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# **PROTECTION OF SYNCHRONOUS GENERATORS DURING UNBALANCED SYSTEM CONDITIONS**

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## PROTECTION OF SYNCHRONOUS GENERATORS DURING UNBALANCED SYSTEM CONDITIONS

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The effect of unbalanced system conditions on generator design and operation has been of continuing concern and study<sup>1-5</sup> during the past twenty-five years. It has been recognized that unbalanced system loads, system impedance dissymmetries and unbalanced faults produce negative phase sequence components of current which can cause excessive heating in critical parts of the generator rotor. As a consequence, standards<sup>6,7,8</sup> were established defining generator continuous and short time unbalanced current capabilities in terms of negative sequence current ( $I_2$ ) and rotor heating criteria  $I_2^2 t$  and it has become standard practice to provide some form of negative phase sequence overcurrent relaying to protect generators of all types and sizes.

In the past, the primary function of generator negative sequence current relaying was to protect the machine in the event line relaying or circuit breakers failed to perform as expected for unbalanced system faults. At that time, system design and operating practices were such that steady state unbalances due to impedance dissymmetries or single phase loads were small or non-existent and therefore were not a major problem.

In more recent years, there have been significant changes in system design and operating practices which have tended to increase the levels of steady state unbalances. For example, the widespread use of nontransposed lines, series capacitor compensation, increasing interest in single phase railroad electrification loads, arc furnace loads and independent pole switching of circuit breakers all increase the possibility of higher levels of steady state unbalances. While the levels of unbalances caused by these system design practices seldom produce damaging levels of negative sequence currents in generators, it is necessary to continually review their possible adverse effects on generator reliability and performance.

It is the purpose of this paper to review briefly the unbalanced current capabilities of generators, the system unbalance conditions that produce negative sequence currents and to discuss the protection of generators for these conditions.

### Generator Unbalanced Current Capability

The effect of unbalanced three phase stator currents has a significant influence on generator design and operation. Excessive current unbalance causes heating and extra losses primarily at the surface of the rotor in turbine generators with solid steel rotors and in the amortisseur windings of salient pole generators. Unbalanced stator currents also produce pulsating torques in both the shaft and the stator core which may cause vibration problems but in general this problem is considered less restrictive than the rotor heating considerations.

The heating and extra losses produced in generator rotors are primarily due to the negative phase sequence components of current. In the

case of a solid rotor of a turbine generator the negative phase sequence stator current induces double frequency currents in the surface of the rotor, the slot wedges, and to a smaller degree, in the field winding. The current distribution at the surface of the rotor corresponds to the current distribution in the rotor of a squirrel cage motor in that the currents flow axially over the length of the rotor and close circumferentially at the ends (as shown in Fig. 1) with the same number of poles as in the stator windings. At 120 Hz, the rotor body currents are confined to a surface layer 0.1 to 0.4 inches deep and the losses resulting from the double-frequency currents can be very high. The heating resulting from these losses is the most severe at the ends of the rotor where the currents flow across the slot wedges and into the retaining ring. Losses can occur at all contact surfaces such as between slot wedges and rotor teeth and between retaining ring and rotor body.

Rotors are designed to minimize these losses. Aluminum slot wedges are used to provide low resistance paths for the axial currents and non-magnetic steel wedges are used at the ends of the rotor body where higher temperatures may occur. Short fingered, silver plated aluminum alloy amortisseur ring segments are used to transfer a portion of the rotor surface currents from the non-magnetic steel end wedges and the retaining rings. The body mounted retaining rings have silver plated shrink fit surfaces which provide low resistance paths for surface current flow from the rotor teeth to the non-magnetic steel retaining ring. These features of rotor design are shown in Fig. 1. In some instances, a complete amortisseur winding is provided to increased rotor surface current carrying capability.

### Generator Capability

All generators have both a continuous and a short time unbalanced current capability which are expressed in terms of negative phase sequence currents. The short time capability (referred to as unbalanced fault capability) expressed in terms of rotor heating criterion  $I_2^2 t$  were first introduced in industry standard in 1955<sup>6</sup>, were revised in 1965<sup>7,8</sup>, and are presently undergoing another revision. This capability is shown below in Table I:

TABLE I

#### ANSI Requirements for Unbalanced Faults on Synchronous Machines

<u>Types of Synchronous Machine</u>	<u>Permissible <math>I_2^2 t</math></u>
Salient pole generator*	40
Synchronous condenser*	30
Cylindrical rotor generators**	
Indirectly cooled	30
Directly cooled (0 - 800 MVA)	10
Directly cooled (801 - 1600 MVA)	See Fig. 2

\*ANSI C-50.12 (1965)

\*\*ANSI C-50.13 (1975)

Figure 2 gives a graphical representation of the relationship between generator  $I_2^t$  capability and generator MVA rating for directly cooled generators. In the above, indirectly cooled refers to conventionally cooled machines while directly cooled refers to conductor cooled machines.

Generator continuous unbalanced current capability is also covered by the new standards for cylindrical rotor machines and in a proposed standard for salient pole machines. This continuous capability is shown in Table II.

TABLE II

Continuous Unbalanced Current Capability

Type of Generator and Rating	Permissible $I_2$ (per cent)
Salient Pole	
With connected amortisseur windings	10
With non-connected amortisseur winding	5
Cylindrical Rotor	
Indirectly cooled	10
Directly cooled	
to 960 MVA	8
961 to 1200 MVA	6
1201 to 1500 MVA	5

A generator shall be capable of withstanding, without injury, the effects of a continuous current unbalance corresponding to a negative phase sequence current of the values listed above, providing rated kVA is not exceeded, and the maximum current does not exceed 105 per cent of rated in any phase. Negative phase sequence current is expressed in per cent of rated stator current.

The above values also express the negative phase sequence current capability at reduced generator kVA capabilities in per cent of the stator current corresponding to the reduced capability.

These new proposals now provide a comprehensive definition of generator unbalanced current capabilities.

System Unbalance Conditions

Generator negative phase sequence currents can result from any unbalance condition on the system. System unbalances can be caused by

system impedance dissymmetries, unbalanced loads, unbalanced system faults and open conductors. These unbalances may produce generator negative sequence currents over a range of 0.01 to 2.5 per unit with the higher levels of current being produced by faults and open conductors.

### Impedance Dissymmetries

The most common cause of system impedance dissymmetries is the non-transposition of transmission lines. Studies have shown that untransposed lines can produce significant unbalanced currents in the untransposed transmission lines but that the unbalanced currents in the generators will be relatively small. In general, the negative sequence currents produced by untransposed lines will be distributed throughout the system and the amount appearing in any one generator will usually be less than 3%. Generators connected directly to an untransposed system would tend to have the greatest negative sequence current.

Series capacitor compensation of untransposed lines tends to increase the current unbalance but even in this instance the level of generator negative sequence currents will still be below 3%.

Series capacitors may introduce other dissymmetries which may require consideration. All series capacitor installations have protective devices which will bypass the capacitors at specified voltage levels during system faults and which will re-insert the capacitors after the fault is cleared. During unbalanced faults and even on three phase faults, these protective devices may operate to bypass the capacitors in only one or two phases on one or more lines. If for some reason the bypassed capacitors are not reinserted after the fault is cleared, the resulting impedance dissymmetries could be relatively large. The capacitor protective systems are designed to recognize this condition and will operate to bypass the capacitances in all three phases after a time interval of 2 to 10 seconds depending on system requirements. In this instance, it may be possible to have generator negative sequence currents in excess of 5%, depending on the system configuration and the proximity of the generators to the unbalanced part of the system. Of course, generators that are connected directly to the series compensated system will see the greatest negative sequence currents.

### Unbalanced Loads

The most common types of unbalanced loads found on power systems are single phase railroad loads, induction furnace loads and three phase arc furnace loads. The magnitudes of these loads will vary between 10 MVA up to 90 MVA and when distributed on large systems, introduce relatively low levels of negative sequence currents in generators, generally below 3%.

On the other hand when these loads are in close proximity to generators or if they are isolated with some generation after some fault or



disturbance, it is possible to have higher levels of generator negative sequence currents. For example, one study<sup>9</sup> on railroad electrification loads indicated that when there were a number of load substations close to generating stations, generator negative sequence current levels could reach peaks of 5 to 6% of generator rating. In that instance, these peaks were attained for only short periods of time but it is possible to have railroad loads with relatively high load factors.

Induction furnaces can introduce substantial levels of negative sequence currents into a system. For example, one study of a two phase induction furnace load (20 MVA per phase) being fed by a radial feeder showed that the negative sequence current at the source could be as high as 48% of the positive sequence current. Normally, this negative sequence current would be dispersed throughout the system and have little effect on remote generation. However, it could have considerable effect on the operation of nearby generators, especially if the load and generation are isolated from the system.

Arc furnace loads and other rectifier type loads may introduce another problem of concern. Both of these loads can introduce higher order harmonics which behave like negative sequence quantities. The effects of these harmonics on nearby generators are presently being studied.

#### Unbalanced Faults

A generator is subjected to negative sequence currents during all types of unbalanced faults; that is, line to ground faults, double line to ground faults, line to line faults and open conductors. Of these faults, the line to line fault causes the largest magnitude of negative sequence current to flow in the generator and this component will be maximum for a fault at the generator terminals. Since the line to line fault imposes the severest duty on the generator, it is used as the basis of the fault studies discussed in this section. The open conductor case is also considered since this condition can cause prolonged high levels of generator negative sequence currents.

In addition, the following discussion will be primarily concerned with  $I_2^2$  duties imposed on solid rotor conductor cooled (direct cooled) generators. For reference purposes, typical ranges of negative sequence reactances for this and other types of generators are given below:

TABLE III

#### Generator Negative Sequence Reactance

	<u>P.U. <math>X_2</math></u>
Hydro generator	.13 - .35
Conventionally cooled	.07 - .15
Conductor cooled	
2 pole machine	.14 - .25
4 pole machine	.20 - .30

Generator Terminal Faults. As mentioned previously, a line-line terminal fault imposes the severest duty on the generator. The magnitude of the negative sequence currents will be high and this current can persist for a number of seconds after the unit has been tripped due to the decay of flux in the machine. In addition there can be a D-C component of fault current which transforms into a 60 Hz rotor quantity which in turn causes additional rotor heating.<sup>3,4</sup> Figure 3 shows both of these components of fault current for a typical large 2-pole conductor cooled generator. In this instance, the main generator breaker and the exciter field breaker were tripped in about three cycles and this figure shows the gradual decay of both components of current.

The rate of decay of the negative sequence current is a function of machine parameters and excitation system design. Figure 4 shows the wide difference that can exist between using an exciter field breaker at one extreme and an inverting thyristor exciter at the other.

It should be noted that generators are designed to withstand the effects of a terminal line-line fault, including the effect of a fully offset D-C component.

System Faults. The duty imposed on the generator for system line-line faults is a function of a number of factors:

1. Location of the fault.
2. Fault clearing times.
3. Generator  $X_2$ .
4. System reactance, particularly that of the step-up transformer.
5. Excitation system response.

Figure 5 shows generator negative sequence current for a HV line-line fault as a function of time and excitation system response for a large 2-pole conductor cooled generator. The machine, operating at full load, is connected to a 15% system through a 10% transformer. Two types of excitation systems are considered: a 3.5 high response system and a .5 conventional response system. The high response system is of the type defined as a "high initial response" in which ceiling voltage is reached within .1 second. The "conventional" 0.5 response excitation system requires one or two seconds to reach its ceiling.

This figure shows that the high response excitation systems tend to cause higher levels of negative sequence currents in the generator; however, while the curves show the negative sequence currents for about two seconds, it is only the current levels during the first .25 second or so that are of practical interest. Typical fault clearing times for lines associated with major generator units are: 3 - 5 cycles primary clearing and 8 - 12 cycles back-up. A maximum fault clearing time of 30 cycles or .5 second might be considered as an upper limit and might occur with an unsuccessful line reclosure and a breaker failure. Within these periods of time the high response excitation system would add only about 10% to the accumulated  $I_2^2t$  duty.

Considering only the negative sequence current levels during the first 0.5 second interval, Fig. 6 shows the  $I_2^{ct}$  duties imposed on a generator as a function of generator  $X_2$  and for different switching times. The generator was initially operating at full load and was connected with a 10% transformer to an infinite system ( $X_s = 0$ ) which tends to give the more pessimistic case.

For fault clearing times of 12 cycles or less and for a typical range of generator  $X_2$  (.15 - .3 p.u.), the curves in Fig. 6 show that the maximum  $I_2^{ct}$  duty ranges from 1 for a 2-pole generator down to .5 for 4-pole units. Even for the extreme case of a 30 cycle fault clearing time, the  $I_2^{ct}$  duty is less than 2.

Transient stability limitations dictate that major faults be cleared in less than 12 cycles for even very stiff systems. Fault clearing time criteria are generally based on three-phase or double line-ground faults. However, as indicated in the cross-hatched area of Fig. 6, stability limitations of even L-L faults near the HV bus impose clearing time criteria which limit  $I_2^{ct}$  duties to 1 or less.

The step-up transformer reactance has a major influence on generator negative sequence current since it adds directly to the generator negative sequence reactance. Minimum standard impedances for transformers range from about 13 per cent for 345 kV to nearly 20 per cent for 765 kV. However, utilities frequently purchase lower reactance transformers as an aid to stability. The transformer reactance of 10 per cent used in Fig. 6 should be a reasonable lower limit for the larger ratings. The effect of a lower or higher transformer reactance than shown can be judged by simply subtracting or adding the difference in transformer reactance to the generator negative sequence reactance entered on the horizontal axis.

The negative sequence current levels associated with these duties are readily derived from the  $I_2^{ct}$  curves and may be seen to range from a maximum of about 2.3 per unit for a low reactance generator and transformer to about 1.2 per unit for the higher reactance generators.

Figure 7 summarizes the foregoing points by giving a profile of a line-line fault situation which should represent a maximum  $I_2^{ct}$  fault duty which could be expected under most adverse circumstances. A very low reactance machine and step-up transformer are assumed. In addition, a sequence is assumed consisting of a L-L fault cleared and then reestablished by an unsuccessful reclosure and finally cleared in back-up time after a "stuck-breaker" occurrence. Under these circumstances, the accumulated  $I_2^{ct}$  duties are approximately 1.5. This would indicate that the new values of machine  $I_2^{ct}$  capability designated in the new standards still provide a reasonable margin above the requirements of the system. High speed reclosing of lines directly out of the station as shown in Fig. 7 is not a recommended practice because of possible damage to generating units in the station. However, it was used in this example because, from the standpoint of  $I_2^{ct}$  duty, it should represent the limiting case.

The "independent pole switching" philosophy which virtually eliminates the possibility of more than one phase of a breaker being "stuck"

is now frequently applied for transient stability purposes but also reduces the maximum  $I_2^t$  duty as shown by the dotted curve of Fig. 7.

Open Conductor. The open conductor type of fault has always been of concern to the industry. While these faults are less severe than other unbalanced faults, they are most insidious since they more easily escape detection.

The most common causes of open phase conditions are broken line conductors or the misoperation of one pole of a circuit breaker. The broken conductor case is usually accompanied by a fault which may be detected and cleared by the normal line relaying. In some instances, the fault currents caused by this double dissymmetry will be such that special relaying schemes may be required.

The open phase resulting from the misoperation of one pole of a circuit breaker usually requires other means than normal line relaying to detect. The magnitude of negative sequence currents accompanying this condition depends greatly on the system configuration and line loading. A simplified example of an open conductor fault is illustrated in Fig. 8. While specific values of negative sequence currents will vary from system to system, the intent of this figure is to show that whereas the negative sequence current can be quite high if the "open" is in a circuit carrying the full machine output, it drops off very quickly if there are other paralleling circuits. If there are a number of generators in parallel, the negative sequence current per generator would also be lower.

The widespread adoption of independent pole switching of circuit breakers for improving transient stability introduces additional possibilities for the open conductor type of unbalances.

Since the time available to take action for this type of unbalance may be too short to depend on operator action, automatic means are required to protect the generator. System primary protection in the form of "pole disagreement" circuitry, negative sequence line relay or other unbalance detectors should be designed to clear the unbalance quickly. As final backup for the open conductor condition, the generator negative sequence relay should be capable of measuring  $I_2^t$  duty over a wide range of negative sequence currents.

### Generator Protection

The preceding section has discussed a number of system unbalanced conditions which can produce generator negative sequence currents. While the discussion indicates that the steady state unbalances due to impedance dissymmetries and unbalanced loads individually produce relatively low levels of negative sequence currents, the cumulative effect of these unbalances has caused a general increase in the negative sequence current levels in generators. This factor along with a growing concern about open circuit type of unbalances and the proposed changes in standards on

generator short time capability has created a need for negative sequence relays having a wider range of  $I_2^t$  setting capability and having increased pickup sensitivity to provide protection at the lower negative sequence current levels approaching the continuous capability of the generator. This need for greater sensitivity has been especially evident for the remotely operated gas turbine and pumped-hydro plants where the unattended nature of these installations require that they be as completely self-protecting as possible.

To meet these requirements, a new static negative sequence time overcurrent relay, type SGC, has been developed which provides a broad range of settings as well as greater sensitivity.

### SGC Relay Characteristics

The SGC relay, recently described in the literature,<sup>10</sup> is a static negative sequence relay having the following features (see Fig. 9):

1. A time overcurrent characteristic which exactly matches the generator  $I_2^t$  capability curve.
2. Sensitivity of the time overcurrent unit can be set down to .09 per unit of generator rating.
3. Reset characteristic which approximates generator rotor cooling rates.
4. A sensitive alarm function.
5. A direct reading meter, calibrated in per cent negative sequence current.

Time Overcurrent Characteristic. The time vs. negative sequence current characteristic of the SGC relay is represented by the equation  $I_2^t = K$ . On log-log graph paper, this characteristic plots as a straight line having the same slope as generator  $I_2^t$  capabilities. The "K" setting is continuously adjustable over the range of 2 - 40 as shown in Fig. 9. This figure also indicates that the relay has a minimum operating time of 0.2 second and a maximum operating time of 250 seconds. The lower limit of .2 second was selected as a security measure. This minimum setting assures coordination with line relays even with an improper K setting. Any correct K setting required to protect a generator will always have an operating time greater than this minimum even under maximum fault conditions.

The upper limit, 250 seconds, was selected as a practical design limitation and was considered long enough (4 minutes) to provide the operator with ample time to take corrective action.

Pickup Sensitivity. The trip pickup level of the time overcurrent unit is continuously adjustable over a range of 0.09 and .4 per unit referred to relay tap setting base. Relay taps are available in 0.2 ampere steps between 3.1 and 4.9 amperes. With this range of adjustment it is possible

to match secondary full-load current of the generator over a spread of 3.0 to 5.0 amperes. The dropout of the trip level detector is over 99 per cent of its pickup level.

Reset Characteristic. If a machine has been subjected to an unbalance current condition which is removed prior to tripping, a subsequent unbalanced condition occurring before the machine rotor has recovered to normal temperature will require a shorter operating time than indicated by the  $I_2^2 t = K$  equation. The SGC relay is designed with a reset time which approximates generator rotor cooling rates and provides reduced operating times if an unbalance reoccurs before the relay resets.

The reset rate is linear and is given by the following expression:

$$\text{Reset time in seconds} = 2.5 \text{ seconds (times) per cent of } I_2^2 t \text{ setting accumulated.}$$

Thus a generator with a  $K = 10$  which has accumulated an  $I_2^2 t$  of 5 would, on removal of the fault, reset to zero in  $2.5 \times 50 = 125$  seconds. If the relay had timed out completely (accumulated  $I_2^2 t = 10$  or 100% of setting) the reset time would be a maximum of 250 seconds.

Alarm Function. The sensitive alarm function has a pick-up range of .03 to .2 per unit on relay tap base. A 3 second time delay is provided with this function to avoid nuisance alarms during transient conditions.

Direct Reading Meter. An optional feature is an external meter calibrated in per cent negative sequence current. This meter can be used to give an operator an indication of the severity of an unbalance after the alarm sounds.

#### Application of the SGC Relay

A number of considerations are involved in determining the settings of negative sequence time overcurrent relays. First, the relay should be set to protect the generator against any unbalanced condition which could damage the generator. Secondly, the negative sequence relay must coordinate with system protective relays to avoid an unnecessary shutdown of the generator during faults that will be cleared by the system relaying. This requires the consideration of the primary and back-up operating times of the line and bus protection.

In general, there is no problem in achieving coordination between the negative sequence relay and system relaying. The most severe condition for which coordination is required is for a L-L fault just beyond the breaker in a feeder off the high voltage bus, where the line breaker fails to trip and the fault must be cleared by the breaker failure backup scheme. The breaker, the line relays and the breaker failure backup scheme must be selected and designed so that the total fault clearing time does not result in an  $I_2^2 t$  that exceeds the capability of the generator. Or in other words, the total fault clearing time, including

breaker failure backup time, must not result in an  $I_2^2t$  that exceeds the setting of the negative sequence relay if an undesired trip is to be avoided. With modern protection practices, which provide 3 - 5 cycles primary and 8 - 15 cycles backup clearing times, there would be no problems in meeting the above requirements.

Relay K Setting. Since the purpose of the relay is to protect the generator from thermal damage, its time-current characteristic should be set, by choice of K factor, so that it falls slightly below the generator  $I_2^2t$  capability. This setting is illustrated in Fig. 10, where an SGC relay is applied to an 800 MVA 2-pole generator having a short time capability of  $I_2^2t = 10$  and a continuous  $I_2$  capability of 8%. In this instance a K setting of 8 has been selected as a typical setting which would protect the machine with some margin and would provide a wide margin for coordination with system relaying. The actual setting employed will depend on the philosophy of the individual user and the margin desired between relay and machine characteristics.

#### Trip Level Pickup

There are a number of approaches that can be used for selecting the pickup level of the trip unit. For the most part, the choice of setting will depend on the degree of responsibility the utility wishes to place in the hands of the operator.

One approach, requiring minimal operator supervision, is to set pickup on the continuous  $I_2$  rating of the machine or at the minimum pickup of the trip level detector, whichever is higher. For example, in the machine used as an illustration of Fig. 10, the continuous  $I_2$  capability is .08 per unit. In this instance, the trip level would be set at .09 per unit. Using this basis, the machine would be over-protected for  $I_2$  levels between .09 and .18 per unit. For example, the machine with a capability of  $I_2^2t = 10$  can withstand an  $I_2$  of .15 per unit for 444 seconds (7.4 min) or an  $I_2$  of .1 per unit for 1000 seconds (16.7 min). Since the relay is designed with a maximum operating time of 250 seconds, it will overprotect in this area. For currents above .18 per unit, the relay will provide protection in accordance with the  $I_2^2t = 8$  curve.

If the continuous rating of the machine is below minimum available pickup setting of the trip unit as it is in Fig. 10, there will be a "dead zone" where the machine might eventually be damaged but where the relay will not start timing. In this instance, the dead zone is only between .08 and .09 p.u. At these  $I_2$  levels the machine capability is sufficiently long to permit the operator to take corrective action. The alarm unit can be used to sound an alarm and the direct reading  $I_2$  meter could be used to give an indication of the  $I_2$  level.

Another approach would be to set the pickup of the trip level at an  $I_2$  value equivalent to 250 seconds on the K curve being used. For example, for the  $I_2^2t = 8$  curve of Fig. 10, a setting of .18 per unit corresponds to an operating time of 250 seconds. This approach avoids

the over protection of the machine but obviously introduces a much wider "dead zone" between the  $I_2$  continuous rating of the machine and the pickup point. When  $I_2$  falls in this range, the operator will be warned by the alarm and he will have time in excess of 250 seconds to take corrective action. Again, the  $I_2$  meter could be used to an advantage to give an indication of the severity of the unbalance.

A third possible approach would be to set the trip pickup level with sufficient sensitivity to assure operation for the minimum negative sequence current expected for an open phase condition. As mentioned earlier, this minimum current will be a function of generator loading, the number of generators in the station and system configuration.

Alarm Level Pickup. The pickup of the alarm unit should be set to detect any negative sequence current that approaches or exceeds the continuous  $I_2$  rating of the protected generator. The alarm unit could be set just above the maximum steady state  $I_2$  level in the generator or at generator continuous rating. Pickup of the alarm unit can be used to sound an alarm to warn station attendants that corrective action must be taken.

Trip Action. The negative sequence time overcurrent relay should be connected to trip the main generator breaker(s) and to remove excitation from the machine.

### Summary

The general increase in steady state levels of negative sequence current in generators, the growing concern about open phase type of unbalance and recent changes in standards on generator  $I_2$  capabilities all have contributed to a need for improvements in the sensitivity and range of negative sequence protection for generators. The static negative sequence time overcurrent relay, SGC, described in this paper has been designed to meet these new system requirements. It is capable of providing comprehensive protection for the large generator ratings now appearing, improved protection for generators now in service as well as improved protection for the smaller generator ratings, particularly the unattended remotely-operated gas turbine and pumped hydro units.



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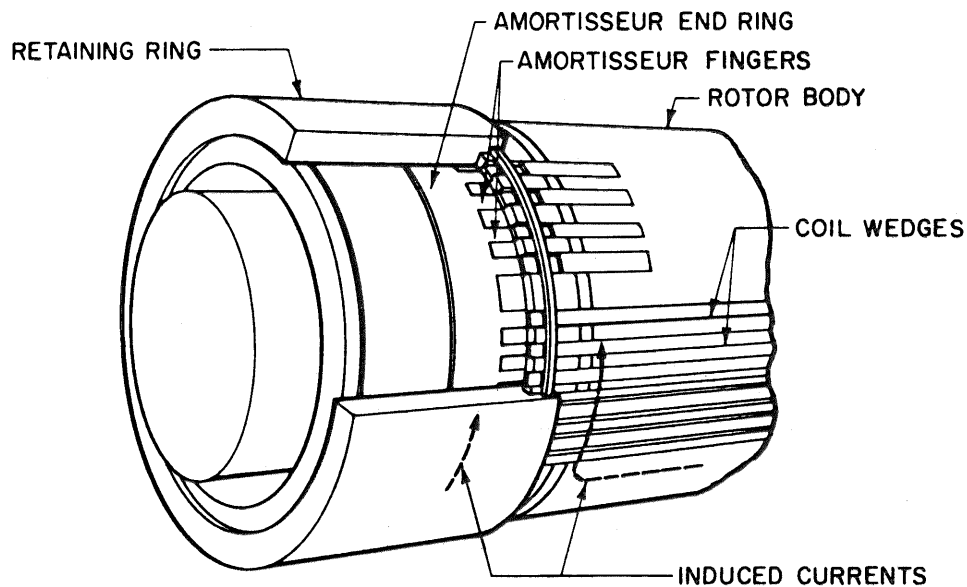


FIG. 1 – ROTOR END SECTION OF GENERATOR INCLUDING RETAINING RING.

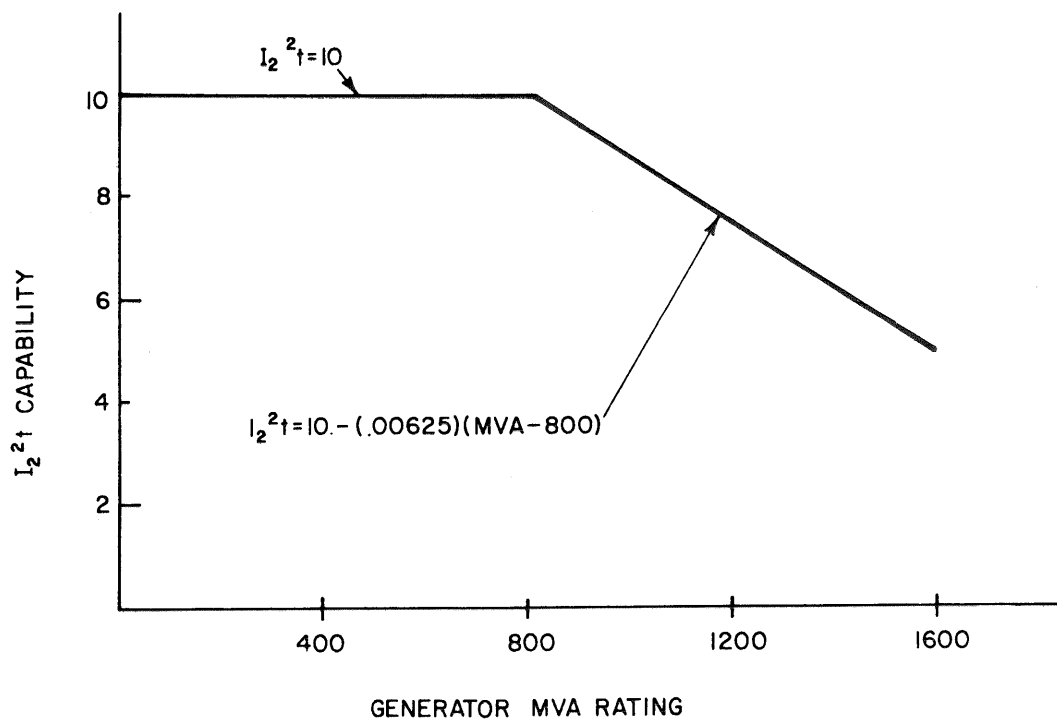


FIG. 2 – PROPOSED REVISED STANDARD FOR UNBALANCED FAULT CAPABILITY  $I_2^2t$ , FOR DIRECTLY COOLED GENERATORS AS A FUNCTION OF GENERATOR MVA RATING.

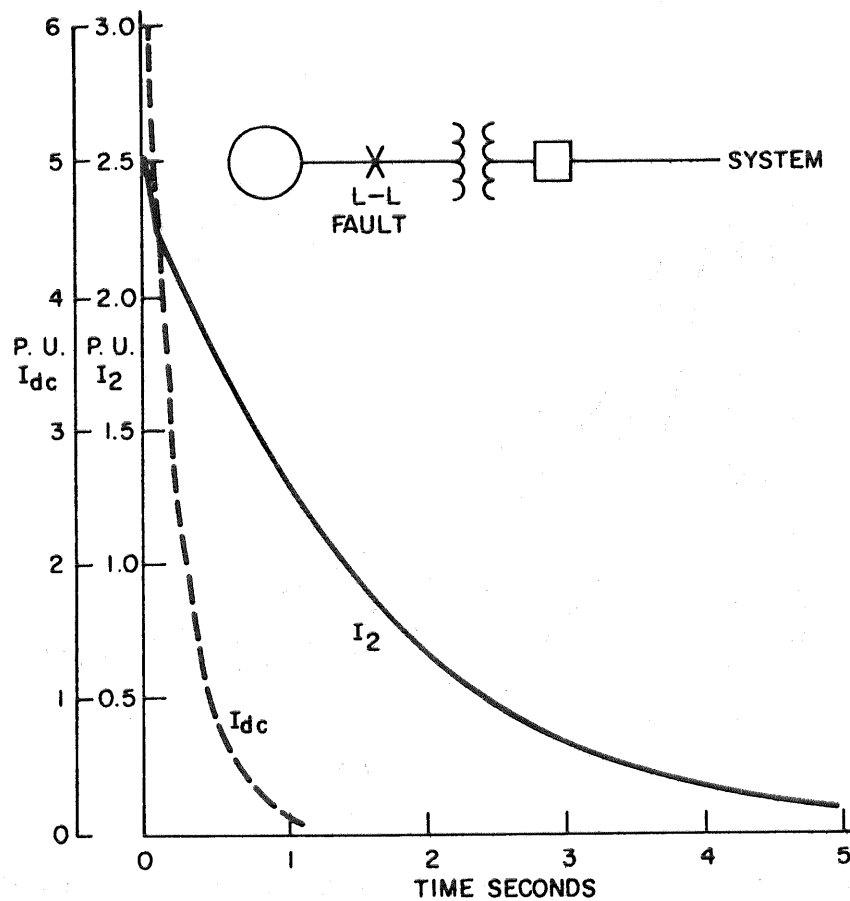


FIG. 3 — L-L TERMINAL FAULT ON LARGE DIRECTLY COOLED 2-POLE GENERATOR WITH EXCITATION REDUCED BY EXCITER FIELD BREAKER. INITIAL CONDITIONS ARE RATED OUTPUT AT 105% VOLTAGE. DC COMPONENT OF STATOR FAULT CURRENT SHOWN FOR FULLY OFFSET WAVE.

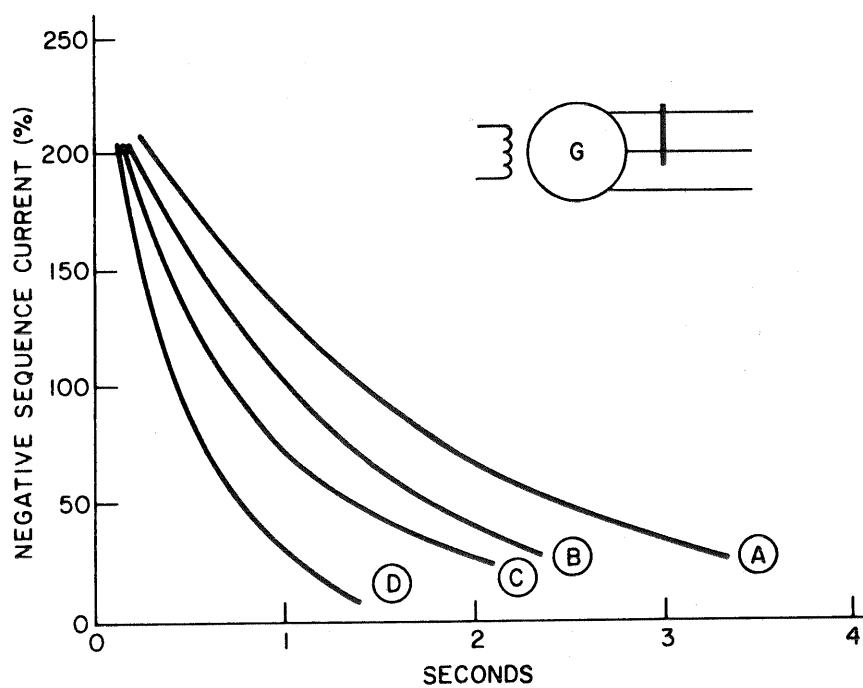


FIG. 4 – GENERATOR NEGATIVE SEQUENCE FAULT CURRENT REDUCTION WITH:

- A – EXCITER FIELD BREAKER
- B – NON-INVERTING THYRISTOR EXCITER
- C – MAIN GENERATOR FIELD BREAKER
- D – INVERTING THYRISTOR EXCITER

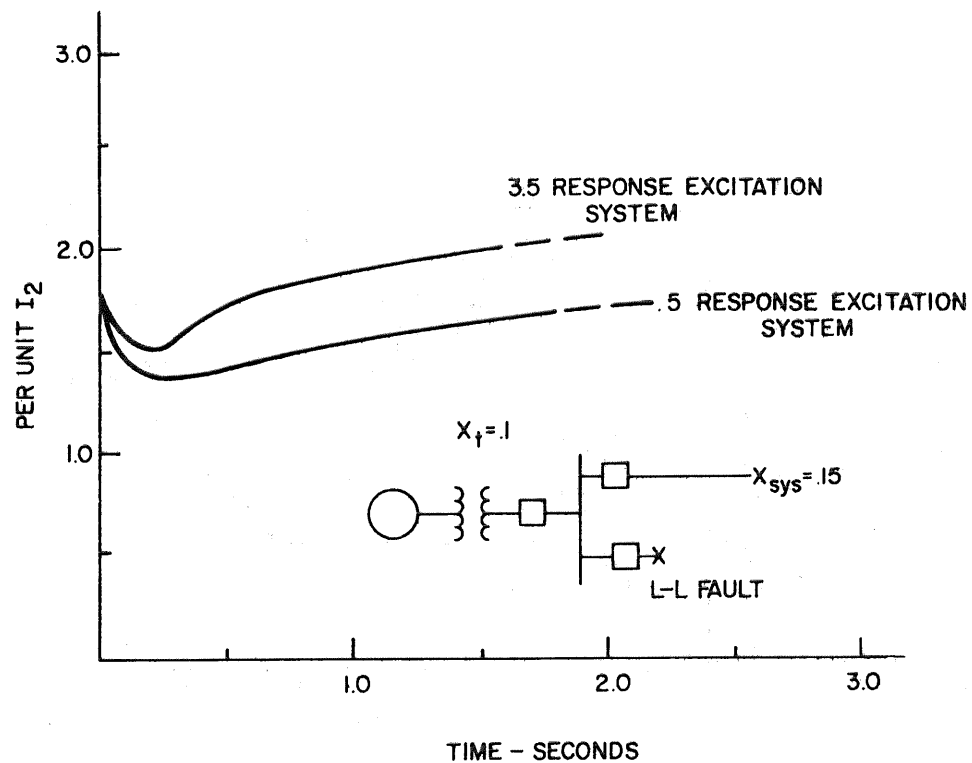


FIG. 5 — GENERATOR NEGATIVE SEQUENCE CURRENTS FOR A CLOSE-IN HIGH VOLTAGE L-L FAULT AS A FUNCTION OF EXCITATION SYSTEM RESPONSE.

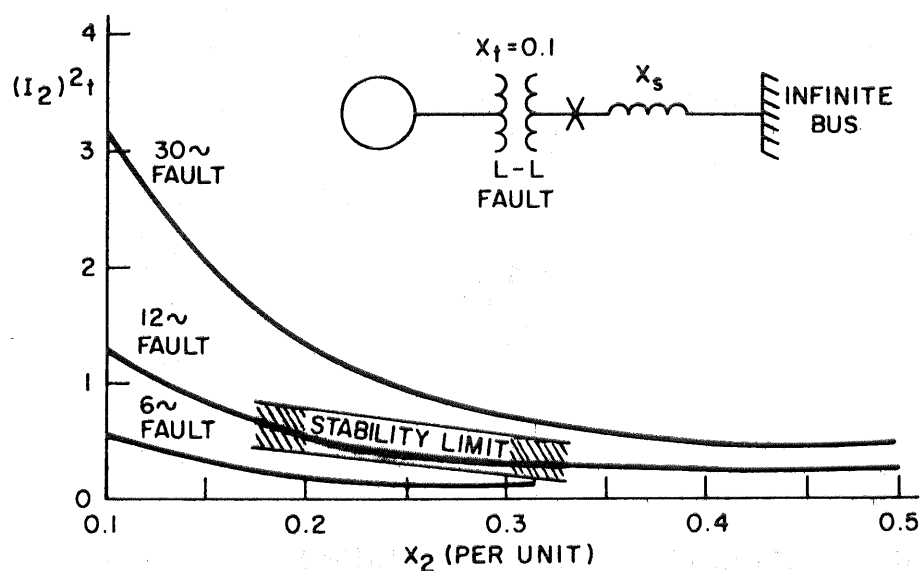


FIG. 6 —  $I_2^2 t$  DUTIES VS. GENERATOR  $X_2$  FOR CLOSE-IN L-L TRANSMISSION FAULTS. CURVES ARE FOR AN INFINITE SYSTEM ( $X_s = 0$ ) EXCEPT AS NOTED. STABILITY LIMITS BASED ON RANGE OF  $X_s$  FROM 0.2 TO 0.6.

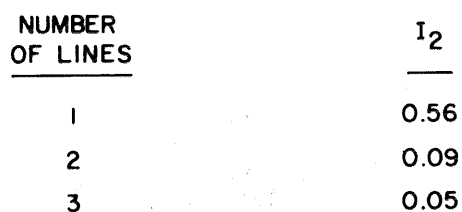
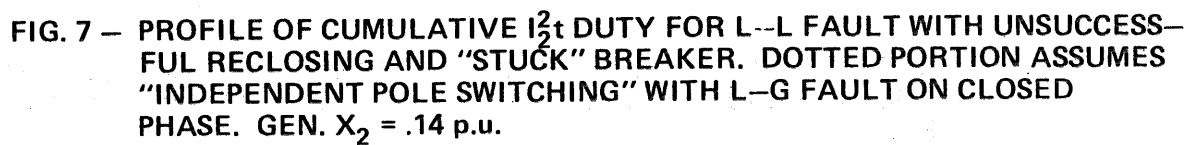


FIG. 8 — GENERATOR NEGATIVE SEQUENCE CURRENTS WITH OPEN CONDUCTOR.

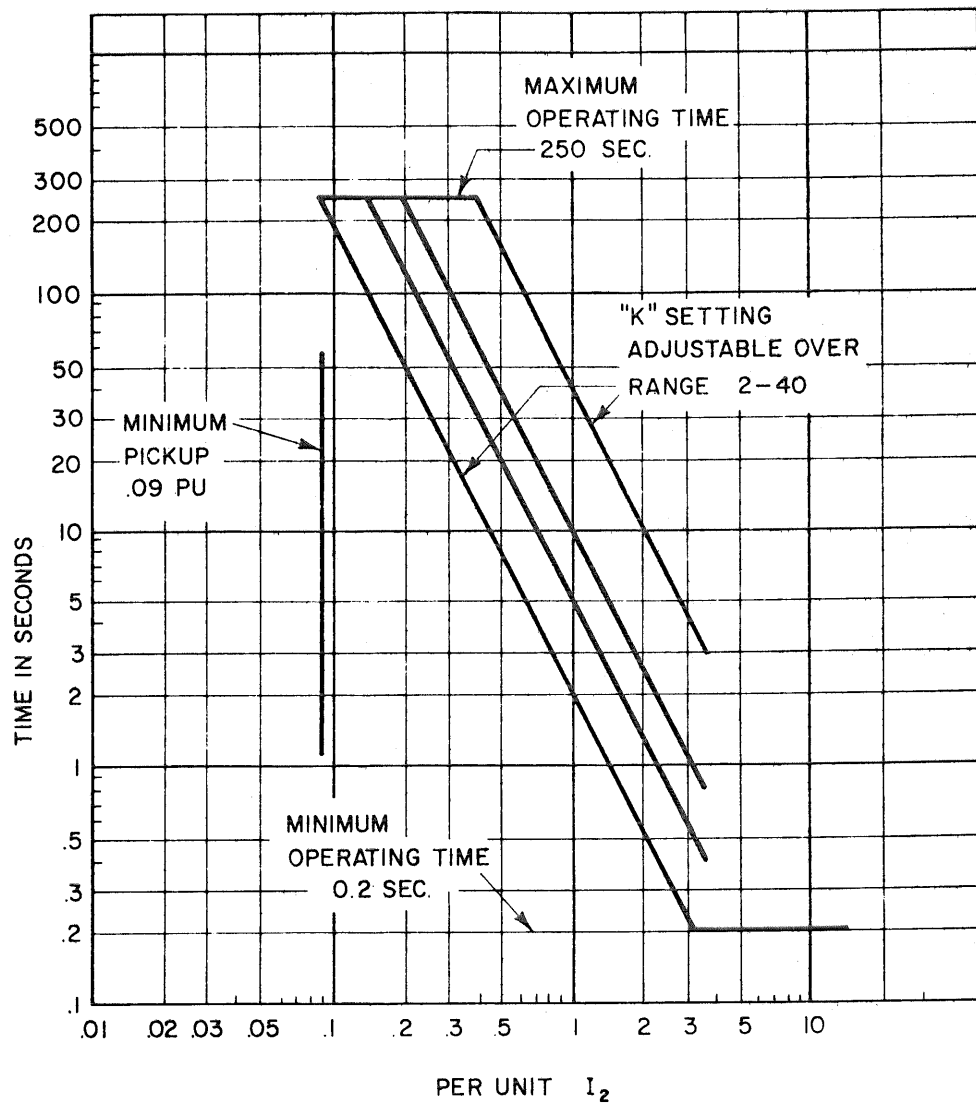


FIG. 9 – CHARACTERISTICS OF THE SGC, STATIC NEGATIVE SEQUENCE TIME OVERCURRENT RELAY.

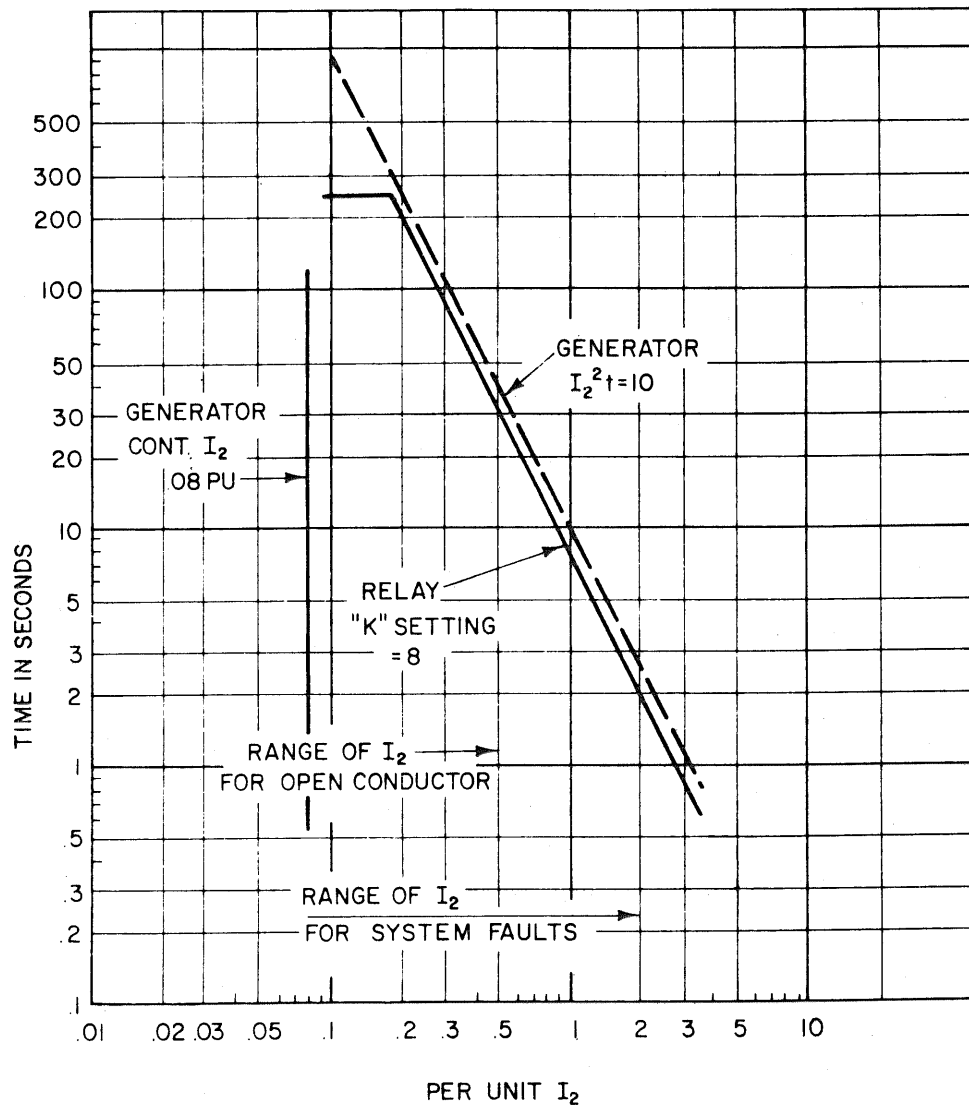


FIG. 10 — APPLICATION OF THE SGC RELAY ON AN 800 MVA, 2-POLE DIRECTLY COOLED GENERATOR.