LOAD-FREQUENCY CONTROL

OF INTERCONNECTED POWER SYSTEMS

A Thesis

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Abstract of Thesis Entitled

LOAD FREQUENCY CONTROL

OF INTERCONNECTED POWER SYSTEMS

A study is carried out into the principal factors involved in the load and frequency control of interconnected power systems. Expressions are developed to give the magnitude of deviation of tie-line power flows and system frequency during times of disturbance in terms of power system and control system parameters. Further expressions are developed to indicate the quality of control likely to be achieved with the given set of parameters.

The results of tests carried out on the load-frequency controls of the Saskatchewan-Manitoba-Northwestern Ontario power interconnection are included and are compared where possible to the theories presented and the expressions developed.

K. H. Williamson,
March, 1962.

PREFACE

The interconnections of power systems evolve in the interests of improved economy, reliability, flexibility and performance. The attainment of these goals is dependent to a large extent upon the performance of the so-called load-frequency or supplementary controls located in the various member areas. The prime function of these controls is to maintain tie-line power flows and system frequency at the scheduled values both during normal operation and during system disturbances. It is desirable, if not mandatory, that these supplementary controls carry out their function rapidly, smoothly and with a minimum of interaction.

The purpose of this study is to assemble and review the principal factors involved in the load-frequency control operation. In the first chapter, the essential parameters involved are defined and expressions are developed in terms of these parameters to give the maximum deviations of system frequency, tie-line power flow and generation imposed by the load-frequency controls as a result of system disturbances. Further expressions, in terms of the same parameters, are developed to indicate the stability tendency of the control systems and controlled generation in the recovery process after system disturbances have occurred. An outline of the more popular supplementary controllers is included.

A description of the design principles of Manitoba Hydro's load-frequency controls is contained in Chapter II as an example of an application of the theories described herein and in the interests of providing a clearer picture of the test results outlined in Chapter III.

Chapter III contains some of the more pertinent results obtained during the commissioning of Manitoba Hydro's load-frequency controls. Confirmation by these tests of the theories presented and expressions developed is the aim of this chapter.

The author is indebted to the following for their suggestions, comments, contributions and interest in the material presented:- Professor G.W. Swift of the University of Manitoba, Mr. H. Kaldor of the Saskatchewan Power Corporation, Mr. G.W. Jackson of the Ontario Hydro, and Messrs: L.M. Hovey, L.A. Bateman, E.M. Scott, C.E. Birston, J.T. Atchison and J.G.B. Iliffe, all of Manitoba Hydro. Thanks are also extended to Mr. R. Fleming for much of the draughting involved and to Miss Lorna Jensen who typed the manuscript.

TABLE OF CONTENTS

LIST OF FIGURES

FIGURE PAGE*

*Page number of facing printed page.

FIGURE PAGE *

TABLE

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*Page number of immediately preceding printed page.

**Actual page number.

CHAPTER I

LOAD-FREQUENCY CONTROL THEORY

I - ADVANTAGES OF INTERCONNECTION

The interconnection of power systems creates, in effect, a single larger system with the greater economies, reliability, flexibility, and overall regulation that a larger system implies. In providing a degree of these advantages for itself, the member systems singly would have to provide greater generation reserves.

In a paper presented recently, the principle of interconnection was expanded to apply to Canada as a whole.[1*] The savings obtained due to the effect of diversity and reduction in reserve capacity amounted to some 2300 mW.** This was based upon the anticipated national capacity requirement in 1965 of some 24,000 mW. The capacity saving, therefore, would be nearly 10%. Another paper, utilizing probability methods, indicates that the capacity savings available to the five member systems due to their mutual interconnection amounted to between 6 and 25%.[2]

In 1956, Manitoba Hydro (MH) and the Northwestern Region of the Hydro Electric Power Commission of Ontario (HEPCO) interconnected their respective systems by means of an existing 83 mile, 138 kV, single circuit tie-line. Three years later, a 170 mile, 230 kV line, to be operated

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*Raised numerals designate references contained in the Bibiography on Pages 79-81.

**See Appendix A on Pages 69-71 for the definition of abbreviations and terms.

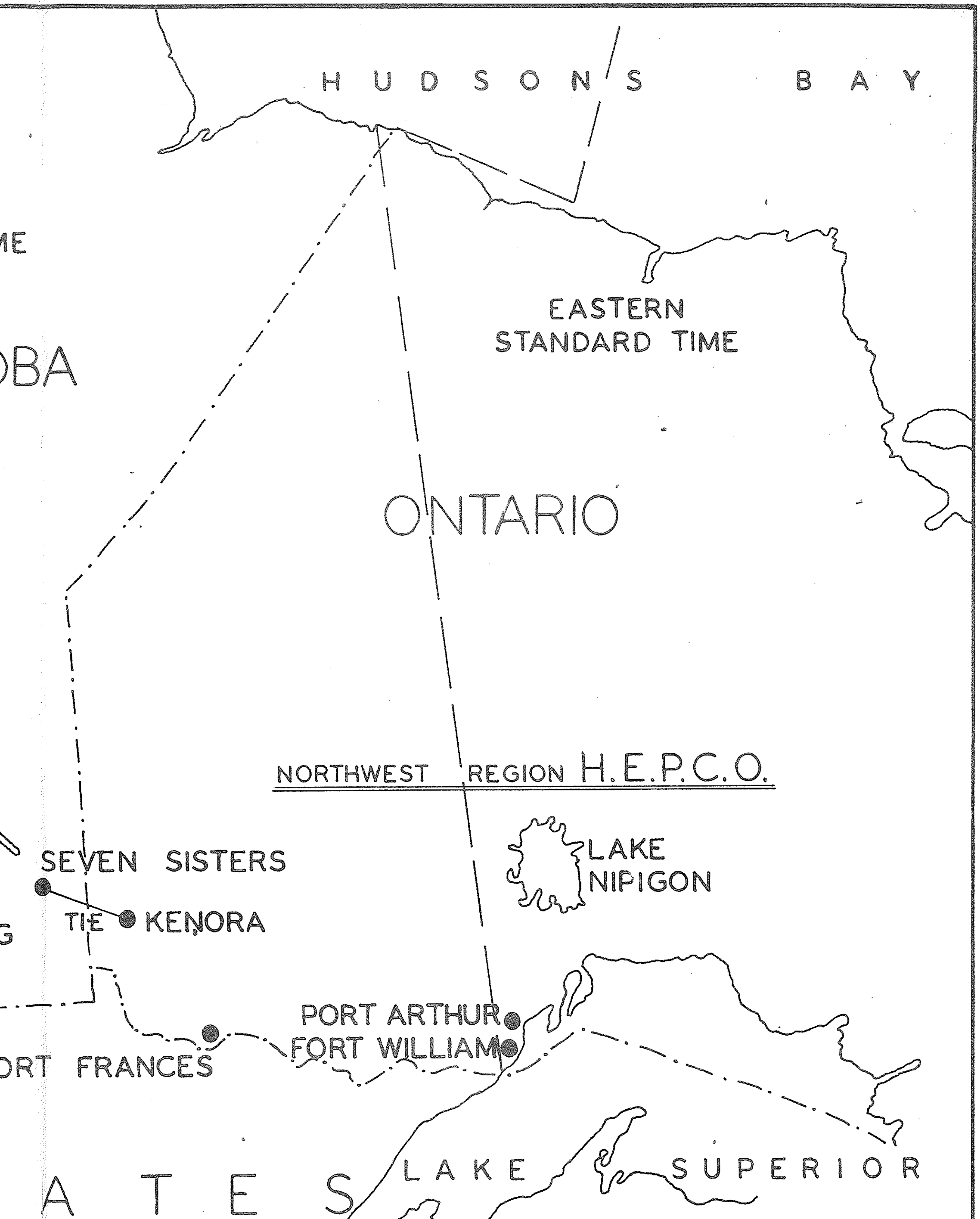
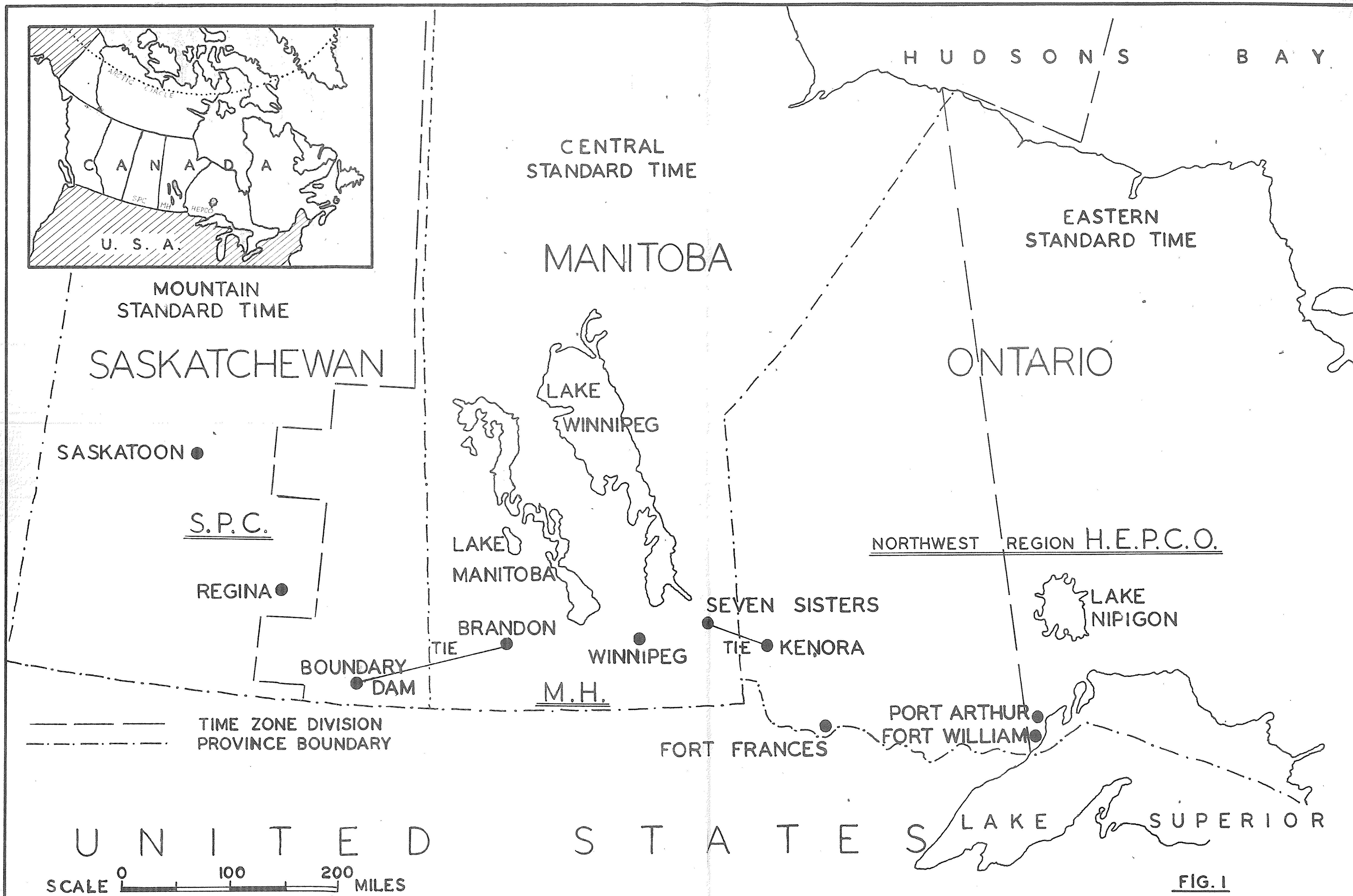
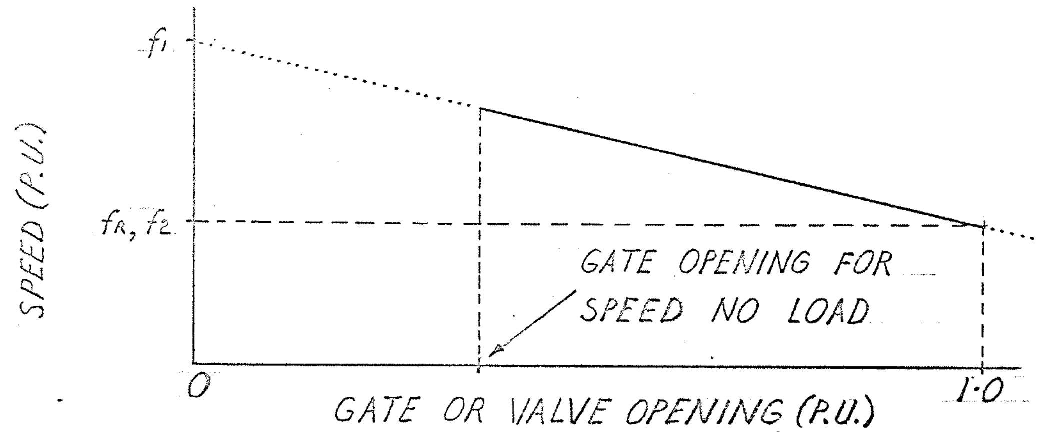

HUDSONS BAY
ME
BA
EASTERN
STANDARD TIME
ONTARIO
NORTHWEST REGION H.E.P.C.O.
SEVEN SISTERS
LAKE
NIPIGON
TIE
KENORA
G
PORT ARTHUR
FORT WILLIAM
ORT FRANCES
ATES
LAKE SUPERIOR

FIG. I



CANADA
U. S. A.
ARCTIC CIRCLE
S.P.C.
M.H.
HEPCO
MOUNTAIN
STANDARD TIME
SASKATCHEWAN
CENTRAL
STANDARD TIME
MANITOBA
HUDSONS BAY
EASTERN
STANDARD TIME
ONTARIO
SASKATOON
S.P.C.
REGINA
LAKE
WINNIPEG
LAKE
MANITOBA
BRANDON
TIE
BOUNDARY
DAM
WINNIPEG
M.H.
SEVEN SISTERS
TIE
KENORA
NORTHWEST REGION H.E.P.C.O.
LAKE
NIPIGON
PORT ARTHUR
FORT WILLIAM
FORT FRANCES
TIME ZONE DIVISION
PROVINCE BOUNDARY
UNITED STATES
LAKE SUPERIOR
SCALE 0 100 200 MILES

FIG. 1

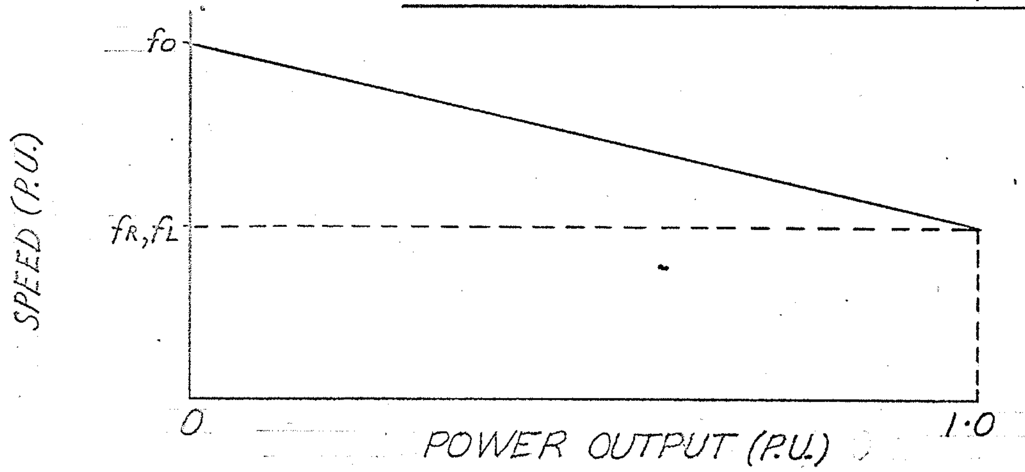


G_D = SPEED DROOP $= \frac{(f_1 - f_2)}{f_R}$ P.U.

WHERE : f_1 = P.U. EXTRAPOLATED SPEED CORRESPONDING TO 0% GATE OR VALVE OPENING

f_2 = P.U. EXTRAPOLATED SPEED CORRESPONDING TO 100% GATE OR VALVE OPENING

FIG 2 (a) GOVERNOR SPEED DROOP



STEADY-STATE SPEED REGULATION $= \frac{(f_0 - f_L)}{f_R}$ P.U. $= G_S$

WHERE : f_0 = P.U. SPEED OF GENERATOR AT ZERO POWER OUTPUT

f_L = P.U. SPEED OF GENERATOR AT 1·0 P.U. POWER OUTPUT

f_R = RATED SPEED = 1·0 P.U.

FIG 2 (b) GOVERNOR STEADY-STATE SPEED REGULATION initially at 138 kV, was completed in 1960 to interconnect the networks of the Saskatchewan Power Corporation (SPC) and (MH). Figure 1 shows the vast area embraced by this three system interconnection. Three time zones are involved and this fact emphasizes the very real advantage of capacity sharing or availability during the time-displaced load peaks within this interconnected area.

II - THE IMPORTANCE OF GOVERNOR SPEED DROOP

Because the action of load-frequency controls is applied to the governing systems of generator units in the form of supplementary control, an outline of power system generation/frequency characteristics brought about by governor action follows.

Figure 2(a) shows the relationship between generator speed and steam valve (thermal unit) or wicket gate (hydraulic unit) opening produced by an ideal governor, i.e. a governor which produces a linear characteristic and has no dead-band with respect to its sensitivity to frequency changes and consequent output change follow up. The reason for the drooping characteristic, which is normally employed, will become apparent presently.

Speed Droop is defined as the overall change in sustained speed, expressed in p.u. (where rated speed = 1.0 p.u.), corresponding to full gate (valve) travel from 0 p.u. to 1.0 p.u. gate (valve) opening with identical setting of all governor adjustments.[3]

$$\text{Speed Droop, } G_D = \frac{(f_1 - f_2)}{f_R} \text{ p.u.} \quad \text{------------} \quad (1)$$

where f_1 = p.u. extrapolated speed corresponding to 0 p.u. gate (valve) opening

f_2 = p.u. extrapolated speed corresponding to 1.0 p.u. gate (valve) opening

f_R = Rated speed = 1.0 p.u. (60 c/s)

Figure 2(b) shows the relationship between generator speed and generator power output produced by an ideal governor.

Steady-State Speed Regulation is defined as the overall change in sustained speed expressed in p.u. (where rated speed = 1.0 p.u.), when the gate (valve) opening of the turbine is reduced from the gate (valve) opening corresponding to 1.0 p.u. power output of the turbine (at rated head, or rated steam conditions) to the gate (valve) opening corresponding to 0 p.u. output of the turbine (at rated head, or rated steam conditions) with identical settings of all governor adjustments.[3]

$$\text{Steady-State speed regulation, } G_S = \frac{f_0 - f_L}{f_R} \text{ p.u.} \quad \text{------} \quad (2)$$

where f_0 = p.u. speed at 0 p.u. power output.

f_L = p.u. speed at 1.0 p.u. power output.

f_R = Rated speed = 1.0 p.u. (60 c/s)

Speed droop as defined above should be more correctly termed "Permanent" speed droop in order to avoid confusion with "Temporary" speed droop which has to do with compensation of the governor action. It will be apparent that steady-state speed regulation is directly related to permanent speed droop so that a desired speed regulation is provided by an appropriate permanent speed droop setting. In much of

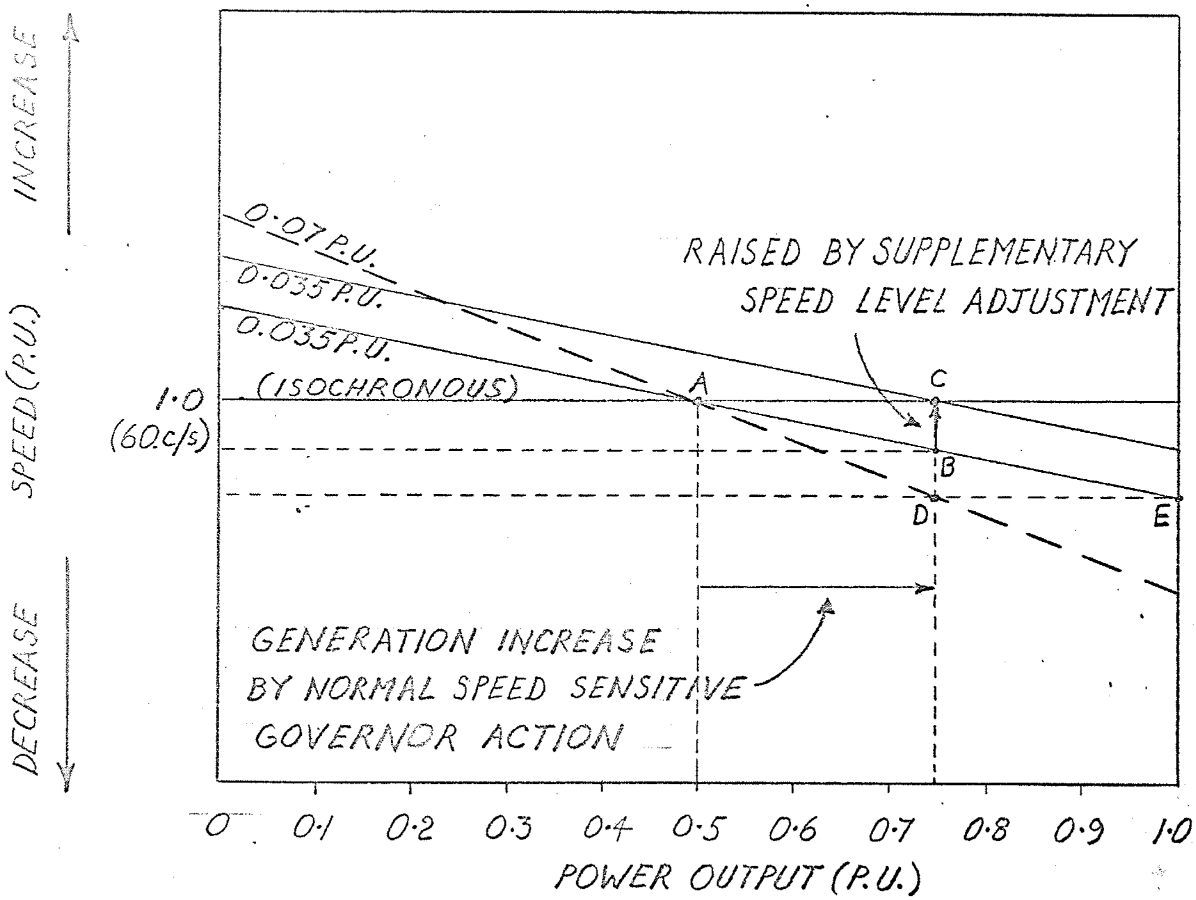


FIG 3 GOVERNOR SPEED REGULATION

the literature on load-frequency controls, steady-state speed regulation is incorrectly referred to as speed droop.

If two units were now considered to be operated in parallel with isochronous (flat frequency) governor characteristics, it would be impossible to load the units according to their capabilities. The division of power between the two units would be unpredictable. For this reason it is necessary to provide the governors of the paralleled machines with drooping generation/frequency characteristics. It must first be realized that for a 60 c/s system (1.0 p.u. speed), generation is considered to balance demand at a speed of 60 c/s only. Deviation from 1.0 p.u. speed, then, is a measure of the excess or deficiency of generation on a system at a given moment. If two identical units are operated alone to supply a connected load and are equipped with governors on .035 p.u. steady-state speed regulation characteristics (See Fig. 3), they will share any load changes equally. If both units are operating at Point A (0.5 p.u. power output) and a load increase depresses the frequency thereby causing operation at Point B, both units will have their power output raised to 0.75 p.u. respectively. Supplementary speed level adjustment to the governor would then be required to bring the frequency back to 1.0 for the new system loading, i.e. Point C.

If one unit were to be operated on 0.07 p.u. speed regulation and the other on 0.035 p.u., it is seen from Figure 3 that the unit on 0.07 would take one-third of the load increase (or decrease) while the one on 0.035 p.u. would take two-thirds. Points D & E in Figure 3 illustrate participation according to the values of percent speed regulation. Participation of a unit in system regulation can therefore be assigned according to this value; the greater the setting, the

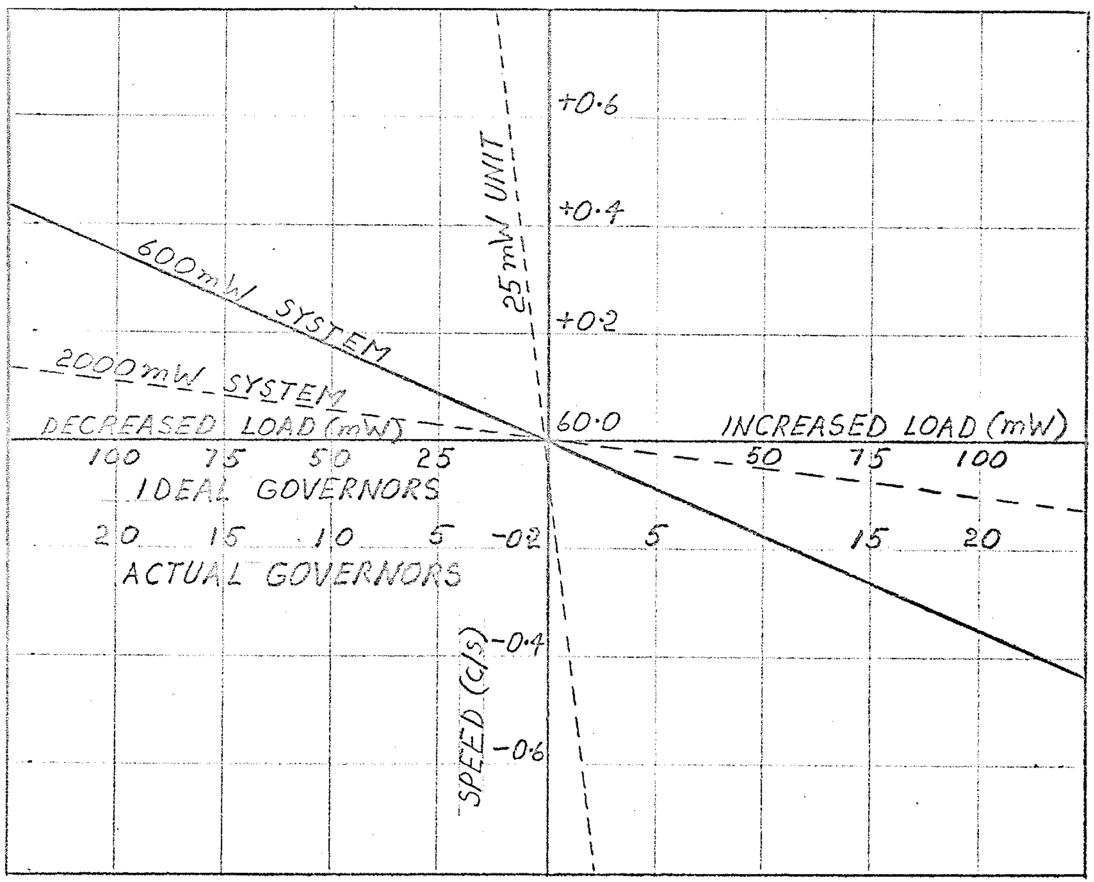


FIG 4. GOVERNING CHARACTERISTICS

(0·035 P.U. STEADY-STATE SPEED REGULATION SETTINGS USED IN ALL CASES AND A SYNCHRONOUS LOAD IS ASSUMED) less will be its relative participation for a given frequency deviation.

The straight speed regulation lines employed represent ideal governors characteristics while those found in practice may deviate considerably from this pattern. However, when a number of units are operated in parallel, the combined characteristic will tend to more closely approximate a straight line; the variations from linear of the indivdual governor characteristics tend to cancel out.[4] This is more nearly so when large power/frequency deviations are involved. Non-linearities show up more on small deviations and therefore incremental regulation may be greater or less than the overall regulation.*

Figure 4 shows a 0.035 p.u. combined speed regulating or governing characteristic for a 600 mW system and for a 2000 mW system where in the latter case the straight line relationship is certainly more justified. The proportionately better frequency regulation of the larger system is evident. This is because there is more capacity available to absorb the load changes. The characteristic for a 25 mW unit, also at 0.035 p.u. speed regulation, is shown for comparison.

Steady-state speed regulation can also be expressed in p.u. spinning capacity per one-tenth cycle frequency deviation.[6,7] In Figure 4, with reference to the characteristic for the 2000 mW system (2000 mW spinning capacity), a change in load of 96 mW will produce a frequency deviation of 0.1 cycle, or, the governing characteristic expressed in terms of p.u. total spinning capacity/0.1 cycle is

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*Greater regulation implies a larger frequency deviation for a given load deviation, i.e. a greater value of G_S.

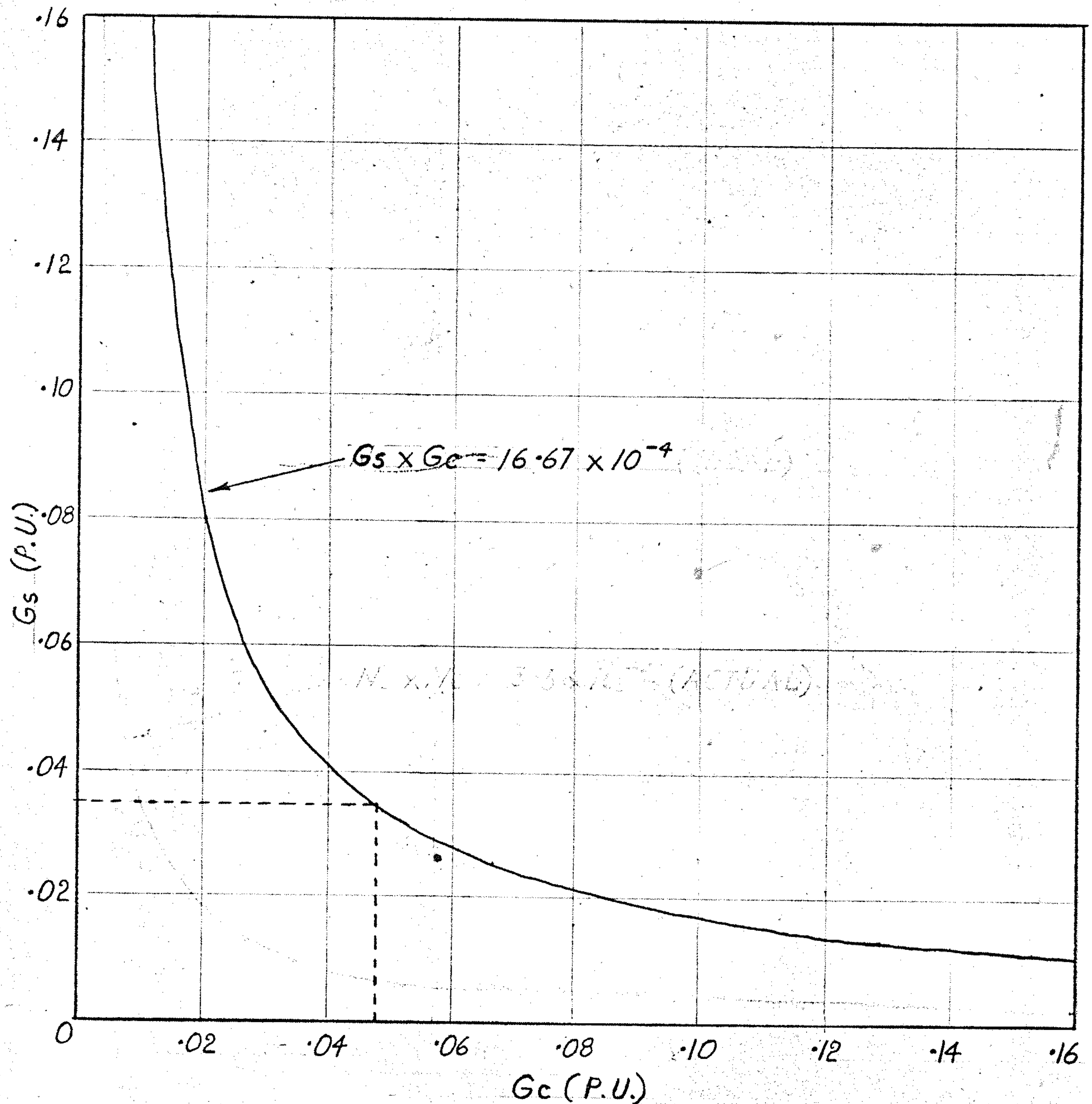


FIG. 5. RELATIONSHIP OF P.U. STEADY-STATE SPEED REGULATION (Gs) AND P.U. SPINNING CAPACITY PER 0·1 CYCLE (Gc)

$G_C = 96$ mW/0.1 cycle

$= .048$ p.u. spinning capacity/0.1 cycle.

Recalling $G_S = \frac{(f_0 - f_L)}{1.0}$ p.u. ——————————— (2)

and for the $(f_0 - f_L)$ deviation, G_C, is given by

$$G_C = \frac{16.67 \times 10^{-4}}{(f_0 - f_L)} \text{ p.u.} \text{ ——————————— (3)}$$

where 0.1 c/s is equivalent to 16.67×10^{-4} p.u.

Multiplying Equations (3) and (2) gives

$$G_S G_C = 16.67 \times 10^{-4} \text{ ——————————————— (4)}$$

A 0.035 p.u. steady-state speed regulation then represents a governing characteristic of $G_C = \frac{.001667}{.035} = .048$ p.u. spinning capacity/0.1 cycle as suggested above.

The relationship of G_S and G_C is plotted in Figure 5.

The above equations are based upon ideal governor action based upon the governors' permanent speed droop settings. Governor response dead-bands, non-linearities in the actual regulating characteristic and machines with blocked governors produce greater regulation than the permanent speed droop settings may indicate.[8] The effective regulation is very often larger for very small frequency changes than for larger changes. G_S may be 0.083 p.u. ($G_C = 0.02$ p.u./0.1 cycle) for large frequency changes and yet G_S may be 0.25 p.u. ($G_C = 0.0067$ p.u./0.1 cycle) for small changes. In other words actual systems behave like systems much smaller than their composite speed droop settings would suggest. The ratio of the effective or apparent spinning capacity, C_E, to that actually spinning, C, can be expressed by

$$\frac{C_E}{C} = \frac{G_S}{G_{SE}} = \frac{G_S\,G_C}{16.67 \times 10^{-4}} \quad \text{------------------------} \quad (5)$$

Where G_S = Steady-State Speed Regulation by Equation (2)

G_{SE} = Effective G_S actually obtained for a given frequency change.

In practice the ratio C_E/C is usually found to be between 0.14 and 0.42 (G_C between 0.0067 and 0.02 p.u.), with a value for G_C of 0.01 p.u. usually employed.[5,9,10,11] This latter value is the basis of the "Actual" abscissae of Figure 4.

It follows that as the total load becomes larger, connected generation is usually increased and the amount of generation or load required to change the frequency by a fixed amount must grow also. Thus, from day to night when the load levels may vary as much as three to one, the slope of the speed/generation curve must also change.

It has been observed that the larger the system the better the frequency regulation, i.e. a greater load change is required to produce a given frequency deviation. Interconnections create larger systems and so offer better frequency regulation than the average of the regulations of the member systems.

In terms of the governing characteristic expressed in p.u. spinning capacity per 0.1 cycle,

$$G_{C(1+2+\text{----}+n)} = G_{C(1)} + G_{C(2)} + \text{------} + G_{C(n)} \quad \text{---} \quad (6)$$

Assuming G_C = .01 (spinning capacity)/0.1 cycle for Areas 1, 2 and 3 of 500, 650 and 850 mW spinning capacity respectively, the regulation of the interconnected system would be, from Equation 6,

$$G_C(2000) = G_C(500) + G_C(650) + G_C(850)$$

$$= 5.0 + 6.5 + 8.5 = \underline{20 \text{ mW}/0.1 \text{ cycle}}$$

which is considerably better than the individual regulationsof 5.0, 6.5 and 8.5 mW/0.1 cycle respectively. The above is apparent from the graphical representation in Figure 4.

In the above discussions of the behaviour of power systems with respect to load, generation and frequency, as dictated by speed sensitive governor action, a synchronous or speed insensitive load has been assumed. In actual systems the load does vary with frequency. The effect of a frequency sensitive load on system governing characteristics is discussed in the following section.

III - THE INFLUENCE OF A FREQUENCY SENSITIVE LOAD

The slope of the load characteristic has been investigated by a number of authors who generally agree that for a 0.01 p.u. change in system frequency a variation in system load of between 0.01 and 0.03 p.u. will result.[12,14,15] The accepted value usually applied is a 0.025 - 0.026 p.u. load change for a 0.01 p.u. frequency change.

In one series of tests the 0.026 p.u. load reduction caused by lowering the frequency 0.01 p.u. was made up of 0.019 p.u. due to the reduction of synchronous and non-synchronous (motor) loads while the remaining 0.007 p.u. was made up from the decreased resistance load due to the voltage reduction which accompanies the frequency reduction. (Though with modern, fast voltage regulators this latter condition would not persist).

From the above, it will be apparent that the load characteristic has a positive slope, i.e., a frequency increase results in a load increase and vice versa.

As noted above, the slope of the load characteristic ranges between a first power to a third power relationship with frequency. That is

$$\text{from } \Delta P_L = (f_R + \Delta f_R) - f_R = \Delta f_R$$

$$\text{to } \Delta P_L = (f_R + \Delta f_R)^3 - f_R$$

where ΔP_L = p.u. load change

Δf_R = p.u. frequency change.

$P_L = f_R = 1.0$ p.u.

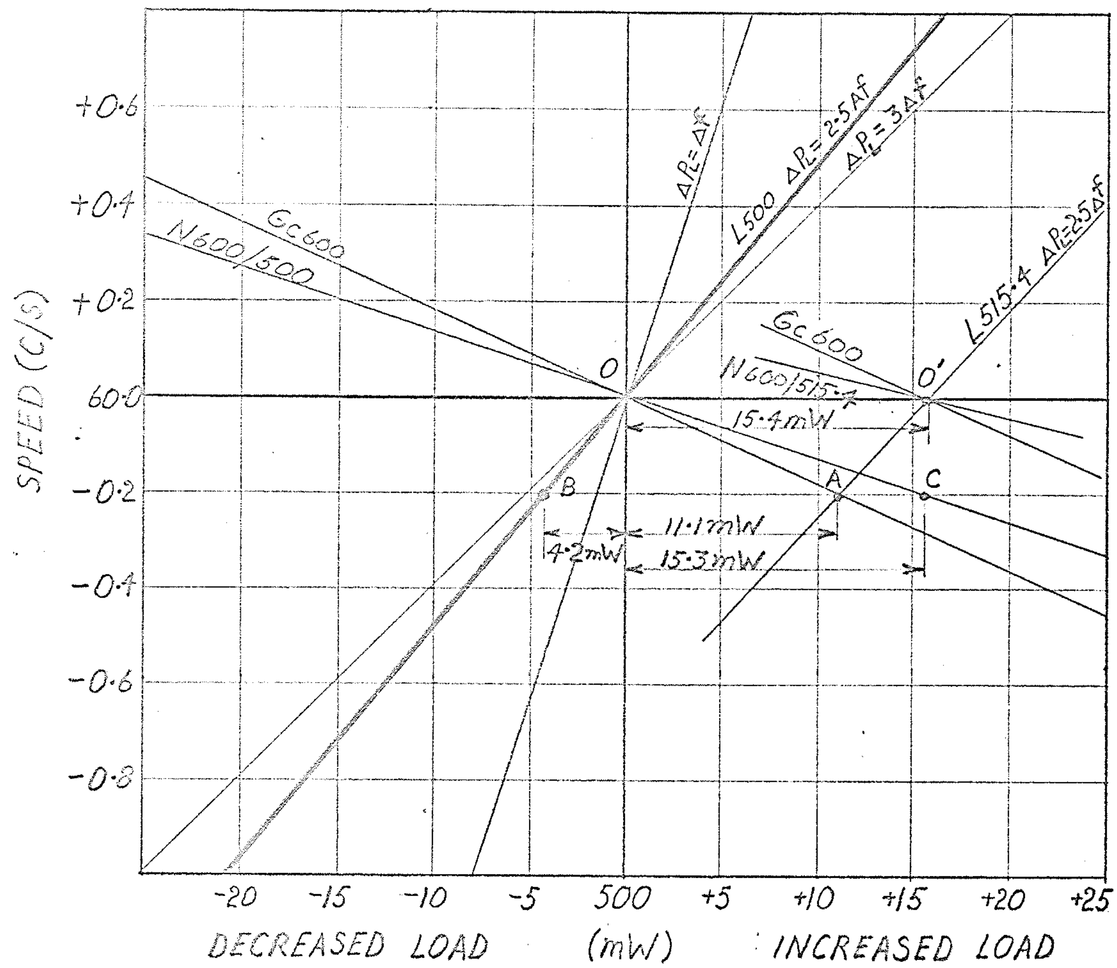
For the purpose of this study, the generally accepted 0.01 p.u. frequency - 0.025 p.u. load change relationship will be employed. That is

$$\Delta P_L = (f_R + \Delta f_R)^{2.5} - f_R$$

If $\Delta f_R \ll f_R$, i.e., if $\frac{\Delta f_R}{f_R} \ll 0.05$

which is usually the case, then

$$\Delta P_L = 2.5\, \Delta f_R \qquad (7)$$



Gc 600 = TYPICAL GOVERNING CHARACTERISTIC 600 mW SPINNING CAPACITY.

L 500 = TYPICAL LOAD CHARACTERISTIC FOR 500 mW LOAD AT 1·0 P.U. SPEED

N600/500 = TYPICAL NATURAL COMBINED CHARACTERISTIC 600 mW SPINNING CAPACITY & 500 mW LOAD

ΔP_L = LOAD DEVIATION

Δf = FREQUENCY DEVIATION

FIG 6. EFFECT OF A FREQUENCY SENSITIVE LOAD ($N = Gc - L$)

which would result in errors in ΔP_L not greater than 3-1/3%.

Figure 6 illustrates the variation of load with frequency for the 1st, 2.5 and 3rd power relationships.

Based upon the 2.5 power relationship, the load characteristic, L, is given by

$$L = \frac{(2.5)\ (16.67)\ x\ 10^{-4}}{f_R} = 0.0042/\mathrm{mW}/0.1 \text{ cycle ----- } (8)$$

A 500 mW load at 1.0 p.u. speed would have a load characteristic of

$$L_{500} = (0.0042)\ (500) = 2.1 \text{ mW}/0.1 \text{ cycle}$$

which would be centered on the co-ordinates f_R = 1.0 p.u. and load = 500 mW.

Figure 6 shows also a typical governing characteristic for a 600 mW spinning system. This is the same characteristic as shown in Figure 4. In the case of Figure 6, however, a 0.0042/mW/0.1 cycle load characteristic is considered. For the assumed load of 500 mW at 1.0 p.u. speed, the load characteristic becomes 2.1 mW/0.1 cycle.

Let it now be assumed (Figure 6) that a disturbance on the system causes a frequency depression of 0.2 c/s. In accordance with the combined governing characteristic, G_{C600}, system generation will be raised by 11.1 mW. As a consequence of the depressed frequency, the system load is reduced by 4.2 mW. This in effect causes a total of 15.3 mW to be available at the decreased frequency of 59.8 c/s. In other words the true behaviour of the system load, generation and frequency changes is given by the algebraic difference of the governing (G_C) and load (L) characteristics which is termed the Natural Combined Characteristic, N.[16] Therefore

$$N = G_C - L \quad \text{------------------------------------} \quad (9)$$

It is to be noted that as G_C is a negative characteristic and L is positive, N must always be negative i.e., power increases as frequency decreases. Further, for any given system, L varies directly as the load, and G_C varies directly as the spinning capacity. N is usually most conveniently expressed in p.u. spinning capacity per tenth cycle.

Supplementary control will, of course, shift G_C only in the appropriate direction maintaining its original slope. This may be seen by reference to Point O' on Figure 6. This is the new operating point after supplementary regulation has compensated for the 11.1 mW generation deficiency by raising G_{C600} to pass through Point O'. It will be observed that the additional load has altered the slope of L and therefore the slope of $N_{600/500}$ to $N_{600/515.4}$. The change in slope of N is so slight for most load changes (say up to a 0.05 p.u. load change), that it can be neglected.

To summarize at this point:-

(a) Governor dead-band, units with blocked governors and non-linearities in the system governing characteristic cause system regulation to be substantially greater than the composite value of the governor speed droop settings, G_S, would suggest. Values of between 0.14 and 0.42 appear to be practical ratios of ideal G_S to actual G_S (see p.6).

(b) Typical load characteristics cause system regulation to

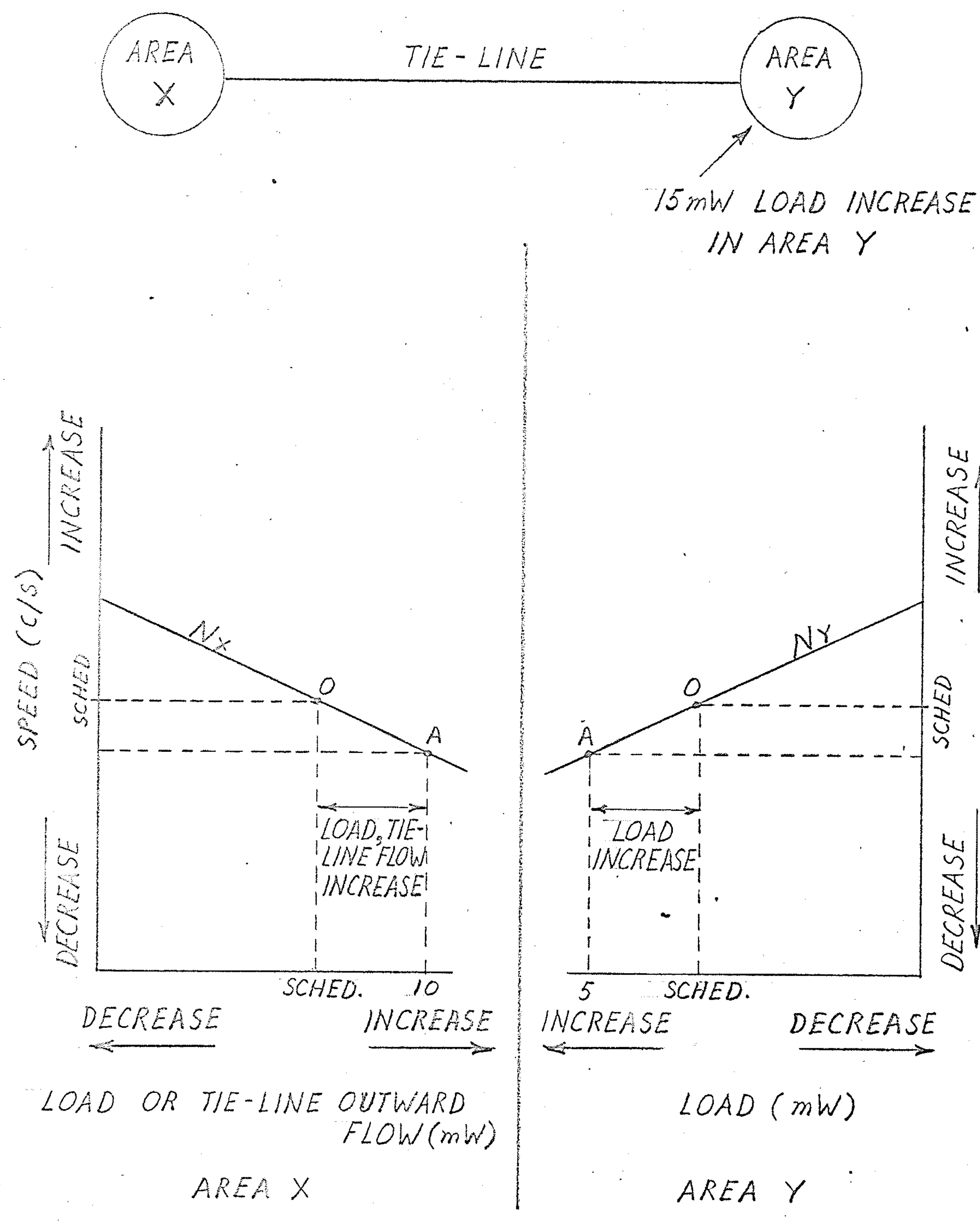


FIG 7. INTERCONNECTED SYSTEM WITH NO SUPPLEMENTARY CONTROL

be slightly decreased.

(c) The algebraic difference of the actual system governing and load characteristics is termed the Natural Combined Characteristic, N, and defines the true behaviour of the system to load, generation and frequency changes.

IV - SUPPLEMENTARY CONTROL REGULATING CHARACTERISTICS

The simple joining of the member systems by tie-line does not, in itself, realize the advantages associated with a larger system. Regulation of tie-line flows is mandatory both for normal operating conditions and during times of disturbances in any one of the member systems of the interconnection that will result in tie-line flow fluctuations. Also, the members must comply with the commandment of interconnection that each area in participating in the benefits of parallel operation will likewise contribute to the regulation of the interconnected system. This implies that each member shall absorb his own load changes and contribute his share to frequency regulation of the combined system.

The above rules and regulations are very desirable, but as the various governors throughout the interconnection cannot discriminate whether or not a load change has occurred in their own particular area (because they are speed sensitive only), they would cause undesirable and unscheduled power flows over the tie-lines in carrying out their functions of matching generation to load demand. Figure 7 illustrates interconnected operation involving Areas X & Y without supplementary control. (There is no significance to the fact that the natural combined characteristic of Area Y, N_Y is reversed in slope.

This is merely to facilitate identification). A load increase of 15 mW takes place in Area Y, where because it is assumed $N_X = 2N_Y$, 5 mW are contributed locally and 10 mW from Area X via the tie-line as a consequence of normal governor reaction in both to the depressed frequency. Point A would become the new operating point in both areas as no supplementary control is available to raise generation in Area Y by the required 15 mW. It is obvious that for external disturbances to an area (Area X here), the increased or decreased tie-line flow is identical to the increased or decreased load. This fact will be employed in subsequent discussions and diagrams.

Manual control of the governor settings could never effectively supply the corrective measures necessary to maintain tie-line schedules and system frequency, especially as each member area would be issuing instructions from its own dispatch centre resulting in a chaotic and therefore unworkable situation. As a consequence, continuously operating automatic control equipments, supplementary to the unit governors, were developed to provide the necessary added intelligence to apply governor action in such a direction as to reduce the deviations in tie-line load and system frequency to zero. These are the so-called load-frequency controls.

Three basic methods of supplementary control of machine governor settings were developed. Their function is to raise or lower the output of certain selected generating units in order to maintain inter-area tie-line flows and/or frequency on schedule during load or generation changes that occur anywhere within the interconnected group. The action effectively shifts the system governing characteristics, G_C, of the member areas in such directions as to return the tie-line flows and frequency to their respective scheduled values. The three basic methods or modes of supplementary control are, (1) Flat Frequency (FF), (2) Flat Tie-Line (FTL), and (3) Tie-Line Bias (TLB).

(1) Flat Frequency (FF) Control - Operation based upon deviations from scheduled frequency is known as the Flat Frequency mode and is represented by the equation

$$\Delta f = 0 \quad \text{------------------------------------} \quad (10)$$

where $\Delta f = f_R - f$
f_R = scheduled speed in c/s
f = actual system speed in c/s

By supplementary action, the generator units under FF control will be caused to raise or lower their output so as to return the system frequency to the scheduled value in accordance with Equation (10).

(2) Flat Tie-Line (FTL) Control - Operation based upon deviations from scheduled tie-line flow is known as the Flat Tie-Line mode and is represented by the equation

$$\Delta P_T = 0 \quad \text{------------------------------------} \quad (11)$$

where $\Delta P_T = P_{TR} - P_T$
P_{TR} = scheduled tie-line power flow in mW
P_T = actual tie-line power flow in mW

By supplementary action, the generator units under FTL control will be caused to raise or lower their output so as to return the system frequency to the scheduled value in accordance with Equation (11).

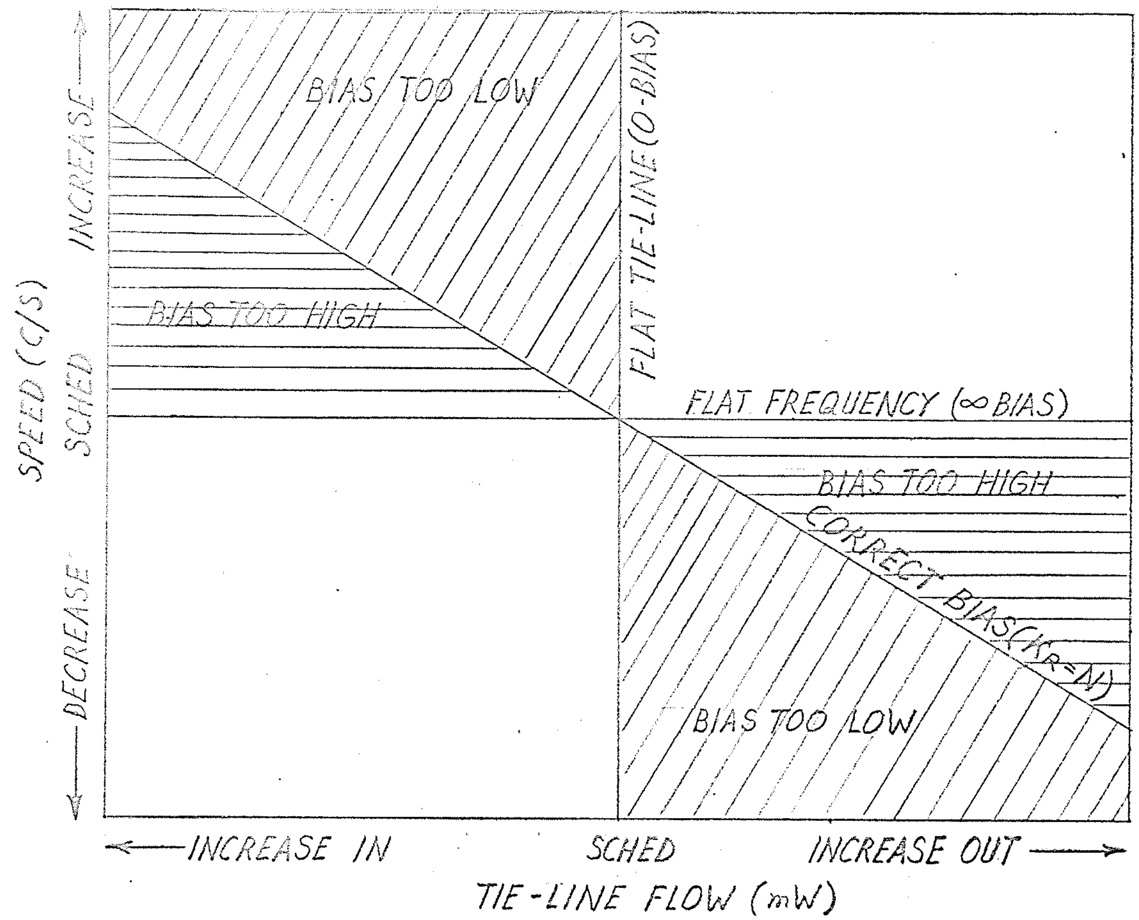


FIG 8. FF, FTL & TLB REGULATOR CHARACTERISTICS

If more than one tie-line relative to a given area is involved, the <u>net</u> deviation from <u>net</u> schedule is involved and therefore P_{TR} and P_T are net values.

(3) <u>Tie-Line Bias (TLB) Control</u> - Control operation which takes into account both frequency and tie-line deviations from scheduled values is known as tie-line bias operation. There are, actually a number of methods based upon tie-line and frequency deviations in existence; however, the term tie-line bias here will represent this class of control mode generally. The particular methods will be discussed in Section VIII of this chapter. Tie-Line Bias control is represented by the equation [13,17]

$$\Delta P_T + K \Delta f = 0 \quad (12)$$

where ΔP_T and Δf are as defined with respect to Equations (10) and (11) above and are expressed in mW and cycles x 10^{-1}/sec respectively.

K = Frequency Bias in mW/0.1 cycle.

Varying K has the effect of varying the slope of the regulator characteristic. Figure 8 shows the regulator characteristics for FF, FTL, and TLB control. It will be observed that FF (infinite bias) and FTL (zero bias) are the limiting values of too high and too low bias values respectively. The "correct" bias, K_R, is considered to be that value of K which gives a regulator slope equivalent to the natural combined characteristic, N, of the area considered.

That is $K_R = |N|$

and as N defines the power/frequency characteristic of an area, then the area's contribution over its tie-line will be in accordance with N, and

$$K_R = |N| = \left|\frac{\Delta P_T}{\Delta f}\right| \quad \text{------------------------} \quad (13)$$

for a given area. As K_R is, in effect, a multiplying factor it is always positive.

It should be noted from Equation (12)that ΔP_T is considered positive when the tie-line net power flow outward from the area considered is above the net scheduled value, and negative when below the scheduled value. Also, Δf is considered positive when the speed is greater than the scheduled value and negative when less than the scheduled value.

For an increased tie-line flow outward relative to a given area and a depressed system frequency, i.e. an external (to the given area) load increase, Equation (12) with correct bias becomes

$$\Delta P_T + K_R\ (-\Delta f) = 0$$

and from Equation (13)

$$\Delta P_T + \frac{\Delta P_T}{\Delta f}(-\Delta f) = \Delta P_T - \Delta P_T = 0 \quad \text{------------} \quad (14)$$

Similarly for a decreased tie-line flow outward and an increased frequency

$$-\Delta P_T + \frac{\Delta P_T}{\Delta f}(\Delta f) = -\Delta P_T + \Delta P_T = 0 \quad \text{------------} \quad (15)$$

The above two conditions represent "external" disturbances. Because the TLB regulator equation (12) has been satisfied no supplementary regulation takes place. It has been shown that when $K_R = |N|$ the desirable condition of non-intervention by the supplementary regulator exists in areas external to the one where the disturbance is taking place. This is known as the Graner-Darrieus condition of non-intervention.[18]

During "internal" disturbances, Equation (12) is not satisfied. When the frequency is low and the tie-line power flow outward is below the scheduled value, Equation (12) becomes

$$-\Delta P_T + \frac{\Delta P_T}{\Delta f}(-\Delta f) \neq 0 \text{ ------------------------------ } (16)$$

and when the frequency and the tie-line power are both above schedule

$$\Delta P_T + \frac{\Delta P_T}{\Delta f}(\Delta f) \neq 0 \text{ ------------------------------ } (17)$$

For these two "internal" disturbance circumstances supplementary controller action is required to "raise" or "lower" generation in order to satisfy Equation (12).

Conclusions relative to this section may be summarized as follows with reference to Figure 8:-

(a) Flat Frequency control is independent of tie-line loadings. If FF control were to be applied to two systems interconnected by a tie-line, a loading schedule on the tie-line could never be maintained.

(b) Flat Tie-Line control is independent of system frequency. FTL control applied to two interconnected systems would result in a chaotic system frequency and time errors.

(c) Neither FF nor FTL control can interpret whether a power change is external or internal to the area considered. As a consequence, on an external disturbance, they will effect supplementary regulation which will have to be corrected later.

(d) Tie-Line Bias control takes into account both tie-line flow and frequency deviations from normal and therefore possesses the required information to detect whether a power disturbance is external or internal. If the bias setting equals the area's natural combined characteristic an external disturbance will cause no supplementary control action. It will be shown in following sections that even an incorrect bias setting is generally to be preferred to either pure FF or FTL control.

V - INTERCONNECTED SYSTEM OPERATION UNDER THE FF, FTL AND TLB SUPPLEMENTARY CONTROL MODES

A comprehensive treatment of the general effects produced on an interconnected system by the FF, FTL, and TLB supplementary control modes is contained in the reference material.[7] The general reasoning embodied in two or three examples to follow should be sufficient here to assess the advantages and disadvantages of the three modes.

To avoid unnecessary complication the sensing and interpretation only of the frequency and tie-line deviations from schedule will be discussed here. The various mechanisms by which the supplementary controls act to raise and lower generation will be discussed in Section VIII of this chapter. At this point it will be assumed that the "Raise" and "Lower" information passed on by the FF, FTL, or TLB regulators will be faithfully executed.

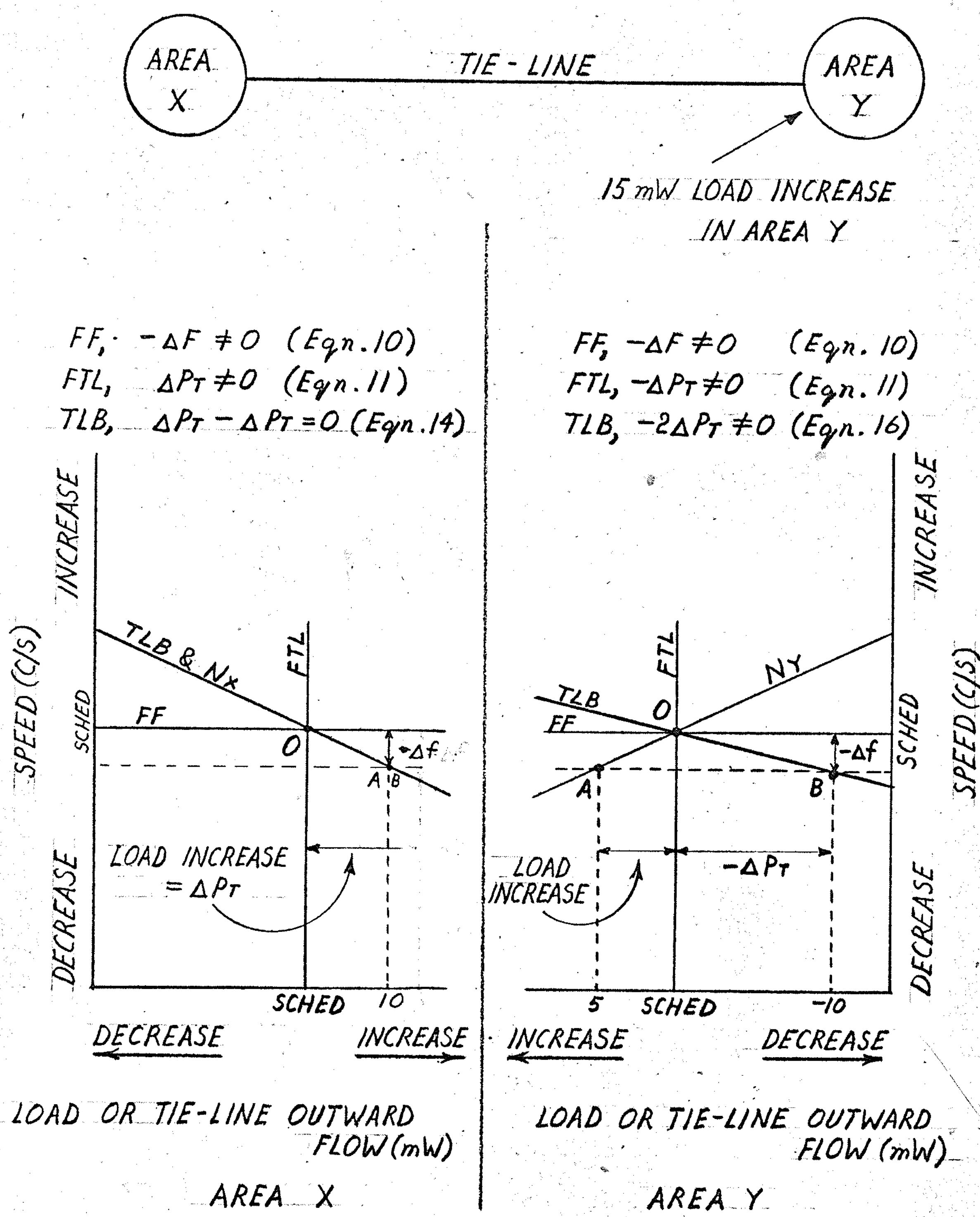


FIG 9. INTERCONNECTED SYSTEM WITH SUPPLEMENTARY CONTROL

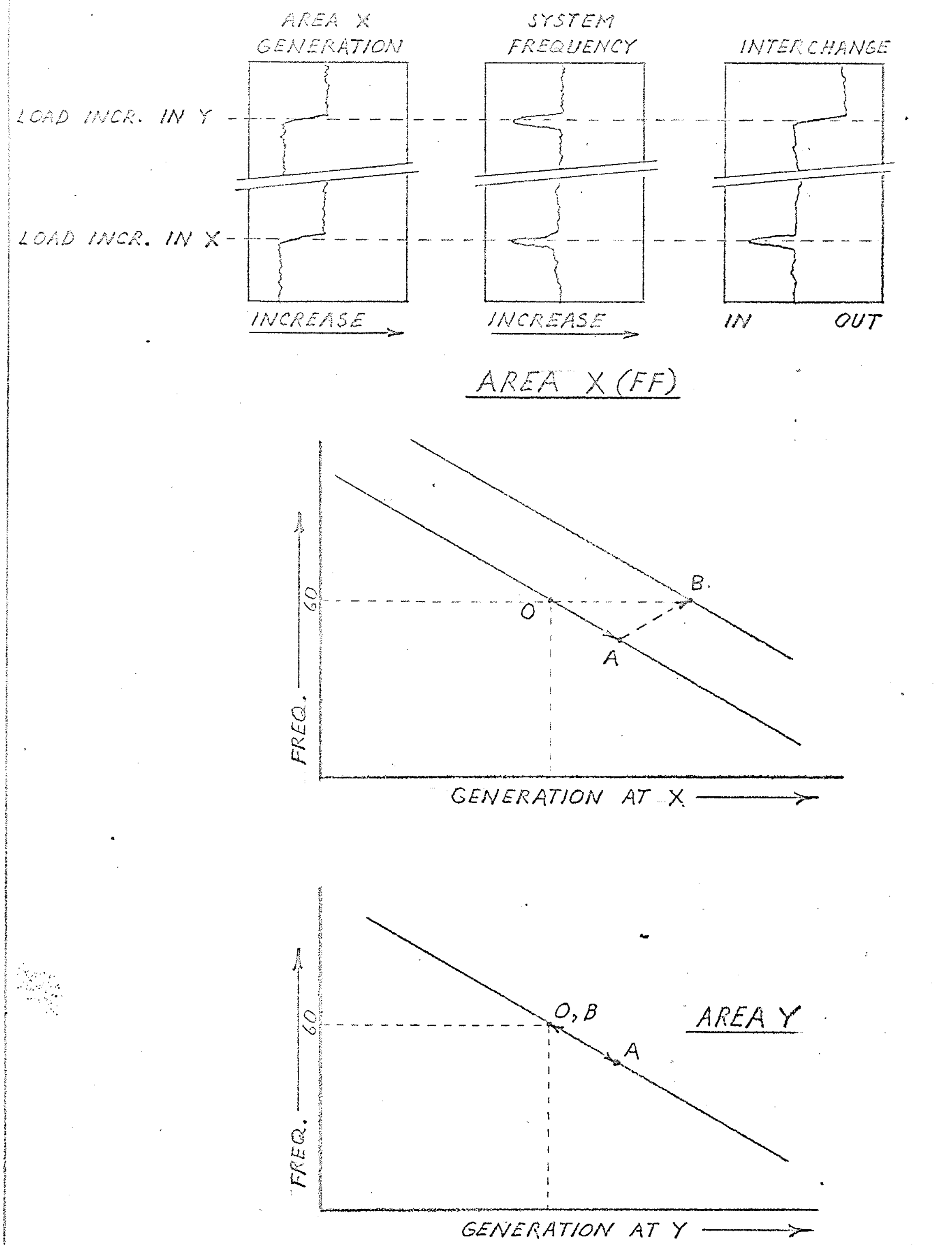


FIG. 10. INTERCONNECTED SYSTEM - FF CONTROL

$N_X = N_Y$

Further simplification can be made by noting that FF, FTL and TLB are all equally effective in dealing with internal power changes or disturbances. This will be apparent upon reference to Figure 9.

Figure 9 represents the same conditions as Figure 7 but with the appropriate FF, FTL, and TLB regulator characteristics added. It is assumed that the bias settings are correct (Equation 13). The load increase in Area Y causes both systems to operat at Point A, while Point B is the equivalent reference point for the TLB regulator and is a point on the reference line for the FTL regulator. In area Y, a FF regulator would raise generation bringing the frequency back on schedule. A FTL regulator would raise generation to bring the tie-line flow back on schedule. A TLB regulator would interpret a decreased tie-line flow and frequency as an internal load increase (or generation loss) and increase generation. Each type of regulator, then, would execute the correct action in Area Y. Area X would be external to the disturbance but only a TLB regulator in Area X on correct bias would be capable of making this interpretation and provide the desirable feature of refraining from causing supplementary regulation.

Flat Frequency Control - Consider Figure 10. Two power systems X and Y are interconnected by a tie-line. Area X has supplementary control equipped generation which will react to keep the system frequency on schedule. Area Y has no supplementary control equipment.

For the condition of a load increase in Area X, i.e. Point A on the lower generation frequency characteristic, the rotating machinery in Areas X and Y decelerate at which time the unit governors acting on their respective droops increase generation to match the new load at a

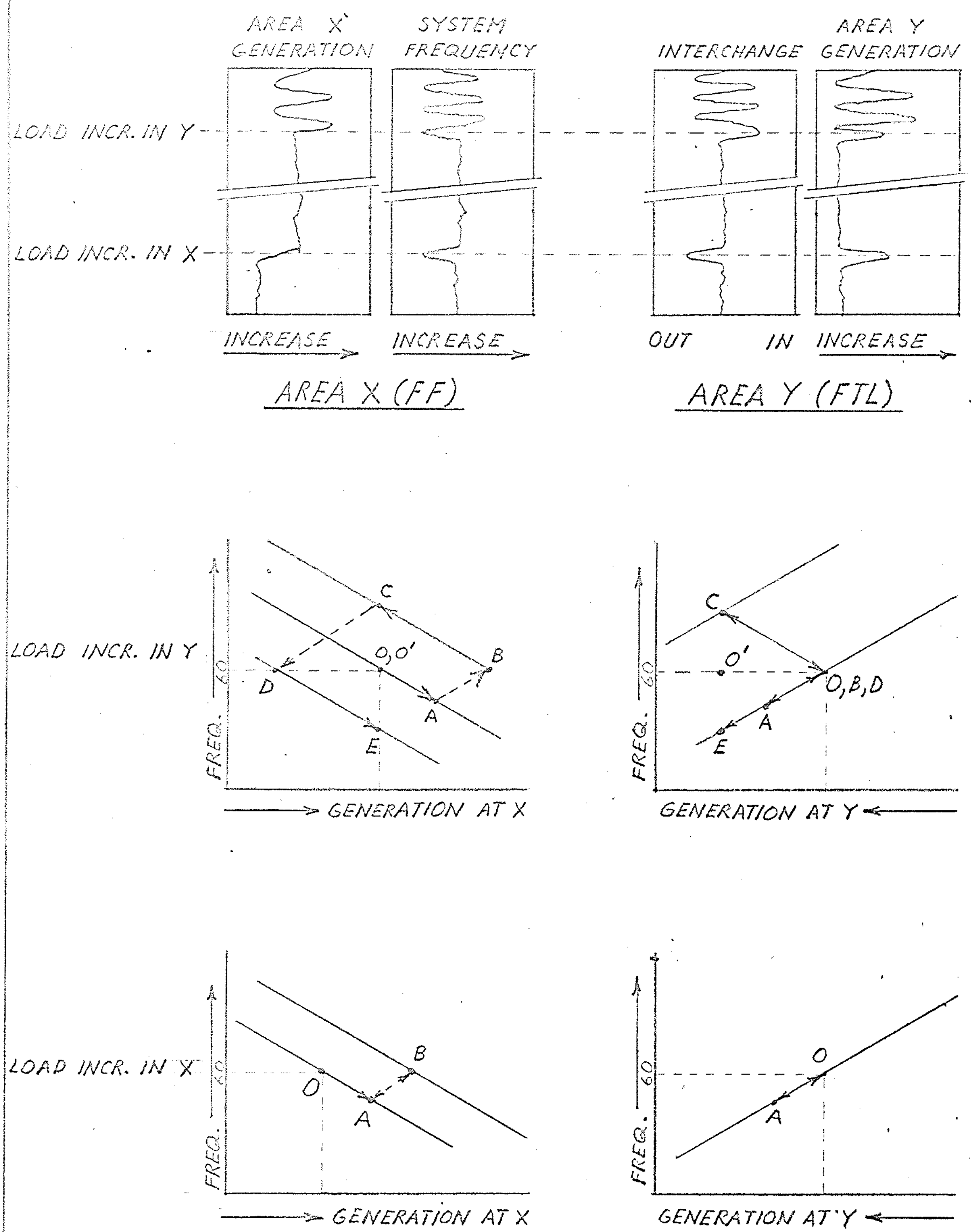


FIG. 11. INTERCONNECTED SYSTEM - FF/FTL CONTROL (FF COMPLETES ACTION BEFORE FTL ACTION BEGINS)

$N_X = N_Y$

lowered frequency. Area Y is contributing to Area X's load increase according to its natural combined characteristic which results in an increased tie-line flow in the direction of Area X. The depressed frequency condition is immediately seen by the FF controller in Area X which initiates action to raise generation in Area X. As the increased generation raises the frequency back to schedule, the machines in Area Y, as well as those not under FF control in Area X, are backed off according to their respective composite governor characteristics. The machines under FF control in Area X have taken care of the area's load increase, while system frequency and tie-line flow have returned to their original values (Point B in the curves). The above control action was a completely satisfactory operation.

Consider the reaction when a load increase takes place in Area Y. Precisely the same reaction will occur but the resultant increased generation from Area X's FF controlled machines will result in an increased flow over the tie-line to satisfy Area Y's increased demand. This is contrary to the accepted philosophy that after the initial reaction each system should cater for its own load changes. FF control, then, as applied here is unsatisfactory.

Flat Frequency - Flat Tie Line Control - Figure 11 illustrates the reaction of interconnected systems to load changes imposed when one end of the tie-line is FF controlled and the other end FTL controlled. For the sake of the illustration it is assumed that the FF controller in X responds and carries out its action before the FTL controller in Y makes any move. This is a pessimistic assumption, perhaps, but it enables a clearer picture to be presented of the process.

For a load increase in Area X the whole controlling process would be identical to that in Figure 10 for a load change in Area X because it has been assumed that the FF controller completes its action before the FTL unit in Area Y commences.

With a load increase in Area Y a decrease in system frequency enables the speed sensitive governors on the interconnected system to raise output according to their respective droops. This results in Point A being reached on the respective Area X and Y natural combined characteristics. The FF regulator in Area X sees the depressed frequency and raises its controlled generation accordingly, bringing the system frequency back on schedule (Point B). At this time the FTL regulator sees the increased tie-line flow inward caused by Area X's supply of Area Y's deficiency and thereby increases generation accordingly, bringing the operating point to C on the characteristics. Area X's FF controller's reaction to the elevated frequency moves the operate point to D. Then Area Y's FTL controller takes it to E and so on.

In actual practice conditions probably would not be as optimistic as those found in the "X load increase" case above nor as pessimistic as those in the "Y load increase" case. Hunting of the controls would occur but the process would undoubtedly "spiral in" to Point O' which would satisfy both controllers and result in the increased generation being supplied entirely by Area Y.

The point to be stressed in the above is that with controls acting on the information of a single variable, either frequency deviation or tie-line deviation, satisfactory results will be obtained

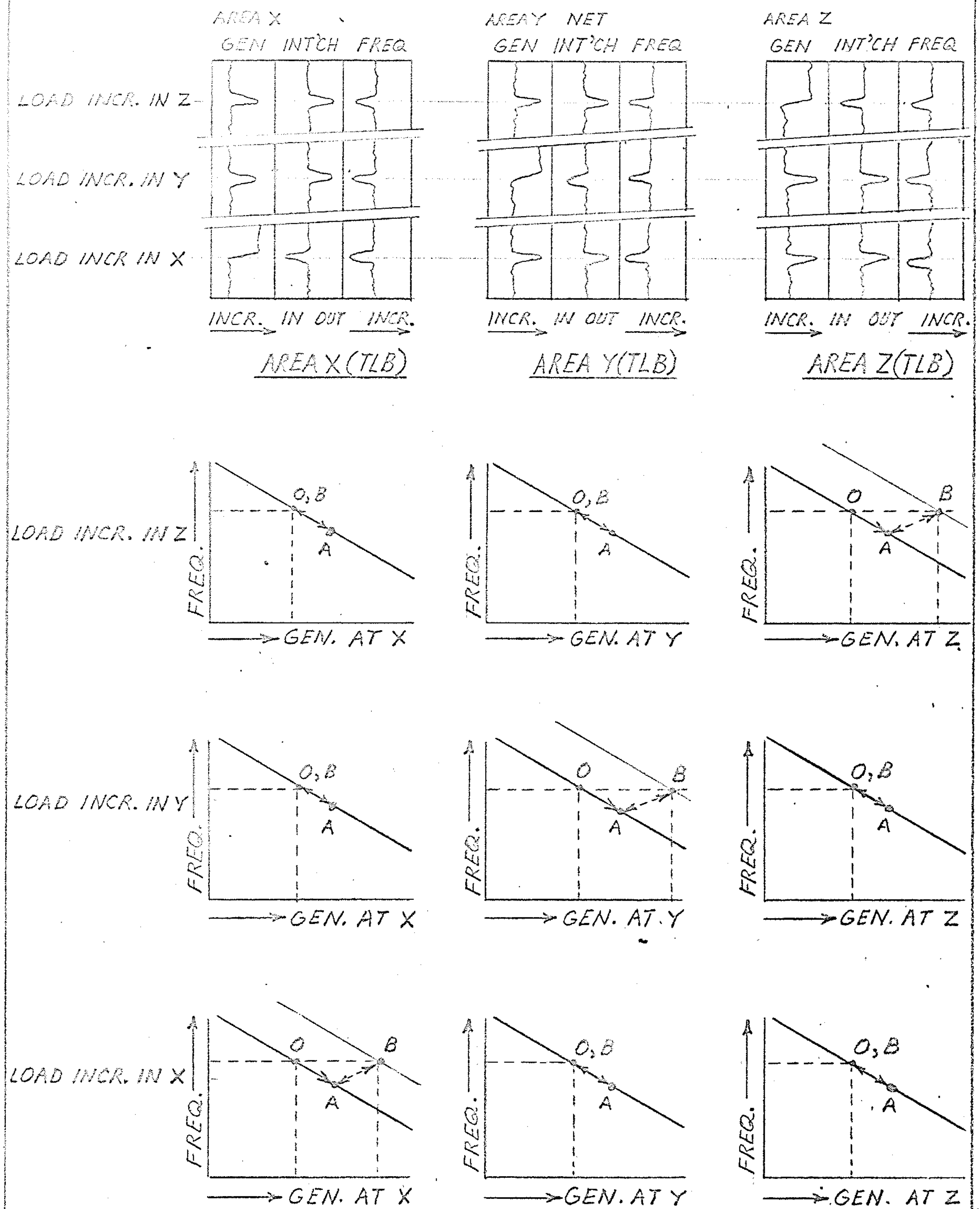


FIG 12 INTERCONNECTED SYSTEM - TLB CONTROL

$N_X = N_Y = N_Z$

only when the load changes occur in the area of the faster regulator. Results less than satisfactory will occur when the opposite takes place. What is even more significant, is that even with equally responsive regulators and generation at either end, both are going to take action, one of which (in the area where no load change took place) will have to undo its action before the desired end result of the affected area satisfying its own load change takes place.

Tie-Line Bias Control at Both Ends - Figure 12 shows a three system interconnection employing TLB throughout. It is assumed that the bias in each area is correct, that is, that the TLB regulator and the natural combined characteristics are identical. For simplicity, it has been assumed further that all areas have identical natural combined characteristics.

For a load increase suddenly applied in Area X, the frequency of the interconnection will decrease and all system governors will act to cause increases in generation in accordance with their respective governor "droops". Because it has been assumed that Areas X, Y and Z are identical, Areas Y and Z each contribute as much as Area X to the latter's load increase. This results in increased tie-line flows towards Area X. Point A is the new operating position on the respective natural combined characteristics. Area Y interprets the depressed frequency and increased tie-line flow outward as a disturbance in another area and therefore takes no supplementary governor action. Area Z, likewise, interprets the depressed frequency and the net increase in tie-line flow outward as an "external" disturbance and does not alter governor settings. Area X on the other hand, sees the depressed frequency and increased inward tie-line flow as a situation of load increase in its own area and therefore raises generation and consequently frequency to Point B while the governors in Area Y and Z (and those on Area X's generators not under LFC) reduce generation due to the rise in the frequency until Point B on their characteristics is obtained.

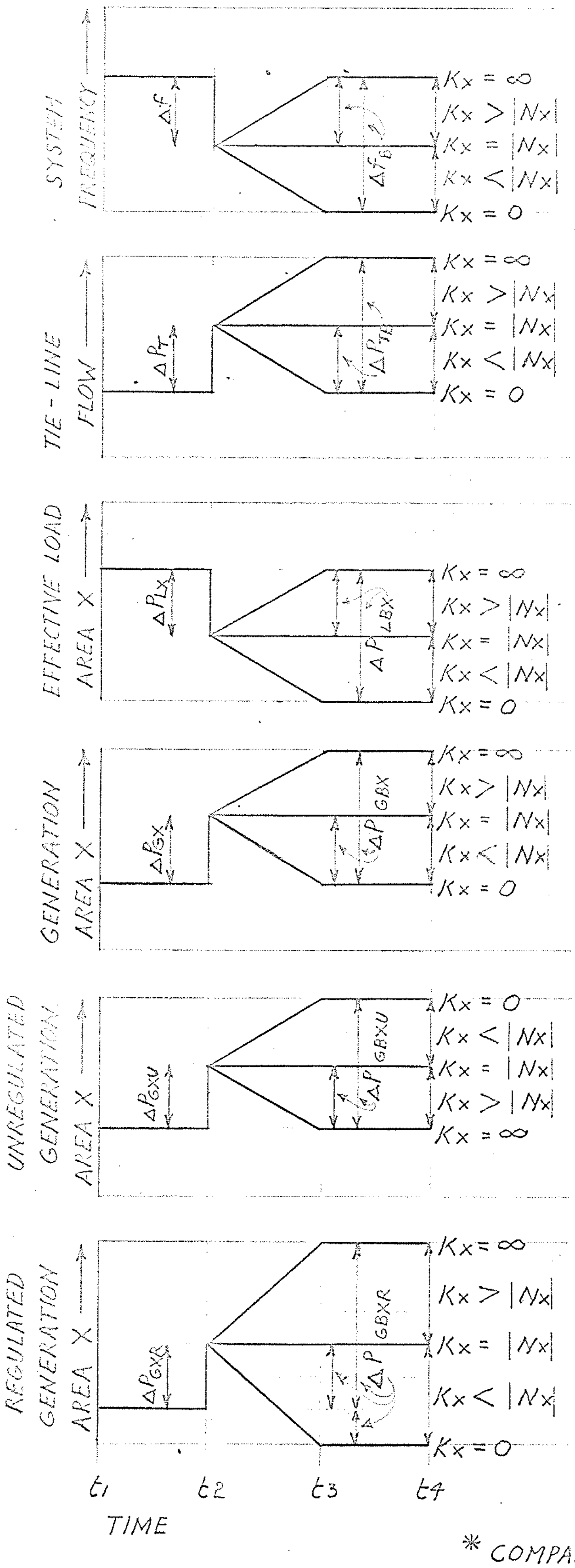
The same reasoning would follow for disturbances in Areas Y and X with the result that only in the area in which the load change actually takes place would correction be applied. This is the ideal state of affairs resulting in a bonus feature that the system is insensitive to one area having a faster response to its load-frequency controls than its neighbors or vice-versa as only the area with the change will actually take supplementary action. Whether it does so sooner or later is relatively immaterial as the other areas will merely wait (on their respective droops) until the remote load change has been corrected.

In all of the above reasoning it of course follows that had load decreases in place of load increases been considered the desirable end results would be the same.

It can be concluded at this point that: -

(a) For any given member of an interconnected group, Flat Frequency, Flat Tie-Line or Tie-Line Bias control are all capable of a satisfactory performance for internal disturbances.

(b) While combinations of Flat Frequency, Flat Tie-Line and Tie-Line Bias control are often workable, Tie-Line Bias control used throughout the interconnection is the only really satisfactory supplementary control mode for external disturbances.



$t_1 - t_2$ — NORMAL OPERATION.
t_2 — LOAD INCREASE IN AREA Y. SUPPLEMENTARY REGULATOR IN AREA X. COMMENCES ACTION.
t_3 — SUPPLEMENTARY CONTROL CEASES ACTION.
$t_3 - t_4$ — NORMAL OPERATION.

FIG 13* STEADY-STATE CHANGES IN FREQUENCY, TIE-LINE FLOW, LOAD AND GENERATION IN AREA X FOR DISTURBANCE IN AREA Y

(REGULATOR IN AREA X COMPLETES ITS ACTION BEFORE THAT IN AREA Y COMMENCES)

* COMPARE WITH FIG 3 IN REFERENCE 16

VI - BIAS - THE IMPOSED SUPPLEMENTARY REGULATION (Fig. 13)

It has been shown in the preceding section that only TLB control on correct bias (K_R) is capable of preventing redundant supplementary control action for external power disturbances. Because of changing load and generation conditions on a system it would be impracticable to fulfill Equation (13), $K_R = |N|$, for even a small proportion of the time. Further, equipment outages, due to maintenance, etc., of the load-frequency controls, it may be necessary to operate an interconnected system with a combination of FF, FTL, and TLB modes. For these reasons it is desirable to investigate quantitatively the imposed effects of the load-frequency controls on frequency, tie-line flows and generation caused by incorrect bias values.

In Reference 16, an analysis of imposed deviations is carried out based upon percent deviation from the natural deviations. This analysis, on the other hand, develops equations for the maximum deviations and indicates whether they are natural or imposed. In a like manner to Reference 16, however, neither incremental line losses nor transient effects are considered. Time intervals comparable to regulator reaction plus generation follow-up, i.e., seconds of time, are applicable. It will be shown in Chapter III that the results so obtained are reasonably accurate.

Throughout this section a two area (X & Y) interconnection is considered. A power disturbance occurs in Area Y and it is assumed that Area X's LFC regulator completes its action before that in Area Y commences.

<u>Effects on System Frequency.</u>

For an interconnected system, the natural combined characteristic, N_{TOT}, is given by

$$N_{TOT} = N_{(1)} + N_{(2)} + \text{---------} + N_{(n)} \text{ ---------------} \quad (18)$$

This is obvious upon reference to Equations (6) and (9).

For a D mW step function load change anywhere within the interconnection, the resulting natural frequency deviation, Δf, prior to supplementary control action is given by

$$-\Delta f = \frac{D}{10(N_{TOT})} \text{ c/s ---------------- ------------ -----} \quad (19)$$

Note:- A load increase or generation loss gives a +D and a $-\Delta f$.

If Area Y's FF, FTL, or TLB regulator were to complete its action before that in Area X commenced, the maximum frequency deviation would remain as indicated in Equation (19). Area Y would be correcting for its own disturbance. If on the other hand the regulator in Area X were to complete its action before Area Y commenced any supplementary control, the frequency deviation caused by D, plus the imposed regulator action in Area X would be given by

$$-\Delta f_B = \frac{D}{10\ (K_X + N_Y)} \text{ c/s --------------------------} \quad (20)$$

where K_X = bias setting in Area X in mW/0.1 cycle

(1) For FF control in Area X, $K_X = \infty$, and Equation (20)becomes

$$\Delta f_{B(FF)} = 0 \text{ ---} \quad (10)$$

This is Equation (10). The imposed regulation will tend to return the frequency to the scheduled value. The maximum frequency deviation for this condition will therefore be in accordance with Equation (19).

(2) For TLB control in Area X with a correct bias setting,

$$K_{RX} = |N_X| \text{ --------------------------------- } (13)$$

Equations (19) and (20) become identical and therefore

$$\Delta f_{B(K_R)} = \Delta f \text{ --------------------------------- } (21)$$

(3) For FTL control in Area X, $K_X = 0$, and Equation (20) becomes

$$-\Delta f_{B(FTL)} = \frac{D}{10(N_Y)} \quad c/s \text{ --------------------------------- } (22)$$

Effects on Tie-Line Flow

For a disturbance, D, applied in Area Y, the tie-line flow deviation experienced between Areas X and Y before supplementary control action takes place is given by

$$\Delta P_T = 10(N_X \Delta f)$$

Note:- A load increase or generation loss in Area Y gives a +D and a $+P_T$. The latter denotes an increased outward flow from Area X.

and Δf from Equation (19) gives

$$\Delta P_T = \frac{D\, N_X}{N_{TOT}} \quad mW \text{ --------------------------------- } (23)$$

The supplementary regulator would impose a deviation given by

$$\Delta P_{TB} = 10(K_X \Delta f_B)$$

and Δf_B from Equation (20) gives

$$\Delta P_{TB} = \frac{D\, K_X}{(K_X + N_Y)} \quad mW \text{ --------------------------------- } (24)$$

(1) For FF control in Area X, $K_X = \infty$, and Equation (24) becomes

$$\Delta P_{TB(FF)} = D \text{ mW} \quad \text{------------------------------------} \quad (25)$$

Area X will supply all of Area Y's deficiency (disturbance, D) over the tie-line in accordance with the frequency deviation, Δf, caused by disturbance, D.

(2) For TLB control in Area X with $K_{RX} = |N_X|$, Equations (23) and (24) become identical, and therefore

$$\Delta P_{TB(K_R)} = \Delta P_T \quad \text{------------------------------------} \quad (26)$$

(3) For FTL control in Area X, $K_X = 0$, Equation (24) becomes

$$\Delta P_{TB(FTL)} = 0 \quad \text{------------------------------------} \quad (11)$$

This is Equation (11). The imposed regulation will tend to return the tie-line flow to the scheduled value. The total tie-line flow deviation will therefore be in accordance with Equation (23).

Effects on Load in Area X

For a disturbance, D, applied in Area Y, the load change experienced in Area X, ΔP_{LX}, before supplementary control action takes place will be

$$-\Delta P_{LX} = (L_X \Delta f) \quad \text{mW}$$

and from Equation (19)

$$-\Delta P_{LX} = \frac{D\ L_X}{N_{TOT}} \text{ mW} \quad \text{------------------------------------} \quad (27)$$

Similarly, from Equation (20), the load change including regulator action is given by

$$-\Delta P_{LBX} = \frac{D\ L_X}{(K_X + N_Y)} \text{ mW} \quad \text{------------} \quad (28)$$

(1) For FF control in Area X, $K_X = \infty$, and Equation (28) becomes

$$\Delta P_{LBX(FF)} = 0 \quad \text{------------} \quad (29)$$

(2) For TLB control in Area X with a correct bias setting Equations (27) and (28) become identical and therefore

$$\Delta P_{LBX(K_R)} = \Delta P_{LX} \quad \text{------------} \quad (30)$$

(3) For FTL control in Area X, $K_X = 0$, and Equation (28) becomes

$$-\Delta P_{LBX(FTL)} = \frac{D\ L_X}{N_Y} \text{ mW} \quad \text{------------} \quad (31)$$

Effects on Total Generation in Area X

For a disturbance, D, applied in Area Y, the generation change experienced in Area X, ΔP_{GX}, before supplementary control action takes place, will be in accordance with

$$N_X = G_{CX} - L_X \quad \text{------------} \quad (9)$$

and

$$\Delta P_{GX} = \Delta P_T - \Delta P_{LX} \text{ mW} \quad \text{------------} \quad (32)$$

This is so because the tie-line flow deviation will be supplied completely in accordance with N_X. That is

$$10(\Delta f\, N_X) = \Delta P_T$$

From Equations (23) and (27)

$$\Delta P_{GX} = \frac{D(N_X - L_X)}{N_{TOT}} \text{ mW} \text{ ---------------------------- } (33)$$

The supplementary regulator would impose a deviation given by Equation (24) minus Equation (28), that is

$$\Delta P_{GBX} = \Delta P_{TB} - \Delta P_{LBX} \text{ ------------------------------ } (34)$$

and

$$\Delta P_{GBX} = \frac{D(K_X - L_X)}{(K_X + N_Y)} \text{ mW} \text{ -------------------------- } (35)$$

(1) For FF control, from Equation (25) minus Equation (29)

$$\Delta P_{GBX(FF)} = \Delta P_{TB(FF)} = D \text{ mW} \text{ ---------------------- } (36)$$

Note that this generation deviation must be supplied totally from the regulated generation in Area X. The unregulated generation in Area X will return to that value prevailing before the incidence of disturbance, D.

(2) For TLB control on correct bias in Area X, Equation (33) will equal Equation (35),

$$\Delta P_{GBX(K_R)} = \Delta P_{GX} \text{ ---------------------------------- } (37)$$

(3) For FTL control, $K_X = 0$, and Equation (35) becomes

$$\Delta P_{GBX(FTL)} = \frac{D(-L_X)}{N_Y} \text{ mW} \text{ -------------------------- } (38)$$

Effects on Unregulated and Regulated Generation in Area X

(a) Natural Governor Reaction - (before supplementary control action).

ΔP_{GX} is made up of regulated, ΔP_{GXR}, and unregulated, ΔP_{GXU}, generation contributions.

$$\Delta P_{GX} = \Delta P_{GXR} + \Delta P_{GXU} \quad \text{------------} \quad (39)$$

and therefore

$$G_{CX} = G_{CXR} + G_{CXU} \quad \text{------------} \quad (40)$$

where G_{CX}, G_{CXR}, G_{CXU} are the total, regulated and unregulated composite governing characteristics respectively for Area X.

Unregulated generation will absorb

$$\Delta P_{GXU} = \frac{G_{CXU}}{G_{CX}} (\Delta P_{GX}) \quad \text{mW}$$

and from Equation (33), noting that $G_{CX} = (N_X - L_X)$,

$$\Delta P_{GXU} = \frac{D\, G_{CXU}}{N_{TOT}} \quad \text{mW} \quad \text{------------} \quad (41)$$

Regulated generation will absorb

$$\Delta P_{GXR} = \frac{G_{CXR}}{G_{CX}} (\Delta P_{GX}) \quad \text{mW}$$

and from Equation (33)

$$\Delta P_{GXR} = \frac{D\, G_{CXR}}{N_{TOT}} \quad \text{mW} \quad \text{------------} \quad (42)$$

(b) Natural Governor Reaction plus Supplementary Control Action

ΔP_{GBX} is likewise made up of regulated, ΔP_{GBXR}, and unregulated, ΔP_{GBXU}, contributions.

$$\Delta P_{GBX} = \Delta P_{GBXR} + \Delta P_{GBXU} \quad \text{------------------------------} \quad (43)$$

Unregulated generation will absorb

$$\Delta P_{GBXU} = 10(G_{CXU}\,\Delta f_B)$$

From Equation (20),

$$\Delta P_{GBXU} = \frac{D\,G_{CXU}}{(K_X + N_Y)} \quad \text{------------------------------} \quad (44)$$

(1) For FF control in Area X, $K_X = \infty$, and Equation (44) becomes

$$\Delta P_{GBXU(FF)} = 0 \quad \text{------------------------------} \quad (45)$$

(2) For TLB control in Area X with correct bias, $K_X = |N_X|$, and

$$\Delta P_{GBXU(K_R)} = \frac{D\,G_{CXU}}{N_{TOT}} \quad \text{------------------------------} \quad (46)$$

(3) For FTL control in Area X, $K_X = 0$, and

$$\Delta P_{GBXU(FTL)} = \frac{D\,G_{CXU}}{N_Y} \quad \text{------------------------------} \quad (47)$$

Regulated generation will absorb, from Equations (43), (35) and (44),

$$\Delta P_{GBXR} = \frac{D(K_X - L_X - G_{CXU})}{(K_X + N_Y)} \quad \text{------------------------------} \quad (48)$$

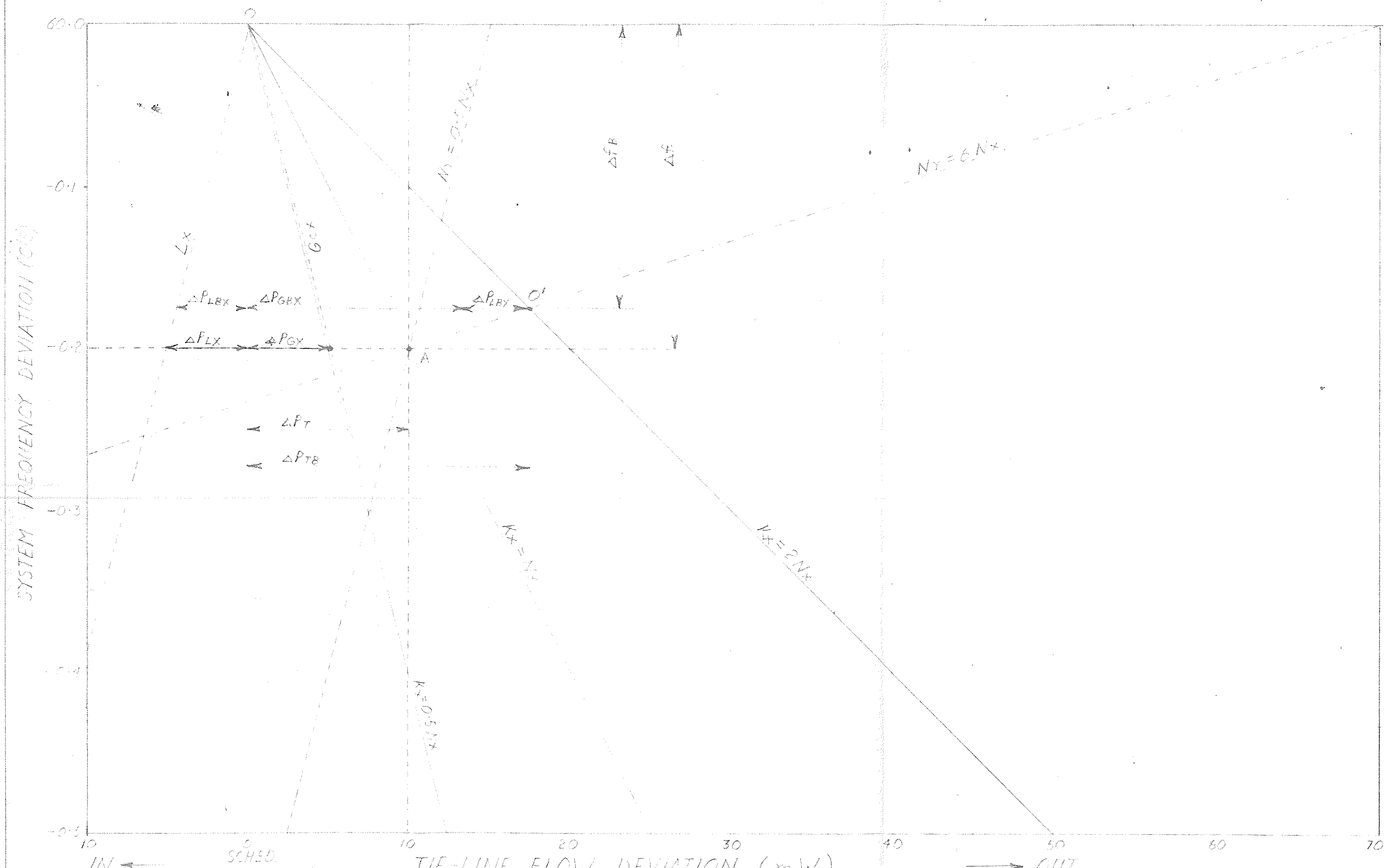


FIG 14 GRAPHICAL REPRESENTATION OF THE DEVIATION EQUATIONS.

(1) For FF control in Area X, $K_X = \infty$, and Equation (48) becomes

$$\Delta P_{GBXR(FF)} = D \quad \text{------------------------------------} \quad (49)$$

(2) For TLB control in Area X with correct bias, $K_X = |N_X|$, and

$$\Delta P_{GBXR(K_R)} = \frac{D(N_X - L_X - G_{CXU})}{N_{TOT}} = \frac{D\,G_{CXR}}{N_{TOT}} \quad \text{-----------} \quad (50)$$

(3) For FTL control in Area X, $K_X = 0$ and

$$\Delta P_{GBXR(FTL)} = \frac{D(-L_X - G_{CXU})}{N_Y} \quad \text{------- ---------------} \quad (51)$$

A summary of the above frequency, tie-line flow, load and generation deviation equations is contained in Table I on Page 33.

A graphical representation of the various deviation equations is contained in Figure 14 for a power disturbance causing a natural frequency deviation of 0.2 cycle. The deviations imposed by different bias settings for the case of $N_Y < N_X$ ($N_Y = 0.5\ N_X$), and for $N_Y > N_X$ ($N_Y = 6.0\ N_X$), can be obtained from the figure. Appropriate values are indicated for $K_X = 2\ N_X$ and $N_Y = 6\ N_X$ for the new point of operation, O!

Conclusions relating to the imposed effects on frequency, tie-line flow, load and generation deviations can be summarized as follows for an external net load increase:-

(a) For a bias value employed in an area that is greater than the natural combined characteristic of that area, supplementary regulation will tend to:-

TABLE I

SUMMARY OF DEVIATION EQUATIONS FOR A TWO AREA INTERCONNECTION

(The equations apply to Area X for an increased power demand (+D) in Area Y. The LFC regulator in Area X is assumed to complete its action before that in Area Y commences).

FUNCTION	NATURAL DEVIATION	IMPOSED DEVIATIONS FF	IMPOSED DEVIATIONS TLB	IMPOSED DEVIATIONS FTL
Frequency (c/s)	(19)* $\frac{-D}{10(N_{TOT})}$	(10) 0	(20) & (21) $\frac{-D}{10(K_X + N_Y)}$	(22) $\frac{-D}{10(N_Y)}$
Tie-Line Flow (mW)	(23) $\frac{D\ N_X}{N_{TOT}}$	(25) D	(24) & (26) $\frac{D\ K_X}{(K_X + N_Y)}$	(11) 0
Load Area X (mW)	(27) $\frac{D(-L_X)}{N_{TOT}}$	(29) 0	(28) & (30) $\frac{D(-L_X)}{(K_X + N_Y)}$	(31) $\frac{D(-L_X)}{N_Y}$
Total Generation Area X (mW)	(33) $\frac{D\ (N_X - L_X)}{N_{TOT}}$	(36) D	(35) & (37) $\frac{D\ (K_X - L_X)}{(K_X + N_Y)}$	(38) $\frac{D\ (-L_X)}{N_Y}$
Unregulated Generation Area X (mW)	(41) $\frac{D\ G_{CXU}}{N_{TOT}}$	(45) 0	(44) & (46) $\frac{D\ G_{CXU}}{(K_X + N_Y)}$	(47) $\frac{D\ G_{CXU}}{N_Y}$
Regulated Generation Area X (mW)	(42) $\frac{D\ G_{CXR}}{N_{TOT}}$	(44) D	(48) & (50) $\frac{D\ (K_X - L_X - G_{CXU})}{(K_X + N_Y)}$	(51) $\frac{D(-L_X - G_{CXU})}{N_Y}$

*Refers to the appropriate equation number in the text.

(i) Reduce the frequency deviation.

(ii) Increase the tie-line flow deviation.

(iii) Increase the load.

(iv) Increase the total local generation.

(v) Reduce the local unregulated generation.

(vi) Increase the local regulated generation.

(b) For a bias value employed in an area that is less than the natural combined characteristic of that area, supplementary regulation will tend to:-

(i) Increase the frequency deviation.

(ii) Reduce the tie-line deviation.

(iii) Decrease the load.

(iv) Reduce the total local generation.

(v) Increase the local unregulated generation .

(vi) Reduce the local regulated generation.

(c) For a correct bias value there will be no imposed deviations. The system will behave as though it had no supplementary control and will wait until the disturbance area has provided for its own deficiency.

(d) If a given area represents a major or substantial proportion of the spinning capacity of an interconnection its bias should be adjusted to a value which will always be either equal to or slightly greater than its own prevailing natural combined characteristic. This will avoid excessive system frequency deviations at the expense of only slightly increased tie-line flow deviations and will assist the other area in its recovery.

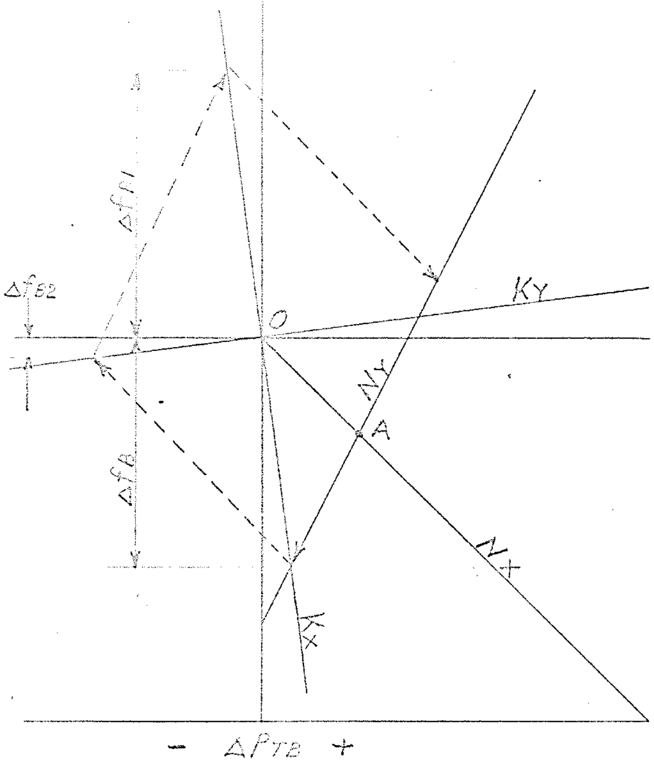
(e) If a given area represents a comparatively small proportion of the spinning capacity of an interconnection its bias should be adjusted to a value which will always be either equal to or slightly less than its own prevailing natural combined characteristic. This will avoid excessive demands on its generation and possible excessive tie-line flow deviations at the expense of only slightly increased system frequency deviations.

(f) It will be observed that the imposed deviation on regulated generation is in fact the only directly imposed variation. Deviations of frequency, tie-line flows, and unregulated generation are consequences of this direct action. Hence Equation (48) does not contain the term G_{CXR} (the normal combined governing characteristic of the regulated generation). Normal governor action on the regulated generation in accordance with G_{CXR} is over-ridden by the LFC regulator.

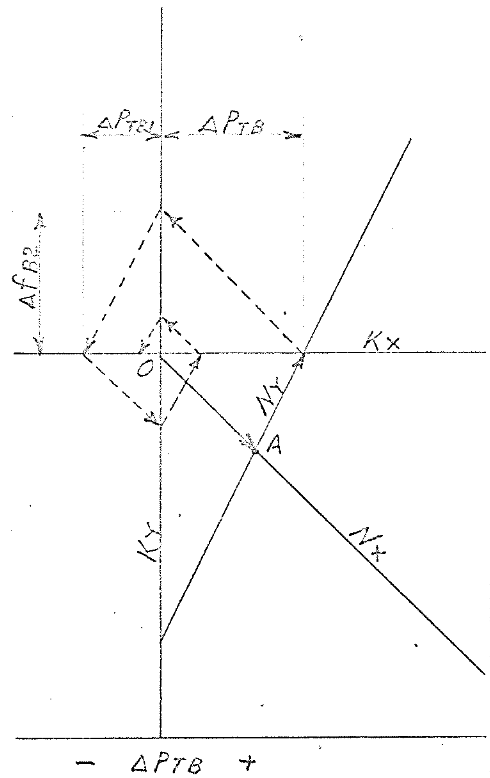
(g) Flat-Frequency (FF) control imposes the greatest demands on the regulated generation.

VII - EFFECT OF BIAS AND THE NATURAL COMBINED CHARACTERISTIC ON CONTROL SYSTEM STABILITY

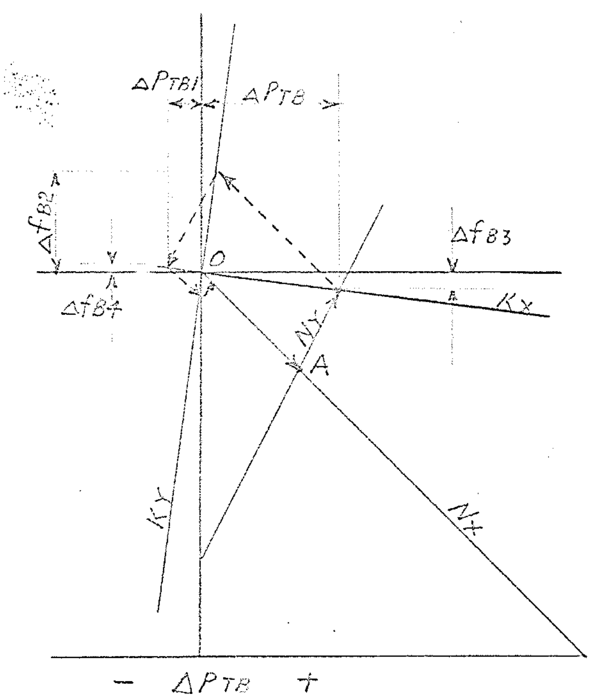
From the foregoing derivation of deviation equations it will be apparent that the natural combined characteristics (N) and bias settings (K) of the areas involved will influence the interaction of the areas in their attempt to reduce the tie-line and/or frequency deviations to zero in accordance with their supplementary control mode. A disturbance +D will be assumed to take place causing a new operation point, A, to be established. Again, it will be assumed that Area X completes its control



(a) TLB/TLB CONTROL
$K_X \leqslant N_X$
$K_Y \geqslant N_Y$



(b) FF/FTL CONTROL



(C) TLB/TLB CONTROL
$K_X \geqslant N_X$
$K_Y \leqslant N_Y$

FIG. 16 INFLUENCE OF THE NATURAL COMBINED CHARACTERISTICS AND BIAS SETTINGS ON THE IMPOSED FREQUENCY AND TIE-LINE FLOW DEVIATIONS

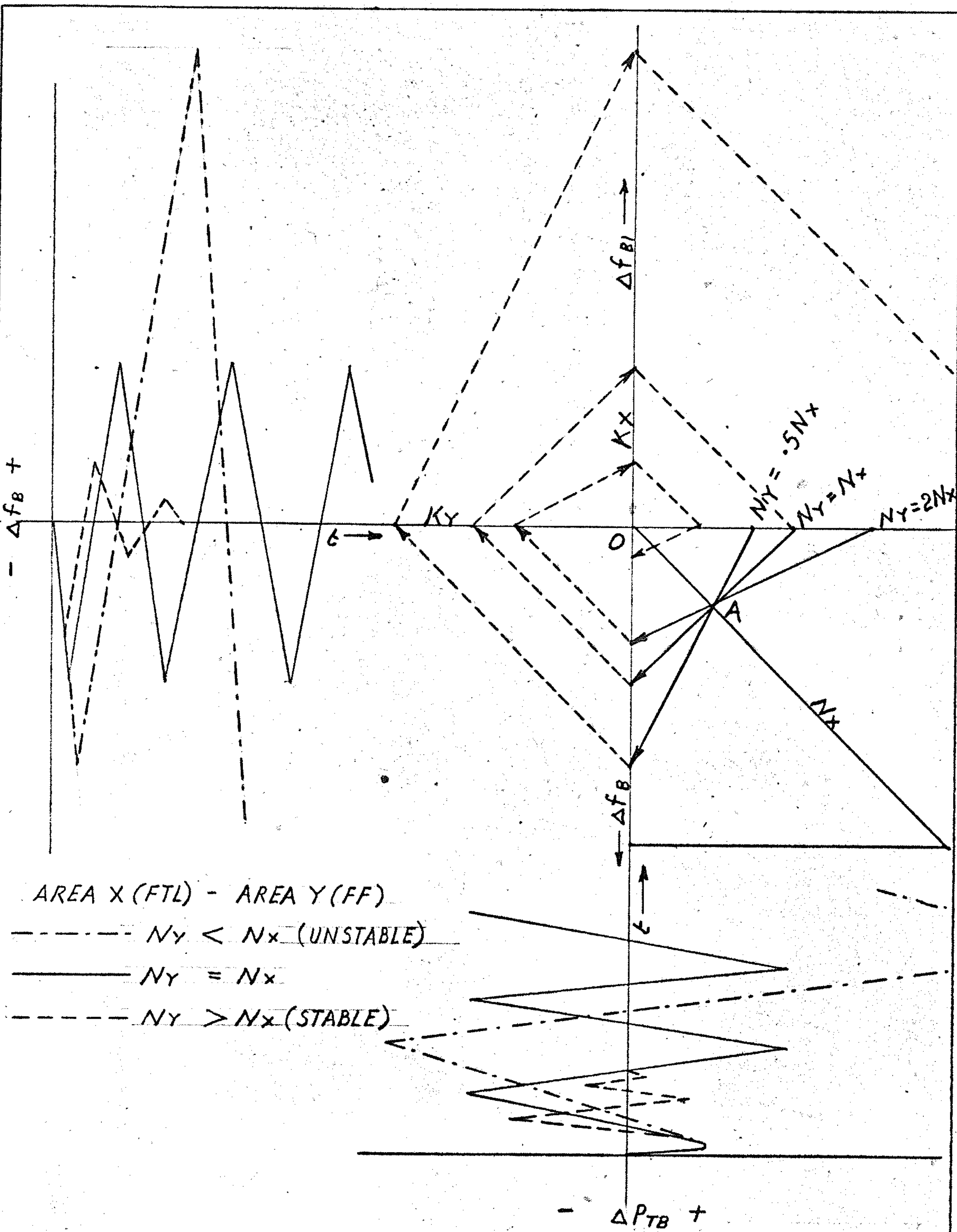


FIG. 15 INFLUENCE OF THE NATURAL COMBINED CHARACTERISTICS ON THE IMPOSED FREQUENCY & TIE-LINE FLOW DEVIATIONS FOR FTL/FF CONTROL

action and generation follow-up before that in Area Y commences, after which Area Y will be assumed to complete its changes, and so on. This is a somewhat idealized though pessimistic approach. It does, however, indicate the relative tendency of the controls to interact in a stable or unstable manner.

Area X (FTL) - Area Y (FF) Control

The imposed frequency deviation, Δf_B, caused by Area X's regulator has already been defined. If Δf_{B1} is defined as the following frequency deviation from schedule caused by overshoot of the controls, then

$$\lim_{t \to \infty} e^{\left[\frac{\Delta f_{B1}}{\Delta f_B} - 1\right] t} \qquad (52)$$

will define whether or not the system tends to be stable. If the $\lim \to 0$, i.e., if $\Delta f_{B1} < \Delta f_B$, a stable tendency will be indicated.

From Figure 11, the interaction behaviour for this type of control combination with $N_X = N_Y$ is shown. From Appendix B(i) and Figure 15 the relationship for $N_X < N_Y$ and $N_X > N_Y$ is developed, from which

$$\frac{\Delta f_{B1}}{\Delta f_B} = \frac{N_X}{N_Y} \qquad (53)$$

TLB/TLB Control for $K_X \leq N_X$ and $K_Y \geq N_Y$ (Refer to Appendix B(ii) and Figure 16(a)).

It should be noted that the examples in Figure 16 are employed to derive the relevant equations in a general sense. The particular N and K values selected are arbitrary and are not intended to imply a generally stable or unstable condition.

From Appendix B(ii),

$$\frac{\Delta f_{B1}}{\Delta f_B} = \left[\frac{(N_X - K_X)}{(N_Y + K_X)}\right]\left[1 - \frac{(N_X + N_Y)}{(K_Y + N_X)}\right] \qquad (54)$$

Note that for FTL control in Area X ($K_X = 0$), and FF control in Area Y, ($K_Y = \infty$), Equation (54) becomes

$$\frac{\Delta f_{B1}}{\Delta f_B} = \frac{N_X}{N_Y} \qquad (53)$$

Note also that for $K_X = |N_X|$ and/or $K_Y = |N_Y|$

$$\Delta f_{B1} = 0 \qquad (55)$$

Area X (FF) - Area Y (FTL) Control

By similar reasoning to that contained in Equation (52) above,

$$\lim_{t \to \infty} e^{\left[\frac{\Delta P_{TB1}}{\Delta P_{TB}} - 1\right] t} \qquad (56)$$

where ΔP_{TB} is the imposed tie-line flow deviation.

ΔP_{TB1} is the following imposed tie-line flow deviation caused by controller overshoot

Equation (56) defines the stability tendency of the supplementary controls for Area X (FF) and Area Y (FTL).

From Appendix B(iii) and Figure 16(b),

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = \frac{N_Y}{N_X} \qquad (57)$$

<u>TLB/TLB Control for $K_X \geqslant N_X$ and $K_Y \leqslant N_Y$</u>

From Appendix B(iv) and Figure 16(c),

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = \frac{\left[\frac{K_X + N_Y}{K_X}\right]\left[1 - \frac{(N_X + N_Y)}{(K_X + N_Y)}\right](N_Y - K_Y)\left[1 - \frac{N_Y}{(K_X + N_Y)}\right]}{(K_Y + N_X)} \quad \text{---(58)}$$

For $K_X = \infty$ and $K_Y = 0$,

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = \frac{N_Y}{N_X} \quad \text{-- (57)}$$

and for $K_X = |N_X|$ and/or $K_Y = |N_Y|$,

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = 0 \quad \text{-- (59)}$$

<u>TLB/TLB Control for $K_X < N_X$ and $K_Y < N_Y$ (Figure 17)</u>

If $K_Y < N_Y$, then from Equation (54), Δf_{B1} will be negative indicating that it is in the same direction as Δf_B. The action is one of oscillation about the scheduled tie-line flow value until the correct point of operation, Point 0, is reached.

<u>TLB/TLB Control for $K_X > N_X$ and $K_Y > N_Y$ (Figure 17)</u>

By similar reasoning, if $K_Y > N_Y$, then from Equation (58), ΔP_{TB1} will be negative indicating that it is in the same direction as ΔP_{TB}. The action in one of oscillation about the scheduled system frequency value until the correct point of operation, Point 0, is reached.

The above two TLB arrangements are generally undesirable as the control recovery process tends to be vague and lengthy. In the ultimate, i.e., $K_X = K_Y = 0$ and $K_X = K_Y = \infty$, are unworkable combinations. The former is not able to maintain system frequency on schedule while the latter cannot maintain tie-line flows on schedule.

The conclusions which may be drawn from this section are:-

(a) For FTL/FF operation with the FTL unit assumed to be the faster controller located in the external area (Area X); then the smaller the ratio N_X/N_Y, the more stable the control action.

(b) For FF/FTL operation with the FF unit assumed to be the faster controller located in the external area (Area X); then the greater the ratio N_X/N_Y, the more stable the control action.

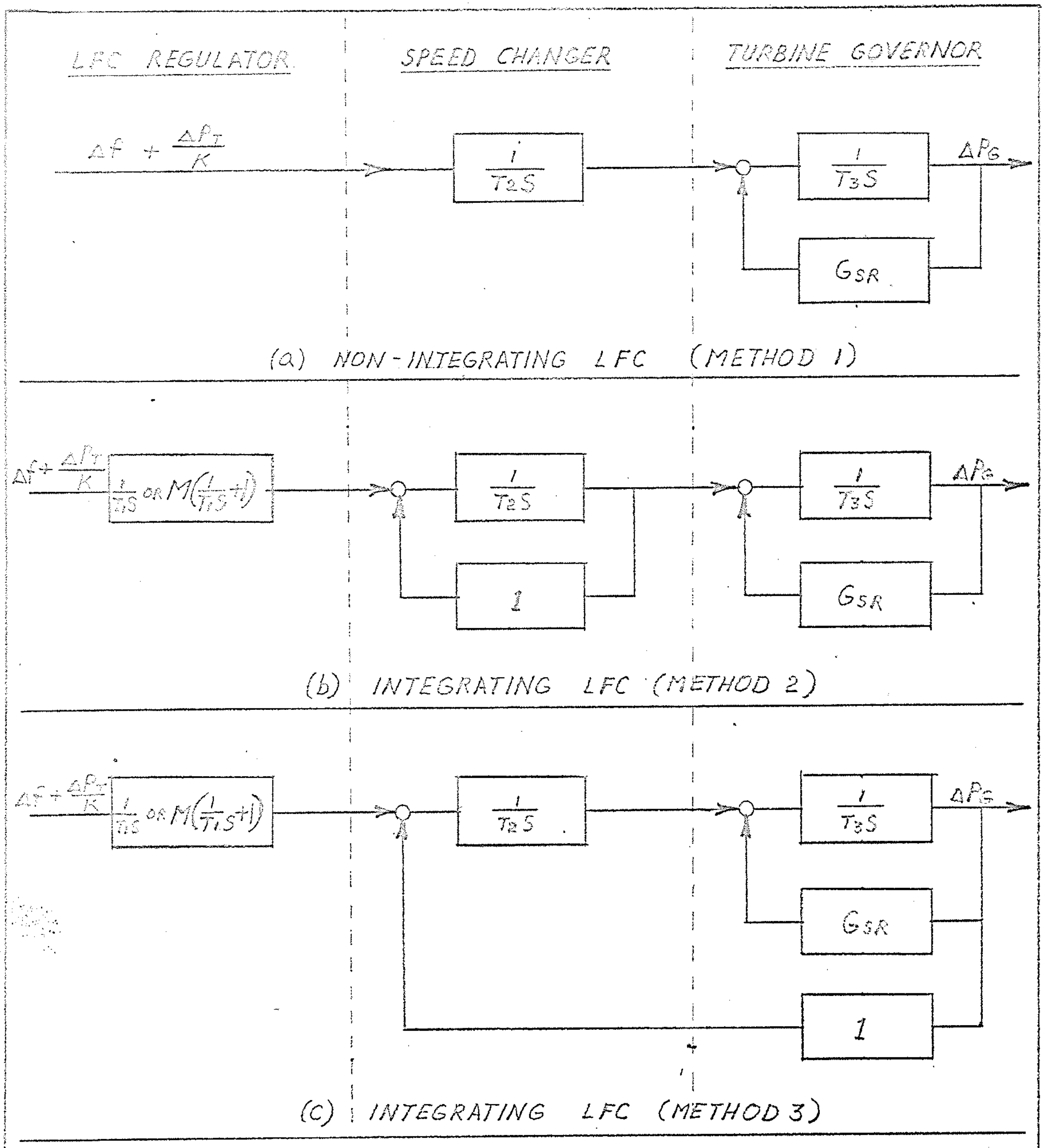
(c) In confirmation of Conclusion (d) of Section VI, a comparatively large area with fast supplementary controlled generation response should employ bias values that equal or are greater than its prevailing natural combined characteristic.

(d) Similarly, in confirmation of Conclusion (e) of Section VI, a comparatively small area with fast supplementary controlled generation response should employ bias values that equal or are less than its prevailing natural combined characteristic.

(e) Appropriate bias values can overcome the adverse effects on stability attendant with different area natural combined characteristics.

(f) Bias values in two interconnected areas that are both greater than or both less than their respective natural combined characteristics tend to give an unnecessarily slow and vague follow-up.

(g) TLB operation even in the disturbance area provides a more stable supplementary control action than FF or FTL particularly if FF or FTL is used in the non-disturbance area.



Δf = FREQUENCY DEVIATION
ΔP_T = TIE-LINE FLOW DEVIATION
ΔP_G = GENERATION DEVIATION
K = BIAS
T_1, T_2, T_3 = TIME COEFFICIENTS
G_{SR} = SPEED REGULATION OF LFC GENERATION
S = d/dt

FIG 18 TYPES OF SUPPLEMENTARY CONTROLS
(SEE FIGS. 3b, 3c, 4a, 4b, 5a + 5b IN REF. 20)

VII - SUPPLEMENTARY CONTROLLERS (Fig. 18)

It was mentioned on p. 15 in Section IV that the term Tie-Line Bias as employed herein would designate that class of controller which functions in accordance with both tie-line flow and frequency deviations from schedule. In other words, the equation

$$\Delta P_T + K\Delta f = 0 \quad \text{------------------------} \quad (12)$$

is continuously being solved by the TLB controller. The binomial, $(\Delta P_T + K\Delta f)$ constitutes the error signal and defines the amount of generation by which the area is deficient in or has an excess of relative to its load at frequency, $f_R = 1.0$ p.u. For this reason the binomial is termed the "Area Requirement". In most literature on the subject, the error binomial is written in terms of an equivalent frequency error, i.e., $(\Delta f + \Delta P_T/K)$.

In order that the error signal be reduced to zero in accordance with Equation (12) a means of integrating the error signal must be accomplished somewhere in the supplementary control process (See Appendix C). A number of different solutions to the problem of utilizing the error signal have evolved of which three are by far the most popular.[18,19,20]

These are:

1. <u>Indirect Regulation with a Non-Integrating Network Regulator</u> (Method B, Ref. 20, p. 9). This method is known as Tie-Line Bias control and involves the measurement of $(\Delta f + \Delta P_T/K)$ at some appropriate location from which it is telemetered to the units under supplementary control. Integration is carried out by the governor speeder motors which effect changes in regulated generation proportional to the error binomial.

The change in area generation, ΔP_G, brought about by this method of control on the area generation under LFC is given in transfer function form (Refer to Figure 18a) by

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = -\left[\frac{P_{GRO}}{T_2 G_{SR} P_{GO} S}\right]\left[\frac{1}{T_3 S/G_{SR} + 1}\right] \quad \text{------------- (60)*}$$

where T_2 = Integrating time coefficient of the speeder motors

T_3 = Characteristic time of LFC regulated machine governors

S = d/dt

G_{SR} = Steady-state speed regulation of LFC regulated generation

P_{GO} = Nominal rating of all area connected generation

P_{GRO} = Nominal rating of all area LFC connected generation

It is assumed that all units under load-frequency control are of the same type, i.e., that T_2, T_3 and G_{SR} are the same for all units.

It is to be noted that as integration is carried out by each speeder motor, load transfers between units would probably occur. Load equalizing facilities are therefore required for these units under LFC. If the units are located in different stations, telemetering of the equalizing information would have to be provided.

2. Indirect Regulation with an Integrating Network Regulator - The unit speed changers are placed under the control of $\int_0^t (\Delta f + \Delta P_T/K)\, dt$ (Method Ca, Ref. 20, p. 14). This method is also known as Tie-Line Bias control but

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* See Ref. 20, p. 13, 2nd equation

differs from Method 1, above, in that both measurement and integration are carried out at the load-frequency controller. This integral is then telemetered to the appropriate generators.

The transfer function associated with this method of control (Refer to Figure 18b) is given by

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = - \left[\frac{P_{GRO}}{T_1 G_{SR} P_{GO} S}\right]\left[\frac{1}{T_2 S + 1}\right]\left[\frac{1}{T_3 S/G_{SR} + 1}\right] \text{ ------ } (61)^*$$

where T_1 = Integrating time coefficient of the LFC regulator.

All other symbols are as defined with respect to Equation (60).

Note: Equation (61) is applicable to mechanical governors with speeder motors. For electric governors, $T_2 = 0$.

If proportional action (See Appendix C) is employed in addition to integral action, in the LFC regulator, Equation (61) becomes.

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = - M\left[\frac{1}{T_1 S} + 1\right]\left[\frac{P_{GRO}}{G_{SR} P_{GO}}\right]\left[\frac{1}{T_2 S + 1}\right]\left[\frac{1}{T_3 S/G_{SR} + 1}\right] \text{ ---- } (62)$$

where M = Proportional sensitivity.

With Method 2, the LFC regulator carries out the only integration process for all machines involved. As a consequence no load equalizing equipment is required so that the machines under LFC can be located practically anywhere on the system without imposing complicated telemetering schemes.

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* See Ref. 20, p. 15, last equation

3. Indirect Regulation with an Integrating Network Regulator - The deviation of power output from each unit under LFC is placed under the control of $\int_0^t (\Delta f + \Delta P_T/K)\, dt$. (Method Cb, Ref. 20, p. 17, and Refs. 21 & 22). This method is known as Load-Phase Tie-Line Energy control and is similar to Method 2 above in that both measurement and integration are carried out at the load-frequency controller. In the designation Load-Phase Tie-Line Energy, "Load" refers to the power supplied by the units, while "Phase" and "Tie-Line Energy" are the integrals of frequency and tie-line power flow respectively in accordance with $\int_0^t (\Delta f + \Delta P_T/K)\, dt$. The integrated error signal is, like Method 2, telemetered to the units under LFC.

The appropriate transfer function applicable to this control method (Refer to Figure 18c) is given by

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = - \left[\frac{P_{GRO}}{T_1 P_{GO} S}\right]\left[\frac{1}{T_2 T_3 S^2 + T_2 G_{SR} + 1}\right] \text{---- ---------} \quad (63)^*$$

and in Proportional-Integral form,

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = - M\left[\frac{1}{T_1 S} + 1\right]\left[\frac{P_{GRO}}{P_{GO}}\right]\left[\frac{1}{T_2 T_3 S^2 + T_2 G_{SR} + 1}\right] \text{-------} \quad (64)$$

This method of control, like Method 2 above, requires no load equalizing equipment. It does differ from Method 2, however, in that the feedback signal proportional to the LFC regulated generation output would tend to vary the output of this generation during times of power disturbances external to the area considered. In other words, participation of the LFC regulated output is not determined solely in accordance with

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* See Ref. 20, p. 18, 3rd equation.

Equation (12) but is dependent also on the deviation from the scheduled output of the LFC regulated machines. This would have the effect of reducing G_{CR}, the generation/frequency characteristic of the units under LFC and therefore would reduce the natural combined characteristic of the area.

To summarize:-

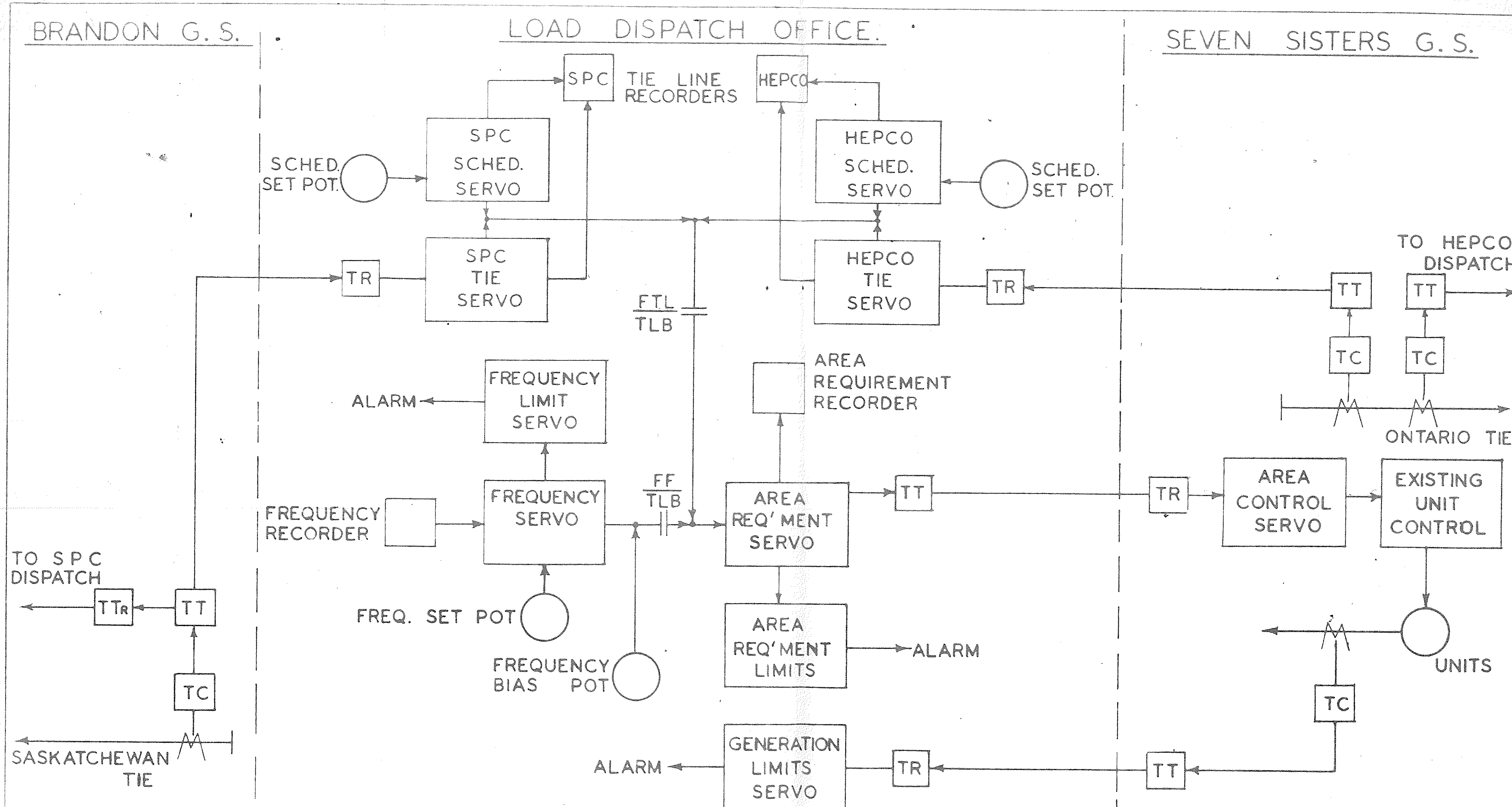
(a) Method 1 involves a simpler load-frequency controller but requires load equalizing equipment between units under supplementary control. This method does not lend itself to proportional-integral control.

(b) Methods 2 and 3 are capable of proportional-integral control and do not require load equalizing equipment. Units anywhere on the system can be selected for supplementary regulation with a minimum of telemetering.

(c)Method 2 appears to offer a higher quality of control than Method 3 because it eliminates the power output feedback loop, thereby maintaining the value of G_{CXR} (and therefore G_{CX}) during external disturbances.

(d) For given response rates of the controllers, speeder motors and turbine governors, a greater proportion of generation under supplementary regulation will speed up the LFC process. For Methods 1 and 2, a smaller governor droop will likewise produce a more rapid response to LFC.

(e) Proportional control can be beneficial provided there is suitably rapid, responsive generation available for control. This would of course involve thermal and/or hydraulic considerations of the units involved.[23,24] Placing inherently rapid-responding thermal units under proportional control and slower, larger hydraulic units under integral control has proven to be perhaps the best combination.[25]



LEGEND

TC	THERMAL CONVERTER	FF — FLAT FREQUENCY CONTROL
TT	TELEMETER TRANSMITTER	FTL — FLAT TIE-LINE CONTROL
TR	TELEMETER RECEIVER	TLB — TIE LINE BIAS CONTROL
TTR	TELEMETER TRANSLATOR	

LOAD & FREQUENCY CONTROL EQUIPMENT

M.H. LOAD DISPATCH OFFICE

(FIG. 2 IN REF. 26)

FIG 19

CHAPTER II

LOAD-FREQUENCY CONTROLS AS APPLIED BY MANITOBA HYDRO

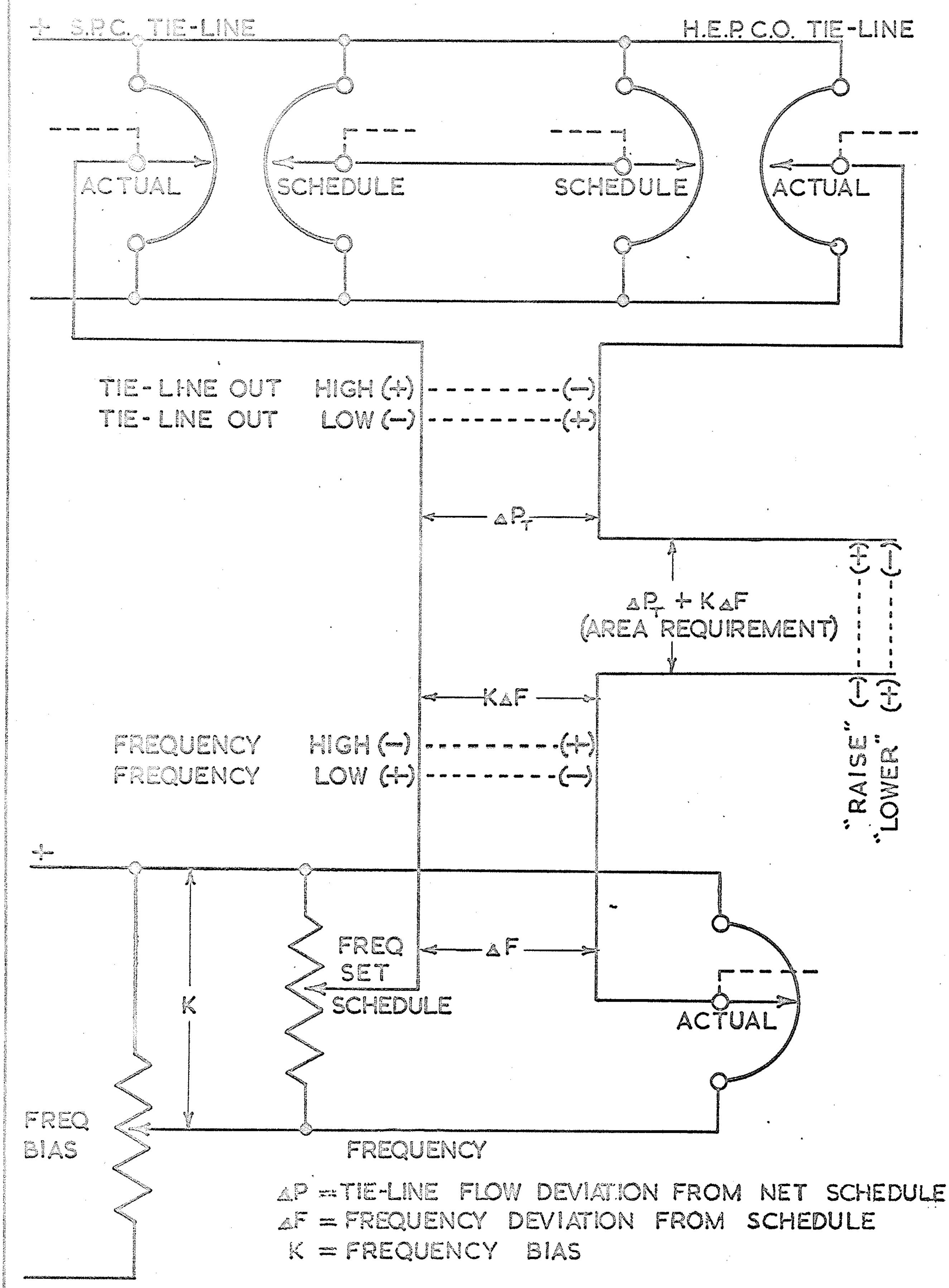
I - GENERAL

This part of the study will concern itself with the operational principles of Manitoba Hydro's load-frequency controls. The methods employed to embody the theories presented in Chapter I are discussed.

II - THE LFC SYSTEM (Fig. 19)

Metering and Telemetering - The SPC, MH and HEPCO LFC equipments are all capable of FF, or FTL, or TLB control so that frequency and tie-line flow information must be made available on a continuous basis. System frequency is of course available throughout the system so it remains necessary to transport the tie-line flows from the ties themselves into the equipment in the three control centres. The SPC and HEPCO tie-line flows are metered at the Brandon and Seven Sisters Generating Stations of the MH respectively. From these points, the megawatt flow quantities are telemetered to each of the two parties concerned.

Tie-Line Schedule and Comparison Circuits - As indicated above, each of the several MH telemeter receivers convert the variable frequency signals from the transmission channels back to millivolts. These are then fed into the tie-line electronic bridge servo-mechanisms. A similar signal based upon the position of the schedule set potentiometer positions the schedule servos. The outputs from the tie-line and schedule



ΔP = TIE-LINE FLOW DEVIATION FROM NET SCHEDULE
ΔF = FREQUENCY DEVIATION FROM SCHEDULE
K = FREQUENCY BIAS

FIG. 20 TIE-LINE BIAS OPERATION
(FIG. 4 IN REF. 27)

set retransmitting slidewires are then compared. If no signal is produced (i.e. the two slides at the same potential), the tie-line flow agrees with the schedule setting and no correction signal is forthcoming. The schedule flow (as set by the load dispatchers) and the actual tie-line flow (telemetered in from the actual tie-lines) are displayed upon a two-pen strip chart recorder for each tie-line.

By reference to Figure 19, it will be observed that the tie-line flow schedules can be set individually. This avoids the possible confusion arising when net deviation is employed, the operator having to contend with net interchange instead of the actual scheduled values. The scheme employed is readily expandable to cater for new interconnections or for additional ties to existing interconnected areas. The error signals from the two or more tie-line equipments are then algebraically combined before being fed into the area requirement servo, thus, automatically providing the net overall tie-line error correction. The above measurements and comparisons would provide the necessary information for the Flat Tie-Line (FTL) control mode.

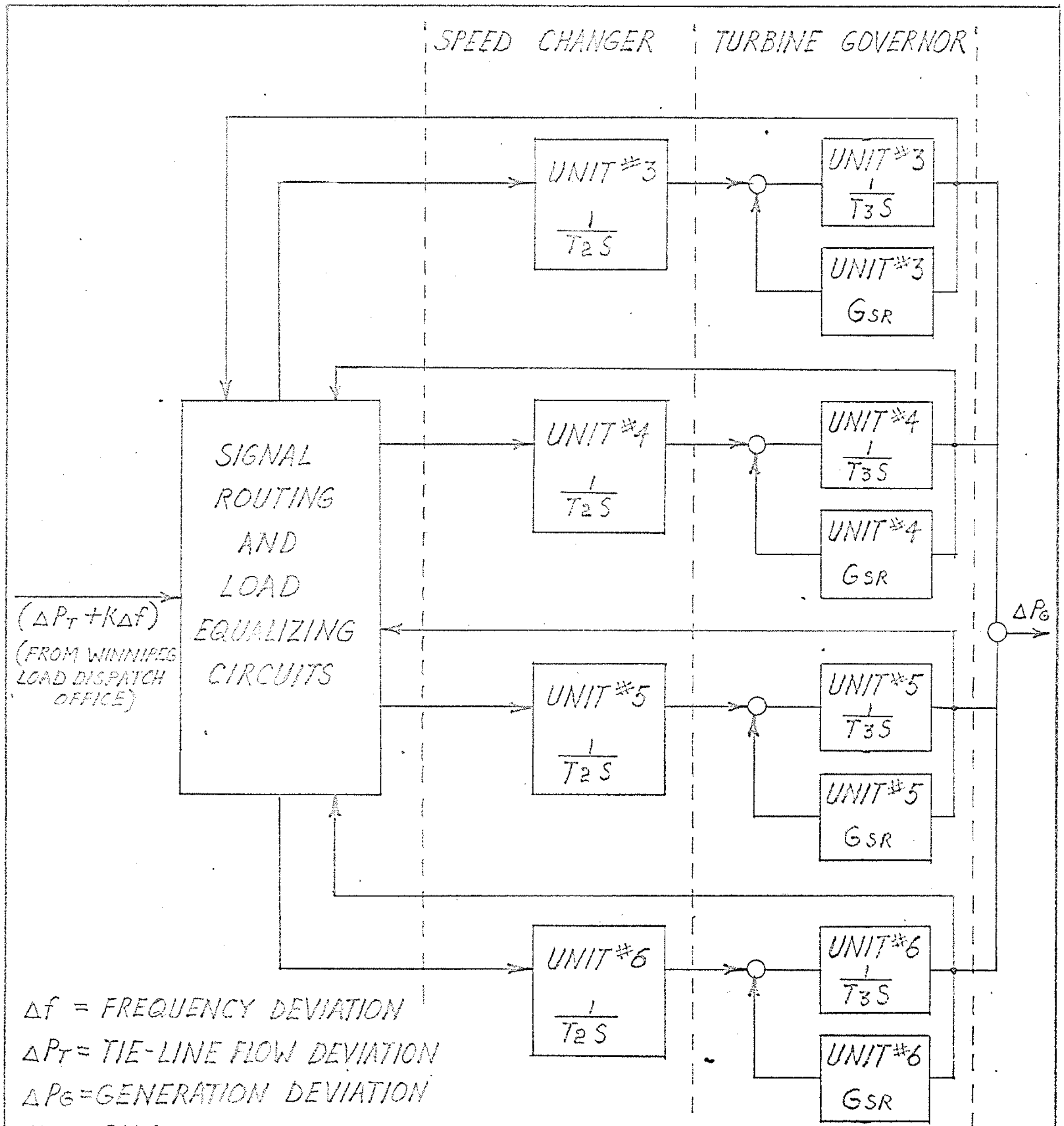
Frequency Schedule and Comparison Circuits - Tie Line Bias - (Fig. 20)

In a similar fashion to the above, frequency error is measured by comparing the frequency set point value to that actually appearing on the system. This procedure would permit an error signal to be provided in accordance with the Flat Frequency (FF) control mode.

For Tie-Line Bias (TLB) operation both the above error signals are combined algebraically. The value of the frequency error signal may be modified and its value relative to that of the tie-line error signal determines the amount by which the latter is "biased". It is evident that the error signal derived through TLB represents a value of power deviation per frequency deviation. It will be seen from the "Freq. Bias" potentiometer in Figure 20 that the frequency deviation error signal may be adjusted in magnitude to give suitable mW/0.1 cycle values.

Area Requirement - For a bias setting that corresponds to the natural combined area characteristic, it may be seen from Figure 20 how TLB operation determines whether a disturbance on the interconnected system is external or internal to the area in which the control is located. The error signal, derived either with reference to tie-line deviation, frequency deviation, or both, is passed on to the "Area Requirement" servo which interprets in accordance with the foregoing whether the MH area is deficient in or has an excess of generation and passes the correcting signal on (by means of high speed telemeters) to the control equipment at Seven Sisters Generating Station. The latter provides the necessary "Raise" or "Lower" signals to the governor synchronizing motors of the generator units under control. Adjustable "High" and "Low" limit alarms fed from a retransmitting slidewire of the Area Requirement servo provide annunciation for unusual disturbances. An "Area Requirement" strip chart recorder provides a continuous check as to how generation is matching load. A return telemeter circuit in the direction Seven Sisters-Harrow Load Dispatch Office, measuring the output of the machines under control, verifies continuously that the control action called for by "Area Requirement" is in fact being carried out.

Integral Control - Supplementary control is applied to four hydraulic



Δf = FREQUENCY DEVIATION

ΔP_T = TIE-LINE FLOW DEVIATION

ΔP_G = GENERATION DEVIATION

K = BIAS

T_2 = SPEEDER MOTOR TIME COEFFICIENT

T_3 = GOVERNOR TIME COEFFICIENT

G_{SR} = SPEED REGULATION

S = d/dt

FIG 21 SUPPLEMENTARY CONTROL AT SEVEN SISTERS GENERATING STATION OF MANITOBA HYDRO turbine-driven units at Seven Sisters Generating Station capable of delivering some 27 mW each. Integral control is derived in accordance with Method 1 described in Section VIII of Chaper I. Equation 65 (Fig. 21) defines the appropriate transfer function for this type of control as applied at Seven Sisters. With the exception of the factor 4 in the denominator, this function is the same as that given in Equation (60).

$$\frac{\Delta P_G}{\Delta f + \Delta P_T/K} = -\frac{1}{4}\left[\frac{P_{GRO}}{T_2 G_{SR} P_{GO} S}\right]\left[\frac{1}{T_3 S/G_{SR} + 1}\right] \qquad (65)$$

The function is divided by 4 because with the type of equipment employed control impulses are routed to only one unit speeder motor at a time. This means that although the capability of LFC regulated generation is some 108 mW, the rate at which it can be applied is dictated by the response of a single unit. The governors of the regulated units at Seven Sisters are adjusted to provide good response consistent with stable operation. (Ref. 28 - particularly Figure 1.).

In both the HEPCO and SPC system, load-frequency control equipment of the proportional - integral type is applied in accordance with Method 2 of Section VIII, Chapter I.

CHAPTER III

OPERATIONAL TESTS

I - GENERAL

This chapter outlines the commissioning tests carried out on Manitoba Hydro's LFC equipment and where appropriate, the theories presented in Chapter I are applied to the results obtained. As the tests were carried out on working power systems during a time of the year when loads were heavy it was not possible to carry out all tests which might be desirable from a theoretical point of view.

At the end of this chapter will be found a tabular and graphic record of the significant data. These include:

Fig. 22 - Table of Test Results

Fig. 23 - Recorder chart - "System Frequency", December 7, 1960, 0800-1700 hours.

Fig. 24 - Recorder chart - "Area Requirement", December 7, 1960, 0800-1700 hours.

Fig. 25 - Recorder chart - "BB-1 Megawatts" (The SPC-MH tie-line) December 7, 1960, 0800-1700 hours.

Fig. 26 - Recorder chart - "SK-1 Megawatts" (The MH-HEPCO tie-line) December 7, 1960, 0800-1700 hours.

II - TESTS AND DISCUSSIONS OF RESULTS

<u>Test 1 - Normal Operation of the LFC</u>

a) System normal.

b) Set MH tie-line bias value to 1% of present generation.

c) Set SPC bias value to 2½% of SPC present generation.

d) Note HEPCO bias setting.

e) Place all LFC equipment in service on TLB and adjust frequency schedule setters and tie-line schedules to match.

f) Line BB-1, set 10 mW SPC to MH.

g) Line BB-1, set 10 mW MH to SPC.

h) Line SK-1, set +10 mW (out) from present import setting.

i) Line SK-1, set -10 mW (in) from present import setting.

j) Line SK-1, return to normal setting.

k) Line BB-1, return to zero setting.

l) With MH bias set a 3.3% (max.) of present generation and SPC bias at 1% of its present generation set BB-1 at +10 mW and SK-1 at -25 mW. Note HEPCO bias setting.

m) Compare the two sets of charts obtained with respect to the different bias settings. There should be no significant differences.

Discussion of Test 1 Results

Prior to the commencement of Test 1, the three systems were synchronized without load-frequency controls applied. This resulted in slight wanderings on some of the charts which, of course, was to be expected. This condition was allowed to exist for approximately twenty minutes. Application of the load-frequency controls on all three systems, employing the tie-line bias mode, brought conditions back to schedule.

As will be seen from Figures 23-26 the results obtained after the application of controls were generally satisfactory. The deviations of the two tie-lines and system frequency from the respective scheduled values were not excessive and represented normal controller reactions for the system capacities involved.

For Part (1) of the test, 20 mW/0.1 cycle bias (3.3% MH generation at the time) was employed on the MH controller and 1% on that of the SPC. The 3.3% value was used as it represented the maximum setting on the MH controller, thereby giving an indication of conditions expected with the highest possible bias setting. As might be expected, because of the fairly stable system-wide conditions obtaining during the test, no significant differences due to imposed regulation were apparent with the different bias settings. It will be seen that under more severe system disturbances imposed in following tests, bias settings and control modes become increasingly important.

<u>Test 2 - Checks on Bias Settings</u>

a) Set SK-1 normal import.

b) Set BB-1 zero power flow. SPC, MH and HEPCO all on TLB control.

c) Using a generator unit at Seven Sisters drop quickly 20 mW generation by gate limit.

d) Check instantaneous contributions from the SPC and HEPCO.

e) SPC and HEPCO are to check on the control signals ("Raise" or "Lower") to units under LFC and adjust bias to suit. Repeat (c) above, until satisfactory bias settings are secured, i.e. no "Raise" or "Lower" impulses received at the controlled units.

f) Drop quickly 20 mW generation in HEPCO and check MH bias settings. Repeat as above until satisfactory bias is obtained.

Note:- Controlling units will decrease or increase generation on change of frequency in accordance with their respective speed droop curves in a similar manner to all other units. On a change of frequency due to a disturbance in another province, units under LFC should not receive supplementary regulation (correcting impulses from LFC) if the bias value is correct.

Discussion of Test 2 Results - A series of imposed generation changes applied were carried out first in the MH system to permit the SPC and HEPCO to determine their correct bias settings and then in the HEPCO system to obtain the setting for the MH.

The above may be examined with respect to the deviation equations contained in Section VI of Chapter I and checked with results in Fig. 22. The maximum deviation is calculated in each case whether it be natural or imposed.

Max. Frequency Deviation - Equation (20).

$$-\Delta f_B = \frac{D}{10(K_{SPC} + N_{MH} + N_{HEP})}$$

where $D = 20$ mW

K_{SPC} = SPC bias value.

N_{MH} & N_{HEP} = MH and HEPCO natural combined characteristics determined by power changes in HEPCO and MH respectively.

Therefore

$$-\Delta f_B = \frac{20}{10(5 + 6.1 + 4.3)} = \underline{0.130} \text{ cycle (decrease)}$$

From Fig. 22 the average of Δf_B for the three tests, where $K_{SPC} = 5$ mW/0.1 cycle, is 0.103 cycle.

Tie-Line Flow Deviation - Equation (28)

(Note: that the natural deviation is used here because SPC's bias setting was low and would tend to reduce ΔP_T).

$$\Delta P_{T(BB-1)} = \frac{D\ N_{SPC}}{N_{TOT}}$$

$$= \frac{(7)(20)}{(7 + 6.1 + 4.3)} = \frac{140}{17.4} = \underline{8.1\ \text{mW}}\ \text{(increase)}$$

From Fig. 22, the average value for the three tests where K_{SPC} = 5 mW/0.1 cycle is 9.7 mW.

As minute-to-minute fluctuations in frequency and tie-line flow (Fig. 23 & 25) are at least some 0.02 cycle and 2 mW respectively, the above results are considered satisfactory.

Max. Load Change - Equations (8) & (28)

$$L_{(SPC)} = (.0042)(230) = 1\ \text{mW/0.1 cycle.}$$

where 230 mW = SPC load at time of test.

$$-\Delta P_L = \frac{D\ L_{SPC}}{(K_{SPC} + N_{MH} + N_{HEP})}$$

$$= \frac{(1)(20)}{(5.0 + 6.1 + 4.3)} = \frac{20}{15.4} = \underline{1.3\ \text{mW}}\ \text{(decrease)}$$

Max. SPC Generation Change - Equation (33)

$$\Delta P_{G(SPC)} = \frac{D(N_{SPC} - L_{SPC})}{N_{TOT}}$$

$$= \frac{20\ (7-1)}{(7 + 6.1 + 4.3)} = \frac{120}{17.4} = \underline{6.9\ \text{mW}}\ \text{(increase)}$$

Control Stability - If an operating condition existed such that the HEPCO tie-line were open, the SPC on FTL, and MH on FF, then from Equation (53)

$$\frac{\Delta f_{B1}}{\Delta f_B} = \frac{N_{SPC}}{N_{MH}} = \frac{7}{6.1} \quad \text{(i.e., an unstable tendency)}$$

Under these power-frequency conditions a bias value applied in accordance with Equation (54) would give the boundary condition for a stable tendency.

$$\frac{\Delta f_{B1}}{\Delta f_B} = \left[\frac{(N_{SPC} - K_{SPC})}{(N_{MH} + K_{SPC})}\right]\left[1 - \frac{(N_{SPC} + N_{MH})}{(K_{MH} + N_{SPC})}\right] = 1$$

solving for K_{SPC} (with $K_{MH(FF)} = \infty$),

$$K_{SPC} = \frac{N_{SPC} - N_{MH}}{2}$$

$$= \frac{7 - 6.1}{2} = \underline{0.45} \text{ mW/0.1 cycles}$$

or solving for K_{MH} (with $K_{SPC(FTL)} = 0$),

$$K_{MH} = \left[\frac{N_{SPC} + N_{MH}}{1 - \frac{N_{MH}}{N_{SPC}}}\right] - N_{SPC}$$

$$= \left[\frac{7 + 6.1}{.13}\right] - 7 = \underline{94} \text{ mW/0.1 cycles}$$

A bias value greater than 0.45 mW/0.1 cycle applied in SPC (MH on FF) or a bias value less than 94 mW/0.1 cycle in MH (SPC on FTL) would result in more stable conditions.

Test 3 – Loss of Tie-Lines

The object of the tests under this heading was to prove the protective cut-out features of the controls. If a tie-line carrying a scheduled load of say 20 mW is tripped for any reason, the tie-line flow could not, of course, remain on schedule (if other than 0 flow). The LFC,[2] however, would attempt to bring the tie-line on schedule - an obvious impossibility. To avoid this situation, the telemeter transmitter signal for the tie-line flow quantity involved (at Brandon) is tripped by an auxiliary contact on the tripped line circuit breaker. The mating receiver in the dispatch office is equipped with a relay which trips on loss of signal. Contacts of this relay trip out the comparison circuits of the tie-line in question thereby avoiding the existence of and unworkable error signal. It will be apparent from the test results that the desired action was obtained.

The tie-line flow and frequency deviations recorded serve as useful checks on the bias values as determined under Test 2. For the BB-1 trip-out, a frequency deviation of 0.25 cycles was recorded on the "separated" SPC system. As the SPC lost 20 mW because of the trip-out, the appropriate bias value (and natural combined characteristic for SPC) would be

$$20/2.5 = 8 \text{ mW}/0.1 \text{ cycle}$$

(8 mW determined in Test 2)

For the SK-1 trip-out, a frequency deviation of 0.48 cycles was recorded on the "separated" HEPCO system. The appropriate bias value would therefore be

$$18/4.8 = 3.8 \text{ mW}/0.1 \text{ cycle}$$

(4.3 mW determined in Test 2)

The value of 18 mW is used in the above calculation because at the moment of trip-out 18 mW was effectively being carried by the tie-line.

Tests 4 & 5

As these tests concern protective equipment checks rather than operational tests they are omitted from consideration here.

Test 6 - Operation Under Different Types of Control

A - MH and HEPCO on TLB; SPC on FF

(a) Set SK-1 - normal interchange.

Set BB-1 - 0 mW.

(b) Change SPC LFC to FF from TLB.

(c) Note that no unusual changes take place on the steady-state of the three interconnected systems.

(d) Increase frequency setting on SPC LFC to 60.1 cycles (from 60.0 cycles)

(e) Note that

i) Frequency will increase approximately 60.1 cycles.

ii) SPC will export about 10 mW.

iii) MH will export (to HEPCO) about 5 mW.

iv) Steady-state is reached under the above conditions.

(f) Set SPC frequency setting to 59.95 and note the results.

B - MH and HEPCO on TLB; SPC on FTL

(a) Set SK-1 - normal interchange.

(b) Set BB-1 - 20 mW to MH.

(c) Set SPC LFC to FTL.

(d) Increase generation quickly with one unit at Seven Sisters using gate limit (20 mW).

Note: Although frequency goes above 60.0 cycles, SPC will increase generation to keep tie-line load constant. This action aggravates the situation and tends to hold the frequency high longer than necessary.

(e) Decrease generation quickly with one unit at Seven Sisters using gate limit (20 mW).

Note: Although the system frequency drops, SPC reduces generation to keep the tie-line load flow on schedule. This action aggravates the situation and tends to hold the frequency down longer than necessary.

Discussion of Test 6 Results

A - Increasing the frequency set point on the SPC LFC above that as set on those of the MH and HEPCO is analagous in effect to a sustained increase of generation in the SPC. If the MH and the HEPCO are on their correct bias values, they will provide no corrective action but wait for the SPC to bring conditions back to normal. As a steady-state was reached at 60.10 cycles during the test, it can be assumed that correct values of bias were applied in the MH and HEPCO. Incorrect bias values would have undoubtedly given rise to hunting of the MH and HEPCO controllers. Appropriate results were obtained likewise when the SPC lowered their frequency set point.

On studying the results of the test, it appears that perhaps not enough time was allowed to lapse in order to observe whether or not a true steady-state was in fact reached. The results are encouraging and certainly indicative if perhaps a little optimistic.

B - The tests did prove that FTL operation on one (SPC) controller did in fact tend to hold frequency up (or down) longer than would be the case for TLB operation throughout. This is clearly shown by comparing the results of Test 2(f) with 6B (d) and (e). The former using TLB throughout is markedly faster than the latter in implementing the restoration of frequency and tie-line values to schedule.

Test 7 - To Demonstrate the Effect of the Opening of the One End of the Tie-Line That is Not Connected to Trip Off LFC

On Line BB-1, should the line trip at the Brandon end only, the MH and SPC BB-1 tie-line servo equipment would be tripped out in accordance with Test 3 above. However, if the line opens at the Boundary Dam end only, the telemeter signals cannot be tripped as the tie-line metering is done at Brandon. The LFC equipment, in such circumstances will attempt to correct for the load and frequency deviations due to the open line.

(a) MH LFC on TLB.

(b) SPC LFC on FTL.

(c) SK-1 - normal interchange with HEPCO on TLB.

(d) BB-1 - set 10 mW to SPC.

(e) Trip line open at Boundary Dam.

Note: MH plus HEPCO frequency will go to approximately 60.1 cycles and remain steady. SPC frequency will drop to approximately 59.9 cycles and because of FTL operation its controller will continue to decrease generation and lower frequency further until the controller is tripped.

Discussion of Test 7 Results

As line faults almost invariably involve the clearing of both ends of the tie-line, correct freezing of the controls will be accomplished according to Test 3. If, however, the circuit breaker at the end of the line not containing the metering or telemetering (e.g., Boundary Dam end of BB-1), trips without the Brandon end clearing, the LFC equipment will attempt to correct for the fact that the open line is not, obviously, on schedule.

In the test carried out, MH exported 10 mW to the SPC. The line was tripped at Boundary Dam so that a zero flow telemeter signal was received at both the SPC and the MH controllers. The MH and the HEPCO, operating on TLB, presumed the disturbance was "remote", and took no action. The SPC on the other hand being on FTL was faced with what looked like an excess in generation being influenced only by the decreased import of power (FTL). No amount of generation decrease satisfied the impossible situation. The SPC control was finally tripped to FF. Use by the SPC of either TLB or FF control would have prevented the degenerative condition from occurring in these circumstances.

This test serves to illustrate how particular operating conditions and LFC modes can provide a combination which produces undesirable results.

TABLE OF RESULTS FOR COMMISSIONING TESTS ON LOAD-FREQUENCY CONTROLS

TEST NO.	TEST	FREQUENCY SET	FREQUENCY DEV.	BB1 SET	BB1 (MW) DEV.	SK1 SET	SK1 (MW) DEV.	AREA REQ'T. (MW) RAISE	AREA REQ'T. (MW) LOWER	TIE LINE BIAS MW/.1 CYCLE SPC	TIE LINE BIAS MHEB	TIE LINE BIAS HEPCO	SYSTEM LOAD (MW) SPC	SYSTEM LOAD MHEB	SYSTEM LOAD HEPCO	CAPACITY UNDER LFC (MW) SPC (THERMAL)	CAPACITY MHEB (HYDRO)	CAPACITY HEPCO (HYDRO)	TIME	REMARKS
1 (f)	BB1 Set 10 MW to MHEB	59.94	+ .01	-10	+ 1	0	- 3	1		5.5	6.1	9.0	230	610	500	66	108	126	0958	
(g)	BB1 Set 10 MW from MHEB	59.94	+ .04	+10	+ 2	0	- 4	3		"	"	"	"	"	"	"	"	"	1017	
(h)	SK1 Set 10 MW from MHEB	59.94	+ .00	+10	+ 3	+10	0	0	0	"	"	"	"	"	"	"	"	"	1025	
(i)	SK1 Set 10 MW to MHEB	59.94	+ .04	+10	0	-10	- 2	2		"	"	"	"	"	"	"	"	"	1030	
(l)	SK1 Set 25 MW to MHEB	59.94	+ .00	+10	+ 4	-25	- 3	5		2.4	20	"	"	"	"	"	"	"	1046	
2 (c)	MHEB Drop 20 MW	59.98	- .10	0	- 11	-30	- 7	14		3.0 Ch'd.to 5.0	6.1 6.1	9.0 Ch'd.to 7.0	230 "	610 "	500 "	66 "	108 "	126 "	1119	SPC Controller lowered. Therefore, bias too low. HEPCO Controller Raised. Therefore, bias too high.
(c)	MHEB Drop 20 MW	59.98	- .12	0	- 11	-30	- 7	19		5.0 5.0	6.1 6.1	7.0 Ch'd.to 4.0	"	"	"	"	"	"	1124	SPC Controller no change. Therefore, correct bias. HEPCO Controller raised. Therefore, bias too high.
(c)	MHEB Drop 20 MW	59.98	- .08	0	- 7	-30	- 6	16		5.0	6.1	4.0	"	"	"	"	"	"	1131	SPC & HEPCO Controllers no significant changes. Therefore, correct biases.
(f)	HEPCO Drop 20 MW	59.98	- .11	0	- 11	0	+ 17	4		5.0 Ch'd.to	6.1 Ch'd. to	4.3	"	"	540	"	"	"	1341	MHEB Controller lowered. Therefore, bias too low.
(f)	HEPCO Drop 20 MW	59.98	- .11	0	- 9	0	+ 15	0	0	7.0	10.0	4.3	"	"	"	"	"	"	1349	MHEB Controller raised and lowered. Bias was left at this value. % of total generation SPC - 3% MHEB - 1.6% HEPCO - 0.8%
3 (c)	BB1 + 20 MW Trip	60.00	+ .26	+20	- 20	0	+ 10		26	7.0	10.0	4.3	230	610	540	66	108	126	1404	SPC Frequency Dev. - .25
(c)	SK1 + 20 MW Trip	60.01	+ .17	0	+ 19	+20	- 18		26	7.0	10.0	4.3	"	"	"	"	"	"	1421	HEPCO Frequency Dev. - .48 Faulty relay operation in SK servo in LDO LFC. Rectifier replaced and test repeated successfully.
4 (c) & (h)	Freezing of appropriate controls satisfactorily obtained.																			
5 (c)	Freezing of appropriate controls satisfactorily obtained and control passed to Seven Sisters on Flat Frequency.																			
6A(b)	SPC - TLB to FF		No significant change.							5.0	10.0	4.3	230	610	540	66	108	126		
(e)	SPC Freq. 60.00 to 60.10	60.00	+ .10	0	- 21	0	+ 7	10		"	"	"	"	"	"	"	"	"	1454	
(f)	SPC Freq. 60.10 to 59.95	60.00	- .08	0	+ 13	0	- 6		7	"	"	"	"	"	"	"	"	"	1506	
B(e)	SPC - FF to FTL		No significant change.																	No. 2 Unit Selkirk G.S. on.
(d)	MHEB Incr. 20 MW	60.00	+ .09	0	+ 9	0	+ 9		16	"	"	"	"	"	"	"	"	"	1525	
(e)	MHEB Decr. 20 MW	60.00	- .08	0	- 11	0	- 7	21		"	"	"	"	"	"	"	"	"	1531	
7 (e)	BB1 + 10 MW Trip at Boundary Dam	60.00	+ .06	+10	- 10	0	+ 4		5	5.0	10.0	4.3	230	610	540	66	108	126	1542	
																			1600	Test repeated but Brandon Circuit Breaker also tripped thereby putting SPC on FF directly and tripping out MHEB BB1 Servo.

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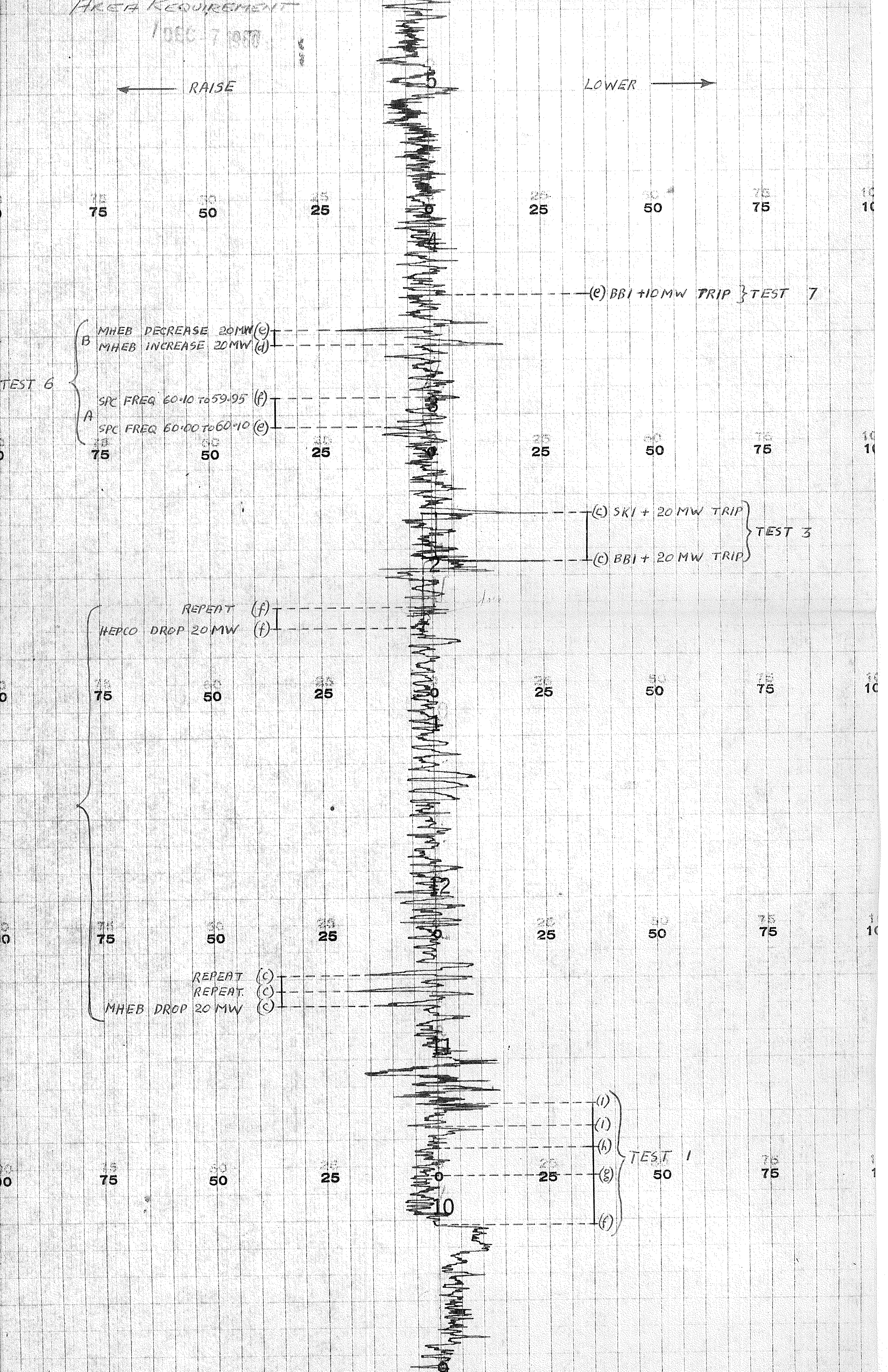


AREA REQUIREMENT
DEC 7
RAISE
LOWER
100 75 50 25 0 25 50 75 100
(e) BBI +10MW TRIP } TEST 7
B MHEB DECREASE 20MW (e)
MHEB INCREASE 20MW (d)
TEST 6
A SPC FREQ 60·10 TO 59·95 (f)
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(c) BBI + 20 MW TRIP
TEST 3
REPEAT (f)
HEPCO DROP 20 MW (f)
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
(i)
(i)
(h)
(g)
(f)
TEST 1

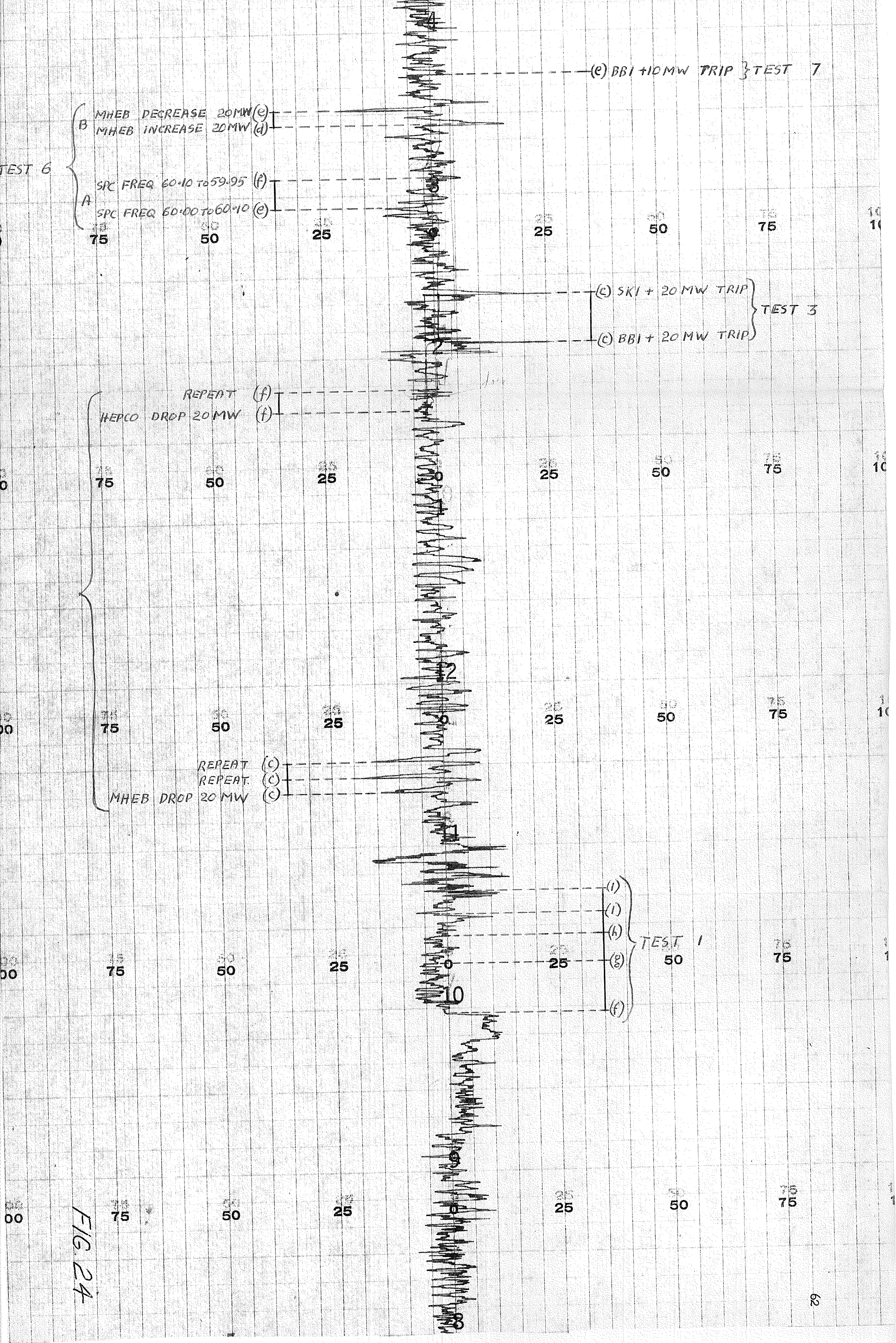

(e) BBI +10 MW TRIP } TEST 7
MHEB DECREASE 20 MW (e)
MHEB INCREASE 20 MW (d)
TEST 6
B
A
SPC FREQ 60·10 TO 59·95 (f)
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(c) BBI + 20 MW TRIP
TEST 3
REPEAT (f)
HEPCO DROP 20 MW (f)
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
(i)
(i)
(h)
(g)
(f)
TEST 1
75
50
25
0
25
50
75

FIG. 24

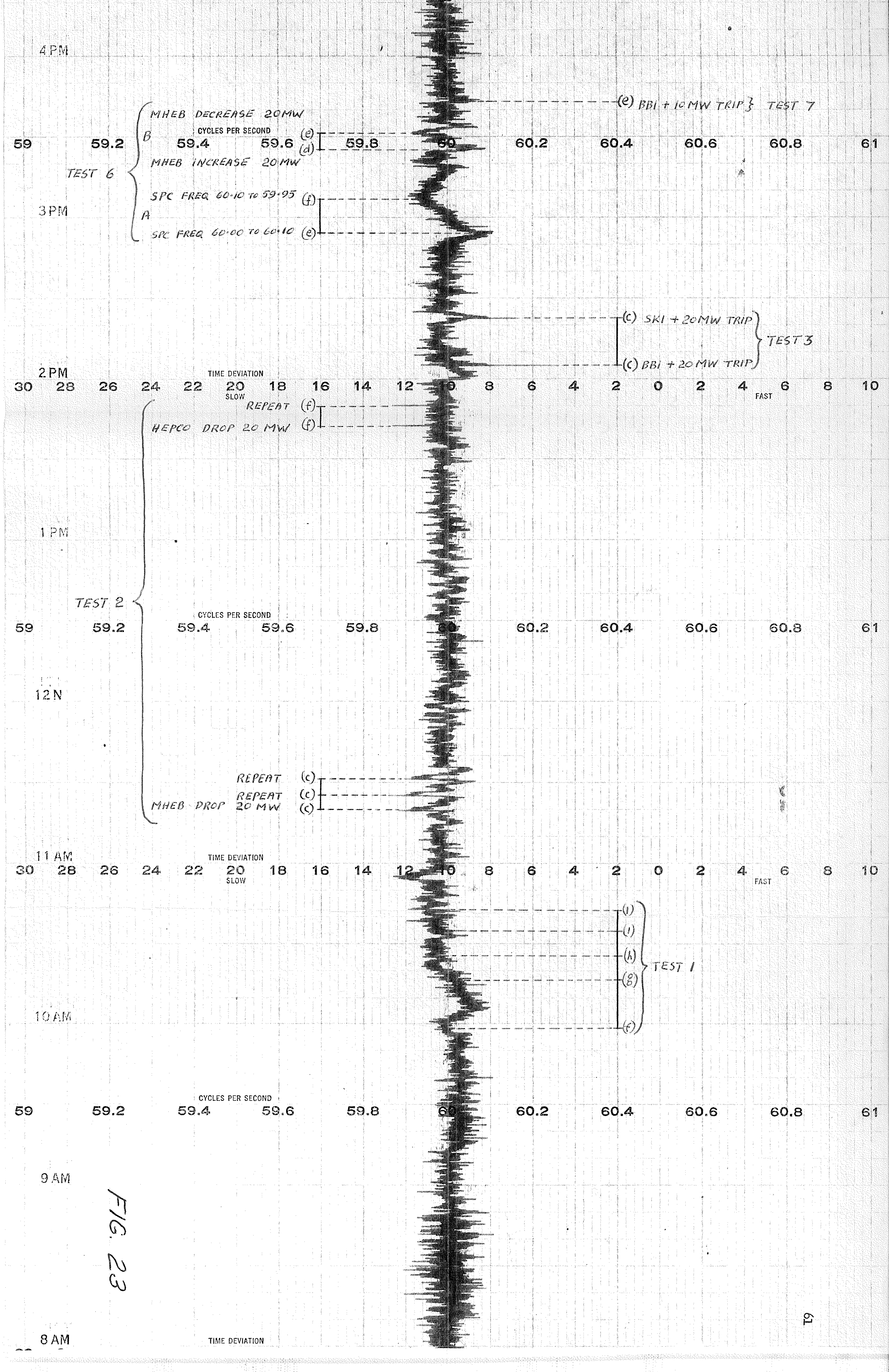
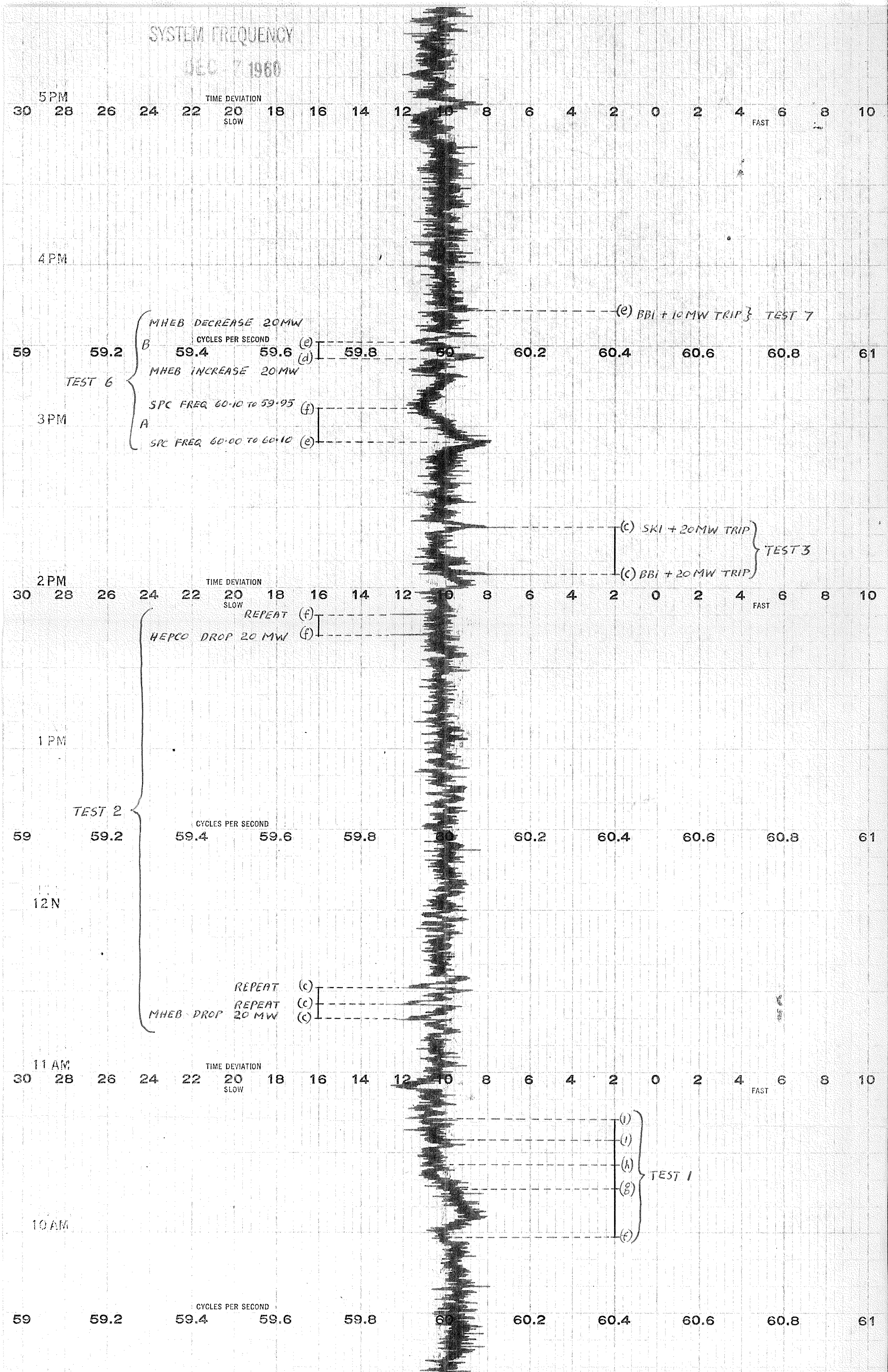
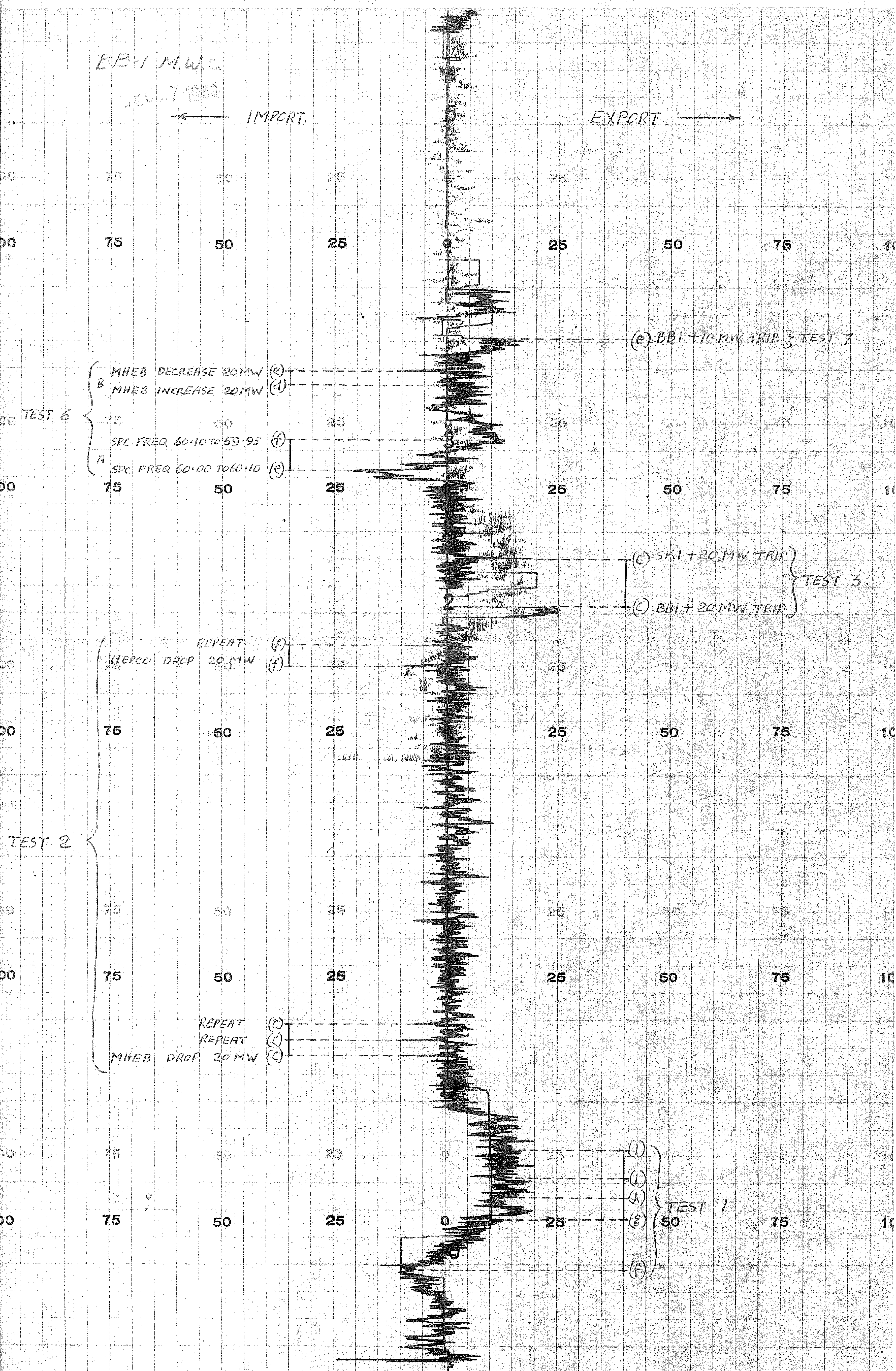

4 PM
3 PM
2 PM
1 PM
12 N
11 AM
10 AM
9 AM
8 AM
CYCLES PER SECOND
59 59.2 59.4 59.6 59.8 60 60.2 60.4 60.6 60.8 61
TIME DEVIATION
30 28 26 24 22 20 18 16 14 12 10 8 6 4 2 0 2 4 6 8 10
SLOW
FAST
(e) BBI + 10 MW TRIP } TEST 7
MHEB DECREASE 20 MW (e)
B
MHEB INCREASE 20 MW (d)
TEST 6
SPC FREQ 60·10 TO 59·95 (f)
A
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(c) BBI + 20 MW TRIP
TEST 3
REPEAT (f)
HEPCO DROP 20 MW (f)
TEST 2
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
(i)
(i)
(h)
(g)
(f)
TEST 1

FIG. 23


SYSTEM FREQUENCY
DEC 7 1960
5 PM
TIME DEVIATION
30 28 26 24 22 20 18 16 14 12 10 8 6 4 2 0 2 4 6 8 10
SLOW
FAST
4 PM
(e) BBI + 10 MW TRIP } TEST 7
MHEB DECREASE 20 MW
CYCLES PER SECOND
B
(e)
(d)
59 59.2 59.4 59.6 59.8 60 60.2 60.4 60.6 60.8 61
MHEB INCREASE 20 MW
TEST 6
SPC FREQ 60·10 TO 59·95 (f)
3 PM
A
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
TEST 3
(c) BBI + 20 MW TRIP
2 PM
TIME DEVIATION
30 28 26 24 22 20 18 16 14 12 10 8 6 4 2 0 2 4 6 8 10
SLOW
FAST
REPEAT (f)
HEPCO DROP 20 MW (f)
1 PM
TEST 2
CYCLES PER SECOND
59 59.2 59.4 59.6 59.8 60 60.2 60.4 60.6 60.8 61
12 N
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
11 AM
TIME DEVIATION
30 28 26 24 22 20 18 16 14 12 10 8 6 4 2 0 2 4 6 8 10
SLOW
FAST
(i)
(i)
(h)
TEST 1
(g)
10 AM
(f)
CYCLES PER SECOND
59 59.2 59.4 59.6 59.8 60 60.2 60.4 60.6 60.8 61



BB-1 MWS
IMPORT
EXPORT
75
50
25
0
25
50
75
(e) BBI +10 MW TRIP } TEST 7
TEST 6
B
MHEB DECREASE 20MW (e)
MHEB INCREASE 20MW (d)
SPC FREQ 60·10 TO 59·95 (f)
A
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(c) BBI + 20 MW TRIP
TEST 3.
REPEAT (f)
HEPCO DROP 20 MW (f)
TEST 2
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
TEST 1

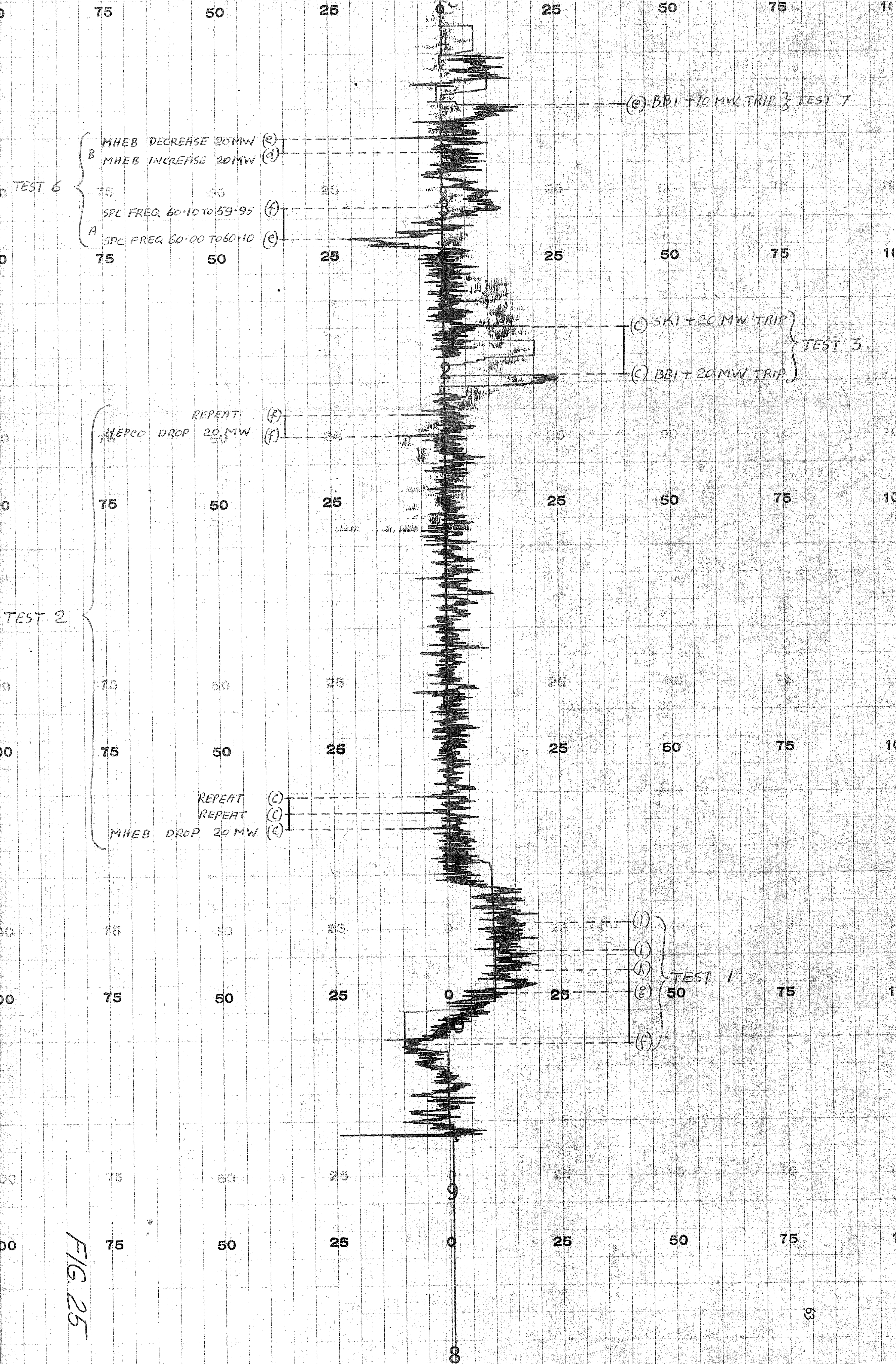
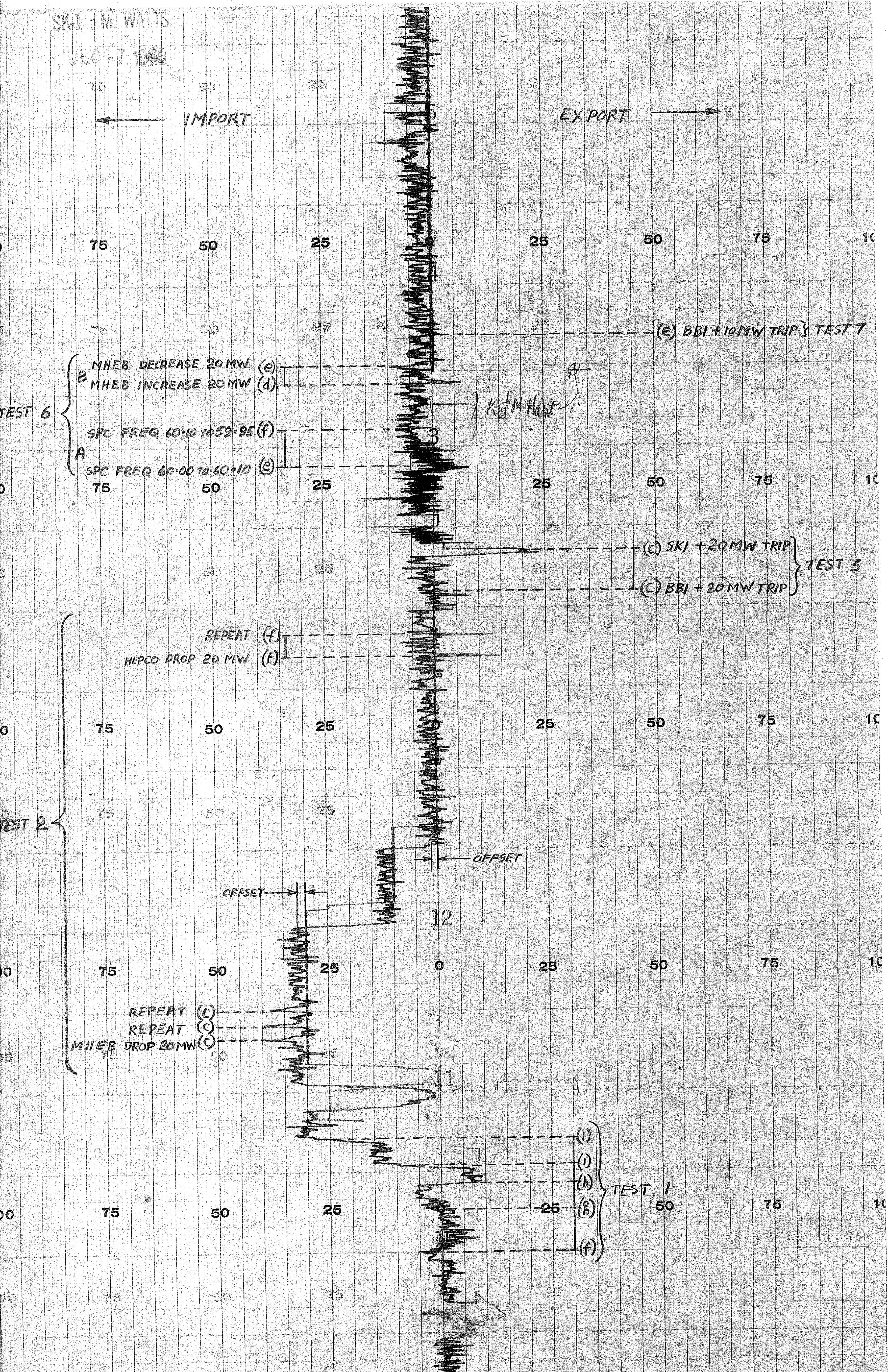
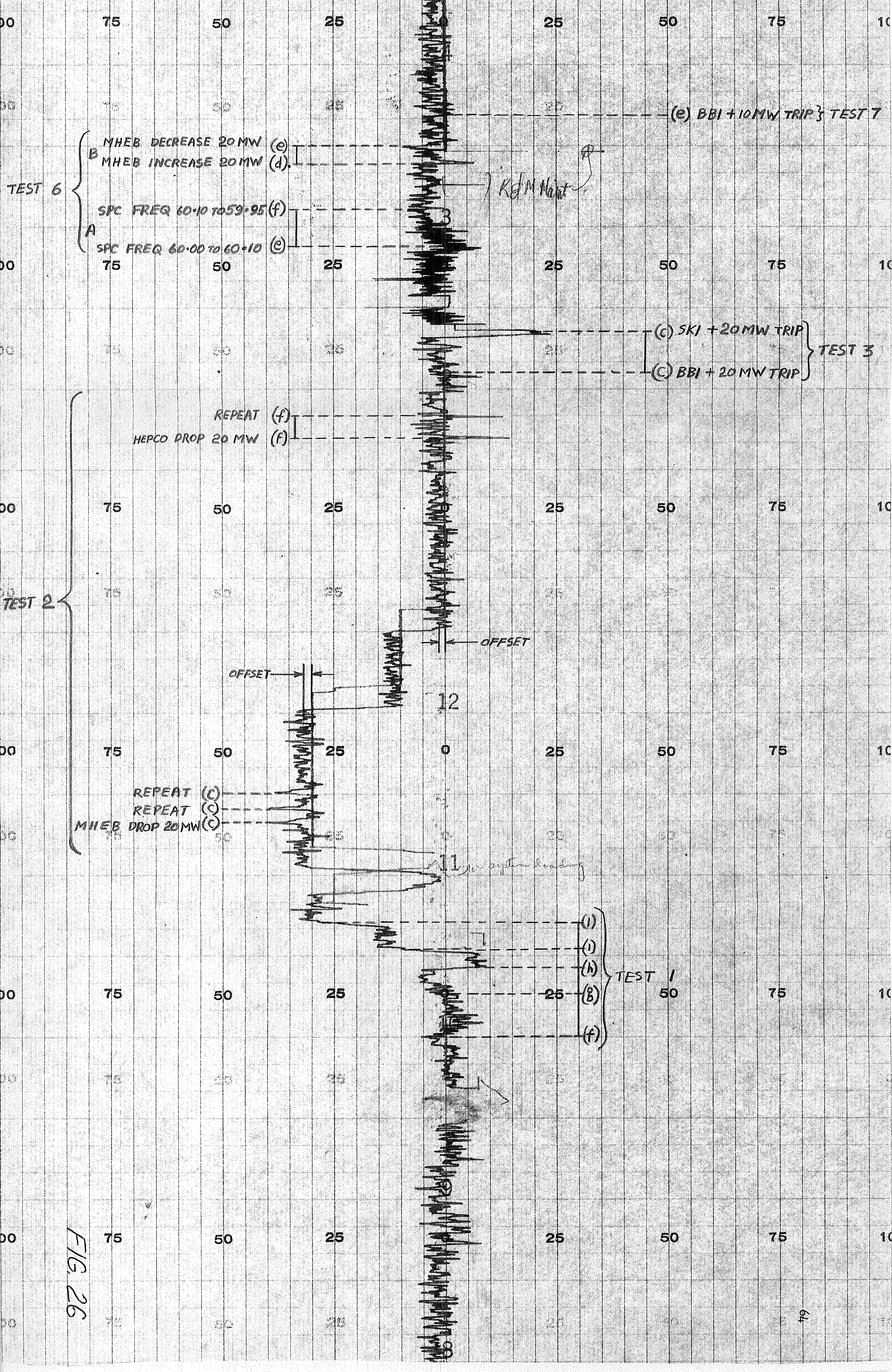

(e) BBI + 10 MW TRIP } TEST 7
TEST 6
B MHEB DECREASE 20 MW (e)
MHEB INCREASE 20 MW (d)
A SPC FREQ 60·10 TO 59·95 (f)
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(c) BBI + 20 MW TRIP
TEST 3.
TEST 2
REPEAT (f)
HEPCO DROP 20 MW (f)
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
TEST 1
(i)
(i)
(h)
(g)
(f)
75
50
25
0
25
50
75

FIG. 25


IMPORT
EXPORT
75 50 25 0 25 50 75
(e) BBI + 10 MW TRIP } TEST 7
MHEB DECREASE 20 MW (e)
MHEB INCREASE 20 MW (d)
B
TEST 6
SPC FREQ 60·10 TO 59·95 (f)
SPC FREQ 60·00 TO 60·10 (c)
A
(c) SKI + 20 MW TRIP
(C) BBI + 20 MW TRIP
TEST 3
REPEAT (f)
HEPCO DROP 20 MW (f)
TEST 2
OFFSET
OFFSET
12
REPEAT (c)
REPEAT (c)
MHEB DROP 20 MW (c)
11
(i)
(i)
(h)
(g)
(f)
TEST 1



(e) BBI + 10 MW TRIP } TEST 7
TEST 6
B
MHEB DECREASE 20 MW (e)
MHEB INCREASE 20 MW (d)
A
SPC FREQ 60·10 TO 59·95 (f)
SPC FREQ 60·00 TO 60·10 (e)
(c) SKI + 20 MW TRIP
(C) BBI + 20 MW TRIP
TEST 3
TEST 2
REPEAT (f)
HEPCO DROP 20 MW (f)
OFFSET
OFFSET
REPEAT (C)
REPEAT (C)
MHEB DROP 20 MW (C)
TEST 1
(i)
(i)
(h)
(g)
(b)
(f)

FIG. 26

CHAPTER IV

SUMMARY AND CONCLUSIONS

1 - <u>Disparity of Actual and Theoretical Area Governing Characteristics</u> -

Actual systems behave like systems that are smaller than the area composite governor speed droop settings would suggest. The ratio of actual to theoretical is usually between 0.14 and 0.42, or in terms of G_C, between 0.0067 and 0.02 p.u. spinning capacity per tenth cycle.

In tests on the SPC - MH - HEPCO power interconnection, power/frequency characteristics obtained for the three areas confirmed these values and were as follows:-[27]

SPC - 0.020 p.u. spinning capacity /0.1 cycle - 100% thermal
MH - 0.011 p.u. spinning capacity /0.1 cycle - 90% hydraulic
HEPCO - 0.007 p.u. spinning capacity /0.1 cycle - 100% hydraulic

These values effectively represent the natural combined characteristics of the respective areas (N) and therefore contain the load characteristics. They are therefore a little larger than the respective G_C values.

The disparity between the actual and theoretical values is due to governor dead-bands, generating units with blocked governors and non-linearities in the unit governing characteristics. Further to the last factor, it is customary to operate hydraulic units at or near maximum output which would be on the flattened portion at the top of the gate opening/power output curve. This undoubtedly contributes toward the proportionately smaller response to frequency deviations of the MH and HEPCO predominatly and totally hydraulic systems respectively compared to the SPC's 100% thermal system with a more linear output characteristic.

2 - The Load Characteristic -

The average typical load characteristic is positive (load increases with frequency) and has a value of approximately 0.0042/mW/0.1 cycle (Equation (8)). It therefore assists regulation by absorbing power on increases of system frequency and requires less power on decreases of frequency. On a typical modern system with a natural combined characteristic of 0.015 p.u. spinning capacity/0.1 cycle, and a spinning reserve of 0.10 p.u. spinning capacity, the load would contribute

$$\frac{.0042}{.015}(.9) = 25\%$$

of the area's power deficiency or absorb 25% of the area's power excess.

3 - The Desirable Operating Mode - Bias Settings

Tie-Line bias operation with bias settings that equal the respective prevailing area natural combined characteristics is the preferred mode of operation. As this condition cannot hope to be fulfilled for even a small percentage of the time due to ever-changing conditions on the system, it is recommended that:-

(a) If a given area represents a major proportion of the spinning capacity of an interconnection its bias should be adjusted to a value which will always be either equal to or slightly greater than its own prevailing natural combined characteristic. This will avoid excessive system frequency deviations at the expense of only slightly increased tie-line flow deviations and will assist the other smaller area in its recovery.

(b) If the given area represents a small proportion of the interconnected spinning capacity, then by analogous reasoning a bias value equal to or slightly less than its prevailing natural combined characteristic should be employed. This will avoid excessive demands on its controlled generation associated with the higher bias values.

For any chosen bias setting, the imposed effects on frequency, tie-line flows and generation may be checked by the equations contained in Table I. The quality of control can then be checked by means of the stability equations contained in Section VII of Chapter I.

It is generally undesirable to operate two interconnected areas with bias values that both either exceed or are less than the respective natural combined characteristics. Vague and lengthy regulator follow-up will be associated with these conditions. In the ultimate, with either FF/FF or FTL/FTL control, regulation of tie-line flows or system frequency, respectively, is impossible.

In any area, controlled generation with enough capacity should be available to fulfill the demands of both local and remote disturbances imposed by the severest operating mode likely to be employed.

4. Supplementary Controllers -

In order to gain the real benefits of interconnected operation, fast-responding, stable control operation and generation follow-up are mandatory. Reduction of the various time constants involved in the control process can realize these aims. From Section VIII in Chapter I it can be concluded that proportional-integral control applied to a large amount of generation, low values of governor droop, and the use of electric governors would all enhance interconnected operation.

5 - Future Investigations -

Although much work has been done in the study of the control of interconnected power systems areas for further investigations might include:-

(a) The application of Proportional-Integral-Differential action to load-frequency controls to further improve regulator action.

(b) The best utilization of thermal and hydraulic generation in the load-frequency control process.

(c) Closer association of the normal unit governors with the supplementary controllers. Electric governors would appear to be advantageous in this regard.

(d) Methods of integrating load-frequency controls into automatic, economic system load dispatch.

APPENDICES

APPENDIX A

NOMENCLATURE

BB-1 - Saskatchewan - Manitoba tie-line

C - Actual Spinning capacity in mW

C_E - Effective spinning capacity in mW

$$C_E = CG_S/G_{SE}$$

c/s - Cycles per second

D - Step function disturbance in mW

Δf - Natural change in system frequency in c/s caused by a disturbance of D mW

Δf_B - Net change in system frequency in c/s caused by a disturbance of D mW plus imposed LFC action

Δf_R - Frequency deviation from schedule in c/s

ΔP_{GBX} - Net change in generation (Area X) in mW caused by a disturbance of D mW plus imposed LFC action

$$\Delta P_{GBX} = \Delta P_{GBXR} + \Delta P_{GBXU}$$

ΔP_{GBXR} - Net change in LFC regulated generation (Area X) in mW imposed directly by LFC action

ΔP_{GBXU} - Net change in unregulated generation (Area X) in mW caused by a disturbance of D mW plus imposed LFC action

ΔP_{GX} - Natural change in generation (Area X) in mW caused by a disturbance of D mW

$$\Delta P_{GX} = \Delta P_{GXR} + \Delta P_{GXU}$$

ΔP_{GXR} - Natural change in LFC regulated generation (Area X) in mW caused by a disturbance of D mW

ΔP_{GXU} - Natural change in unregulated generation (Area X) in mW caused by a disturbance of D mW

ΔP_{LBX} - Net change in load (Area X) in mW caused by a disturbance of D mW plus imposed LFC action

ΔP_T - Natural change in tie-line power flow in mW caused by a power disturbance of D mW

ΔP_{TB} - Net change in tie-line power flow in mW caused by a power disturbance of D mW plus imposed LFC action

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f - System speed or frequency in p.u. or c/s as designated

f_O - p.u. speed at 0 p.u. power output (of a generator)

f_1 - Extrapolated p.u. speed corresponding to 0 p.u. gate (valve) opening

f_2 - Extrapolated p.u. speed corresponding to 1.0 p.u. gate (valve) opening

f_L - p.u. speed at 1.0 p.u. (rated) power output (of a generator)

f_R - Rated or scheduled speed = 1.0 p.u. = 60 c/s

FF - Flat frequency

FTL - Flat tie-line

G_{CX} - Governing characteristic (Area X) in p.u. total spinning capacity per 0.1 cycle

$$G_C = (16.67 \times 10^{-4})/G_{SE} \text{ mW/0.1 cycle}$$

G_{CXR} - Governing characteristic of regulated generation (Area X) in p.u. total spinning capacity per 0.1 cycle

G_{CXU} - Governing characteristic of unregulated generation (Area X) in p.u. total spinning capacity per 0.1 cycle

G_D - Governing characteristic in terms of speed droop

$$G_D = (f_1 - f_2)/f_R \text{ p.u.}$$

G_S - Governing characteristic expressed in terms of steady-state speed regulation

$$G_S = (f_O - f_L)/f_R \text{ p.u.}$$

G_{SE} - Effective G_S actually obtained for a given frequency change

G_{SR} - Steady-state speed regulation of area LFC generation

HEPCO - Northwestern Region of the Hydro-Electric Power Commission of Ontario

K_{RX} - Correct Bias (Area X) in mW/0.1 cycle

$$K_{RX} = |N_X|$$

K_X - Bias (Area X) in mW/0.1 cycle

kV - Kilovolts, i.e., volts x 10^3

L_X - Load characteristic (Area X) in mW/0.1 cycle

LFC - Load-frequency control

M - Proportional sensitivity

MH - Manitoba Hydro

mW - Megawatts, i.e., watts x 10^6

N_{TOT} - Natural Combined characteristic of the interconnected system in mW/0.1 cycle

N_X - Natural Combined characteristic (Area X) in mW/0.1 cycle

P_{GO} - Nominal rating of all area connected generation

P_{GRO} - Nominal rating of all area LFC connected generation

p.u. - Per unit

S - d/dt

SK-1 - Manitoba-Ontario tie-line

SPC - Saskatchewan Power Corporation

T_1 - Integrating time coefficient of the LFC regulator

T_2 - Integrating time coefficient of the LFC generator unit speeder motors.

T_3 - Characteristic time of LFC regulated machine governors

TLB - Tie-line bias

APPENDIX B

DERIVATION OF THE STABILITY EQUATIONS

(Based upon the effects of bias settings and natural combined characteristics of a two-area interconnection).

In the derivations which follow, it will be assumed that Area X completes its control action and generation follow-up before that in Area Y commences, after which Area Y will be assumed to complete its changes, and so on.

If

$$\frac{\Delta f_{B1}}{\Delta f_B} \text{ or } \frac{\Delta P_{TB1}}{\Delta P_{TB}} < 1$$

where Δf_B, ΔP_{TB} = The initial imposed frequency and tie-line flow, deviations respectively

Δf_{B1}, ΔP_{TB1} = The following imposed frequency and tie-line flow deviations respectively caused by controller overshoot

a stable tendency is indicated.

(i) Area X (FTL) - Area Y (FF) (Figure 15)

Now

$$\Delta f_B = \frac{D}{10(N_Y)} \qquad \text{------------------------------------} \quad (22)$$

and from Figure 15,

$$\Delta f_{B1} = \Delta f_B \frac{N_X}{N_Y}$$

Therefore

$$\frac{\Delta f_{B1}}{\Delta f_B} = \frac{N_X}{N_Y} \qquad (53)$$

(ii) TLB/TLB Control for $K_X \leqslant N_X$ and $K_Y \geqslant N_Y$ (Figure 16 (a))

$$\Delta f_B = \frac{D}{10(K_X + N_Y)} \qquad (24)$$

and from Figure 16(a),

$$\Delta f_{B1} = \frac{\Delta f_B(N_Y + N_X) - D - \Delta f_{B2}(N_X + N_Y)}{(N_Y + K_X)}$$

From Equation (24)

$$\Delta f_{B1} = \frac{\Delta f_B(N_X - K_X) - \Delta f_{B2}(N_X + N_Y)}{(N_Y + K_X)}$$

and

$$\Delta f_{B2} = \frac{\Delta f_B(N_X - K_X)}{(K_Y + N_X)}$$

therefore

$$\frac{\Delta f_{B1}}{\Delta f_B} = \left[\frac{(N_X - K_X)}{(N_Y + K_X)}\right]\left[1 - \frac{(N_X + N_Y)}{(K_Y + N_X)}\right] \qquad (54)$$

(iii) Area X (FF) - Area B (FTL) (Figure 16(b))

Recall

$$\Delta P_{TB} = D \qquad (25)$$

and from Figure 16(b)

$$\Delta P_{TB1} = \Delta f_{B2}(N_Y)$$

and

$$\Delta f_{B2} = \frac{D}{N_X}$$

Therefore from Equation (25),

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = \frac{N_Y}{N_X} \text{ --------------------------------------- } (57)$$

(iv) <u>TLB/TLB Control for $K_X \geqslant N_X$ and $K_Y \leqslant N_Y$</u> (Figure 16(c))

$$\Delta P_{TB} = \frac{K_X\ D}{(K_X + N_Y)} \text{ -------------------------------- } (24)$$

and from Figure 16(c)

$$\Delta f_{B2} = \frac{D - \Delta f_{B3}(N_X + N_Y)}{K_Y + N_X}$$

where

$$\Delta f_{B3} = \frac{D}{K_X + N_Y}$$

therefore,

$$\Delta f_{B2} = \frac{D - \left[\frac{D(N_X + N_Y)}{(K_X + N_Y)}\right]}{K_Y + N_X}$$

$$\Delta P_{TB1} = \Delta f_{B2}(N_Y - K_Y) - \Delta f_{B4}N_Y$$

where

$$\Delta f_{B4} = \frac{\Delta f_{B2}(N_Y - K_Y)}{K_X + N_Y}$$

$$\Delta P_{TB1} = \Delta f_{B2}(N_Y - K_Y) - \Delta f_{B2}(N_Y - K_Y) \left[\frac{N_Y}{(K_Y + N_Y)}\right]$$

$$= \Delta f_{B2}(N_Y - K_Y) \left[1 - \frac{N_Y}{K_X + N_Y}\right]$$

and

$$\frac{\Delta P_{TB1}}{\Delta P_{TB}} = \frac{\left[\frac{K_X + N_Y}{K_X}\right]\left[1 - \frac{(N_X + N_Y)}{(K_X + N_Y)}\right](N_Y - K_Y)\left[1 - \frac{N_Y}{K_X + N_Y}\right]}{(K_Y + N_X)} \text{-----} \quad (58)$$

APPENDIX C

PROPORTIONAL-INTEGRAL CONTROL

Integral Control (Reset or Sustained Control) - This control mode is given by the equation

$$Y = \frac{1}{T_1}\int E dt + Q_1$$

where Y = Manipulated variable

T_1 = Integral time

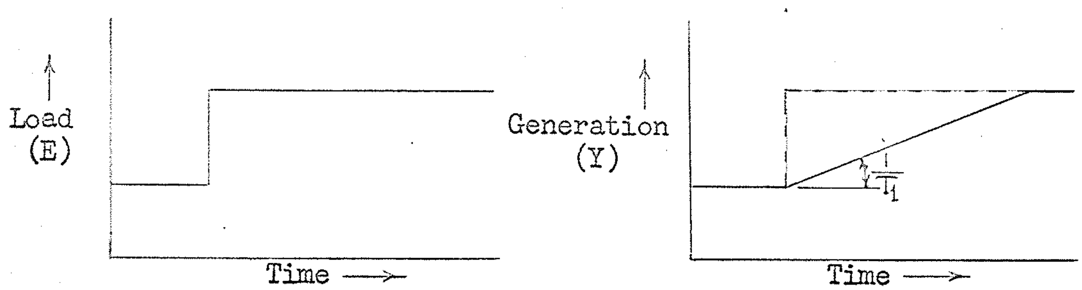
E = Error signal (e.g., $(\Delta f + \Delta P_T/K)$)

Q_1 = Constant of integration

Upon differentiation

$$\frac{dY}{dt} = \frac{E}{T_1}$$

This type of control provides a manipulated variable which is changed at a rate which is proportional to the error. When there is no error signal (on schedule) there is no control action forthcoming thereby providing automatic reset action. Integral action is shown in the sketch below.



Integral Control

Proportional Control (or Fringe Control) - This control mode is given by the equation

$$Y = ME + Q_2$$

where Y and E are as defined above

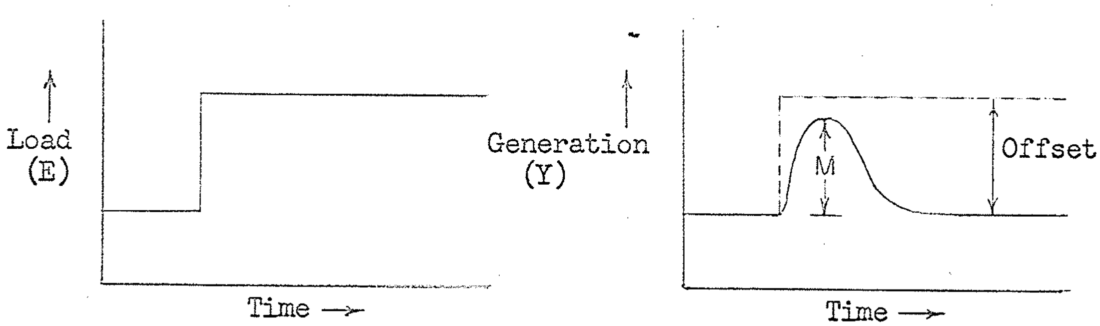
M = Proportional sensitivity

Q_2 = Constant

Upon differentiation

$$\frac{dY}{dt} = M\frac{dE}{dt}$$

This type of control provides a manipulated variable which is changed at a rate which is proportional to the rate of change of the error. There is no control action forthcoming for both conditions of zero or a constant error. Proportional control, then, although providing a faster action than integral control does not possess the automatic reset feature (See sketch below).



Proportional Control

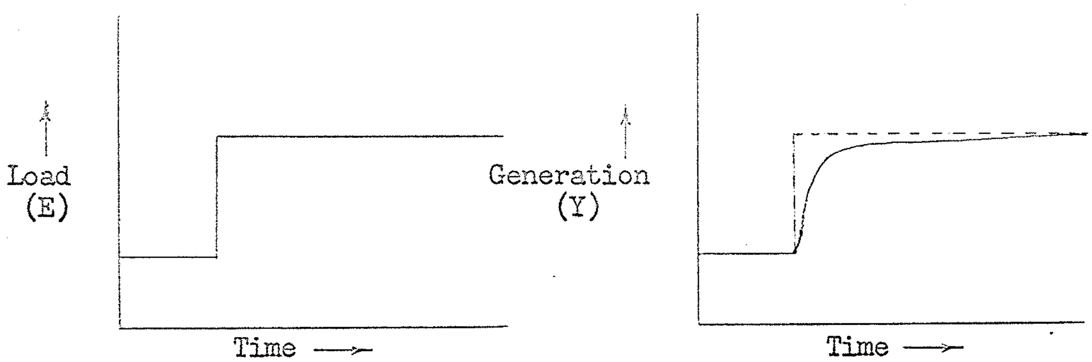
Proportional-Integral Control - This is a combination of the above two modes and is given by the equation

$$Y = \frac{M}{T_1}\int E\,dt + ME + Q_3$$

where Y, M, T_1 and E are as defined above

Q_3 = Constant of integration

This type of control combination provides the fast response of proportional control with the automatic reset feature of integral control (See sketch below).



Proportional-Integral Control

In operational form, proportional-integral control action is given by

$$\frac{Y}{E} = M\left[\frac{1}{T_1 S} + 1\right]$$

where S = d/dt

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