GET-6449

Load Shedding, Load Restoration and Generator Protection Using Solid-state and Electromechanical Underfrequency Relays

CONTENTS

INTRODUCTION

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by

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This publication provides a comprehensive coverage of load shedding, load restoration and generator protection schemes using solid state, Type SFF, and high-speed electromechanical, Type CFF, underfrequency relays.

Section 1 briefly covers various applications that can be made using underfrequency relays and include:

a. load shedding
b. load restoration
c. special problems in load shedding
d. underfrequency protection of generators
e. bibliography

Section 2 provides relay descriptions, specifications, and tables showing the available types of relays, the features of each, the usual applications, ratings, options, time delays, outputs, etc.

Sections 3 and 4 contain the complete texts of two most pertinent technical papers applicable to the subject. The titles and authors of these papers are:

Section 3 "Load Shedding – An Application Guide," by John Berdy: General Electric Company, Electric Utility Engineering Operation, Schenectady, N.Y. (1968)

Section 4 "Protection of Steam Turbine Generators During Abnormal Frequency Conditions," by J. Berdy & P.G. Brown, Electric Utility Engineering, and L.E. Goff, Switchgear Engineering, all of General Electric Company, presented at Georgia Tech Protective Relaying Conference in 1974.

Section 1
BASIC APPLICATIONS OF UNDERFREQUENCY RELAYS

LOAD SHEDDING

Any part of a power system will begin to deteriorate if there is an excess of load over available generation. The prime movers and their associated generators begin to slow down as they attempt to carry the excess load. Tie lines to other parts of the system, or to other power systems across a power pool, attempt to supply the excess load. This combination of events can cause the tie lines to open from overload or the various parts of the systems to separate due to power swings and resulting instability. The result may be one or more electrically isolated islands in which load may exceed the available generation.

Further, the drop in frequency may endanger generation itself. While a hydro-electric plant is relatively unaffected by even a ten percent reduction in frequency, a thermal generating plant is quite sensitive to even a five percent reduction. Power output of a thermal plant depends to a great extent on its motordriven auxiliaries such as boiler feedwater pumps, coal pulverizing and feeding equipment, and draft fans. As system frequency decreases, the power output to the auxiliaries begins to fall off rapidly which in turn further reduces the energy input to the turbine-generator. The situation thus has a cascading effect with a loss of frequency leading to a loss of power which can cause the frequency to deteriorate further and the entire plant is soon in serious trouble. An additional major concern is the possible damage to the steam turbines due to prolonged operation at reduced frequency during this severe overload condition.

To prevent the complete collapse of the island, underfrequency relays are used to automatically drop load in accordance with a predetermined schedule to balance the load to the available generation in the affected area. Such action must be taken promptly and must be of sufficient magnitude to conserve essential load and enable the remainder of the system to recover from the underfrequency condition. Also, by preventing a major shutdown, restoration of the entire system to normal operation is greatly facilitated and expedited.

Where individual operating utility companies are interconnected, resulting in a power pool, it is essential that system planning and operating procedures. be coordinated to provide a uniform automatic load shedding scheme. The number of steps, the frequency levels and the amount of load to be shed at each step are established by agreement between the power pool members.

LOAD RESTORATION

If a load shedding program has been successfully implemented, the system frequency will stabilize and then recover to 60 Hz. This recovery is assisted by governor action on available spinning reserve generation, or by the addition of other generation to the system. The recovery of system frequency to normal is likely to be quite slow and may extend over a period of several minutes. When 60 Hz operation has been restored to an island, then interconnecting tie lines with other systems or portions of systems can be synchronized and closed in.

As the system frequency approaches the normal 60 Hz, a frequency relay can be used to automatically begin the restoration of the load that has been shed. The amount of load that can be restored is determined by the ability of the system to serve it. The criteria is that the available generation must alwavs exceed the amount of load being restored so that the system frequency will continue to recover towards 60 Hz. Any serious decrease in system frequency at this point could lead to undesirable load shedding repetition, which could start a system oscillation between shedding and restoration. This would be a highly undesirable condition. The availability of generation, either locally or through system interconnections, determines whether or not the shed load can be successfully restored. Therefore, a load restoration program usually incorporates time delay, which is related to the amount of time required to add generation or to close tie-lines during emergency conditions. Also, both the time delay and the restoration frequency set points should be staggered so that all of the load is not reconnected at the same time. Reconnecting loads on a distributed basis also minimizes power swings across the system and thereby minimizes the possibility of initiating a new disturbance.

In general, wide frequency fluctuations and the possibility of starting a load shedding/restoration oscillation can be greatly minimized if the amount of load restored per step is small and the spinning reserve generation available is adequate. Reference (35) suggests a spinning reserve availability at least three times the size of the load to be restored at any given step. There should also be adequate time delay provided between load restoration steps to allow the system to stabilize before an additional block of load is picked up.

SPECIAL PROBLEMS IN LOAD SHEDDING

MOTOR LOADS

A substation which has an extreme amount of motor loads may present a problem of time coordination in the application of underfrequency relays for load shedding. If the transmission sources to such a substation were tripped out for any reason, the motor loads would tend to maintain the voltage while the frequency decreased as the motors were slowing down. This would especially be true if the line capacitance kept the motors excited. This slow decay of voltage may last longer than the usual three to six cycle trip delay used with a high speed underfrequency relay, and the relay may trip and lock out breakers undesirably. In an unattended installation, restoration of the load would not then be accomplished by simply reenergizing the transmission line. One solution that has been applied is to further delay the operation of the underfrequency relay to about 20 cycles. This has apparently been adequate for most applications. Some attempts have also been made to use an undervoltage cutoff to help correct this problem. While this could be successful, care must be exercised in choosing the setting for the undervoltage device since a normal underfrequency condition on the system is usually accompanied by a lower than normal voltage. Too high an undervoltage setting would possibly block the underfrequency relay from doing a load shedding function when needed. Section 2 lists available static and electromechanical relays suitable for, this application.

HIGH-SPEED RECLOSING

Many large industrial plants have adopted some form of load shedding program. One such application is a case where an industrial plant is tapped on to a power company through a transmission circuit that utilizes high-speed automatic reclosing. For faults on the transmission circuit the power company will usually trip both ends of the line, and then initiate high-speed reclosure of at least one end of the line. Since this reclosing is not synchronized with anything else, it is important that the industrial load be disconnected prior to the reclosure to prevent damage to heavy motors and local generators, if present. The motors and/or generators will likely have slowed down during the line interruption and their voltages would be out of synchronism with the power company voltage when the line is reenergized.

This is a good application for Type SFF high-speed static underfrequency relays to disconnect the industrial from the utility system before high-speed reclosing is accomplished. Refer to Section 2 for the static relays available for this application.

UNDERFREQUENCY PROTECTION OF GENERATORS

A major concern in the operation of steam turbine-generators is the possibility of damage due to prolonged operation at reduced frequency during a system overload condition. Such a condition would result from an under-shedding of load during a system disturbance. Recognizing this possibility, many utilities have used or are considering the application of underfrequency relays and timers to protect steam turbine generators from damage.

Section 4 provides some general guidelines for providing reliable underfrequency protection for a steam turbine generator. It reviews the off-frequency capabilities of steam turbine generators, outlines a procedure for obtaining co-ordinated protection, and describes a number of protective control arrangements for achieving maximum dependability and security.

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Section 2

UNDERFREQUENCY RELAYS FOR LOAD SHEDDING

INTRODUCTION

There are two basic types of underfrequency relays available for application in load shedding schemes. They are the static relay, Type SFF, and electromechanical relay, Type CFF. The operating characteristics and features of each of these relays are described in the following paragraphs.

STATIC RELAY, TYPE SFF

The static underfrequency relay employs digital counting techniques to measure system frequency. Basically, this relay consists of a highly stable, crystal-controlled oscillator which continuously supplies two mHz pulses to a binary counter. The counter, in conjunction with other logic circuitry, determines system frequency by counting the number of two mHz pulses which occur during a full cycle (one period) of power system voltage. For any preset frequency, a specific number of pulses should occur during a one-cycle period. If the number of pulses is less than this specific number, it would indicate that system frequency is above the setting. Conversely, if the number of pulses is greater than this specific number, it indicates that the system frequency is less than the setting. For security reasons, an underfrequency indication must occur for a minimum of three consecutive cycles before the relay produces an output. This minimum time can be extended to 80 cycles by means of an adjustable auxiliary timer. If the system frequency should recover even for one cycle during the timing period, the timing circuits will be reset and the relay will immediately start monitoring system frequency again. The relay operating time is independent of the rate of change of the system frequency.

The static underfrequency relay is an extremely accurate and stable device. It can be adjusted over a frequency range of 54.2 to 60.8 Hz in increments of 0.05 Hz, and its setting will be accurate within ± 0.005 Hz of the desired set point. This accuracy is maintained over an ambient temperature range of -20°C to +60°C and is independent of voltage over the range of 50 to 115 percent of rating. All models of the SFF relay are provided with an undervoltage detector which blocks operation of the relay when the applied voltage falls below the set level of the detector. See Tables 2-1 and 2-2 for undervoltage detector setting or range of setting.

The SFF relay has a minimum operating time of three cycles, as described previously, when the output is a silicon controlled rectifier (SCR). Most models provide electromechanical contact outputs and, in these models, the minimum operating time is increased to four cycles simply because of the operating time of the output telephone relay.

The adjustable auxiliary static timer can extend the operating time of all models up to 80 cycles. All models of SFF relays have a single set point for underfrequency tripping and, where applicable, a single set point for load restoration as the frequency recovers.

In applying the underfrequency relay in a load shedding program it must be recognized that a low frequency condition does not begin to be corrected until a circuit breaker operation occurs to disconnect some load. The curves in Fig. 2-1 are constructed to show the system frequency vs the time to open the breaker after the disturbance starts. These curves include:

a. An allowance of six cycles for total breaker clearing time.

b. The SFF underfrequency relay minimum operating time of four cycles.

c. Two different pickup settings of the SFF underfrequency relay.

d. Various constant rates of decay of the system frequency.

Curves can be plotted for actual system conditions and they can be read directly to determine the system frequency at which the load is actually removed.

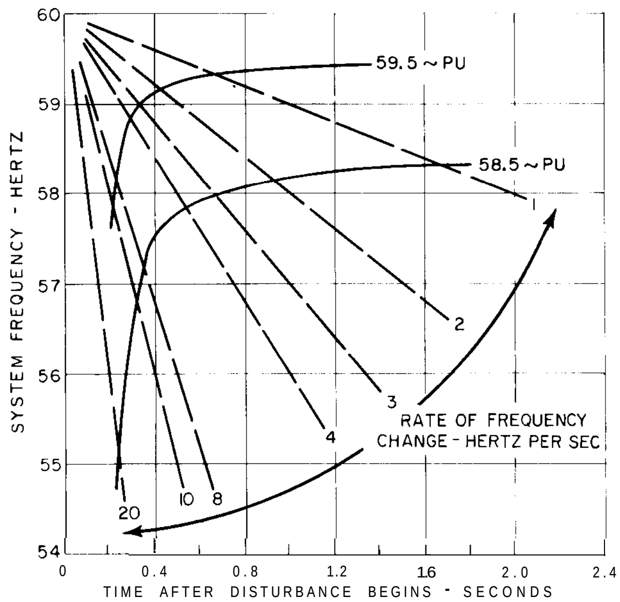

Fig. 2-1 Type SFF Underfrequency Relay, Frequency vs Time Characteristics for Total Clearing Time.

TABLE 2-1

TYPE SFF RELAYS – LOAD SHEDDING ONLY

MODEL	Target*	Trip Output**	Trip Delay, Cycles	Control Power	Under Voltage Cutoff, Percent	Comments
SFF21A	TSI	1c	4-80	dc	50 fixed	
SFF21 B	T	1-SCR	3-80	dc	50 fixed	
SFF21H	TSI	1c,1b	4-80	dc	50 fixed	
SFF23C	TSI	1c	4-80	ac	50-90 adjustable	
SFF23H	TSI	1c,1b	4-80	ac	50-90 adjustable	Additional a/b contact, field convertible

TABLE 2-2

TYPE SFF RELAYS – LOAD SHEDDING AND RESTORATION

MODEL	Target*	Trip output**	Trip Delay, Cycles	Restore output,** Note 1	Control Power	Under Voltage Cutoff, Percent	Comments
SFF22A	2-TSI	2a	4-80	2a	dc	20-90 adjustable	
SFF22C	2-TSI	2a	4-80	2a	ac	50-90 adjustable	
SFF22E	2-TSI	2a	4-80	2a	dc (Dual rated)	20-90 adjustable	Note 2
SFF22F	2-TSI	2a	4-80	2a	ac	50-90 adjustable	Note 2

*Targets: TSI-series operated target seal-in.
T-series operated target only.

**Contacts:
a-normally open
b-normally closed.
c-transfer or a normally open and a normally closed contact with a common connection.
SCR-silicon controlled rectifier.

Note 1: Restore contacts have 6-8 cycle delay in closing and 15 cycle delay on dropout. See text, Section 2.

Note 2: Auxiliary relay provides external supervision of restore contacts, rated for dc control only.

Type SFF21 and SFF23 are the basic relays to be applied in general load shedding schemes and in the protection of steam turbine generators. They are also readily adaptable for the special problems in load shedding applications discussed in Section 1, including motor loads and high-speed reclosing.

Type SFF22 relays are specifically designed for application in a load shedding scheme supplemented by a load restoration scheme when the system frequency returns to normal or near normal. The operating time range for the underfrequency tripping output is 4 to 80 cycles as in other models of the SFF relay. The operating time to close the restoration output contact as the system frequency recovers to the restoration frequency set point is six to eight cycles and is not adjustable. Usually load restoration will be accomplished on a relatively long time basis (minutes not seconds) and external timers, as well as additional auxiliary equipment will be required. To minimize any possible disturbance to these external timers and the complete load restoration scheme, the load restoration output relay is provided with a time delay dropout of about 15 cycles. Once the "restore" relay contacts close on overfrequency, they will not reopen as a result of a short duration loss (less than 15 cycles), or reduction of either the ac and/or the dc inputs to the relay.

ELECTROMECHANICAL RELAY, TYPE CFF

The Type CFF underfrequency relay is a high-speed, induction cup type. Its basic principle of operation is the use of two separate coil circuits which provide increasing phase displacement of fluxes as the frequency decreases, thereby causing torque to be developed in the cup unit to close the tripping contacts. The quantity of torque produced is proportional to the sine of the angle between these two fluxes. As the frequency decays the angular displacement increases, thereby increasing the torque produced. If the frequency decays rapidly the torque will increase rapidly and cause the relay to close its contacts in less time. Thus the relay operating time is a function of the rate-of-change of frequency. The CFF relay setting is continuously adjustable over a range of 56 to 59.5 Hz. Relay models listed in Table 2-3 are provided with compensation for voltage variation and self-heating; repeatability of set points is held within LO.25 Hz over the normal temperature range from -2O°C to + 55°C, and ac input voltage variations from 50 to 1 10 percent of rating.

The curve in Fig. 2-2 shows the operating time of the Type CFF12 underfrequency relay vs a constant rate-of-

Table 2-3

TYPE CFF RELAYS – LOAD SHEDDING ONLY

MODEL	Target*	Trip output**	Trip Delay, Cycles	Control Power	Comments
CFF12A	TSI	1a,1b	6	dc	
CFF12C	Shunt	1a,1b	6	ac	
CFF12H	TSI	1a,1b	6	dc	Special calibrating resistors.
CFF15A	TSI	1a,1b	21	dc	
CFF15C	Shunt	1a,1b	18-30	ac	
CFF23A	TSI	2a,1b	6-60	dc	Includes static timer.
CFF23C	Shunt	1a,1b	6-60	ac	Includes static timer.

*Targets: TSI – series operated target seal-in.
Shunt – voltage operated, parallel target only.

**Contacts: a-normally open.
b-normally closed.

change of system frequency. This curve gives the relay operating time after the system frequency has reached the relay pickup setting. The Type CFF12 relay includes an added fixed time delay of six cycles to prevent incorrect relay operation when the ac input voltage is suddenly applied or removed.

Type CFF12 is the basic relay to be applied in general load shedding schemes. Type CFF15 and CFF23 relays are applied where additional delay in the relay output is desirable. They are particularly applicable for special problems in load shedding applications involving motor loads, as discussed in Section 1.

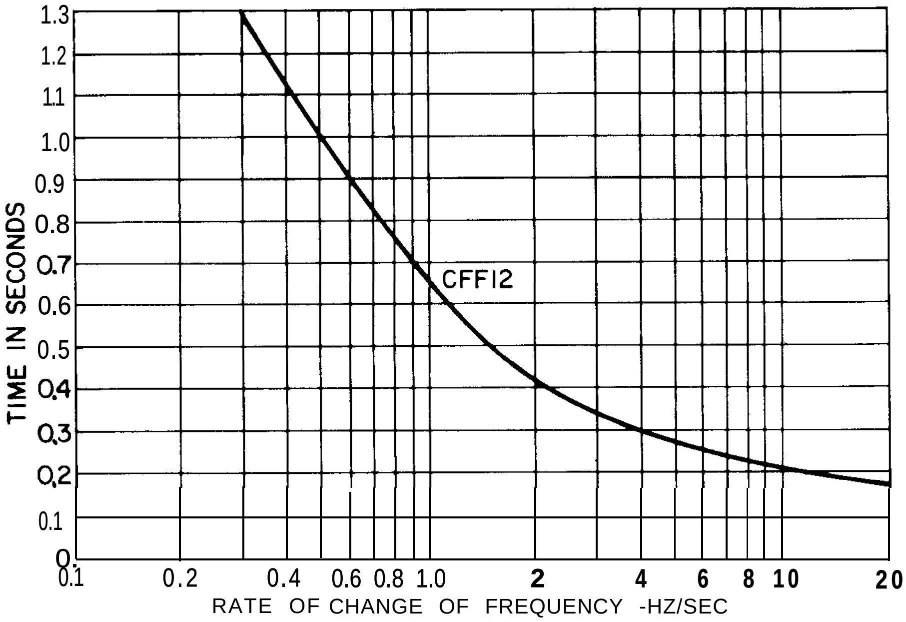

Fig. 2-2 Time-Frequency Characteristic for CFF Relay Operating Time After System Frequency Reaches Relay Pickup Setting.

Section 3

LOAD SHEDDING – AN APPLICATION GUIDE

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INTRODUCTION

The maintenance of maximum service reliability has always been the primary concern of the electric utility industry. To attain this end, power systems are designed and operated so that for any predicted system condition, there will always be adequate generating and transmission capacities to meet load requirements in any system area. For the most part, this design and operating procedure has been successful in producing a high degree of service continuity, even under emergency conditions. However, regardless of how great the planned margins are in system design and operation, there have been, and probably always will be, some unpredictable combination of operating conditions, faults, forced outages, or other disturbances which cause system split-ups and/or a deficiency in generating capacity for existing area loading. When this occurs on a modern power system, it generally indicates that a highly improbable and potentially catastrophic event has occurred. Therefore, it is essential that the generation deficiency be quickly recognized and the necessary steps taken to prevent the disturbance from cascading into a major system outage.

The immediate problem is to attain a balance between generation and load before the decaying system frequency caused by the overload affects the performance of the remaining generation and power plant auxiliaries. This balance can be achieved by increasing generation or by automatic load shedding on low frequency. In general, the first alternative, increasing generation, can not be accomplished quickly enough to prevent a major decrease in system frequency, or in the extreme, there may not be sufficient available generating capacity to pick up the additional load.

On the other hand, the second alternative, automatic load shedding on low frequency, provides a quick and effective means for attaining a generation-load balance and for restoring system frequency to normal. The application of underfrequency relays throughout the load area, preset to drop increments of load at specific levels of low frequency, provides a simple and direct method for alleviating system overloads and for minimizing the magnitude and duration of any service interruption. Since system overloads are generally caused by a major disturbance of unknown cause and system collapse may be imminent, load shedding should be performed quickly and automatically.

It is the intent of this Section to discuss the factors involved in applying underfrequency relays for load shedding, and to describe the available relay characteristics and their application on electric utility and industrial systems.

SYSTEM CHARACTERISTICS

To apply underfrequency relays for load shedding, it is necessary to have some knowledge of how the frequency will vary when load exceeds the generating capacity of a system, and when the system is recovering from such an overload. Because of the numerous variables involved, it is usually difficult, if not impossible, to obtain a precise frequency characteristic for a system of appreciable size. However, it is not essential that a precise characteristic be known in order to apply underfrequency relays. It is only necessary to obtain a basic knowledge of the phenomena involved and the effect of the various parameters on the overall characteristic.

GENERAL

It is generally recognized that the sudden loss of generating capacity on a system will be accompanied by a decrease in system frequency. The frequency will not suddenly deviate a fixed amount from normal but rather will decay at some rate. The initial rate of frequency decay will depend solely on the amount of overload and on the inertia of the system. However, as the system frequency decreases, the torque of the remaining system generation will tend to increase, the load torque will tend to decrease and the overall effect will be a reduction in the rate of frequency decay. Assuming no governor action, the damping effect produced by changes in generator and load torques will eventually cause the system frequency to settle-out at some value below normal. If governor action is considered, and if the remaining generators have some pick-up capability, the rate of the frequency decay will be reduced further and the frequency will settle out at some higher value. In either case the system would be left at some reduced frequency which may cause a further decrease in generating capacity before any remedial action could be taken.

The variation of system frequency during such a disturbance is not a smooth rate of decay but rather is oscillatory in nature because of the interaction of the interconnected generators. Moreover, the rate of decay and the period of oscillation may differ appreciably across the system. For example, Fig. 3.1 shows the results of a computer study of a system for a five percent loss of generation. The frequency variations at three different bases on the system are shown. During the initial three seconds of the disturbance the frequency deviation was minor and is not shown. However, at about three seconds, the system area separated from the network, and the frequency decayed, as shown in Fig. 3.1. In this instance, the system was able to recover from the loss of generation and the frequency settled out at 59.5 Hz.

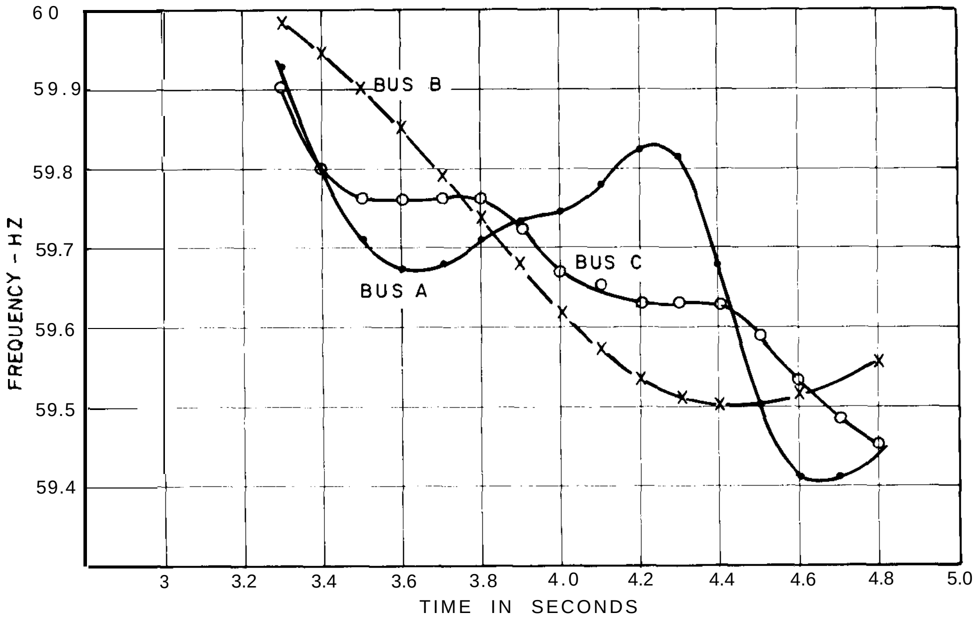

Fig. 3-l Time-frequency Characteristic of a System After a Five Percent Loss in Generation.

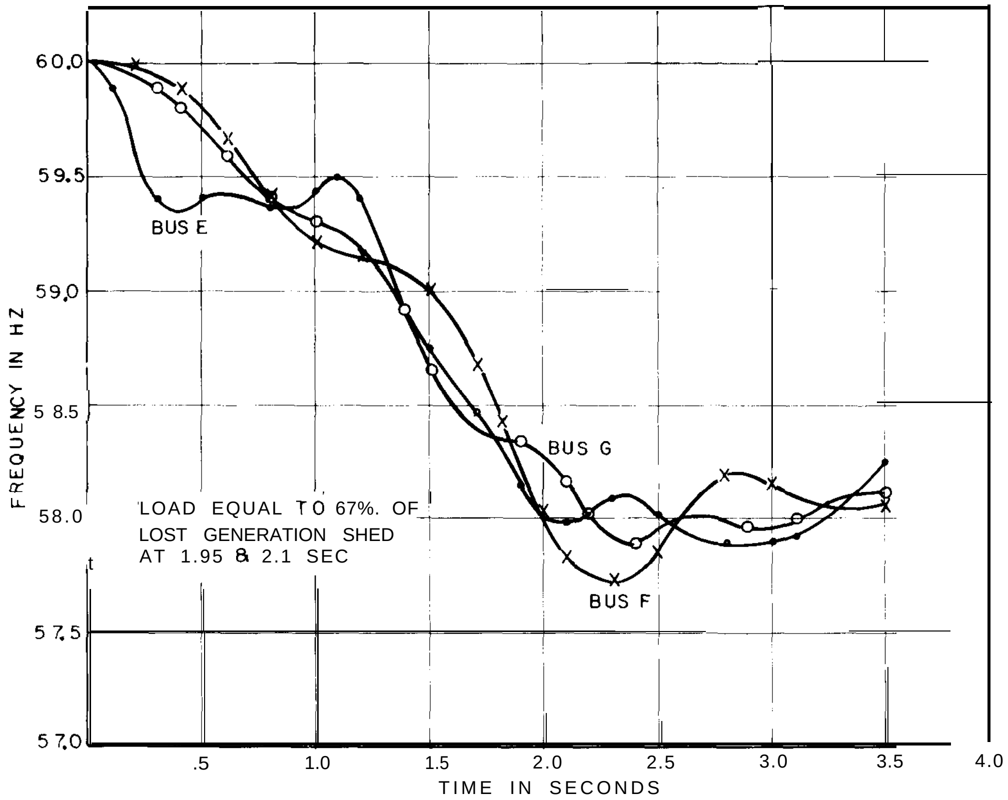

Fig. 3-2 Time-frequency Characteristic of a System After a 15 Percent Loss in Generation.

Figure 3.2 illustrates the case of a 15 percent loss of generation. In this instance, the frequency dropped quite rapidly until load was shed at about two seconds. The amount of load shed was equal to 67 percent of the lost generation. This was sufficient to stop a further decrease in frequency but not enough to restore the frequency to normal.

In both of the above illustrations, it is readily apparent that the frequency deviations and the rate of change of frequency at some buses was appreciably greater than at others. In Fig. 3-1, bus A had an initial rate of decay of 1.0 Hz/sec and later (at 4.3 sec) had a rate of decay of about 1.5 Hz/sec. The other buses had an average rate of decay of about 0.5 Hz/sec. In Fig. 3-2, bus E had an initial rate of decay of about 3.5 Hz/sec while the other buses had an average decay of less than 1.0 Hz/sec. In both instances, the rate of change of frequency at buses A and E would indicate a more serious loss of generation than had actually occurred.

The above examples, while for a specific system, illustrate typically the frequency variations which can occur on a system during a sudden loss in generation. In general, it is not possible to analytically determine the frequency oscillations that can occur on a system of appreciable size during such a disturbance. The nature of these oscillations can only be determined from detailed computer studies of the system. However, it is possible to determine, and predict with reasonable accuracy, the average rate of frequency decay that can occur for different magnitudes of generation deficiencies. In the following paragraphs, the system frequency decay characteristic will be discussed, first assuming constant load and generation torques, and then showing the effect of load and generation torque variations with frequency. Speed-governor action will not be considered in this discussion since it is difficult to generalize as to the overall effect it will produce. Whether or not governor action will increase power output depends on such factors as initial generator loading, control sensitivity, boiler time constants, etc., all of which may differ appreciably between systems and even within a system.

FREQUENCY CHARACTERISTIC

Constant Load and Generator Torques

The basic relationship which defines the variation of frequency with time is derived from the equation for the motion of a rotating machine. This relationship, derived in Appendix 1, page 28, is:

$$\frac{df}{dt} = \frac{T_a f_o}{2H}$$

where

df/dt = rate of change of frequency in Hz/sec.

f_o = base frequency, 60A Hz

T_a = net accelerating torque in per unit of existing system generation. This torque is the difference between generator torque and load torque (T_G - T_L).

H = system inertia constant. This is equal to the sum of all the generator inertia constants in per unit on the total generation base.

When there is a sudden loss of generation on the system without a compensating decrease in load, the net torque T_a will be negative, or decelerating. If it is assumed that the remaining generator torques (T_G) and the load torques (T_L) remain constant during the disturbance, the variation of frequency with time will be a straight line. The frequency variation for different magnitudes of overload and for a system inertia constant of 5, is shown in Fig. 3-3. Percent overload is defined as

$$\textbf{\% overload} = \frac{\textbf{Load} - \textbf{Remaining Generation}}{\textbf{Remaining Generation}} \textbf{ X 100}$$

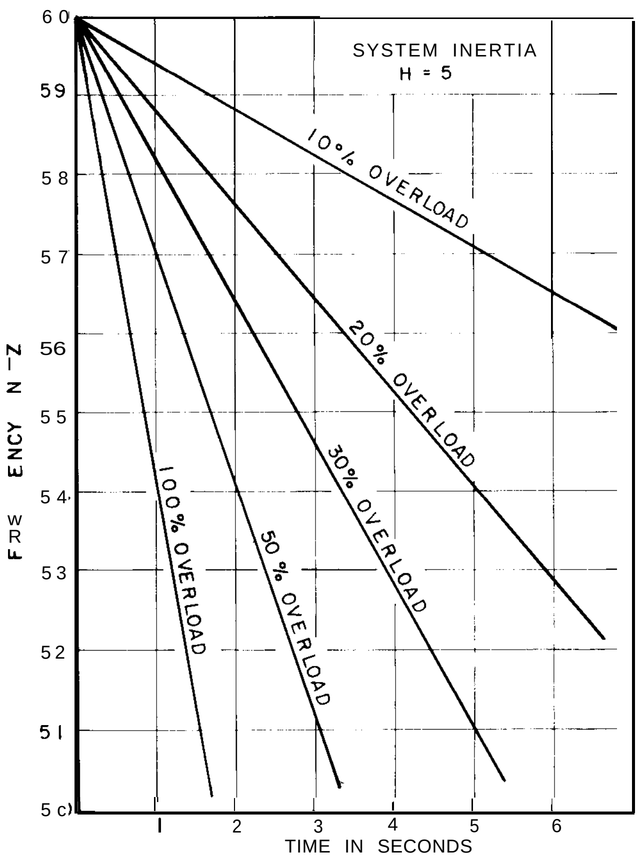

Fig. 3-3 Time-frequency Characteristic of a System for various Degrees of Overload, Generator and Load Torques Constant.

It should be noted that the percent overload does not equal the amount of generation lost. The percent generation lost on the original generation base will be somewhat lower than the overload percentages. For example, the 10 percent overload corresponds to a 9.1 percent loss in generation on the original generation base while the 100 percent overload corresponds to a 50 percent loss in generation.

The effect of varying the system inertia constants is shown, Fig. 34, for two magnitudes of overload. The higher the system inertia constant, the lower the rate of change of frequency and vice versa.

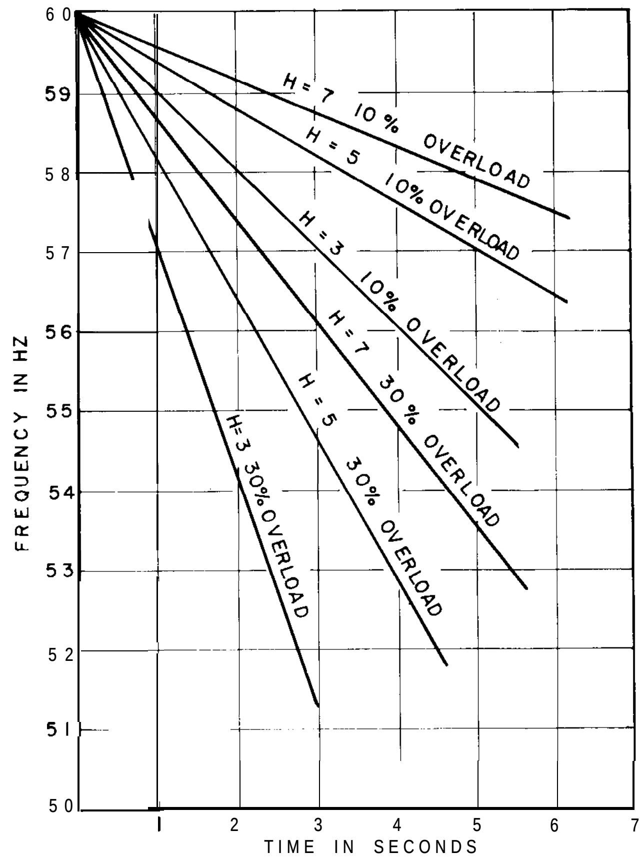

Fig. 3-4 Time-frequency Characteristic of a System, Effect of Varying System inertia, Generator and Load Torques Constant

The system recovery characteristic can also be obtained from the same equation. For example, if an increment of load equal to the overload is shed, the torque T_a will be zero and therefore the rate of change of frequency will be zero. The frequency would remain at the value it had reached at the time the load had been shed. This is shown by the solid lines in Fig. 3-5 for an initial overload of 10 percent. If the amount of load shed is greater than the overload, T_a will be greater than zero and will be positive (accelerating) and the frequency will increase in a, straight line. This is shown by the dashed lines in Fig. 3-5.

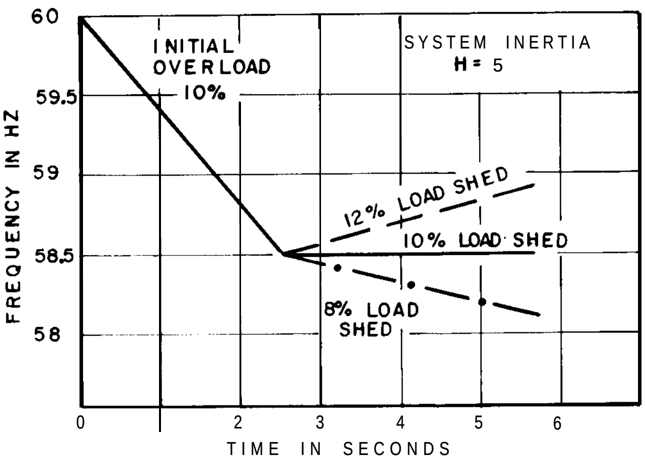

Fig. 3-5 Time-frequency Characteristic of a System, Effect of Shedding Different Amounts of Load.

If the amount of load shed is less than the overload, the frequency will continue to decay but at a slower rate as shown by the dash-dot lines in Fig. 3-5. The new rate-of-change of frequency will be proportional to the new value of torque T_a.

If the load is shed in steps, the frequency characteristic will be as shown in Fig. 3-6. In this instance, the initial overload was 20 percent and 5 percent load was shed on the first step, 10 percent on the second and 10 percent on the third. The percentages of load shed are with respect to the remaining generation base.

It should be noted that in all cases when load is shed, there is an abrupt change in the rate of change of frequency. This is typical of what actually occurs on a system.

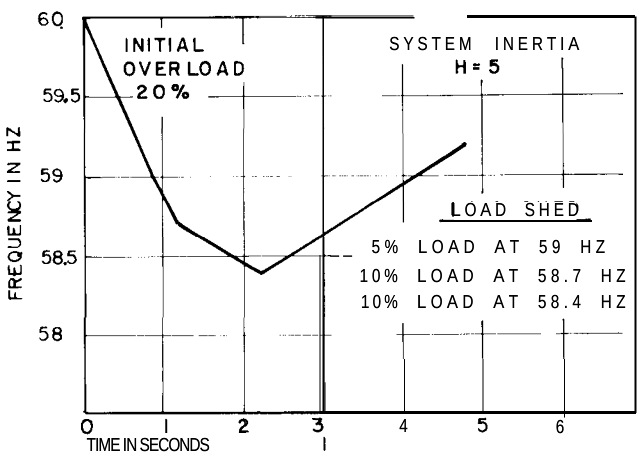

Fig. 3-6 Time-frequency Characteristic of a System, Effect of Shedding Load in Steps.

The above approach provides a simple and approximate procedure for determining the frequency characteristic for a system for a sudden loss in generation. The results are pessimistic in that they show a greater decay in frequency and a poorer recovery characteristic than actually occur on a system. In an actual case, both generator and load torques will vary with frequency and will tend to dampen the rate of change of frequency. The effect of these factors are discussed in the following paragraphs.

Effect of Variations in Generator and Load Torques

In the basic equation for rate of change of frequency, it was noted the accelerating torque T_a is equal to the difference between generator and load torques ($T_G - T_L$). Both of these torques will vary as some function of frequency.

Appendix II, page 29, shows how the generator and load torques will be affected by frequency. It is shown that generator torques will vary inversely with the first power of frequency. For small changes in frequency ($\pm$10%), generator torques will increase in direct proportion to a decrease in frequency. That is, a one percent decrease in frequency produces a one percent increase in generator torque and vice versa.

On the other hand, load torques will vary directly as some power of frequency. It is not possible to generalize as to how the kilowatt loading will vary with frequency on all systems. However, studies would indicate that in most instances the kilowatt loading will vary somewhere between the first and second power of frequency. For purposes of this discussion it was assumed that kilowatt loading varied as the 1.5 power of frequency ($P_L = kf^{1.5}$).

Voltage will also affect the system kilowatt loading. It is usually assumed that a one percent change in voltage will produce a corresponding one percent change in load power. However, since it is difficult to evaluate the effect of voltage variation on load during a system overload (some voltages may be above normal, some normal while others may be slightly depressed), this factor will not be considered in this discussion.

The overall effect of changes in generator and load torques on the variation of frequency with time is derived in Appendix II and is shown in Fig. 3-7 for various magnitudes of overload and for a system inertia of 5. These curves indicate that as the frequency decreases, the increasing generator torque and the decreasing load torque tends to dampen the rate of decay and will cause the frequency to settle-out at a constant value below normal. The final frequency for each overload is indicated at the end of each curve. It is interesting to note that the initial rate of change of frequency will be the same as for the case where generation and load torques are assumed constant.

The recovery characteristic is also affected by the changes in generator and load torques and will vary exponentially, as did the decay characteristic. For example, for an initial overload of 10 percent, Fig. 3-8 shows the recovery characteristics and the final frequencies when various amounts of load are shed at 58.8 Hz. Of particular interest is the curve which shows that the frequency will recover to normal (60 Hz) when the amount of load shed equals the overload. This is in contrast to the simplified approach of the preceding section, where the frequency remained at the level where the load was shed (Fig. 3-5). This is due to the fact that as the frequency decreases, the generator torque increases faster than the total load torque decreases and therefore the overload at 58.8 Hz (or at any other frequency below 60 Hz) will be less than it was at 60 Hz. Even if the generator and load damping was only a fraction of that assumed, the frequency would eventually reach normal (60 Hz) if the load shed equals the overload. With smaller damping, it would take a longer time to reach normal.

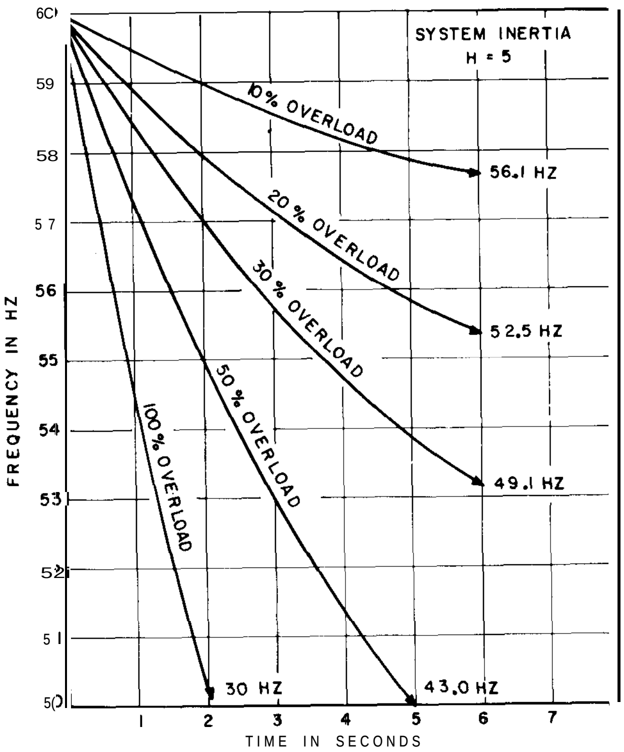

Fig. 3-7 Time-frequency Characteristics of a System for Various Degrees of Overload. Generator & Load Torques Vary as a Function of Frequency.

If the load shed is less than the overload, the final frequency will be less than 60 Hz, as indicated in Fig. 3-8. If a seven percent load is shed, the frequency will for all practical purposes remain at 58.8 Hz. If less than seven percent load is shed, the frequency will continue to decay but at a slower rate.

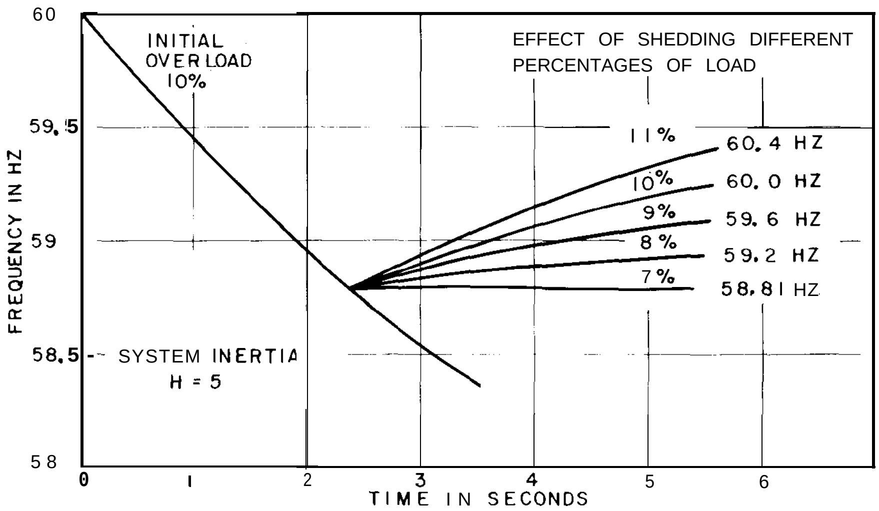

Fig. 3-8 Time-frequency Characteristic of a System, Generator and Load Torque Vary with Frequency.

If the load is shed in steps, the frequency characteristic would be as shown in Fig. 3-9. In this case the initial overload is 20 percent and load is shed in two ten percent steps. The frequency characteristic with any number of load shedding steps can be obtained by using the procedures outlined in Appendix I I. Again, the amount of overload and the load shed are in percent on the remaining generation base.

It will be noted that in Figs. 3-3 and 3-7, that there is an appreciable difference in the rate of change in frequency between 10 percent and 100 percent overload. In general, the 50 percent overload condition (33.3% loss in generation) is probably the maximum overload condition that would be experienced on a utility system. On the other hand, it is quite possible to experience 100 percent or higher overloads on an industrial or a small municipal system which is operating in parallel with a utility, and which is receiving a large portion of its required power from the utility.

Whatever the system size, it is possible to obtain a reasonably accurate frequency characteristic using the procedure outlined and thereby establish an effective load shedding program.

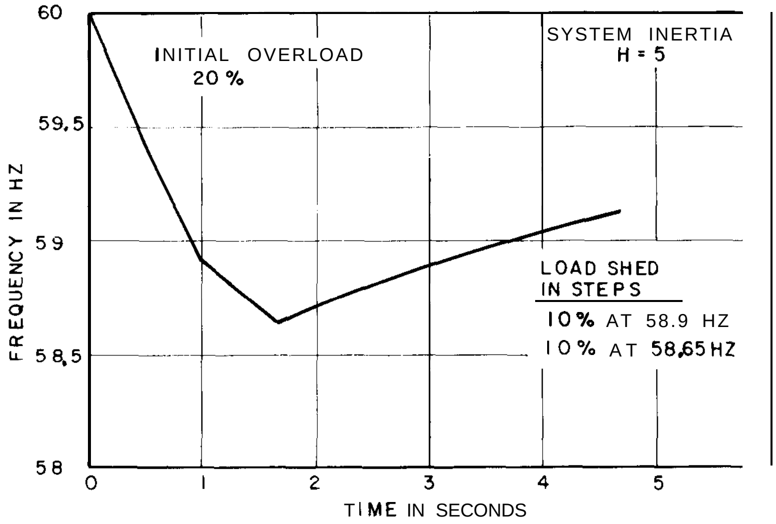

Fig. 3-9 Time-frequency Characteristic of a System. Generator and Load Torque Vary with Frequency.

RATE OF CHANGE OF FREQUENCY DETECTION

It has often been suggested that a relay operating solely on rate-of-change-of-frequency would be desirable for load shedding. Offhand, it would appear that such a relay would not provide any practical advantages and might even tend to shed more load than necessary. For example, in the preceding discussion on system frequency characteristics, it was noted that the frequency decay was oscillatory in nature. Moreover, it was pointed out that the rate-of-change-of-frequency during the frequency oscillations could be quite high and could indicate a more serious loss of generation than had actually occurred. For instance, it was noted that bus E in Fig. 3-2 had an initial rate-of-change-of-frequency of 3.5 Hz/sec. This rate of decay would indicate almost a 33 percent loss in generation instead of the actual 15 percent loss. A rate-of-change-of-frequency relay, set to quickly trip substantial load on high rates of decay, would have tripped more load than necessary in this instance at that bus.

Considering the oscillatory nature of the frequency decay and the momentary high rates of decay that might occur, it is readily apparent that considerable time delay would have to be used with a rate-of-change-of-frequency relay in order to obtain a reasonably accurate indication of the true rate of decay. The time delay required would probably eliminate any benefits which could be derived from this characteristic, especially during severe overload conditions.

LOAD SHEDDING PROGRAMS

Ideally, a load shedding program should quickly recognize a generation deficiency, determine accurately the degree of overload, and then precisely shed only the amount of load required to restore system frequency to normal. While it may be possible to closely realize this ideal on a small system for predicted events, it will be difficult, if not impossible, to achieve on a system of appreciable size.

Considering the oscillatory nature of the frequency decay, it should be apparent that it will be difficult to establish a load shedding program which will precisely drop equal increments of load at the same instant all over the system. These frequency oscillations will tend to introduce a certain degree of randomness in underfrequency relay operation and, hence, in the amount of load shed. Moreover, because of these oscillations, it may be inevitable that more load will be shed than necessary at some system locations.

In general, it will not be possible to accurately predict the degree of randomness or the amount of overshedding that will occur under all system conditions. Computer studies of the system can provide a good indication of the frequency oscillations which will occur at various load buses for some emergency conditions, but this data will not necessarily be pertinent during an actual disturbance.

In spite of these unpredictable parameters, it is possible to establish an effective load shedding program. For the most part, these programs are developed from the type of frequency decay curves shown in Fig. 3.7, although the simplified approach shown in Fig. 3.3 may provide sufficient accuracy. The following paragraphs discuss the factors which must be considered in developing a load shedding program and describe the procedure involved in achieving relay settings.

LOAD SHEDDING PROGRAM REQUIREMENTS

Before a load shedding program can be developed, it is necessary to determine the maximum overload level the program is to protect, the maximum load to be shed, the frequency level at which load shedding will be initiated and the maximum permissible decay in frequency.

Maximum System Overload

Load shedding programs are usually designed to protect for some maximum overload condition. In many instances, it is difficult, if not impossible, to determine what this maximum overload will be. For example, on large interconnected systems, it may be difficult to define where and how an area is going to separate from the system and therefore what the generation-load balance will be. In some cases, system stability studies will indicate the likely points of separation and the probable overload can be estimated for the separated area.

Obviously, it will be less difficult to determine the possible overloads on industrial or small municipal systems which receive a major portion of their required power from a utility over one or two tie-lines.

Maximum Load to be Shed

The amount of load shed should be sufficient to restore system frequency to normal or close to normal (above 59 Hz). To accomplish this, it would mean the load that is shed should nearly equal the amount of overload, as can be seen in the system recovery characteristics of Fig. 3-8.

It is not essential that the frequency be restored exactly to 60 Hz. If the frequency is restored above 59 Hz, the remaining system generation may pick-up the remaining overload through speed-governor action and restore the frequency to normal. If the generation does not have pick-up capability, operation above 59 Hz will not be detrimental and the system operator will have ample time to drop additional load or add generation.

Because of the possibility of damage to steam-turbines, it is not recommended that less load be shed and thereby permit system frequency to settle-out at some level below

59 Hz. A conservative estimate of the time-frequency limitation for steam-turbines is shown below.

FREQUENCYAT FULL LOAD – Hz	MINIMUM TIME TO DAMAGE*
59.4	continuous
58.8	90 minutes
58.2	10 minutes
57.6	1 minute

*These times are cumulative, that is, ½ minute of full load operation at 57.6 Hz today leaves only ½ minute left at that frequency for the remainder of the life of the unit.

If it is not possible to determine the maximum overload, the amount of load to be shed will have to be assumed. In this respect, it is better to be pessimistic and shed more load than necessary rather than too little, recognizing the fact that the disturbance which caused the overload may be potentially catastrophic. A recent survey, would indicate that of the utilities who use underfrequency load shedding, 30 percent shed 10-25 percent load; 56 percent shed 25-50 percent load; 12 percent shed 50-75 percent load. While shedding more than 50 percent of the load may seem extreme, there is no valid reason to stop the load shedding process until frequency is restored, even if it means shedding most of the load.

Load shedding programs are usually designed to shed load in steps, to minimize the possibility of shedding too much load during less severe overload conditions. Moreover, the load shed at each step is usually distributed at a sufficiently large number of points around the system or interconnected systems to minimize spurious power swings, which may cause tripping of major transmission lines and/ or tie-lines.

The factors which affect the selection of the number of load shedding steps, and the amount of load shed per step will be considered later in “relay settings.”

Initiation of Load Shedding – Frequency Level

The frequency level at which load shedding is initiated depends on several factors. For one, the level should be below any frequency drop from which the system could recover or below any frequency at which the system could continue to operate. For example, in the system shown in Fig. 3-1, where there was five percent loss in generation, the frequency stabilized around 59.5 Hz. If the speed governors did not restore the frequency to normal, the system could continue to operate at this frequency without any detrimental effects for some period of time.

On isolated systems, systems without interconnections, it may be reasonable to operate at some reduced frequency during emergency conditions.

In both of the above cases, the frequency level for initiating load shedding could be at 59.0 Hz.

On large interconnected systems, frequency deviations of more than 0.2-0.3 Hz usually indicate a severe disturbance and therefore load shedding could be initiated at a higher level, say 59.3 Hz.

Another factor which must be considered is the frequency deviations which occur during system swings. For example, consider the system shown in Fig. 3-10. When the local generation swings with respect to the large system, there can be a large frequency variation on the high voltage bus. If the electrical center of this system is somewhere in the line, the bus frequency will vary around the generator frequency. In the more common case, the electrical center will be somewhere in the transformer, and the bus frequency will vary around 60 Hz. If the generator swings are large, the frequency deviations can be appreciable. For instance, Fig. 3-l 1 shows the frequency variation on the

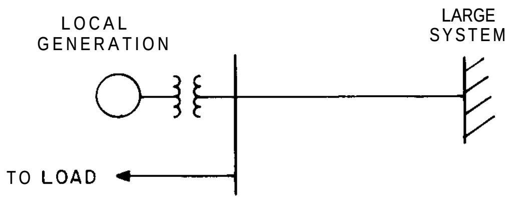

Fig. 3- 10 Small System Connected to a Large Utility

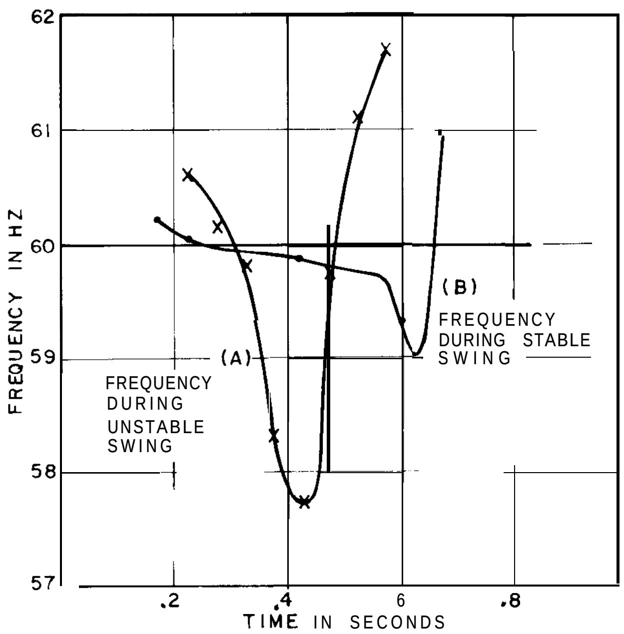

Fig. 3- 11 Frequency Variations During Swings.

bus after a three-phase fault is cleared from the bus. Curve A shows the variation in bus frequency for the case when the local generation lost synchronism with respect to the system. The frequency drops to 57.7 and remains below 60 Hz for almost 0.2 second. Curve B shows the frequency deviation for the case where the generation does not lose synchronism. Even in this instance, the frequency dipped to 59 Hz for a short period of time. While these cases may be extreme, they indicate the frequency deviations that could occur on a load bus which may be close to generator bus. In both these instances, underfrequency relay operation can be prevented through the use of a lower frequency setting and/or some time delay.

Permissible Frequency Reduction

The load shedding programs must be coordinated with equipment operating limitations during low frequency operation. These limitations are usually associated with operation of power plant auxiliaries.

According to tests, the performance of power plant auxiliaries begins to fall off and power plant output begins to decrease at frequencies below 59 Hz and reach a limiting condition between 53-55 Hz. To provide some margin, the maximum frequency decay is usually limited to 56 Hz, although in most instances it will be limited to 57 Hz. It should be noted that if the decay is to be limited to 56 Hz or some higher frequency, load shedding must occur at some higher level. Because of relay and breaker operating times, the frequency will continue to drop below the relay setting before the load is actually shed.

DETERMINATION OF RELAY SETTINGS

The determination of relay settings for a load shedding program is essentially a trial and error procedure. The purpose of this procedure is to determine the best combination of number and size of load shedding steps and corresponding relay settings which will shed the required load within the frequency limits specified for a maximum overload condition, and yet which will shed a minimum amount of load for less severe conditions. In general, this is not a complicated procedure and requires only a few trials to arrive at optimum settings.

Number and Size of Load Shedding Steps

The initial step in the procedure is the selection of the number of load shedding steps and the load to be shed per step.

The number of load shedding steps selected is usually related to the maximum load to be shed. The larger the total load to be shed, the larger the number of load shedding steps used. In general, the number of load shedding steps should be limited to three to five steps. Experience has shown that relay coordination is easier to achieve and the minimum amount of load will be shed when the number of load shedding steps fall in this range.

The load shed per step is not particularly critical. The amount of load shed on the initial step is usually related to the size of the largest generator or the pick-up capacity of the interconnecting tie-lines. A number commonly used for this first step is ten percent of system load. The amount of load shed in each succeeding step is usually determined by arbitrarily allocating some portion of the remaining load to be shed to each step.

It should be apparent that the selection of the number and size of load shedding steps is more or less arbitrary. In some instances, it will be possible to obtain coordinated load shedding within the specified frequency range with the initial selection. In others, it will be necessary to adjust both the number and size of steps in order to shed all of the load within the prescribed limits.

RELAY SETTINGS

The procedure for determining underfrequency relay settings is similar in many respects to the methods used in coordinating any group of protective relays. Selectivity is achieved through the adjustment of pick-up settings and through time coordination. Before considering the procedure for obtaining a selective load shedding program, it is necessary to comment briefly on a few factors which affect time coordination.

There is a minimum time delay required for each load shedding step. This time delay is necessary to prevent unnecessary shedding of load during the frequency oscillations which can occur on the load bus. For example, in Fig. 3-2, the frequency on bus F drops below 57.75 Hz after sufficient load has been shed to start recovery of system frequency. If there was a load shedding step at 57.8 Hz, this load might be shed unnecessarily. In this instance, a time delay of 0.3 second would prevent such operation. While it is not possible to generalize on the amount of time delay to use on all systems, it appears that a 0.3 to 0.4 second time delay will be sufficient in most instances.

Some types of load will require additional time delay in order to prevent unnecessary shedding of load. For example, a load which is tapped on a transmission circuit can experience a gradual decay in voltage and frequency when the transmission line is tripped because of a fault, or for any other reason. The decay may be caused by the characteristic of the line or by the slowing down of motors associated with load. This decay will be sustained long enough to cause operation of high-speed underfrequency relays. A time delay of 0.35 to 0.5 second will usually be sufficient to ride over this condition. If there are only a few loads of this type, it is not necessary to consider this additional time delay in the general load shedding program. These loads would be taken care of on an individual basis.

Procedures

The method of obtaining selectivity can best be described by giving an example of the procedures involved. For example, assume that a load shedding program using static underfrequency relays (Type SFF), is to protect for a 50 percent overload condition. The load is to be shed in four steps and the size of each step will be as follows:

1st step – 10%
2nd step – 10%
3rd step – 15%
4th step – 15%

Load shedding will be initiated at 59.3 Hz and the maximum permissible frequency drop is 57 Hz. For purposes of this discussion a system inertia constant of 5 will be assumed, and the straight line type of decay, shown in Fig. 3-3, will be used. This simplified approach will give pessimistic results but provides a quick insight as to how the program will perform. If the results are marginal, the more accurate representation of the frequency decay can be used.

The minimum time delay required to ride through frequency oscillations will be assumed to be 0.3 second and breaker time will be assumed to be 0.1 second.

1st Load Shedding Step (10%):

Pick-up setting: 59.3 Hz
Relay time delay: 0.3 second
Breaker time: 0.1 second

2nd Load Shedding Step (10%):

The second step must be set so that it will not operate for an overload which only requires shedding by the first step. In other words, for a ten percent overload, the pick-up setting of the second step should be such that the first step of load is shed before the frequency reaches the Step 2 setting. Curve A in Fig. 3-12 shows a ten percent overload condition. The first step relay R_1 picks up at 1.15 seconds and load is shed at 59.05 Hz and 1.55 seconds. The Step 2 relay can be set at 59.0 or slightly lower. In this case, a setting of 58.9 Hz is chosen to provide additional margin. The time setting of this step is also 0.3 second.

3rd Load Shedding Step (15%):

The third step must be set so that it will not operate for an overload which only requires shedding by the two preceding steps. The Step 3 setting can be obtained graphically as before. Curve B in Fig. 3-12 shows a 20 percent overload conditions. The first step will shed load at T_1. The slope of the curve changes at this point. Step 2 will pick-up at 58.9 Hz and shed load at T2 (58.63 Hz). A relay setting of 58.5 Hz is chosen for Step 3 in this instance and the time setting is again 0.3 second.

4th Load Shedding Step:

As before, this step must be set so that it will not operate for an overload which can be alleviated by the preceding three steps. In this case, the setting is determined by assuming a 35 percent overload. Curve C in Fig. 3-12 shows the points where the preceding three steps will shed load. Step 3 will shed load at 58.0 Hz and therefore a setting of 57.9 Hz is chosen for Step 4. Relay time is again set at 0.3 second.

After the settings have been determined, the program is checked for performance under maximum overload conditions (50% overload). Figure 3-13 shows the overall performance under this condition. In this case, the last step of load shedding will take place at 57.35 Hz, well above the permissible minimum of 57 Hz. If load and generation damping are taken into account, all of the required load will be shed at some higher frequency and the system frequency will recover to 60 Hz.

This procedure for obtaining settings is fairly simple and straightforward when static underfrequency relays are used. Since these relays have a definite time characteristic, which is independent of the rate-of-change frequency, it is a simple matter to predict when and how the relay will operate.

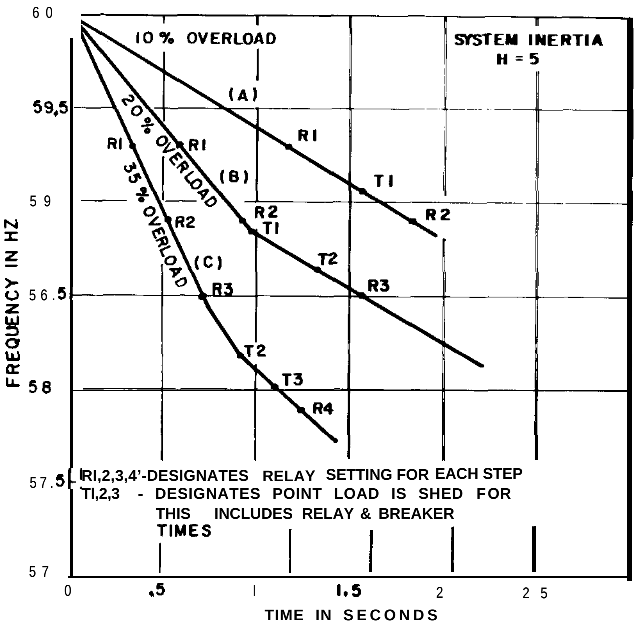

Fig. 3-12 Time-frequency Characteristics used to Determine Settings for SFF Static Under Frequency Relays.

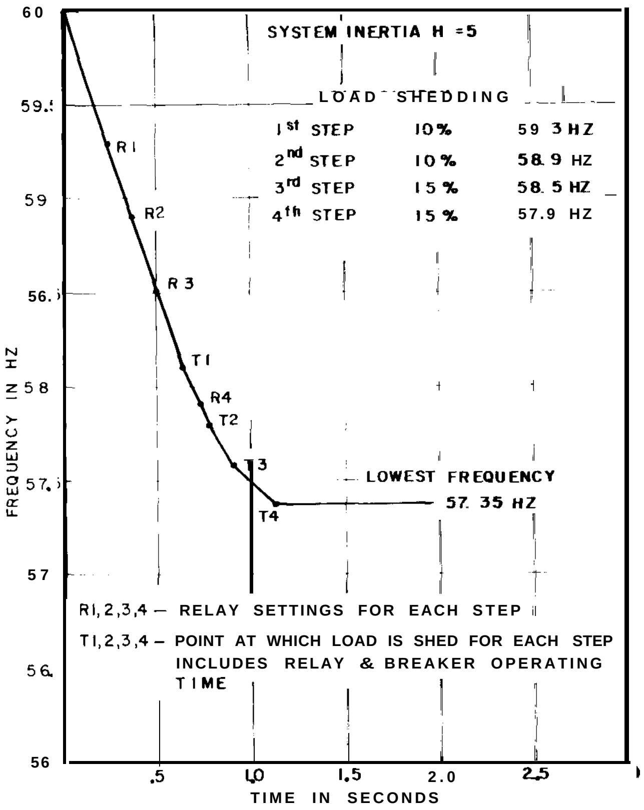

Fig. 3- 13 Load Shedding Program Protecting for 50 Percent Overload – using SFF Static Underfrequency Relay.

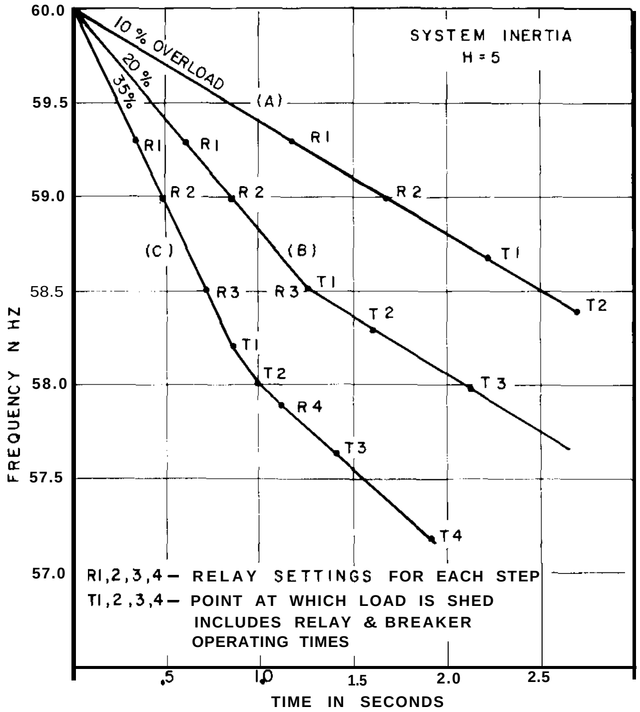

Fig. 3- 14 Time-frequency Characteristics used to Determine Settings for CFF Underfrequency Relays.

Conversely, the procedure is considerably more difficult when using electromechanical type relays, since the operating time of these units is affected by the rate-of-change of frequency. When several load shedding steps are involved, the rate-of-change of frequency will be changing as each step is shed and it is difficult, if not impossible, to predict the exact operating time of the relays in each step. For instance, Fig. 3-14 shows a set of curves used to determine electromechanical relay settings for the same example. Since relay operating times were slow at low rates of change of frequency (see Section 2) the pick-up settings of each step had to be set above the tripping level of the preceding step, and coordination was achieved on a time basis. For example, in Curve A, Step 1 trips at 58.7 Hz and Step 2 relay is set at 59.0 Hz. In this case, the total operating time of Step 2 relay was about 0.9 second so that it was possible to use a 0.5 second coordinating margin. It was necessary to use the above procedure in each step in order to keep the frequency above 57 Hz, under the maximum overload condition. Figure 3-15 shows the performance of the load shedding program for the maximum overload condition. It is of interest to note that Steps 2, 3 and 4 will see various rates of change frequency before tripping occurs. Since it is impossible to predict how the operating time of the relays will be affected by these changes, one alternative is to assume an average rate-of-change and select an operating

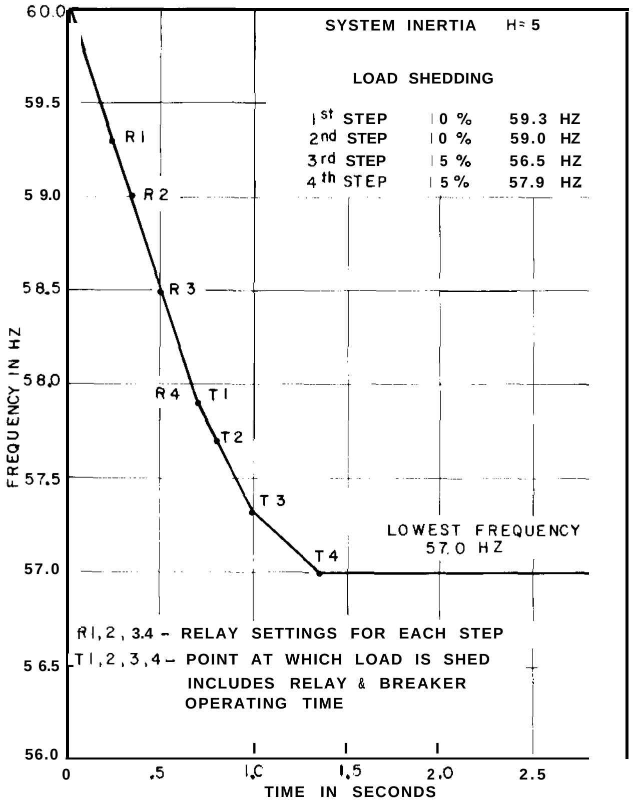

Fig. 3- 15 Load Shedding Program Protecting for 50 Percent Overload using CFF Underfrequency Relays.

time on this basis. Or a more pessimistic approach would be to select an operating time on the basis of the lowest rate-of-change-of-frequency and then determine how this will affect the overall performance of the program.

The preceding paragraphs have outlined one method for obtaining a selective load shedding program. By varying the number of load shedding steps, the amount of load shed per step, and the time delay per step, it may be possible to achieve some other combination of settings which will provide recovery at some higher frequency level. Again, it should be noted that the approach used gave pessimistic results. Generator and load damping effects and speed-governor action will reduce frequency decay and will promote recovery at a higher frequency.

CONCLUSIONS

Automatic load shedding is basically a last resort backup measure. As such, it will be called on to operate only when a highly improbable, potentially catastrophic disturbance occurs. Therefore, if the possibility of complete system collapse is to be avoided during such a disturbance, load shedding should be simple and drastic, rather than elaborate and complex.

Implementing an effective load shedding program is not difficult. Calculations are not complex and extensive system studies are unnecessary. Moreover, new static relays with their greater precision and stability can achieve secure, coordinated, system-wide automatic load shedding and load restoration.

Section 4

PROTECTION OF STEAM TURBINE -GENERATORS DURING ABNORMAL FREQUENCY CONDITIONS

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General Electric Company

presented at
Georgia Tech Protective Relaying Conference in 1974

INTRODUCTION

During recent years, considerable attention has been given to the operation of steam turbine-generators during major system disturbances. In particular the major concern has been with regard to the possible damage of the steam-turbine due to prolonged operation at reduced frequency during a severe overload condition, as might result from a system separation.

To prevent both total system collapse as well as minimize the possibility of equipment damage during these disturbances, considerable effort has been expended in the development and implementation of automatic load shedding programs on electric utility systems. Ideally, these load shedding programs have been designed to shed just enough load to relieve the overload on the remaining generators and thus quickly restore system frequency to near normal. In actual practice this ideal is not always achieved. Considering the possible oscillatory nature of the frequency decay, the variation in the distribution and magnitudes of system loads at different time periods, and the unpredictable load-generation composition of an isolated area it is almost inevitable that either overshedding or undershedding of load may occur during a disturbance.

Overshedding will cause system frequency to overshoot and exceed normal. This condition should be studied to ascertain that the resultant frequency characteristic under a combination of governor and operator action will be satisfactory. In general, overshedding of load poses less serious problems since operator and/or control action can be used to restore system frequency without tripping units.

On the other hand, undershedding of load may raise serious problems. Aside from the possibility of total system collapse, undershedding of load can cause an extremely slow return of frequency to normal, or the bottoming-out of system frequency at some level below normal. In either instance, there exists the possibility of operation at reduced frequency for sufficient time to damage steam turbines. Recognizing this possibility, many utilities have used, or are considering, the application of underfrequency relays and timers to protect steam turbine generators from damage.

It is the purpose of this paper to provide some general guidelines for providing reliable underfrequency protection for a steam turbine generator. The paper reviews the off-frequency capabilities of steam turbine generators, outlines a procedure for obtaining coordinated protection, and describes a number of protective control arrangements for achieving maximum dependability and security.

STEAM TURBINE-GENERATOR OFF-FREQUENCY CAPABILITIES

While both the turbine and generator are limited in the degree of off-frequency operation which can be tolerated, the turbine is the more restrictive since there are mechanical resonances which could cause turbine damage in a relatively short time for small departures in speed. Therefore the following discussion pertains solely to turbine limits.

TURBINE LIMITS

A steam turbine is comprised of many stages of turbine buckets of various lengths and designs, each of which has its own characteristic natural frequencies. This is illustrated in Fig. 4-1, where the three nearly horizontal lines represent resonant frequencies characteristic of one such bucket. The diagonal lines drawn at integral multiples of the running speed, i.e., multiples of once-per-revolution represent the stimulus frequencies inherent in the steam flow. Turbines are carefully designed so that the bucket resonance and stimulus frequencies at rated speed are sufficiently far apart to avoid vibration and excess stress. However, depar-

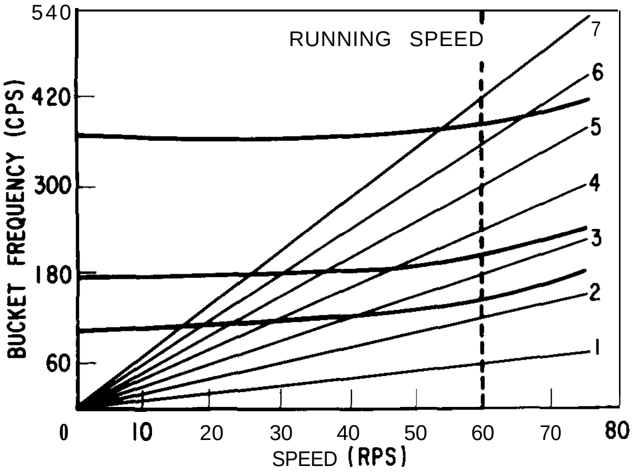


Fig. 4-1 Bucket Vibration Chart.

tures from rated speed will bring the stimulus frequencies closer to one or more of the bucket natural frequencies with resulting higher vibratory stresses. The diagrams in Fig. 4-2 illustrate the phenomena involved in off-frequency operation. Figure 4-2A shows the bucket vibration stress amplitude for a composite of the stages of the turbine as a function of running frequency. Note that as the turbine moves off frequency, the amplitude increases and some damage is accumulated. Stress levels A, B and C in Fig. 4-2A are also marked in Fig. 4-2B, which shows a typical fatigue strength curve for bucket structures. Note that below level A, the vibration stress amplitude is low enough that the buckets can run indefinitely without any damage. Operation at stress level B would product a failure in 10,000 cycles of vibration and at a still higher stress level C, failure would occur at 1,000 cycles. If there is a mixture of operation at stress level B and stress level C, a life fraction rule is used to determine the number of cycles which would result in failure.

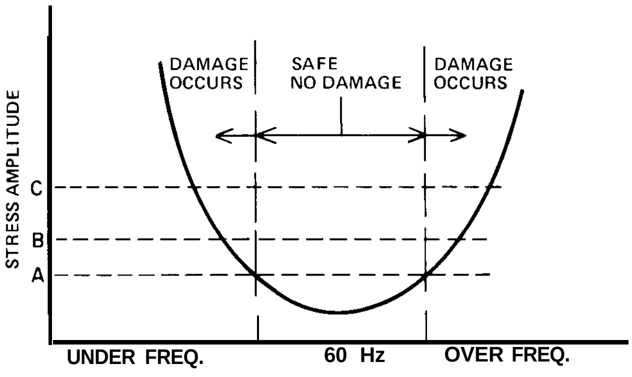


Fig. 4-2A increase in Vibration Amplitude with Off-frequency Operation.

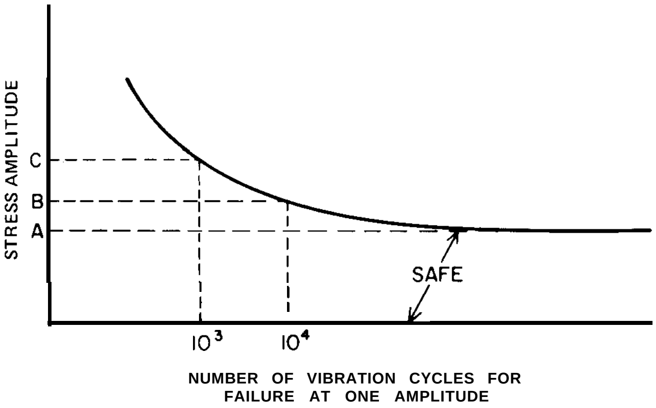


Fig. 4-2B Stress vs Number of Cycles to Failure.

An examination of a large amount of vibration frequency data for different turbine stages leads to the recommended time limits for off-frequency operation given in Fig. 4-3. This curve represents the estimated minimum time to cracking of some parts of the bucket structure, most likely the tie wires or bucket covers. While tie wire and bucket cover cracks are not in themselves catastrophic failures, they change the vibration behavior of the bucket assembly so that it is likely to have natural frequencies closer to running speed, which may produce bucket fatigue failure under normal running operation.

Figure 4-3 shows both the overfrequency as well as the underfrequency time limits for a steam turbine throughout the load range. This diagram illustrates that at frequency departures of five percent or more, the times to damage become very short and it is not practical to plan on running more than a few seconds in this range. A minimum allow-

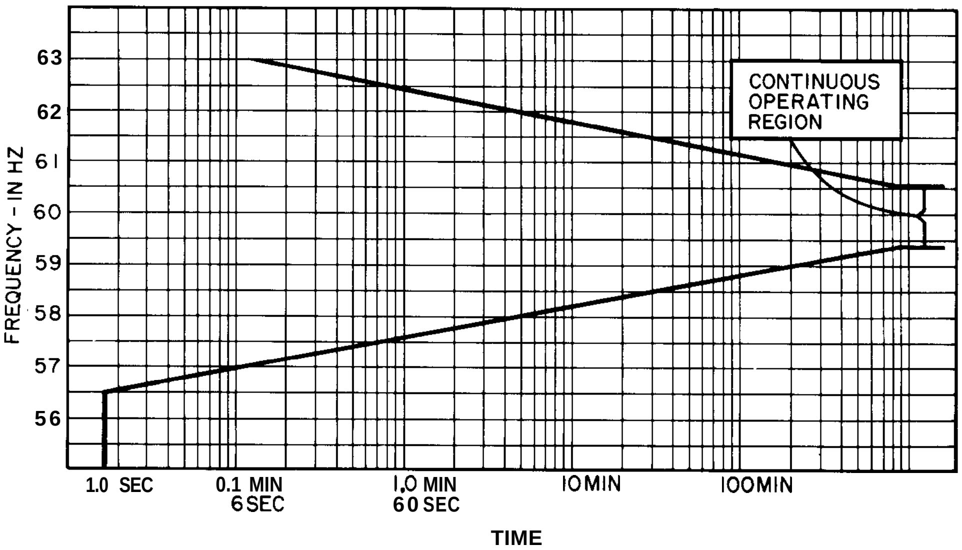


Fig. 4-3 Turbine Off-frequency Limits.

able time of one second applies to the extreme lower frequencies. At the near-rated frequency end, the curves may be seen to flatten, indicating that a change of frequency of one percent to 59.4 Hz (or 60.6 Hz) would not have any effect on bucket life.

It is important to note also that the effects of off-frequency operation are cumulative. For example, two or three minutes of operation at 58 Hz would leave two minutes of remaining tolerance for operation at that frequency. Cumulative effect applies as well to a mixture of off-frequency operations, i.e., whatever life reduction was accumulated in an underfrequency event applies across the range of frequencies.

The most frequently encountered overfrequency condition is that of a sudden load rejection resulting from a generator breaker trip. Under these conditions, the governor droop characteristic may permit a steady state speed as high as 105 percent to be held following the transient speed rise, and therefore speed reduction to near rated should be initiated promptly. For the type of sudden load reduction described, units equipped with modern EHC control provide this speed reduction function automatically.

For instances of partial load reduction on the turbine-generator, such as might accompany a system isolation, the frequency held by the governors in the isolated system would be along some average droop characteristic. In other words, assuming a 5 percent droop characteristic, a load reduction of 50 percent of rated would cause a 2½ percent rise in frequency. Referring to Fig. 4-3, the operating time limit at this frequency is about 35 minutes, which is within the practical range for operator action to reduce speed settings. For higher frequencies, automatic control action, such as use of an overfrequency relay to initiate runback of the governor load reference should be employed.

Underfrequency operation of a steam turbine becomes the more critical area since the operator does not have the option of control action. For that reason, the emphasis should be placed on the methods to protect the turbine in the underfrequency range.

UNDERFREQUENCY PROTECTION FOR STEAM TURBINES

Being aware of the underfrequency vs time to damage characteristic previously discussed and shown in Fig, 4-3, a comprehensive protective scheme can be developed to protect the turbine for any system underfrequency contingency.

Establishing underfrequency protection for the turbine is not simple since it requires some knowledge of system behavior and the performance of the load shedding program during system disturbances. The protection procedure requires the coordination of essentially a definite time relay characteristic with a varying turbine capability curve. Moreover, since the effects of subnormal frequency operation are cumulative, this introduces another variable - previous history. If a machine has been operated at reduced frequency for a considerable period of time in the past, the relay operating times at present and in the future may have to be reduced accordingly.

PROTECTION PROCEDURE

The procedure for developing turbine underfrequency protection is relatively straightforward. Since the permissible operating time of the turbine at reduced frequency decreases with decreasing frequency, it may be desirable to use a number of steps of underfrequency relay and timer settings to protect the turbine. The protection should be down to some frequency level where it can be assumed the system area is lost and, therefore, it would be desirable to isolate the generating unit. Ideally, the number of underfrequency relay and timer steps should be selected so that the stresses on the turbine are minimized for any prolonged underfrequency condition, and yet provide long enough operating times so that no generator is tripped unnecessarily for a disturbance from which the system could recover. In general, in order to accomplish this, four or five steps of protection may be required to meet this criterion.

The procedure for developing this ideal protective scheme can be best illustrated by an example. For purposes of this discussion, assume that turbine underfrequency protection is to be provided on a system where 33 percent of the generation can be lost during the worst system disturbance, and that a four step load shedding program using static underfrequency relays is used to protect the system for this overload condition. Figure 4-4 shows a calculated time-frequency characteristic of the system and the performance of the load shedding program for this contingency. In this case, the system frequency would decrease to 57.7 Hz but will return to above 59.4 Hz in about 8 seconds after the disturbance had occurred.

Because of the extreme frequency dip possible in this instance, it is decided to use five steps of static underfrequency relays and timers to protect the turbine. This number was selected in order to maximize the required timer settings.

The underfrequency relay protective levels selected and their function are shown below:

	Underfrequency Setting	Function
f l	59.0 Hz	Time delay Trip - T1
f2	58.5 Hz	Time delay Trip - T2
f3	58.0 Hz	Time delay Trip - T3
f4	57.5 Hz	Time delay Trip - T4
f5	57.0 Hz	Direct trip

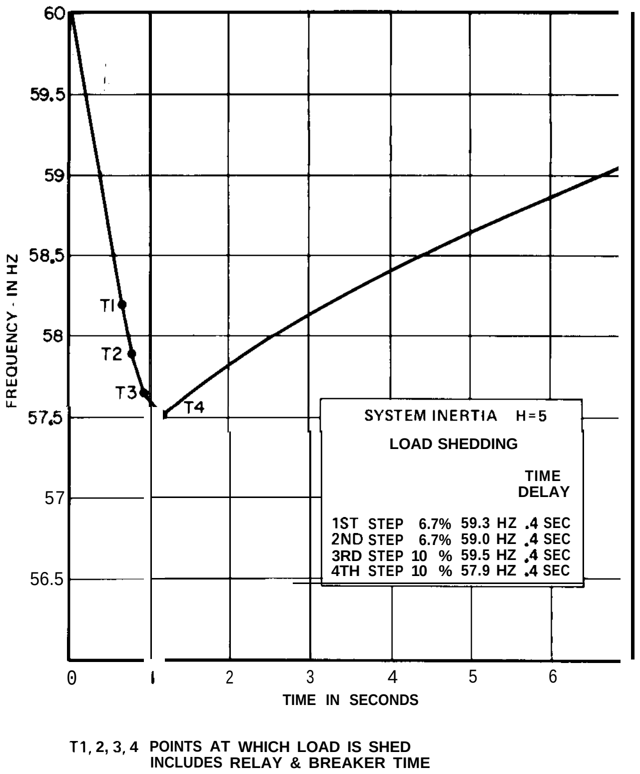


Fig. 4-4 System Load Shedding Program Protecting for a 33 Percent Loss of Generation with System at Full Load.

The first underfrequency step is set at 59 Hz. Above this level, the permissible turbine operating time varies from a minimum of 3.3 hours up to continuous operation at 59.4 Hz. If the frequency should bottom-out in the range of 59 to 59.4 Hz, there should be sufficient time for an operator to remedy the condition.

The 59 Hz underfrequency step provides protection over the frequency range of 59 Hz to 58.5 Hz. The timer setting T1 is determined by the time to damage at the frequency of the next lower step, which in this case, is 58.5 Hz. This assumes that for some disturbance the frequency may bottom-out just above 58.5 Hz. In addition, in selecting this or any time setting, the user will have to decide how much loss of life he is willing to accept for any one disturbance. It should be recalled that the damaging effects of underfrequency operation are cumulative and therefore the loss of life during any one disturbance should be small enough so that the availability of the steam turbine-generator is not affected. In this example, it was decided to accept a 10 percent loss of life and, hence, from Fig. 4-3, the timer setting Tl was set at 3 minutes which is equal to 10 percent of 30 minutes at 58.5 Hz.

For the subsequent underfrequency steps, f2 provides protection for the frequency range 58.5 to 58.0 Hz, f3 protects over the range 58.0 to 57.5 Hz, and f4 protects over the range of 57.5 to 57.0 Hz. The time settings for each step (58.5, 58, 57.5 Hz) are determined, as discussed previously, by using 10 percent of the time to damage at the frequency of the next lower step. The resulting time settings are:

	Underfrequency Setting	Timer Setting 10% Loss of Life
f1	59 Hz	T1 = 3 min.
f2	58.5 Hz	T2 = 30 sec.
f3	58.0 Hz	T3 = 5 sec.
f4	57.5 Hz	T4 = 0.7 sec.
f5	57.0 Hz	Direct trip

The last step, 57 Hz, is essentially last ditch protection to prevent turbine damage for some unpredictable extreme overload condition (50 - 75% loss of generation) from which the system can not recover. In general, it is desirable to provide this last ditch protection on all generators.

Once the underfrequency relay and timer settings are established, the performance of the protective scheme should be checked for the worst system disturbance; that is, the disturbance that requires maximum load shedding to save the system. This should produce the severest frequency dip and the longest recovery time and, therefore, the greatest likelihood of tripping the generators unnecessarily. The greatest possibility of unnecessary generator tripping will occur at the low frequency settings (57, 57.5, or 58 Hz) since the required time settings will be low. If unnecessary tripping can occur, the load shedding should be increased to reduce the extreme frequency dip and the recovery time.

For the example presented here, all timer settings are above the expected time at any frequency level during the disturbance. For example, as shown in Fig. 4-4, the system frequency remains at 58 Hz for only 1.75 sec., at 58.5 Hz for 3.8 seconds and at 59 Hz for 6.2 seconds. All are well below the timer settings. While the calculated frequency characteristic does not go below 57.5 Hz, the actual frequency decay may be oscillatory and there may be a momentary dip below 57.5 Hz. The 0.7 second setting of the relay at this level should be sufficient to ride over this dip.

It should be noted that the required timer settings are a function of both the acceptable loss of life and the number of underfrequency steps used. The effect of using a different loss of life is shown below.

	Underfrequency Setting		Timer Setting 5% Loss of Life	20% Loss of Life	50% Loss of Life
f1	59 Hz	T1	1.5 min.	6 min.	15 min.
f2	58.5 Hz	T2	15 sec.	1 min.	2.5 min.
f3	58.0 Hz	T3	2.5 sec.	IO sec.	25 sec.
f4	57.5 Hz	T4	0.35 sec.	1.4 sec.	3.5 sec.
f5	57.0 Hz			Direct trip	

It should be apparent that with a lower acceptable loss of life, the timer settings will be lower and therefore there would be an increased possibility of unnecessary generator tripping. Conversely, the use of a higher acceptable loss of life provides higher timer settings and more security but increases the possibility of turbine damage.

A reduction in the number of underfrequency steps used also increases the possibility of unnecessary generator tripping. For example, for the system shown in Fig. 4-4, assume that only three turbine underfrequency protective steps are to be used. These would be 59 Hz, 58 Hz and 57 Hz. The required timer settings would now be:

	Underfrequency Setting	Timer Setting 10% Loss of Life
f1	59 Hz	30 sec.
f2	58 Hz	0.7 sec.
f3	57 Hz	Direct trip

With these settings, the 58 Hz relay would have tripped unnecessarily for the conditions shown in Fig. 4-4. This situation could be alleviated by increasing the load shedding so that the frequency dip does not go below 58 Hz.

In developing underfrequency protection for a particular system, the user should consider and evaluate such factors as the probability of having a major system overload condition, the expected performance of the system load shedding program, the loss of life that would be acceptable for any one disturbance, and the desired reliability of the turbine underfrequency protection. As noted, ideal protection for the turbine may require the use of four, five, or perhaps even more steps of underfrequency relays and timers to provide long enough relay operating times so that no generator is tripped unnecessarily. This approach would provide comprehensive protection but the protective arrangement could become rather complex because of the number of relays required. The use of fewer underfrequency steps (two or three steps) would provide a simplier protective arrangement, but the resulting lower relay operating times may cause unnecessary tripping of generators during a major disturbance. Considering all of these factors, the user will have to evaluate the advantages and disadvantages of various approaches and select a scheme that best meets his system requirements.

EFFECT OF CONNECTIONS ON RELIABILITY

Any device employed to trip a generator off the system, particularly at a time when the system may be deficient in generation must be applied judiciously. It is the objective of the following paragraphs to describe and discuss several possible arrangements of underfrequency relays and associated timers that may be considered to achieve maximum dependability and security.

To be considered satisfactory, any protective arrangement should satisfy the following basic requirements:

1. It should provide adequate protection of the turbine-generator during reduced-frequency operation by tripping correctly at the selected frequency and timer settings (dependability).
2. It should not trip for any other reason under any reasonable circumstances, including failure of a device to function properly (security).

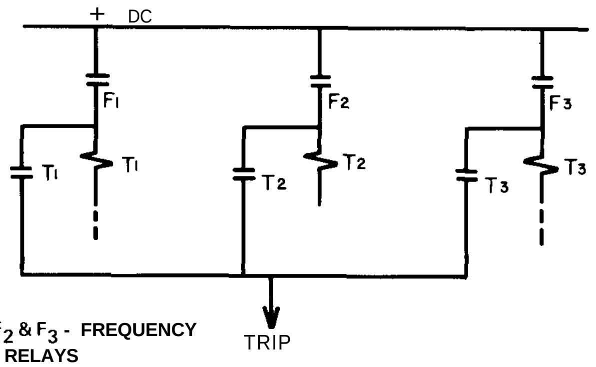
Although conditions 1 and 2 above tend to be mutually limiting, it is important to seek an arrangement that minimizes this interdependency.

To simplify the discussions, only three frequency levels have been assumed. It is recognized that this does not relate directly with the preceding discussions, nor necessarily with the protective arrangement adopted by the user.

UF RELAY SETTING	TIMER SETTING
F1	T1
F2	T2
F3	T3

In this tabulation it is assumed that frequency F1 is higher than F2, and that F2 is higher than F3; it is further assumed that time T1, is longer than T2, and that T2 is longer than T3. The ideas presented here could then be applied regardless of the number of steps employed.

A number of possible arrangements of underfrequency relays and timers are illustrated in the accompanying figures and discussed in the following paragraphs. In order to minimize effects on the system from a misoperation, it is recommended in all cases that the application be on a "per machine" basis.



F_1, F_2 & F_3 - **FREQUENCY RELAYS**

T_1, T_2 & T_3 - **TIMERS**

Fig. 4-5 Three Step Underfrequency Protective Scheme using One Relay & One Timer per Step.

PROTECTIVE ARRANGEMENTS

A possible arrangement for providing protection at three frequency steps using three frequency relays and timers is illustrated in Fig. 4-5. The underfrequency relay at each frequency level is shown as initiating tripping via an associated timer. In practice the user might elect to use the outputs differently. For example, the F1 level might be used to alarm only, the F2 level to trip via the timer, and the F3 level for direct trip.

While the typical arrangement in Fig. 4-5 is simple, and might be acceptable functionally, the scheme tends to lack dependability and security. For example, incorrect operation of any one of the underfrequency sensing relays could result in eventual operation of its associated timer and incorrect trip of the machine. Or a failure of one of the relays or timers to operate could prevent or delay a correct trip of the machine.

Some gain in security could be realized by "cascading" the frequency relay contact connections as shown in Fig. 4-6, which reduces the chance of a single failure causing an incorrect trip. However, this security is gained at the expense of dependability since the failure of relay F1 would eliminate all protection. Moreover, it should be noted that if the frequency were to fall below the setting of relay F1, and then if relay F2 operated incorrectly at that frequency, a trip output would occur in a shorter time than intended.

An increase in security from the standpoint of the frequency relay itself could be realized by connecting the contacts of two (or more) frequency relays in series to operate the timer at each desired frequency step, as illustrated in Fig. 4-7. The circuit shown here would be substituted for each frequency relay (F1, F2 and F3) in Fig. 4-5. It is apparent, however, that in improving security in this manner, dependability has been sacrificed because the failure of any one of the relays to operate when it should, would prevent a desired correct removal of the machine at that frequency level. An alternative to Fig. 4-7 would be to have each frequency relay operate a separate timer, as shown in Fig. 4-8, with the timer contacts connected in series. But again a failure of any one relay or timer to operate would jeopardize correct operation of the scheme. In fact this case is less dependable than that of Fig. 4-7 since two relays and two timers have to function properly to effect a trip.

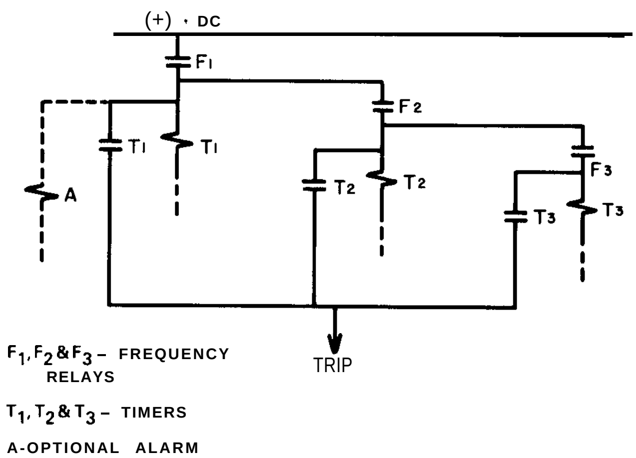


Fig. 4-6 Three Step Underfrequency Protective Scheme with Cascaded Connection of Underfrequency Relay Contacts.

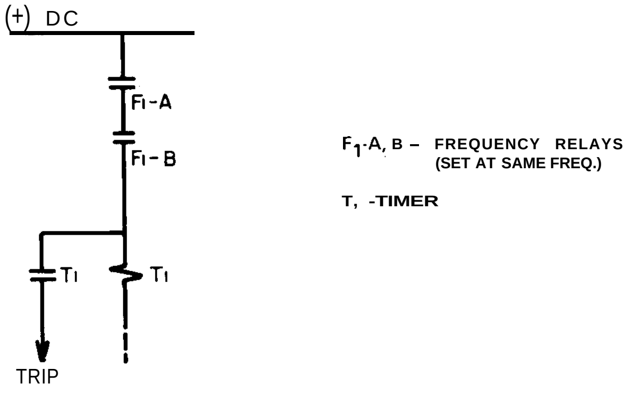


Fig. 4-7 Series Connection of Underfrequency Relay Contacts. Two Relays & One Timer per Step.

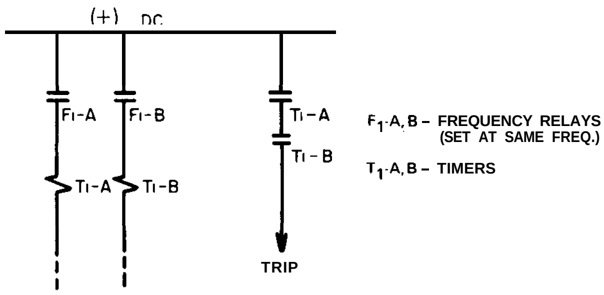


Fig. 4-8 Series Connection of Timer Contacts. Two Relays & Two Timers per Step.

If the arrangements in Figs. 4-7 or 48 represent a high degree of security, achieved at the expense of dependability, then the arrangement in Fig. 4-9, where the contacts of two or more UF relays are in parallel, represents a high degree of dependability, but achieved now at the expense of security. A similar arrangement using separate timers for each frequency relay is another possibility.

Since a high degree of both security and dependability is desired, the user may want to consider a scheme that combines the advantages of the circuits shown in Figs. 4-7 through 4-9. The diagram in Fig. 4-10 shows one possible method. Here the contacts of four UF relays, all set at the same frequency (Fl), are connected in a series-parallel arrangmenet to energize the timer T1. An incorrect opera-

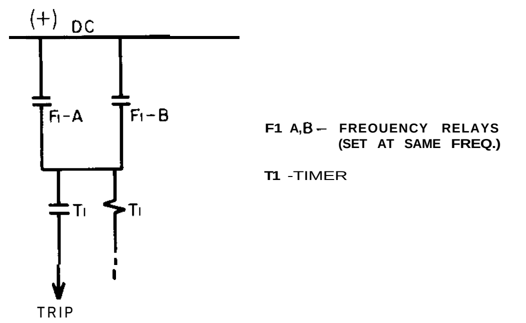


Fig. 4-9 Parallel Connection of Underfrequency Relay Contacts. Two Relays & One Timer per Step.

tion of one of the UF relays will not cause an incorrect trip, nor will a failure of any one to operate prevent a desired trip. Some users might prefer to use two separate timers with this scheme. The combination would have to be repeated with a separate timer (or timers) for each frequency step desired.

Similar results can be accomplished at lower cost by means of an "auctioning" circuit, as shown in Fig. 4-11. This circuit is arranged so that operation of any two of the three frequency relays A, B, or C at the set frequency will initiate a trip via the timer. An incorrect operation of any one of the relays (A, B, or C) will not cause an incorrect trip, and a failure of any one of the relays (A, B, or C) will not prevent a desired trip. It should be noted that the use of a single timer common to the autioning circuits tends to reduce both dependability and security. Dependability is reduced because failure of the timer will prevent a desired trip even though the underfrequency relays in the autioning circuit performed correctly. Security is reduced because if the timer should fail in the operated position, coordination with the load shedding program would be lost on a subsequent operation of the underfrequency relays.

In the alternate scheme shown in Fig. 4-12, a separate timer, T_A T_B and T_C, is provided for each of the frequency

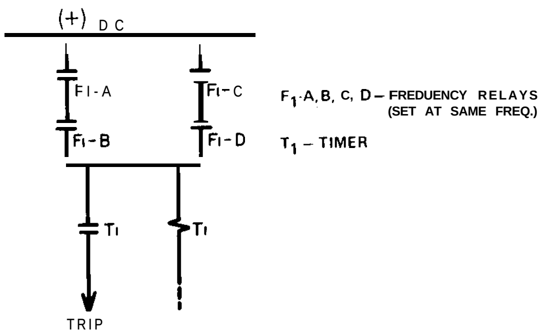


Fig. 4- 10 Series – Parallel Connection of Underfrequency Relay Contacts. Four Relays & One Timer per Step.

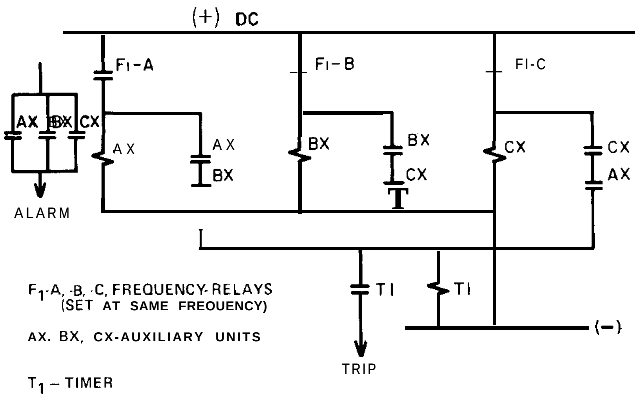


Fig. 4-11 Auctioning Circuit using Three Relays & One Timer per Step.

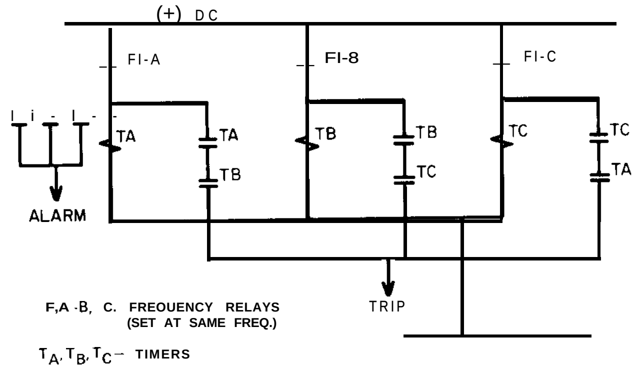


Fig. 4-12 Auctioning Circuit using Three Relays & Three Timers per Step.

relays A, B, and C. As in the previous scheme, incorrect operation of any one relay or timer will not cause an incorrect trip, and a failure of any one device to operate, either a relay or timer, will not prevent a desired trip.

In the schemes illustrated in Figs. 4-11 and 4-12, an alarm function would be used to detect a circuit that failed in the trip mode. If the underfrequency relay used in any of the schemes described is equipped with a seal-in device, care must be taken that this device does not operate on the current drawn by the timer or auxiliary unit. For example, in Fig. 4-12 it is obvious that if the seal-in units were tc operate on the timer current, even though the frequency recovered and the frequency relays reset, the timers would continue to operate and an incorrect trip would occur via the seal-in contact.

The circuit arrangements described above are offered as possible means of protecting a machine from damage at various levels of reduced frequency, with varying emphasis on dependability and security. Obviously many other circuit arrangements are possible. It is anticipated that the user will want to study each installation and develop a scheme which best suits his specific requirements.

APPENDIX I

FREQUENCY CHARACTERISTIC CONSTANT LOAD AND GENERATING TORQUES

The relationship which defines the variation of frequency with time after a sudden loss of generation is derived from the basic equation for the motion of a rotating machine. This equation is:

$$\frac{H}{\pi f_o}\frac{d^2\delta}{dt^2} = T_G - T_L = T_a \qquad (1)$$

where

H = generator inertia constant

f_o = base frequency

δ = electrical displacement angle

T_G = per unit mechanical torque

T_L = per unit electrical torque on TG base

T_a = net accelerating torque

The velocity of the machine is given by the expression

$$\frac{d\delta}{dt} + \omega_o = 2\pi f \qquad (2)$$

where

ω_o = synchronous velocity

f = actual frequency

Taking the derivative of both sides of the equation with respect to time, the equation becomes

$$\frac{d^2\delta}{dt} = 2\pi \frac{df}{dt} \qquad (3)$$

Substituting equation (3) in equation (I), and rearranging

$$\frac{df}{dt} = \frac{(T_G - T_L)\, f_o}{2H} \quad \frac{T_a f_o}{2H} \qquad (4)$$

This expression can be used to give system frequency when there is sudden change in generation and when generator and load torques remain constant.

In this case

$\frac{df}{dt}$ = rate-of-change of frequency in Hz/sec.

H = system inertia constant. This is equal to the sum of all of the generator inertia constants in per unit on the total remaining generation base.

T_G = per unit torque of the remaining system generation.

T_L = per unit load torque on the remaining system generation base.

T_a = net accelerating torque. When $T_G > T_L$, T_a is positive and accelerating. When $T_G < T_L$, T_a is negative and decelerating.

Since T_a is constant, this equation represents a straight line, (starting at 60 Hz at t = 0), having a slope of $\frac{T_a f_o}{2H}$

APPENDIX II

FREQUENCY CHARACTERISTIC VARIATION OF LOAD AND GENERATOR TORQUES WITH FREQUENCY

LOAD TORQUE

Load power will vary directly as some power of frequency

(1) $$P_L = kf^{D_L}$$

where

P_L = per unit load power

k = constant

f = frequency

D_L = factor which is a function of the composition of the load

Per unit load torque (T_L) is equal to load power divided by frequency

$$T_L = \frac{P_L}{f} = \frac{kf^{D_L}}{f}$$

(2) $$T_L = kf^{D_L - 1}$$

For small changes in frequency, the load torque may be obtained by the following procedure:

$$T_L = kf^{D_L-1}$$

$$\frac{dT_L}{df} = (D_L - 1)\, kf^{D_L-2}$$

$$\Delta T_L = (D_L - 1)\, kf^{D_L-2}\Delta f$$

$$T_L + \Delta T_L = kf^{D_L-1} + (D_L-1)\, kf^{D_L-2}\Delta f$$

$$= kf^{D_L-2}\,[\, f + (D_L - 1)\Delta f\,]$$

$$= \frac{kf^{D_L-1}}{f}\,[\, f + (D_L - 1)\Delta f\,]$$

substituting $kf^{D_L-1} = T_{Lo}$

$$T_L + \Delta T_L = T_{Lo}\,[\,1 + (D_L - 1)\, f'\,]$$

Then

(3) $$T_L = T_{Lo}\,[1 + (D_L - 1)\, f'\,]$$

where

$f' = \frac{\Delta f}{f}$ = per unit change in frequency.

f' is negative for a change below 60 Hz

f' is positive for a change above 60 Hz

D_L = function of load composition – damping factor

T_{Lo} = initial per unit load torque

T_L = per unit load torque after a per unit frequency change of f'.

GENERATOR TORQUE

Generator torque varies inversely as the first power of frequency

(4) $$T_G = \frac{k}{f} = kf^{-1}$$

For small changes in frequency, the load torque can be obtained by using the procedures described in the preceding section. The result will be

(5) $$T_G = T_{Go}(1 - f')$$

where

f' = per unit change in frequency

f' is negative for a change below 60 Hz

f' is positive for a change above 60 Hz

T_{Go} = initial per unit generator torque

T_G = per unit generator torque after a per unit frequency change off'.

FREQUENCY VARIATION WITH TIME

From Appendix I, equation (4) gives

$$2H\frac{df'}{dt} = T_a = T_G - T_L$$

in substituting the torque expressions in this equation

$$2H\frac{df'}{dt} = T_{Go}(1 - f') - T_{Lo}[1 + (D_L - 1) f']$$

$$= T_{Go} - T_{Lo} - [T_{Go} + (D_L - 1) T_{Lo}] f'$$

Let $D_T = T_{Go} + (D_L - 1) T_{Lo}$ **= total damping factor**

$$2H\frac{df'}{dt} + D_T f' = T_{Go} - T_{Lo} = T_a$$

The solution of this differential equation is

$$f' = \frac{T_a}{D_T}\left[1 - \epsilon^{-\frac{D_T}{2H}t}\right] \qquad (6)$$

where

f' = **per unit change in frequency**

T_a = **accelerating torque in per unit on remaining generation base.**

D_T = **total damping factor**

H = system inertia constant. This is the inertia of remaining system generation on the remaining generation base.

The change in frequency (f') times base frequency (f_o) gives the change in Hz. If T_a is negative, the change in frequency will be negative and the frequency at any instant of time will be equal to (f_o – f).

The preceding assumes that the frequency decay starts at 60 Hz. The frequency decay starting at some other frequency level (after some load has been shed) can be obtained using the same expression. In this case, the net accelerating torque at the new frequency must be determined using the generator and load torques equations. To illustrate this procedure consider the curves in Fig. 3-9. The initial overload was 20 percent. The initial frequency vs time curve was calculated assuming the following:

Initial generator torque = 1.0

Initial load torque = 1.2

System inertia constant H = 5

Generator damping = 1

Load damping = 1.5

Total damping = $D_T = [T_G + (D_L - 1) T_L] =$ **1.6 (initial)**

Accelerating torque = .-0.2

Substituting the above quantities in equation (6) will give the initial frequency variation with time.

At 58.9 Hz, ten percent of the overload is shed. The accelerating torque after load has been shed can be obtained as follows:

1. **At 58.9 Hz, the frequency change is-1.1 Hz which is equal to (-0.018350 per unit change.**

2. **The total load torque just.before load is shed is**

   T_L = 1.2 [1 – (1.5 – 1) (-0.01835)]

   T_L = **1.189 per unit.**

3. **The equivalent load shed at 58.9 Hz is not ten percent, but some lower value. The equivalent load shed is**

   T_{SL} = 0.1 [1 – (1.5 – 1) (-0.01835)]

   T_{SL} = **0.0991**

4. **After load is shed the net load torque is**

   $T_{L\,net} = T_L - T_{SL}$

   $T_{L\,net}$ = **1.0899**

5. **Generator torque at 58.9 Hz is**

   T_G = 1.0 [1 -(-0.01835))

   T_G = **1.01835**

6. **The accelerating torque T_a after load is shed is**

   $T_a = T_G - T_{L\,net} = [1.01835 - 1.0899]$

   T_a = **-0.07153**

7. The total damping factor at 58.9 Hz is

$$D_T = [T_G + (D_L - 1) T_L]$$

$$= [1.01835 + .5 (1.0899)]$$

$$D_T = 1.563$$

Substituting the new DT and T_a in equation (6), the change in frequency is obtained. The change in frequency thus obtained is subtracted from 58.9 Hz to obtain the new curve.

At 58.65 Hz another ten percent load is shed. The new accelerating torque can be determined using the procedures described above.

The frequency change is 58.9 – 58.65 = 0.25 Hz

The initial load torque = 1.0899

The initial equivalent load torque to be shed = 0.0991

The initial generator torque = 1.01835

Using the procedures in Steps 2 through 7 above, the new accelerating torque and D_T is derived. In this instance, the net T_a is positive and therefore the system frequency will begin to recover as shown in Fig. 3-9.

This step by step procedure can be used to obtain the frequency decay curves for any degree of overload and for any number of load shedding steps.

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