

LOAD-FREQUENCY CONTROL  
OF INTERCONNECTED POWER SYSTEMS

---

A Thesis  
Presented To  
The Faculty of Graduate Studies and Research  
University of Manitoba

---

In Partial Fulfillment  
of the Requirements for the Degree  
Master of Science in Electrical Engineering

---

by  
Kenneth Henry Williamson  
March, 1962<sup>v</sup>



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. Liffie, 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

CHAPTER	PAGE
I. LOAD FREQUENCY CONTROL THEORY . . . . .	1
Advantages of Interconnection . . . . .	1
The Importance of Governor Speed Droop . . . . .	2
The Influence of a Frequency Sensitive Load . . . . .	8
Supplementary Control Regulating Characteristics . . . . .	12
Flat-frequency (FF) control . . . . .	14
Flat-tie-line (FTL) control . . . . .	14
Tie-line bias (TLB) control . . . . .	15
Interconnected System Operation Under the FF, FTL and TLB Supplementary Control Modes . . . . .	18
Flat frequency control . . . . .	19
Flat frequency-flat tie-line control . . . . .	20
Tie-line bias control at both ends . . . . .	22
Bias - The Imposed Supplementary Regulation . . . . .	24
Effects on system frequency . . . . .	24
Effects on tie-line flow . . . . .	26
Effects on load . . . . .	27
Effects on total generation . . . . .	28
Effects on unregulated and regulated generation . . . . .	30
Effect of Bias and the Natural Combined Characteristic on Control System Stability . . . . .	35
Supplementary Controllers . . . . .	40

CHAPTER	PAGE
II. LOAD FREQUENCY CONTROLS AS APPLIED BY MANITOBA HYDRO . . .	45
General . . . . .	45
The LFC System . . . . .	45
Metering and telemetering . . . . .	45
Tie-line schedule and comparison circuits . . . . .	45
Frequency schedule and comparison circuits . . . . .	46
Area requirement . . . . .	47
Integral control . . . . .	47
III. OPERATIONAL TESTS . . . . .	49
General . . . . .	49
Tests and Discussions of Results . . . . .	49
Test 1 - normal operation of the LFC . . . . .	49
Test 2 - checks on bias settings . . . . .	51
Test 3 - loss of tie-lines . . . . .	54
Test 6 - operation under different types of control . . . . .	56
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 . . . . .	58
IV. SUMMARY AND CONCLUSIONS . . . . .	65
1 - disparity of actual and theoretical area governing characteristics . . . . .	65
2 - the load characteristic . . . . .	66

CHAPTER	PAGE
3 - the desirable operating mode . . . . .	66
4 - supplementary controllers . . . . .	67
5 - future investigations . . . . .	68
APPENDICES . . . . .	69
Appendix A - Nomenclature . . . . .	69
Appendix B - Derivation of the Stability Equations	72
Appendix C - Proportional-Integral Control . . . .	76
BIBLIOGRAPHY . . . . .	79

## LIST OF FIGURES

FIGURE	PAGE*
1. Map . . . . .	2
2. Governor Speed Droop and Governor Steady-State Speed Regulation . . . . .	2
3. Governor Speed Regulation . . . . .	4
4. Governing Characteristics . . . . .	5
5. Relationship of p.u. Steady-State Speed Regulation and p.u. Spinning Capacity per Tenth Cycle . . . . .	6
6. Effect of a Frequency Sensitive Load . . . . .	10
7. Interconnected System with no Supplementary Control . .	12
8. FF, FTL and TLB Regulator Characteristics . . . . .	15
9. Interconnected System with Supplementary Control . . .	19
10. Interconnected System - FF Control . . . . .	19
11. Interconnected System - FF/FTL Control . . . . .	20
12. Interconnected System - TLB Control . . . . .	22
13. Steady-State Changes in Frequency, Tie-Line Flow, Load and Generation . . . . .	24
14. Graphical Representation of the Deviation Equations . .	32
15. Influence of the Natural Combined Characteristics on the Imposed Frequency and Tie-Line Flow Deviations for FTL/FF Control . . . . .	36

---

\*Page number of facing printed page.



FIGURE	PAGE *
16. Influence of the Natural Combined Characteristics and Bias Settings on the Imposed Frequency and Tie-Line Flow Deviations . . . . .	36
17. TLB/TLB Operation . . . . .	38
18. Types of Supplementary Controls . . . . .	40
19. Load and Frequency Control Equipment MH Load Dispatch Office . . . . .	45
20. Tie-Line Bias Operation . . . . .	46
21. Supplementary Control at Seven Sisters Generating Station of Manitoba Hydro . . . . .	48
22. Table of Test Results . . . . .	60 **
23. Recorder Chart - "System Frequency" . . . . .	61 **
24. Recorder Chart - "Area Requirement" . . . . .	62 **
25. Recorder Chart - "BB-1 Megawatts" . . . . .	63 **
26. Recorder Chart - "SK-1 Megawatts" . . . . .	64 **

## TABLE

1. Summary of Deviation Equations for a Two Area Interconnection . . . . .	33
--	----

---

\*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.<sup>1\*</sup> 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%.<sup>2</sup>

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

---

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

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

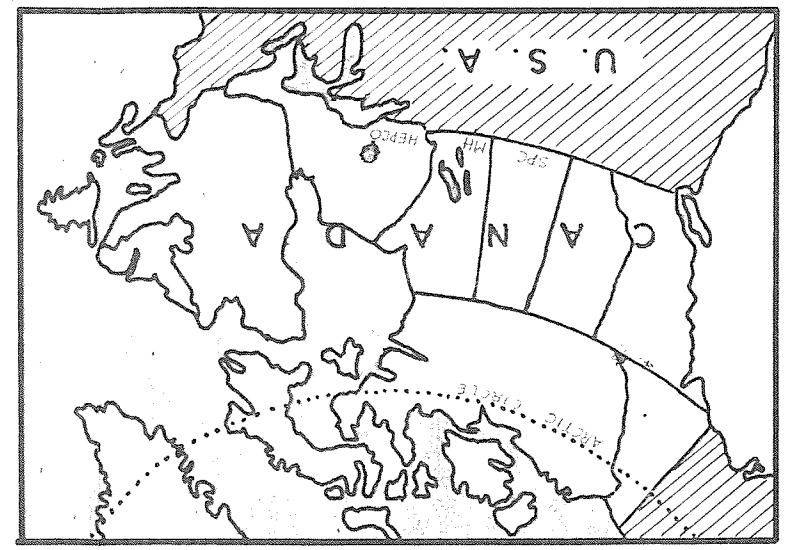
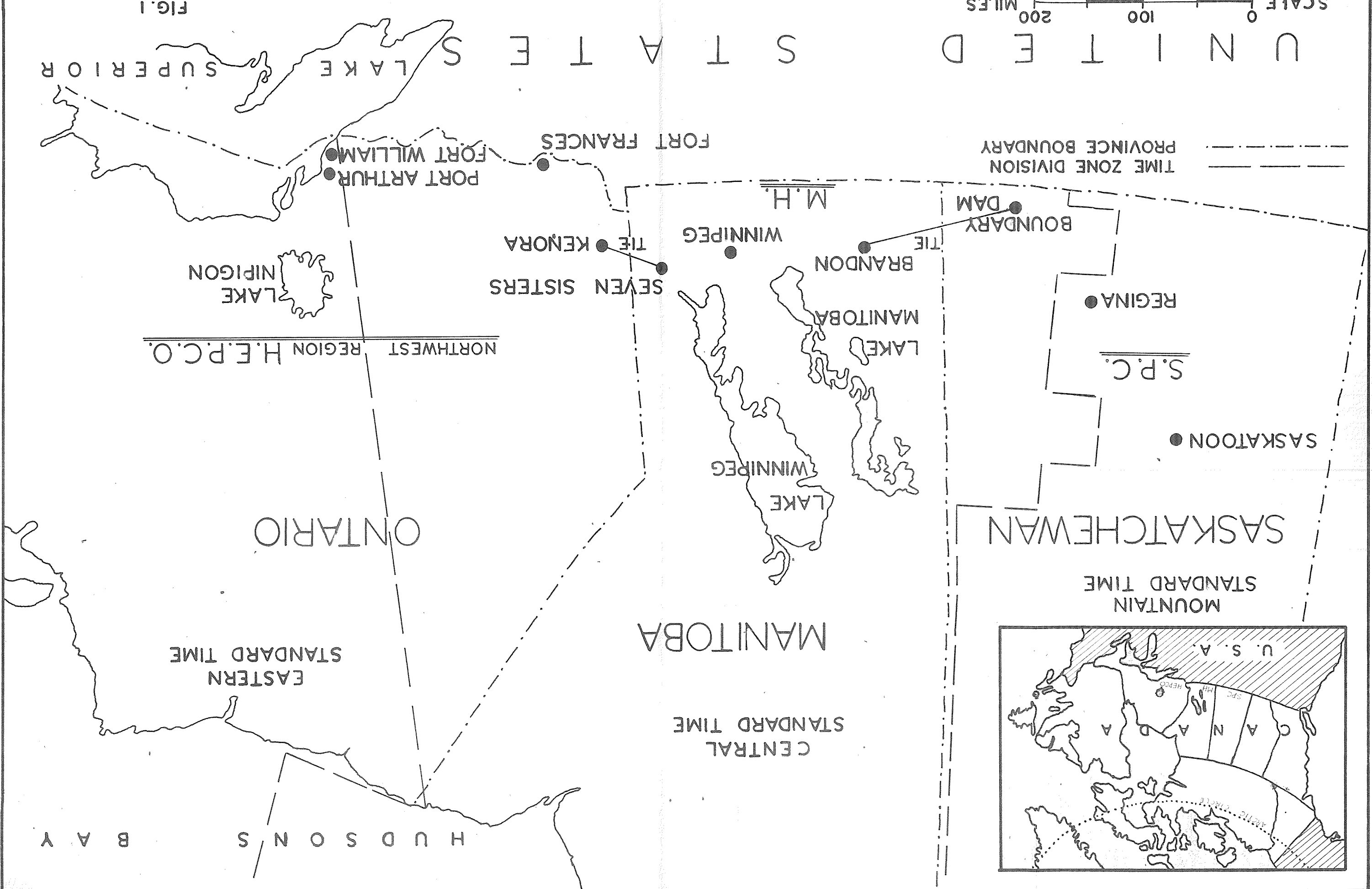


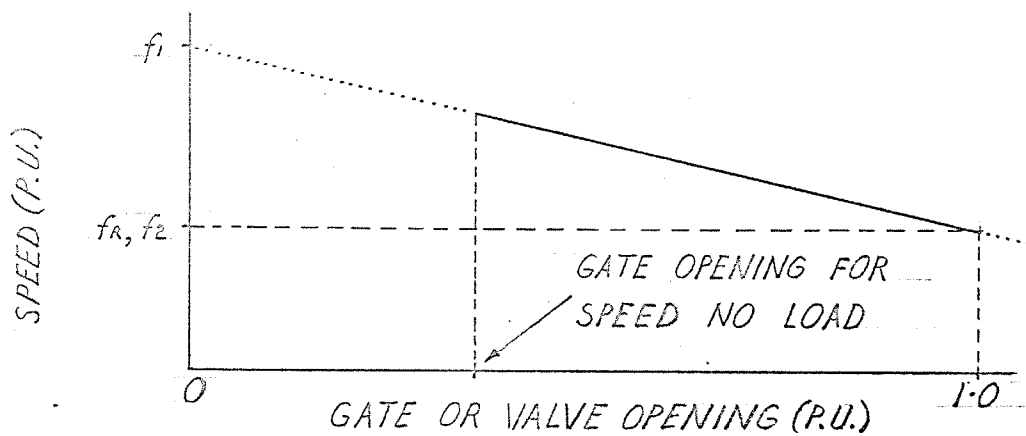
SCALE 0 100 200 MILES

# UNITED STATES

FIG. 1

TIME ZONE DIVISION  
PROVINCE BOUNDARY



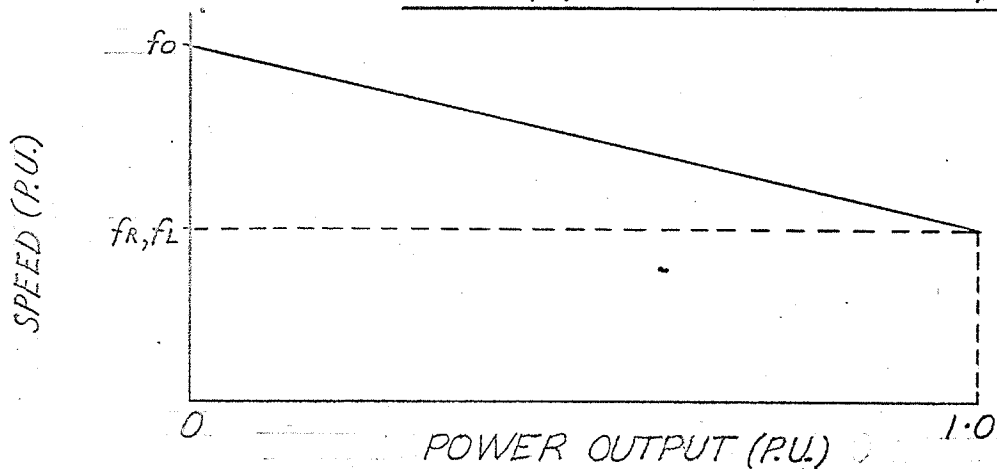


$$G_D = \text{SPEED DROOP} = \frac{(f_1 - f_2)}{f_R} \text{ P.U.}$$

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



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

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.<sup>3</sup>

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

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.<sup>3</sup>

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

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

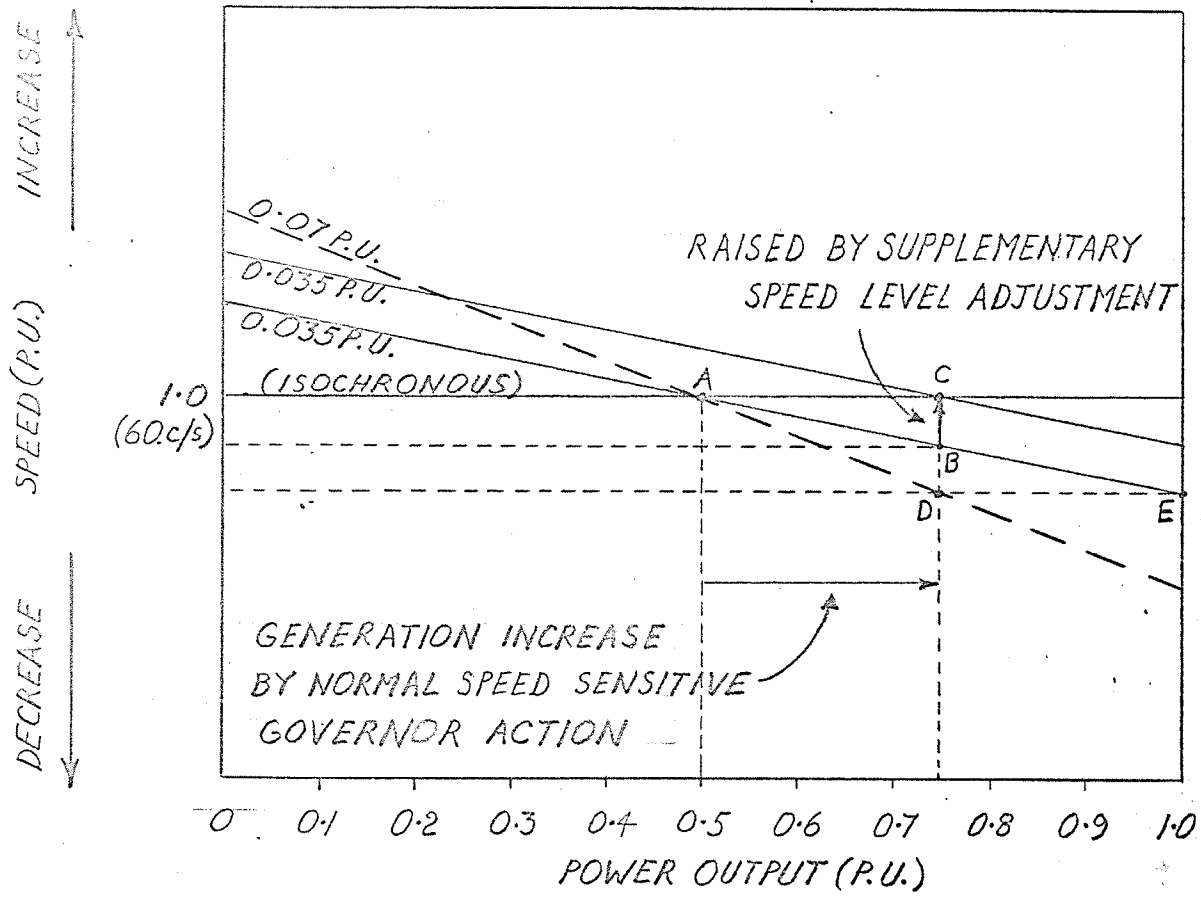


FIG 3 GOVERNOR SPEED REGULATION



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

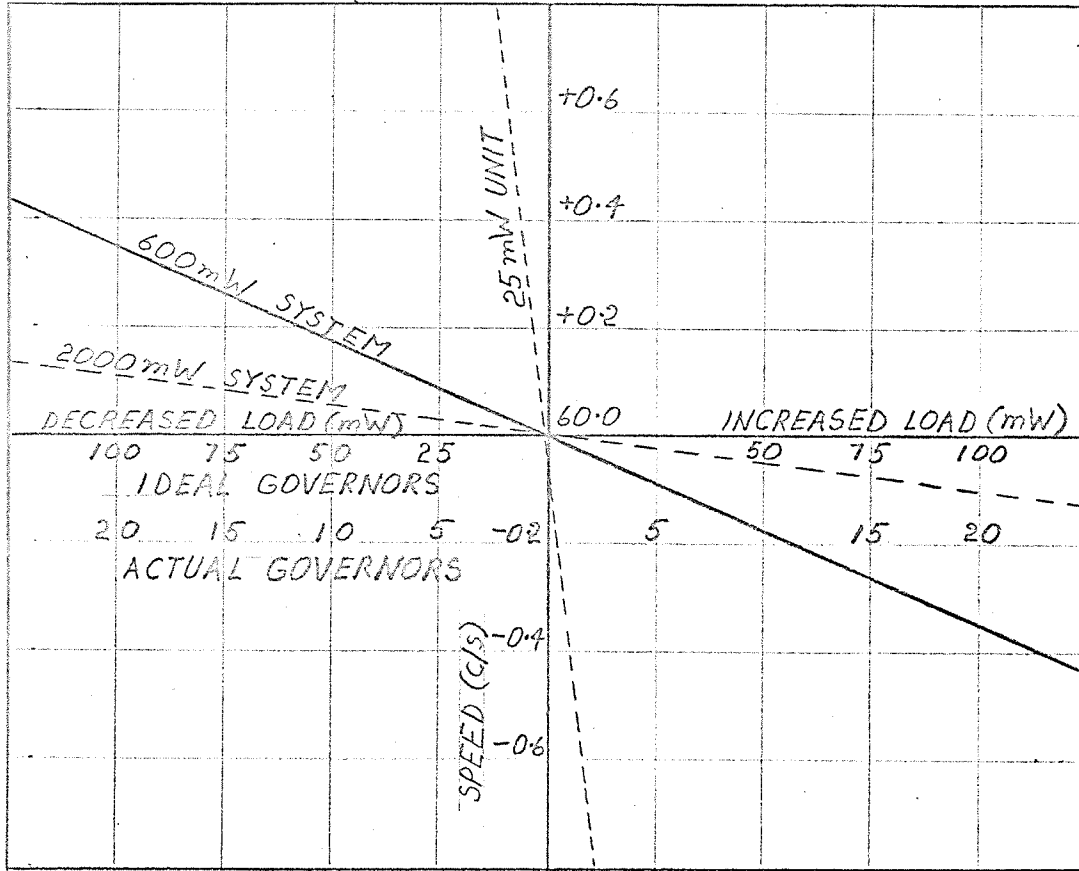


FIG 4. GOVERNING CHARACTERISTICS

(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 governor 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 individual governor characteristics tend to cancel out.<sup>4</sup> 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.<sup>6,7</sup> 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

---

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

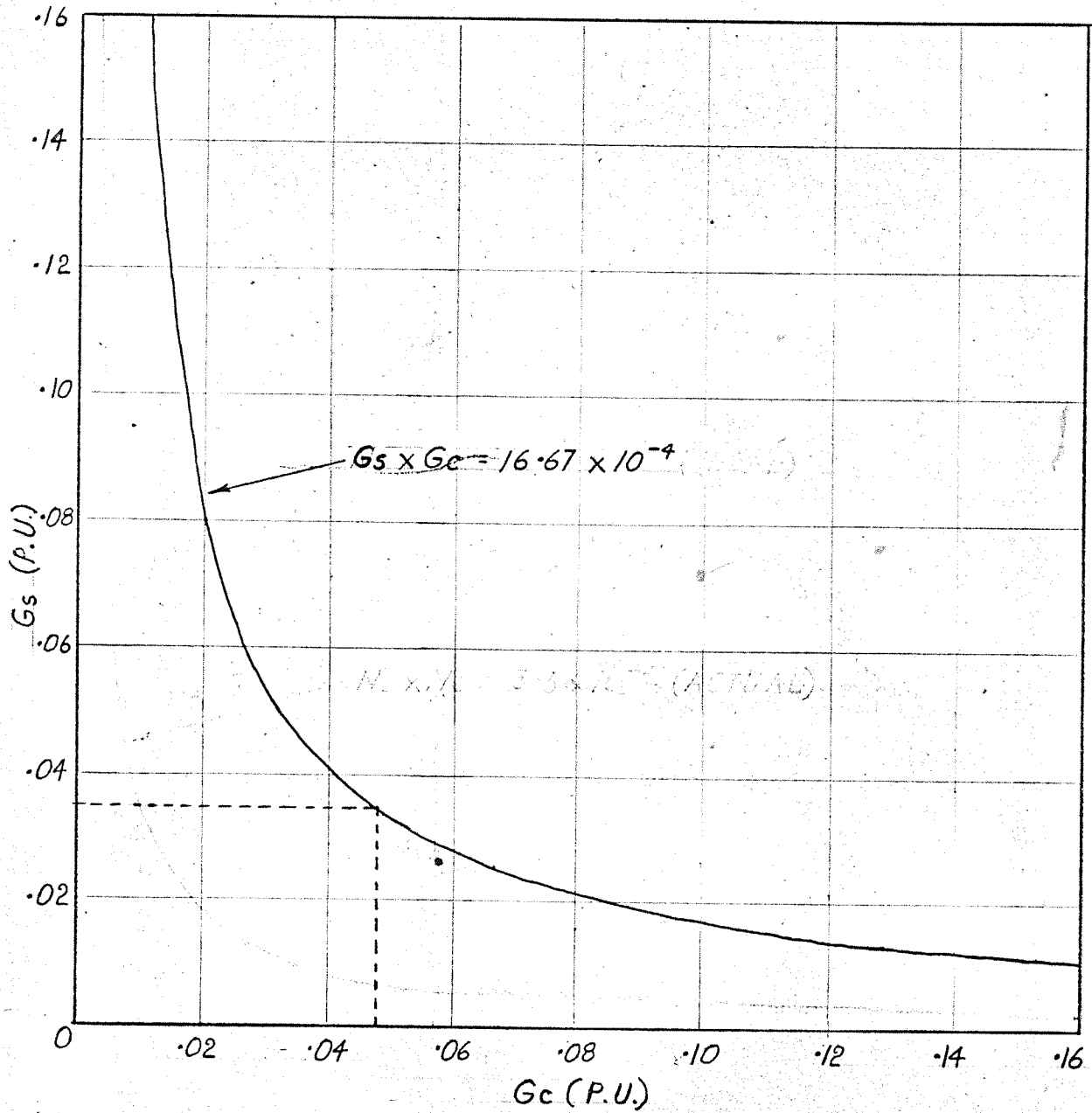


FIG. 5. RELATIONSHIP OF P.U. STEADY-STATE SPEED REGULATION ( $G_s$ ) AND P.U. SPINNING CAPACITY PER 0.1 CYCLE ( $G_c$ )

$$G_C = 96 \text{ mW}/0.1 \text{ cycle}$$

$$= .048 \text{ p.u. spinning capacity}/0.1 \text{ cycle.}$$

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

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

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

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

Multiplying Equations (3) and (2) gives

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

A 0.035 p.u. steady-state speed regulation then represents a governing characteristic of  $G_C = \frac{.001667}{.035} = .048 \text{ p.u.}$

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.<sup>8</sup> The effective regulation is very often larger for very small frequency changes than for larger changes.  $G_S$  may be 0.083 p.u. ( $G_C = 0.02 \text{ p.u.}/0.1 \text{ cycle}$ ) for large frequency changes and yet  $G_S$  may be 0.25 p.u. ( $G_C = 0.0067 \text{ p.u.}/0.1 \text{ cycle}$ ) 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

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

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

$G_{SE}$  = Effective  $G_S$  actually obtained for a given frequency  $f_s$  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.<sup>5,9,10,11</sup> 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,

$$G_C(1 + 2 + \text{----} + n) = G_C(1) + G_C(2) + \text{-----} + G_C(n) \text{ --- (6)}$$

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,

$$\begin{aligned} G_C(2000) &= G_C(500) + G_C(650) + G_C(850) \\ &= 5.0 + 6.5 + 8.5 = \underline{20 \text{ mW}/0.1 \text{ cycle}} \end{aligned}$$

which is considerably better than the individual regulations of 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.<sup>12,14,15</sup> 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  $\Delta P_L = \text{p.u. load change}$

$\Delta f_R = \text{p.u. frequency change.}$

$$P_L = f_R = 1.0 \text{ p.u.}$$

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

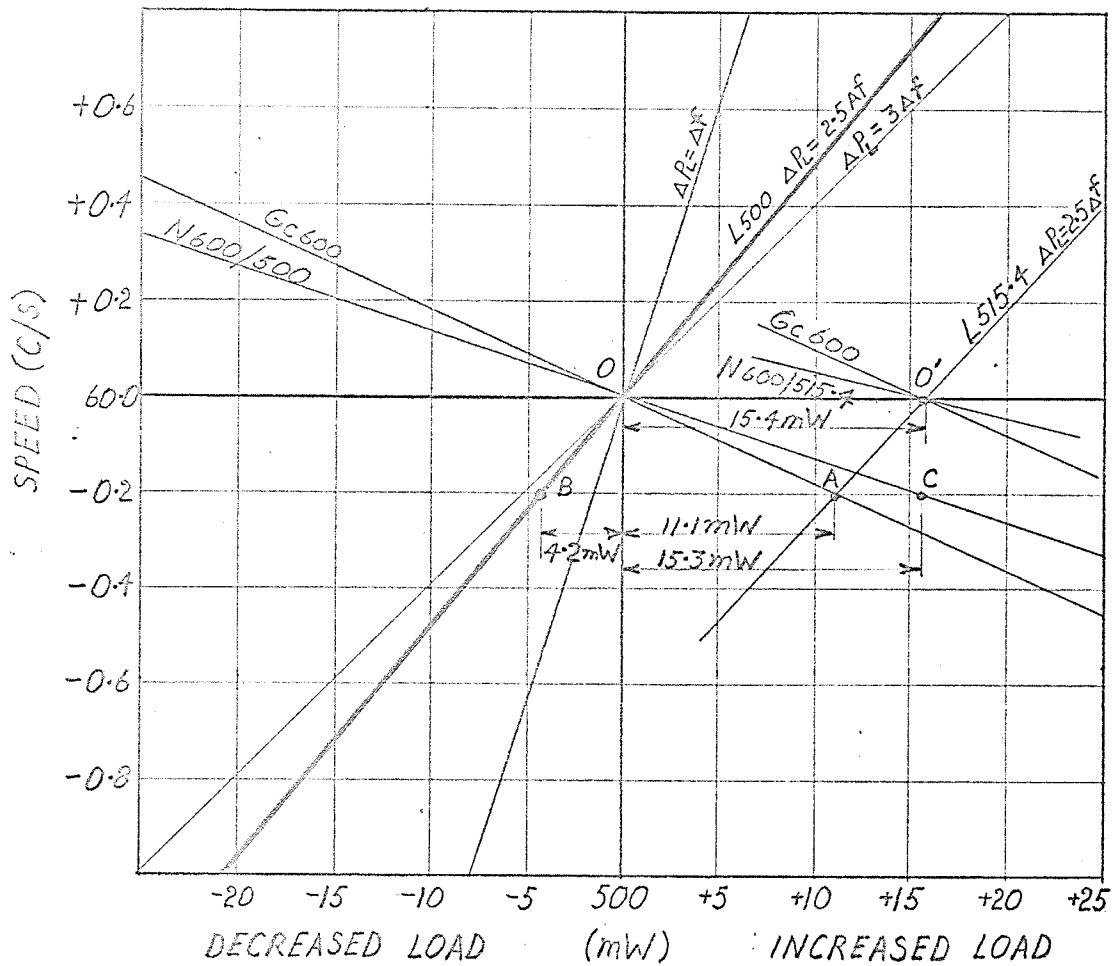
$$\Delta P_L = (f_R + \Delta f_R)^{2.5} - f_R$$

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

$$\Delta P_L = 2.5 \Delta f_R \text{ ----- (7)}$$





$G_c 600$  = TYPICAL GOVERNING CHARACTERISTIC 600mW SPINNING CAPACITY.  
 $L 500$  = TYPICAL LOAD CHARACTERISTIC FOR 500mW LOAD AT 1.0 P.U. SPEED  
 $N 600/500$  = TYPICAL NATURAL COMBINED CHARACTERISTIC 600mW SPINNING CAPACITY & 500mW LOAD  
 $\Delta P_L$  = LOAD DEVIATION  
 $\Delta f$  = FREQUENCY DEVIATION

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

which would result in errors in  $\Delta P_L$  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

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

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,  $N$ .<sup>16</sup> Therefore

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

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

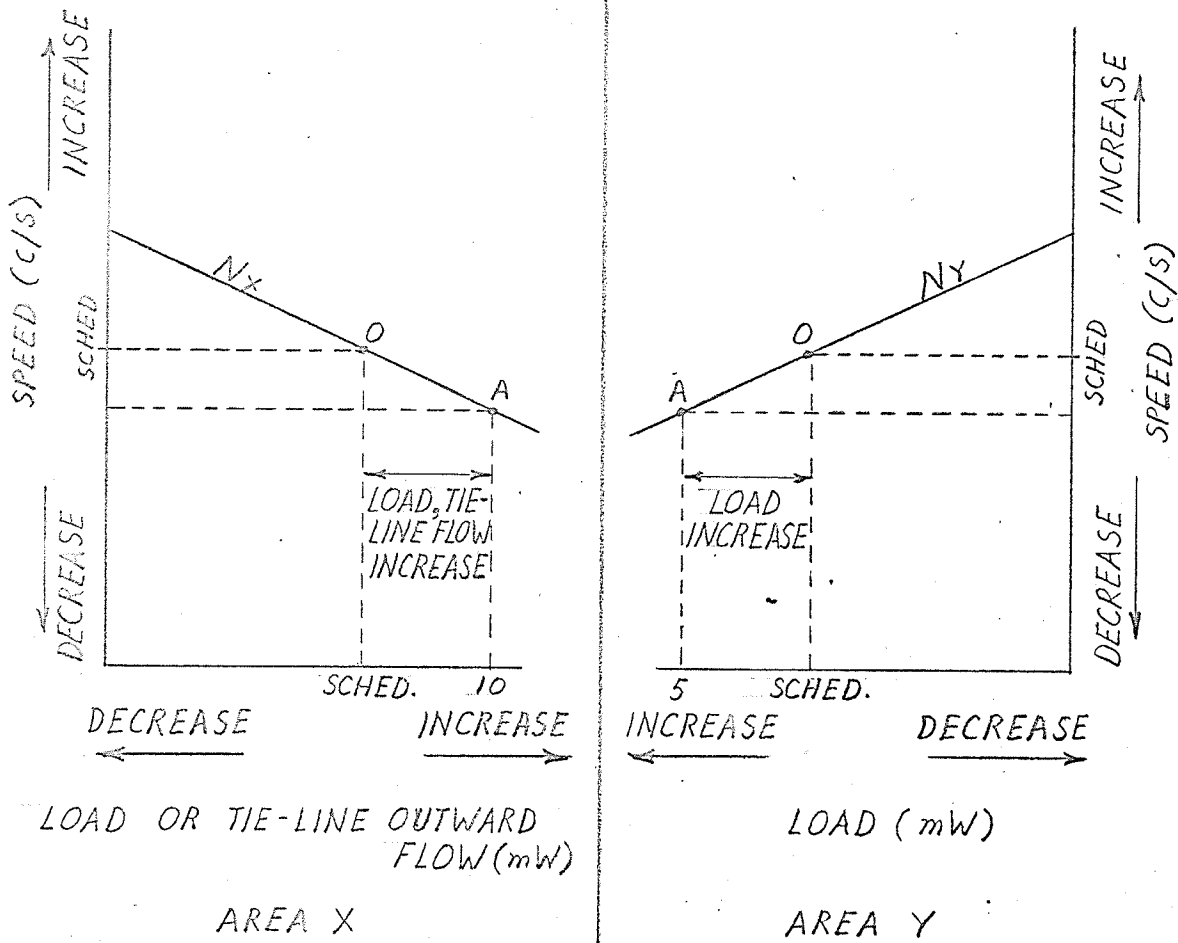
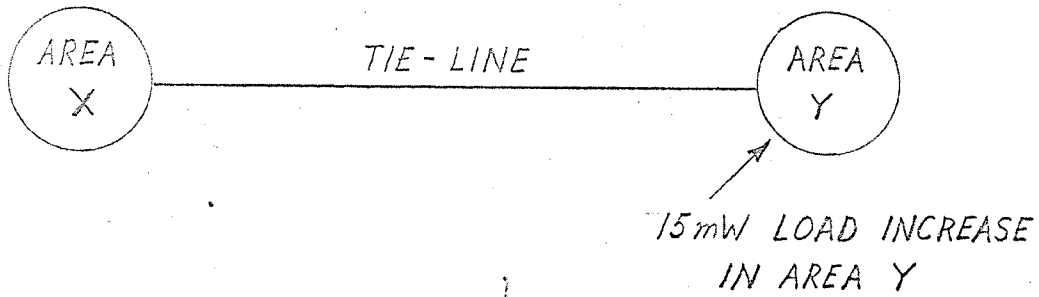


FIG 7. INTERCONNECTED SYSTEM WITH NO SUPPLEMENTARY CONTROL

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.

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

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

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

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).

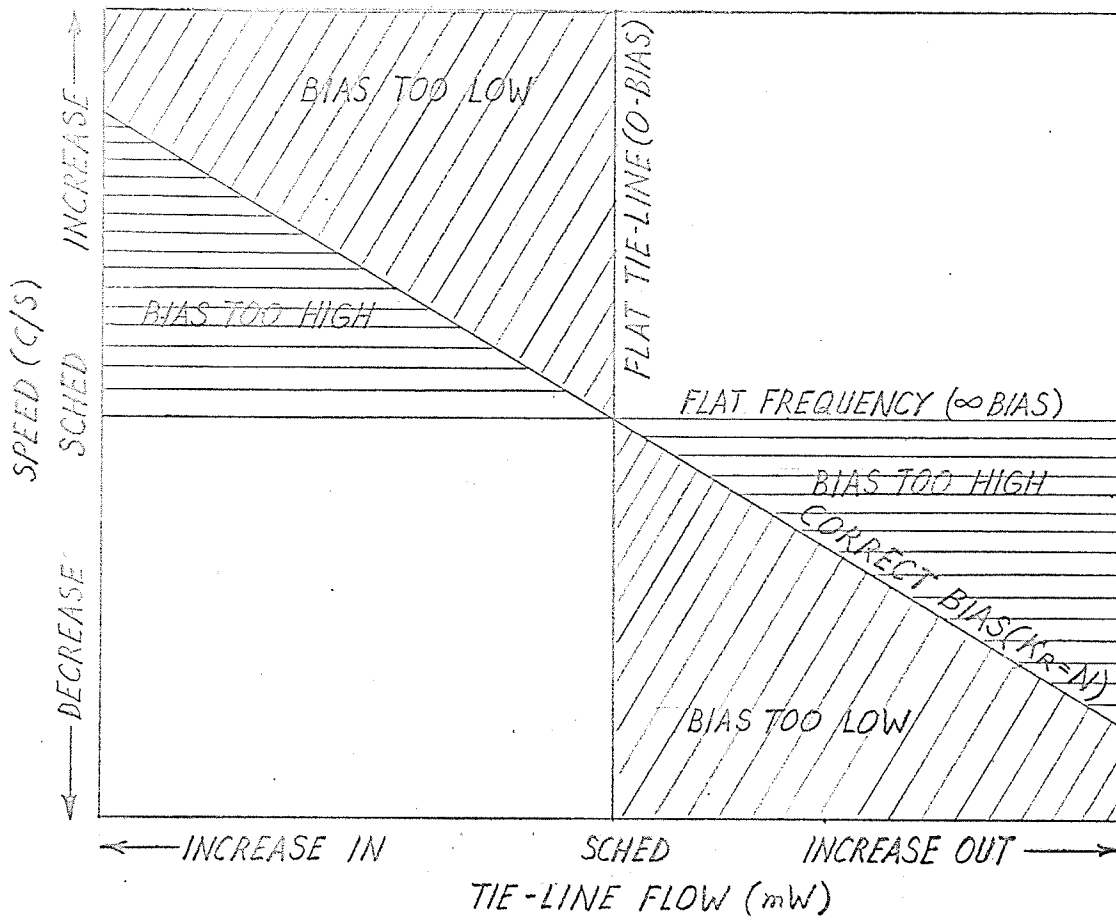


FIG 8. FF, FTL & TLB REGULATOR CHARACTERISTICS



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

(3) Tie-Line Bias (TLB) Control - 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

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

where  $\Delta P_T$  and  $\Delta f$  are as defined with respect to Equations (10) and (11) above and are expressed in mW and cycles  $\times 10^{-1}$ /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  $\Delta P_T$  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,  $\Delta f$  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.<sup>18</sup>

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.

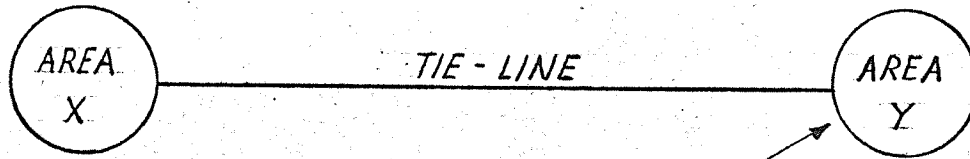
(d) Tie-Line Bias control takes into account both tie-line flow and frequency deviations from normal and therefore possesses the required information to detect whether a power disturbance is external or internal. If the bias setting equals the area's natural combined characteristic an external disturbance 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.<sup>7</sup> 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.

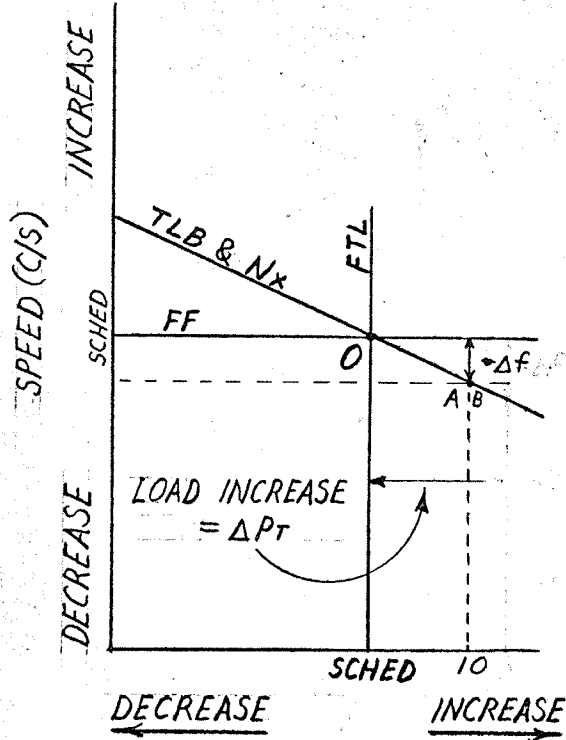
To avoid unnecessary complication the sensing and interpretation only of the frequency and tie-line deviations from schedule will be discussed here. The various mechanisms by which the supplementary controls act to raise and lower generation will be discussed in Section VIII of this chapter. At this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



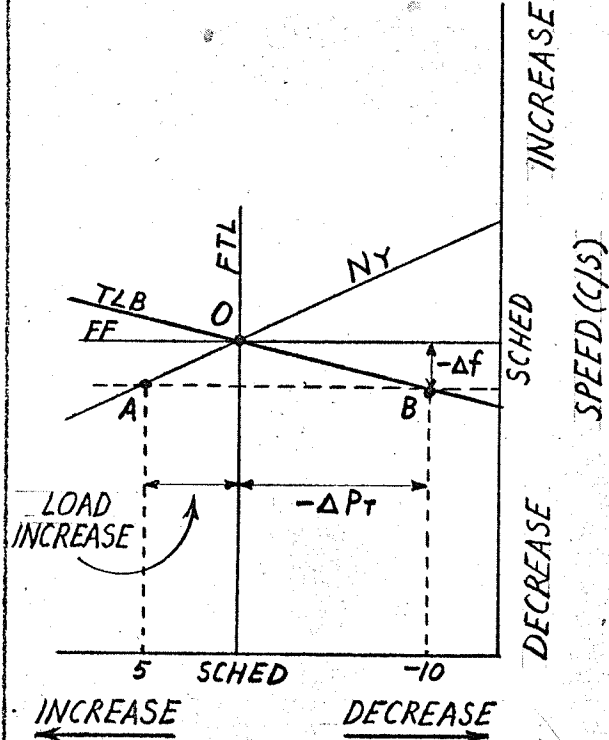
15 mW LOAD INCREASE  
IN AREA Y

FF,  $-\Delta F \neq 0$  (Eqn. 10)  
FTL,  $\Delta P_T \neq 0$  (Eqn. 11)  
TLB,  $\Delta P_T - \Delta P_T = 0$  (Eqn. 14)

FF,  $-\Delta F \neq 0$  (Eqn. 10)  
FTL,  $-\Delta P_T \neq 0$  (Eqn. 11)  
TLB,  $-2\Delta P_T \neq 0$  (Eqn. 16)



AREA X



AREA Y

FIG 9. INTERCONNECTED SYSTEM WITH SUPPLEMENTARY CONTROL

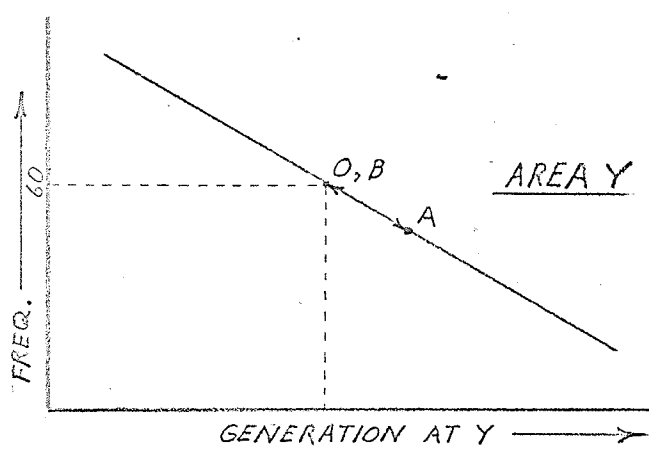
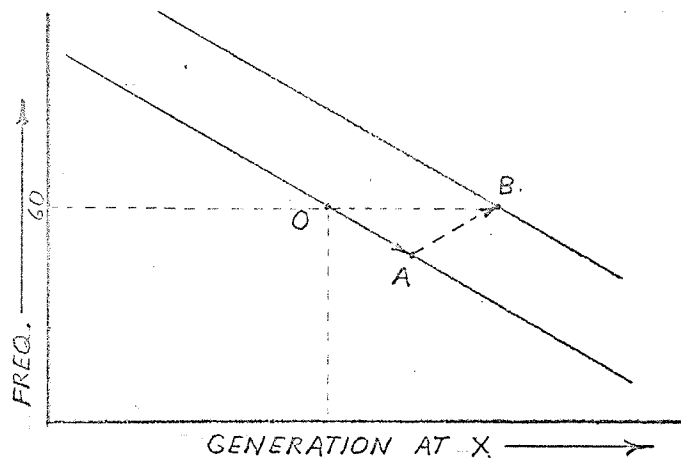
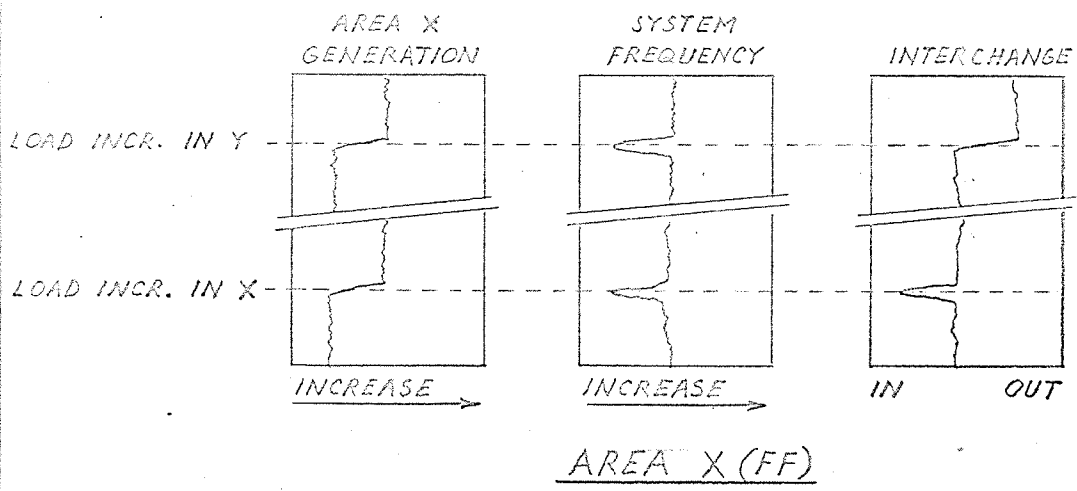


FIG. 10. INTERCONNECTED SYSTEM-FF CONTROL  
 $N_X = N_Y$

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 operate 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

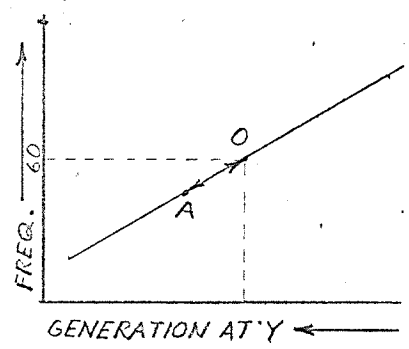
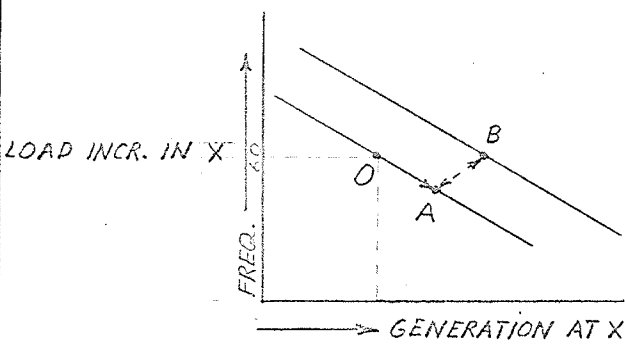
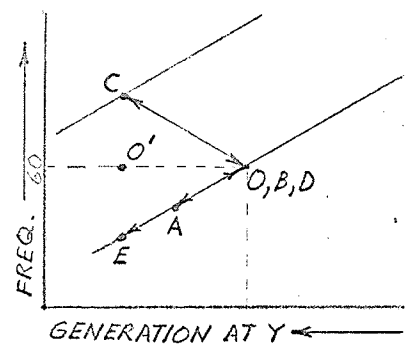
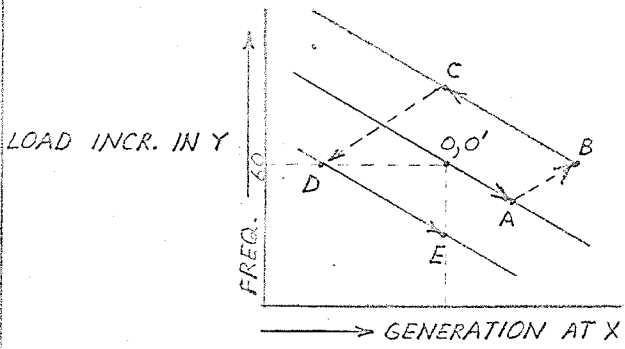
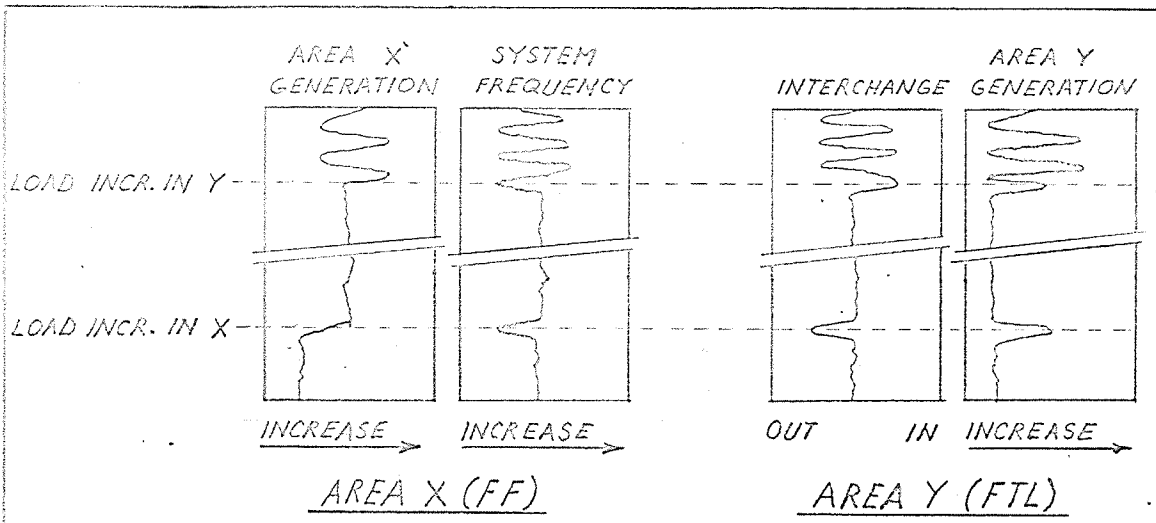


FIG. 11. INTERCONNECTED SYSTEM - FF/FTL CONTROL (FF COMPLETES ACTION BEFORE FTL ACTION BEGINS)  
 $N_X = N_Y$



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

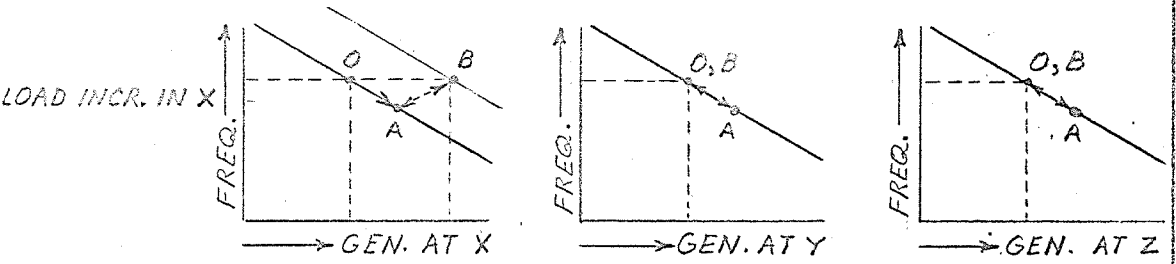
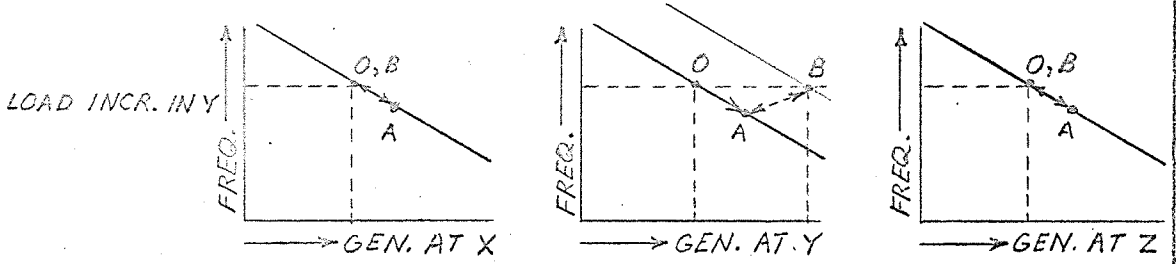
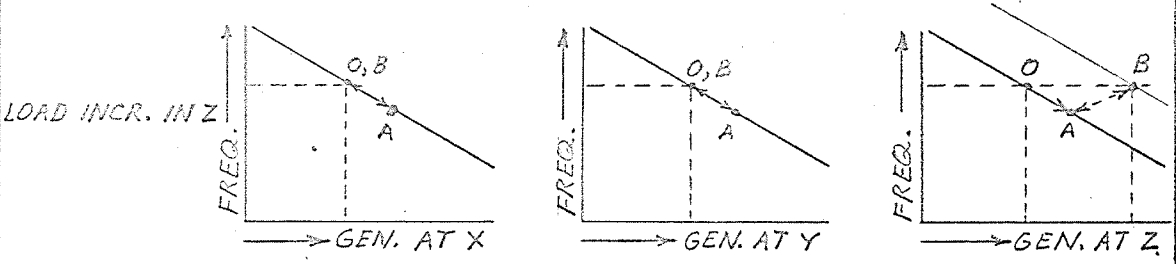
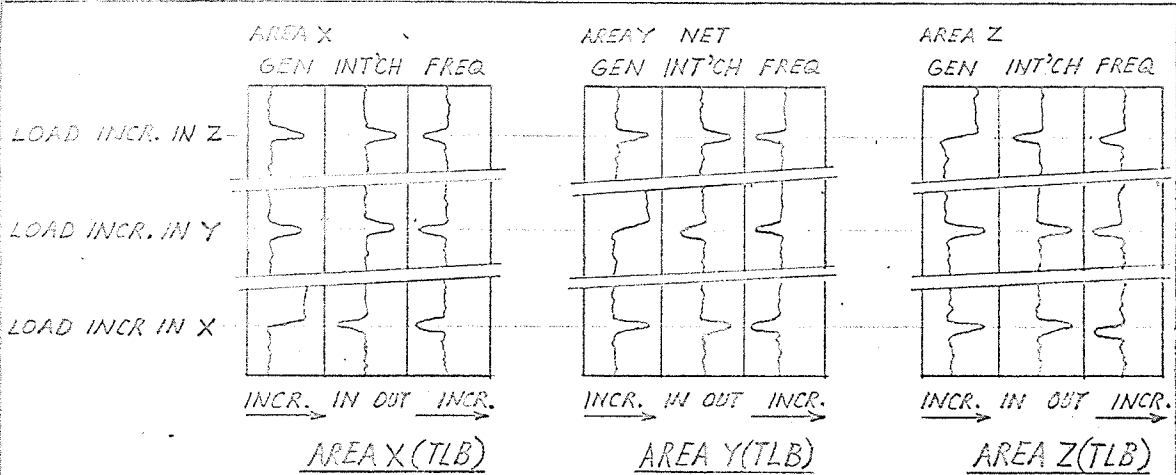


FIG 12 INTERCONNECTED SYSTEM - TLB CONTROL  
 $N_X = N_Y = N_Z$

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.

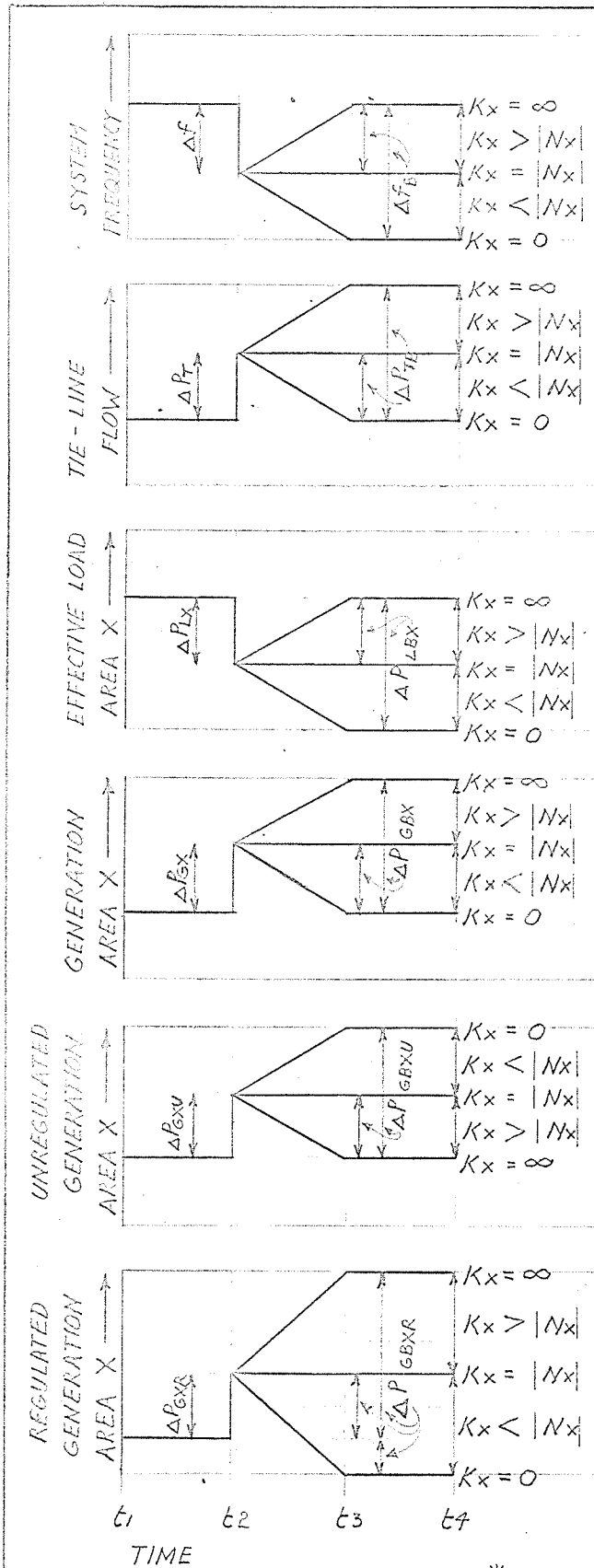
The same reasoning would follow for disturbances in Areas Y and X with the result that only in the area in which the load change actually takes place would correction be applied. This is the ideal state of affairs resulting in a bonus feature that the system is insensitive to one area having a faster 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.

### Effects on System Frequency.

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

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

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

For a D MW step function load change anywhere within the inter-connection, the resulting natural frequency deviation,  $\Delta f$ , 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

$$\Delta f_B(\text{FF}) = 0 \quad (10)$$

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 FLB control in Area X with a correct bias setting,

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

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

$$\Delta f_B(K_R) = \Delta f \quad \text{-----} \quad (21)$$

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

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

#### 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  $\Delta f$  from Equation (19) gives

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

The supplementary regulator would impose a deviation given by

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

and  $\Delta f_B$  from Equation (20) gives

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

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

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

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

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

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

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

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

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,  $\Delta P_{LX}$ , before supplementary control action takes place will be

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

and from Equation (19)

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

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

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

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

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

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

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

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

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

#### Effects on Total Generation in Area X

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

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

and

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

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),

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

(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).

$\Delta P_{GX}$  is made up of regulated,  $\Delta P_{GXR}$ , and unregulated,  $\Delta P_{GXU}$ , generation contributions.

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

and therefore

$$G_{GX} = G_{GXR} + G_{GXU} \text{ ----- (40)}$$

where  $G_{GX}$ ,  $G_{GXR}$ ,  $G_{GXU}$  are the total, regulated and unregulated composite governing characteristics respectively for Area X.

Unregulated generation will absorb

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

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

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

Regulated generation will absorb

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

and from Equation (33)

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

(b) Natural Governor Reaction plus Supplementary Control Action

$\Delta P_{GBX}$  is likewise made up of regulated,  $\Delta P_{GBXR}$ , and unregulated,  $\Delta P_{GBXU}$ , contributions.

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

Unregulated generation will absorb

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

From Equation (20),

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

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

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

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

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

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

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

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

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

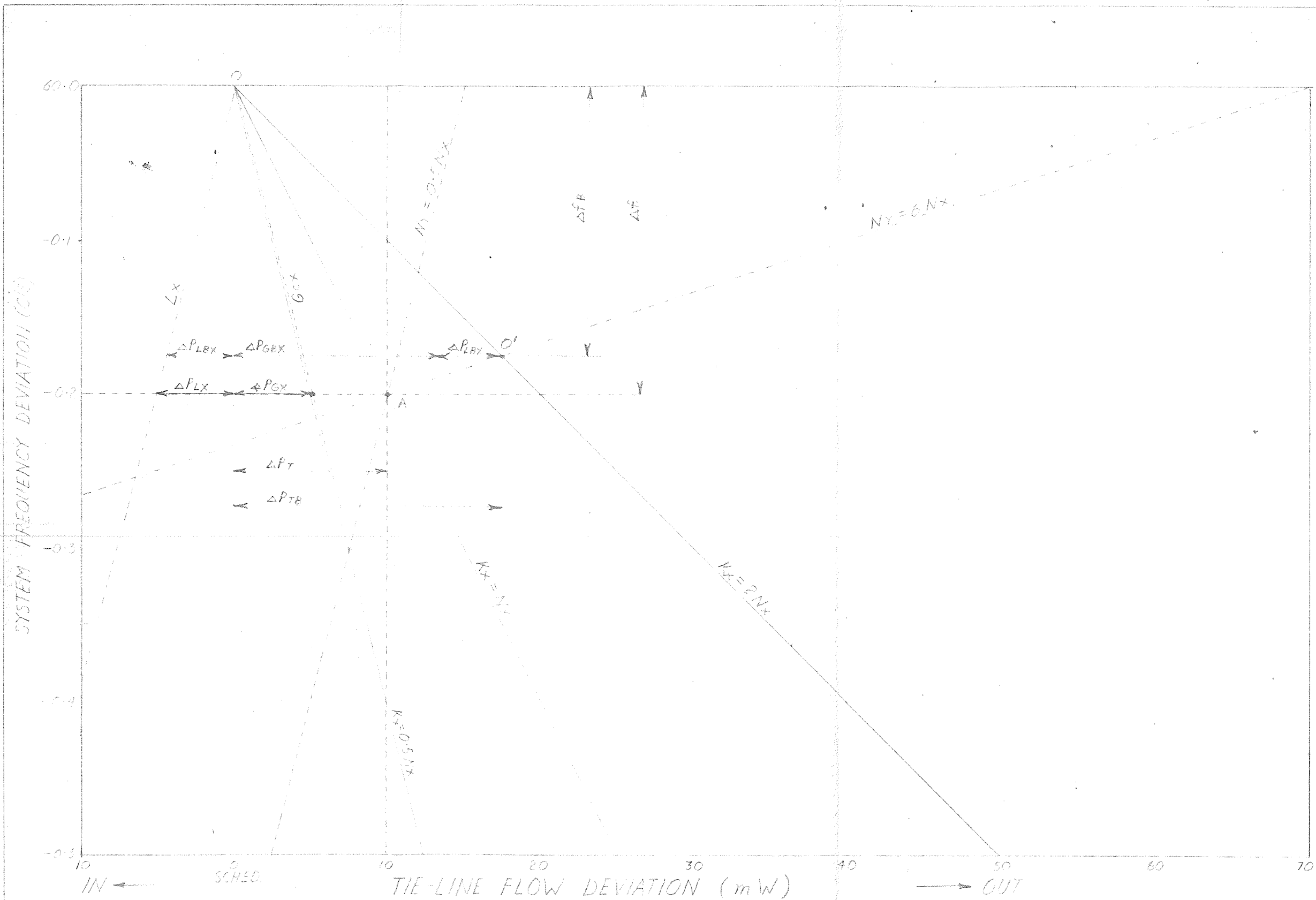


FIG 14 GRAPHICAL REPRESENTATION OF THE DEVIATION EQUATIONS.

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

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

(2) For TLE control in Area X with correct bias,  $K_X = \frac{N_X}{N_Y}$

and

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

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

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

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

\*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.

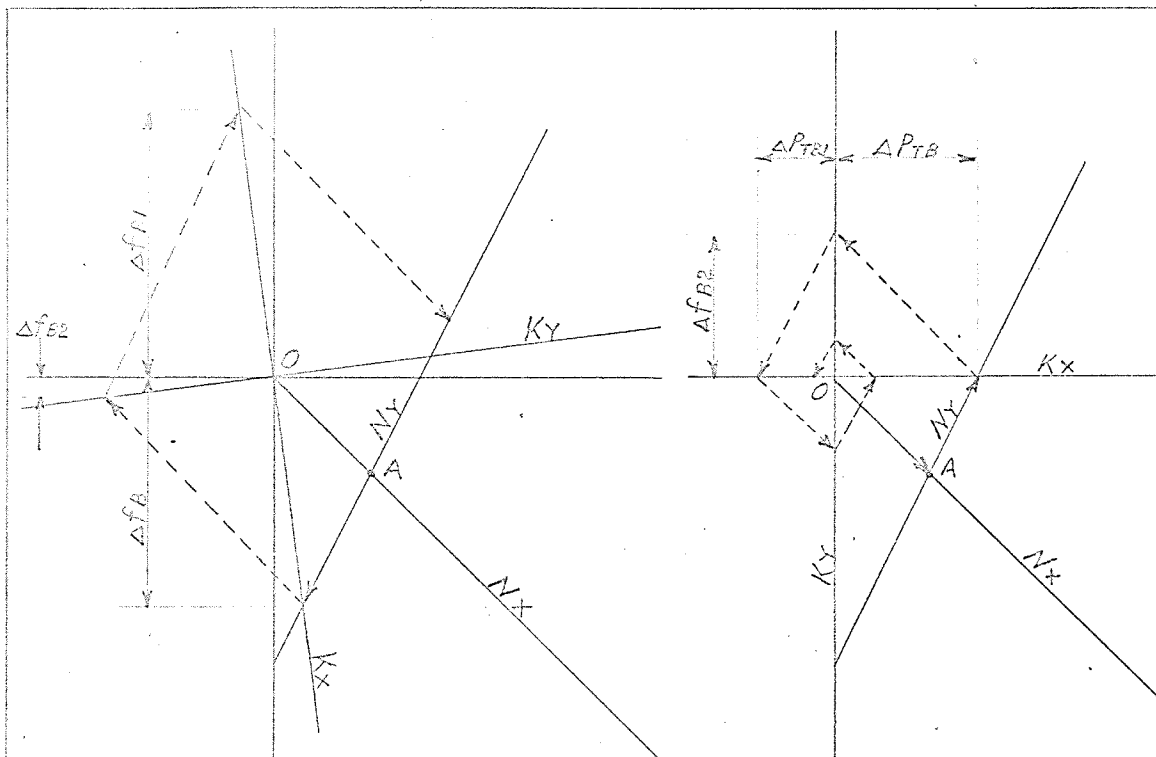
(e) If a given area represents a comparatively small proportion of the spinning capacity of an interconnection its bias should be adjusted to a value which will always be either equal to or slightly less than its own prevailing natural combined characteristic. This will avoid excessive demands on its 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  $G_{OXR}$  (the normal combined governing characteristic of the regulated generation). Normal governor action on the regulated generation in accordance with  $G_{OXR}$  is over-ridden by the LFC regulator.

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

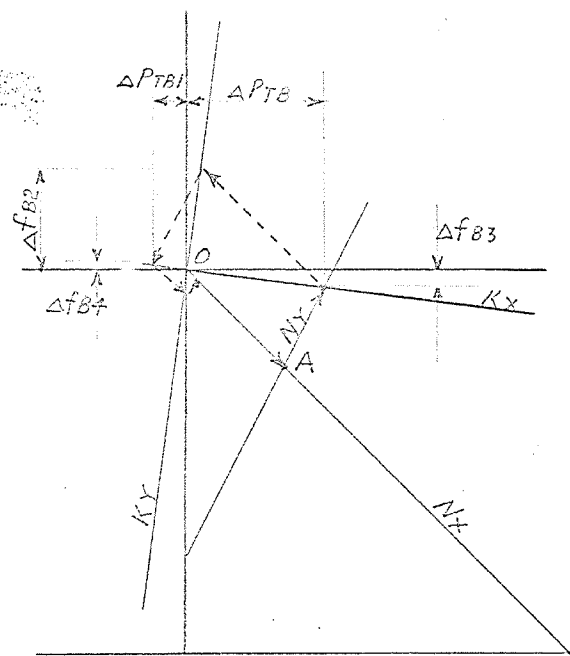
## VII - EFFECT OF BIAS AND THE NATURAL COMBINED CHARACTERISTIC ON CONTROL SYSTEM STABILITY

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



-  $\Delta P_{TB}$  +  
 (a) TLB/TLB CONTROL  
 $K_x \leq N_x$   
 $K_y \geq N_y$

-  $\Delta P_{TB}$  +  
 (b) FF/FTL CONTROL



-  $\Delta P_{TB}$  +  
 (c) TLB/TLB CONTROL  
 $K_x \geq N_x$   
 $K_y \leq N_y$

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

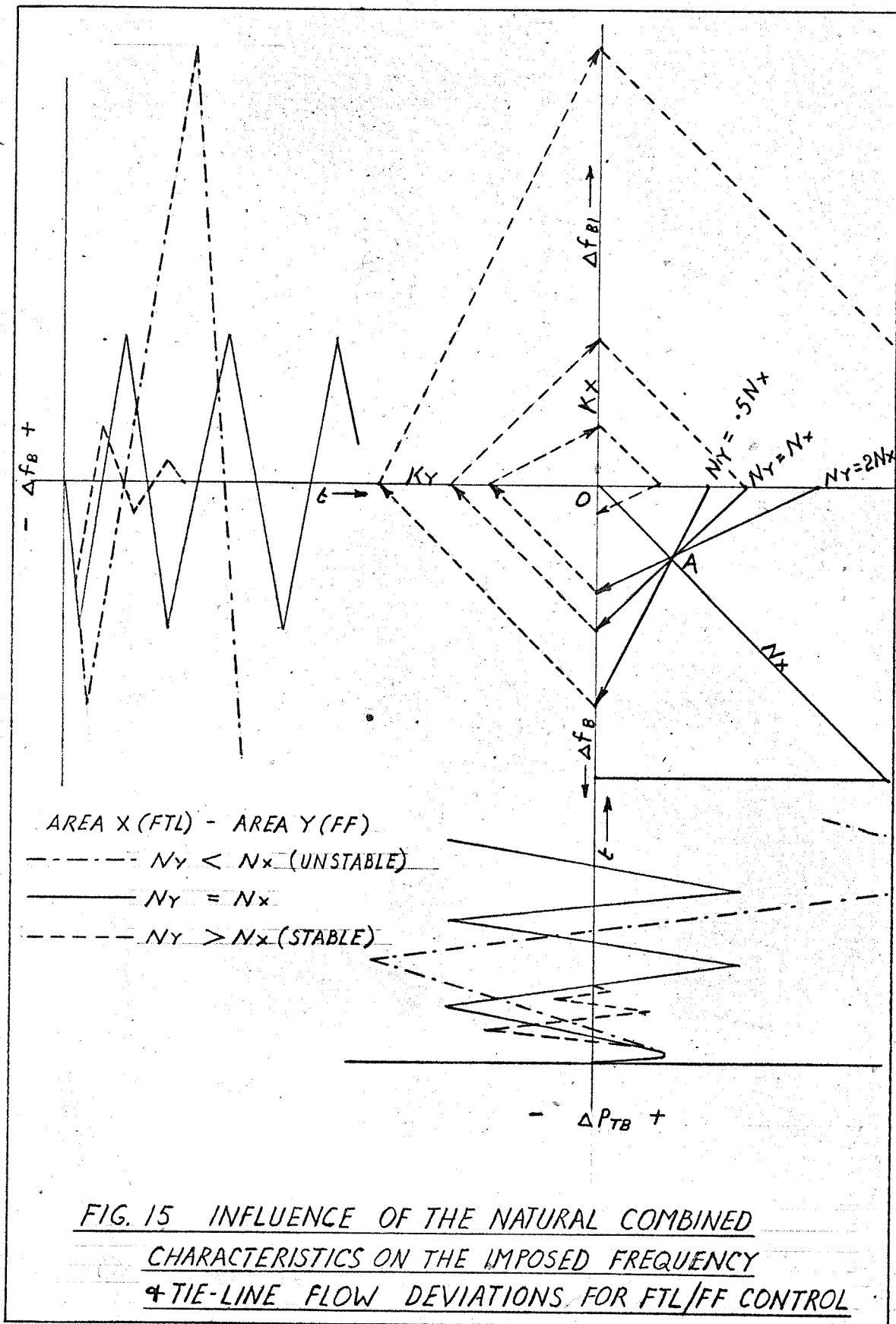


FIG. 15 INFLUENCE OF THE NATURAL COMBINED CHARACTERISTICS ON THE IMPOSED FREQUENCY & TIE-LINE FLOW DEVIATIONS FOR FTL/FF CONTROL

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,  $\Delta f_B$ , caused by Area X's regulator has already been defined. If  $\Delta f_{B1}$  is defined as the following frequency deviation from schedule caused by overshoot of the controls, then

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

will define whether or not the system tends to be stable. If the  $\lim \rightarrow 0$ , 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

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

TLB/TLB Control for  $K_X < N_X$  and  $K_Y > N_Y$  (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),

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

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

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

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

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

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

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

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

where  $\Delta P_{TB}$  is the imposed tie-line flow deviation.

$\Delta P_{TB1}$  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),

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





TLB/TLB Control for  $K_X \geq N_X$  and  $K_Y \leq N_Y$

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  $K_Y = |N_Y|$ ,

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

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

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

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

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

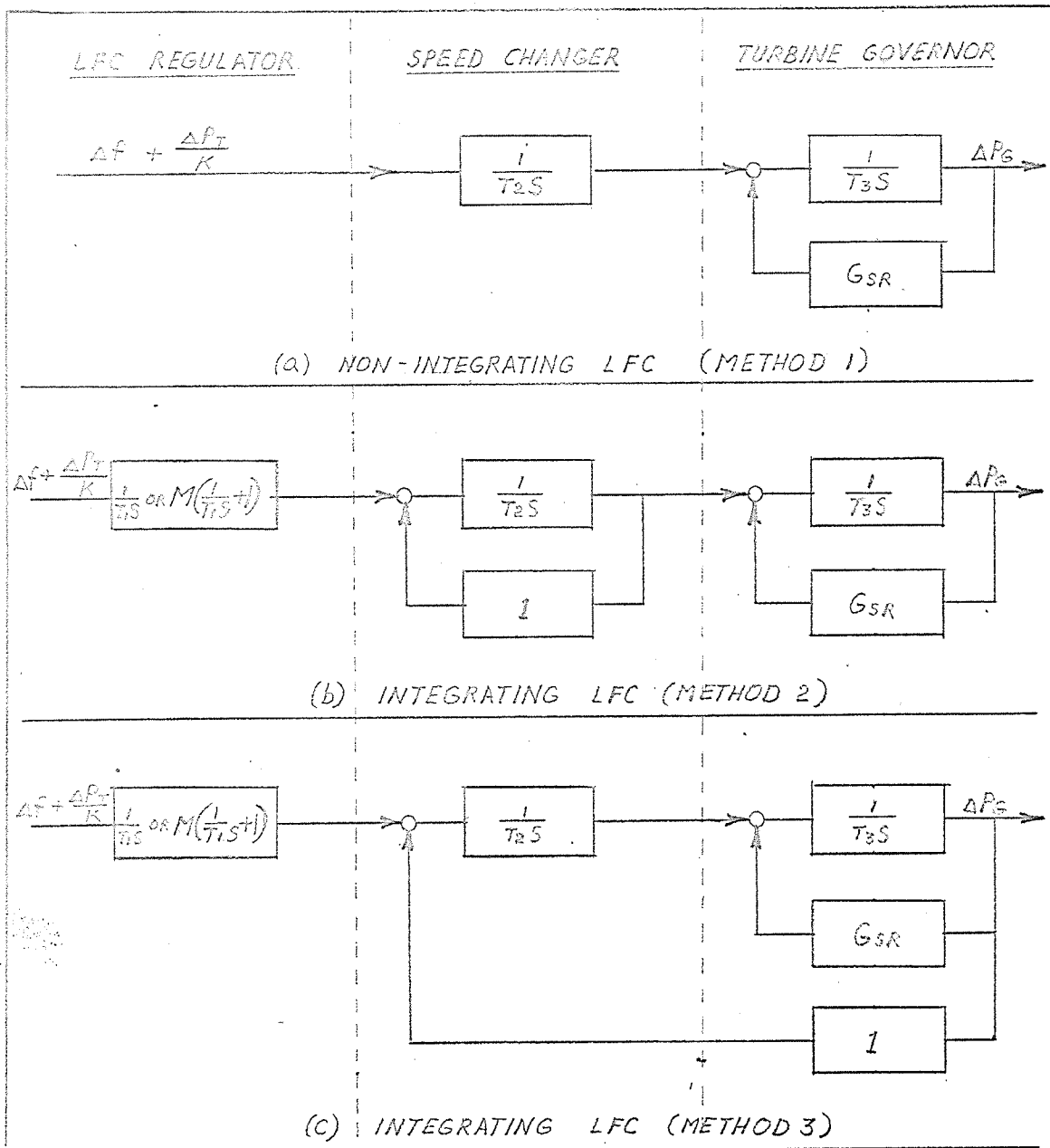
(c) In confirmation of Conclusion (d) of Section VI, a comparatively large area with fast supplementary controlled generation response should employ bias values that equal or are greater than its prevailing natural combined characteristic.

(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.



$\Delta f$  = FREQUENCY DEVIATION  
 $\Delta P_T$  = TIE-LINE FLOW DEVIATION  
 $\Delta P_G$  = GENERATION DEVIATION  
 $K$  = BIAS  
 $T_1, T_2, T_3$  = TIME COEFFICIENTS  
 $G_{SR}$  = SPEED REGULATION OF LFC GENERATION  
 $S$  =  $\frac{d}{dt}$

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

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

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. Indirect Regulation with a Non-Integrating Network Regulator (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,  $\Delta P_G$ , brought about by this method of control on the area generation under LFC is given in transfer function form (Refer to Figure 18a) by

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

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

---

\* 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.

---

\* 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

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

and in Proportional-Integral form,

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

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

---

\* 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.

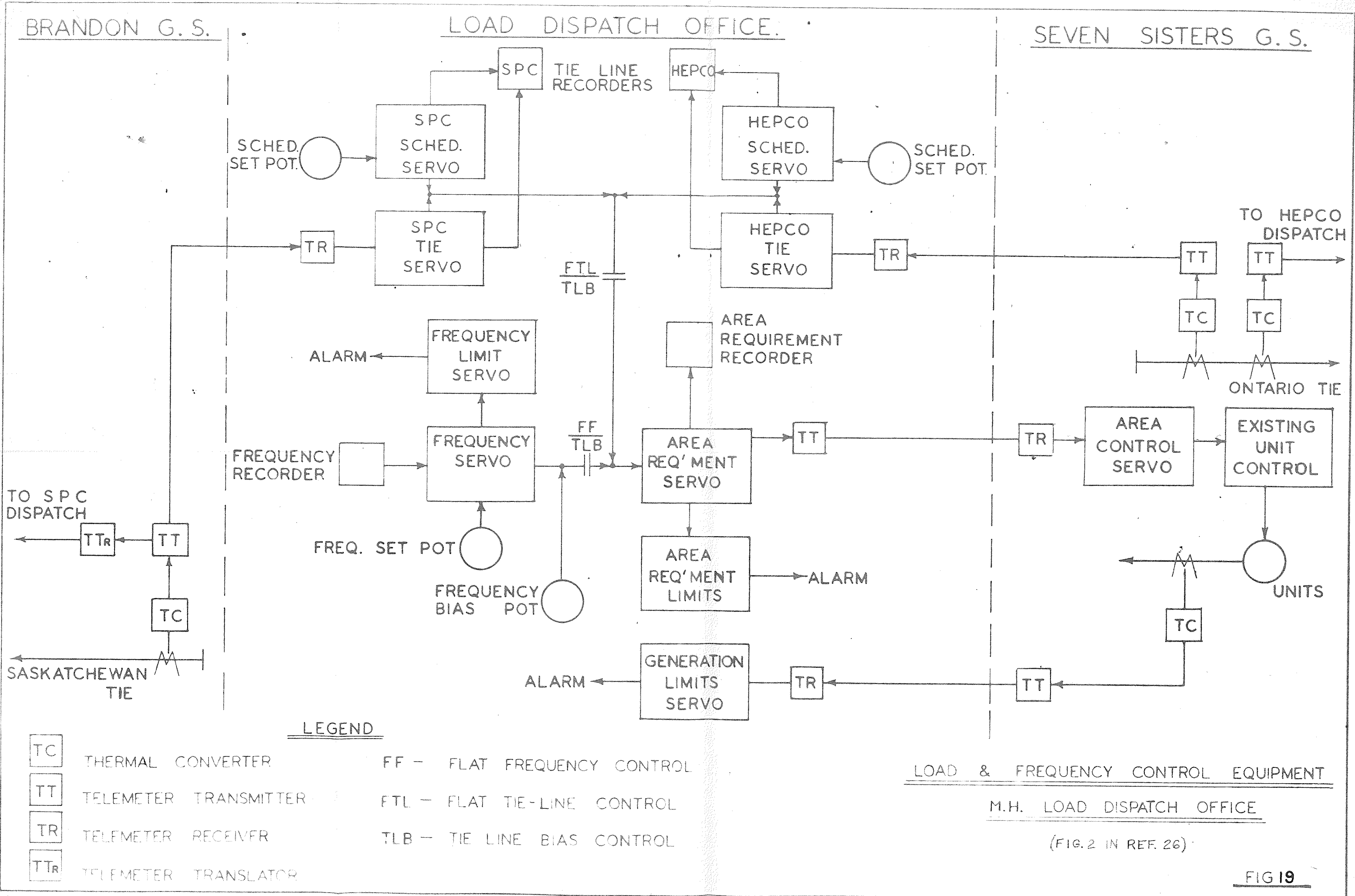
(b) Methods 2 and 3 are capable of proportional-integral control and do not require load equalizing equipment. Units anywhere on the system can be selected for supplementary regulation with a minimum of telemetering.

(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. <sup>23,24</sup> 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.<sup>25</sup>





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 <sup>26</sup>

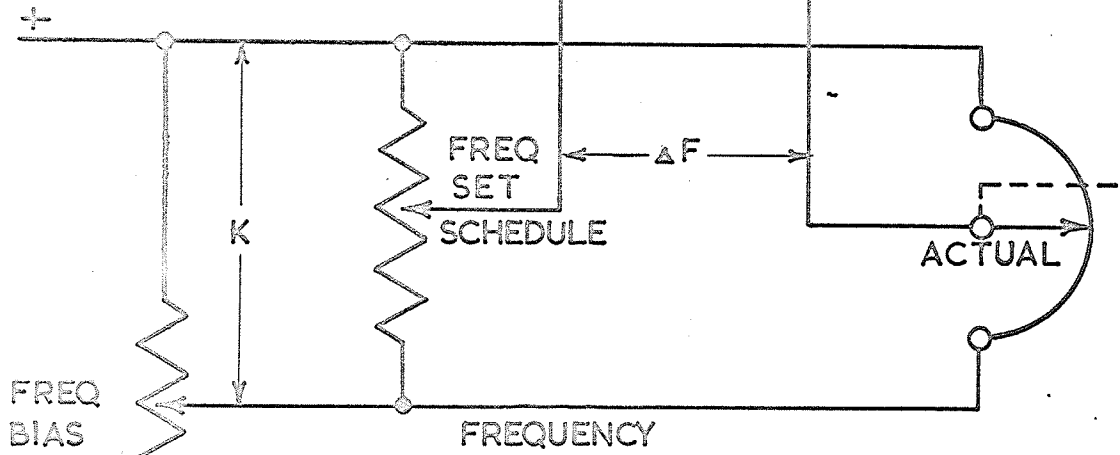
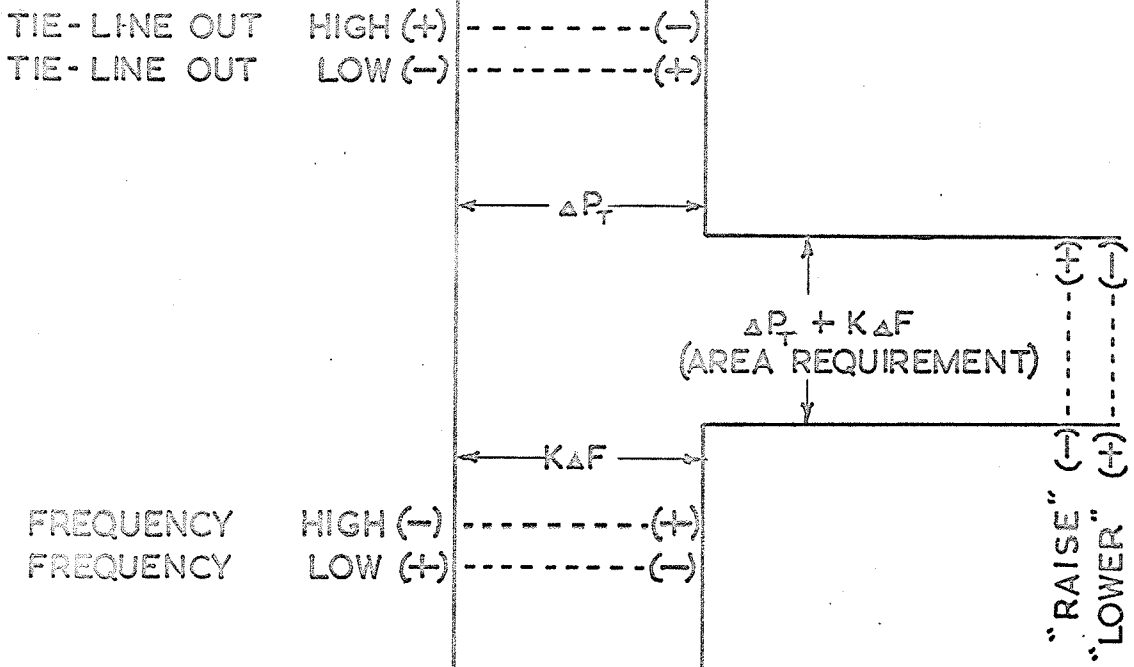
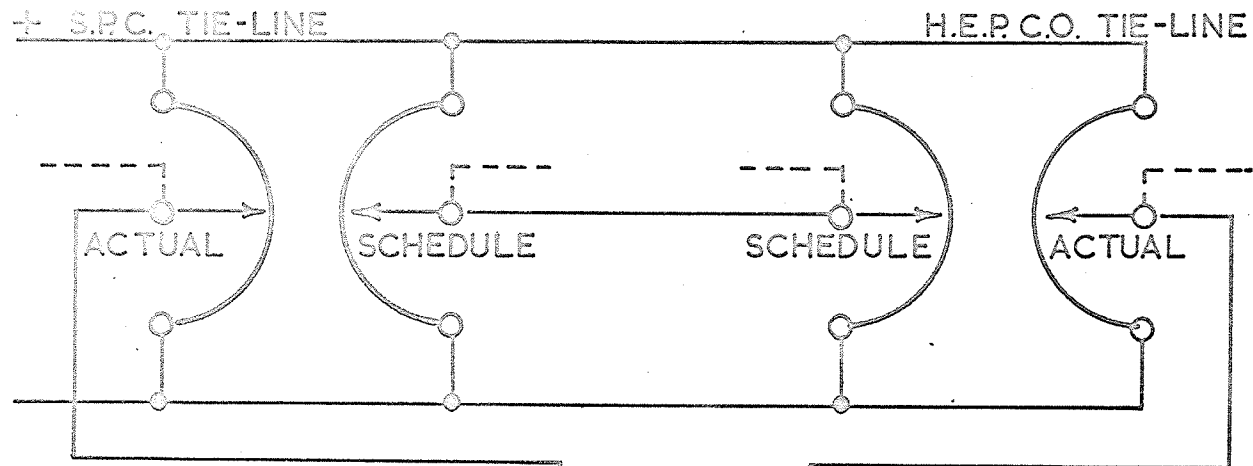
#### I - GENERAL

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



$\Delta P$  = TIE-LINE FLOW DEVIATION FROM NET SCHEDULE  
 $\Delta F$  = 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)

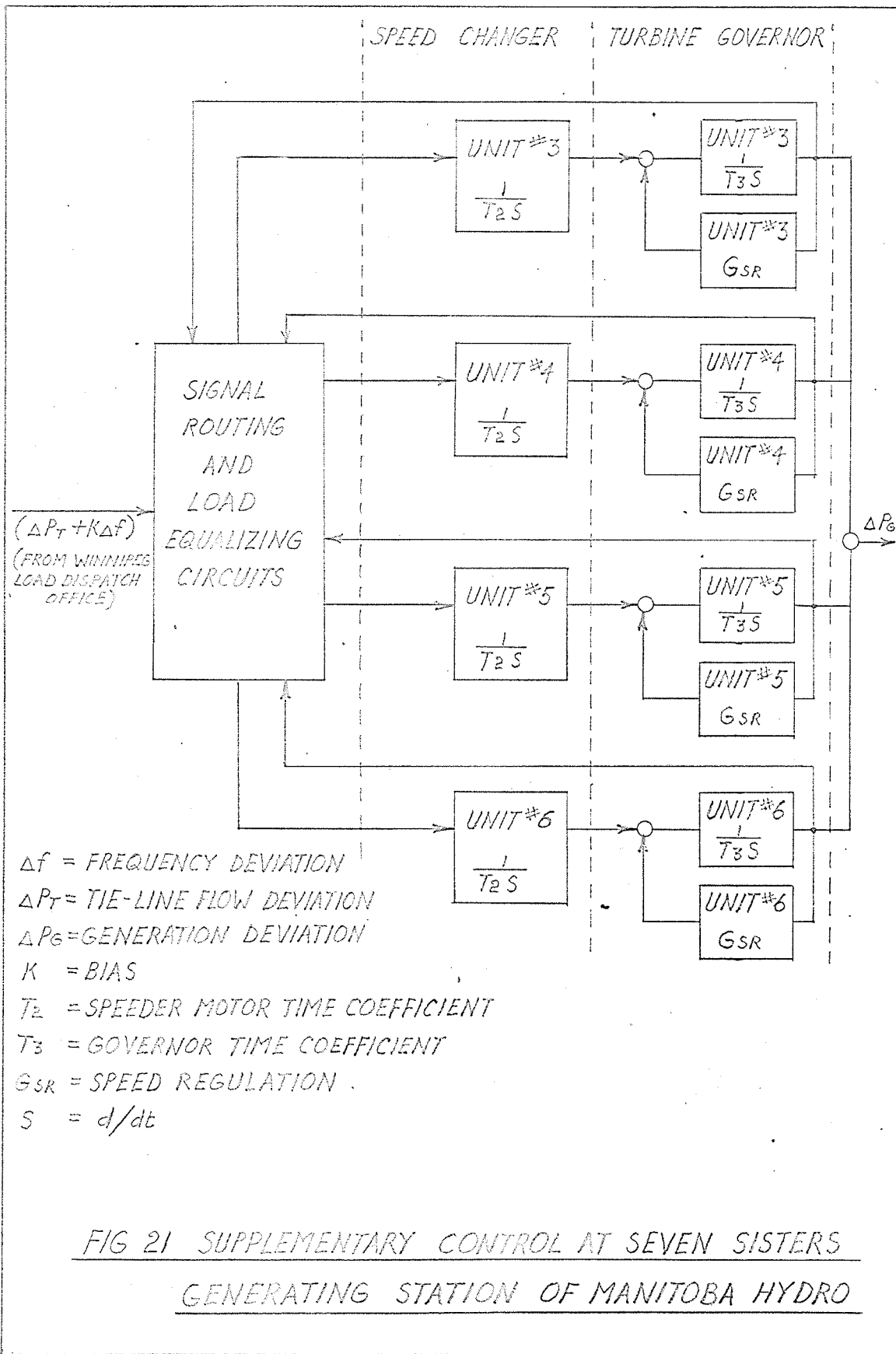
In a similar fashion to the above, frequency error is measured by comparing the frequency set point value to that actually appearing on the system. This procedure would permit an error signal to be provided in accordance with the Flat Frequency (FF) control mode.

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



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 Chapter 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).

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

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

##### Test 1 - Normal Operation of the LFC

- 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.

#### Test 2 - Checks on Bias Settings

- 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  $D = 20 \text{ mW}$

$K_{SPC}$  = 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  $\Delta f_B$  for the three tests, where  $K_{SPC} = 5 \text{ mW}/0.1 \text{ cycle}$ , 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  $\Delta P_T$ ).

$$\begin{aligned}\Delta P_T(\text{BB-1}) &= \frac{D N_{\text{SPC}}}{N_{\text{TOT}}} \\ &= \frac{(7)(20)}{(7 + 6.1 + 4.3)} = \frac{140}{17.4} = \underline{8.1 \text{ mW}} \text{ (increase)}\end{aligned}$$

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

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)

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

where 230 mW = SPC load at time of test.

$$\begin{aligned}-\Delta P_L &= \frac{D L_{\text{SPC}}}{(K_{\text{SPC}} + N_{\text{MH}} + N_{\text{HEP}})} \\ &= \frac{(1)(20)}{(5.0 + 6.1 + 4.3)} = \frac{20}{15.4} = \underline{1.3 \text{ mW}} \text{ (decrease)}\end{aligned}$$

Max. SPC Generation Change - Equation (33)

$$\begin{aligned}\Delta P_G(\text{SPC}) &= \frac{D(N_{\text{SPC}} - L_{\text{SPC}})}{N_{\text{TOT}}} \\ &= \frac{20(7-1)}{(7 + 6.1 + 4.3)} = \frac{120}{17.4} = \underline{6.9 \text{ mW}} \text{ (increase)}\end{aligned}$$

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)

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

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

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

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

$$\begin{aligned} K_{SPC} &= \frac{N_{SPC} - N_{MH}}{2} \\ &= \frac{7 - 6.1}{2} = \underline{0.45} \text{ mW}/0.1 \text{ cycles} \end{aligned}$$

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

$$\begin{aligned} K_{MH} &= \frac{(N_{SPC} + N_{MH})}{\left[ 1 - \frac{N_{MH}}{N_{SPC}} \right]} - N_{SPC} \\ &= \left[ \frac{7 + 6.1}{.13} \right] - 7 = \underline{94} \text{ mW}/0.1 \text{ cycles} \end{aligned}$$

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,<sup>a</sup> 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.