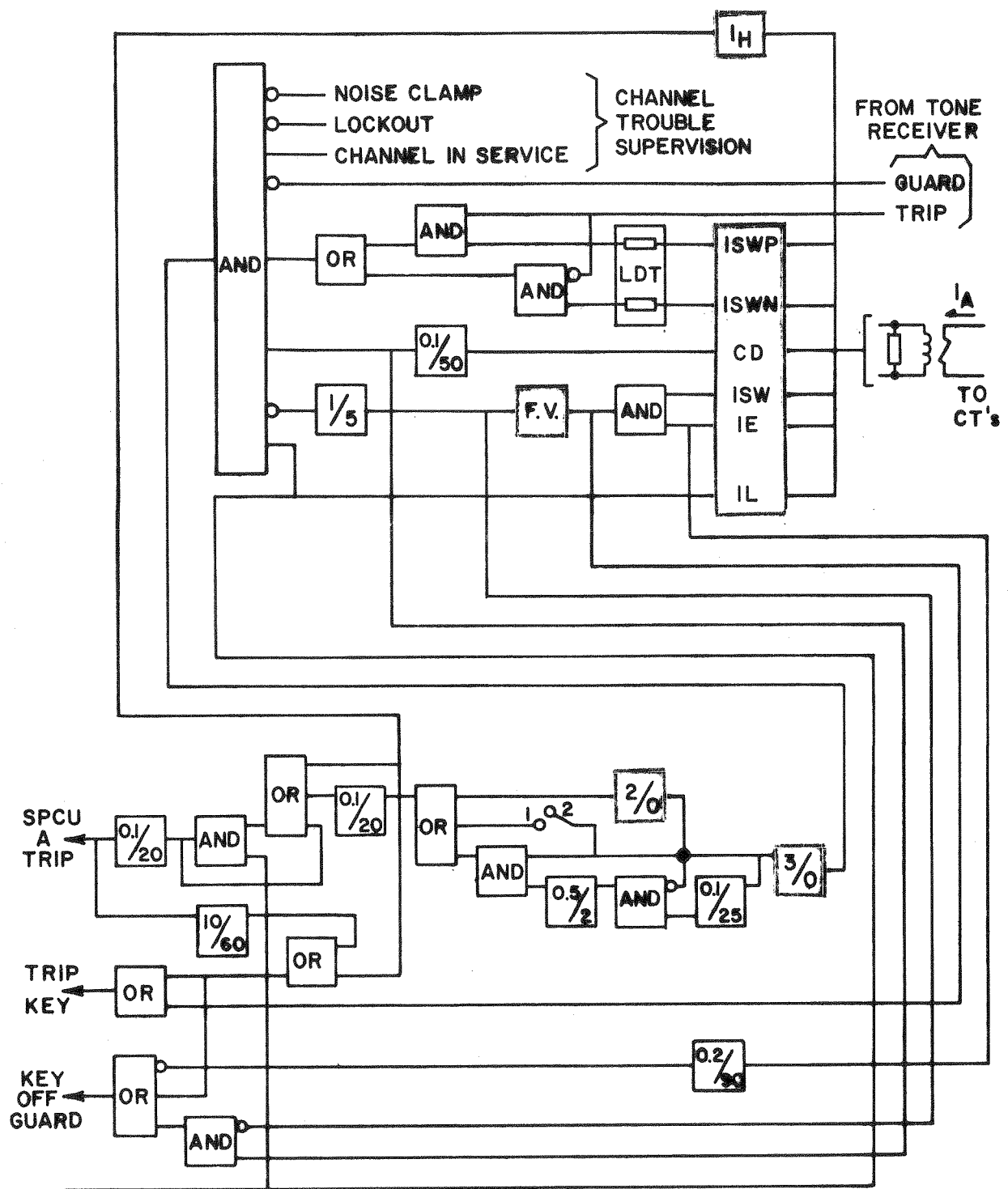
B.C. HYDRO 500KV TRANSMISSION SYSTEM

FIG. 1



MICA 500KV TRANSMISSION SYSTEM

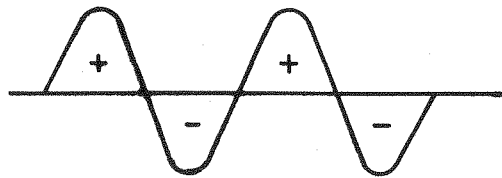
FIG. 2



BASIC SPCU 0 LOGIC

FIG. 3

SYSTEM
S.L.G. FAULT
CURRENT



PRIMARY
Φ SUBSYSTEM



- TRIP
- GUARD

PRIMARY
NEUTRAL
SUBSYSTEM



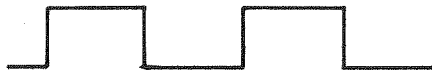
TRIP
GUARD

STANBY
Φ SUBSYSTEM



TRIP
GUARD

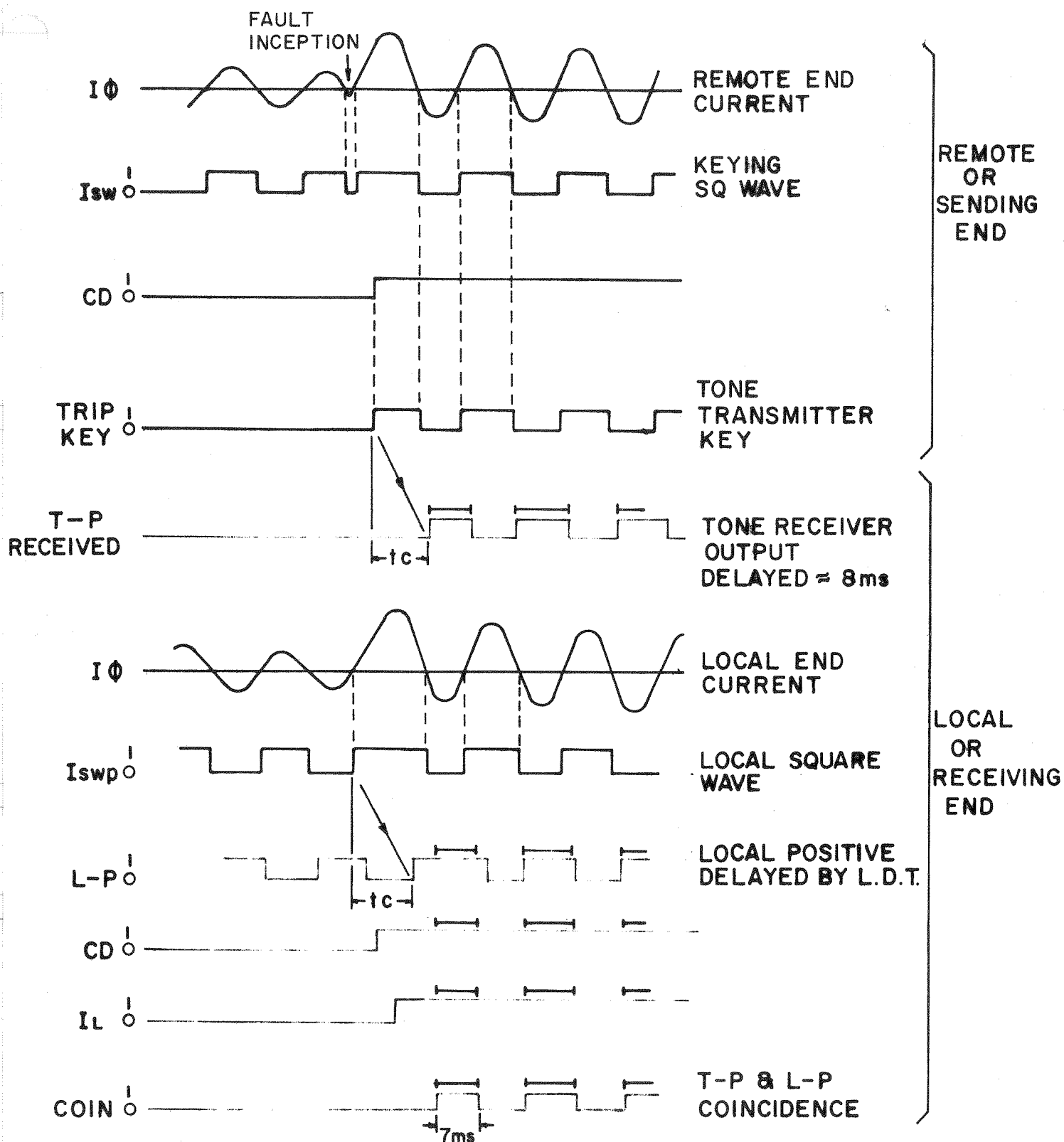
STANDBY
NEUTRAL



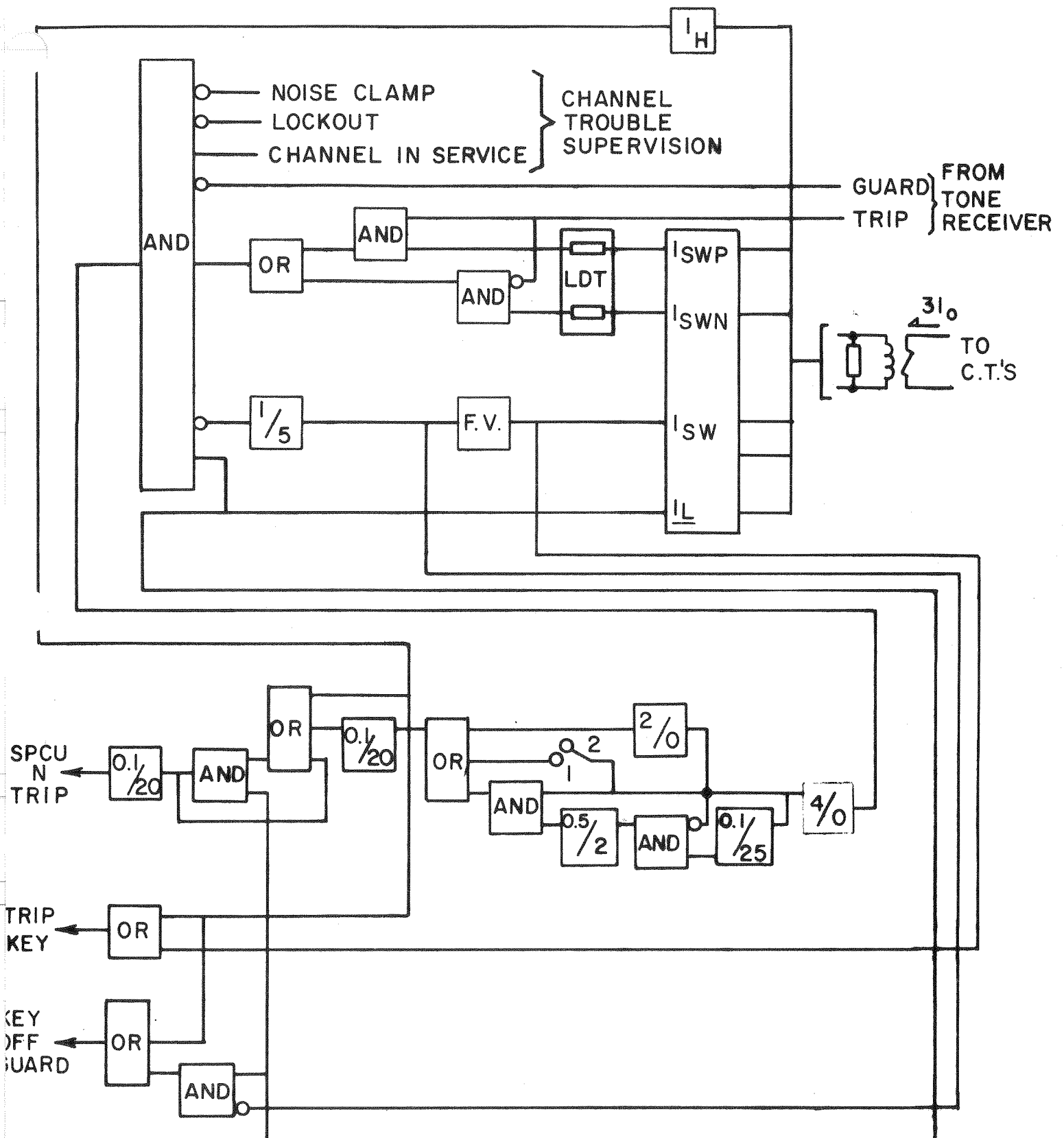
TRIP
GUARD

TONE
TRANSMITTER
KEYING

SPCU SINGLE COMPARE MODE

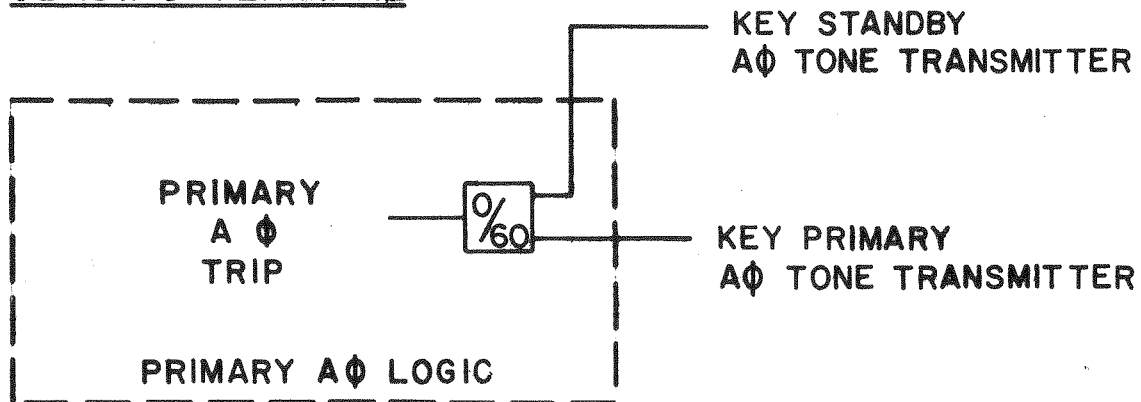


SPCU LINEUP FOR INTERNAL FAULT
PRIMARY PHASE SUBSYSTEM

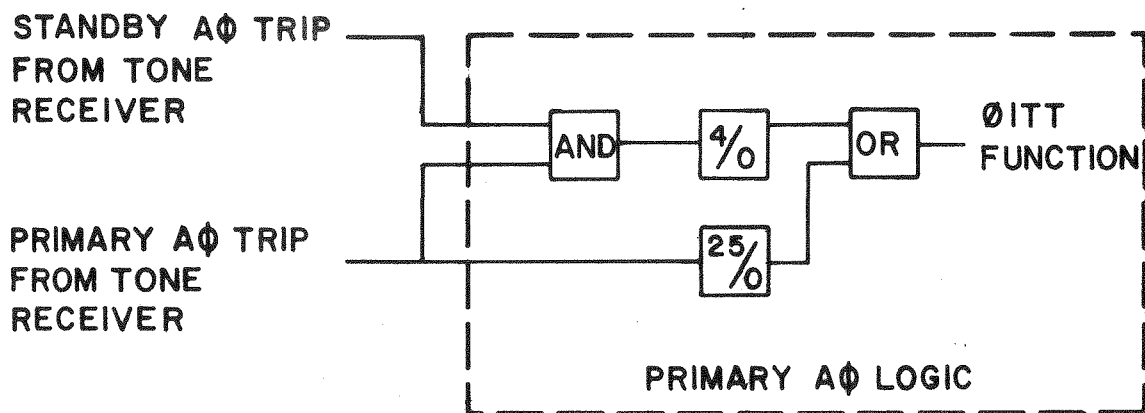


BASIC SPCU N LOGIC

SENDING TERMINAL

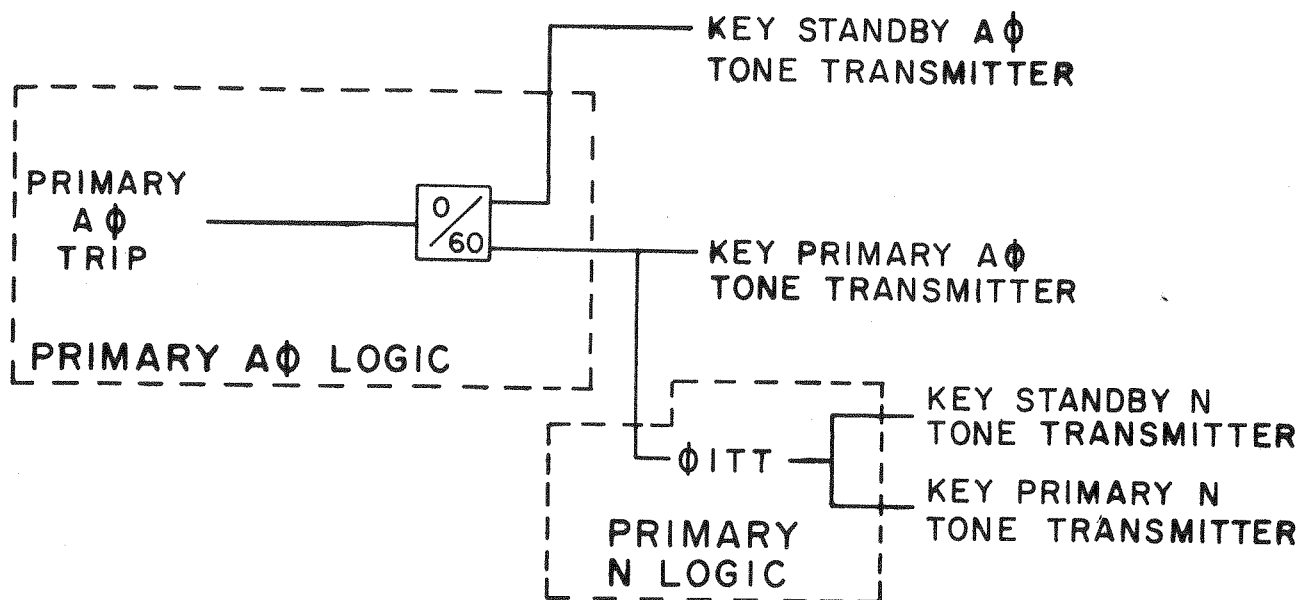


RECEIVING TERMINAL

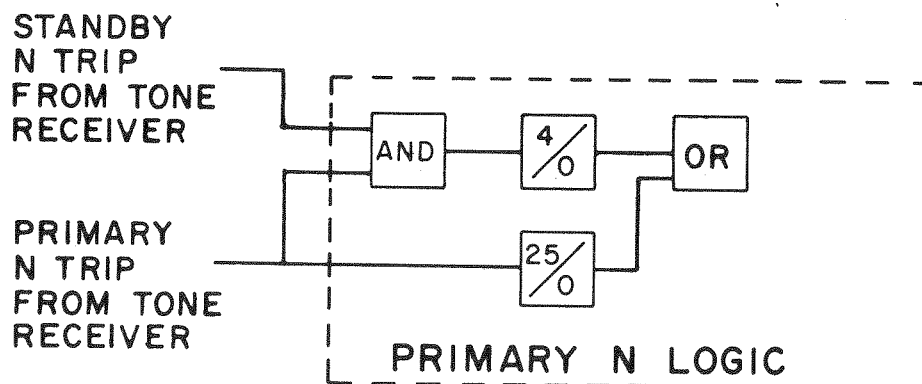


ØITT - PHASE IDENTIFIED
TRANSFER TRIP LOGIC

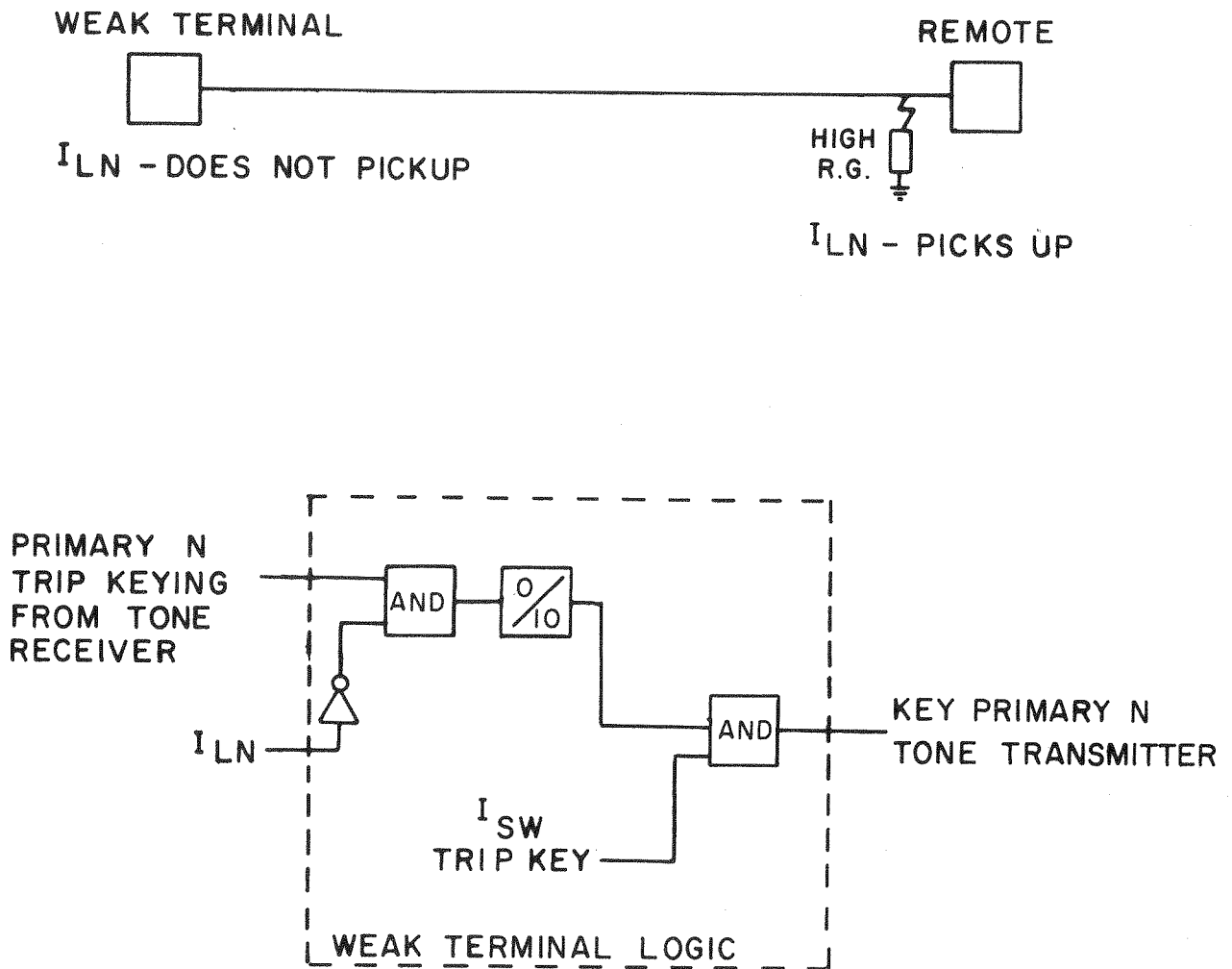
SENDING TERMINAL



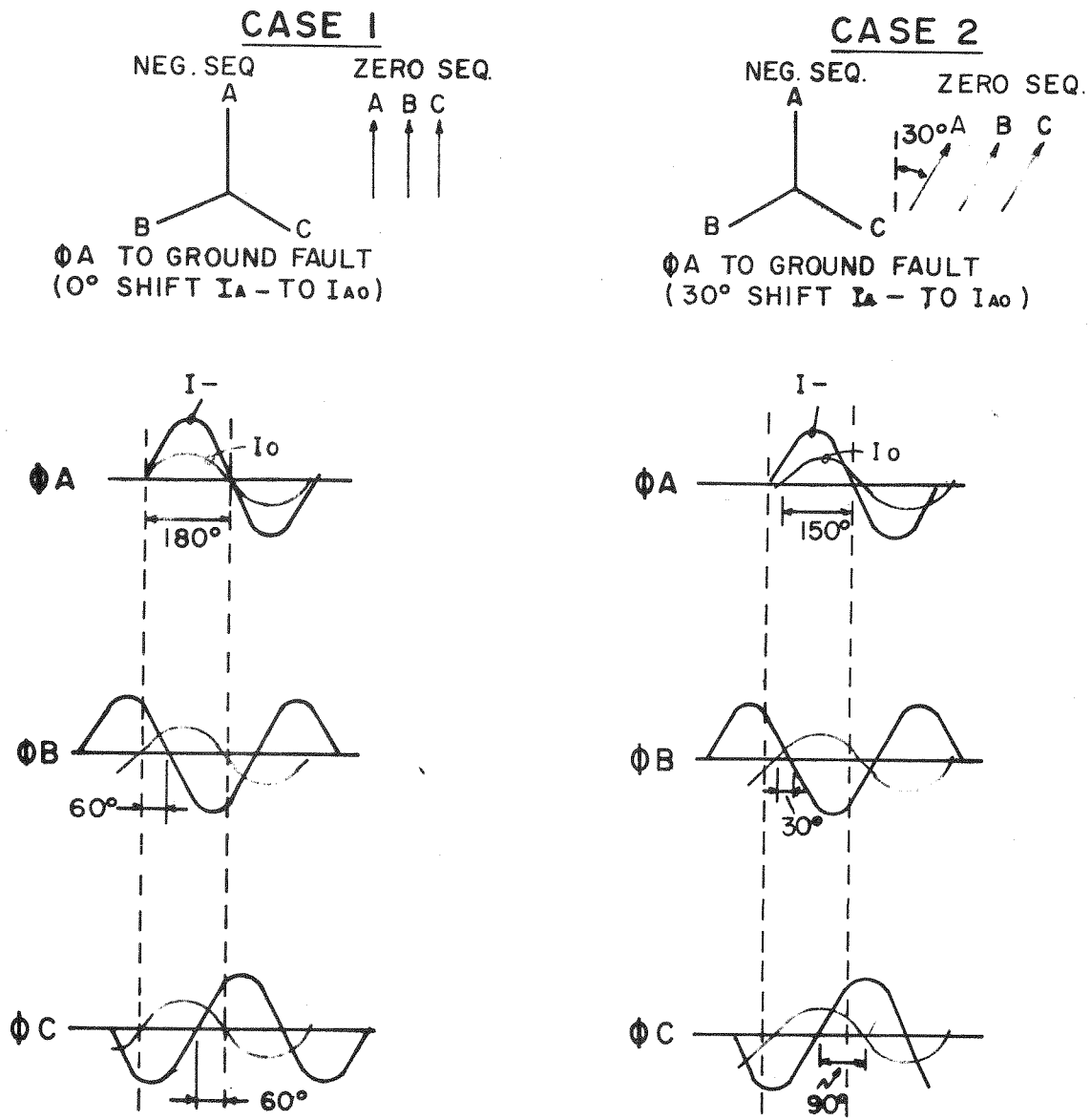
RECEIVING TERMINAL



TTN – TRANSFER TRIP NEUTRAL LOGIC

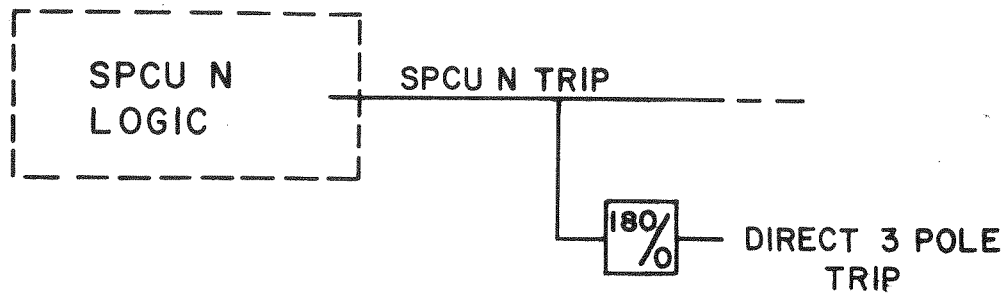


I_{sw} NEUTRAL SYSTEM RETURN KEYING CIRCUIT



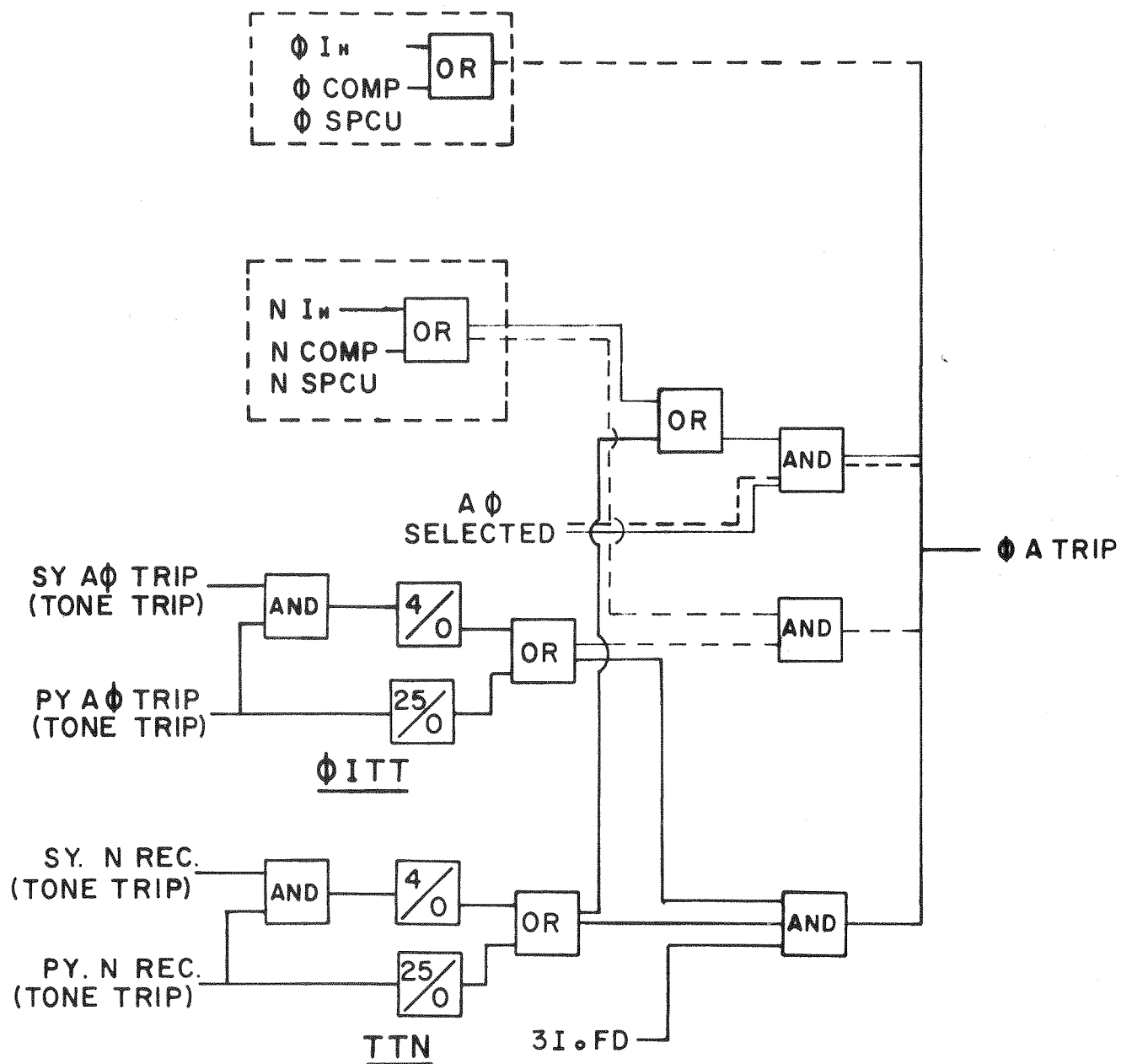
- PHASE SELECTORS FOR EACH PHASE
 SET FOR 5 MSEC. (108°) COINCIDENCE WILL
 CORRECTLY SELECT ΦA FOR CASES 1 AND 2

PHASE SELECTOR



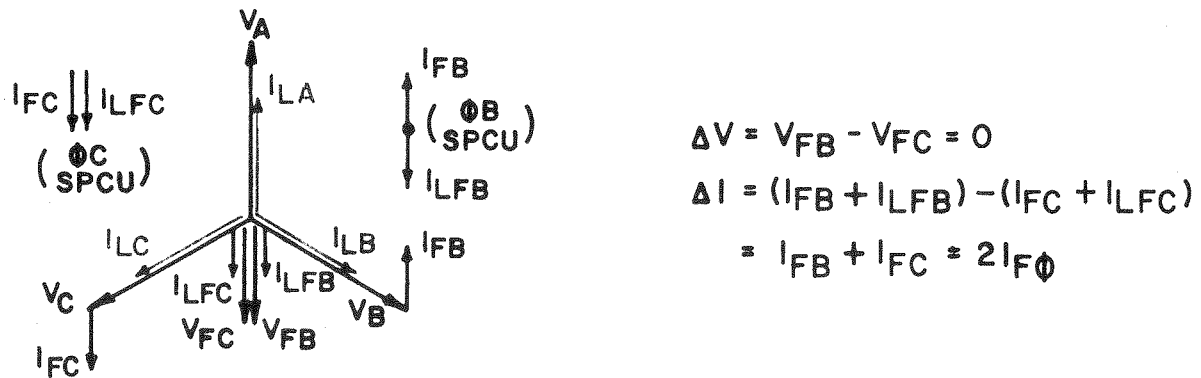
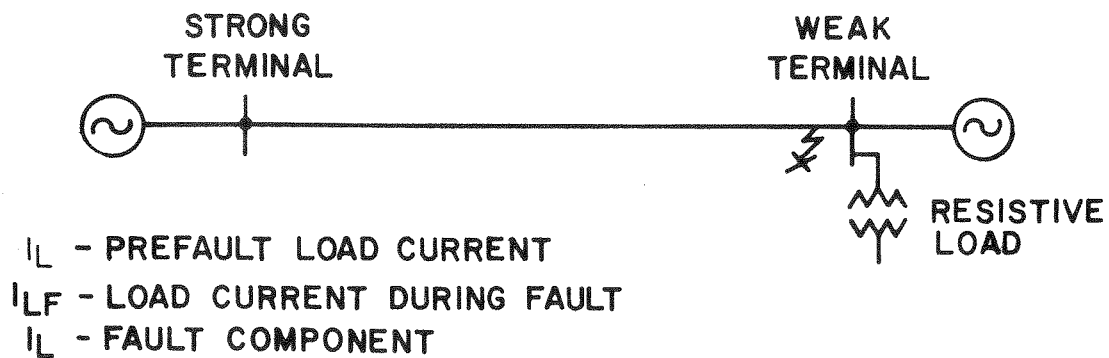
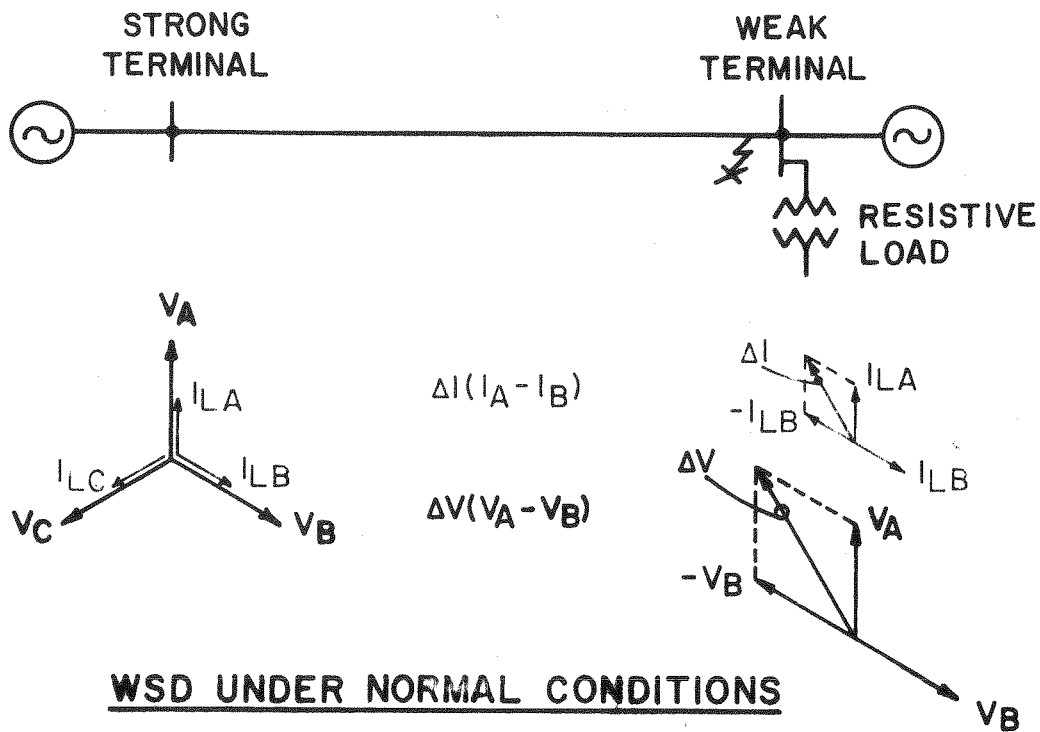
- GROUND BACKUP TIMER (180 MSEC)
SET TO OVERRIDE LONGEST SPCU N TRIP WHICH
CAN OCCUR FOR PHASE IDENTIFIED FAULT

GROUND BACKUP TRIP

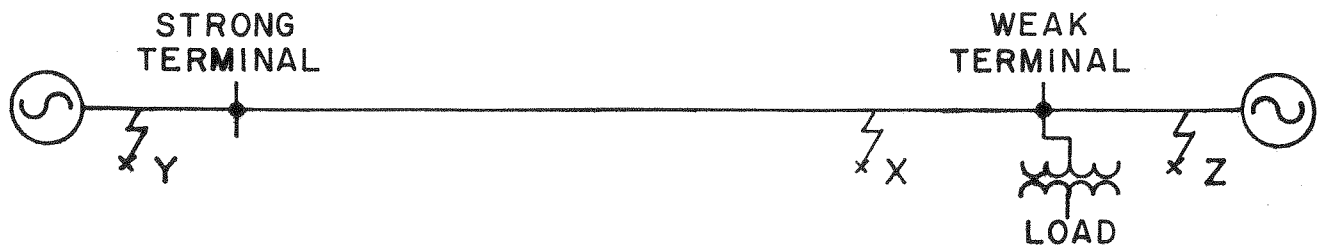


- 1) Φ SPCU I_M
- 2) Φ SPCU COMP
- 3) N SPCU I_M + Φ A SELECT
- 4) N SPCU COMP + Φ A SELECT
- 5) N SPCU I_M + Φ ITT
- 6) N SPCU COMP + Φ ITT
- 7) TTN + Φ ITT + 3I. FD
- 8) TTN + Φ A SELECT

SINGLE LINE TO GROUND FAULT TRIP PATHS



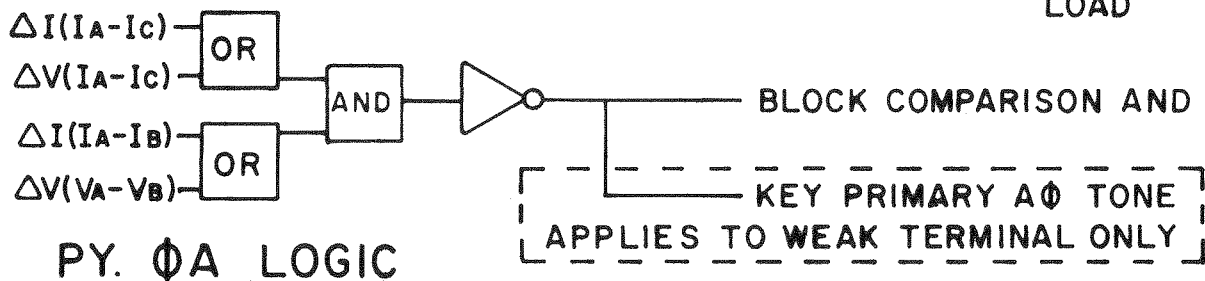
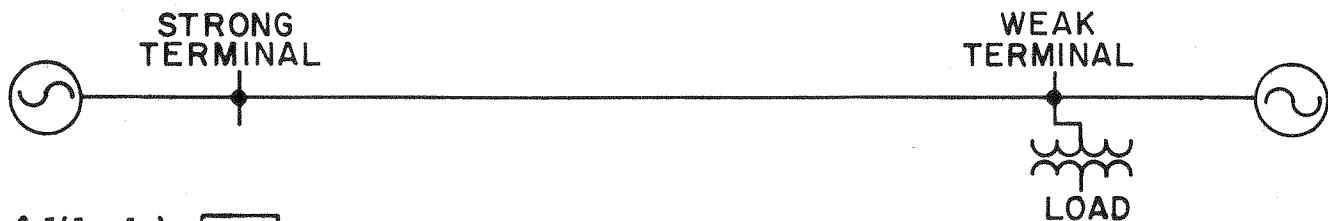
WSD WITH $\Phi - \Phi$ FAULT AT WEAK TERMINAL



FOR $\phi - \phi$ OR 3ϕ FAULTS

FAULT LOCATION	WEAK TERMINAL	STRONG TERMINAL
X	OPERATES FOR FAULTS NOT PRODUCING ADEQUATE CURRENT FOR I_{sw} KEYING.	DOES <u>NOT</u> OPERATE
Y	OPERATES <u>IF</u> FAULT IS SUFFICIENTLY CLOSE TO STRONG TERMINAL	OPERATES <u>IF</u> OPERATION OCCURS AT WEAK TERMINAL
Z	DOES <u>NOT</u> OPERATE	DOES <u>NOT</u> OPERATE

WSD OPERATION TABULATION

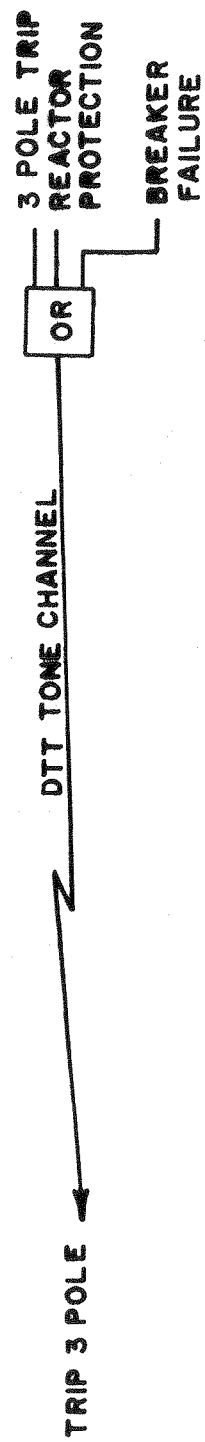
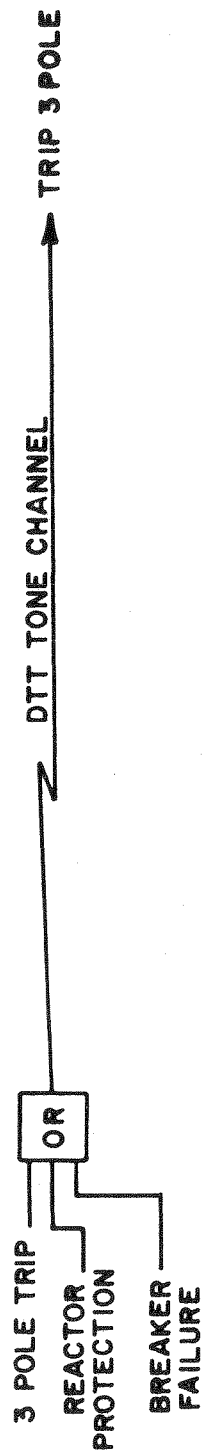
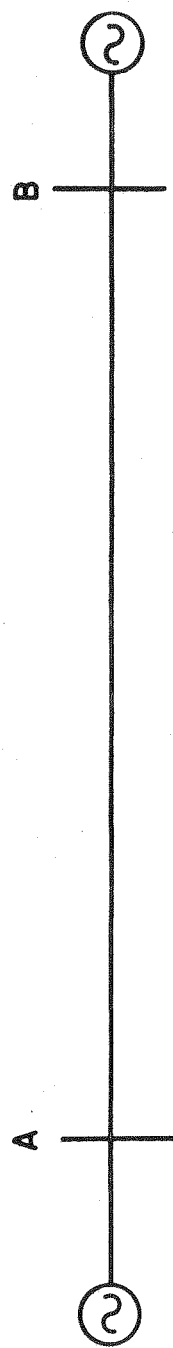


NOTE = WSD OPERATION DEEMED WHEN BOTH ΔV AND ΔI DROP OUT.

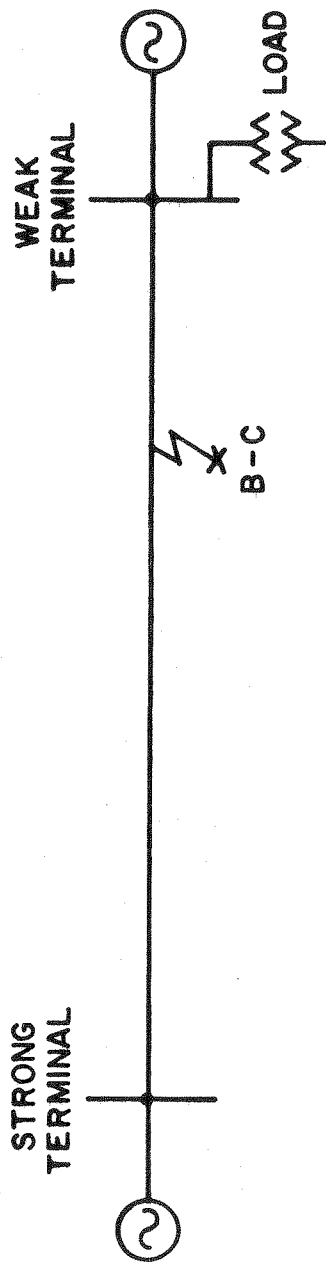
AT **WEAK** TERMINAL WSD KEYS TO STRONG TERMINAL AND BLOCKS LOCAL COMPARISON AND.

AT **STRONG** TERMINAL WSD INDICATES FAULT BEHIND STRONG TERMINAL AND BLOCKS LOCAL COMPARISON AND.

WSD FUNCTIONS



DTT FACILITY

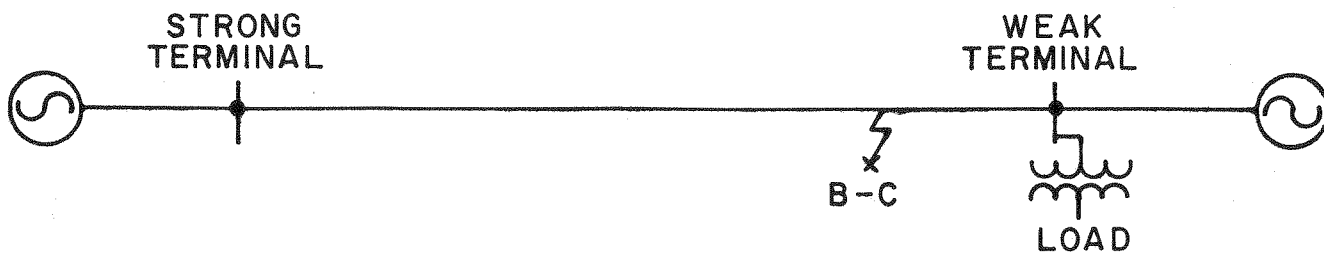


- WITH INADEQUATE CURRENT AT WEAK TERMINAL FOR SPCU Φ KEYING

SEQUENCE	STRONG TERMINAL		WEAK TERMINAL	
1			KEY Φ SPCU TRIP	
2	Φ COMP.			
3	TRIP 3 POLE		KEY DDT	
4				
			TRIP 3 POLE	

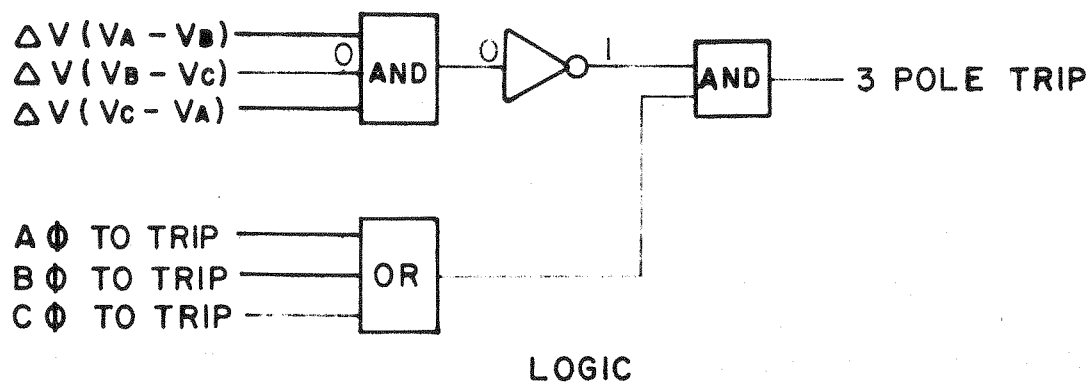
NOTE: ABOVE OPERATION SHOULD OCCUR FOR BOTH ΦB & ΦC

OPERATION OF WSD AND DTT



CONDITIONS:

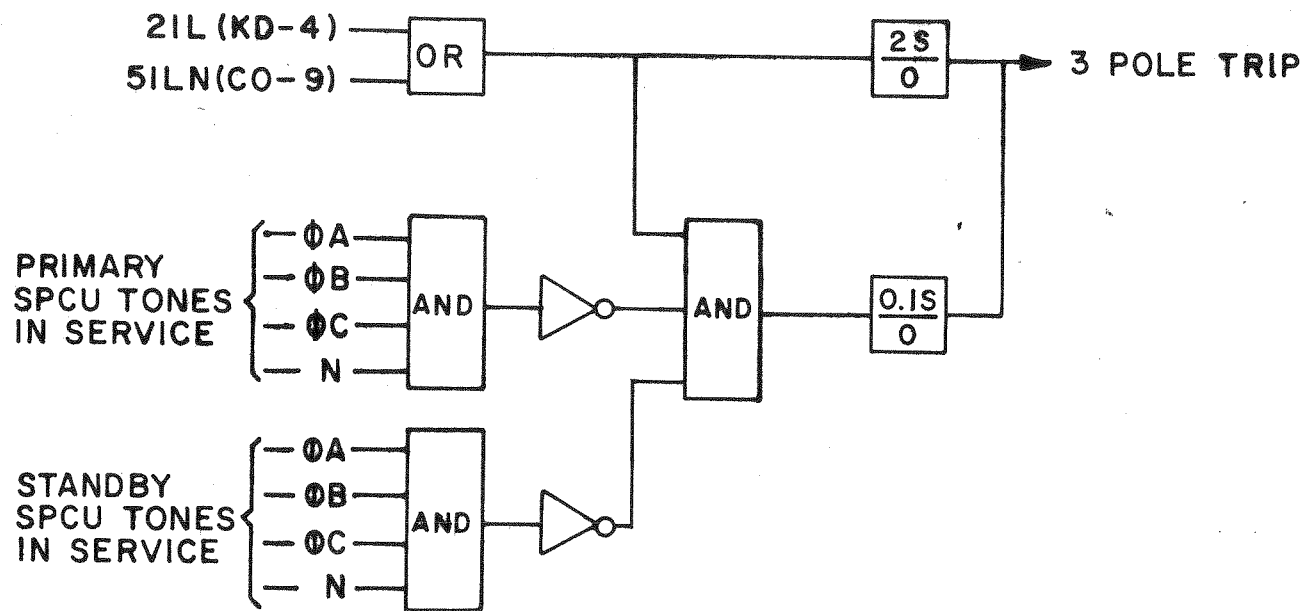
- C ϕ SPCU COMPARISON OCCURS
- B ϕ BLINDED BY LOAD AT WEAK TERMINAL



UNDERVOLTAGE 3 POLE TRIP

- 1) 2 ϕ SPCU I_H
- 2) 2 ϕ SPCU COMP
- 3) 1 ϕ SPCU COMP + ΔV
- 4) DTT

PHASE TO PHASE FAULT TRIP OPTIONS



- NORMALLY 2IL & 5ILN OPERATE VIA LONG SET TIMER (2 SEC.)
- FOR FAILURE OF TONES IN BOTH PRIMARY AND STANDBY SYSTEMS 2IL & 5ILN REVERT TO SHORT TIME (0.1 SEC)

CHANNEL INDEPENDENT BACKUP PROTECTION

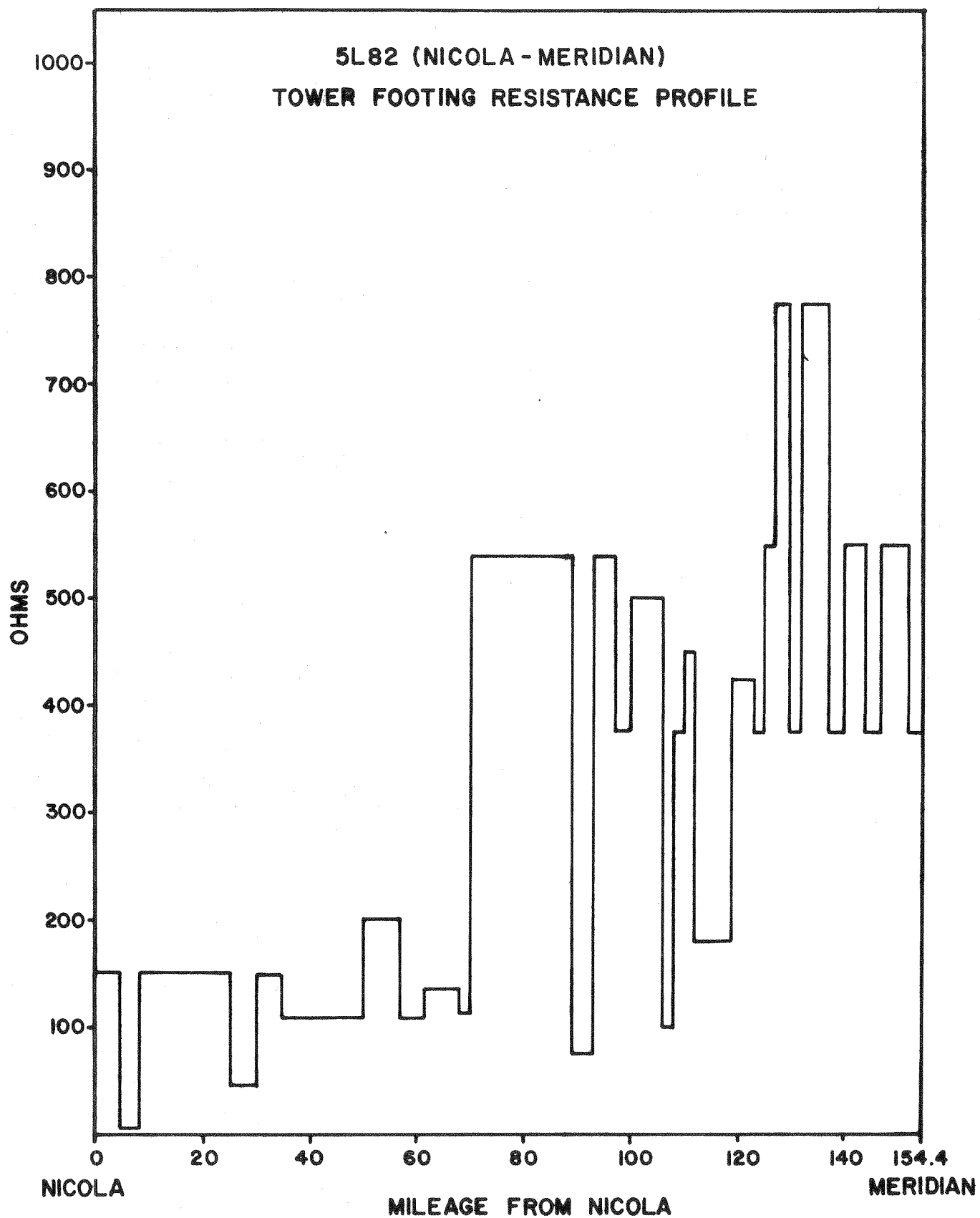


FIG. 20

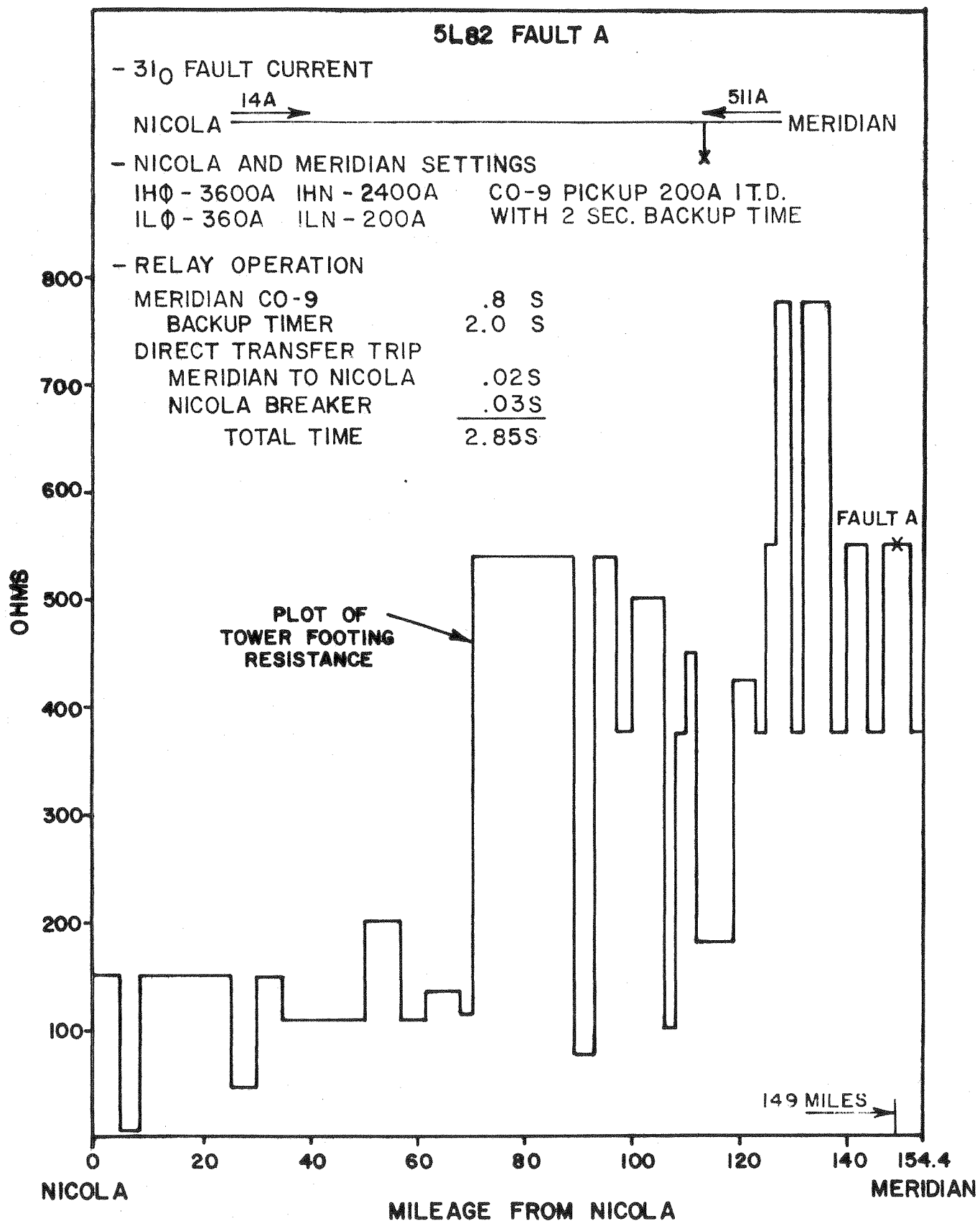


FIG. 21

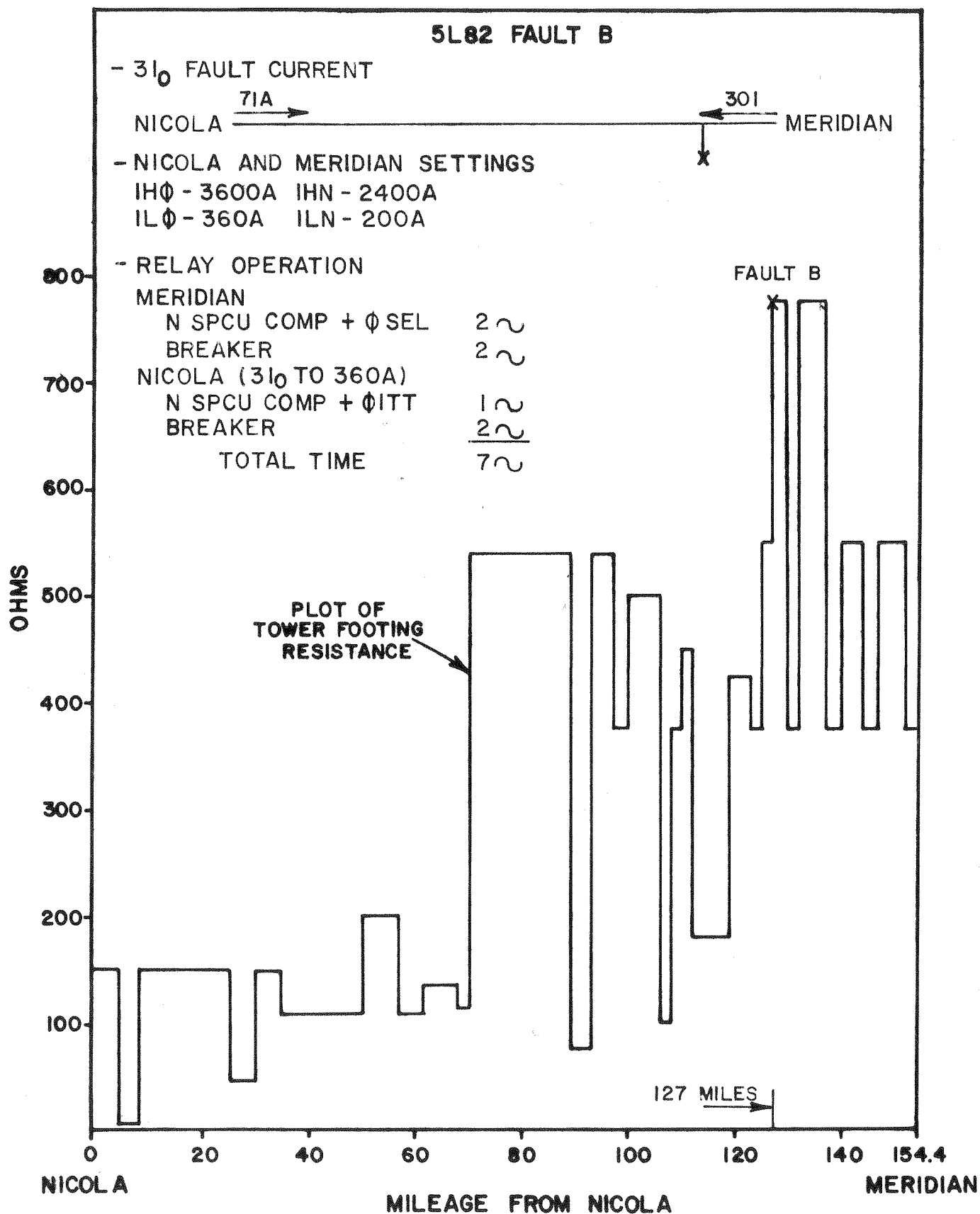


FIG. 22

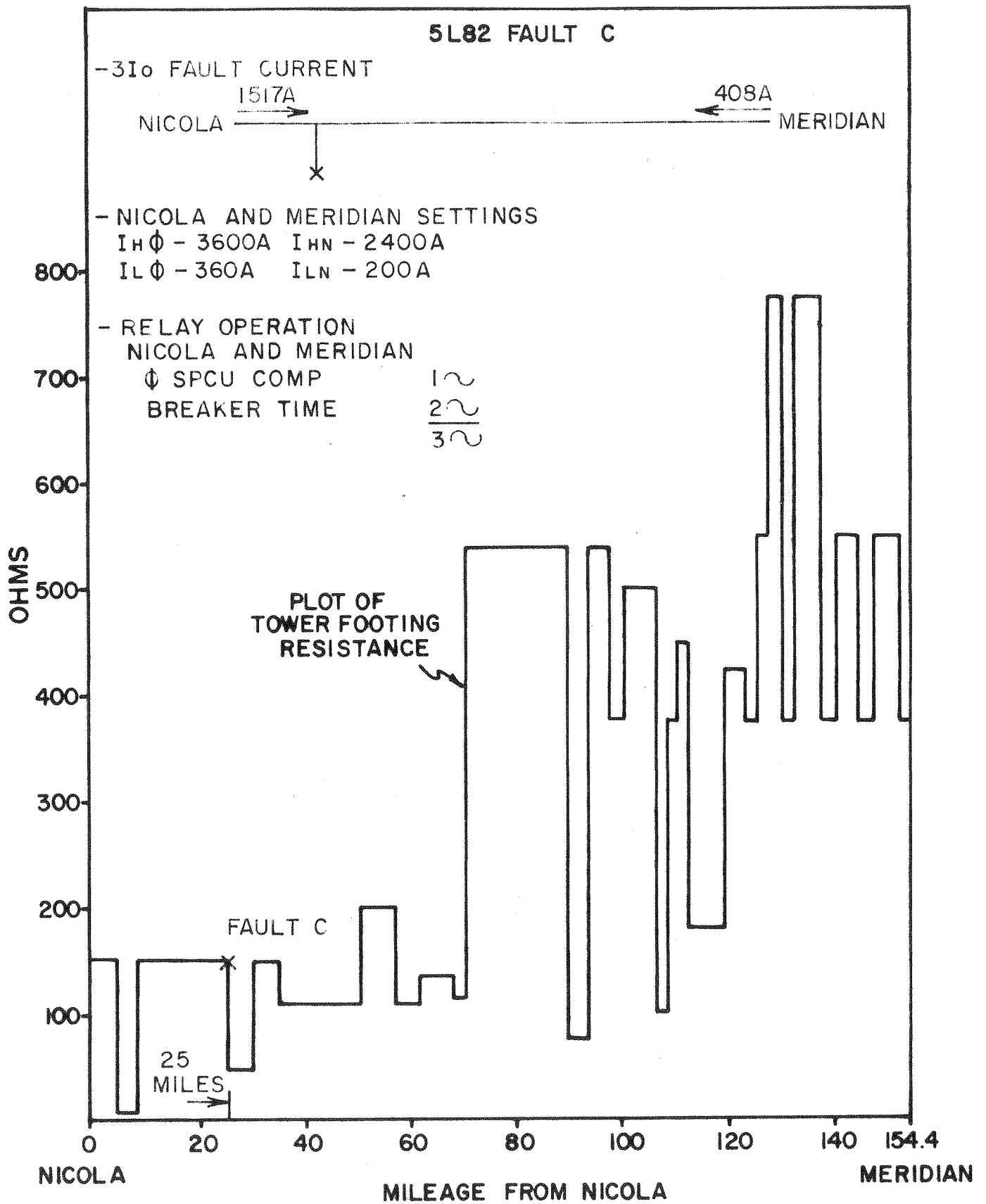


FIG 23

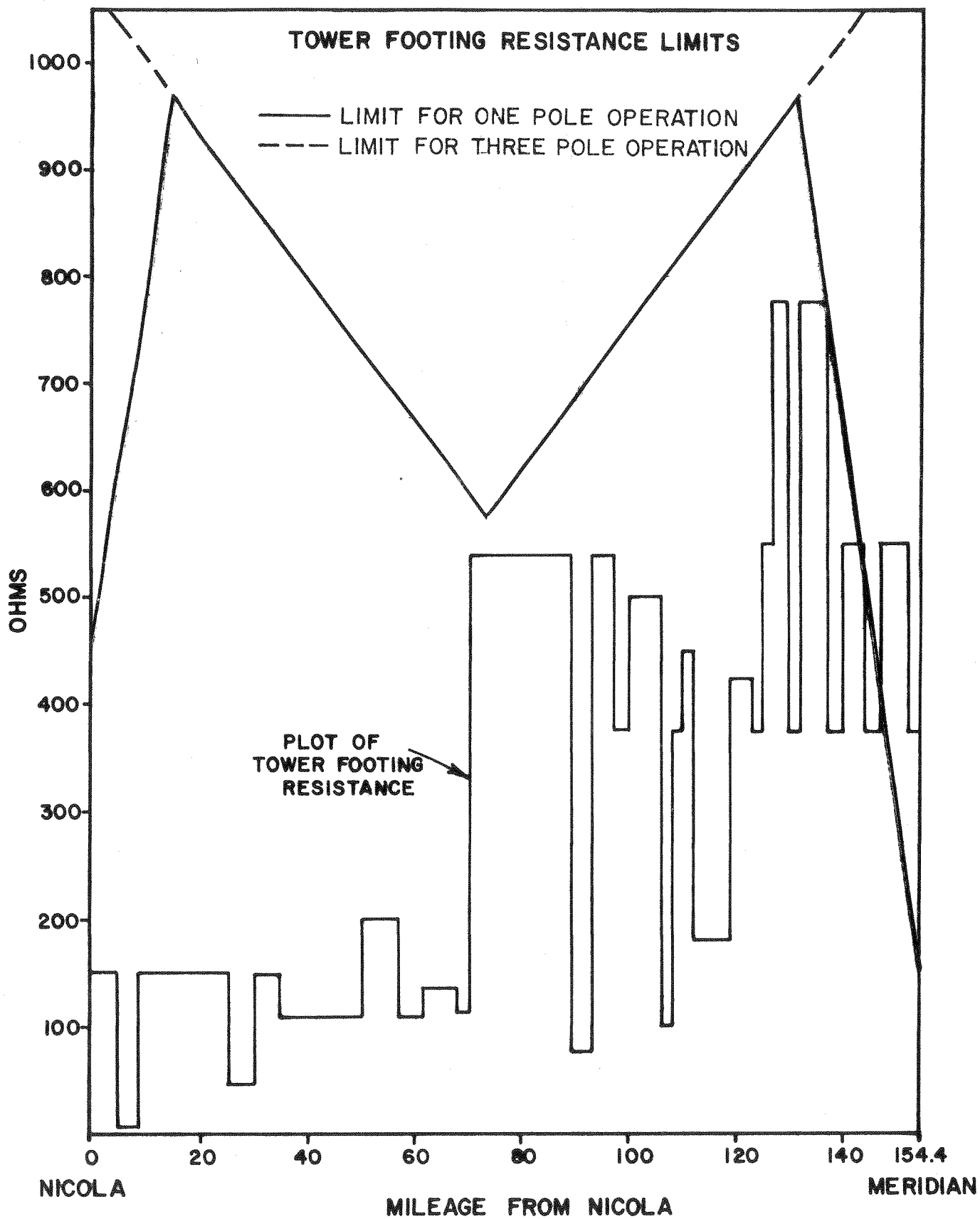


FIG. 24

CORPORATE ECONOMIC MODELING
ENCOURAGES RELAY STANDARDIZATION

C. P. DALPIAZ
D. T. NORMAN
UTAH POWER & LIGHT COMPANY
RELAY ENGINEERING

PRESENTED AT THE OCTOBER 1978
WESTERN PROTECTIVE RELAY CONFERENCE
SACRAMENTO, CALIFORNIA

TABLE OF CONTENTS

	<u>Page</u>
I. ABSTRACT	1
II. INTRODUCTION	1
III. MODELING TOOLS	3
IV. PROTECTION AND CONTROL EQUIPMENT STANDARDIZATION	5
V. USE OF STANDARDIZED/COMPUTERIZED DATA	5
VI. OTHER SPINOFFS	6
VII. SUMMARY	7

I. ABSTRACT

Rapidly varying economic considerations make corporate planning very dependent on multiple-case evaluation. Computer modeling of many of these considerations as inputs to an overall corporate model allows examination of available alternatives. Standardization to assist in computer modeling by providing building-block estimating modules also spins off benefits in relay panel design, application, personnel training, and faster construction cycle times. Many companies already use standard packaging which can be computer-listed for estimating. This method of organizing equipment, accounting and approval procedures to accurately project time and money required is very beneficial when a vigorous construction program is being pursued.

II. INTRODUCTION

Why is there a need for a Corporate Model? The increased usage of electric power, due to a strong economy in Utah Power & Light Company's service area, has resulted in an unprecedented Company growth rate. The cost of providing increased service has escalated faster than the regulatory commission has granted rate relief. Financing this record high level construction program requires an unprecedented amount of outside financing in the current competitive money market.

Management at Utah Power & Light Company needs fast answers to several questions. For example: When to ask for a rate increase? How large? Should bonds or stock be sold? Should short-term loans be used? Corporate modeling needed to be developed to simulate the present needs and forecast the future capital requirements of Utah Power & Light Company.

Management first wanted to develop a financial model that would be 100 percent correct in its internal logic. That is, the model would make use of the present bond rate, rate base, tax laws, etc., and then from the projected construction budget forecast, provide the various performance evaluation ratios shown in Table 1. From these ratios management could plan the financial program for the Company according to various scenarios run for examination. To be most effective these scenarios must closely parallel the actual Company expansion requirements and associated costs.

Various Company departments (Planning, Rate, Marketing, Engineering) joined together to forecast the percent growth rate, percent spinning reserve, and capital expansion required. Management then ran sensitivity analyses with the financial model, fluctuating the parameters and monitoring the results. When certain ratios went out of tolerance they were noted, then the inputs were varied, other case studies were run to identify the most critical inputs and the best alternative.

This initial method of analysis required every department to produce one year, five year and ten year construction budget forecasts for every variation management needed. Because of time requirements and manpower limitations, only a limited number of alternatives could be explored. The best possible solution could easily be overlooked.

To cope with these estimating problems, each department in the financial model was asked to produce models for their input. Then, when the forecast scenario changed to add or defer transmission lines, delay plant construction, etc., the computer could be used to quickly calculate overall numbers for many case studies, in order that the best one could be chosen. Once the chosen plan was selected, these modular listings could be used to plan the various department activities.

In developing departmental models, the first requirement was usefulness to that department. It was not meant to be an added chore that needed to be done in addition to the normal work load, but rather the model needed to streamline exactly what was being done by hand. This was one factor which necessitated consideration of a modular or standard package approach.

Personnel addition and turnover are also problems during expansion, as new positions open and engineers move from section to section. Although "standard" equipment complements were already being used, the detail assembly was being re-engineered for each new application, requiring the engineer to study details before grasping concepts. This was true in all sections, but especially in protection and control, where preparation of wiring and schematic drawings was fast becoming a bottleneck. Estimating at budget time was too often done by engineers who did not have enough time or

experience to foresee all the required expenditures. Consequently, missed estimates, both high and low, compounded the financial planning problem both with shortfalls requiring high-interest borrowing, and with overcompensation and unnecessary borrowing.

Operating departments are faced with similar personnel problems during expansion, and designs which are completely re-done for each new facility hamper ease of operation and maintenance. Training of operators and technicians is much easier with some "standard" practice to learn, where deviations are minimized. Also, consistent design practice allows eventual optimization, whereas random problem-solving leads away from ease of operational training.

Closely regulated accounting procedures and approval routing paths can also forestall equipment requisition to the point that project schedules are adversely affected. The corporate model can also point out the need for early approval of long-term projects by developing work schedules similar to critical-path modeling. Availability of these schedules to the various sections and departments can help integrate the total work effort, rather than completing parts of different projects randomly.

III. MODELING TOOLS

Moving from the overall Corporate Model to the Engineering Department sub-model, an analysis of the planning method divides into several "Budget Items," as shown in Figure 1. Each of the Budget Items concerns a needed addition, whether large or small specific items, or ongoing general items. For example, a specific item might read "400 MW unit X-1 and associated transmission facilities," whereas a general item could be "transmission system improvements up to \$20,000."

Budget Items usually affect several locations within the Company, and federal regulations require that each location be accounted for separately. The accounting vehicle used is the "Expenditure Requisition" or "ER." A Budget Item for a new stepdown substation would include separate ER's for the source substation termination, the transmission line, the new substation, feeder line taps and re-conductoring, and any communication links required.

In the process of developing the Engineering Model, two new levels of description were defined, although more could be used, if felt necessary. The first is the "module," which is a functional grouping of all the components necessary to build a particular portion of the substation or addition. The second and lowest level of definition is the "hardware item." This level provides the components which group to become a module. Another reference to Figure 1 shows this relationship. The terms used in UP&L's organizational assembly are probably similar to terms used by other utilities in their budgeting and accounting process.

The various sections within the Engineering Department used the above tools in slightly different fashion. Reference to the various sheets of Figure 2 will show the definition of "functional" modules chosen by Substation Design, Relay, Communications and Transmission Line Engineering. Each section's listings are on a somewhat different plane than the others. This is a decision which each section makes, and involves their individual practices in procuring equipment. Some buy components for assembly within the Company, and others buy assembled units from outside manufacturers. The modeling tools are available in either case. Figure 2-D, the relay modules, also shows an early attempt to segregate the various types of labor involved in a project, so that forecasting and detailed comparison to actual would be possible. This will be approached on a department scale, and each section can define up to nine different types of crews on many different types of work. For example, on a power transformer, specifying and ordering, unloading, foundation work, locating, assembly, HV wiring, control wiring, and checkout can all be individually estimated, searched, forecasted, and accounted. Some time is required, after training of crew supervisors on documentation, before valuable data becomes available concerning forecasting, however. A commitment to the method is as important as the method itself, and considerable attention must be paid to motivating the field personnel.

IV. PROTECTION AND CONTROL EQUIPMENT STANDARDIZATION

Segmenting of equipment into hardware items was done, again, functionally by UP&L's Relay Engineering. The functional level grouped several components onto a standard sized panel of 90 inch height and width in multiples of 10 inches. Protection was separated from control, and types of each were indexed, i.e.: transmission line, sub-transmission line, substation equipment, etc.

Each panel is documented with a description, specification sheets, and drawings. The description contains application data, design notes, and setting guidelines. Two specification sheets are used to list the two major component manufacturers' items as well as other items. These sheets are supplied to panel vendors for bidding. Two sets of drawings in mylar reproducible form are available, presenting panel layout, wiring, and schematic information for the panel using the two major manufacturers' components. After selection of manufacturer, one of the mylars becomes a part of the drawing file for that particular station. Several descriptive photographs of the standard panels are included.

V. USE OF STANDARDIZED/COMPUTERIZED DATA

A. Estimation and Approval - Gathering of cost estimate data into organized Expenditure Requisitions has been greatly simplified, increasing the chance of quick approval of optimized configurations while the facts of the problem are still fresh in the minds of management. Refer to Figures 3A & 3B which describe the total costs of a small 138/46 kV substation.

B. Design - Engineering and drafting costs can be significantly reduced. For example, on a 345/138 KV substation recently done, Relay Engineering showed that since only interconnection of standard panels is required, and that since mylar reproductions of standard linens can be used for 70% of the drawings of the protection and control equipment, 66% of the former engineering and drafting effort was saved. This amounted to about \$15,000.00 on a station of the size investigated, and allows for slight modifications (10%) to the protection and control circuits to custom-fit the installation.

C. Procurement - As the designs solidify, and bidders become more aware of the repeatability of the hardware items, cost and delivery should tend to reduce. Also, as usage history develops,

some stocking of frequently used panels could be undertaken. A sample material forecast is shown in Figure 4.

D. Construction - The free-standing arrangement allows rapid cabling and wiring both to other devices inside the control building and to the yard devices. Wiring lists can be easily prepared to be used by wiremen unfamiliar with the function of the panels. A segment of the schedule of events for the sample project is shown in Figure 5.

E. Checkout - The redundant nature of the panels allows a technician to move his test set from one to the next during checkout, without having to research drawings completely to verify function. Also, increased familiarity with the panels allows more detailed testing, increasing reliability.

F. Maintenance & Modification - Interchangeability of components and standardization of protection and control philosophy allows rapid maintenance on a periodic basis. Also, upgrading of these functions by panel replacement becomes more straightforward as the role of a substation increases in importance.

G. Corporate Planning - The ability to vary planned facility configuration quickly and accurately improves the selection of alternatives. The tracking of costs related to projects approved and underway allows financial reserve planning to operate with less margin. These two effects combine to provide a significant reduction in escalating costs to the customer.

VI. OTHER SPINOFFS

A. Training - The standardized documentation of each hardware item allows all levels of users to be trained more rapidly and effectively. Engineers, drafters, and technicians can all be given the big picture, with effective restraint on non-standard solutions to relaying problems.

B. Application Considerations - Arguments over detail wiring and connection methods can be elevated to discussion of the correctness of the overall protection or control equipment application. Also, the standard serves as a point from which to start when control and protection philosophy changes occur.

V. SUMMARY

The Relay Engineering and Relay Maintenance sections at UP&L have used the corporate model/standardization program to critically examine the physical and electrical protection and control methods in use and to optimize them for maximum benefit. The Engineering Department as a whole has provided itself with faster estimating, training, procurement and overall construction cycle times. The Company has much more accurate input to it's financial model and thereby much more efficient financial requirement guidelines.

FINANCIAL MODEL OUTPUT

Ratios	1977	1978	1979	1980	1981
LONG TERM DEBT AS PCT OF TOTAL CAPITAL	48.9582	50.1197	49.9680	49.9751	49.9611
PREFERRED STOCK AS PCT OF TOTAL CAPITAL	10.7945	9.7578	9.9936	9.9950	9.9922
COMMON EQUITY AS PCT OF TOTAL CAPITAL	40.2474	40.1225	40.0384	40.0298	40.0466
PCT EARNINGS ON AVERAGE TOTAL CAPITAL	7.3777	7.1224	7.2430	7.2640	7.3535
PCT EARNG ON AVE TOT CAP INCL ST NOTES	7.2227	7.1125	7.2336	7.2634	7.3532
PCT EARNINGS ON AVERAGE COMMON EQUITY	5.9999	6.0000	5.9999	6.0000	6.0000
EMBEDDED DEBT COST	7.5936	7.7723	7.8933	7.9802	8.0361
EMBEDDED PREFERRED STOCK COST	8.7097	8.7078	8.7594	8.7847	8.8093
TIMES INTEREST EARNED BEFORE TAXES	1.7346	2.2683	2.2083	2.3088	2.2639
TIMES INTEREST EARNED AFTER TAXES	1.8252	1.8671	1.8084	1.8039	1.7859
TIMES BOND INTEREST EARNED BEFORE TAXES	2.0241	2.5255	2.4149	2.5270	2.4906
TIMES BOND INTEREST EARNED AFTER TAXES	2.1298	2.0787	1.9776	1.9744	1.9648
TIMES TOT INT & PREF DIV BEFORE TAXES	1.3952	1.8366	1.8280	1.9122	1.8827
TIMES TOT INT & PREF DIV AFTER TAXES	1.4680	1.5117	1.4970	1.4940	1.4852
ALLOWANCE FOR FUNDS USED DURING CONST EARNINGS PER SHARE	1.4531	.5421	.4152	.1071	.0000
DIVIDEND PAYOUT RATIO	2.2228	2.1297	2.2075	2.2906	2.3737
DIVIDEND DECLARED PER SHARE	140.3634	65.7364	65.2317	64.6108	65.7214
REVENUE ADJUSTMENT -- CUMULATIVE	3.1200	1.4000	1.4400	1.4800	1.5600
	.8013	1.0488	1.1481	1.2535	1.3827

Table 1

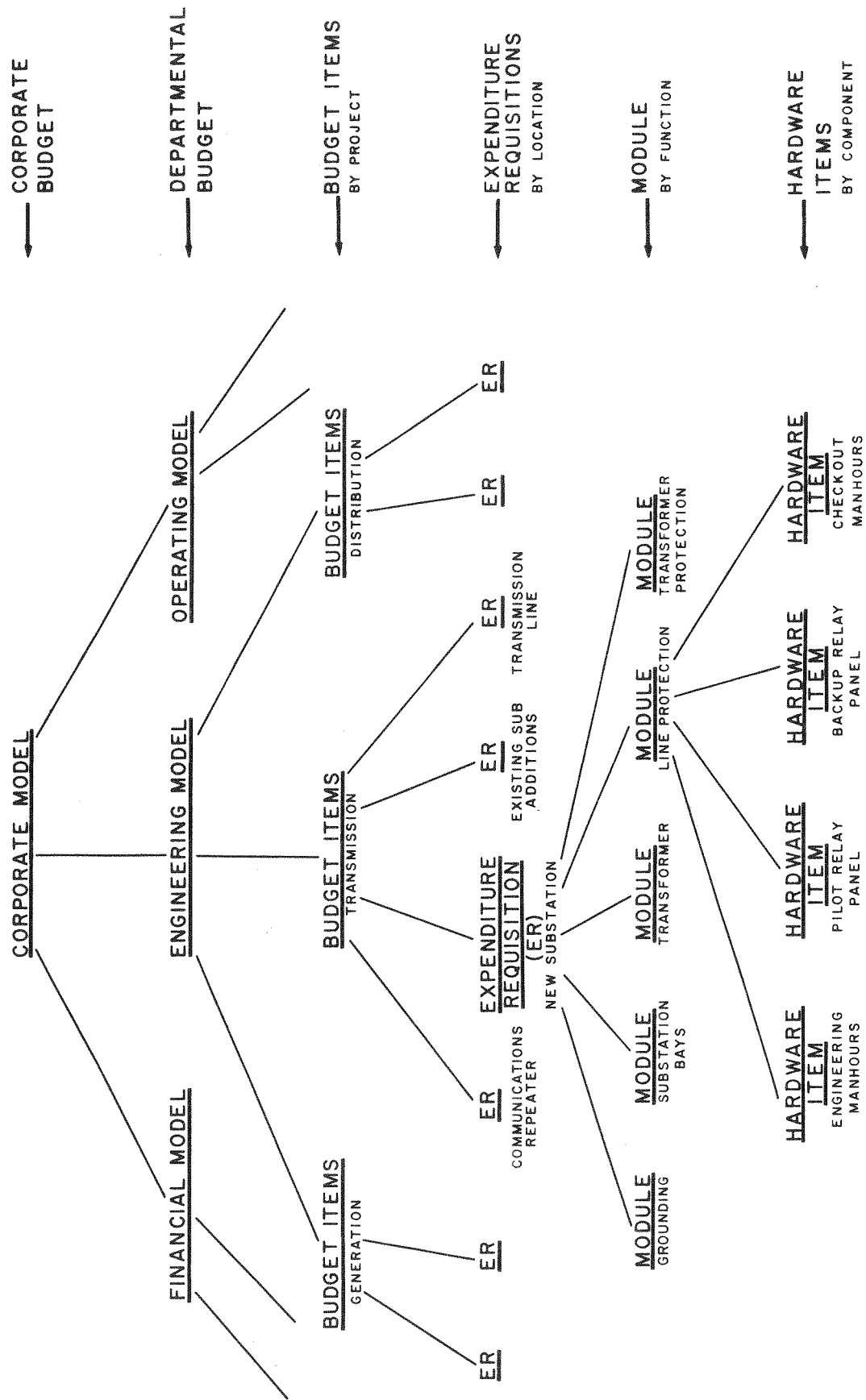


FIGURE 1
BUDGET PROCESS
HIERARCHY

[illegible]

FIGURE 2-B

RELAY HARDWARE ITEMS

FIGURE 2-C

RELAY MODULES

FIGURE 2-D

TRANSMISSION LINE HARDWARE ITEMS

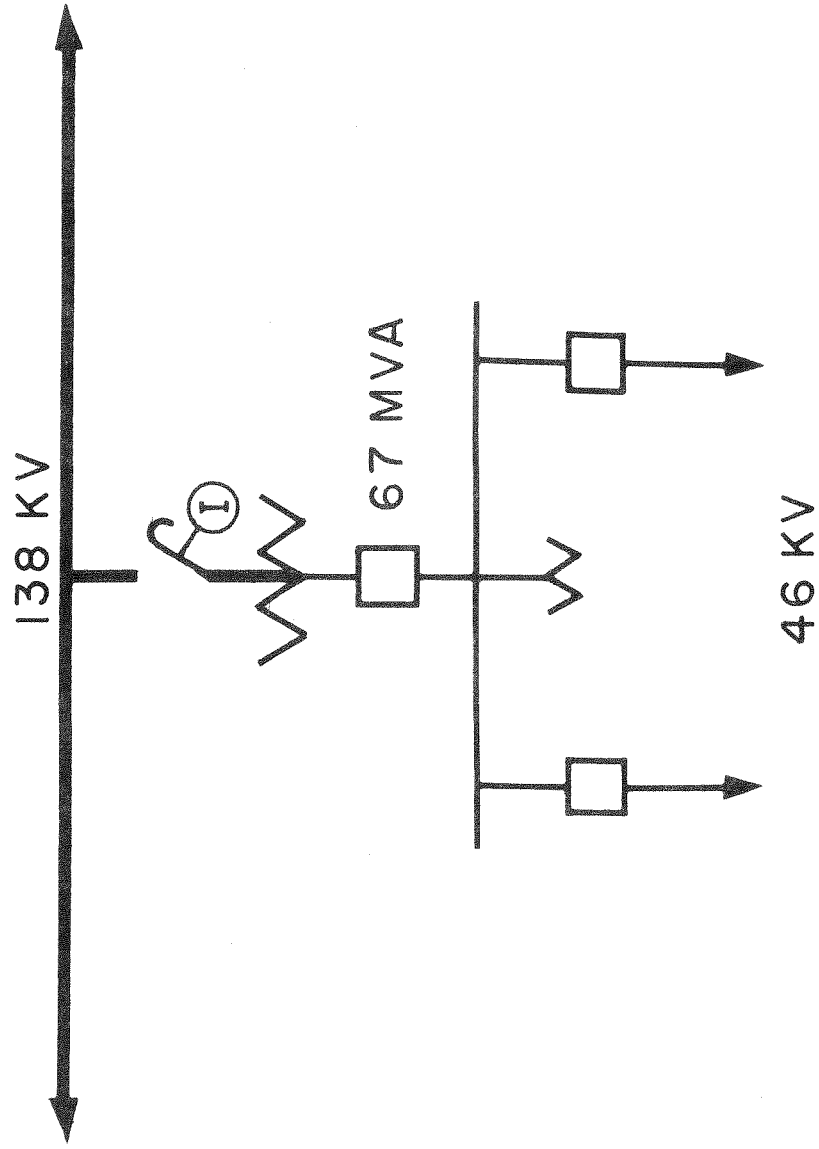
FIGURE 2-G

[illegible]

NO. 19	MODULE 721010	SUB DISPATCH CIRCUIT (RENOISE)		MATERIAL COST		MAN-HRS		*****	
TIME	QUANTITY	HDW ID	OBJECT DESCRIPTION	LABOR	ACC.	ACC.	ACC.	*****	
1	1	764	ADAPTER	255.00	100.00	255.00	37.78	12.00	*****
1	1	715	TELEPHONE LINE DIAL, WAL, BEIGE, 55413BA30M	0.00	100.00	0.00	37.78	4.00	*****
1	1	735	GENERATOR, RING, 20HZ SUPPLY 850	0.00	100.00	0.00	37.78	1.00	*****
				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.78		*****
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				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.78		*****
				0.00	100.00	0.00	37.		

COMMUNICATIONS MODULES

FIGURE 2-F



SAMPLE

WEST VALLEY SUBSTATION

FIGURE 3-A

ER NO. 8600000

LABOR COSTS

SUMMED LABOR COST =

85183.69

FACTOR

+ LABOR EXPENSE

350

29814.29

+ LABOR OVERHEAD EXPENSE

050

29814.29

+ TRAVEL TIME

051.

12777.55

TOTAL LABOR COST =

157589.69

TOTAL MATERIAL COST = 748521.56

TOTAL LABOR AND MATERIAL COST = 906111.25

906111.25

FACTOR	AMOUNT
1. <u>RECEIVED</u>	100.00
2. <u>PAID</u>	100.00
3. <u>ADJUSTED</u>	100.00
4. <u>OTHER</u>	100.00
5. <u>TOTAL</u>	100.00

+ EQUIPMENT HAULING AND RENTAL

9061.11

SUBTOTAL = 915172.31

915172.31

+ ENGINEERING EXPENSE

54910.35

SUBTOTAL = 970082.62

970082.62

+ CONTINGENCY

97008-19

TOTAL COST = 1067090.00

1067090.00

TOTAL 1067090.

1067090.

WEST VALLEY COSTS

FIGURE 3-B

[illegible]

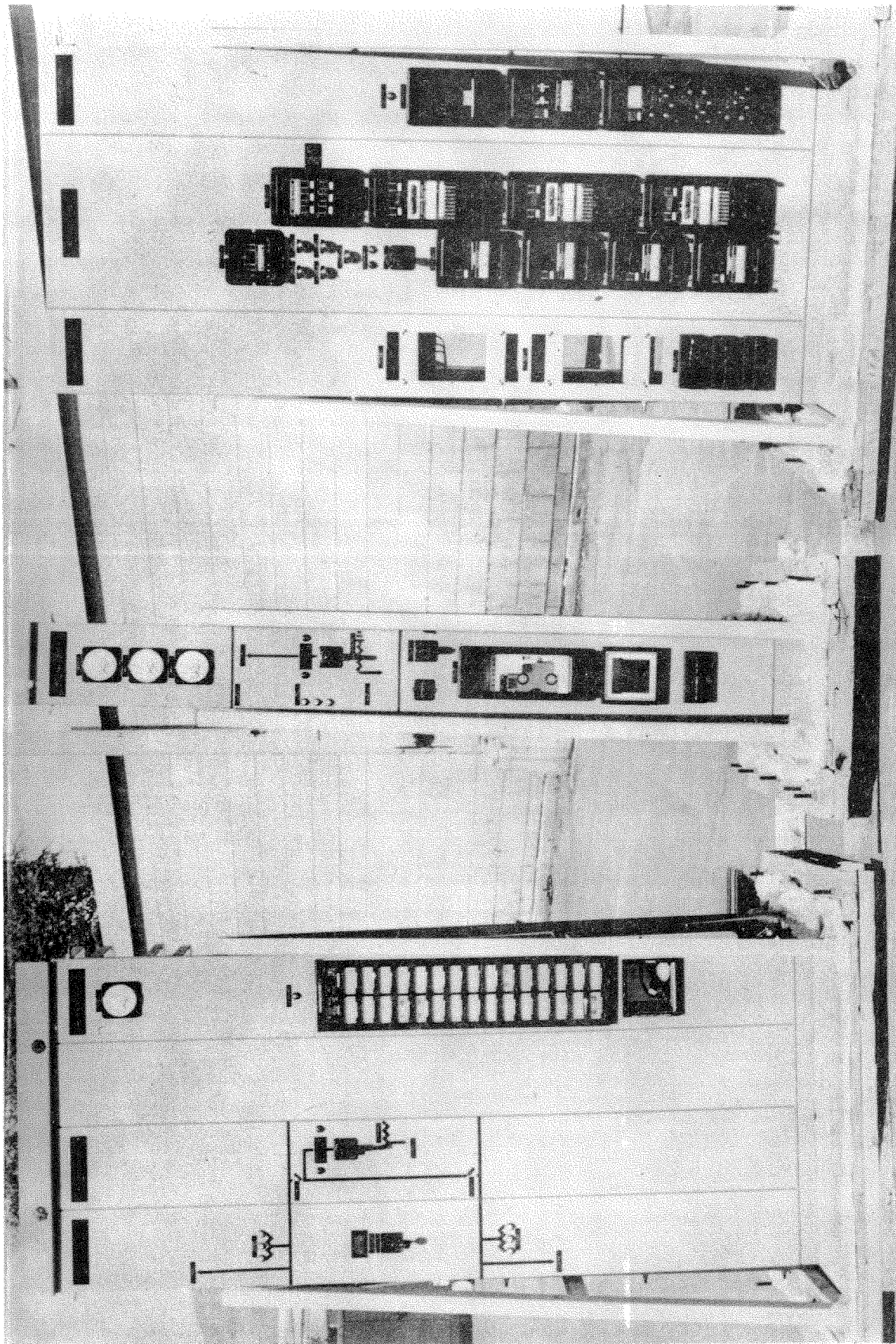
MATERIAL FORECASTING

FIGURE 4

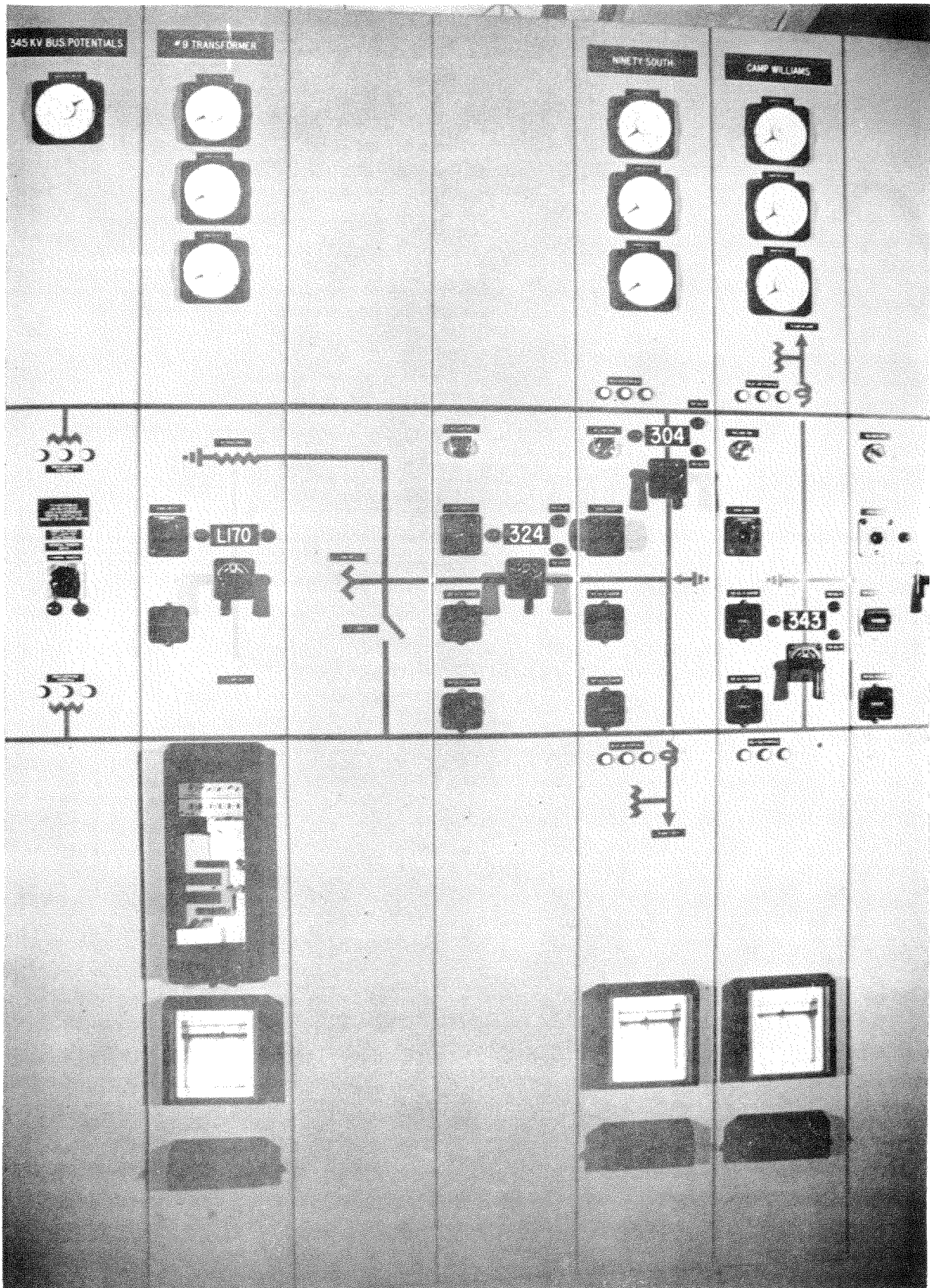
[illegible]

SCHEDULE OF EVENTS

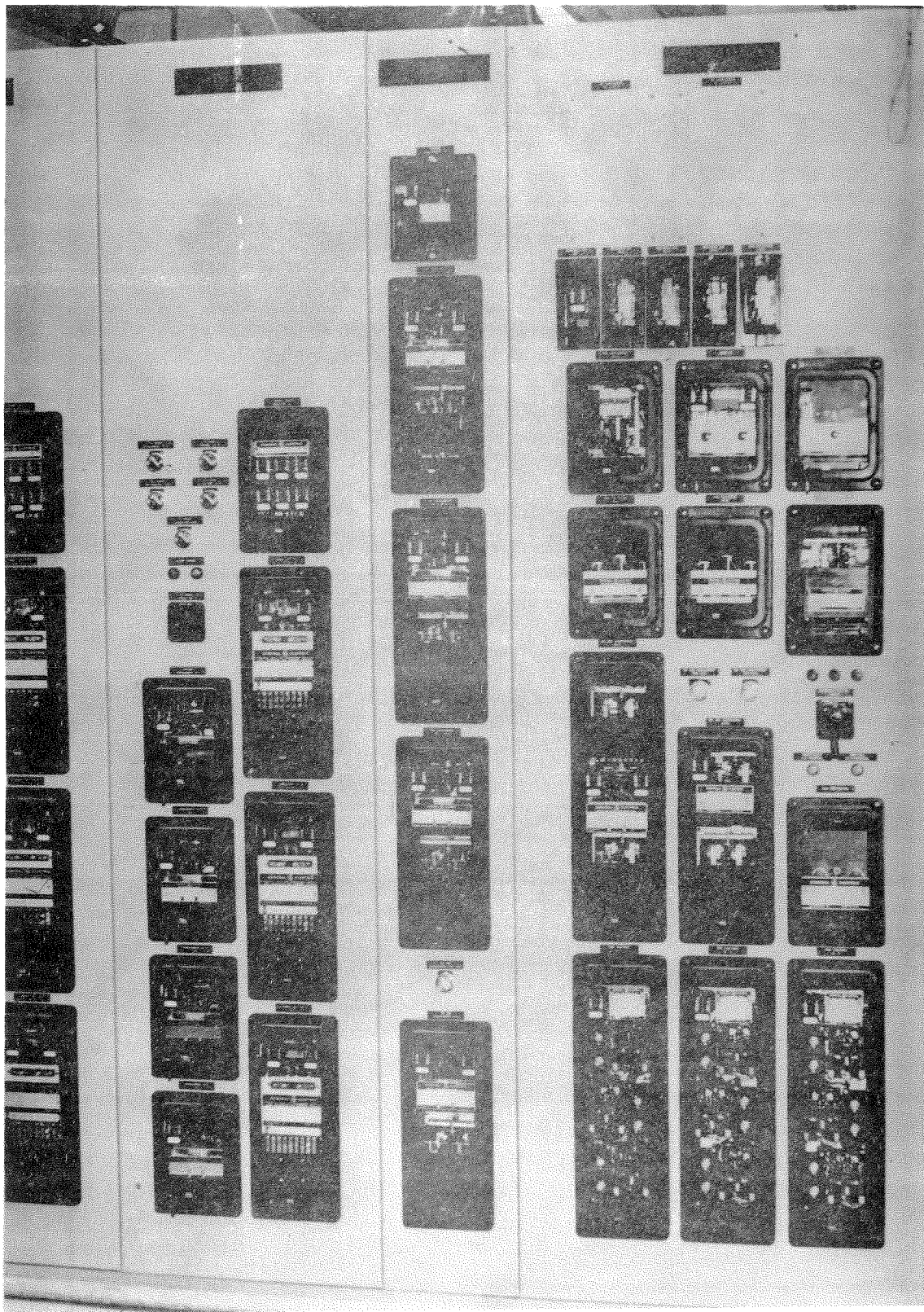
FIGURE 5



SHIPPING GROUP



CONTROL PANELS



RELAY PANELS

DYNAMIC CHARACTERISTICS OF MHO DISTANCE RELAYS

By S. B. Wilkinson and C. A. Mathews

General Electric Co.
Philadelphia, Pa.

Presented to
Western Protective Relay Conference
October 16-18, 1978

DYNAMIC CHARACTERISTICS OF MHO DISTANCE RELAYS

INTRODUCTION

For many years phase mho distance relays, of both electromechanical and static design, have used memory action to produce a short duration output for zero voltage faults at the relay location. The polarizing circuit contains a tuned circuit and, in effect, "remembers" the prefault voltage long enough for the relay to make a decision as to whether the fault is in front of, or behind, the relay. Usually the relay output lasts for only a few cycles and then the relay resets, since it is impossible for it to produce a steady state tripping output if the polarizing voltage is zero.

The above explanation of memory action is usually associated with zero voltage, or bolted, faults. However, in many cases fault impedance exists due to the presence of an arc, and the voltage is not zero. The memory action actually produces a dynamic characteristic that has a much greater capability to handle high-resistance close-in faults than is indicated by the steady-state characteristic. The purpose of this paper is to describe this dynamic characteristic.

It should be emphasized that this is not a new development, but is a description of a feature that is present in any mho relay which uses the faulted phase voltage as the polarizing voltage and which also uses memory action in the polarizing circuit. (1)

THEORY OF OPERATION

Relay Circuitry

This analysis refers to one relay unit of a three-phase mho distance relay, for example the AB phase pair unit. Phase distance relays normally use line-to-line voltage, V_{AB} , and "delta currents," $I_A - I_B$, so that the reach is the same in positive sequence ohms for phase-to-phase or three-phase faults.

This analysis is based on a static mho distance relay, such as the SLY51B (used in static terminals), which uses a phase angle comparator to make a distance measurement. The measuring unit for

the AB phase pair is shown schematically in Fig. 1. The current input, $I_A - I_B$, is passed through a replica impedance, Z_R , which determines the reach and the maximum reach angle of the mho measurement. The voltage input, V_{AB} , is used both as the restraint portion of the operating signal and as the polarizing signal.

In the polarizing circuit, the memory circuit is a band-pass filter tuned to the system frequency. If the input signal to the filter is suddenly short-circuited, as would happen for a nearby bolted fault, the memory circuit will continue to oscillate for several cycles at system frequency. If the fault is nearby and contains fault resistance, the voltage V_{AB} will be reduced and phase-shifted to a position in phase with the fault current, and the phase shift of the memory circuit output will be delayed for several cycles.

For the standby condition with no load or fault current flowing, the operating signal, V_{OP} , is 180° out of phase with the polarizing voltage, and for this condition there is no input to the coincidence timer. If a phase-to-phase AB fault with no fault resistance occurs within the reach of the relay, and if the angle of Z_R is equal to the line angle, $(I_A - I_B)Z_R$ will be greater than V_{AB} , V_{OP} will be in phase with V_{POL} , and the input to the coincidence timer will be a chain of coincidence blocks that are almost one-half cycle long, with very narrow gaps between the blocks (see Fig. 2). This will produce a trip output.

If fault resistance is present, V_{OP} will not be in phase with V_{POL} , and operation of the relay will occur when the coincidence timer input blocks are greater than 90° . Fig. 3 illustrates by means of an IR-IX diagram the way in which a phase angle measurement produces a steady-state mho characteristic. Regardless of the angle between V_{AB} and I (or I_R), the 90° relationship between V_{OP} and V_{AB} required for operation causes the resulting characteristic to be a circle. Output occurs when the angle Θ is equal to or less than 90° , or when the tip of the V_{AB} phasor falls within the circle. Dividing the voltages by I produces a mho circle on an R-X diagram, and operation occurs when Z_F falls within the circle.

Dynamic Characteristic

The dynamic characteristic of the mho relay with memory action is the result of the delay (in the

memory circuit) of the phase shift of the polarizing voltage from the prefault to the fault condition.

To illustrate the dynamic characteristic, consider the simple radial feed system of Fig. 4, where impedances are given in secondary ohms. The source impedance is 6 ohms at 85° and the line impedance from relay location to fault location is 2 ohms at 85° . The fault resistance is assumed to have a value of 5 ohms, which is much larger than typical arc resistance values. This large value of fault resistance is used only to illustrate the size of the dynamic characteristic.

For the prefault condition the voltages at the source (V_S), at the relay (V_R), and at the point on the line where the fault occurs (V_X) are all in phase and equal to the source voltage as shown in Fig. 4. When the fault occurs, the voltage at the relay location shifts lagging by 33° , and the voltage across the fault resistance is in phase with the fault current and lagging by 54° , as shown at the bottom of Fig. 4.

Fig. 5 is a phasor diagram with source voltage, V_S , as the reference. Note that the voltage drop in the source impedance leads the source voltage by 31° and that the voltage drop from the relay to the fault, which is the same as V_{AB} at the relay, lags the source voltage by 33° .

When the phasor diagram of Fig. 5 is plotted on an IR-IX diagram it appears as shown on Fig. 6, with all the phasors rotated clockwise by 36° . V_{AB} at the source is the initial polarizing voltage, and V_{AB} at the relay terminals is the restraint portion of the V_{OP} signal, and therefore immediately after the fault occurs these two voltages are different as shown in Fig. 6. The angle Θ is measured between V_{OP} and V_{AB} at the source and this produces an initial dynamic characteristic as shown in Fig. 6. The angle of Z_R was chosen to be the same as the source impedance angle, and the magnitude of Z_R was chosen to produce a circle which passes through the tip of the $V_{AB} = IZ_F$ phasor. This construction illustrates the point that the diameter of the initial dynamic characteristic circle is equal to Z_S (source impedance) plus Z_R (relay reach). It also illustrates the point that the dynamic characteristic has a much greater reach along the R-axis than does the steady-state characteristic.

It might appear at first glance that this characteristic is no longer directional because it includes a large area below the R-axis. This is not true, because the construction of Fig. 6 is only valid for

current flow through the source impedance behind the relay and passing through the relay location in the tripping direction. The area below the axis would permit tripping on a dynamic basis for capacitive faults in front of the relay (if series capacitors are used) but it does not mean that the relay would operate for faults behind the relay.

The dynamic characteristic as shown in Fig. 6 is the characteristic that exists immediately after the inception of the fault. Following fault inception, the characteristic begins to “shrink” towards the steady-state characteristic as shown in Fig. 7. The particular characteristic which determines the actual reach along the R-axis depends on the operating time of the relay. As far as the polarizing voltage itself is concerned, the time for V_{AB} to shift from the pre-fault to the fault position is determined by the memory circuit time constant and the magnitude of the fault voltage present during the fault at the input to the memory circuit. In general, this time constant is designed to be long enough to provide a trip output for “practical” faults in the first quadrant, i.e. faults with arc-drop.

Arc-Drop Considerations

A practical fault between phases A and B will have a non-linear fault resistance established by the fault arc. Since the arc voltage is relatively constant for all values of fault current, being typically 4 to 5% of V_{AB} , the fault resistance is inversely proportional to the fault current. However, the fault current is inversely proportional to the line and source impedance between the fault location and the infinite bus behind the relay. The net result is that fault resistance due to arc drop increases as the source impedance and relay dynamic characteristic diameter increases, and conversely the fault resistance decreases as the source impedance and relay dynamic characteristic diameter decrease.

This relationship is illustrated in Fig. 8 and Fig. 9. Figure 8 shows the practical fault impedance that will occur for a phase-to-phase fault at location R. $(IZ_{1S} + IZ_F)$ is equal to the pre-fault voltage and IR_F is equal to 5% of the prefault voltage. Therefore R_F is equal to approximately 5% of $(Z_{1S} + Z_F)$. Fig. 9 shows the same fault condition but with a smaller source impedance and therefore a smaller R_F for a fault at the same fault location. It is interesting to note that in both of these conditions, even with an 85° reach angle on the steady state characteristic, the fault impedance is well within the dynamic characteristic, and that the dynamic characteristic automatically increases in size as the fault resistance increases.

Because the arc-drop voltage is essentially constant, infeed from the opposite terminal that is in-phase with the local fault current does not change the effective fault resistance seen by the local relay. Therefore Figures 8 and 9 apply to both double-end feed or single-end feed conditions provided that the two source impedances are in-phase.

Effects of Load Flow

For most applications, on lines that are part of a strong system, there will be no significant effect on the dynamic characteristic due to load flow. The key factor is the difference in angle between the pre-fault voltage at the relay location and the voltage at the equivalent source which is driving the fault current.

A system condition which could have a significant effect on the dynamic characteristic is shown in Fig. 10, where several transmission lines in series connect a generating station (A) at the left with a load center (B) at the right. Z_D is the positive sequence impedance between A and Bus 1, Z_E is the positive sequence impedance between Bus 1 and Bus 2, etc. R_1 , R_2 , and R_3 , etc. are relay locations. The angular relationship of each bus voltage with respect to source A is shown below each bus location. F_1 , F_2 , F_3 , etc. are fault locations in front of each relay location. For simplicity, it is assumed that the relay replica impedance angle is the same as the impedance angle of the various line sections, and that this angle is 85° .

To explain the effect of load angle on the dynamic characteristic, consider first the relay at location R_1 . The source of fault current flow at R_1 for a fault at F_1 is the voltage at A, but the pre-fault voltage at R_1 lags that voltage by 5° . In the previous description of the dynamic characteristic, for the no-load condition, the pre-fault voltage was the same as the source voltage, and the dynamic characteristic was much larger than the steady-state because the pre-fault voltage angle was leading with respect to the fault voltage. In the case of the R_1 relay of Fig. 10, the initial polarizing voltage lags the source voltage by 5° , and this will cause a slight reduction in the first quadrant reach along the R-axis.

Fig. 11 illustrates the effect of the load angle on the dynamic characteristic. The source impedance plus the relay reach form a "constant chord" for both characteristics. If the angle subtended by

the no load characteristic is 90° , the angle subtended on the load characteristic is $90^\circ + \delta$ where δ is the angle that the prefault voltage at R_1 lags the voltage at the source A. The same effect applies at the other relay locations. For example, for the relay at R_3 the subtended angle is $90^\circ + 25^\circ$ or 115° . This characteristic is illustrated in Fig. 12.

For a condition such as this the dynamic characteristic can be shifted to the right by introducing a fixed leading phase shift in the polarizing voltage, provided that the load flow is always in the same direction. Of course, this also shifts the steady-state characteristic toward the R-axis, or to a lower maximum reach angle.

For relay locations, such as R_4 , R_5 , and R_6 , where the direction of load current flow is opposite to the direction of fault current flow, the shift of the dynamic characteristic because of load flow angle is in the opposite direction, or such that it takes in more area in the first quadrant.

A more direct method of evaluating relay performance is shown in the next series of figures. Since the item of chief concern is the ability to detect a fault with fault resistance and located just in front of the relay, these figures show the voltage phasors for V_{OP} and the initial polarizing voltage for faults at F1, F2 and F3. In each case it is assumed that I lags the left source voltage by 85° , so that IZ in the relay is in phase with the source voltage at the left.

In Fig. 13a, for the R_1 relay and F1 fault, the arc voltage is small compared to IZ, and V_{OP} leads IZ by 2° . V_{POL} lags the source voltage by 5° , so the angle between V_{OP} and V_{POL} is 7° , a very favorable angle for high-speed operation.

Fig. 13b shows the phasors for the R_2 relay and F2 fault. For this case, the arc voltage is a larger percentage of the IZ signal, and V_{OP} leads IZ by 5° . V_{POL} lags IZ by 15° resulting in a total angular separation of 20° between V_{OP} and V_{POL} .

Fig. 13c shows the phasors for the R_3 relay and F3 fault. The arc voltage is a still larger percentage of IZ and shows a phase shift in the clockwise or lagging direction due to the infeed to the fault from the right hand source. The total angle between V_{OP} and V_{POL} is 38° . While this is still well under

90°, it is a less favorable condition than that for R₂ and F₂, and, as stated earlier, could be improved by introducing a fixed leading phase shift of the polarizing voltage, provided the load flow direction is always the same.

Fig. 13d shows the input signals for the R₆ relay and F₆ fault, which is the condition where load flow direction and fault current flow are opposite. Here V_{POL} leads I_Z (and the right hand source voltage) by 20° but is only 15° away from V_{OP} because V_{POL} and V_{OP} are both shifted in the same direction from I_Z . This is a favorable condition.

Figs. 13a, 13b, and 13c illustrate another important point. As the fault location moves towards the right-hand bus, the arc voltage shifts in the lagging direction because the amount of current fed in from the right increases. The V_{ARC} phasor shown in Fig. 13c for example, is the minus V portion of $I_Z - V$. The steady-state polarizing voltage is 180° from the V_{ARC} shown, and is therefore more than 90° from V_{OP} , which means that the relay with 85° maximum reach angle will not operate steady-state for this fault. This is illustrated in Fig. 14. In this case the dynamic characteristic is relied upon to produce an output.

Other Polarizing Methods

It is possible to use the "healthy-phase" voltage as the polarizing voltage, either alone or as a supplement to the faulted phase voltage, and by this means obtain a steady-state output for zero-voltage phase-to-phase faults. The latest designs of GE phase mho relays use a combination of faulted phase and unfaulted phase voltage, and the design of these relays will be described in a subsequent paper. With this polarizing method, the dynamic characteristic is still relied upon to produce an output for three-phase faults.

CONCLUSIONS

The use of a memory circuit in mho distance relays gives those relays a dynamic characteristic with much greater reach along the R-axis than the steady-state reach. The diameter of the initial dynamic characteristic is equal to the sum of the source impedance and the relay reach. The diameter automatically increases in size as arc resistance increases. The dynamic characteristic "shrinks" to the steady-state characteristic at a rate determined by the time constant of the memory circuit. The dynamic characteristic permits tripping on a transient basis for some marginal conditions that would not provide a steady-state trip output.

REFERENCES

1. L. M. Wedepohl, "Polarized Mho Distance Relay." Proceedings of IEE, Volume 112, No. 3, March 1965.

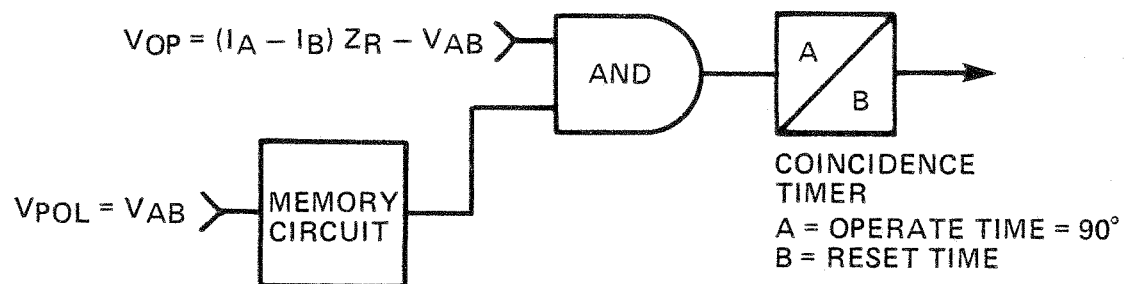


Fig. 1 Phase Angle Comparator Mho Distance Relay for the AB Phase Pair

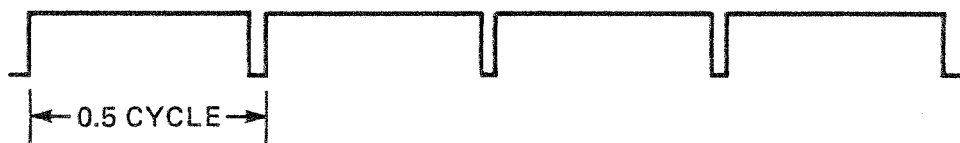


Fig. 2 Chain of Coincidence Blocks for Internal Fault with No Fault Resistance

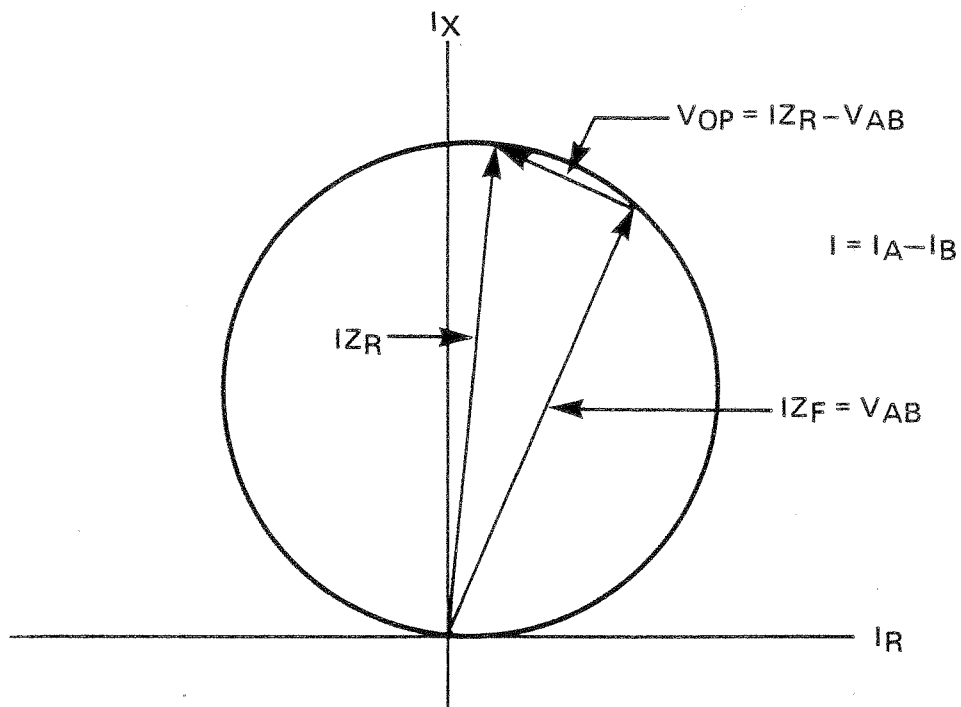


Fig. 3 Steady-State Mho Characteristic

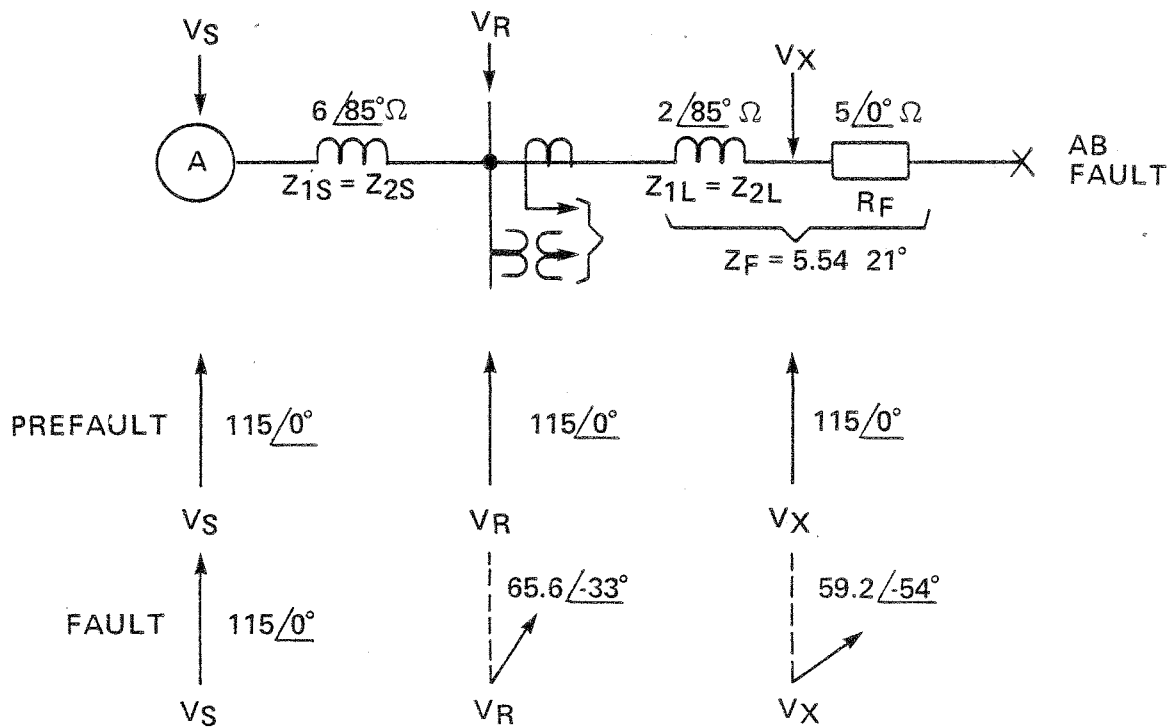


Fig. 4 System Arrangement, with Prefault and Fault Voltages. Secondary Impedance and Voltage Values Shown.

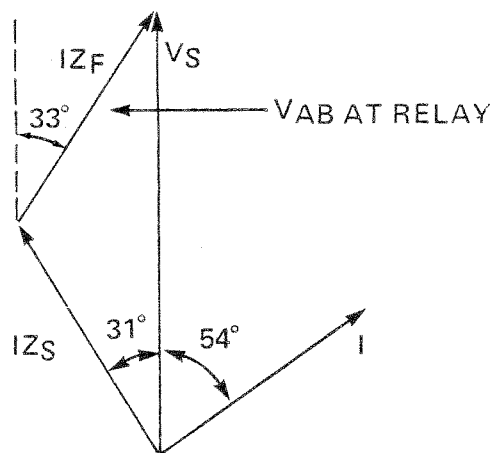


Fig. 5 Voltage Drops for System of Fig. 4

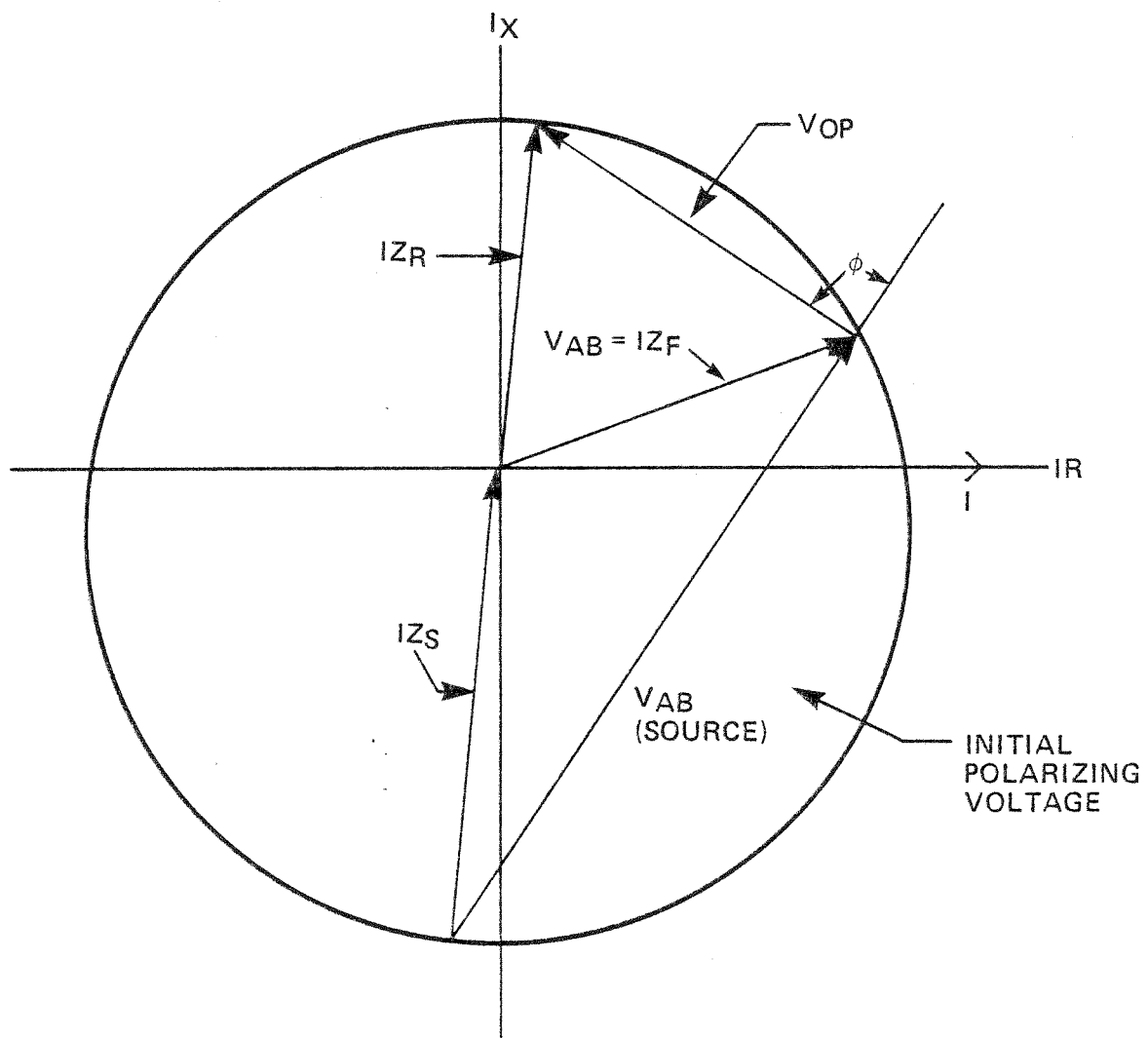


Fig. 6 Dynamic Mho Characteristic, Based on Conditions of Fig. 4

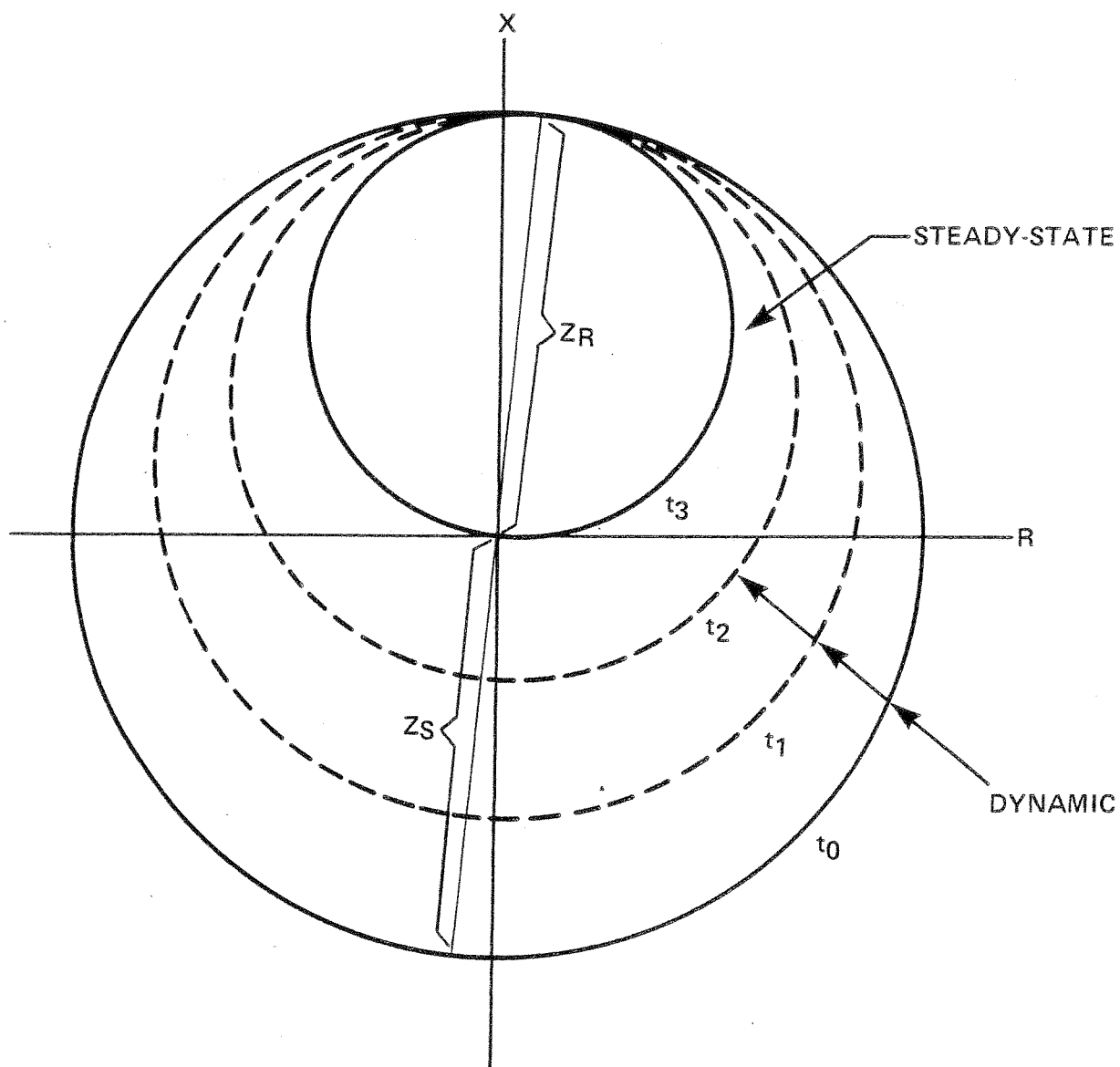


Fig. 7 Transition from Dynamic Characteristic to Steady-State Characteristic

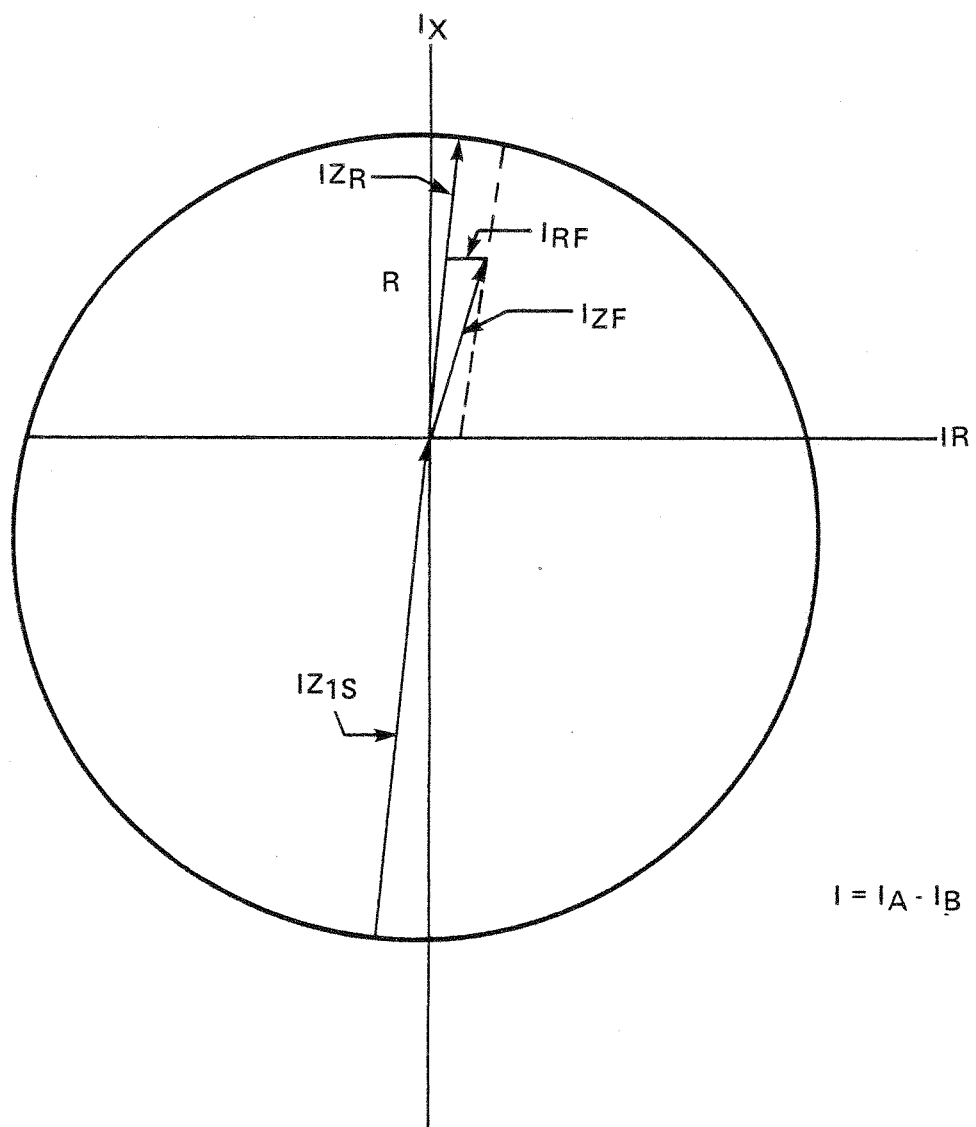


Fig. 8 Fault Resistance on Interphase Faults and Dynamic Characteristic

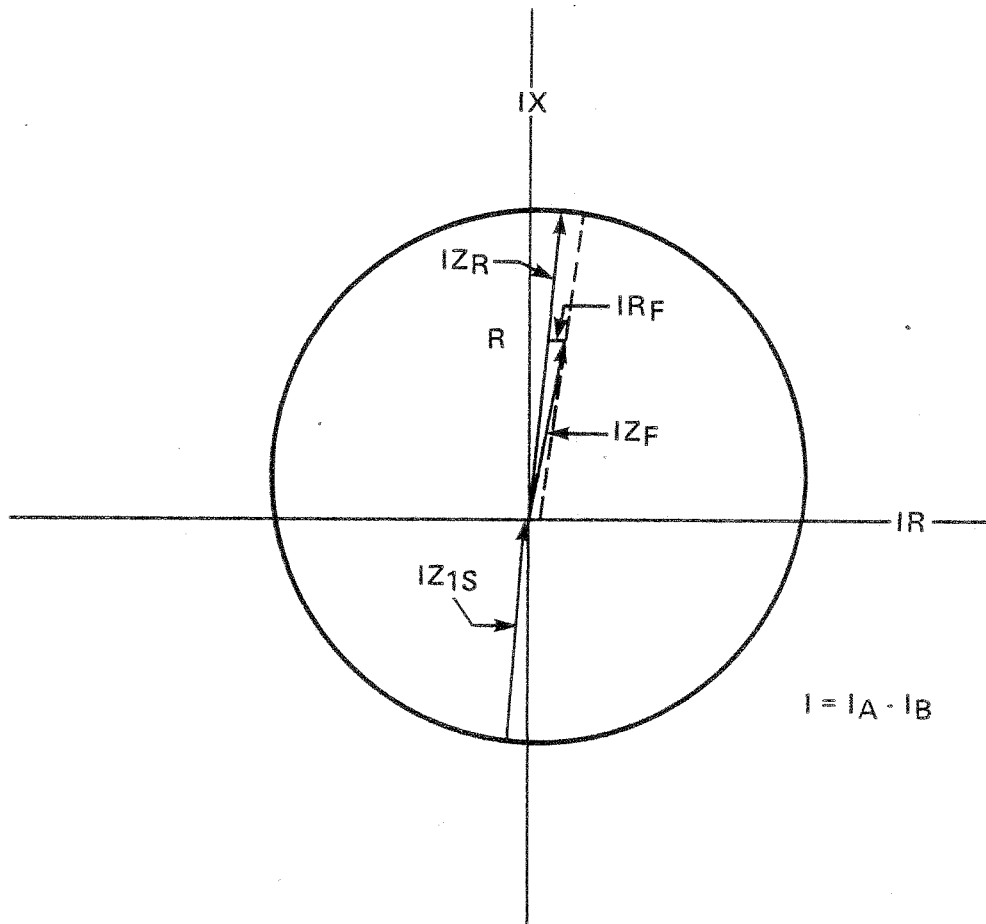


Fig. 9 Similar to Fig. 8 but with Smaller Source Impedance

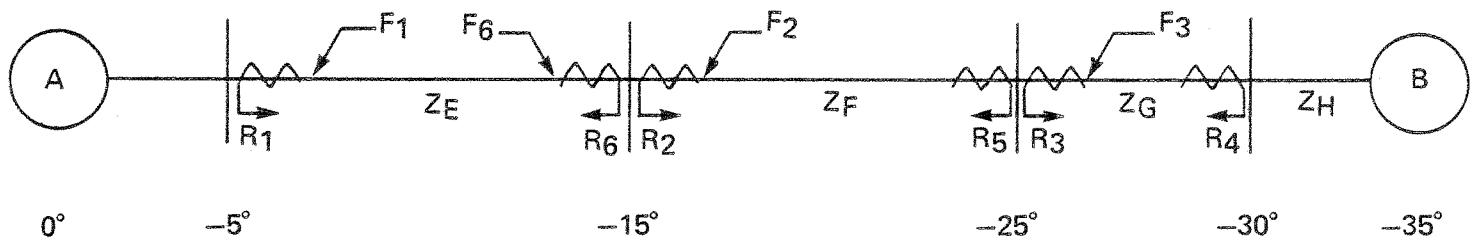


Fig. 10 Simple Two Machine System

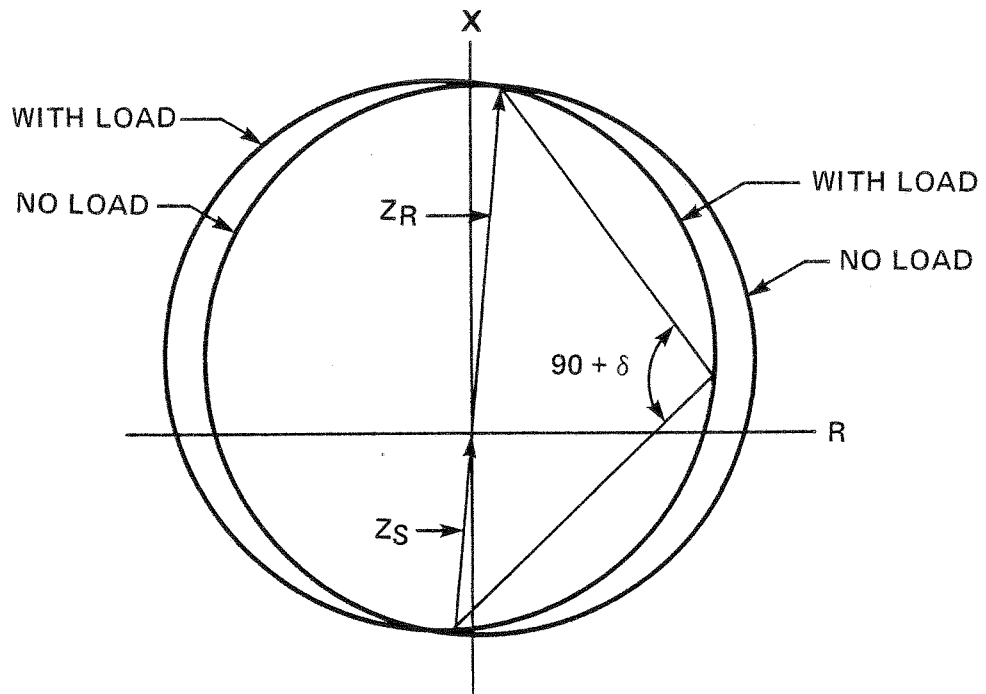


Fig. 11 Dynamic Characteristic With and Without Load

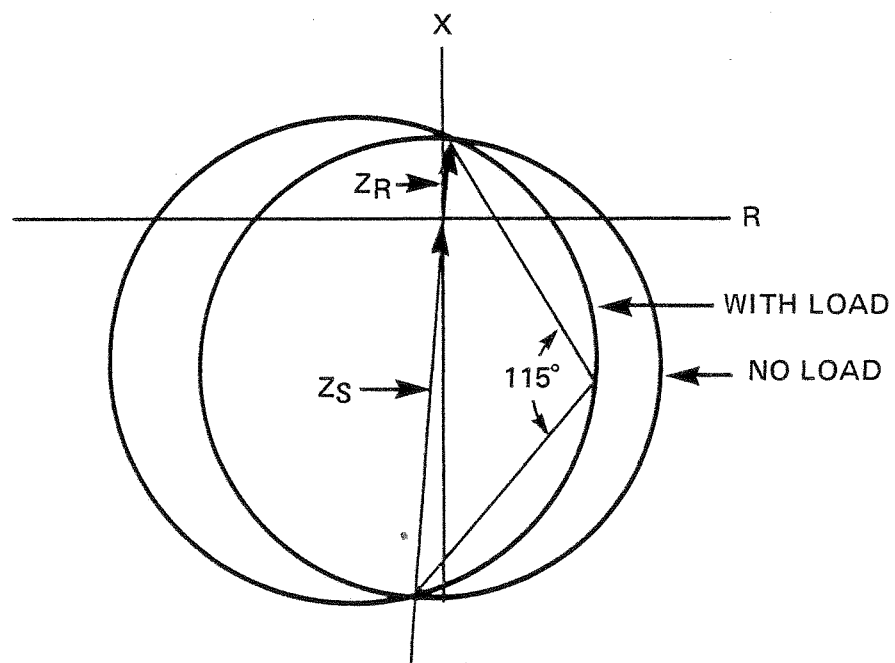


Fig. 12 Dynamic Characteristic for R3 Relay in Fig. 10, With and Without Load

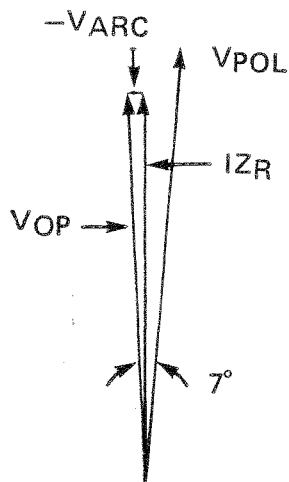


Fig. 13(a) Input Signals for R1 Relay, F1 Fault

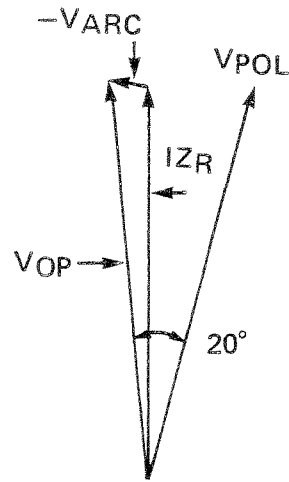


Fig. 13(b) Input Signals for R2 Relay, F2 Fault

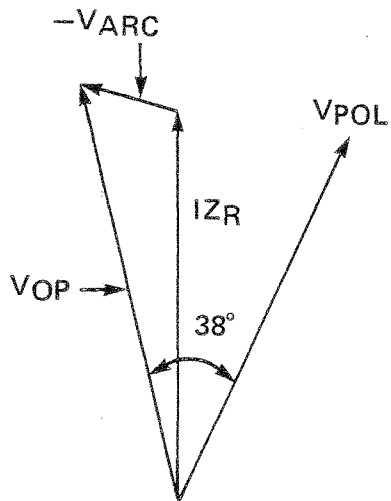


Fig. 13(c) Input Signals for R3 Relay, F3 Fault

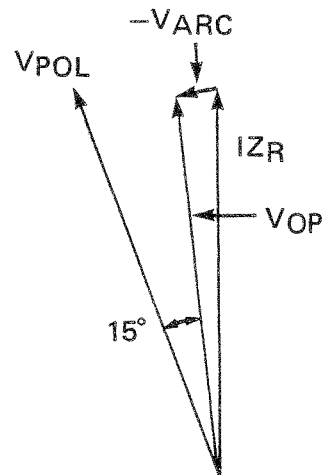


Fig. 13(d) Input Signals for R6 Relay, F6 Fault

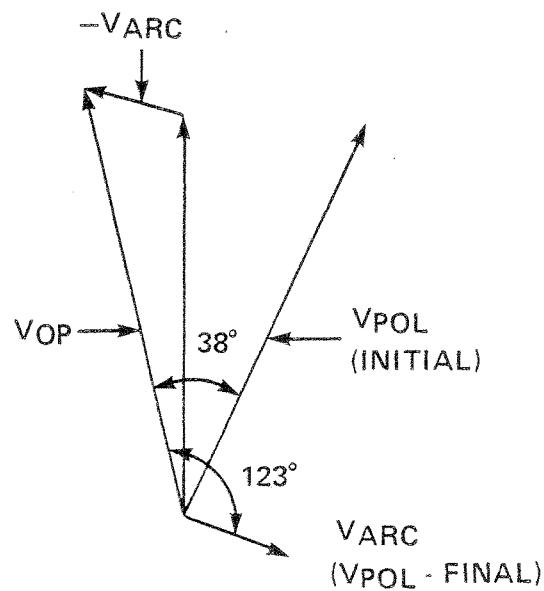


Fig. 14 Steady-State Angle Between V_{OP} and V_{ARC} for R3 Relay, F3 Fault, With Load Flow as in Fig. 10

APPLICATION OF TIME DISTANCE RELAYS

TO TRANSMISSION LINE PROTECTION

M M MANN - C A DIFFENDAFFER - D G RUSSELL

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APPLICATION OF TIME-DISTANCE RELAYS

TO TRANSMISSION LINE PROTECTION

ABSTRACT

This paper describes a new approach to transmission line relaying in which "fault magnitude variable tripping time" is used to achieve relay coordination without use of communication channels.

INTRODUCTION

A conventional distance relay provides the same tripping speed (fast) for all faults located within the relay reach setting. Application of this type relay requires a communication channel between line relay terminals to insure 100% of the line protection and still prevent tripping for line faults which are located outside of the protected line section.

The time-distance relay provides tripping time proportional to the distance from the relay to the fault and thus proportional to fault magnitude. In a time-distance relay application, the relay distance is set to overreach the protected line section by approximately 200%. This provides 100% coverage on the protected line and back up tripping for faults in the adjacent line section.

Communication channels are a source of problems in relaying and require considerable investment in initial and maintenance costs. In a search for a less complex and therefore less costly and more reliable relay scheme, it was decided to develop a scheme which does not require communication channels. A time distance scheme in which tripping time is proportional to fault distance appeared to fit this requirement and provide good protection. A tentative design for a time-distance relay was made and later it was discovered that Westinghouse was already making a time-distance relay, the SD-2.

Use of the time-distance concept is made possible by "fault magnitude variable tripping time" - the fact that as the fault is moved farther away from the relay bus, fault current at the relay bus is

diminished and damage to apparatus, lines, and system stability is reduced thus allowing longer tripping times. Longer tripping times for far end faults allow the relays to be time coordinated with relays in adjacent line sections with no communication channel being required to prevent overreach tripping.

Comments on "Fault Magnitude Variable Tripping Time"

It is acknowledged that the factors influencing required fault clearing time are complex. Some considerations are line damage, transformer damage, insulator damage, and transient stability. Review of published computer studies on transient stability shows a wide range of calculated critical clearing times (1 cycle to 30 cycles). It is also apparent that critical clearing times from computer studies vary widely depending on the system and on which calculation method is used.

Idaho Power Company's approach is to determine required clearing times based on fault severity, which is related to both stability and damage. The guide used to determine maximum clearing time is based on an (IT) product of 1500 Ampere seconds for fault currents in the 1000 to 10,000 amp range and an (I^2T) product of 15×10^6 Ampere² seconds for fault currents above 10,000 amps.

Amps Fault Current	Max. Clearing Time in Cycles	
	IT = 1500	$I^2T = 15 \times 10^6$
1,000	90	---
2,000	45	---
4,000	23	---
6,000	15	---
8,000	11	---
10,000	9	9
12,000	---	6
14,000	---	4.6
16,000	---	3.5
18,000	---	2.8

Using the above guide, the designer determines maximum clearing times and designs to stay as far under these times as is economically reasonable. This utility has been using this guide for the past 8 years.

It has given good system protection with no equipment damage and has caused no problems with transient stability.

Application of the relays described herein as primary protection is limited to lines which can tolerate 12 cycles or more total clearing time for end zone (far end) faults. 12 cycles clearing time is not usually a limitation if an open minded approach is taken on the question: "How fast a clearing time is actually required?"

The Time-Distance Relay

The Westinghouse type SD-2 is a time-distance relay described by Westinghouse as suitable for phase to phase and 3 phase protection on 19 KV through 33 KV lines. The standard relay has tripping times ranging from 0.2 to 3.0 seconds.

With suitable modification to electronic circuits the tripping times of this relay are reduced to a range of 0.03 to 0.4 seconds. This faster tripping speed makes the relay suitable for protection on 138 KV and 230 KV lines.

Another modification of the SD-2 relay involves reconnecting internal current and voltage circuits so that an SD-2 can also be used for ground relaying.

A full complement of relays for one line terminal (using the SD-2) consists of;

- 1 - type SD-2 phase relay modified for fast trip
- 1 - type SD-2 relay modified for ground fault use and fast trip
- 1 - type KC-4 3 element induction cylinder instantaneous relay
- 1 - type 1RD-9 relay used for ground trip

Description of Individual Relay Functions

Type SD-2 Relay for Phase Fault Protection: This relay measures line to line voltage, and positive and negative sequence current (zero sequence current is excluded). It has been modified to give faster

operating time by changing capacitor and resistor values in the electronics. Typical operating time is 0.04 seconds for a fault at 75% of relay reach. Time is adjustable over a wide range. Relay distance setting range is 0.8 to 25.6 ohms. The relay has a mho characteristic with maximum sensitivity at an angle of 60° current lagging voltage. The circle is slightly offset in the forward direction from the relay measuring point and cannot detect zero voltage faults. This relay is applied to give coverage between 20% and 200% of the protected line on phase to phase and 3 phase faults. Time setting is selected to give far end adjacent breaker clearing time for a close-in fault plus 5 cycles coordinating time.

Type SD-2G Relay for Ground Fault Protection: This relay has been modified to give faster tripping time in the same manner as the SD-2 for phase protection. It is modified to operate on line current which includes zero sequence current. Distance setting range is 1.6 to 51.2 ohms. Range of operating time and circle characteristics are the same as the SD-2 for phase protection. Because this relay is connected in phase currents, it measures $I_1 + I_2 + I_0$ and will respond to 3 phase and phase to phase faults as well as phase to ground faults and thus provides back up for the 3 phase SD-2 relay. Relay reach setting and tripping time are selected the same as the relay for phase protection. Because of the time distance characteristic, relay reach accuracy is not critical. Reach must be set shorter than line load (usually not a serious limitation).

Type KC4 Relay for Phase and Ground First Zone Protection: a type KC4 3 element cylinder type instantaneous unit is connected with one element in each phase current and measures $I_1 + I_2 + I_0$. This relay has a trip time of 1.5 cycles and is set to cover zero to 30% of line length. All 3 separate elements operate independently of each other providing redundancy on 3 phase faults.

Type IRD Relay for Ground and Ground Back Up Protection: The IRD is used in a conventional manner to measure $3I_0$ current polarized with broken delta voltage, and or current. This relay is set to cover 50% of the line on its instantaneous unit and provide time coordinated over-reaching back up on the time overcurrent unit.

All internal line faults are covered by one primary and at least one backup function.

Fault Testing

This scheme has been tested on the Utah Power and Light "Power System Simulator" at Salt Lake City. Also Idaho Power Company has performed staged fault tests on the scheme (2 terminals have been in service for approximately one year). Advantages of the scheme are; much lower cost, no channel reliability problems, it can be designed, set, and tested single ended.

Summary

Often fast clearing times are requested due to lack of knowledge about what is actually required on a specific application. Broad generalization about needing to clear all faults as fast as possible can lead to costly, complex and less reliable relay schemes. Application of the time-distance scheme to transmission line protection is made possible by using realistic longer tripping times for clearing remote terminals when fault currents are low. This allows coordination time for end zone faults and no communication channel is required. The advantages of increased reliability, reduced cost, reduced maintenance, and reduced complexity are considerable.

APPENDIX 1

Cost Comparison of SD2 Scheme VS Conventional Relays

SD2 SCHEME

- 1 - Modified SD2 time distance relay for phase protection
- 1 - Modified SD2 time distance relay for ground protection
- 1 - KC4 for first zone instantaneous protection
- 1 - IRD directional overcurrent ground relay for ground protection

Total cost of relays - \$5,800

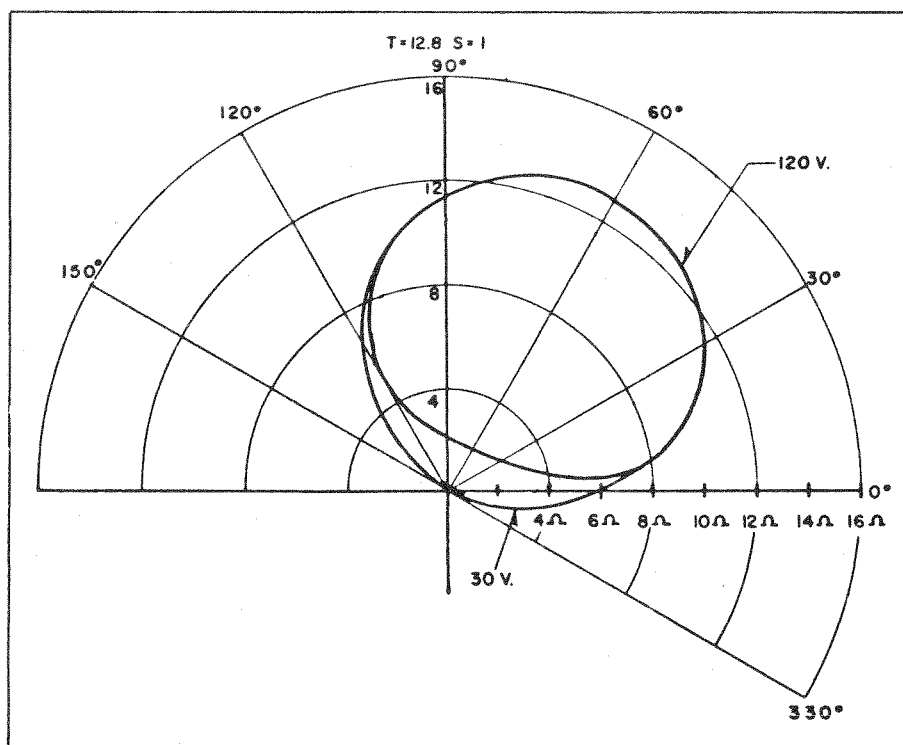
Conventional Scheme

- 1 - Impedance relay for zone 1 protection
- 1 - Impedance relay for zone 2 protection
- 1 - Impedance relay for zone 3 protection
- 1 - Directional overcurrent ground relay
- 1 - Directional overcurrent ground relay for ground backup
- 1 - Time delay relay for backup timer
- 1 - Carrier auxiliary relay
- 1 - Carrier set
- 1 - Test switch
- 1 - Milliammeter
- 1 - Carrier coupler
- 1 - Carrier wave trap
- 1 - Carrier line tuner

Total cost of equipment - \$13,800

The reduction of equipment cost is $\$13,800 - \$5,800 = \$8,000$ per line terminal. This is a 58% reduction. Also, the SD2 scheme results in a reduction of 50% in panel space, 40% in wiring time, and 50% in design time. Installation testing is reduced by 60%. Estimated total reduction is \$9,420 per line terminal, or 68%

FIGURE 1



Impedance Circles for the SD-2 Relay

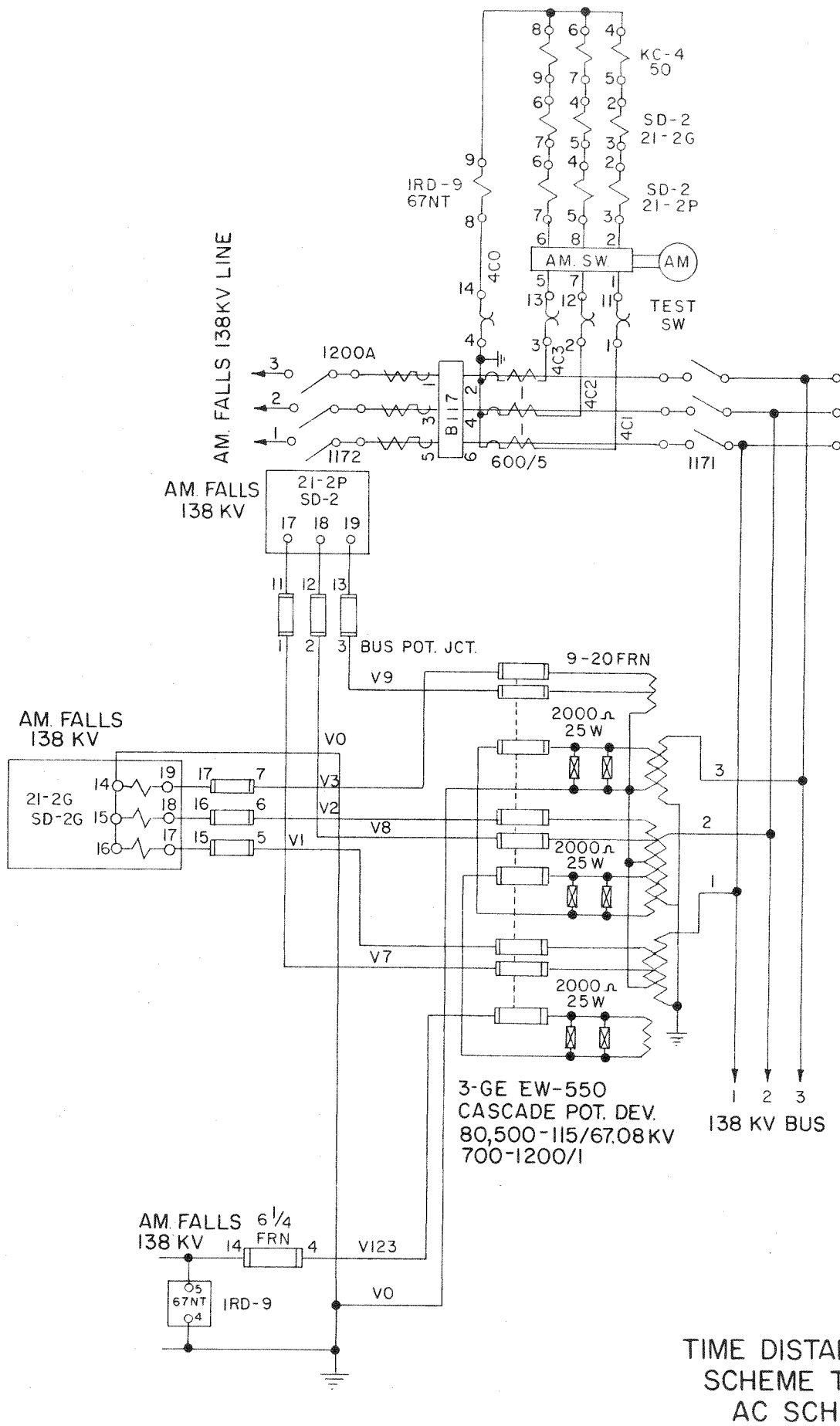
FIGURE 2

Typical Relay Responses and Operating Times

Relay Output Time in Cycles (60 HZ Base)

Fault Location	Relay Bus	25% of Line	50% of Line	Remote End	150% of Line
Fault Type	1.5 (KC4)	1.5 (KC4)	3.5 (SD2-G)	10.5 (SD2-G)	18 (SD2-G)
3Ø		1.5 (SD2-Ø)	4.0 (SD2-Ø)	11.0 (SD2-Ø)	19 (SD2-Ø)
		1.6 (SD2-G)			
Ø-G	2.0 (IRD-IT)	4.0 (SD2-G)	8.0 (SD2-G)	11.0 (SD2-G)	36 (SD2-G)
	3.0 (KC4)	2.0 (IRD-IT)	8.1 (IRD-IT)	42.0 (IRD-T)	
	4.0 (SD2-G)	3.0 (KC4)			
Ø-Ø	2.0 (KC4)	2.0 (KC4)	4.5 (SD2-Ø)	10.5 (SD2-Ø)	21 (SD2-Ø)
	4.0 (SD2-G)	3.0 (SD2-Ø)	5.5 (SD2-G)	11.0 (SD2-G)	22 (SD2-G)
		3.0 (SD2-G)			

FIGURE 3



BREAKER FAILURE RELAYING

*By
W. A. Elmore
Manager, Consulting Engineering Section
Westinghouse Electric Corporation
Relay Instrument Division
Newark, N.J.*

*Hung Jen Li
Sr. Design Engineer
Westinghouse Electric Corporation
Relay Instrument Division
Newark, N.J.*

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BREAKER FAILURE RELAYING

INTRODUCTION

Traditional breaker failure schemes have sensed the requirement for tripping a breaker, energized a timer, then initiated clearing of the breaker if current were not interrupted before the timer timed out. Using this concept, we have become dependent on consistent fast **dropout** of the overcurrent units used to sense this breaker current flow. This paper describes a new important concept that uses overcurrent unit **pickup** as the necessary ingredient for breaker failure clearing.

Another important topic examined in this paper is a method of detecting pole disagreement for a breaker. Breaker failure is of no less consequence if it occurs under non-fault conditions than if it occurs under fault conditions. The conventional breaker failure schemes only respond if the protective relays detect a fault.

THE NEED FOR BREAKER FAILURE PROTECTION

In backup protection techniques, it is not practical to have complete redundancy of all relay and breaker in the protection chain. For example, for some important protection systems, separate ac currents, ac potentials, dc supplies and redundant trip coils with separate connections for the primary and backup systems are used. Duplication of the major parts of the breaker (trip mechanism and interrupter) is impractical. Breaker backup must be provided by the tripping of other breakers. The breaker failure relaying scheme provides this backup protection by initiating the tripping of the minimum number of breakers necessary to clear the fault.

Since breaker backup must be provided by adjacent breakers, and the clearing of adjacent breakers may involve the loss of a large portion of the power system, it must be avoided unless absolutely necessary. An adequate time delay should be provided for normal interruption. This introduces a basic timer setting problem to the breaker failure schemes. The clearing of the backup breakers should not be faster than the protected breaker if the latter interrupts normally but should be cleared as fast as possible if the protected breaker fails.

TRADITIONAL PRACTICES

The basic approach of the traditional breaker failure scheme is shown in the flow chart and block diagram of figure 1 and figure 2, respectively.

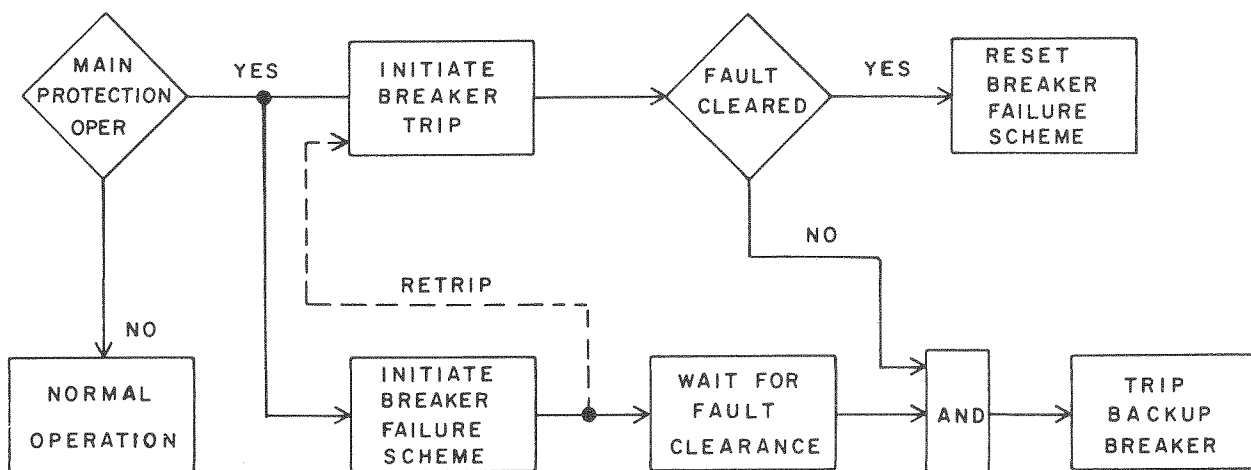


Figure 1. Flowchart of the Traditional Breaker Failure Scheme.

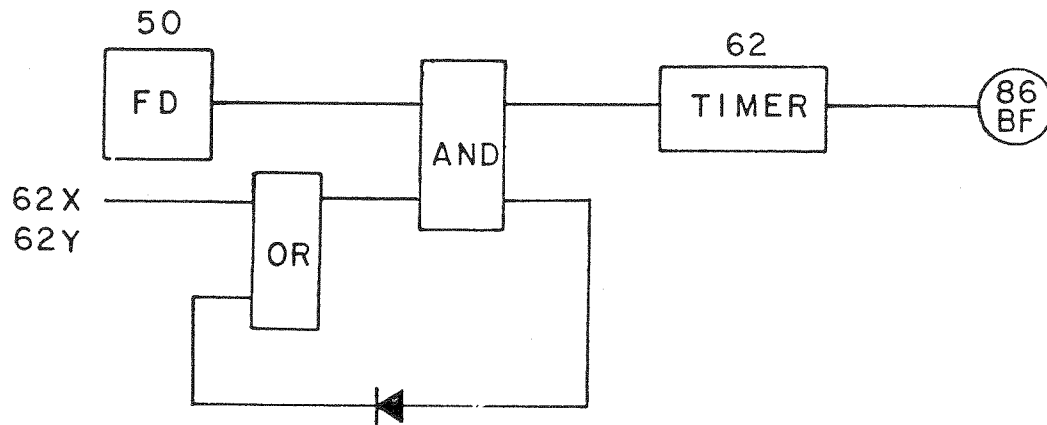


Figure 2. Block Diagram of the Traditional Breaker Failure Scheme.

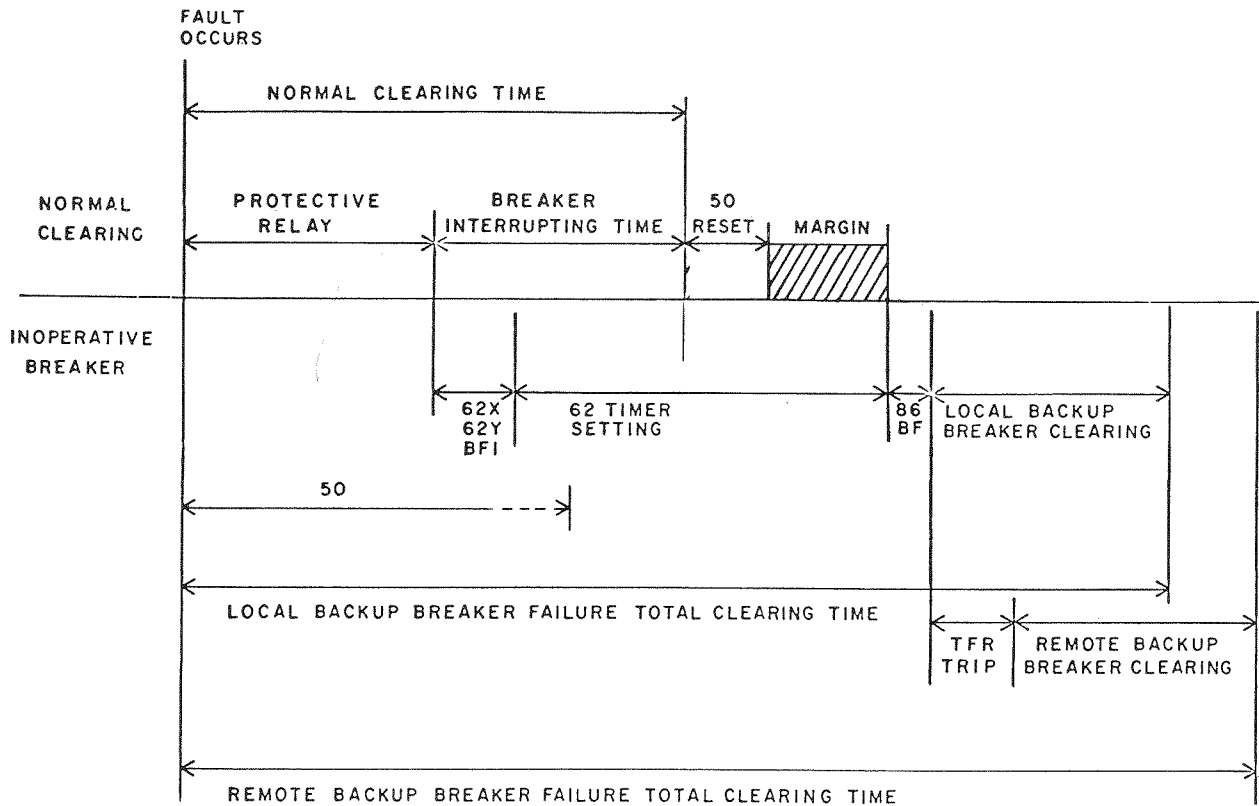


Figure 3. Time Chart of the Traditional Breaker Failure Scheme.

Refer to figure 2. The timer (device 62) is energized whenever the overcurrent unit fault detector (device 50) and the breaker failure initiation (device 62X or 62Y) are operated simultaneously. If the condition lasts for the duration of the timer setting, the lockout relay (device 86BF) is operated to clear the backup breakers.

The shaded time in figure 3, "margin" must have adequate duration to ensure security. This margin takes into account the following variables:

(1) Excessive breaker interrupting time

At low magnitude of fault currents, breaker interrupting time may be longer than those experienced at higher magnitudes. For example, the interruption may be one cycle longer for three cycle breakers at current below 25% of maximum rating (reference 2). Also, the interrupting time may be longer on close-open duty.

(2) Inconsistency in 62X, 62Y times

These are minimized by static breaker failure initiation. However, the wide time range associated with electromechanical BFI is primarily a function of variation in dc voltage. The BFI AR contact output in the SRU relay or ARM module (Uniflex) has an operating time of 3-5 ms. The BFI telephone relay in the SRU relay has an operating time of 8-16 milliseconds. The SG relay 62X/62Y in the KC-4/TD-5 scheme has an operating time of 33-50 milliseconds. The assumption is made that the pickup of device 50 will be at least as fast as the protective relay plus 62X, 62Y time. If this is not the case, the backup clearing time is longer and the margin is increased.

(3) Overtravel of the timer after device 50 reset

(4) Inconsistency in 62 timing

(5) Timer setting error

Considering human error, instrumentation error, etc.

(6) Safety factor

Because of the widespread harmful effects of a false 86BF operation, it is recommended that a generous safety factor be incorporated in the margin time. The degree of safety required is a direct function of the user's confidence level in all elements of the protective system. Two cycles safety factor appears to be adequate with 3 cycles being a widely used total "margin".

Refer to figure 2 the reset time of device 50 is a critical characteristic in the performance of the breaker failure system. It will affect the margin value as well as the 62 timer setting. Device 50 resetting **stops** the timer; with 62X 62Y seal-in, it is the **only** function that stops the timer (figure 2). It is affected by several factors:

1. Whether or not the current level after interruption is zero, the reset times are longer when the current after interruption is non-zero. Certain type of circuit breakers are equipped with arcing contacts and shunting resistors. When the main breaker contacts interrupt a fault, the current does not drop immediately to zero but to a level determined by the shunting resistor. It falls to zero when the arcing contacts open. The reset time of device 50 on such application may be longer.
2. The fault current level at which the unit is energized prior to interruption.
3. The setting of the unit.

To prevent the device 50 reset time variables from affecting margin, it is usually recommended that the 62 time delay be determined for **maximum** device 50 reset time. Any faster 50 reset will then merely add to the safety margin.

It should be noted that the longer the reset time of device 50 to be considered the longer the 62 timer has to be set. Consequently, it may be difficult to set the timer securely and still avoid system instability.

NEW BREAKER FAILURE SCHEME

Many approaches have been devised for improving the traditional breaker failure scheme such as using a shorter reset time of device 50 or using separate timers for different levels of fault current. These approaches will still be affected by the reset time of the device 50 and still present difficulties in determining the reset time especially when information on shunting resistor current is not available.

The new approach described in this paper is to use the pickup characteristic of the overcurrent unit instead of the reset characteristic as the significant ingredient for the scheme.

Figure 4 shows the basic concept of the new approach and figure 5 is the detail logic and typical external connections of the new static breaker failure relay type SBF-1, that uses this new approach.

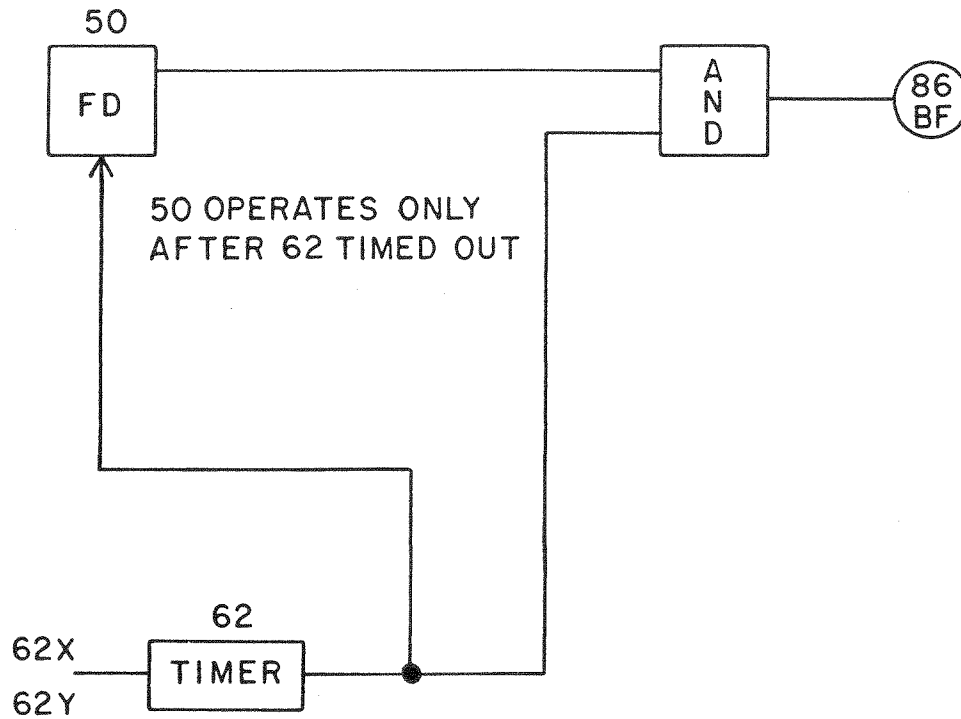


Figure 4. Block Diagram of the SBF-1 Relay.

The new approach has many advantages over the traditional ones:

- (1) The device 50 will not operate before the 62BF is timed out, therefore, it will never operate when clearing normally and device 50 reset time is not a consideration.
- (2) It permits shorter margin and shorter overall clearing times, and will give a net saving of 1-2 cycles over the traditional approach. This can be illustrated as below:

(a) Traditional scheme (figure 3)

Total clearing time = protective relay
 + (breaker interrupting time x 2)
 + max. 50 reset time
 + margin + 86BF(A)

(b) New scheme (figure 6)

Total clearing time = protective relay
 + (breaker interrupting time x 2)
 + margin + 86BF(B)

equ. (A) - (B)

(Saving in clearing time) = max. 50 reset time(C)

Equ. (C) shows that the saving in total clearing time equals to the device 50 max. reset time. The maximum reset time is one cycle for the ~~STU~~ ^{SBFU} relay and is 2 cycles for the KC-4 relay.

- (3) The overall clearing time for the new scheme varies with fault current level. The higher the fault current, the faster the breaker failure clearing time. This is consistent with the requirements of system stability.

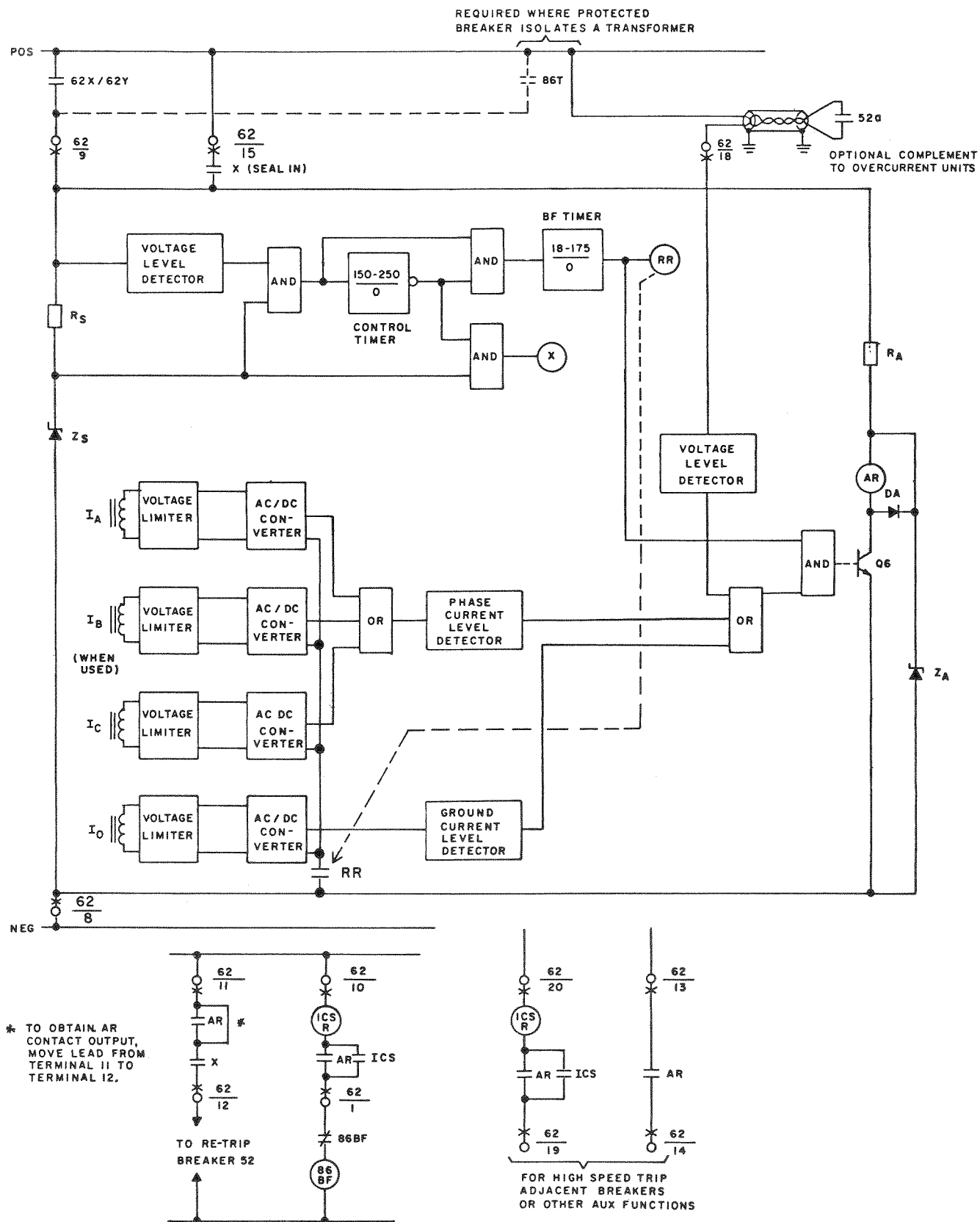


Figure 5. External Connection of SBF-1 Relay.

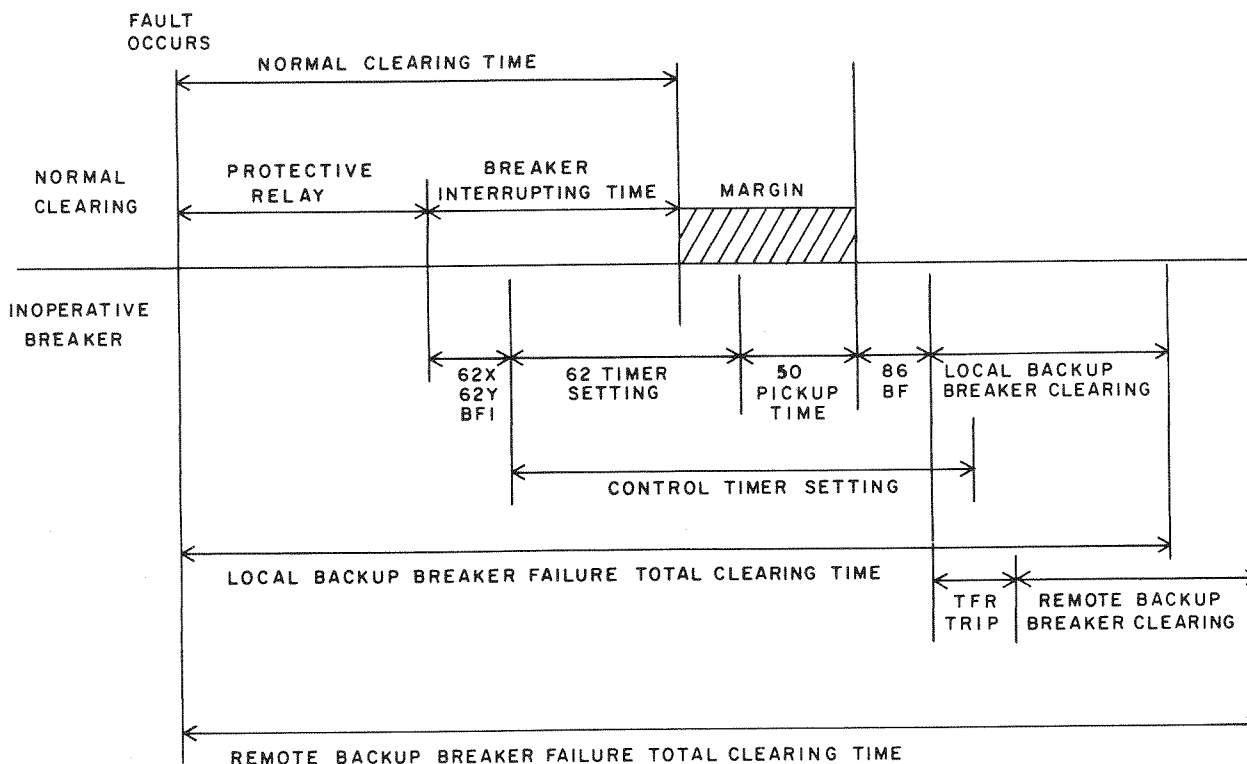


Figure 6. Time Chart of the SBF-1 Scheme.

The pickup time of the overcurrent units in the SBF-1 relay is 3-8 millisecond for fault current level from 2-20 times its tap setting.

- (4) The overcurrent unit will never operate when clearing normally so it can be set lower than load current, if necessary. This avoids delayed tripping associated with low current until other breakers clear.

THE TYPE SBF-1 RELAY

The type SBF-1 relay is a solid state relay that uses the new concept for ^{breaker failure} breaker failure protection. It contains three (or four) overcurrent sensing units and timers for controlling the sequence of action. Detection of a fault by a protective relay provides an input (by the 62X, 62Y, or BFI contacts) to the SBF-1 relay to start the adjustable pickup timer, figure 5. Until timing is completed, the overcurrent units are restrained from operation. If current is still flowing following completion of the timing, the overcurrent unit operates and trips. Table 1 shows the major features of this relay.

SETTING OF THE TYPE SBF-1 RELAY

(a) Overcurrent unit

The phase units must be set below the minimum expected (ct secondary) phase fault current through the protected breaker, and the ground unit must be set less than the minimum expected $3I_0$ fault current.

Settings should be made to assure a multiple of pickup of at least 2 under minimum fault conditions.

Where the breaker contains a resistor that is inserted on tripping, the overcurrent fault detectors are set below the resistor current.

(b) **Breaker failure timer**

The breaker failure timer should be set to exceed the breaker normal clearing time by an appropriate margin. A secure margin for the SBF-1 is 2 cycles.

(c) **Control timer**

The control timer is for resetting the relay. It must be set at least 32 ms. (16 ms. plus the maximum 86BF time) longer than the breaker failure timer. The 16 ms. is based on the maximum pickup times of RR 50 and AR units in figure 5.

TABLE 1

Overcurrent unit range	0.5 to 13.5 amperes
Continuous rating	250 amperes for 1 sec.
Pickup time of o/c units	3 (min.) to 8 (max.) ms. for current level of 2X to 20X of setting.
Breaker failure timer	18 to 175 ms. continuously adjustable
Control timer	150 to 250 ms. continuously adjustable
Battery drain (125Vdc)	standby 0 timing 95 mA. tripping 130 mA.
Output	4 (N.O.) AR contact outputs, with 2 ICS, one telephone relay contact can replace an AR contact for retrip function.
Seal-in	Telephone relay contact seal-in for (1) BFI contact bounce, (2) Close-in 3-phase fault when memory action of the distance relay is decayed.
Voltage level detector	To restrain the relay from operating if dc supply voltage is below 60% of its rated value.

SOME SPECIAL BREAKER FAILURE PROBLEMS

BREAKER POLE DISAGREEMENT

At voltages of 345 kV and above, the physical size of the operating components and the phase spacing requirements of power circuit breakers have led to the use of an independent operating mechanism for each phase. Also, with the trend to larger and larger turbine-generator sizes, system stability criteria have often dictated the use of independent pole operated breakers at voltages below 345 kV to obviate the three-phase fault, three-pole "hung" breaker fault condition. Rarely will more than one fail to interrupt fault current. Therefore, serious faults (those involving two or three phases) will always be downgraded if not entirely cleared, reducing the danger of system instability.

Field experiences have shown it necessary to consider the consequences of unsymmetrical operation of such a breaker. Electrical or mechanical failures have left one phase open when the others are closed, and vice versa. Since the pole disagreement may occur under no-fault condition, the breaker failure initiation circuit may not be energized. Therefore, the conventional breaker failure relay scheme will not cover the pole-disagreement condition. A type SLB relay, as shown in figure 10 and figure 11, should be used to cover this condition. Refer to reference paper 5 for the details of this problem.

UNEQUAL BREAKER CURRENTS

Double breaker terminals may experience unequal current distribution prior to the clearing of a sound breaker. Figure 7 illustrates this condition. If breaker B fails, for a traditional breaker failure scheme, the breaker B timer may not start until breaker A opens. This condition results in unduly long backup clearing time unless a shorter 62 timer setting or lower overcurrent unit setting is provided. However, the shorter timer setting or lower overcurrent unit setting may affect the security of the traditional breaker failure scheme. This problem can be eliminated by using the new approach, type SBF-1 relay, since the new scheme does not require the overcurrent unit operation before the sound breaker trips.

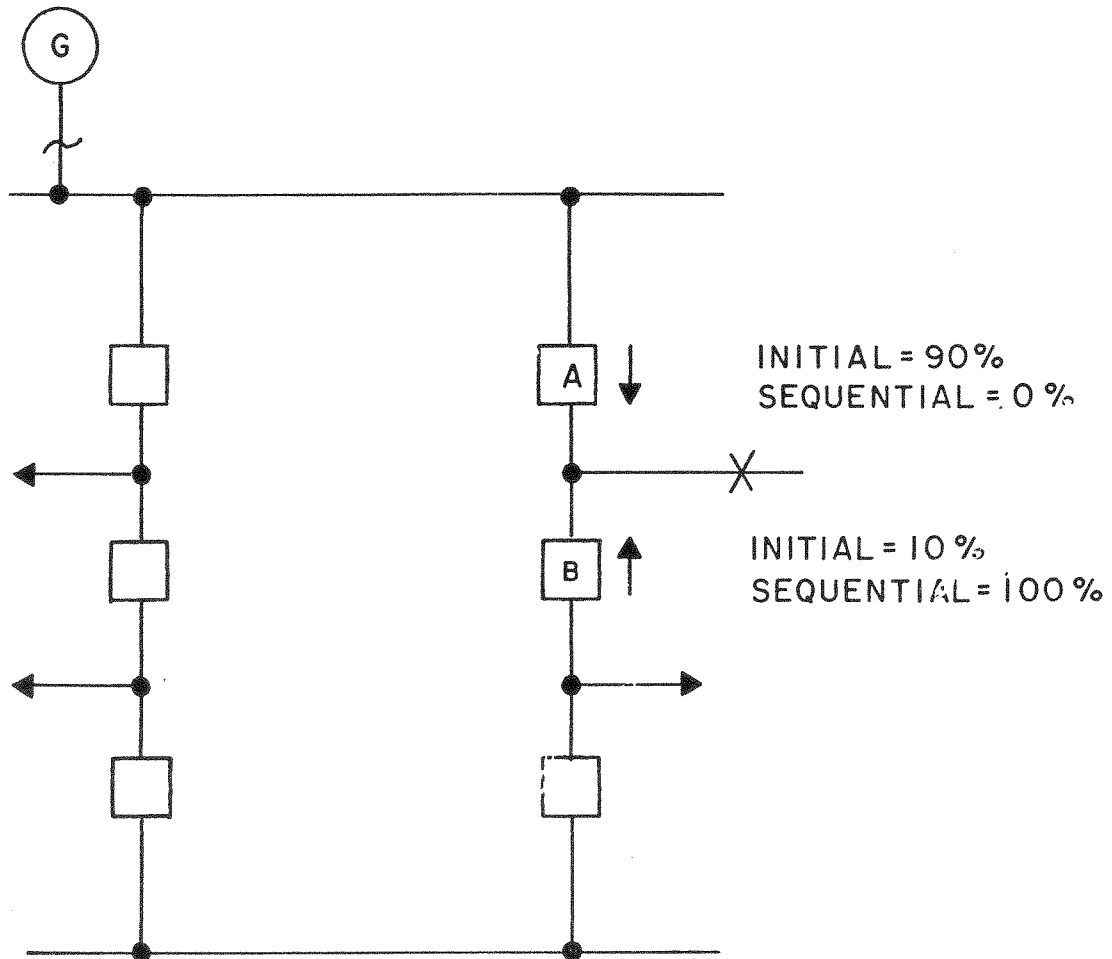


Figure 7. Breaker-And-A-Half System with Sequential Current Change.

WEAK SOURCE

Figure 8 illustrates the isolated weak source condition. When sound breaker 1 opens, the current from the isolated weak source, W, is not adequate to maintain the protective relay outputs, 62X and 62Y. This application requires the use of the 62X, Y seal-in circuit as shown in figure 5.

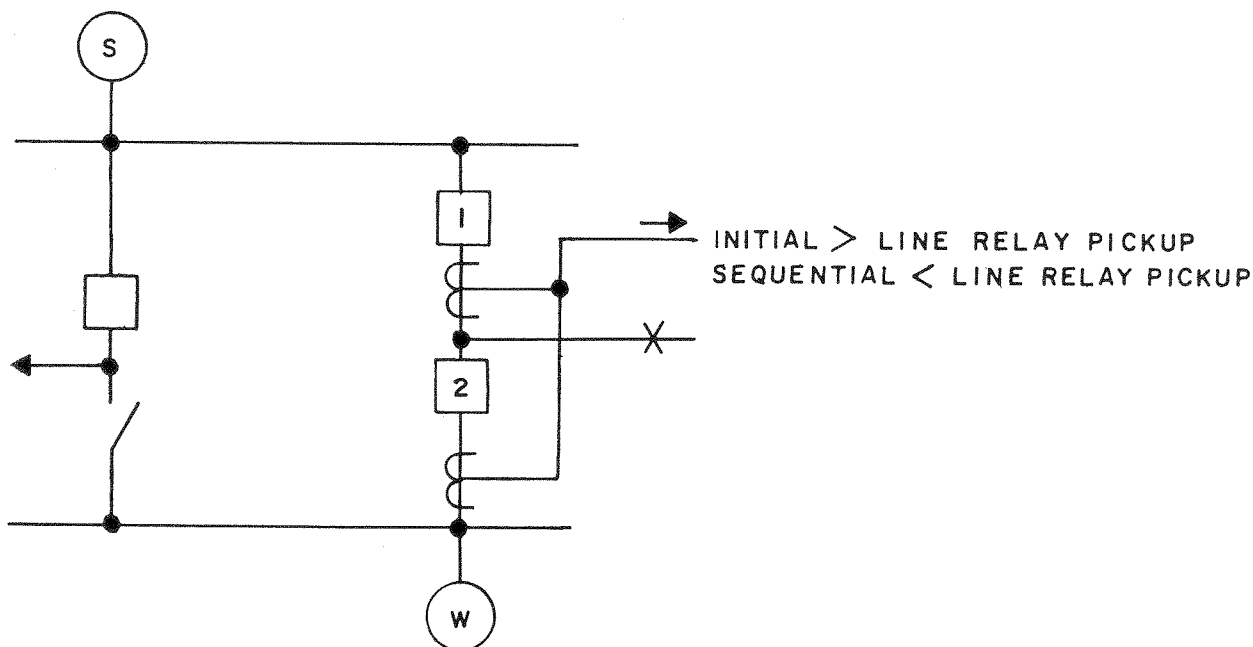


Figure 8. Example of Weak Feed Source Incapable of Holding up 62X or 62Y.

BREAKER CIRCUITS

Inherent in breaker failure is the possibility that the trip coil will remain energized and the mechanism not move. To avoid possible trip coil damage caused by inability of the 52a contact to open, it is advisable to use a back-contact of 86BF, the breaker failure lockout relay, to interrupt this circuit. The re-trip option of the SBF-1 relay will, of course, not be aborted by the presence of this contact. This provision cannot be included where a bus lockout relay is used as the breaker failure lockout relay because of the incompatible simultaneous requirements to trip and to open the trip circuit with the same relay.

Also, a contact of the 86BF relay should be used to block **all** closing of the breaker (automatic or manual). This assures that the cause of the breaker failure is examined and corrected and the 86BF is reset before closure is possible.

MULTIPLE BREAKER SCHEMES

Figure 9 shows a source of possible difficulty in breaker failure relaying in ring-bus and breaker-and-a-half systems.

If breaker A clears satisfactorily and B doesn't, large current, I_B through burden Z_R will apply voltage V_R across current transformer A. If V_R approaches the ANSI relaying accuracy class voltage (for example 400 volts for a C400 ct), the current in 50A can approach 10 amperes even though there is no current in breaker A.

The burden, current transformer quality and connection, and system configuration should be considered in choosing a breaker failure overcurrent relay setting. If it were set below the value in 50A above, false sensing of failure of breaker A would result for the case described.

BREAKER FAILURE AUXILIARY

The speed of the auxiliary BFI (breaker failure initiate) is not critical in any of the breaker failure relaying schemes is described here. Its operating time can be deducted from the timer setting. However, most users prefer to use a very high speed auxiliary relay and have virtually all of the time in the timer itself. There is wisdom in this. A 2 ms AR relay can be used instead of an 83 ms MG-6 relay. A 10% error in the expected operating time of the AR is 0.2 ms while the same 10% would be 8.3 ms in the MG-6. The timer on the other hand, is a refined, accurate timing device and will produce a lower total timing error using the faster relay for BFI.

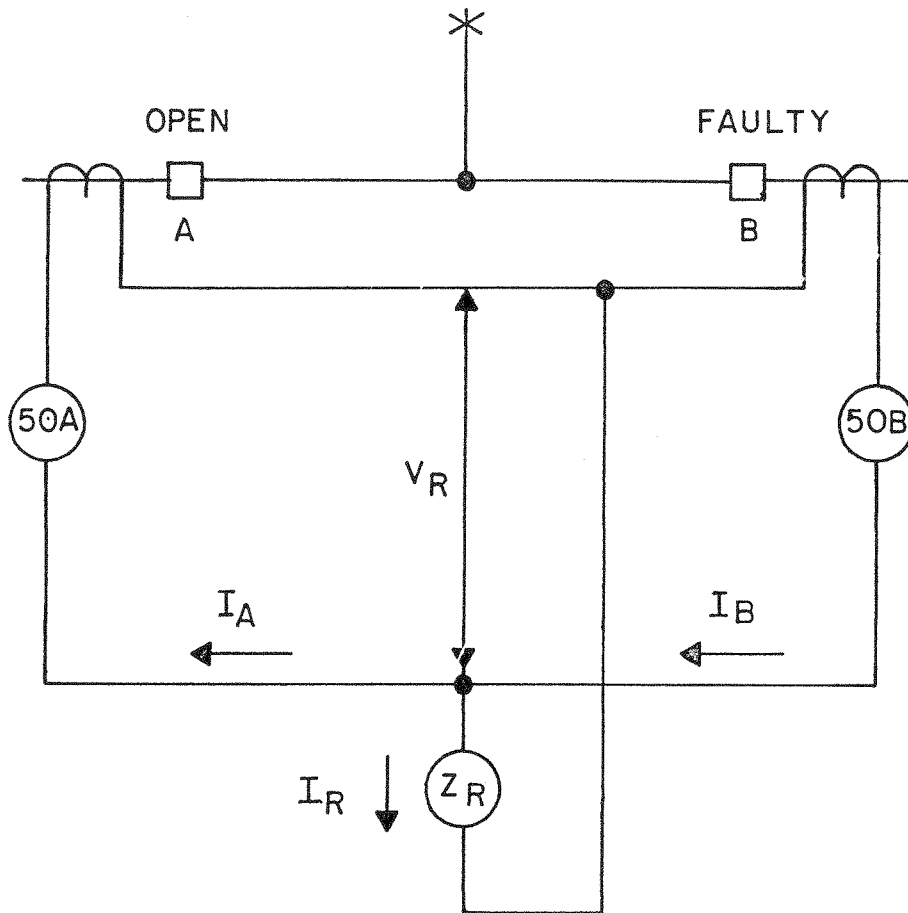
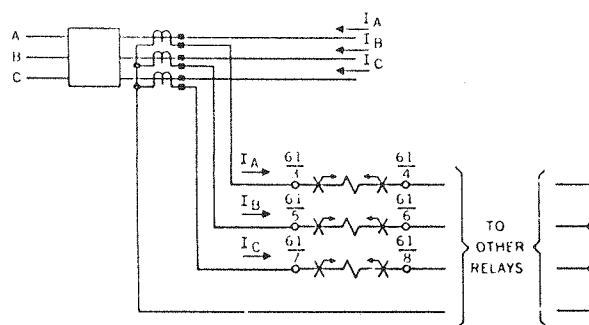


Figure 9. Example of Back-Feed to Breaker Failure Current Detector.



DEVICE NUMBER CHART
 61 - POLE FAILURE RELAY,
 TYPE SLB, WITH TWO TIMERS
 86BF - BREAKER FAILURE
 LOCK-OUT RELAY
 52 - POWER CIRCUIT BREAKER
 ICS - INDICATING CONTACTOR
 SWITCH.

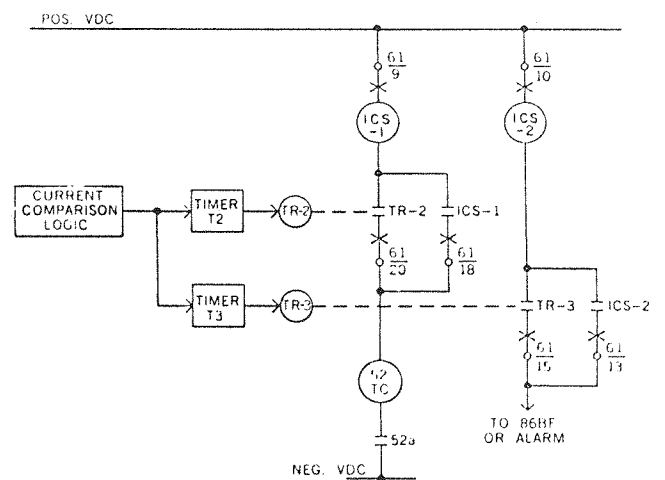


Figure 10. External Connections for SLB Relay with Two Timers.

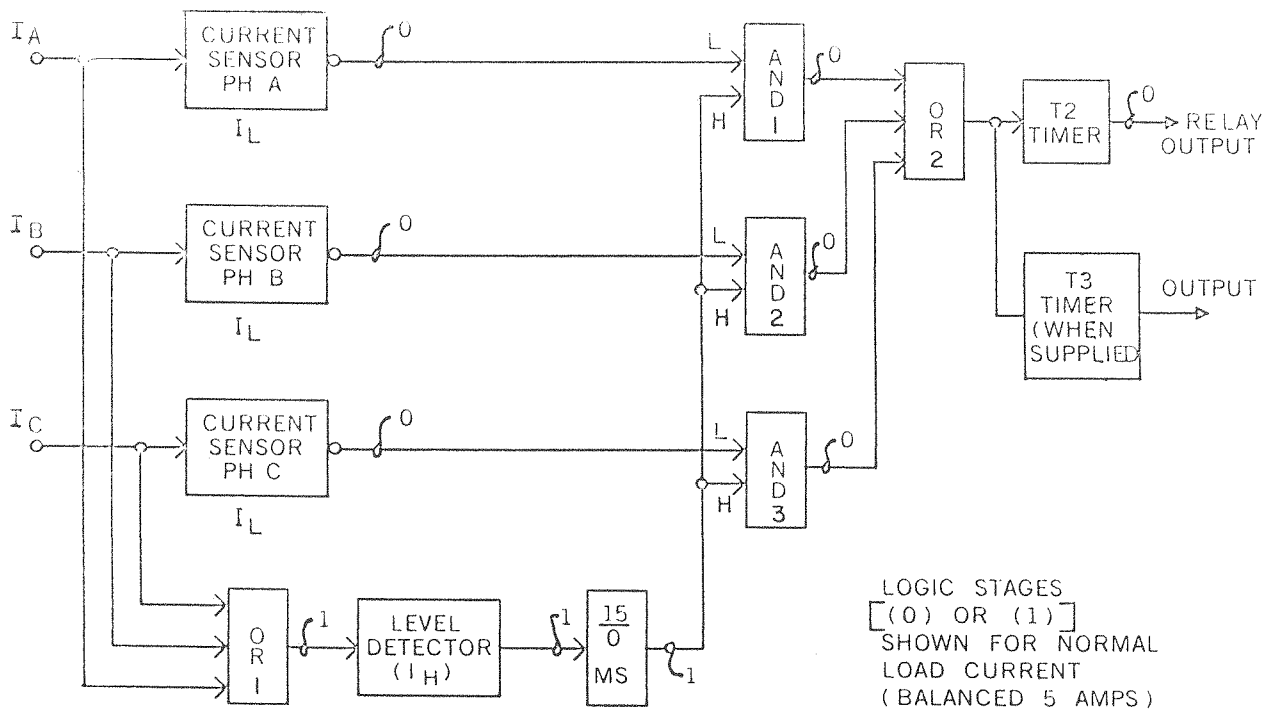


Figure 11. SLB Relay Logic Diagram

SINGLE POLE TRIP

Where a single pole trip scheme is used, breaker failure detection is complicated by the fact that phase to ground faults are cleared by opening one pole only. Load current continues to flow in the other two phases. During the open phase interval, a SLB relay would respond incorrectly. It should, therefore, not be used in this application.

CONCLUSION

This paper describes a new innovation in breaker failure relaying that should allow a **reduction** in trip times while achieving a **higher** degree of security. Other considerations are described that are pertinent to any breaker failure scheme but have received little amplification in the literature.

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Development, Design, Application, and Field
Experience of an Ultra High Speed Relaying
System for EHV/UHV Transmission Lines

by

J. Esztergalyos
Bonneville Power Admin.
Portland, OR

J.R. Linders
Consultant
Cleveland, OH

L. Matele
ASEA
Västerås, Sweden

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The Fifth Annual Western Protective Relay Conference
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INTRODUCTION

With the ever increasing demand of electric power, the efficiency of all available power resources must be maximized. Moreover, due to different locations of power resources and consumer areas, it may be required to transfer huge bulk of power over long distances. BPA's 500 kV a.c. and + 400 kV d.c. interties as well as the Swedish 400 kV grid are good examples.

To cut down the losses and save land costs, the transmission voltages have been continuously increased. The AEP-ASEA, UHV project (1) is focussed on UHV transmission schemes for system voltages 1200 kV and above.

The ultra high speed clearing of faults on all locations is one of the most effective forms of dynamic control, particularly on EHV intertie lines and close to large sources of generation as the rotational transient kinetic energy introduced into a power system is proportional to the square of the fault clearing time. The derived benefits are increased system transient stability and better power transfer capability of surplus power between large regional systems (2). With the latest developments in fast clearing times of the circuit breakers, it was desired to have a ultra high speed relaying system.

Another aspect of high importance for the UHV system voltages is that fast and correct relay operation must be achieved even after partial or total loss of information in the instrument transformers as the growing fault MVA levels and large primary time constant drive conventional current transformers into an early saturation with the subsequent loss of information about the exact nature of the primary current. Even if linearized CT's are used, the true information is not obtained on the secondary side as the aperiodic component can be heavily distorted and thereby causing partial loss of information. The transients generated by the CCVT's when subjected to large drops in primary voltage due to a close-in fault diminish further the possibility of the relay to measure correctly.

The use of series capacitors to improve the power transfer capacity and the static and dynamic stability of the power system often requires particular consideration when designing protective schemes due to influence of the negative impedance seen by relays based on impedance measurement.

DEVELOPMENT OF THE ULTRA HIGH SPEED RELAYING SYSTEM

UHSR feasibility studies had been carried out by ASEA during 1971-73 within the framework of a joint American-Swedish R & D program, the AEP-ASEA UHV Project. Based on these studies it was concluded that a relaying system based on travelling wave approach rather than the conventional principles would have high speed of operation and still be selective.

In response to BPA's solicitation for UHSR, a proposal was submitted and a contract subsequently awarded in July 1974 to develop a system using this novel relaying approach.

In conventional relaying systems filtering techniques are applied to suppress the transients gene-

rated by a fault in order to extract the power frequency component for measurement. This filtering circuits will automatically slow down the operation of the protective system since the system has to be delayed long enough to allow the filter circuits to tune in to the fault condition in RMS 60 Hz quantities, before accurate information can be received by the measuring elements. It was therefore vital to make use of the transients under the fault conditions to avoid delay and obtain an ultra high speed of operation. Based on theoretical studies using a digital computer simulation technique and later verification tests indicated that fault generated transients contain useful information which when processed can yield a very fast and reliable protection.

2.1 Principle of operation

The protective relays process the information received from the instrument transformers. Analysing the pre-fault and post-fault quantities one can write the following equations:

$$i = i_{pf} + \Delta i \quad 2.1.1$$

$$u = u_{pf} + \Delta u \quad 2.1.2$$

where index pf refers to pre-fault quantities. Δ is the change caused by the fault. i and u are locally measured fault current and voltage quantities.

Further, the change Δ can be subdivided into the steady-state change (ss) and transient change (tr) as follows:

$$\Delta i = \Delta i_{ss} + \Delta i_{tr} \quad 2.1.3$$

$$\Delta u = \Delta u_{ss} + \Delta u_{tr} \quad 2.1.4$$

It can be clearly seen from equations 2.1.3 and 2.1.4 that if a measurement is based on the change in current and voltage, pre-fault load conditions have not to be considered. However, it will be required to eliminate the pre-fault current and voltage and this can be done by steady-state frequency suppressors.

In a transmission line with distributed parameters, the relationship between voltage, current, time, and distance is fully described by the so-called "telegraph equations".

Assuming a lossless line, the telegraph equations revert to the so-called wave equations (3).

$$u = f_1 \left(t + \frac{x}{v} \right) - f_2 \left(t - \frac{x}{v} \right) \quad 2.1.5$$

$$i = \frac{1}{Z_c} \left[-f_1 \left(t + \frac{x}{v} \right) + f_2 \left(t - \frac{x}{v} \right) \right] \quad 2.1.6$$

where u , i , t , x , v , and Z_c are voltage, current, time, distance, velocity of propagation, and surge impedance respectively and f_1 , f_2 are arbitrary functions.

It can also be shown that wave velocity v , inductance L and capacitance C of the line are inter-related as follows:

$$v = \frac{1}{\sqrt{LC}}, \quad Z_c = \sqrt{\frac{L}{C}}, \quad \text{and } u = \pm i Z_c$$

The physical significance of equations 2.1.5 - 2.1.6 is that any function of the form:

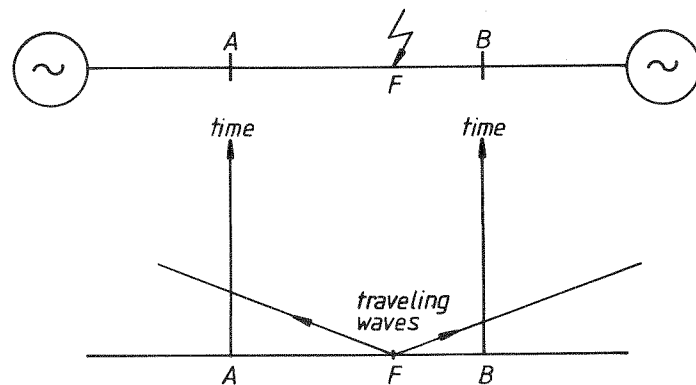
$$f = \left(t \pm \frac{x}{v} \right) \text{ or } f(x \pm vt)$$

represents a rigid distribution or a travelling wave, because for any value of a corresponding value of x can be found such that $(x + vt)$ has a constant value and therefore defines a fixed point on $f(x + vt)$.

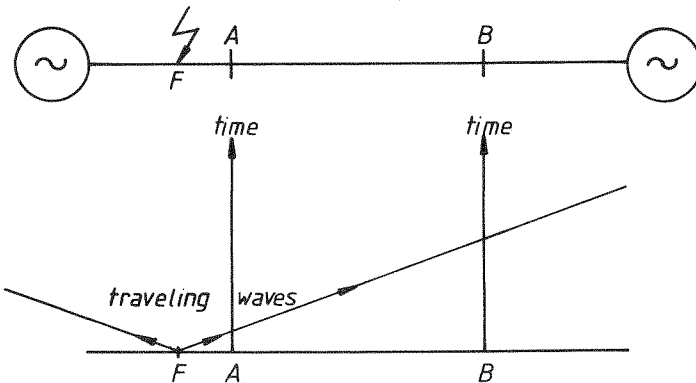
$f_2(t - \frac{x}{v})$ defines a forward wave moving in a direction of positive x and

$f_1(t + \frac{x}{v})$ defines a backward wave.

It can thus be said that while the forward voltage and current waves are of the same sign, the backward waves are of opposite sign. The travelling wave theory can therefore be usefully applied for relaying purpose as shown in Fig. 1. By observing the sign of the voltage with respect to the current immediately after the fault inception, the direction of motion of the travelling wave can be determined.



a) Internal fault



b) External fault

Fig. 1. Propagation of travelling wave, (a) internal fault (b) external fault

2.2 Directional determination

As stated earlier, a comparison of polarity between Δi and Δu directly after the fault inception will automatically yield the direction of motion of the first travelling wave that reach point A. Fig. 2 below illustrates this. The application of the fictitious source at the point F causes travelling waves (current and voltage waves) moving from F towards the two terminals A and B. Positive current is defined locally as a current flowing from A to F and from B to F.

Consider an internal fault, Fig. 2 a. If the pre-fault voltage u_{pf} is positive, the fictitious source causes negative voltage waves towards A and B. But the current waves are positive since the fictitious source causes currents to flow from A to F and from B to F. Thus at point A, Δi is positive and Δu is negative during the first moments after fault inception. Likewise at point B, Δi is positive and Δu is negative.

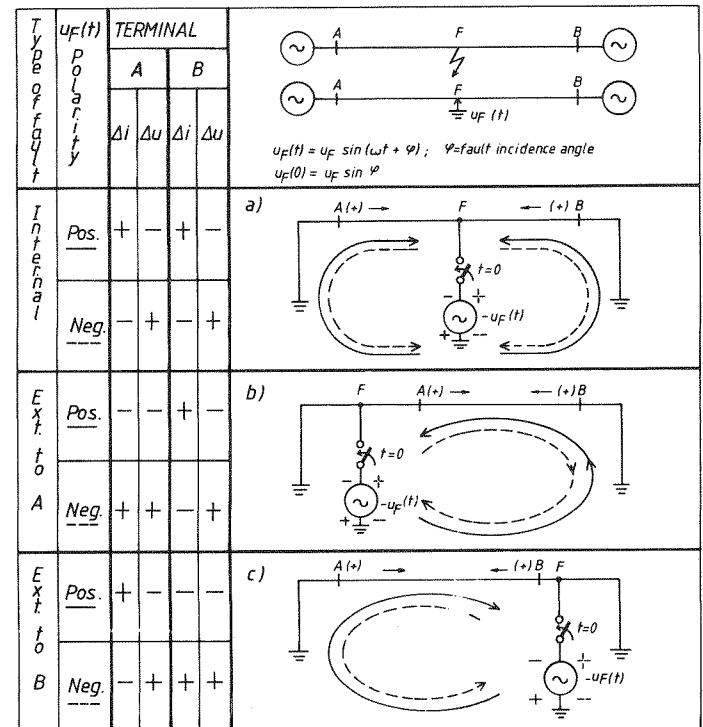


Fig. 2. Directional determination. Changes incur Δi and voltage Δu for different faults: Δi and Δu have opposite signs for internal faults and same signs at one end for external faults. The dotted lines show the current flow during the other half cycle.

2.3 Computer simulation studies

As shown in Fig. 3 below, the relay response was verified by computer simulations. The computer print-out shows a single-phase fault initiated at $t=0$ at 110 km (68 miles) distance from the measuring point.

The plot shows clearly the propagation time of the travelling wave (arriving at $t = 0.37$ ms) and that Δi and Δu are opposite in sign immediately after fault inception. The relay response is extremely fast exceeding a trip detection level within approximately 0.5 ms from the arrival of the first travelling waves. Further the relay response in the unfaulted phases indicates a single-phase tripping capability.

The computer studies also confirmed the possibility of obtaining a directional discrimination with limited reach along the transmission line, a feature of great value for fast fault clearance of close-in faults.

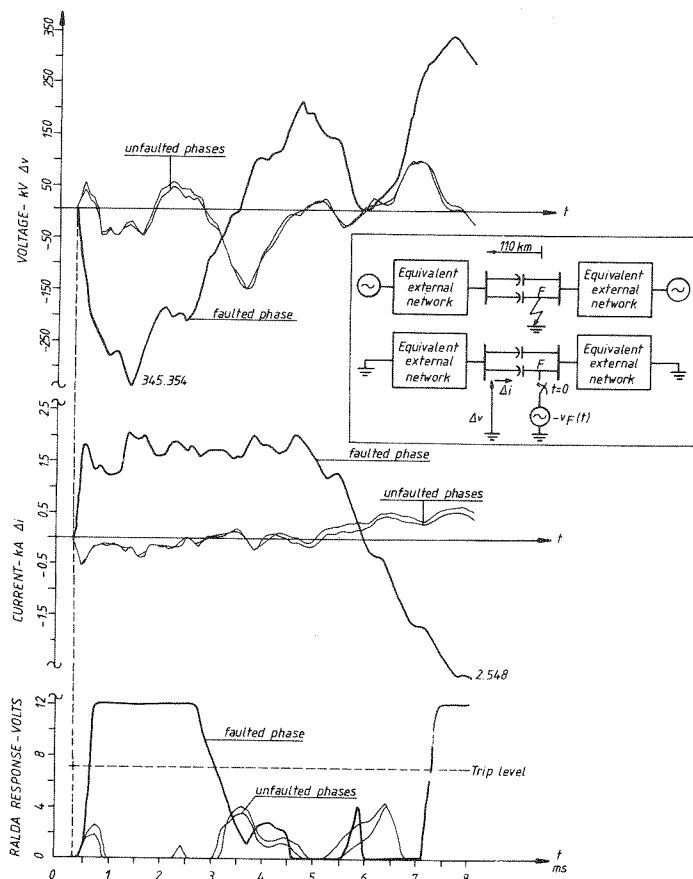


Fig. 3. Changes in primary voltage and current and relay response for an internal single-phase fault 110 km away.

The results shown above were also verified in May 1973 during field tests carried out on AEP 765 kV power system where a number of switching operations were performed on the Dumont-Marysville line as part of the AEP-ASEA, UHV project. The signals generated within the relay were recorded and compared with corresponding results from computer studies and were found to be in agreement.

3 UHSR SYSTEM DESIGN

3.1 Design consideration

a) Reliability of the protective system in the substation environment is essential. The possibility of interference being coupled to the relay inputs must be considered.

Selecting Δi and Δu as measuring quantities, it is possible for the relay to operate on information contained in both steady-state and transient changes. The bandwidth of the relay can be deliberately limited to a few kHz without impairing the basic relay operation. This also makes the relay compatible with the performance of conventional and also non-conventional instrument transformers. In other words, the relay does not have any special requirements on the transient response of instrument transformers.

b) Travelling waves can be generated by faults but also by switching operations, lightning surges, etc. It

is therefore necessary that the relay can discriminate between changes due to faults and changes due to other reasons.

Lightning strokes that do not lead to a fault, involve a transport of energy along the line in the form of coupled current and voltage waves exhibiting a high frequency character. The relay design is such that it damps heavily the amplitude of high frequency components, and requires also that a measuring signal if any, should last for a time longer than the relay minimum decision time. This time criterion coupled to the fact that the relay operates only if both Δi and Δu have magnitudes larger than set values (amplitude criteria), make it possible to distinguish a lightning stroke that does not lead to a fault from one that does lead to a fault as well as from a fault due to any other cause. In the latter cases the transients will also contain power frequency and low frequency components, that are not so heavily damped by the relay circuits during the first moments after fault inception, and that last for an appreciable time, much longer than the relay decision time.

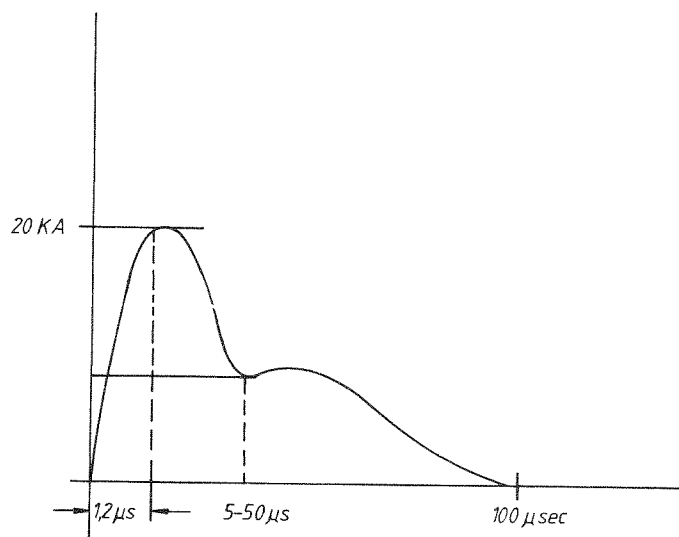


Fig. 4. Lightning stroke.

c) For discrimination against switching surges it is important to note that travelling waves originate from the point where the change in the electrical state of the power system was initiated. Thus simply by excluding the circuit breakers from the protected zone switching operations will always be interpreted as external events. This is obtained automatically in most EHV systems since voltage normally is measured on the line side of the breaker. The fact that most EHV breakers have pre-insertion resistors that damp the amplitude of the switching surge give the relay better discrimination capability.

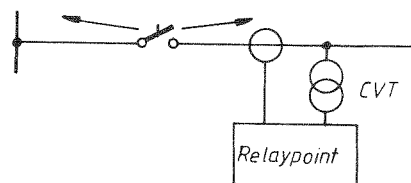


Fig. 5. Line switching

3.2 Operation

The UHSR system is designed on a segregated phase basis. Each phase has two simultaneous modes of operation. The first operates as a directional comparison blocking scheme, i.e. it requires the use of a communication channel between relay terminals. Dependability and speed of operation have been further enhanced by the provision of a second independent mode of operation. This independent mode has an underreaching setting similar to a zone one type of relaying enabling local circuit breaker tripping without the need of a communication channel. It is also intrinsically selective and since it does not require time coordination it is particularly valuable for ultra high speed clearing of close-in faults. Typical operating times of 2-3 ms are possible in this mode. The directional wave comparison mode has essentially the same response time, but the communication channel introduces an additional delay. The delay is a function of the audio tone equipment and the characteristics of the microwave or power line carrier system. A block diagram of the relay system is shown in Figure 6.

The analog interface provides the required galvanic isolation and surge immunity and a transformation of the input signal to a level suitable for static circuits. The steady-state frequency suppressors eliminate the pre-fault quantities. The transfer function of the circuits is such that the initial changes generated by a fault are transmitted with insignificant delays.

An amplifier stage supplies the suitable amplitude criterion required to achieve a minimum or maximum reach along the line depending on whether an overreaching or underreaching operation is desired.

The signals are then fed to so-called directional detectors where the direction to the fault is determined by comparing the signs of Δi and Δu . The forward looking detectors give a "tripping direction" signal (T) if the current and voltage changes are opposite in sign, while the reverse looking detectors give a "blocking direction" signal (B) if the changes are of equal sign. The normalized signals S_i (V/kA) and S_u (V/kV) derived from Δi and Δu respectively are combined to yield T and B according to the following relations:

$$T = \max [\min (S_i^+, S_u^-), \min (S_i^-, S_u^+)] \quad 3.2.1$$

$$B = \max [\min (S_i^+, S_u^+), \min (S_i^-, S_u^-)] \quad 3.2.2$$

where upper index +/- refer to the signal polarity.

This particular arrangement enhances security since both Δi and Δu must have a certain magnitude before the detectors give an output signal. For example, sudden loss of a.c. voltage input alone will therefore not lead to any output from the directional detectors.

The output signals from the directional elements of each phase must exceed certain levels before they are processed in a logic circuit to determine the sequence between T and B and to directly, upon fault inception, establish whether T was sensed before B or vice versa. The sequence is remembered in order to avoid the confusion that could be caused by multiple reflexions of the incident waves. This memory effect lasts until the relay resets.

Further the logic circuit will determine if the fault is a single or multi-phase fault and perform the appropriate phase selection as required in single-phase tripping schemes. Normally the relay is connected so that three-phase tripping is always obtained for multi-phase faults and also if the voltage to neutral of one phase is low at the same time as another phase is faulted.

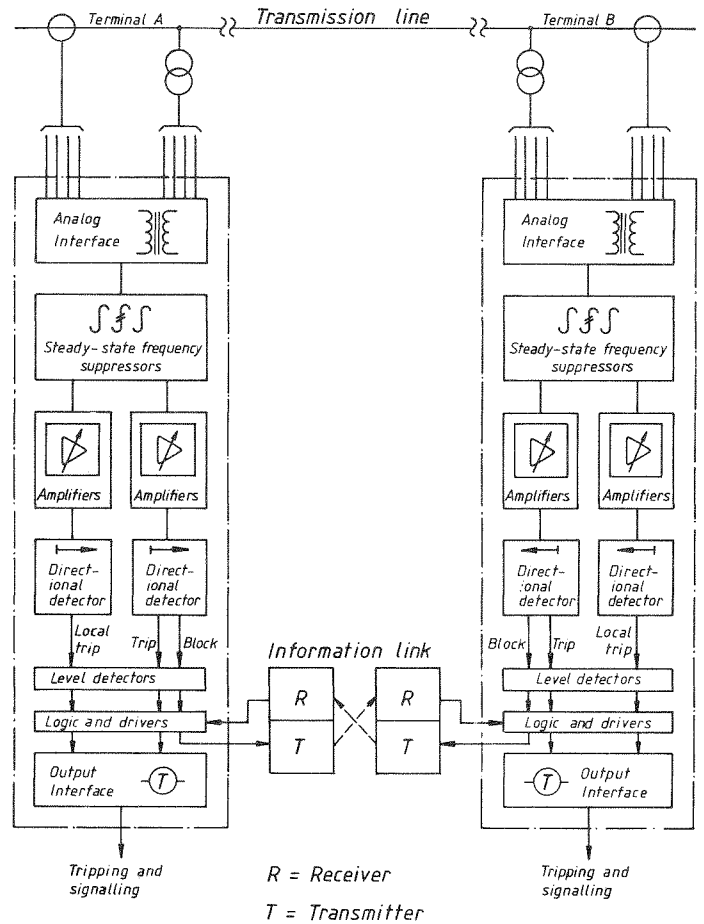


Fig. 6. Block diagram of UHSR system

Another function of the logic circuit is to coordinate the local relay decision with the remote relay via a communication channel. Since each relay terminal inherently has the phase selection information the communication channel needs only to transmit a single permissive trip or block signal.

To cope with the possibility of the circuit breaker being closed against a permanent line fault, particularly under the very adverse condition when the voltage is zero both before and after the circuit breaker operation, the relay system includes a special switch-into-fault detector. Based on current and voltage measurements this unit recognizes switch-into-fault condition and enables direct local tripping. To meet BPA requirements the relay was supplemented with a fast resetting (less than 10 ms) breaker failure initiation unit and a static autoreclosure initiation unit. Also included were miniature circuit breakers to protect the a.c., d.c., and tripping voltage circuits.

The output interface includes solid state tripping relays and electro-mechanical signal relays with corresponding flag indicators. Tripping, blocking,

phase selection, and mode of operation information is displayed and signalled as well as alarm functions.

The auxiliary power is supplied through a dc/dc convertor providing full galvanic isolation between the relay circuitry and the auxiliary power source as well as effective suppression of surges that might be impressed on the dc input.

Static circuits perform processing of all signals and the use of modern semi-conductor technology and integrated circuits contributes to a high reliability. High threshold logic is used to enhance noise immunity. The main technical data of the relaying system are given in Table I.

TABLE I

Technical data of the UHSR system intalled by BPA	
Rated voltage to neutral U_n	$120/\sqrt{3}$
Nominal rated current input I_n	1 V corresponding to 5 A
Auxiliary voltage	90-145 V dc
Ambient temperature	- 20°C to + 55°C
Insulation test voltage (per IEC Publ. 255-4)	2 kV, 50/60 Hz during 1 min.
Impulse test (per IEC Publ. 255-4)	5 kV, 1.2/50 μ s, 0.5 joule
Surge withstand capability (SWC) test (per IEC Publ. 255-4 and ANSI C37.90a)	1-1.5 MHz, 2.5-3 kV crest wave decaying to 1/2 value in $\geq 6 \mu$ s
Showering arc test (per Swedish National Standard 361503)	2-4 kV self oscillatory discharge from 300 H inductance into a distributed capacitance of 200 pF, coupling capacitor 100 pF
Operating times	
Direct local trip	2-3 ms
Directional comparison trip	4-6 ms (incl. 2 ms channel)
Rated power consumption	
Current input	0.005 VA/phase
Voltage input	0.3 VA/phase
DC-circuits	27 W
Setting possibilities	
Current change	0.2-5.1 I_n
Voltage change	0.05-1.05 U_n
Tripping time delay ($\approx$ channel time)	0-20 ms

The basic relay design consists of plug-in units, many of which are interchangeable offering a high degree of flexibility and reducing the spare part count. Secondary injection tests can be performed whenever required through the standard test switch provided in the relay. For ease of maintenance a built-in test unit is available. Internal, external, single or multi-phase faults can be simulated on both the positive and negative half cycles to check the relay performance.

3.3 Laboratory tests

The later stage of the prototype testing necessitated a series of laboratory tests. Part of BPA's 500 kV system was simulated on an analog Transient System Simulator (TSS) with a network configuration according to Fig. 7 featuring a 143 km long double circuit with 75 percent series compensation and an adjacent uncompensated 30 km long line. The lines were stimulated with the proper frequency dependency taking into account the shunt capacitance and mutual coupling effects as well as shunt reactor and series capacitor compensation. For the purpose of investigation a fictitious large shunt capacitor bank was also included. A large number of tests were recorded using a 14-channel analog tape recorder. The recording were then fed back into the relays through a suitable set of amplifiers. This technique was adopted in order to avoid blocking the TSS facility unnecessarily during the evaluation procedure after each test. Another advantage is the "off-line" testing capability even outside the laboratory.

The test cases included internal and external faults as well as various switching operations (shunt reactor switching, series capacitor by-pass, transformer and line energization, sequential tripping of breakers, switching into faults, auto-reclosing, etc). All cases were repeated with different fault incidence angles in order to obtain maximum information regarding the relay response. During the test two relay terminals with associated tone equipment were linked back-to-back, the channel delay being approximately 2 ms.

Correct relay operation was obtained for all tests both on the compensated and on the uncompensated lines. The overall operating time of the relay in the directional comparison blocking mode was measured to range from 4-6 ms., including a 2 ms. channel time. The operating time of the under-reaching mode was 2-3 ms. The relay was also successfully subjected to different types of insulation and surge tests (see Table I).

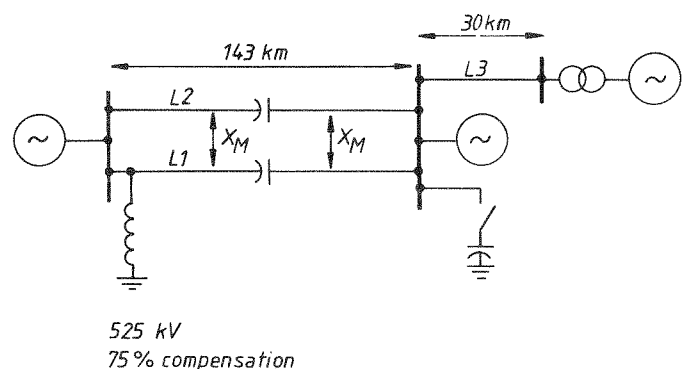


Fig. 7. Network configuration of analog simulations

Fig. 8 shows the relay response for a close-in fault. The independent mode direct local trip was given in 2 ms while the dependent mode directional comparison was obtained in 4 ms including the channel time. Fig. 9 shows the relay response for a switching operation on an existent remote end permanent fault 143 km (89 miles) away. The simulated breakers had pre-insertion resistors which were shorted after 7-8 ms. The relay tripped in 1 ms after the resistors were short circuited.

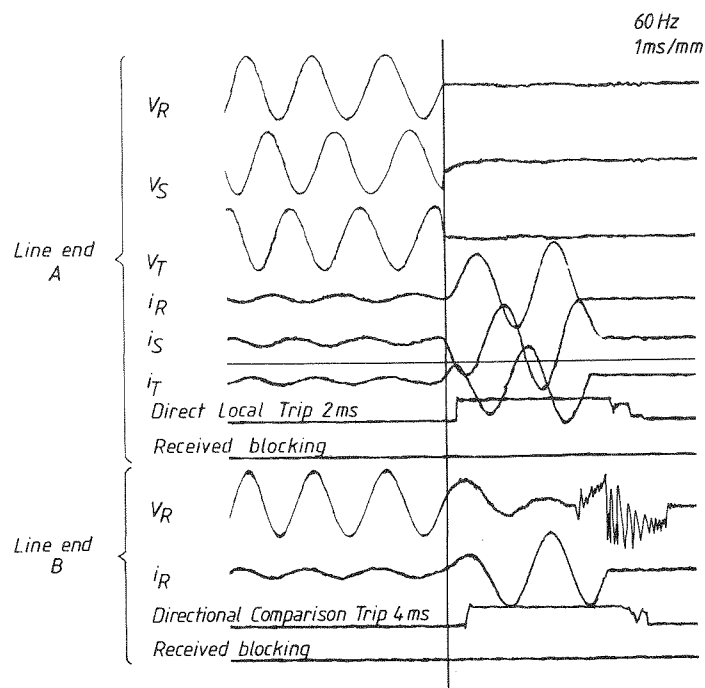


Fig. 8. Relay response for a three-phase fault close in to line end A.

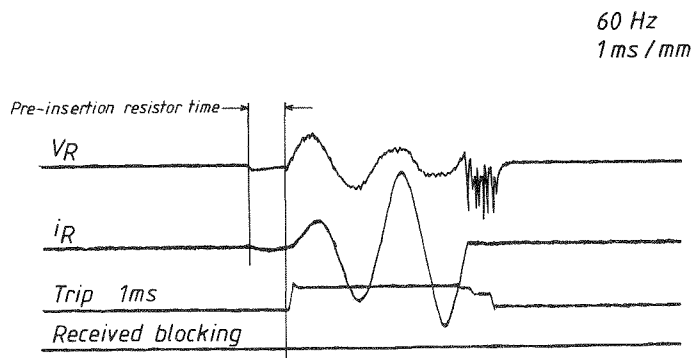


Fig. 9. Relay response when switching into a remote end persistent fault.

3.4 Setting Principles

Since the operating principle of the UHSR system is based on the change in current and voltage rather than the total fault quantities, the relay setting can be calculated without taking the pre-fault load into consideration. This ensures a high sensitivity even at high through load levels and/or high fault resistance.

The setting calculations do not require advanced mathematics but simple and conventional short circuit calculation familiar to the relay engineers.

The setting calculations are performed on fundamental frequency, as the relay senses both the steady-state and transient change (eq. 2.1.3 and 2.1.4). If the settings are based on the steady-state change, the transient component contributes to an improved sensitivity.

The independent mode to cover the direct local trip is therefore based on an underreaching scheme to take into consideration the transient component and thus avoiding transient overreach. It has been verified through tests and simulations that the upper limit of the instantaneous value of the current change is about twice the steady-state amplitude when all losses are neglected. However, it will be lower for transmission lines. The settings are therefore based on maximum values of Δi_{ss} and Δu_{ss} for faults at the remote end and reducing it by a transient reduction factor.

The dependent mode to cover the whole line length and cooperating with communication channel on directional comparison blocking principle is simply set on minimum changes in Δi_{ss} and Δu_{ss} for faults at the remote end. It is most often possible to include a large amount of fault resistance coverage in the settings unless the fault currents are very low, which is rather unlikely in UHV systems. The overall coverage of fault resistance is much better than the conventional relays.

4 UHSR SYSTEM APPLICATION FEATURES

The scope of the UHSR project was focused on the development of ultra high speed relaying. Since the relay is based on the travelling wave principle its ultra high operation is inherent. As with many new concepts it soon became apparent that the relay possesses other inherent properties which were of the scope of this development program but turned out to be more significant in future relay applications as follows:

- a) Basically the relaying system can be used with any type of communication channel although, to maintain the ultra high speed of operation even for remote-end faults, a fast channel is preferred. It is possible however to achieve a compromise between channel speed, channel reliability and cost without affecting the design of the overall system. In terms of end-to-end communication only one signal is required to be transmitted from one line to the other even when single-pole auto-reclosure is practiced. The transmitted signal has no bearing on starting on phase selection since this is accomplished locally. The interpretation of the received signal depends on whether the system operates in a tripping or a blocking scheme.

Note that selective and extremely fast operation is obtained for close-in faults independent of the communication channel by the addition of directional detectors set in an underreaching mode.

- b) The relaying system can use both conventional and non-conventional instrument transformers and is not affected by saturation of transformer cores and/or relaxation transients generated by capacitive coupling voltage transformers. These exceptional qualities are accounted to be partly due to the operating

principle and partly due to the specific choice of measurands; the changes rather than the remaining values.

Tests and practical experience have demonstrated that CT-saturation does not occur instantaneously. Even in the most adverse cases one can expect a closed core CT to give a correct secondary output during the first 2-3 ms after fault inception. Since the relay decision time is in this range, a correct decision can be made and remembered before the CT saturates. This is a valuable feature because it means that the relay will trip dependably for internal faults and maintain full stability for external faults, even after saturation.

c)

The use of the change in voltage offers the advantage of a simple solution to the problems normally caused by capacitor coupling voltage transformer transient response. For a close-in fault the noise generated by the CCVT could be many times larger than the actual remaining voltage, which represents a very difficult condition for conventional relays. The change in voltage, however, is quite large for a close-in fault and since the relay uses this change for measurements, the signal to noise ratio will be satisfactory and will ensure a correct operation of the relay.

d)

It is common to install series capacitors in order to compensate the line losses and increase power transfer capability. However, this in turn imposes problems for protective schemes working on conventional principles. The impedance measuring relay will on such lines see negative impedance if the capacitor banks are located near to the line ends. The distance relay will operate incorrectly where the impedance or voltage drop between the fault and the relay is capacitive. Generally spark gaps are installed across the capacitor unit to short out the capacitor when the current exceeds a given magnitude. However, in such cases the operating time of the relays will be prolonged. The phase comparison relay is also prone to maloperation if the net impedance to one of the source becomes capacitive causing 180° current reversal with respect to the generated voltage. If the gaps do not flash over, an internal fault may appear to be external. Early saturation of CT's may also impose problems for this type of scheme.

The UHSR system is, however, devoid of these problems. The series capacitors do not impose any problem as the protection scheme is not based on impedance measurement. Any fault behind the relay, even if the series capacitor are installed in the station are seen as external faults. The problem associated with delayed gap flash over in series capacitors is eliminated.

e)

Single-phase operation is inherent as the signals are processed on phase segregated basis. Multi-phase faults automatically lead to three-phase tripping, only one carrier signal is needed from the remote end for either single-phase or three-phase trip operation.

f)

The relay is not affected by power swings since the time and amplitude criteria in the suppresser and

detector units have been chosen so that such gradual changes will not be picked up.

g)

The UHSR system is stable for fuse failure on the ac supply as the inherent operating principle implies that simultaneous change in current and voltage must take place to cause operation.

h)

A very interesting feature of the UHSR is the possibility to distinguish between a loaded phase conductor rupture and normal deenergization of a loaded line. In the former case, a travelling wave is generated and the relay may give operation before the conductor touches ground or the rupture develops into a flash over. Safety hazards to human beings in heavily populated areas are therefore reduced.

i)

The UHSR can give operation even at zero fault inception angles. As shown in Fig. 10 the voltage change is of substantial magnitude and steady-state nature for a solid ground fault.

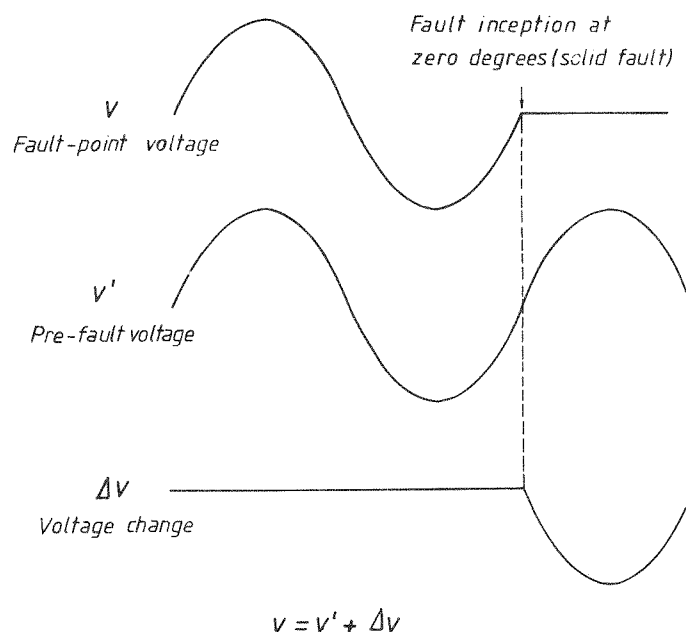


Fig. 10. Voltage change during a fault initiated at zero degrees.

j)

The relay is well suited for the protection of three terminal lines. A contract was recently awarded by BPA to ASEA, to investigate such applications.

k)

The transmission line length is no limiting factor as the two relays measure locally and no time co-ordination between the measuring quantities between the two ends is necessary.

l)

Because of the low burden, the relay can easily be applied in all installations. The small ac circuit burden will also enable a direct application of the relay to non-conventional analog current and/or voltage transducers. The current input can be fed with a voltage proportional to current or directly with current.

5.1 Installation and commissioning

The UHSR system was installed on April 2, 1976 on BPA's 500 kV PNW-PSW intertie on the John Day - Grizzly No. 1 line in a series compensated double circuit configuration 143 km long.

Installation went according to plans and no problems were encountered except in ascertaining the polarity of an external auxiliary CT set which was taken for granted due to instrumentation and service conditions but later turned out to be erroneous (see further Table II, second comment). The secondary of the auxiliary CT's was terminated in a 0.2 ohms wire wound resistor making 5 A proportional to 1 V. This voltage signal was then fed to the relay.

The relay hardware and settings were checked with conventional test equipment arranged to provide simultaneous changes in secondary voltage and current levels through the standard test switch provided in the relay, as well as with the built-in test unit mentioned in Section 3.2.

The blocking output of the relay was connected to a specially developed microwave tone equipment, provided for by BPA, featuring a single tone transmitter-receiver operating at a carrier frequency of $72 \text{ kHz} \pm 1 \text{ kHz}$ and occupying four 4 kHz channel spaces. The channel delay of a one-way signal from Grizzly to John Day was measured to be 2.1 ms.

Trip and alarm outputs were connected to a time coded substation data system (SUDS) sequence of events recorder with 1 ms resolution. In addition the trip output was monitored on the sub-station oscillograph at both end terminals.

5.2 Staged fault tests

One problem with any new relaying concept after development is the extraordinary time it takes to accumulate actual field performance data due to the limited number of faults. The opportunity to collect additional data on UHSR performance was presented when a staged fault test was conducted in October 1976 on the John Day - Grizzly No. 1 line at the Bakeoven series capacitor switching station.

The network configuration is shown in Figure 11. Four single-phase internal faults were initiated on No. 1 line at Bakeoven using a crossbow technique, giving random fault incidence angles. The pre-fault power flow was 2200 MW to the North on No. 2 Grizzly - John Day line, while No. 1 line was open at Grizzly.

Three close-in external single-phase faults were applied directly on the Grizzly bus by closing a circuit-breaker at random against a metallic earth connection. The pre-fault power flow was the same as mentioned above with a subsequent reversal when the faults were applied. Both parallel lines were in operation in this case.

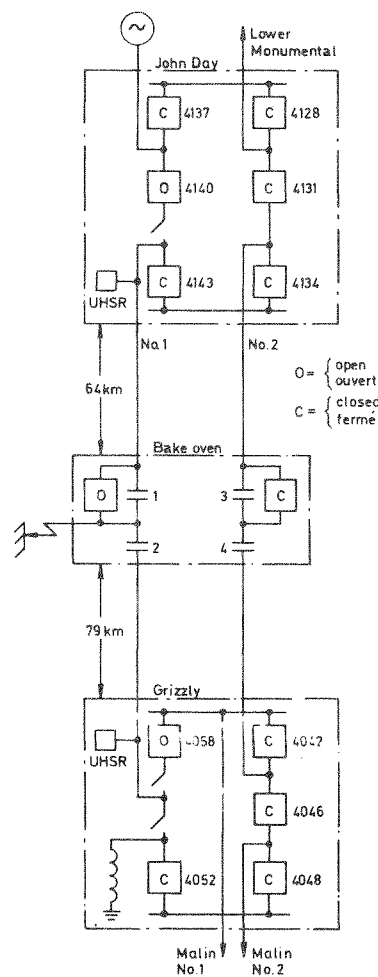


Fig. 11. The John Day - Grizzly 500 kV network configuration during the staged fault tests of internal faults on Oct. 5-6 1976. All four faults were single-phase. Tripping times obtained: 5.5 - 6.1 ms.

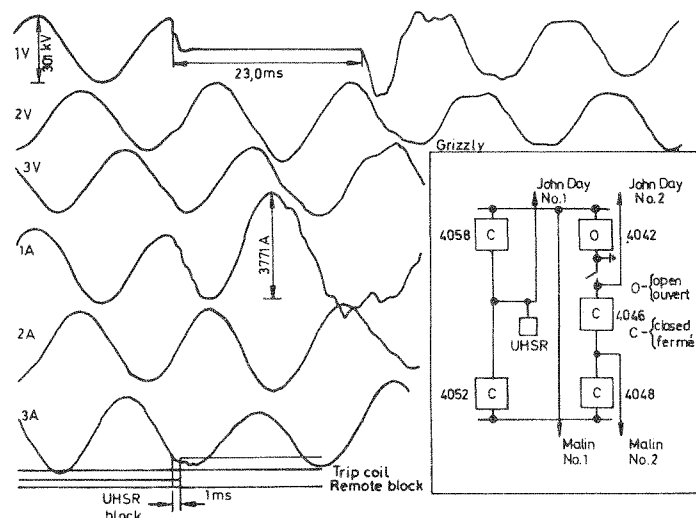


Fig. 12. Grizzly substation oscillogram of a staged fault test of a close-in external A-phase fault on Oct. 7 1976 initiated by closing PCB 4042. The relay blocked locally in 1 ms.

High-speed tape recorders were installed at both end terminals to provide accurate measurements of the voltage and current magnitudes and the UHSR tripping and blocking time.

The results of the staged fault test show that the relay tripped for all internal faults in 5.5-6.1 ms and blocked locally for all external faults in 0.5-1.5 ms yielding blocking at the remote terminal in 2.7-3.5 ms. Figure 12 shows an A-phase external fault. Approximately 15 correct blocking operations were recorded due to switching operations in conjunction with the test. However, one misoperation during line switching south of Grizzly occurred where the John Day terminal tripped indicating a B-phase fault.

This case was investigated in detail and a plausible explanation was found. The fact that the substation fault locator indicated an internal fault close to Bakeoven and that an internal fault developed at Bakeoven the following day with the B-phase disconnection switch burning off, suggests that the switch was not properly secured after the field test on B-phase. Thus an internal fault of transient nature ("spitting") may have occurred. This is substantiated by the station oscillograph record. The "spitting" may have been caused by overvoltage created during the switching operation. The Grizzly end terminal could have been delayed in operation by the combined effect of the switching operation (external event) and the "spitting" (internal event).

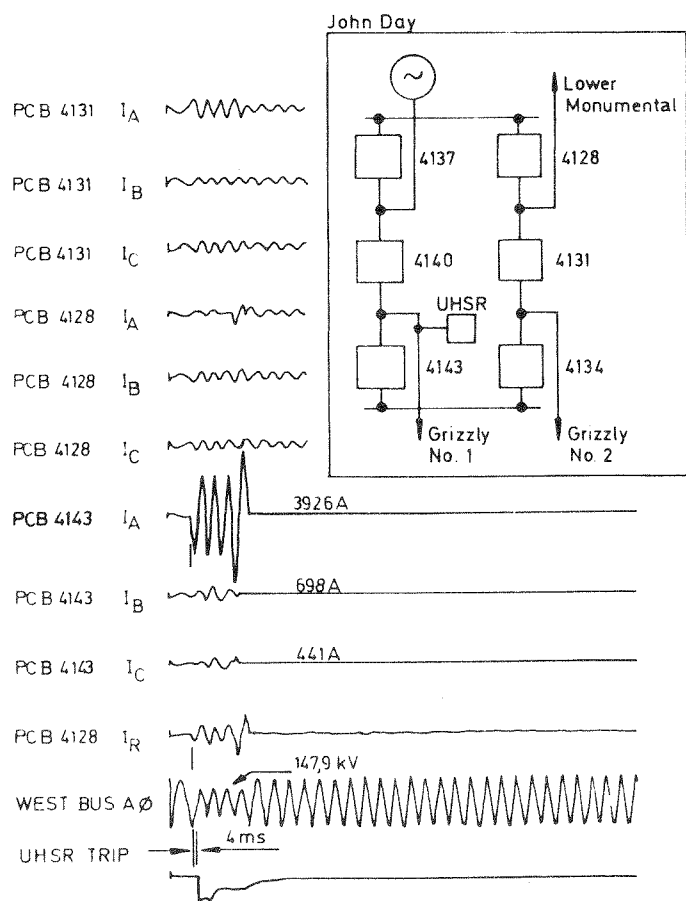


Figure 13. John Day substation oscillogram of a spontaneous internal A-phase fault 29 km (18 miles) from John Day on Jan. 30, 1977. Direct local trip (independent of channel) at John Day.

5.3 Field Experience

During over two years of service from April, 1976 to July, 1978, numerous operations have been recorded. They are summarized in Table II, which also includes the staged fault test. A station pre-fault recorder oscillogram of a spontaneous A-phase and B-phase to ground fault is shown in figures 13 and 14 respectively. For these faults the UHSR system tripped in 4 and 3 ms.

Out of 45 operations listed, we have identified one false trip due to improper CT connection (June 8, 1976). One false trip due to the thermal leakage of the A phase trip output module (September 8, 1976). Two false trips (August 19, 1976, and October 6, 1976) are suspected due to flashovers of transient nature during routine switching operations. (Ref. 5.2.) One false trip occurred under similar circumstances (January 8, 1978), and could possibly be due to a restriking breaker at Grizzly.

One false trip occurred with the line open ended at Grizzly and a lightning arrester arcing at Round Mountain (May 4, 1978). Note in this instance the arcing lasted for 10 cycles before the UHSR tripped at the John Day terminal. Possibly mutually coupled transient or spitting across series capacitor spark gap operated the John Day relay during the elevated voltage condition at Grizzly when the Grizzly end was open and its relay out of service.

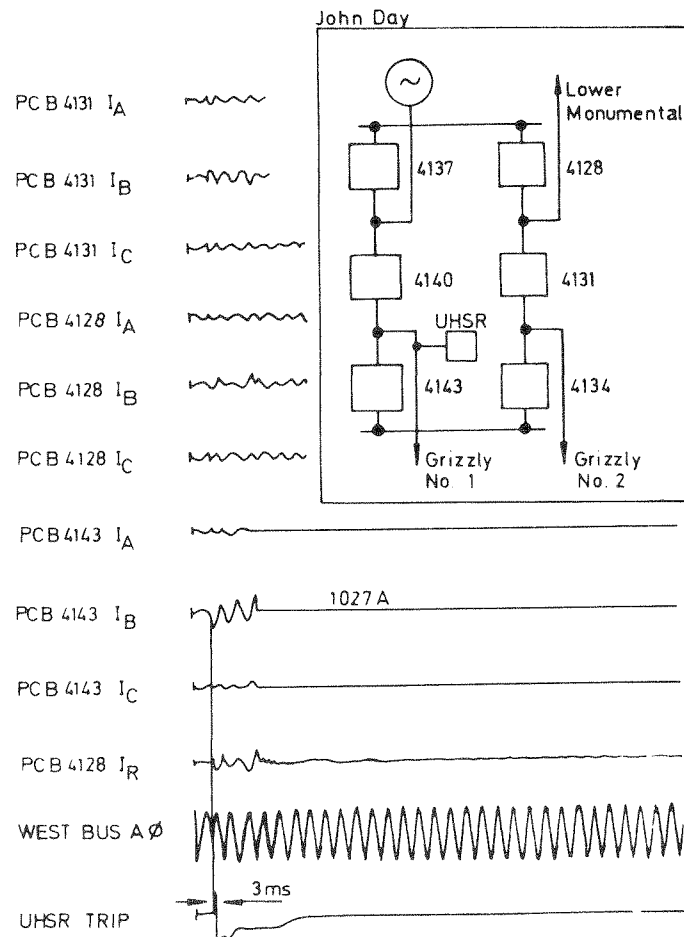


Figure 14. John Day substation oscillogram of a spontaneous internal B-phase fault 122 km (76 miles) from John Day on April 3, 1977. Direct local trip at Grizzly.

One false trip occurred during fault on the John Day - Grizzly No. 2 line. The line was faulted between Bakeoven series capacitor station and Grizzly (Fig. 11). The UHSR at the Grizzly terminal blocked (correct operation) the microwave system squelched during the fault, therefore, no remote block signal was sent to John Day. The John Day UHSR reverse block module did not operate consequently the relay was tripped via dependent mode (correct but unde-

sirable operation). A permissive communication scheme would be more secure and would not have been operational during microwave breakdown. Blocking techniques however has this weakness.

In addition, we have over 400 system blocking operations on record due to microwave squelch, and routine switching that were not listed on Table II, due to lack of space.

TABLE II UHSR SYSTEM LIST OF OPERATIONS
SEQUENCE OF EVENTS PRINTOUT

DATE 1976	OPERATOR'S LOG.	JOHN DAY SUBSTATION	GRIZZLY SUBSTATION	COMMENTS
June 8	Fault at Malin on the 500 kV PNW-SW Intertie.	UHSR TRIPPED TRIP *) Dependent mode	UHSR TRIPPED TRIP *) Dependent mode	Fault external. Incorrect operation. After detailed investigation it was discovered that the auxiliary CT's which were purchased from a foreign firm did not have US Standards of polarity markings and were incorrectly connected. The connections were reversed at Grizzly Substation.
July 4	500 kV PNW-SW Intertie Separation at Malin on out of step	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External Correct operation.
July 18	500 kV John Day-Grizzly No.1. A-phase-Ground Fault	UHSR TRIPPED. A-phase TRIP 4.7 msec. Dependent mode	UHSR TRIPPED. A-phase TRIP 4.8 msec. Dependent mode	Fault Internal. Correct operation.
July 27	500 kV Grizzly-Rnd Butte Pilot Trip	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
Aug. 14	500 Kv J.Day-Hanford. A-ph.-GND fault	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault External. Correct operation.
Aug. 15	500 kV J.Day-Grizzly No.1. A-ph.Shunt Reactor tripped on sudden pressure.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault Internal. Correct operation. Note:The RALDA relay is designed to block on low magnitude transients created by switching surges as well as low magnitude fault internal to a shunt reactor.
Aug. 19	500 KV PNW-SW Intertie Los Banos-Midway Single-L-G fault.	UHSR TRIPPED TRIP *) Dependent mode	Fault locator operated	Fault external.Incorrect operation. Note:Investigation of this operation suspected an internal flashover of transient nature at Bakeoven capacitor station due to overvoltage, indicating that the John Day terminal is set too sensitive but no change in setting was made.
Aug. 22	500 kV Grizzly-Rnd. Butte line relayed on pilot.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
Aug. 24	500 kV John Day-Hanford. A-phase-Gnd Fault.	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault External. Correct operation.
	500 kV John Day-Lower Monumental B-phase-Ground fault	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault External. Correct operation.
Aug. 25	500 kV John Day-Lower Monumental C-phase Ground Fault	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault External. Correct operation.
Aug. 26	500 kV PNW-SW Intertie Malin-Round Mtn. No.2 line relayed.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.

*) TRIP time not recorded.

DATE 1976	OPERATOR'S LOG.	JOHN DAY SUBSTATION	GRIZZLY SUBSTATION	COMMENTS
Sept. 8	Air Conditioner down at John Day ambient temperature up between 80-90°F. (27-32°C)	UHSR A-phase TRIP continuous trip		The UHSR A-phase SCR trip output module is keyed continuously. After detailed investigation by the manufacturer it was found that at 44°C the increased leakage current through the transistors gated the SCR trip output. The trip modules were redesigned and test was performed for temperatures between -25°C to 80°C. The trip modules remained stable. All trip modules at John Day were redesigned to include an additional zener diode.
Oct. 5	Staged Fault Test 500 kV J.Day-Grizzly No.1. A-ph.-Gnd	UHSR TRIPPED.A-phase TRIP. Dependent Mode. 5.9 msec.	LINE PCB OPEN	Fault Internal. Correct operation. Gnd Perm. 16 ms. Clearing time 69.5 ms.
	500 kV J.Day-Grizzly No.1. A-ph.-Gnd	UHSR TRIPPED.A-phase TRIP. Dependent Mode. 6.1 ms.	LINE PCB OPEN	Fault Internal. Correct operation. Gnd. Perm. 16 ms. Clearing time 73.2 ms.
	500 kV J.Day-Grizzly No.1. B-ph.-Gnd	UHSR TRIPPED.B-phase TRIP. Dependent Mode. 6.1 ms.	LINE PCB OPEN	Fault Internal. Correct operation. Gnd Perm. 14 ms. Clearing time 73.3 ms.
Oct. 6	Staged Fault Test. 500 kV J.Day-Grizzly No.1. C-ph.-Gnd	UHSR TRIPPED.C-phase TRIP. Dependent Mode. 5.9 ms.	LINE PCB OPEN	Fault Internal. Correct operation. Gnd. Perm. 10 ms. Clearing time 60.8 ms.
	500 kV Malin-Grizzly No.2. Line OPEN on routine switching	UHSR TRIPPED	LINE PCB CLOSED	No Fault. Incorrect operation. Note:Recalculated system data the dependent mode at John Day was reset to a shorter reach on December 2, 1976.
Oct. 7	Staged Fault Test 500 kV Malin-Grizzly No.2. Line A-ph.- Gnd Fault.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
	500 kV Malin-Grizzly No.2. Line C-ph.- Gnd Fault.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
	500 kV Malin-Grizzly No.2. Line A-ph.- Gnd End of staged fault test.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
	500 kV J.Day-Grizzly No.1. Line B- phase-Gnd	UHSR TRIPPED. B-phase TRIP. Dependent Mode. 4.0 ms.	UHSR TRIPPED. B-phase TRIP *) Dependent Mode	Fault Internal. Correct operation. B-phase Disconnect blade burned off at Bakeoven Series Capacitor Switching Station.
Oct. 22	500 kV J.Day-Grizzly No.2. Line re- layed	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation. Note:Both terminals block locally for faults on parallel line yielding increased security during channel failure.
Oct. 25	500 kV J.Day-Grizzly No.2. Line re- layed	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
<u>1977</u>				
Jan. 30	500 kV J.Day-Grizzly No.1. Line re- layed A-phase-Gnd	UHSR TRIPPED. A-phase TRIP. Dependent Mode 4.0 ms.	UHSR TRIPPED. A-phase TRIP. Dependent Mode 4.0 ms.	Fault Internal. Correct operation.
Feb. 28	500 kV Tesla-Med- calf.Line relayed	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.

*) TRIP time not recorded.

DATE	OPERATOR'S LOG.	JOHN DAY SUBSTATION	GRIZZLY SUBSTATION	COMMENTS
Apr 3	500 kV J.Day-Grizzly No.1. Line B-phase-Gnd	UHSR TRIPPED. B-phase TRIP. Dependent Mode 3.0 ms.	UHSR TRIPPED. B-phase TRIP. Dependent mode 4.8 ms.	Fault Internal. Correct operation.
May 27	500 kV Grizzly-Malin No.2. Line relayed	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
July 25	John Day-Marion line relayed B-phase-Gnd. 6000A	NO UHSR OPERATION	NO UHSR OPERATION	Fault external. Correct operation. Note: No UHSR Block at John Day.
Aug. 5	PNW-SW Intertie south of Malin opened due to forest fire.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault external. Correct operation.
Aug. 6	John Day-Hanford line B-phase-Gnd and BRKR fail on PCB 4194.	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault external. Correct operation.
Aug. 9	PNW-SW Intertie open at Malin on out of step.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault external. Correct operation.
Aug. 21	John Day-Ostrander line relayed	NO UHSR OPERATION	NO UHSR OPERATION	Fault external. Correct operation. Note: No UHSR block at John Day.
Oct. 6	John Day-Big Eddy line relayed.	UHSR BLOCKED (LOCAL)	UHSR BLOCKED (REMOTE)	Fault External. Correct operation.
Oct. 21	Round Mtn.-Table Mtn. line relayed	No Record.	UHSR BLOCKED (LOCAL)	Fault External. Correct operation
Nov. 27	Grizzly-Malin No.2 line B-ph.-Gnd.	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
Dec. 20	John Day-Grizzly No.1 line relayed Fault 16.4 mi from John Day.	UHSR TRIPPED (LOCAL) A-ph. TRIP. Dependent Mode. 5.3 ms.	UHSR TRIPPED (LOCAL) AO TRIP. Dependent Mode 5.6 msec.	Fault Internal. Correct operation.
Dec. 21	Tesla line relayed	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
Dec. 28	John Day-Grizzly No.1 line relayed	UHSR TRIPPED (LOCAL) A-ph. TRIP. Dependent Mode 5.3 ms.	UHSR TRIPPED (LOCAL) A-ph. TRIP. Dependent Mode *)	Fault Internal. Correct operation.
<u>1978</u>				
Jan. 8	John Day-Grizzly No.1 line opened manual trip	No Record.	UHSR TRIPPED (LOCAL) Fault recorder operation, one count.	No fault indication. Incorrect operation. Note: the line is opened at John Day first then at Grizzly. See comments section 5.3.
Jan. 13	John Day-Grizzly No.1 line relayed	UHSR TRIPPED (LOCAL) B-ph. TRIP. Dependent Mode 4 ms.	UHSR TRIPPED (LOCAL) BO TRIP. Dependent Mode *)	Fault Internal. Correct operation.
Jan. 16	John Day-Grizzly No.1 line relayed. Fault 16.4 mi from John Day.	UHSR TRIPPED (LOCAL) B-ph. TRIP. Dependent Mode 5.3 ms.	UHSR TRIPPED (LOCAL) BO TRIP. Dependent Mode *)	Fault Internal. Correct operation.
May 3	Table Mountain-Tesla line relayed	UHSR BLOCKED (REMOTE)	UHSR BLOCKED (LOCAL)	Fault External. Correct operation.
May 4	PNW-SW Intertie open. Lightning arrester arcing at Round Mtn.	UHSR TRIPPED (LOCAL)	Line PCBs open, line reactor saturation.	Fault External. Incorrect operation. Note: Round Mountain lightning arrester arcing for ten cycles before the UHSR trips at John Day. See comments section 5.3.

*) TRIP time not recorded.

July 1	John Day-Grizzly	UHSR TRIPPED (LOCAL)	UHSR BLOCKED (LOCAL)	Fault External. Incorrect operation. Note: Microwave system squelched during the fault the Grizzly end could not send remote block. No lo- cal block at John Day. See comments section 5.3.
	No.2 line relayed			

6 CONCLUSION

The paper presented the application of the travelling wave concept in protective relaying. The UHSR system demonstrates that information contained in power system primary transients can be processed for obtaining dependable ultra high speed relaying. In addition, the operating principle offer inherent quantities which makes the UHSR relay applicable for single pole relaying. Application of the principle for three terminal line protectionis also being investigated.

The new relaying concept and hardware implementations described in this paper, together with the staged fault test studies and over two years of practical experience show that the power system primary transients can be successfully used to obtain a secure and dependable Ultra High Speed Relaying system. The ultra high speed of operation can be successfully utilized in reducing total fault clearance times without the replacement of existing switch gear with the obvious cost economics. The relay has the flexibility of usage with conventional CT and CCVT's. It has also other application capabilities which make the relay suitable for systems where duplicate protection is desired using different operating principles.

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MICROPROCESSOR ALGORITHM FOR
REVENUE METERING OFFERS HIGH ACCURACY
AND MINIMAL COMPUTATIONAL BURDEN

Edmund O. Schweitzer, III
Assistant Professor
Department of Electrical Engineering
Ohio University
Athens, Ohio 45701

presented at

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1. INTRODUCTION

The ever-decreasing cost of hardware suitable for digital signal processing of analog data provides an impetus to study applications of such hardware to power system metering and relaying. Although the relaying area receives much attention in this respect, there is no published research on simple digital signal processing techniques which are suitable for revenue metering.

This paper presents a computationally efficient and extremely accurate algorithm for the computation of real and reactive power (P , Q) from voltage and current. A theoretical development, and analyses of the effects of noise, harmonics and averaging are presented. Simulation results are also presented and discussed. The algorithm is quite simple; straightforward implementation of it in a low-cost microprocessor is feasible. Accuracies better than 0.1% are attainable.

Although the algorithm was originally developed with substation metering in mind, other applications could include residential metering, laboratory measurements, and protective relaying.

2. ALGORITHM DEVELOPMENT

The purpose of this algorithm is to provide a computationally convenient yet accurate means to determine real power, P , and reactive power, Q , given a sinusoidal voltage across and current through a load represented by a linear impedance. Since the algorithm is to be implemented in a digital processor, the algorithm must accept sampled data derived from the voltage and current waveforms. In the development which follows, a time-continuous algorithm is presented first. Then, it is adapted to provide time-discrete processing of input data derived from the time-continuous voltage and current waveforms by two different sampling methods. The sampling methods are: impulse sampling of low-pass-filtered inputs, and integrate-and-dump sampling of the inputs.

2.1 Time-Continuous Algorithm Development

Let $v(t) = V \sin(\omega t + \phi)$ and $i(t) = I \sin(\omega t + \phi - \theta)$ be the voltage and current waveforms from which P and Q are to be determined. (1) (2)

Consider two Walsh functions, $SAL(t)$ and $CAL(t)$ defined by:

$$\begin{aligned} SAL(t) &= 1 & 0 \leq t < 1/2 \\ &= -1 & 1/2 \leq t < 1 \end{aligned} \quad (3)$$

$$\begin{aligned} CAL(t) &= 1 & 0 \leq t < 1/4; 3/4 \leq t < 1 \\ &= -1 & 1/4 \leq t < 3/4 \end{aligned} \quad (4)$$

Correlate $v(t)$ with $SAL(\frac{\omega t}{2\pi})$ and with $CAL(\frac{\omega t}{2\pi})$ over one cycle to provide correlation coefficients S_V and C_V :

$$S_V = \int_0^{2\pi/\omega} v(t) SAL(\frac{\omega t}{2\pi}) dt = \frac{4V}{\omega} \cos \phi \quad (5)$$

$$C_V = \int_0^{2\pi/\omega} v(t) CAL(\frac{\omega t}{2\pi}) dt = \frac{4V}{\omega} \sin \phi. \quad (6)$$

Similar correlations of $i(t)$ with the Walsh functions yield:

$$S_I = \frac{4I}{\omega} \cos(\phi - \theta) \quad (7)$$

$$C_I = \frac{4I}{\omega} \sin(\phi - \theta). \quad (8)$$

The correlation coefficients can be used to find P and Q. First, note that with $v(t)$ and $i(t)$ as described earlier,

$$P = \frac{VI}{2} \cos \theta$$

$$Q = \frac{VI}{2} \sin \theta$$

$$\text{Define } A = S_V S_I \text{ and } B = C_V C_I$$

Then,

$$\begin{aligned} A &= \left(\frac{4}{\omega}\right)^2 VI \cos \phi \cos (\phi - \theta) \\ &= \left(\frac{4}{\omega}\right)^2 VI (\cos^2 \phi \cos \theta + \cos \phi \sin \phi \sin \theta) \end{aligned}$$

and

$$B = \left(\frac{4}{\omega}\right)^2 VI (\sin^2 \phi \cos \theta - \cos \phi \sin \phi \sin \theta)$$

The sum (A+B) provides an expression proportional to the power P :

$$\begin{aligned} A+B &= \left(\frac{4}{\omega}\right)^2 VI (\sin^2 \phi \cos \theta + \cos^2 \phi \cos \theta) \\ &= \left(\frac{4}{\omega}\right)^2 VI \cos \theta \end{aligned}$$

But, $P = \frac{VI}{2} \cos \theta$, so:

$$P = 1/2 (A+B) \left(\frac{\omega}{4}\right)^2 = 1/2 \left(\frac{\omega}{4}\right)^2 (S_V S_I + C_V C_I) \quad (9)$$

Similar steps yield:

$$Q = 1/2 \left(\frac{\omega}{4}\right)^2 (C_V S_I - S_V C_I) \quad (10)$$

2.2 Time-Discrete Algorithm Development

If the correlation coefficients S_V , C_V , S_I , and C_I can be found from the input data, then (9) and (10) provide simple means to obtain P and Q. Consider how to determine these correlation coefficients.

The correlation $SAL\left(\frac{\omega t}{2\pi}\right)$ with $v(t)$ is:

$$S_V = \int_0^{2\pi/\omega} v(t) SAL\left(\frac{\omega t}{2\pi}\right) dt = \int_0^{\pi/\omega} v(t) dt - \int_{\pi/\omega}^{2\pi/\omega} v(t) dt \quad ; \quad (11)$$

and the correlation of $CAL\left(\frac{\omega t}{2\pi}\right)$ with $v(t)$ is:

$$C_V = \int_0^{\pi/2\omega} v(t) dt - \int_{\pi/2\omega}^{3\pi/2\omega} v(t) dt + \int_{3\pi/2\omega}^{2\pi/\omega} v(t) dt \quad (12)$$

$$\text{Let } x_k = \int_{k\pi/2\omega}^{(k+1)\pi/2\omega} v(t) dt \quad (13)$$

Each x_k represents the integral of the input voltage $v(t)$ over a one-fourth cycle period of time.

Substitution of (13) into (11) and (12) yields:

$$S_V = (x_0 + x_1) - (x_2 + x_3) \quad (14)$$

$$C_V = x_0 - (x_1 + x_2) + x_3 \quad (15)$$

Thus, the correlation coefficients are easily obtained from time-discrete data x_k . The x_k values are samples derived from $v(t)$ by integrating $v(t)$ over successive one-quarter cycle time periods. A circuit which performs this sampling function (an integrate-and-dump sampler) is easily constructed, and is generally simpler than an adequate low-pass anti-aliasing filter followed by an impulse sampler.

The same sampling procedure must be applied to the current waveform to obtain integrate-and-dump current samples.

That is, let

$$y_k = \int_{\frac{k\pi}{2\omega}}^{(k+1)\pi/2\omega} i(t) dt \quad (16)$$

then

$$S_I = (y_0 + y_1) - (y_2 + y_3) \quad (17)$$

$$C_I = y_0 - (y_1 + y_2) + y_3 \quad (18)$$

Suppose it is desired to apply the algorithm to samples of $v(t)$ and $i(t)$ obtained by low-pass filtering and impulse sampling the inputs. Assume the inputs are given by (1) and (2), and that the low-pass filters introduce a phase shift ψ and a gain G at the input frequency ω . Then, the values of samples taken at a sampling rate of N samples per cycle are:

$$v_k = GV \sin\left(\frac{2\pi k}{N} + \phi - \psi\right) \quad (19)$$

$$i_k = GI \sin\left(\frac{2\pi k}{N} + \phi - \theta - \psi\right) . \quad (20)$$

If a time discrete correlation of the v_k samples is performed with samples of the SAL function, then, with $\alpha = \phi - \psi$,

$$\begin{aligned} S'_V &= \sum_{k=1}^{N/2} \left(v_k - v_{k+\frac{N}{2}} \right) \\ &= GV \sum_{k=1}^{N/2} \left(\sin\left(\frac{2\pi k}{N} + \alpha\right) - \sin\left(\frac{2\pi(k + N/2)}{N} + \alpha\right) \right) \\ &= \frac{2GV}{\sin(\frac{\pi}{N})} \cos\left(\alpha + \frac{\pi}{N}\right) . \end{aligned} \quad (21)$$

Correlation with samples of the CAL function yields:

$$C'_V = \frac{2GV}{\sin \frac{\pi}{N}} \sin\left(\alpha + \frac{\pi}{N}\right) . \quad (22)$$

The corresponding current correlation results are:

$$S'_I = \frac{2GI}{\sin(\frac{\pi}{N})} \cos\left(\alpha + \frac{\pi}{N} - \theta\right) \quad (23)$$

$$C'_I = \frac{2GI}{\sin(\frac{\pi}{N})} \sin\left(\alpha + \frac{\pi}{N} - \theta\right) . \quad (24)$$

The primes denote the correlation coefficients are obtained from impulse-sampled data.

If (21-24) are used to compute P and Q, using the same approach that lead to (9) and (10), then:

$$P = 1/2 \left(\frac{\sin(\pi/N)}{2G} \right)^2 \left(S'_V S'_I + C'_V C'_I \right) \quad (25)$$

$$Q = 1/2 \left(\frac{\sin(\pi/N)}{2G} \right)^2 \left(C'_V S'_I - S'_V C'_I \right) . \quad (26)$$

If a sampling rate of four samples per cycle ($N = 4$) is used, then:

$$P = \frac{1}{16 G^2} (S_V' S_I' + C_V' C_I') \quad (27)$$

$$Q = \frac{1}{16 G^2} (C_V' S_I' - S_V' C_I') \quad , \quad (28)$$

and the correlation coefficients are found from the samples using (14, 15, 17, 18) by replacing the integrate-and-dump samples with the impulse samples.

2.3 Algorithm Summary

1) Sample $v(t)$, $i(t)$ using either integrate-and-dump sampling or impulse sampling at a rate of four samples per cycle.

2) Compute the correlation coefficients S_V , C_V , S_I , C_I using (14, 15, 17, 18).

3) From the correlation coefficients, compute P and Q using either (9, 10) or (25, 26).

The algorithm is computationally efficient. To find P and Q once per cycle, the computer must perform fourteen signed additions and four signed multiplications. This neglects the scaling terms (e.g. $\frac{1}{2}(\frac{\omega}{4})^2$) which may be included by analog scaling of the input quantities or by digital scaling of the outputs.

If P and Q are required less frequently, say, once per second, averaging can be applied to either the P and Q outputs or to the correlation coefficients. In the latter case, the number of multiplications per unit time is reduced by the number of cycles averaged. Averaging techniques are analyzed in the next section.

3. ALGORITHM ANALYSIS

The effects of noise, averaging, and harmonics on the performance of the algorithm are treated in the next sections.

3.1 Noise Analysis

If the inputs defined by (1,2) are corrupted by additive white noise, then

$$v(t) = V \sin(\omega t + \phi) + n_v(t) \quad (29)$$

$$i(t) = I \sin(\omega t + \phi) + n_i(t) \quad (30)$$

Assume the noise terms are stationary, zero mean and independent random processes. Then the expected values of $v(t)$, $i(t)$ are

$$E[v(t)] = V \sin(\omega t + \phi) \quad (31)$$

$$E[i(t)] = I \sin(\omega t + \phi - \theta) \quad (32)$$

Since the correlations defined by (5, 6) are linear and time-invariant,

$$E[S_v] = \frac{4V}{\omega} \cos \phi \quad (33)$$

$$E[C_v] = \frac{4V}{\omega} \sin \phi \quad (34)$$

The autocorrelation function for $n_v(t)$ is given by

$$R_v(t) = N_v \delta(t), \quad (35)$$

where $\delta(t)$ is the Dirac delta function, and N_v is the power spectral density of the noise on the voltage signal. The effective value of the noise is, therefore

$$\sigma_v = N_v^{1/2} \delta(0). \quad (36)$$

The variance of the correlation coefficient S_v , denoted $\sigma_{S_v}^2$ is

$$\begin{aligned} \sigma_{S_v}^2 &= E \{ (S_v - E(S_v))^2 \} \\ &= E \left\{ \left(\int_0^{\pi/\omega} n_v(t) dt - \int_{\pi/\omega}^{2\pi/\omega} n_v(t) dt \right)^2 \right\} \end{aligned}$$

$$\begin{aligned}
&= E \left\{ \int_0^{\pi/\omega} \int_0^{\pi/\omega} n_V(\sigma) n_V(u) d\sigma du + \int_{\pi/\omega}^{2\pi/\omega} \int_{\pi/\omega}^{2\pi/\omega} n_V(\sigma) n_V(u) d\sigma du \right. \\
&\quad \left. - 2 \int_0^{\pi/\omega} n_V(\sigma) d\sigma \int_{\pi/\omega}^{2\pi/\omega} n_V(u) du \right\} \\
&= \left\{ \int_0^{\pi/\omega} \int_0^{\pi/\omega} R_V(\sigma-u) d\sigma du + \int_{\pi/\omega}^{2\pi/\omega} \int_{\pi/\omega}^{2\pi/\omega} R_V(\sigma-u) d\sigma du \right\} \quad (37)
\end{aligned}$$

Using (35),

$$\sigma_{S_V}^2 = N_V \frac{2\pi}{\omega} \quad (38)$$

Similar analyses yield the results:

$$\sigma_{C_V}^2 = N_V \frac{2\pi}{\omega} \quad (39)$$

$$\sigma_{S_I}^2 = N_I \frac{2\pi}{\omega} \quad (40)$$

$$\sigma_{C_I}^2 = N_I \frac{2\pi}{\omega} \quad (41)$$

These variances may be used, along with (9, 10) to determine the variances of P and Q:

$$\sigma_P^2 = E \{ (P - E(P))^2 \} \quad (42)$$

$$= 1/4 \left(\frac{\omega}{4} \right)^4 E \{ [(S_V S_I + C_V C_I) - (\hat{S}_V \hat{S}_I + \hat{C}_V \hat{C}_I)]^2 \}$$

$$= 1/4 \left(\frac{\omega}{4} \right)^4 [\sigma_V^2 \left(\frac{4I}{\omega} \right)^2 + \sigma_I^2 \left(\frac{4V}{\omega} \right)^2 + 2\sigma_V^2 \sigma_I^2],$$

where $\sigma_V^2 = \sigma_{S_V}^2 = \sigma_{C_V}^2$; $\sigma_I^2 = \sigma_{S_I}^2 = \sigma_{C_I}^2$.

Using the substitutions (38-41),

$$\sigma_P^2 = \frac{\pi}{32} \left[N_V I \omega^2 + N_I V \omega^2 + \frac{\pi N_V N_I \omega^2}{4} \right] \quad (43)$$

A signal-to-noise ratio can be defined by:

$$\begin{aligned} \text{SNR}_p &= \frac{E^2(P)}{\sigma_p^2} \\ &= \frac{8V^2 I^2 \cos^2 \theta}{\pi\omega[(N_V I^2 + N_I V^2) + \frac{\pi\omega}{4} (N_V N_I)]} \end{aligned} \quad (44)$$

As an example, let $V = I = 1$, $\theta = 0$, $\omega = 377$ and $N = 10^{-4}$ watts/radian/second. Then,

$$\text{SNR}_p = 33.28 \quad (45)$$

It is informative to compare the signal-to-noise ratio (44) obtained using the algorithm with the signal-to-noise ratio obtained by direct computation of P . That is, let the true power averaged over one cycle be

$$P_a = \frac{\omega}{2\pi} \int_0^{2\pi/\omega} v(t)i(t)dt \quad (46)$$

Then, the signal-to-noise ratio obtained using (46) and inputs (29,30) can be determined. Note $E(P_a) = 1/2 VI \cos \theta$, as before. The variance of P_a is now determined:

$$\begin{aligned} \sigma_a^2 &= E\{[P_a - E(P_a)]^2\} \\ &= \frac{\omega}{4\pi} (I^2 N_V + V^2 N_I) + \left(\frac{\omega}{2\pi}\right)^2 N_V N_I \end{aligned} \quad (47)$$

The signal-to-noise ratio is:

$$\begin{aligned} \text{SNR}_a &= \frac{E^2(P_a)}{\sigma_a^2} \\ &= \frac{V^2 I^2 \cos^2 \theta}{\frac{\omega}{\pi} [N_V I^2 + N_I V^2 + \frac{\omega}{\pi} N_V N_I]} \end{aligned} \quad (48)$$

The signal-to-noise ratios of (44) and (48) can be compared by forming the ratio:

$$\frac{\text{SNR}_p}{\text{SNR}_a} = \frac{8[N_V I^2 + N_I V^2 + \frac{\omega}{\pi} N_V N_I]}{\pi^2 [N_V I^2 + N_I V^2 + \frac{\pi\omega}{4} N_V N_I]} \quad (49)$$

If we assume $N_V = N_I = N$, and if $V = I = X$, then

$$\frac{SNR_p}{SNR_a} = \left(\frac{8}{\pi^2}\right) \frac{2\gamma + 1}{2\gamma + \pi^2/4}, \quad (50)$$

where

$$\gamma = SNR_{INPUT} = \frac{\frac{1}{2} X^2}{\frac{\omega}{2\pi} N}.$$

For $\gamma = 10$, the ratio (50) is about 0.76. In the limit as γ approaches infinity, the ratio is about 0.81. Thus, the algorithm performance in the presence of uncorrelated, white gaussian noise is nearly the same as the average power definition performance (46).

In practical applications, the values of P and Q are probably not required once every cycle. Instead, average values every ten or 60 cycles might be more useful. Consider now two ways of obtaining average values over k cycles.

Method 1: Define an average power over k cycles by:

$$\hat{P} = \frac{1}{k} \sum_{i=1}^k P_i. \quad (51)$$

Method 2: Find k-cycle averages of the correlation coefficients:

$$\hat{S}_V = \frac{1}{k} \sum_{i=1}^k S_{V_i}, \text{ etc.} \quad (52)$$

Then, using these averages, compute power using (9,10).

The noise performance of these two methods is now compared.

Method 1. Simple averaging effectively reduces the variance of P by a factor equal to the number of cycles of averaging. Thus, the signal-to-noise ratio for a k-cycle average is:

$$SNR_p(k) = k SNR_p = \frac{kE^2(P)}{\sigma_p^2} \quad (53)$$

Method 2. The averaging process reduces the variances $\sigma_{S_V}^2$, $\sigma_{C_V}^2$, $\sigma_{S_I}^2$, $\sigma_{C_I}^2$ by $1/k$. Therefore, the variance of P, computed using averaged values of the correlation coefficients is:

$$\sigma_p'^2(k) = \frac{\pi\omega}{32k} [N_V I^2 + N_I V^2 + \frac{\pi N_V N_I \omega}{4k}] . \quad (54)$$

The signal-to-noise ratio is now:

$$\text{SNR}'_p(k) = \frac{E^2(P)}{\sigma_p'^2} \quad (55)$$

The signal-to-noise ratios for the two methods may be compared by forming the ratio ψ .

$$\begin{aligned} \psi = \frac{\text{SNR}_p(k)}{\text{SNR}'_p(k)} &= \frac{\sigma_p'^2}{k\sigma_p^2} \\ &= \frac{N_V I^2 + N_I V^2 + \frac{\pi N_V N_I \omega}{4k}}{N_V I^2 + N_I V^2 + \frac{\pi N_V N_I \omega}{4}} \end{aligned} \quad (56)$$

As before, let $N_V = N_I = N$, $V = I = X$ and $\gamma = \frac{X^2}{\frac{\omega}{\pi} N}$. Then,

$$\psi = \frac{\gamma + \frac{\pi^2}{8k}}{\gamma + \frac{\pi^2}{8}} \quad (57)$$

For $\gamma = 10$ and $k = 10$, (57) yields $\psi = 0.90$. Thus, Method 1 averaging does not offer as much improvement as Method 2. For $\gamma = 10$ and a one-second period average, $k = 60$ and $\psi = 0.89$.

If the example following (44), which yielded $\text{SNR}_p = 33.28$ is modified by applying Method 2 averaging with $k = 60$, then

$$\text{SNR}'_p(60) = 1968. \quad (58)$$

Had Method 1 been used, the SNR would have been about two percent lower.

Note for large γ (i.e., large input signal-to-noise ratios) the choice of method of averaging has little effect on the output SNR. However, the computational burden of Method 2 is much less than Method 1. It is fortunate Method 2 also offers better performance!

3.2 Harmonic Analysis

The SAL and CAL Correlation processes are linear, so the values of the correlation coefficients (S_V, C_V, S_I, C_I), due to an input which is the sum of harmonic terms and the fundamental, can be determined by superposition. However, P and Q are not linear functions of the correlation coefficients, so superposition cannot be applied to determine P and Q.

In the following analysis, the correlation coefficients are determined for sinusoidal inputs which are harmonically related to the fundamental, but at arbitrary phase and amplitude. Then, under particular conditions, the effect of harmonics is illustrated.

$$\text{Let } v_k(t) = V_k \sin(k\omega t + \phi_k) \quad (59)$$

$$i_k(t) = I_k \sin(k\omega t + \phi_k - \theta_k) \quad (60)$$

represent sinusoidal voltages and currents at the k^{th} harmonic of the fundamental. Using the same procedure as before the correlation coefficients are:

$$S_{vk} = \frac{4V_k}{k\omega} \cos \phi_k \quad (61)$$

$$C_{vk} = \frac{4V_k}{k\omega} (-1)^{\frac{k-1}{2}} \sin \phi_k \quad (62)$$

k odd

$$S_{Ik} = \frac{4I_k}{k\omega} \cos(\phi_k - \theta_k) \quad (63)$$

$$C_{Ik} = \frac{4I_k}{k\omega} (-1)^{\frac{k-1}{2}} \sin \phi_k \quad (64)$$

For k even, $S_{vk} = C_{vk} = S_{Ik} = C_{Ik} = 0$.

Consider the P and Q values due to sinusoidal voltage and current at harmonic k only; that is, all other harmonics are zero. Then,

$$P_k = \frac{1}{2k^2} V_k I_k \cos \theta_k \quad (65)$$

and

$$Q_k = \frac{1}{2k^2} V_k I_k \sin \theta_k, \text{ for all odd } k. \quad (66)$$

For k even, $P_k = Q_k = 0$.

Observe that for $k = 1$, the correct values for P and Q are obtained. For $k = 0$, the P and Q values are zero. This can be interpreted to mean the algorithm cannot detect any DC power component which might exist. Furthermore, for other even values of k , the P and Q values are also zero. Thus, the algorithm is insensitive to power flow at even harmonics of system frequency.

For k odd, the P and Q values are attenuated by a factor $(1/k)^2$ from their true values.

Consider now the superposition of two sinusoidal inputs. Let

$$v(t) = v_1(t) + v_3(t) = V_1 \sin(\omega t + \phi_1) + V_3 \sin(3\omega t + \phi_3)$$

$$i(t) = i_1(t) + i_3(t) = I_1 \sin(\omega t + \phi_1 - \theta_1) + I_3 \sin(3\omega t + \phi_3 - \theta_3),$$

and denote by $S_{v1,3}$; $C_{v1,2}$; $S_{i1,3}$; $C_{i1,3}$ the correlation coefficients resulting from these inputs. These inputs represent a fundamental frequency component and a third harmonic component.

By superposition of correlation coefficients $S_{v1,3} = S_{v1} + S_{v3}$, etc. Thus,

$$\begin{aligned} P_{1,3} &= 1/2 \left(\frac{\omega}{4}\right) [S_{v1,3} S_{i1,3} + C_{v1,3} C_{i1,3}] \\ &= P_1 + P_3 + 1/6 [V_3 I_1 \cos(\phi_1 + \phi_3 - \theta_1) + V_1 I_3 \cos(\phi_1 + \phi_3 - \theta_3)]. \end{aligned} \quad (67)$$

(This result verifies the previous statement that the principle of superposition cannot be applied to find $P_{1,3}$ from P_1 and P_3 .)

As an example, consider the power dissipated in a one-ohm resistor from two voltage sources in series. Assume $v_1 = 1$, $v_3 = 0.1$, $\phi_1 = \phi_3$. Then $I_1 = 1$, $I_3 = 0.1$ and $\theta_1 = \theta_3 = 0$. Using these data,

$$\begin{aligned} P_{1,3} &= \frac{1}{2} + \frac{1}{1800} + \frac{1}{6} (0.1 + 0.1) \\ &= 0.5339 \text{ watts.} \end{aligned}$$

The true value is:

$$P_{\text{TRUE}} = \frac{1}{2} + \frac{1}{20} = 0.55 \text{ watts.}$$

Thus, an error of 3% is incurred.

If the one-ohm resistor is replaced with an impedance $Z = R + j\omega L$ and if we let $\beta = (\frac{\omega L}{R})^2$ at the fundamental frequency, and if $\alpha = v_3/v_1$, then the ratio of the power $P_{1,3}$ to the true power P_{TRUE} given by:

$$\frac{P_{1,3}}{P_{\text{TRUE}}} = \frac{(\alpha + 3)^2 + \beta (\alpha + 3)(\alpha + 27)}{9[(\alpha + 1) + \beta (\alpha + 9)]} \quad (68)$$

Using this expression, it can be shown that ten percent third harmonic produces about two-to-three percent error for $0 < \beta < 100$. For twenty percent third harmonic, with $0 < \beta < 100$, the error is about five percent.

4. Simulation

A computer program was developed to test the revenue metering algorithm by simulation. The simulation verifies the theory of the algorithm is sound, and provides a convenient means of determining the effects of quantization caused by an analog-to-digital converter.

Pure sinusoidal voltage and current inputs are sampled four times per cycle using the integrate-and-dump sampling technique. These samples are quantized by a quantizer having selectable resolution. Then, the algorithm is applied to the quantized sampled data.

To accomodate transient data and overrange conditions, the limits of the voltage quantizer were set to 1.5 times the peak value of a one per-unit input. The current limits were set to three times the peak value of a one per-unit input. These scaling conditions do not take full advantage of the quantizer range. Therefore, one per-unit voltage and current inputs do not correspond to a "full scale" condition, and therefore, do not provide maximum accuracy conditions. However, these conditions seem realistic from an applications standpoint.

Tables 1, 2 and 3 present the percent error between the true power and the computed power as a function of the resolution of the quantizer and the power factor. The resolution of the quantizer, N , is the number of bits in the binary representation. For example, $N = 8$ means the data are quantized into one of $2^8 = 256$ levels between the quantizer lower and upper limits.

Table 1 data reveal that at normal full load input levels even an eight-bit ADC could provide reasonable accuracy. However, for a current input of $I = 0.1$ p.u., the eight-and-ten bit resolution tests show serious accuracy degradation, as can be seen in Table 2.

The Table 3 data were obtained with $I = 0.01$ p.u. Note this corresponds to one percent of full load, or about one-fourth percent of "full scale." Yet the twelve-and-fourteen bit resolution tests demonstrate what is thought to be more than adequate accuracy at such a low input level.

θ	pf	N = 8	N = 10	N = 12	N = 14
0	1	-1.12	0.11	0.01	0.01
30	0.866	-1.04	-0.15	-0.05	0.03
60	0.5	-1.12	0.12	-0.19	-0.03

Table 1. Percent Error in Power for Various Quantizer Resolutions (N) and Power Factors. $V = 1, I = 1$.

θ	pf	N = 8	N = 10	N = 12	N = 14
0	1	-1.12	-0.71	0.61	-0.05
30	0.866	-4.86	-4.46	0.42	0.17
60	0.50	-1.12	-0.71	0.67	-0.02

Table 2. Percent Error in Power for Various Quantizer Resolutions (N) and Power Factors. $V = 1, I = 0.1$

θ	pf	N = 8	N = 10	N = 12	N = 14
0	1	—	-17.25	3.53	-1.59
30	0.866	—	- 4.45	7.59	-1.32
60	0.50	—	65.48	3.53	-1.32

Table 3. Percent Error in Power for Various Quantizer Resolutions (N) and Power Factors. $V = 1, I = 0.01$

Base case tests with no quantization were performed to establish the fundamental accuracy of the simulation. These tests revealed that the fundamental accuracy is within 0.01%, and the base case error is due to the numerical integration techniques used to simulate the integrate-and-dump sampler.

5. HARDWARE CONSIDERATIONS

5.1 Sampling Schemes

An integrate-and-dump sampler is preferred over the conventional low-pass filter/impulse sampler since it is less complicated. However, as shown in the development of the algorithm, either approach is acceptable.

Note that it is necessary to sample the current and voltage inputs simultaneously. The effect of staggered sampling is to introduce an artificial phase shift between the input quantities. This effect could be used to advantage to cancel any known phase shift between the current and voltage caused by the sensors.

5.2 Analog-to-Digital Conversion

The simulation results reveal that a twelve-bit analog-to-digital converter (ADC) is sufficient to provide better system performance than is offered by conventional metering techniques.

5.3 Digital Processor

A low-cost eight-bit microprocessor, such as the Motorola 6800 or Intel 8080, should provide sufficient throughput capabilities to compute P and Q on three phases, with averaging periods from one cycle to in excess of one second. The memory requirements appear modest: less than 100 bytes of random-access-memory (RAM), and less than one kilobyte of read-only memory (ROM). It may be feasible to use a processor chip which contains integral RAM and ROM. Such an implementation appears especially economically attractive.

5.4 Data Display and Output

Local data display of P and Q is feasible using low-cost LED or LCD devices. Since other computer systems are now widely deployed in substations for control and monitoring, it is feasible to display the meter output quantities on the CRT or printer of the substation computer. This, of course, requires a simple digital interface between the metering processor and the substation computer.

If watt-hour or VAR-hour data are required, the substation computer provides a convenient tool for performing the numerical integration of P and Q. However, the low computational burden of the algorithm should leave sufficient processor capability to perform these computations within the revenue meter itself.

5.5 Current and Voltage Sensors

The accuracy attainable using the metering algorithm and well-designed sampling, conversion and processing hardware ultimately depends on the quality of the current and voltage sensors. Fortunately, the metering hardware can be designed to present an extremely low burden to the sensors. The lower limit of burden is determined by noise considerations in the electronics; however burdens below one volt-ampere are certainly achievable. Furthermore, the meter input impedances can be assumed to be linear, known, and purely resistive over the frequency range of interest. As mentioned earlier, any known, constant relative phase shift introduced between the true voltage and current by the sensors is easily compensated for by employing staggered sampling of the inputs. Constant ratio errors can be compensated for by adjusting the gains of the input channels.

Sensor errors which are more troublesome are ones which depend on the value of the measured quantity. For example, the excitation current in a magnetic CT is a nearly constant percentage of the measured current for currents above, say, ten percent rated current, and below saturation. But, for smaller currents, nonlinearities about the origin of the hysteresis curve tend to cause an increase in the percentage of magnetization current. A practically-unattractive but technically-feasible cure would be to use two CT's: one for high accuracy at rated current; another for high accuracy at a small fraction of rated current. The microprocessor could be programmed to accept the appropriate input.

6. SUMMARY AND CONCLUSIONS

The digital algorithm theoretically provides a high-accuracy means to determine P and Q from voltage and current inputs. From a practical standpoint, overall system accuracy is limited by sensor capabilities. However, implementations are feasible which compensate for ratio errors and known phase errors. Many sensor problems should be obviated by the low-burden requirements of a practical implementation.

Noise and harmonic analyses demonstrate the capabilities and limitations of the algorithm, as well as the predictability of its performance as a function of noise and harmonic content. When the harmonic analysis was performed, the power computed using the algorithm was compared to the true power, i.e., the power at system frequency and at harmonics of system frequency. Small errors resulted from reasonable assumptions on harmonic content. It is perhaps an open question whether a revenue meter should measure true power or power at system frequency only. If the latter is desired, simple low-pass filters at the input could be used to eliminate harmonics. In such a case, the traditional low-pass filter/impulse sampler is preferred over the integrate-and-dump sampler.

Applications of the algorithm could include the following:

- 1) Revenue Metering
 - a) Substation and central station
 - b) Industrial customers
 - c) Local and remote-reading watt-hour metering for residential applications
- 2) Laboratory Metering
 - a) Low burden
 - b) Accuracy in excess of 0.1% is straightforward
- 3) Relaying
 - a) Extremely sensitive reverse-power relay for urban subtransmission and distribution
 - b) Motor and generator protection.
 - c) Power differential schemes

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EPRI R&D in Protective Relay Systems
for Power System Applications

by

Stig L. Nilsson
Project Manager
Electrical Systems Division
Electric Power Research Institute
Palo Alto, California

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Abstract

In its short existence, EPRI has initiated many research and development projects of importance to the power system protective relay engineer. The R&D activities are intended to serve both near- and long-term needs of the utilities.

An important part of the R&D program is the development of new electrical sensing elements. An ac current transducer has been developed that is now being field-tested in a Bonneville Power Administration substation. A similar dc CT will soon be field-tested by the Los Angeles Department of Water and Power. Both of these units incorporate low loss optical waveguides for signal transmissions. This is an important new technology expected to have many benefits to the substation designers in the future.

A major project for development of a new substation control and protection system has not been started. This project will end in a demonstration system to be installed in an existing transmission substation in 1981. The new system will make extensive use of the microprocessor and fiber-optics technologies. This is expected to result in significant cost and performance improvements to the utilities. It should provide the flexibility and processing power needed for control and protection of the power transmission systems of the 1980s and beyond.

A special data acquisition system for monitoring EPRI's Prototype HVDC Link in New York City has recently been delivered. The system incorporates several features that may be of future value to power system operators. The primary function is to make fault analyses easy by providing detailed and accurate fault records within minutes after the fault.

Other ongoing projects will produce improved monitoring gauges for transformers and a special protective relay for high impedance faults. Emphasis is also placed on study projects that will provide utility engineers and equipment designers with needed data for development of new products and properly maintain existing equipment.

1. Introduction

In its short existence, EPRI has initiated many research and development projects that will produce results of importance to power system protective relay engineers. The Electrical Systems Division of EPRI is funding projects for development of new measuring devices and new control and protective systems for transmission and distribution substations, as well as projects that will generate the fundamental knowledge needed by control and protective systems designers. The majority of the hardware development funds is used for system development projects where the protective relaying functions are a special and critical part of the system.

R&D related to instrumentation, control and protection systems within EPRI's Electrical Systems Division is applicable to all six of its technical programs, but to date, funding has come primarily from the AC/DC Substations and the Distribution programs.

2. Goals and Objectives

Our R&D activities are intended to serve both near-term and long-term needs of the utilities. The near-term problems are the ones that are more readily defined. Usually a particular relaying problem, such as the high impedance fault detection problem, is easily identified.

Long-term problems are more difficult to identify. We all know that one key to reliable power system operation is the effective use of instruments and protective relaying systems by experienced operators. This is generally the case now, but we believe there is ample reason to question whether we fully understand what it will take to protect the concentrated high-capacity systems of the future. Consider, for instance, the following generally accepted assumptions:

- o A conservative estimate of growth in electric power use shows that the power production target for the year 2000 should be at least 7500 billion kWh, almost four times the present level.
- o Advanced UHV overhead transmission lines of the future can be expected to carry three to six times the power per mile of their lower-voltage predecessors.
- o Newly installed underground transmission lines promise a doubling of underground power transfer capacity by 1985.
- o DC transmission systems will augment many ac systems, and compact, gas-insulated substations will further concentrate future power transfers.
- o Fault current limiters and similar devices will be introduced that will require a re-evaluation of our control and relay systems.

Although existing protective equipment is serving the utilities well, we believe that because of anticipated growth of tomorrow's power systems, utilities will require greater sophistication of their control systems. As a minimum, we should expect improved accuracy, better reliability, and the usual economy. To accomplish this, better measuring and sensing techniques will have to be developed, the signal transmission systems improved, and new processing techniques exploited. However, these new protective relays and control systems of the future will have to be integrated with the existing systems, since utilities obviously are not going to replace all of their existing equipment with new equipment at one time.

A major motivation for EPRI's R&D activities is to help utilities take advantage of new technologies. This is both a short-term and a long-term objective. There are two emerging technologies that no doubt will have a significant impact on how we design future control and protective systems for substations. These are the microprocessor and fiber-optical signal transmission technologies.

We have seen the computer become an accepted component of power system dispatching systems. If the cost of computer systems continues downward, they will become the cornerstone for substation control and protection too. The computer, specifically the microprocessor, coupled with inexpensive optical communication links and multiplexers, now appears to be a natural component of new substation integrated control systems. This is the basic premise for EPRI's recently initiated substation control and protective development project.

3. Electrical Sensing Elements

Our ability to measure voltage and current is fundamental to the control and protection of power systems. From these, other quantities such as real and reactive power, total energy, line impedances, and so on are derived. The measuring elements must support data acquisition systems, which require information with a frequency ranging from once an hour to once every 100 microseconds or less. The data must be accurate to within a fraction of one percent for revenue-metering purposes; it must also be reliable for support of protective relaying functions.

Modern current transformers (CTs) and potential transformers (PTs) are remarkably good devices, meeting the requirements listed above very well. However, for high voltage applications, their cost is very high. The fidelity of the output signals from today's CTs and PTs is also in doubt in the high-frequency region, which is of interest for high-speed relaying. Further, the cables leading from the transformers to the control houses now pick up high-frequency noise, interfering with operation of relay and control and equipment. Saturation of transformer cores also poses problems for the user.

Another concern is the hazard to people and equipment from CT failures. Catastrophic CT failures (explosions) are rare occurrences, but even infrequent failures are of concern, since porcelain fragments could injure people, as well as damage insulators and bushings of nearby equipment. The fire hazard and the outage that can result from CT

failures are additional reasons to continue the search for safer current measuring equipment.

The demand for very high accuracy transducers has also been raised. The need for this is quite obvious when one considers that only one ampere through a 500-kV line represents almost 1 MW. Hence, a small CT or PT error could mean a lot of lost revenue to a utility. Presently used current transformers are unable to satisfy this need.

Many attempts have been made to build electronic current transducers (ECTs) for high-voltage transmission lines. The idea is simple and attractive. Although previous attempts to build ECTs have been commercial failures, the interest in ECTs is still high. For air-insulated UHV substations or lines, it is probably the only viable type of transducer. And since presently available solid-state relays can be readily made to accept the output of ECTs, their market potential is probably better today than ever before.

3.1 Digital Current Transducer for AC Applications

A digital electronic current transducer for EHV applications is being developed by Westinghouse, Pittsburgh (RP560). The target specification for the transducer was to meet metering, relaying, and fault recording requirements with one unit. The frequency response, specified at 10 kHz minimum, should also be adequate for future current limiters and ultrahigh-speed relays.

A digital ECT that meets the above specifications has been designed, built, and factory tested. The ECT shown in Figures 1 and 2 makes use of a 12-bit analog-to-digital converter, combined with a ranging amplifier that gives an effective dynamic range equal to 16 bits, but with 12-bit resolution. The sampling rate is one sample every 22 μ s (i.e., one sample for every half electrical degree on a 60-Hz basis, providing a bandwidth of 10-15 kHz). The estimated mean time between failures for the electronics equipment of the high-voltage unit is approximately 50,000 hours, which means that the mean time to failure for two parallel redundant units is about once every 500 years, if one assumes about one-week's mean time for repair. This does not include the ground electronic units, which are much simpler to repair because they do not require access to the high-voltage circuits.

A major development effort of the project was the design of the power supply unit feeding the electronic equipment at high potential. The power is taken from a second current transformer and connected in line with the ECT unit. The power supply unit makes the ECT fully operational within 200 μ s, assuming that a 4-per-unit short circuit current is starting to flow through the CT. The time is counted from the zero crossing of the current. This means in broad terms that the ECT will be fully operational before the insertion resistors used in most 500-kV breakers are bypassed. In fact, the response time of the unit should be adequate for detection of ground faults or short circuits on a line being energized prior to bypassing of the insertion resistors if an ultrahigh-speed relay

were used with the ECT. If the units is required to operate below 0.02 per unit, the power must be supplied from ground.

The developed ECT makes use of single-fiber optical waveguides (made by SIECOR) for transmission of the data from high potential to ground. In fact, the design length for the optical link is 300 m, which is sufficient to bring the data all the way into the relay house. The outputs provided by the ECT are capable of driving solid state protective relays (assuming that the 5 A current input is bypassed) and will produce bit-serial and bit-parallel digital outputs that can be processed further in digital equipment.

The unit is now installed in a Bonneville Power Administration 500-kV substation for one year's evaluation. During the first few months of operation, a few problems with the fiber-optic system have been encountered, and a design flaw in the fast-starting power supply has been uncovered and corrected. The fiber-optic problems seem to be related to handling problems that should be readily resolved through improvements of the packaging design.

3.2 Current Transducer for DC Applications

In many cases, it may be desirable to have dc metering equipment directly on the dc line, but voltage and current transducers of the required metering accuracy are not yet available. To date, ac metering equipment has therefore had to satisfy the metering needs of HVDC links. DC metering equipment will no doubt be necessary in multiterminal HVDC systems. In recognition of these needs, EPRI has sponsored development of an electronic current transducer with the desired performance for metering as well as control and protection. The transducer is being developed by General Electric (RP668). The specifications of the transducer are equivalent to present standards for metering class ac current transformers.

For this project, it was decided to rely on proven technology for the current sensor. A shunt was therefore selected because it was considered to be the best component to satisfy the accuracy and linearity requirements.

Several different electronic system concepts have been studied as a part of the project. The selected concept is an all-digital system similar to the ECT for ac described above. A block diagram of the unit is shown in Figure 3.

The electronics located in the head of the transducer next to the shunt requires a power supply for its operation. It was decided to use a 10-stage, 30 kHz cascade transformer power supply capable of providing about 100 W from ground to the electronics in the top of the electronic current transducer (ECT). This is sufficient for temperature compensation of the temperature-sensitive components in the measuring head. Ten stages satisfies the basic insulation level for 400-kV dc operating voltage.

The optical communication link selected for this ECT is also 300 m long. This is the design distance from the transmitter to the receiver in the control room. The estimated attenuation in the optical transmission system is less than 6 dB. This link is also manufactured by SIECOR.

3.3 Voltage Transducer for DC Applications

A new way of measuring the high voltages of HVDC transmission lines without using a resistive voltage divider was developed by General Electric in EPRI's Prototype HVDC Link project (RP213-1).

It is, of course, impossible to use the devices presently available for ac measurements for dc, since the steady-state (dc) quantity would not be reproduced. A dc measuring device must, of course, provide the dc information, but must also accurately reproduce all transient information, which makes the measuring problems more difficult. For gas-insulated systems, it is also necessary to have a compact device.

The new voltage transducer uses the static voltmeter (field mill) principle, sensing capacitive displacement currents from the dc bus, and producing an ac voltage proportional to the electrostatic field.

The measuring device is compatible in size with other gas-insulated components of the compact terminal. All electrode equipment is at ground potential. Its reliability and predicted performance are promising, with an accuracy that seems to meet metering requirements.

The essential circuitry is shown in Fig. 4, and the principle of operation is shown in Fig. 5. The new transducer is now installed in the Prototype HVDC Link that will begin test operation in early 1979.

4. Substation Control and Protective System Development

In a typical substation, shown in Fig. 6, the data received from the sensing elements must serve a variety of users. The needs of the different users are diverse indeed. For example, the accuracy of a fault recording device can be much less than that of a metering device. The frequency response of a SCADA system interface is less than 1 Hz, whereas a fault recorder may need 1.5 kHz or more. As new needs surface, we have a tendency to satisfy them with new devices. This has led to a proliferation of devices, many of them overlapping each other. An example of this might be the use of conventional annunciators in parallel with a sequence-of-events recorder. This method of operation is costly. The events recorder was, however, developed to satisfy the need for improved fault records that could not be provided from the simple annunciator systems.

The time now seems to be right for a new generation of control and protective devices for substation applications. The new devices should make

it possible to reduce the cost of the control and protective system while at the same time maintaining or improving the performance of the system to satisfy present and foreseeable future needs. New technologies that can be applied in the new system are the fiber-optic and microprocessor technologies. Fiber-optic communication systems coupled with multiplexers for data acquisition and distribution should reduce cable costs, reduce installation time and minimize EMI problems in high voltage substations. Advanced data analysis is feasible through the use of microprocessors. This should improve the flexibility of the system so that future needs can be more readily satisfied. EPRI has one project in this area of system development almost completed, and two projects are in the start-up phase.

4.1 Fault Data Acquisition System

For a demonstration project such as the Prototype HVDC Link, EPRI project RP213,⁽¹⁾ complete and accurate operating history and detailed fault information is vital for evaluation of the new technology. A fault data acquisition system (FDAS) has therefore been developed that will capture all pertinent fault data and produce a log of operational data as well. The FDAS has been built by Boeing Engineering and Construction (a division of the Boeing Company) under a contract with EPRI (RP213-3).

The resulting system, shown in Fig. 7, has a master station located in the Astoria East Converter Terminal of the Prototype HVDC Link. This is the normally manned terminal. A remote station is located in the Astoria West Converter Terminal. Since the two HVDC terminals are located only about 700 m from each other, a high-speed multiplexer system is used for most of the data acquisition. One of the five multiplexer terminal units used in the FDAS is located in the yard, close to a splice in the dc cable connecting the two dc terminals. The use of this remote multiplexing system has significantly reduced the cost of the data acquisition system. The fourth major assembly, shown in Fig. 7, is an operator's console that is intended to be used by an operations or relay engineer at a remote office. The console has output devices that will produce a complete record of a fault from either terminal within a few minutes after the occurrence.

The FDAS, a block diagram of which is shown in Fig. 8, has been built from standard, commercially-available pieces of equipment. Siemens' fault recorders, a Digital Equipment Corporation minicomputer, and a Boeing multiplexer system are the major components of the system. The major R&D areas have been:

- o the design of a common time base for the system,
- o the data concentration method used for transmissin of oscillographic fault data, and
- o the general system interfaces and integration.

The system configuration is modular, and a two-computer configuration, where one computer is placed in each terminal, will be relatively easy to accomplish. This is important since, in a conventional HVDC transmission system, the HVDC terminals are normally several hundred miles apart. With some additional effort, it should be possible to configure the system with dial-up lines for the fault data transmission. Thus, dedicated communication lines for the fault data transmission will not be required. In this application, dial-up lines should be economical, since it is expected that fault data transmission will be very infrequent.

The selected output device for the transmitted fault records is a slow recorder of the same type as is used in each local fault recorder system. It is, of course, conceivable to change this slow-speed recorder to a small computer with a disc memory (or other large bulk storage media). In this way it will be possible to perform computer analyses of the fault data, which could further enhance the fault analysis. This capability could, if properly utilized, be of significant value to system operators or troubleshooters in the future, even for ac systems. Control capability can also easily be added to the system, since the base for the system is the same as for the substation integrated control system already used by Bonneville Power Administration.

4.2 Substation Control and Protective System Development

A new project (RP1359), for development of a new control and protection system for transmission class substations, is in its start-up phase. Another matching project dealing with distribution system automation is also due to started.

The substation control and protective system development project will make effective use of fiber-optic links for data acquisition and will incorporate microprocessors for effective and reliable signal processing. Many different system solutions are possible when using computers combined with communication links. We feel that a distributed processing-type system is needed because protective functions will need special processors to achieve the needed reliability. Hence, high-level processors will probably only be used for logging of relaying operations and for monitoring and supervision of the relay performance. One such system concept is shown in Fig. 9.

The use of fiber-optic links requires the use of multiplexers for the data acquisition subsystem. Radial and looped data links are the two candidate systems for connection between the multiplexer terminals. Two different ways of handling the signal transmission system are shown in Figs. 10 and 11. These figures show very early concepts, and the R&D work may lead us to quite different results.

Two contracts have been executed, one with Ohio University for investigation of algorithms suitable for revenue metering. The second contract is with Texas A&M Research Foundation for the development of guides for electro-magnetic interference (EMI)

testing of the manufactured equipment. This project will investigate the EMI in the range from power frequencies to 100 MHz, and characterize it in both the time and frequency domain.

The system development will be conducted by Westinghouse. This part of the project should lead to a full system demonstration in an existing high voltage substation. The demonstration will include the protection relay functions for a line, a bus, and a transformer. A second line relay development is expected to be started in 1979 with General Electric as the contractor.

Digital systems, in contrast to the conventional systems used for protective relays, can incorporate checking as well as error-correcting features at a reasonable cost. The cost-effective use of self-checking features will be an important factor in this project. It is therefore expected that corrective rather than preventive maintenance strategies can be used.

Optical fibers have been used in many of the ongoing project described here. The new single-fiber, low-loss, optical waveguide appears to solve the EMI-related problems at a cost that is expected to be competitive with existing cables in a few years. Optical fibers no doubt have several other advantages over cables. They cannot start an electrical fire, and the fibers do not need physical separation from each other, since interference between fibers is negligible. This allows the use of very simple, inexpensive ducts for the fiber cables instead of the relatively expensive conduit systems used in today's substations. On the negative side is the fact that the fibers are relatively fragile, but this should not be a problem if the fiber cables are simply rolled out in shallow surface ducts.

The optical communications systems, coupled with transducers like those described above, or relatively simple multiplexers placed strategically in switchyards, could revolutionize the design of instrumentation and control systems in substations, as well as in power plants in general. The potential cost-benefit of these new systems could be substantial.

The distribution automation project has progressed through contractor selection, and project authorization is being requested from the EPRI Board of Directors. Start-up of the project is expected in late 1978 or early 1979.

5. Protection and Monitoring Device Development

An important part of EPRI's Electrical Systems Division R&D program is the development of needed or improved equipment monitoring devices. These devices can often be used to protect the equipment that is monitored, after a proper time to prove their reliability. The only ongoing project specifically for protective relay development addresses the special high-impedance fault system protection problem. It is likely that similar projects will be added in the future, once the need is identified.

5.1 High-impedance Fault Protection

The current that flows during a fault depends on a number of variables. One of these is the impedance of the fault. High impedance at this point can limit the fault current to values that are below the level of a fault-sensing device, and thus the fault condition persists because it cannot be recognized as a fault. An example of such a fault is a broken phase conductor of a grounded wye system that is in contact with the earth at a relatively nonconductive point, such as on a macadam street. In this case, the current that flows between phase conductor and ground may be limited to a few amperes. This condition cannot be recognized by conventional fault-sensing devices, and the conductor remains energized, thereby presenting a safety hazard to anyone who might touch it. The complexity of this problem has suggested a parallel effort by three contractors. Power Technologies, Inc., in a comprehensive study of the behavior of high-impedance faults, will aim at identifying characteristic parameters, and will also develop specifications for a detection instrument (RP1285-1). Hughes Research Laboratories (RP1285-2) and Texas A&M University (RP1285-3) will each conduct studies of existing detecting concepts, and will develop prototype detection instruments if these concepts prove feasible.

5.2 Transformer Monitoring

The transformer is the most expensive component in a ^{substation} system. Its reliability is normally high, but a catastrophic failure occurs frequently enough to be of concern. Improved monitoring of the winding temperature might be used to prevent excessive aging of the winding insulation materials. Westinghouse developed a sensing element under RP994, which is shown in Fig. 12. Another temperature sensor is being developed by Sigma Research Corporation (RP1137). Monitoring of the transformer oil might make it possible to take the transformer out of service before a transformer defect leads to a catastrophic failure. The operating principle of the detector developed by Westinghouse (RP748) is shown in Fig. 13. On-line monitoring, or partial discharges within the transformer, might lead to the same result. A device for this has been developed by the McGraw-Edison Company (RP426).

6. Supporting R&D

Data that supports protective relay hardware development can be as important to the utility industry as the development itself. Methods and procedures, such as calibration methods or similar tools, are also very important, since they help the utilities to keep their instrumentation systems "tuned up." A number of ongoing projects fall into one of these two categories.

6.1 Coupling Capacitor Voltage Transformer (CCVT) Calibration System

A field calibration system for CCVTs of metering class has been developed by the National Bureau of Standards (NBS). This project (RP134), jointly sponsored by EPRI and NBS in 1973, was initiated

because utility people had doubts about the long-term accuracy of CCVTs for energy metering applications. The problem is that even if the CCVTs are delivered with acceptable accuracy from the factory, very little is known about their long-term stability. Periodic calibration of the CCVTs seems to be an obvious solution, but calibrations with the required accuracy, 0.05% or less, are difficult to make in the laboratory, much less in the field. Consequently, few utilities are willing to make use of CCVTs in metering applications.

The principle for the calibration measurement is shown in Fig. 14. Prior to some field trials, the calibration system underwent thorough laboratory testing, which verified that the design goals for the equipment (amplitude error of 0.05% and angle error of 0.3 mrad or less) had been met. In one field test of the calibration system at a 500-kV substation, 3 out of 6 metering class CCVT units were found to have errors exceeding the accepted 0.3%, 4.6 mrad (16') error limits. These units had been in operation for four years. They were not actually used for energy metering, but the maximum measured error (2.4%) was even beyond the normal error limit for relaying purposes. In another field test, six newly-installed cascade potential transformers all had almost exactly the same accuracy as they had before leaving the factory. This proves that the calibration system by itself, is useful for accurate field calibrations. The CCVT performance data obtained through this project is too small to justify any recommendation of calibration intervals, especially since three of the CCVTs reportedly were part of a batch of units with design defects. The discovery of the design problem was, however, unrelated to this project. These units have now been replaced. The large deviation (about 1%) from expected accuracy of some of the other units has not been fully explained. It would therefore seem prudent to calibrate CCVTs periodically, at least until the long-term behavior of the CCVT is better known. This is particularly important if the CCVTs are used for metering purposes.

(Utility people interested in using the calibration system may contact NBS, since the equipment will be maintained and operated by NBS, at least for the immediate future. A detailed description of the system is given in EPRI Report EL-690.)

6.2 Analyses of Transmission Line Transients

EPRI is in the process of developing high-speed fault current limiters. One utility is independently pursuing an ultrahigh-speed relay. Such devices must be capable of detecting faults in a small fraction of a cycle. However, our knowledge about the frequency spectrum within which these devices have to operate is limited. For example, the noise spectrum to which the devices will be exposed is not well defined. EPRI is therefore sponsoring a project to analyze and classify transients on transmission lines in the 2-Hz to 100-kHz frequency range. Westinghouse is developing the instrumentation system that will be needed (RP751).

A total of two instrumentation systems will be built. They will be shipped for installation in Florida Power and Light Company substations before the end of 1978. One system will be installed in a 500-kV substation and the other system in a 138-kV substation in the Fort Lauderdale area. Each instrumentation system comprises the following major components:

- o Three high-frequency current transducers rated 500-kV
- o Six 500-kV capacitive voltage dividers
- o Three 5-A high-frequency current transducers for measurement of current in current transformer secondaries
- o Three 115-V high-frequency transducers for measurement of voltage in potential transformer or coupling capacitor voltage transformer secondaries
- o One 15-channel digital recording system for the transducers mentioned above.

The instrument system is built for unattended operation. A surge will automatically trigger the recorder, which will store 8192 samples per channel during each recording interval. At the fastest sampling rate, it can record one full cycle (60 Hz) each time it is triggered. However, in order to conserve memory space, the recorder will automatically switch between two selectable sampling rates, which could extend the recording interval to one second or more if little high-frequency content is present in the transient. The signal path within the recording system is shown in Fig. 15.

It is unrealistic to expect that an instrumentation system of this type can collect all the information needed to better understand surges. A worst-case surge, for instance, that is assumed for design of equipment, may not be recorded during the entire field monitoring period. Of course, this does not mean that such a surge can never occur. The value of the system is therefore to gather real data that can be used to verify theoretical development work. This could lead to improved fault models that are needed to fully understand how to best apply and build ultrahigh-speed relays. It is also likely that the transient errors of current and voltage transformers may have adverse effects on both control devices for fault current limiters and ultrahigh-speed relays. These errors should be possible to estimate using recorded data. Data analyses will be conducted by researchers at the University of Pittsburgh and the Rensselaer Polytechnic Institute (RP1422). Westinghouse engineers will also perform some data analyses as a part of the same contract (RP751). The resulting data base of power system transients will be made available to the utility industry. The data can, for instance, be used for testing or verification of digital, protective relay algorithms, and may also provide statistical information of importance to substation equipment designers.

6.3 Distribution Fault Current Analysis

The objective of a project being carried out by Power Technologies is to make available to utilities comprehensive statistical data on fault currents as they are actually experienced on primary distribution systems (RP1209). The continuing growth in electric power demand has made it necessary to increase the size of all system components. Consequently, the fault current duty on all system equipment is increasing--a matter of considerable concern.

Reliable data to establish the actual values of fault currents experienced are not available. While it is well known that almost all faults produce currents below calculated values, the actual magnitudes, fault characteristics, and frequency of occurrence are not generally known. The lack of this type of test data results in imprecise system design, incorrect selection of equipment, and a strong tendency toward conservative applications. A by-product of this 3-year research project might be better information about "cold load pick-up."

6.4 System Studies for DC Circuit Breakers

Multiterminal dc systems have been discussed for years. Such systems will probably be using dc circuit breakers. System studies are conducted by IREQ (Hydro Quebec's Institute of Research) for EPRI that will provide basic information about the duties of different dc circuit breakers in four basic multiterminal dc schemes, and the control and protection requirements for the breakers. The different concepts that are studied are shown in Fig. 3. The study should produce the basic information needed for development of the protection needed to operate the breakers in multiterminal HVDC systems, but it should be useful to anyone working with control and protection of HVDC systems in general.

7. Future R&D Related to Protective Relay Systems

The substation control and protection system development and the distribution automation projects will no doubt take a lions share of the R&D funds available within EPRI's Electrical Systems Division for instrumentation and protection work. No new protective relay development projects are currently in our latest 5-year plan. However, EPRI as an organization, is trying to remain flexible making it responsive to needs as they are identified by out program advisory committees and task forces. It is conceivable that fault current limiters need more sophisticated control devices than are presently anticipated. Further, it is apparent that it is less costly to improve fault clearing time by shortening the relay response time than it is to make the power circuit breaker ultra-fast. It is possible that EPRI might be called upon to fund development projects in any of these areas. Subsynchronous resonance problems, multiterminal HVDC schemes, UHV transmission systems, and superconducting generators are all subjects that might require work to develop suitable protective relay devices or systems. One thing is certain. That is that the favorable cost trade-off between main circuit capability on one hand, and control and protection equipment on the other

will be exploited wherever a small investment in control and protection equipment development can offset a large investment in main circuit equipment.

References

- (1) "Compacting DC Terminals" by N.G. Hingorani and S.L. Nilsson, EPRI Journal No. 10, December 1976.

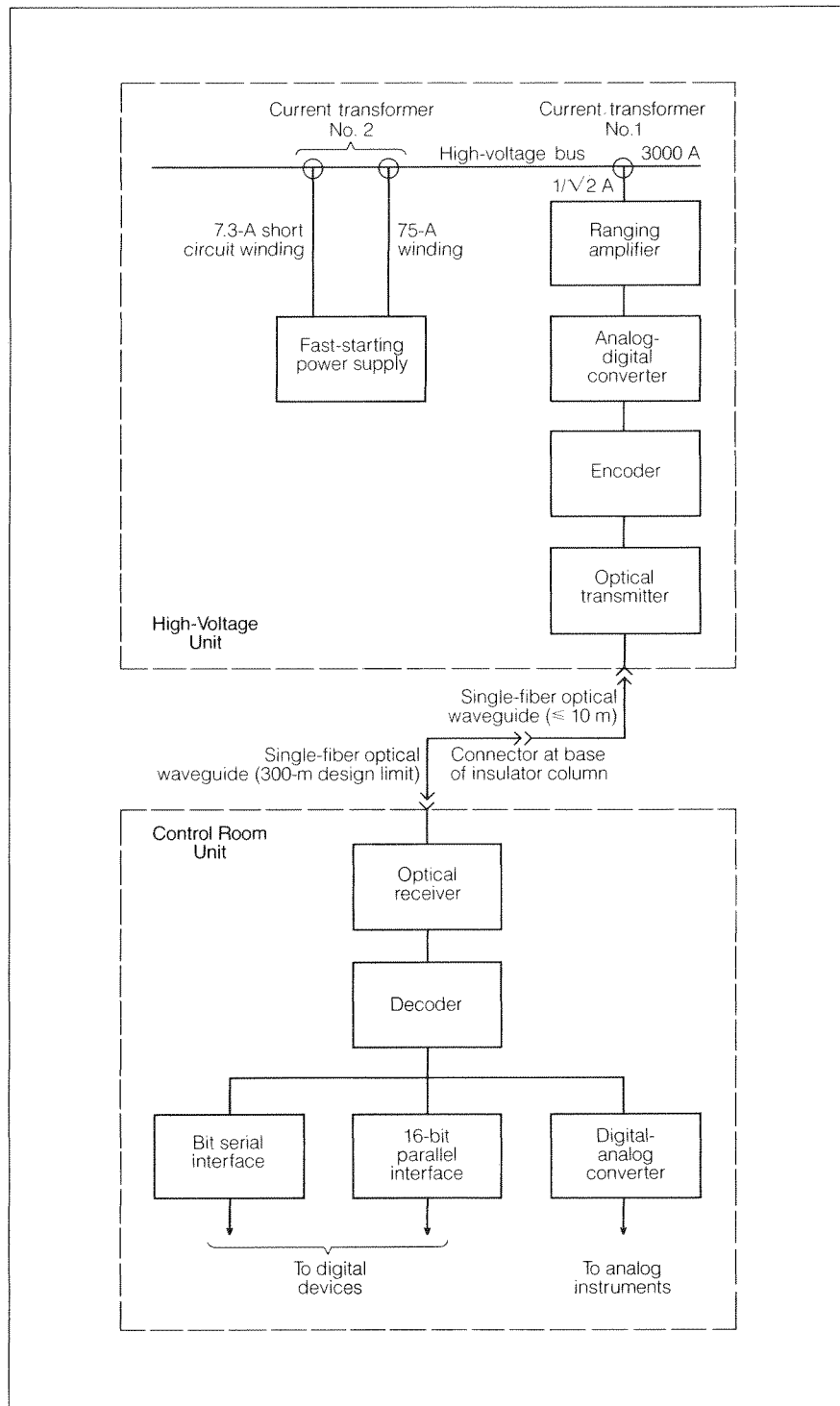


Figure 1. Electronic current transducer (ECT) incorporating a single, 300-m-long waveguide for signal transmission between the high-voltage unit and the control room unit. The ECT is built for the substation environment. Its 12-bit resolution, 16-bit dynamic range, and 10-kHz bandwidth satisfy all current accuracy and speed-of-response requirements for metering, relaying, oscillographic recordings, and so on. It may suffice for future ultra-high-speed relaying requirements as well.

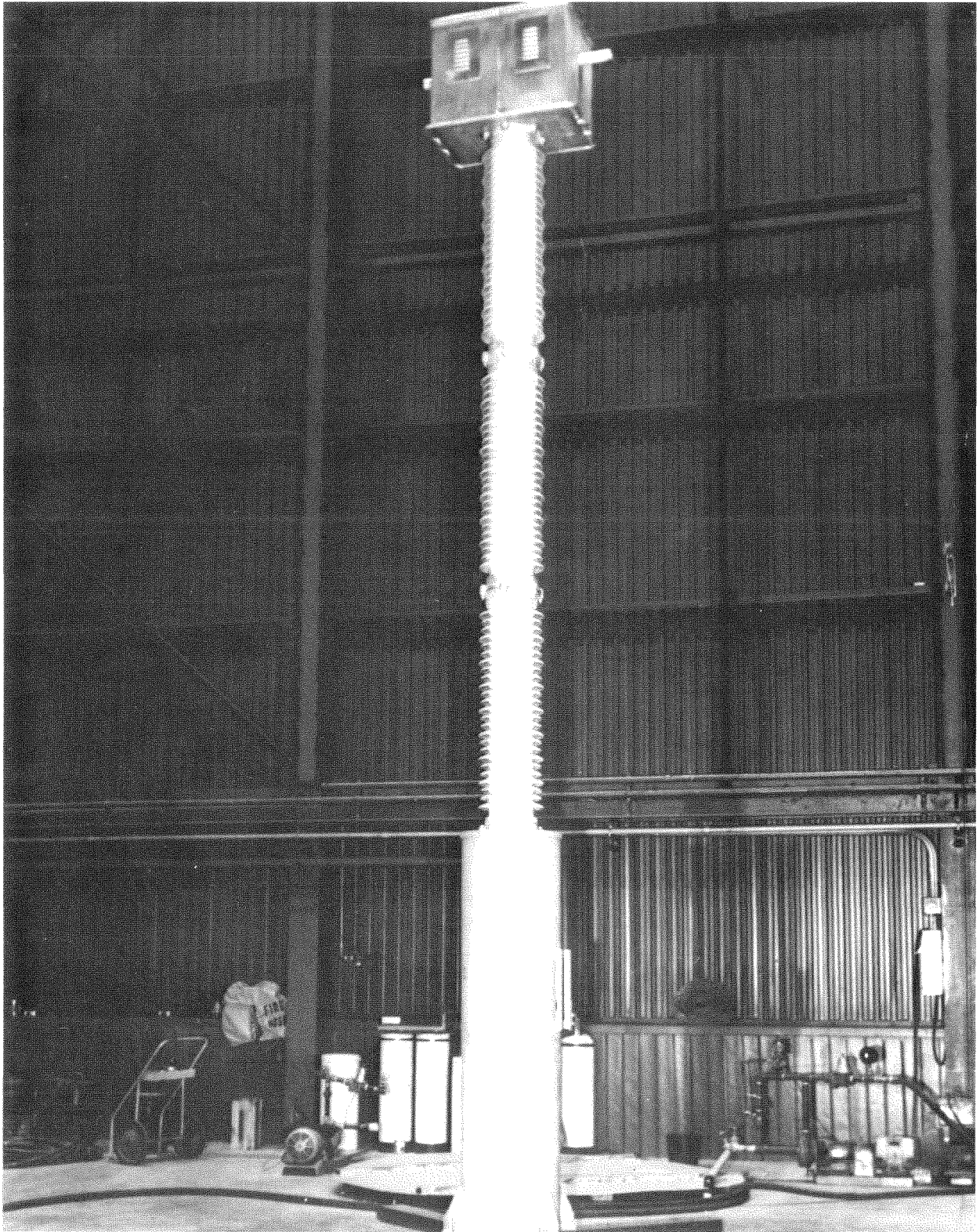


Figure 2. A 500-kV electronic, digital current transducer prototype shortly before verification tests in the manufacturer's laboratory.

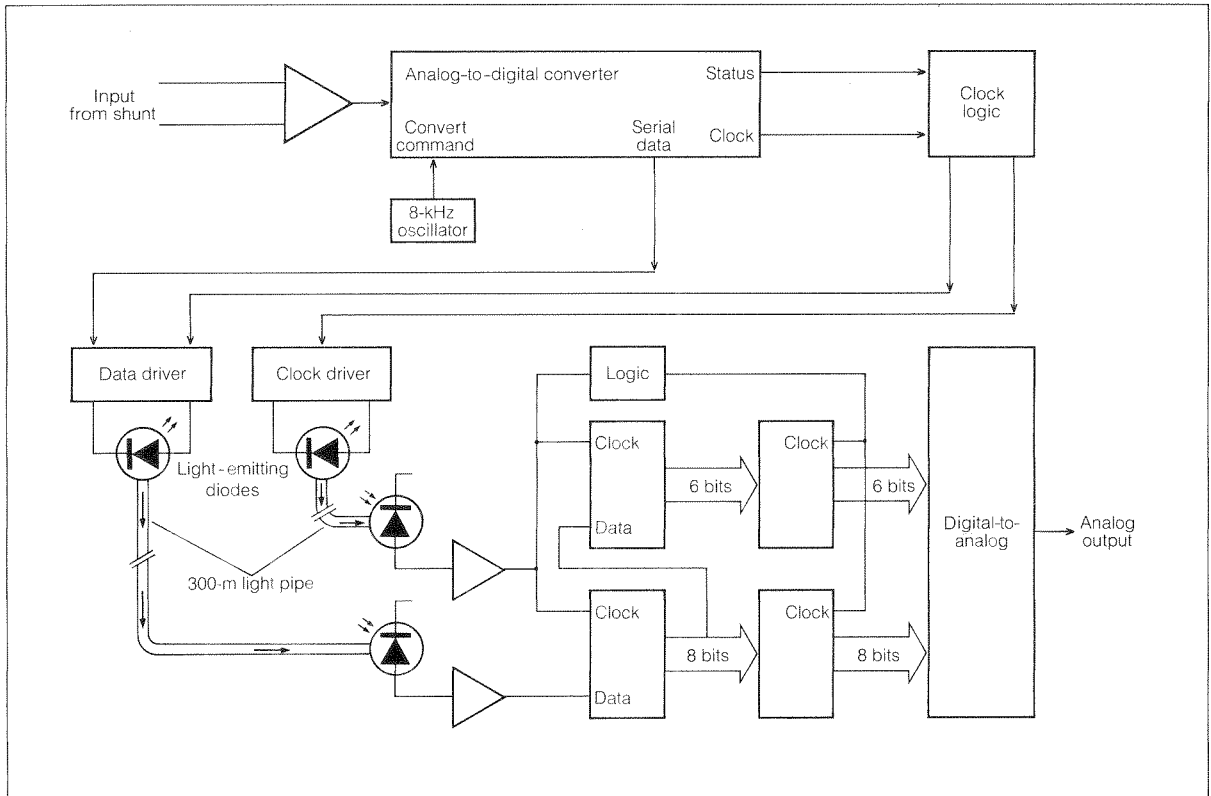


Figure 3. Block diagram of a digital electronic current transducer developed for dc power systems.

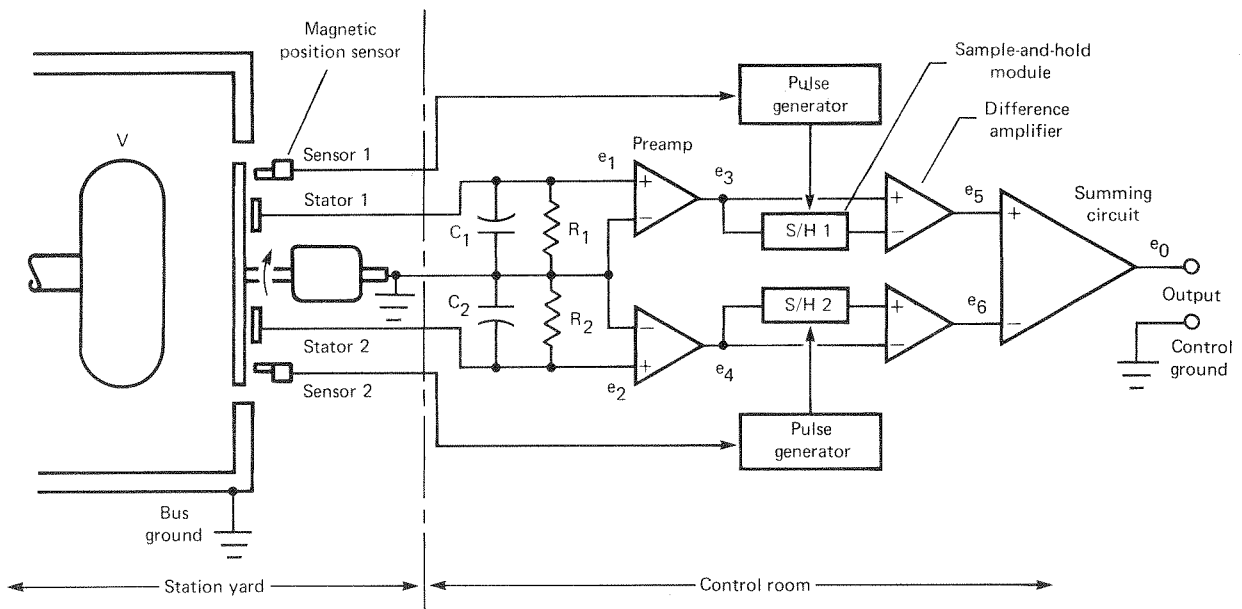


Figure 4. Essential circuitry for the GVM.

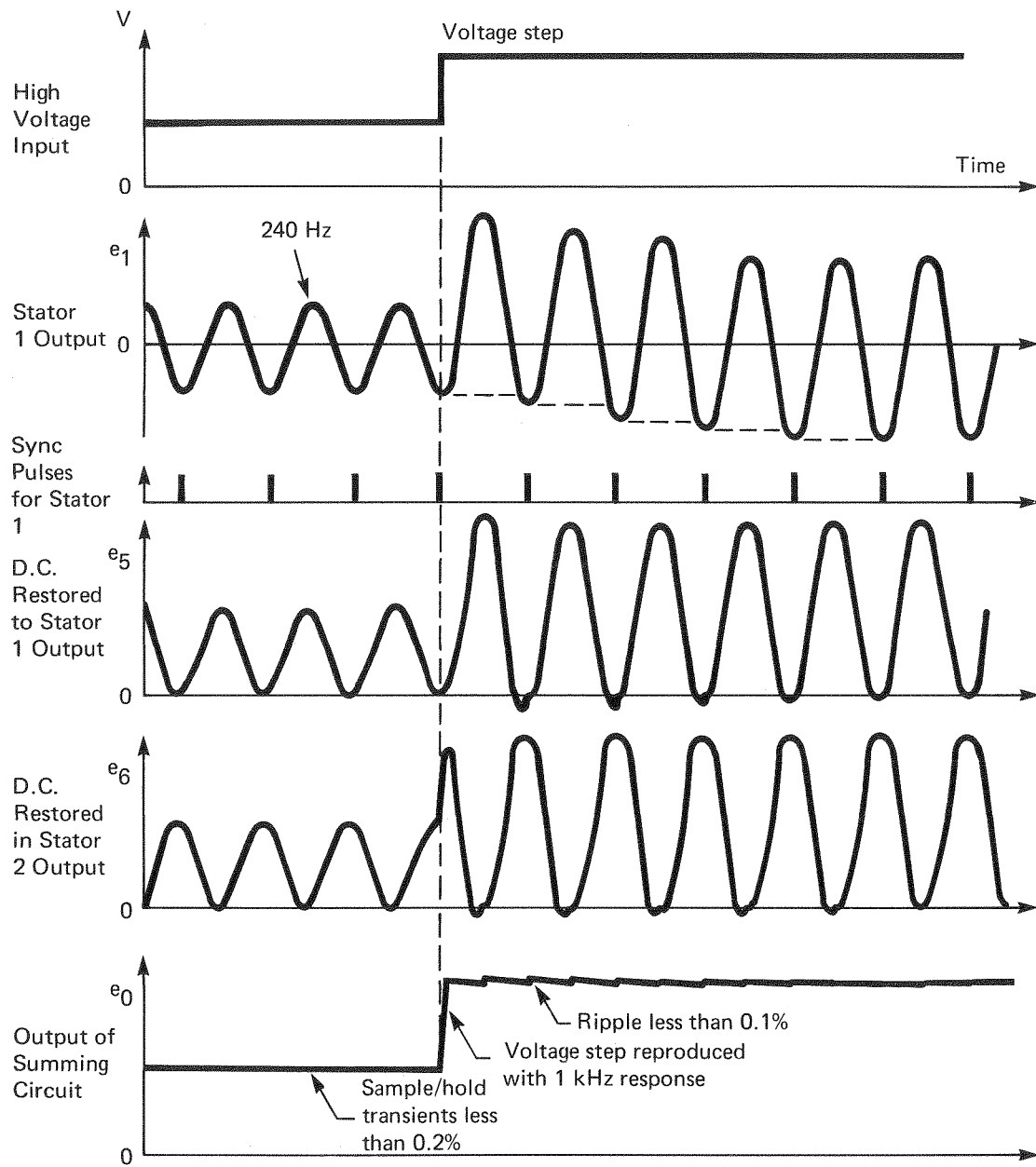


Figure 5. GVM waveforms from Applied Step Voltage.

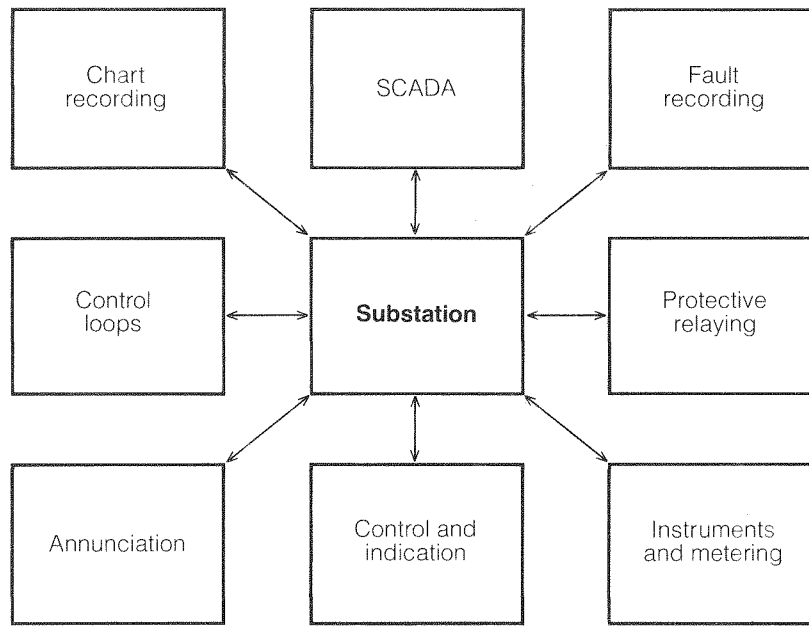


Figure 6. The conventional control and monitoring of a substation is now handled by a multitude of separate instrumentation systems.

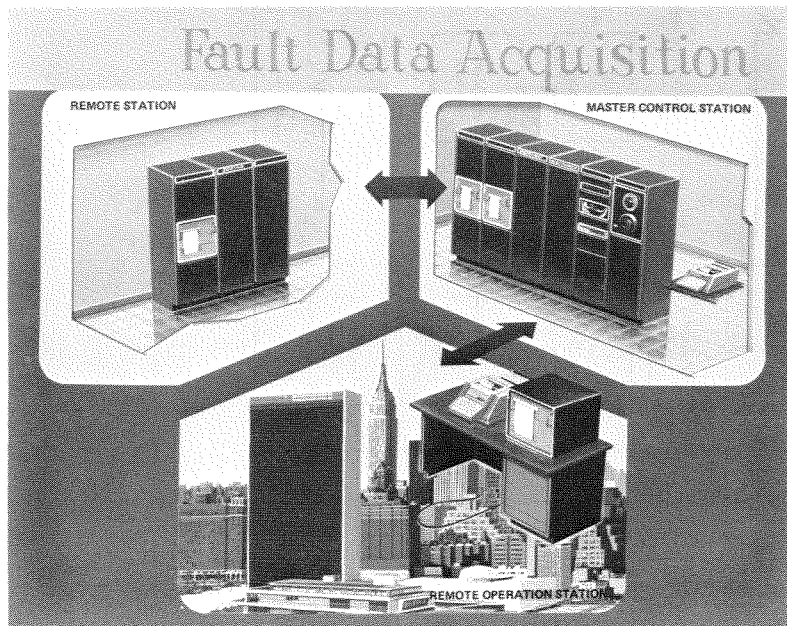


Figure 7. Fault data acquisition system for the prototype HVDC link in New York City. The system will be used to acquire and route oscillographic type fault data and sequence-of-events information. It will also produce an operations log. The system comprises four major subsystems. The operator's console, which is intended for a remote operations center, will provide a full fault record, including transient (oscillographic) fault data within minutes after a fault in any of the two converter terminals. Noteworthy also is the use of a remote multiplexing in a substation for the first time. This feature minimizes the need for cables by placing the data acquisition terminals close to the equipment being monitored.

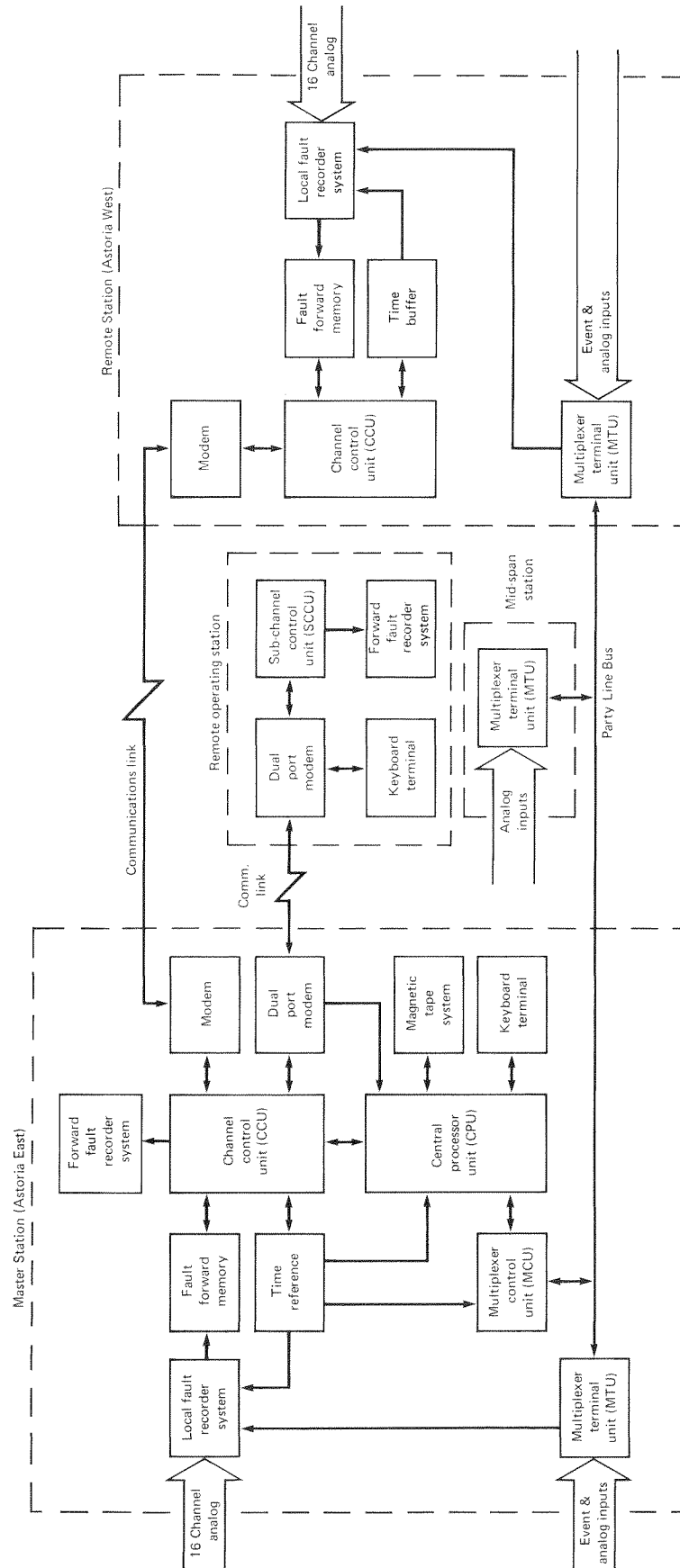


Figure 8. Fault data acquisition system block diagram.

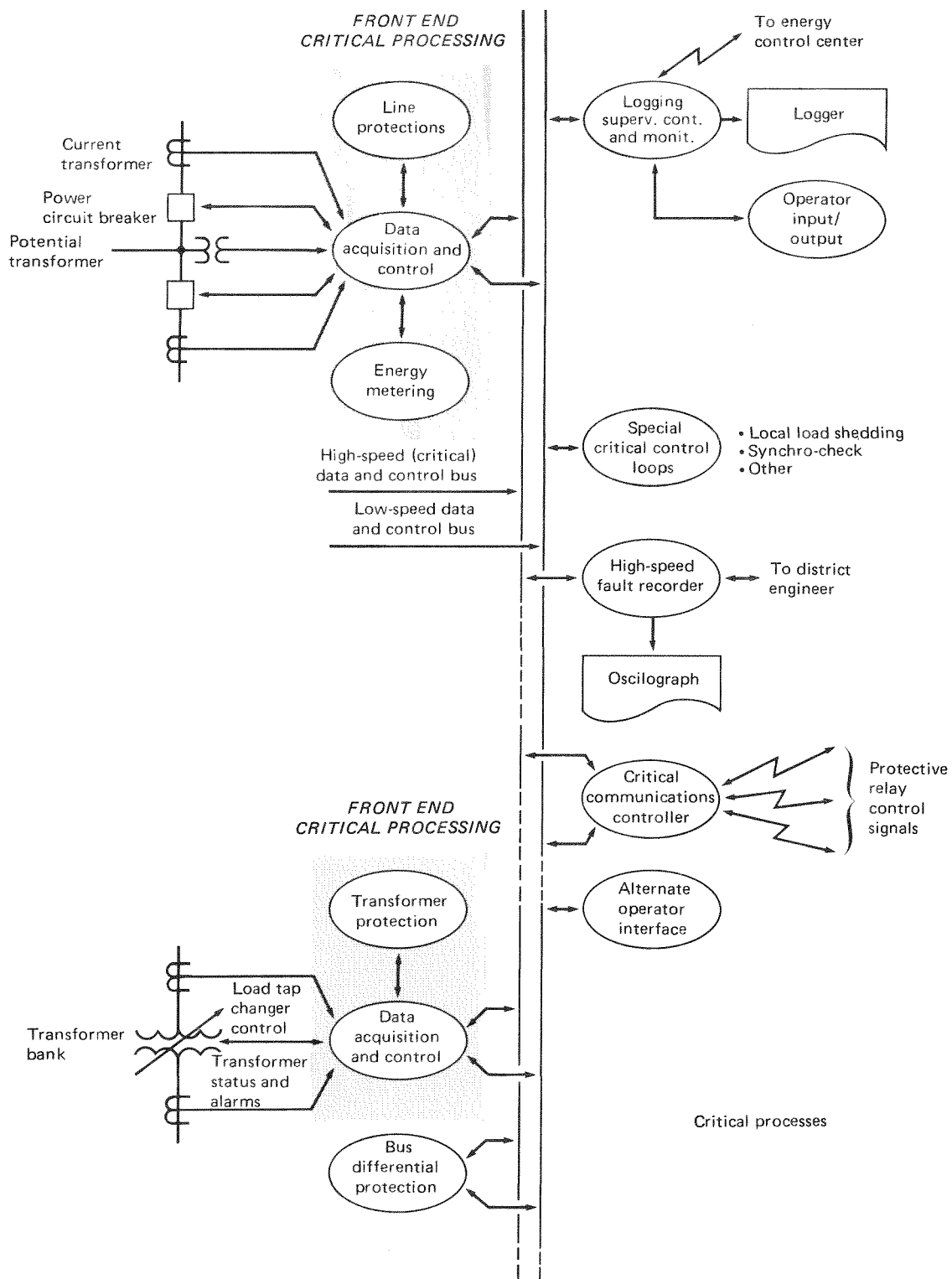


Figure 9. Substation control and protection system that features a common signal bus (center lines) to control recording, comparison, and follow-up actions (right).

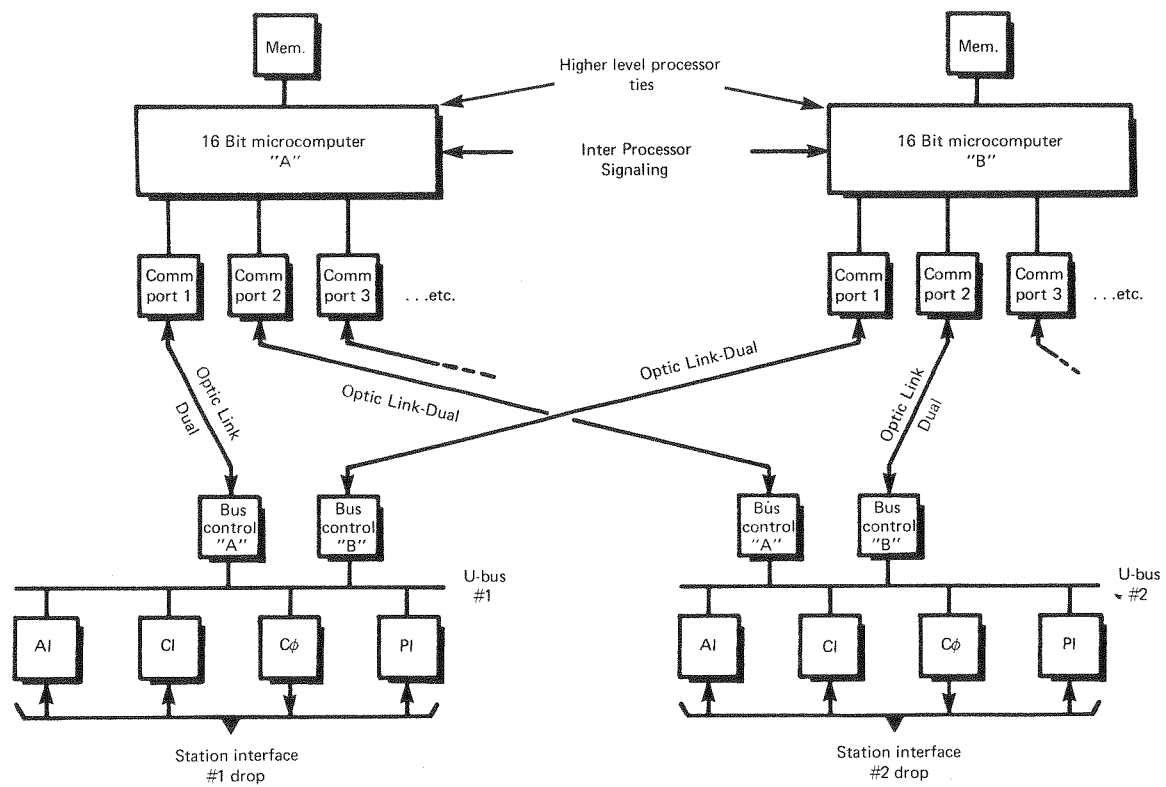


Figure 10. Typical dual configuration with radial optic links.

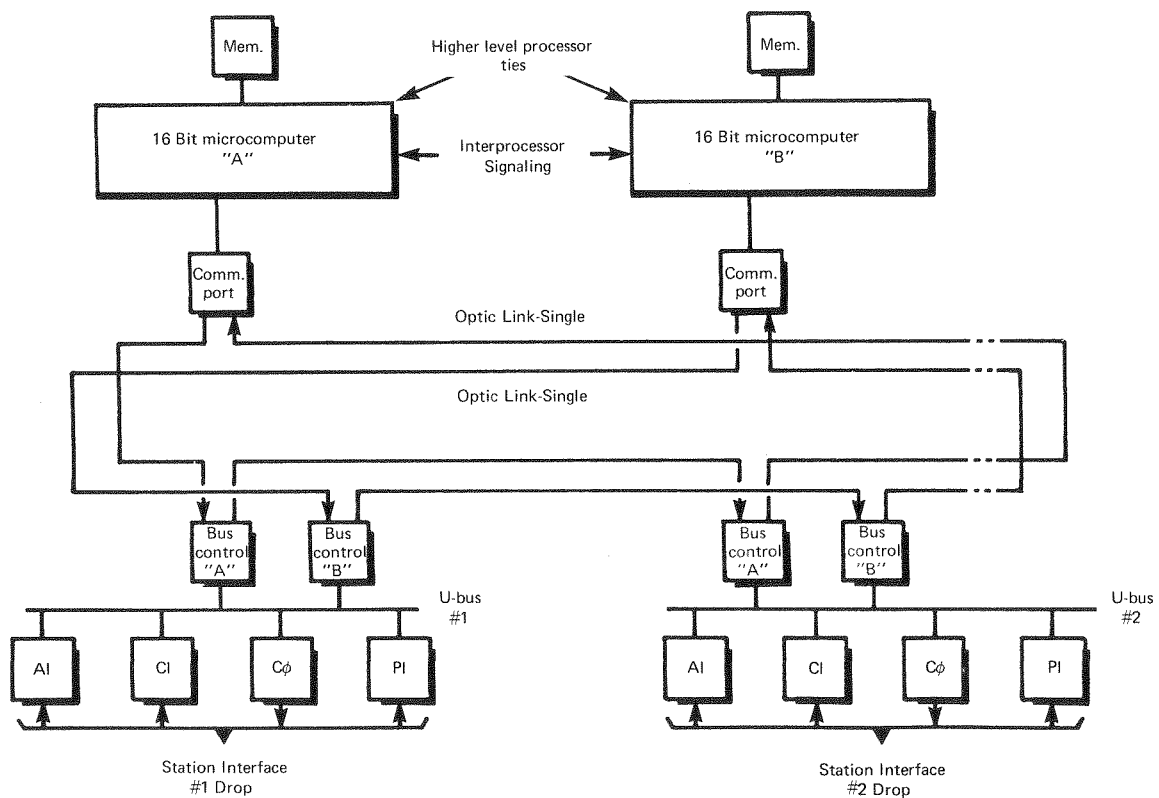


Figure 11. Typical dual configuration with daisy-chain optic links.

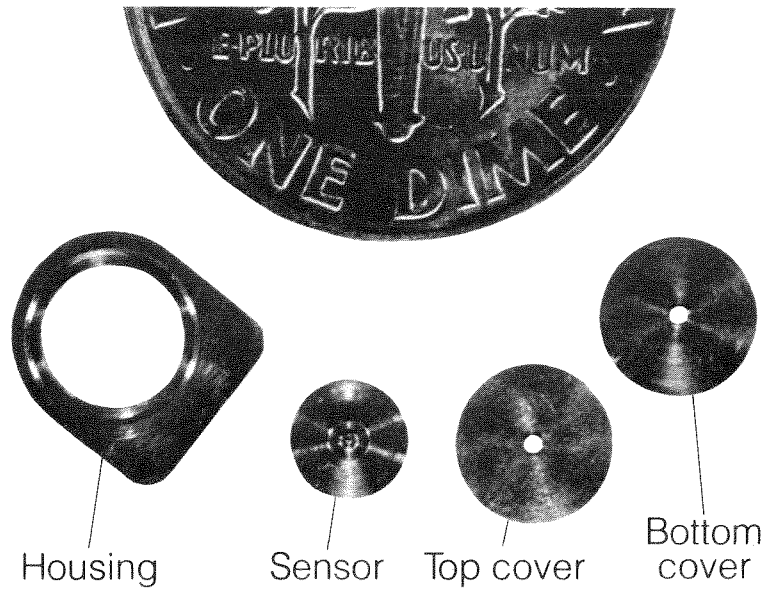


Figure 12. Components of a direct-reading, ultrasonic temperature sensor for transformer hot spot detection.

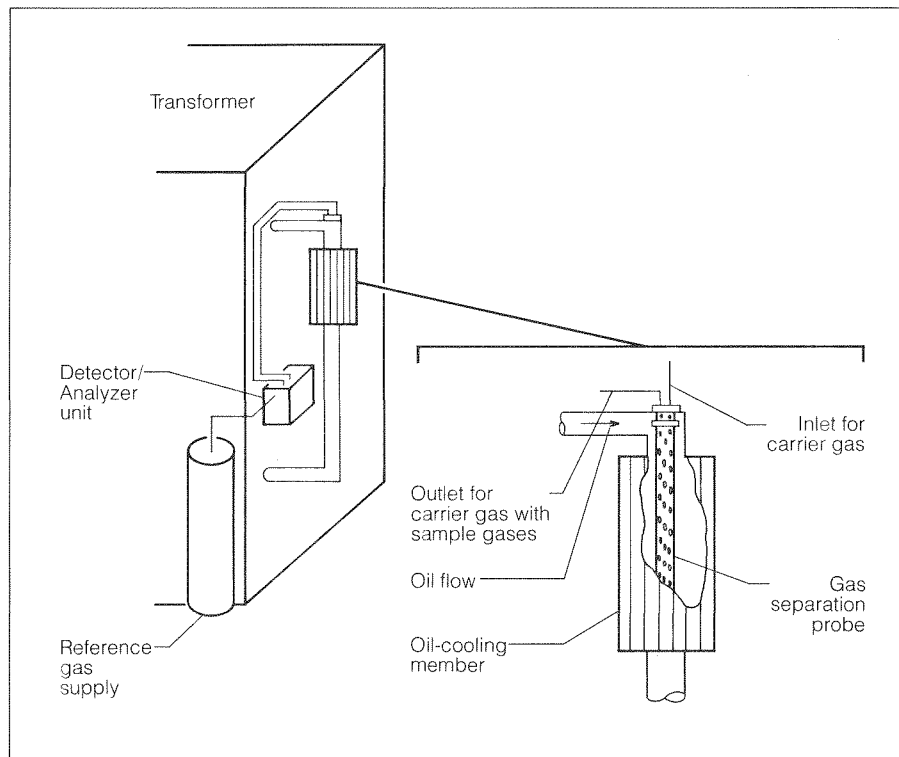


Figure 13. Schematic showing principle of operation for a gas-in-oil detection system soon to be available for testing in medium-size and large power transformers. The thermosiphon principle is used to move oil past the gas separation cell, and carrier gas is used to collect gasses to be studied in the analyzer.

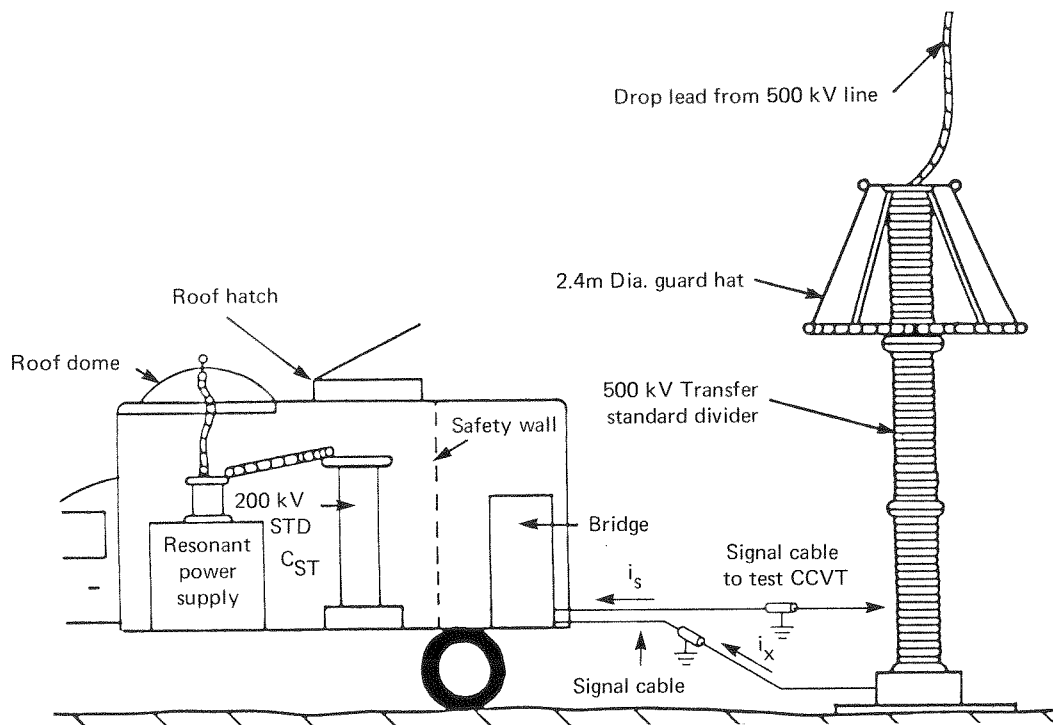


Figure 14. Semi-pictorial representation of the calibration of the CCVT against transfer standard divider at line voltage.

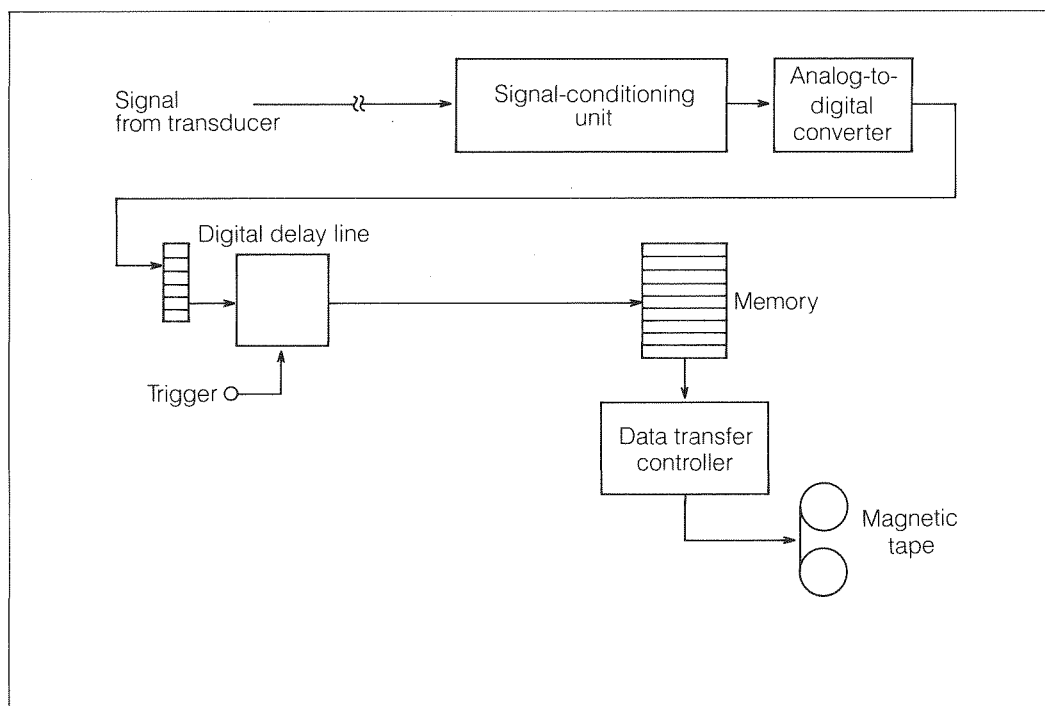


Figure 15. Digital recording system for high-frequency transients that occur during switching surges. A surge will trigger the recorder, which will store 8192 samples per channel during each recording interval. Its maximum sampling rate is 1 sample every $2 \mu\text{s}$.

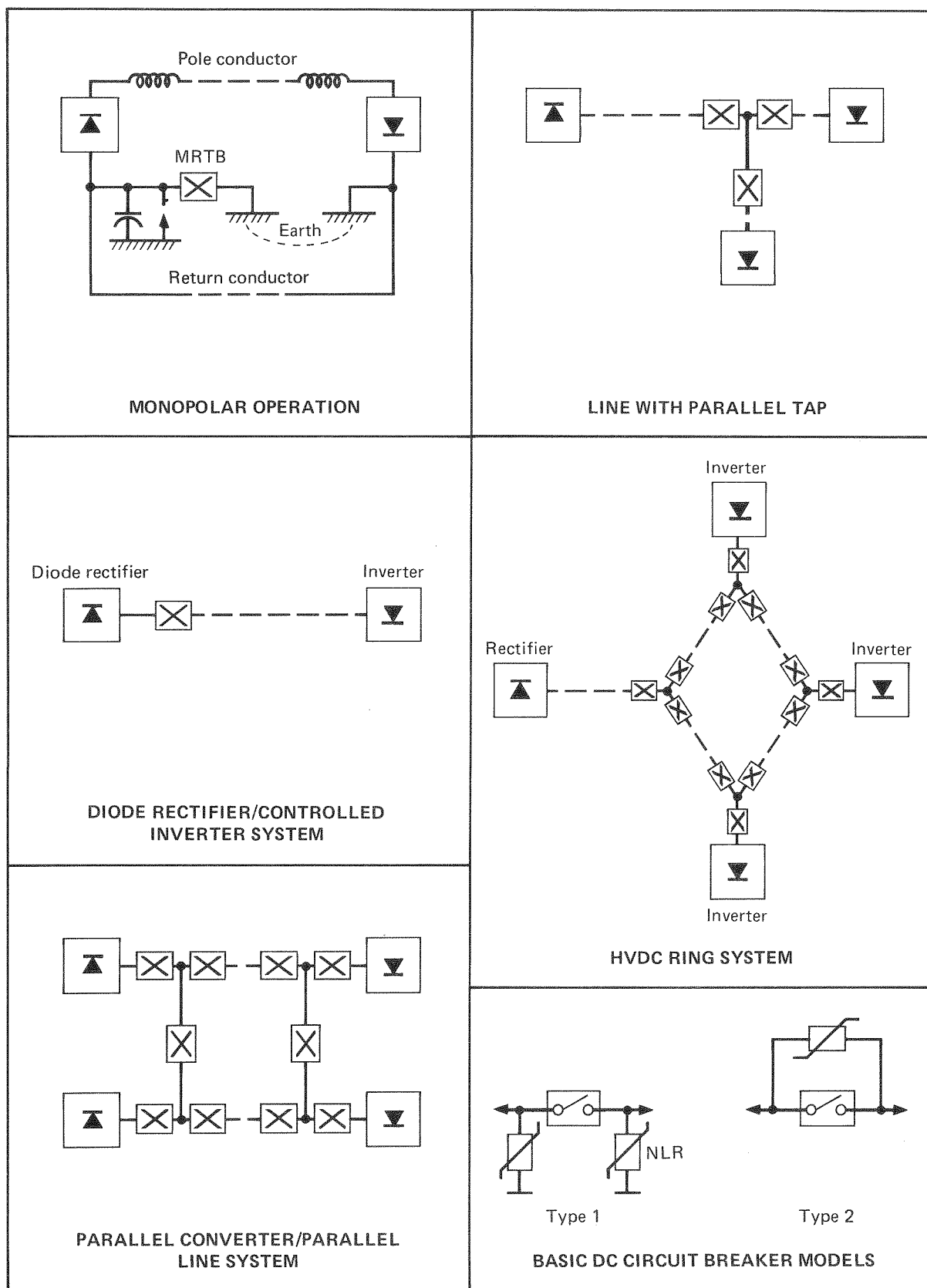


Figure 16. System studies for dc circuit breakers.

SIX PHASE FAULT COMPUTATION AND RELAYING METHODS

Lyle L. Gleason
Seattle City Light (retired)
F. Robert Bergseth
University of Washington

I. INTRODUCTION AND ACKNOWLEDGEMENT

The discussion in the following pages is based on a study performed for Seattle City Light by Harstad Associates, Inc., under the leadership of Mr. A. W. Moody, Vice President and Chief Electrical Engineer.

The study was concerned with the possibility of converting a double circuit 230 Kv transmission line (Diablo to Bothell) on the City Light system. By converting to a six-phase system with 230 Kv still maintained between adjacent conductors the line-to-neutral voltage would be increased by a factor of $\sqrt{3}$ and the power handling capability increased by a factor of 3 with the same line current. Electric field gradients may preclude operation as high as 230 Kv without reconductoring and these matters were included in the study. The following pages, however, are concerned only with the relaying and fault computation problems involved in such a conversion.

II. RELAYING METHODS (L. L. Gleason)

The nature of the fault currents of a six-phase line are subject to the type of transformations used to obtain the phase displacement and how the phases are voltage stabilized with respect to earth. The proposal of this study was to retain the existing switching facilities by interleaving two three-phase lines to obtain 60 degree phase displacement using two separate transformer banks and two separate three-phase line terminals at each line end and fixes the parameters for the recommended protective relaying of this report. The 60 degree displacement is obtained by advancing one of the three-phase lines 30 degrees and retarding the other

line 30 degrees from the present 230 Kv phase position. To obtain this 30 degree shift, a delta-wye or extended zig-zag phase-shift transformation must be used. Each of these transformations isolates the higher voltage interleaved circuit such that the interleaved system does not have any zero sequence current flow into or out of the 230 Kv system. The transformation also isolates the zero sequence of the advanced three-phase line from the zero sequence of the retarded three-phase line and vice versa. Because of these conditions, the conductor to earth voltage stabilization of the higher voltage line is solely by the line-end transformers of each of the three-phase interleaved lines. The protective relay significance of these conditions can be summed into five statements:

1. There are no significant mutual impedance involvements for line-to-ground fault currents of either the 230 Kv system or the interleaved lines.
2. There is no need for directional control of the residual relays on the interleaved three-phase lines.
3. For a single-line-to-ground fault on the interleaved three-phase lines, only one of the interleaved lines needs to be cleared to remove the fault from the system.
4. Phase-to-phase faults between the two interleaved three-phase circuits result in residual fault currents in each line detectable by the relays for the single line-to-ground faults.
5. Except for magnetizing inrush and equivalent ground wire currents, any residual current detected indicates a need to clear the circuit from the system.

The other, less probable, faults to be detected are phase-to-phase and three-phase for either the advanced or retarded circuit. These faults can be detected by the impedance relays on the current transformers and potential transformers presently operating on the 230 Kv lines. Since

the power transformer impedance in each end of the advanced or retarded lines equals about 25 per cent of the per unit impedance from 230 Kv bus to 230 Kv bus, the first zone impedance setting will terminate within the transformer for both the phase-to-phase and three-phase faults. Zone two will be set to overlap the 230 Kv bus. With the combined per unit transformer and interleaved line per unit impedance being approximately equal to the 230 Kv line per unit impedance, the settings for interleaved operation will function for a temporary 230 Kv operation. However, the phase-to-phase settings should take into account the phase shift as outlined in C. R. Mason's book, Art and Science of Relays, (page 172).

Added Relays

With the modern relays and the transfer trip of the 230 Kv lines, the only added relays at each end of the line will be six harmonic-restraint transformer differential relays; six instantaneous over and under voltage relays on the 230 Kv side of the transformer; two non-directional over-current residual relays with time and instantaneous elements; and a fault pressure relay in each of the transformers. The One Line Relay Diagram (Figure 1) shows the relaying of one interleaved three-phase line of a six phase line.

Fault Current Diagrams

Four fault-current flow diagrams are attached to indicate the adequacy of the above relays, the absence of a mutual impedance problem, and the most significant positive, negative and zero sequence impedance paths. These Figures, 2 through 5, are diagrams of the interleaved line system with arrows showing the current path for four types of short-circuit faults. These figures are included to indicate how the Delta-Wye or extended zig-zag transformers isolate the 230 Kv zero-sequence paths from the zero-sequence path of the interleaved lines, and how the non-directional residual overcurrent relay is capable of detecting only the faults of the interleaved

lines. In order to show the fault current path with only solid and dashed arrows, only the fault currents from the short circuit duty source of the 230 Kv bus at each end of the interleaved system is diagrammed.

Line to Ground on 230 Kv Fault

Figure 2 diagrams the fault current for a single-line-to-ground 230 Kv fault, and shows that no zero sequence current flows in the transformer-isolated interleaved lines. The currents of each interleaved line are equal in each direction and produce no residual current. Also, with no zero sequence (earth flow) current in the interleaved lines, there is no mutual-impedance concern with other lines on the same corridor.

Line to Ground Fault on Six-Phase Line

Figure 3 diagrams the fault current for a single-line-to-ground fault on an interleaved line. The isolating ability of the zig-zag transformer is indicated by the residual or zero sequence current in the faulted line transformers only. See fault calculation diagrams (Figures 7 and 8).

Current flow in the unfaulted line conductors resulting from the parallel to earth path and close proximity to the faulted phase is not shown. These unfaulted phase conductors of the companion interleaved line represent ground wires with transformer impedance at each end, and produce a three times I_0 residual current in the overcurrent relay for the unfaulted line. This particular potentially false tripping current cannot be eliminated by a directionally controlled relay; therefore, setting the relays above this residual current value is necessary. It should be noted that, since these phase conductors are insulated throughout the line, these parallel-to-earth return currents are only significant for a single line-to-ground fault near the line end.

Line to Line (Adjacent) Fault

Figure 4 diagrams the fault current for an adjacent 60 degree displacement conductor to conductor fault between the two interleaved three-phase lines.

This fault will necessitate tripping both of the interleaved lines, which is accomplished by the residual relay of each line even though there is no zero sequence flow of current in either of the interleaved lines or 230 Kv lines. The zig-zag transformer neutral current appears in the ground at each line end because two transformers are used to get the 60 degree phase displacement. It should be noted that the fault short circuits a voltage equal to the line-to-ground voltage and this line-end fault current magnitude will likely control the setting of the residual relay. See calculation (Figures 9 and 10).

Line to Line Diametrical Fault

Figure 5 diagrams the 180 degree displacement conductor to conductor fault currents. Similar to the Figure 4 fault, no zero sequence current flows; however, only one conductor per interleaved three-phase line is involved so the residual relays will trip both lines. The short circuited voltage is twice that of the 60 degree displacement with a resultant higher fault current than the adjacent line fault of Figure 4. See calculation (Figures 11 and 12).

Unstabilized L-G 230 Kv Fault

Since the phase shifting transformer provides no voltage-to-earth stabilization for the 230 Kv system, a 230 Kv ground fault occurring on the transformer when not connected to the station bus will not have positive differential relay protection. To cover this possible fault, instantaneous over and under voltage relays on existing potential source are proposed. These relays will be set to operate at about 75 Kv under and 150 Kv over for line-to-earth voltage. The overvoltage and undervoltage contacts will be connected such that any two phases with overvoltage and one phase with undervoltage will transfer trip to the remote end of the respective interleaved three-phase line when the adjacent line terminal breakers are open.

Relay Conclusions

In conclusion, it must be kept in mind that this study is for a specific set of existing conditions. Also, in the Northwest we are acquainted with line rated autotransformers to obtain three-phase 345 Kv lines within a 230 Kv system with the switching done at the 230 Kv level. A paper on six-phase transmission presented April 25, 1978 at the American Power Conference, Chicago, Illinois, approached the subject from a more general basis. However, nowhere did the paper make any reference to switching the six-phase line as two interleaved three-phase lines, as in this study.

III. COMPUTATION OF FAULT CURRENTS - (F. R. Bergseth)

In connection with the relay studies reported above, fault current computations were made for representative faults on a six-phase system.

Six-Phase Symmetrical Components

Just as is the case with three-phase circuits, unbalanced fault computations are facilitated by means of a symmetrical component transformation. With the six complex number degrees of freedom of a six-phase system, six components are required. The six components have been treated in early works such as Clarke*. Briefly, the six components are identified by numbers 1 through 5 and zero. Components numbered 1 are the usual balanced set of six phasors, 60° apart, and of normal (positive) phase sequence. Components numbered 5 are similar but of reverse (negative) phase sequence. Components numbered zero are all equal and in phase (zero-phase-sequence). These three components are then very similar to the better known components of three-phase systems. The remaining three components form symmetrical groupings peculiar to six-phase systems and are illustrated in the reference cited above.

*Circuit Analysis of A-C Power Systems, by Edith Clarke, John Wiley, 1943.

Impedances

If the six conductors of an overhead transmission line are symmetrically disposed at the corners of a hexagon, or if the line is suitably transposed, then there is no mutual coupling between the several symmetrical components. This means that currents of one sequence cause voltage drops of that same sequence, and only of that same sequence. As an illustrative example, the series reactances of the particular line involved in this study worked out to be:

$$X_1 = X_5 = 0.9016, \quad X_2 = X_4 = 0.7391,$$

$$X_3 = 0.7085, \quad X_0 = 4.1323$$

all in ohms per phase per mile at 60 Hz.

The system proposed in the present study involves a six-phase segment embedded in an otherwise three-phase system. It is at the transformer banks that the six-phase components are coupled into the three-phase system and become three-phase symmetrical components. For the system using two oppositely directed zig-zag banks it works out that the six-phase components are related to the components on the three-phase side by the following equations:

Six-phase positive sequence currents result in three-phase positive sequence currents, changed in magnitude and shifted in phase in accordance with the equation:

$$I_{A1(3\phi)} = 2\sqrt{3} \angle -30^\circ I_{a1(6\phi)}$$

Six phase negative sequence currents result in three-phase negative sequence currents, changed in magnitude and shifted in phase in accordance with the equation:

$$I_{A2(3\phi)} = 2 \sqrt{3} \angle +30^\circ I_{a2(6\phi)}$$

None of the other six-phase components pass through to the three-phase side with this particular connection. It must be emphasized that these relations are a consequence of the particular transformer bank connections proposed in this study and would not necessarily always be true.

Sequence Networks and Interconnections

With the necessary symmetry out to a possible fault point it is possible to define equivalent circuits, or sequence networks, which apply the same constraints to the symmetrical components as does the actual system. It is only at the point of an unbalanced fault that these networks affect each other. By analyzing the relations between the actual voltages and currents at a point of unbalance it is possible to derive the corresponding constraints which relate the six-phase symmetrical components at the fault point. In some cases there are striking similarities to the analogous three-phase cases. For example a six-phase fault is represented by a short-circuit on the positive sequence network only, while a one-line-to-ground fault representation calls for a series connection of all six sequence networks.

Figure 6 shows the actual fault currents in amperes for a fault at the Bothell end of the line. The fault currents form a balanced set in the six-phase sense. The two three-phase lines in parallel with the proposed six-phase conversion also pass a small current to the fault which is actually of positive-phase-sequence in the three-phase sense.

A single-line-to-ground fault at the Bothell end is represented by Fig. 7 in terms of the six-phase symmetrical components, while Fig. 8 shows the actual currents in amperes for this fault. It will be noted that there is a small zero-phase-sequence current induced in the parallel

three-phase lines.

As another example of an unbalanced fault it seems reasonable to expect that a line-to-line fault between adjacent lines would be very possible. For such a fault from phase a to phase b the following equations determine the symmetrical components of the fault currents:

$$I_3 = \frac{2E / 60^\circ}{Z_1 + 3Z_2 + 4Z_3 + 3Z_4 + Z_5}$$

$$I_0 = 0$$

$$I_1 = \frac{1}{2}(1 - b)I_3$$

$$I_2 = \frac{1}{2}(1 - b^2)I_3$$

$$I_4 = \frac{1}{2}(1 - b^4)I_3$$

$$I_5 = \frac{1}{2}(1 - b^5)I_3$$

where: E is the positive-phase-sequence prefault voltage at the fault point.

The several Z's are the sequence impedance equivalents looking back into the system at the fault point and,

b is a complex number, $b = e^{j60^\circ}$, analogous to the number $a = e^{j120^\circ}$ of three-phase symmetrical components.

It may be seen that the relations are rather more complex than those of the corresponding three-phase case.

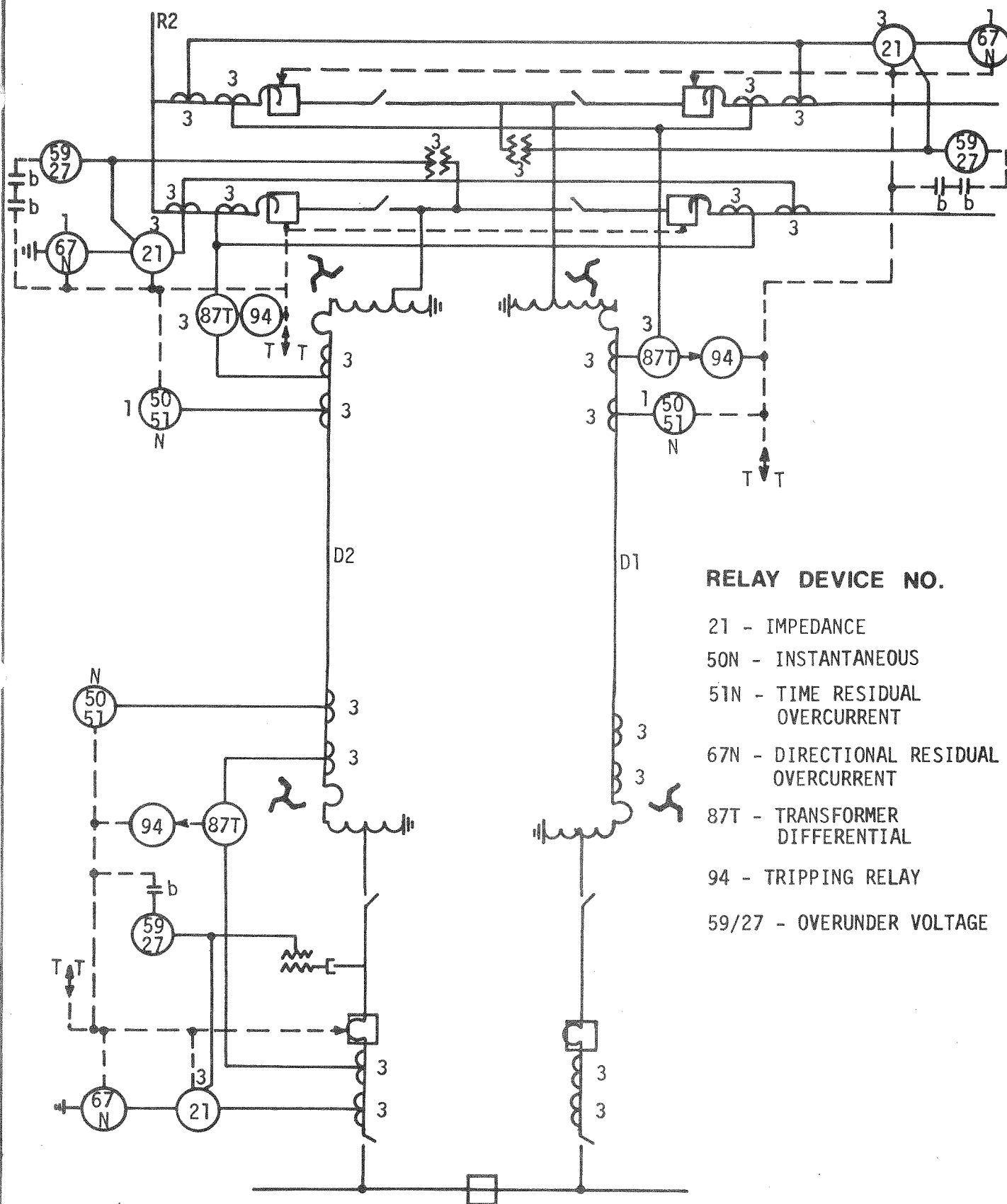
The symmetrical components of the fault currents for a line-to-line fault between adjacent conductors at the Bothell end are shown in Fig. 9. It should be emphasized that, although no zero-sequence currents are present in the six-phase sense, the two interleaved three-phase groups forming the the six-phase line each have zero-sequence (residual) current in the three-phase sense, and this fact has led Mr. Gleason to the relaying pattern proposed in the foregoing pages. The actual currents for the line-to-line fault are shown in Fig. 10.

Another type of unbalance was analyzed; that of a line-to-line fault between conductors diagonally opposite in the six-phase system. Although the probability of occurrence of such a fault might be questioned, that fault would involve the largest possible pre-fault voltage and was felt important enough to include in the study. The symmetrical components of the fault currents for such a fault at the Bothell end of the six-phase line are shown in Fig. 11 and the actual currents in Fig. 12.

Future Studies

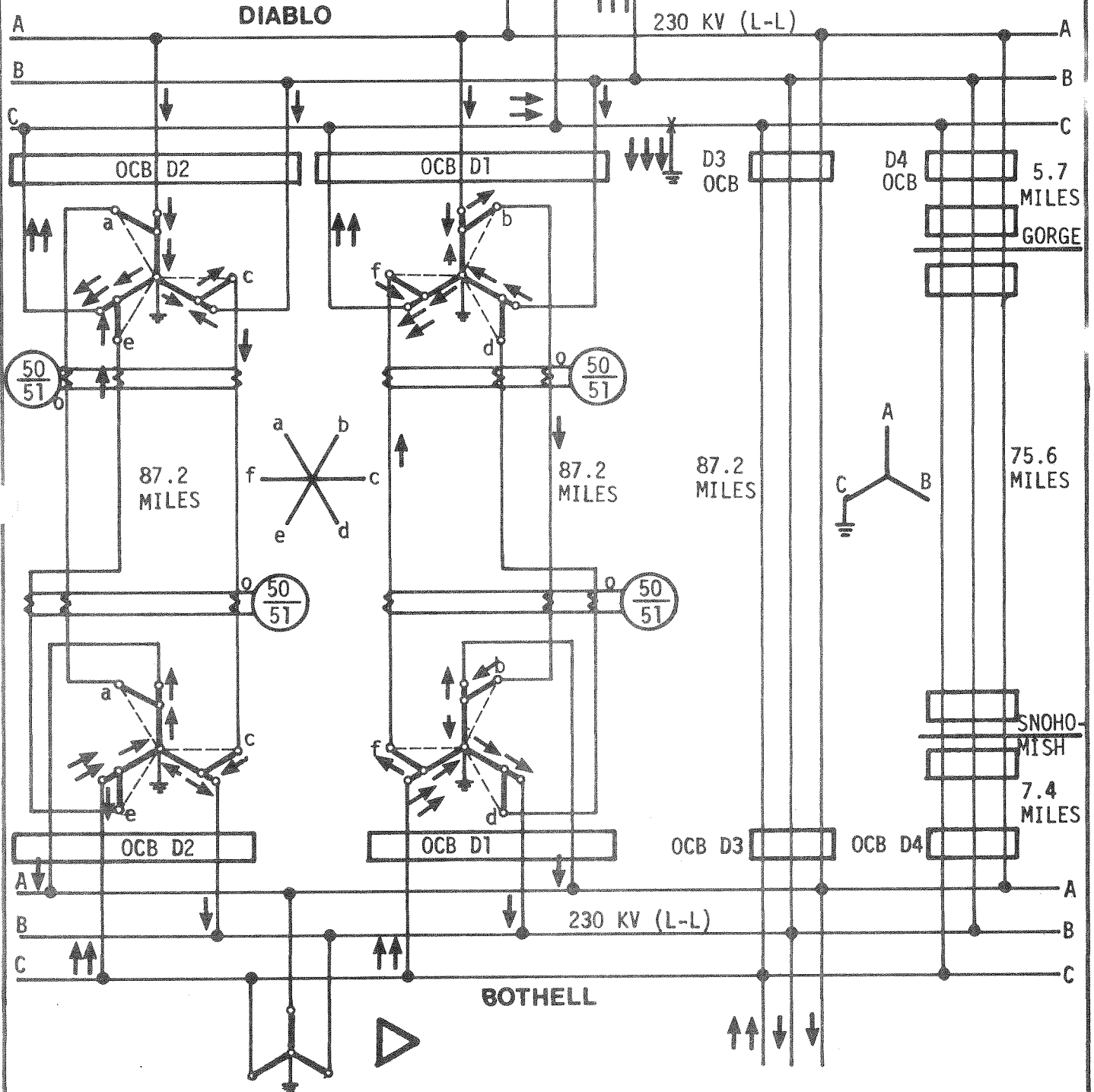
A bewildering number of other types of unbalances are possible on a six-phase system and it remains to be seen from practical experience which faults will be most significant. As might be expected certain types of unbalance on a six-phase system have no counterpart in the familiar three-phase case and the analysis can be quite complex mathematically.

In applying relays to a three-phase system it is common to base settings on two cases: a three-phase fault, and a single-line-to-ground fault. For a six-phase system the necessary experience is lacking to determine which types of faults will be most significant to relay operation. The proposals outlined above give one possible answer for the particular system configuration under study.



ONE LINE RELAY DIAGRAM

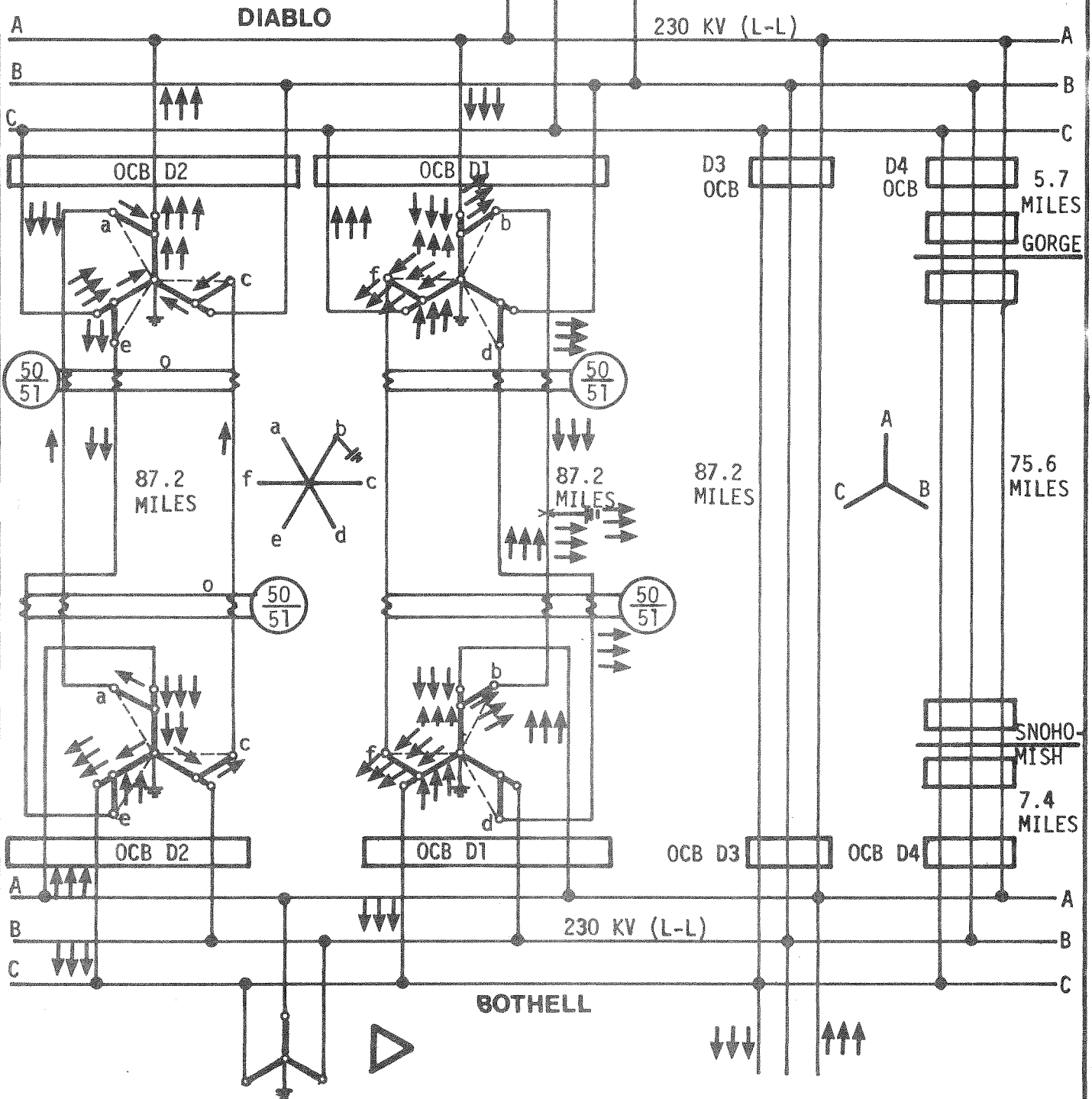
PHASE RELATIONS	
THIS. DWG.	CITY LIGHT
A	1
B	3
C	2



**INTERLEAVED LINE CURRENT FLOW
TO 230 KV LINE TO GROUND FAULT**

Figure 2

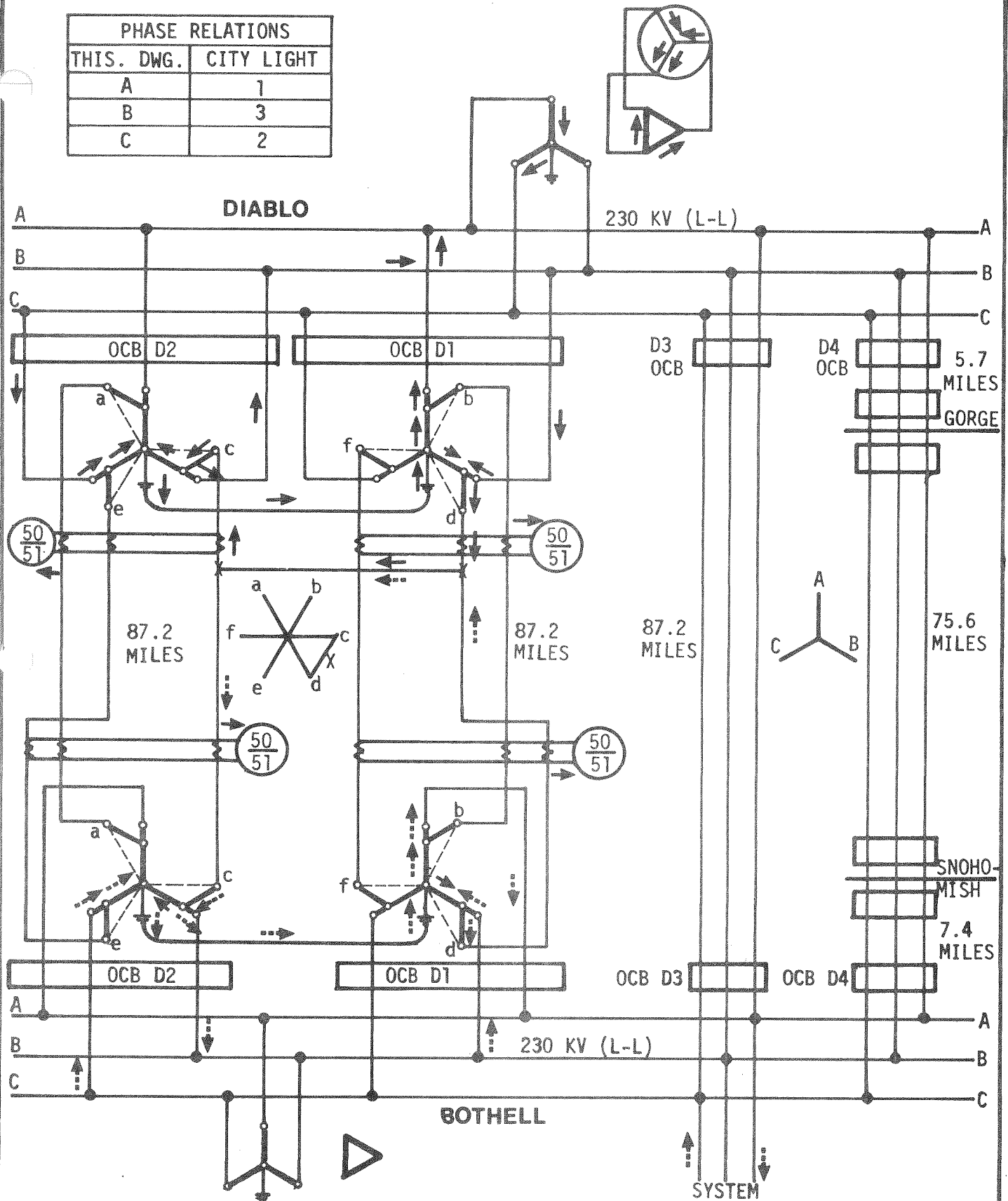
PHASE RELATIONS	
THIS. DWG.	CITY LIGHT
A	1
B	3
C	2



**SINGLE LINE TO GROUND FAULT
ON INTERLEAVED LINE**

Figure 3

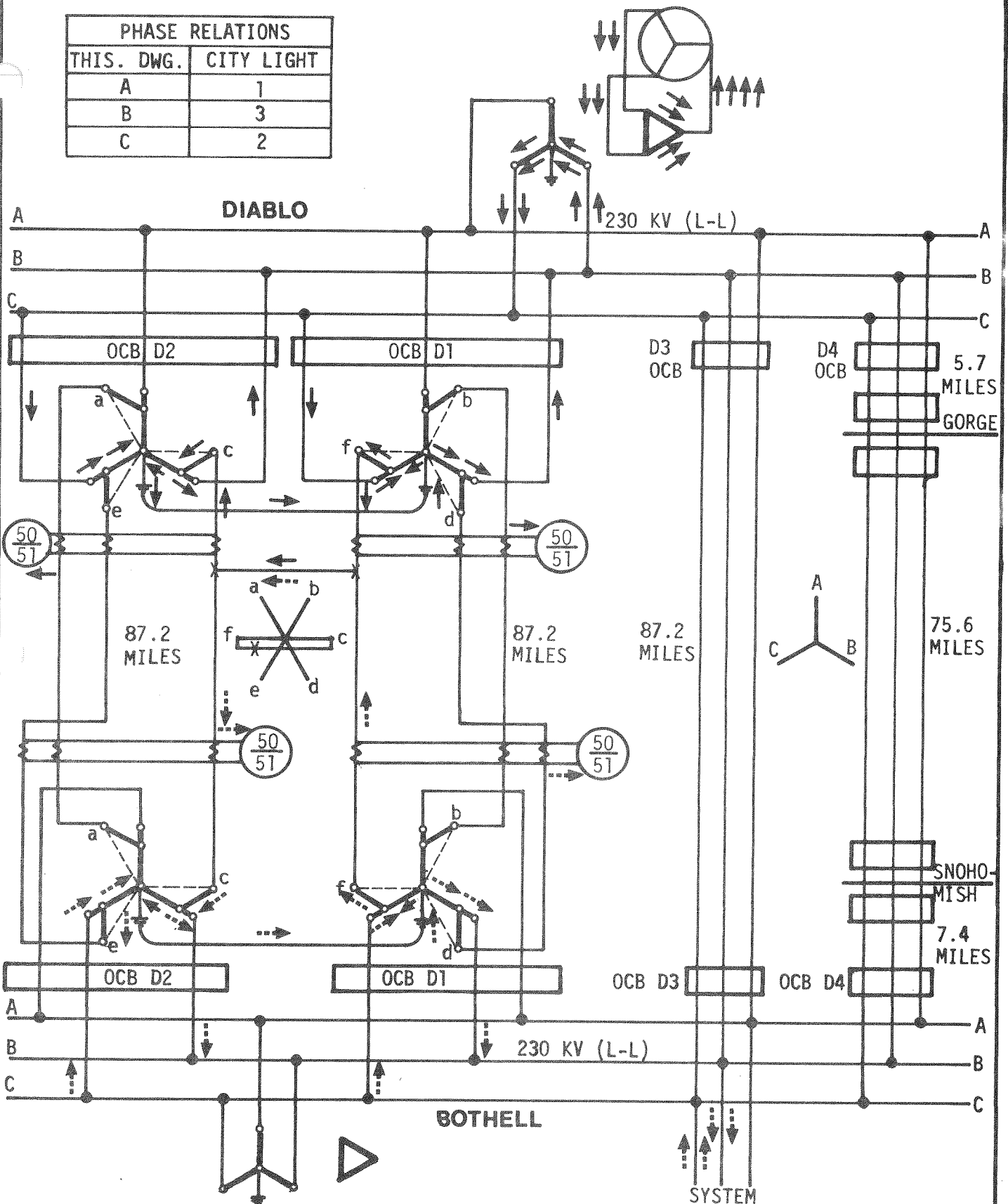
PHASE RELATIONS	
THIS. DWG.	CITY LIGHT
A	1
B	3
C	2



**ADJACENT CONDUCTOR FAULT
60° PHASE DISPLACEMENT
INVOLVING BOTH LINES**

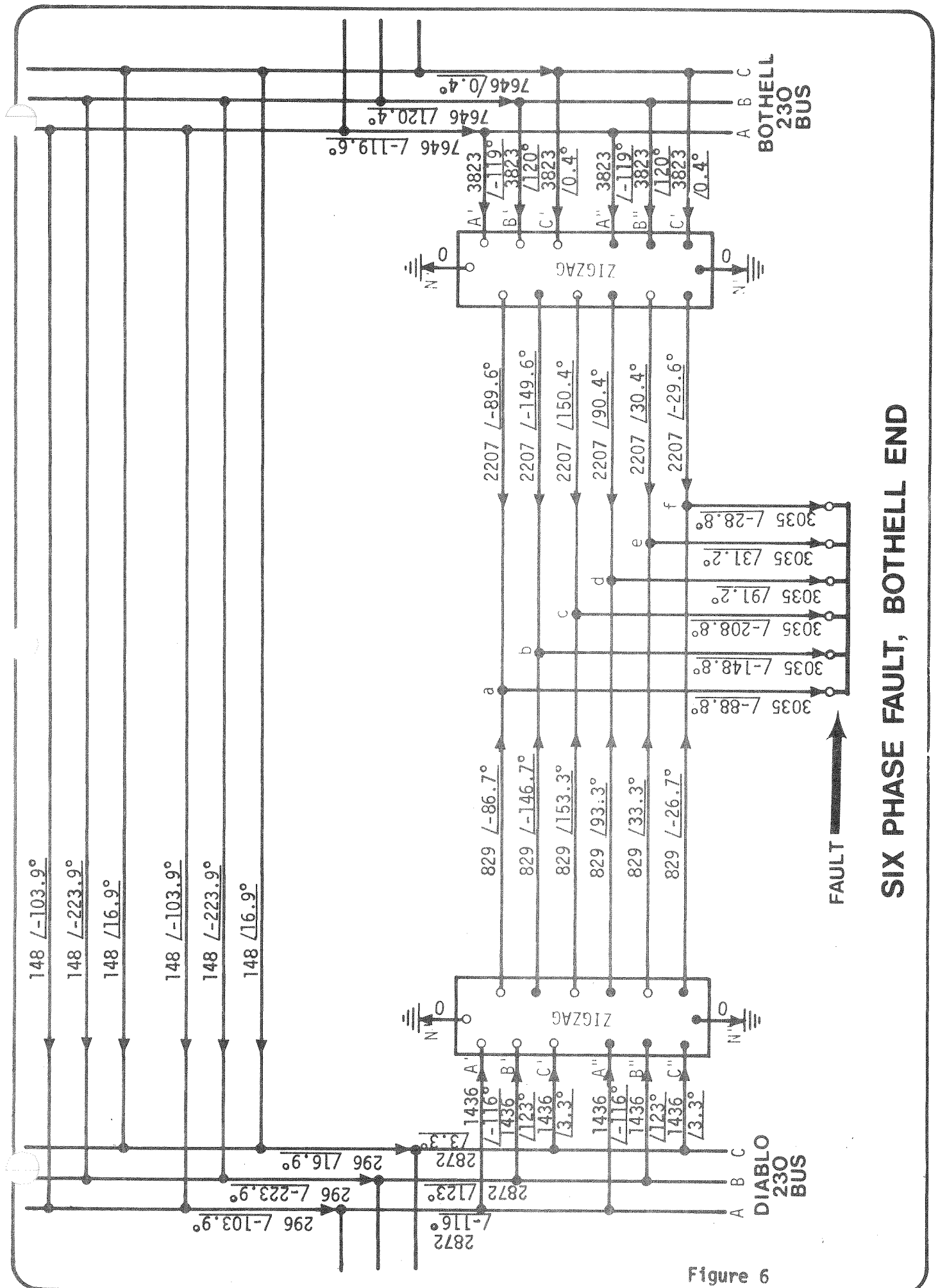
Figure 4

PHASE RELATIONS	
THIS. DWG.	CITY LIGHT
A	1
B	3
C	2



**CONDUCTOR TO CONDUCTOR FAULT
180° PHASE DISPLACEMENT
INVOLVING BOTH LINES**

Figure 5



SIX PHASE FAULT, BOTHELL END

Figure 6

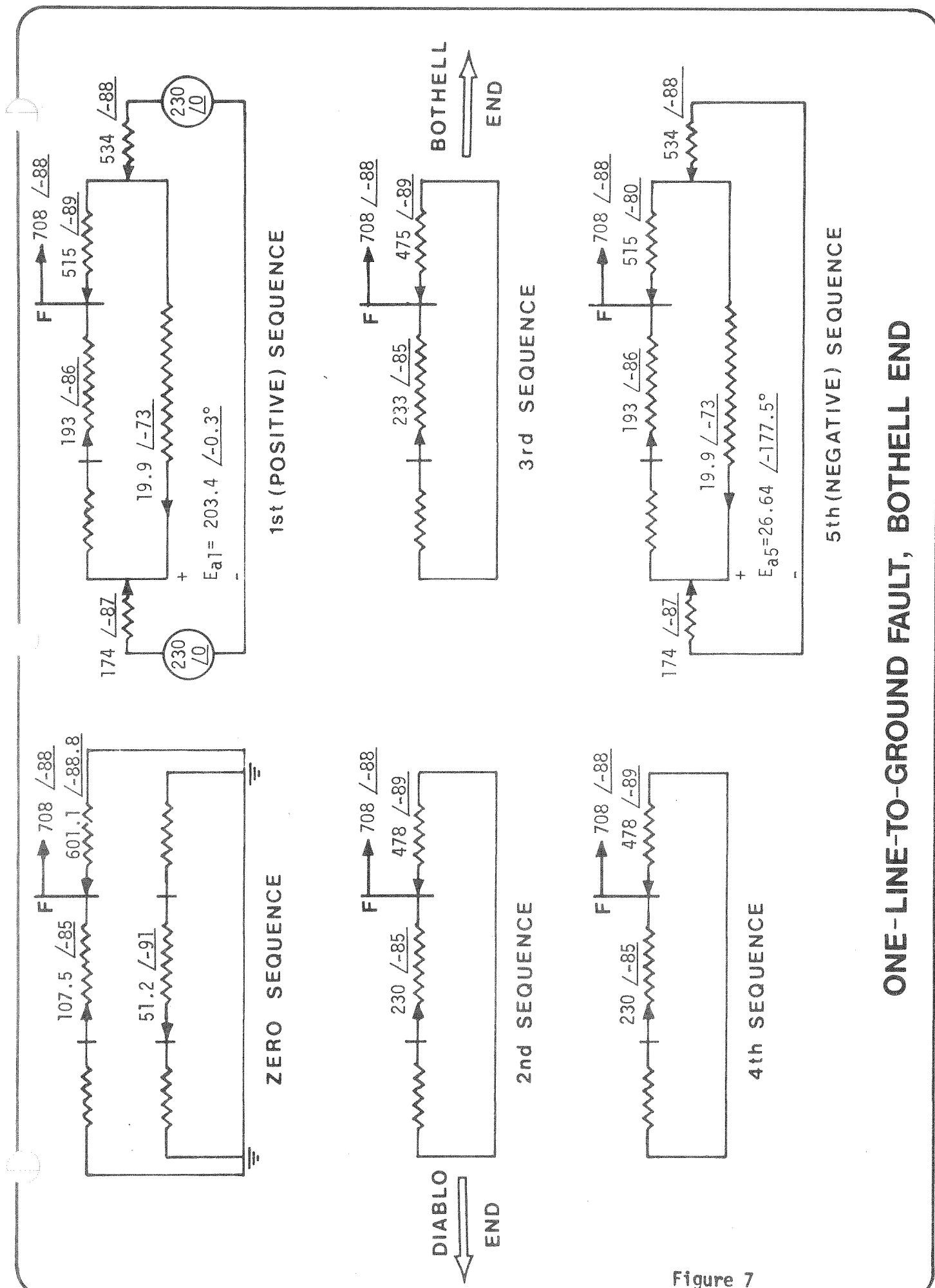
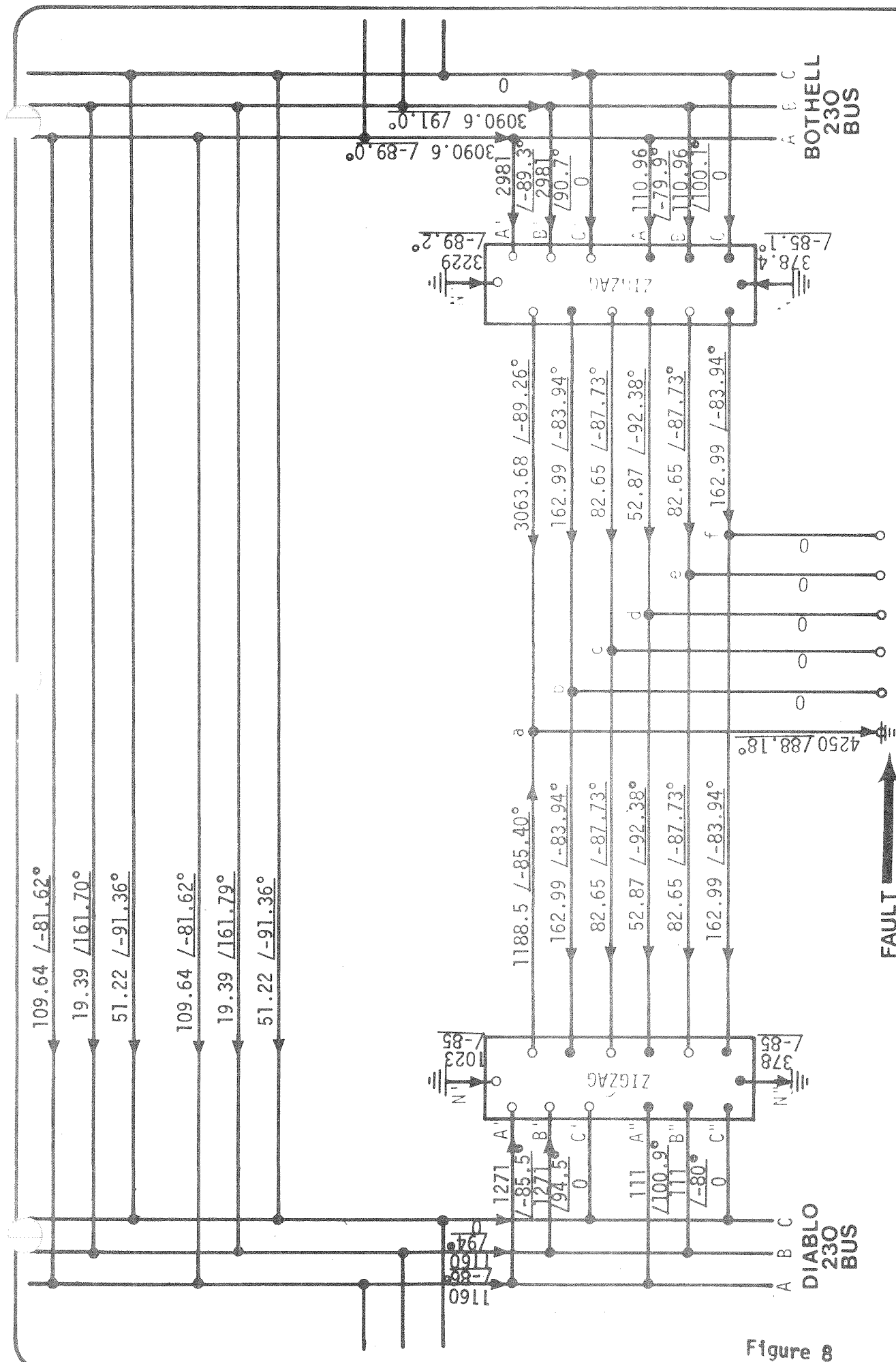


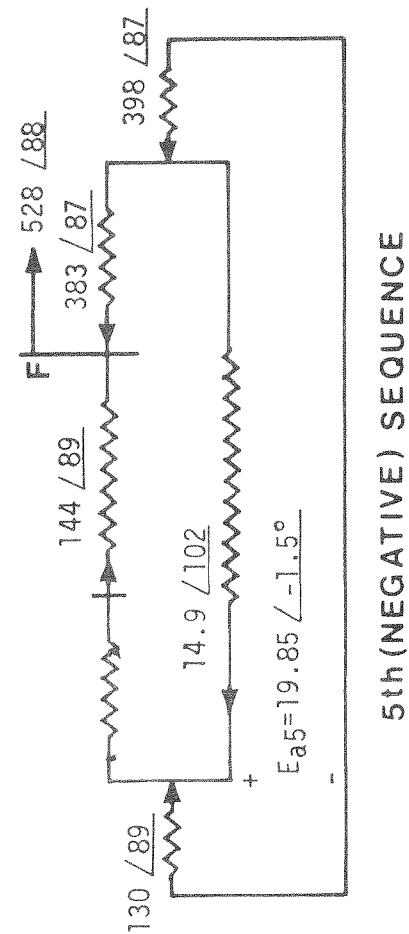
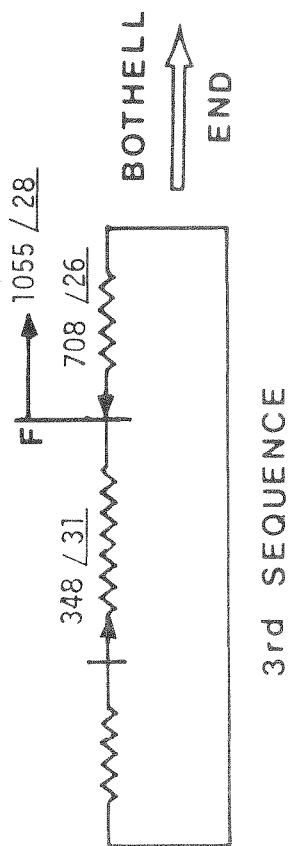
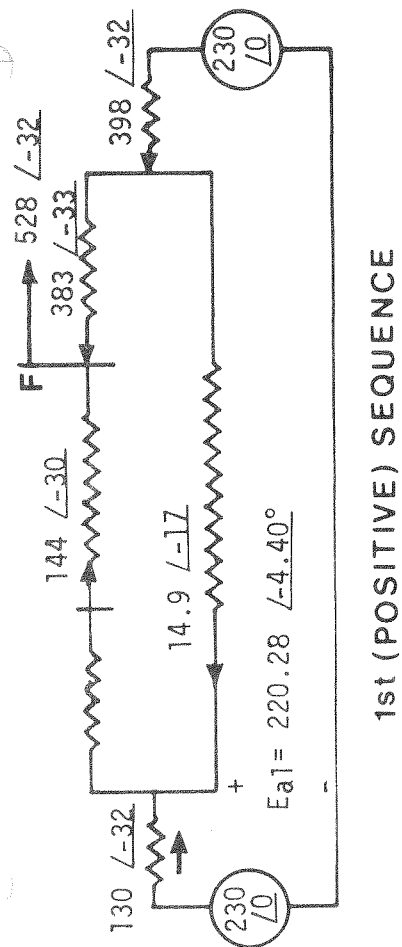
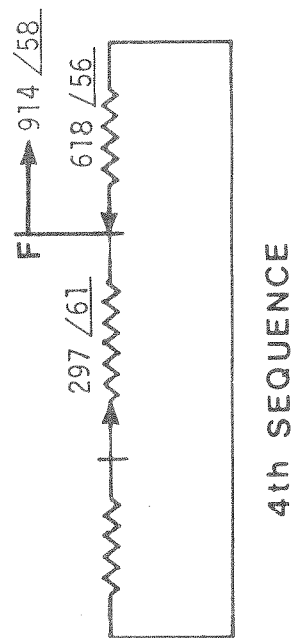
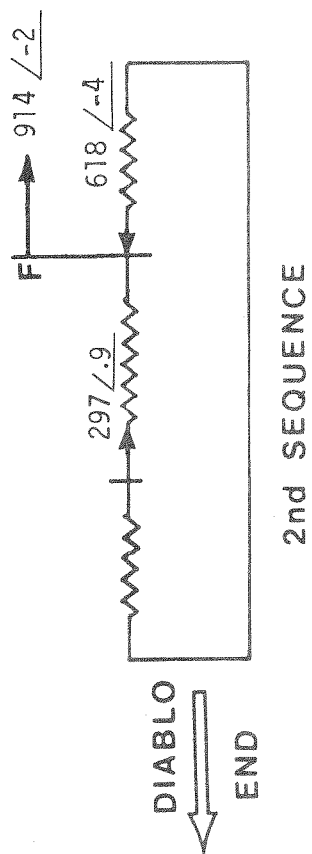
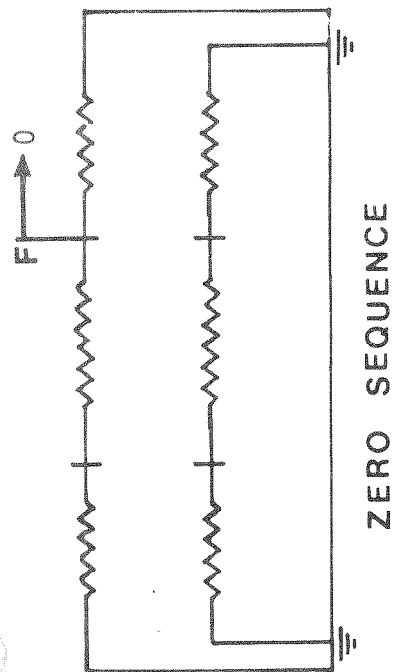
Figure 7

ONE-LINE-TO-GROUND FAULT, BOTHELL END



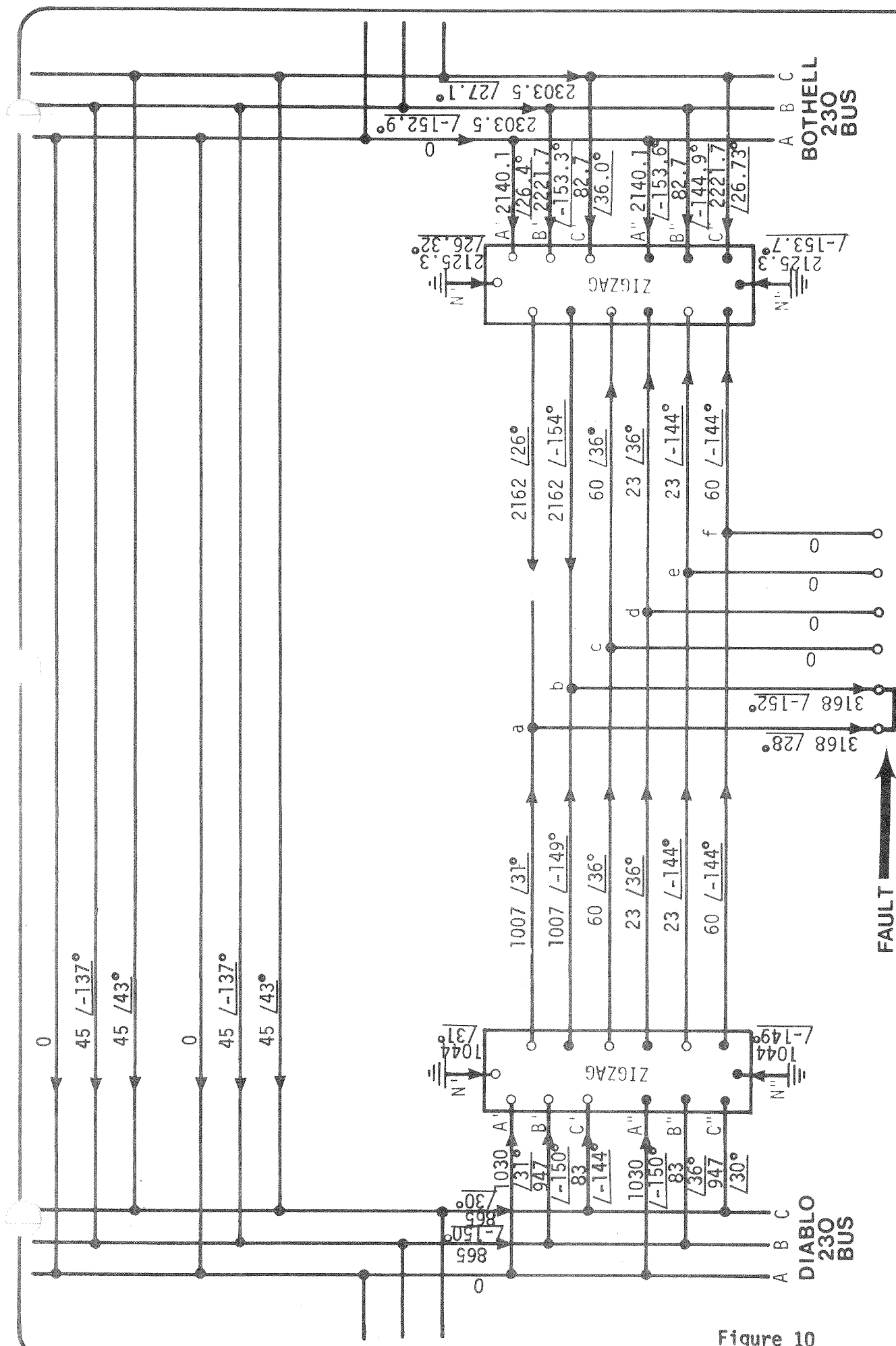
ONE-LINE-TO-GROUND FAULT, BOTHELL END

Figure 8



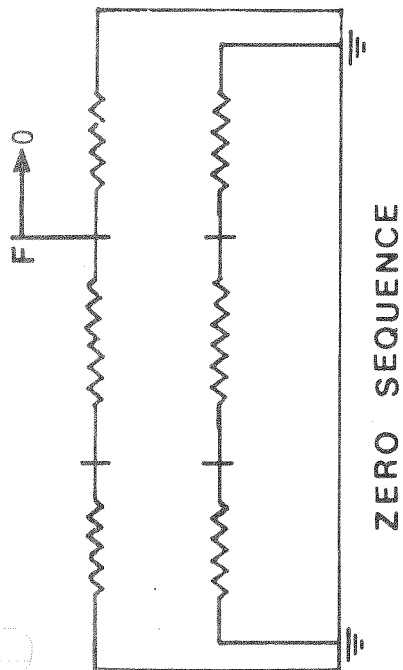
LINE-TO-LINE (ADJACENT) FAULT, BOTHELL END

Figure 9

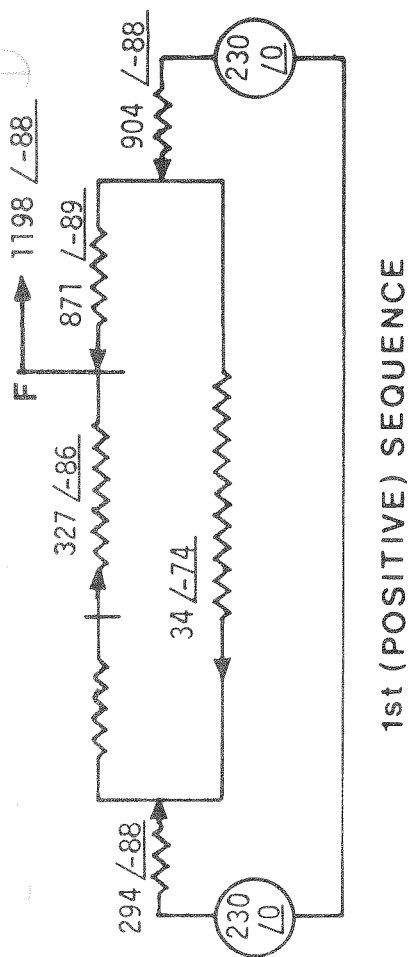


LINE TO LINE (ADJACENT) FAULT, BOTHELL END

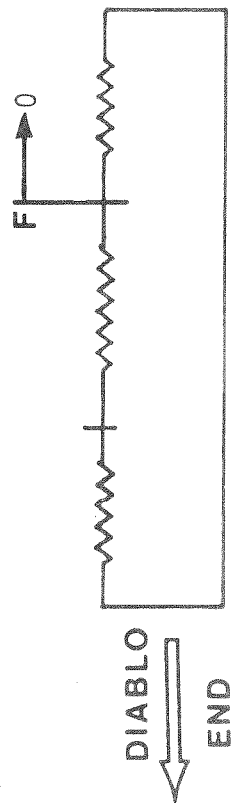
Figure 10



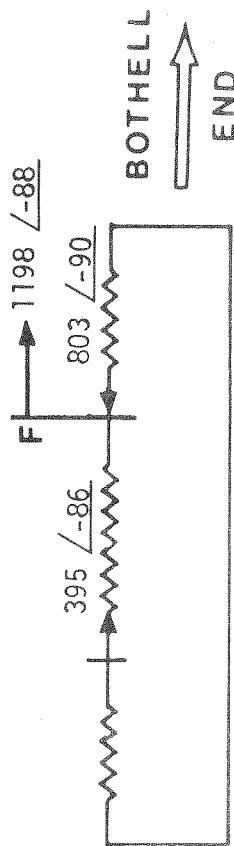
ZERO SEQUENCE



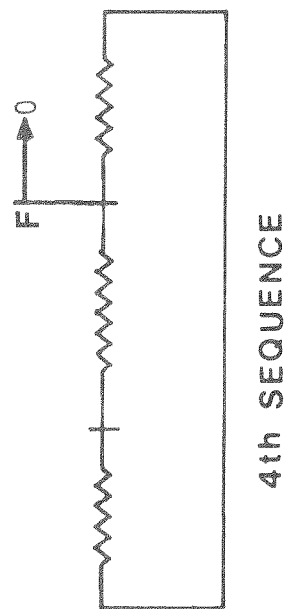
1st (POSITIVE) SEQUENCE



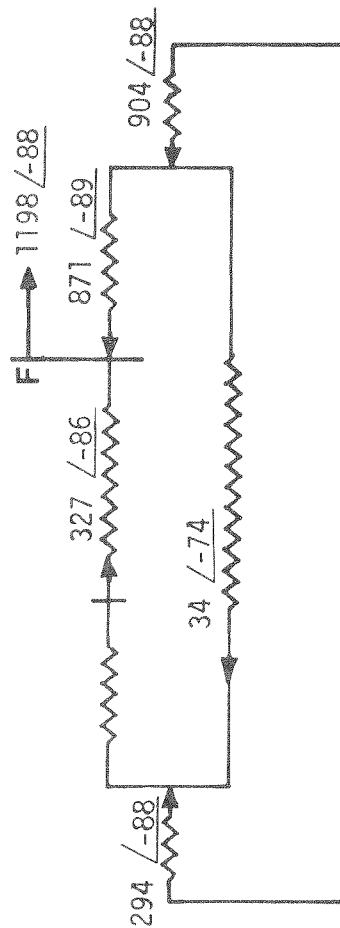
2nd SEQUENCE



3rd SEQUENCE



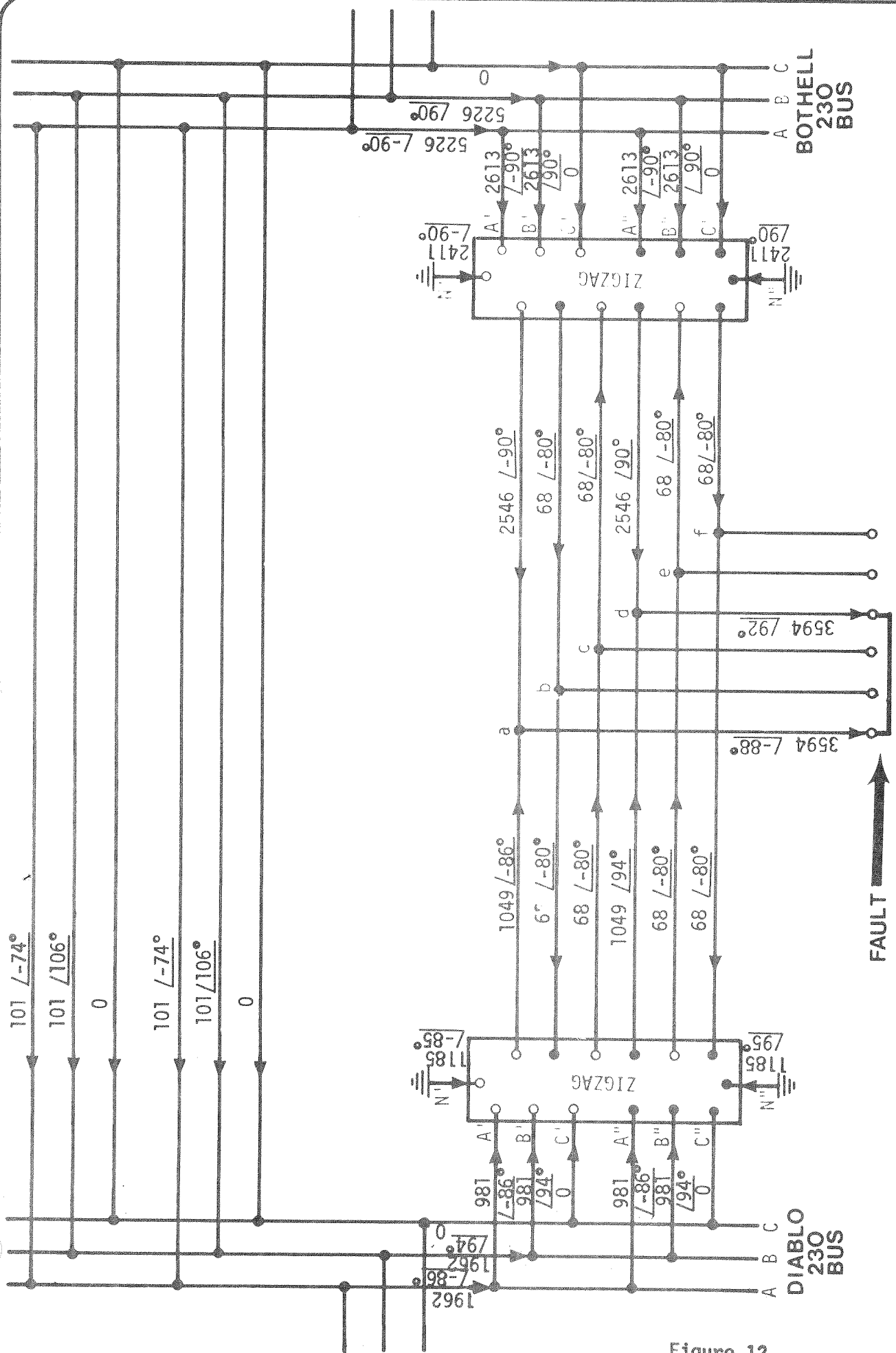
4th SEQUENCE



5th (NEGATIVE) SEQUENCE

LINE-TO-LINE (DIAMETRICAL) FAULT, BOTHELL END

Figure 11



LINE-TO-LINE (DIAMETRICAL) FAULT, BOTHELL END

Figure 12

A Synchronism Check Relay for Auxiliaries System Bus Transfer

J.C. Appiarius S.L. Smith
Electric Utility Systems Engineering Dept.
General Electric Company
Schenectady, N.Y.

J.B. Williams
Power Systems
Management
Business Dept.
General Electric Company
Philadelphia, PA.

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Western Protective Relay Conference
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Abstract

Auxiliaries systems in generating plants at times need to be transferred from one source of power to another. There are three general methods of performing this transfer, two of which result in the auxiliaries system being energized while there is significant residual flux in the auxiliaries motors. This energization with significant motor flux requires assurance that the phase angle between the motor residual voltage and the incoming source voltage is not excessive in order to limit the duty imposed on the motors when the transfer is completed. Moreover, there are various contingencies that may result in source voltages that are significantly out of phase, which creates a need to provide a check of phase angle of the incoming source with respect to the motor bus voltage.

This paper reviews bus transfer methods, identifies the need for synchronism check in these methods, presents an advanced synchronism check relay — the type SLJ12A relay to perform the function for auxiliary bus transfer — and describes studies which illustrate the performance of the auxiliaries bus and application of the relay during a typical bus transfer.

Introduction

Most "unit-connected" generating units have at least two sources of power for the auxiliaries. Figure 1 is a simplified one-line diagram of the auxiliaries system for a typical unit.

During normal operation the auxiliaries are supplied from the unit auxiliaries transformer which is connected to the main generator leads, usually by means of a tap in the isolated phase bus. During plant startup before the generator is able to accept load or during periods when the unit auxiliaries transformer is out-of-service the auxiliaries power is supplied through the station service transformer (also referred to as "startup" or "reserve" transformer). During startup, when the generator is able to accept load, the auxiliaries loads are transferred from the station service transformer to the unit auxiliaries transformer; and during plant shutdown a transfer back to the station service transformer may be necessary. Such transfers are commonly known as bus transfers or throwovers.

Most generating units and particularly nuclear units require power for the auxiliaries that must operate during and after shut down. The station service transformer supplies the auxiliaries power during these periods also.

A number of generating units do not have a unit auxiliaries transformer and use the station service transformer for the auxiliaries power during all circumstances. Nuclear units require a minimum of two off-site sources of power for the Class 1E systems (engineered safeguards) in addition to the standby a-c generator. Figure 2 illustrates a simplified one-line diagram for a nuclear unit with the conventional unit-connected scheme. The second off-site source need only have capability for starting and supplying the Class 1E and related loads. At some stations the second off-site source is capable of supplying the unit auxiliaries under normal operation, since it may be the station service transformer for another generating unit. In addition to the transfers between the station service and the unit auxiliaries transformers, it is necessary to provide for transfer of the Class 1E buses between the two off-site power sources.

A variation of the unit-connected scheme is one in which a generator circuit breaker or load-break switch is installed between the generator terminal and the bus tap to the unit auxiliaries transformer as shown in Figure 3. A number of nuclear units are being built with this arrangement. With the generator breaker open the generator step-up transformer serves as an off-site source to the unit auxiliaries transformer. The unit can be started up using the unit auxiliaries and generator step-up transformers and the generator is synchronized with the system by closing the generator breaker. Similarly the unit auxiliaries can continue to be supplied during shutdown by opening the generator breaker. Routine transfers for startup and shutdown are therefore eliminated. The generator step-up and unit auxiliaries transformers qualify as an off-site source for Class 1E power systems eliminating one of the station service transformers that served as the alternate off-site source in the system shown in Figure 2. The capability for bus transfer is still required for circumstances requiring the Class 1E loads. The Class 1E buses would be transferred to the station service transformer if the source of power through the generator step-up transformer became unavailable. There may be other non-routine conditions which would require a transfer of all auxiliaries to the station service transformer.

Bus Transfer Methods

Some methods of bus transfer result in all external sources of power being removed from the auxiliaries buses for some period of time. Electric motor driven equipment will decelerate with all external power sources removed from the buses. The rates of deceleration depend upon the inertias of the drives, and the synchronizing power flowing between motors due to the relative trapped motor fluxes. As the drives decelerate, the motor fluxes will drift with respect to the voltage angle of the auxiliaries system sources. If these relative angles become large enough at the time the incoming source breaker is closed, the resultant voltages between the source and the motors will produce inrush currents which may be significantly larger than normal full-voltage starting currents. These high currents cause high winding forces and transient torques that can damage the rotating equipment. The motor fluxes and the resulting residual voltage at the auxiliaries bus decay with time. The rate of decay depends upon the motor time constants and is affected by power transfer between dissimilar motors and by deceleration. Electrical faults can have a significant effect on the rate of decay.

The majority of auxiliaries system bus transfers are executed using one of three basic methods:

1. "Parallel" or "Closed Circuit" Transfer.
2. "Intentional Time Delay" Transfer.
3. "High-Speed" or "Fast" or "Non-Intentional Time Delay" Transfer.

Parallel Transfer is executed by closing the circuit breaker to the source to which the auxiliary system is being transferred, before opening the circuit breaker to the source from which the system is being separated. Parallel transfer, which ensures that the auxiliary system is not simultaneously separated from both sources, eliminates problems associated with the deceleration of the drives. Parallel transfer should be avoided in situations where the sources are significantly out-of-phase. Unit auxiliaries and station service transformers can be subjected to excessive duty during out-of-phase parallel transfers.

Intentional Time-Delay Transfer is executed by opening the circuit breaker to the source from which the system is being separated and allows the residual voltage in the auxiliary system to decay to a specific level before the incoming source breaker closes. The transfer is completed after a specific time delay or, more frequently, after the residual bus voltage reaches an acceptable, pre-determined value which will not result in inrush currents that are high enough to damage the rotating equipment regardless of the phase-angle difference. When the motors are re-energized many or all of them will draw currents which could be equal to or nearly equal to normal starting current since they may have decelerated well below full speed. Unless non-essential motors are stripped from the bus the total "starting" current for all of the drives may cause excessive voltage dip, preventing some or all of the drives from re-accelerating.

High speed transfer, employing fast-closing, stored-energy-mechanism circuit breakers, can minimize drive deceleration to a level that will limit motor inrush currents to acceptable values. High speed transfer can be accomplished in either of two ways. Both source breakers can be simultaneously signalled to operate, usually resulting in the auxiliary buses being disconnected from both sources for a time of less than three cycles. (Ref. 4, page B-10). There is some probability with certain circuit breakers that the sources will be paralleled for a very short time using this scheme. As an alternate method to avoid paralleling the sources, a fast auxiliary contact on the opening breaker can be employed to signal the incoming source breaker to close, resulting in disconnecting the buses from both sources for a maximum time of two to five cycles, depending upon the ratings of the breakers. (Ref. 4, page B-10) This method provides positive indication that the opening breaker has started to open before the closing breaker is signalled to close. Any auxiliary relays which are interposed between the opening breaker auxiliary contact and the closing coil of the incoming source breaker will increase the time that both sources are disconnected from the bus.

A number of generating stations, where more than one transmission voltage is available, are arranged with the station service transformer connected to a different transmission voltage than the generator step-up transformer. In these situations, a significant phase angle can exist between the voltages of the two sources. Care must be exercised to evaluate the effect of this initial phase angle difference when considering the high speed transfer method. The intentional time delay transfer must provide sufficient time for motor fluxes to decay, so that the motor inrush currents are reduced to acceptable levels. Transfer times, falling between the times associated with high speed and intentional time delay transfers, will greatly increase the risk of damage to equipment.

To limit the exposure of motors and driven equipment to excessive inrush currents and transient torques, it is recommended that the resultant voltage between the motor residual volts per hertz and the incoming source volts per hertz not exceed 1.33 per unit volts-per-hertz of the motor rated voltage and frequency bases (Ref. 1, paragraph 15, page 14).

Need for a High Speed Synchronizing Check Relay

There is a need for a high speed synchronism check relay for high speed automatic bus transfers. Such a relay is also desirable for parallel transfer operations.

The rate at which rotating equipment decelerates when electric power to the motors is interrupted is basically a function of the inertias of the rotating parts. Large generating station boiler fans and reactor coolant pumps with large flywheels generally decelerate very slowly and the phase angle of the motor residual voltage does not change very much with respect to the system voltage during a high-speed transfer. On the other hand low inertia drives such as circulating water pumps decelerate quite rapidly and the change in phase angle of the motor residual voltage with respect to the system voltage can be relatively large during a high-speed transfer. The degree to which individual motors are loaded also affects the rate of deceleration. It is quite common practice to group motor drives of different applications and ratings on a single bus. In these situations the high inertia drives will decelerate faster and the low-inertia drives will decelerate slower than if they were isolated from each other. Examples of an isolated fan drive, an isolated circulating water pump and a bus with dissimilar loads are presented later. At a particular time the combination of motors connected to a bus can be different from the combination required for a different operating condition. The degree to which the individual motors are loaded can vary also. Under varying load circumstances the changes in bus residual voltage during bus transfer operations can vary between the extremes for the individual drives operating alone on the bus.

Where it is desired to apply a fast transfer scheme it is necessary to determine the worst conditions of resultant voltage between the motor residual flux (or voltage) and the incoming source at the time the transfer is completed. Any initial phase angle difference between the sources must be taken into account.

Where the high-voltage windings of the generator step-up transformer and the station service transformers are connected to the same high-voltage bus the assumption that the sources are in phase is usually a reasonable one. The step-up transformers of many large contemporary generating units are connected to 500 kV and 765 kV systems. The costs associated with connecting the station service transformers to these EHV systems is considerably higher than the cost of connecting them to lower voltage transmission systems. If lower voltage transmission is available at the plant site or even nearby, the startup or reserve transformers are often connected to the lower voltage systems. In these situations assumption that the sources are in phase is no longer a valid one since the possible maximum phase angle differences between the systems can be significant. For instance when a transmission-tie autotransformer at the generating station is out of service, the phase angle difference between the voltage levels can be significant if the systems are tied together remotely or not at all. A number of situations exist where the phase angle difference can be 20 to 30 degrees prior to the transfer operation. Angles of this magnitude can provide quite a head start for the motors which will begin decelerating and drifting away from the source after a high speed transfer is initiated. The authors are aware of a contingency situation at a large generating station where the initial phase angle prior to transfer is close to 70 degrees.

The initial phase angle is a very important factor in determining where the motor fluxes will be relative to the power source after a given time during a transfer. For such situations it is more important than ever to determine the expected resultant volts/hertz between the incoming power source and the motor residual volts/hertz to determine whether excessive duty will be imposed on the motors or the driven equipments. Where contingencies or operating conditions can cause

changes in the phase angle between the source voltages and these changes can result in excessive duty on motor drives as the result of a bus transfer operation, there is a need to continuously monitor the source voltages and block high speed transfers when an acceptable initial angle is exceeded.

Another example of the need for monitoring the phase angle between sources involves a generating unit where the auxiliaries are not automatically transferred to the station service transformer when a load rejection occurs (the generator high side breaker trips). Such a situation exists where particular units are to be used to reenergize the transmission system after a major system disturbance. Under these circumstances the transmission system is unavailable to supply power to the auxiliaries through the station startup transformer. The auxiliaries must continue to be supplied from the generator through the unit auxiliaries transformers. These units must be capable of operating with only their auxiliaries for load. Many automatic transfers are initiated by mechanical problems such as boiler or turbine trips. When a unit experiences a load rejection the turbine-generator accelerates rather rapidly until control action corrects the speed. The motors which remain connected to the unit source follow the speed of the generator. If a load rejection occurs that is not the result of, or accompanied by, a loss of the transmission system, the source through the station service transformer might still be available. If a mechanical problem develops subsequent to the load rejection and an automatic transfer is initiated, the auxiliaries would probably be at some random phase angle and frequency with respect to the station service source. The transfer could occur at any time and the motor drives could be subjected to severe transient torques as a result. If the phase angle between the auxiliaries bus and the station service source exceeds a predetermined value, the automatic transfer could be blocked by action of a synchronism check relay which is capable of monitoring the phase angle continuously. The expected acceleration rates of the turbine-generator and auxiliary motors should be considered when determining the limiting phase angle at which the relay should initiate blocking action.

At a number of generating stations, bus transfers are initiated when certain electrical faults occur. It is not uncommon for the operation of a unit auxiliaries transformer differential relay to initiate a bus transfer. When a short circuit occurs the motors contribute fault current. The amount of fault current contributed by the motors depends upon the impedance between the fault and the motors. If the fault is located between the auxiliaries transformers and the auxiliaries bus there is little impedance between the motors and the fault. The motor contributions will be significant and will decay within a few cycles. Typical large squirrel cage induction motors for power station applications have short-circuit time constants ranging between 1.5 and 6 cycles with most falling between 2.5 and 4 cycles. Synchronous motors with excitation maintained during the fault will have longer short circuit time constants than induction motors. Any significant impedance between the motors and the point of fault will reduce the motor fault currents and lengthen the time constants. The decay in motor fault current is caused by the decay of the motor fluxes. Since the rate of decay of the fluxes is dependent on the total circuit time constants to the point of fault the level of fluxes in the motors at a given time will vary depending upon the location of the fault. If the resulting residual bus voltage is depressed to a value below the value acceptable

for an intentional time delay transfer then the transfer can be completed without concern for excessive duty on the motors and driven equipment. If, however, there is significant, although possibly depressed, residual voltage on the bus when the transfer is initiated the phase angle between the bus and the incoming source is of concern just as in the case of a transfer from a healthy electrical system. In these situations it is desirable for a synchronism check relay to maintain pickup angle accuracy for depressed bus voltages.

If it is still desirable or necessary to transfer the auxiliaries after automatic high-speed transfer has been blocked, the bus transfer logic could revert to a time delay transfer.

Operation of the Synchronism Check Relay

A synchronism check relay for use in the fast transfer of motor circuits must be capable of being continuously energized, must exhibit an extremely fast dropout, and measure phase angle accurately even with one input depressed from nominal. It is for this application along with one other that the SLJ12A relay was developed. The other application is synchronism check in a high-speed reclosing scheme on transmission lines.

The SLJ12A relay provides the synchronism check function by directly comparing the coincidence between the bus voltage and the line voltage. The three basic functions of the relay are diagrammed in Figure 4. These are: the bus and line undervoltage units, the comparison of the angle between the bus and line voltage, and the intentional time delay accomplished by TL2. This latter function requires that a number of successive cycles be in phase.

The undervoltage functions are provided by electro-mechanical units, device 27B for bus, and device 27L for line detection. These units pick up at slightly over 50 percent of rated voltage and drop out at slightly under 50 percent rated voltage. Detection of undervoltage by either unit will prevent further operation of the relay by applying a positive d.c. signal to the NOT input of AND 3 as shown in Figure 4.

The comparison of the angle between the bus voltage and line voltage is made by T1, T2, AND 1, AND 2, and TL1, as illustrated in Figure 4. The two voltages are coupled through separate transformers, T1 and T2, where the positive half cycle of voltage provides a signal to AND 1 while the negative half cycle of voltage provides a signal to AND 2. When both the bus voltage and line voltage are positive and feeding a signal to AND 1, a signal is transmitted to timer TL1. If this coincidence of bus and line voltage lasts longer than the setting of the pickup time A, then timer TL1 provides an output. In a like manner, the negative coincidence of these voltages provides an output through AND 2 to TL1.

The input to TL1 timer is shown in Figure 5. The top two traces are the bus and line voltages. The third trace is the output of AND 1 that occurs whenever both the bus and line voltage are positive by at least a small amount. The fourth trace is similarly positive when these two voltages are negative by a small amount. The fifth trace in Figure 5 is the input to timer TL1, which is positive whenever either AND 1 or AND 2 provides a signal. If the signal persists for longer than A, the pickup time of TL1, then a signal is provided to the middle input of AND 3, indicating a bus and line angular difference less than the setpoint of the relay. This signal indicates that on an instantaneous basis, the angular difference between the two voltages is less than the synchronism check angle setting. This signal will persist for 9 milliseconds after the input to TL1 disappears.

Again referring to Figure 4, there are two other inputs to AND 3 in addition to the signal from TL1. One is the output of contact converter CC1 controlled by a supervising contact if desired, and the other is the output of the undervoltage units 27L and 27B through the NOT input. For the auxiliary bus transfer application, no supervising contact would be connected to contact converter CC1. Instead a d.c. signal would be applied continuously to CC1, thus allowing continuous operation of the synchronism check relay. The bus and line undervoltage detectors will be picked up if their voltage is above about 50 percent.

Thus, with CC1 continuously supplied with d.c., at least 50 percent voltage on both the bus and line and the synchronism check angle setting satisfied, the necessary inputs will be present at AND 3 and a signal will be applied to TL2. When this signal persists at TL2 for its setting of B milliseconds, an input is provided to AND 4.

Timer TL2 provides an intentional time delay in the pickup of the relay. This time delay depends on the setting of TL2, which can be set between 10 and 160 milliseconds. This intentional time delay performs two functions. First it requires that a number of half cycles confirm that instantaneous synchronism check angle setting has been satisfied. Second, it limits the maximum frequency difference between the two voltages which will still allow the SLJ12A relay to pick up. The frequency difference will be discussed further in Relay Performance.

TL3 is a timer used to inhibit relay operation for 100 milliseconds after d.c. energizing to prevent false operations during turn on transients.

With the output of both TL2 and TL3 to AND 4, the output relay is energized to close the synchronism check contacts. These contacts will remain closed until any of the relay conditions fail to be satisfied.

Relay Performance

The SLJ12A synchronism check relay provides several desirable performance features. First, it has a fast dropout time. If after pickup, the angular displacement between the bus and line voltage exceeds the relay set point, the output contact will open in 25 milliseconds. This dropout time provides verification that the systems were still within the angular setting of the SLJ12A relay until one and one-half cycles before the incoming source breaker is energized. A second contact is provided to prevent transfer initiation in a similar time if desired. With the previously postulated conditions and the proper relay settings, this dropout limitation should limit transfer to acceptable angular conditions. The second desirable performance feature of the SLJ12A is that it can be continuously energized. With the resulting continuous synchronism check, no time delay is introduced prior to initiation of the transfer.

A third desirable characteristic is the consistency of the relay synchronism check pickup angle with variations in voltage. Figure 6 demonstrates the SLJ12A variations in pickup angle as a function of voltage. Note that, the relay changes its characteristic by only 3 degrees down to 50 percent voltage at which the bus undervoltage relay will inhibit the synchronism check function. On the same plot, this SLJ characteristic is compared with that of a conventional synchronism check relays. The conventional relay compares the voltage difference versus the bus or line voltage. The improvement is apparent, and the SLJ12A relay will give an accurate angular verification even if

the motor bus voltage is reduced. If the voltage is below 50 percent, no relay output will result. A separate voltage cutoff of source voltage may be desirable in order to prevent fast or simultaneous transfer if the alternate source is less than that voltage which would provide satisfactory operation of the loads.

Finally, there is a possibility of the two voltages (bus and source or the two source voltages) having a different frequency. With each voltage having a different frequency, there will be some times that these voltages are in phase, and other times when the two voltages will be 180 degrees out-of-phase. If the synchronism check relay provides an output when the two voltages are within its angular setting, before the breaker can close its contacts these two voltages may have swung considerably apart, and there is a possibility of damage to equipment. To prevent the above possibility, the pickup should be time delayed. If accomplished properly, this time delay will limit the frequency difference between the two voltages to a reasonable amount before the synchronism check output relay will pick up. It is for this purpose that the TL2 time delay of B milliseconds was introduced into the SLJ12A relay. For instance this time delay should be long enough to prevent the relay from providing an output if the auxiliaries bus has been separated from a source long enough to slip a complete cycle.

The slip angular cutoff of the relay is inversely proportional to the pickup time of the relay and directly proportional to the angular setting. Equation 1 defines the relationship.

$$S = A/180 * (P.U.) \quad \text{(Equation 1)}$$

where: S is the cutoff slip in hertz

A is the angle at which the relay is set

P.U. is the pickup time of the relay in seconds

A pickup of the relay with large slip between the bus and line voltage could create a large angular difference between these two systems at the time when the closing breaker closes even if the systems were in phase at the instant the closing breaker was given the close signal. This is because of the time delay between the instant at which a breaker receives a close signal, and the instant at which the breaker closes its contacts.

For example: If the relay is set at 20 degrees maximum angle of pickup, the pickup time is set at 170 milliseconds by means of the TL2 timer, shown in Figure 4, and the closing breaker takes 5 cycles to close, the worst angle of disparity allowed by the synchronism check relay can be determined. The maximum slip for this condition, using Equation 1 and the above constants is .65 Hertz or 235 degrees per second. If the breaker takes 5 cycles or 83 milliseconds to complete its close cycle, then the motor voltage can slip 19.6 degrees in the time that the breaker takes to close. This 19.6 degrees added to the relay setting of 20 degrees gives a 39.6 degree separation between bus and source voltage as the maximum angle that can result with the assumed conditions.

For the auxiliary bus transfer application, TL2 should normally be set at maximum, thus limiting slip to values compatible with the previous example.

These performance characteristics are illustrated in Figure 7, and are compared with the requirements of the bus transfer application as follows in application examples.

Application Examples

Three application examples are discussed:

1. A typical auxiliaries bus with several dissimilar motor loads.
2. A typical low inertia circulating water pump drive operating alone on a bus.
3. A typical high-inertia induced draft fan operating alone on a bus.

These examples illustrate various conditions of drive deceleration and residual voltage during a high speed transfer typical of those which should be considered when applying an SLJ12A relay. A typical circulating water pump drive, in isolated operation, will have a rapid deceleration rate compared to that for a system with pumps, fans, pulverizers, etc. all connected to the same bus. Conversely a typical boiler fan in isolated operation will have a relatively slow deceleration rate compared to a system with drives for several applications. In addition to illustrating the different deceleration rates for low and high inertia drives connected to separate buses the pump and fan examples indicate possible boundary conditions of deceleration rates for a typical bus where the pumps or fans could be the only connected load at some time when a transfer is initiated.

The system configuration for the examples is shown in Figure 8. All of the examples represent high speed transfers. Upon initiation of the transfer, breaker "U" is signalled to open and its auxiliary "b" switch signals breaker "S" to close. The resultant volts " V_R " across the open breaker "S" just prior to the closing of the breaker contacts, is the voltage which is indicative of the duty to which the motors will be subjected.

The following conditions and criterion apply to the examples:

1. No electrical faults exist in the system.
2. Unit and station service source voltages are 1.0 per unit, and do not change in magnitude or relative phase angle.
3. Breaker closing time of 5.4 cycles from time that auxiliary "b" switch operates. (Figure 9A illustrates the breaker sequence for the examples. A range of closing times of 3.6 to 5.4 cycles is shown.)
4. Criterion for acceptable duty for motor drives: Maximum resultant voltage between station service source and bus residual Volts/Hz of 1.33 per unit volts/Hz on motor voltage and frequency bases (Reference 1).

For each example a maximum permissible initial phase angle difference between the unit and station service sources will be determined based on the deceleration and decay rates for the particular examples.

The examples representing a typical auxiliaries bus with dissimilar connected loads is based on oscillograph data showing the phase angle drift and voltage decay on a bus after the unit source was interrupted during a test. Figures 9A and 9B are constructed from the oscillograph trace. The voltage decay on this particular bus is more rapid than for many auxiliaries buses. This indicates a sizeable amount of synchronizing power was being interchanged between very dissimilar drives. Figure 10 is a vector diagram illustrating the magnitude and phase angle relationships of per unit volts per hertz for the unit source voltage, the auxiliaries bus residual voltage just prior to the closing of the station service source breaker contacts, and the limits of maximum acceptable station service source phase angle for leading and lagging conditions. These limits were determined for maximum resultant volts per hertz between the bus and station service source of 1.33 per unit as previously specified. The indicated limit for the station service source leading the unit source voltage (or auxiliary bus voltage prior to transfer) is 58 degrees. For a lagging source voltage the limit is 116 degrees. The relay should be conservatively set for 53 degrees or less, for this example, to meet the motor criteria.

The results for a typical circulating water pump drive are illustrated in Figure 11. The maximum phase angle by which the station service source can lead the unit source (or auxiliaries bus voltage prior to transfer) and meet the resultant volts per hertz criterion for the motors is 35 degrees. The bus transfer method and system conditions were as previously stated. The results for a typical fan drive are illustrated in Figure 12. The maximum phase angle by which the station service source can lead the unit source (or auxiliaries bus voltage prior to transfer) and meet the resultant volts per hertz criterion for the motors is 84 degrees. Since the application range of the relay is 10 to 60 degrees, the relay would be set for some expected initial phase angle difference between the sources of 60 degrees or less.

For any combination of expected transfer conditions the limiting initial phase angle difference satisfying motor duty criteria should be determined. The limiting phase angle difference satisfying motor duty criteria for all expected transfer conditions should be determined and the relay be set accordingly.

Conclusion

The methods of transferring power plant auxiliaries from one source to another have been discussed. For many bus transfer conditions, it is desirable to verify that the phase angle between the motor bus voltage and the incoming source voltage is not excessive in order to minimize the exposure of equipment to severe duty. To perform this angular check, the type SLJ12A synchronism check relay is proposed. A further study was performed verifying the satisfactory performance of the SLJ12A relay for variations of auxiliary motor loads and characteristics.

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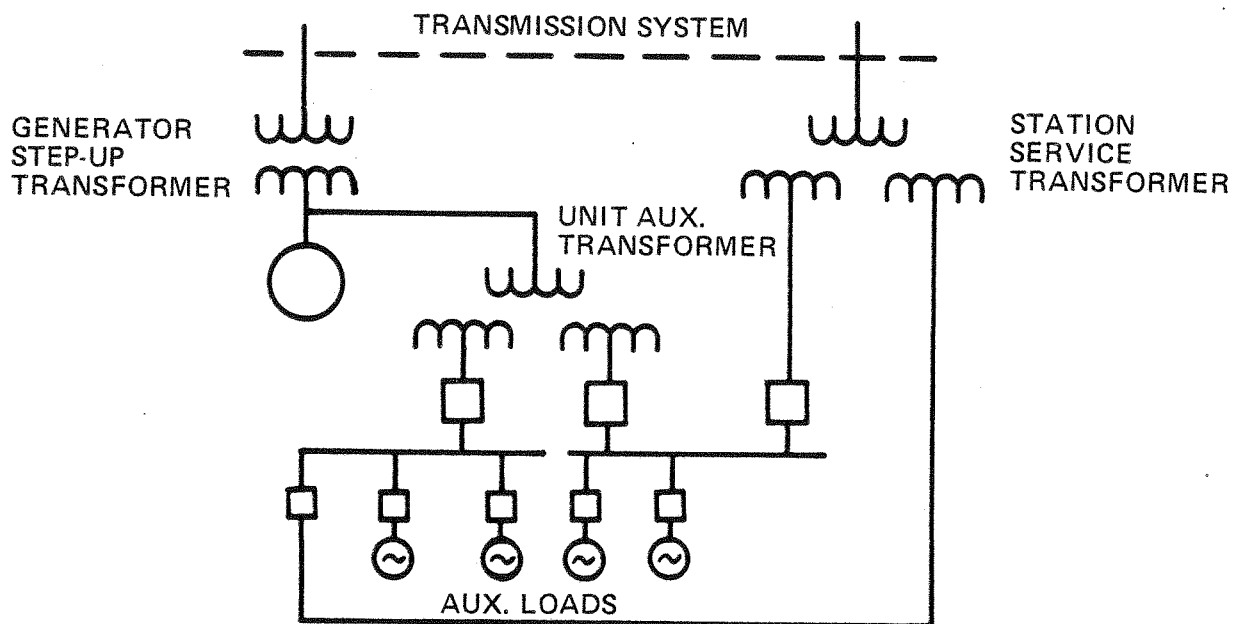


FIGURE 1
SIMPLIFIED ONE-LINE DIAGRAM OF THE AUXILIARIES
SYSTEM FOR A TYPICAL UNIT

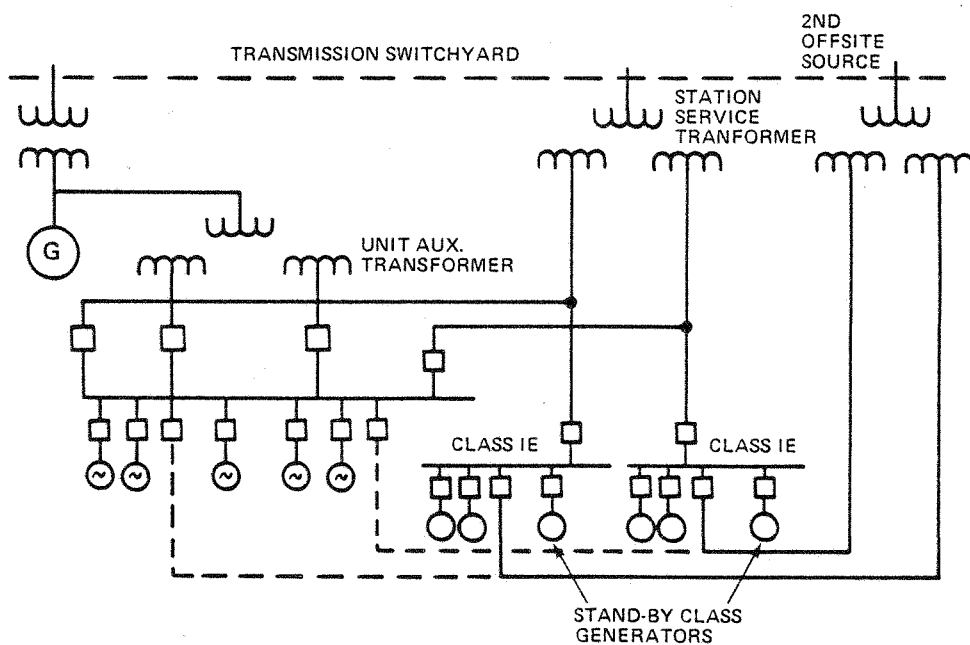


FIGURE 2
SIMPLIFIED ONE-LINE DIAGRAM FOR A NUCLEAR UNIT
WITH THE CONVENTIONAL UNIT CONNECTED SCHEME

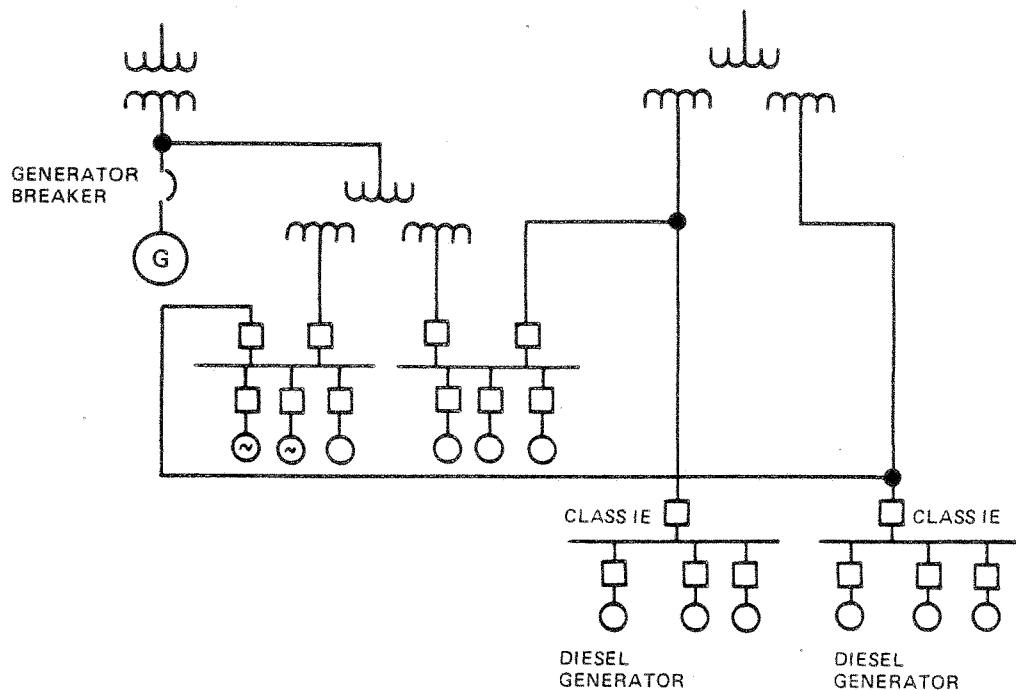


FIGURE 3
SIMPLIFIED ONE-LINE DIAGRAM FOR A NUCLEAR UNIT
WITH GENERATOR DISCONNECT DEVICE

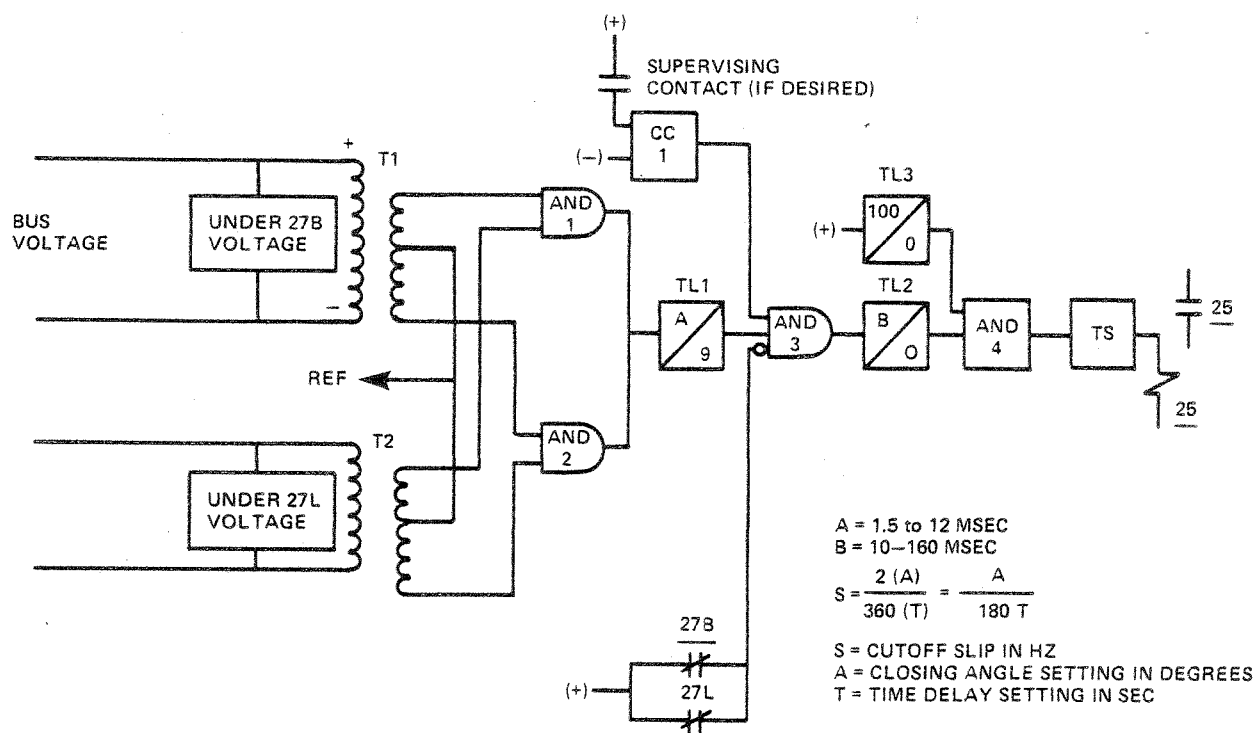


FIGURE 4
SLJ12 LOGIC DIAGRAM

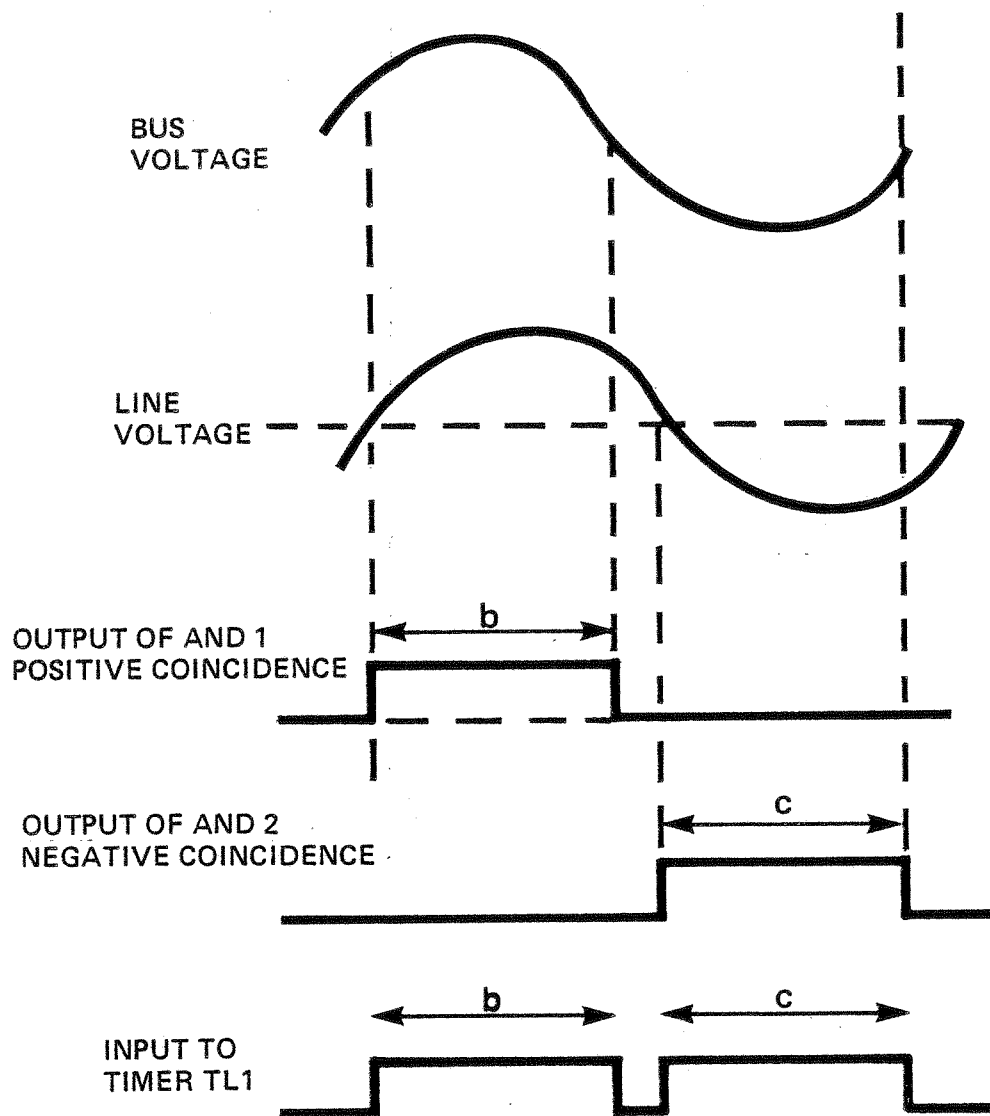


FIGURE 5
SLJ12A ϕ VOLTAGE PHASOR DIAGRAM

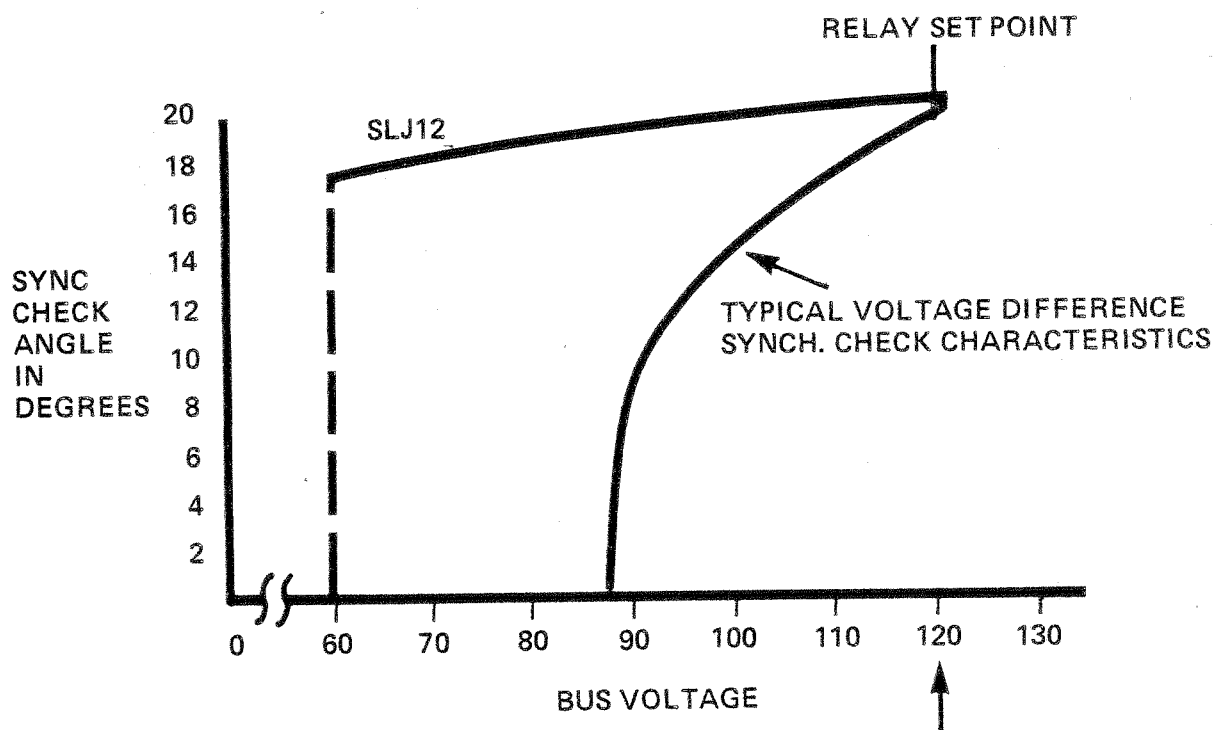


FIGURE 6
CHANGE IN RELAY CHARACTERISTICS WITH BUS VOLTAGE

FUNCTION	RATING	SYMBOL	HOW SET
Operate Continuously	Yes		Bypass Supervising Contact
Drop Out Time	25 Milliseconds	D.O.	No Setting
Pick Up Time	20–170 Milliseconds	P.U.	B Time of TL2 in Figure 4
Angle Setting	10–60 Degrees	A	A Time of TL1 in Figure 4
Slip Cutoff	$S = A/180$ (P.U.)	S	Dependent on Setting Pickup and "A"
Temperature Range	–20 to 55° C Per ANSI (Proper Operation and No Damage at 65° C)	–	–
Seismic Capability	At Least 6ZPA	–	–
Applications	Synchronism Check of 1. Fast Bus Transfer 2. High Speed Reclosing of Transmission line 3. Reclosing With Significant Voltage Difference		

FIGURE 7
SYNCHRONISM CHECK SLJ12 CHARACTERISTICS

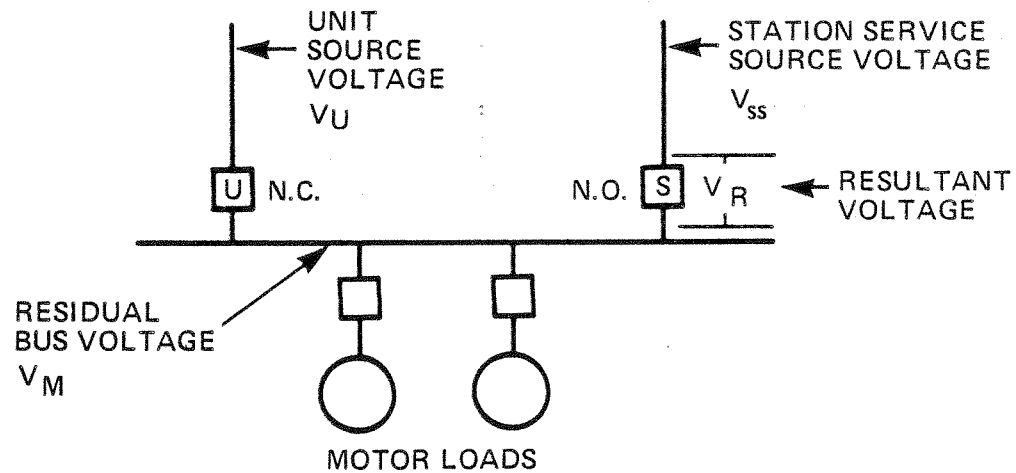


FIGURE 8
SYSTEM CONFIGURATION FOR EXAMPLES

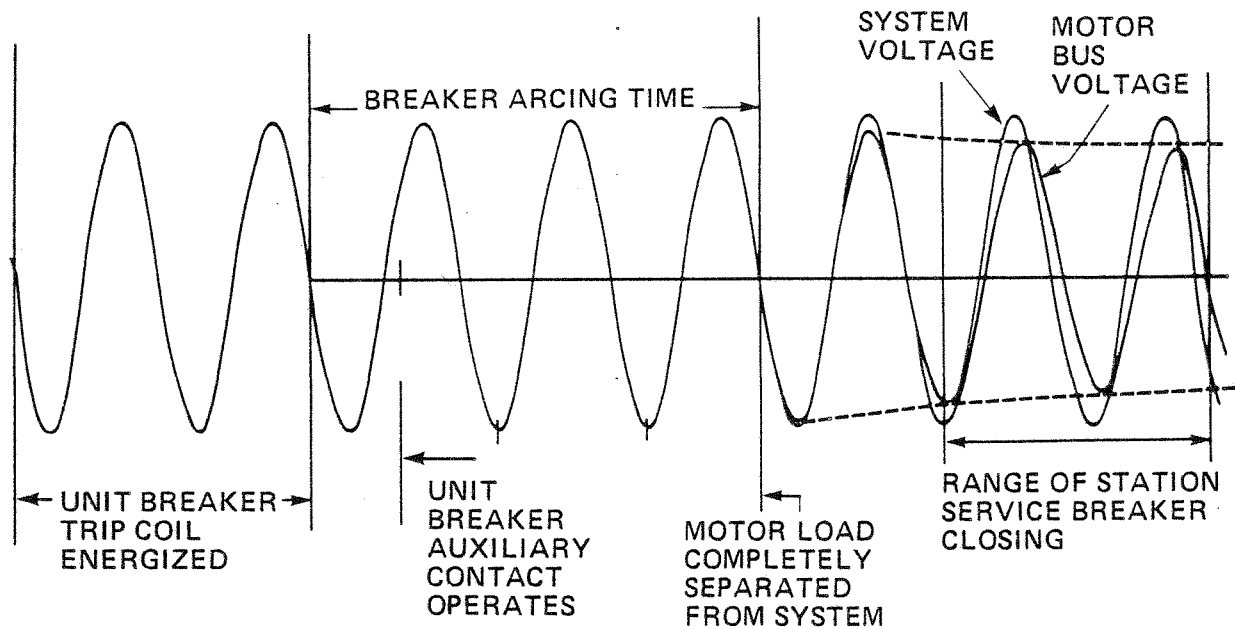


FIGURE 9A
SYSTEM VOLTAGE & AUXILIARIES BUS RESIDUAL VOLTAGE
DURING HIGH SPEED TRANSFER OF TYPICAL AUXILIARY SYSTEM

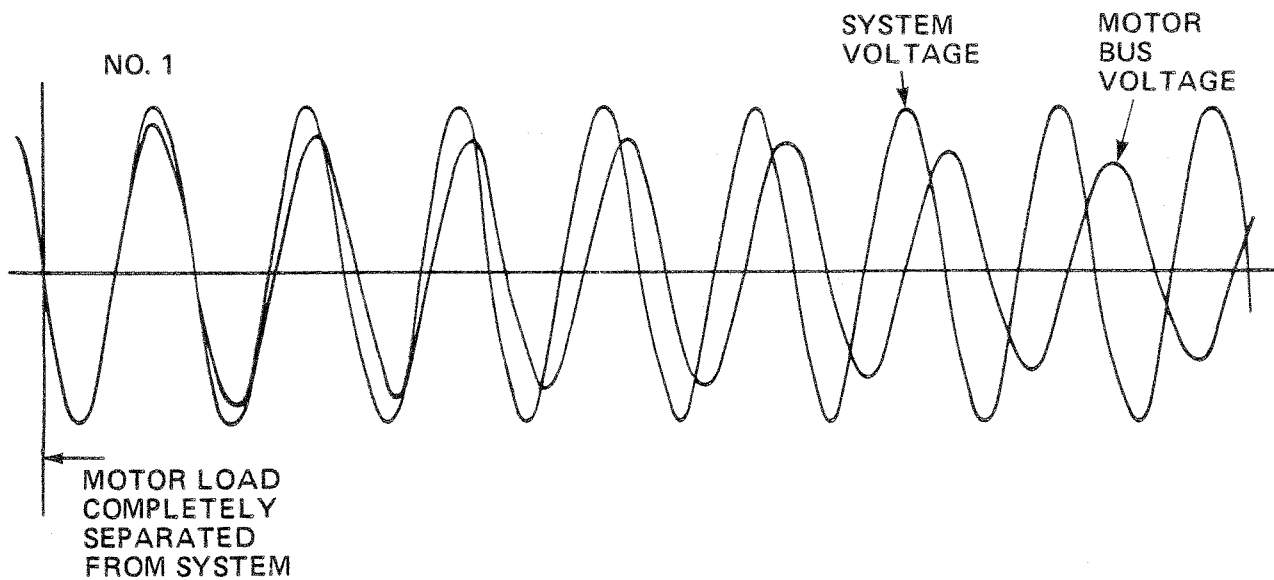


FIGURE 9B
SYSTEM VOLTAGE & AUXILIARIES BUS RESIDUAL VOLTAGE
WITHOUT COMPLETION OF TRANSFER AFTER SOURCE BREAKER OPENS.

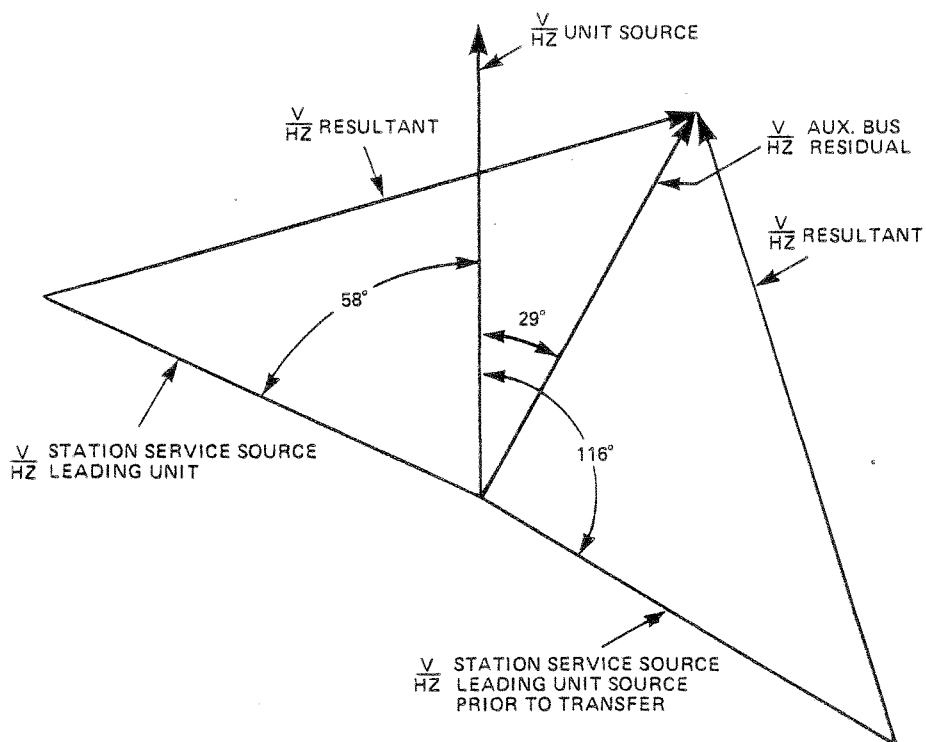


FIGURE 10
VECTOR DIAGRAM FOR RESULTS OF
TYPICAL AUXILIARIES BUS EXAMPLE

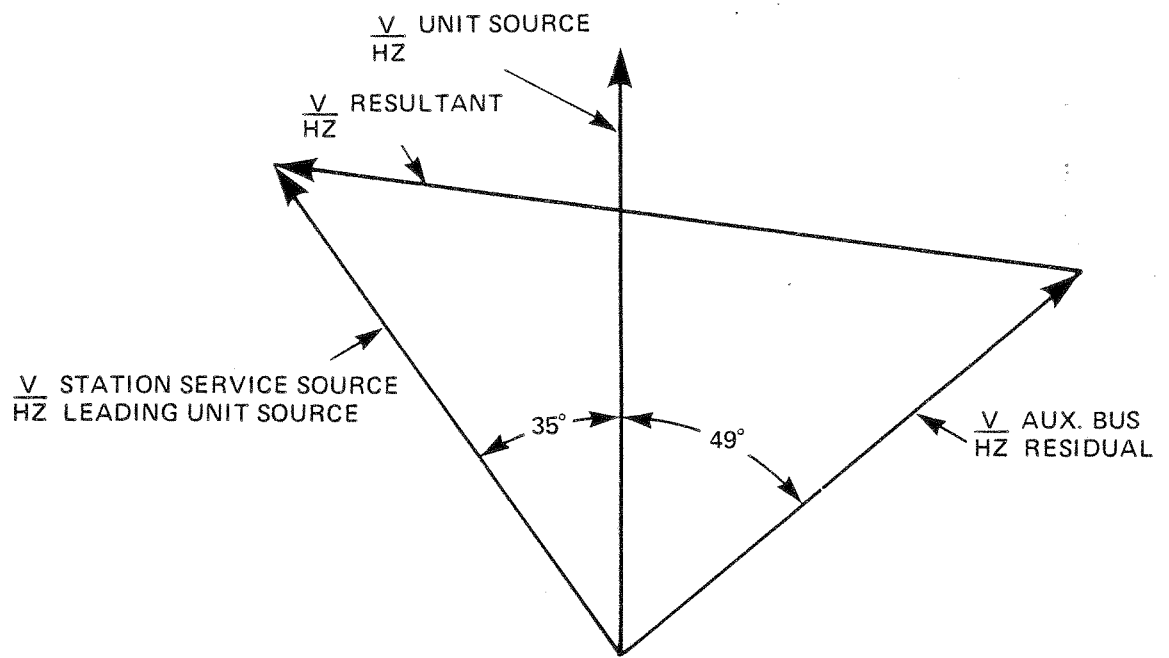


FIGURE 11
VECTOR DIAGRAM FOR RESULTS OF TYPICAL
CIRCULATING WATER PUMP EXAMPLE

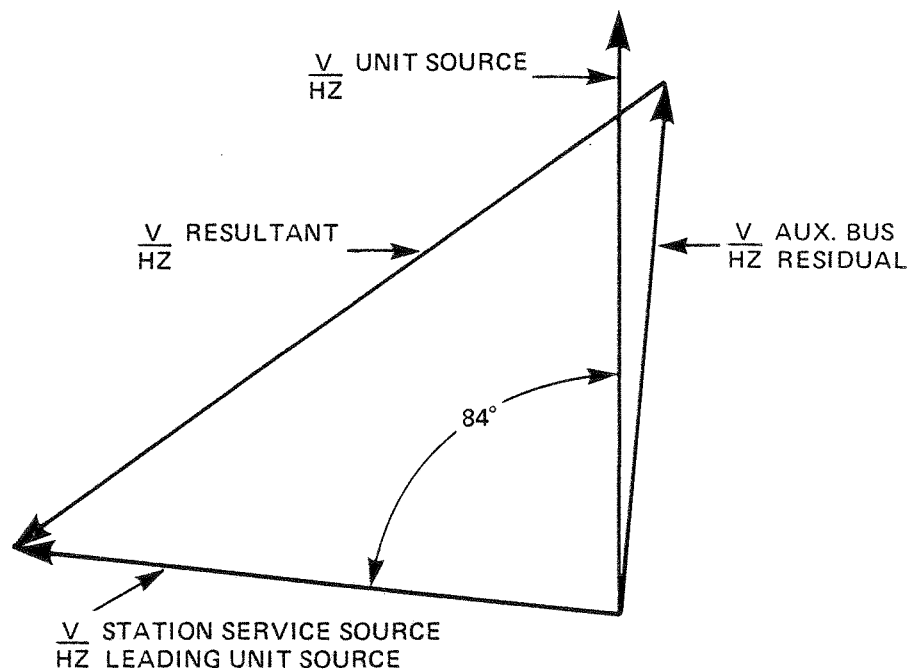


FIGURE 12
VECTOR DIAGRAM FOR RESULTS OF TYPICAL
INDUCED DRAFT FAN EXAMPLE

AN INTEGRATED APPROACH TO MOTOR PROTECTION

C. Pencinger
Brown Boveri Corporation
North Brunswick, NJ

D. Carreau
Brown Boveri Corporation
Canada

F. Von Roeschlaub
Consultant

V. Narayan
Brown Boveri Corporation
Baden, Switzerland

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AN INTEGRATED APPROACH TO MOTOR PROTECTION

INTRODUCTION

Improvements in motor design and manufacturing technology in recent years have resulted in a decrease of the size to power ratio and a corresponding reduction in overload capability. Early motors which had a high tolerance to overloads could be protected by relatively simple devices. More sophisticated techniques are now necessary.

This paper describes modern protective relay functions and their integration into a coordinated and compact package. New relaying techniques are included whereby the motor capabilities and relay operating characteristics can be closely matched.

An understanding of motor protection can be obtained by examining the following points:

1. Analysis of failure modes
2. Protection schemes
3. Integrated motor protection

ANALYSIS OF FAILURE MODES

Vulnerable Aspects of Motors

Basically motor failures are either load induced, supply induced or are internal motor failures. There are two components of motors that are particularly vulnerable. These are the insulation system and certain mechanical parts, notably the bearings. Of these the insulation system is exposed to a greater variety of potentially damaging influences. Accordingly, a large number of insulation protection schemes have been developed.

Load Induced Failures

Overloads due to excessive shaft loading cause the stator temperature to rise above its normal operating level.

The acceptable level of temperature to which motor insulation may be subjected depends upon the design of the insulation system. Copper losses in the motor represented by I^2R create overheating during an overload condition. The eventual result of prolonged overheating is insulation failure in the motor.

Locked Rotor. If the rotor is blocked from rotating, the motor will overheat if left energized longer than the allowable locked rotor time. The lack of rotation does not allow a counter emf to be developed. The result is a sustained current equal to the starting current which can be 5 to 8 times rated current. Figure 1 shows typical full voltage starting current of an induction motor.

Locked rotor current may lead to either stator or rotor damage depending on motor design. Since the locked rotor current depends upon voltage, the maximum allowable current can be either rotor or stator limited.

Long Accelerating Time. The motor starting time depends on the opposing torque. Figure 2 shows the speed vs torque relationship of a typical induction motor (Curve I). Curve II of Figure 2 shows the speed vs torque characteristic of the load. The difference between the two curves is the accelerating torque. If for any reason the load torque exceeds the motor torque, the motor will not come up to rated speed. As the accelerating torque decreases, the acceleration time increases. Long accelerating times may overheat the rotor or the stator if the thermal limit is exceeded.

Motors applied to high inertia loads require long accelerating times. Current during this period remains at a high level comparable to the locked rotor value. The result is a high rate of temperature rise.

Frequent starting without adequate intervening, running or idle time to permit heat dissipation can also cause excessive temperature rises.

Failures Caused by Abnormal Supply Condition

Phase unbalance of the supply voltage or an open phase causes substantial negative sequence current to flow. This negative sequence current (I_2) causes an abnormally high frequency voltage to be induced in the rotor. The resultant rotor current appears as excessive heat. Additionally, a high percentage of I_2 causes overheating of the stator.

Overvoltage. Voltage surges can cause insulation breakdown. Insulation which has deteriorated is particularly vulnerable and may fail at the same surge level that new insulation could withstand. Sustained overvoltages are uncommon because of the normal controls in the supply system. However, when they occur, they also can break down insulation. Overvoltage relaying is usually not provided for motors.

Reenergizing the motor after a brief power interruption before the motor back emf has subsided may result in exceptionally high inrush currents. This condition may be particularly troublesome if the supply voltage and motor back emf are out of phase. This may produce overtemperature or damage resulting from mechanical disturbance of the windings.

Internal Motor Failures

Insulation failure can result from overtemperature conditions extending over a period of time. The rate of deterioration is a function of the overtemperature and duration. A commonly applied criterion is that the life of the insulation is halved for each 10°C incremental increase. Because of its gradual influence, it would be helpful to detect the overtemperature condition in two stages. An alarm stage would allow corrective action to be taken before the trip level is reached.

Effects other than temperature that cause insulation failure include overvoltage, mechanical damage and the entry of moisture and other contaminants.

Short circuits are the direct result of insulation failure. Short circuits cause considerable damage to the motor. Such damage may burn the iron and break down the interlaminar insulation in the core, in addition to causing burning of the coil insulation. Core damage is usually more costly to repair than winding damage. The following types of faults are all recognized as capable of creating motor damage resulting from excessive heating at the point of fault:

Phase to ground

Interphase faults

Turn to turn faults

For all of these fault conditions prompt tripping of the motor is desirable in order to limit damage.

PROTECTION SCHEMES

Relay Input Quantities

Relay input quantities available for measurement include motor current, terminal voltage and frequency. Non-electrical quantities including speed of rotation, vibration and temperature are not addressed in this paper.

These quantities are often used in combination to give indication of motor conditions. Derived values of both real and reactive power, phase angle, power factor and impedance are commonly used. Simulated motor temperature rise may be obtained from the current which is directly related to the energy of the internal losses. Most of this is I^2R energy converted to heat in the motor.

The current and voltage inputs to a protective relay are usually obtained from current or potential transformers which interface with the power system. Because of saturation effects in these devices, it is desirable to use relays that impose the least burden possible.

Relaying Techniques

Overload protection. To understand how overload protection can be successfully employed for large motors, it would be helpful to first examine some physical relationships. The equation for heat transfer in a motor under steady flow conditions can be stated in the following manner:

$$Q_i = Q_a + Q_e \quad (1)$$

The heat input to the system, Q_i , must equal the heat accumulated in the system, Q_a , plus the heat removed by cooling, Q_e , during the same time interval. Q_i may be directly measured because it is proportional to the electrical losses (I^2R).

Equation (1) is valid for heat transfer in a motor for load conditions which allow cooling Q_e to be effective. However, for very high current/low speed conditions, such as during starting, the cooling effect Q_e approaches zero. Thus, for high currents Equation (1) becomes:

$$Q_i = Q_a \quad (2)$$

An effective overload protection system must be able to recognize the two conditions reflected by Equations (1) and (2). Additionally, it must remember the conditions prior to the overload, i.e. whatever motor pre-heating may have occurred. A cold motor has a greater ability to withstand an overload than a hot motor. Thus, a memory of previous overloads would be helpful.

The temperature rise in a running motor follows a different characteristic than the temperature fall when the motor stops. Hence, the thermal memory must take this into account. This effect is illustrated in Figure 9.

A practical break point in a thermal overload characteristic between the Equations (1) and (2) can be assumed to be twice full load current ($2 I_{FL}$). It can be shown that a time current characteristic can be derived from the Equations (1) and (2) taking the above assumption into account. Please refer to Appendix I for the exact derivation of the following equations.

$$t = \tau \cdot \ln \frac{M^2 - \Delta\theta_o}{M^2 - \Delta\theta} \quad \text{for } I \leq 2 I_{FL} \quad (3)$$

$$t = \tau \cdot \frac{(\Delta\theta - \Delta\theta_o)}{M^2} \quad \text{for } I \geq 2 I_{FL} \quad (4)$$

Equations (3) and (4) can be combined into a single relay time - current characteristic which depends upon:

1. Multiples of relay setting current M
2. Initial temperature rise $\Delta\theta_0$ above ambient
3. Allowable temperature rise $\Delta\theta$ above ambient
4. Motor thermal time constant τ

For given values of $\Delta\theta_0$ and $\Delta\theta$, the relationship between current squared (expressed as M^2) and time t is exponential below twice full load current, and linear above that point. Figures 10 and 11 illustrate the overload characteristic defined by Equations (3) and (4) for a τ of 10 minutes with "hot" and "cold" motor conditions. Through the use of the relay time constant " τ ", the relay characteristic could be closely matched to the actual thermal time constant of the motor. The physical meaning of τ is more clearly illustrated in Figure 3.

Two Stage Overload Protection. The continuous permissible ultimate temperature depends on the kind of insulation used and is equal to the ambient temperature, plus the machine temperature rise due to losses. When the continuous permissible value is exceeded for a short time, the insulation is negligibly affected. This situation can usually be tolerated. Detection of this condition can be used for alarm which allows time for taking corrective action such as reducing the load. On the other hand, if the overtemperature persists or reaches an excessive level, automatic tripping is necessary. It follows that a two-stage overload protection system is desirable. One stage is set to alarm while the second stage is set to trip. Such a scheme is shown in Figure 4.

Locked rotor protection is applied for protecting large motors during start up and acceleration. Figure 1 shows the starting current in a large induction motor for an across the line full voltage start. The motor inrush contains an initial transient followed by a large starting inrush of five to seven times rated current. This level is maintained with only a gradual decrease until about 80 percent speed is reached. As the speed increases above 80 percent, the current drops rapidly to the rated value. The value of the starting current depends upon the motor design and not upon the load. The combined inertia of the load and the rotor and its speed-torque characteristic determines the length of time it takes the motor to accelerate from standstill to rated speed.

The allowable locked rotor time determines the setting of a definite time overcurrent relay that can protect the motor for this condition. Figure 5 shows a typical motor start and run characteristic protected by a definite time overcurrent relay. The advantage of using a definite time relay is that the timer runs whenever the pickup is exceeded. Thus, if the allowable locked rotor time is known, the time delay can be set above that value with a safety margin.

If the load requires a starting time greater than the allowable locked rotor time, it would not be possible to start the motor and still provide locked rotor protection with a time overcurrent relay. The acceleration of such motors is made possible with safety because of the increasing ventilation and cooling of the machine as it accelerates. Thus, the safe period for the same current levels is greater when the machine is accelerating than when it is at a standstill. Additional protection other than overcurrent protection must be provided for this special locked rotor case.

Short circuit protection can be divided into two areas, depending on the method of grounding. Namely, these areas are phase and ground faults.

Phase Faults. The current that flows during low impedance phase faults in a motor is determined mostly by the impedance of the supply system. This current will usually exceed the locked rotor current. For phase faults under this condition, it is customary to use instantaneous overcurrent relays. The pickup is set such that the relay does not operate on the starting current. There should be enough time delay such that the instantaneous relay does not operate on the initial transient.

After the motor starts there is no need to have such a high setting on the instantaneous protection. Instantaneous relays have been designed so that the setting can be reduced using an external signal once the motor has started.

Ground fault protection is perhaps the simplest protection system used for motors. Coordination with phase relaying is seldom needed, and the load current may usually be ignored. In general, zero sequence current I_0 is derived by suitable connection of CTs or by a single slipover CT. The pickup of the I_0 relay is set above the possible CT error current during starting conditions to avoid false tripping. A small time delay is usually incorporated.

If the system is solidly grounded or low impedance grounded, it might not be necessary to use separate ground fault protection. However, for high impedance grounded systems, separate ground fault protection is usually provided.

Protection Against Unbalanced Currents. Normal phase relays may not recognize a phase failure or phase unbalance condition. The load current magnitude may not rise significantly during such a condition. If the supply voltage becomes unbalanced, or if there is a break in one conductor, the motor is forced to carry currents which contain components that oppose the normal rotating field. Only a slight unbalance in the voltage can cause serious current unbalance. This

unbalanced current appears as a negative sequence current. The motor is exposed to increased phase currents (stator heating) and nearly double frequency eddy currents in the rotor as mentioned previously. For this reason, it is generally not enough to just measure the stator currents and temperature rise. The negative sequence current must also be measured. Relays incorporating negative phase sequence filters are applied for this purpose.

Differential relaying may be applied for large important motors. Such relaying is usually very fast and sensitive. Differential relays are immune to starting current inrush, and as such, provide excellent short circuit protection.

INTEGRATED MOTOR PROTECTION

New techniques with integrated circuits permit development of multi-function protective devices, offering combined protection against all types of situations which are to be expected. In the integrated relay package, a single relay can fulfill the functions that previously required nine relays.

ITX 162/163 Relay

The ITX relay is a three phase motor protection relay which contains the following functions:

1. Two stage overload protection with thermal memory
2. Time overcurrent locked rotor protection
3. Instantaneous short circuit protection
4. Protection against unbalance (I_2)
5. Ground fault protection

Please refer to Figure 6 for the functional block diagram. Figure 8 shows the external connections. The complete block diagram is shown in Figure 7. The relay is housed in a drawout type case occupying panel space of 4" x 10 $\frac{1}{2}$ " with rear terminal connections. Considerable space is saved with this compact design.

The overload function has two stages, one early warning alarm stage and one trip stage. The thermal time constant (τ) of the relay is selected to match the thermal time constant of the motor. The overload function contains a thermal memory which takes into account the thermal history of the machine (pre-heating and cooling). The overload characteristics can be adjusted on the front panel of the relay. The settings are in terms of percent temperature rise, $\Delta\theta(\%)$, based on the steady state rise for full load.

The time current characteristic for $\tau = 10$ minutes is illustrated in Figures 10 and 11. The equations governing these curves can be found in Appendix I, Equations (6) and (8). Notice that there is a discontinuity at two multiples of relay setting current. Below two multiples ($2M$) of setting current the characteristic is exponential. Above $2M$ the characteristic is proportional to current squared. These features assure a coordinated overload protection function.

The locked rotor protection is a definite time overcurrent function with adjustable time delay. The pickup is normally set at twice full load current; however, other settings are available. This function is effective when locked rotor protection with overcurrent relays may be successfully applied.

The short circuit protection consists of an overcurrent element with adjustable pickup and a 50 ms time delay to override initial starting transients. The pickup range of the instantaneous protection may be changed to 50% of its setting by an external signal. In installations where motor starting is infrequent and the motor runs practically continuously, it is undesirable to use an instantaneous setting at 7 to 10 times full load current to override starting current. If a timer or speed indicator is available to indicate that the motor has started, the reduced pickup setting may be activated to provide more sensitive short circuit protection. The setting would be reduced 3 to 5 times full load current.

Protection against unbalance is provided by a negative sequence overcurrent relay with adjustable pickup. The phase currents are filtered to obtain the negative sequence current. The filter output then passes through a level detector and timer.

Ground fault protection is provided by means of an instantaneous zero sequence current relay. The zero sequence may be derived from the current transformer connection or by a separate slipover CT which surrounds all three conductors. Refer to Figure 8.

Indication is provided by separate auxiliary relay contacts for each function or by light emitting diodes (LED's) activated by each separate function. The output is channeled to a single auxiliary tripping relay. A separate contact is provided for the first stage overload alarm.

Power Supply. The auxiliary supply to the electronic circuits is obtained from a reliable ac supply. If a battery is available, the relay can be supplied with a separate power supply to convert the battery voltage to 24 volts dc required for operation. Since there is a storage capacitor in the power supply, brief interruptions (up to 200 ms) of the auxiliary supply do not affect the relay. Failure of the auxiliary supply is monitored by a built in undervoltage relay with output contacts for alarm purposes. When the undervoltage relay operates, all functions are blocked. The integrator in the thermal memory circuit is blocked when the auxiliary supply fails. This enables the values stored at the moment the voltage failed to be retained for several minutes.

Appendix II illustrates an application of the ITX relay, to protect a 9000 horsepower motor.

CONCLUSION

The ITX relay is an integrated protection package which provides reliable motor protection against the most common hazards which may be encountered. The integrated approach provides significant space savings while using the most modern techniques. Although the package is standardized, the relay can be tailored to suit the requirements of almost any specific motor. To protect against load induced failures, internal motor failures and supply induced failures, the six function approach is used. Thus, by providing two stage overload, short circuit, locked rotor, phase unbalance, and ground fault protection in one package, the ITX relay is a step forward in motor protection technology.

APPENDIX I
DERIVATION OF OVERLOAD CHARACTERISTICS
OF THE ITX 162/163 RELAY

In general, by the law of conservation of energy, over a given period of time the energy input to the motor in the form of losses equals the energy dissipated plus the energy stored by a temperature rise of the mass.

$$Q_i = Q_e + Q_a \quad (1)$$

The losses in watts are equal to the heat energy per unit time with the proper conversion factor. Therefore, it is more convenient to use dQ/dt .

By differentiation Equation (1) becomes:

$$\frac{dQ_i}{dt} = \frac{dQ_e}{dt} + \frac{dQ_a}{dt} \quad (2)$$

The heat energy input per unit time is assumed to be caused by losses proportional to the square of the current,

$$\frac{dQ_i}{dt} = A I^2 \text{ where } A \text{ is a constant} \quad (3)$$

The dissipated energy is removed at a rate proportional to the temperature rise of the motor above ambient, $\Delta\theta$

$$\frac{dQ_e}{dt} = K\Delta\theta \text{ where } K \text{ is a constant related to the motor cooling mechanisms} \quad (4)$$

Energy is stored in the motor at a rate proportional to the rate of temperature rise, $d\Delta\theta/dt$ and to the mass and specific heat of the motor parts, identified here as the constant C . Thus,

$$\frac{dQ_a}{dt} = C \frac{d\Delta\theta}{dt} \quad (5)$$

From Equations (2), (3), (4) and (5):

$$A I^2 = K\Delta\theta + C \frac{d\Delta\theta}{dt} \quad (6)$$

$$\text{OR } \frac{A}{K} I^2 = \Delta\theta + \frac{C}{K} \frac{d\Delta\theta}{dt} \quad (6a)$$

For a constant current input, representing a steady overload, the steady state temperature rise $\Delta\theta_{\infty}$ is reached at $t = \infty$ when $\frac{d\Delta\theta}{dt} = 0$.

$$\frac{A}{K} I^2 = \Delta\theta_{\infty} + 0 \quad (6b)$$

$$\text{THUS } \Delta\theta_{\infty} = \Delta\theta + \frac{C}{K} \frac{d\Delta\theta}{dt} \quad (7)$$

The solution to this first order linear differential equation is:

$$\Delta\theta = \Delta\theta_{\infty} + C_1 e^{-t/\tau} \quad (8)$$

where $\tau = \frac{C}{K}$ the thermal time constant of the motor.

At time $t = 0$ the temperature rise of the motor above ambient is defined as $\Delta\theta_0$. Thus, from Equation (8):

$$\Delta\theta_0 = \Delta\theta_{\infty} + C_1 \text{ OR } C_1 = \Delta\theta_0 - \Delta\theta_{\infty} \quad (9)$$

Equation (8) becomes:

$$\Delta\theta = \Delta\theta_0 + (\Delta\theta_0 - \Delta\theta_{\infty}) e^{-t/\tau}$$

$$\text{OR } \Delta\theta = \Delta\theta_0 + (\Delta\theta_{\infty} - \Delta\theta_0) (1 - e^{-t/\tau}) \quad (10)$$

This function is shown graphically in Figure 4.

Solving Equation (10) for t ,

$$t = \tau \ln \frac{\Delta\theta_{\infty} - \Delta\theta_0}{\Delta\theta_{\infty} - \Delta\theta} \quad (11)$$

According to Equation (6b) $\Delta\theta_{\infty}$ is proportional to I^2 . It is convenient to use multiples of relay pickup current when discussing time - current characteristics. Thus, by definition $M = I/I_E$. The ratio I/I_E is the relay current divided by the setting. Therefore:

$$\Delta\theta_{\infty} \propto M^2 \quad (12)$$

by calibrating the relay in terms of percent temperature rise $\Delta\theta\%$, based upon the steady state temperature rise at full load current, Equation (11) becomes:

$$t = \tau \cdot 60 \cdot \ln \frac{M^2 - \Delta\theta_O (\%) \cdot 10^{-2}}{M^2 - \Delta\theta (\%) \cdot 10^{-2}} \quad (13)$$

where t is in seconds

and τ is in minutes.

From Equation (13) the time to trip or alarm may be determined in terms of the temperature rise $\Delta\theta$. This equation is generally applicable for the lower range of overload currents where the long time duration permits heat dissipation to be effective. For higher overload currents, the heating process is assumed to be adiabatic because of the rapid temperature rise.

From experience, the discontinuity in the characteristic is made at twice the relay setting. Thus, for $I \leq 2I_E$, Equation (13) holds. For $\geq 2I_E$, the adiabatic condition is assumed, thus from Equation (4):

$$\frac{dQ_e}{dt} = K \Delta\theta = 0$$

In other words, no heat is removed by cooling. Equation (6) for this condition becomes:

$$A I^2 = C \frac{d\Delta\theta}{dt}$$

And for a constant overload current, the solution is:

$$\Delta\theta = \frac{\Delta\theta_{\infty}}{\tau} t + \Delta\theta_0$$

$$\text{OR } t = \frac{\tau \cdot 60 \cdot (\Delta\theta(\%) - \Delta\theta_0(\%) \cdot 10^{-2})}{(M)^2} \quad (14)$$

This is a linear function of current squared vs time. Figures 10 and 11 show the relay curves for two initial values of temperature rise, $\Delta\theta_0 = 100\%$ and $\Delta\theta_0 = 0\%$.

DEFINITION OF TERMS

- Q_i = heat input to the motor
- Q_e = heat removed by cooling processes
- Q_a = heat stored by the motor
- m = Mass in kg
- c = Specific heat of the material in $\frac{\text{kW} \times \text{min}}{\text{kg} \times ^\circ\text{C}}$
- C = mc
- A = A constant representing the motor's ability to accumulate heat due to copper losses
- $\Delta\theta$ = Temperature rise $^\circ\text{C}$ above ambient
- K = Motor cooling constant in $\frac{\text{kW}}{^\circ\text{C}} = \frac{P_L}{\Delta\theta_\infty}$
- τ = Thermal time constant of the motor, i.e., the time in minutes the motor takes to reach 63% of the temperature rise to its new steady state rise ($\Delta\theta_\infty$) starting from the sustained initial value $\Delta\theta_0$.
- $\Delta\theta_\infty(\%)$ = Ultimate temperature rise in percent, based on steady state rise at full load.
- $\Delta\theta_0(\%)$ = Initial temperature rise in percent, based on steady state rise at full load.
- P_L = Power losses in the motor I^2R
- M = Multiples of relay pickup current
- I_E = Set current

APPENDIX II

SETTING CALCULATIONS

We present below the considerations taken into account and the calculations performed in order to optimally set the ITX 163-2 relay for the selective protection of a 9000 horsepower motor.

A - Motor Characteristics

B - Relay Data

C - Setting Calculations

A. Motor Characteristics

Rated voltage: 13200 V $\pm$ 10%

Rated frequency: 60 Hz $\pm$ 5%

Rated current, I_N (motor): 343 A

Maximum operating current: $0.98 \times I_{N(\text{motor})}$

Maximum starting current: $6.5 \times I_{N(\text{motor})}$

Maximum starting time: 12 seconds

Maximum admissible continuous current: $1.08 \times I_{N(\text{motor})}$

Maximum ground fault current: 200 A (primary)

B. Relay Data

Rated current, I_N (relay): 5 A

C.T. ratio: 600/5 A

C. Setting Calculations

Determination of the set current (for phases A and B) and motor matching factor k.

$$I_N(\text{relay}): 5 \text{ A}$$

The set current on the relay must correspond to the rated current of the motor. The adaptation of the two is accomplished via an adjustment factor k which is defined as follows:

$$I_E = k \cdot I_N \quad \text{Where } I_E \text{ is the current value to which the relay is actually set and which should be close as possible to the motor rated current value.}$$

From the motor characteristics and the above C.T. ratio, we see that the optimal setting of k for phases A and B is

$$k = \frac{I_E}{I_N} = \frac{343}{600/5} \cdot \frac{1}{5} = 0.57$$

Chosen value would be $k = 0.6$

The deviation from the ideal match is small and must be taken into account only for the setting of the overload unit.

$$\text{Thus } I_E = 0.6 \times 5 = 3 \text{ A}$$

The set current in primary amperes is:

$$I_E \times \frac{600}{5} = 3 \times \frac{600}{5} = 360 \text{ A}$$

The correction factor for perfect matching of relay and motor is:

$$k_c = \frac{I_N}{I_{E \text{ prim}}} = \frac{343}{360} = 0.95$$

Short-circuit protection setting of $I_{t\infty}$

The rule-of-thumb for setting the short circuit current level is approximately 30 percent above the maximum motor starting current.

$$\begin{aligned} I_{t\infty} &= 1.3 \times I_A \text{ (starting current)} \\ &= 1.3 \times 6.5 \times I_N \text{ (motor)} \end{aligned}$$

The rated motor current is related to the relay set current I_E via the correction factor defined above $k_c = 0.95$. Thus,

$$\begin{aligned} I_{t\infty} &= 1.3 \times 6.5 \times 0.95 \times I_E \\ &= 8 \times I_E \quad \begin{array}{l} 8 \text{ is the value to be set on the} \\ \text{potentiometer} \end{array} \end{aligned}$$

OR

$$= 8 \times 3 = 24 \text{ A (secondary)}$$

Locked Rotor Protection (setting of t_1 start)

This protection which uses current as its only criteria is not suitable for the cases where the maximum admissible blocked rotor time (t_E) is less than the maximum rotor starting time (t_A). If however $t_E > t_A$, then t_1 start should be set to approximately 20 percent above the maximum motor starting time, t_A , thus permitting correctly timed tripping in the case of blocked rotor.

$$t_1 \text{ start} = 1.2 \times t_A = 15 \text{ seconds}$$

Overload protection

By definition, the ultimate temperature rise for a given current is given by:

$$\Delta\theta_{\infty} (\%) = \left(\frac{I}{I_E} \right)^2 \times 100$$

whereas the temperature rise is given as a percentage of that occurring when relay set current flows in the thermal replica. As a rule-of-thumb, the tripping stage of the overload protection ($\Delta\theta_2$) should be set approximately 10 percent above $\Delta\theta_{\infty B}$, that is, the temperature rise resulting when maximum admissible continuous current flows in the thermal replica.

$$\begin{aligned} \Delta\theta_2 &= 1.1 \times \Delta\theta_{\infty \text{ max.}} \\ &= 1.1 \times \frac{I_{\text{max. th.}}^2}{I_E} \times 100 \\ &= 1.1 \times \frac{1.08 \times I_E \times k_C^2}{I_N} \times 100 \\ &= 1.1 \times (1.08 \times 0.95)^2 \times 100 = 116\% \end{aligned}$$

As rule-of-thumb, the alarm stage of the overload protection should be set approximately to the mean value between $\Delta\theta_{\infty B}$ which is the steady-state temperature rise at motor operating current, and $\Delta\theta_2$ calculated previously.

$$\begin{aligned} \Delta\theta_1 &= \frac{\Delta\theta_{\infty B} + \Delta\theta_2}{2} \\ &= \frac{\frac{I_B^2}{I_E} \times 100 + 116\%}{2} \end{aligned}$$

$$\Delta\theta_1 = \frac{\left[\frac{I_B}{I_N} \times k_c \right]^2 \times 100 + 116\%}{2}$$

$$\Delta\theta_1 = \frac{(.98 \times .95)^2 \times 100 + 116\%}{2} = 101\%$$

Protection Against Unbalanced Currents

Setting of I_2 (in % of I_E)

The protection against asymmetrical currents built into the relay is mainly designed as a protection against unacceptable temperature rises in the rotor circuit. The negative sequence component of the phase currents is measured.

The normal setting is:

$$I_2 = (0.3 \text{ to } 0.4) \times I_E$$

This setting may vary; however, for different applications, and for this reason, a setting range of $0.25 \text{ to } 0.5 \times I_E$ is available.

This assures tripping in case of an open phase, line breakage or inverted phase sequence.

In order to prevent unselective tripping, a built-in time delay is supplied with a normal set value of 4 seconds. Other time delays are available (1, 2, 3 sec.) should the application warrant it.

$$T_{12} = 4 \text{ seconds}$$

Ground Fault Protection

Since the ground currents are detected with a separate measuring circuit with its own current input and its own setting selector switch, the sensitivity can be selected in a wide range (0.06 - 4.8 A).

The setting is mainly determined by:

- the measuring method (neutral current measurement - summation current of three C.T.'s or separate slipover C.T.).
- transformation ratio of the transformer(s) relative to the maximum possible current value in case of unipolar ground fault.
- ground capacitances of the system.

In the case where 3 current transformers are used, that is two phase measurements and one zero sequence measurement, the setting of I_O would be $0.2 - 0.4 \times I_E$ with the same k setting for the phases.

$$I_O = 0.2 \times I_E \text{ and } k = 0.6$$

With these settings, the relay sensitivity in amperes would be:

$$\frac{600}{5} \times 0.2 \times 0.6 \times 5 = 72 \text{ A (primary)}$$

which represents 36% of the maximum ground fault current (primary). If instead of the above connection scheme a separate summation current transformer is used for the zero sequence measuring circuit, then other settings can be used which afford greater sensitivity:

$$I_O = 0.2 \times I_E \text{ and } k = 0.3$$

which yields

$$\frac{600}{5} \times 0.2 \times 0.3 \times 5 = 36 \text{ A}$$

which represents 18% of the maximum ground fault current (primary). This is, of course, a greater sensitivity than in the previous case.

FIG. 1 - TYPICAL STARTING CURRENT OF AN INDUCTION MOTOR

I_s = PEAK VALUE OF TRANSIENT
CURRENT

I_k = MOTOR STARTING CURRENT

I_L = LOAD CURRENT

t_A = STARTING TIME

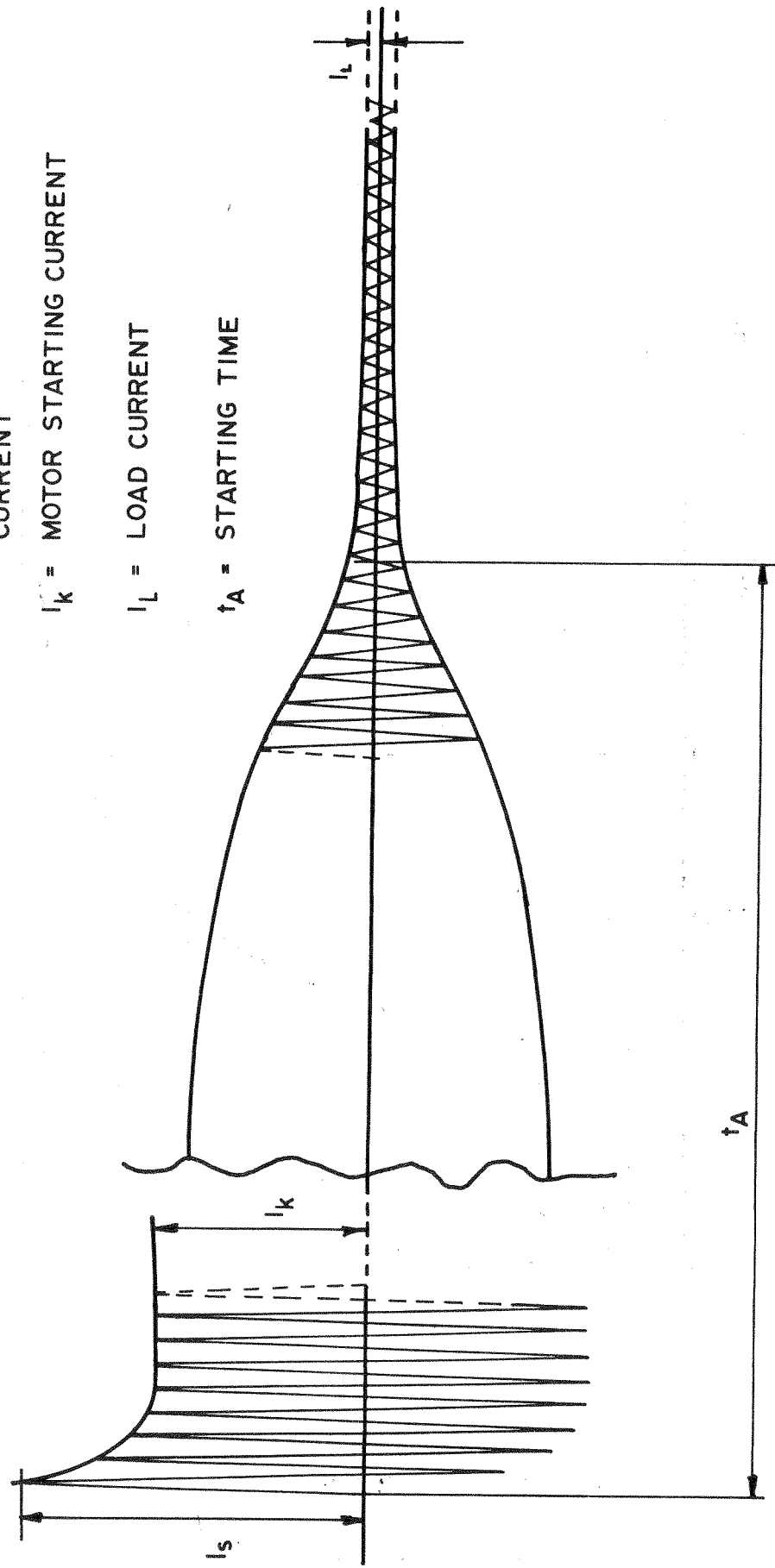
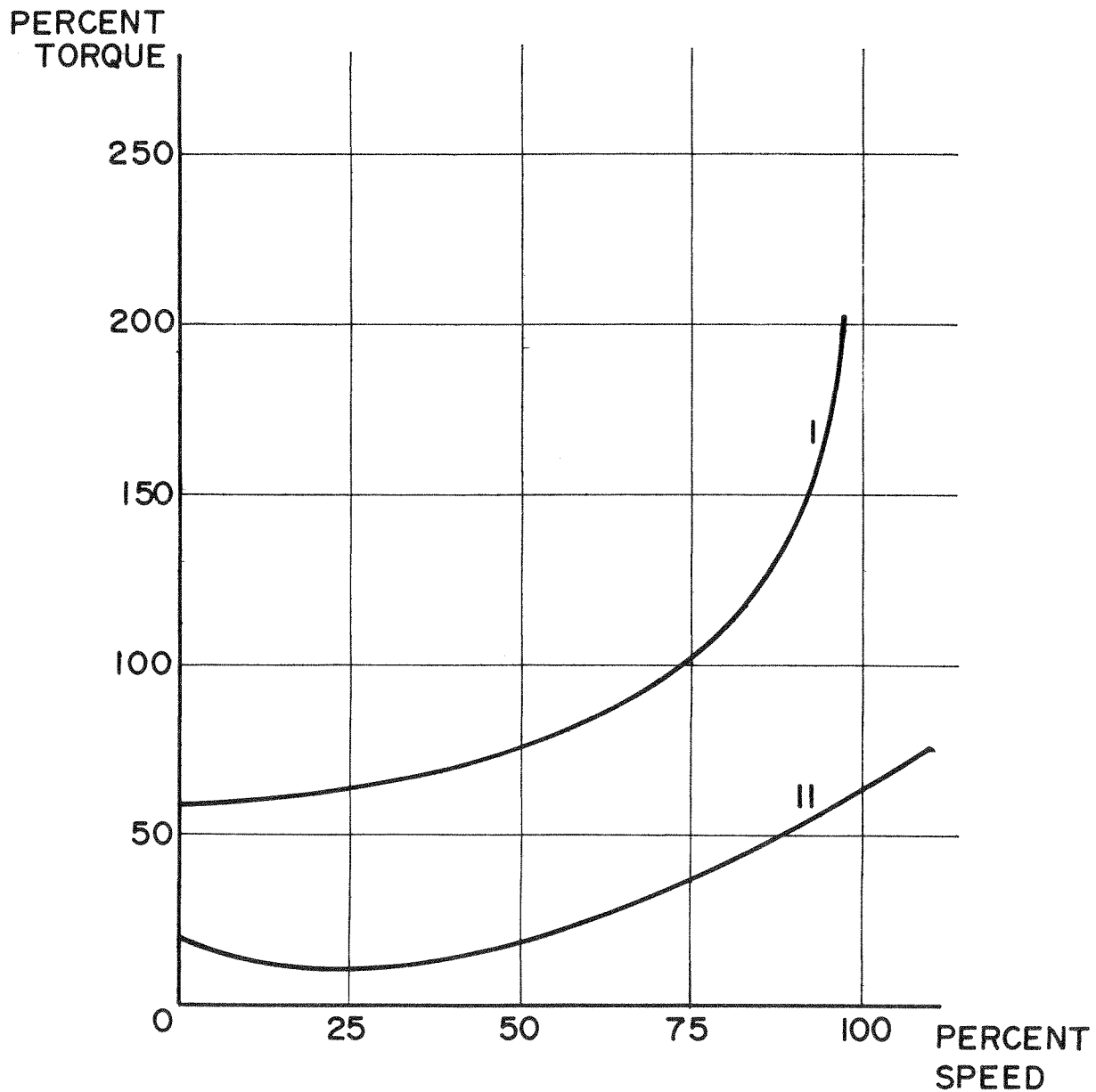


FIG. 2 - SPEED-TORQUE CURVES FOR AN INDUCTION MOTOR



I = DEVELOPPED MOTOR TORQUE

II = LOAD TORQUE

I - II = ACCELERATING TORQUE

FIG. 3 - STATOR TEMPERATURE RISE DUE TO OVERLOAD

θ_{∞} = STEADY STATE TEMPERATURE RISE
 τ = STATOR THERMAL TIME CONSTANT

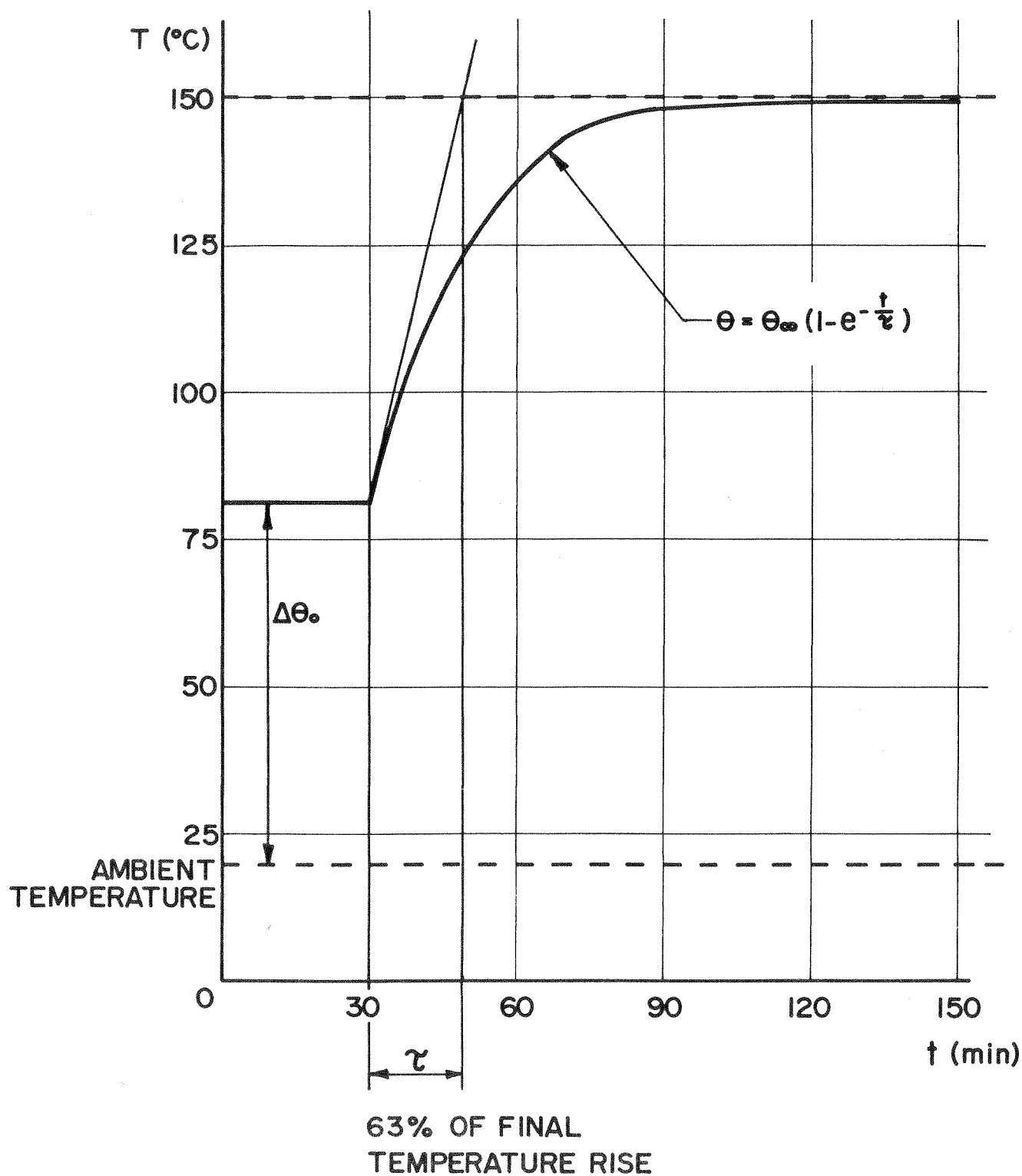


FIG. 4- TWO STAGE OVERLOAD PROTECTION

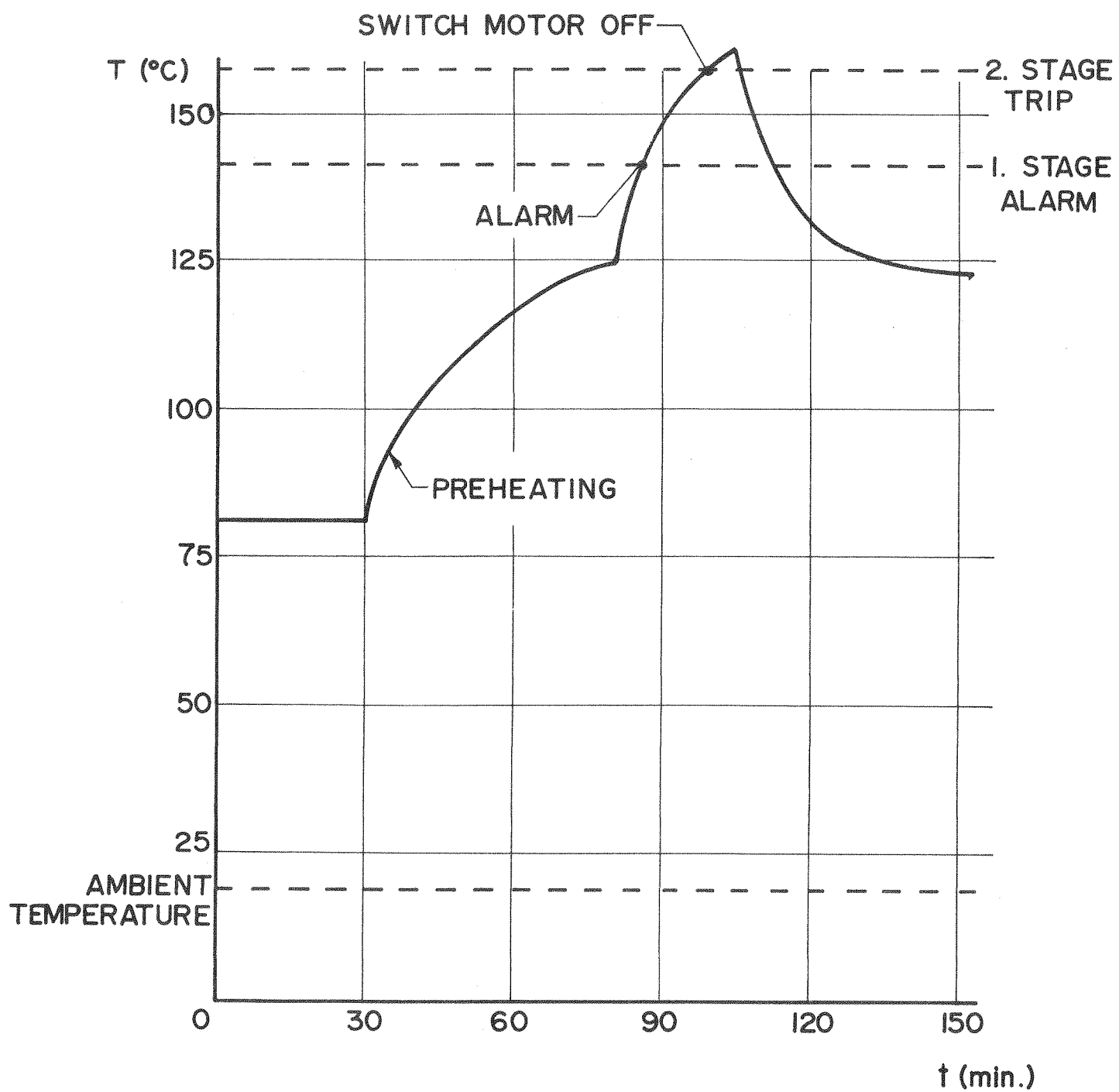


FIG. 5 - LOCKED ROTOR PROTECTION

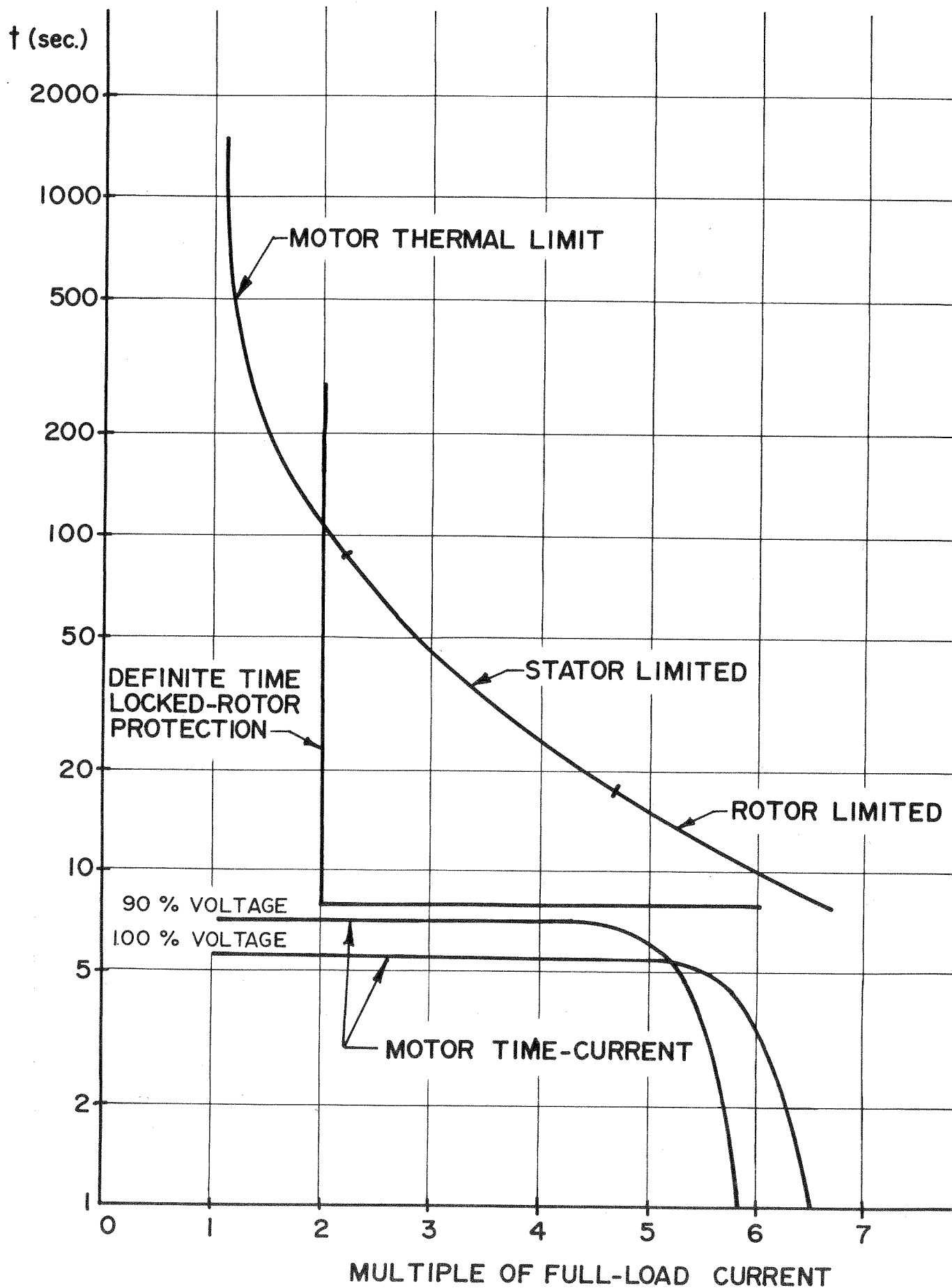


FIG. 6 - ITX 162

BLOCK DIAGRAM

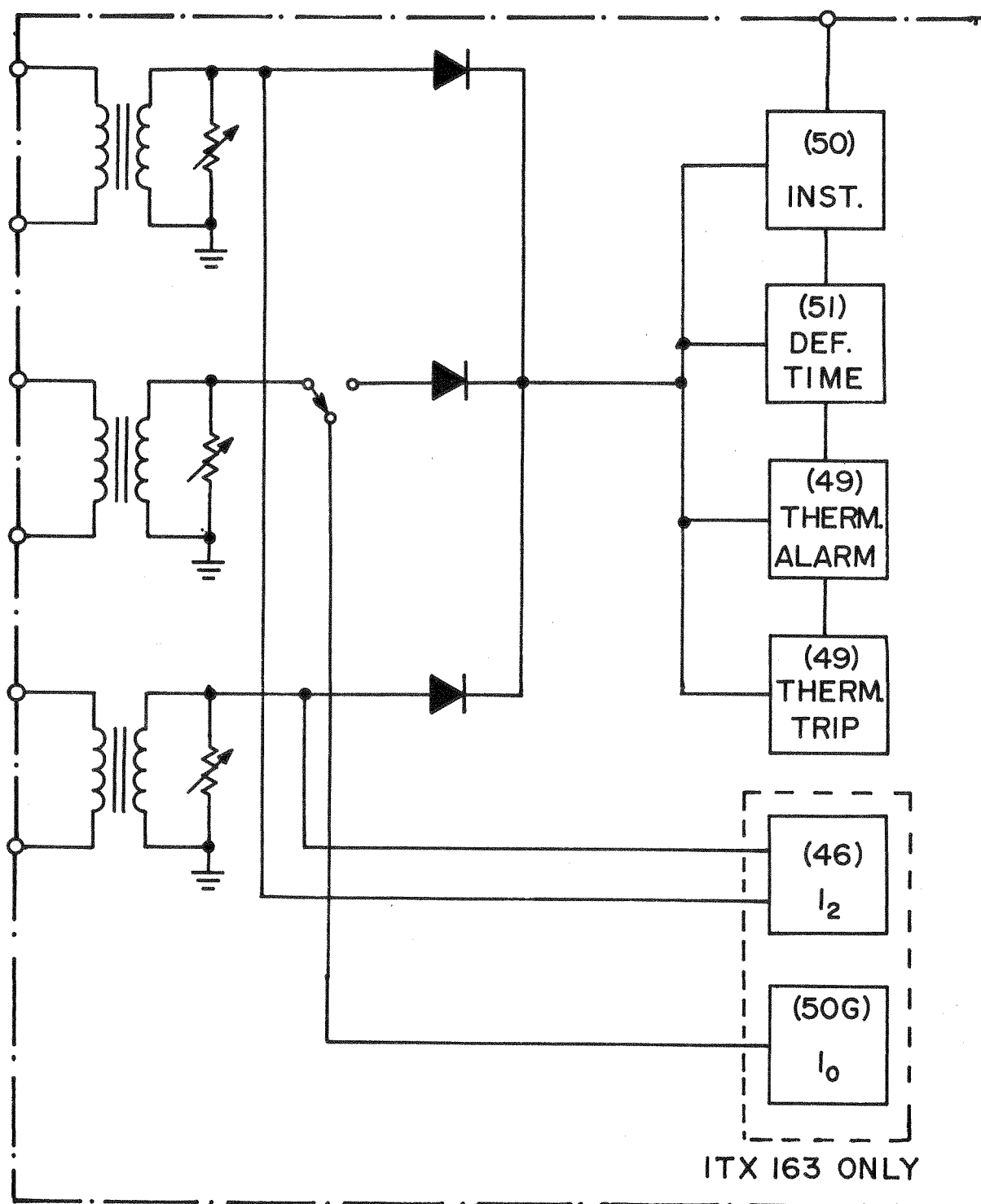


FIG. 7- BLOCK DIAGRAM OF RELAY ITX 163-2
PROTECTING A MOTOR

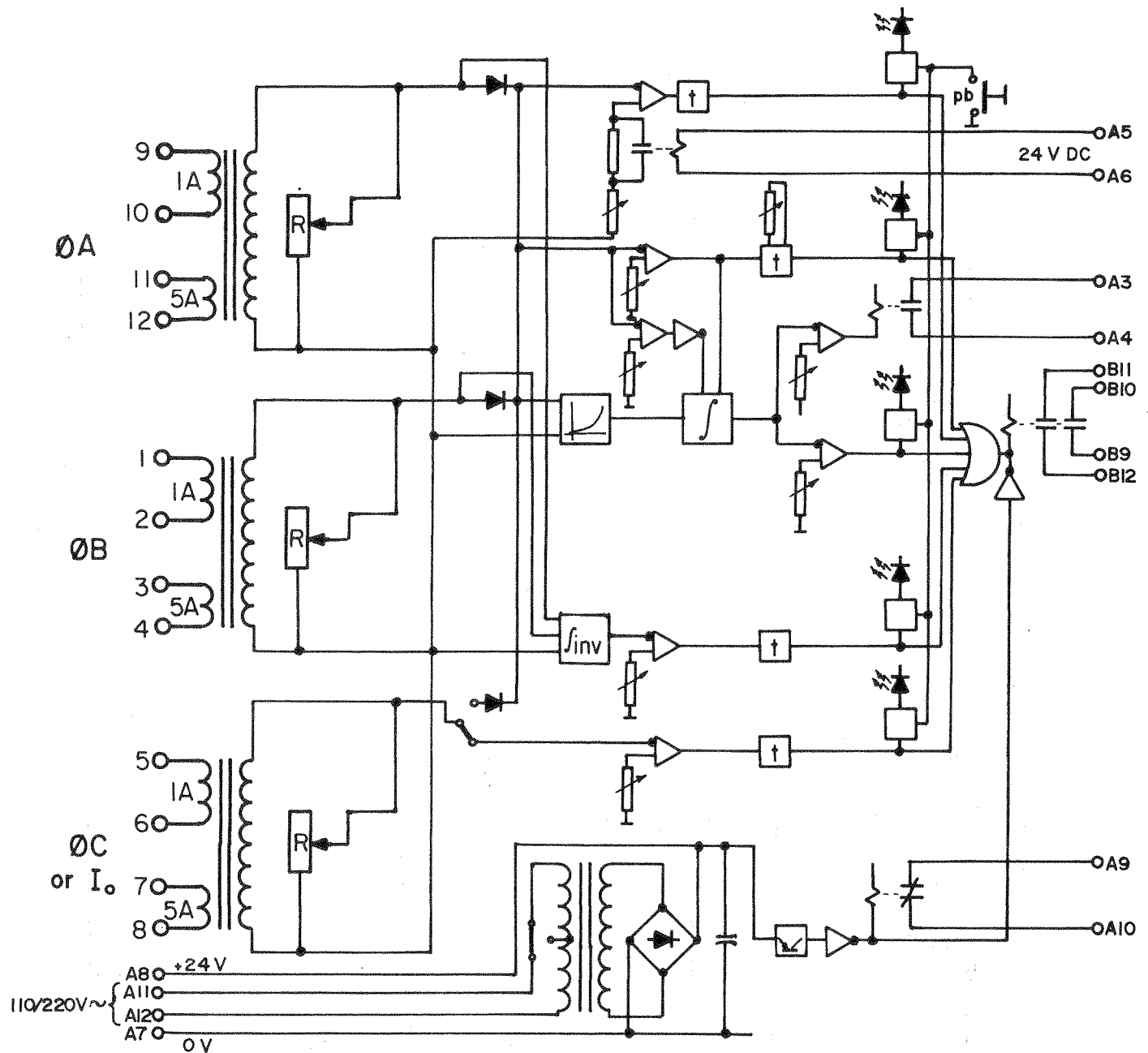


FIG. 8 - ITX 163 CONNECTION DIAGRAM

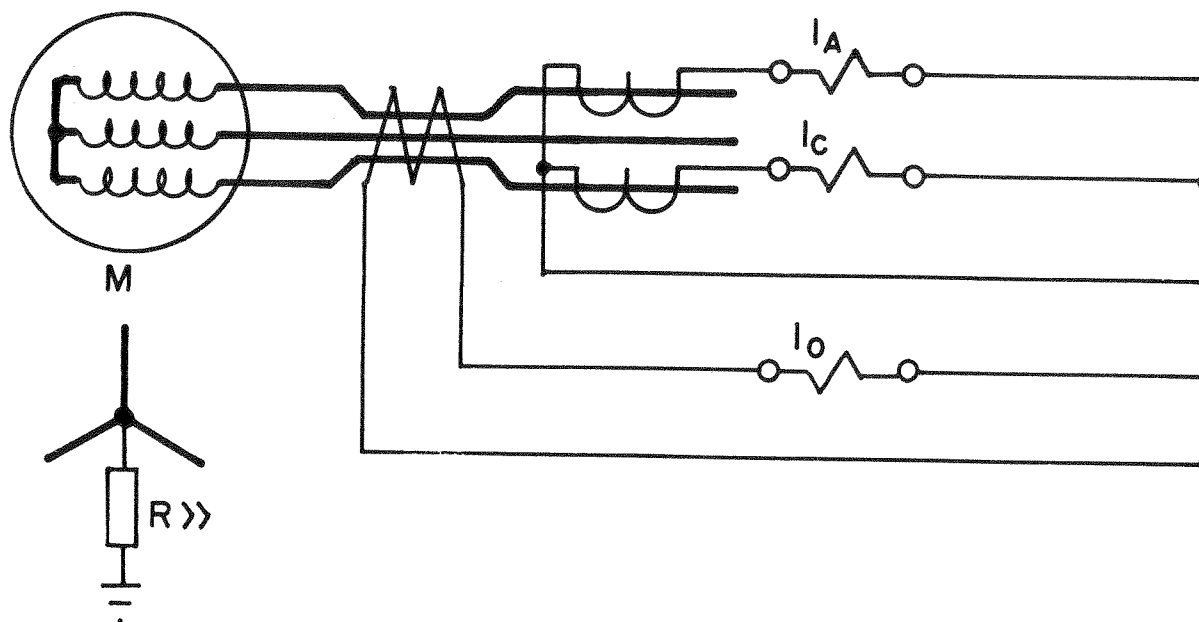
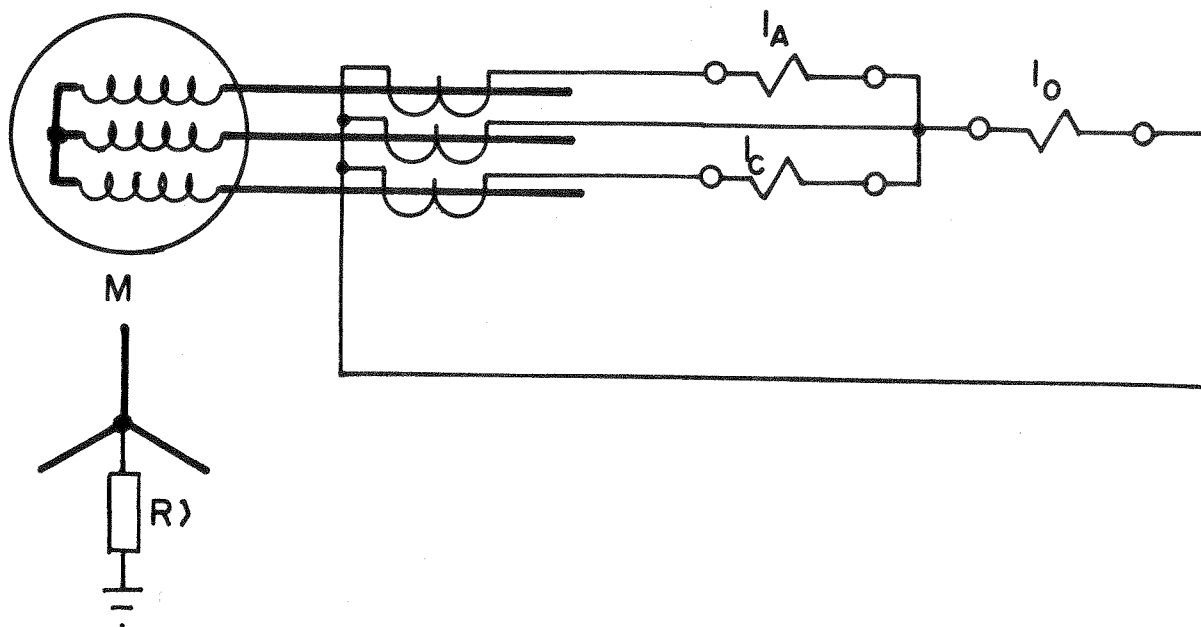
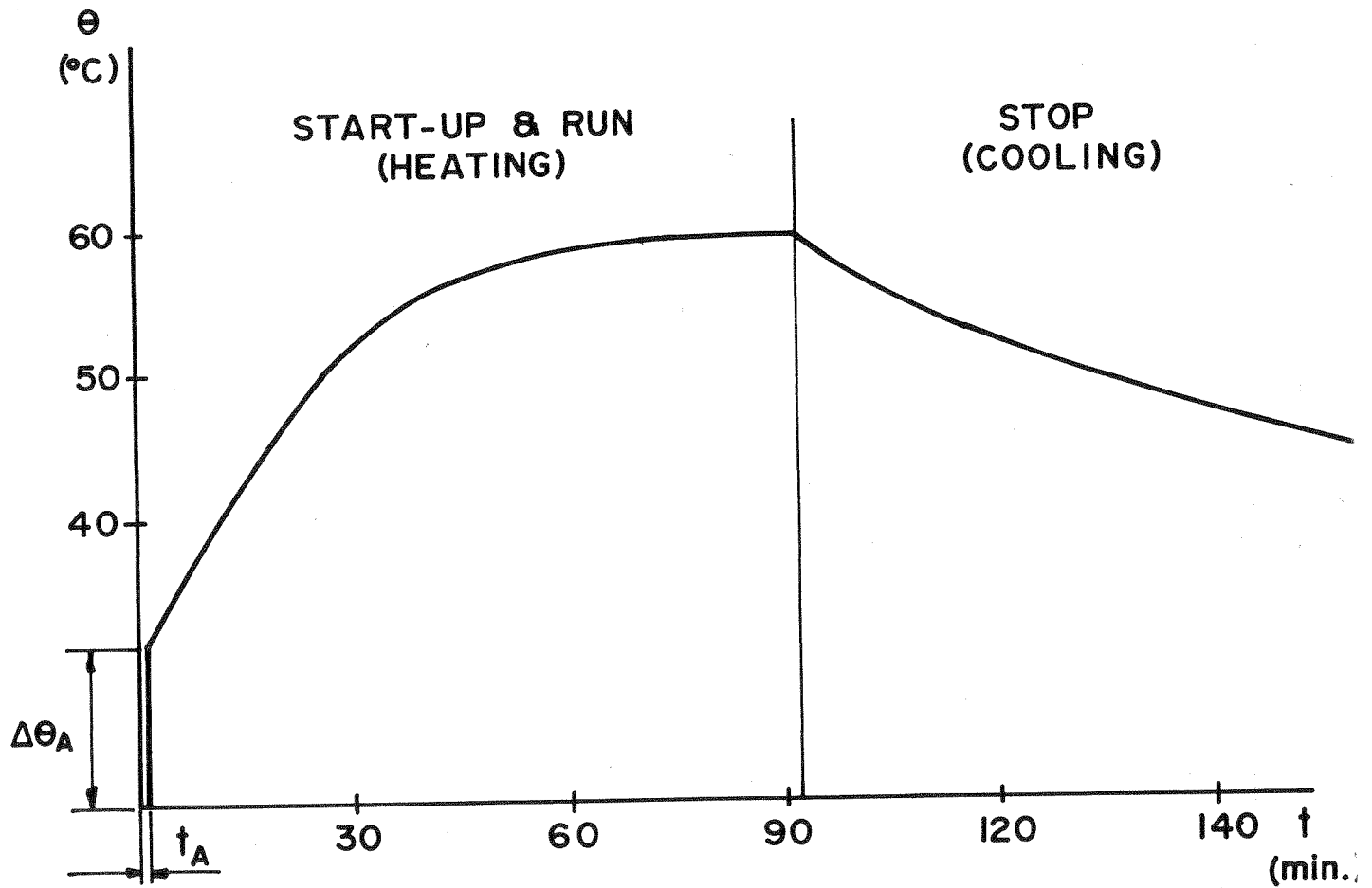


FIG. 9 -

TYPICAL STATOR TEMPERATURE RISE DURING THE
START-UP AND COOLING PERIODS



t_A = STARTING TIME

$\Delta\theta_A$ = TEMPERATURE RISE DURING
STARTING TIME

FIG. 10 -
ITX RELAY CHARACTERISTIC
(HOT CONDITION)

$\tau = 10 \text{ min.}$
 $\Delta\theta_0 = 100\%$

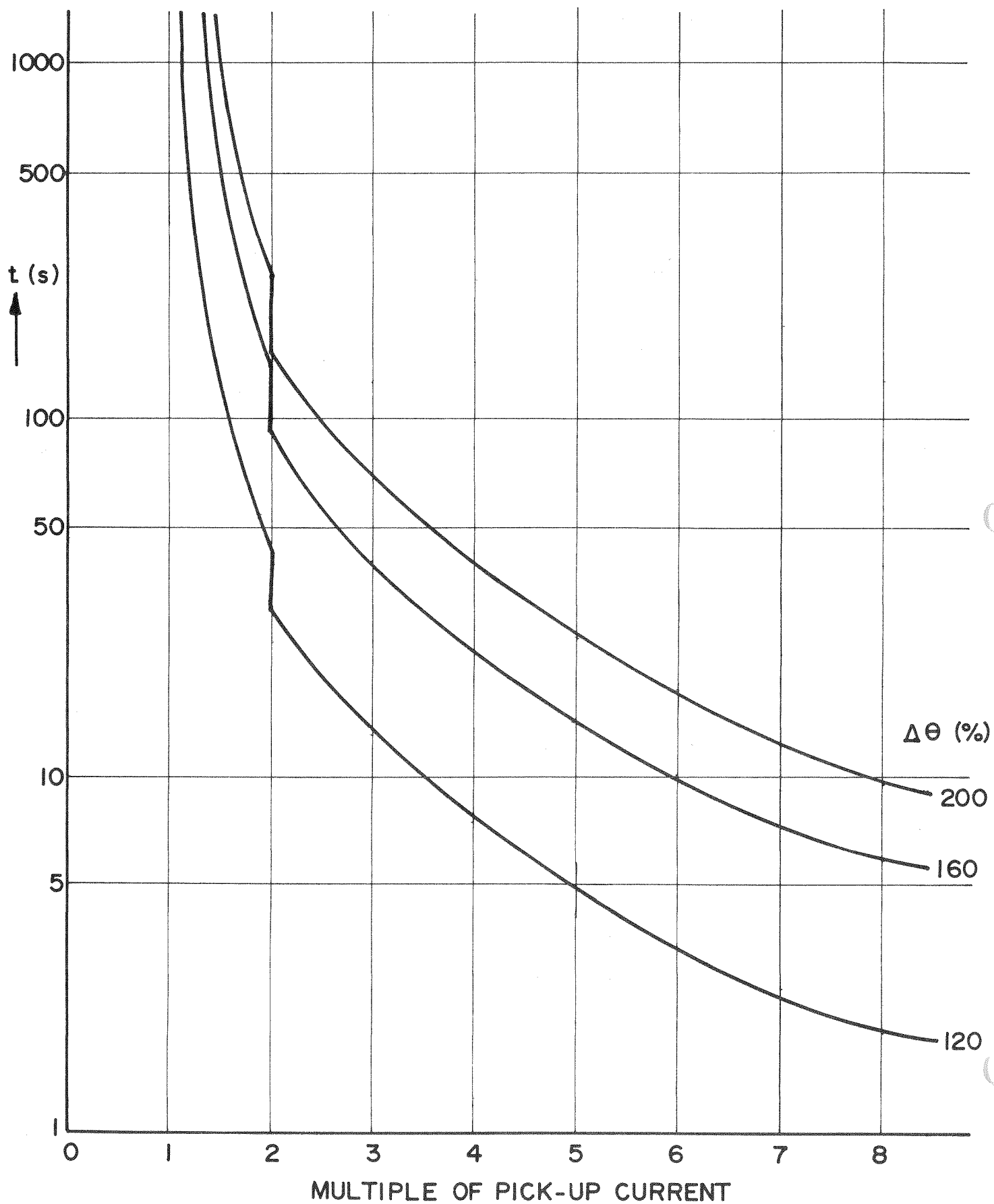
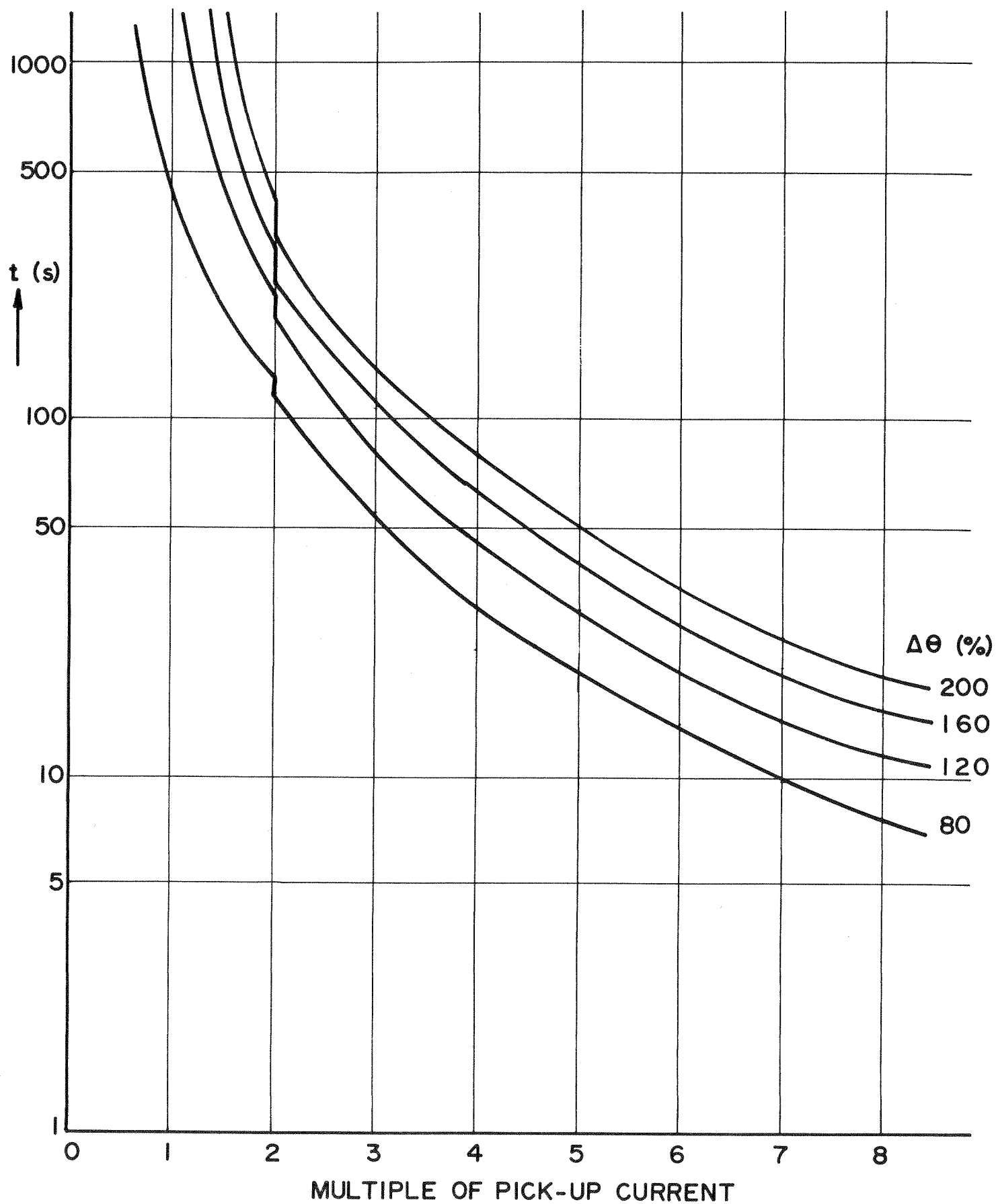


FIG. II -

ITX RELAY CHARACTERISTIC
(COLD CONDITION)

$\tau = 10 \text{ min.}$
 $\Delta\theta_0 = 0$

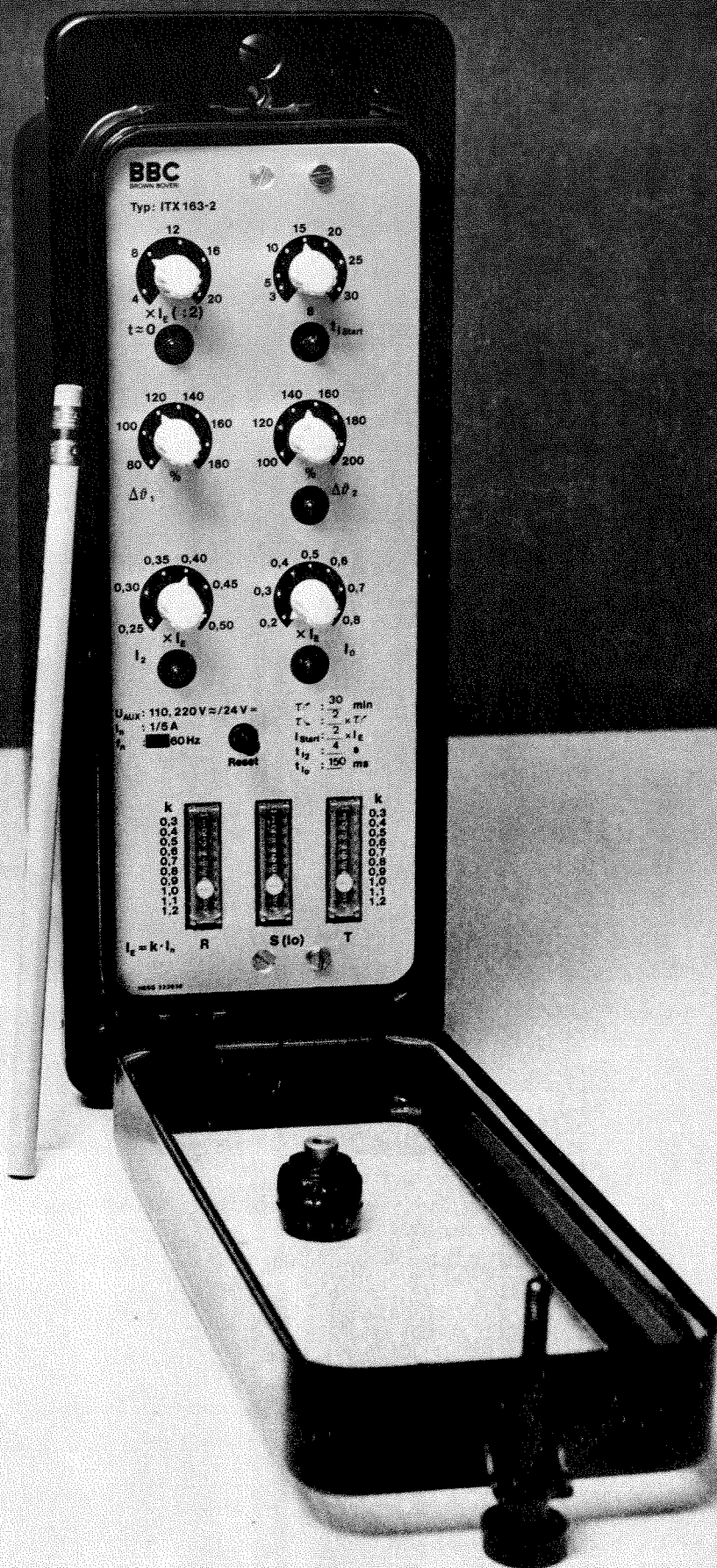


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NEW CONCEPTS IN GROUND RELAYING
FOR TRANSMISSION LINES

By

L. E. Goff W. C. New J. B. Williams

All of

Power Systems Management Business Department

General Electric Company

Philadelphia, Pennsylvania

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L. E. GOFF

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J. B. WILLIAMS

INTRODUCTION

Since the single-phase-to-ground fault is the most common type of fault that occurs on transmission lines it is natural that relay engineers, both in the utility and manufacturing area, have devoted a great deal of attention to ground relay designs and ground relaying schemes. It is the intent of this paper to review a number of problem areas encountered in ground relaying, to discuss how these problems affect the application and performance of various types of ground relays, and finally to describe two unique concepts in ground relay design.

PROBLEM AREAS

Before describing any new relay designs, let us first define some of the problem areas that have existed with previously available ground relaying schemes:

1. Variations in system configuration—By definition these variations involve changes in connected generation, addition or removal of tie lines, and addition or removal of ground sources. The magnitude of fault current will, of course, vary as generation and ties are changed, and the ratio of zero sequence current to positive sequence current (I_0/I_1) over the protected line will change as ground sources are added or removed. The example in Figure 1 illustrates the effect of removal of a ground source. The example represents a single-phase-to-ground fault at one end of a 65 mile line in a typical 345 KV system. The zero sequence fault current in the fault and at the relay location R are calculated for two assumed conditions: (a) all systems in service, and (b) with the autotransformer at bus B removed. In this example although the total I_0 at the fault decreased with the transformer out, I_0 at the relay location increased by about 25 percent.

2. Mutual Induction—When two or more lines are in parallel on the same right-of-way, fault current in one line may induce voltages in the parallel line or lines. A typical configuration of 345 KV lines on a double-circuit tower, demonstrating extremely close coupling, is shown in Figure 2, together with the self and mutual impedances for a set of assumed conditions.

Note that the zero sequence mutual impedance is about two-thirds of the zero sequence self impedance. By contrast the positive and negative sequence mutual impedances are on the order of one-twelfth of the self impedances. Consequently, the positive and negative sequence mutual impedances can usually be ignored in relay applications. The zero sequence mutual impedance on the other hand is significant and usually must be considered. Its effect on directional over-current and distance relays is discussed later.

3. Ground fault resistance—The magnitude of resistance or impedance encountered during a phase-to-ground fault is frequently much larger than that found on interphase faults. An interphase fault usually strikes from phase-to-phase via an electric arc of the shortest path. A line-to-ground fault, on the other hand, may be initiated by a flashover of a single insulator string to a steel tower, but from that point on the total ground fault impedance will be influenced by such parameters as the impedance of the shield wires, the tower footing resistance and the resistivity of the earth return path between the fault location and the ground current source.

The highest values of ground fault resistance are usually encountered during mid-span faults caused by trees growing under the lines or by brush fires which occur under the lines. Such fault resistances are highly variable in magnitude and are usually much higher than the resistances introduced by flashover faults at the towers.

4. Unreliable polarizing source—When ground relays require a negative or zero sequence polarizing quantity, the reliability of the polarizing source must be considered. For example, zero sequence potential polarization is better suited for use when the relay is remote from a ground source; zero sequence current polarization would be lost if the transformer bank used as a source were removed from service; and current polarization from a CT in the neutral of an autotransformer must be considered suspect. Polarization is discussed in a later section of this paper and is covered in detail in reference 2.

PERFORMANCE OF AVAILABLE RELAYS

Now that several possible problem areas have been defined, we will next consider how these problems affect the various types of relays that have been used for ground fault protection of transmission lines.

1. Non-directional Overcurrent Relays—Although they are the least complex of the relays to be considered here, non-directional overcurrent relays are most affected by many of the problem areas previously cited and hence are difficult to apply. They are for example most affected by variations in available fault current resulting from changes in system configuration. A direct trip instantaneous ground overcurrent relay must be set so that it will not operate for faults beyond its prescribed zone of protection under conditions of maximum generation or the highest level of zero sequence fault current that is anticipated. Thus, with lower levels of fault current contribution, its zone of protection will be greatly reduced.

The example in Figure 1 is typical of the problems that may be encountered in the application of instantaneous ground overcurrent relays. In this example a ground overcurrent relay at breaker A, set to reach 80 percent of line A-B with all systems in service, would overreach bus B with the autotransformer at bus B out of service.

These relays may also be adversely affected by zero sequence mutual coupling with a parallel line. For example, in Figure 4 if system conditions are such that the zero sequence current flow in line 2 is opposite to that in line 1 for an internal fault near breaker Y, the magnitude of zero sequence current in line 1 will be higher than would otherwise be expected and hence an instantaneous ground overcurrent relay at X will tend to overreach.

The performance of these relays will also be affected by the magnitude of ground fault resistance since the presence of such resistance will reduce the amount of ground fault current that can flow.

2. Directional overcurrent relays—The overcurrent units in directional overcurrent relays are affected by variations in available fault current, by zero sequence mutual coupling with a parallel line, and by the presence of ground fault resistance to essentially the same degree as the non-directional overcurrent relays discussed above. They do enjoy one advantage, however, since they need only be selective for faults in the tripping direction of the supervising directional unit.

(a) Zero sequence directional unit reversal—The classical configuration that can result in undesired operation of relays on a parallel line is that of closely coupled lines that terminate in electrically isolated zero sequence systems, such as lines of different voltage levels. A typical example of this is shown in Figure 3. With a single-line-to-ground fault at Bus B, zero sequence current will flow along the line from A to B. Because of the mutual coupling, the zero sequence current in line 1 tends to produce a zero sequence voltage in line 2, which in turn causes a zero sequence current to flow.

With a zero sequence current source at both busses C and D, the direction of zero sequence current flow in each ground source and across line 2 will be as shown in Figure 3. For zero sequence current polarized directional relays, this represents a tripping condition at both ends of line 2. If the mutual coupling results in enough current to operate the zero sequence overcurrent units, as well as the directional units, an undesired trip will occur.

It must be emphasized that undesired tripping caused by zero sequence mutual coupling is not restricted to parallel totally isolated systems. Undesired tripping can occur whenever the mutual coupling causes zero sequence current flow in a parallel line that is sufficient to operate the zero sequence polarized directional unit and the associated overcurrent unit. Nor is it restricted to current polarized directional units. When zero sequence potential polarization is used, the relation between the zero sequence voltage and the zero sequence current flow in the line resulting from mutual coupling also is such that a tripping condition will occur.

The experience of one utility with this problem area is discussed in Reference 1. It was determined that for some combinations of fault location and system configuration the majority of lines checked could experience undesired tripping by pilot schemes using zero sequence directional overcurrent relays.

(b) Choice of polarizing quantity—An important consideration in the application of zero sequence polarized directional relays is the source of polarization. Since zero sequence potential is a maximum at the fault location and very low near a strong zero sequence source, potential polarization of a zero sequence directional relay is only appropriate when the relay is remote from a ground source. On the other hand, current polarization from a CT in the neutral of a wye-delta transformer bank is a dependable means of polarization when the wye connection is on the system side of the bank, but would of course be lost if the bank is removed from service. Consequently, most relays of this type now employ dual polarization which provides better assurance that adequate polarization will be present for all expected system conditions.

If current polarization is obtained from a CT in the neutral lead of an autotransformer the application must be carefully considered to be sure the direction of polarizing current flow will be correct. This condition, as well as other considerations with zero sequence polarization, is covered in detail in references 2 and 3.

Although there are as noted some situations unfavorable to the application of zero sequence directional relays, there are a great number of cases where they can be successfully applied. Because of their relatively low cost and simplicity, they remain today a popular form of ground relaying. However, the present trends in transmission systems, especially in the EHV area, are resulting in many instances where zero sequence directional relays are not applicable.

(c) Negative sequence polarized relays—Negative sequence directional overcurrent relays are much less subject to undesired operations from mutual coupling with parallel lines than are zero sequence relays. This is because, as previously noted, the negative sequence coupling coefficient is so much smaller that the effect is negligible. In the past, however, the use of negative sequence overcurrent relays has had its own problems, one of which has been the sensitivity of electromechanical relays. A negative sequence relay responds to negative sequence voltage (V_2) and current (I_2), whereas the quantities fed into a zero sequence relay are three times the sequence quantities, that is $3V_0$ and $3I_0$. Consequently, the available energy level at a given location tends to be lower for the negative sequence relay and situations may be encountered where electromechanical relays will not be sensitive enough.

With available static technology it is possible to design negative sequence directional relays that are extremely sensitive. However, as their sensitivity increases, so does the possibility of misoperation from such conditions as three-phase faults on untransposed lines or negative sequence mutual between parallel lines.

A recent innovation in static negative sequence relay design makes possible a relay with adequate sensitivity that still provides excellent security. This design principle is described in a later section under the heading 'Recent Developments in Ground Relay Design'.

3. Ground Distance Relays—A ground distance relay is relatively unaffected by the amount of current available at the time of the fault. A first zone relay is usually set for about 80% of the protected line and this zone of protection will be practically constant under widely varying system conditions. When ground distance relays are used in overreaching functions, such as pilot protection or second zone backup, their reach will be affected by current infeeds at intervening busses. This is a well known problem which must be considered in the application of all distance relays as described in Reference 5.

Ground distance relays are frequently provided with a means of zero sequence current compensation for the protected line as described in Reference 6. This is done so that the relay measures only the positive sequence impedance of the line to the fault. The accuracy of the ground distance relay measurement will depend upon how closely this compensation reflects the ratio of the positive to zero sequence impedance of the protected line section both in magnitude and in phase angle.

Depending on system conditions in the vicinity of the relay location, the presence of mutual induction can cause ground distance relays to either overreach or underreach. A typical system involving mutually coupled lines is shown in Figure 4. Two conditions can be cited in which mutual induction between lines 1 and 2 will cause the relay at breaker X to overreach:

- Case 1 - Tie breaker Z open, a single-phase-to-ground fault at bus B, and a relatively large percentage of line 1 zero sequence fault current flowing in line 2 in the reverse direction, i.e., from T to S.
- Case 2 - Breakers S and T open, a single-phase-to-ground fault at bus B, and all three phase conductors of line 2 grounded at both ends of the line as with maintenance grounding chains hung on breakers S and T.

Either of these two conditions tends to increase the magnitude of zero sequence current that will flow in line 1 over the value that would otherwise be expected. The increased current may cause a ground distance relay at breaker X to overreach. This is of concern in the application of first zone ground distance relays to prevent a relay misoperation under these conditions. The conditions of Case 1 and Case 2 are calculated in the appendix to determine the percent overreach expected and what modification of the relay setting is needed to prevent a misoperation. Case 2 may represent the most severe overreaching condition which a utility may encounter in ground distance relay applications. If this situation exists, distance relay settings will need modification.

Zero sequence mutual induction can also cause ground distance relays to underreach when the currents in the parallel line and the protected line are in phase. In Case 3 in the appendix the underreach for these conditions has been calculated. The important consideration here is to be certain that an overreaching ground distance relay being used in a pilot relaying scheme will operate for a fault at the next bus with an adequate margin. The results of Case 3 show that the breaker X relay set for 175% of the line impedance would effectively reach to 130% of the line impedance with the effect of mutual induction included. Thus the application is satisfactory.

It is theoretically possible to compensate a ground distance relay so that the effect of zero sequence mutual on its reach will be minimal. This is accomplished by injecting a percentage of the zero sequence current from the parallel line into the relay to offset the increase or decrease in the zero sequence voltage induced in the protected line. However, mutual compensation may be impossible or undesirable for one of the following reasons:

- (a) Where lines run parallel for a portion of their total length, but do not terminate at the same substation at one or both ends, it of course is not possible to obtain a portion of the zero sequence current from the parallel line.
- (b) In what is probably the most severe condition of zero sequence mutual coupling, the case where the parallel line is open and grounded at both ends, it again is not possible to obtain a zero sequence current from the parallel line for use in the compensation circuit since the grounding point is usually beyond the CT location.
- (c) The use of mutual induction compensation with a directional ground distance unit is likely to cause a misoperation. This can occur on a close-in fault on the parallel line behind the relay location where, if mutual compensation were used, it could overpower the normal directional function of the unit and cause it to operate incorrectly. For this reason mutual compensation is seldom used on directional ground distance units (see Reference 7).

The effect of ground fault resistance must also be considered in the application of ground distance relays. A ground distance relay which uses quadrature polarizing voltage has a capability of detecting ground faults with considerable fault resistance. The response of the relay can be predicted by its "variable mho" characteristic. The quadrature voltage is used instead of line to neutral voltage because it provides a reliable polarizing voltage even under the extreme of a near-zero-voltage single-phase-to-ground fault.

The relay characteristic thus produced is called a "variable mho", which is a function of the relay reach and the effective source impedance behind the relay. This characteristic is shown

in the R-X diagram of Figure 5. The MTG mho circle is the representation of the overreaching mho characteristic as it is usually shown. The ACTUAL MTG characteristic is the "variable mho" characteristic produced in this case. The relay is still completely directional. That part of the relay characteristic which falls below the R axis of the R-X diagram still applies to faults on the line in the forward or tripping direction for the relay. The fault impedance in this area now has a capacitive reactance component.

To illustrate the development of the "variable mho" characteristic, a static relay is used as an example. Assume the situation of Figure 6. This is phase A of a system with a single-phase-to-ground fault with ground fault resistance R_F . Also assumed are radial feed and zero load flow. The static ground distance relay is located at Bus A. It is supplied with quadrature polarizing voltage V_{BC} which is phase shifted 90 degrees so that it is in phase with E_{AN} , the generated voltage behind the source impedance Z_S . During the fault, the voltage E_{AN} can be represented as follows:

$$E_{AN} = IZ_S + IZ_F + IR_F$$

where: $IZ_F + IR_F = V_{AN}$, the relay restraint voltage.

Therefore: $E_{AN} = IZ_S + V_{AN}$ which is in phase with $V_{BC} \angle 90^\circ$.

Figure 7 shows a simplified block diagram of the Phase A distance unit showing the voltage phasors, $V_{BC} \angle 90^\circ$ and $IZ_R - V_{AN}$, which are compared via the AND and the 90° TIMER to produce the circular characteristic. The voltage phasor diagram is shown in Figure 8. Since $V_{BC} \angle 90^\circ$ is in phase with E_{AN} , the 90 degree coincidence of E_{AN} with the vector $IZ_R - V_{AN}$, operating voltage minus restraint voltage, will define the circular characteristic with a diameter of the vector sum of IZ_S and IZ_R . This is the variable mho characteristic previously described. The characteristic is variable depending upon the magnitude of the system source impedance Z_S behind the relay.

The three characteristics in Figure 9 represent the "variable mho" characteristic of three different source conditions. The characteristic labeled AA is for a large source impedance, AB is for a smaller source impedance, and MTG is for the theoretical condition of Zero source impedance.

The variable mho characteristic we have discussed here is a steady state characteristic, not a transient one. This is so because the polarizing voltage V_{BC} will remain at normal level during a phase-A-to ground fault with or without the use of memory action. This concept is not new to ground distance relays but it has not been previously discussed in detail. The variable mho characteristic obviously provides positive relay operation for a much higher level of ground fault resistance than would be evident from considering the usual mho unit plot of the relay characteristic. However, the ground fault resistance accommodation or tolerance is not unlimited. In fact, mid-span to ground faults are still quite likely to produce such a high level of ground fault resistance that even these relays may not operate.

Although ground distance relays of conventional design are relatively immune to many of the pitfalls of directional overcurrent relays used for ground protection, they do have some pitfalls of their own which sometimes limit their application. One limitation is encountered when an excessive reach setting is used on a ground distance mho unit. This may cause incorrect tripping by a relay on an unfaulted phase for faults in the reverse direction, either

single-phase-to ground or double-phase-to-ground.

The system conditions most likely to cause a mho ground distance unit to operate incorrectly on an external single-phase-to-ground fault in back of the relay location are shown in Figure 10. Bus B is a high impedance (low current) positive sequence source and a low impedance (high current) zero sequence source. Bus A, on the other hand, has exactly the opposite characteristics, low impedance positive sequence source and high impedance zero sequence source. The R-X diagram of Figure 11 shows an approximation of the impedance areas seen by the phase B and phase C relays for a phase-A-to-ground fault in back of the relay, with a typical MTG reach setting. It is apparent that if the MTG reach is set too great, the phase C relay would be likely to operate for this external fault condition. Therefore, it was necessary to determine the maximum permissible reach setting of the ground mho units to avoid a possible misoperation for this condition.

Ground distance relays of conventional design will also overreach on double-phase-to-ground faults where significant ground fault resistance is present. The analysis of these conditions is quite complex. However, in general, for a phase B-C-ground fault the leading phase B relay will overreach and the lagging phase C relay will underreach. These conditions are of particular concern in the application of first zone ground distance relays. The operation of the leading phase relay may have to be restricted for such cases.

RECENT DEVELOPMENTS IN GROUND RELAY DESIGN

In the previous sections we have reviewed many of the problem areas encountered in ground relaying of transmission lines, and how these problem areas have affected the performance of various types of ground relays. The following paragraphs will describe two recent innovations in ground relaying.

A NEGATIVE SEQUENCE DIRECTIONAL OVERCURRENT RELAY

A recent innovation in static relay design makes possible a negative sequence directional overcurrent relay with adequate sensitivity and excellent security. The negative sequence polarizing voltage, V_2 , has added to it an adjustable compensating quantity, KI_2Z , which is typically equivalent to about 25 percent of the protected line. The resulting polarizing quantity ($V_2 + KI_2Z$) is considerably larger than V_2 at the relay location for faults at the remote end of a long line, and assures dependable polarization, even in the presence of a strong source behind the relay resulting in a very small V_2 . This is shown in Figure 12.

In addition the overcurrent trip supervision unit, while primarily responsive to negative sequence current, has a restraint proportional to positive sequence current. That is, the unit responds to $(I_2 - KI_1)$ where K has an adjustment range of 0.1 to 0.3. This positive sequence restraint feature prevents undesired tripping caused by negative sequence current resulting from load flow over untransposed lines, CT saturation effects or unsymmetrical gap flashing on series-compensated lines.

The excellent sensitivity of this negative sequence directional overcurrent relay scheme provides for the detection of very high resistance ground faults. The greatest sensitivity is realized on a radial feed system where the relay can detect fault resistances of approximately 600 ohms primary when it is possible to use the maximum sensitivity in making the unit pickup settings.

For a typical system condition with double-end feed capability figures are 350 ohms primary for no load flow and 175 ohms primary for a load flow of 3 amperes. This assumes that one line terminal or the other will see the fault.

Ground fault resistance capability of this magnitude will certainly provide relay protection against many mid-span to ground faults that have in the past been very troublesome to clear. The features and operating principles of this static negative sequence directional overcurrent relay are covered in detail in Reference 4.

A NEW GROUND DISTANCE RELAY

A new static ground distance relay has been developed to overcome the shortcomings of the relays of conventional design while retaining the good features of these relays, such as the variable mho characteristic. The use of a four input phase angle comparer produces a relay which performs like a quadrature polarized ground distance relay for internal single-phase-to-ground faults. On the other hand, it is much less likely to operate incorrectly for those conditions where operation is not desirable as was discussed at length in an earlier section. The component relay is designated SLYG81 and an equivalent relay designated SLYG61 is available for static relaying equipments. A photograph of the type SLYG81 is shown in Figure 13.

The complete relay consists of three separate ground distance measuring units, each with its own four input phase angle comparer and 90 degree characteristic timer. The comparer is simply a four input AND logic which provides an output only when all four inputs are coincident, either on the positive half cycle or on the negative half cycle. The sine wave diagram of Figure 14 shows the conditions where all four comparer inputs are coincident for just 90 degrees. This indicates an impedance just at the balance point on the circular mho characteristic.

Using phase A as an example, the four inputs to the phase angle comparer are as follows :

- (1) The operating quantity, $(IZ - V)$, in detail is $(I_A - I_0)Z_{R1} + K_0 I_0 Z_{R0} - TV_{AN}$
- (2) Polarizing voltage No. 1, $V_{BC} \angle 90^\circ$, the quadrature voltage shifted 90 degrees so as to be in phase with the prefault voltage V_{AN} .
- (3) Polarizing voltage No. 2, $CK_0 I_0 Z_{R0} - V_0$, a current compensated zero sequence polarizing voltage.
- (4) Zero sequence current supervision, $I_0 Z_{R0}$.

where: Z_{R1} and Z_{R0} are relay replica impedances for positive and zero sequence respectively

T is a tap setting adjustment

K_0 is a zero sequence ratio adjustment

C is a design constant

A block diagram is shown in Figure 15.

The operating quantity input is designed to match the positive and zero sequence impedance of the line both in magnitude and phase angle. A memory filter is used in the No. 1 polarizing circuit to delay any change in this voltage for a few cycles after the inception of the fault. The operating circuit contains a bypass filter which consists of a bandpass filter plus circuitry to

partially bypass the filter section for operating signals of high magnitude. This bypass filter is a key element in obtaining high speed operation on close-in internal faults plus security against transient effects on external faults.

The inputs (1) and (2) to the comparer are basically the same as the inputs for a quadrature polarized ground distance relay of conventional design. Therefore, the new relay also has the variable mho characteristic described earlier. When inputs (3) and (4) are added they provide the function of a zero sequence directional relay. A combination of the four inputs also provides the equivalent of a faulted phase selector. These added functions make the relay secure against the undesirable operations discussed earlier.

For example, with an external single-phase-to-ground fault behind the relay, comparer inputs (3) and (4) will be out of phase with each other by approximately 180 degrees. Thus, the incorrect operation of unfaulted phase units on an external single-phase-to-ground fault is prevented by the lack of coincidence between comparer inputs (3) and (4).

The phasor diagram for an internal phase-A-to-Ground fault is shown in Figure 16. The four voltage phasors being supplied to the phase A comparer are all well within the 90 degree coincidence required for relay operation. The unfaulted phases, B and C, however, have their quadrature polarizing voltages, $V_{CA} \angle 90^\circ$ and $V_{AB} \angle 90^\circ$ respectively, nearly 120 degrees out of phase with the number two polarizing voltage $K_0 I_0 Z_{R0} - V_0$. This lack of coincidence prevents operation of either the phase B or the phase C unit on an internal phase-A-to-ground fault.

The four input comparer is also responsible for the elimination of the overreach of the leading phase unit during a double-phase-to-ground fault with high ground fault resistance. Just at the relay characteristic balance point the comparer I_Z voltage minus the V_{LN} voltage will be zero if there is zero fault resistance. With fault resistance present the voltage is $-3I_0 R_F$. The angular relationship in the leading phase unit comparer of this fault resistance voltage and the current supervision phasor $I_0 Z_{R0}$, input (4), is greater than 90 degrees thus precluding an output from the leading phase comparer and its 90 degree coincidence timer. Thus the overreach is eliminated.

The significance of the four input comparer and the foregoing analysis of the operation of the relay is that it is very secure against false operations. Thus the complex calculations that were necessary in the application of previously available ground distance relays are no longer required.

CONCLUSIONS

Applications of ground relaying for transmission line protection have been quite successful for some time utilizing existing conventional relays and schemes. The various problems discussed in this paper have been encountered in the field and in most cases satisfactory settings and solutions have been obtained. It is quite likely that many future applications of ground relaying will be satisfactorily made in the same way.

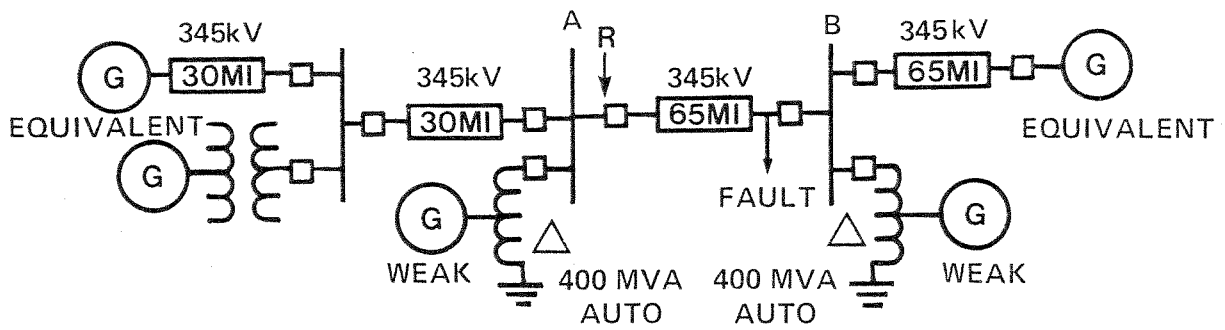
Improved protection has now been made available with a new scheme for ground relaying using negative sequence quantities. This involves a negative sequence directional unit and a negative sequence overcurrent unit which are particularly applicable to faults where a very high level of ground fault resistance can be encountered. This scheme is adequate for many mid-span

to ground faults caused by trees or brush fires. It provides protection that has heretofore not been available for these particular faults.

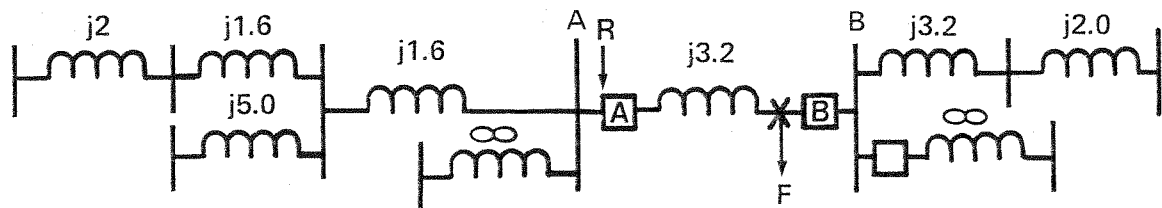
Another improvement in protection has been made available in a new ground distance relay. It features a four-input phase angle comparer which provides greatly improved security against overreaching and false tripping on certain faults. Complex calculations of system conditions are no longer required to verify the application. The new relay also retains the fault resistance capability of the conventional quadrature polarized ground distance relay with its variable mho characteristic.

References

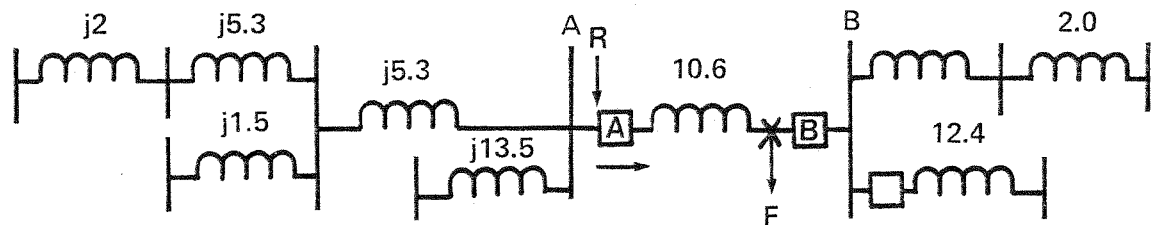
1. "V₀ - Reversal on Mutually Coupled Lines - Relay Analysis, Experience and Remedies", K. H. Engelhardt, Western Protective Relay Conference, 1974.
2. "Polarizing Sources for Directional Ground Relays", J.G. Andrichak, Electric Council of New England, Fall 1973.
3. "Negative Sequence Relaying for Mutually Coupled Lines", J.L. Blackburn, 1972 Conference for Protective Relay Engineers, Texas A. & M. University.
4. "Type SLYP-SLCN Static Directional Comparison Relaying, Description and Application", Bulletin GET-6456, General Electric Co., 1978.
5. "The Art and Science of Protective Relaying", C. Russell Mason, John Wiley & Sons., New York. Pages 347-348.
6. "Ground Distance Relaying", by A.J. McConnell, presented at Pennsylvania Electric Association Relay Committee Meeting, Hagerstown, Maryland, October 1965, Page 2, and Appendix V.
7. Ibid, page 6



POSITIVE SEQUENCE NETWORK (% ON 100 MVA BASE)



ZERO SEQUENCE NETWORK (% ON 100 MVA BASE)



ALL SYSTEMS IN SERVICE:

$$I_{OT} = 9.6 \text{ P.U.} \quad I_{OR} = 2.83 \text{ P.U.}$$

TRANSFORMER AT BUS B TAKEN OUT OF SERVICE:

$$I_{OT} = 7.8 \text{ P.U.} \quad I_{OR} = 3.57 \text{ P.U.}$$

FIGURE 1
SEQUENCE EQUIVALENT IMPEDANCE NETWORKS
FOR A TYPICAL 345 KV SYSTEM

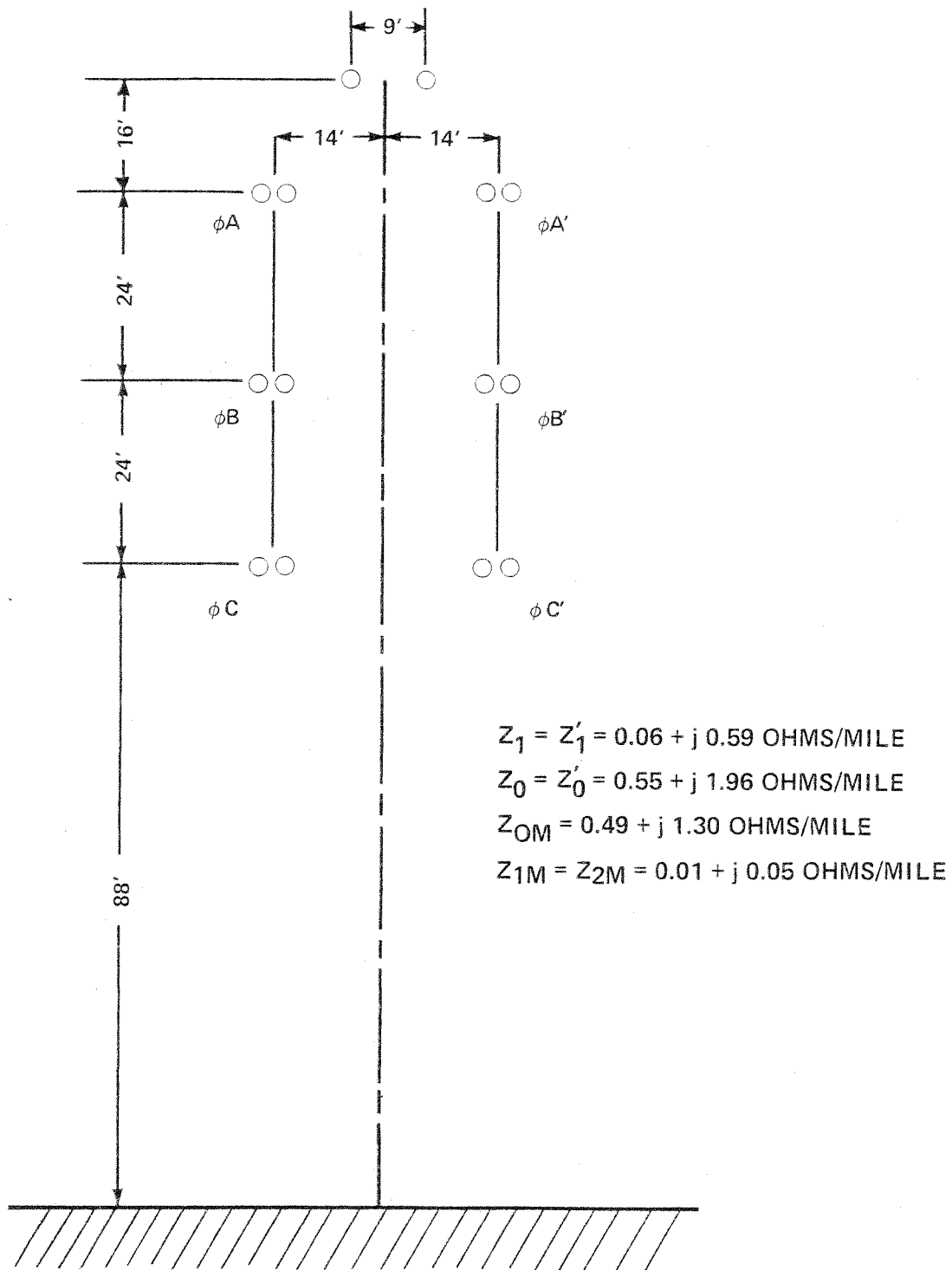


FIGURE 2
TYPICAL CONFIGURATION OF 345 KV
LINES ON A DOUBLE-CIRCUIT TOWER

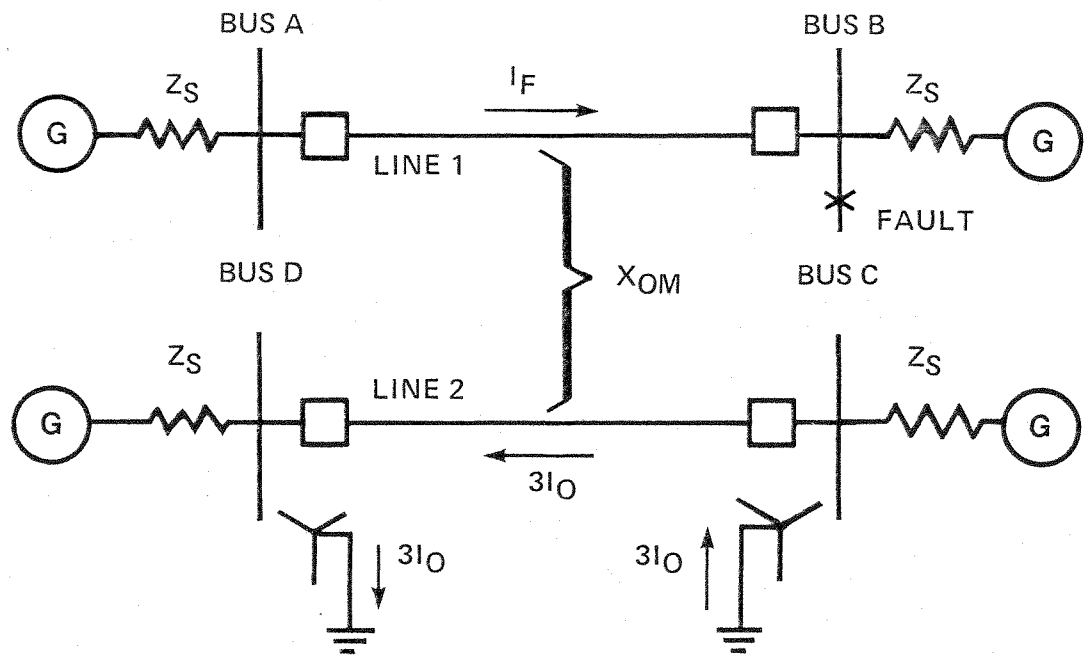


FIGURE 3
CLASSICAL EXAMPLE OF MUTUAL COUPLING
BETWEEN TWO PARALLEL LINES

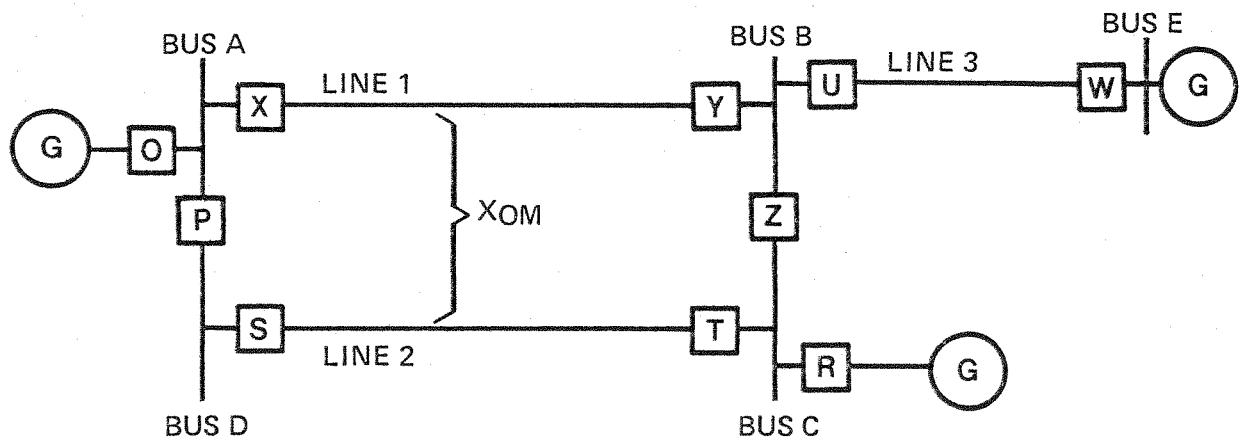


FIGURE 4
TYPICAL EXAMPLE OF MUTUAL COUPLING
BETWEEN PARALLEL LINES

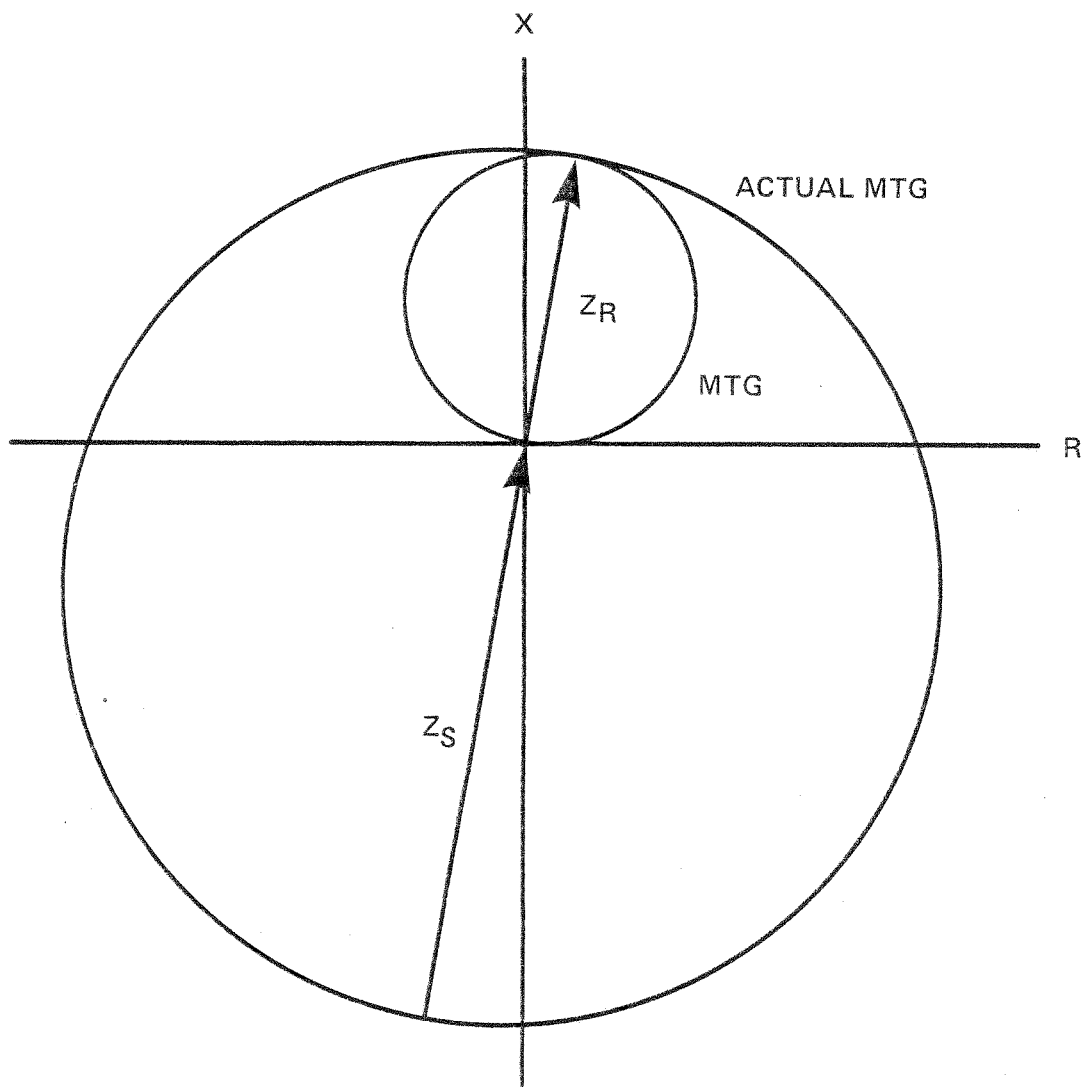


FIGURE 5
"VARIABLE MHO" CHARACTERISTIC

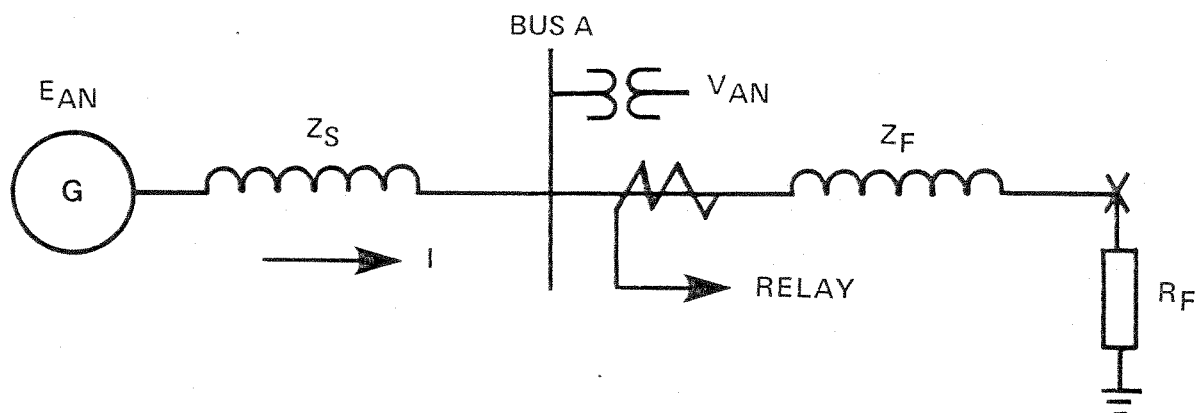


FIGURE 6
SINGLE-PHASE-TO-GROUND FAULT ON RADIAL SYSTEM

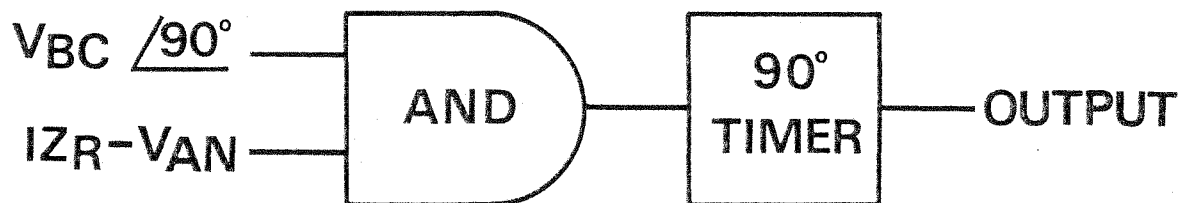


FIGURE 7
SIMPLIFIED BLOCK DIAGRAM OF QUADRATURE POLARIZED DISTANCE RELAY

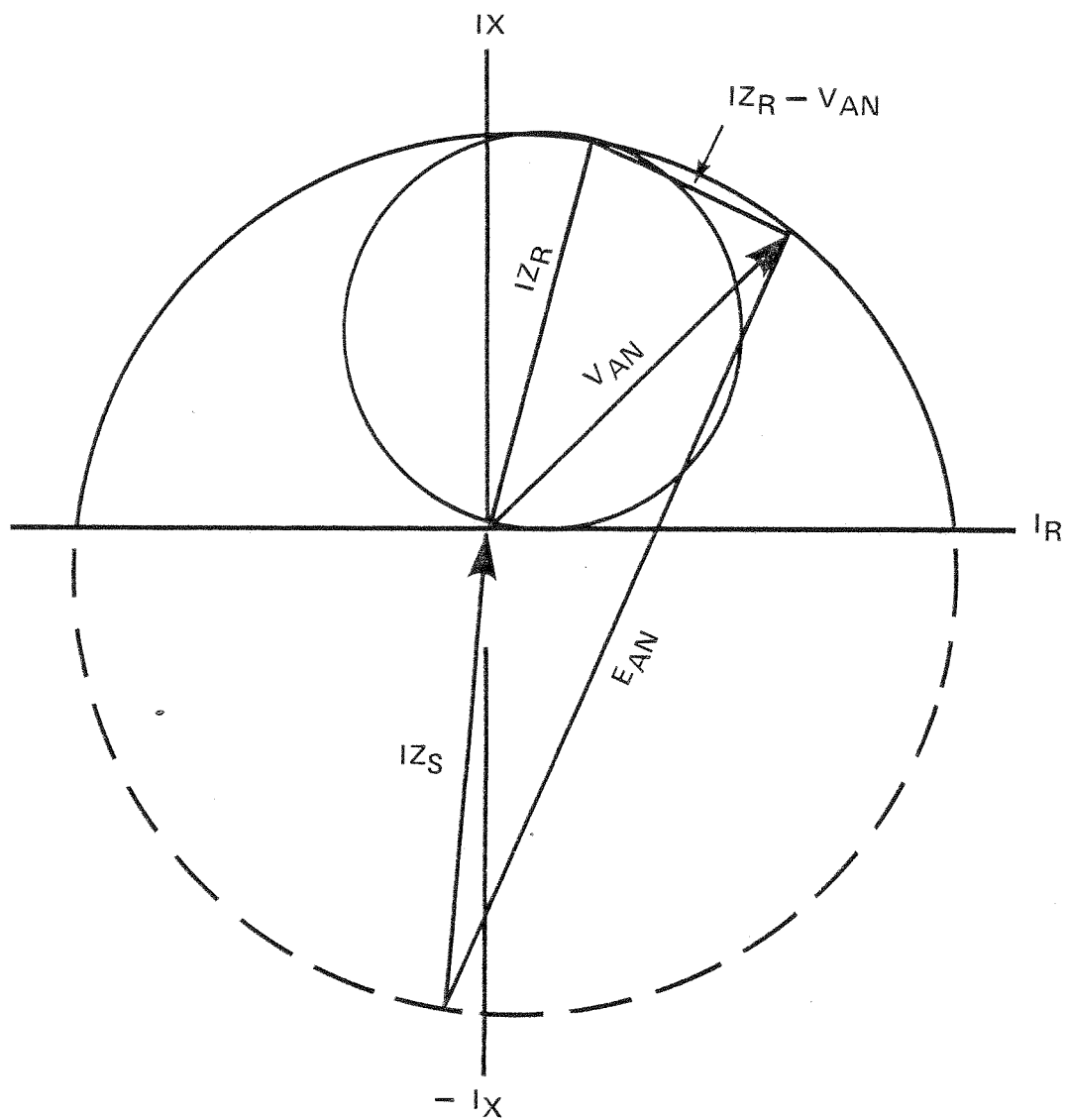


FIGURE 8
VOLTAGE PHASOR DIAGRAM

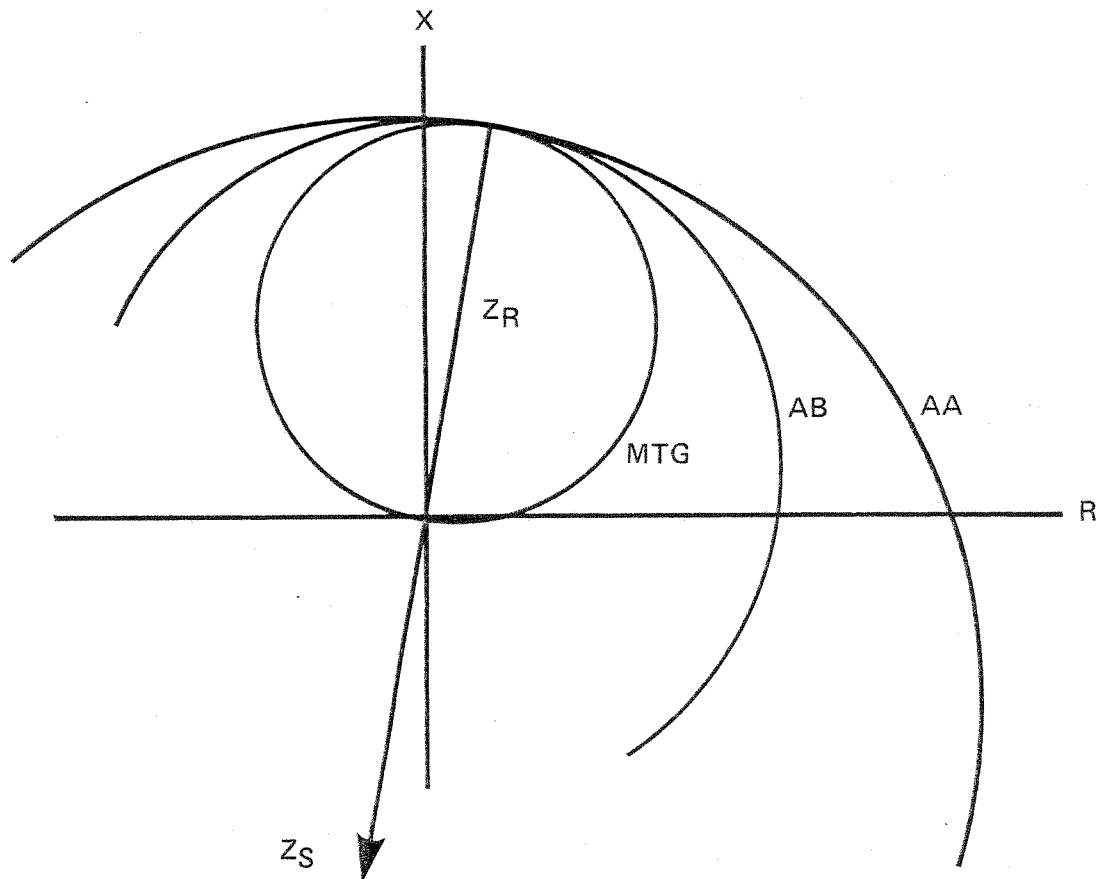


FIGURE 9
VARIABLE MHO CHARACTERISTICS

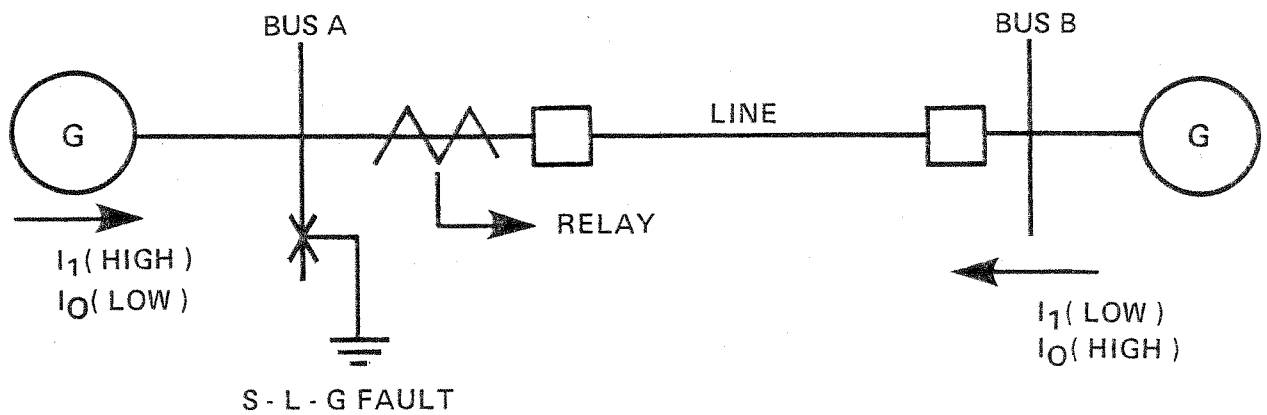


FIGURE 10
SYSTEM CONDITIONS REQUIRING
CHECK OF MAXIMUM PERMISSIBLE MTG REACH

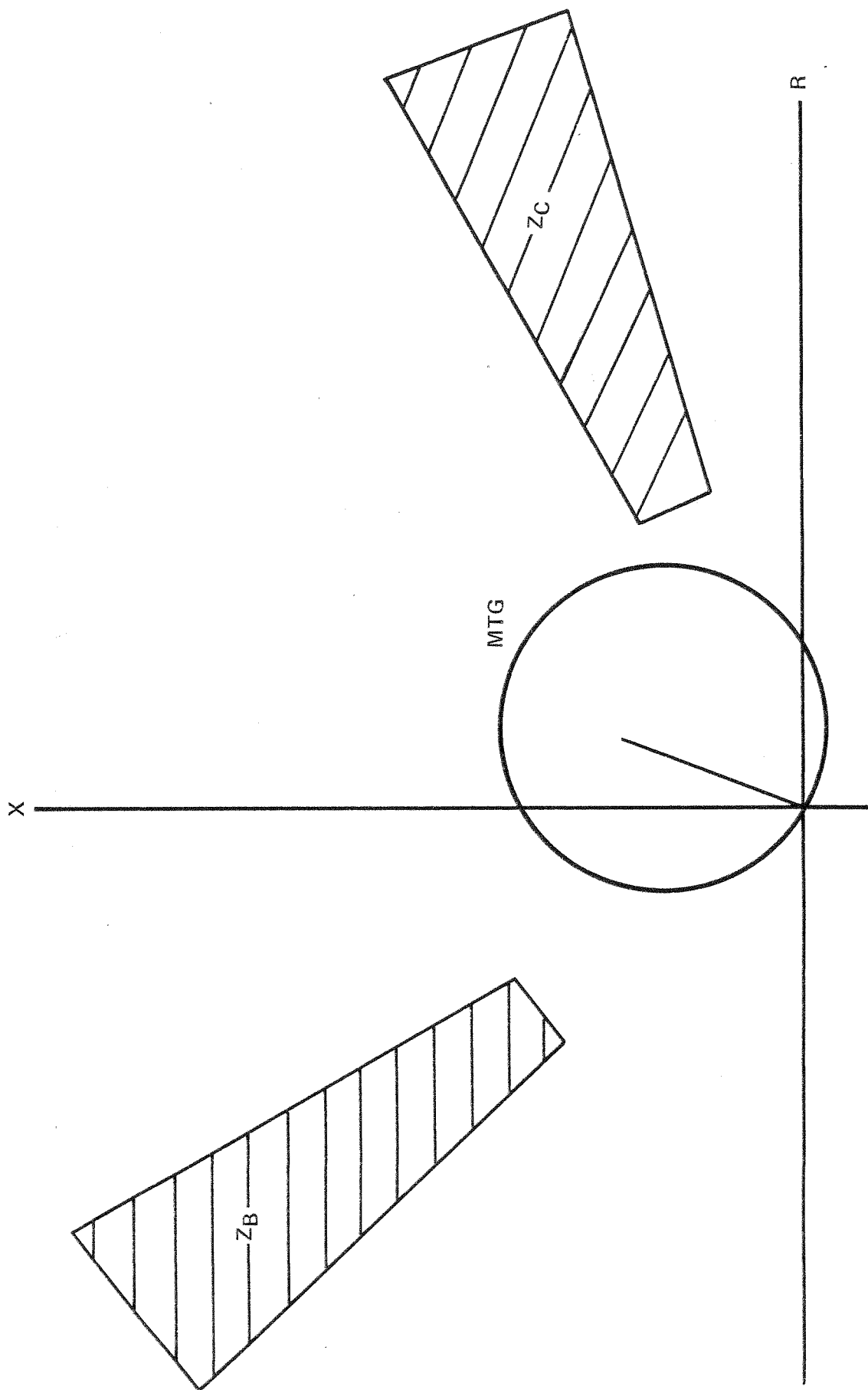


FIGURE 11
APPROXIMATE IMPEDANCE AREAS SEEN BY PHASE
B AND C RELAYS FOR PHASE A-TO-GROUND FAULTS

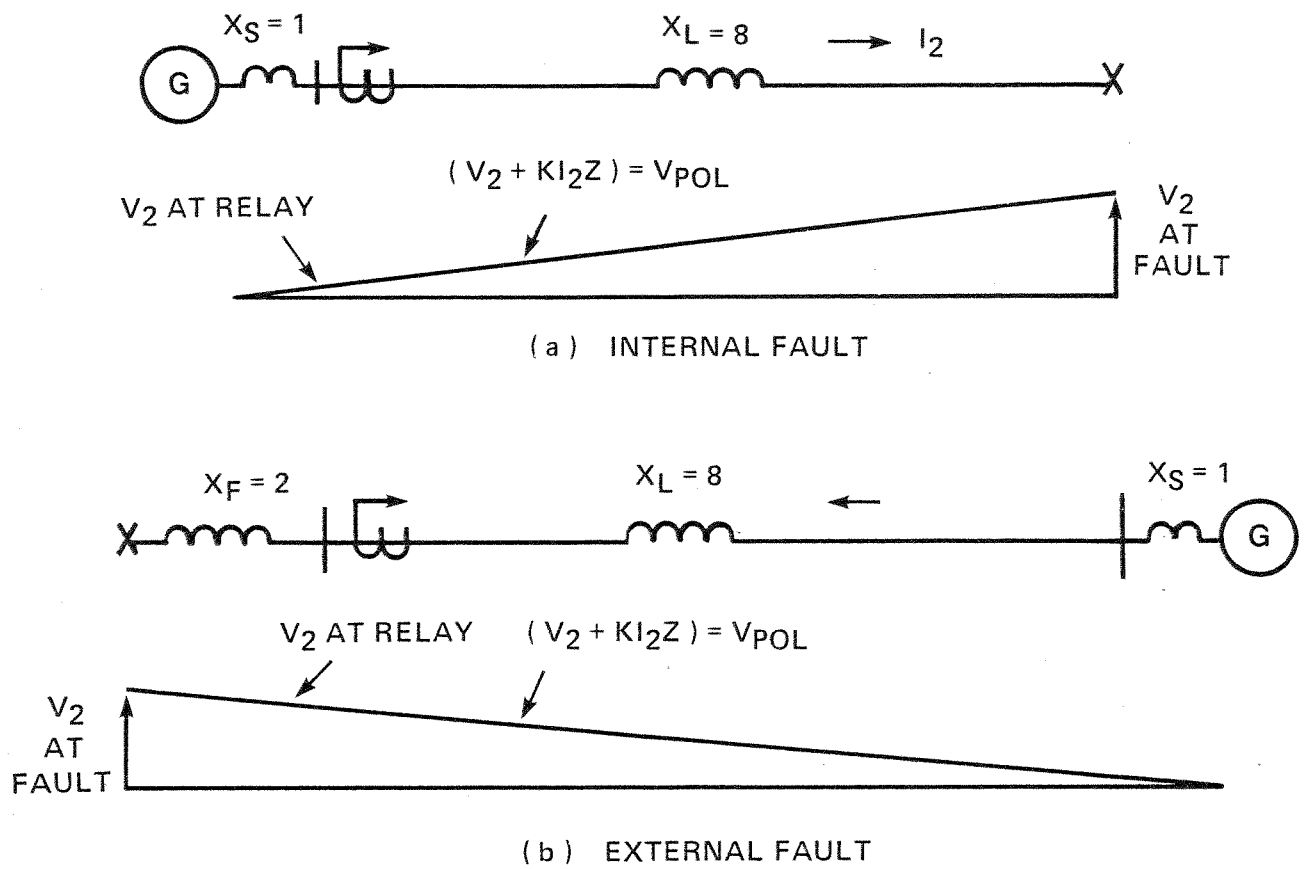


FIGURE 12
ILLUSTRATION OF COMPENSATED
NEGATIVE SEQUENCE POLARIZATION

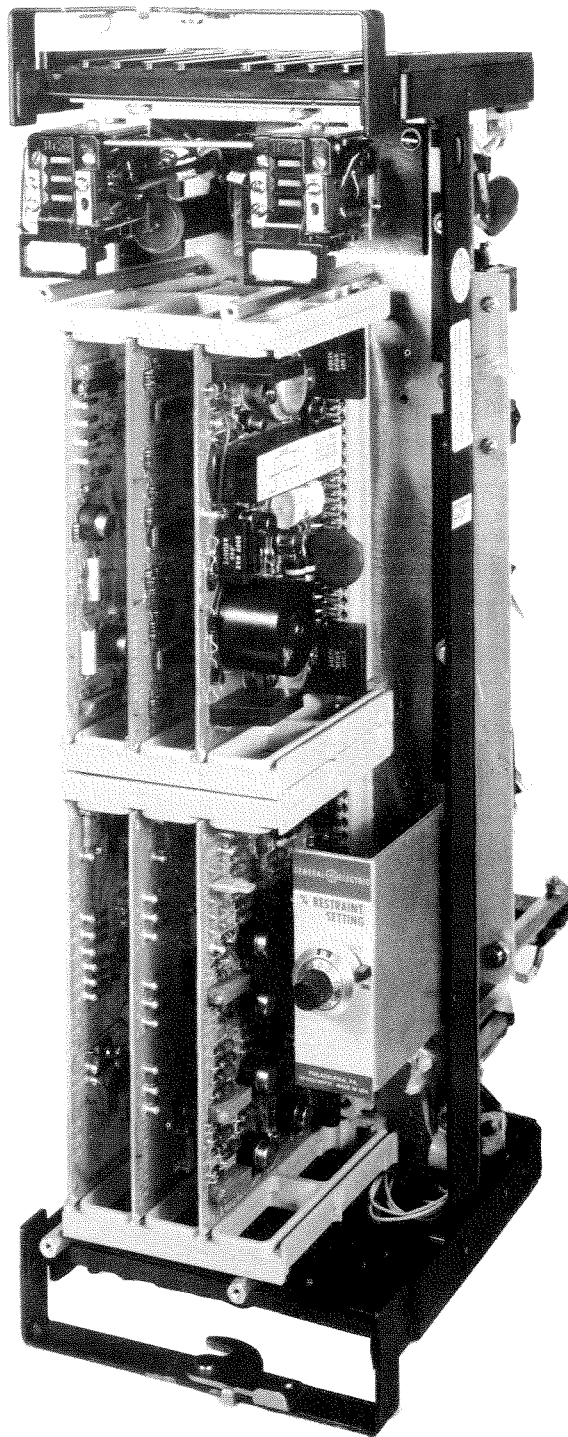


FIGURE 13
TYPE SLYG81 GROUND DISTANCE RELAY

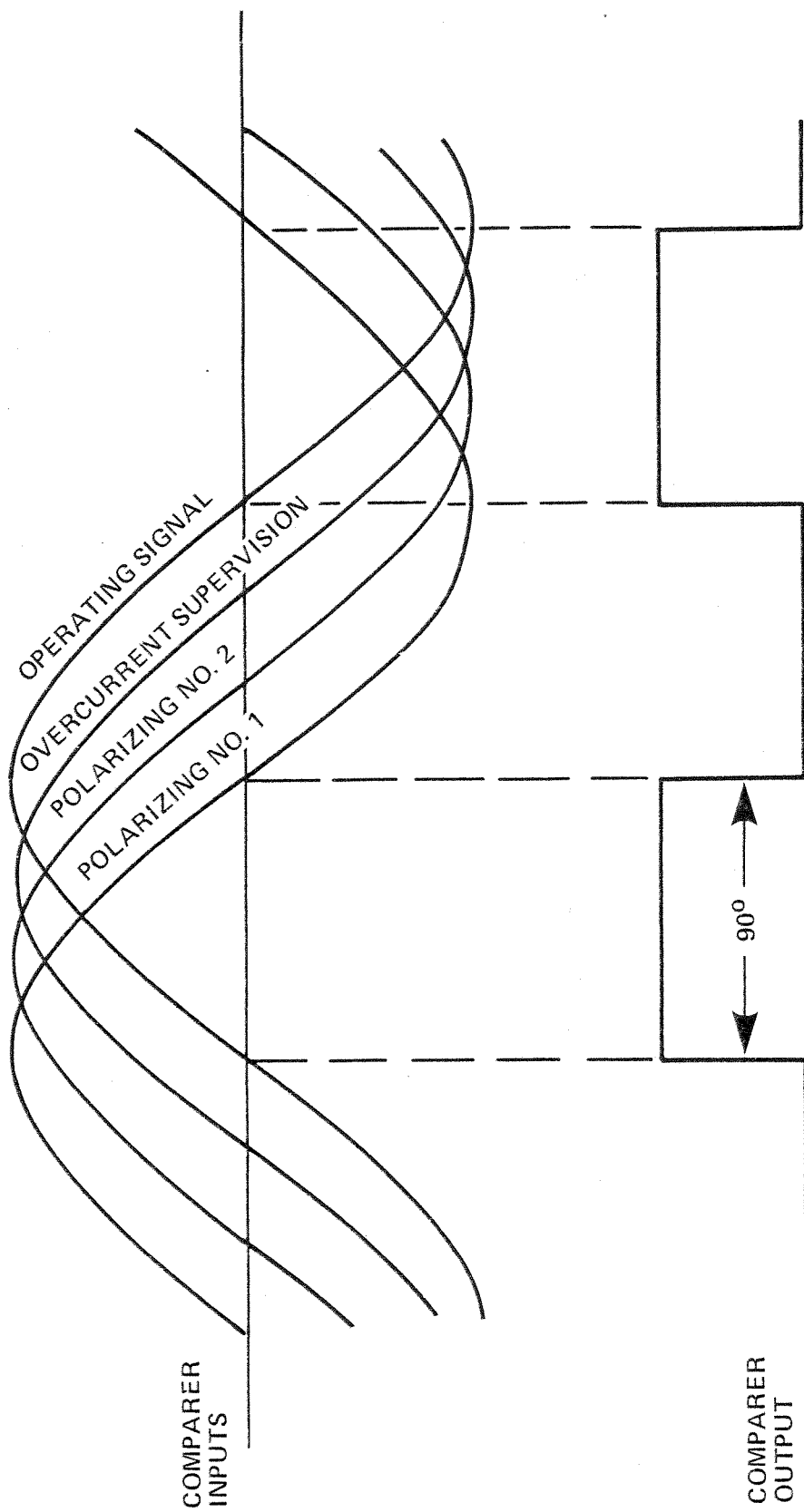


FIGURE 14
COINCIDENCE OF COMPARER INPUTS

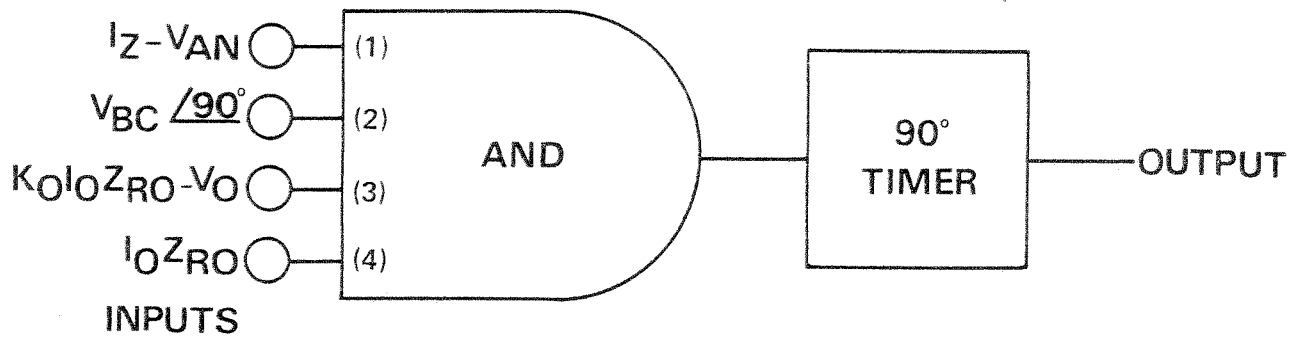


FIGURE 15
BLOCK DIAGRAM OF FOUR-INPUT COMPARER

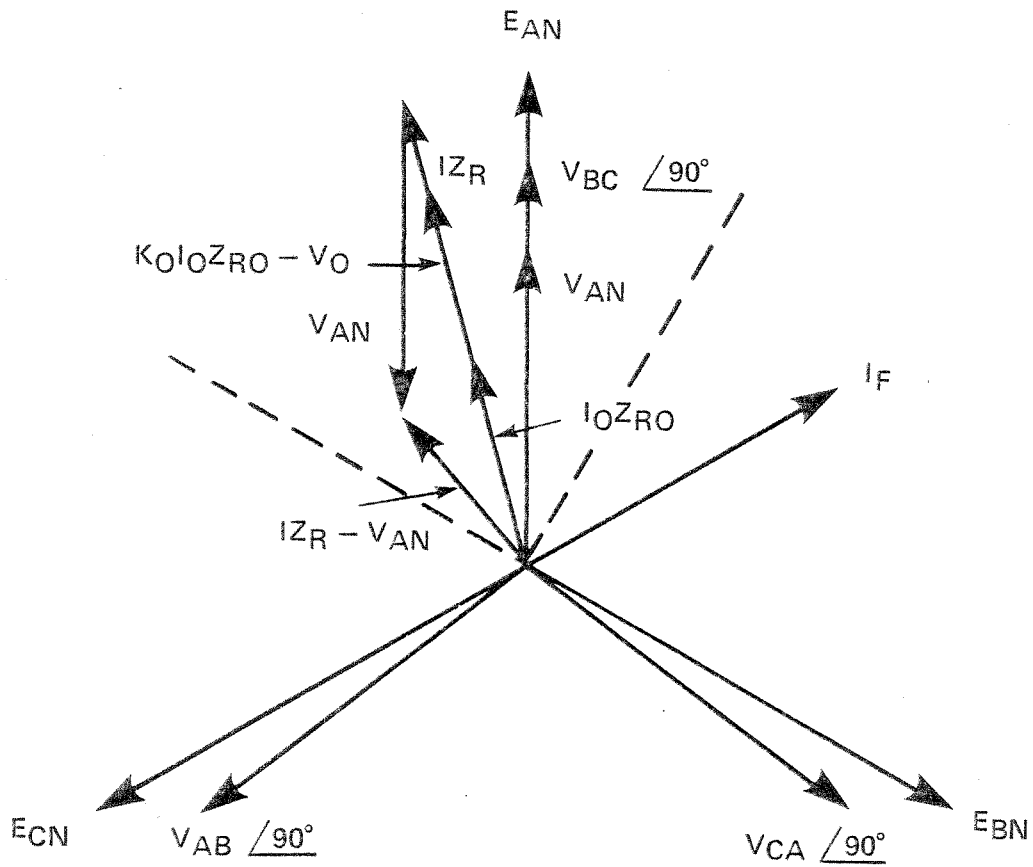


FIGURE 16
PHASOR DIAGRAM FOR INTERNAL PHASE-A-TO-GROUND FAULT

APPENDIX I

Change in Reach of Ground Distance Relays Caused by Mutual Induction.

Depending on system conditions, the presence of mutual induction between two parallel lines can cause a ground distance relay to either overreach or underreach. Three cases representing different conditions are described below.

Case 1: Zero sequence current in a parallel line flowing in a direction opposite to that in the protected line.

The condition to be considered for Case 1 is represented in Figure I-A. The apparent impedance seen by the ground distance relay is defined by the phase to neutral voltage at the relay location divided by a current. Consequently, any change in the voltage resulting from the mutual inductance, assuming no corresponding change in current, will cause the relay reach to change. For the situation in Figure I-A, line to neutral voltage on the faulted phase at location X can be expressed as follows :

$$V_L = I_1 Z_1 + I_2 Z_2 + I_0 Z_0 - I'_0 Z_{0M} \quad (I-1)$$

Adding and subtracting $I_0 Z_1$, and substituting Z_1 for Z_2 , yields the following:

$$V_L = I_1 Z_1 + I_2 Z_1 + I_0 Z_1 - I_0 Z_1 + I_0 Z_0 - I'_0 Z_{0M} \quad (I-2)$$

$$V_L = (I_1 + I_2 + I_0) Z_1 + I_0 (Z_0 - Z_1) - I'_0 Z_{0M} \quad (I-3)$$

$$V_L = I_L Z_1 + I_0 (Z_0 - Z_1) - I'_0 Z_{0M} \quad (I-4)$$

The percent change in reach, in this case overreach, when mutual compensation is not employed can then be represented by the following:

$$\% \text{ overreach} = \frac{I_L Z_1 + I_0 (Z_0 - Z_1)}{I_L Z_1 + I_0 (Z_0 - Z_1) - I'_0 Z_{0M}} \times 100 \quad (I-5)$$

Assume the following system conditions as a most severe case and refer to Figure I-1 for system configuration:

1. Line constants of the double-circuit 345 KV tower shown in Figure 2 are :

$$Z_1 = Z'_1 = .061 + j .588 \text{ ohms/mile}$$

$$Z_0 = Z'_0 = .549 + j 1.964 \text{ ohms/mile}$$

$$Z_{0M} = .489 + j 1.3 \text{ ohms /mile}$$

2. Line S-T parallels line X-Y for 100 percent of line length.
3. Source A contributes 50% of I_0 in line X-Y, and source C contributes the other 50% over line T-S.
4. The ratio of zero sequence current to total line current is 1:3.

For these conditions:

$$I_0 = \frac{I_L}{3} \quad (I-6)$$

$$I'_0 = \frac{I_L}{6} \quad (I-7)$$

Substituting these current values and the impedance values into equation (I-5) yields an overreach of approximately 25 percent. That is a relay set to reach 68 percent of the impedance of the protected line will now reach 85 percent of the line.

Case 2: Grounded parallel line.

The conditions to be considered in Case 2 are as follows:

1. Line S-T is out of service with three-phase grounding chains at both ends.
2. The ratio of zero sequence current in the line to total line current is 1:3.
3. Impedances are the same as in Case 1.

The phase to neutral voltage on the faulted phase at breaker X is :

$$V_L = I_1 Z_L + I_0 (Z_0 - Z_1) - \left(\frac{Z_M^2}{Z'_0} \right) I_0 \quad (I-8)$$

The percent overreach is determined by the following equation:

$$\% \text{ overreach} = \left\{ \left[\frac{I_1 Z_L + I_0 (Z_0 - Z_1)}{I_1 Z_L + I_0 \left(Z_0 - Z_1 - \frac{Z_M^2}{Z'_0} \right)} \right] - 1 \right\} \times 100 \quad (I-9)$$

Substituting the current and impedance values into equation (I-9) yields an overreach of approximately 38%.

Thus, a zone-1 ground distance relay, normally set for 80 percent of the protected line, would have to be set for 58 percent of the line in order to maintain the same margin.

Case 3: Zero sequence current in a parallel line flowing in the same direction as that in the protected line.

The condition for Case 3 would be represented by the system in Figure 4 of the main text with all breakers closed, and with an external fault to the right of bus B. For this condition $I_0 = I'_0$, and assume that $I_0 = \frac{I_L}{4}$. The phase to neutral voltage on the faulted phase at location X is:

$$V_L = I_L Z_1 + I_0 (Z_0 - Z_1) + I'_0 Z_M \quad (I-10)$$

The percentage underreach can then be expressed as follows:

$$\% \text{ underreach : } \left[1 - \frac{I_L Z_1 + I_0 (Z_0 - Z_1)}{I_L Z_1 + I_0 (Z_0 - Z_1) + I'_0 Z_{OM}} \right] \times 100 \quad (I-11)$$

Substituting the current and impedance values into equation (I-11) indicates a percentage underreach of 26 percent. Thus, a zone-2 relay set to reach 135 percent of the protected line would actually reach just 100 percent of the line for the conditions assumed.

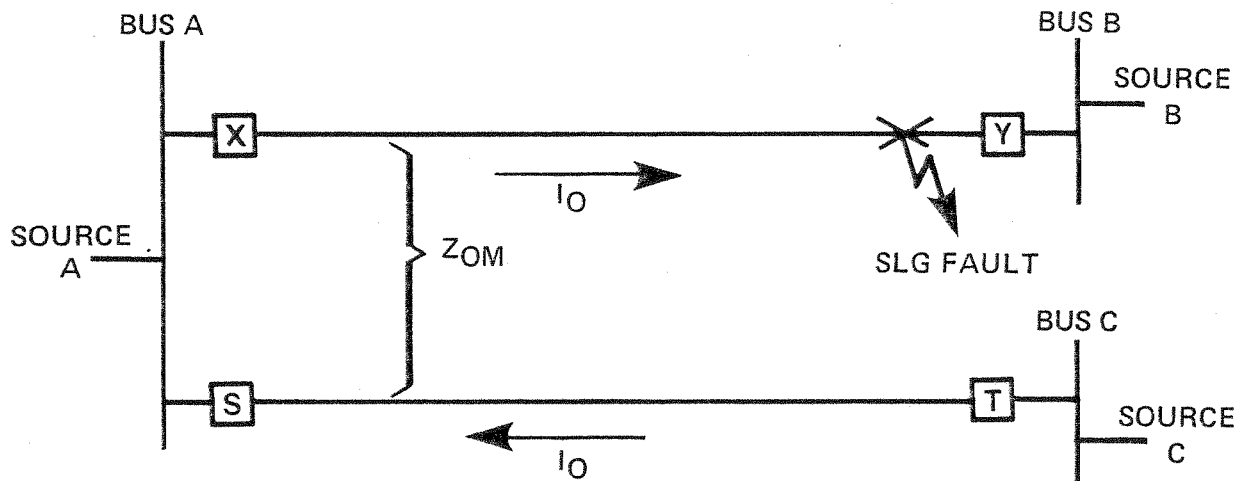
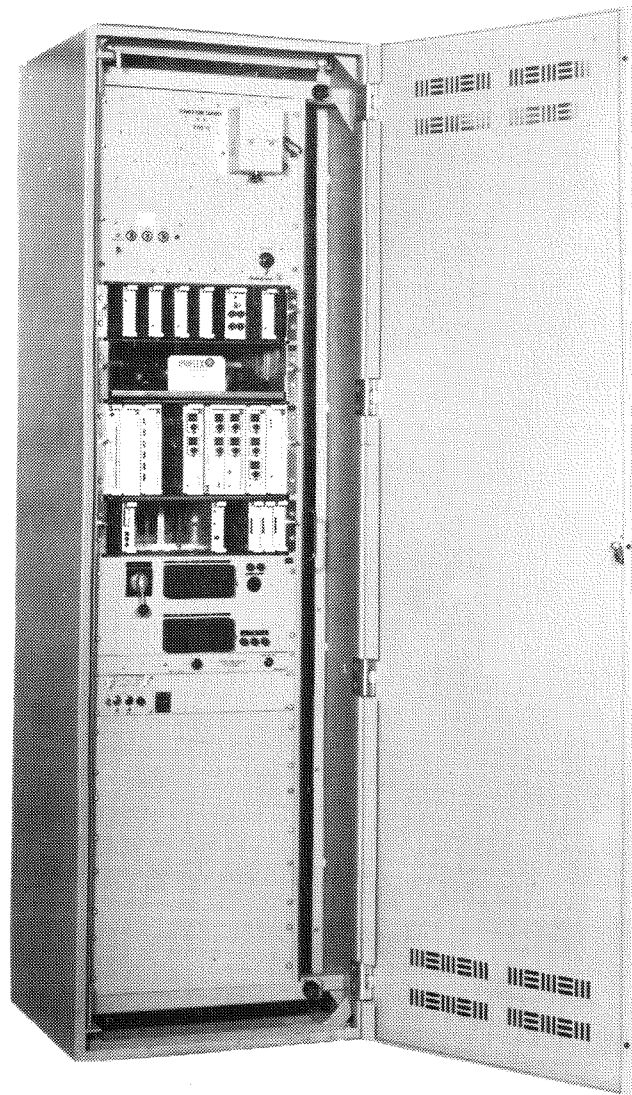


FIGURE I-A

UNIFLEX CONCEPTS ON TRANSMISSION LINE RELAYING



*By J. E. Greene
Fellow Engineer
Westinghouse Electric Corp.
Relay Instrument Division
Newark, New Jersey*

*Presented at the
Western Protective Relay Conference
October 16-18, 1978
Sacramento, California*

UNIFLEX CONCEPTS ON TRANSMISSION LINE RELAYING

INTRODUCTION

Solid state relay systems for the protection of transmission lines began to replace their electro-mechanical counterparts in the early "sixties" chiefly for EHV lines. These systems initially were comprised of relays that used discrete components that were housed in the same flexitest cases that are used for electromechanical relays.

These solid state relay designs were upgraded and repackaged in rack mounted chassis with plug-in printed circuit boards. However, the designs were substantially the same as before.

Developments during the early "seventies" indicated the need for low energy relay systems. The availability of the operational amplifier integrated circuit, the high threshold logic integrated circuits, the optical isolator IC package, and the light emitting diode caused a re-evaluation of the entire concept of solid state relay system design.

SYSTEM DESIGN CONCEPTS

The Uniflex solid state relay systems were designed "from the top down". The requirements of the various systems were defined from a system viewpoint. Elements that could be common to more than one system were identified. The packaging then was developed using plug-in relays and modules to the greatest practical extent.

The organization of the system functions is shown in Figure 1 for the directional comparison family of pilot systems: blocking, unblock, and permissive overreaching transfer trip (POTT). The sets of modules that are typically required to implement the functions in Figure 1 are shown in the following figures:

Figure 2 Blocking System With No Options

Figure 3 Blocking System With All Options

Figure 4 Unblock System With No Options

Figure 5 Unblock System With All Options

Figure 6 POTT System With No Options

Figure 7 POTT System With All Options

Figure 8 and Figure 9 show similar information for the non-pilot system.

Certain "logic functions" are not plug-in entities, but consist of a dedicated set of hardware, printed circuitry, and printed circuit board area. These are the "option functions" on the DBL blocking logic, DUL unblocking logic, NPL non-pilot logic, and the OPT-1 logic modules.

The Uniflex instruction leaflets follow the modular concept with each relay system option having its own unique publication. The instruction book for a system is subdivided into sections to minimize the search for a given bit of information. In addition, the book contains only those leaflets that apply to the particular system.

The modular approach inherently invites the use of computer aids for engineering, drafting, and manufacturing. In addition to various lists, the computer generates punched tapes that operate a numerically controlled semi-automatic wiring machine on which all relay chassis backplanes and all cabinet harnesses are wired.

The low burden of the Uniflex relay system allows the use of the type UFTB portable test box for functional testing. The test box is powered by single phase 120 volts 60 hertz and generates internally the three phase test voltages necessary to simulate all phase and ground faults. A single phase test current

is provided such that internal and external faults may be simulated to operate all relays for any setting. A variac provides voltage control which allows a recheck of the balance point of the distance relays. The UFTB test box is shown in Figure 10. It plugs into the UTP test panel shown in Figure 11.

NOISE IMMUNITY

The Uniflex relay system utilizes a number of techniques to provide noise immunity. Cables for connection to the switchyard are enclosed in a steel trough to provide shielding. Surge suppression capacitors are provided for leads with switchyard exposure immediately as the conductor exits the trough with very short leads to ground via the steel trough. This provides a quiet relay cabinet environment. Even so, the analog signals for the operational amplifiers are via shielded twisted pair, and the digital signal wiring is on the side opposite the cable trough.

The Uniflex relay system is isolated from the outside world by transformers or optical isolators on inputs, and by "dry" contacts or optical isolators on outputs. Decoupling capacitors are provided on all operational amplifier boards. All digital logic is high threshold design providing the highest noise immunity available.

THE UNIFLEX SYSTEMS

Common to all Uniflex systems are the following 19 inch rack mounted assemblies:

- USPS Power Supply
- UCT Current Transformation
- UBR Basic Relays
- UIO Input/Output
- UTP Test Panel

The UOP1 option relay assembly may be supplied with any system. The UOP2 option relay assembly may be supplied with the unblock system or with the permissive overreaching transfer trip system.

The channel equipment for pilot systems normally is mounted above the USPS power supply. However, in some cases it is remote from the Uniflex cabinet.

The UMO monitor assembly may be supplied with any Uniflex system. Typical Uniflex systems are shown in the following figures:

- Figure 12a Blocking System
- Figure 12b Blocking System With UOP1 and UMO
- Figure 13a Unblock System
- Figure 13b Unblock System With UOP1
- Figure 13c Unblock System 3 Terminal Line, With UOP1, UOP2, and UMO
- Figure 14a POTT System
- Figure 14b POTT System With UOP1
- Figure 14c POTT System 3 terminal line With UOP1, UOP2, and UMO
- Figure 15a Non-Pilot System
- Figure 15b Non-Pilot System With UOP1 and UMO

THE 19 INCH RACK MOUNTED ASSEMBLIES

The USPS power supply is shown in Figure 16 and is a dc to dc converter type which provides isolation from the station battery. It provides a tracking regulated ± 15 volt supply for the operational amplifiers, and a separately regulated +15 volt supply for the digital logic, the light emitting diodes, and the auxiliary relays. The USPS is self-protecting.

The UCT current transformation assembly contains air gap current transformers which provide isolation from the switchyard current transformer secondary circuits. The air gap reduces the effect of dc offset current on the measuring relays. The secondary of the air gap transformer is permanently loaded with a 10 ohm shunt which provides a fixed burden of less than 2 VA per phase at 5 amperes and which precludes an open secondary. The voltage supplied to the relays is that across the shunt and is 1 volt $\angle 75^\circ$ at 5 amperes.

The UBR basic relay assembly contains the system logic and the measuring relays as well as the LTI test indicator module and the LVT voltage transformation module. Typical assemblies are shown in the following figures:

- | | |
|------------|----------------------------|
| Figure 17 | UBR Typical – With Details |
| Figure 18a | UBR Blocking System |
| Figure 18b | UBR Unblock or POTT System |
| Figure 18c | UBR Non-Pilot System |

The LVT voltage transformation module contains the voltage transformers that provide isolation from the switchyard voltage transformer secondary circuits. The ratio is 12/1 which supplies 6 volts to the relays. The total burden is less than 1 VA per phase. A phase shifting circuit is provided to permit switching the angle of maximum sensitivity from 75° , which is inherent with the UCT, to 65° . Trim-pots provide for adjusting the angle from 65° to 75° . For angles from 75° to 90° a different style number LVT is available.

The LTI test indicator module provides a light emitting diode (LED) for each logic output in the assembly. It has a pushbutton switch to activate the LEDs for testing.

The UOP1 optional relay assembly contains the relays for Zone 1 high speed trip and either zone 3 timer trip or double blinder out-of-step. Typical assemblies are shown in the following figures:

- | | |
|------------|--------------------------|
| Figure 19a | UOP1 Zone 1, Zone 3 |
| Figure 19b | UOP1 Zone 1, Out-of-Step |
| Figure 19c | UOP1 Zone 3, Out-of-Step |

The UOP2 optional relay assembly contains the relays for weakfeed terminals where either the unblock system or the POTT system is used. A typical assembly is shown in Figure 20.

The UTP test panel assembly is shown in Figure 11. The FT-1 test switches provide for measuring relay system currents and voltages, or introducing test currents and voltages either from calibration test equipment or from the UFTB portable test box. The trip cutout switch isolates the Uniflex system outputs from the breaker control devices during testing.

The UIO input/output assembly contains the modules that provide dc isolation from external devices. In addition, LEDs provide target indication. Typical assemblies are shown in the following figures:

- | | |
|------------|--------------|
| Figure 21a | UIO ARM Trip |
| Figure 21b | UIO SRM Trip |

The ARM module provides type AR relay contact outputs for breaker trip and for breaker failure timing initiate. It has LED targets for breaker trip and a reset pushbutton for all target LEDs.

The SRM module provides thyristor outputs for breaker trip and reed relay outputs for breaker failure timing initiate. It has LED targets for breaker trip and a reset pushbutton for all target LEDs.

The BFM module provides type AR relay contact outputs for breaker failure timing initiate where the reed relay contacts are not suitable. It has LEDs for relay test.

The IFM module provides interface with the channel equipment and contains the variable features required by the channel. It has pushbuttons for transmitter key and channel simulate and a pushbutton switch for pilot trip cutout. As an option, it may have a carrier level indicator.

The RIM module provides reed relay outputs for reclose initiate. It has LED targets for high speed trips.

The RBM module provides reed relay outputs for reclose block. It has LED targets for time delay trips.

The PRM module provides programmable reed relay outputs for trip functions and for non-trip functions. It has LED targets for non-trip functions.

The CBM module provides a manually initiated check back feature that permits testing of the channel in both directions from a single station.

The UMO monitor assembly is shown in Figure 22. The UMPS power supply provides a regulated +15 volts to the monitor modules. The monitor modules provide dc isolated outputs, either reed relays or optical isolators, to operate remote event recorders, oscillographs, etc. Any logic output in the Uniflex system may be monitored. The modules are available in the following types:

<u>MODULE</u>	<u>+15V INPUTS (MAX)</u>	<u>OUTPUTS</u>	<u>OUTPUTS (TYPE)</u>	<u>LED TARGETS</u>
RRM	10	10	Reed Relay	None
RRIM	6	6 or 12	Reed Relay	6
SSM	10	10	Optical Isolator	None
SSIM	6	6 or 12	Optical Isolator	6

REMOTE INTERFACING

The Uniflex system always provides optical isolators for input and output signals where the channel equipment is remote. Often the channel equipment provides similar isolation. The PSM-7 module provides a regulated +15V to power the external circuits as shown in Figure 23. The PSM-7 module, when used, is mounted in the USPS power supply assembly.

CHANNEL EQUIPMENT

The TC-10 carrier set is on-off type and normally is used with the blocking system. It consists of a 10 watt transmitter and a wide-band receiver which is comprised of modules that plug into a Uniflex type 19 inch chassis, 3 rack units high. A voice adapter module is available for telephone communications. Reserve signal detection is optional. All frequency conversions are accomplished with plug-in module and plug-in component changes. The carrier level indicator, if used, is on the detector module and has a linear dB scale. An output is provided for an additional carrier level indicator on the Uniflex IFM-1 interface module where the TC-10 is remote from the Uniflex relay cabinet. A separate 100 watt amplifier is available to provide 10dB additional power. The transmitter frequency is adjustable ± 150 hertz for multi-terminal lines. Receiver bandwidth can be changed by changing a plug-in module.

The TCF-10 carrier transmitter and receiver normally are used with the unblock system. Each consists of modules that plug into Uniflex type 19 inch chassis 3 rack units high. A frequency change may be accomplished by changing modules.

The transmitter is 1 watt/10watt with 50 watt capability. A separate 100 watt amplifier is available. A hybrid, either balanced or skewed, may be supplied in the transmitter chassis.

The wideband receiver may have an optional carrier level indicator with a linear dB scale and with an output to drive an additional carrier level indication on the Uniflex IFM-2 interface module where the TCF-10 is remote from the Uniflex relay cabinet. Outputs may be optical isolator type. Noise detection is in-band signal/noise ratio type. The receiver output logic module is designed to complement the Uniflex IFM-2 interface logic. Logic is provided to restore trip capability following a low signal clamp during open breaker keying.

The DIT-3U audio tone set normally is used with the permissive overreaching transfer trip system. It consists of modules that plug into a 19 inch chassis, 3 rack units high, that uses the Uniflex cover. The transmitter and receiver share the same chassis. The second receiver, if used, requires another chassis. A tone level indicator with a linear dB scale is available on the receiver. An output may be provided to drive a tone level indicator on the Uniflex IFM-2 interface module where the tone set is remote from the Uniflex relay cabinet. Noise detection is signal/noise ratio type with noise sampled out of band. A 650 hertz pilot tone with a 650 hertz notched receiver filter provides frequency translation protection. The receiver output logic is designed to complement the Uniflex IFM-2 interface logic. Logic is provided to restore trip capability following a low signal clamp during open breaker keying.

MEASURING RELAYS

The modular concept is found also in the design of the measuring relays where operational amplifiers are used to design amplifiers, adders, subtractors, integrators, differentiators, phase shifters, level detectors, etc. These circuits provide improved flexibility of relay design. All relays use the common voltage and current input signals as shown in Figure 24 typical for one phase.

The LKD phase to phase unit operation is shown in Figure 25. The three subtractor circuits provide the phasor $V_{AB}-I_{AB}Z_C$. Z_C is the compensator reach setting. The -90° phase shifter circuits are not shown. However, the polarizing phasor $-j(V_{AB}-I_{AB}Z_C)$ is compared with the operating phasor $V_{CB}-I_{CB}Z_C$ whose circuits are similar to those shown. For a fault at the balance point, the operate phasor $V_{CB}-I_{CB}Z_C$ is at point Y and the output of the "AND" gate is uncertain. For a fault beyond the balance point, the operate phasor is to the left of point Y and out of phase with the polarizing phasor and thus the "AND" gate has no output. For a fault within the balance point, the operate phasor is to the right of point Y and is in phase (less than 90° apart) so that there is an output from the "AND" gate for a duration greater than 4.16 milliseconds (90°).

The LKD three phase unit operation is shown in Figure 26. A subtractor, a filter, and an inverting amplifier provide the polarizing phasor $-V_{CA}$. A subtractor and an adder provide the operate phasor $V_{CA}-I_{CA}Z_C$. For a fault beyond the balance point, the operate phasor falls short of V_A and is out of phase with $-V_{CA}$ thus no "AND" output. For a fault within the balance point, the operate phasor extends beyond V_A and is in phase with $-V_{CA}$ which causes the "AND" output.

The LD-1 carrier start phase unit uses the "block sequence" scheme for maximum speed as shown in Figure 27. For a fault within the balance point, the operate phasor leads the polarize phasor which causes Q2, Q3, and Q4 to turn on to cause 21S output. Q1 is disabled by circuitry not shown. For a fault beyond the balance point, the operate phasor lags the polarize phasor and Q1 turns on first to gate the thyristor and preclude the turn of Q3 and Q4 thus no 21S output.

The LDG and LDGZ ground distance units are shown in Figure 28 for phase A. The restraint quantity V_{XN} contains only positive and negative sequence current and voltage because the zero sequence current and voltage is subtracted from the total. The operate quantity V_{WO} is compared on a magnitude basis with the restraint quantity V_{XN} . For a fault within the balance point $V_{WO} > V_{XN}$ which causes the output 21N. The phase B and phase C restraint quantities V_{YN} and V_{ZN} are derived in similar circuits and similar comparisons are made.

The LDG output logic is shown in Figure 29. A switch provides optional control of the distance ground unit Z by the directional ground unit D which removes the restriction on the reach setting as well as providing a trip output by the D unit for faults not "seen" by the Z unit. Trip by the D unit is delayed 20 milliseconds and limited to 50 ms.

The LDGZ output logic is shown in Figure 30. The two phase to ground fault desensitizer reduces the reach 40% upon the occurrence of a two phase to ground fault. A two count mode is provided to enhance security where CCVTs are used.

The LDZ phase unit phasors are shown in Figure 31. For a fault within the balance point, the operate phasor will extend beyond point V_B and thus will be in phase with the polarize phasor which causes the 2I-1 output. A fault beyond the balance point will result in the operate phasor being short of point V_B and thus out of phase with the polarize phasor.

The LRG directional ground unit is shown in Figure 32. The phasor are shown for the voltage polarized phase A to ground fault condition. The angle θ is the inherent 75° angle of the UCT air gap current transformer. The effective angle could be 65° if that option was selected on the LVT voltage transformation unit.

THE RELAY LOGIC

All of the Uniflex system digital logic is high threshold type with transfer characteristics as shown in Figure 33. The 5 volt noise margin is minimum. A 6 volt noise margin is typical. This contrasts with the 1.2 volt noise margins found in the 5 volt digital logic families.

The three types of HTL logic outputs are shown in Figure 34. The open collector output in the inactive state allows the input of the next gate to float which provides the least immunity. The passive output provides a 15K pullup resistor in the inactive state which provides improved noise immunity. For outputs that drive inputs on a different module, the active output provides a 1.5K pullup resistor in the presence of negative going disturbances. A two input NAND gate is shown in Figure 35. Both inputs high will cause the output to be low.

General purpose timers are shown in Figure 36. These are used where accuracy is not critical. Prior to activation, the on timer input and output are high and transistor Q1 is turned on. When a signal pulls the input low, Q1 turns off and the capacitor charges via the 3K and 12K resistors. When the capacitor reaches threshold level, the output transistor turns on to clamp the output low. When the input signal disappears, the input goes high and Q1 turns on to discharge the capacitor instantaneously causing the output transistor to unclamp the output.

The input and output of the off timer is low prior to activation; Q1 is off and the capacitor is discharged. When the input signal goes high, Q1 turns on to charge the capacitor instantaneously and to cause the output transistor to unclamp the output. When the input signal again goes low, Q1 turns off and the capacitor discharges via the 3K and 12K resistors. When the capacitor reaches the threshold level, the output transistor will turn to reclamp the output.

An on-off timer consists of an on timer driving an off timer in keeping with the modular building block concept.

Where timing accuracy is critical, a combination of an HTL gate and an operational amplifier is used as shown in Figure 37. Resistors R2, R3, and R4 together with the op-amp form a level detector circuit. The absence of negative feedback causes the output to switch from one saturation level to another for only a few millivolts difference between the input terminals. Thus, R4 is effectively in parallel with either R2 or R3, and the bias on the + terminal is determined by the output of the op-amp. Prior to activation, the open collector output of ICJ clamps the capacitor low and the output of the op-amp is high placing R4 in parallel with R2 and the bias at vb2. An input to the gate causes it to unclamp the capacitor and it charges via R1. When the capacitor voltage reaches vb2, the output switches to zero placing R4 in parallel with R3 and the bias at vb1. Thus, a lower voltage is required at the -terminal to

reset the output than is required to switch it originally. The timer shown is an on timer. Off timers and on-off timers are similar except R1 is replaced by resistor/diode networks to control the charge/discharge times of the capacitor.

The flip-flop consists of two NAND gates cross connected in textbook fashion.

CONCLUSION

The Uniflex relay systems emphasize modular concepts at all levels of design, hardware implementation, relay functions, and documentation which results in a set of "building blocks" that allows greater flexibility of specification and application as well as improved efficiency in engineering, manufacturing, testing and field commissioning.

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1. R. W. Gonnam, "Operational Amplifier Circuits for Relay Applications", presented to the PEA Relay Committee, Hasbrouck Heights, New Jersey, May 22-23, 1975.
2. S. Salowe, "Considerations in a Changing Technology", presented to the PEA Relay Committee, Hasbrouck Heights, New Jersey, May 22-23, 1975.
3. W. L. Hinman, L. Husak, "Low Burden Sensing Units for Directional Comparison Systems", presented to the 1976 Conference for Relay Engineers, Texas A&M University, College Station, Texas, April 12, 1976.

UNIFLEX GLOSSARY

STRUCTURES & ASSEMBLIES

Type	Description
UF	19 In. Open Rack
UFS	19 In. Swing Rack Cabinet
UFF	19 In. Fixed Rack Cabinet
USPS	Systems Power Supply Assy.
UCT	Current Transformation Assy.
UBR	Basic Relay Assy.
UOPI	Option Relay Assy.
UIO	Input/Output Assy.
UTP	Test Panel Assy.
UFTP	Functional Test Box
UMO	Monitor Assembly

RELAYS & MODULES (5 RACK UNITS)

Device	Type	Description
	LT1	Test Indicator Mod.
85B, 85U	DBL DUL	Pilot Logic Rel.
50	LI	Over Current Rel.
21P	LKD	Distance Rel.-Pilot Phase
21NP	LDG	Distance Rel.-Pilot Ground
67NP	LRG	Distance Rel.-Pilot Ground
21S	LD-1	Distance Rel.-Phase Carrier Start
	LVT	Voltage Transformation Mod.
95	OPT1	Option Logic Rel.

21-1	LDZ	Distance Rel.-Zone 1 Phase
21N-1	LDGZ	Distance Rel.-Zone 1 Ground
21-3	LKD	Distance Rel.-Zone 3 Phase
21N-3	LDG	Distance Rel.-Zone 3 Ground
21B	LDB	Blinder Rel.
27/59	LV	Under/Over Voltage Relay
36	LAO-1	Analog Option Relay
	WFL	Weak Feed Logic Relay

MODULES (3 Rack Units)

	IFM-1	Channel Interface
	CBM-1	Channel Checkback
	IFM-2	Channel Interface
	CBM-2	Channel Checkback
	CCM	Contact Converter
94	ARM	Breaker Trip-AR
94	SRM	Breaker Trip-SCR
	BFM	Breaker Failure Initiate
	RIM	Reclose Initiate
	RBM	Reclose Block
74	PRM	Alarm
	PSM-1	Transformer
	PSM-2	Inverter
	PSM-3	Filter
	PSM-4	Regulator-Digital
	PSM-5	Regulator-Tracking
	PSM-6	Monitor
	PSM-7	Regulator-External
	SSM	Monitor
	RRM	Monitor
	SSIM	Monitor With Indication
	RRIM	Monitor With Indication

OPTION FUNCTIONS (HARDWARE SETS)

Function Name	Location	Description
50DT	DBL	Overcurrent Direct Trip
	DUL	
	NPL	
Z2T	DBL	Zone 2 Timer Trip
	DUL	
	NPL	
OS-3	DBL	Out of Step (Tomato)
	DUL	
	NPL	
3ØRB	DBL	Three Phase Reclose Block
	DUL	
	NPL	
Z1	OPT1	Zone 1 High Speed Trip
Z3T	OPT1	Zone 3 Timer Trip
OS-2	OPT1	Out of Step (Double Blinder)

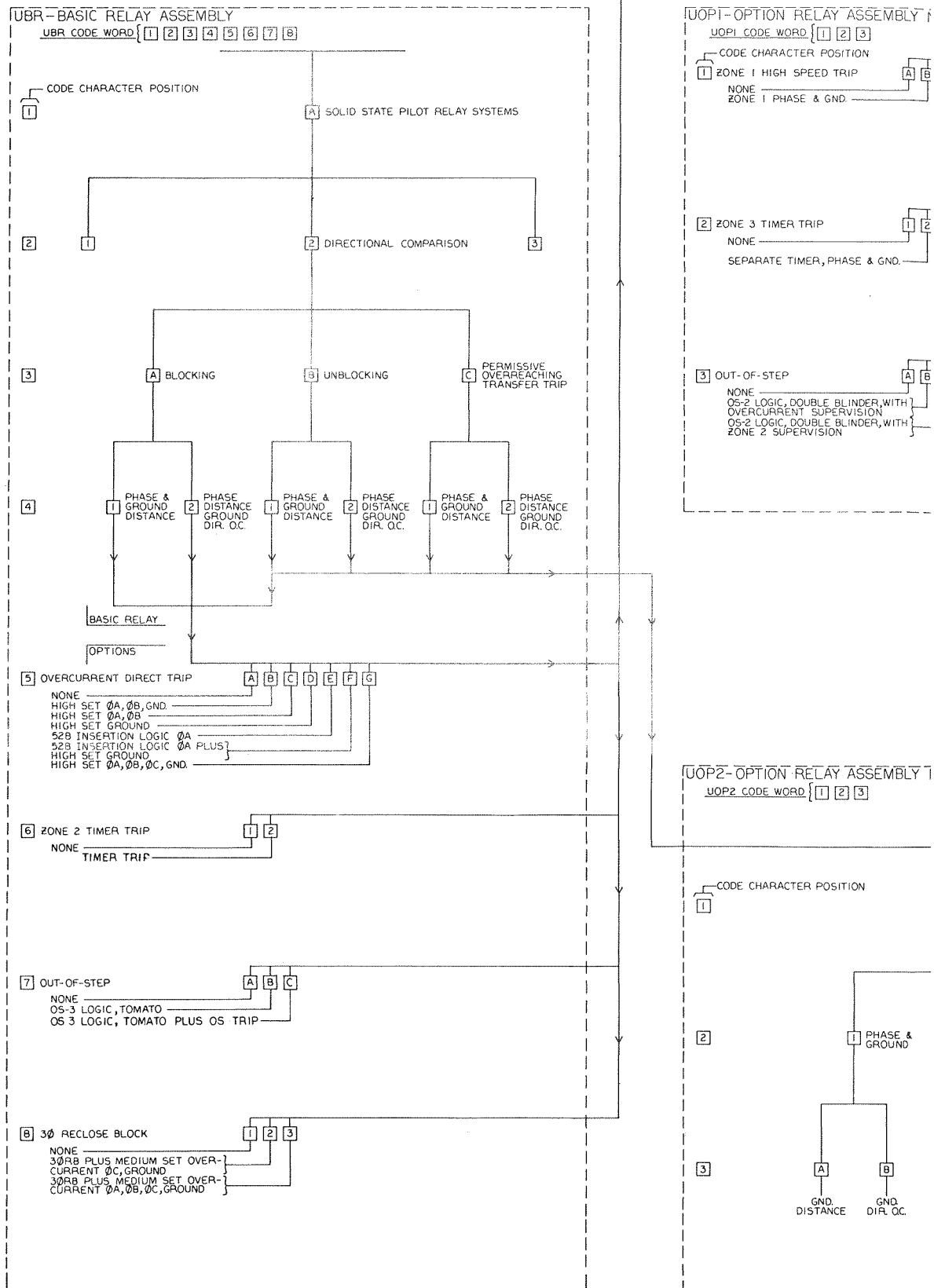


Figure 1. Family Tree for

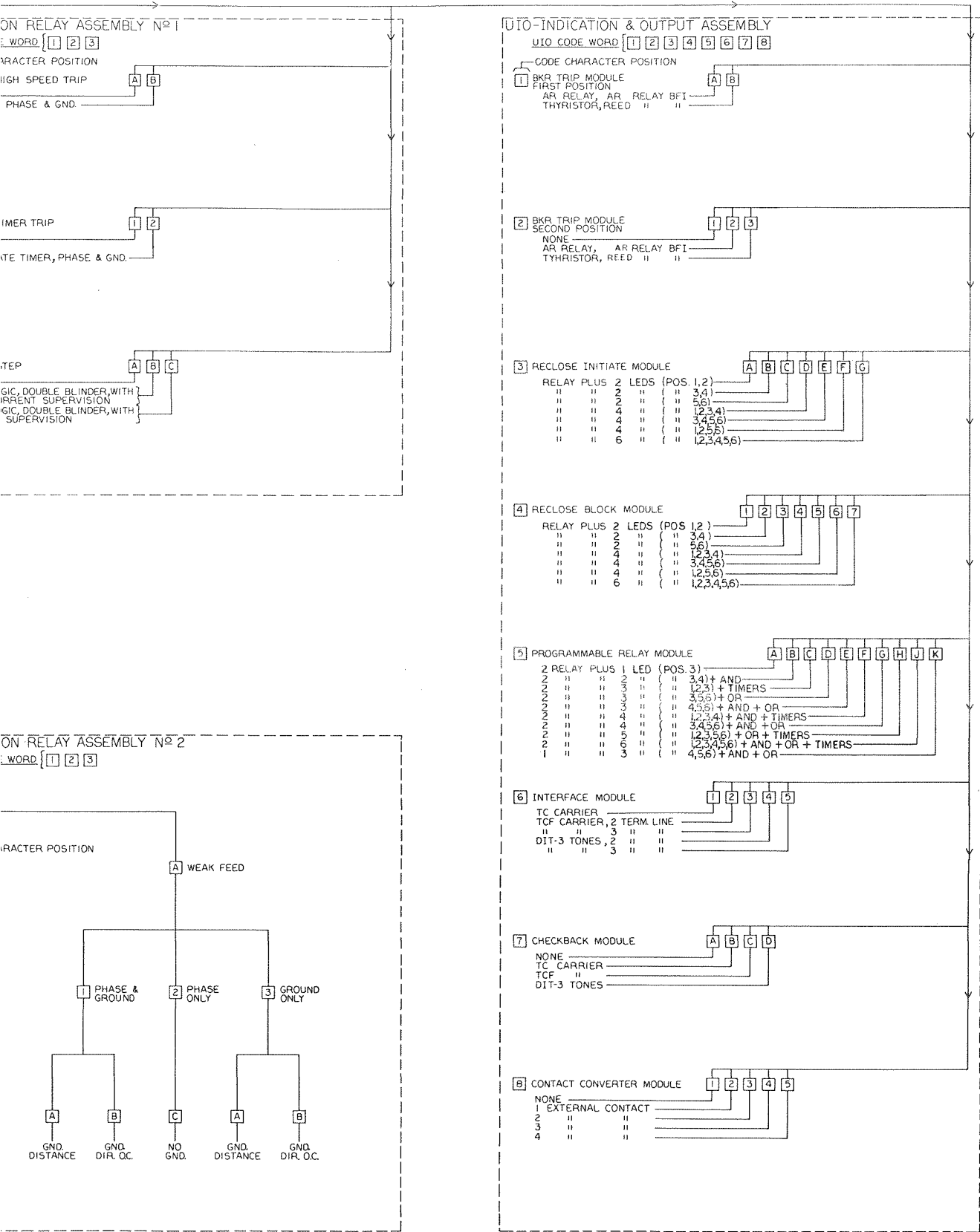


Fig. 1. Family Tree for Relay Functions.

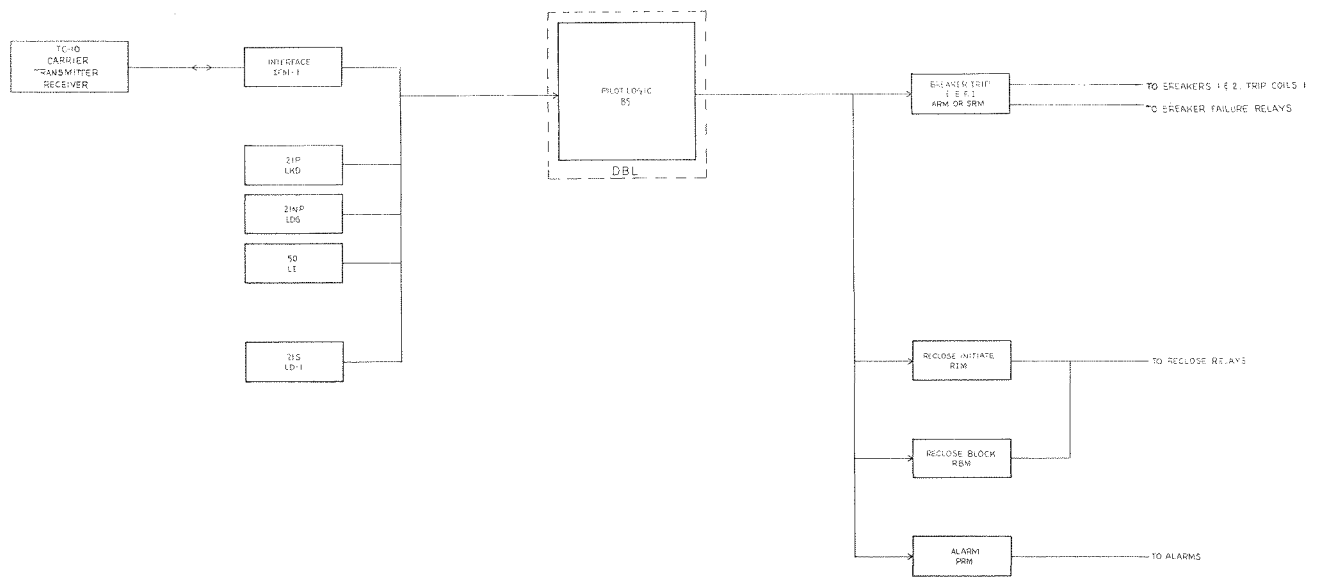


Figure 2. Module Diagram Blocking System with No Options.

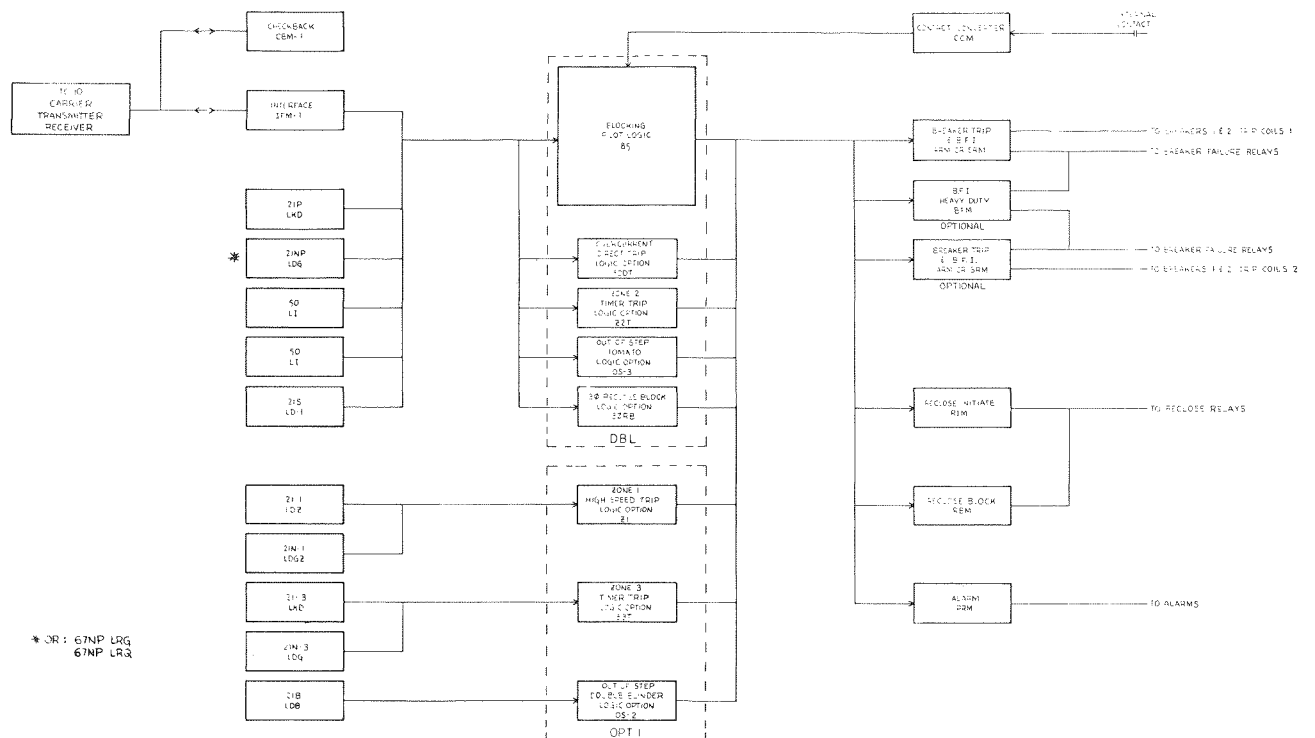


Figure 3. Module Diagram Blocking System with All Options.

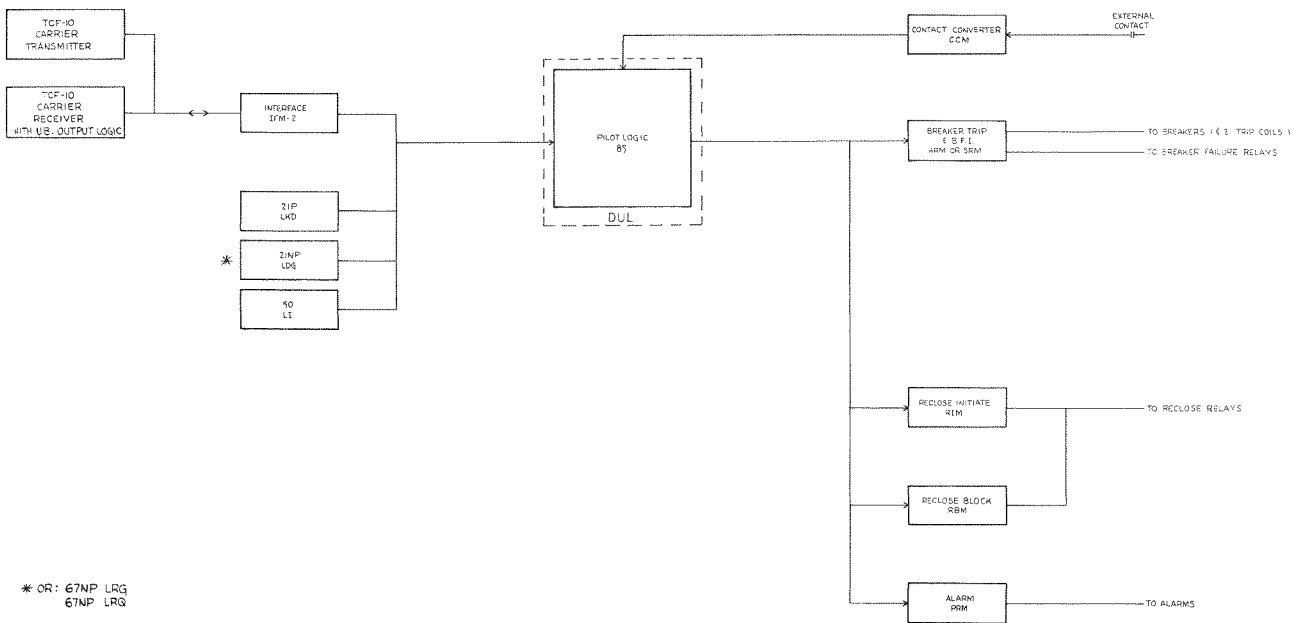


Figure 4. Module Diagram Unblock System with No Options.

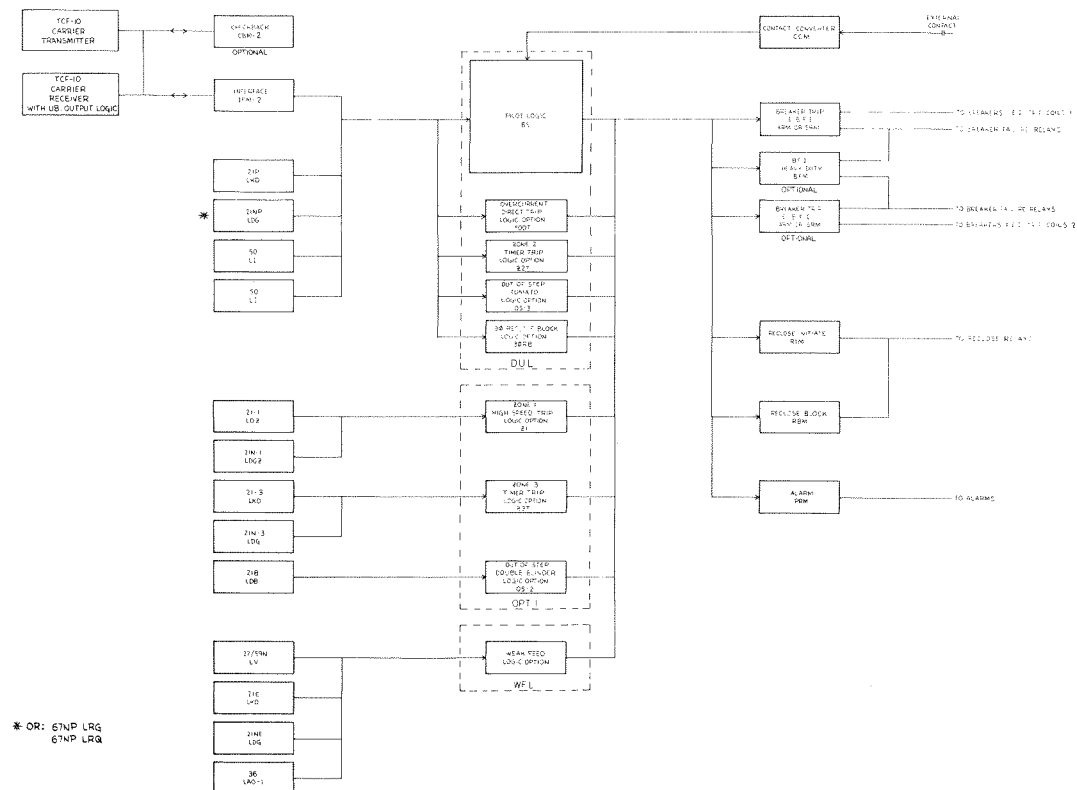


Figure 5. Module Diagram Unblock System with All Options.

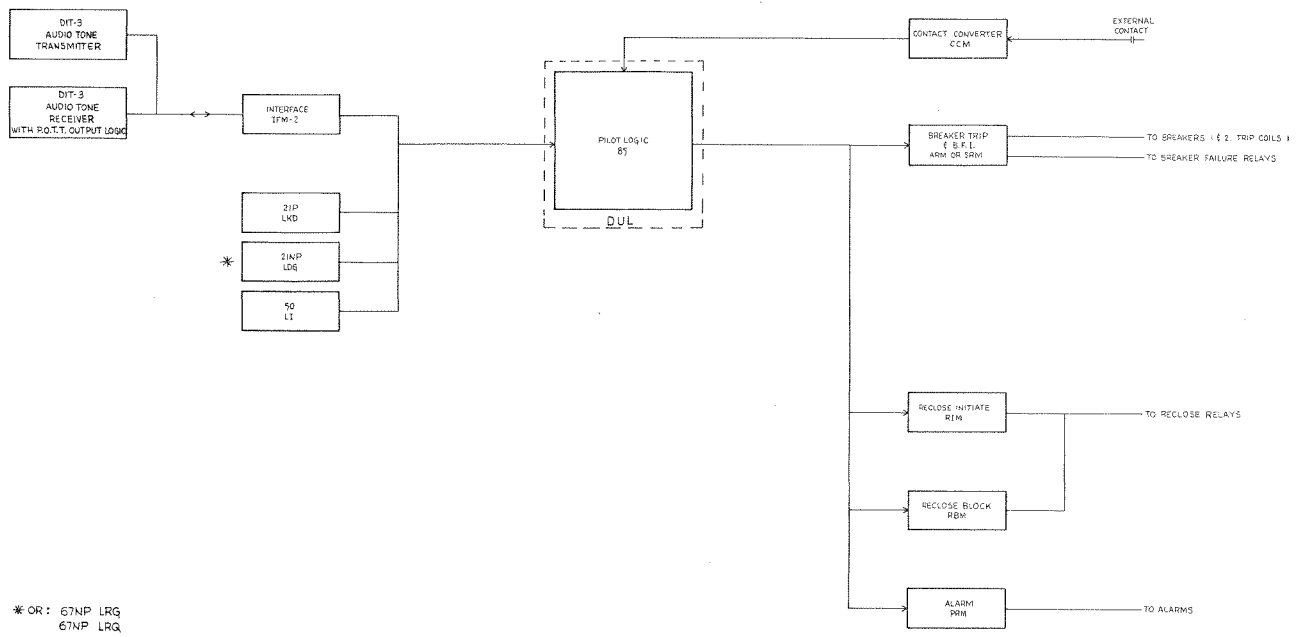


Figure 6. Module Diagram Permissive Overreaching Transfer Trip System with No Options.

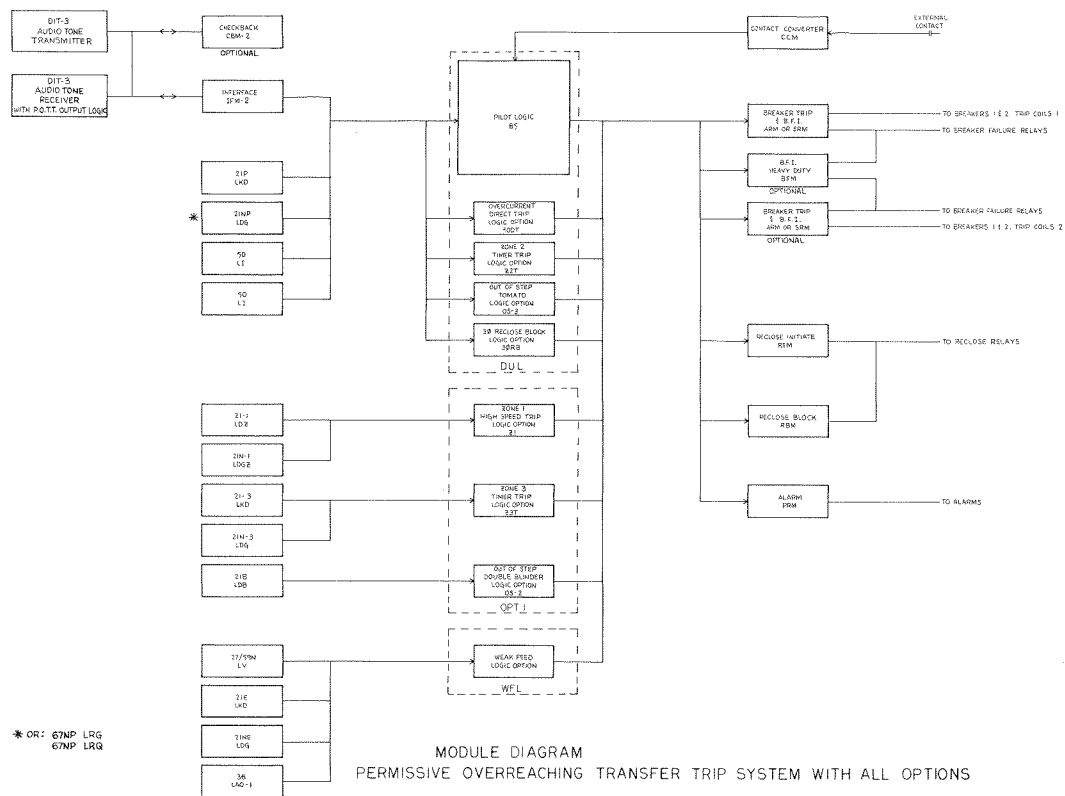


Figure 7. Module Diagram Permissive Overreaching Transfer Trip System with All Options.

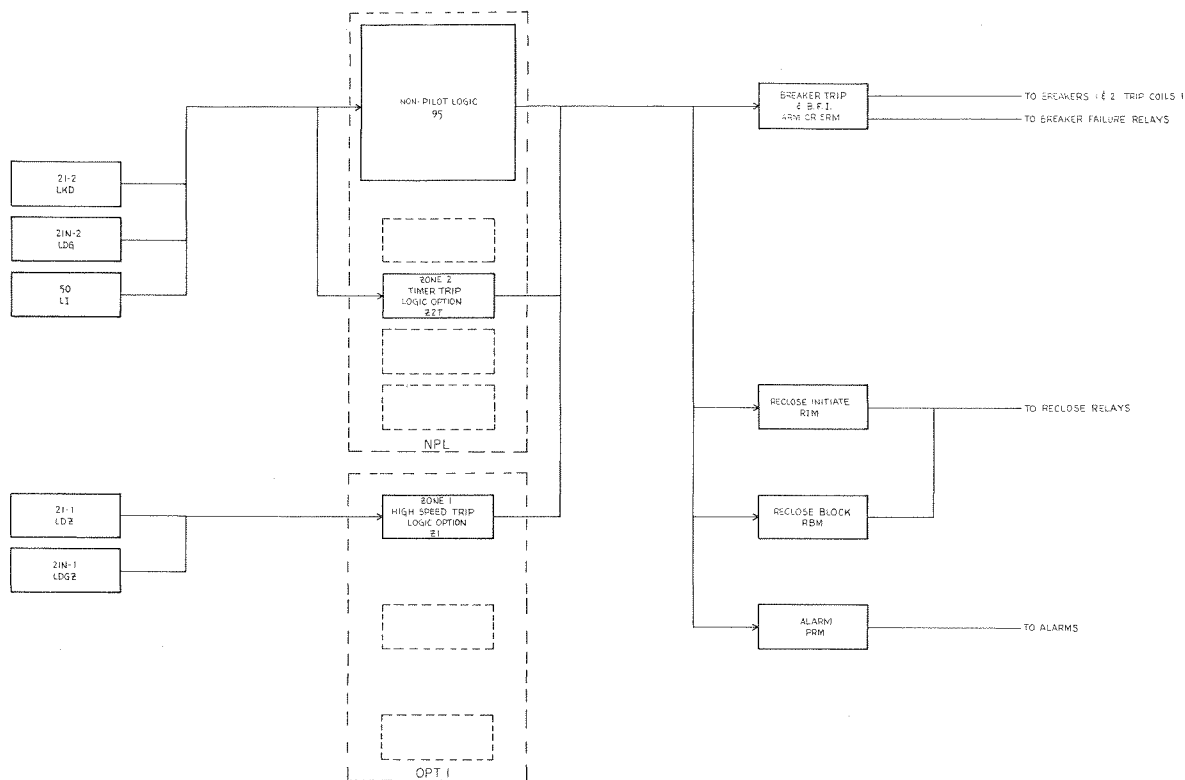


Figure 8. Module Diagram Non-Pilot System with No Options.

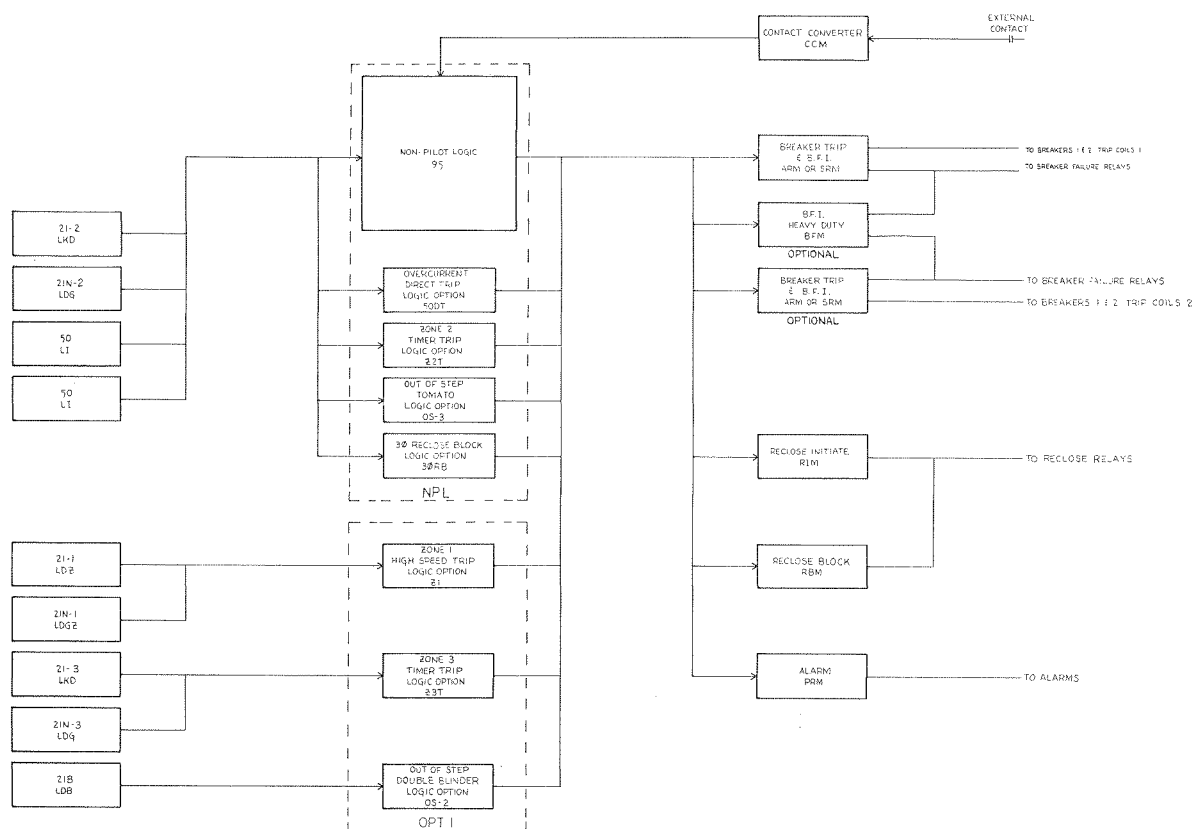


Figure 9. Module Diagram Non-Pilot System with All Options.

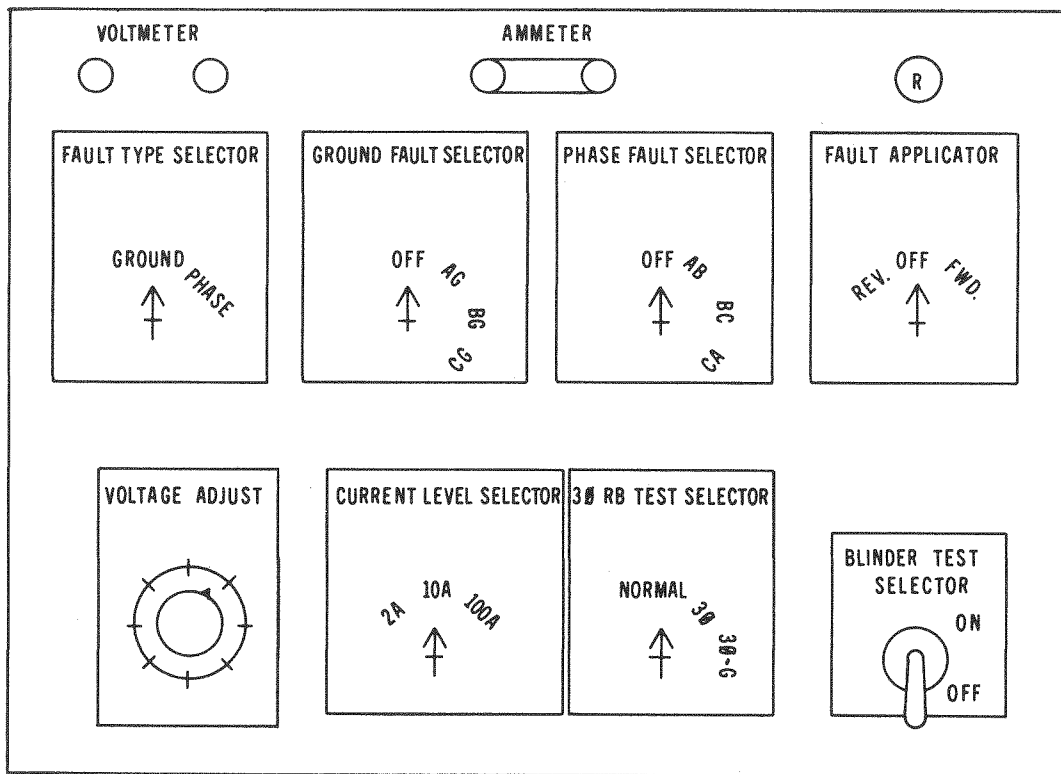


Figure 10. UFTB Functional Test Box.

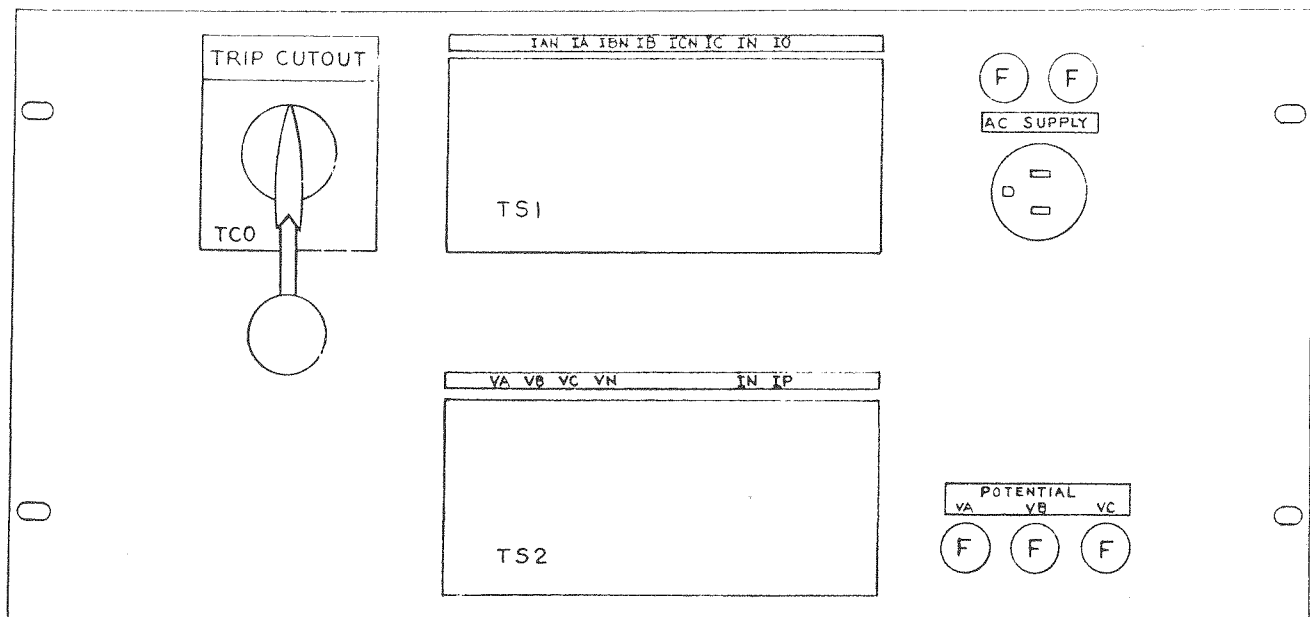


Figure 11. UTP Test Panel.

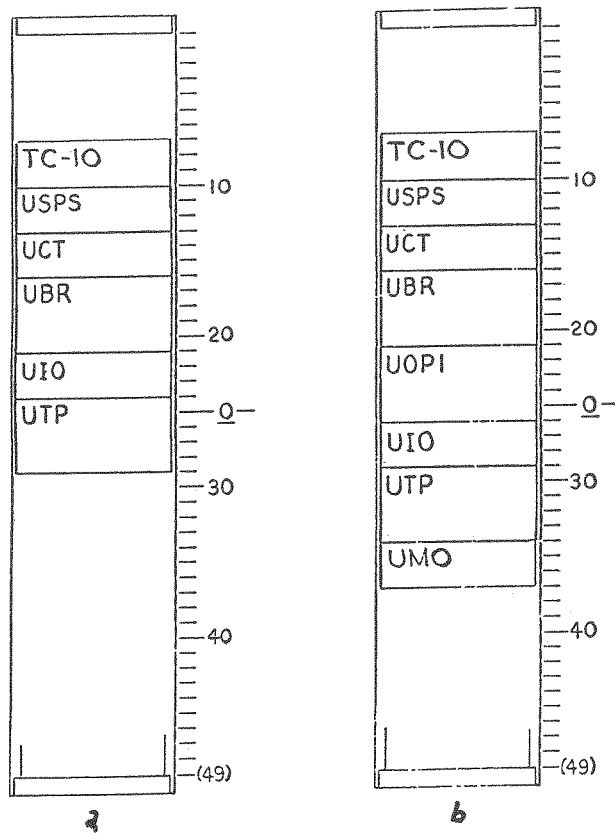


Figure 12. Blocking Systems.

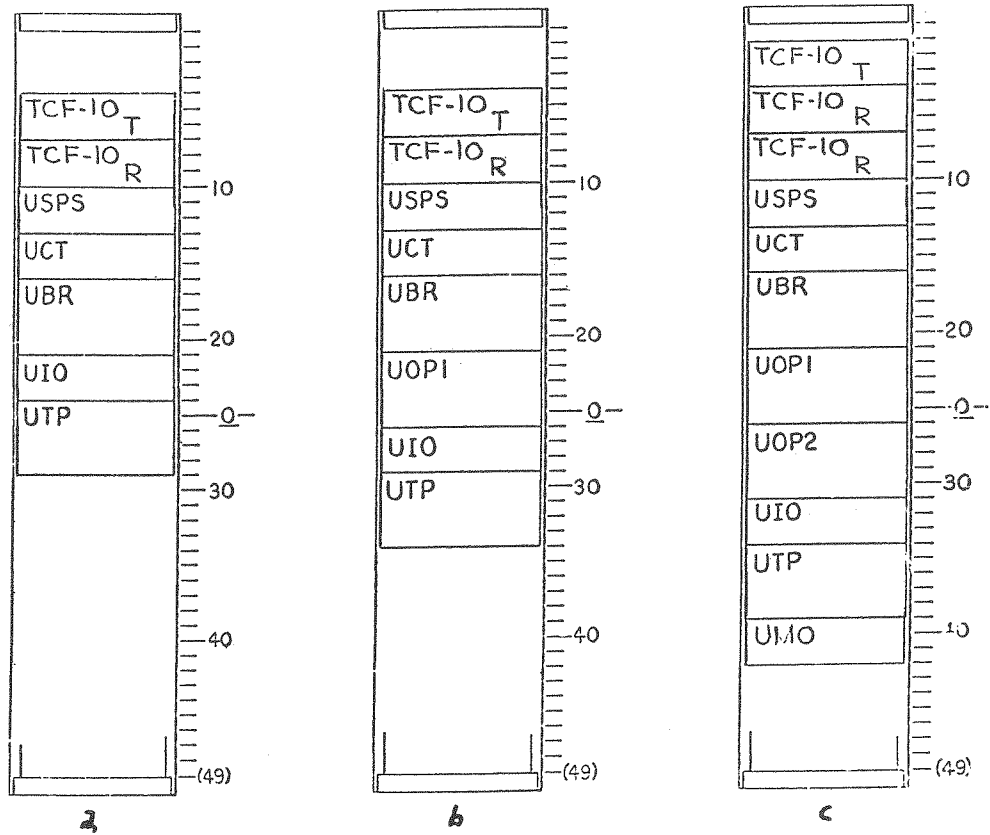


Figure 13. Unblock Systems.

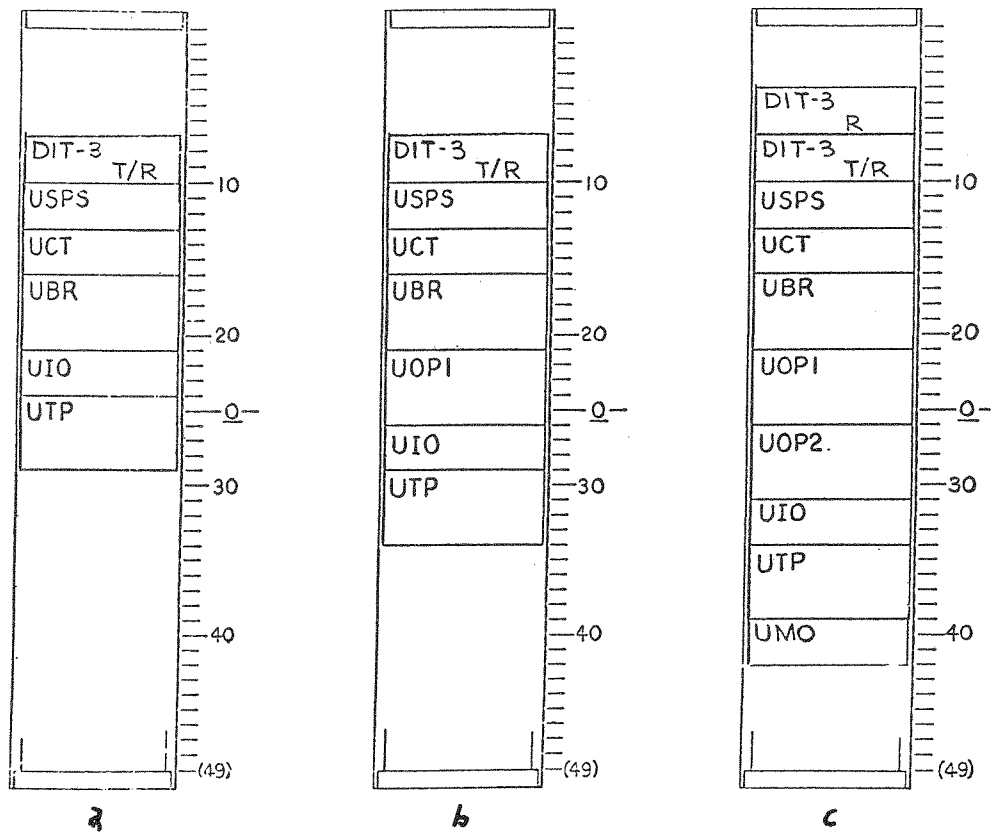


Figure 14. Permissive Overreaching Transfer Trip Systems.

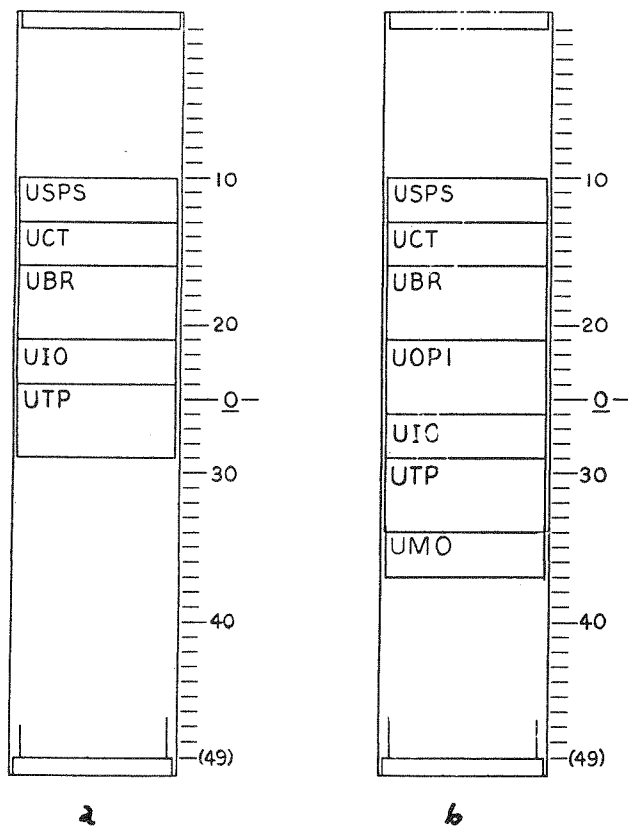


Figure 15. Non-Pilot Systems.

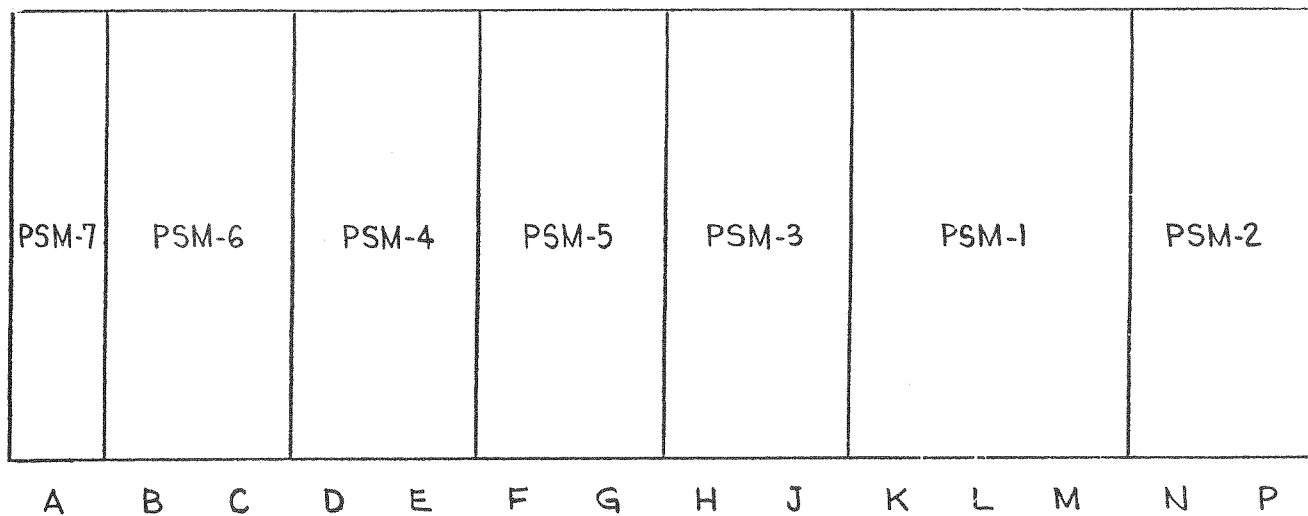


Figure 16. USPS Power Supply Assembly.

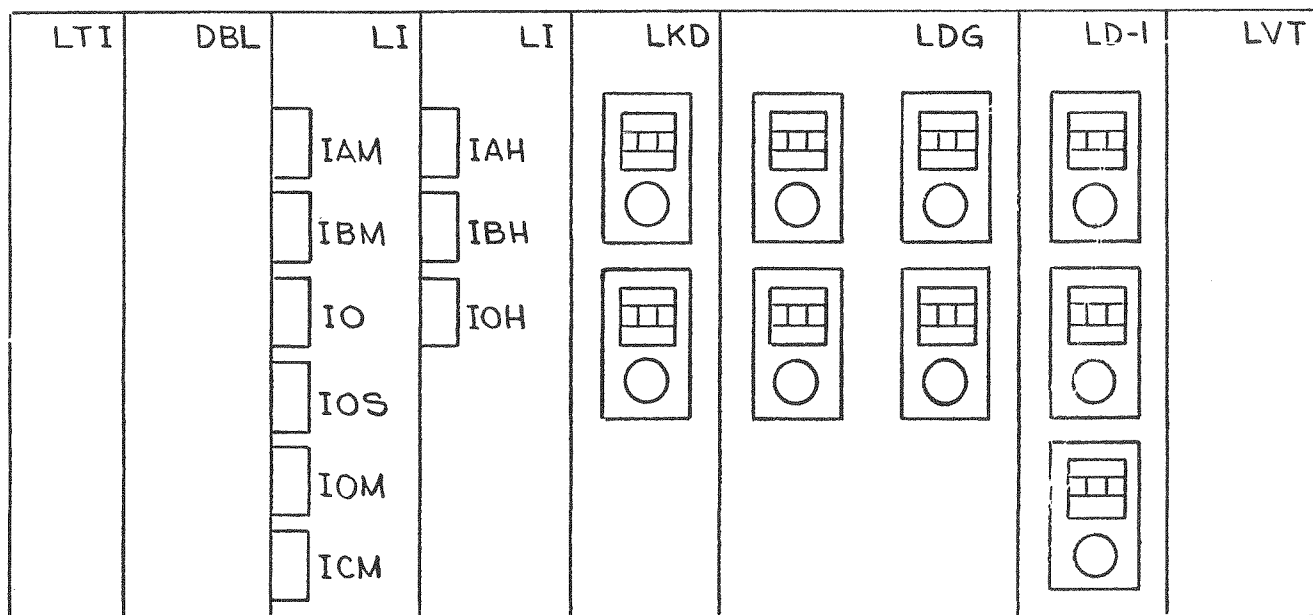


Figure 17. Basic Relays.

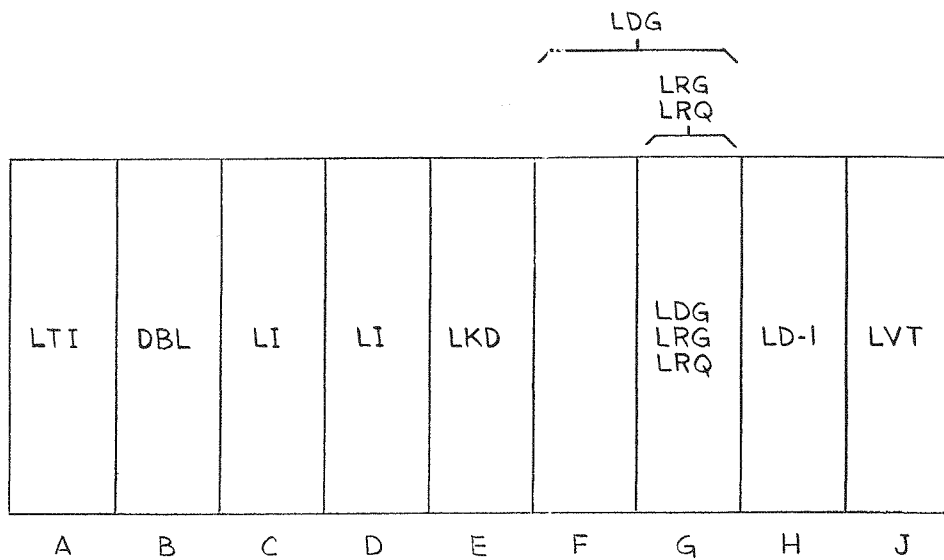


Figure 18a. UBR Basic Relay Assembly Blocking System.

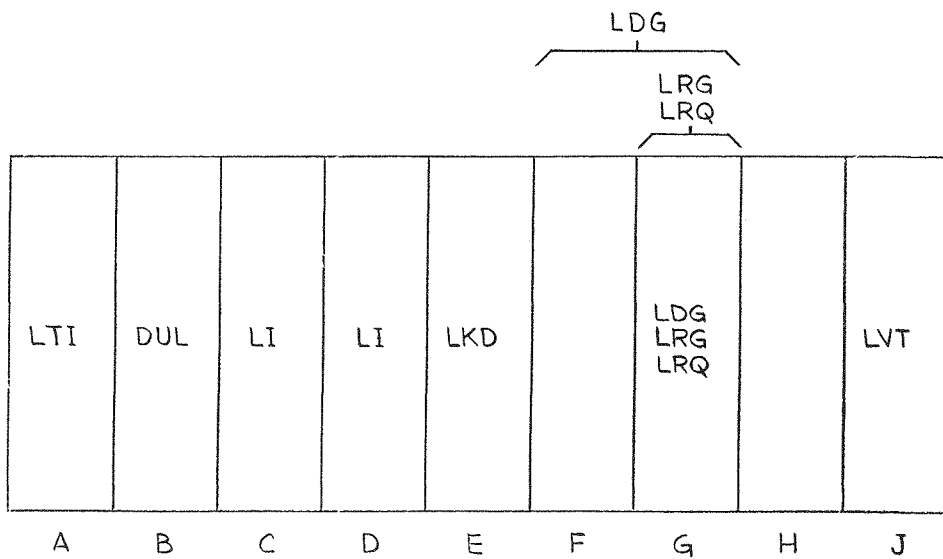


Figure 18b. UBR Basic Relay Assembly Unblock System or P.O.T.T. System.

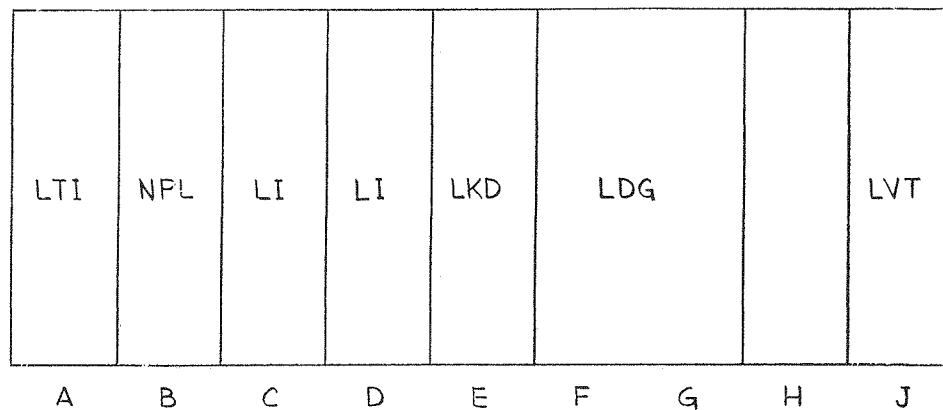


Figure 18c. UBR Basic Relay Assembly Non-Pilot System.

LTI	OPT-I	LI	LKD	LDZ	LDGZ	LDG		
A	B	C	D	E	F	G	H	J

Figure 19a. UOPI Option Relay Assembly Zone 1 & Zone 3.

LTI	OPT-I	LI		LDZ	LDGZ		LDB	
A	B	C	D	E	F	G	H	J

Figure 19b. UOPI Option Relay Assembly Zone 1 & Out of Step.

LTI	OPT-I	LI	LKD		LDG		LDB	
A	B	C	D	E	F	G	H	J

Figure 19c. UOPI Option Relay Assembly Zone 3 & Out of Step.

						LDG		
						LRG		
						LRQ		
LTI	WFL	LAO-I	LV	LKD		LDG		
						LRG		
						LRQ		
A	B	C	D	E	F	G	H	J

Figure 20. UOP2 Option Relay Assembly Weak Feed.

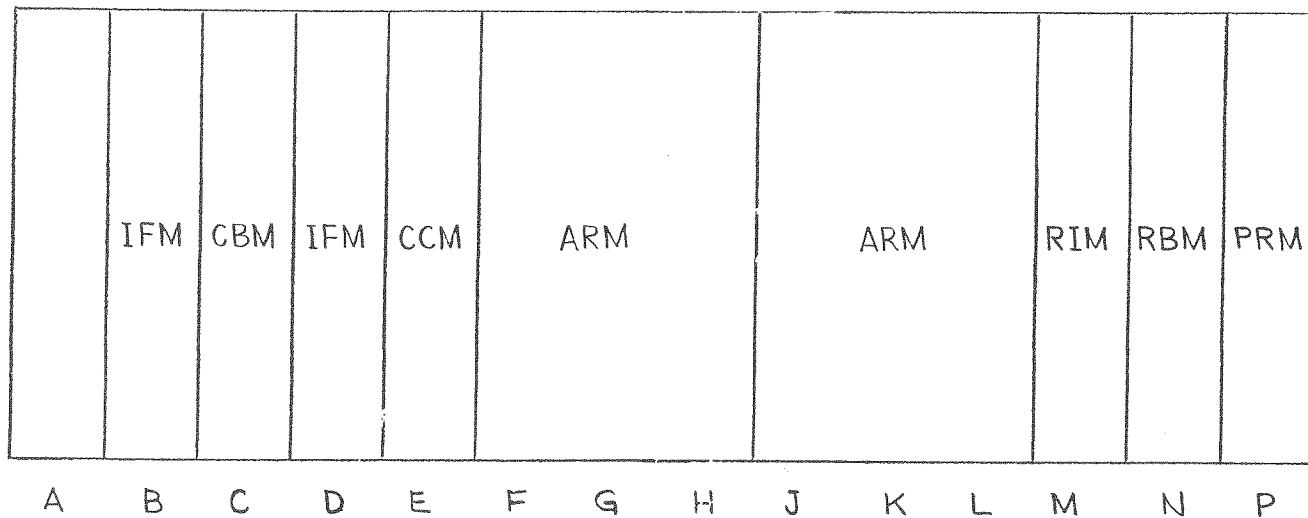


Figure 21a. UIO Input/Output Assembly With Arm Trip.

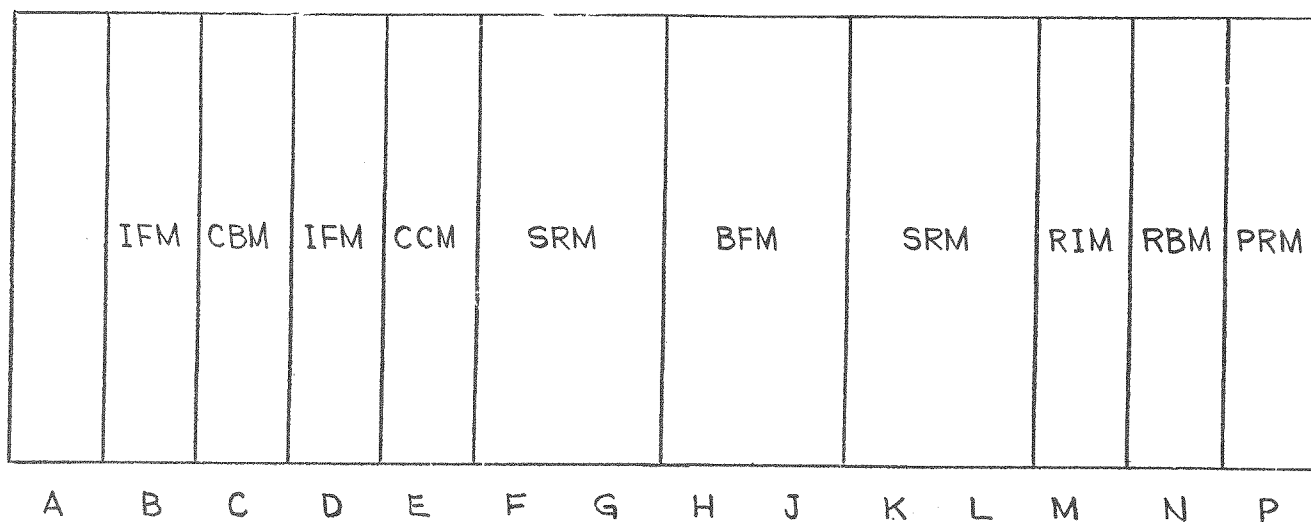


Figure 21b. UIO Input/Output Assembly With SRM Trip.

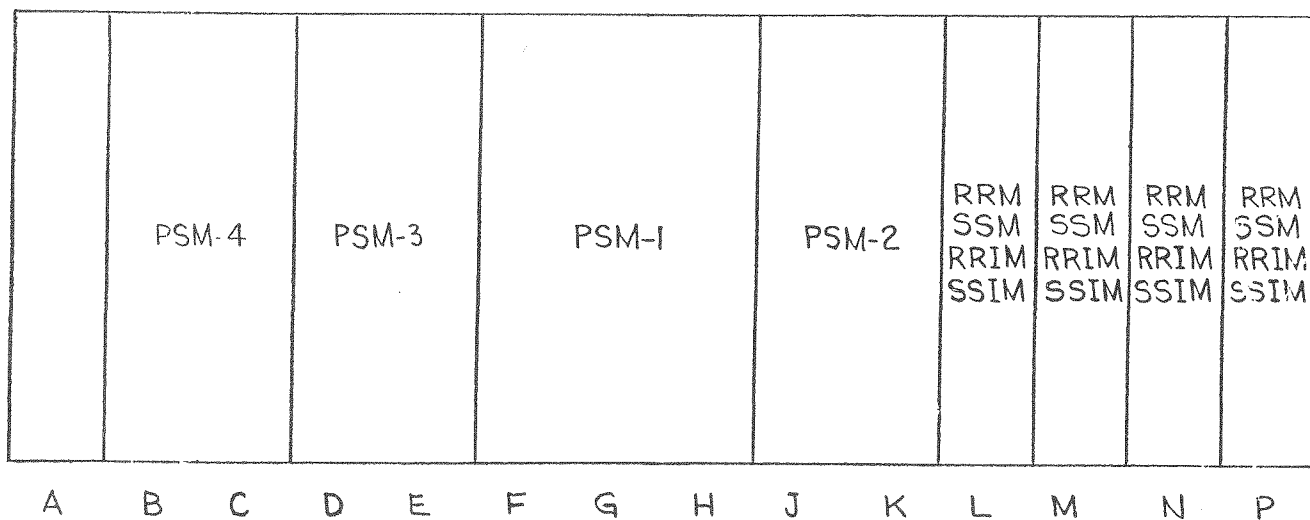


Figure 22. UMO Monitor Assembly.

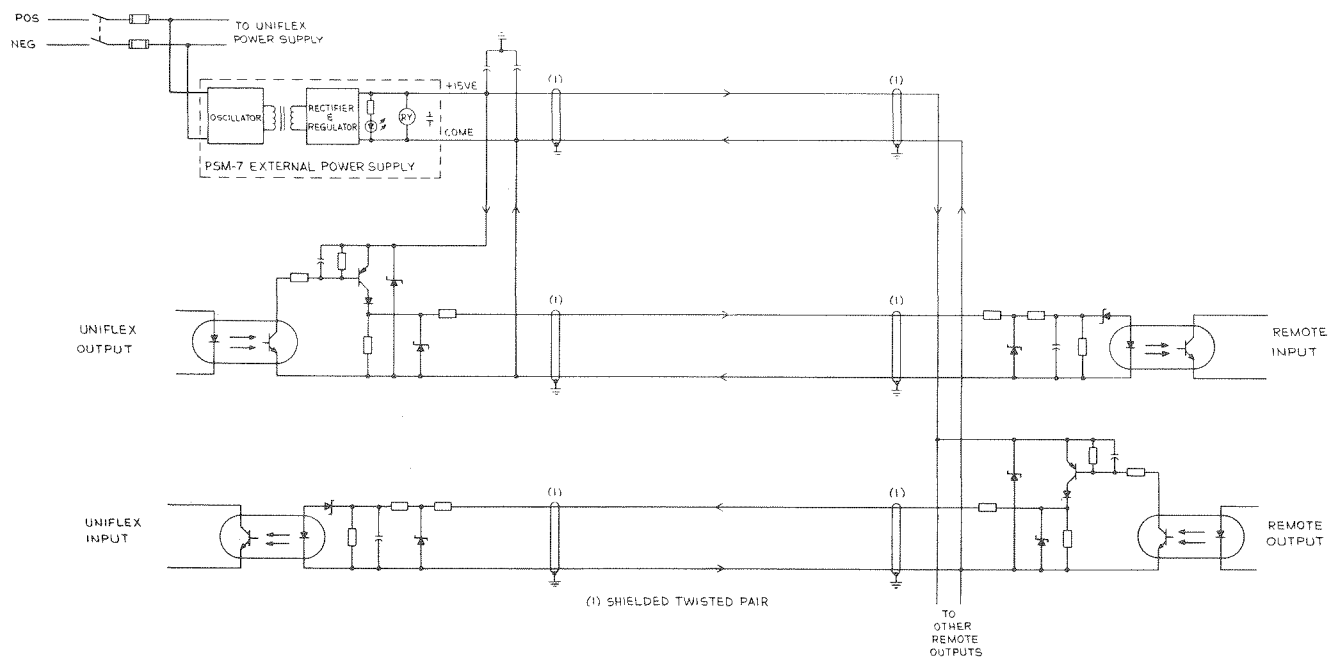


Figure 23. Interface Scheme With dc Isolation at Both Ends.

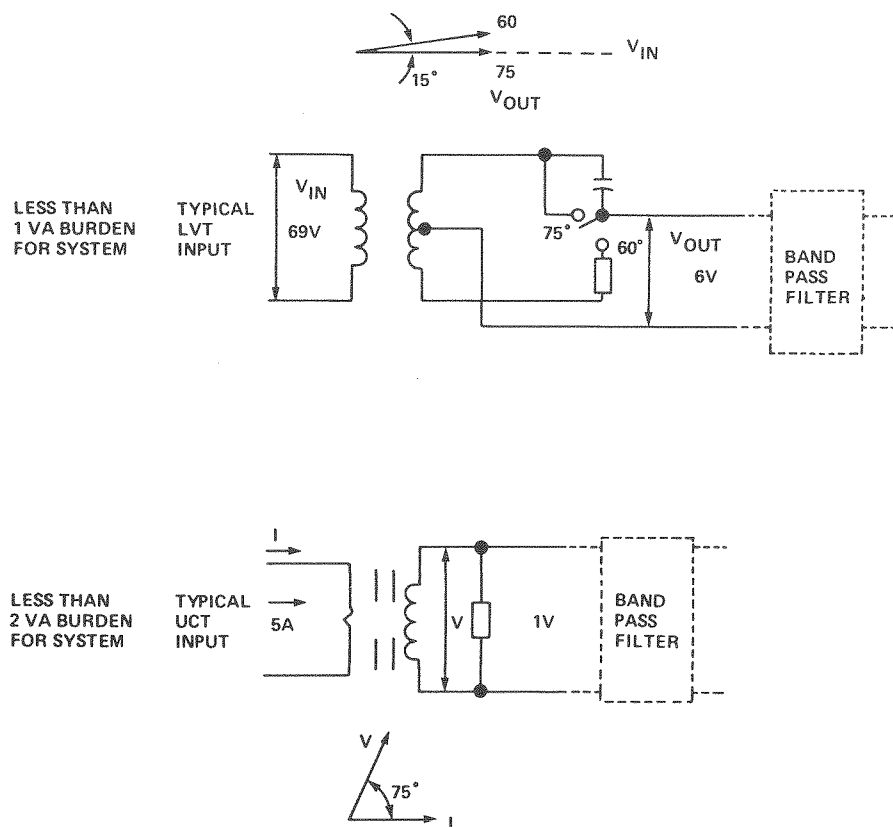
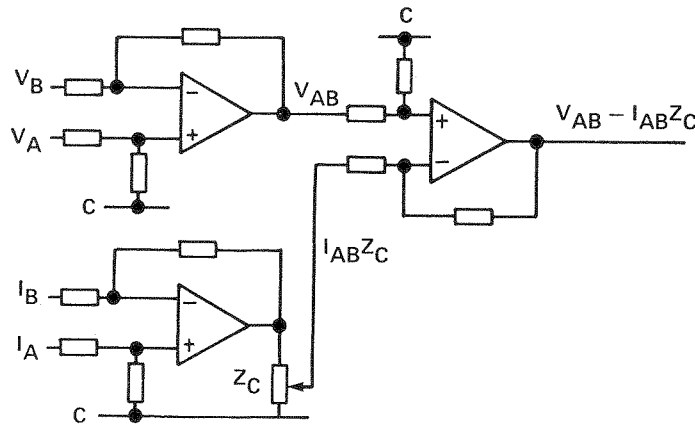
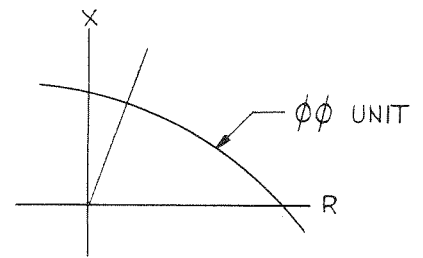
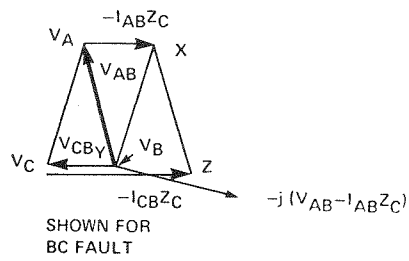


Figure 24. Analog Inputs.



$$\frac{-j(V_{AB} - I_{AB}Z_C)}{V_{CB} - I_{CB}Z_C} \text{ AND } \left[\frac{4.16}{10} \right]$$

Figure 25. LKD Phase To Phase Unit.

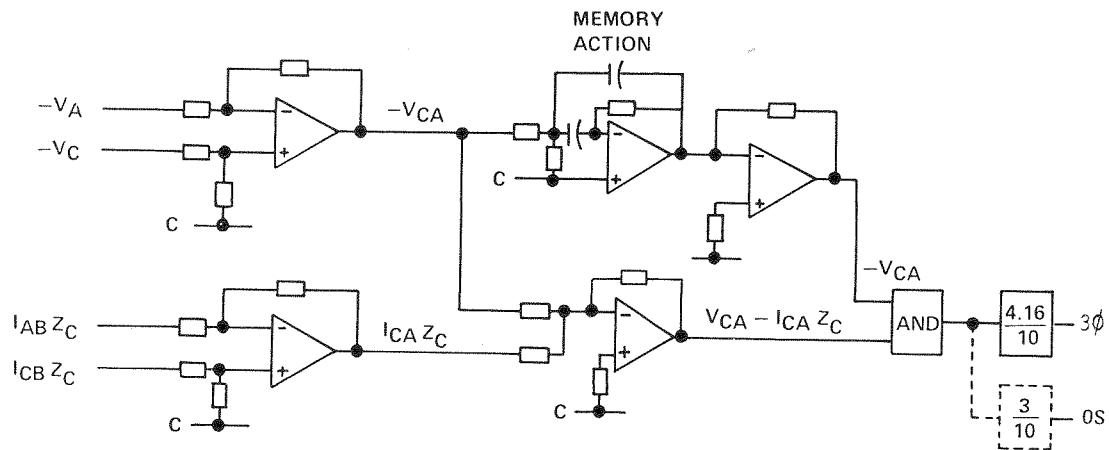
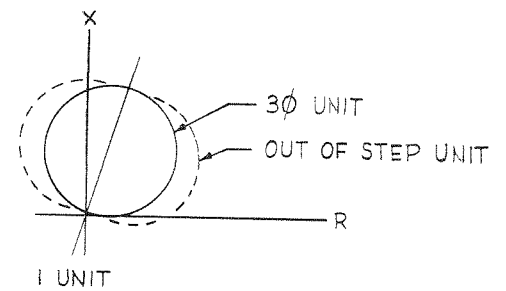
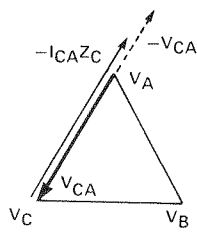
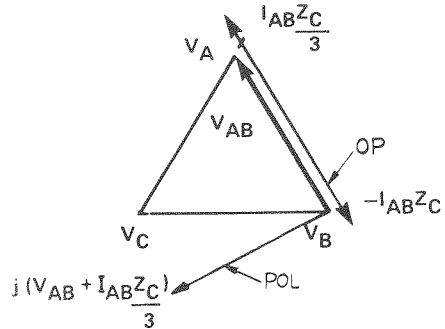


Figure 26. LKD Three Phase Unit.



SHOWN WITH FAULT IN
NON-TRIP DIRECTION
FOR SYSTEM (21 S OPERATES)

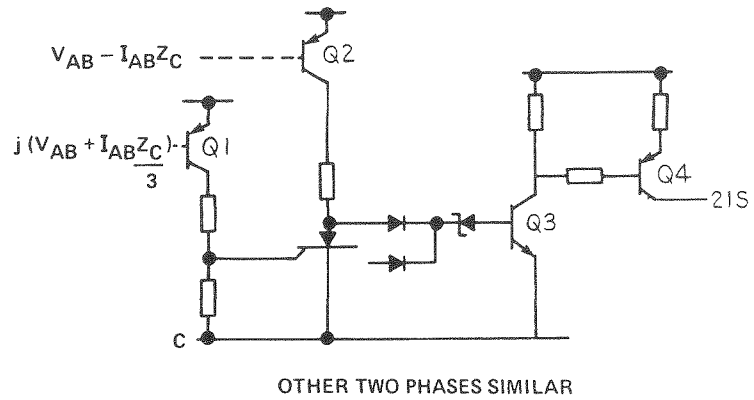
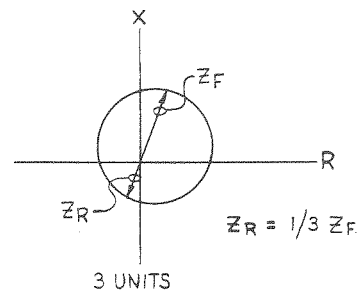


Figure 27. LD-1 Carrier Start Phase Unit.

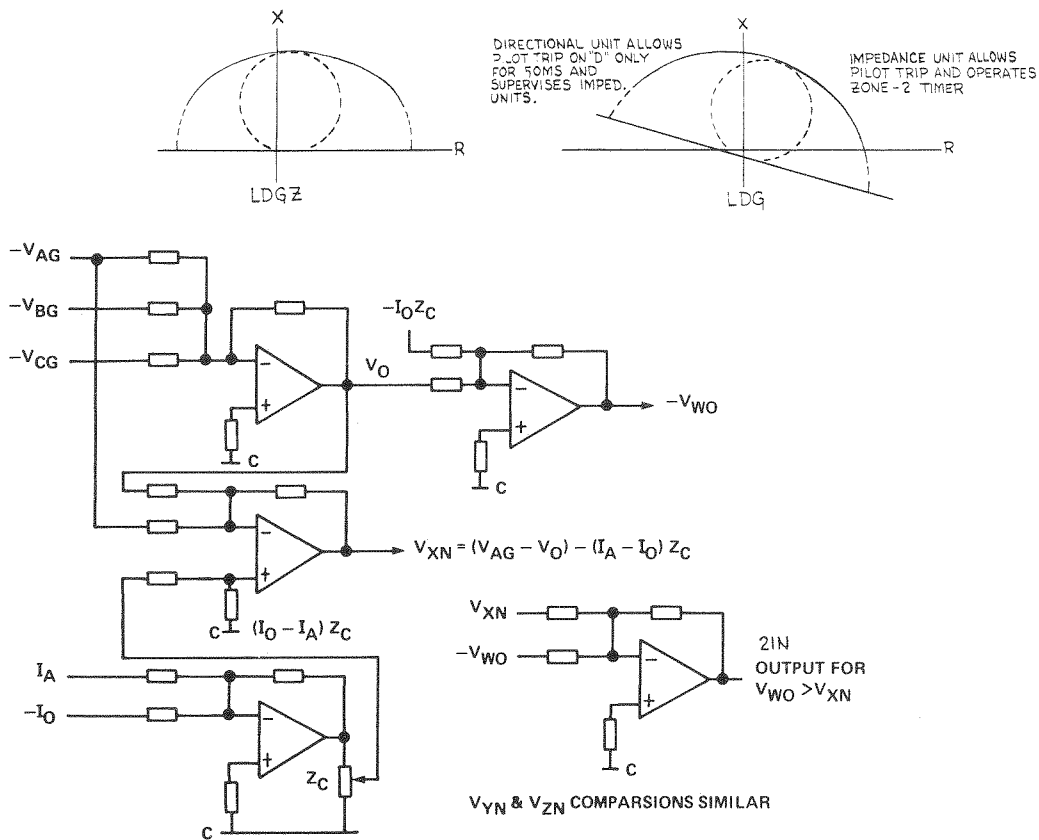


Figure 28. LDG Ground Distance Unit LDGZ.

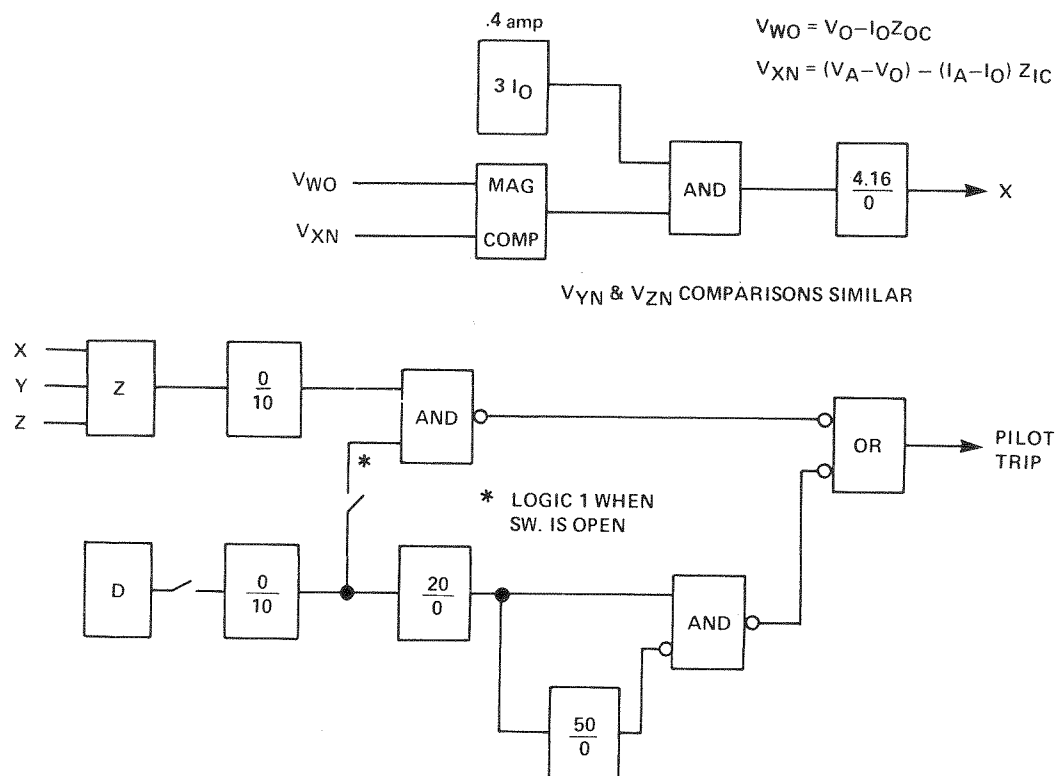
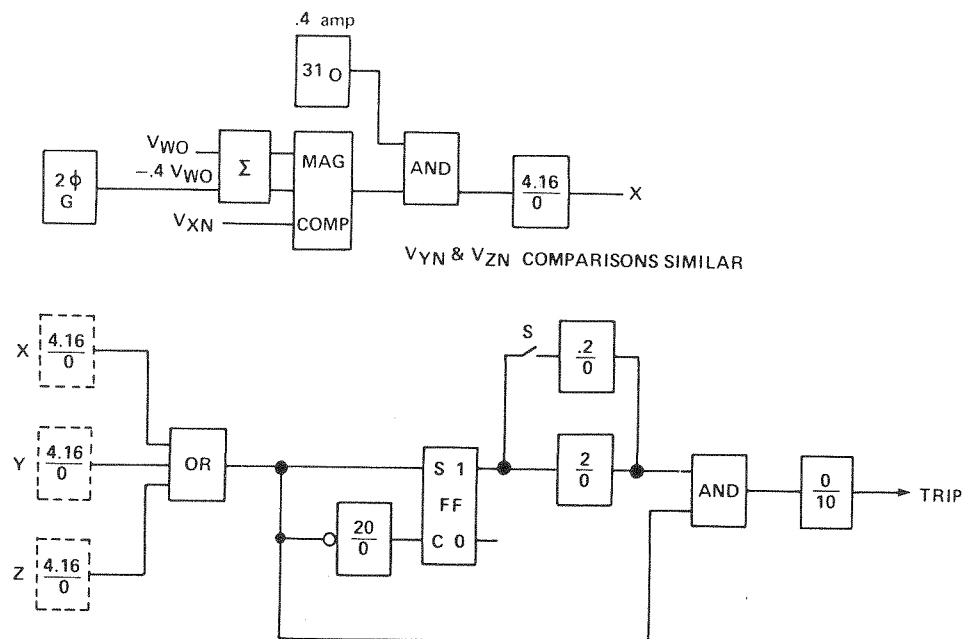


Figure 29. LDG Output Logic.



WITH S OPEN:
 TRIPS ON BLOCK COINCIDENCE > 6.16 MS
 WITH S CLOSED:
 TRIPS ON BLOCK COINCIDENCE > 4.36 MS
 WITH SWITCH IN EITHER POSITION:
 1. TRIPS ON SECOND OUTPUT FROM
 "OR" WITH HOLE > 20 MS

Figure 30. LDGZ Output Logic.

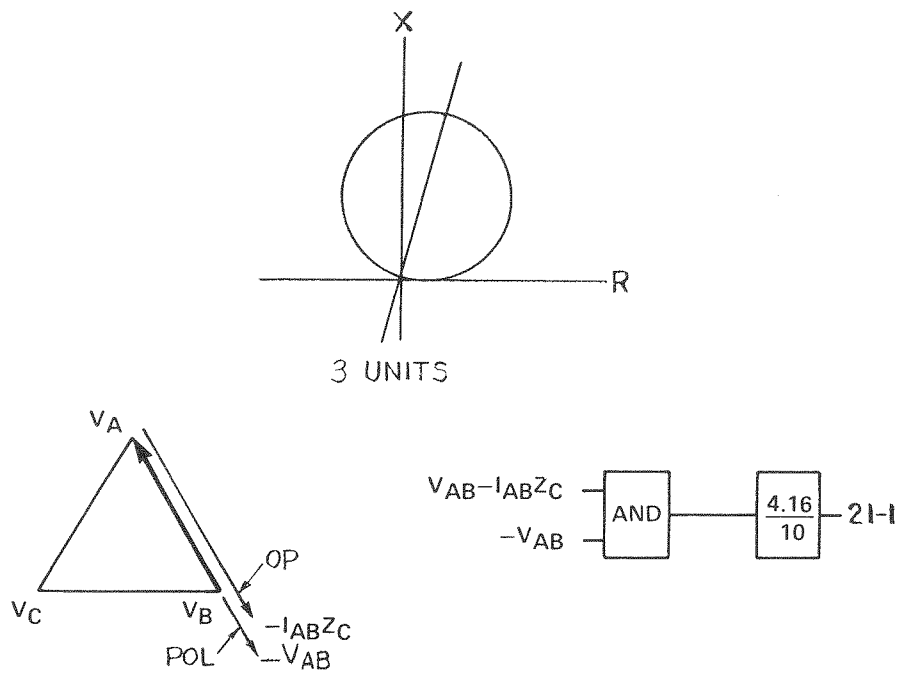


Figure 31. LDZ Zone 1 Phase Unit.

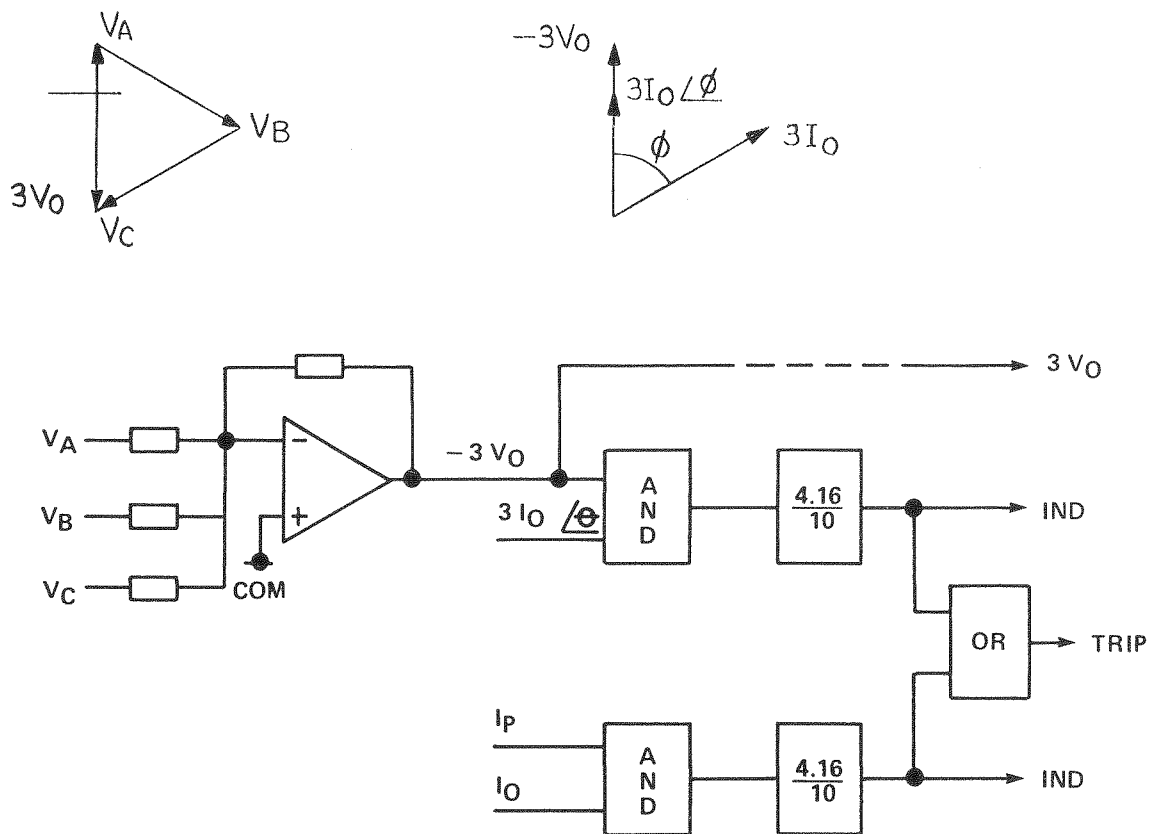


Figure 32. LRG Directional Ground Unit.

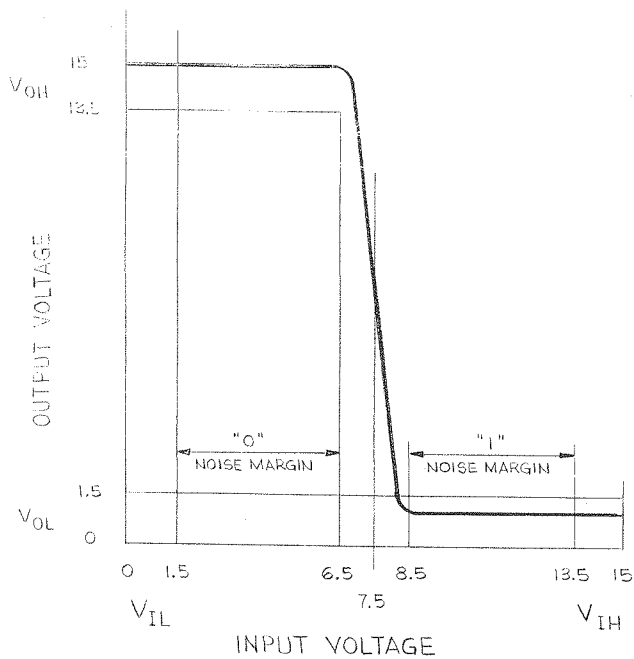


Figure 33. High Threshold Logic Transfer Characteristic.

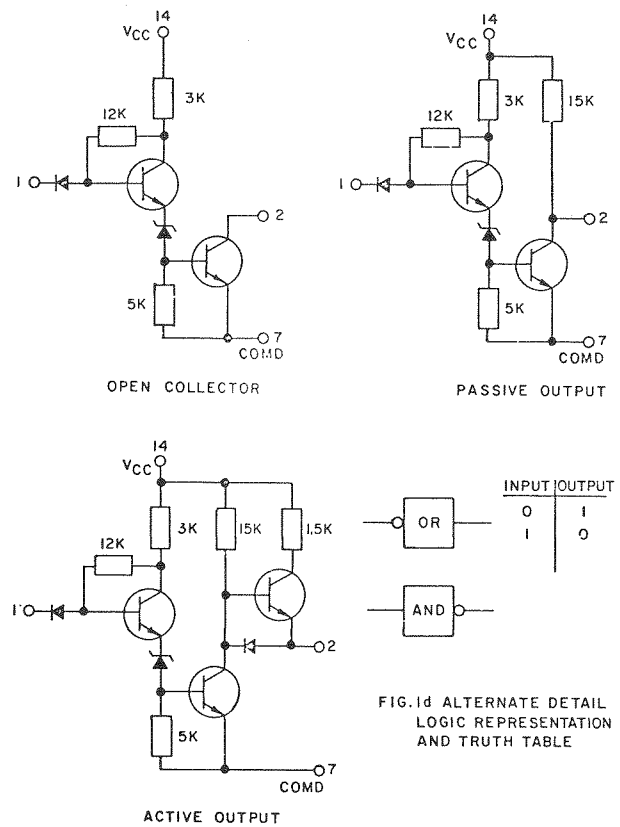


Figure 34. HTL Outputs.

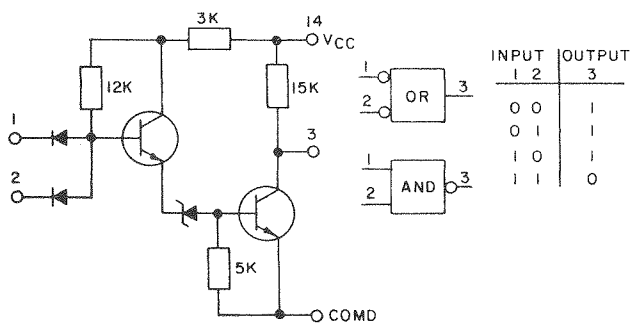


Figure 35. Two Input Gate.

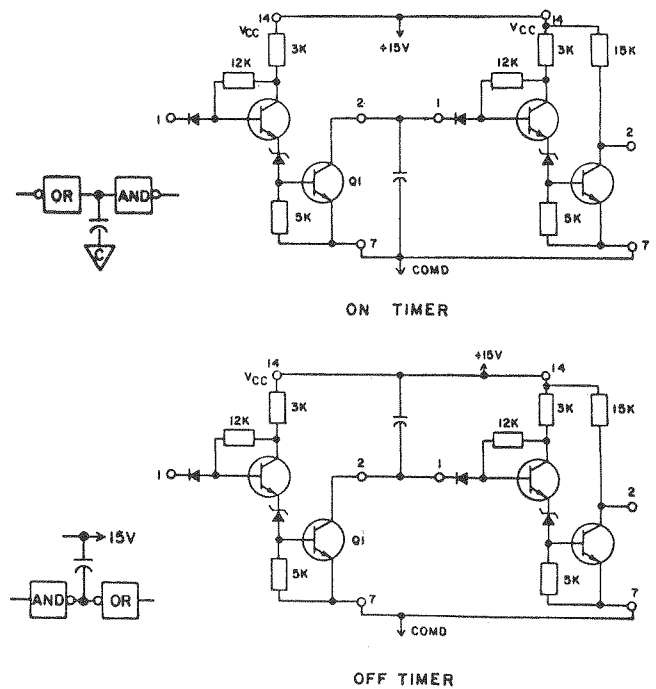


Figure 36. General Purpose Timers.

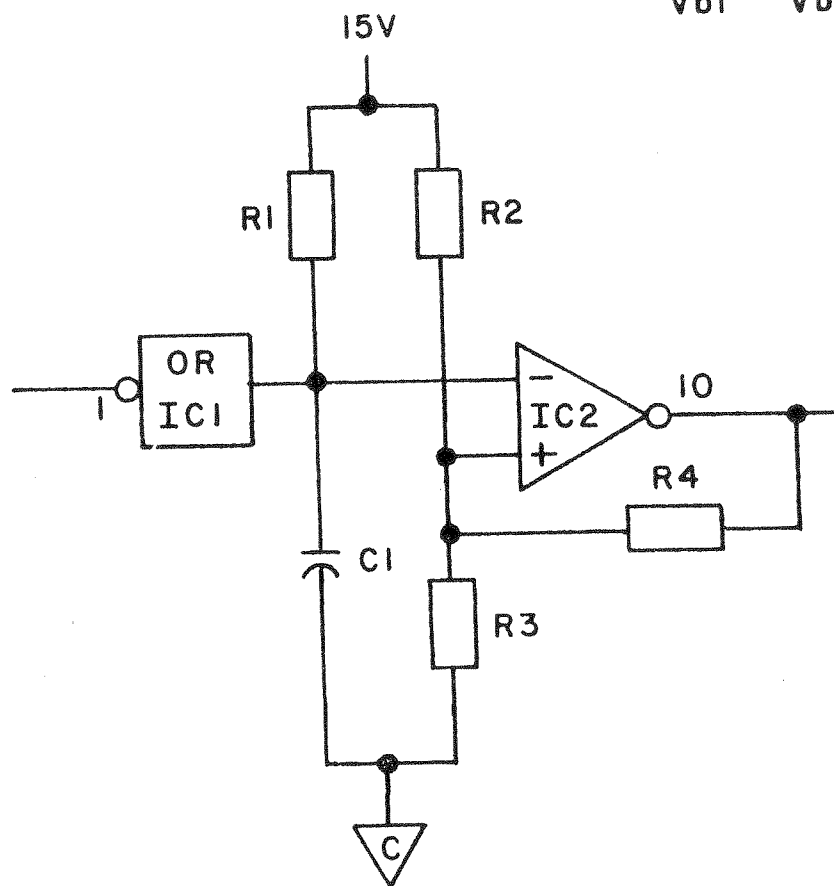
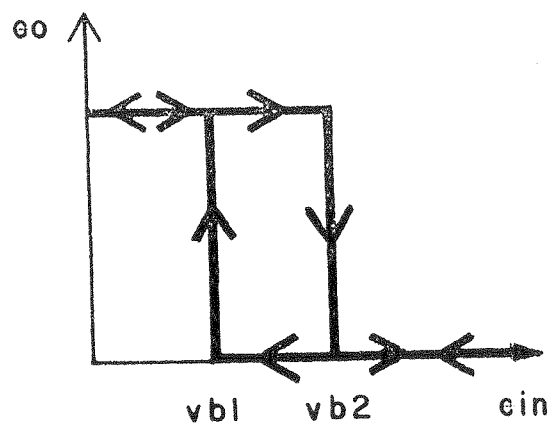
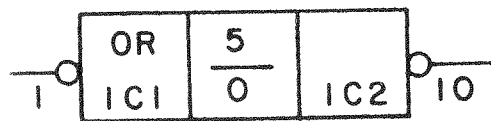


Figure 37. Basic Timer Using Gate And OP-AMP.

**DESIGN CONSIDERATIONS
FOR A NEW SOLID-STATE TRANSFORMER DIFFERENTIAL RELAY
WITH HARMONIC RESTRAINT**

JAMES E. WALDRON STANLEY E. ZOCHOLL

GOULD INC.
SWITCHGEAR DIVISION
HORSHAM OPERATION
HORSHAM, PA

PRESENTED BEFORE THE FIFTH ANNUAL
WESTERN PROTECTIVE RELAY CONFERENCE
OCTOBER 15-18, 1978
SACRAMENTO, CALIFORNIA



DESIGN CONSIDERATIONS
FOR A NEW SOLID-STATE TRANSFORMER DIFFERENTIAL RELAY
WITH HARMONIC RESTRAINT

SUMMARY

Some of the history of transformer differential relaying is reviewed for the purpose of establishing criteria for the design of a new relay. Among the basic requirements of a sound design are ratio-matching taps, a percentage-differential characteristic, and restraint based on the harmonic content of the relay currents.

Magnetizing inrush current is, of course, the principal cause of malfunctions of relays of this type. The characteristics of this type of current are analyzed in detail, and the conclusion drawn that restraint by fifteen percent second harmonic content is appropriate. As the text explains, the reasons for this decision include the undependable nature of the other harmonics due to inevitable delta connections, as well as the presence of those harmonics in legitimate fault currents.

The electrical design of the new solid-state relay is discussed in detail, with mathematical analysis of the circuitry. Oscilloscope traces of points of interest within the circuit confirm these analyses.

Finally, data on tests conducted at full power in a typical installation confirm the results of the analysis, with data presented to verify proper operation of the new relay design.

INTRODUCTION

In order to overcome the problem of nuisance tripping experienced on energizing power-transformers, modern transformer differential relays have for years been designed utilizing the principle of "harmonic restraint". To our knowledge, the first relay to use the powerful concept of restraint proportioned to the harmonic frequency component of current was reported by Kennedy and Hayward in 1938 (1).

Although a transformer-differential relay using harmonic restraint was apparently being developed at that time, it was not reported until 1941 (2). Curiously, the 1938 report disclosed a relay not for transformer protection, but for bus protection. Harmonic restraint was used in the 1938 bus relay to provide security against tripping on external faults causing severe saturation of the current-transformer on the faulted feeder.

We consider the work reported in that paper among the most valuable in the differential relay literature. However, the extension of the principles of that paper to the design of percentage-differential relays for transformer protection can be questioned.

Table 1 emulates Table 1 of Kennedy and Hayward's paper. It gives the author's Fourier analysis of three waveforms which are difficult for differential relays to handle:

Internal Fault, No CT Saturation
External Fault, with CT Saturation
Transformer Magnetizing Inrush

These are illustrated in Figures 1, 2 and 3 respectively.

TABLE 1

HARMONIC WAVE ANALYSES OF TYPICAL CURRENTS APPEARING
IN DIFFERENTIAL RELAY CIRCUITS DUE TO VARIOUS CAUSES

COMPONENT	DIFFERENTIAL CURRENT DUE TO:		
	INTERNAL FAULT FIGURE 1	SATURATED C.T.'s FIGURE 2	MAGNETIZING INRUSH FIGURE 3
Peak	145%	126%	244%
DC	38%	0%	58%
Fundamental	100%	100%	100%
Second Harmonic	9%	4%	63%
Third Harmonic	4%	32%	22%
Fourth Harmonic	7%	9%	5%
Fifth Harmonic	4%	2%	32%
Sixth Harmonic	6%	1%	4%
Seventh Harmonic	2%	3%	3%

The high content of third-harmonic in the presence of saturated CT's (Figure 2) is the principal reason in the author's decision to use all harmonics to restrain the relay. After long analysis, we have decided that this decision is not appropriate for transformer relays, for two reasons:

1) Modern transformer relays are designed to take advantage of both percentage-restraint as well as harmonic restraint; this bus differential relay was not provided with percentage restraint.

2) The assumption that the CT on the faulted feeder is the most likely to saturate on an external fault is only true for a bus situation, since all the other sources connected to the bus are feeding the one circuit. However, in protecting transformers, an internal fault is just as apt to produce large currents (particularly for bushing faults). Therefore, these CT's will saturate just as badly, and probably worse, for an internal, as for an external fault.

MAGNETIZING INRUSH CURRENTS

The Currents Taken By Each Winding of the Transformer

The nature of the inrush current is shown in Figure 3. References 2, 3 and 4 each contain Fourier analyses of the frequency components of such waveforms.

Table 2 lists the results of these analyses. Although some 35 years had elapsed in the interval spanning this work, and different methods used to obtain the results, one observes close correlation among the data presented - startling when the number of variables involved is considered.

TABLE 2

MAGNETIZING INRUSH CURRENTS

COMPONENT	REF- ERENCE 2	REFERENCE 3		REFERENCE 4*		
		CYCLE #2	CYCLE #13	240°	210°	180°
Peak	244	203	133	-	-	-
DC	58	70	6	75	-	64
Fundamental	100	100	100	100	100	100
Second Harmonic	63	23	33	17	29	42
Third Harmonic	27	9	3	9	7	0
Fourth Harmonic	5	-	-	2	3	8
Fifth Harmonic	4	-	-	2	4	0

*For Reference 4, a progression from 240° thru 180° represents elapsed time, during which the inrush is subsiding.

The variance of the second-harmonic components reported is most probably attributed to the particular cycle analyzed. A characteristic of inrush current is that the base-width of the sinusoidal pulses decreases, as well as its peak, as the inrush

subsides. See Figure 4 for a representation of this effect. The second-harmonic component of the phase-winding suffering the worst inrush will gradually increase, and then decrease to zero. Therefore, References 3 and 4 are in basic agreement as to the nature of the second-harmonics' performance. The fact that Reference 4 is purely theoretical, and References 2 and 3 report measured data, justifies both approaches and makes each more valuable.

In line with the theory of Fourier analysis, the higher harmonics appear in ever-decreasing amplitude, and for this reason, those above the fifth are not analyzed since their contribution is negligible.

The Line Currents of Delta-Connected Banks or CT's

In delta-wye connected power-transformers or banks, the current-transformers are connected wye-delta, in order that they:

- 1) Obtain the proper phase-shift from high-to-low side load or through-fault currents, and to
- 2) Supply the required zero-sequence elimination to provide proper relay performance on external-ground faults.

In wye-wye connected banks, the CT's are connected delta-delta for the second reason above. In all cases, a delta winding is encountered in either the power-, or the current-transformer connections.

Because of these connections, the currents supplied to the relay are not those listed in Table 2, but modified due to manner in which the delta-winding currents combine to form the line currents. As shown in Figure 5, the fundamental components add at 60° while the second-harmonics add at 120° the third-harmonics at 180° , and so forth.

In the worst case, that is when the inrush current is the same in two adjacent windings, the dc component delivered to the relay decreases to zero, the second harmonic to 57.7%, the third to zero, the fourth to 57.7%, and the fifth is unchanged. The results of these operations are indicated in Table 3, and represents the actual currents delivered to the relay for the inrush currents listed in Table 2.

We stress here that Table 3 does not represent any actual test result with which we are familiar, but rather is a worst-case situation, illustrating the quantities on which a relay designer may depend. In considering quantities for restraint, any of the harmonics may be greater than indicated.

TABLE 3

WORST-CASE MAGNETIZING INRUSH CURRENTS

Delivered to the relay, as a result of Delta Connection.

COMPONENT	REF- ERENCE 2	REFERENCE 3		REFERENCE 4		
		CYCLE #2	CYCLE #13	240°	210°	180°
DC	0	0	0	0	0	0
Fundamental	100	100	100	100	100	100
Second Harmonic	36	13	19	10	17	24
Third Harmonic	0	0	0	0	0	0
Fourth Harmonic	3	-	-	1	2	5
Fifth Harmonic	4	-	-	2	4	0

SOME CONSIDERATIONS IN THE RELAY DESIGN

The Odd Harmonics and CT Saturation

While it is certainly true that the current-transformers should be selected so that they do not saturate for the largest anticipated fault current, this is often impossible to realize, and so problems of CT saturation should be addressed in the design of protective relays.

Saturation of current-transformers produces harmonic components for reasons similar to those causing the harmonics in inrush currents. In the steady-state, however, the harmonic analysis will show that there are only odd harmonics (plus fundamental) since there is no dc component. Thus the odds are characteristic of CT saturation and the evens are not. This indicates that the odd harmonics not be used for restraint, lest undesirable restraint be provided in the event of a severe fault, internal to the power transformer, which causes the current-transformers to saturate.

Arcing Faults and Waveform Distortion

A common occurrence is a fault occurring within the transformer winding, not adjacent to the terminals, so that the fault current is limited by the relatively high reactance between different portions of the winding, and also that of the laminations. Such a fault, both through the action of the iron involved, and on account of the low current and high voltage in the resulting arc, will tend to produce harmonics of appreciable magnitude.

As in the case of CT saturation, when symmetrical conditions are achieved, only odd harmonics will be present. Thus, restraint with any of the odd harmonics is liable to prevent tripping in this instance.

The DC and Third-Harmonic Components

As noted in Table 3, each of these is a "zero-sequence" harmonic, in that either may tend to cancel in the lines to a delta winding. For this reason, either the dc or the third harmonic component is not reliable to supply the required restraint on inrush.

Selection of Harmonics for Restraint

On consideration of the factors discussed above, it was decided to use only the second-harmonic to restrain the relay. While the fourth has desirable characteristics for this purpose, it is present in too small a quantity to justify the complexity of adding another filter circuit. If the same filter were used to obtain both second and fourth harmonic restraint, it would probably introduce some undesirable third-harmonic restraint as well.

A plausible objection to the use of the second-harmonic for restraint is that an offset fault current has a transient second-harmonic content which might delay tripping. While this is theoretically true, it is also true that the second-harmonic content is relatively small, and quickly falls below the level required for restraint, allowing trip times in the one cycle range for practical situations, provided that the proportion of restraint is properly selected.

Fifteen Percent Second Harmonic Restraint

Analysis of the data available indicates that fifteen percent is the appropriate level. By this is meant that the relay will just restrain when the second-harmonic is 15% of the fundamental component of any complex waveform. In order that this parameter be precisely defined, the relay design is such that the operating quantity is the fundamental component only.

An inspection of the data of Reference 4, Table 3, shows that the second harmonic might (in the worst-case) be only 10% during the first cycle or so of the inrush. We reiterate here that this data is purely theoretical, an analysis of sinusoidal segments resembling actual inrush currents. The analysis, however, does not take into account the damping effect provided by circuit resistance, which has the effect of modifying the actual waveshape as shown in Figure 4. The decrement, due to damping, contributes an extra measure of second-harmonic in the actual case. This fact is seen to be true when the data of Reference 3 (measured value), is considered.

Further, as will be discussed below, careful selection of the filters used to segregate the fundamental and second-harmonic allow the restraint to build up more rapidly than the operate quantity, thus providing an extra margin of coordination.

RATIO MATCHING TAPS

The main current-transformers' ratios should be chosen with regard to maintaining near equality in the currents delivered to the relay during load conditions, or for faults external to the zone protected by the relay. In order to correct for any mismatch in these currents, however, the ITE-87T is provided with ratio-matching taps.

The taps are the basic means of adjusting for these differences (which appear as false differential current to the relay). Note, however, that the percentage characteristic may also be used for this purpose, as a part of "fine-tuning" on the tap selection. In virtually all applications, these balancing devices will obviate the necessity of using auxiliary current-transformers, resulting in simpler interconnections. In addition, the added burden of the auxiliary CT's need not be imposed on the main current transformers, resulting in a higher-performance system.

PERCENTAGE-DIFFERENTIAL CHARACTERISTIC

This feature is perhaps more desirable for transformer relays than any other type of differential relay since the transformer relay will almost always suffer a mismatch in CT ratios due to the ratio of the power-transformer being protected, and the mismatch caused by action of Load-Tap-Changing equipment.

In addition, the location of an external fault can seriously affect the performance of current transformers, causing severe saturation of one CT and not the other. Some of the reasons for this unbalance are listed below:

Bus Configuration

Breaker-and-a-half, or ring bus schemes with the transformer primary winding between two breakers: the fault currents through each breaker are limited by their respective (and probably different) source impedances.

This will almost always lead to unequal distribution of fault currents, and correspondingly different CT performance.

Location of Current Transformers

When one CT is an appreciable distance from the other, the lead-drop from one CT to the relay will tend to be greater than the other. Some of this disparity may be corrected by larger-sized wire for the long run, but usually, the remote CT will have a more difficult task to remain unsaturated.

Difference in CT Ratios

Required to balance the secondary currents delivered to the relays, unfortunately the different ratios produce another problem, in that the higher ratios tend to have higher saturation voltages. This problem can be particularly acute in switchgear applications with low ratio CT's mounted in the switchgear, as C100 or C200 accuracy classifications are quite common for this type of CT, and space is only expensively available for the large volume required for the higher voltage classifications.

PRIOR STATE OF THE ART

A transformer differential relay with harmonic restraint measures the ratio of the difference of winding currents to the sum of the larger of the winding currents. The relay trips if the difference exceeds a predetermined percentage of the larger winding current. At the same time, the harmonic content of the difference current is separated by L-C filters and tripping is restrained if a predetermined harmonic content is present. This content is representative of magnetizing inrush current.

Formerly, relays have used separate restraint current transformers for each winding and one or two differential transformers. The transformers are connected in a T-circuit to derive both restraint and operate voltage signals.

When ratio correction taps are provided on each of these transformers, the T-connection forces a complex interconnection of windings and tap blocks. In addition, the use of conventional diodes and polarized output relays have imposed a large signal level. The large signal level has adversely affected the size and weight of the transformers of necessity and forced the use of bulky reactors and large capacitors in filter circuits.

THE NEW DESIGN

The limiting factors in previous designs have largely been overcome by the use of small-signal design and the novel input circuitry to be described below. The relay design is represented in block diagram form in Figure 6.

INPUT CIRCUIT

Figure 7 shows the input circuit of a 3-winding transformer differential relay. Burden resistors R300, R301, and R302 connected in the secondaries of input transformers T300, T301 and T302 develop signal voltages proportional to the current in each winding. Taps are provided on the primary of each transformer in the manner of a simple overcurrent relay.

Each signal is rectified by precision positive polarity full wave rectifiers U100, U101 and U102. The rectified signals are dioded coupled to obtain the signal of largest absolute value. This is the restraint signal $|V_R|$.

In addition, the AC signal voltages V_1 , V_2 and V_3 are summed by means of operational amplifier U104. The resulting signal V_0 is proportional to the difference of the current in the three windings.

ZERO-DROP RECTIFIER CIRCUITRY

This signal is rectified by zero-drop (precision) full wave rectifier U103 to extract its negative absolute value. This is the operate signal $|V_0|$.

The use of simple diodes for rectification penalizes the choice of signal level since the signal must be large compared to the inherent half volt diode junction drop and its attendant change with temperature. However, operational amplifiers in conjunction with diodes produce temperature stable zero-drop rectifiers in order to utilize small signal levels.

As an example, the precision rectifier circuit U103 is shown in Figure 8. The circuit may be analyzed using the following common assumptions:

- 1) The gain of each amplifier is high enough to consider the voltage between its input terminals to be virtual zero.
- 2) The input impedance of each amplifier is high enough to consider no current enters the amplifier.

In Figure 8, the first amplifier U103A is connected as a non-inverting amplifier and feeds the output when the input V_1 is negative. With negative input diode D2 is forward biased and D1 is reversed biased.

Considering conditions 1 and 2 above, resistor R_B is at the output potential E, R_A is at virtual zero, and the junction of R_A and R_B is at the input potential .

The output, therefore, can be expressed by

$$v_2 = \frac{R_a + R_b}{R_a} v_1 \quad (v_1 < 0)$$

The second amplifier, U103B, is connected as an inverting amplifier and gets an input signal v_1 through R_A . With negative input U103B, output is poled positive, diode D4 reversed biased, and the amplifier cannot feed the output. However, when the input goes positive, the U103B output goes negative. Diode D4 is then forward biased, and U103B feeds the output. For this connection:

$$v_2 = - \frac{R_a + R_b}{R_a} v_1 \quad (v_1 > 0)$$

Consequently, the output is again negative and equal to the value produced by the negative input. At the same time, the non-inverting amplifier output is positive for positive input and diode D2 decouples it from the output.

In summary, the input circuit of Figure 7 uses operational amplifiers to derive the restraint and operate signals. The small signal circuitry allows simple tapped input transformers to provide the required differential characteristic. However, the relay has excellent immunity against transients, as discussed in the section on testing.

HARMONIC RESTRAINT UNIT

The harmonic restraint circuit is shown in Figure 9. In this circuit, operational amplifiers are used to construct second order band pass filters for segregating the fundamental and the second harmonic from the complex waveform of the differential circuitry (V_0). The fundamental is poled to operate this unit, and the second harmonic poled to restrain.

The operate signal V_0 , obtained from the input circuit of Figure 7, feeds a 60 hertz band pass filter utilizing operational amplifier U200 as an "ideal current inversion negative immittance converter".

It can be shown that the output to input voltage transfer function of either the 60 Hz. or the 120 Hz. filter is the second order bandpass function,

$$K \frac{s/\omega_0}{\frac{s^2}{\omega_0^2} + \frac{2d}{\omega_0} s + 1}$$

In this equation, ω_0 is the center frequency, 60 and 120 Hz. respectively for the operate and restraint quantities, and d is the damping factor (1/Q).

The center frequency of each filter is determined by precision resistors and capacitors R, C and the desired Q by potentiometer R_0 . Both filters are adjusted by a Q of 10. The frequency response of the 60 Hz. filter is shown in Figure 10. The response of the 120 Hz. filter is exactly the same, but centered at 120 Hz. rather than 60.

TRANSIENT RESPONSE

A vital consideration in the selection of filter design is the response to a suddenly applied current. Figure 11 shows the response of the 60 Hz. and 120 Hz. filters to a simulated inrush current. Note that the 120 Hz. filter output rises at a rate twice that at which the 60 Hz. filter does. The reason for this may be understood by analyzing the response of the transfer function to an impulse. Such a solution would be of the form:

$$e^{-2d\omega_0 t} \sin \omega_0 t$$

This type of exponential is seen in Figure 11. Note that the time-constant of the build-up is determined by both the circuit damping and the center-frequency. With the same damping in each filter, the 120 Hz. response early in the inrush period must be twice as fast as that of the 60 Hz. filter. This allows an extra measure of coordination between the two signals and provides for transient stability.

Figures 12 and 13 show the response of each filter to offset and non-offset fault currents. Of interest here is the lack of difference - the filters virtually ignore the dc component.

PROPORTION OF HARMONIC RESTRAINT

As indicated in Figure 9, rheostat R217 adjusts the proportion of second-harmonic required to balance the fundamental (thru R208). As previously discussed, 15% has been selected as the proper amount. However, should other considerations occur, this ratio may be easily varied by the user's adjustment of R217.

This operation is preceded by the rectification of the two signals, V1st, V2nd by rectifiers U201 and U203. Rectifier U201 produces the absolute value of the fundamental signal with negative polarity. This signal drives current in resistor R208 and tends to pole the output of U204 positive at the same time rectifier U203 produces the absolute value of the second harmonic content of the operate signal with a positive polarity. This signal drives positive current through resistors R217 and R218 which tends to pole the output of U204 negative, which is the non-operating direction.

PERCENTAGE DIFFERENTIAL CIRCUIT

Figure 14 shows the comparator circuit utilizing the operate and restraint signal to produce the percentage differential circuit. The circuit is analyzed as follows:

With no operate signal, the positive restraint signal causes the comparator output to pole negative. As a result, resistor R120 is negative while R121 connected to positive. The resistors form a voltage divider and their values are chosen so that at their common junction is zero.

The negative operate signal tends to pole the comparator output positive, producing a positive output at V_D , the junction of R120 and R121. The balance point occurs where the negative current due to the operate signal equals the positive current due to the restraint signal, as

$$V_o/R_o = V_R/R_R$$
$$V_o = \frac{R_o}{R_R} V_R$$

It can be seen that the ratio of operate and restraint resistors (R_o/R_R) is the per unit slope differential characteristic. The resistance R_o includes the variable resistor R115 which provides the percentage. Consequently, the circuit produces a positive output for V_o greater than $(R_o/R_R)V_R$.

Figures 15a and 15b show the percentage characteristic thus obtained. As shown, the relay may be adjusted from 15 to 40% restraint, with sensitivity varying from 13 to 46% of tap setting.

OUTPUT CIRCUIT

Figure 16 shows the output circuit of the differential relay. To produce an output, both the differential signal V_D and the harmonic restraint signal V_H must be present at the input of the nand gate U107-2.

The RC circuit and diode, together with the two gates U107-2 and U107-3, form a retriggerable one-shot multivibrator and continues its DC output when the pulse of the unfiltered inputs occur. At the same time, the output of U107-3 feeds transistor relay and target drive circuits.

Thus, relay output occurs only when a differential signal is present and inrush containing second harmonic restrains operation by producing a zero at the V_H input.

INSTANTANEOUS UNIT

A separate unrestrained instantaneous unit, with circuitry similar to that described above, is also included in the new relay. The setting is adjustable from 8 to 20 times tap rating.

TRANSIENT IMMUNITY

As part of the standard design procedure for solid-state protective relays, the new design has successfully passed various transient immunity tests against false tripping, component damage and changes in calibration as a result of subjecting the relay to:

- 1) Surge Withstand Capability (SWC) Tests (ANSI 37.90a)
- 2) Fast-Transient Tests
- 3) Electromagnetic Interference Tests, utilizing 5 watt transceivers of various frequencies in the range of 48-465 MHz, at distances of a fraction of an inch from the relay.

TRANSFORMER INRUSH CURRENT TESTS

The ITE-87T was tested on a working installation consisting of a 1500 kVA, 4160/480V secondary unit substation supplying power to the Gould Switchgear Assembly Plant.

Figure 17 shows the transformer being energized from the 4160V side, with no load connected. As shown, the output of the 120 Hz. filter restrains the relay from tripping. The magnetizing current was measured as 23 amps secondary (300/5 CT's) or 8X full-load. Relay settings for all tests: 15% slope and instantaneous element at 29 amps.

The detail of the initial primary and secondary currents, when load is connected, is shown in Figure 18, along with the 120 Hz. filter output. The relay restrains as it did above, with no load. Of particular interest in this photo, is the apparent short-circuit of the transformer secondary during the first several cycles after energization.

The basic sensitivity of the 87T is illustrated in Figure 19. Here, the secondary CT's were disconnected from the relay so that the relay currents were zero. A legitimate trip occurs in about 0.4 seconds, when the magnetizing current has sufficiently decayed.

This seems an inordinately long time, however, since the load current was very low, the relay is operating at $(.145 \div .13)$, only 111% of minimum sensitivity.

CONCLUSION

Solid-state design techniques have been exploited to implement a new relay for transformer protection utilizing the time-proven principle of percentage differential and harmonic restraint. Previously, relays designed according to these powerful principles had to suffer the disadvantages of bulky iron-core inductors, complex interconnections, and time-related calibration changes.

The use of modern electronic components such as integrated operational amplifiers, precision resistors and capacitors has eliminated these problems.

The paper has shown that solid-state designers can develop the circuitry required by the application of the device within the power-system, without suffering limitations inherent to the component parts.

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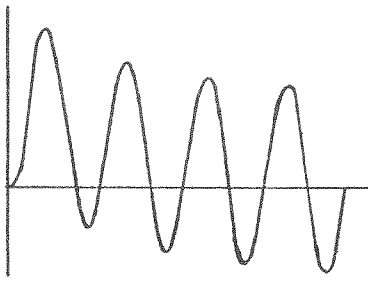


FIGURE 1
Offset Fault Current

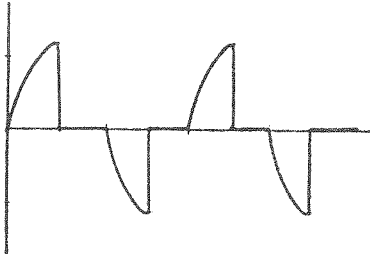


FIGURE 2
Saturated Current-Transformer
(Resistive Burden)

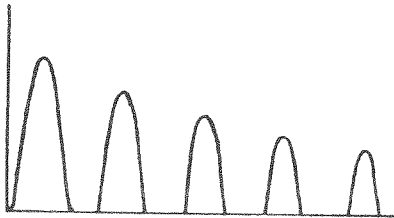


FIGURE 3
Magnetizing Inrush Current

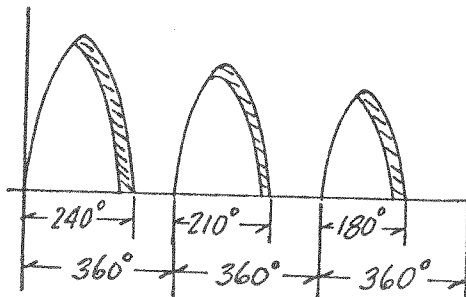


FIGURE 4
Magnetizing Inrush Current
Showing Narrowing Bases and
Effect of Damping

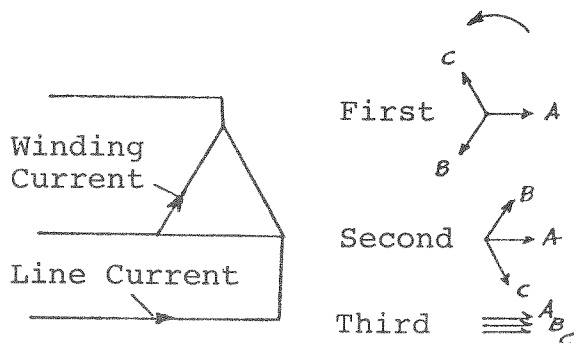


FIGURE 5
Winding and Line Currents
First, Second, Third Harmonics

FIGURE 6
Block Diagram - Type ITE-87T
Transformer Differential Relays

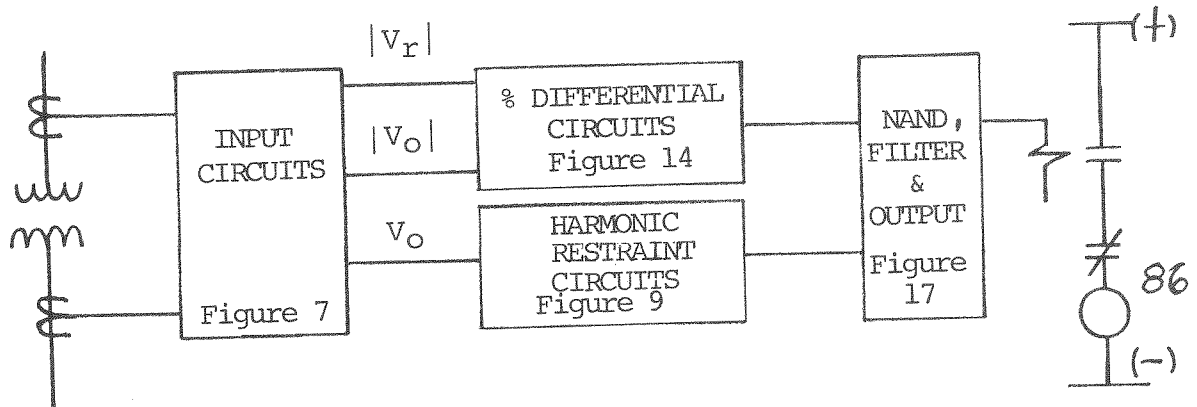
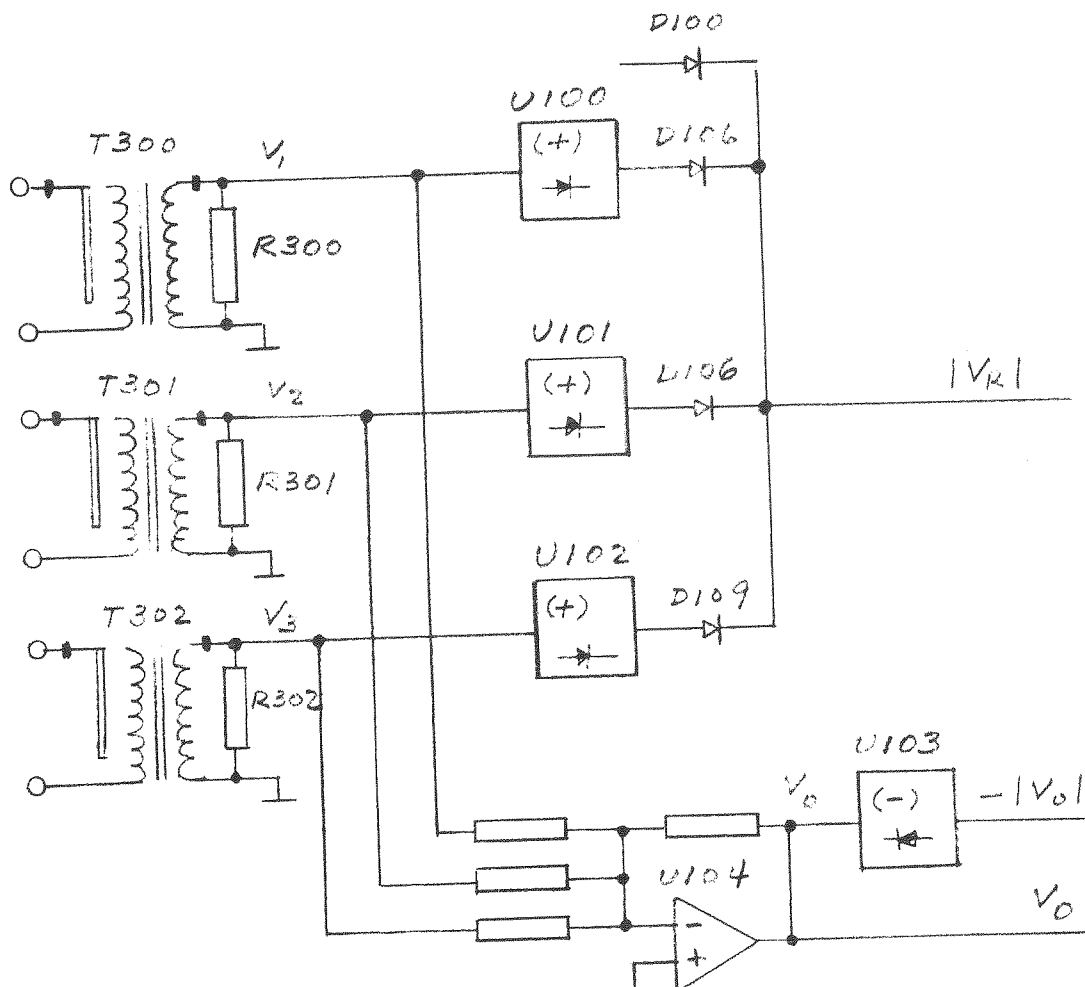


FIGURE 7
3-Winding Input Circuit to Develop
Restraint and Operate Signal



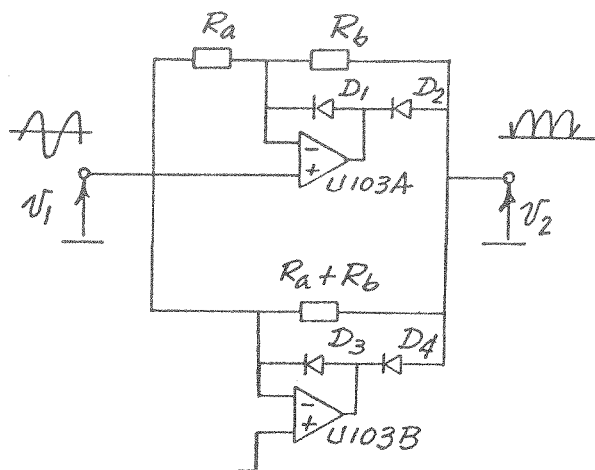


FIGURE 8
Zero-Drop
Rectifier Circuitry

FIGURE 9
Harmonic Restraint
Circuitry

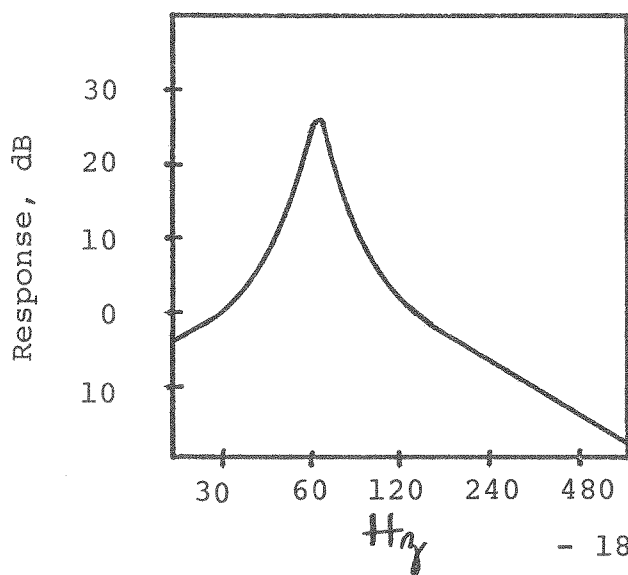
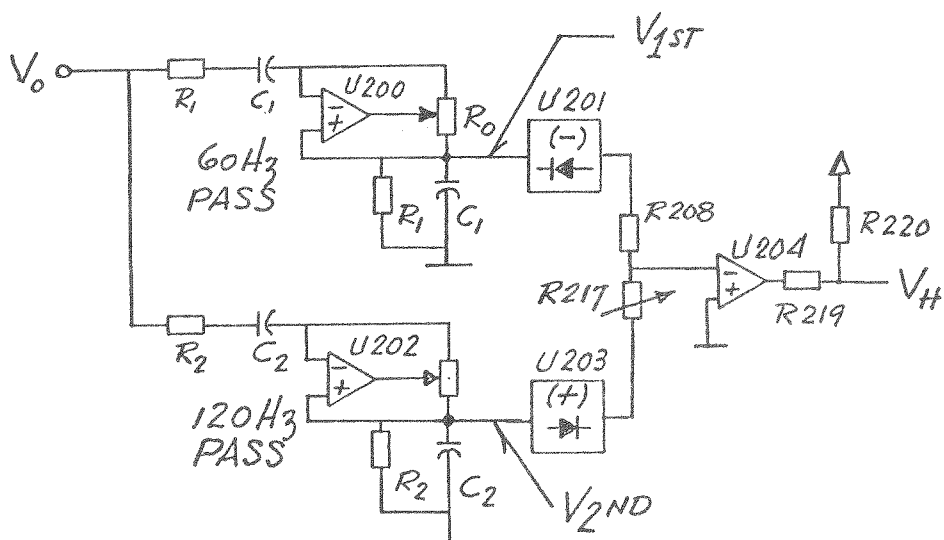


FIGURE 10
Frequency Response
60 Hz. Pass Filter

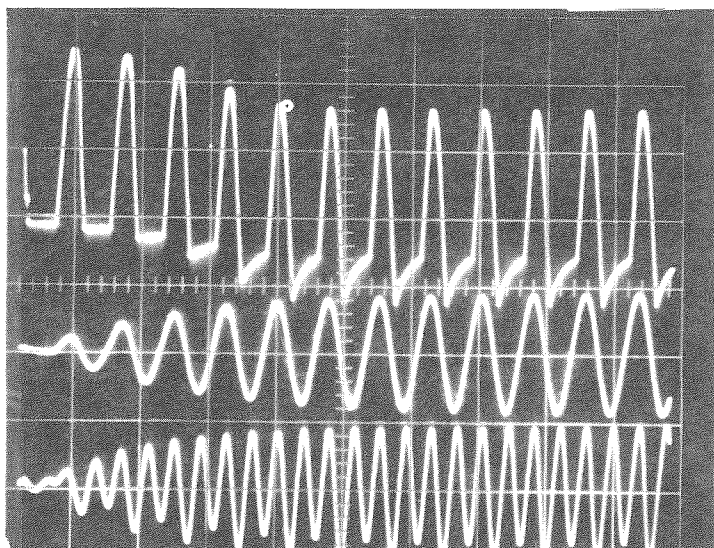


FIGURE 11
Filter Response to Inrush

—— 60 Hz. Filter

—— 120 Hz. Filter

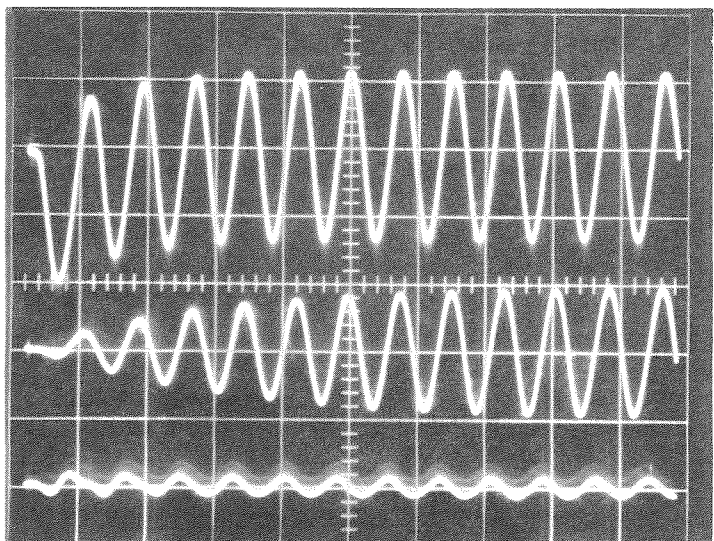


FIGURE 12
Filter Response to
Offset Fault Current

—— 60 Hz. Filter

—— 120 Hz. Filter

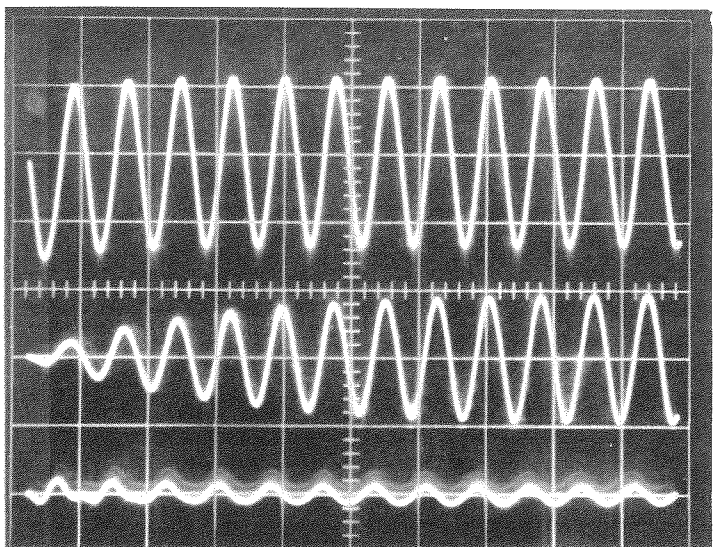


FIGURE 13
Filter Response to
Non-Offset Fault Current

—— 60 Hz. Filter

—— 120 Hz. Filter

FIGURE 14
Percentage Differential Circuit

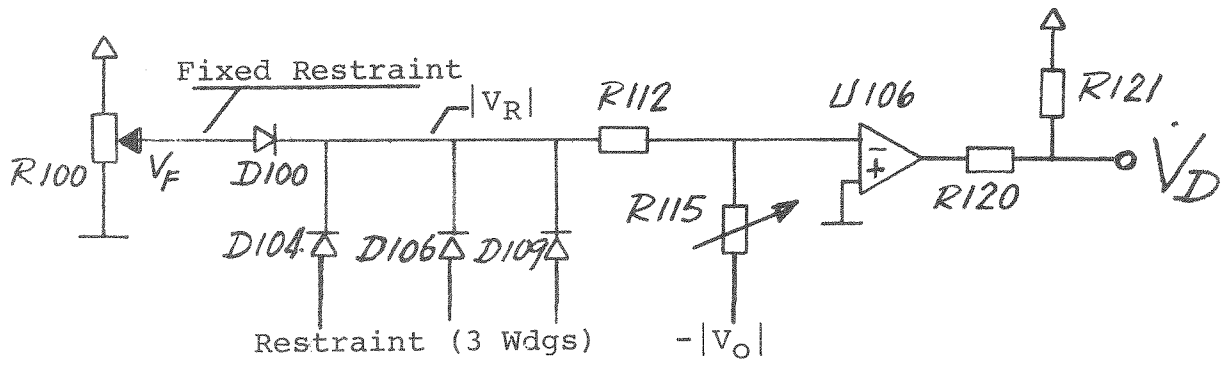


FIGURE 15
Percentage Differential Characteristic

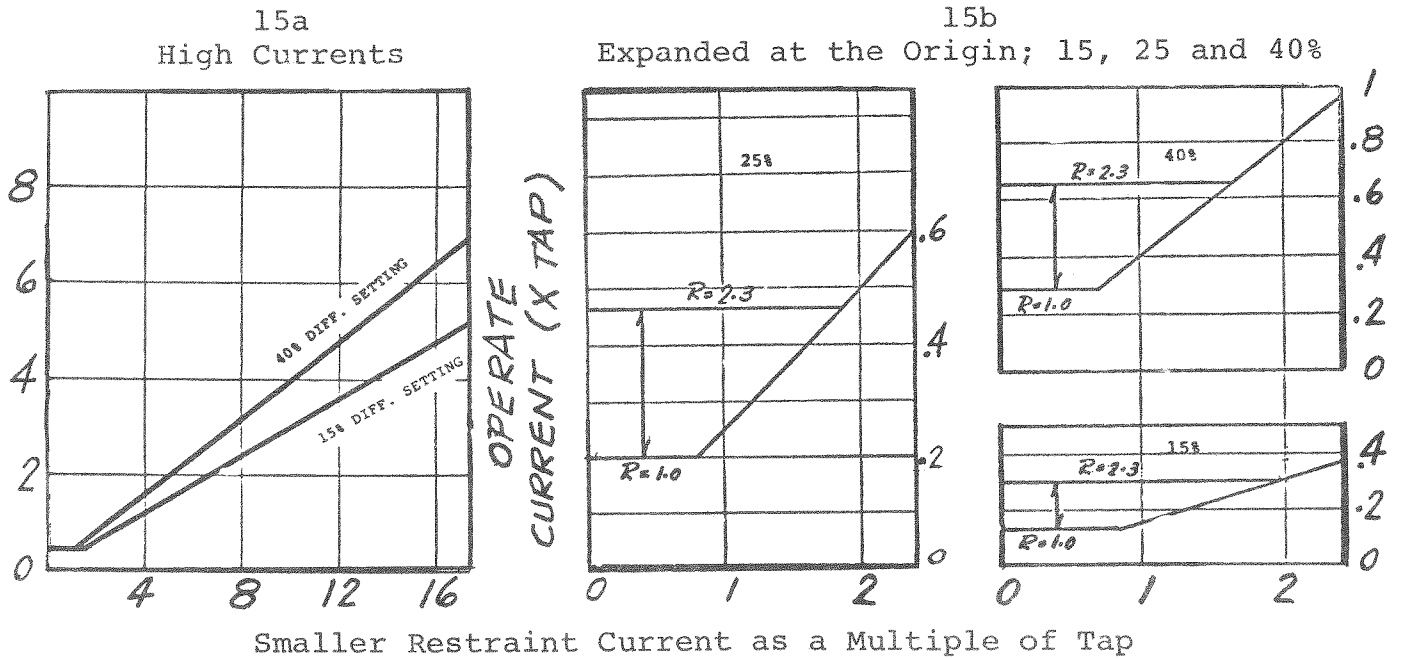
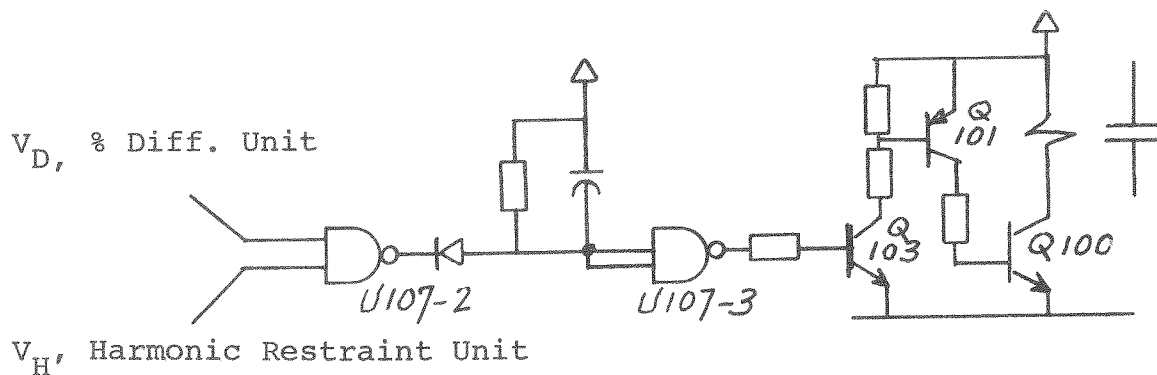


FIGURE 16
Nand, Filter, and Output Circuit



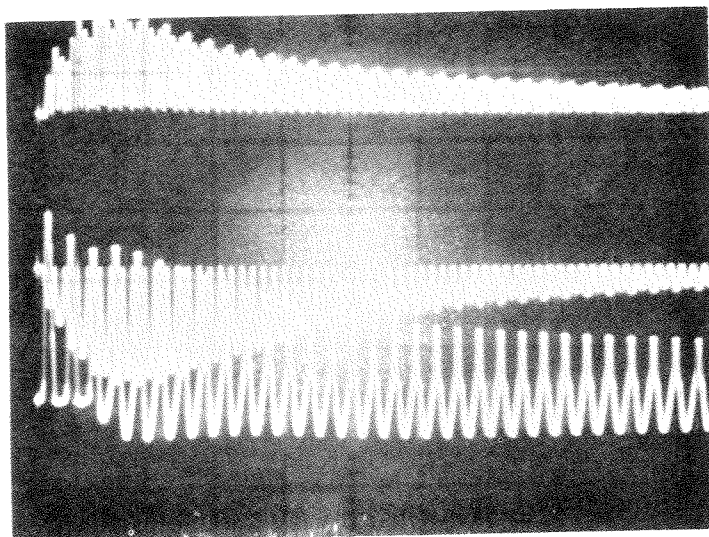


FIGURE 17

— 120 Hz. Filter

— 60 Hz. Filter

— Primary Current

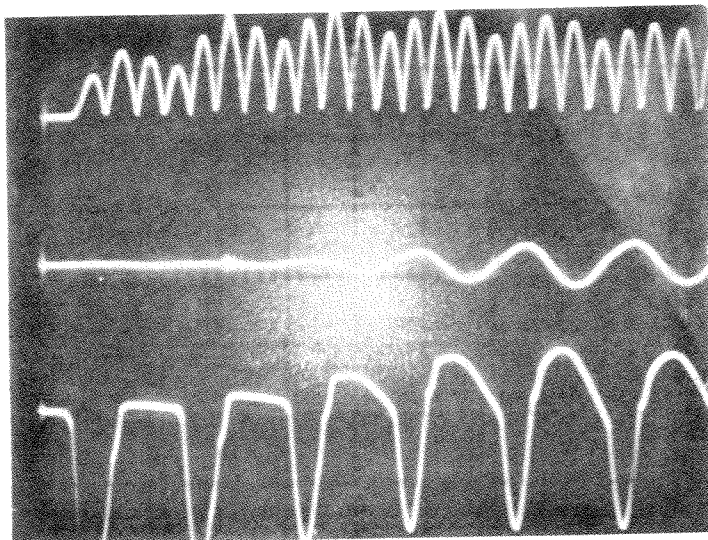


FIGURE 18

— 120 Hz. Filter

— Secondary Current

— Primary Current

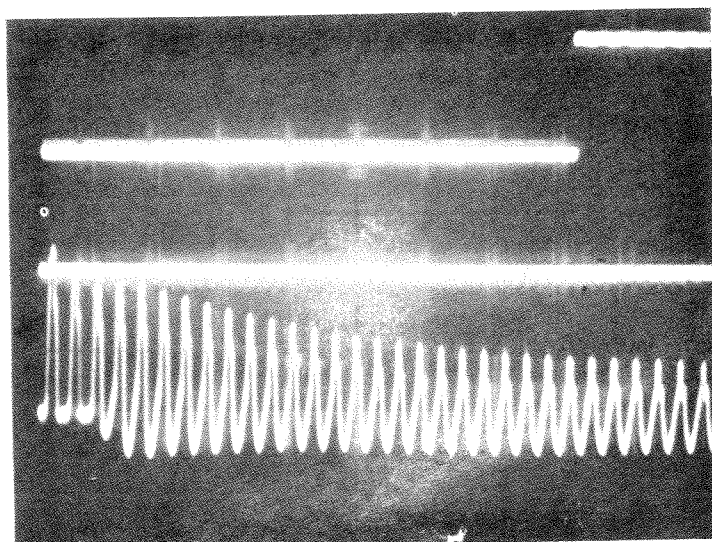
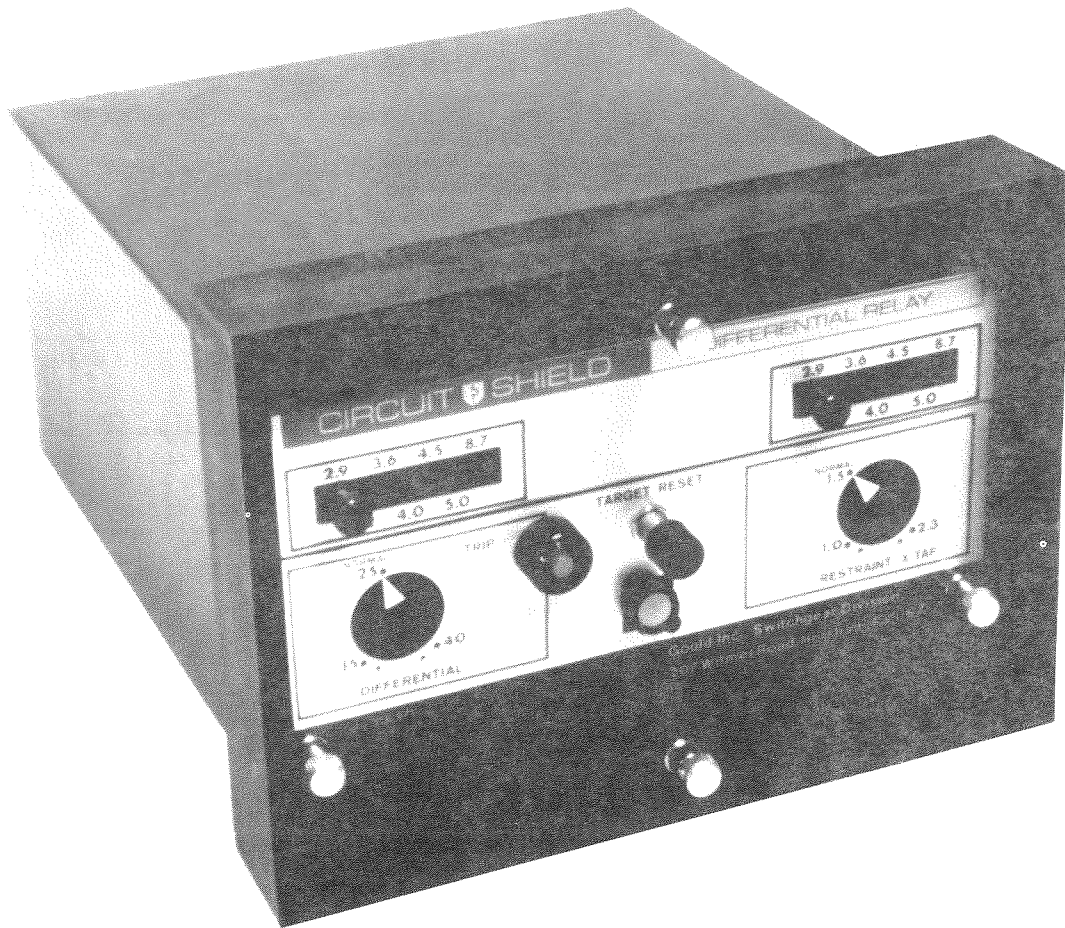


FIGURE 19

— Trip Signal

— Secondary Current
as seen by Relay

— Primary Current



Type ITE-87T
Transformer Differential Relay



Relay and Circuit-Board Extender
Showing Solid-State Circuitry