Experience, Improvements in Operation, Limitations, and Successes of an Ungrounded Distribution Network Protection Scheme

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Abstract—**This paper discusses the application considerations, improvements in operation, and experience with state-of-the-art numerical techniques in protective relaying for ungrounded power systems in ETESAL, the transmission company in El Salvador. ETESAL operates the substations from which 46 kV feeders distribute energy to El Salvador's distribution companies. The network is ungrounded and requires a better protection scheme than the traditional overvoltage (59N) protective relaying scheme.**

The paper provides a brief review of the challenges and theory in the protective relaying of ungrounded power systems. It also describes the 46 kV distribution network of El Salvador and the experiences before implementing the protective relaying scheme, then illustrates the performance improvement in interconnections to the distribution network. This discussion includes references to the limitations, both technical and economic, that ETESAL faced in implementing the relaying scheme. The paper concludes with illustrations of typical faults.

I. Introduction

Medium voltage distribution networks throughout the world can have a variety of grounding techniques, and in each system there are special considerations for protective relaying against power system faults [1]. These distribution networks could be electrical utilities serving residential and commercial customers, industrial installations, or specialized applications such as in the naval industry [2]. The type of grounding classifies the distribution network as: solidly grounded, low-impedance grounded, high-impedance grounded, resonant grounded, and ungrounded.

Ungrounded and resonant-grounded networks may be a group of their own because ground faults in these types of networks present very low fault-current magnitudes. It is precisely for this reason that a great number of distribution networks are chosen to be ungrounded or resonant grounded. A low ground-fault current magnitude provides the power system with the opportunity of continuous operation, even under the presence of a ground fault. The loads in ungrounded and resonant-grounded distribution networks are connected phase-to-phase and ground faults do not disturb their operation. In industry and in several utilities around the world, ungrounded networks may be considered first since there is no requirement for the resonant inductance (Petersen Coil) and the associated equipment that makes resonant networks more expensive. In other situations, however, short-circuit magnitude constraints may make resonant networks the only option available.

As an illustration of the behavior of an ungrounded network, consider the simple symmetrical components network connection for a ground fault in Fig. 1 [3]. The Z1 and Z2 impedances are the positive- and negative-sequence impedances of the system. To stress the ungrounded nature of the system, the zero-sequence impedance (Z0) is shown to be infinite, an opening in the zero-sequence network. The figure, for simplicity, does not consider any stray capacitance.

In the sequence network connection in Fig. 1, ideally there is no current (I1 = I2 = I0 = 0) and therefore no voltage drop in the sequence impedances. Therefore, V1 = Vs, V2 = 0 and V0 = (-Vs). As Fig. 1 shows, the voltage triangle remains intact when the sequence voltages are converted to phase voltages. The phase-to-phase voltages (VBC, VCA, VAB) can keep the loads running and, ideally, the fault current magnitude is zero. Load currents are barely disturbed during a ground fault in an ungrounded network.

The unfortunate effect of a line-to-ground fault in an ungrounded power network is that the unfaulted phases reach the phase-to-phase voltage magnitudes (VB = VBA, VC = VCA), as illustrated in Fig. 1. The unfaulted phases can reach 1.73 ($\sqrt{3}$) times their normal magnitude. This situation requires that the power system be designed with higher insulation than an equivalent grounded power system. In most industrial installations where the distribution is indoors and through power cables, this requirement can be met. In utility distribution networks, overhead distribution lines are subject, in some areas, to changing environmental conditions that may degrade the electrical insulation. This should be considered in the design of feeder structures and spacing between conductors. In an ungrounded distribution network, the presence of a ground fault and the high stress in the unfaulted phases increases the chances of a second ground fault in the healthy phases. If this second fault occurs, it would not necessarily be in the same location, but at the weakest insulation point in the network.

Fig. 2 illustrates the distributed capacitances in an ungrounded distribution network. The phase-to-ground capacitive impedances are the only connection to ground in the network. The phase-to-phase capacitances depend on the geometry of the overhead line. Typical distributed capacitive impedances are in the kΩ range. These capacitances are the dominant component in the zero-sequence network of an ungrounded system.

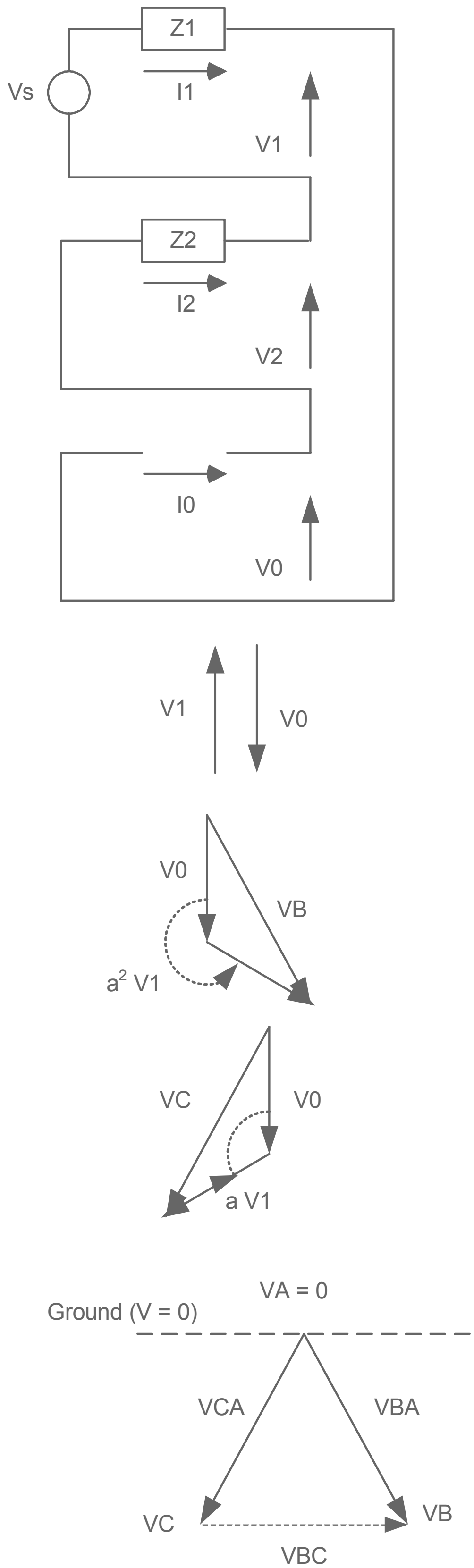


Fig. 1. Theoretical symmetrical component analysis for an AG fault in an ungrounded network

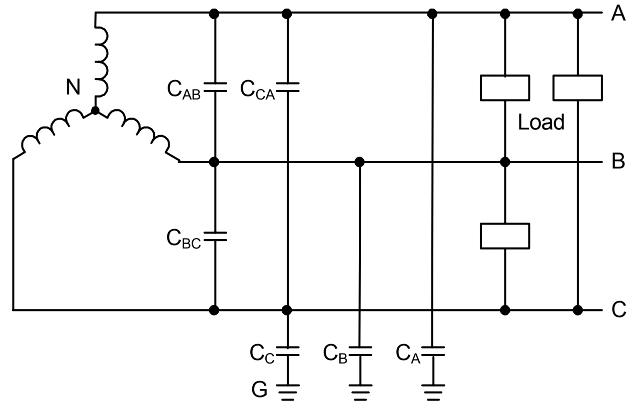


Fig. 2. Capacitive impedance in ungrounded power systems

The zero-sequence equivalent of an ungrounded system is the sum of all the zero-sequence capacitances, or in other words, the parallel combination of all the capacitive impedances of the feeders, bus structures, transformer, and so on. Regardless of its length, a feeder will have a zero-sequence capacitive impedance, as shown in Fig. 3. This figure also shows the equivalent zero-sequence network for an ungrounded network. If a feeder is our reference (in the case of Fig. 3, it is feeder 01, shown with a relay measurement), the zero-sequence equivalent capacitances can be divided into an equivalent system capacitance ($C0_S$) and the reference feeder capacitance (CO_L). Any measurement of the feeder zero-sequence current (3I0) will be related to the total fault current and the current divider caused by the two capacitances.

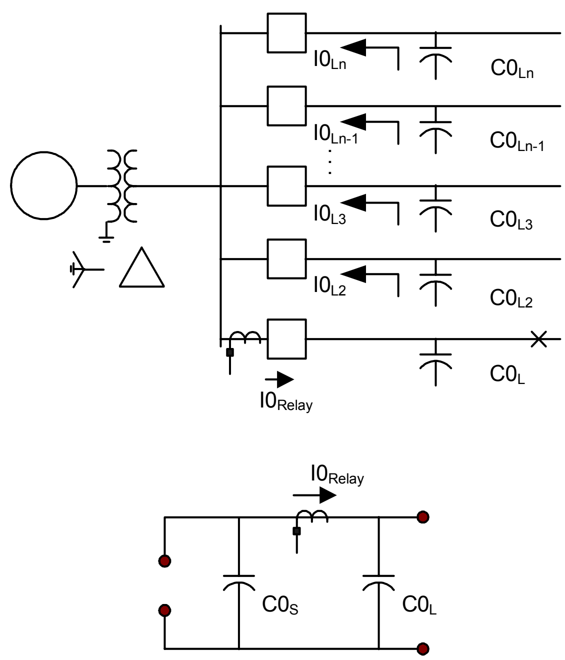


Fig. 3. Zero-sequence capacitive impedance in an ungrounded network

During phase-to-ground faults, the fault current is capacitive as determined by the equivalent zero-sequence capacitance of the network. The ground fault current flows through all the capacitances, even the unfaulted feeder capacitances. This is illustrated in Fig. 3, where for a ground fault in feeder 1, the other feeders contribute capacitive current to the fault as shown.

A. Protective Relaying for an Ungrounded Distribution Network

Distribution and industrial networks generally have radial feeders with loads at the ends of the feeders. Ungrounded distribution networks may have delta-connected three-phase loads, or loads connected phase-to-phase, as shown in Fig. 3. When providing most protective relaying functions to distribution networks, the type of grounding is not a consideration. Phase over-current and negative-sequence overcurrent protection applications do not consider the network-grounding configuration. Ground fault protection, on the other hand, is very dependent on the type of grounding.

Ungrounded distribution networks are subject to the same occurrence of ground faults as grounded distribution networks. Ground faults are typically 80 percent or more of the type of faults experienced in a distribution network [1]. The limited ground-fault current magnitude and the distributed capacitance of the feeders in an ungrounded network make the protective relaying scheme more involved than the schemes for grounded networks, where fault-current magnitudes are easy to measure and faulted feeders are easy to identify.

In Fig. 3, which illustrates a simple ungrounded network, a ground fault in feeder 1, for example, requires that the healthy feeders also contribute to the fault. This illustrates that measuring the fault current is not sufficient to discriminate the faulted feeder from the healthy feeders because the healthy feeders are also contributing to the fault and can have appreciable fault current.

Traditional ground-fault protection for ungrounded networks uses a simple overvoltage protective relay measuring the zero-sequence voltage component (59N). Fig. 4 illustrates the protective scheme in a typical application. As shown in Fig. 1, the zero-sequence voltage for a ground fault will be very healthy, equal to the magnitude of the source voltage, $|V0| = |Vs|$. The 59N scheme is a simple and sensitive protective relaying scheme for ungrounded networks.

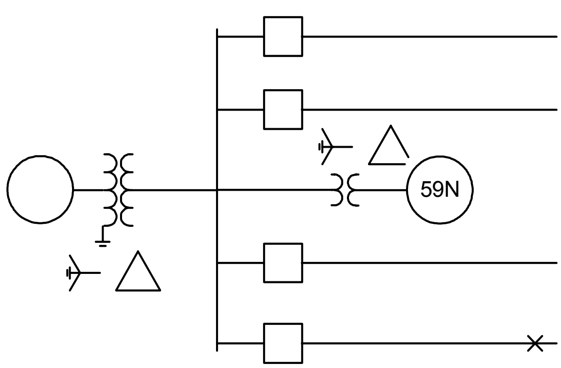


Fig. 4 Zero-sequence overvoltage protective scheme for an ungrounded network

The 59N protective device lacks two major functions required for modern protective schemes. The first one, and major one, is that the simple 59N device cannot tell which of the feeders is faulted. A ground fault in any of the feeders will produce the same magnitude of zero-sequence fault voltage. The second function that 59N lacks is phase identification. An AG fault cannot be discriminated from a BG fault.

The 59N scheme is sensitive enough for most applications and will detect the majority of ground faults in an ungrounded network. It is still in use in several industrial installations and possibly some electric utilities. In most industrial installations with this scheme, an alarm alerts the operator to the presence of a ground fault. Once the alarm is issued, operators can identify the faulted feeder by manually opening one feeder at a time until the alarm is gone. If this operating procedure is acceptable, the 59N protective scheme provides sensitive, inexpensive, and reliable fault detection. Some automated protection schemes start tripping feeder breakers in a predetermined sequence until the fault is gone.

In electric distribution utilities, however, this operating procedure is no longer acceptable because of lost revenue and, in some cases, penalties associated with unnecessary tripping of healthy feeders. Utilities may require a more sophisticated protective scheme that is reliable and provides feeder identification and phase identification functions.

While fault location algorithms are well known and widely available for phase faults, the same functionality becomes extremely complex for ground faults in ungrounded networks. The sophisticated techniques proposed for this function [4] generally require additional equipment or very high sampling rates. Fault location in an ungrounded network is a complex problem because fault voltage and current profiles are very similar regardless of the location of the fault.

Identifying the faulted feeder in an ungrounded network requires a directional unit in each feeder. The faulted feeder directional unit should detect the fault in the forward direction; the unfaulted feeders' direction should be reverse or none.

As mentioned previously, the phase-fault protection for ungrounded networks is the same as for any other type of grounding. Definite and/or inverse-time phase overcurrent units (50P/51P) are used to coordinate phase-fault detection with downstream devices. Phase-directional elements are redundant for radial feeders. Phase-fault magnitudes are generally large enough to discriminate whether the fault is in the feeder or behind the feeder. For ground fault protection of ungrounded networks, however, a ground directional unit supervises the ground overcurrent protection (50N/51N).

Reference [1] proposes a ground directional unit that uses the zero-sequence voltage and zero-sequence current measured at the feeder. As shown in Fig. 3, the zero-sequence network, for an ungrounded system, is the combination of all the shunt capacitive impedances of the system. Fig. 3 illustrates the behavior of a single feeder relay. We can determine two capacitances from looking at this figure: the feeder zero-sequence capacitance, $C0_L$, and the system capacitance, $C0_S$, which is the combination of all the system capacitances behind the feeder relay. The system capacitance is approximately the sum of all the healthy feeder capacitances.

The numerical algorithm in a protective relay is continuously measuring the quantity $z0 = V0/I0$. It is possible to identify the direction to the ground fault by looking at the sign of z0. Fig. 5 shows the characteristic of the ground directional element. As this figures illustrates, we can use the voltage and the direction of the capacitive current to determine the direction to the ground fault. Determining fault direction in an ungrounded system makes it possible to identify the faulted feeder.

Faulted phase identification is a desirable function in a feeder protective relay for ungrounded networks. Phase faults produce enough current and information to distinguish the faulted phases. Ground faults, on the other hand, do not, so a method for determining the faulted phase is necessary. Reference [2] provides the algorithm for identifying the faulted phase.

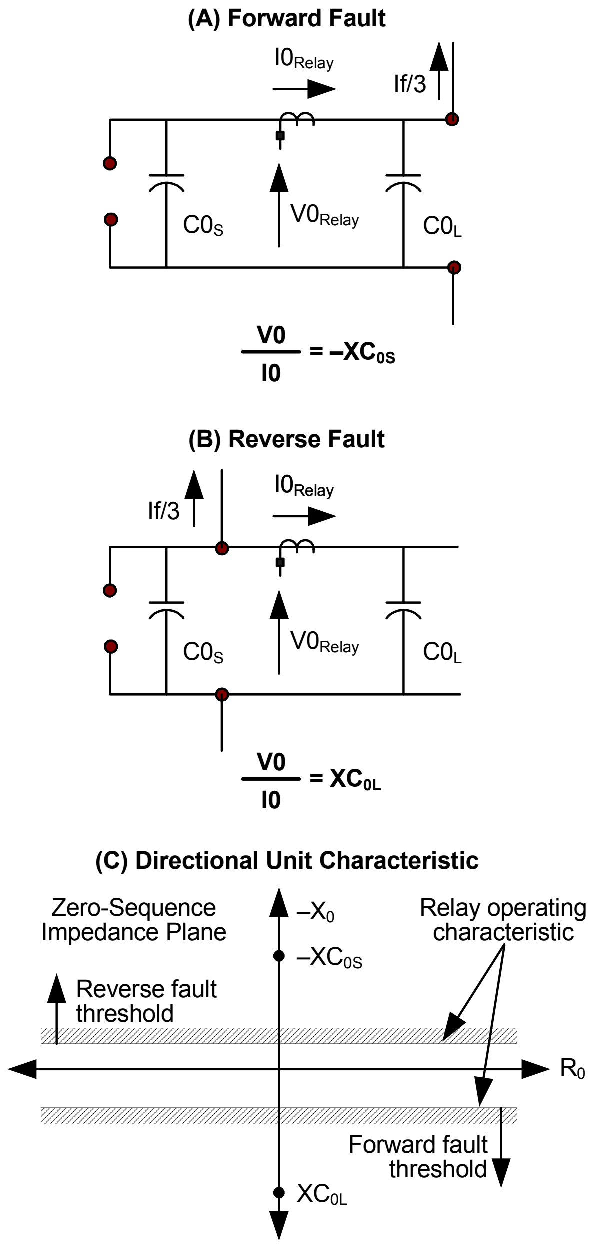


Fig. 5 Forward and reverse direction determination of a Ground Directional Unit for ungrounded networks

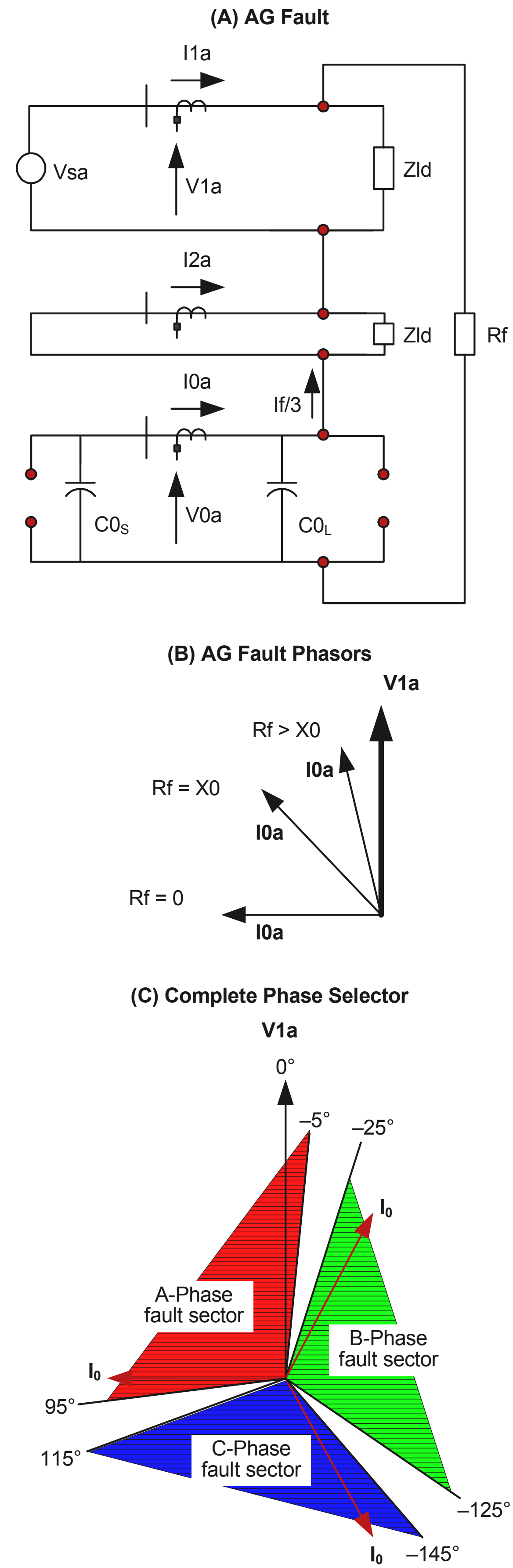


Fig. 6 Phase-selector algorithm for forward faults

Fig. 6 illustrates an AG fault and the phase-selector algorithm for ungrounded networks. The sequence network connection in Fig. 6(A) shows that the positive-sequence voltage is a very reliable quantity because its value is that of the source voltage. Also, the zero-sequence current, at the relay location, is capacitive and the load impedance does not change its angle because the loads are not connected to ground. In Fig. 6(B), the relationship between V1a and I0a is described with different values of fault resistance. The fault selection considers the fact that fault resistance of very high values changes the angle between I0a and V1a. The phase-A selection defines a range of -95^{o} to 5^{o} for the angle difference between I0a and V1a. For phases B and C the phase-selection areas should be shifted by 120^{o} and 240^{o}, respectively, because there is an equivalent comparison for V1b and V1c, as shown in Fig. 6(B). Therefore, Fig. 6(C) illustrates the phase-selection areas for the three possible cases.

The magnitude of the capacitive impedance in the zero-sequence network limits the fault-current magnitude drastically. Protective relays for ungrounded system feeders should be able to measure very small currents, somewhere in the milliampere range.

Modern hardware makes measurement of small secondary currents possible because protective relays can measure small magnitudes of current. To provide sensitivity for ground faults in ungrounded networks, measuring the zero-sequence current using a toroidal current-transformer arrangement, as shown in Fig. 7, is preferred.

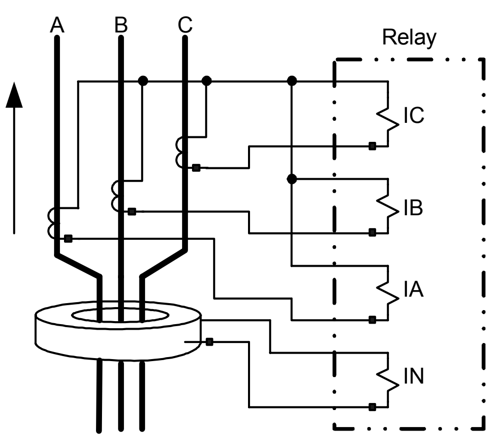


Fig. 7 Preferred measurement of the zero-sequence current

The arrangement of Fig. 7 provides a more sensitive measurement of the zero-sequence current (3I0) because the CT ratio is smaller than the ratio used for the phase CTs. The arrangement is also more secure because the zero-sequence current is not dependent on unequal performance of the phase CTs. In some cases however, a toroidal CT is not available for measuring the zero-sequence current. The arrangement in Fig. 7 may not be necessary if the lost sensitivity caused by phase-CT ratios and additional considerations about unequal CT performance are acceptable in the application. Protective relays designed for ungrounded network feeders can still provide substantial protection for ground faults without the use of a toroidal CT.

II. ETESAL NETWORK

ETESAL is the transmission company in El Salvador. It is responsible for the maintenance and system growth of the country's electric power system. This includes the 230 kV and 115 kV transmission networks and all the power transformers (115/46 kV, 115/34.5 kV, and 115/23 kV) that belong to the country's interconnected network.

In El Salvador the transmission network physically starts where the generating units are connected to the grid and ends at the interconnection points where distribution companies or large industrial installations connect directly to the transmission network. Approximately 36 115 kV transmission lines span 1021.5 kilometers, and two 230 kV lines interconnect El Salvador with Guatemala and Honduras. These 230 kV lines total 259.6 km. Of this total, line lengths of 14.6 and 93 km, respectively, actually belong to El Salvador. The system includes 23 substations with 27 power transformers (115/46/23 kV) and four autotransformers (230/115 kV) for a total of 1590 MVA. Fig. 8 shows the 2006 El Salvador single-line diagram for the transmission network.

El Salvador is located in Central America. It has a total area of 7336 square miles (19000 square km) and a population of 6.9 million. El Salvador is bordered to the north by Guatemala and to the west by Honduras. Its climate is tropical, humid, and very susceptible to tropical storms.

The transmission lines are mechanically supported on structures carrying one or two circuits, and as mentioned, the transmission voltage is 115 kV, which is appropriate for the size of this country. In the 115 kV/46 kV substations, ungrounded 46 kV feeders deliver power to distribution companies around the country.

Fig. 9 shows the simplified arrangement of the 115 kV/46 kV substation and power delivery. As the transmission company, ETESAL delivers energy to different distribution companies and large industrial installations around the country. ETESAL serves five distribution companies, transmitting energy from the generating stations. As illustrated in Fig. 9, ETESAL is responsible for the equipment in the 115 kV/46 kV substation, up to the feeder breakers. The distribution companies are responsible for maintaining the line. However, ETESAL is responsible for protecting the feeders because the 115 kV/46 kV substations are ETESAL property. In the distribution company substation, 46 kV/13.2 kV, a grounding bank provides better sensitivity for ground faults. Distribution in El Salvador is 13.2 kV and 23 kV. The 46 kV system consists of 16 substations and 44 feeders.

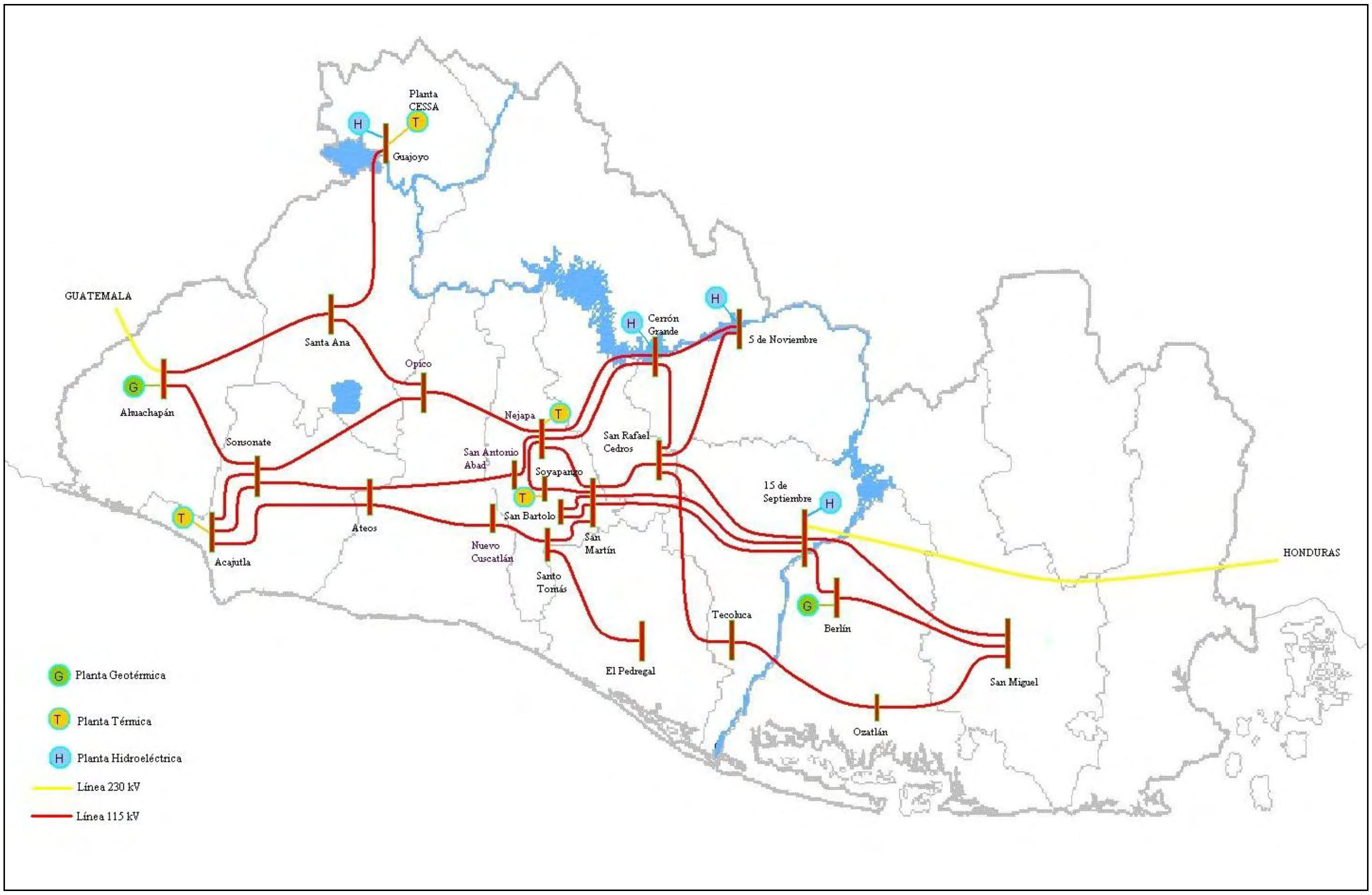


Fig. 8 El Salvador transmission network (2006)

Because ETESAL inherited the 46 kV ungrounded network, the exact reasoning for choosing this grounding arrangement is not known. However, this network grounding was presumably chosen because ETESAL could then have a subtransmission network that allowed continuous operation, even with a ground fault. Ninety percent of the faults on the 46 kV network are phase-to-ground faults; of these, 80 percent are transient. Therefore, the choice of an ungrounded system for the 46 kV subtransmission network seems appropriate for the characteristics of the environment. An 80 percent chance of transient faults means that there is no immediate need to trip and disconnect loads or use a reclosing scheme. In El Salvador, a one-second fault duration, in the 46 kV ungrounded network, is the discrimination time between a transient fault and a permanent fault. If the fault duration is longer than one second, the ground fault is considered to be permanent.

The typical feeder configuration is composed of wooden poles with an average height of 12 meters, approximately 40 feet. The conductors are arranged in a flat configuration. The distance from conductor to conductor is 1.5 meters, approximately 5 feet. The conductors are 4/0, rated for about 350 Amps continuous. The 44 feeders in the ETESAL system vary from 5 km to 60 km in length. In El Salvador this voltage level is considered part of the distribution network. Therefore, we use the term feeder instead of line, although it is more on a subtransmission level.

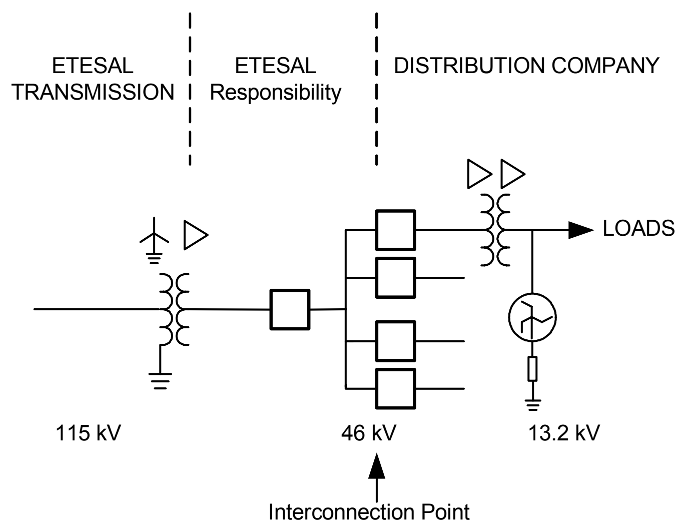


Fig. 9 ETESAL 115/46 kV power delivery to distribution companies

A. El Salvador 46 kV Ungrounded Network: Ground Fault Considerations

Ungrounded networks with overhead lines are no different from other subtransmission or distribution networks. They experience frequent single-line-to-ground faults (SLGFs). In El Salvador for example, the 46 kV network experienced 496 SLGFs in 2003 and 425 SLGFs in 2005. The above statistics only include permanent faults, because transient faults are not considered.

The theory explained in Fig. 1 for a SLGF is well understood by ETESAL personnel. SLGFs create an unbalance of the phase-to-ground voltages, but not the phase-to-phase voltages. Line currents remain almost unchanged during SLGFs. This allows power system loads to operate normally. Unfortunately, substation equipment is subject to overvoltages by both healthy phases (Fig. 1). These overvoltages can substantially degrade the insulation of substation equipment. For example, lightning arresters exposed to overvoltages for too long can be damaged when the energy dissipated is greater than their capacity. Continuous operation of the power system with a ground fault greatly increases the possibility of a second fault in a weak point in the power system. It is not unusual for an ungrounded network to experience a second ground fault if the first fault is not isolated properly.

Ground-fault protection for ungrounded networks presents a challenge to companies like ETESAL. The 46 kV system is a very important power delivery system, so it must perform reliably. Traditional ground overcurrent relays do not have the sensitivity required for detecting low-magnitude ground-fault currents.

Historically, ETESAL provided ground-fault protection on the 46 kV system by using a zero-sequence overvoltage relay (59N) with automatic time-delayed sequential tripping of feeders. This sequence disconnected the first feeder five seconds after the 59N relay operated. If the fault persisted, a second feeder was disconnected five seconds later. If the fault still persisted, the third feeder was disconnected after a further five seconds, and so forth. Eventually, the faulted feeder would be identified when the 59N relay reset. The disconnection sequence was evaluated yearly, and adjusted so that the feeder with the highest number of faults was disconnected first.

Even with yearly sequence adjustments, healthy feeders were often erroneously disconnected, creating unacceptable outages. Restoration of the healthy lines took approximately 5 to 10 minutes. The operator of the SCADA system needed that time to interpret the sequence of events and send restoration commands to each of the healthy feeders. The 59N relay informed operators of the fault and allowed identification of the faulted feeder; but gave no information about the faulted phase. Finding the fault was sometimes very difficult. At times, determining the faulted phase was also very difficult. In recent years, new legislation imposed drastic fines for disconnection of loads for no reason. In fact, fines were the main incentive for evaluating a better and more modern protective scheme than the old 59N relay.

Another important factor was the possible danger to human life. On one occasion, a horse running loose in the countryside bumped into a feeder structure. The structure could not handle the impact of the animal and collapsed. One of the conductors collapsed onto the horse, burning the animal to death. The 59N relay in the substation detected the fault, but the sequence of feeder disconnection took too long to identify the faulted feeder. This event caused justifiable concerns about public safety. The 46 kV lines run across El Salvador's rural areas, so it is easy to imagine accidents occurring. Fortunately, ETESAL's experience does not include any incident where human life was endangered.

El Salvador is located in the tropical, mountainous territory of Central America. With so much vegetation growing, it is very hard, in some situations, to keep the undergrowth vegetation from creating ground faults. During the wet season, the country experiences extreme rain and thunderstorms. El Salvador experiences several tropical storms during the year and heavy rain in the hurricane season. Although the country has not been struck by a hurricane lately, it has received the aftermaths of hurricanes that struck other Central American countries.

These are the conditions under which the 46 kV feeders and other ETESAL lines operate. The occurrence of faults in the lines and feeders may be higher than in other parts of the world. ETESAL does not have the transient fault statistics for the 46 kV system. A ground fault lasting more than one second is considered a permanent fault and counted in ETESAL's statistics. Moreover, ETESAL's experience has shown that there is a greater chance of ferroresonance in the 46 kV side, damaging substation equipment, if the fault is left longer.

B. Protective Relay Considerations

The traditional 59N protective scheme requires a faulted feeder identification process that is not desirable. This protective scheme is not acceptable in modern power systems except as a backup protective scheme. With modern numerical protective relays, faulted feeder identification is possible without sequential tripping of feeders and complex wiring arrangements with timers and auxiliary relays. A modern electric power transmission or distribution utility cannot operate effectively with such an archaic scheme.

When ETESAL investigated available protective schemes, they decided that protecting the 46 kV ungrounded feeders required a sensitive ground-directional element, based on discussion similar to that illustrated in Fig. 5. Protective relays for ungrounded networks have sensitive neutral inputs and adequate directional elements for ground fault protection. ETESAL did not have experience with these devices, so they asked the manufacturer for a monitoring period during which the device would be connected to a feeder and the response evaluated. Because of technical considerations and important economic considerations, ETESAL also required that the protective device operate properly without a toroidal CT. ETESAL needed to find the most economical solution because, like many electrical companies in Latin America, they have internal regulations and limited resources. They did not have the options of providing the substations with grounding transformers or of modifying the existing substation arrangements and providing toroidal CTs to sensitively measure the 3I0. ETESAL hoped that state-of-the-art numerical protective relays had the algorithms and sensitivity to solve this problem. They were also aware, however, that lack of a toroidal CT greatly reduces the sensitivity of ground-fault protection algorithms and that using phase CTs to calculate the 3I0 of the feeder requires review of the CT characteristics.

The protective relays were evaluated for a year to gain experience with the technology and evaluate the response of the devices in all seasons. After the evaluation period and successful operation detecting ground faults, both internal and reverse, ETESAL concluded that the results were satisfactory. They observed the correct selectivity of the protective scheme, which satisfactorily tripped for internal faults and restrained for external faults with proper sensitivity. Therefore, they decided to upgrade the protective schemes in 10 feeders initially. They chose two substations: San Miguel (six feeders) and Ateos (four feeders). ETESAL expected the protective relaying scheme to measure sufficient fault current, based on the discussion in the next section and the operating experience, which showed that ETESAL feeders experienced at least 2 A primary during ground faults.

The two substations were equipped with the new numerical protective relays at the end of 2003. Because of the success in their operations, all of ETESAL's 16 46 kV substations and their 44 feeders have the protective relays in place. The newer numerical devices have drastically improved the service to ETESAL customers

C. CT Considerations

When reviewing the protective relaying schemes available for ungrounded networks, ETESAL evaluated the necessity of a toroidal CT to measure the zero-sequence current. They recognized that the arrangement of Fig. 7 is the preferred method for measuring the 3I0. There are two important reasons for preferring a toroidal CT:

1. A lower CT ratio than the phase CT ratio is possible, allowing the measurement of smaller primary 3I0.
2. Unsymmetrical CT performance of the phase CT cores causes some 3I0 to be generated in the CT neutral path. A toroidal CT does not have that problem since it has only one core.

The protective relaying systems for ungrounded networks have very sensitive neutral-current measurement. The sensitivity of the 3I0 measurement is in the mA range, 5 mA minimum. The overcurrent threshold setting for the application should be set above the maximum error expected. The 46 kV feeders serve distribution substations and the load is balanced. Moreover, the zero-sequence unbalance is usually very small, mainly because of the unequal distributed capacitances between phases.

To evaluate the sensitivity required and the suitability of using phase CTs, ETESAL considered the 46 kV feeder configuration and construction. Fig. 10 shows the typical conductor arrangement. It was considered appropriate to estimate the fault current by calculating the zero-sequence capacitance for the configuration.

$$\text{Geom} = \ln\left(\frac{\sqrt[9]{\text{Daai Dbbi Dcci Dabi Daci Dbci Dbai Dcai Dcbi}}}{\sqrt[9]{\text{ra rb rc Dab Dac Dbc Dba Dca Dcb}}}\right)$$

$$\text{C0} = 1/3 \bullet \frac{2\,\pi\,\varepsilon_0}{\text{Geom}} \bullet \text{F/m} \tag{1}$$

Equation (1) is an approximate equation for the zero-sequence capacitance of a feeder. It is the result of a classical analysis with conductor images and the assumption of a perfectly conducting ground plate [5]. The expressions ra, rb, and rc are the conductor radius. Dab, Dac, etc. are the distances between the conductors. Finally, Daai, Dbbi, etc. are the distances from the conductors to their images.

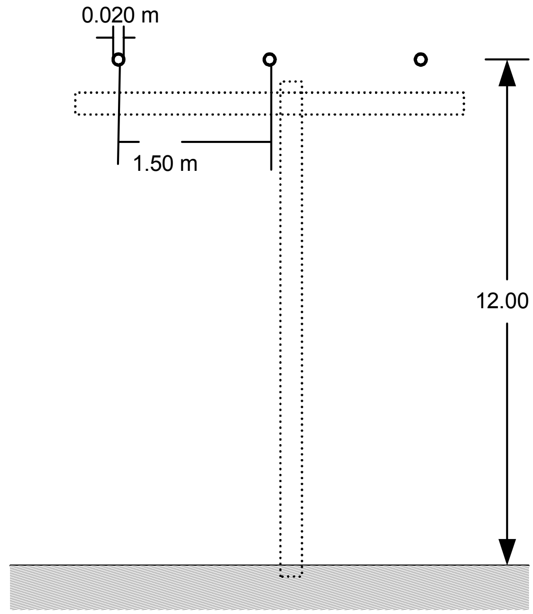


Fig. 10 Conductor arrangement

The zero-sequence capacitance was estimated using (1) and the configuration shown in Fig. 10. The result allows the estimation of equivalent zero-sequence capacitive impedance for the feeders at 60 Hz:

$$\text{C0} = 4.665 \text{ pF/m} \tag{2}$$

$$\text{X0} = \frac{1}{2\,\pi f\,(\text{C0 length})} \text{ ohms} \tag{3}$$

Calculation of the fault current magnitudes considered two 115/46 kV substations and resulted in (3) and the symmetrical component network in Fig. 1. These two substations, San Miguel (refer to Fig. 13) and Ateos (refer to Fig. 16) represent typical substation arrangements.

TABLE I
FAULT CURRENTS IN SAN MIGUEL SUBSTATION

Feeder	Length (Km)	External Fault		Internal Fault	
		A pri	MA sec	A pri	MA sec
34-4-81	5.86	0.821	8.211	34.821	348.213
34-4-82	59.3	8.309	83.095	27.333	273.330
34-4-83	54.7	7.665	76.649	27.978	279.776
34-4-84	46.3	6.488	64.878	29.155	291.546
34-4-85	39.4	5.521	55.210	30.121	301.215
34-4-86	48.8	6.838	68.381	28.804	288.043

TABLE II
FAULT CURRENTS IN ATEOS SUBSTATION

Feeder	Length (Km)	External Fault		Internal Fault	
		A pri	MA sec	A pri	MA sec
44-4-80	17.5	2.452	24.522	5.423	54.229
44-4-81	24.7	3.461	34.611	4.414	44.140
44-4-82	13.0	1.822	18.216	6.053	60.534
44-4-83	1.0	0.140	1.401	7.735	77.350

Table I and Table II illustrate the results of calculating the contribution to an external ground fault in a particular feeder. This calculation uses (4), which is derived from the network connection in Fig. 1:

$$\text{If} = 3\,\frac{\left(46000/\sqrt{3}\right)}{\dfrac{1}{2\pi f\ \text{C0 (length)}}} \tag{4}$$

The internal fault current is the sum of the external fault-current magnitudes of the healthy feeders. The protective relay measures the contribution from the healthy feeder capacitances, as illustrated in Fig. 3. The results presented in Table I and Table II are useful approximations. The actual fault magnitudes were slightly different, as will be shown in a later section.

The number of feeders operating determines the total fault magnitude in the faulted feeder. Operating a substation with a single feeder would mean that for a ground fault in the single feeder, there would be no fault current measured in the protective relay, neglecting the small contribution from the power transformer and bus arrangement. ETESAL realizes that the operation of a single feeder may not allow the ground directional overcurrent element to detect the fault. Fortunately, the old 59N backup scheme is enough in this situation. With only one feeder, there is no need for faulted feeder identification.

The calculations in both Table I and Table II do not consider fault resistance. Ground-fault resistance (Rf) has adverse effects in the detection of ground faults because the magnitude of the fault current is smaller and the available zero-sequence voltage is divided between the zero-sequence impedance of the network (XC0) and the fault resistance (3Rf). Because the zero-sequence capacitive impedance of the 46 kV substations was usually a few kΩ, ETESAL believed that most of the ground faults would be detected for typical fault resistances (Rf).

In ETESAL's 46 kV substantiations, it is standard to equip the feeders with C800, 2000/5 multiratio CTs. The CT ratio used in the majority of the feeder CTs is 500/5. Table I and Table II were calculated with this ratio.

Fig. 11 illustrates the approximate average of the excitation curves for the CTs used in each of ETESAL's substations. The upper curve, which uses all of the CT capabilities, corresponds to the full winding ratio (2000/5). The lower curve is for the 500/5 ratio, which is the one used in ETESAL substations.

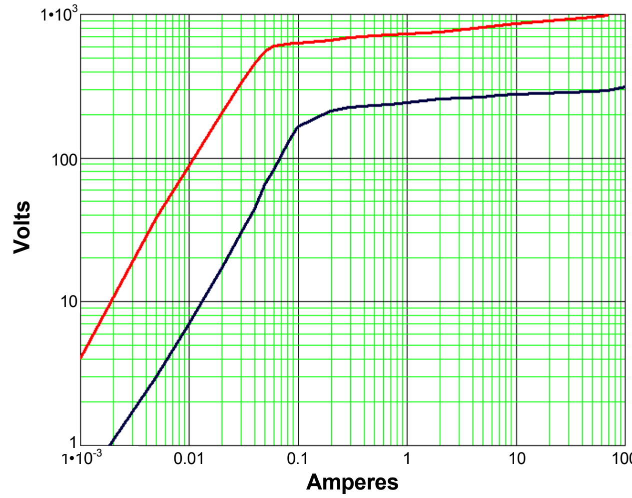


Fig. 11 CT excitation curve for ETESAL 46 kV feeders (upper curve 2000/5, lower curve 500/5)

An excitation curve for a CT, such as the one shown in Fig. 11, represents the error current in the magnetizing branch of a CT for a certain voltage across its terminals. The curve is generally used to estimate the performance of CTs and evaluate the propensity to saturate under heavy fault conditions.

In ungrounded networks, the application of CTs should follow the same recommendations for phase-fault protection as in any type of distribution network. Phase faults can be very high and if the burden of the CT is too high, the CT will eventually saturate. Guidelines are available for applying CTs and avoiding saturation.

However, for ground faults in ungrounded networks, the curve in Fig. 11 can be used for error estimation. Phantom 3I0 created by unequal performance of the CTs is a concern when evaluating relay sensitivity and when no toroidal CT is used. The curve in Fig. 11 shows the rms value of the current and says very little about the harmonic content of the excitation current. Because there is a nonlinear branch in the excitation impedance of the CT, the excitation current will not necessarily follow the fundamental frequency. Most likely, it will have higher harmonics, and as with all the magnetic-based devices in the power system, the third harmonic will probably have a high component. A very conservative error can be calculated by assuming all three CT errors are in phase, creating a 3I0 current. This may be much more than the actual error would be; however, it was the criterion considered. There may be other less demanding, and perhaps more realistic, error criteria.

In a typical ETESAL substation, the CTs are wired with 10 AWG cable. The yard-to-control-house distance is approximately 60 m. The lead impedance, therefore, is approximately Zlead = 0.313 ohm. The internal CT impedance is approximately Zct = 0.21 ohm. The relay impedance is approximately Zrelay = 0.018 ohm. The traditional wiring diagram in Fig. 12 shows the location of each of the above impedances.

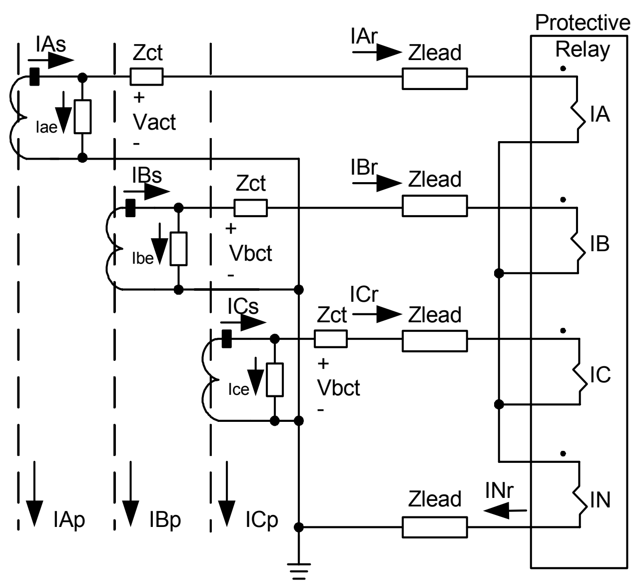


Fig. 12 Traditional CT-relay circuit

The error caused by load current is a concern. Assume full load as |Iap| = |Ibp| = |Icp| = 500 Amps, or in secondary current magnitudes, |Ias| = |Ibs| = |Ics| = 5 Amps. When solving for the terminal voltages of the CTs, there is a need for iteration to relate the calculated excitation current (Ie) from the excitation curve, to the currents flowing and the voltage drops across the different impedances. The calculation shows that the voltage across the CT terminal is Vct = 1.6 V. Notice that the excitation current is off the scale in Fig. 11. We can safely assume that Ie = 0.003 and that the composite error could not be more than 3Ie = 0.009 A.

Three-phase faults are another concern when trip times are comparable to the phase overcurrent. Consider that three-phase faults are the worst case (the phase-to-phase fault is 87 percent of its magnitude for radial feeders) and we can conservatively assume the error to be three times the Ie. ETESAL normally allows for one-second time delay for ground faults, so phase faults are not necessarily a consideration. However, typical three-phase fault magnitude is in the range of 15 kA. The voltage across the CT terminal is Vct = 80.81 V. The excitation current is Ie = 0.05. We can conservatively assume that the error is no more than 3Ie = 0.15 A. Although this data is interesting to estimate, phase fault considerations to estimate a 3I0 error are not needed for the following reasons:

- In the ETESAL system phase faults have faster clearing times than ground faults
- Reference [6] discusses the setting of a ground-fault detector (aN0) which requires the ratio IN/I1 > aN0 to enable the ground directional unit. This requirement prevents the operation of the ground directional unit for large phase currents and expected errors even if one of the CTs saturates.
- ETESAL added extra security to the ground directional units by supervising them with a 3V0 overvoltage element (59N).

The previous discussion and calculation indicate that a toroidal CT was not needed in the ETESAL installations because:

- The phase-to-ground fault currents are within the range of the 5 mA maximum sensitivity of the proposed distribution relay. Table I and Table II show the fault currents in all the feeders.
- The maximum error caused by unequal CT performance under load conditions was assumed to be 9 mA. The pickup setting for the ground overcurrent could be approximately 10 mA, which is a safe setting.

However, more important than the above considerations was the previous experience operating the power system and reviewing fault records indicating the fault magnitudes. During the period of evaluating the protective relays, ETESAL gained considerable experience evaluating the fault magnitudes in the feeders and the appropriate configuration for their protective relays.

D. Numerical Relays Improve Power Delivery

The San Miguel and Ateos substation installations were commissioned in early 2004, so ETESAL has gained significant experience in operating the protective relays, and performance indicators have improved. The selectivity these numerical relays provide when detecting ground faults has reduced the number of healthy feeder disconnections.

As would be expected, ETESAL experienced an increase in power delivery reliability and better customer service. Table III illustrates a comparison of the number of feeder interruptions per year. There were significantly fewer outages of healthy feeders.

Table III also illustrates the dramatic improvement with the newer technology. This improvement was very much appreciated by ETESAL and the receiving distribution companies.

Table IV summarizes “Energy not delivered” because of SLGFs. This table shows the missed opportunities for ETESAL to profit from selling power. Although the number of outages in 2003 was comparable to that in 2005, the company lost less income in 2005 because more of the outages were caused by permanent faults. The savings in 2005 have already paid for all the protective relaying schemes and more.

TABLE III
NUMBER OF FEEDER OUTAGES

Substation	46 kV feeder disconnection					
	2003			2005		
	Outages	Healthy Feeder Outages		Outages	Healthy Feeders Outages	
San Miguel	263	119	45.25%	226	0	0%
Ateos	67	34	50.74%	38	0	0%
TOTAL	330	153	46.36%	264	0	0%
Note. In 2003 only the 59N scheme was available.						

TABLE IV
ENERGY NOT DELIVERED

Substation	46 kV Feeder: Energy Not Delivered Because of SLGF (kWh)	
	2003	2005
San Miguel	971,004	601,024
Ateos	249,646	139,501
Total	1,220,650	740,525

E. Protective Relaying of an Ungrounded Distribution Network

Throughout several months of operation since early 2004, the ETESAL network experienced ground faults in feeders where the protective relays were located. During 2004, ETESAL learned a great deal about both the protective relaying equipment and its benefits. A few misoperations occurred because initial settings in the relays were not well understood. However, after the learning period, the protective relays operated very satisfactorily.

For ETESAL, undergrowing vegetation is a big contributor to the occurrence of ground faults. Tree branches falling on conductors or debris being transported by the high winds of tropical storms create interesting fault sequences that may not necessarily follow a logical sequence.

The purpose of this section is to share three events that illustrate the type of faults possible in ungrounded networks. The first summarizes the previous discussion and illustrates the theory in Fig. 1. The second illustrates an event already familiar to ETESAL during tropical storms, where the fault evolves from a ground fault to a three-phase fault and to a ground fault again. The third one illustrates an evolving cross-country fault in two 46 kV parallel feeders.

F. Ground Fault in San Miguel Substation

Fig. 13 shows the ETESAL San Miguel substation. It is representative of a typical 46 kV substation in El Salvador. In this section, we describe a ground fault that occurred in the 34-4-82 feeder and show the alignment of the phasors for both an internal and an external ground fault.

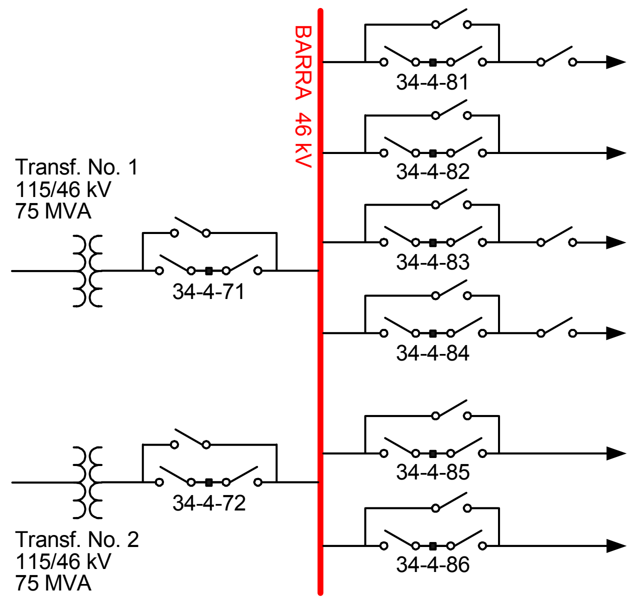


Fig. 13 San Miguel substation one-line diagram

Fig. 14 and Fig. 15 illustrate the oscillographic information for a BG in feeder 34-4-82. Fig. 14 shows the waveforms corresponding to the faulted feeder (34-4-82) and Fig. 15 shows the waveforms for one of the healthy feeders (34-4-83). The waveforms from the other two healthy feeders are not shown but these waveforms showed similar behavior.

The faulted feeder shows the maximum capacitive fault current. Fig. 14 shows that the measurement is approximately 34 primary Amps. The prefault capacitive zero-sequence current in this feeder measures approximately 1.5 Amps primary, or 15 mA secondary. This is above any error caused by the CT arrangement, as discussed in the previous section, and can be attributed to the natural unbalance of the line. The forward and reverse sensitivities for the ground directional unit are set above the unbalance [6].

The healthy feeder oscillography in Fig. 15 shows the measurement of approximately 11 Amps primary for the fault current. The prefault capacitive zero-sequence current in this feeder is approximately 0.75 Amps primary, or 7.5 mA secondary. The forward and reverse sensitivities for the ground directional unit are set above the unbalance [6].

Table V shows the actual fault current magnitude values. The sum of the healthy feeder contributions added to the faulted feeder fault-current magnitude: 2 + 11 + 5 + 8.0 + 9 = 35 mA. This value is close to the 34 mA measured by the faulted feeder relay.

TABLE V
FAULT CURRENTS IN SAN MIGUEL SUBSTATION FEEDERS

Feeder	Length (Km)	Fault Currents	
		A pri	mA Sec
34-4-81	5.86	2	20
34-4-82	59.3	34	340
34-4-83	54.7	11	110
34-4-84	46.3	5	53
34-4-85	39.4	8	80
34-4-86	48.8	9	90

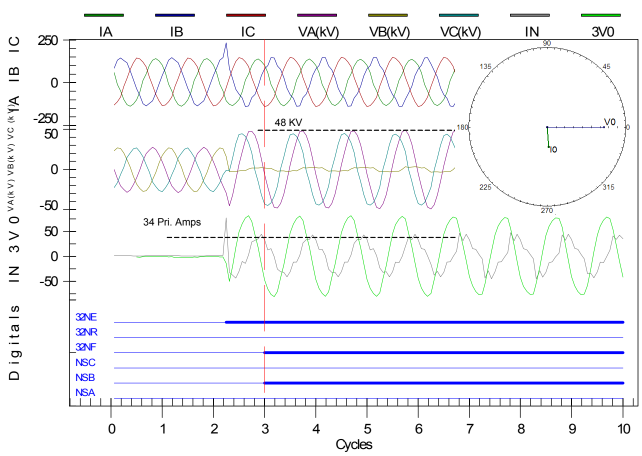


Fig. 14 Feeder 44-4-82 forward BG fault

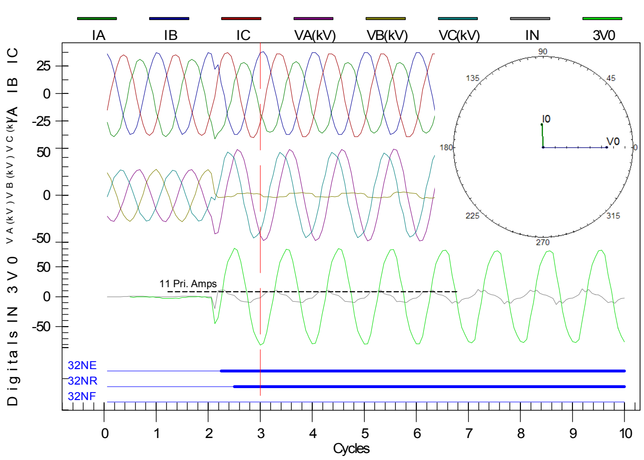


Fig. 15 Feeder 44-4-82 reverse BG fault

Together Fig. 14 and Fig. 15 illustrate in a practical case all the theory discussed in the previous paragraphs and summarized in Fig. 3:

- For a ground fault in an ungrounded network, there is no significant disturbance to the load currents in either the faulted or the healthy feeders.
- The healthy phase voltages raise their magnitudes. In the event shown in the figures, phases A and C reached approximately 47 kV.
- There is a healthy zero-sequence voltage after the fault (3V0). The zero-sequence voltage does not reach the source voltage. Its value (V0 = 26.86 kV) indicates that there was fault resistance in the fault.
- The phase relationship between the zero-sequence voltage and the zero-sequence current in both figures illustrates the expected V0/I0 phase relationship.
  - In Fig. 14, the current lags the voltage, indicating a negative capacitive impedance $\left(\frac{V0}{I0} = -(XC0_s) = -\left(\frac{-j}{\omega\, C0_s}\right) = j\,\left|XC0_s\right|\right)$, or the current (I0) lags the voltage (V0) by 90°.
  - In Fig. 15, the current leads the voltage, indicating a positive capacitive impedance $\left(\frac{V0}{I0} = +(XC0_L) = +\left(\frac{-j}{\omega\, C0_L}\right) = -j\,\left|XC0_L\right|\right)$, or the current (I0) leads the voltage (V0) by 90°.
- The internal relay logic signals illustrate the correct directional determination. The 32NF signals the forward ground directional element and the 32NR signals the reverse ground directional element.
- The faulted-phase-selection outputs shown in Fig. 14 indicate the faulted phase. The faulted feeder relay correctly indicated a phase-B fault (NSB).

By agreement with the distribution companies downstream, ETESAL delays the tripping for a permanent fault by one second. The feeder is tripped after one second. Once the feeder is tripped, the downstream distribution company responsible for the line, as shown in Fig. 9, dispatches a maintenance crew. A fault location report would be a very good tool for the crew to find the fault, but it is not a function of the protective relaying scheme, as discussed previously. Fortunately, the maintenance crews are able in most cases to find the fault location and, if required, perform any repairs needed. Once the crew determines that the feeder can be reenergized, they contact ETESAL to close the tripped feeder via SCADA.

G. Evolving Fault: Ateos Substation Feeders

ETESAL experiences some unusual fault sequences in the 46 kV lines. It may be the topography of the country and the high frequency of tropical storms and winds that create these interesting fault sequences. The event shown in Fig. 17 occurred in one of the feeders (44-4-82) in the Ateos substation, illustrated in Fig. 16.

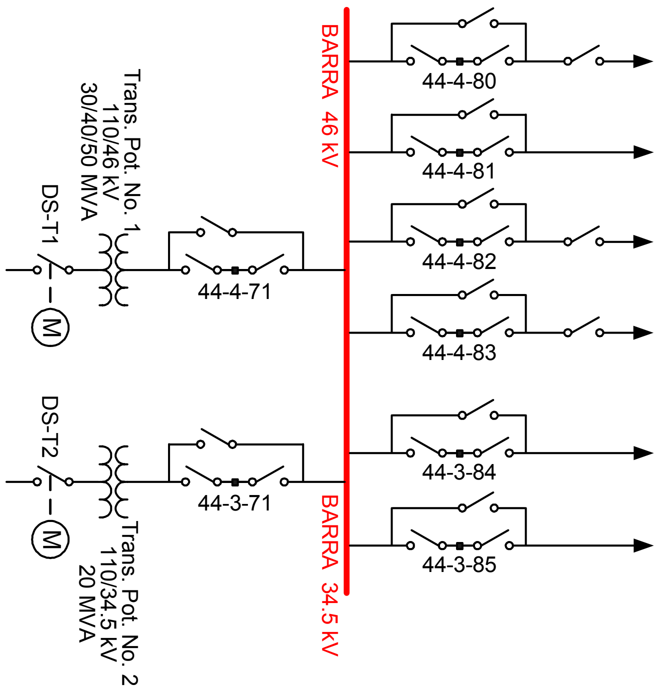


Fig. 16 Ateos substation one-line diagram

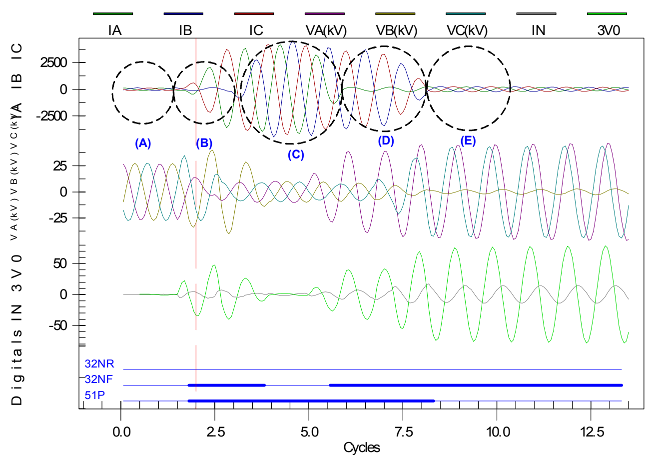


Fig. 17 Fault in the 44-4-82-Feeder

The event occurred during a storm. The prefault shows balanced load flow (A). The fault starts with the collapse of the phase-A voltage and almost immediately the phase-C voltage collapses. At the same time the A and C currents increase dramatically, effectively showing a CAG fault (B). In (C), the phase-B voltage also collapses, creating a three-phase fault in the feeder with very high current. In (D), phase-A voltage recovers and the fault is a BCG fault. After 2 cycles, the fault evolves into a permanent BG fault (E). This sequence of evolving faults is very peculiar; ETESAL has frequently observed faults evolving from one type to the other. During the trajectory, the phasing of the line is commuted, and each phase is in a different position, depending on the transposition. It is, therefore, possible to speculate the sequence of the fault evolution.

It is believed that during the storm, a tree branch being carried by the high winds made contact with ground and phase A first, then phase C. This is illustrated in Fig. 18(B). As the wind carried the tree branch, it also involved phase B, creating the three-phase fault, as shown in Fig. 18(C). Because of the high winds, phase A was released from the fault, yielding the BCG fault shown in Fig. 18(D). The wind force was also enough to release phase C, which finally created the BG fault. The phase-B insulator string may have stayed flashed-over, creating the permanent BG fault in Fig. 18(E).

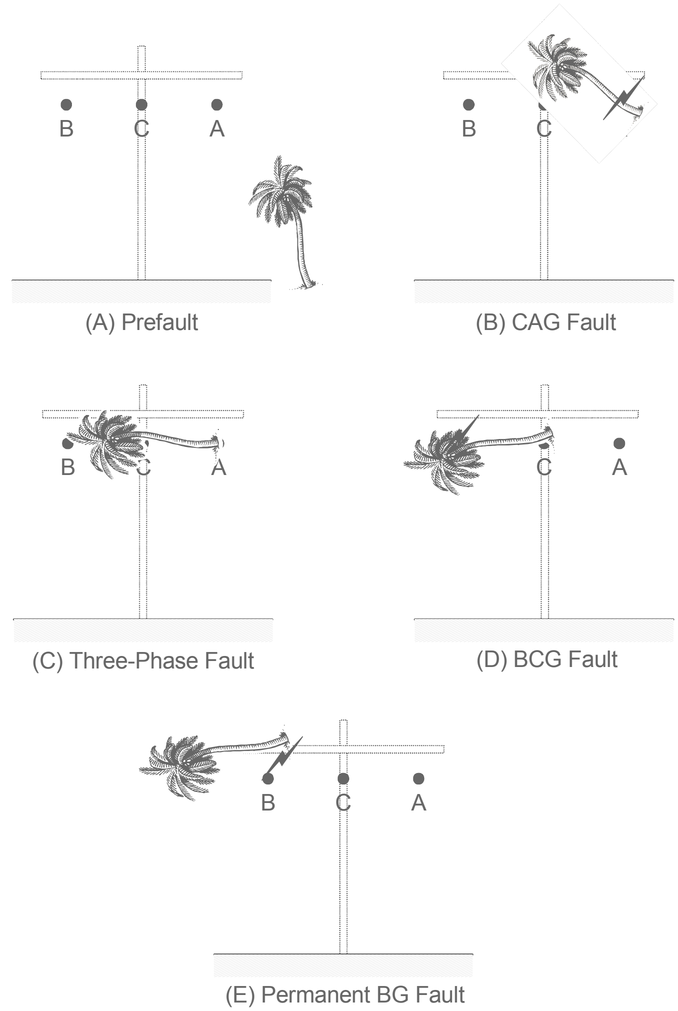


Fig. 18 Possible fault sequence for the fault

The fault sequence just described illustrates the proper operation of the phase and ground overcurrent units. Based on Fig. 16, we can conclude:

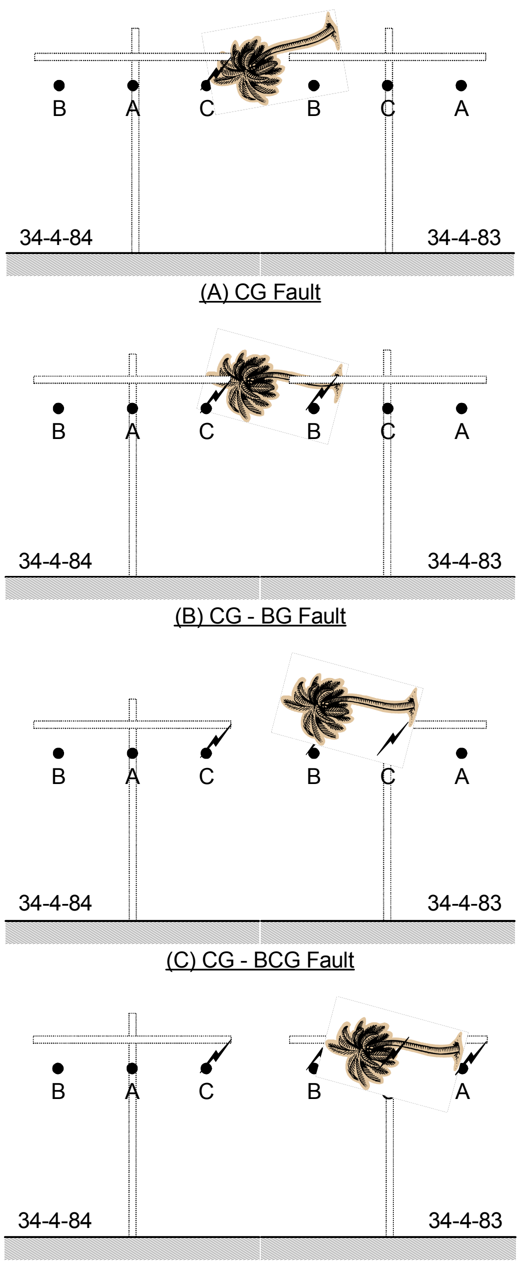
- The phase overcurrent unit (51P) started timing for the phase-to-phase-to-ground faults and the three-phase fault.
- The ground directional element required for ungrounded networks properly determined the direction of the fault, forward, and, although this is not shown in the waveforms, the trip was issued after one second.
- The events from the other feeders; although not actually illustrated, showed proper operation. During the phase faults, the other feeders did not have enough current to start their own 51P (phase overcurrent) and during the final BG fault, the fault was determined to be in the reverse direction.

H. *Cross-country fault: San Miguel substation feeders*

Referring back to Fig. 13, which illustrates the one-line diagram of the San Miguel substation, two of the outgoing feeders, 34-4-83 and 34-4-84, share a common corridor and even share the same structure in some lengths of the trajectory from the substation to the load.

During a tropical storm, a very curious fault sequence was observed. Unfortunately, the whole event is not available in one single oscillogram and some information was not completely captured by the event recorder of the protective relay. However, the sequence of the fault can still be identified.

Fig. 19 illustrates the assumed fault sequence. The fault starts in feeder 34-4-84 as a CG fault (Fig. 19[A]). The fault was identified by the relay in the 34-4-84-feeder as an internal fault, and the other relays in the other feeders reported the fault as reverse.



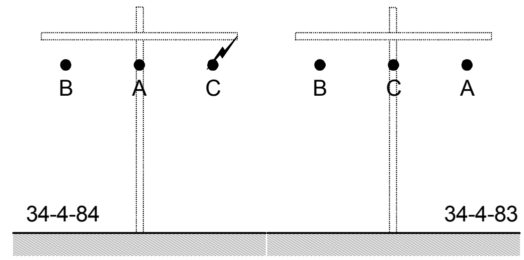


Fig. 19 Assumed fault sequence

The waveform recorder did not capture the whole sequence, but sometime in the sequence there is a simultaneous fault (cross-country) in both feeders, as illustrated in Fig. 19(B). Fig. 20 shows the simultaneous fault, (B). Fig. 20 also shows the transition in Feeder 34-4-83 from a BG fault to a BCG fault in (C). Both simultaneous faults create significant zero-sequence current and phase current. The phase element properly detects the overcurrent condition (51P).

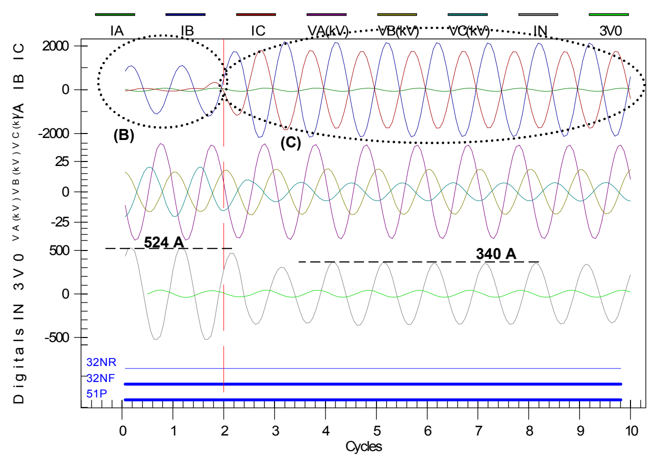


Fig. 20 Feeder 34-4-83 BG to BCG transition (Fig. 19(B) and Fig. 19(C))

Fig. 21 illustrates the three-phase fault in the 34-4-83 feeder. Fig. 21(D) shows the high current in the three phases and at the same time the unbalance in the zero-sequence quantities caused by the ground fault in the parallel feeder. Fig. 21(E) shows the opening of the feeder 34-4-83, which corresponds to the transition from the simultaneous fault to the CG fault in feeder 34-4-84.

Fig. 22 illustrates the transition from the high fault-current magnitude simultaneous CG fault to the single-occurrence CG fault after the parallel breaker opens, corresponding to Feeder 34-4-84. The unfortunate situation illustrated in Fig. 22 is that the phase element resets (51P) because the parallel line trips and the ground element regains the proper directionality (32N) once the breaker opens.

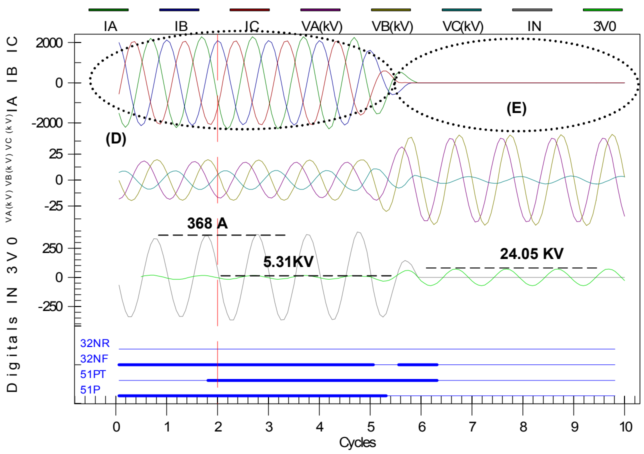


Fig. 21 Three-phase fault and opening of the 34-4-83-feeder

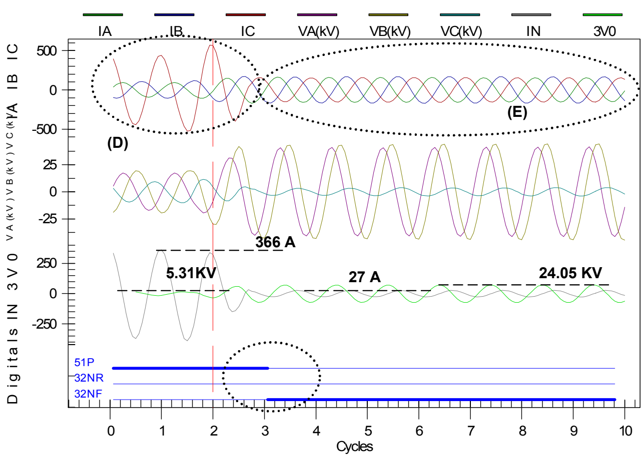


Fig. 22 End of the simultaneous fault in Feeder 34-4-84

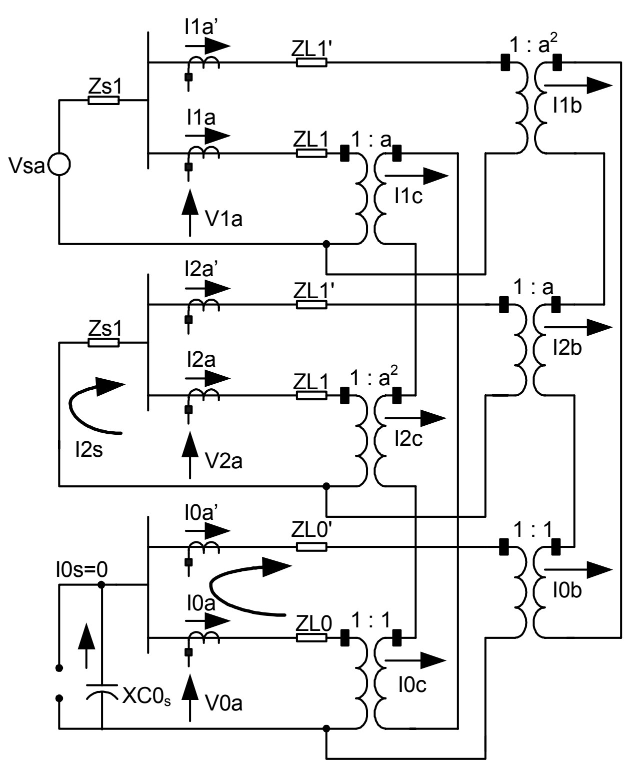


Fig. 23 Simultaneous CG in one feeder and BG in the other

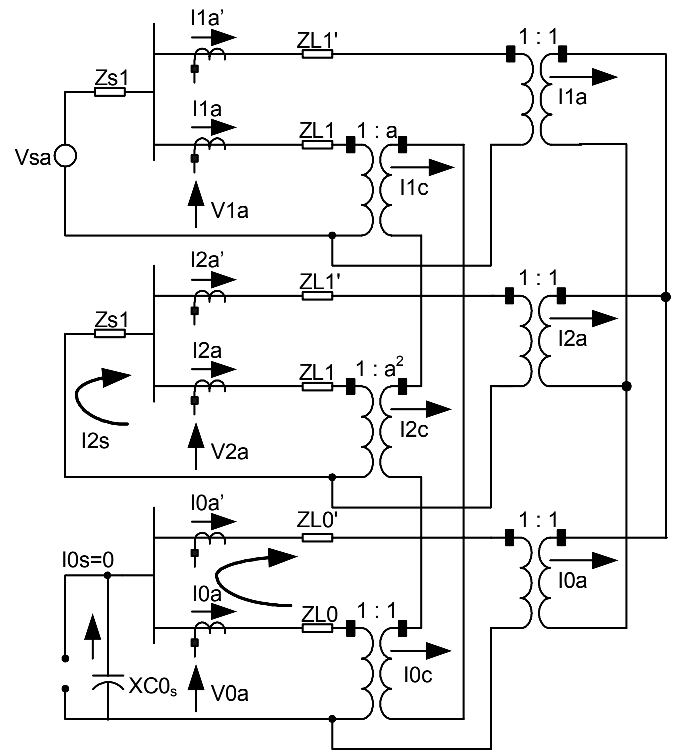


Fig. 24 Simultaneous CG in one feeder and BCG in the other

The interesting sequence of faults and the behavior of the currents and directional units can be visualized graphically in Fig. 23, simultaneous CG and BG faults in different feeders, and Fig. 24, simultaneous CG and BCG faults in different feeders. For simplicity, the fault is located at the end of the feeders and there is no load flow. The purpose of the diagrams is to illustrate the following:

- The zero-sequence fault current encounters a very high capacitive impedance and almost no zero-sequence current flows in the source (I0s). The zero-sequence current has no other path, but the feeders and the zero-sequence direction are 180^{o} from each other.
- The zero-sequence impedances of the feeders are comparable in magnitude to the positive-sequence (approximately a factor of 3), so there is plenty of zero-sequence current measured at the feeders. The waveforms of the event show the high magnitude zero-sequence current. It is therefore very important that the IN input of the protective relay be designed to withstand high currents.
- The ground directional element (32N) of one feeder will correctly determine the simultaneous fault in the forward direction, but the element in the other feeder will determine the fault to be in the reverse direction, as experienced in the fault waveforms.
- As suggested by [8], the phase elements (51P) or more sensitive negative-sequence element (51Q), with the CG and BG faults, may have tripped simultaneously. However, the CG and BCG event made the feeder with the BCG fault measure higher fault current and time earlier, creating the sequential fault as shown in the oscillographic information.

The fault sequence just described is not a common one. In the two-and-a-half years the protective relaying schemes have been operating, this has been the most curious event observed, and has shown the benefit of the relaying scheme.

III. Summary

The purpose of this paper was to share ETESAL's experiences in the protective relaying of the company's interconnection points to the 46 kV system:

- Modern electric utilities operating ungrounded networks require a protective relaying scheme that clearly identifies the faulted feeder and provides the proper faulted-phase selection. Numerical relays can provide these functions and other functionality, such as oscillographic information, that is very valuable in the operation of ungrounded networks.
- The traditional 59N scheme can still be used, but as a backup scheme. ETESAL has the 59N scheme complementing the ground directional elements for ungrounded faults.
- The El Salvador 46 kV network is subject to a large number of ground faults that usually turn out to be transient. A one-second discrimination time determines whether the fault is permanent or transient. The protective relaying scheme has been very valuable in properly identifying the feeder with the permanent fault without tripping healthy feeders.
- The use of numerical protective relays for ungrounded networks has dramatically improved reliable power delivery by the 46 kV feeders.
- The numerical protective relaying scheme does not require a toroidal CT. There is enough sensitivity to properly detect ground faults. Error considerations, as discussed in this paper, can provide an approximation of the maximum sensitivity without the more sensitive toroidal CT ratio.
- Not using a lower ratio toroidal CT implies less sensitivity for ground faults. In the case of ETESAL, there was sufficient capacitive ground-fault current to detect ground faults in the 46 kV system. Per ETESAL's experience, it is suggested that an evaluation of the available ground fault current be performed to evaluate the actual sensitivity of the ground-relaying scheme. ETESAL's feeders had enough capacitance to supply enough ground-fault current that no toroidal CT was needed.
- Normal ETESAL operation is to have all feeders on line. However, the fewer feeders there are on line, the smaller the fault current gets. It is, therefore, always wise to have the 59N scheme available as backup.
- ETESAL shared three experiences with faults:
  - The first fault event described detection of ground faults with a ground directional element, as shown in the Fig. 1 theory.
  - The second event described an interesting fault sequence created by the tropical storms that frequently hit ETESAL's territory.
  - The third event described a parallel line cross-country fault and illustrated the need for a very well-designed neutral current input. Cross-country faults in ungrounded networks can create very high neutral currents and the relay inputs need to be designed accordingly.

The experiences described in this paper correspond to an electrical transmission company. However, other industries can benefit from ETESAL's experiences. The theory and current transformer considerations should be applicable to other industries, including petroleum and naval industries, where ungrounded electrical power systems are operated.

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V. Biographies

Carlos Erroa has an Industrial B.S. with concentration in Electrical Power Systems from Instituto Nacional Isidro Menéndez, San Miguel, El Salvador (1985), and a degree of Electrical Engineer from the University of El Salvador (1992). He started his professional career in Corporacion Centroamericana de Servicios de Navegacion Aera (COCESNA) as a maintenance engineer and Technical Training Coordinator (1993–2000). Mr. Erroa taught at the University of El Salvador in the fields of Power Electronics, Electronics I, Transmission Lines (Telecommunications), and Electromagnetism (1991–1993). In 2000, Mr. Erroa started his assignment at Empresa Transmisora de El Salvador (ETESAL), as a substation engineer in Protection Systems (2000), and later transferred as an operations engineer in the Operations Center of the company. Between 2001–2003, Mr. Erroa was the Engineering Coordinator, where he was also assigned the responsibility of the settings of the pilot schemes and protection equipment for the transmission system. In 2004, he became the Planning Manager, responsible for the El Salvador transmission system expansion and the associated studies. He is still providing support to the operation and settings calculation of the protective relaying schemes. In 2005 he participated as the ETESAL representative to the Regional Operating Entity (EOR) and the Regional Electrical Interconnection Commission (CRIE), both regional entities related to the new Central American Electrical Market and the Project for the Central American Electrical Interconnection System (SIEPAC), where the regulations for the regional Electrical Transmission were reviewed and approved (Libro III-RMER). Mr. Erroa was a panel member in the XXIV Central American and Panama IEEE convention (CONCAPAN), San Jose, Costa Rica, November 2004.

Miguel Cruz received his B.S.E.E. in Power Systems from the Universidad Autonoma de Baja California in 1988, and is a registered Professional Engineer in the state of California. He joined SEL in 1997 as a Field Application

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Fernando Calero has a BSEE (1986) from the University of Kansas, Lawrence KS, an MSEE (1987) from the University of Illinois at Urbana-Champaign, Urbana, IL, and an MSEPE (1989) from Rensselaer Polytechnic Institute, Troy, NY. He started his professional career with Westinghouse as a transformer design engineer (1989) and later transferred to the ABB Relay Division in Coral Springs, Florida when ABB acquired Westinghouse's T&D business. In ABB's relay division, Mr. Calero worked in the support, training, testing, and design of protective relays (90–96). He later worked for Itec Engineering (1997). He was then employed by Florida Power & Light in the EMS group (1998) and by Siemens Energy Automation in Norcross, GA 1999). In 2000, he joined Schweitzer Engineering Laboratories, Inc. as an International Field Application Engineer, based in South America. Mr. Calero has authored technical papers for IEEE and protective relay conferences and has authored four patents in the field of protective relaying. Mr. Calero is a registered professional engineer in the state of Florida.