AN H.V.D.C. INSTABILITY AT A.C. SYSTEM FREQUENCY

A REPORT PRESENTED TO
THE DEPARTMENT OF ELECTRICAL ENGINEERING
UNIVERSITY OF MANITOBA

SUBMITTED IN PARTIAL FULFILLMENT OF
A MASTER OF ENGINEERING DEGREE
IN ELECTRICAL ENGINEERING

by
D. T. Y. TANG

AN H.V.D.C. INSTABILITY AT
A.C. SYSTEM FREQUENCY

BY

D. T. Y. TANG

An Engineering Report submitted to the Faculty of Graduate Studies of the University of Manitoba in partial fulfillment of the requirements of the degree of

MASTER OF ENGINEERING

ACKNOWLEDGEMENT

The author wishes to thank both Manitoba Hydro and Professor M. Z. Tarnawecky for their aid and assistance, which made this report possible.

ABSTRACT

When the h.v.d.c. transmission line along with its termination has a resonance close to the a.c. system frequency, at least two problems may arise. Firstly, high amplitude of the a.c. fundamental frequency voltage appears on the d.c. for the otherwise rather mild a.c. and d.c. disturbances such as misfires, commutation failures and transformer energizations. Secondly, a form of instability may occur especially when the a.c. system is weak (high impedance).

The h.v.d.c. link of Manitoba Nelson River project had experienced this form of instability. The following report describes and examines this phenomenon, based on the experience of Manitoba Nelson River Project; and attempts to relate this phenomenon with those reported in the papers (1, 2, 3).

TABLE OF CONTENTS

LIST OF FIGURES

APPENDICES

Chapter 1 - Introduction

The Nelson River h.v.d.c. transmission system of Manitoba Hydro is presently the largest of its kind in commercial operation in the world. It transmits electric power from the hydro electric power stations to Southern Manitoba near Winnipeg over a distance of about 900 km. Bipole I uses mercury arc valves and has a rating of 1620 MW, ±450 kV, 1800 A. Its last stage went into service in 1977. Bipole II equipped with water cooled thyristor valves is rated at 1800 MW, ±500 kV, 1800 A. Its first stage (900 MW, ±250 kV, 1800 A) was put into commercial operation in October 1978. Until this time, Bipole I had been operating with two lines in parallel to reduce losses. Since then BPI has had to operate in single line transmission line configuration to accommodate Bipole II transmission. In this single line configuration the line has a natural frequency at 60 Hz.

This situation had created some operating problems. Commutation failure, misfire, and occasional transformer energization produced severe voltage oscillations on the d.c. The other more serious problem was the occasional appearance of instabilities. The primary characteristic of this form of instability was an alternating voltage at system frequency (60 Hz) superimposed on the d.c. voltage. The amplitude of this alternating voltage increased until the pole asymmetry protection operated and blocked a pole or bipole.

This type of instability was first observed in the Kingsnorth h.v.d.c. link. The instability was termed 'core saturation instability' (ref. 1). The actual mechanism of the instability was theorized to be the saturation of the convertor transformer core. A cure was prescribed by adding an extra control loop called a flux control unit, to the existing control. Two other separate investigations and analyses on the same subject concluded that instability could occur even without core saturation.

The objective of this report is to describe the experience of the Nelson River BPI 60 Hz instability in light of the stated theories, and identifies the 'core saturation' instability as the type of instability BPI has experienced. In chapters 1 and 2 the report explains the 60 Hz instabilities phenomenon and the problems of BPI d.c. line which is resonant at its system frequency and offers a brief history of BPI instability. In Chapter 3, the theories of the instability are described with heavy emphasis on the principle of 'core saturation instability'. The detailed operation of the 'flux control unit' is also described. Finally, Chapter 4 presents several analyses of the BPI's 60 Hz disturbance, utilizing 'core saturation' theory as a fundamental approach.

Chapter 2 - Background

In h.v.d.c. transmission, the d.c. lines are terminated with smoothing reactors and filters to minimize telephone interference; these terminations along with d.c. lines usually have a first resonance at a frequency between 45 - 75 Hz in the existing h.v.d.c. scheme (ref. 2). BPI's d.c. line has a first resonance at the system frequency which is 60 Hz. This chapter describes the nature and the problems associated with this resonance. A brief history of BPI instability is also given.

2.1 The resonance phenomenom of BPI d.c. line

The BPI d.c. transmission lines are terminated with a line surge capacitor, two smoothing reactors and a sixth and a twelfth harmonic filters, as shown in figure 1. The line side smoothing reactor was added to improve d.c. filtering.

At natural frequency of the d.c. line and terminations, the most important pieces of equipment are the smoothing reactors which have quite a high impedance. The transmission line therefore, appears to be almost open-circuited; and due to the very low resistance, the circuit has very little damping. The transmission line can therefore resonate and become unstable and exhibit very high voltage if disturbed at its natural frequency.

In a single line configuration, BPI line has a natural frequency at around 60 Hz and has a relatively small impedance looking in from the valve side. The line circuit is therefore very sensitive to the 60 Hz component of valve voltage. The valve voltage is normally a d.c. level with harmonics superimposed. The valve voltage can be modulated by firing angle control, can be altered greatly by missed firing pulses or commutation failure, or can be affected by harmonic voltage distortion of the a.c. system voltage such as the distortion caused by transformer energization. Let us take a closer look at these events.

2.1.1 The effect of valve misfire and commutation failure

A mercury arc valve can misfire due to failure of the firing circuit or withholding firing pulses. The intentional valve misfire is used as a protection to prevent cracking of the cathode porcelain insulator.

The cracking of the insulator results when the main arc transfers behind a quartz heat shield and a runback of mercury occurs between the heat shield and the porcelain (ref. 3). The localized heating causes the porcelain to crack. When the arc transfer (spot transfer) occurs it can be detected and the firing pulse is withheld for about 200 msec. If the arc strikes in the proper place, very little power transfer will be lost.

The amplitude of the oscillations at various points of the line circuit was measured in Appendix A. It varied from approximately 64 kV r.m.s. to 230 kV r.m.s. at the d.c. line terminal, depending on the number of valve groups in service. A sample of these oscillations can be seen in Appendix B.

2.1.2. The effect of transformer energizations

The inrush current and the resultant voltage distortion on the a.c. associated with transformer energization are well explored in reference 4. Briefly, the magnitude of the inrush current is dependent on the point of the a.c. voltage waveform at which the breaker closes and is also dependent on the remnance flux in the transformer core prior to the energization of the transformer. The inrush current contains second harmonics; the second harmonic voltage generated is proportional to the second harmonic system impedance (ohm's law). This second harmonic voltage is then converted into fundamental frequency on the d.c. side through the bridge. Since the d.c. circuit resonates at 60 Hz, the oscillation that appears on the d.c. line is amplified.

The decay of these oscillations is usually slow, and the time constant is in the order of one second. The 60 Hz oscillation at the d.c. line terminal has been observed to be as high as 90 kV r.m.s.

2.2 The history of BPI 60Hz instability

The severe oscillations mentioned above were highly undesirable. There were at least two ways these oscillation could be reduced.

(a) detune the d.c. line circuit - As was mentioned in the previous section, the smoothing reactor plays a role in the natural frequency of the d.c. line circuit. Removing the added line side smoothing reactor from service, however, shifted the natural frequency of the line circuit only slightly. In order that the shift in natural frequency be 'significant', major capital investment would be required to modify the filtering circuit.

(b) control changes - The method of controlling the line current is shown in Fig. 2. The current order is compared to the actual line current and a component of the derivative of the line current. The current control amplifier controls the timing of the firing pulses. The firing pulses determine the firing time of the valve which affects the overall valve group voltage. The valve group voltage in turn changes the line current. This form of control is used at the rectifier;and the inverter normally operates at a constant extinction angle which results in constant d.c. voltage. The entire control equipment and transmission line represent a closed loop control system. The most effective way to minimize the 60 Hz oscillation is by increasing the derivative feedback of the current regulator.

For economic reasons, option (b) was chosen. Since then, however, Bipole I experienced a number of 60 Hz instabilities in which the bipole was blocked by the 'd.c. filtering asymmetry protection'. Since the cause of the instability was unknown, the di/dt was reduced after each disturbance between July 1978 to October 1978 until it was reset to its original setting (Appendix C).

The HVDC scheme in Kingsnorth, as was explained by Mr. J.D. Ainsworth (ref. 1), experienced a phenomenon called 'core saturation instability' that resulted mainly from d.c. resonance close to the fundamental frequency of the a.c. system. Consulted by BPI representatives, Mr. Ainsworth confirmed that the BPI instabilities were similar to those he had experienced at the Kingsnorth scheme. He recommended adding an extra control loop (flux control unit) in the valve group control to avoid the instability.

Manitoba Hydro purchased two such units in November, 1978 and placed these units in service on a trial basis. However, in spite of repeated testings and checkings, the flux units never seemed to work correctly. 60 Hz instabilities continued to appear, especially in the summer of 1980 (Appendix C).

As an intermediate step, BPI control was optimized by adjusting its proportional and integral feedback of the current regulator so that the di/dt feedback could be minimized.

Mr. Ainsworth was again consulted. After reviewing all the disturbances, he maintained that BPI had core saturation instability (although it was of a slightly different type); and also indicated that the flux control units were not functioning properly.

In October 1981, the core saturation test was repeated in the presence of Mr. Ainsworth, (Appendix D). He uncovered a wiring error in the flux control unit and he insisted that core saturation instability existed in the BPI system although there were doubts among some of the Manitoba Hydro engineers who witnessed the tests. The steps Manitoba Hydro is taking at present are outlined in Appendix E.

Chapter 3 - Theories relating to 60 Hz instabilities on the d.c.

There are three basic theories related to d.c. 60 Hz instabilities. All three theories predicate their principal causes on the d.c. line with a natural resonance frequency close to the a.c. system frequency. The three theories are:

(a) core saturation instability
(b) a.c./d.c. harmonics resonance instability
(c) h.v.d.c. control instability

This chapter describes how the theories purport to alleviate these various instabilities.

3.1 Core saturation instability

As the name implies, this particular instability is related to convertor transformer core saturation. Core saturation of the convertor transformer can be caused by a number of events: solar induced ground current, d.c. ground current, misfire, uneven firing as a result of oscillations on the d.c.; or, in other words, events which produce a net d.c. current in the winding of the convertor transformer.

3.1.1 Core saturation caused by ground current

A potential difference is created on the earth surface when ground current flows through the ground. Two distribution stations will experience certain d.c. potential differences between their grounding mats depending on the distance between the stations in the direction of the current flow. D.C. current will then flow through the neutral of the transformers, the transformer windings and the lines that connect the two stations. The transformers will be saturated to a certain degree depending on the magnitude of the ground current. There are two ways in which ground current can appear:

3.1.1.1 d.c. transmission monopolar operation

Fig. 3 shows the interconnection of Nelson River a.c. collector system, the relative location of the station grounds and the d.c. ground electrodes. When BPII goes into monopolar operation, the d.c. current that passes through the ground electrode produces a potential gradient on the earth surface. This creates a potential difference between the grounding mats at Long Spruce and Radisson. Current then flows through the converter transformer neutral, its windings, and the lines that interconnect them, - all of which tends to saturate the converter transformers. The d.c. current has been measured as high as 50 A in a neutral of a converter transformer during BPII monopolar operation.

3.1.1.2 Solar induced ground current

The phenomenon known as telluric current is induced in the earth by the magnetic field of the earth. The variation of the magnetic field is believed to be caused by fluctuations in the stream of charged particles emitted by the sun. Some particles are positively charged; others are negatively charged. As these particles approach the earth, the earth's magnetic field deflects them eastward or westward, depending on the sign of the charge. They form a large ring of current around the earth in an ecliptic plane. If this ring current were constant in magnitude, it would contribute only a static component to the earth's magnetic field. However, the density of the stream of charged particles intercepted by the earth as it travels in its orbit varies with time. The resultant ground current flow also varies with time. The peak to peak amplitude of this ground current ranges from 0.4 to 2400 MA/m. The large amplitude is related to the so-called magnetic storms which are associated with the heightened sunspot activity.

These currents tend to saturate the core of the convertor transformer symmetrically in all three phases since the d.c. currents are the same in all three phases. The second harmonic current and voltage generated as a result of the saturation, therefore have the same phase angle with respect to its fundamental phase voltage.

Let V_2 be the second harmonic voltage
ϕ be the phase of the second harmonic voltage with respect to the fundamental

$$\text{A phase voltage} = A \sin (wt) + \underline{V2 \sin (2\ wt + \phi)}$$

$$\begin{aligned} \text{B phase voltage} &= B \sin (wt + 120) + V2 \sin (2\ (wt + 120) + \phi) \\ &= B \sin (wt + 120) + \underline{V_2 \sin (2wt + \phi + 240)} \end{aligned}$$

$$\begin{aligned} \text{C phase voltage} &= C \sin (wt + 240) + V_2 \sin (2\ (wt + 240) + \phi) \\ &= C \sin (wt + 240) + \underline{V2 \sin (2wt + \phi + 120)} \end{aligned}$$

As demonstrated in the above equations, the second harmonics generated as the result of the symmetrical saturation by d.c. ground current is of negative sequence. It can be shown that a negative sequence second harmonic converts into 3rd harmonics on the d.c. and the ones with positive sequence into fundamental frequencies. Thus, core saturation caused by ground current does not cause 60 Hz oscillation on the d.c.

3.1.2 Core Saturation Caused by Misfire

When a valve is misfiring persistently, half cycles of the valve winding current are missing. As a result, this valve winding current has a net d.c. component which is approximately one-third of the d.c. line current. This causes the affected phase of the converter transformer to saturate very quickly. Since the saturation of the three phases are asymmetrical, positive sequence of the second harmonics exists and results in 60 Hz oscillation on the d.c.

3.1.3 Core saturation caused by uneven firing

When a 60 Hz oscillation appears on the d.c. side, the rectifier current control alters the firing angle in an attempt to regulate the oscillating d.c. current. This uneven firing, however, creates a net d.c. current component in the valve winding current which tends to saturate the converter transformer asymmetrically.

3.1.4 Core saturation by 60 Hz frequency current on the d.c. side

When the d.c. line is resonant at 60 Hz, the impedance of the filtering circuit (along with the line circuit looking from the converter side) is relatively small at 60 Hz. BPI line circuit has a theoretical impedance of approximately
50 + 31° ohm at 60 Hz. A small 60 Hz driving voltage at the converter terminal can result in a relatively large component of 60 Hz current. This fundamental current converts into a d.c. component and second harmonic component in the valve winding current. As an example, Figure 4 shows the resulting three phase valve winding currents when this fundamental current is in phase with the 'A' phase valve winding current. The fourier analysis of the valve winding current content shows,

Phase	dc Content (in p.u. of the Fundamental Current on the d.c. Side)	2nd Harmonics (also in p.u.)
A	.707	.707
B	-.35	.707
C	-.35	.707

The d.c. component that appears on the phases tends to saturate the converter transformer core.

3.1.5 The concept of core saturation instability

The theory is based on the assumptions that the a.c. system is weak (high impedance), and that a resonance near the fundamental frequency exists on the d.c. side due to the combination of d.c. reactor, d.c. filters and d.c. line capacitance. The instability starts off with a second harmonic (positive sequence) on the a.c. voltage, which can be caused by transformer energization etc.; a fundamental voltage is generated on the d.c. side. Since the d.c. line circuit is resonant at fundamental frequency, a relatively large fundamental frequency current is generated. The current control responding to this oscillation causes unequal firing. A net d.c. component will appear on the valve winding side. This tends to saturate the converter transformer core and extra magnetizing current containing second harmonic is generated. An instability occurs when this second harmonic in the magnetizing current reinforces the original postulated second harmonic voltage.

3.1.6 The instability of the Kingsnorth - Willesdon scheme

The Kingsnorth - Willesdon h.v.d.c. link experienced this instability, as reported by Mr. J.D. Ainsworth (ref. 1); There the d.c. was resonant near the system frequency, and an anti-resonance of the 12th harmonic existed on the a.c. side for some of the a.c. system configuration (mainly a resonance between the 11th and 13th filter). When this form of instability occurred, the oscillation on the d.c. was small, but the a.c. system anti-resonance magnified the 12th harmonics component of the magnetization current and caused the filter to trip.

3.1.7 The instability of the Nelson - River BPI project

BPI's 60 Hz instability is believed to be core saturation instability. The cause and effect of BPI instability differ slightly from the Kingsnorth scheme. These phenomena will be described in chapter four.

3.1.8 The Cure

This type of instability has been successfully cured by adding an extra 'flux control loop' in the Kingsnorth Scheme. The function of this control loop is to minimize the saturation of the converter transformer by altering the firing angle slightly. The degree of converter transformer saturation is obtained through the measurement of the second harmonics component of the magnetizing current per core. The signal is used to modulate the valve winding current's signal; and, subsequently, the output to the phase lock oscillator of the bridge control. This output signal has a very small amplitude and its effect on the normal operation is negligible.

3.1.8.1 The detail operation of the flux control unit

A block diagram of the flux control unit is shown in Figure 5. The circuit can be divided into three parts: - mean flux measuring circuits, modulation circuits, and the mean flux d.c. voltage conditioning circuit. A brief description of these circuts is presented below.

3.1.8.1.1 Mean Flux Measuring Circuits (one per phase)

These circuits first extract a signal proportional to magnetizing current per phase of the converter transformer by differential connection of the current transformers to line windings and valve windings ($i_{lw} - i_{vw}$). The second harmonic component is extracted from this and converted to a d.c. voltage by a phase sensitive rectifier, using the a.c. line voltage as reference. These three d.c. voltages are applied to voltmeters to give readings (with arbitrary calibration) approximately proportional to the mean fluxes of the converter transformer.

3.1.8.1.2 Modulation Circuits

These circuits take signals proportional to valve winding currents and apply in a controlled amount of each (adjustable in magnitude and polarity, by the mean flux DC voltage) to form a total a.c. modulating signal to the phase lock oscillator for the bridge.

The effect of the modulating signal is to change the normal regular valve firing pulses at 60° intervals by slight time displacements, in a pattern which will generate a controlled mean d.c. current component in the three valve winding.

The phase lock oscillator in BPI has an auxiliary input which allows the frequency of the oscillator to be altered slightly. A positive signal through this input tends to slow down the oscillator which delays subsequence firing pulses. A negative signal tends to do the opposite - advances the firing pulses.

Figure 6 illustrates an injection of an a.c. signal proportional to 'A' phase valve winding current, into the auxiliary input of the phase lock loop; and the resultant d.c. component in the valve winding current.

At 'A' in Figure 6, the normal firing pulse (firing pulse without influence from input signal) is the same as the firing pulse with the input signal. The next two firing pulses (B and C) are delayed by the positive portion of the input signal. Assuming the delay angle for firing pulse 'B' is X degrees, then the delay angle for firing pulse 'C' is 2X degrees because of accumulated delay. Similarly the firing pulses 'E' and 'F' advance by X and 2X degrees repectively as the result of the negative portion of the input signal. The final 'F' pulse coincides with the normal firing pulse. The change in the firing instance slightly alters the formation of the three phase valve winding current. Let us analyze the phases individually.

3.1.8.1.2.1 'A' phase valve winding current

The positive cycle of this phase has been increased by 2X degrees, and the negative cycle has been decreased by 2X degrees. The net d.c. component in this phase is proportional to the difference between the positive and negative cycles. In this case, the net d.c. component is proportional to 4X degrees in the positive direction.

3.1.8.1.2.2 'B' phase valve winding current

The positive cycle of this phase has a net reduction of 1X degree (see figure 6). The negative cycle has an increase of 1X degrees. The d.c. component for this phase is proportional to 2X degrees negatively.

3.1.8.1.2.3 'C' phase valve winding current

The positive cycle has a net reduction of 1X degrees and the negative cycle has an increase of 1X degrees. The net d.c. component is, therefore, proportional to 2X degree negatively.

The effect of this a.c. input signal becomes apparent when a signal proportioned to the 'A' valve winding current is injected into the phase lock oscillator. 'A' phase valve winding current has a net d.c. component which is twice as large as in the other two phases but with an opposition polarity. Similar conclusions can be made for 'B' and 'C' phase valve winding currents if the respective a.c. waveforms are injected into the phase-lock oscillator.

Utilizing this fact, the flux controller modulates the individual phases of the valve winding current by a factor which is determined by the saturation of the respective phases. The modulated three phase signals are then summated and output to the phase lock oscillator which subsequently produces a d.c. component to 'desaturate' the convertor transformer core.

3.1.8.1.3 Mean flux dc voltage conditioning

This part of the circuit determines the amount of modulation required for the valve winding current. The mathematical expressions of the circuit are

$$Ka = \left(Va - \frac{Vb + Vc}{2}\right) \qquad \text{(i)}$$

$$Kb = \left(Vb - \frac{Va + Vc}{2}\right) \qquad \text{(ii)}$$

$$Kc = \left(Vc - \frac{Va + Vb}{2}\right) \qquad \text{(iii)}$$

where Ka, Kb and Kc are the required modulating factors for the valve winding current of A, B and C phase.
Va, Vb and Vc are the mean flux voltages of A, B and C phases.

In order to understand the meaning of the mathematical expressions, the capability and the goal of the flux control unit have to be defined. It is clear that the sum of the three valve winding current must be zero at all times, since there is no transformer neutral on the valve winding side of the convertor transformer. The sum of d.c. component of the three phase valve winding current must be zero, and therefore, the net change of flux in the cores of the converter transformer must also be zero. This means at best that the flux control unit can only balance the flux in the three phase transformer core; that is, each phase having equal saturation. Therefore, the flux that needs to be changed in each phase is the difference between its flux and the average flux of all three phases; and thus can be expressed by these equations.

$$Ka = Va - \frac{Va+Vb+Vc}{3} = \frac{2}{3}\left(Va - \frac{Vb + Vc}{2}\right) \qquad (iv)$$

$$Kb = Vb - \frac{Va+Vb+Vc}{3} = \frac{2}{3}\left(Vb - \frac{Va + Vc}{2}\right) \qquad (v)$$

$$Kc = Vc - \frac{Va+Vb+Vc}{3} = \frac{2}{3}\left(Vc - \frac{Va + Vb}{2}\right) \qquad (vi)$$

It is quite evident that equation iv, v, and vi are the same as i, ii, and iii except for the constant of .667. This constant has been taken care of by other gain in the circuit. It is also quite evident that the unit will not do anything if the converter transformer core has equal saturation, as in the case of ground current flowing through the transformer windings. Let Va = Vb = Vc (equal flux), then Ka = Kb = Kc = 0 by equation (i to vi). The output of the flux control unit is therefore zero. As was explained in section 2.1.1, such symmetrical saturation does not cause 60 Hz oscillations on the d.c. and therefore does not induce core saturation instability.

3.1.8.2 The effectiveness of the flux control unit

BPI's flux control unit was not working properly initially. A wiring error was later found by Mr. Ainsworth during the testing in October, 1981. He demonstrated the effectiveness of flux control unit through testing procedures (Appendix F), during which the converter transformer was saturated by misfires and transformer energizations (force oscillations) with and without the flux control unit in service. Without the flux control unit in service, the flux in the core lingered on after the force oscillation had disappeared. With the flux control unit in service, the flux in the core diminished very quickly; but the 60 Hz oscillations on the d.c. voltage persisted. Mr. Ainsworth explained that this 'extra' oscillation was the result of the flux control unit attempting to 'desaturate' the transformer. The flux control units in BPI are now believed to be functional and can eliminate asymmetrical core saturation.

3.2 a.c./d.c. harmonics resonance instability (ref. 5)

The concept of this theory based its instability mechanism on the harmonics conversion through the d.c. bridge and a 60 Hz resonance d.c. line. The method used by the author analyzed the converter in more detail than other methods dealing with the same subject. This method, unlike classical methods, calculated a.c. harmonics and d.c. harmonics based on a non-infinite a.c. and d.c. system.

The technique was essentially an iterative procedure in which the a.c. and d.c. harmnics voltage and current were repeatedly calculated with the inclusion of the control actions. In this way, the steady state harmonics was calculated. If the solution converges, the system being analyzed is said to be stable. If the solution diverges, the system is assumed unstable. The procedure can be briefly described as follows:

1) Assume an initial a.c. voltage - it can be either balanced, sinusoidal or unbalanced voltage.

2) Based on (1), calculate the valve firing instants using the selected pulse generator method.

3) Using (1) and (2) calculate the d.c. side voltage.

4) Calculate the d.c. side current based on (3) and the d.c. side impedance.

5) Based on the firing instants of step (2) and the d.c. current in step (4), calculate the a.c. side currents.

6) Using the result in step (5), the assumed a.c. system impedance, calculate the new bus voltage.

7) Repeat the process from step (1), if the new bus voltage is significantly different from step (1).

The paper concluded that 60 Hz instability could occur even without the mechanism of core saturation. It only required a d.c. circuit resonant at the system frequency and a weak a.c. system. The normal constant current feedback loop was ineffective for this type of instability.

3.3 Control instability with the DC resonance close to the fundamental frequency.(ref. 6)

This type of instability was first observed during the trial operation at the Shir-Shunane converter station in Japan. The problem was studied and analyzed both mathematically and by simulator; and the findings confirmed the suspected instability. Mathematically, the problem was analyzed using a non-linear control loop model. As in the simplified version of non-linear control loop in Figure 7, G(S) is a linear controller and N(E) is a non-linear quantity. For a self-sustained oscillation condition, it may be written as

$$G(jw) \cdot N(E) = -1$$

$$\text{or} \quad G(jw) = -\frac{1}{N(E)} \qquad \text{(viii)}$$

Figure 8 is the detailed block of the model. It contained the standard d.c. control loop with additional frequency conversion due to rectification; that is, second harmonic voltage on the a.c. side converts into fundamental component on the d.c. side while the fundamental component of the d.c. current converts into the second harmonics on the a.c. side. The contribution of second harmonics caused by core saturation was not included.

The stability was determined by plotting the vector locus of the linear transfer function G(S) and the non-linear portion - 1/N(E) on the same complex plane. If the locus of the non-linear portion - 1/N(E) was encircled by G(S) at fundamental frequency, the system would be unstable (derive from eqn viii). It was found that instability could occur with a certain choice of parameters of the current controller combined with ac/dc system impedance. With a proper choice of control based on the outlined analytical method, be the instability was eliminated.

Chapter 4 - Analysis of BPI 60 Hz Instability

There are a total of thirty-three cases of 60 Hz disturbances recorded as in Appendix C. Only fifteen of these cases can be classified as 60 Hz instability. These 60 Hz instabilities can be divided into two categories.

(a) 60 Hz instabilities initiated by force oscillations such as transformer energization and misfire.

(b) 60 Hz instabilities that were started with no apparent causes.

In this chapter, two typical cases of the force oscillation type are analyzed based on two of the three theories described in the previous chapter. A fortuitous event is also described to show how the third theory may be applied. Finally, comparisons between these three theories are presented, based on actual BPI experiences.

4.1 BPI 60 Hz instability initiated by force oscillations

In some of BPI's 60Hz disturbances, the instabilities had been initiated by prolonged 'force oscillations', such as severe transformer energization, or persistent misfire. The core saturation instability in the Kingsnorth - Willedon scheme did not require these initiating events.

4.2 July 30, 1981 disturbance analysis

The configuration of the northern collector system prior to the disturbance is shown in Fig. 9. The transient fault recording is included in Appendix E.

Time	Reference (in Cycles)	Events	Comments
2:13	00	VGII suffered a spot transfer (Spot transfer protection blocks the faulted valve from conducting for 14 cycles)	
	14	Spot transfer protection reset releasing the faulted valve	Very little oscillation on the d.c. seen after the misfires.
	21	VGII suffered another spot transfer	
	35	VGII temporary block - VG asymmetry protection operated after two consecutive spot transfers.	More oscillation could be seen on the d.c. voltage after the second spot transfer.
	76	VGII deblocked after temporary block expired	
	85	VGII suffered the third spot transfer	
	99	The third spot transfer reset	More oscillations on the d.c. voltage. The oscillation contains a large amount of 4th with a little bit of fundamental.
	150	Long Spruce generator tripped by its impedance relay (overload> 160 MVA for 1 sec delay)	The oscillations on the d.c. voltage changed in its harmonic content. It contained mainly the fundamental with little fourth harmonic.
	173	Pole 1 blocked by d.c. filter asymmetry protection.	Pole 2 oscilliation continued to grow even as pole 1 was blocked.
	188	Pole 2 blocked by d.c. filter asymmetry protection.	

4.1.2 Analysis

This was a classical case of 60 Hz instability which occurred as a result of 'forced oscillations'; or, in other words, the repeated misfire (spot transfer protection produces approximately 14 cycles of misfires). The primary core saturation, as previously explained, was produced by missing half cycles of the valve winding current of the misfiring phase. The secondary core saturation was caused by uneven firing by current control, in an attempt to correct the 60 Hz oscillations brought about by the misfire.

Since various harmonics generated from core saturation (Ref. 7) reflect themselves as oscillations on the d.c. voltage, the severity of core saturation can be measured by the amplitude of the oscillation on the d.c. voltage (in the absence of 'force oscillation' by misfire). The oscillation on the d.c. voltage increases after each sequence of misfire due to spot transfer protection, indicating the converter transformers are becoming more saturated (see appendix F). The effect of the a.c. system impedance on the oscillation on the d.c. could be observed at 150 cycles when Long Spruce unit tripped. Prior to the tripping, the a.c. system was resonant at around 3rd harmonics (impedance of 293 ohms at 180 Hz, see Fig. 10). The oscillation on the d.c. was predominantly 4th harmonics (3rd harmonics on the a.c. side converted to 4th on the d.c. side), and the oscillation was self-sustaining (neither increasing nor decreasing). Once the Long Spruce generator tripped, the oscillation on the d.c. became predominantly fundamental. The system impedance resonances had shifted with the first resonance at 140 Hz (Fig. 11). The second harmonic impedance increased to 193 ohm from 63 ohm. The second harmonic voltage increased correspondingly since the magnetizing current of the saturated converter transformer remained unchanged. The increase of the second harmonic voltage subsequently converted into an increase of the fundamental voltage on the d.c., and thus accelerated the instability. The oscillation on the d.c. continued to increase until the bipole was blocked.

Hence, this disturbance has shown the effect of the second harmonic impedance on this instability - it set in more quickly with higher second harmonics impedance. There is another theory (described later in this report) as to how this disturbance might have developed into another type of instability, based on a.c. system impedance.

4.2 October. 27, 1979 60 Hz instability as a result of transformer energization

The disturbance was initiated during transformer energization testing at Henday. In the second test, bipole 1 went into 60 Hz instability and was blocked by its d.c. filter asymmetry protection. This disturbance was classified as 60 Hz instability due to 'forced oscillation'.

4.2.1 Observation and analysis

Prior to the energization, both the d.c. and the a.c. voltages were normal, and there was no sign of instability. The system configuration is shown in Fig. 12. When the transformer was energized at Henday, considerable 60 Hz oscillation appeared on BPI d.c. voltage, and started to decay (transient fault recording is attached in Appendix G). All these were normal occurrences for transformer energizations. After the oscillations decayed for approximately 60 cycles they started to increase, which indicated that 60 Hz instability had begun to set in. Core saturation instability started at this point instead of at the beginning of the oscillation.

The moment the 60 Hz oscillation appeared on the d.c. side, a d.c. component, which was proportional to the amplitude of the 60 Hz oscillation, appeared in the valve winding current. The manner in which the amplitude of the 60 Hz oscillation decays for a normal transformer engergization,shows a profile similar to an expression A $\exp(^{-t}/T_1)$

when A is the initial amplitude of the oscillation at t = 0

T_1 is the time constant of decaying rate

t is the time

The d.c. component in the valve winding current would, therefore, have the same profile. Given the d.c. current, the saturation of the converter transformer can be derived as shown in Appendix H. It turned out that the flux increased in a form of $[\exp(-t/T_1) - \exp(-t/T_2)]$ (profiled as in Fig. 13). This meant the most severe saturation occurred some time after the initial oscillation (.3 - 3 sec depending on the system impedance). It is, therefore, quite conceivable that the core saturation instability did not occur until the saturation reached a high enough level.

4.2.2 BPI 60 Hz instabilities with no apparent initiating events

These disturbances (case 9, 14, 15, 16, 21 and 24 in Appendix C), unlike the previously described forced oscillations, ocurred when there were no apparent initiating events. They ranged from absolutely nothing to relatively mild switching, such as switching off a generator(s) several minutes before the instability occurred. A typical characteristic of this type of instability was that the oscillation built up very slowly. This slowness and its unpredictability led to the conclusion that it was the core saturation instability as Mr. J. Ainsworth originally described in his paper (ref. 1).

4.2.3 Other 60 Hz disturbance

These disturbances could not be classified as 60 Hz instability because oscillations in these instances decayed until BPI was blocked by its d.c. filter asymmetry protection. Transformer energizations initiated these oscillations. As explained in section 2.1.2, the magnitude of these oscillation depended on a number of system parameters and was of a statistical nature.

4.3. Application of the concept to the analysis of the July 30, 1981 disturbance

What follows is an attempt to analyze portions of the July 30, 1981 disturbance (described in section 4.2.1.1) ultilizing the conclusion of the theory of 'a.c/d.c. harmonics resonance instability' described in section 3.2.

One of the conclusions made was that in a d.c. scheme where the d.c. line is resonant close to the fundamental frequency, and the a.c. system has relatively high second harmonic impedance, 60 Hz instability can occur with or without control action. For simplicity's sake, the action of control has been ignored in the following analysis. The process on which the instability thrives is illustrated in Figure 14. Briefly, a second harmonic voltage on the a.c. side converts into fundamental frequency voltage on the d.c. side; and, because of the resonance of the d.c. circuit, a relatively large fundamental frequency current is generated. This current is reconverted into second harmonic current on the a.c. side. This second harmonic current in turn produces second harmonic voltage on the a.c. thus forming a possible regeneration loop. As in control theory, instability of this loop occurs when the loop gain equals or exceeds one (phase angle has been ignored in this simple analysis). Mathematically, Loop gain = $Zac_2 \ . \ GB \ . \ Ydc_1 \ . \ GB > 1$ . . . . . (vii)

Zac_2 is the second harmonic a.c. system impedance

GB gain factor the conversion process through the bridge. - maximum is .707

Ydc_1 is the fundamental admittance of the d.c. line circuit, BPI is found to be at $50\angle{+31^\circ}$ ohms at 60 Hz.

Thus, by substituting the appropriate value in equation (vii), the minimum second harmonic a.c. system impendance that will lead to this type of instability is found to be 100 ohms. If the phase angle of the impedances is included in the analysis, higher second harmonic impedance will probably be needed for instability to occur.

In the July 30, 1981 disturbances (as described in section 4.2.1.1), second harmonics system impedance Zac_2 was thought to play a role in the instability. Prior to the tripping of the Long Spruce generator, the Zac_2 was 63 ohms, the 60 Hz oscillation on the d.c. was stable or might have been increasing at a very slow rate. After the Long Spruce unit tripped, the Zac_2 went up to 193 ohms, and the oscillation increased drastically. These phenomena support this theory and the calculated second harmonic impedance of 100 ohms for instability. When the Zac_2 of the system was below the 100 ohms, the oscillation was stable; but once it reached a configuration where the Zac_2 exceeded 100 ohms, the instability set in.

The present analysis in no way attempts to prove that BPI experienced this type of instability; rather, it serves merely to explain this particular disturbance. Instability of BPI in other disturbances had occurred with Zac_2 at less than 15ohms. This investigation therefore does not apply to these disturbances.

4.4. BPI control modification

As mentioned in Chapter 2, the BPI current regulator was modified in November 1980. The purpose of the unit's modification was to adjust its integral and proportional feedback in order to minimize the di/dt feedback. The criterion here required that the control respond well for a step change in current order, as well as for 60Hz oscillation. The current regulator was then modified from the circuit in Figure 15 to that in Figure 16. Since then, there has been no 60 Hz instability. Has the 60 Hz instability unintentionally been alleviated by control changes? It may indeed be too early to tell. A close look at the modification reveals that it does not differ significantly from the old circuit, especially at 60 Hz.

The following are the comparisons of the two controls

		old circuit (Fig. 15)	modified circuit (Fig.16)
Transfer function	$\frac{V_o}{V_i}(s)$	$\frac{-91.6}{s}[1+.0069S]$	$\frac{-182}{s}[1+0.0026s]$
Steady State at 60 Hz	$\frac{V_o}{V_i}(jw)$	$-255\angle 68^\circ$	$-257\angle 45^\circ$

Except for 23° difference, the gains of the two circuits are almost identical at 60 Hz. The other change made was the reduction feedback from .5 p.u. to .3 p.u. However, there has been disturbance in which the di/dt setting was below .3 p.u. (see appendix C, case 16). It is, therefore, difficult to relate these changes to the seeming lack of 60 Hz instability subsequent to feedback reduction.

4.5 Discussion of BPI 60 Hz instabilities based on the three theories

Detailed scrutiny of the entire range of 60 Hz instabilities experienced by BPI (appendix III), indicated that they had occurred more often when the di/dt feedback setting was high. This tendency can be explained by both core saturation instabiliy and control instability.

In core saturation instability, the saturation of the convertor transformer is induced by uneven firing. The machanics of the uneven firing are similar to the action of the flux controller, as shown in Figure 6. The degree of core saturation is proportional to the severity of the uneven firing. The main cause of this uneven firing in the case of BPI is the di/dt feedback which is over ten times (twelve times when di/dt = .3 and twenty times when di/dt = .5) the normal current feedback for any oscillation. Therefore, increasing di/dt signaled more uneven firing and thus more transformer saturation; which in turn meant that the likelihood of achieving core saturation instability was correspondingly higher.

The effect of di/dt setting on control instability was more straightforward. Higher di/dt feedback meant higher loop gain, which could put the control system into an unstable region under certain operating conditions. Using the concept in Section 3.3, the situation can be readily seen. As di/dt increases, $|G(s)|$, the gain of the linear controller increases also. The circle of G(s) on the complex plane is enlarged. Therefore, more of the -1/N(E) locus is encircled by G(s) (it was said to be unstable if -1/N(E) was inside the circle of G(s)) and thus the d.c. is unstable in more situations.

The fact that BPI on many occasions had required a big 'kick' by forced oscillation before instability could set in suggested that its instability were not consistent with the types described in Section 3.2 and section 3.3. These theories implied that the instability required only a very small perturbation, which meant that the system should have become unstable even before the 'force oscillation' had occurred. Moreover, system configuration, which was identical to some of the disturbances, had been used during testings without inducing instability. The core saturation, on the other hand, based its mechanism largely on the saturation of the transformer core. Instability might not occur until a certain degree of core saturation had been reached. Remnance flux left in the transformer core from previous disturbances, as well as the duration of 'forced oscillations', became significant factors in the formation of the instability. The 60 Hz instabilities experienced in BPI are thus believed to be of 'core saturation' origin.

5. Conclusion

1. BPI 60 Hz instability was mainly of the 'core saturation type as described by Mr. J. Ainsworth, although it varied slightly from his original concept.

2. BPI 60 Hz instability was found in some instances to require 'forced oscillations' to kick the system into instability. Occasionally, however, the instability had occurred with no apparent cause.

3. There were signs that other theories of 60 Hz instabilities might also be involved.

4. a.c. system impedance had been found to affect BPI 60 Hz instability.

5. The primary cause of the instability was that the d.c. line, along with its termination was found to have a natural frequency close to the system frequency.

6. The di/dt feedback setting was shown to be an important factor in the formation of 60 Hz instability.

7. Manitoba Hydro had reduced the time delay of valve group asymmetry protection in an attempt to minimize the effect of forced oscillations due to misfire.

8. Manitoba Hydro had desensitized the d.c. filter asymmetry protection which had been tripping the pole in all the 60 Hz disturbances.

6.0 Bibliography

1. Ainsworth. J.D., 'Core saturation instability in the Kingsnorth h.v.d.c. link' paper presented to CIGRE study committee no. 14, Winnipeg, Canada. June 20 - 24, 1977.

2. Harrison, R.E. and Krishnayya, 'System considerations in the application of d.c. filters for h.v.d.c. transmission', P.C.S. CIGRE paper 14-09, 1978.

3. La Blanc, L.P., and Thomas, D.H., 'Operating experience with Nelso River + 450Kv HVDC transmission system', C.E.A. October, 1974.

4. Thio, C.V., "Nelson River HVDC Bipole II, part I - System aspects", IEEE transaction on Power apparatus and systems, vol. Pas - 98, pp. 165 - 173, January/February 1979.

5. Yacamini, R. and Olivina, J.C., 'Instability in h.v.d.c. schemes at low-order integer harmonics', IEE Proc., Vol. 127, Pt. C., No. 3, May 1980.

6. Sakural, T., Ohara, J., Ucda, M., Mase, A., Horuchi, T., Arai, J., 'A study of a certain AC oscillation of HVDC system', IEEE, PES Winter Meeting, New York, N.Y. February 4 - 9, 1979 paper A 79 100-9

7. Yacamini, R. and de Oliveira, J.C. 'Harmonics produced by direct current in convector transformers' proc, IEE, 1978, 125, (9), PP. 873 - 878

A1 Tang, D., "Bipole 1 DC Filter Asymmetry Protection and its Setting"

A2 Mr. B. Willis, "Supervision of Pole Asymmetry Protection", Dated 81 05 05, File 23470.

A3 Mr. R. B. Wagg to Mr. C. V. Thio "Bipole-one: Problem resonances on d.c. filter-interim review" dated Sept. 14, 1977, File No. 81-01317.

E1 System Performance Report on "Time Delay Setting for Bipole-1 Value Group Asymmentry Protection to Minimize Core Saturation", by. D. Tang, August 14, 1981.

E2 System Performance Report on "DC Filter Asymmentry Protection and its setting", by D. Tang, August 14, 1981.

E3 SPD TM 81-39, J. McNichol to C.V. Thio, June 5, 1981, "Bipole-Two 60 HZ Line Ringing Problems".

E4 Letter to Mr. J.D. Ainsworth from C.V. Thio, May 22, 1981.

E5 Memo Mr. B. Willis to K.R. Ouelette, April 5, 1981, "Spot Transfers, Communication Failures, etc.".

E6 Letter from Mr. J.D. Ainsworth to C.V. Thio, March 2, 1981, re Bipole-One DC Line 60 Hz Resonance.

E7 Mr. J.D. Ainsworth's report of Tests at Radisson on October 18-20, 1981.

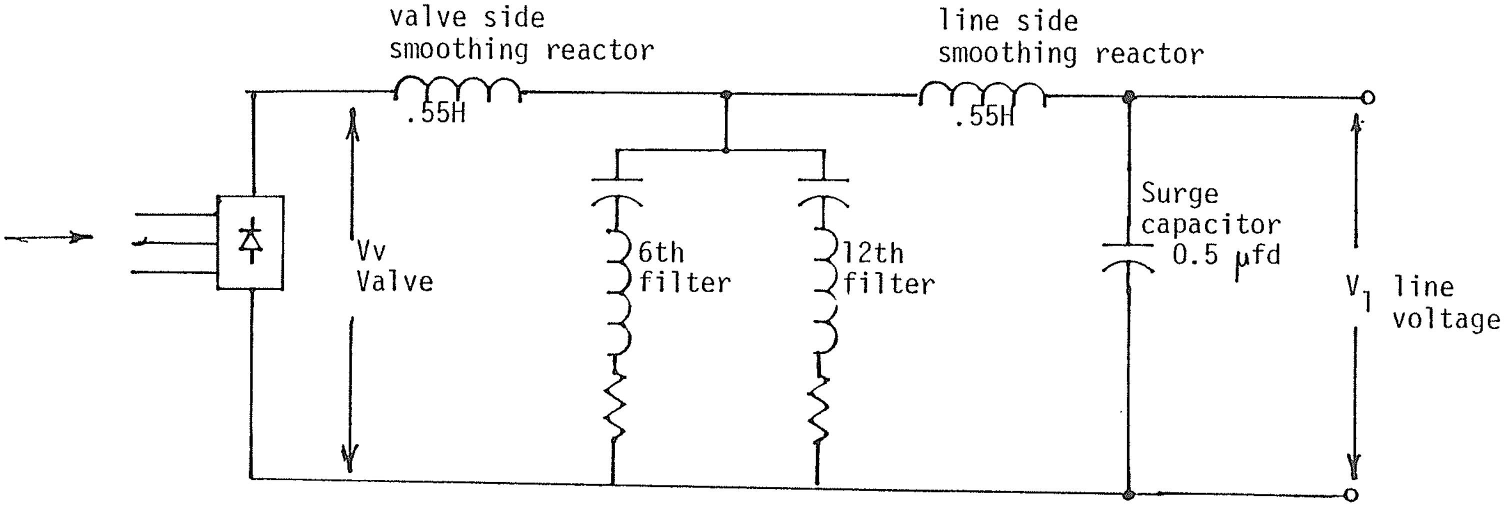


Fig.1 H.V.D.C. Line Termination Equipment

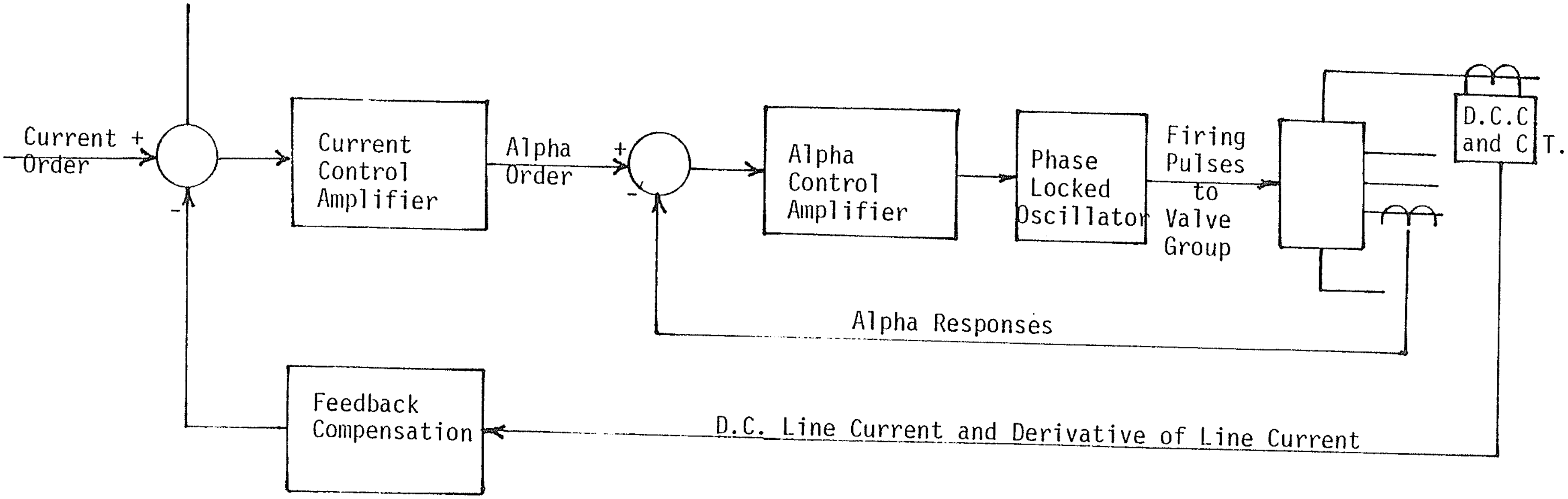


Fig.2 THE CURRENT AND ALPHA ORDER CONTROL CIRCUITRY

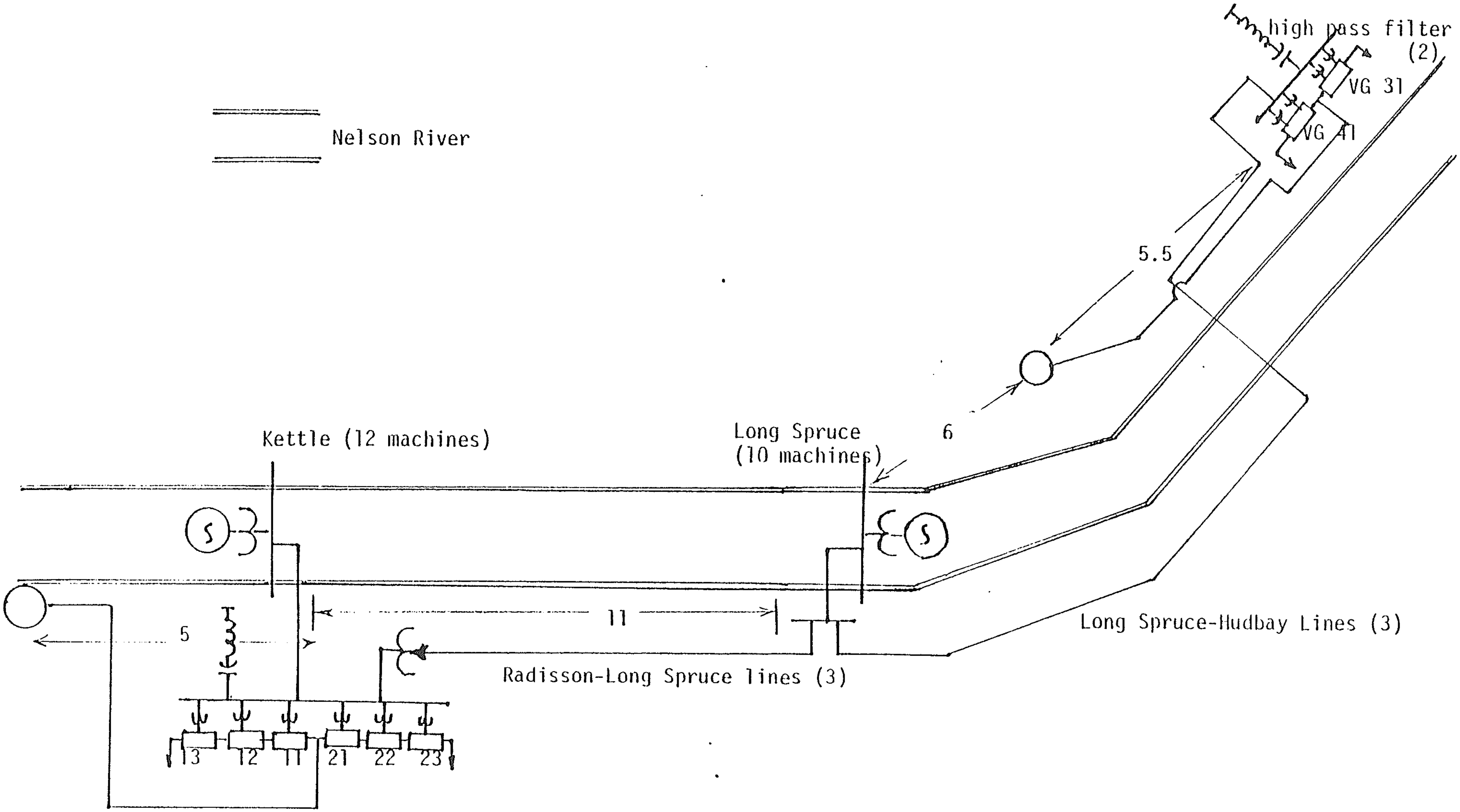


Fig.3 a.c. filter banks at Radisson

5th filter	(2)
7th filter	(2)
11th filter	(1)
13th filter	(1)
HP	(1)

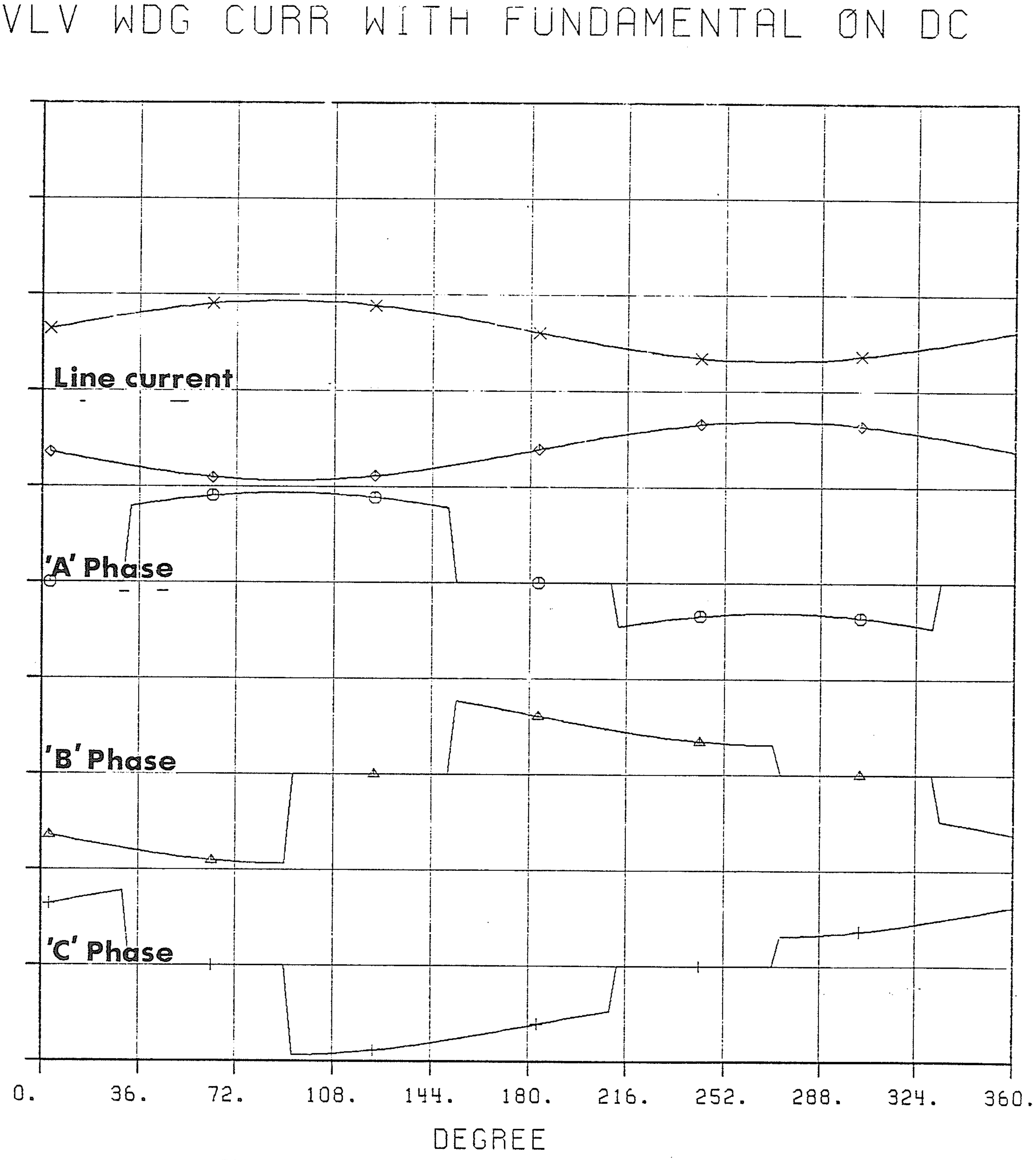


Fig. 4 Valve winding current with fundamental a.c. current

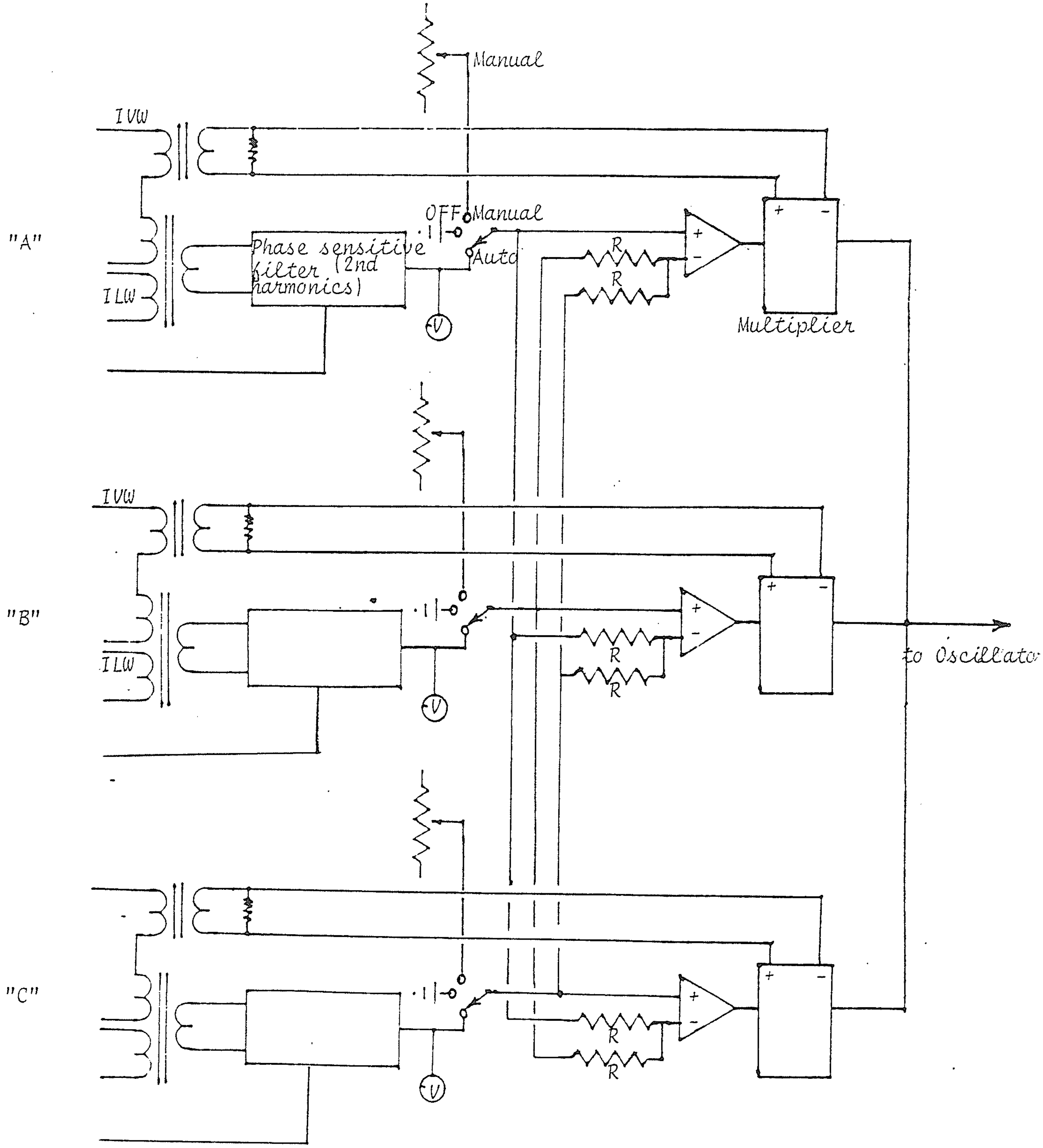


Fig. 5 Block diagram of the flux control unit

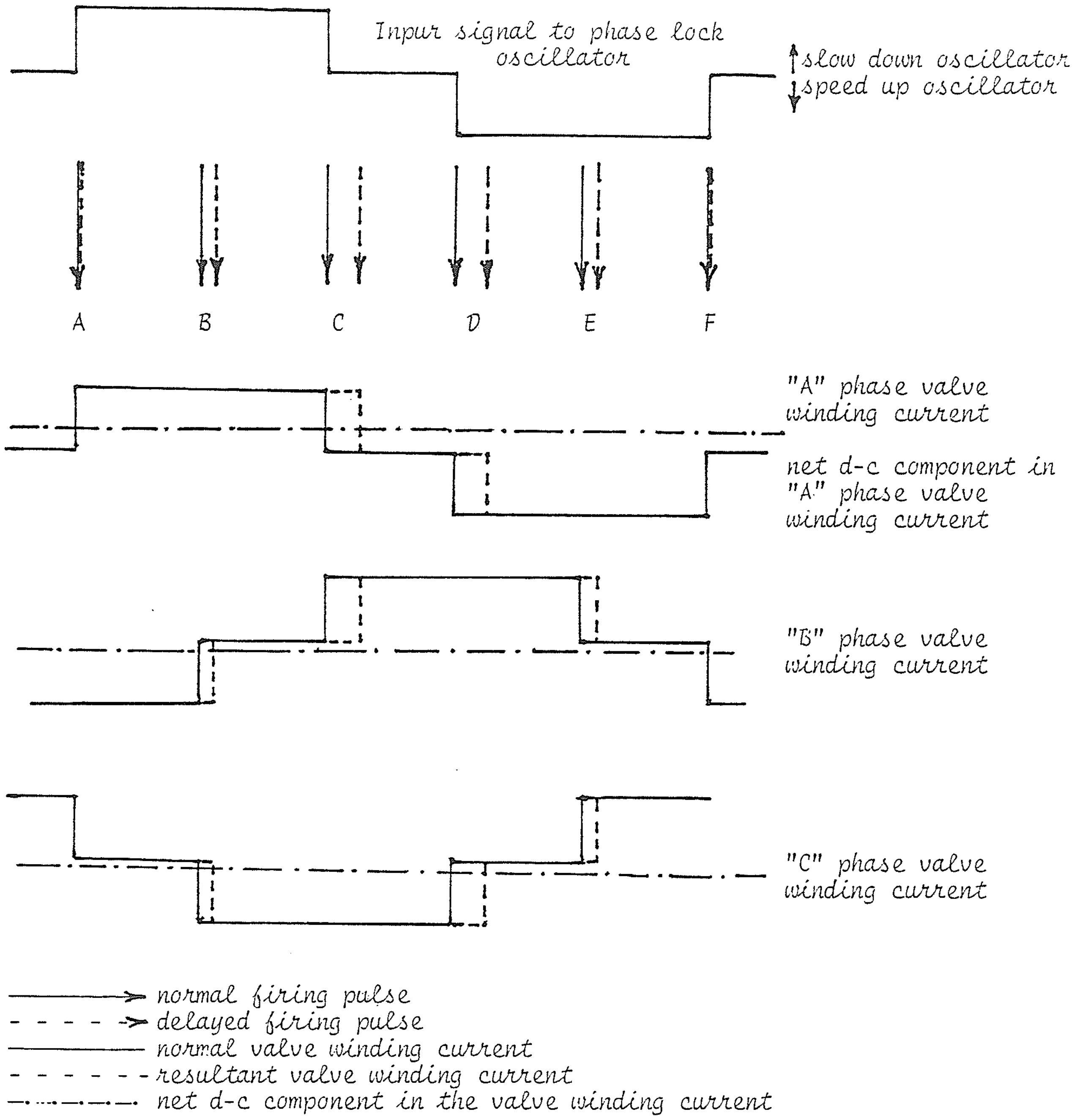


Fig.6 The d-c component in the valve winding current as the result of injection of our ac voltage signal into the phase lock oscillator.

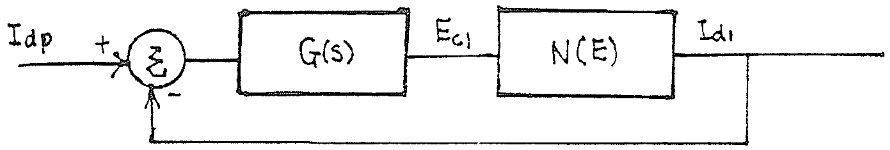
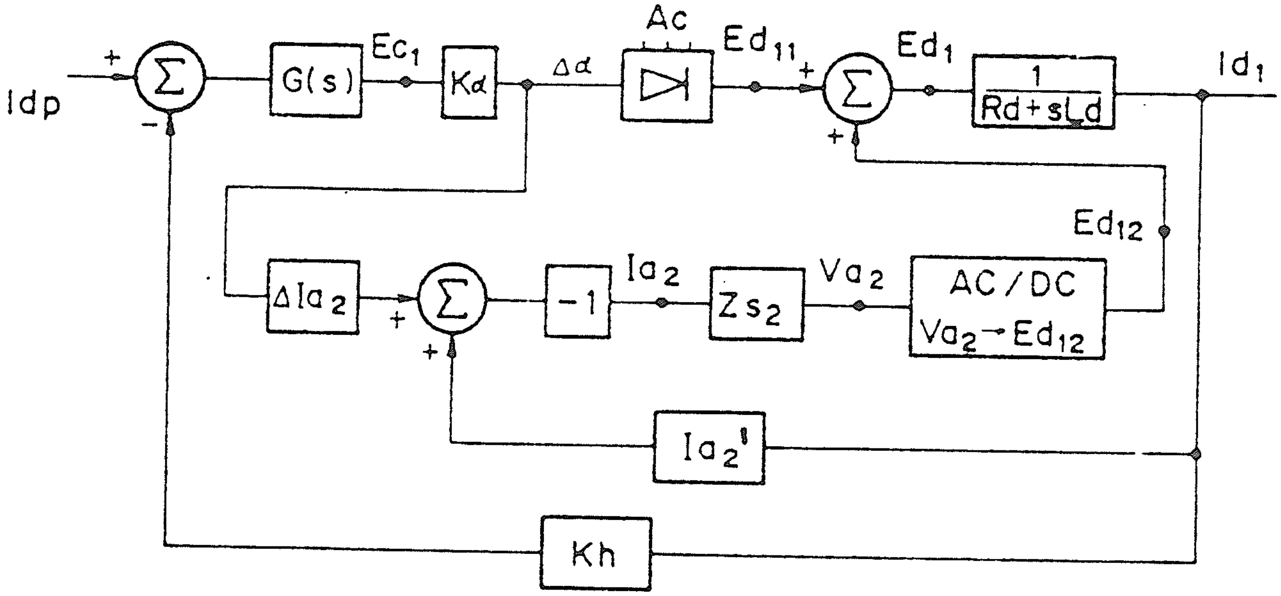


Fig. 7 Simplified non-linear model



Z_{s2} - second harmonic impedance in the a.c. system
Ed_{12} - fundamental frequency voltage on the d.c. voltage as a result of 2nd harmonic voltage on the a.c. side
Kh - current/voltage proportional constant
K_2 - delay angle/voltage proportional constant
G(s) - linear controller
N(E) - non-linear controller
Id_1 - a.c. component of the fundamental frequency in the d.c. current
Ed_1 - a.c. component of the fundamental frequency in the d.c. voltage
Ia_2' - the second harmonic current injected into the a.c. system as the fundamental frequency current on the d.c. side
Ia_2 - total 2nd harmonic current
Ia_2 - 2nd harmonic current caused by uneven firing

Fig.8 Detail non-linear model

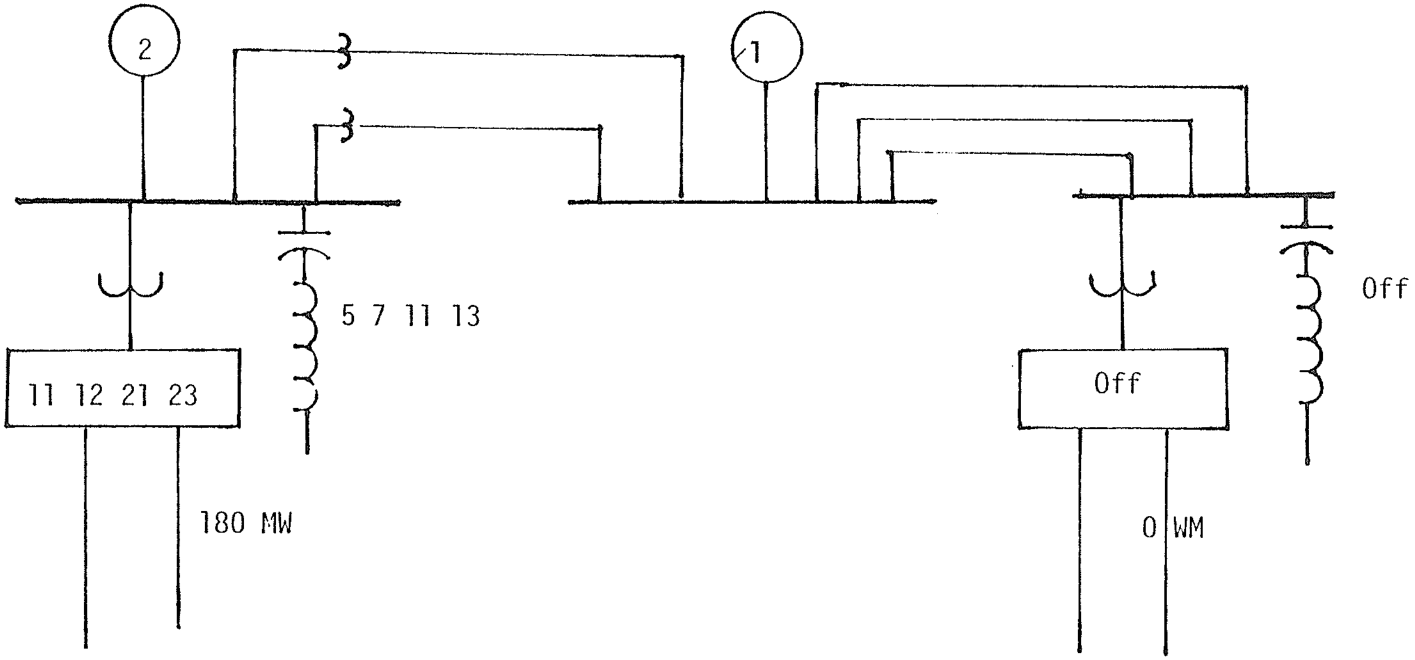


Fig.9 System Configuration July 30, 1980 2:13

Fig.10 SYSTEM IMPEDENCE PROFILE FOR JULY 30,80 DISTURBANCE BEFORE LS UNIT TRIPPED

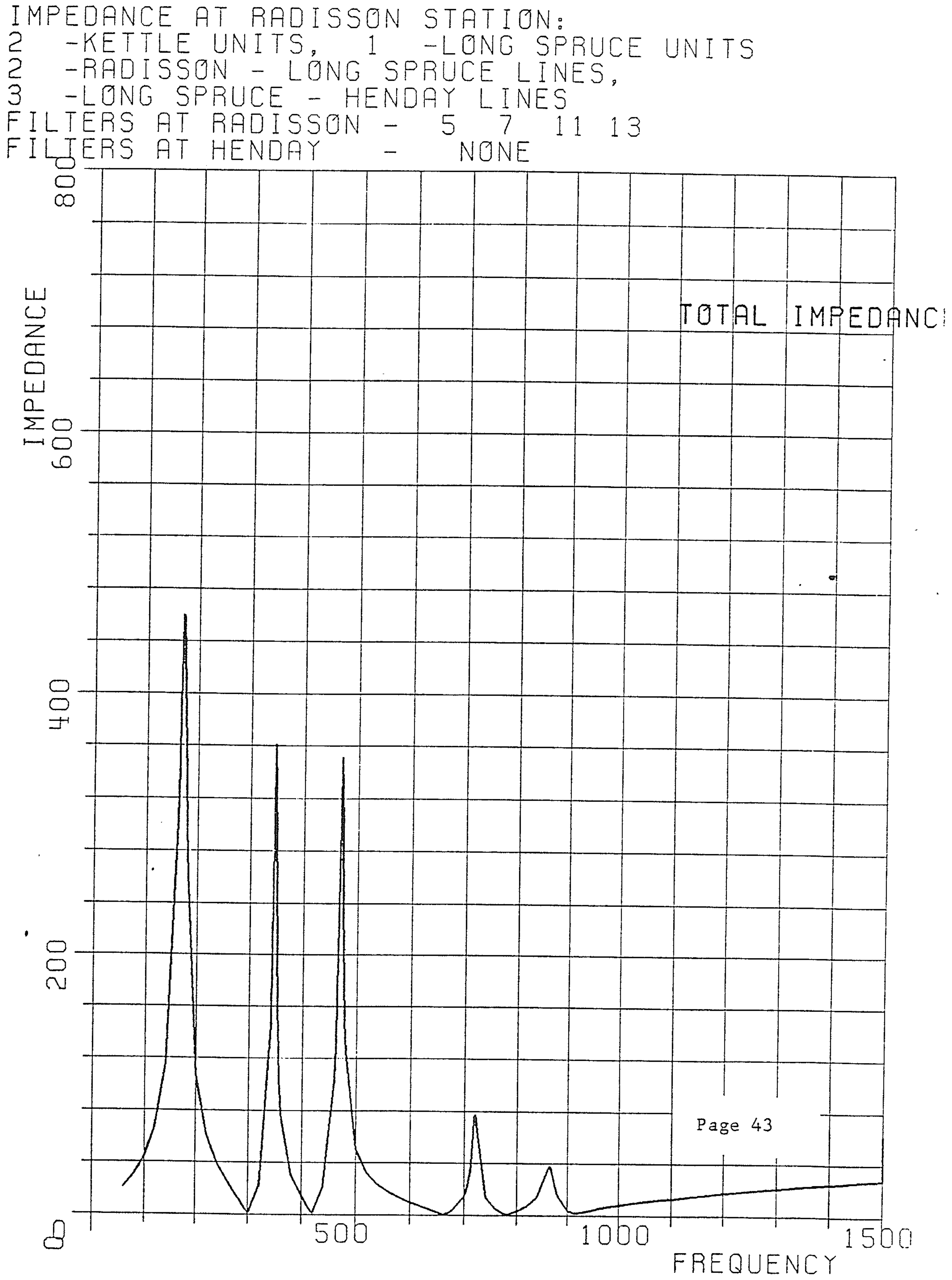
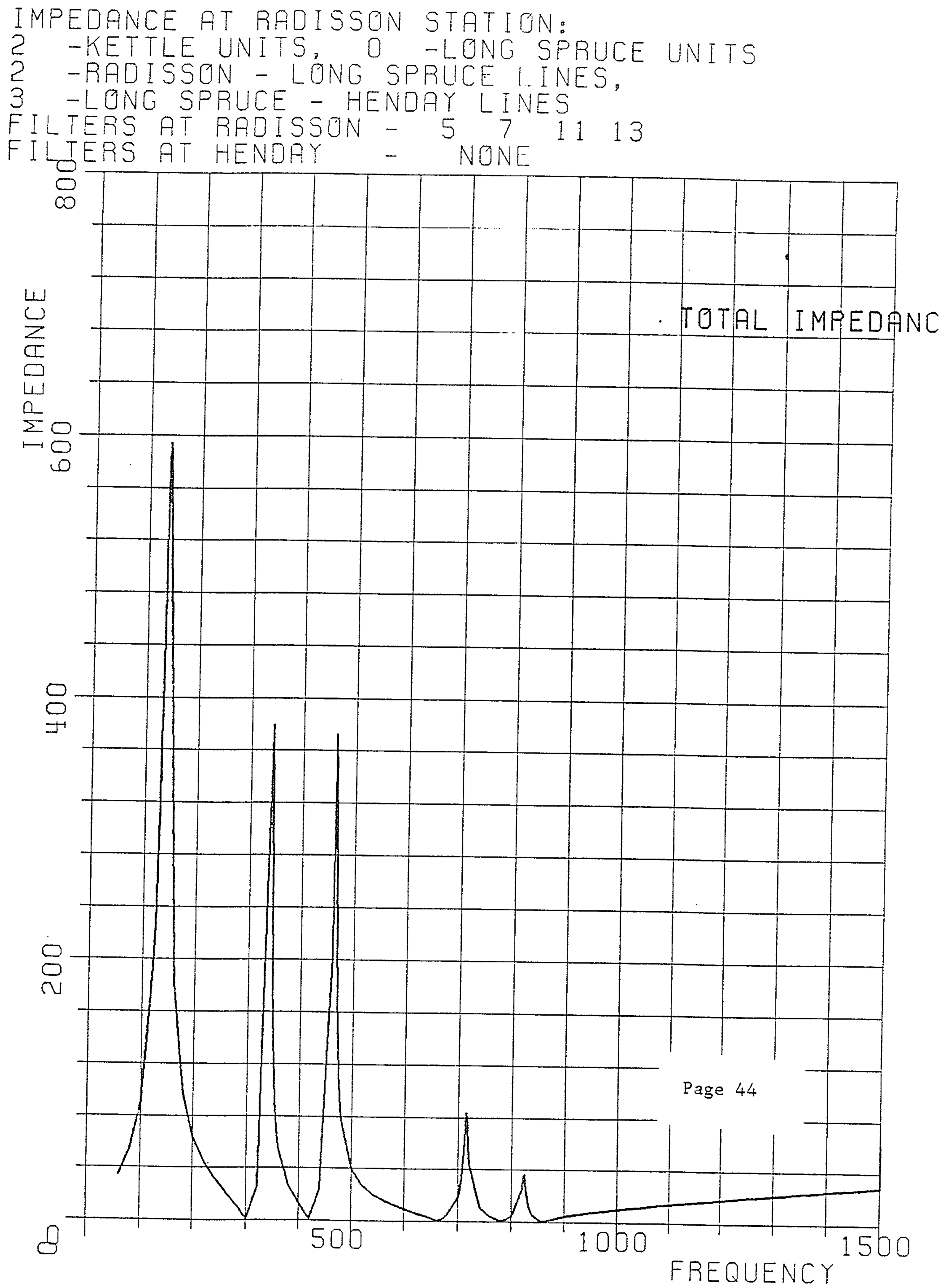


Fig.11 System impedence profile for July 30,80 disturbance after LS unit tripped



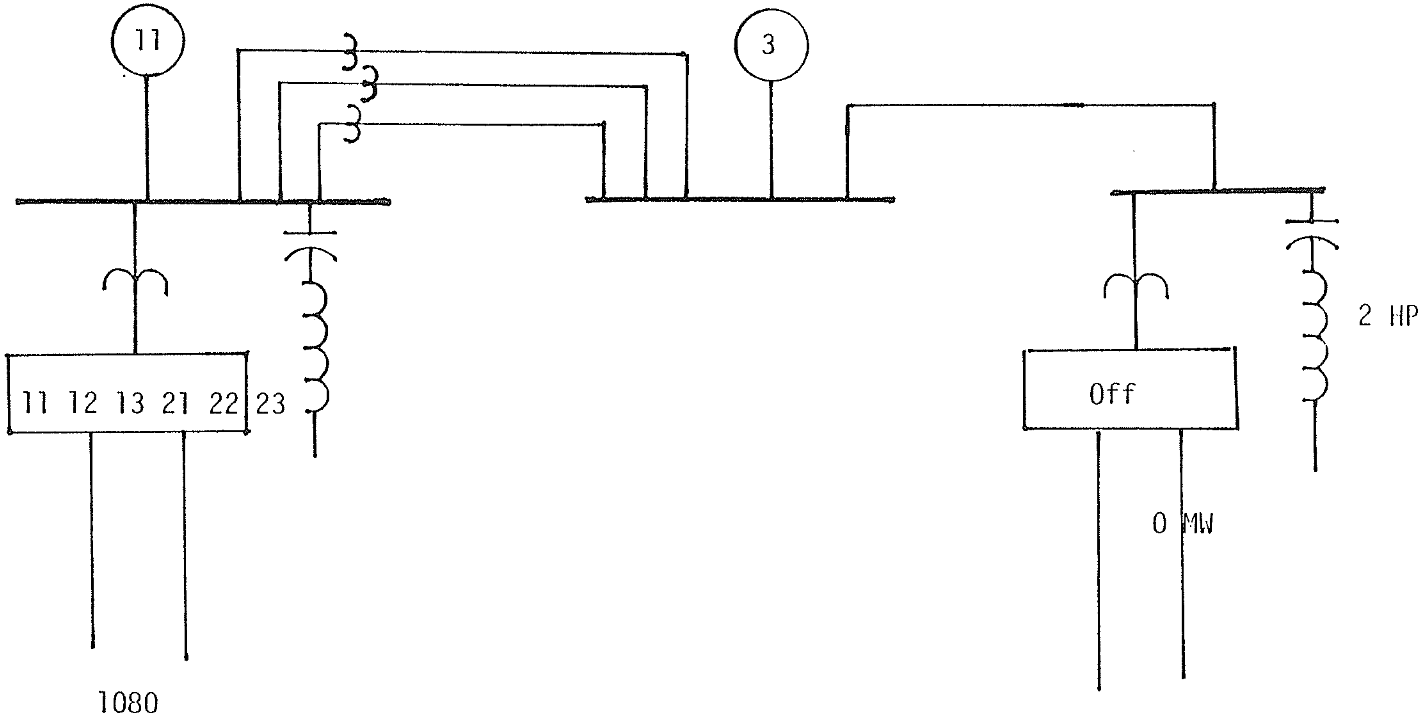
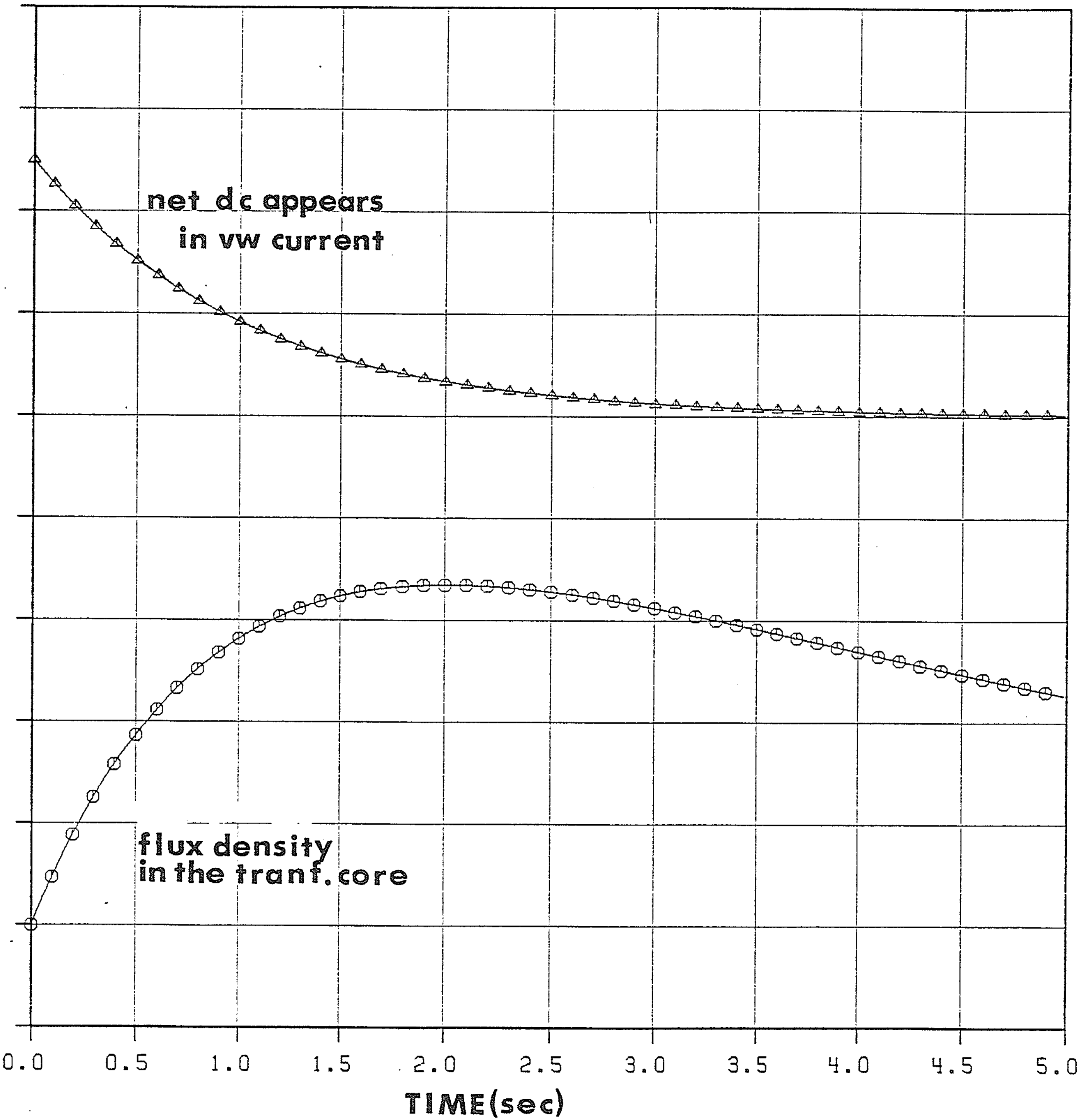


Fig.12 System Configuration for October 27, 1978 at 23:34

Fig. 13 The net d.c. component in the valve winding current and the flux in the convertor transformer during a transformer energization



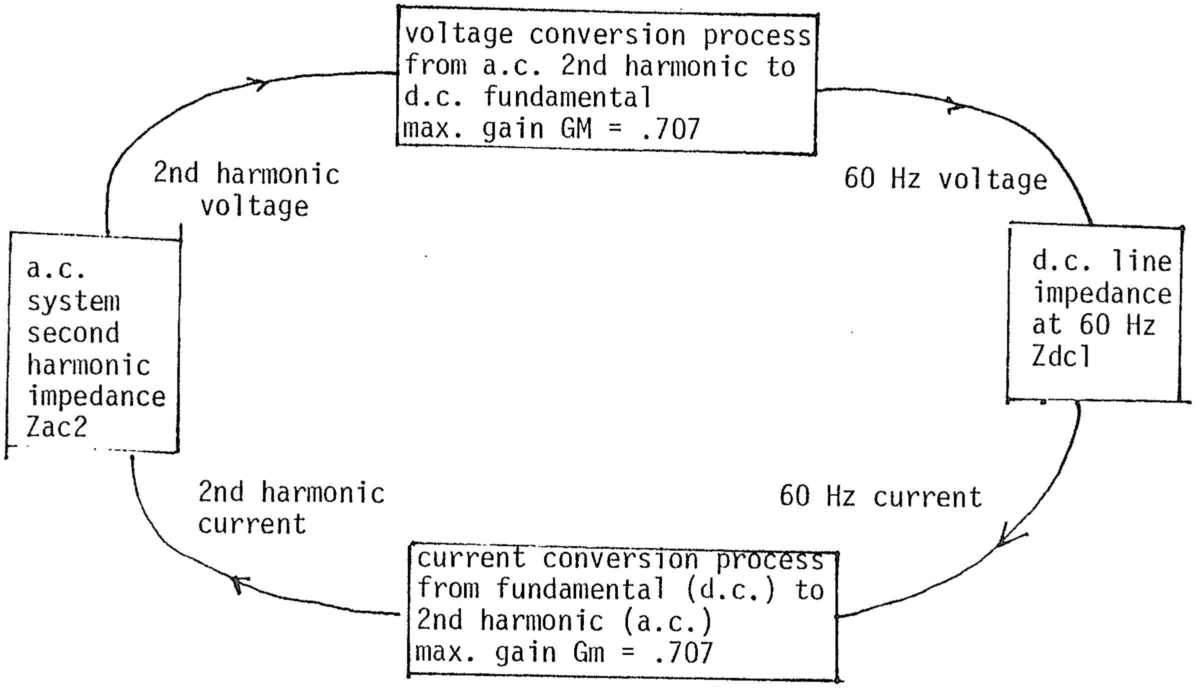
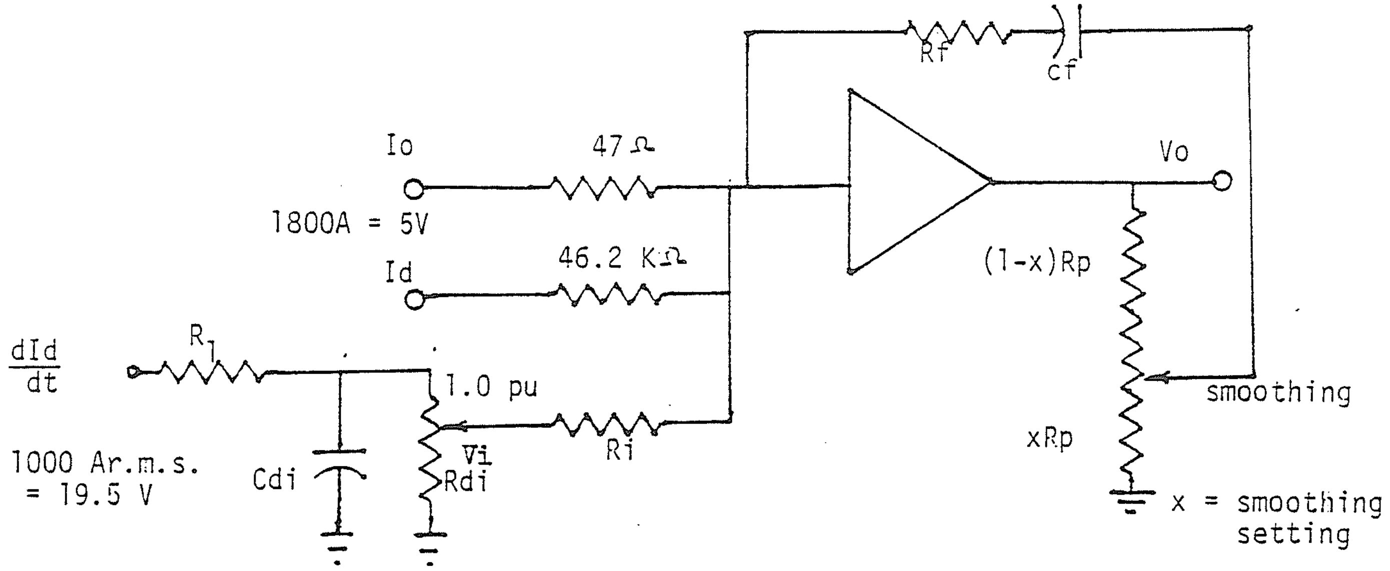


Fig.14 Block Diagram of a.c./d.c. Conversion Process Through the d.c. Bridge at Second/Fundamental Frequencies



$$\frac{V_o}{V_i} = - \frac{1}{R_i C_f x s} (1 + sC_f(x(1 - x) R_p + R_f)$$

Fig. 15 BP1 Current Regulator Before Modification

Rf = 470 ohm
cf = 2.2 μF
Rp = 10 KΩ
Rdi = 10 KΩ
Cdi = 1 μF
Cf' = .67 μF
Rf' = 3.9 KΩ

$$\frac{V'_o}{V_i} = - \frac{1}{R_i C'_f s} (1 + R'_f C'_f s)$$

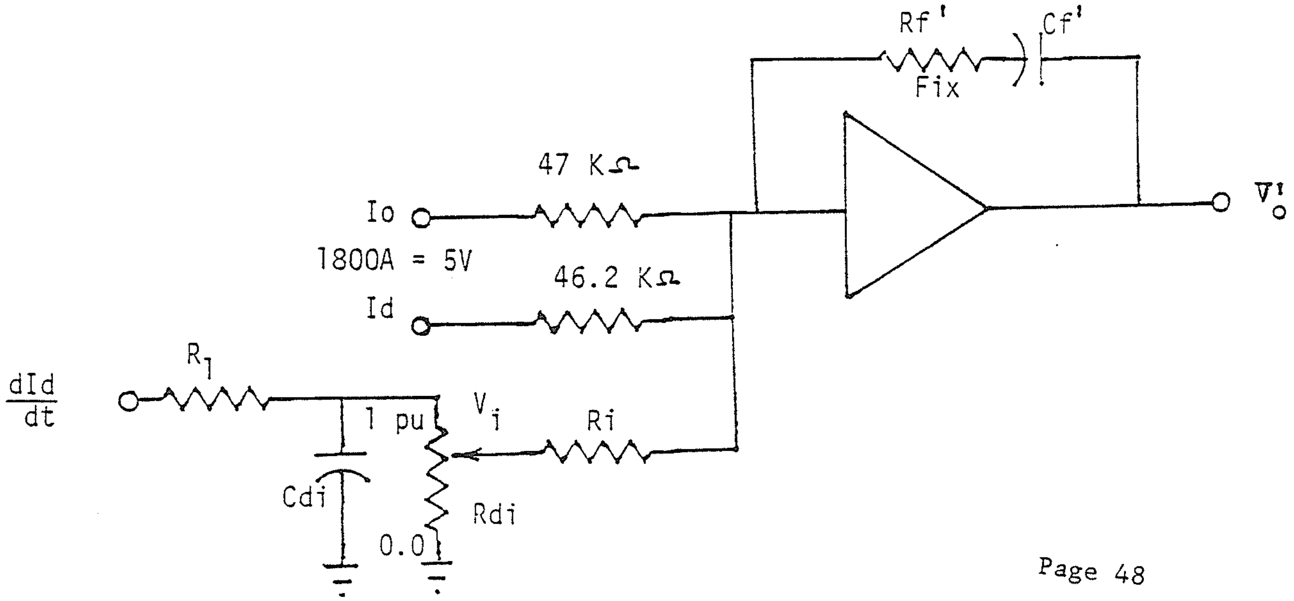


Fig.16 BP1 Current Regulator after Modification

APPENDIX A

DC FILTER ASYMMETRY PROTECTION AND ITS SETTING

Prepared by D. Tang

MANITOBA HYDRO

System Operating Department

System Performance Section

Report on

DC FILTER ASYMMETRY PROTECTION
AND ITS SETTING

PROVINCE OF MANITOBA
T. Y.
TANG
REGISTERED ENGINEER

System Performance Section

Prepared by:

Checked by:

Date: Aug 14, 81

BPI DC FILTER ASYMMETRY PROTECTION AND ITS SETTING

Introduction

During transformer switching, severe 60 Hz oscillations appear on the BPI d.c. voltage. They are caused by the second harmonic voltage produced by the inrush current. On a number of occasions, these oscillations were sufficient to set off the filter asymmetry protection and thus block a pole. These disturbances were considered to be undesirable. There are two proposals presently under consideration to overcome this: raise the setting of d.c. filter asymmetry protection[1] and supervise the protection with a rate of decay detection[2]. This report examines the above two proposals and recommends a necessary course of action.

Discussion:

The d.c. filter asymmetry protection is part of a system of asymmetry protections (the detection points and existing settings are as shown in Fig. II) designed to detect oscillations of 60 and 120 Hz in the d.c. voltage. Once the oscillations exceed a certain amplitude and time delay, the protection operates.

Bipole II has two asymmetry protections (Fig 3): 60 Hz I and 60 Hz II. They are similar to Bipole I asymmetry protections. The 60 Hz I is set at 40 kVrms for 200 ms. and the 60 Hz II is set at 80 kVrms for 25 ms. Their functions are for protection against persistent commutation failure, misfire, and for similar faults in the remote station during telecom failure. Since very little has been documented about the purpose of the asymmetry protections on Bipole 1, it appears reasonable that BPI is provided with asymmetry protections for the similar reasons as Bipole 2.

The existing level settings of the valve group asymmetry protection (30 kVrms) and the convertor side asymmetry protection (40 kVrms) suggest that they are meant for misfire or commutation failure which produces an amplitude of approximately 50 kVrms of 60 Hz in the valve group voltage and around 35-42kVrms (as in table 1, the measurement of the 'convertor side' voltage was not reliable because of the presence of large amount of 6th and 12th harmonics) in the 'convertor side' voltage. The 60 Hz oscillations at the 'convertor side' was lower than the valve group because of control action of the current regulator. This still leaves the d.c. filter asymmetry protection setting of 22 kVrms in question.

The asymmetry protection across the d.c. filter is not a d.c. filter protection. The d.c. filter is fully protected by its overvoltage and overcurrent protections (See AppendixAII). The d.c. filter can take a much higher voltage than the existing 22 kVrms setting on the asymmetry protection.

This asymmetry protection is thus believed to be a back up protection for other asymmetry protections. With two lines operation, as before 1978, the lines were not resonant at 60 Hz, and the 60 Hz voltage at the d.c. filter was therefore approximately half the voltage at the converter side. The existing setting of the 22 kVrms for the asymmetry protection across the d.c. filter would thus provide the back-up protection for 2 line operation against misfire or commutation failure. (Misfire or commutating failure would produce approximately 45 kVrms oscillation on the convertor side) With one line operation, however, the line is resonant at 60 Hz. The 60 Hz voltage is larger at the d.c. filter than at the convertor side as indicated by the misfire tests (See AppendixAl). The lowest 60 Hz voltage observed across the d.c. filter was above 60 kVrms for misfire (3 VG operation). Any setting lower than 60 kVrms is therefore sufficient to detect misfire.

The typical characteristic of the d.c. oscillation caused by transformer energization is that the oscillations build up very quickly in the first two cycles but decay slowly thereafter. After reviewing a number of events of this type, especially the ones that had caused the pole to block, one could observe that the 60 Hz voltage oscillations at the rectifier d.c. line terminal decayed to 50 kVrms and lower (as shown in Fig I) at 1.5 sec. Based on the result of misfire test, the voltage across the d.c. filter would thus be 33 kVrms at 1.5 sec. The d.c. filter asymmetry protection will therefore not operate for transformer energization if its level setting is higher than 33 kVrms with a time delay longer than 1.5 sec.

From the above discussion, the range of level setting for d.c. filter asymmetry protection becomes apparant: it has to be higher than 33 kVrms to overlook transformer energization and has to be lower than 60 kVrms to provide backup protection for misfire and commutation failure. A setting of 50 kVrms is thus recommended.

A time-delay setting longer than 1.5 sec duration (at 33 kVrms level) is required to overlook transformer energization. The existing time-delay setting (2 sec) meets this requirement. No change to the time-delay setting is required.

There was another concern that the d.c. filter asymmetry protection is a protection against a complete failure of control and protection including the telecom at the remote station due to dead batteries. Since protection at the remote station will not be able to take action and the last two conducting valves stay conduct, large amount of 60 Hz will be injected into d.c. The d.c. filter asymmetry protection at the local station should be sensitive enough to detect this situation. The recommended setting satisfies this requirement as evidenced from the test results in table 1.

The idea behind the proposed rate of decay supervision that is under consideration by the HVDC Task Force is to block the pole asymmetry protections (both converter side and d.c. filter) when the oscillation is decaying and thus not block a pole unnecessarily for transformer energizations. This is a workable scheme. However, the slope detector supervision is not necessary for the following reasons:

1. The converter side asymmetry protection does not need slope detector supervision because this protection has not operated for transformer energizations in the past. Its existing setting of 40 kVrms is high enough that it will not operate for transformer energization (only approximately 16 kVrms at 1.5 sec. appeared on the converter side during

transformer energization on July 16, '80 disturbance as shown in Figure 1).

2. If this report's proposal of setting d.c. filter asymmetry protection to 50 kVrms is carried out, pole blocking caused by transformer energization will no longer be a problem. The slope detector will unnecessarily complicate the protection. Moreover the reliability of such scheme has yet to be proven.

Conclusion:

(a) From the limited documentation that is available on the subject of BPI asymmetry protections, it appears that the asymmetry protection across the d.c. filter can be regarded as a back-up to other asymmetry protections, including those in the remote station.

(b) The setting of the d.c. filter asymmetry protection should be changed because of the change in the line configuration from double line to single line, the latter configuration being resonant at 60 Hz.

(c) Pole blocking caused by transformer energization can be eliminated by raising the setting of d.c. filter asymmetry protection to 50 kVrms. This will not prevent the d.c. filter asymmetry from detecting persistent misfire or commutation failure.

(d) For the recommended setting on the d.c. filter asymmetry protection the rate of decay supervision is not required.

Recommendations:

(a) The filter asymmetry protection setting should be changed from 22 kVrms to 50 kVrms (dial setting from .25 to .50) at both stations without any change to its timer setting of 2 sec..

(b) The rate of decay supervision that is being considered by the HVDC Task Force for the pole asymmetry protections across VGs and the d.c. filter is not required.

(c) The manufacturer should be contacted to verify our assessment of the asymmetry protections.

References:

(1) "Bipole 1 DC Filter Asymmetry Protection and Its Setting", by D. Tang.

(2) "Supervision of Pole Asymmetry Protection" by Mr. B. Willis. Dated 81 05 05 File 23470.

TABLE 1

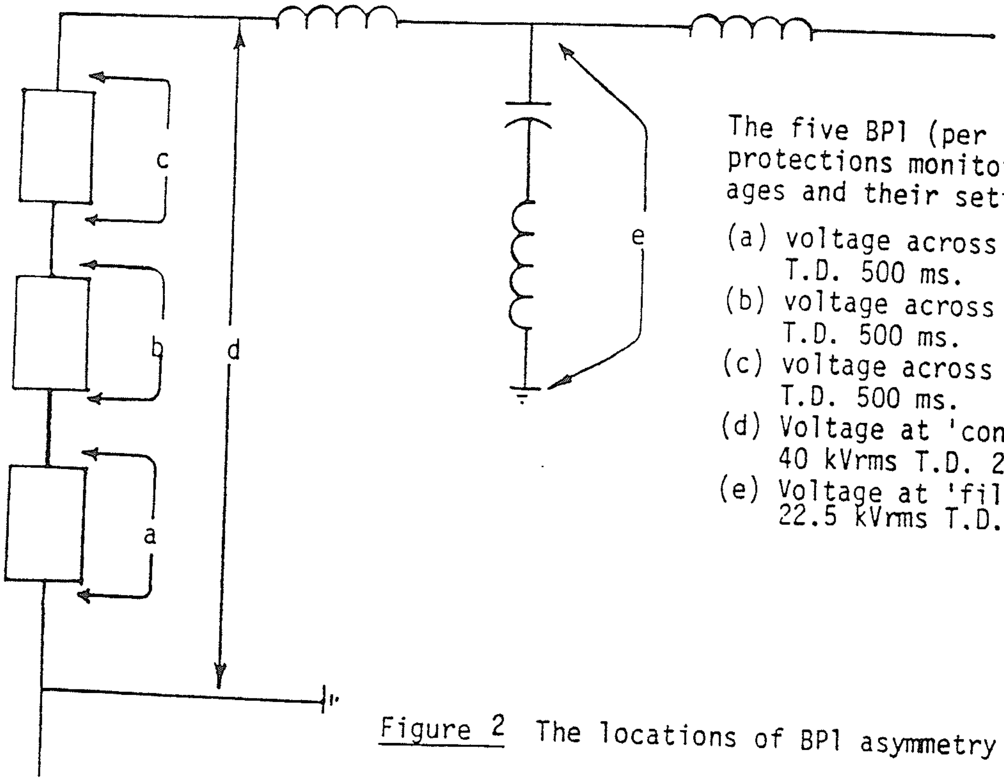
VALVE MISFIRE TEST RESULTS

No. of VG in service	Event	Dorsey voltages			Radisson voltages		
		Valve side	d.c. filter	line	line	d.c. filter	valve side
3 VG	Dsy Comm. Failure	140 kV (49)	260 kV (92)	400 kV (141)	260 kV (92)	200 kV (71)	125 kV (44)
2 VG	"	160 kV (56)	300 kV (106)	560 kV (198)	330 kV (117)	200 kV (71)	120 kV (42)
1 VG	"	180 kV (64)	360 kV (127)	660 kV (233)	450 kV (159)	240 kV (85)	100 kV (35)
3 VG	Rad. Mis.	100 kV (35)	200 kV (70)	340 kV (120)	240 kV (85)	180 kV (64)	100 kV (35)
2 VG	Rad. Mis.	80 kV (28)	260 kV (92)	500 kV (177)	360 kV (127)	200 kV (71)	110 kV (39)
1 VG	Rad. Mis.	80 kV (28)	320 kV (113)	660 kV (233)	600 kV (212)	380 kV (134)	120 kV (42)

NOTE: The number outside the bracket is a peak to peak value. The number in the bracket is a r.m.s. value.

These tests were done on June 10, 1981. Misfire was initiated on VG11 of both stations.

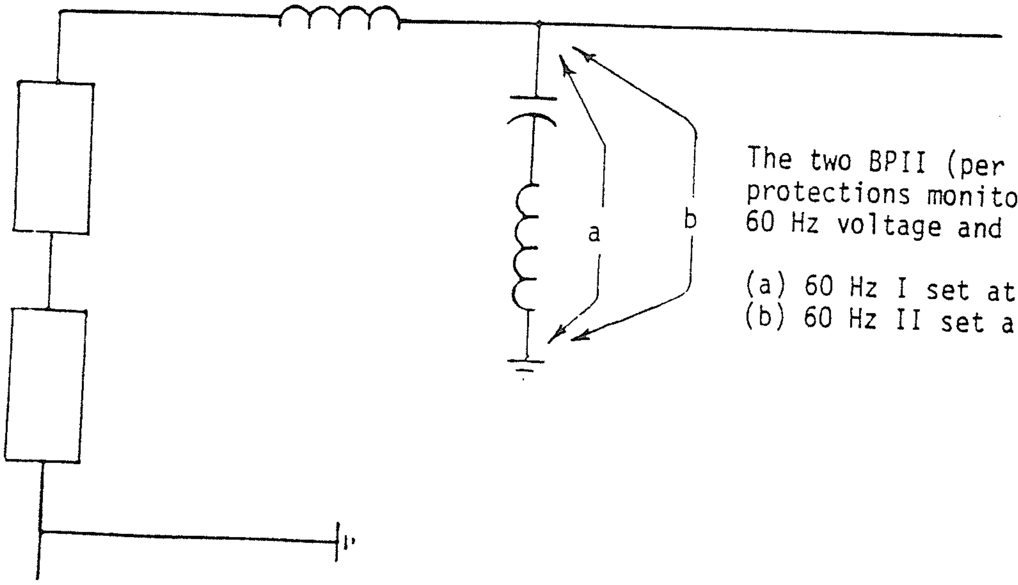
DT/eh
1981 06 23



The five BP1 (per pole basis) asymmetry protections monitor the following voltages and their settings:

(a) voltage across VG 1. Set at 30 kVrms T.D. 500 ms.
(b) voltage across VG 2. Set at 30 kVrms T.D. 500 ms.
(c) voltage across VG 3. Set at 30 kVrms T.D. 500 ms.
(d) Voltage at 'convertor side'. Set at 40 kVrms T.D. 2 sec.
(e) Voltage at 'filter side'. Set at 22.5 kVrms T.D. 2 sec.

Figure 2 The locations of BP1 asymmetry protection monitorings



The two BPII (per pole basis) 60 Hz protections monitor the 'filter side' 60 Hz voltage and their settings are:

(a) 60 Hz I set at 40 kVrms 150 ms
(b) 60 Hz II set at 80 kVrms 25 ms

Figure 3 The location of BPII 60 Hz protection monitorings

Appendix I

SUMMARY OF MISFIRE TESTS (81 06 10)

The Purpose of the Misfire Test

System Planning, in their studies,[A3] found that the amplification of 60Hz through the filter circuit was quite high. Since these values had not been verified by actual measurements, they were assumed to be correct. Recently, however, the re-evaluation of the setting of the d.c. filter asymmetry protection required these actual values especially the ones caused by misfire. The misfire tests were therefore prompted.

Test Procedure

Misfire was initiated by blocking firing pulses to a valve in VG11 for 80 to 100 ms. Both stations, Dorsey and Radisson initiated their own set of misfire in the configurations of three groups, two groups, and one group of pole 1. The voltages at valve side, d.c. filter and line side were monitored and recorded. (Sample test results are as attached Fig. 1 and Fig. 2)

Results Analysis and General Observation

The general form of the result was as anticipated except the amplication was not as high as System Planning had calculated, the general observation can be summarized as following:

(a) Because of the presence of the large amount of the 6th and 12th harmonics voltage, the accuracy of the measurement of the 60Hz voltage at the valve side had been severely reduced.

(b) With less groups operating in the pole, the control becomes less effective in controlling the 60Hz oscillations. This trend is quite evident in table 1.

(c) The trend of voltage amplication through the filtering circuit at both terminals was similar to System Planning's calculation.

(d) The actual amplication was found to be lower than theoretical. The actual voltage ratio of d.c. filter side/valve side is from 1.6 to 2.0 whereas, the theoretical[1] is 3.9 times. The actual voltage ratios for line side/d.c. filter side is 1.6 to 2 whereas the theoretical is around 4.

(e) The 60Hz oscillation at Dorsey d.c. filter and its line terminal were higher than Radisson's for all cases.

Reference:

1. "Bipole-one: Problem resonances on d.c. filter-interim review" Mr. R.B. Wagg to Mr. C.V. Thio dated: Sept. 14, 1977. File no. 81-01317.

TABLE 1

VALVE MISFIRE TEST RESULTS

No. of VG in service	Event	Dorsey voltages			Radisson voltages		
		Valve side	d.c. filter	Line	Line	d.c. filter	valve side
3 VG	Dsy Comm. Failure	140 kV (49)	260 kV (92)	400 kV (141)	260 kV (92)	200 kV (71)	125 kV (44)
2 VG	"	160 kV (56)	300 kV (106)	560 kV (198)	330 kV (117)	200 kV (71)	120 kV (42)
1 VG	"	180 kV (64)	360 kV (127)	660 kV (233)	450 kV (159)	240 kV (85)	100 kV (35)
3 VG	Rad.Mis.	100 kV (35)	200 kV (70)	340 kV (120)	240 kV (85)	180 kV (64)	100 kV (35)
2 VG	Rad.Mis.	80 kV (28)	260 kV (92)	500 kV (177)	360 kV (127)	200 kV (71)	110 kV (39)
1 VG	Rad.Mis.	80 kV (23)	320 kV (113)	660 kV (233)	600 kV (212)	380 kV (134)	120 kV (42)

NOTE: The number outside the bracket is a peak to peak value. The number in the bracket is a r.m.s. value.

These tests were done on June 10, 1981. Misfire was initiated on VG11 of both stations.

DT/eh
1981 06 23

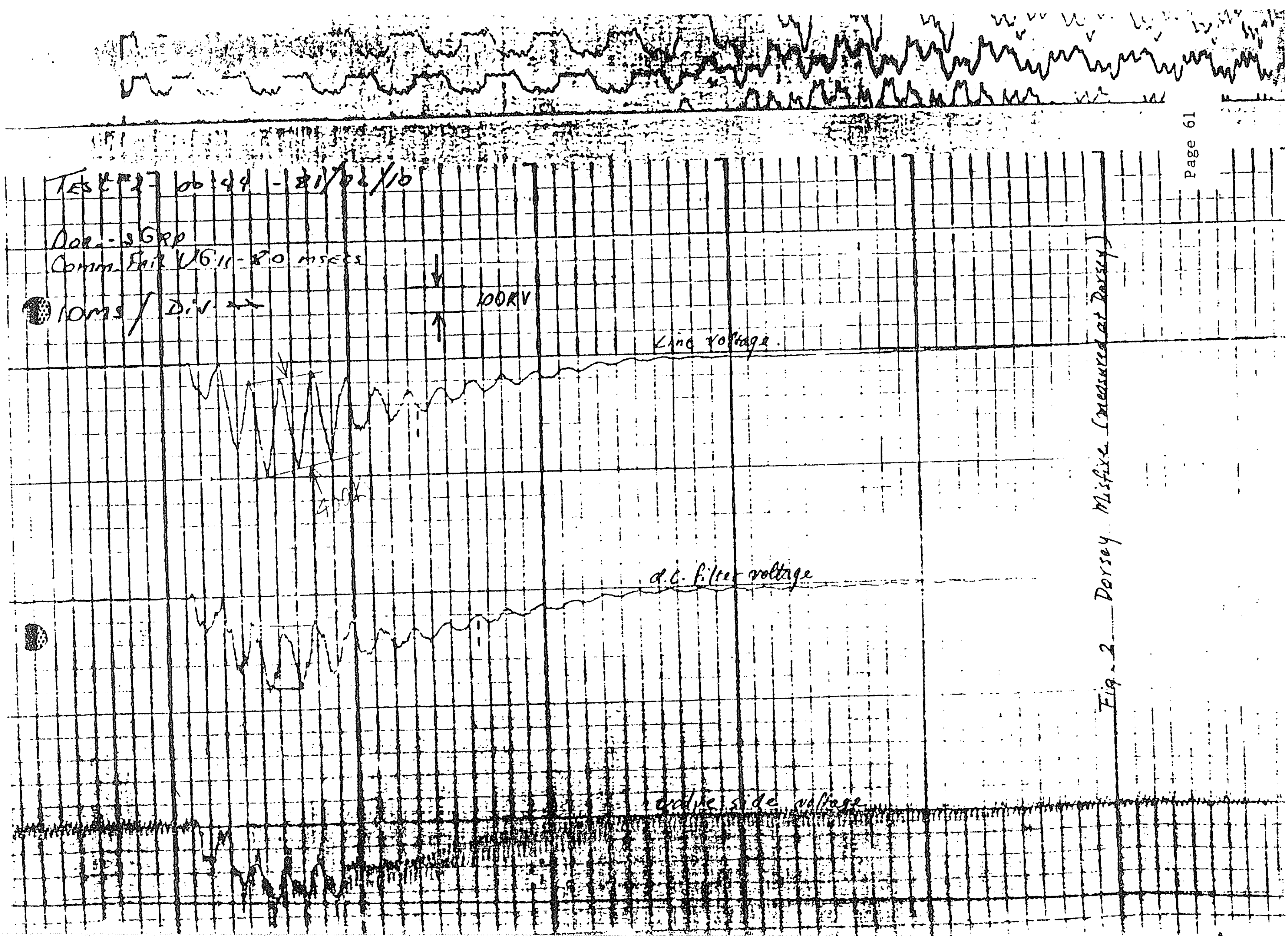


Fig. 2 Dorsey Misfire (measured at Dorsey)

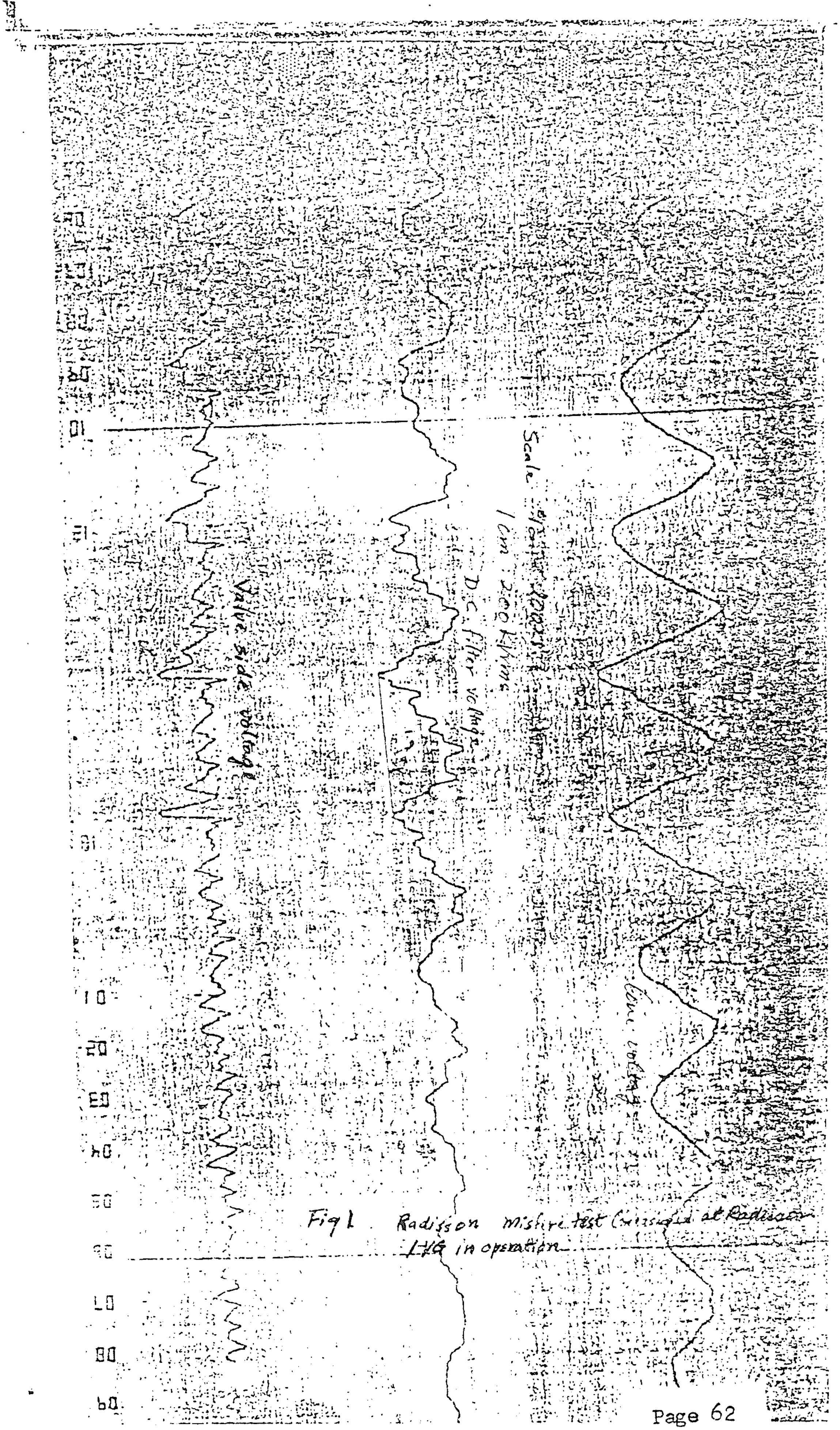


Fig 1 Radisson misfire test (Chisasibi at Radisson
1 HG in operation

Appendix II

TESHMONT CONSULTANTS LTD.
225 - 2025 CORYDON AVENUE • TELEPHONE 284-5350, AREA CODE 204
WINNIPEG 29, MANITOBA

PLEASE REPLY IN DUPLICATE
REFER TO FILE No. 81-2046

July 3, 1970

Mr. G. MacGregor,
Project Manager,
Nelson River Transmission Project,
Atomic Energy of Canada Limited,
1360 St. Matthews Avenue,
Winnipeg 21, Manitoba.

Dear Sir:

RE: DC FILTER CAPACITOR PROTECTION

We enclose for your information a copy of "Addendum to Preliminary Report on DC Filter Capacitor Protection, dated June 19th, 1970," which was handed over to Teshmont by English Electric at the meeting held June 24, 1970.

Yours very truly,

TESHMONT CONSULTANTS LTD.,
R.E. Harrison, P. Eng.,
Project Engineer - Stations,
Per:

M.B. Jones

DF/lk

Encl. (2)
cc: MH, Attn: Mr. L.A. Bateman (Encl.)

TO:	
G MacG	
[illegible] W H	
V S	
[illegible]	
R J H	
A H J	
D A S	
W S W	
M H H	
R H W	
H H S	
B A G	
[illegible] W	

FILE NO.
20463

20470

[illegible]0111/T430
19th June, 1970

ADDENDUM TO PRELIMINARY REPORT ON D.C. FILTER CAPACITOR PROTECTION.

Summary.

Since issuing the preliminary report on the overvoltage protection of the d.c. filter capacitors, Canadian Westinghouse have given further information on the capability of the capacitor units. We have therefore had to reassess the definite time protective settings to ensure an adequate coverage of the bank.

A.C. Ratings.

From an allowable stress against internal hotspot curve it is possible to determine the permitted a.c. stress for a given applied d.c. voltage. This can then be converted to a total bank rating with due regard to the capacitive tolerances and the removal of two cans. The resulting voltage is then equated to 1.1 p.u. overvoltage on the NEMA CP-1, 1968 curve.

The reduction of the d.c. stress component, by blocking valve groups, permits an increase in the a.c. stress component. This is, however, limited to a value derived from the minimum corona extinction level. The result of this is that no benefit is gained from blocking two valve groups from the point of view of increasing the a.c. overvoltage capability.

A further limitation is the unit creepage. This is, in certain instances, insufficient for the permitted unit stress level to be confidently reached. However, the implications of exceeding the allowed creepage will be determined by environmental factors.

Proposed settings.

It is proposed that the overvoltage protection of the d.c. filter capacitors be achieved, with three valve groups operating, by means of a three level definite time characteristic with a supplementary alarm level. This is indicated in Figure 1., where the alarm level corresponds to the designed unit creepage and the three settings proposed are:

1.1 p.u.	182 kV	130 kV..	5 minutes time delay.
1.2 p.u.	198 kV	140 kV	5.0 seconds time delay.
1.51 p.u.	250 kV	[illegible]	Instantaneous.

Where one or more valve groups are blocked the proposed settings are:-

1.1 p.u.	250 kV	5 minute time delay.
1.2 p.u.	273 kV	Instantaneous.

The above settings indicate that five measuring units will be required to implement the protection in addition to two time delay devices.

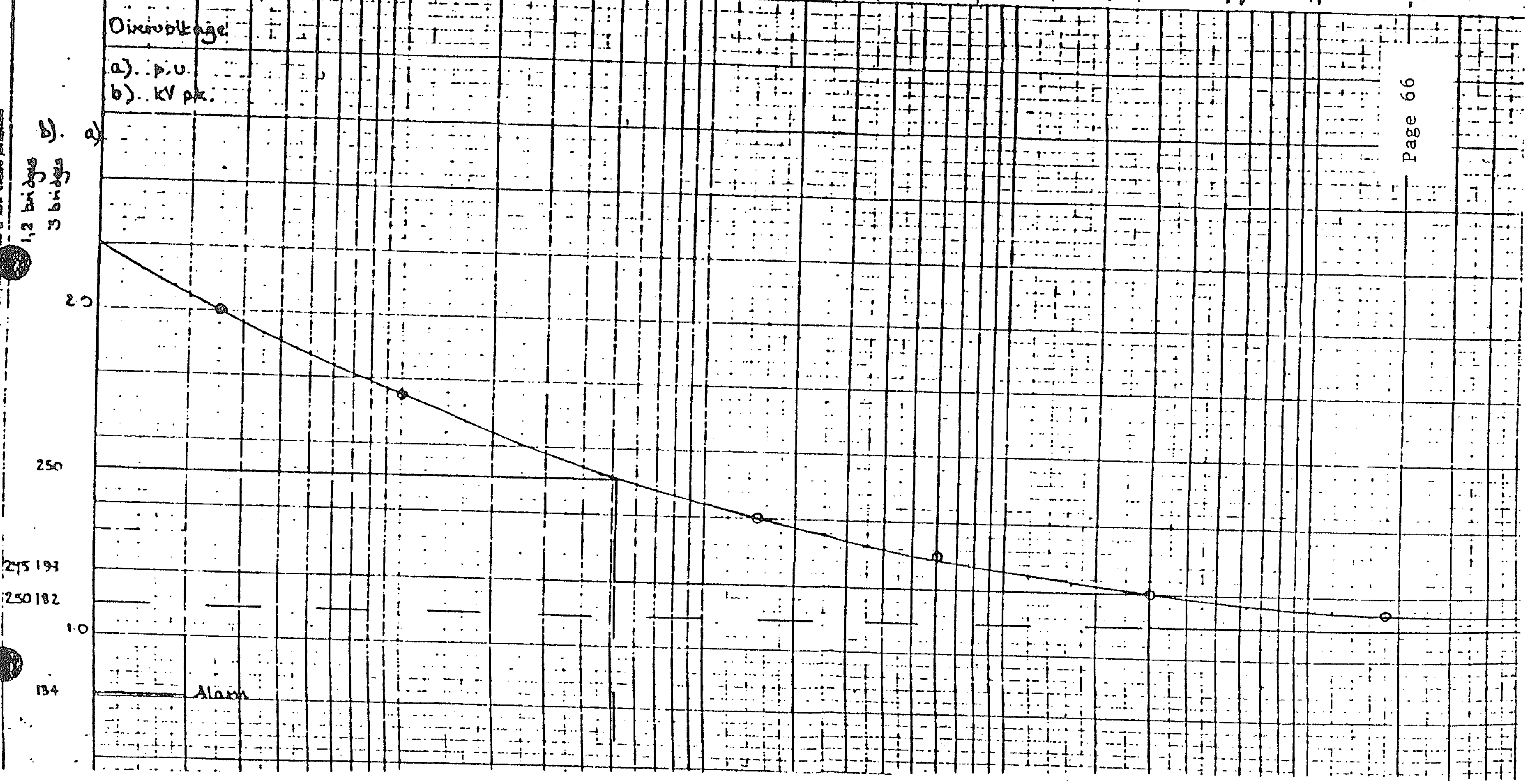
Conclusions.

As a result of further information being received on the d.c. filter capacitor overvoltage capabilities, revised settings have been proposed for the protection.

The major change the revisions cause is the reduction in time given to obviate a protective trip at the lowest overvoltage setting. This time could be increased, but it can be seen that the slope of the curve in the region of 1.2 p.u. would create practical difficulties of level detector setting.

[illegible] capacitor bank - initial design

Overvoltage - time curve for the protection of the 6th arm capacitor bank - initial design



HWH	
HVS	
~~WAD~~	
RJH	
AHJ	
DAS	
~~WSW~~	
MHB	
RBW	
HHS	
BAG	
MW	
FILE No.	

81-20463
81-20470

13 Feb. 1970

R.W. Haywood

R.J. Hamlin

Capacitor Protection

Due to the recent concern for the AC and DC filter capacitors I have been doing some reading. This memo will serve to record some of the highlights of this reading.

General

"The life of a capacitor is shortened by overstressing, overheating, chemical change, physical damage or repeated temperature changes." CP 1 - 6.01

Capacitors must operate at a lower temperature rise than most other equipment because -

1) Shunt capacitors operate at full load continuously (line voltage is always present).

2) Capacitors are designed to operate at comparatively high dielectric stresses for reasons of economy. The combination of these stresses with operation at high temperature for extensive periods of time will result in gradual deterioration and shorten life.

Capacitor Ratings

Capacitors are rated in continuous Kvar, voltage and frequency.

Standards have been set to allow capacitors to operate at 110 percent of rated voltage provided the maximum Kvar is not exceeded.

The maximum Kvar not to be exceeded is 135% of rated Kvar, including the Kvar due to the fundamental voltage and the harmonic voltages.

Capacitor failure is usually in one of two modes:

1) If the voltage is high enough minute discharges will be initiated in tiny unavoidable voids that exist in the dielectric. If the discharge is large enough in duration the progressive deterioration of the dielectric will eventually permit the discharge to reach from electrode to electrode with consequent failure.

2) If currents are in the range just below that causing discharge inception voltage, the magnitude is invariably sufficiently large to cause at least localized heating in sections of the dielectric which leads to accelerated reactions and again consequent failure.

Shunt capacitor protection must:

1) Detect a unit failure by either a fuse failure or an unbalance current in the filter bank.

2) Protect from overheating (overcurrent).
NEMA Figure 6-2 and 6-3.

3) Protect from overvoltage. The voltage withstand is a function of time.
NEMA CP-1-6.02.

$$\text{KVAR} = \frac{(2\pi f)\ C\ E_{rms}^{2}\ (\text{rated}) \times 10^{-6}}{1000}$$

List of References

1) NEMA Standards Publication
Shunt Capacitors CP1-1968

2) General Data on Construction Application Maintenance and Field Testing of Power Capacitor Units
R.E. Marbury

3) "Protecting Series Capacitor Banks"
M.K. Price
Electrical News and Engineering Dec. 1966 pp 46 - 53

4) Chapter 8 Westinghouse Transmission and Distribution Reference Book

ORIGINAL SIGNED BY
R. J. HAMLIN
R.J. Hamlin.

RJH/bg

P.S. See Attachment 1 enclosed.

ATTACHMENT 1

KVAR Rating:

The kvar rating includes the kvar of the fundamental and the harmonics. When the applied voltage contains harmonics, the total voltage is given by:

$$V_{RMS} = \sqrt{(V_f)^2 + (V_{2f})^2 + (V_{3f})^2 + \ldots\ldots (V_{nf})^2}$$

V_f = RMS of fundamental

V_{nf} = RMS of n 'th harmonic

The capacitor will draw a certain kvar at fundamental V_f, a certain kvar at Vnf. the total kvar drawn will be the sum of these values. The kvar rating of 135% of design value should not be exceede

Voltage Rating:

The problem with capacitor voltage protection is the duration of the overvoltage. The equipment should be able to detect the peak voltage level but send a continuous voltage reading to the capacitor overvoltage protection relays. The instantaneous relay must examine peak voltage but the time overvoltage relay may be able to use on RMS voltage that includes any DC and all harmonics.

ORIGINAL SIGNED BY
R. J. HAMLIN
R.J. Hamlin

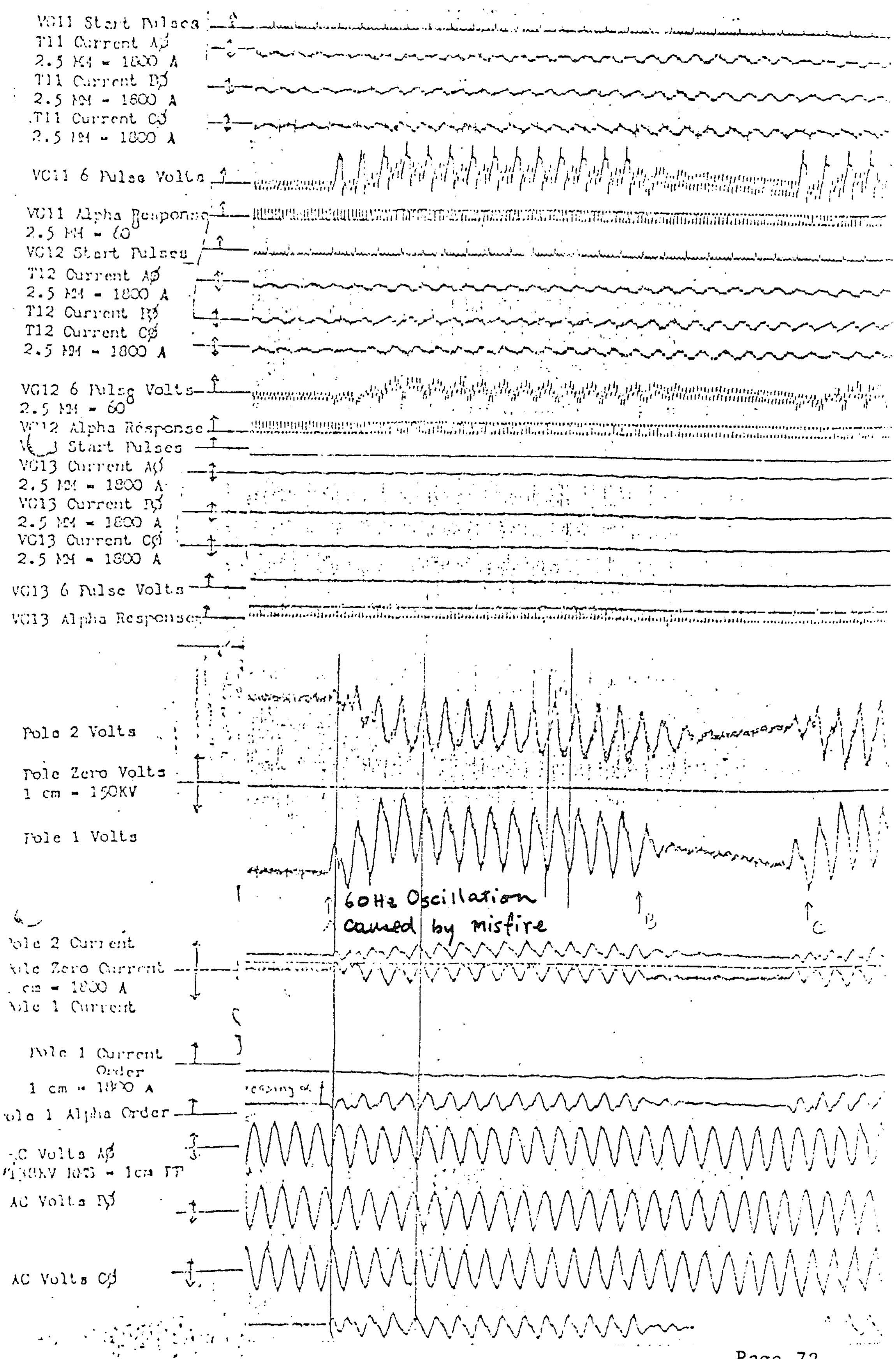
RJH/bg

APPENDIX B

OSCILLOGRAM SHOWING OSCILLATIONS CAUSED BY MISFIRE

POLE 1 HATHAWAY

KEY



60Hz Oscillation caused by misfire

APPENDIX C

SUMMARY OF ALL 60 Hz RELATED DISTURBANCES

SUMMARY OF SOME MAJOR DC LINE RESONANCE EVENTS

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
1.	Apr. 21, 23:10 /78	DVG21 per.comm.fail. 30 ~ before block	P1-2 V.G., 2 lines, 2 S.R., 700a P2-3 V.G., 1 line, 2 S.R., dc filt? 1300a	0.2	0.2	P2-large 60 Hz	Appears undamped. P1 O.K.
2.	Apr. 22, 1:42 /78	DVG21 per.comm.fail. 30 ~ before block	P1-3 V.G., 2 lines, 2 S.R., 500a P2-3 V.G., 2 lines, 2 S.R. dc filt? 900a	0.2	0.2	P2-small 60 Hz	60 Hz small and controlled compared to Event 1 showing effect of 2 vs 1 dc line.
3.	Apr. 23, 10:04 /78	DVG22 per.comm.fail. followed by recovery	Same as Event 2.				Same as Event 2.
4.	Apr. 23, 19:02 /78	DVG21 per.comm.fail. then block.	Same as Event 2.				Same as Event 2.
5.	Apr. 27, 14:34 /78	Rad. P1 misfires followed by P1 block (1 V.G.)	P1-1 V.G., 1 line, 1 S.R., 1200a P2-3 V.G., 2 lines, 2 S.R.,dc filt? 1200a	0.2	0.2	P1-large 60 Hz	P2 O.K. Seems 1 line & 1 Rad. S.R. is still close enough to 60 Hz to cause some ringing.
6.	June 4 /78	Test 12 & 13 of di/dt testing on P2. Test 12-10 Hz D. Misfire. Test 13-DV.G.block-debl.	P1-2 V.G., 1 S.R., 900a P2-3 V.G., 1 line, 2 S.R., 6,12 off, 1260a		1.2	P2-No resonance-good response	Compare to Event 1 shows that high di/dt cures major 60 Hz resonance.

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
7.	June 25, 13:10 /78	P1 blocked by assymetry after VG13 deblocked. After di/dt reduced to 0.7 P1 deblocked successfully.	P1-2 V.G., 1 line, 2 S.R., 1200a P2-2 V.G., 1 line, 2 S.R., 6&12 off, 1200a 8K, all Rad. filt., BP-2 off 2R-L-H lines	1.0	1.0	Slow res. buildup at approx. 100 Hz & 6th or 7th for approx. 2.2 sec.on P1. AC resonance-3rd,6th, 8th	This is a new type of resonance compared to 60 Hz above & came in with high di/dt indicating control instability.
8.	June 25, 18:50 /78 & 22:03	P1 blocked by assymetry after VG11 deblock.	6 uK, 3 u L.S., all Rad. filt. P1-2 V.G., 1 line, 2 S.R., 900a P2-2 V.G., 1 line, 2 S.R., 6&12 off, 900a 22:03-5K, 3 LS 2R-L-H lines	0.7	1.0	Same as above. 100 Hz. AC resonance-3rd, 6th, 8th	Seems control still unstable with lower di/dt.
9	July 4, 8:55 /78 & 10:06	8:55-P1 & P2 started undamped res. P1 block. Then di/dt reduced. 10:06 DVG 11 single comm. fail.	11 machines on. 8K, [illegible] P1-3 VG, 1 line, 2 S.R.,1300a P2-2 VG, 1 line same tower, 2 S.R., 6 & 12 off, 1300a All Rad. filt., H-1 H.P. 2 R-L-H lines	8:55 0.7 10:06 0.5	1.0 0.7	Slow res. @ 60 Hz & 4th or 5th P1 & P2 P2 damped 60 hz AC resonance-2.8, 4.7 small, 6.2, 8.6	Same as above. Also with line 60 Hz res. (1 line, 2 S.R.), seems 0.7 slightly low to minimize 60 Hz ringing.
[illegible]	July 29 /78	P1 block by assymetry after T22 energ.	6 uK, 2 u L.S., 5,7,5,7,11 P1-3VG, 1 line, 2 S.R., 900a P2-2VG, 1 line, 2 S.R., 6&12 off, 900a 2R-L-H lines	0.5	0.7	60 Hz & 4th for 10 sec. Res. damped at first but increases after 3 sec. AC resonance-3.6,6.1, 9.2	Control still unstable with lower di/dt.
11.	July 31 /78	P1 block by assymetry after Henday filt. switch	6 uK, 3 u L.S., all filters in. P1-2VG, 1 line, 2 S.R., 1300a P2-3VG, 1 line, 2 S.R., 6&12 off, 900a 2R-L-H lines	0.5	0.7	60 Hz & 4th with faster rising 60 Hz this time. At first res. 60 Hz & 7th. AC resonance-3.2,5.9, 8	Same as above.

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
12.	Aug. 17, 1:33 /78	P1 block by assymetry after VG22 block.	5 uK, 4 u L.S., all Rad. & 1 Hend. filt. P1-3VG, 1 line, 1 S.R., 1500a P2-blocked. 2R-L-H lines	0.5	0.35	P1-slow res. @ 60 Hz & 5th. AC resonance-2.6, 4.7 small, 6.2, 8.3	Control still unstable with 0.5 di/dt, 1500 a & 1 line 1 S.R.
13.	Aug. 26, 7:38 /78	P2 res. after Rad. T11 energ. VG21 AB & block.	6 uK, 4 u L.S., all Rad. filt. P1-blocked P2-2 V.G., 1 line, 2 S.R., 6 & 12 off, 1800a 2 R-L-H lines	0.2	0.35	P2-slow res. @ 60 Hz & 5th & 3rd in current. AC resonance-3.3, 5.9, 8	Control near instability with 0.35 di/dt, 1800a & 1 line, 2 S.R.
14.	Aug. 27, 2:10 /78	P1 res., 2 Ku energ.	P1-3 V.G., 1 line, 1 S.R., 1500a P2-blocked. 2 R-L-H lines	0.2	0.35	P1-slow res. @ 60 Hz & 5th, 6th or 7th.	
15.	Sept. 18, 23:33 /78	P2 block by assymetry after no cause for res.	7 uK, 3 u L.S., all filters in. P1-2 V.G., 1 line, 1 S.R., D6 & 12 off, 1100a P2-2 V.G., 1 line, 1 S.R., R6 off, 1100a H-1 H.P., 2 R-L-H lines	0.2	0.35	P2-slow res. @ 60 Hz & 5th, 6th or 7th AC resonance-2.8, 4.7 small, 6.2, 8.5	Control unstable with 0.35, 1100a, & 1 line, 1 S.R.

NOTE: Core saturation tests in Nov./78. It was concluded 90-100 Hz oscillations due to basic control instability (too high di/dt) & not core saturation. In these tests di/dt = 0.8 and configuration 7K, 4LS, 5, 7, 5, 7, 11, 13, HHP, VG11, 12, 13, 22, 31, 41, BP-1 540 MW, BP-2 400 MW. Flux control units on VG's 13 & 22 on Nov. 16.

16	Oct 13 1:45 /78	P1 blocked by asymmetry prot. Kettle had taken one unit off at 1:35	6K, 3 LS. All BP1 filters in service. Pole 2 0 6th off. BP1 not in service.	.2	.2	2nd harmonic $17\angle87^\circ$ ohms 3rd harmonic $77\angle60^\circ$ ohms resonant at 196 Hz	very slow in building up

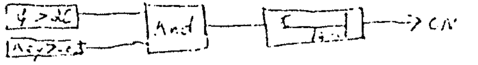
NOTE: Operating guidelines were changed on 79/04/18 (G. Rheault).

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
17. & 18.	Aug. 26/79 13:51	VG11 deblock & dc tie reduction. Later event with T23 energ. & 3 VG P1	P2-off, P1-VG 12, 1. P1-810 MW, then VG11 A/B, then 1300a after dc red. BP-2 - 390 MW, VG41 All Rad. filt., H-1 H.P. 7 K, 7 LS	0.5 Smooth 0.6	0.5 0.6	60 Hz (70 kV p-p) steady osc. for ≥6½ sec. AC resonance-3,6.5,8.8	

COMMENTS: Appears to be the 1st case of core sat. since flux control. Subsequent Dorsey hath. indicates di/dt damps normal 60 Hz fairly quickly. Core flux cont. operated as indicated by PAAS but control continuously "on" when BP-2 operating monopolar. Oscillation becomes higher when dc red. is received. A second disturbance due to Rad. transf. energ. shows 60 Hz osc. is damped in less than 1 sec. A note in disturbance report (LDR) says that no osc. of this type was noticed with the flux cont. on Auto? I have a note on Oct. 1/79 that the "on" supervision is installed so that there must be a certain level of flux on the meter as well as on osc. Then the "on" triggering is delayed so that we should see the buildup of osc. as well as correction.

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
19.	Oct. 27/79 22:53	Henday transf. energ. Test 1		0.5 Smooth 0.6	0.5 0.6	60 Hz osc. appears damped	Flux unit on P1 had been removed week prior. P2 unit apparently did not come on due to level set.

NOTE: Flux unit set to ± 20 u on meters. If this level attained and if assymetry detection on line is up to level set (1/2 level of trip setting on relay) then flux unit cuts in. P1 flux unit may not have had this time delay in.



	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
20.	Oct. 27/79 23:34	Henday Transf. energ. Test 2. P1 & P2 trip by dc filt. assym.	11K, 3LS, All Rad. & H. filters. 1 line LS-H. BP-1 - ± 450 kV BP-2 off	0.5	0.5	60 Hz AC resonance-2.1, 4.3, 6.2, 8.6	Osc. appears damped at first but then increases again perhaps due to increase of some [illegible]

	Date	Event	System Configuration	Rad. di/dt Pole 1	 Pole 2	Resonance Condition	Comments
21.	Apr. 22/80 1:44	P1 & P2 blkd. by assymetry, P1 via Dorsey & P2 via Rad. Prior to this 500 kV line was energ. at 1:22 and 1 Ku removed at 1:43.	6K, 5LS, all Rad. filt., 1H HP P1-3 VG, P2-VG22, 23 BP-2-41-148 MW BP-1-880 MW (976 MW?) 3R-LS-H lines	0.5	0.5	60 Hz & 4th AC resonance-2.8, 6.4, 8.8	P1 flux cont. operated. P2 flux cont. did not oper. because of missing connection which was subsequently corrected. Tape rec. for monitor of sat. was on P2 & thus it failed to record event.

NOTE: Re LDR memo (80/05/14) flux cont. oper ≃5 sec. prior to P1 block and thus would not have been in long enough to prevent trip.

	Date	Event	System Configuration	Rad. di/dt Pole 1	 Pole 2	Resonance Condition	Comments
22.	May 18/80 13:53	Transf. energ. Osc. damped. No trip.	5K, 4LS, R H.P. off 3R-LS-H lines BP-2 off BP-1 - 11, 13, 21, 22 - 890 MW	0.5	0.5	60 Hz & 4th AC resonance-3.6, 6.1, 8.9	Both flux cont. in.
23.	June 4/80 4:13	11th filt. sw. off. BP-1 trip by assym. 2LS u trip on O/V.	2K, 0 LS, 5, 7, 11 2 R-L, 1 L-H lines BP-2 off BP-1 - 11, 12, 22, 23 - 345 MW	0.5	0.5	60 Hz & 4th AC resonance-2.6, 5.9, 8.2	P1 flux cont. off.
24.	June 9/80 1:14	2 Ku off. P1 trip.	3K, 3LS, R HP off 2 R-L, 3 L-H lines BP-2 off BP-1-11, 12 - 440 MW	0.5	0.5	60 Hz & 4th AC resonance-3.1, 6, 8.7	Both flux cont. off.
25.	June 9/80 1:30	V.G. deblock. P1 trip	3K, 3LS, R HP off 2R-L, 3 L-H lines BP-2 off BP-1 - 11, 12, 21, 23 - 310 MW	0.5	0.5	60 Hz & 4th AC resonance-3, 6, 8.7	Note: Both flux cont. off. Deblock in P1 caused trip. Deblock in P2 did not indicating controls different. It had been found about 2 yrs. ago di/dt in P1 more effective than in P2.

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
26.	July 16/80 23:58	Transf. energ. Osc. damped. P2 block	3K, 2LS, 5, 7, 11, 13 2 R-L, 3 L-H lines BP-2 off BP-1 - 13, 21, 22, 23 - 490 MW	0.5	0.5	Largely 4th, 2nd harm. in dc curr. AC resonance-3.4, 6, 8	Both flux cont. in.
27.	July 21/80 9:34	Transf. energ. Osc. damped. No trip.	6K, 5LS, 5, 7, 11, 13 2 R-L, 3 L-H lines BP-2 - 41, 1 H. H.P. BP-1 - 11, 21, 22, 23 - 1000 MW	0.5	0.5	60 Hz & 4th damped quite fast. AC resonance-3.2, 6.7, 9	P1 flux cont. off.
28.	July 30/80 2:13	P1 & P2 blkd. by assymetry. P1 via Dorsey & P2 via Rad. VG11 spot transfer, then LS unit trip.	2K, 1LS; then 2K, OLS, 5, 7, 11, 13 P1 - 11, 12, P2 - 21, 22 BP-1 - 180 MW BP-2 - off 2 lines Rad.-L.S., 3 lines L.S.-H.	0.5	0.5	60 Hz & 4th, 60 Hz increasing quickly after L.S. unit trip. AC resonance-2.9,5.8, 7.9 (2K, 1 LS) - 2.2,5.8,7.8 (2K, 0 LS)	P1 flux cont. on VG13 which was off
29.	Aug. 23/80 7:31	P1 & P2 blkd. by assymetry. L.S. unit transf. energ. P1 via Dorsey & P2 via Rad.	3K, 3LS, then 3K, OLS, R HP off P1-3 VG's, P2-VG21, 23 BP-1 - 465 MW BP-2 - off 2 lines R-LS, 3 lines LS-H	0.5	0.5	60 Hz & 3rd, then mainly 4th, then 60 Hz & 4th after 0 LS units. AC resonance-3.1,6, 8.7 (3K, 3 LS) - 2.2,5.9,8.4 (3K, 0 LS)	P2 flux cont. on VG22 which was off
30.	Sept. 7/80 11:14	P1 blkd. by assymetry via Dsy after adding 1 Ku.	5K, 4LS, R HP off P1 - 3VG, P2 - off BP-1 - 700 increase to 810 MW 3 lines R-LS-H	0.5	0.5	AC resonance-3.6, 6.1, 8.8	P1 flux cont. operated 8 sec. prior to block.

NOTE: Re Syst. Perf. - Based on a few events it may be advisable to have Rad. assyummetry operate first. If Rad. is interblocked from Dsy, the osc. on the poles will go even higher.

	Date	Event	System Configuration	Rad. di/dt Pole 1	Rad. di/dt Pole 2	Resonance Condition	Comments
	Nov. 23/80 01:21	P1-blkd. by assymetry at Dorsey after T23 was energized.	6K, 3 LS, 3 lines; R-LS, 2 lines LS-H. P1 3 VGs. P2 blocked. Radisson all filter banks energized. Henday only F1 energized. VG41 deblocked. BP1 P.O. 8/0 MW.	0.3	0.3	P1 60 Hz oscillation picks up to asym. level in 4 cycles, but appears to be damped. AC resonance 2.8, 6.5, 8.8, 11.9	This event occurred following optimization of the current regulators at both terminals. T23 was the 3rd converter transformer bank to be energized within 72 seconds.
	Sept. 21/81 00:03:43	P2-blkd. by DC filter asym. protection at Dorsey, following T13 energization.	6K, 2 LS, 3 lines; R-LS, 3 lines LS-H. P2 3 VGS-P1 off. Radisson all filters except high pass. Henday no filters BP2-off. BP1 P.O. MW. 400	0.3	0.3	P2 60 Hz picks up to protection level in 63 msec. following T13 energizing. The oscillation is steady in magnitude. The oscillation improves when T13 tripped by connection protection. AC Resonance 3.5-8.6.	P2 Flux Control Unit is in service. T11, T12 where energized prior to T13 energizing.
33	Oct. 31/81 01:29	P1 and P2 both suffer oscillation when T11 was energized at Radisson. No block.	6K-2 LS, 3 lines; LS-H, 2 lines LS-R. P1 and P2 2 VGS each. Radisson 1 5, 7 1 11, 13 Henday no filters. BP2 off.	0.3	0.3	The general trend is that the oscillation is dying as the inrush current dies. During the disturbance there is a slight increase in the magnitude of oscillation . The asym protection filter side is set at 100 kV r.m.s. at both Dorsey and R. AC resonce 4th, 6th, 8th, 12th.	

APPENDIX D

J.D. AINSWORTH'S SUMMARY OF OCTOBER 18 - 20, 1981 TEST RESULTS

Prepared by Mr. J.D. Ainsworth

POWER TRANSMISSION DIVISION
GEC Power Engineering Limited

Report S/SDr 654
Date 23rd October 1981
Ref.
Issue B 6.11.81

Title

BIPOLE 1 RESONANCE :

TESTS AT RADISSON ON OCTOBER 18-20, 1981

Report by J.D. Ainsworth

NOTES AND PROVISIONAL CONCLUSIONS :

1. The original theory that part at least of the problem is core saturation instability was confirmed. The other problem is forced d.c. line oscillation caused principally by switching in transformers and by single valve blocking or misfire (e.g. due to spot transfers).

2. Brief Description of Problems

A: Core saturation instability

This is a true instability which can spontaneously start "from nothing", growing very slowly to a limited amplitude, or can sometimes be driven rapidly up in amplitude by almost any disturbance, and then remains there after the disturbance has gone. It is principally caused by a combination of d.c. line resonance close to fundamental, a.c. sending end system of high impedance at 2nd harmonic (not necessarily resonant at 2nd), operation at high d.c. current, and use of high di/dt control settings (e.g. 0.7). It is intimately concerned with saturation effects in convertor transformers. Its worst effect has been increase of d.c. line oscillati to a level at which d.c. filter asymmetry protection trips out the bipole. During the particular tests spontaneous oscillation occurred in a particular system condition, but only at a relatively low amplitude. (From previous history, higher amplitude spontaneous oscillations can however occur in other system conditions).

B: Forced oscillation due to transformer switching in at the rectifier

This causes substantial temporary 2nd harmonic on the a.c. side, dying very slowly, which cross-modulates through the convertor to produce fundamental frequency which drives the d.c. resonance. The a.c. (r.m.s.) amplitude on the d.c. line is then typically 10% or more of d.c. voltage and can again be enough to operate d.c. filter asymmetry protection, and trip the bipole. It can occur even with a diode rectifier.

C: Forced oscillation due to single valve misfire.

This gives a much larger a.c. amplitude than B (though total peak d.c. line voltage is not excessive due to reduction of d.c. component). The a.c. amplitude can be reduced somewhat by high di/dt setting (e.g. 0.6) in controls. Generally this is not an important case since it is automatically terminated in less than d.c. filter (or pole) asymmetry trip time. It becomes important either for a very long train of misfires (believed to be becoming rarer due to renovation of valves, etc.) or as D below. A similar case could be failure to close of a bypass vacuum switch during blocking; this will trip the bipole due to pole and line asymmetry but is also believed to be rare.

Bipole 2 has been known to trip due to the relatively high 60Hz voltage induced in it.

D: Forced oscillation plus core saturation instability.

A terminated forcing cause such as C has been known to leave the system oscillating continuously (sometimes with growing amplitude) even after the prime disturbance has vanished, eventually causing bipole trip.

3. Summary of Tests

All of the various effects as above were observed in the tests. Flux control units installed in one bridge in each pole, after correction of minor wiring errors, were tested with various flux control gain settings, and a suitable value of this was determined. It was demonstrated that :

(a) The flux control units cure core saturation instability, by holding the system stable, with convertor transformer mean fluxes close to zero in steady state. This was shown only with a relatively mild prospective instability, but the behaviour of these units was obviously such that stability could virtually be guaranteed for a much worse system condition (e.g. a.c. system resonance nearer to 2nd harmonic).

(b) The flux control units cannot appreciably affect d.c. line oscillations due to transformer switching. This amplitude will be highest for 3 groups in a pole, and the d.c. filter asymmetry protection must be set high enough not to operate in this condition.

(c) For temporary valve misfire, transformers are driven heavily into d.c. saturation, but after removal of the fault, although each flux control unit may take about 1 second to desaturate all three transformers in its group, d.c. line oscillations are always reduced sufficiently rapidly to prevent operation of d.c. filter asymmetry protection if its time is set high enough (2s). This applies even in a case which, without flux controls, would lock into a state of core saturation instability.

4. Recommendations

(a) D.C. filter capacitor asymmetry protection setting should be raised to about 90 kV rms or higher with a time setting of 2s. This will prevent spurious tripping for transformer switching and some other causes. This is not part of filter capacitor protection (which has even higher setting) hence involves no risk to equipment. (Historically, the much lower settings used in the past were relevant to a non-resonant d.c. line, before adding the second set of d.c. reactors to reduce telephone interference).

(b) The asymmetry (a.c. voltage) protection setting on BP2 d.c. line should be set to a value higher than the highest value caused by transformer switching on BP1 or BP2, and its time setting should be longer than the expected time of BP1 misfire (asymmetry per bridge) protection. This means say 400ms setting on BP2, assuming the existing 300ms on BP1. Alternatively you could try reducing BP1 asymmetry per bridge setting to say 150ms, though you should check for spurious operation due to normal transients (e.g. commutation failure). However we cannot see any reason why BP2 60Hz detector 1 time settings should not be increased from the existing value of 200ms (40kV). The BP2 detector 2 settings of 80kV may be sufficiently insensitive not to operate from the long-term component of BP1 disturbances, but its time setting (25ms) seems much too short, and may cause it to operate spuriously. We suggest say 100ms.

(c) If single valve blocking due to spot transfer or other causes on BP1 continues to be a problem you should install extra optic fibre couplings from each valve to ground, to initiate whole bridge blocking rather than single valve blocking.

(d) Flux control units should be fitted to all six bridges at Radisson. (There is some evidence to show that thus treating only one bridge per pole is sufficient, but there is the possibility of outage of the treated bridge).

(e) Provided there is an adequate number of flux control units per pole, the control di/dt settings may be increased to 0.6. This is not strictly necessary but assists in reduction of oscillation amplitude due to valve misfire, etc.

(f) In the meantime the two temporary flux control units should be left in service (AUTO position), but main control di/dt settings left at 0.3 for the present in case of outage of their groups.

APPENDIX E

SUMMARY OF MANITOBA HYDRO'S FINAL ACTION WITH REGARD TO THE 60 Hz INSTABILITY

Prepared by Mr. C.V. Thio

XIO-1910 REV. 75 10

MANITOBA HYDRO

INTER-OFFICE MEMORANDUM

FROM C. V. Thio, Manager
Transmission Planning Department
System Planning Division

TO HVDC Task Force

ATE 1981 11 05

ILE NO. 81-01317

UBJECT BIPOLE-ONE DC LINE 60 HZ RESONANCE

Following are the overall comments and conclusions arising out of the resonance tests conducted at Radisson from October 16 to 19, 1981 in the presence of Mr. J. D. Ainsworth from GEC.

1) It is now recognized that there are two distinct problems included in the general 60 Hz resonance instability. One is a true core saturation instability which can grow spontaneously and slowly, or be driven rapidly up in amplitude by any disturbance and remain after the disturbance is gone. The other is a forced oscillation caused mainly by transformer energization or valve misfires (spot transfers). The forced oscillations are generally a decaying or time limited type but they can apparently trigger a following core saturation instability. Of the approximate 30 events analyzed in the past, about 15 of these contain core saturation instability. Five of these 15 are somewhat questionable, however. The remaining events are all of the forced oscillation type.

2) The bipole and pole trips due to resonance have all been via the dc filter asymmetry protection. The existing setting of 22 kV has never been changed or clarified from the original in-service but is apparently much too low. It is believed that the setting was chosen merely to act as backup and coordinate with the valve side asymmetry protection. When the second smoothing reactor was added in the design stage this protection was not recalculated, and the fact that valve side problems and oscillations are magnified at the filter due to the line resonance was overlooked. Even the need for this protection is somewhat questionable since the filters have their own protection (129 kV rms for 5 min, 140 kV for 5 sec, 177 kV instantaneous) and there is also a valve group asymmetry protection (30 kV rms for 500 msec.) and a valve group side pole asymmetry protection (40 kV rms for 2 sec.) which act as backup. It is recommended therefore to raise the dc filter asymmetry level to 60 kV rms for 2 sec. at least for a trial period. This should cure all the bipole trips due to the forced oscillations based on Report Ref E2. If it does not then the setting should be made even higher because it is still less than Mr. Ainsworth's recommended setting of 100 kV rms.

3) The di/dt control signals in both poles were checked and appear correct. Some wiring errors were found in one flux control unit and corrected. It is not known what effect this had on previous incidents. The gain of the flux control units were also optimized. It was found that a high gain could seriously aggravate the stability during the forced oscillation events but the units basically could not cure these oscillations. Main control settings, including a trial dc line voltage feedback, also could not cure oscillations. High di/dt settings up to 0.6 help somewhat in controlling the amplitude of the oscillations but theoretically the higher levels are worse for core saturation instability. It was concluded that the optimization tests done in the fall of 1980 arrived at a good compromise setting of di/dt at 0.3 (Radisson and Dorsey) and it is recommended that this setting remain. The di/dt could be raised to 0.6 in future depending on further experience and on what is ultimately decided for the number of flux units installed. A setting change to 0.6 at Dorsey only may be useful to help control forced oscillations without aggravating saturation instability. It should be noted that since the optimization tests in 1980 we have not experienced any core saturation instability even though the flux units were out of service for considerable time. The two events in the past year were both of the forced oscillation type.

4) A number of recommendations were previously made to the HVDC Task Force regarding the solution of resonance problems. Mainly because of the tests plus the reports prepared by System Performance (Ref.E1 &E2) these recommendations are now restated as follows:

a) The dc filter asymmetry should be set as discussed in (2) above. Also as recommended in Report Ref.E2 the rate of decay supervision on the pole asymmetry protections is no longer required.

b) Reduce the valve group asymmetry protection time delay from 500 msec to 100 msec at Radisson and Dorsey. This will greatly reduce the 60 Hz excitation time to the poles. To prevent all valve groups from blocking due to ac system faults caused by backup clearing an ac undervoltage (.85 pu) supervision scheme must be installed. This undervoltage relay will delay the asymmetry protection.

c) The spot transfer detector operated signal should be paralleled to the anode unbalance signal on the light beam unit. This will produce a spot transfer/anode unbalance alarm which when combined with the use of oscillograms will allow differentiation between G.P.G. or S.P.G. faults and operation of spot transfer detectors.

5) In spite of the fact that the tests demonstrated that the flux control units would cure core saturation instability and that Mr. Ainsworth recommended installing units to all six valve groups the following alternatives remained in question:

a) Install six flux units as per recommendation. The cost of this is very roughly estimated as $150,000 but this is not based on any recent GEC quote.

b) Have only the existing units in operation for a trial period to determine if the problems still exist and if more units are justified. The problem with this alternative is that we may never know if the units are performing a function or if they are unnecessary.

c) Same as (b) except place the units under a time delay and possibly demonstrate that instability has started and that the flux units can subsequently correct the instability.

d) Remove the existing units from operation to determine if the optimized control settings and revised protection settings have permanently cured the problem. Operation over the past year would indicate this.

The present consensus is in favour of alternative (d) and therefore this alternative is recommended for a trial period.

6) The change in protection settings in bipole-one could place bipole-two in jeopardy. Inductive coupling between poles during resonance requires a check on the bipole-two 60 Hz detectors.

a) The 60 Hz Detector 1 has a pickup of 40 kV rms for 200 msec and gives $I_d$ref = 0.3 p.u.

Since the pole coupling is about 33% this requires a BP-1 oscillation of about 120 kV rms. A BP-1 persistent group commutation failure can cause an oscillation of 318 kVrms and therefore the asymmetry time delay reduction to less than 200 msec as discussed in (4) (b) is necessary to save BP-2.

The Working Group in their TN E44 V5-F, May 14/79 (letter of April 9 1979) clarify this protection by saying that due to the 60 Hz amplifying effect on the line a higher setting than 40 kV can be adopted and still cover an inverter misfire (one pulse missing in one bridge). A figure may be 60 or 80 kV but it could be tried on the system by suppressing one firing pulse in the inverter for about 200 msec.

It is unlikely, however, that the kV setting alone could be raised high enough to prevent protection operation.

b) The 60 Hz Detector 2 has a pickup of 80 kV rms for 25 msec and gives $I_d$ref = 0. This requires a BP-1 oscillation of about 240 kV rms which may be possible even with the reduced time delays.

This protection is required for inverter pulse blocking by ac undervoltage and telecoms out of service. When the ac voltage recovers and during pulse blocking no bypass operation is achieved, a strong 60 Hz voltage would be applied to the dc line resulting in current interruption and line overvoltage.

The W.G. clarify this protection by saying that 80 kV was chosen for operation with one group and reduced ac voltage. Because of the 60 Hz amplifying effect on the line the value can be set higher, for example 120 kV, but the value can be checked by a test of blocking the inverter valves for 3 or 4 cycles with one group operation and recording the dc line voltage. The setting should be so as to pick up in the first two cycles before the current is interrupted by the 60 Hz component.

It is therefore likely that the voltage level of this protection can be raised enough to prevent BP-2 trips due to BP-1 induction. This will be investigated further and a system test done if required.

CVT/bhs

HVDC Task Force

W. J. Tishinski
J. T. Atchison
L. Ingram
A. F. Buelow
F. Jost
K. R. Ouelette
R. W. Haywood
B. Willis

Test Participants

G. Thompson
M. Rashwan
I. McKay
J. Chand
B. Kolt
J. McNichol
N. Dhaliwal

References:

E 1) System Performance Report on "Time Delay Setting for Bipole-1 Valve Group Asymmetry Protection to Minimize Core Saturation", by D. Tang, August 14, 1981.

E 2) System Performance Report on "DC Filter Asymmetry Protection and Its Setting", by D. Tang, August 14, 1981.

E 3) SPD TM 81-39, J. McNichol to C. V. Thio, June 5, 1981, "Bipole-Two 60 Hz Line Ringing Problems".

E 4) Letter to Mr. J. D. Ainswroth from C. V. Thio, May 22, 1981.

E 5) Memo Mr. B. Willis to K. R. Ouelette, April 5, 1981, "Spot Transfers, Commutation Failures, etc".

E 6) Letter from Mr. J. D. Ainsworth to C. V. Thio, March 2, 1981, re Bipole-One DC Line 60 Hz Resonance.

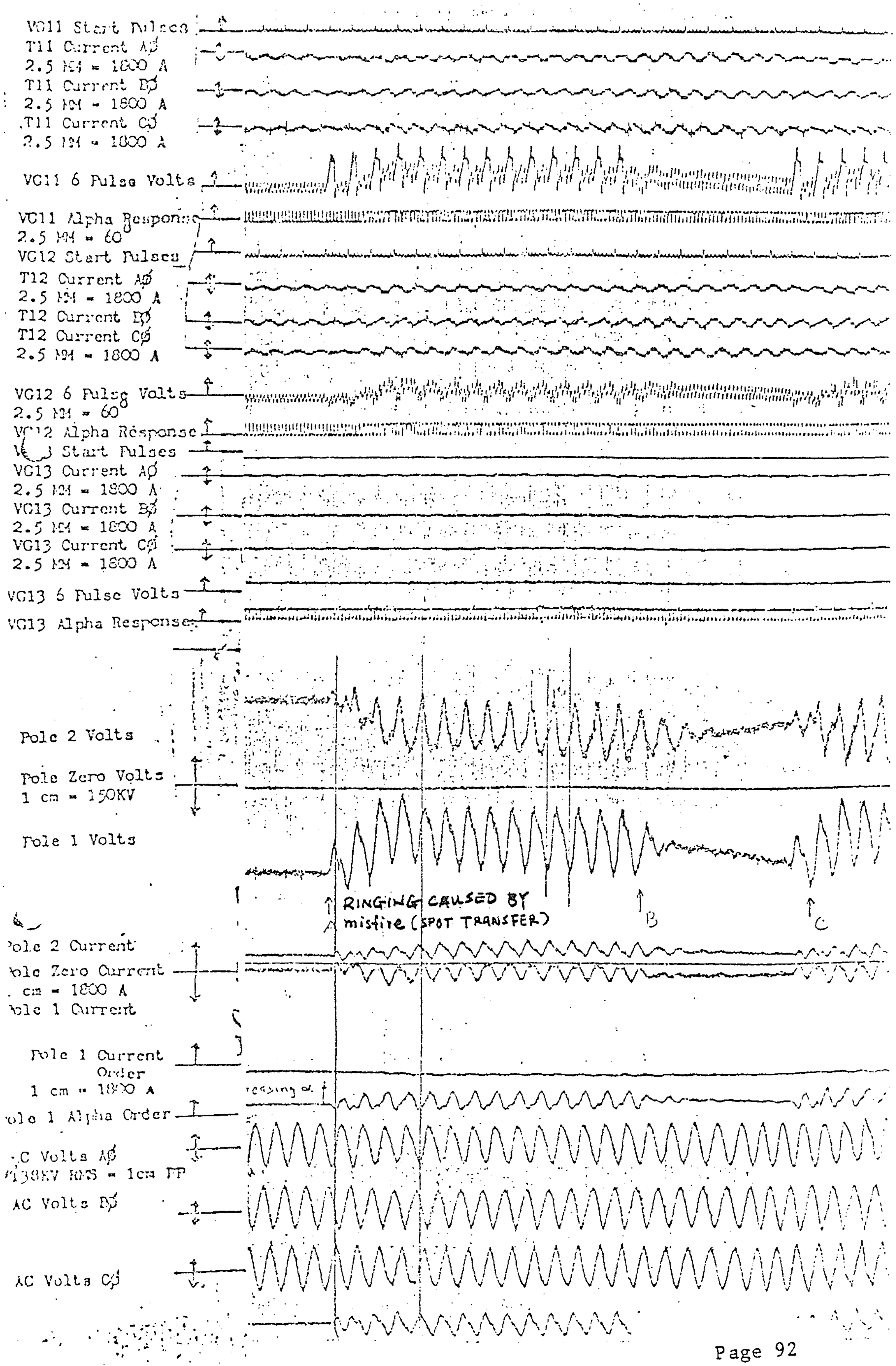
E 7) Mr. J. D. Ainsworth's report of Tests at Radisson on October 18-20, 1981 (attached).

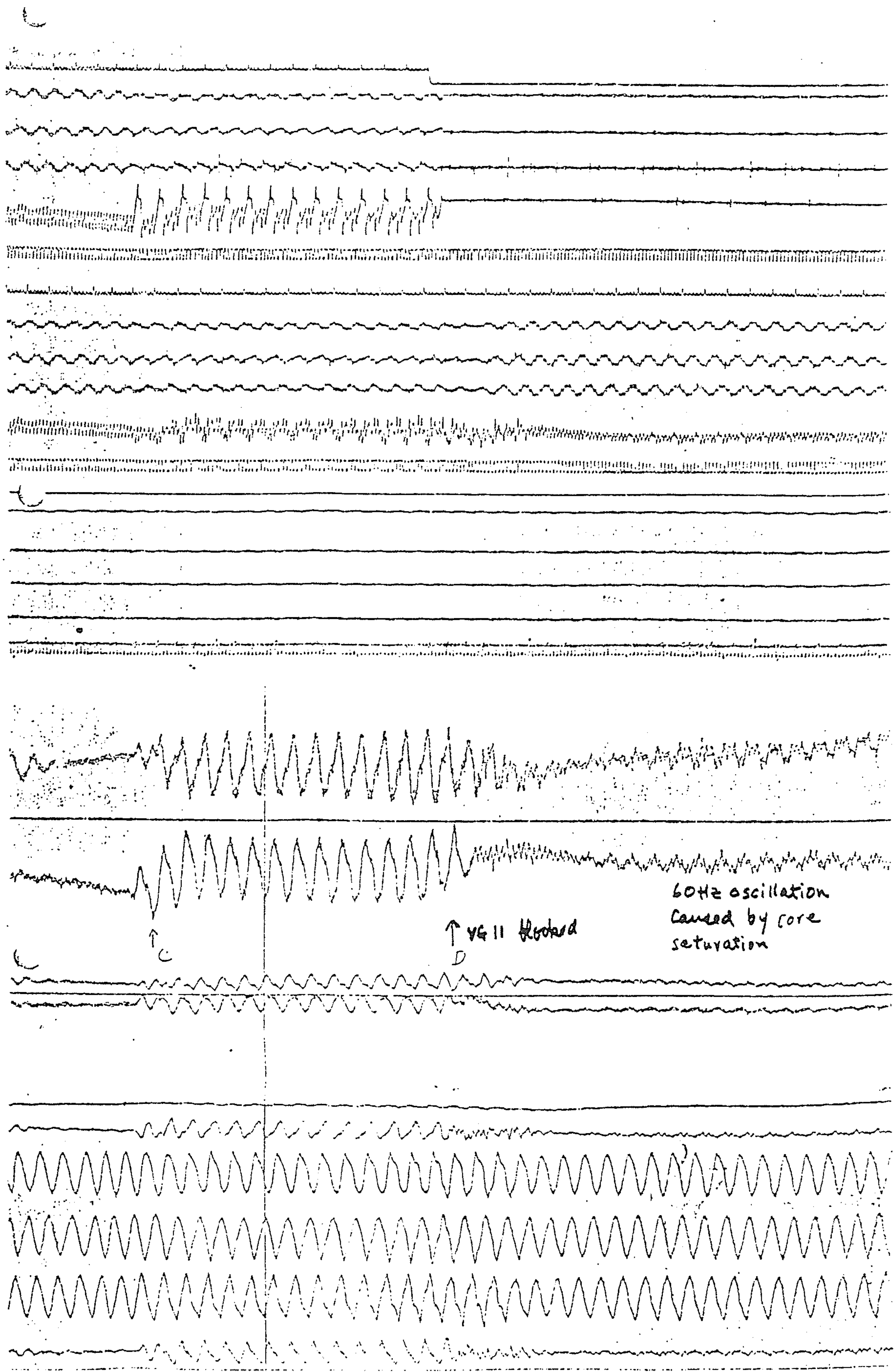
APPENDIX F

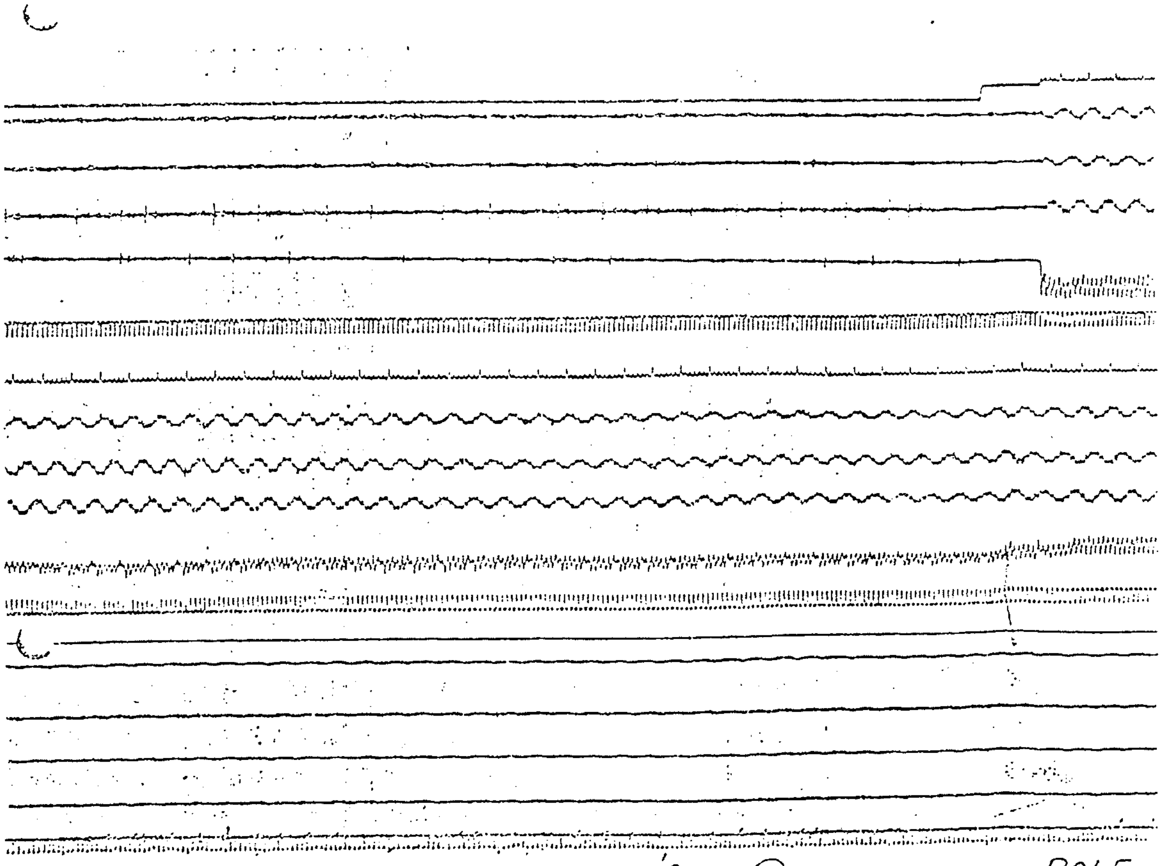
OSCILLOGRAM OF JULY 30, 1980 DISTURBANCE

POLE 1 HATHAWAY

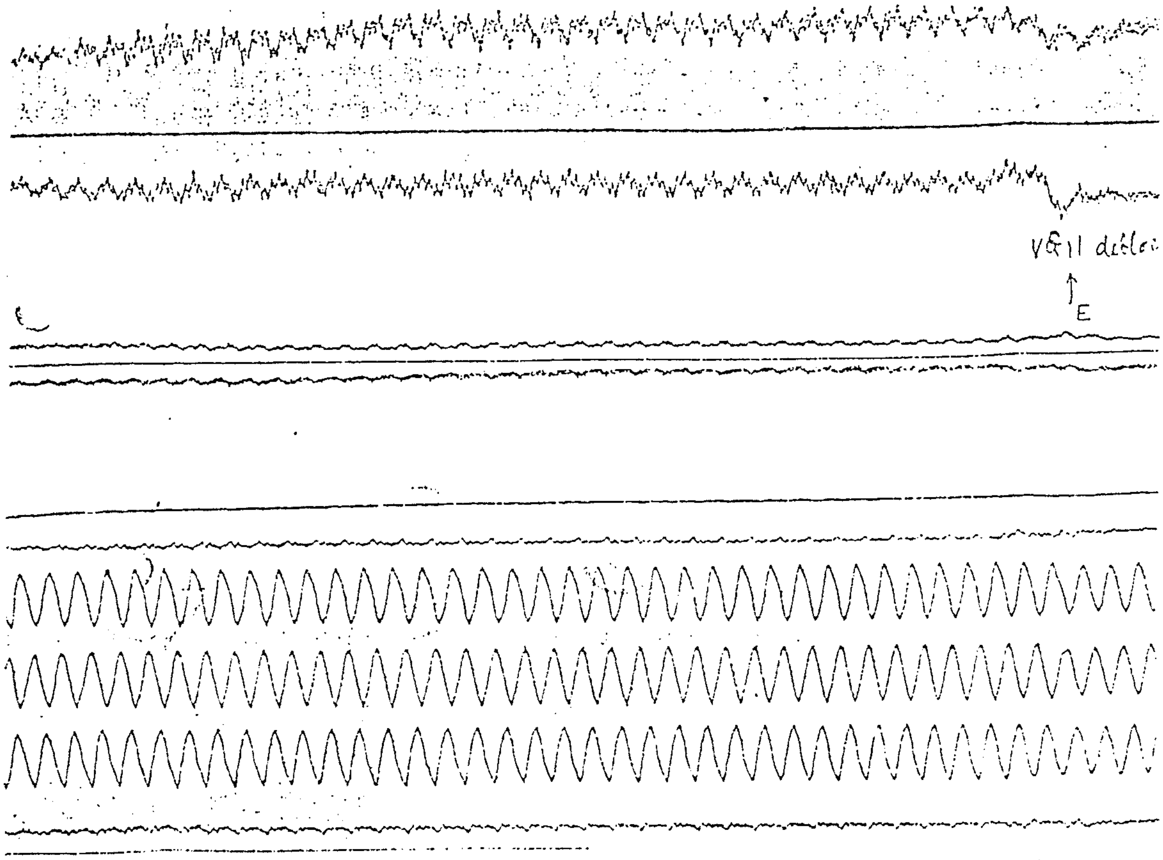
KEY

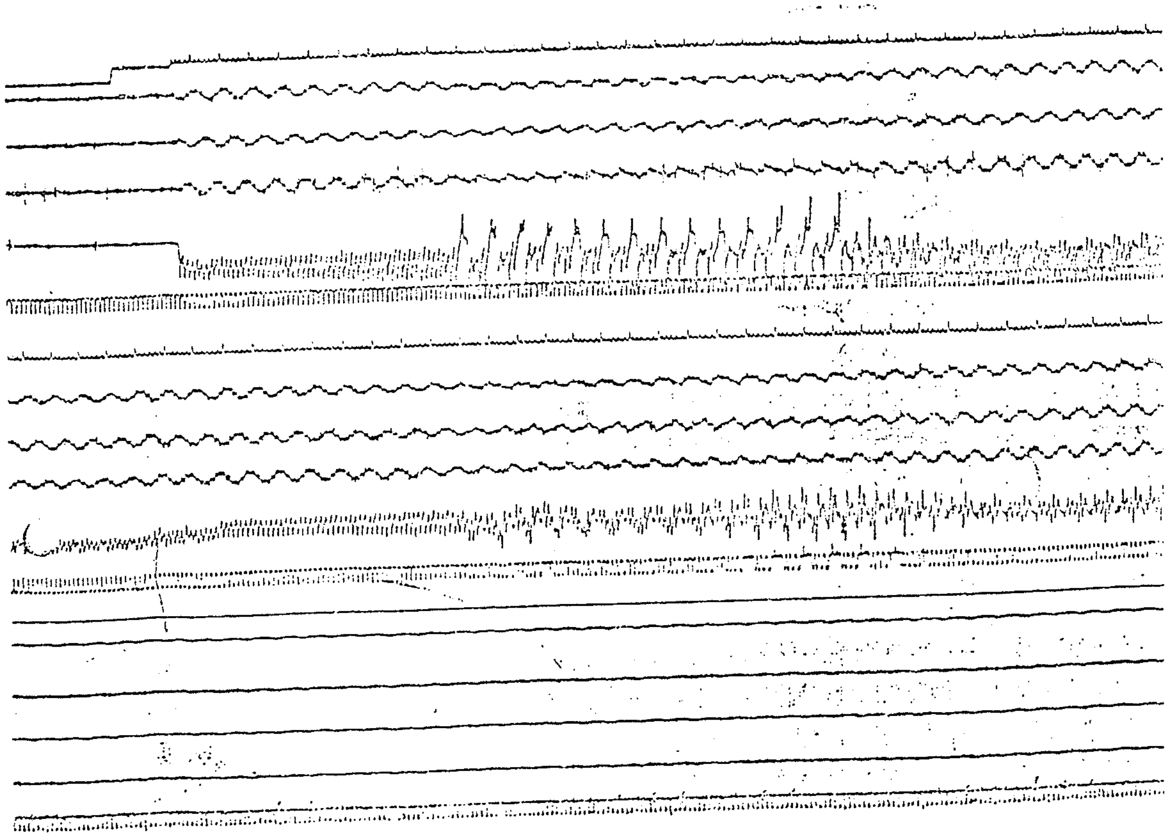



C
↑ VG 11 Blocked
D
60Hz oscillation
Caused by core
saturation

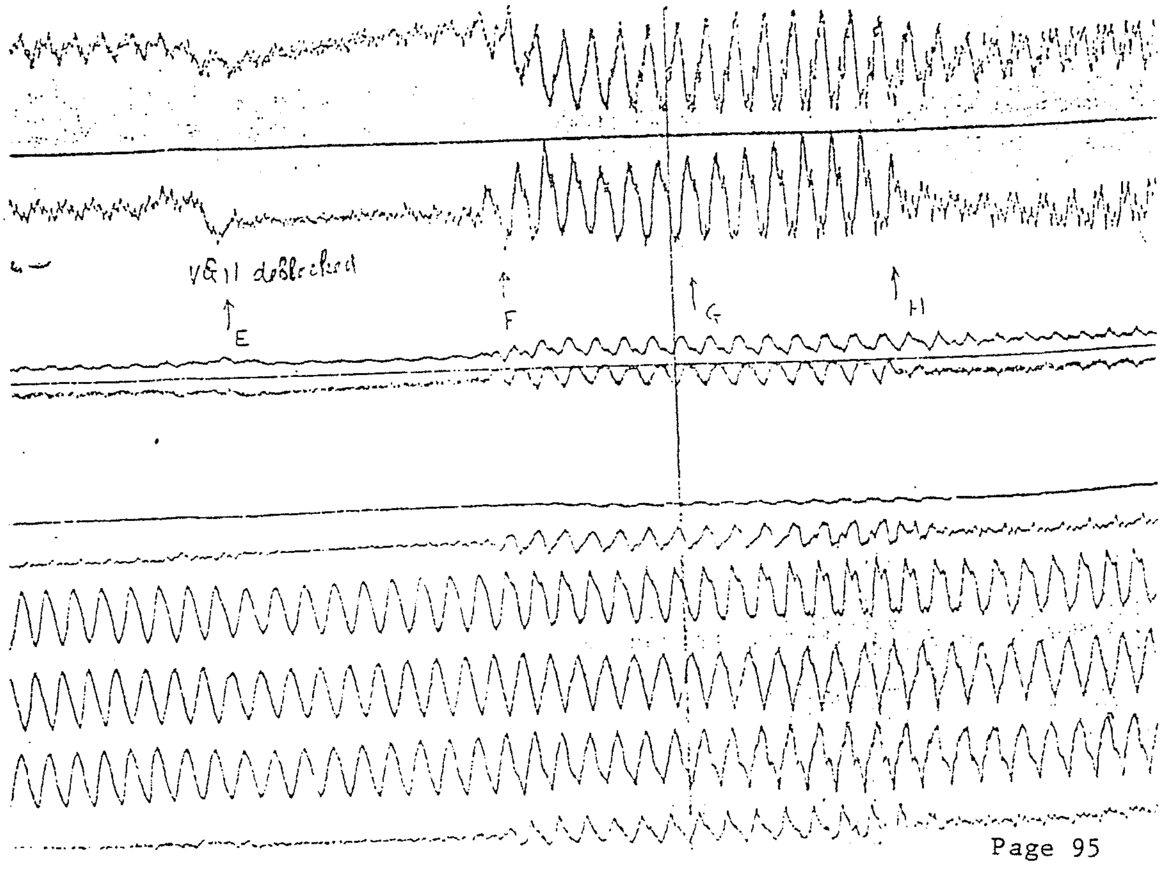


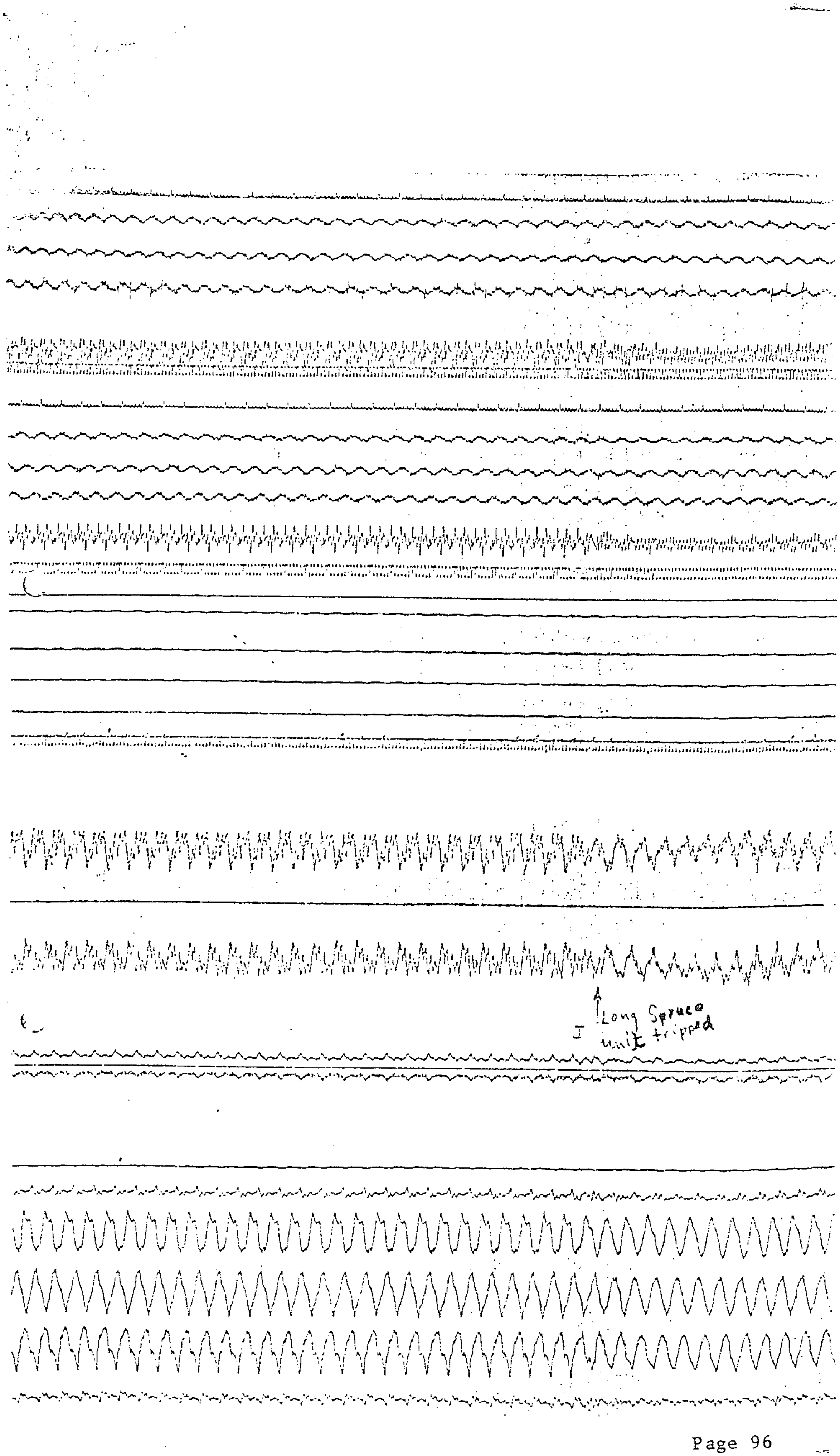
JULY 30, '80 @ 02:13 POLE

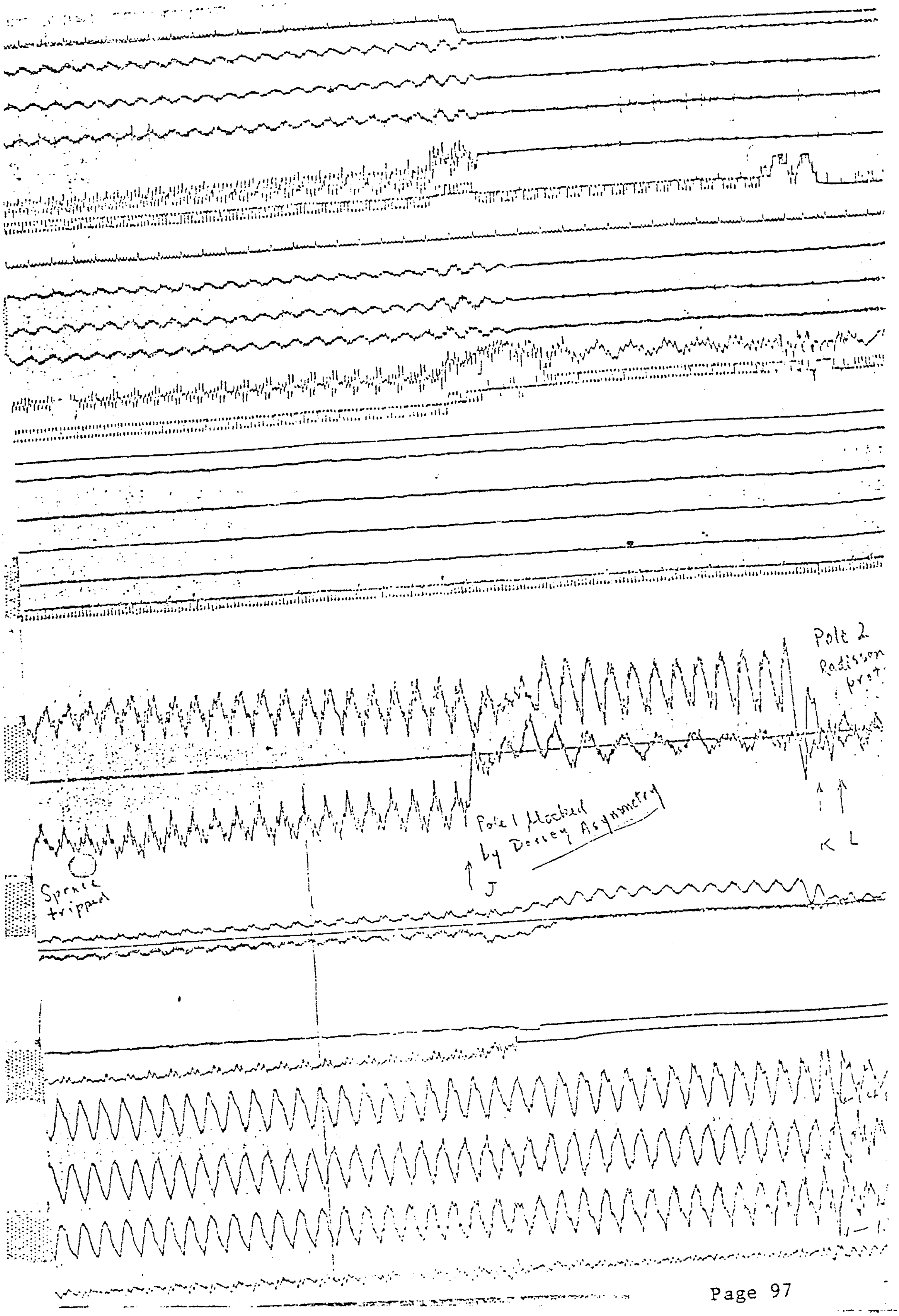




:13 POLE 1. - RADISSON



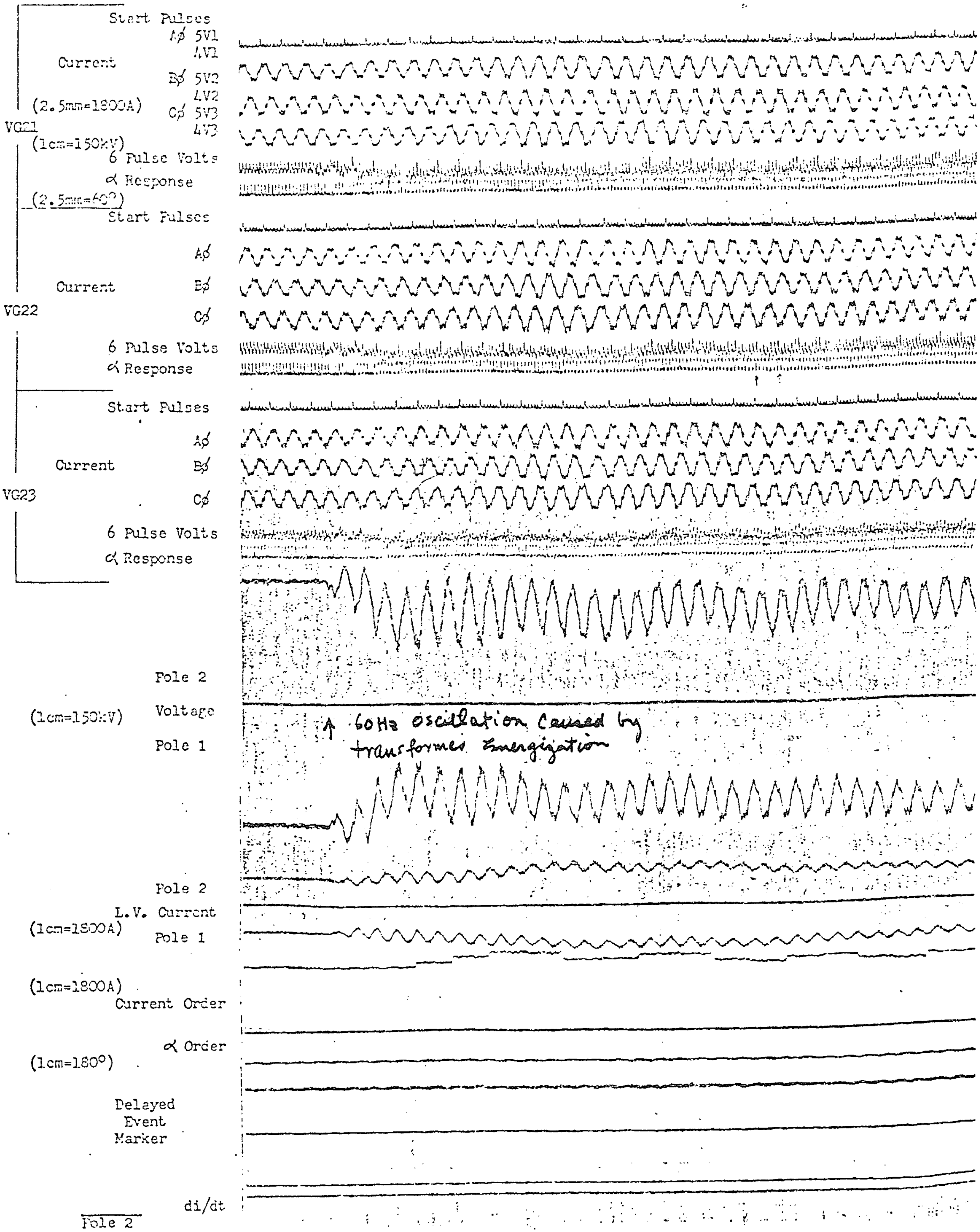

I
Long Spruce unit tripped


Pole 2
Radisson
prot
Pole 1 blocked
by Dorsey Asymmetry
Sprace
tripped
J
K
L

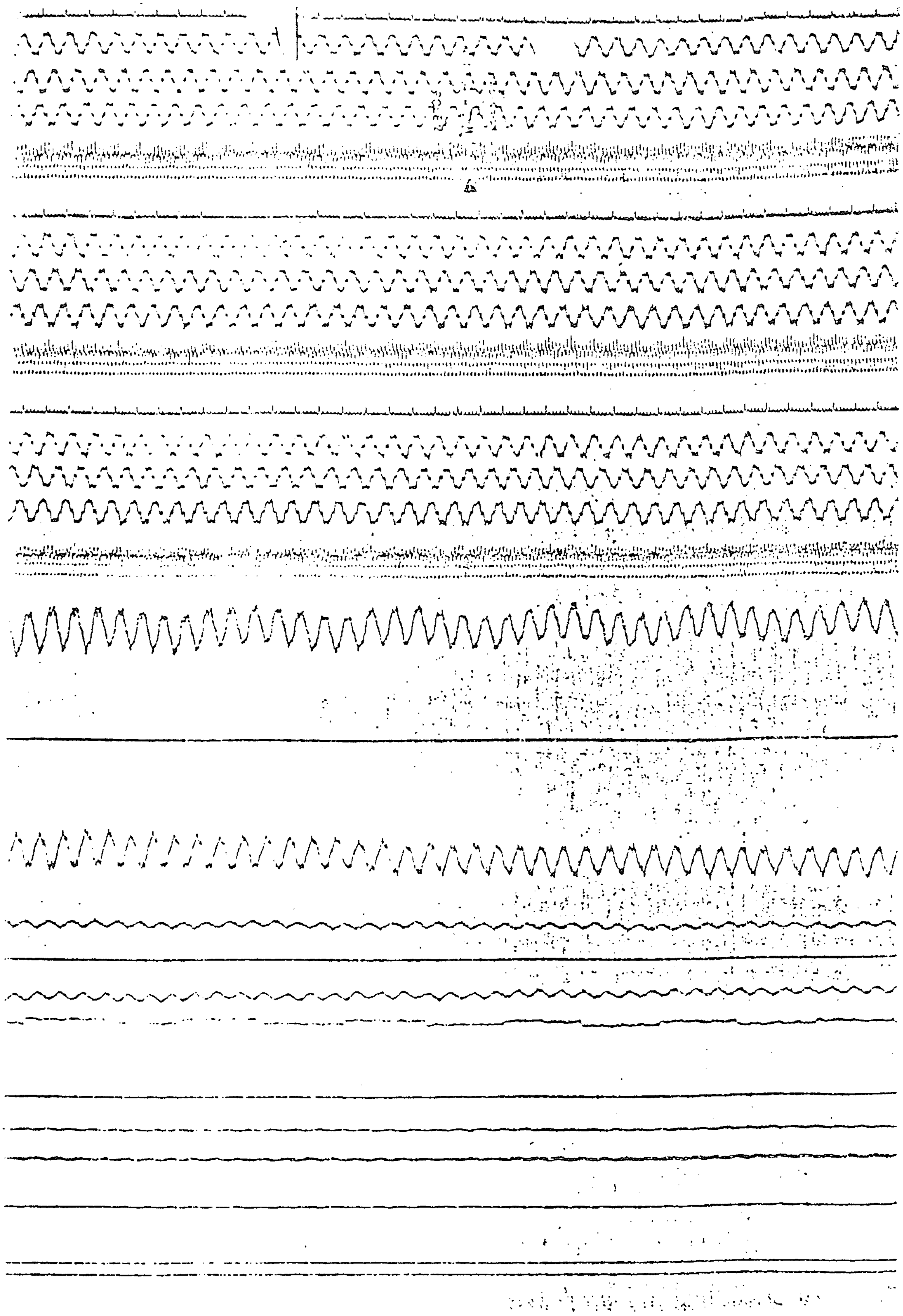
APPENDIX G

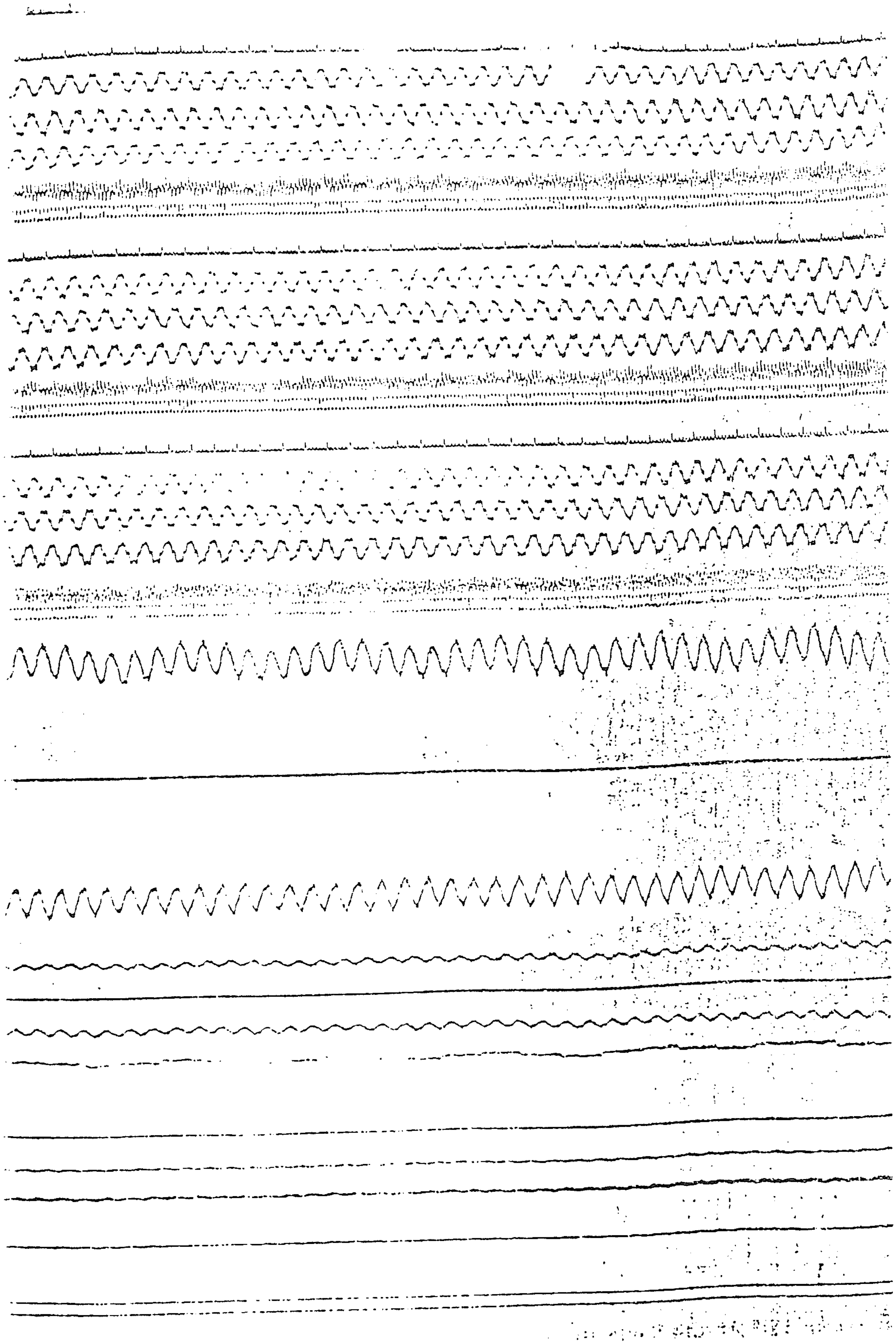
OSCILLOGRAM OF OCTOBER 27, 1979 DISTURBANCE

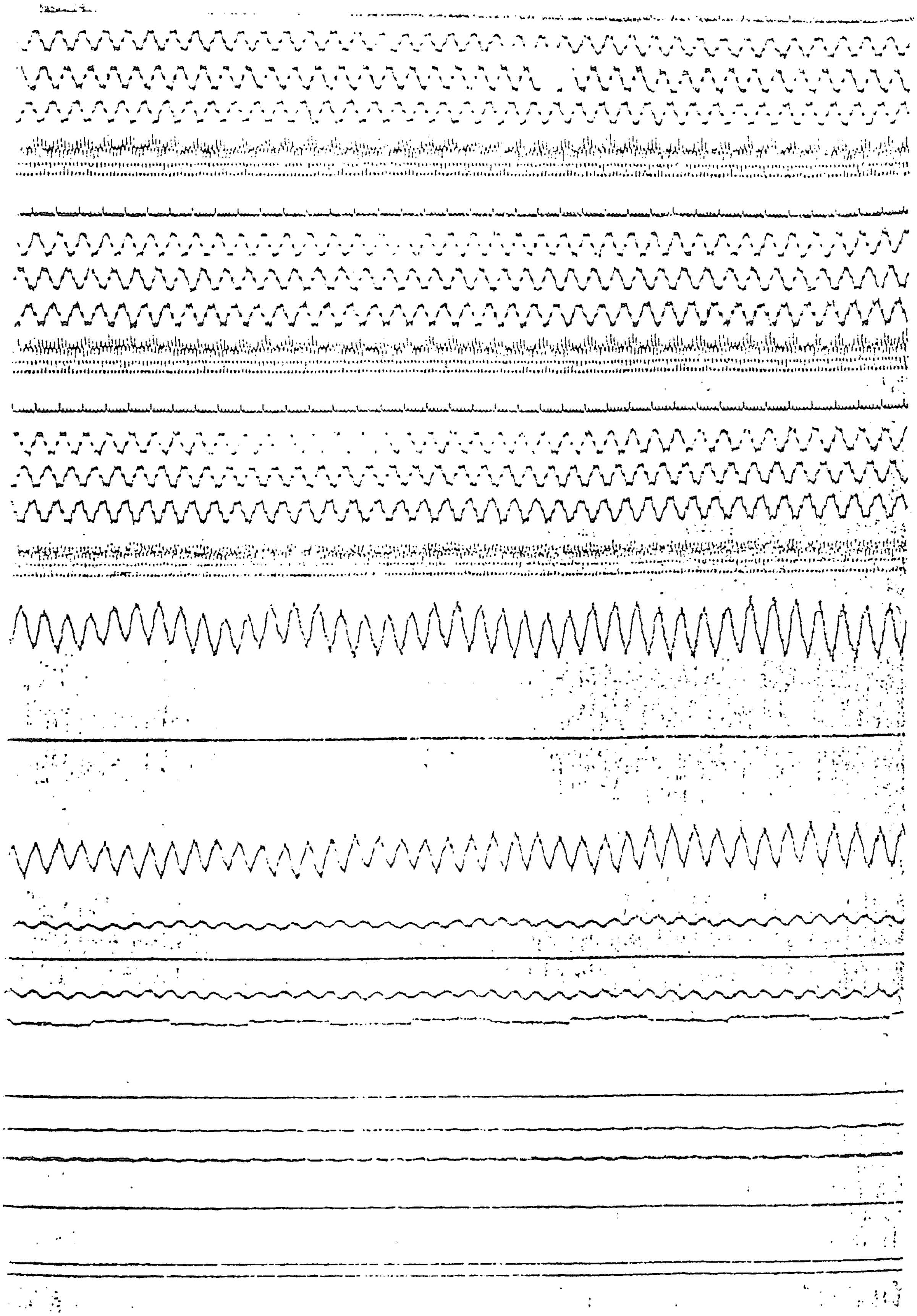
POLE 2

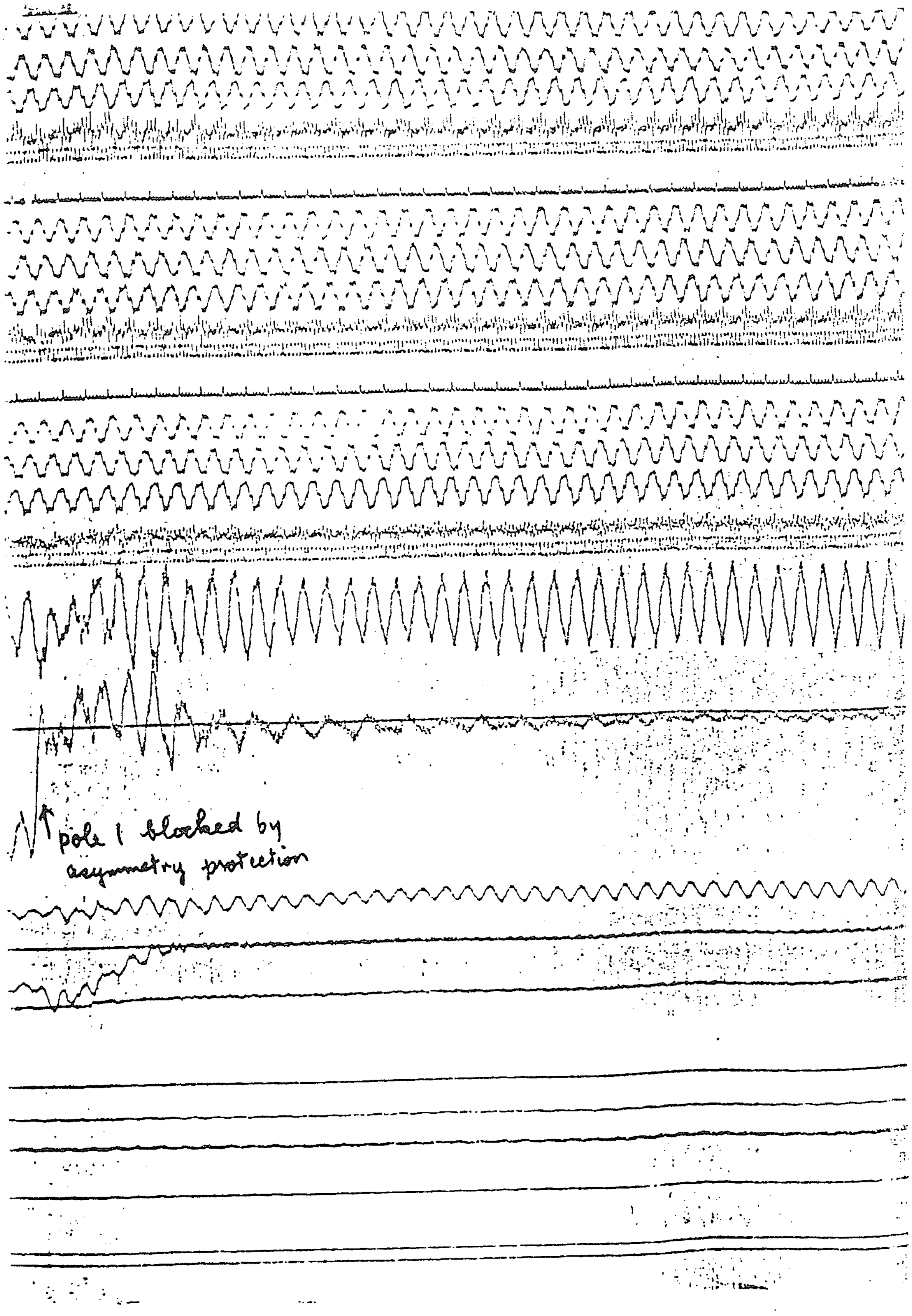


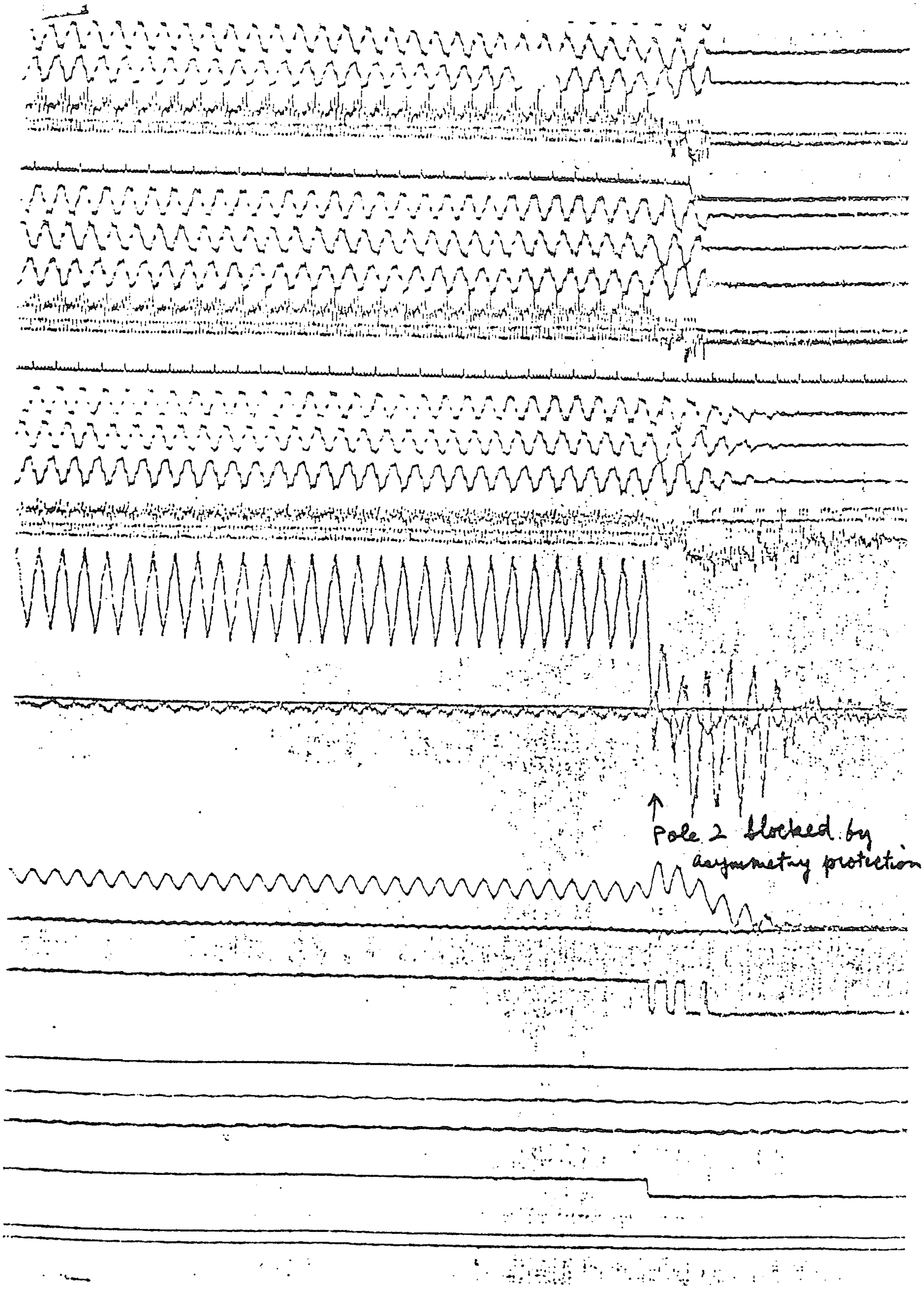
↑ 60Hz oscillation caused by transformer energization








pole 1 blocked by
asymmetry protection



Pole 2 blocked by asymmetry protection

APPENDIX H

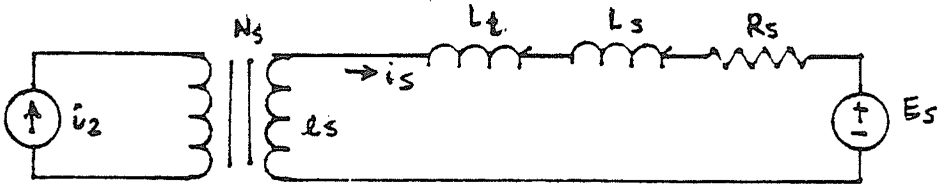
DERIVATION OF FLUX DENSITY IN THE CONVERTOR TRANSFORMER CORE DURING TRANSFORMER ENERGIZATION

Prepared by D. Tang

An example of calculation of instaneous flux in BPI convertor transformer due to uneven firing

Uneven firing as a result of fundamental frequency oscillation on the d.c. tends to produce a net d.c. current in the valve winding current The magnitude of this d.c. current isproportional to the amplitude of the oscillation. In the case of transformer energization in BPI, the 60Hz produced decays in the form of Ae^{-bt}. The d.c. current produced therefore has the same profile. The derivation of the flux in the convertor transformer core is as follows.

The equivalent circuit of the convertor transformer and the system for the injection of d.c. current from the valve side is



where R_s = a.c. system resistance
L_t = transformer leakage inductance
L_s = system inductance
e_s = convertor transformer system side voltage
i_s = system side transformer current
N_s = no. of transformer turns
E_s = voltage source(60Hz)

$e_s = i_s R_s + L_2 \frac{di_2}{dt} + E_s$ KVL around the system loop.

where $L_2 = L_s + L_T$ ------- 1

Since the flux linkage of the transformer can be written as

$\lambda_s = N_s \phi = N_s BA$ ------ 2

where ϕ = magnetic flux mutual to the primary and the secondary

B = flux density

A = cross sectional area of the transformer core

$\therefore$ From 1 we get

$N_s A \frac{dB}{dt} = i_s R_s + L_2 \frac{di_s}{dt} + E_s$ ------ 3

Since $v = \frac{d\lambda}{dt}$

The system current may be expressed in terms of valve winding current and mmf acting on the core

$N_s i_s = N_{vw} i_{vw} - hl$

substituding for h $h = \frac{B}{\mu_o \mu_r}$ where $\mu_o = 4\pi \times 10^{-7}$

we get $i_2 = i_1 - \frac{Bl}{N_s \mu_o \mu_r}$

The derivative of the secondary current is

$\frac{di_s}{dt} = \frac{di_{vw}}{dt} - \frac{dB}{dt} \frac{l}{\mu_o \mu_r N_s}$

Substituting into eqn 3

$$\therefore \quad A\frac{dB}{dt} = R_s\left[i_{VW} - \frac{Bl}{N_s \mu_o \mu_r}\right] + L_2\left[\frac{di_s}{dt} - \frac{dB}{dt}\frac{l}{N_s \mu_o \mu_r}\right] + E_s$$

$$\frac{dB}{dt} = \frac{R_s i_{VW}}{A} - \frac{B l R_s}{N_s \mu_o \mu_r A} + \frac{L_2}{A}\frac{di_s}{dt} - \frac{dB}{dt}\frac{L_2 l}{N_s \mu_o \mu_r A} + \frac{E_s}{A} \quad \cdots 4$$

If we assume a constant value for μ_r,

$$\frac{l}{N_s \mu_o \mu_s A} = \frac{1}{M_2} \quad , \text{ a constant}$$

Eqn. 4 become

$$\frac{dB}{dt} = \frac{R_s i_{VW}}{A} - \frac{B R_s}{M_2} + \frac{L_2}{A}\frac{di_{VW}}{dt} - \frac{L_2}{M_2}\frac{dB}{dt} + \frac{E_s}{A}$$

The Laplace transform of this equation is

$$B(s)\left[s + \frac{R_s}{M_2} + \frac{sL_2}{M_2}\right] = \left[\frac{R_s + sL_2}{A}\right] I_{VW}(s) + \frac{E_s(s)}{A}$$

---- 5

Assuming a exponential decay d.c. component

$$i_{VW} = I_1 e^{-t/T_1}$$

Laplace transform

$$I_{VW} = \frac{I_1}{s + \frac{1}{T_1}}$$

Simplify eqn 5 by ignoring the sinusoidal term for the moment and insert I_{VW}

$$B(s)\left[s+\frac{R_s}{L_2+M_2}\right]\frac{L_2+M_2}{M_2} = \frac{I_1 L_2}{A}\left[s+\frac{R_s}{L_2}\right]\left[\frac{1}{s+\frac{1}{T_1}}\right]$$

$$B(s) = \frac{I_1 L_2 M_2}{A(L_2+M_2)}\left[\frac{\left(s+\frac{R_s}{L_2}\right)}{\left(s+\frac{R_s}{L_2+M_2}\right)\left(s+\frac{1}{T_1}\right)}\right]$$

Let $\beta = \dfrac{R_s}{L_2+M_2} = \dfrac{1}{T_2}$

$\gamma = \dfrac{1}{T_1}$

rearranging term in time domain

$$B(t) = \frac{I_1}{A}\,M_2\left[\left(\frac{R_s}{L_2+M_2}\right)\frac{(e^{-\beta t}-e^{-\gamma t})}{(\gamma-\beta)} + \left(\frac{L_2}{L_2+M_2}\right)\frac{(\gamma e^{-\beta t}-\beta e^{-\beta t})}{(\gamma-\beta)}\right]$$

———— 6

In general

$M_2 >> L_2$
$\omega M_2 >> R_s$
$\omega = 377$

With these relationship, the second term in eqn 6 can be neglected.

$$\therefore\ B(t) = \frac{I_1}{A}\,\frac{R_s T_1 T_2}{T_2 - T_1}\left(e^{-t/T_2} - e^{-t/T_1}\right)$$