LOCAL ASSESSMENT OF TRANSIENT STABILITY FOR GENERATOR TRIPPING

by

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ABSTRACT

The local variables of a synchronous generator are investigated as possible indicators of the transient stability of the generator. A number of case studies are carried out on three test systems to find out which generator variable or variables can be used. By comparing the conventional swing curve of each generator with its local acceleration curve during the same transient period, a new criterion for transient stability assessment is developed to replace existing generator tripping schemes that rely upon pre-determined contingency studies. The new criterion is based upon the behavior of the acceleration of the generator following a disturbance to the system. No measurements from any other machine in the system are required to assess the stability of the generator.

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CHAPTER 1

INTRODUCTION

When power system engineers use the term 'stability' they mean the property which ensures that the power systems will remain in equilibrium through normal and abnormal operating conditions. As power systems grow larger and more complex, stability studies become very important. With the ever increasing demand for electrical energy and dependence on an uninterrupted supply, the associated requirement of high reliability dictates that power systems be designed to maintain stability under specific disturbances, consistent with economy.

The problem of stability arises when the system is disturbed. The nature or magnitude of the disturbance greatly affects the stability of the power system. If the disturbance is large, then the oscillatory transients that occur will also be large. The question of whether the power system will settle to a new stable operating state, or whether it will lose synchronism then becomes important. This is known as the transient stability problem.

Generators that are likely to lose synchronism under certain disturbances must be disconnected from the power system to prevent system breakup or generator damage. This needs a complete analysis of the stability problem to know which generators must be disconnected from the power system for a certain disturbance in order to maintain stability.

The conventional method used to analyze the transient stability problem is the time solution of the differential equations using a digital computer. Then, based on consideration of various large disturbances on the power system, the transient stability problem is solved (specifically) and the results can be used to design the power system switchgear and to adjust the protective relays for these specific disturbances.

The results of such transient stability studies for a power system can be stored in an on-line computer at the central control room. Suitable action can be taken automatically when any of the specified disturbances occurs. This method is very rigid because it is only valid for specific disturbances and is based upon pre-determined results. Usually the most severe cases of disturbances only are considered, so incorrect decisions may be made in some instances. Present day practice of generator tripping is based upon these contingency studies.

The conventional method used in stability studies is expensive and time consuming because a large number of differential equations must be solved for each disturbance considered. Also, the conventional protection system against instability relies heavily on pre-determined results and requires extensive high-reliability communications equipment to transmit the commands for tripping lines, generators, etc.

There have been attempts at solving the transient stability problem directly using Lyapunov functions and control theories [1,2], but the results obtained are usually too conservative.

A simple and less expensive solution is still needed. The best solution to this problem is probably to rely upon the measurements of variables available locally at each generator and to assess its transient stability based upon these local measurements. This will not require prior digital computer studies and the expensive dedicated communication equipment presently used.

There are two generator tripping schemes that do not use the conventional technique. The first one is a power swing relay installed at the northern terminal of the Ontario Hydro 500 KV transmission line [3]. The basic idea of this relay is to use measurements of the instantaneous accelerating power with the equal area criterion to estimate the power angle and to compare it with the critical clearing angle of the protected generator. A trip signal is produced if this angle is exceeded. Of course, this scheme depends on the assumption of a one-machine-infinite-bus system which may be valid only for special cases. However, the technique does look at local variables of an individual generator.

The second generation tripping scheme is that used at Coldstrip - Montana [4]. The scheme relies on speed and acceleration measurements to predict the transient stability of the protected generator. Mini-computers are used to process the measured information instantaneously and the trip signal is issued for a special configuration of the acceleration curve only. This scheme was designed for a limited protected area of the Montana system and for two generators in the system only. The scheme cannot be applied generally unless a new criterion for transient stability is developed based on the acceleration and speed measurements.

The goal of this thesis project has been to search for an alternative method to solve the transient stability problem using local measurements. A proposed approach is presented in this thesis.

Chapter 2 will review the present methods used to solve the problem of transient stability and will introduce the proposed method of local assessment of transient stability. The system models and test systems used in the proposed method will be presented in Chapter 3. Chapter 4 presents the results of a number of studies of different transient cases to investigate the various local measurements available for stability assessments. Chapter 5 summarizes the results and suggestions for future work.

CHAPTER 2

TRANSIENT STABILITY ANALYSIS

2.1 Introduction

Stability of a generator implies that it will remain in synchronism with the rest of the power system. Transient stability refers to the amount of power that can be transmitted with stability when the power system is subjected to a large disturbance such as a sudden change in load or generation, switching operations, or faults with subsequent circuit isolation. Such a large disturbance creates a power imbalance between supply and demand in the system. This imbalance actually takes place at each generator shaft. The mismatch between the mechanical power input and the electrical power output (neglecting losses) accelerates or decelerates the generator [5].

In the case of a fault on the high voltage side, at the beginning of the disturbance the generator rotors are at their pre-fault steady state operating condition. During the fault period there is excess mechanical power which is converted to kinetic energy, causing the rotors to speed up. When the fault is cleared, most of the kinetic energy produced during the fault must be absorbed or transformed into potential energy in order to maintain stability. If the system after the fault is not capable of absorbing this kinetic energy then the rotors will continue accelerating (or decelerating) until they lose synchronism. The situation during and after the fault is more complicated in the case of a large interconnected power system, because the power imbalance involves groups of generators. Some generators will accelerate and some will decelerate, at different rates depending upon their inertia constants and operating conditions, i.e., there is an energy interchange between accelerating and decelerating rotors after the fault is cleared. The exchange of energy continues until a new stable operating condition is reached. Otherwise some highly accelerated generators may pull-out and cause other generators to lose synchronism. These generators have to be tripped before they pull-out some other generators and cause the system to break up.

Loss of synchronism must be prevented or controlled, because it has a disturbing effect on voltages, frequency and power, and it may cause serious damage to generators which are the most expensive element in any power system [6]. The generators which tend to lose synchronism should be tripped and subsequenty brought back to synchronism before any serious damage occurs. While this can be done readily with gas and water turbine generators, steam turbine generators require many hours to rebuild steam so that the operator has to shed load to compensate for loss of these generators.

Loss of synchronism may also cause some protective relays to operate falsely and trip the circuit breakers of unfaulted lines.

2.2 Assessment of Transient Stability

Since interconnected power systems have been recognized and established, power engineers have worked continuously to solve the problem of transient stability. But the problem is far from being completely solved in spite of the vast amount of work done. An easily reached conclusion is that the problem is so complex when fully treated that an exact answer is almost hopeless to obtain.

In spite of the fact that the digital computer is being used, detailed stability studies are very time consuming since the problem involves many non-linear and detailed machine equations. Some of the methods that have been used in assessing transient stability will now be discussed.

2.2.1 The Conventional Method

This method relies on the digital computer to analyze the transient behavior of the interconnected synchronous machines. The synchronous machines are described by a set of differential equations. A time solution is obtained, starting with the pre-transient condition and continues until each synchronous machine can be shown to maintain or lose synchronism.

Transient stability studies are routinely conducted on a power system. The major objective of each study is to ascertain whether the existing (or planned) switchgear and network arrangements are adequate for the system to withstand a pre-scribed set of disturbances without loss of synchronism. The results of the transient stability studies are the main tool for setting the protection equipment in order to protect each synchronous machine from losing synchronism.

The numerical method of stability analysis is very reliable and has been widely used and accepted by the power industry, but there are certain situations in the day to day operation of the power system, where an operator has to decide quickly the transient stability of the machines. These situations could arise due to certain unforseen circumstances, like equipment breakdown, circuit breaker failure and multiple disturbances in the system. These situations need a quick and reliable decision. Furthermore the conventional technique consists of numerically integrating a large number of differential equations for each fault case [7]. A number of repeat simulations are thus required. Hence, in terms of computational cost using the digital computer, this method is expensive and time consuming.

2.2.2 The Equal Area Criterion

The equal area criterion is a valuable conceptual tool for the analysis of power system stability. It is particularly useful for the study of transient stability, and in visualizing the behavior of the synchronous machine during the transient. But this criterion can only be applied to a single-machine-infinite-bus system or to larger systems that have been reduced to two equivalent machines [5,6].

For each generator the following swing equation may be

$$M \frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad \text{pu} \tag{2.1}$$

where $M = \frac{2H}{\omega_r}$ = inertia constant

ω_r = rated synchronous speed

δ = generator rotor angle

P_m = mechanical power input

P_e = electrical power output

P_a = accelerating power.

Multiplying both sides of equation (2.1) by $\frac{d\delta}{dt}$ we get

$$M \frac{d^2\delta}{dt^2} \cdot \frac{d\delta}{dt} = P_a \frac{d\delta}{dt}$$

$$\frac{1}{2} M \frac{d(d\delta/dt)}{dt} = P_a \frac{d\delta}{dt}$$

Now multiplying both sides by dt and integrating

$$\left(\frac{d\delta}{dt}\right)^2 = \int_{\delta_o}^{\delta} \frac{2P_a}{M} d\delta$$

$$\frac{d\delta}{dt} = \sqrt{\int_{\delta_o}^{\delta} \frac{2P_a}{M} d\delta}$$

where δo is the rotor angle before the disturbance. Before and after the disturbance $\frac{d\delta}{dt} = 0$ since the system is in steady state.

$$\text{i.e.} \quad \int_{\delta_o}^{\delta} \frac{2P_a}{M} d\delta = 0 \tag{2.2}$$

Now consider the case of a single machine connected to an infinite bus as shown in Fig. 2.1.

Consider a three-phase fault on the transmission line CD followed by the simultaneous opening of circuit breakers C and D at steady state

$$P_e = \frac{E \cdot V}{x_1} \sin \delta_o \qquad (2.3)$$

$$= P_{max} \sin \delta_o$$

Where E = generator voltage

V = infinite bus voltage

δ_0 = steady state rotor position

X1 = reactance between E and V

Pe = electrical power delivered from the generator.

The power delivered during the fault is

$$P_e = r_1 P_{max} \sin \delta \qquad (2.4)$$

and the power after the fault is cleared is

$$P_e = r_2 P_{max} \sin \delta \qquad (2.5)$$

where the constants r_1 and r_2 represent the change in the effective inductance between the machine and the infinite-bus. The power before, during, and after the fault curves are shown in Figure 2.2.

For the machine to be stable in this case, equation (2.2) has to be satisfied, i.e., the algebraic sum of the areas A1 and A2 has to be zero, or A1 must be less than or equal to A2.

The area A1 represents the kinetic energy gained by the generator rotor during the fault, and area A2 represents the

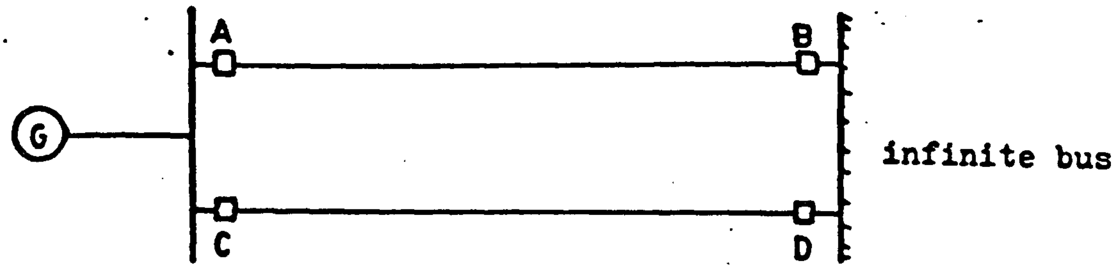
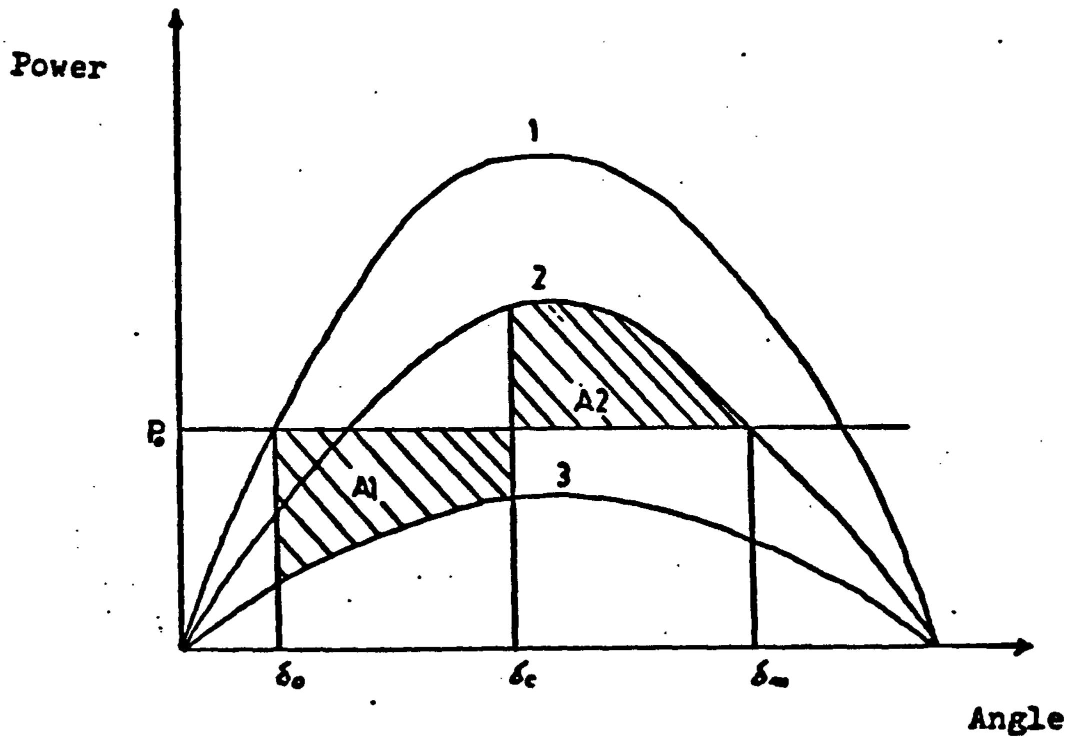


Fig 2.1 Single machine infinite-bus



curve 1 pre-fault power
curve 2 post-fault power
curve 3 during-fault power

Fig 2.2 The equal area criterion

potential energy that can be stored after the fault is cleared at δ_c. If all the kinetic energy can be converted to potential energy for a rotor angle $\delta \leq \delta max$, then the system will be stable, otherwise the extra kinetic energy will build up the rotor's acceleration increasing δ and causing instability.

This brief presentation of the equal area criterion shows that the criterion is useful and very simple to carry out for transient stabilty, given the pre-fault steady state condition.

The criterion is fundamentally incorrect because it equates the product of power and angle to energy. If the speed of the synchronous machine were constant during the transient period, the criterion would be exact, but it is used to analyze machine performance when the angle is varying. Since the angle varies, however, the speed cannot be exactly constant. The error is however very small. Even the most dynamic generators requires a second to advance 360° relative to the rest of the system [4] i.e., they are turning at an average angular velocity of 61 Hz rather than 60 Hz. The error is therefore maximum of 1 part in 60 which is small when compared to other errors introduced in the stability study. Although the criterion gives very valuable results about transient stability, it cannot be applied to the multi-machine power systems to analyze the behavior of each generator because many generators are involved in the energy interchange.

2.2.3 Energy Function Method

This method has been developed on the basis of using the energy function as a Lyapunov function to find the stability region for the power system [2,8]. Considerable effort has been devoted to Lyapunov methods for power system stability analysis in the last decade. A substantial part of the effort has involved the search for better Lyapunov functions, i.e., a Lyapunov function that either gives larger regions of stability in state space or is valid for more complex system models [9].

The transient energy function contains both kinetic and potential terms. The system kinetic energy, associated with the relative motion of machine rotors, is formally independent of the network. The system potential energy, associated with the potential energy of network elements and machine rotors, is always defined for the post fault system. The principal idea of the energy function method [10] is that transient stability can, for a given contingency, be determined directly by comparing the total system energy which is gained during the fault-on period, with a certain critical potential energy. For a two-machine system this critical energy is uniquely defined and the direct analysis is equivalent to the equal area criterion. For a system with three or more machines the direct analysis becomes more difficult, because of the fact that most of the machine rotors are involved in the energy interchange. Formulation in terms of an inertial centre, or sometimes called centre-of-angle, overcomes the problem of reference. In the inertial centre formulation, the equations describing the motion of the synchronous machines are formulated with respect to a fictitious inertial centre [11]. The importance of this formulation lies in clearly focusing on the motion that tends to separate one or more generators from the rest of the system.

Consider the classical model of the power system. The equation of motion of any machine unit in a power system is:

$$M \frac{d^2\delta_i}{dt^2} = P_i - P_{ei} \tag{2.6}$$

where $$P_{ei} = \sum_{\substack{i=1 \\ j \neq i}}^{n} E_i E_j Y_{ij} \cos(\delta_{ij} - \delta_i + \delta_j) \tag{2.7}$$

$$P_i = P_{mi} - E_i^2 G_{ii} \tag{2.8}$$

Pm_i = mechanical power input

G_{ii} = real part of the driving point admittance for the internal generator node

Y_{ij} = transfer admittance between node i and j

E_i, E_j = constant voltage behind transient reactance

δ_i = generator rotor angle

M_i = moment of inertia constant = 2Hi/Wr

W_r = rated synchronous speed.

Equations 2.3 and 2.4 were written with respect to an arbitrary synchronously rotating frame of reference.

For the inertial centre, define:

$$\delta_o = \frac{1}{M_t} \sum_{i=1}^{n} M_i \; \delta_i \qquad , \qquad M_t = \sum_{i=1}^{n} M_i \tag{2.9}$$

$$\omega_o = \frac{1}{M_t} \sum_{i=1}^{n} M_i \; \delta_i \tag{2.10}$$

then the motion of the inertial centre is given by

$$M_t \dot{\omega}_o = \sum_{i=1}^{n} P_i - P_{ei} = P_{coA} \tag{2.11}$$

where δ_O, ω_O are the position and speed of inertial centre, M_tt is the inertia constant of the inertial center. The generators' angles and speeds with respect to the inertial centre are defined by:

$$\begin{aligned} \theta_i &= \delta_i - \delta_o \\ \omega_i &= \dot{\delta}_i - \omega_o \end{aligned} \tag{2.12}$$

the equation of motion of the individual machines with respect to the inertial centre become [11].

$$M_i \ddot{\theta}_i = P_i - P_{ei} - (M_i/M_t)\, P_{coi} \tag{2.13}$$

Multiply equation (2.13) by $\dot{\theta}_i$ and form the sum then

$$\sum_{i=1}^{n} \left[M_i \ddot{\theta}_i - P_i + P_{ei} + (M_i/M_t)\, P_{coi}\right] \dot{\theta}_i \tag{2.14}$$

Integrating (2.14) with respect to time using as a lower limit t = ts, where $\theta(ts) = \theta_{is}$ is the steady state condition (pre-fault condition), we get the energy function Vi

$$V_i = \frac{1}{2} M_i \tilde{\omega}_i^2 - P_i(\theta_i - \theta_{is}) + \sum_{\substack{j=1 \\ j \neq 1}}^{n} E_i E_j Y_{ij} \int_{\theta_{is}}^{\theta} \cos(\theta_{ij} - \theta_i + \theta_j)\, d\theta_i$$

$$+ (M_i/M_t) \int_{\theta_{is}}^{\theta_i} P_{coi}\, d\theta_i \quad , \quad i = 1, 2, \ldots\ldots n \tag{2.15}$$

The energy function of equation (2.15) can be physically explained as follows:

1. The first term represents the change in kinetic energy and potential energy due to the motion of the rotor of machine i
2. The second term represents the change in potential energy due to the change in rotor position between θ_{is} and θ_i
3. The third term represents the change in potential energy due to the power flow from node i to j and from node j to i
4. The fourth term represents the change in potential energy due to the ith machine contribution to the acceleration of the centre of inertia (COI).

Equation (2.15) can be written as

$$V_i = \text{kinetic energy} + \text{potential energy}$$

$$V_i = V_{KEi} + V_{PEi} \tag{2.16}$$

the total energy function of the system is

$$V = \sum_{i=1}^{n} V_i = \sum_{i=1}^{n} (V_{KEi} + V_{PEi}) \tag{2.17}$$

for stability V_i = zero

or $\sum_{i=1}^{n} V_{KEi} = \sum_{i=1}^{n} V_{PEi}$

Total kinetic energy = total potential energy.

Analogy with Equal Area Criterion

The energy function method is similar to the equal area criterion. Both methods compare the kinetic energy with the potential energy during and after the fault. Figure 2.3 shows two plots with the same abscissa [11]. The upper plot illustrates the familiar equal area criterion in which the critical clearing angle is defined by the equality of areas A1 and A2. The lower plot illustrates the transient energy method which can be used to specify the critical angle in terms of potential and kinetic energy as shown in Figure (2.3). PE (δ_u) is the maximum value of potential energy that occurs at δ_u. It provides a measure of the energy-absorbing capacity of the system, and is called the critical energy. In the transient energy method, the excess kinetic energy, which contributes to instability during the fault-on period, is added to the potential energy at the corresponding angle coordinate. This gives the total energy at clearing. The total energy at clearing is compared with the value of critical energy. The system is stable when the total energy is less than or equal to the critical energy. The critical clearing angle is defined when the total energy at clearing just becomes equal to the critical energy.

For a system with three or more machines, the energy function method becomes more difficult to use because the critical energy cannot be defined. However, recent work [12] has been done based on the fact that for a large power system

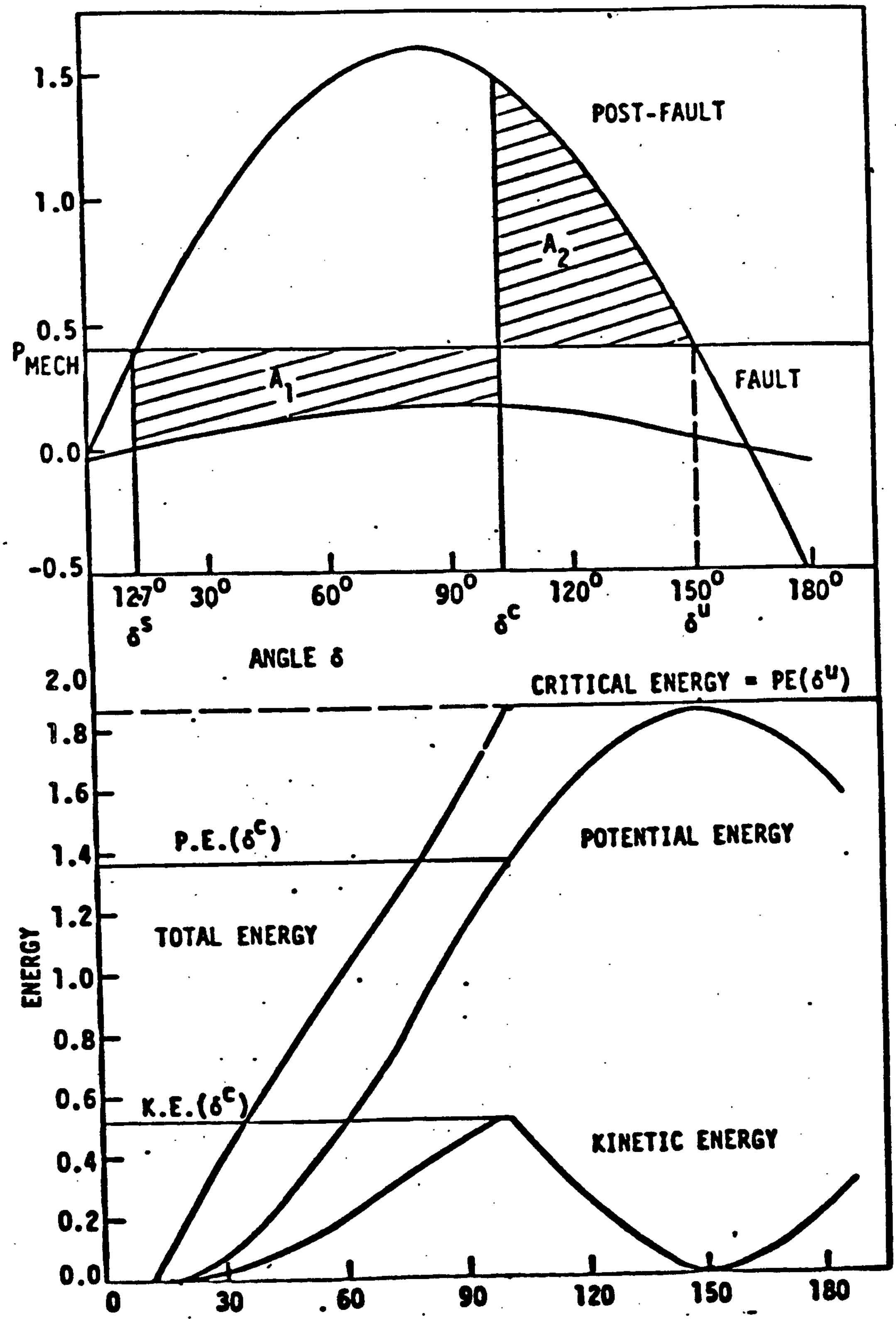


Fig 2.3 Comparison of equal area criterion and energy method

only a few machines are important for any particular fault location. The energy function method can then be applied successfully to those critical machines to assess their stability. But for many fault locations, this method cannot be applied because many machines contribute to the fault energy exchange. The energy function method can be used to assess the overall transient stability of the power systems by using the total kinetic and potential energies of all the machines, or a critical group of machines.

2.2.4 Local Assessment

Local assessment of transient stability refers to the monitoring of some important quantities of a generator locally that will help to indicate the transient stability of that generator.

Montana Power Company developed [4] a digitally controlled device for generator tripping in June 1979. The idea of this device is to predict whether the generator is stable or not and then issue a trip signal to shed the generator when it is unstable. The device relies on speed and acceleration measurements using a toothed wheel bolted to the generator's rotor and counting the number of teeth which pass in some period of time. It was possible to predict when the generator was going to be unstable and to trip it at the right time. The device has been functioning very well since it was installed and there has been no false trips. However, the criterion used to determine stability is very special to the Montana Power System because two units of the system were to be controlled to limit their output power and the system is a radial system, with the two units connected through the transmission lines to the rest of the larger western U.S. system.

There are some facts about the behavior of the synchronous machines during transient disturbances which suggest the possibility of assessing stability. First, an imbalance between mechanical input and electrical output power takes place in the airgap between rotor and stator of the machine. Second, the rotor undergoes instantaneous acceleration or deceleration on the occurrence of a fault. Third, in the case of instability, pole slipping takes place between rotor and stator locally. Therefore, there is significant information imbedded in the generator variables regarding the disturbance and the stability of the generator.

For the case of steady state stability a group of Japanese scientists were able to monitor and measure the air gap flux [13], and they designed a local automatic stability prediction device (ASPAC) [14]. This device has functioned very well.

In this thesis we will use the generator local variables to get significant information for transient stability assessment.

2.3 Stability Controls

This section is a quick survey of some methods used in the power industry to control and improve transient stability. These methods are known in the literature as supplementary controls of transient stability to distinguish them from primary and continuous controls such as the speed governer and the excitation system control [15]. Supplementary controls are applied only under certain severe conditions to maintain stability. Most turbogenerators are controlled successfully with a combination of primary and supplementary controls.

2.3.1 Dynamic Braking

Dynamic brakes are resistive elements that are switched on-line to absorb power. Generally located near generators, they are switched on in case of faults to dissipate excess rotor energy. Since the excess energy is consumed by the braking resistor, the transmission system is relieved from having to transmit the energy to the load and so it reduces the acceleration of the generator. This method has been successfully used in some power systems. However, there are some limitations to the use of dynamic brakes such as the following [15,16].

1. Picking the proper size of the resistance for several disturbance contingencies can be a problem [17].
2. The maximum size of the braking resistance is realized when the resistance is equal to the machine transient reactance.

3. The braking resistance is most needed when δ is large, and the generator is accelerating. However, under these conditions the generator's terminal voltage is low, and when the brake is applied the voltage goes even lower.

2.3.2 High Speed Circuit Breaker Reclosing

When a fault occurs a transmision line , the circuit breakers at each end of the line will open to isolate the fault from the system, remain open for a specified time, and then reclose. If the transmission line fault has been cleared, then the circuit breakers remain closed and the transmision system returns to its prefault condition. If the fault still exists, the circuit breakers will open and lockout.

The procedure of opening and final closing must take place before any generator in the system reaches its critical clearing angle. This method is used because approximatley 80% of transmission line faults are transient in nature [18]. That is, if the line is de-energized for a short time the fault arc will deionize and the integrity of the insulation system will be re-established. Typically, the fault arc can deionize in approximately 12 cycles. The advantage of this method is that it keeps generating units on-line for transient transmission line faults and it also minimizes the number of outages that the generator experiénces in its lifetime. However, it has some serious disadvantages as a consequence of unsuccessful reclosure [15,19,20] , as follows ;

1. A second major transient could be applied to the shaft before the initial oscillations have damped out, and this may damage the shaft.
2. Existence of two successive voltage dips.
3. Increased duty on circuit breakers.
4. Increased damage at fault locations.
5. Possible instability.

2.3.3 Series Capacitors

Series capacitors are used to increase the power transfer capacity [21] by compensating for the inductive reactance of the transmission lines. Series capacitors are good for improving steady state stability, but it can present some problems under transient conditions:

1. When a fault occurs, protective devices may bypass series capacitors in the faulted and nearby lines thus removing them from service.
2. Subsynchronous resonance may damage machine shafts [22].
3. Series capacitors are expensive compared to other methods of improving transient stability.

2.3.4 Fast Valve Action

Fast valve action [23] is the rapid closing of the generator's steam valves following a transient disturbance. Mechanical input to the generator is thus reduced and this will reduce the acceleration. This method can maintain transient stability in many cases, but it needs good prediction of the post-fault network in order to reopen the valves at a certain level of power, otherwise a second transient may occur and cause loss of synchronism. Also when the valves are closed the pressure and the temperature in the boiler will increase. The boiler cannot withstand this pressure and temperature increase for more than 10 minutes, so quick action is required, either reopening the valves or bypassing the pressure. Although fast valving can do nothing to prevent steady state instability, it is acceptable and used by some power companies [24]. Furthermore, studies are required and field tests may be necessary to evaluate fast valving and to determine their effect on: second swing instability, steam pressure and temperature, shaft and valve stresses, and transients in steam supply systems.

2.3.5 Independent Pole Operation of Circuit Breakers

Independent pole operation of a circuit breaker refers to the mechanism by which the three phases of the breaker are closed or opened independently of each other [25]. The failure of any one phase does not automatically prevent any of the two remaining phases from proper operation. However, for a three phase fault, the three phases are simultaneously activated for operation by the same relaying scheme. The three phases are mechanically indépendent, such that the mechanical failure of any one pole does not prevent operation of the remaining poles [15]. This method helps maintain system stability by quickly clearing or reducing the severity of multiphase faults. Independent pole operation is used at locations where the design criterion is to guard against a three phase fault coincident with breaker failure. Successful independent pole operation of a failed breaker will reduce a three phase fault to single line-to-ground fault (if one pole of the breaker is stuck), or to a double line to ground fault(if two poles of the breaker are stuck). This method can increase the critical clearing time by as much as two to five cycles [26]. Independent pole operation is easy to install; the only additional complexity is to provide a separate trip coil for each pole (most EHV breakers are equipped with separate pole mechanisms).

2.3.6 Generator Tripping

Generator tripping is a form of energy control much like fast valving or dynamic braking. If generator tripping is applied it improves both transient and steady state stability. Originally the method was confined to hydro generators and was a means of providing transient stability for remote generation. Recently generator tripping has been extended to certain thermal generation. Generator tripping can be initiated from a transfer trip scheme, arranging the breakers at the power plant or by a local trip scheme by measuring the generator quantities locally [4].

Schemes have been used where the generator load is maintained connected to the unit after tripping and the unit is rapidly reloaded after the disturbance. Generally the unit can be resynchronized to the system and full load restored in about 15-30 minutes [15].

The most common technique used to trip generators is out-of-step relaying which is basically a distance scheme. The trip signal depends on the voltage measurements at the involved locations and then the signal has to be transmitted to the generator location to trip the synchronizing breakers. This technique cannot provide total protection unless signals from every significant station are transmitted. These signals would have to be permissively controlled by the generator output and line flows. The resulting logic and communication system used would have to be as complex as the power systems to provide total protection. However, the significant information for generator tripping is already at the generator location. It is imbedded in the generator speed, acceleration and angle. These will be further discussed in Chapter 4.

CHAPTER 3

SYSTEM MODELS AND TEST SYSTEMS

3.1 Classical Model of Synchronous Machines

The induced voltage in the stator windings of a synchronous machine can be considered as having two components; a component E_1 that corresponds to the flux linking the main field winding, and a component E_2 that counteracts the armature reaction. E_2 can change instantaneously because it corresponds to currents in the armature, but E_1 cannot change instantaneously (until the exciter acts).

When a sudden change occurs in the network, the flux linkage in the affected synchronous machine will not change and hence E_1 cannot change. Currents will be produced in the armature. Hence other currents will be induced in the various rotor circuits to keep this flux linkage constant. Both the armature and rotor currents will usually have AC and DC components as required to match the ampere-turns of various coupled coils. The flux will decay according to the effective time constant. Under no-load conditions this is on the order of several seconds while under load it is on the order of one second.

From the above discussion we can see that for a period of one second the flux linkage and hence E_1 can be considered constant. Usually exciters do not respond fast enough in a period of one second or less. This period is often considered adequate for determining the transient stability of the synchronous machine. The main field winding flux is almost the same as a fictitious flux that would create EMF behind the machine direct axis reactance. This model is called the classical model of synchronous machine. It is a voltage source behind the direct transient reactance X'_d as shown in Fig 3.1.

E and δ_o can be determined from the initial conditions i.e., pretransient conditions

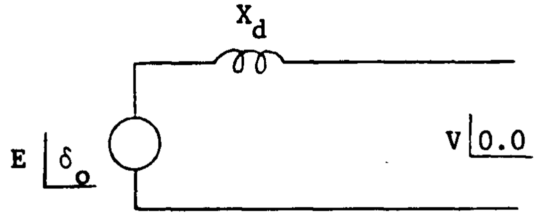


Fig 3.1

During the transient the magnitude E is considered constant while the angle δ is considered as the angle between the rotor position and the terminal voltage.

The machine output power will be affected by the change in the rotor position and any changes in the impedance seen by the machine terminals. However, until the speed changes to the point where it is sensed and corrected by the governor, the change in the output power will come from the stored energy in the rotating masses. The important parameters here are the kinetic energy in MW.S/MW usually called H, or the machine inertia constant.

3.2 System Representation

Since we are concerned about the transient stability in the first swing, it is reasonable to consider the classical model of the synchronous machine and of the power system which can be summarized in the following assumptions:

1. Constant voltage behind direct transient reactance model for the synchronous machine is valid in the period of the first swing.
2. The mechanical rotor angle (rotor position) of a machine coincides with the angle of the voltage behind the direct transient reactance.
3. Mechanical power input to each generator is constant.
4. The transmission network is modeled by steady state equations.
5. Damping or synchronizing power is negligible.
6. Loads are represented by constant passive impedances for the classical model being considered. The equations of motion for each machine in a power system are:

$$M_i \dot{\omega}_i = P_i - P_{ei} \tag{3.1}$$

Where $P_{ei} = E_i^2 G_{ii} + \sum_{\substack{i=1 \\ j \neq i}}^{n} (B_{ij} \sin(\delta_i - \delta_j) + G_{ij} \cos(\delta_i - \delta_j))$

P_{mi} = mechanical power input

G_{ii} = driving point conductance

E_i, E_j = constant voltage behind transient reactance

$\delta_{i,j}$ = generator rotor angle

B_{ij} = transfer susceptance between nodes i and j

G_{ij} = transfer conductance between nodes i and j

ω_r = speed deviation with respect to synchronous speed ω_r

M_i = inertia constant ($M_i = \frac{2H}{\omega_r}$)

3.3 The Three Test Systems

In this project a detailed investigation of individual machine speed and acceleration is carried out for three phase faults in different locations in each system. Three systems were studied: a three-generator system, a four-generator system and a five-generator system.

3.3.1 The Three Machine System

This test system is the well known nine-bus, three-machine, three-load system widely used in the literature and often referred to as the WSCC system.

The system is shown in Figure 3.2. All the impedances are in per unit on a 100-MVA base. Machines 2 and 3 are steam turbogenerators with rated speed of 3600 rev/min, while machine 1 is a hydro generator with rated speed of 180 rev/min.

The generator data and the initial operating conditions are given in Table 3.1.

3.3.2 The Four Machine System

This system is the same as the three-machine system except for the following changes:

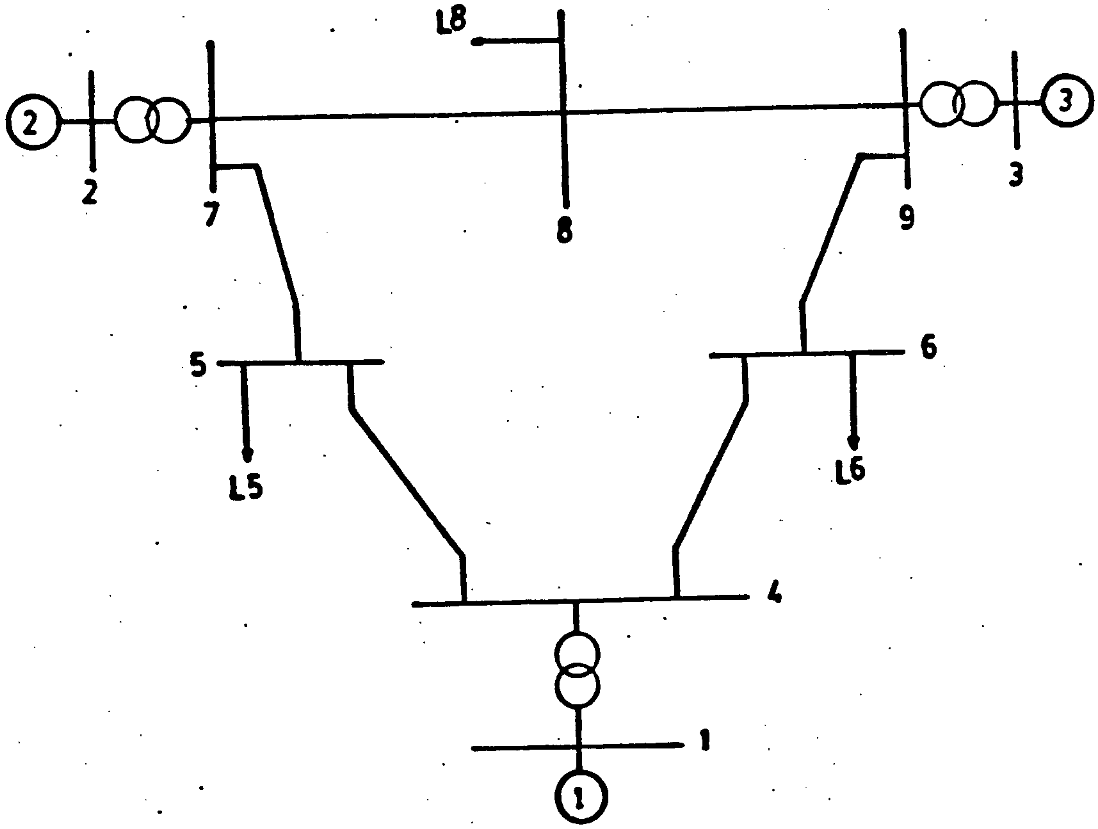


Fig. 3.2 The three-machine system

Table 3.1 Generator data and initial conditions of the three-machine system

Generator data			Initial conditions		
Gen. No.	H (MW/MVA)	X'_d (pu)	P_{mo} (pu)	E (pu)	(degree)
1	23.64	.0608	2.269	1.096	6.95
2	6.40	.1198	1.6	1.102	13.49
3	3.01	.1813	1.0	1.024	8.21

Table 3.2 Generator data and initial conditions of the four-machine system

Generator data			Initial conditions		
Gen. No.	H (MW/MVA)	X'_d (pu)	P_{mo} (pu)	E (pu)	(degree)
1	23.64	.0608	2.269	1.0967	6.95
2	6.4	.1198	1.6	1.102	13.49
3	3.01	.1813	1.0	1.1125	8.21
4	6.4	.1198	1.6	1.074	24.9

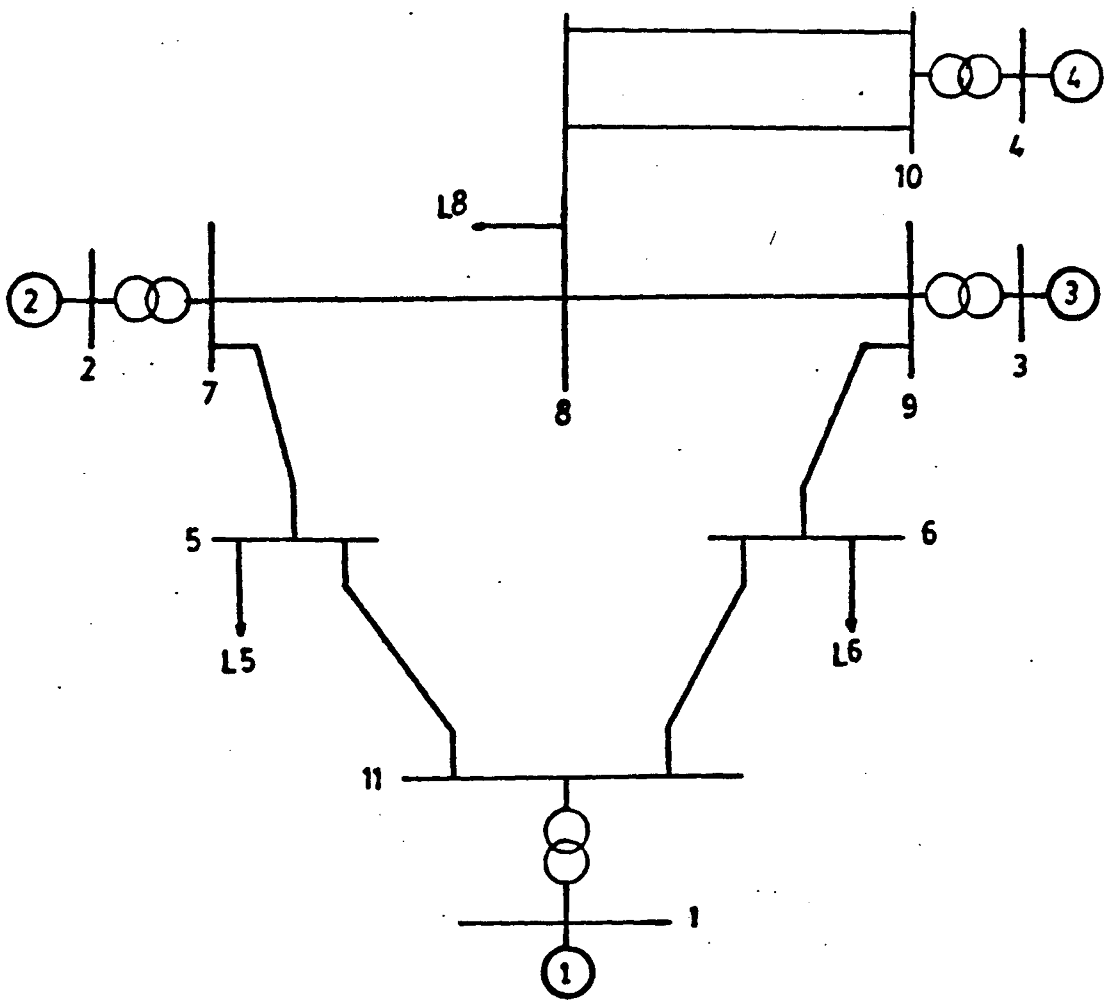


Fig 3.3 The four-machine system

- The rating of the transmission network was changed from 230 KV to 161 KV; the R and X values of the lines in pu remain the same.
- A fourth generator was connected to the original network through a step-up transformer and a double circuit transmission line (161 KV) to bus 8. The new generator has the same rating as generator 2. The system is shown in Figure 3.3 and the initial operating conditions are given in Table 3.2.

3.3.3 The Five-Machine System

This system is shown in Figure 3.4. The transmission lines and load data are given in Table 3.3. The data are given in per unit on the 10,000 MVA and 500 KV bases. The machine initial conditions and parameters are given in Table 3.4.

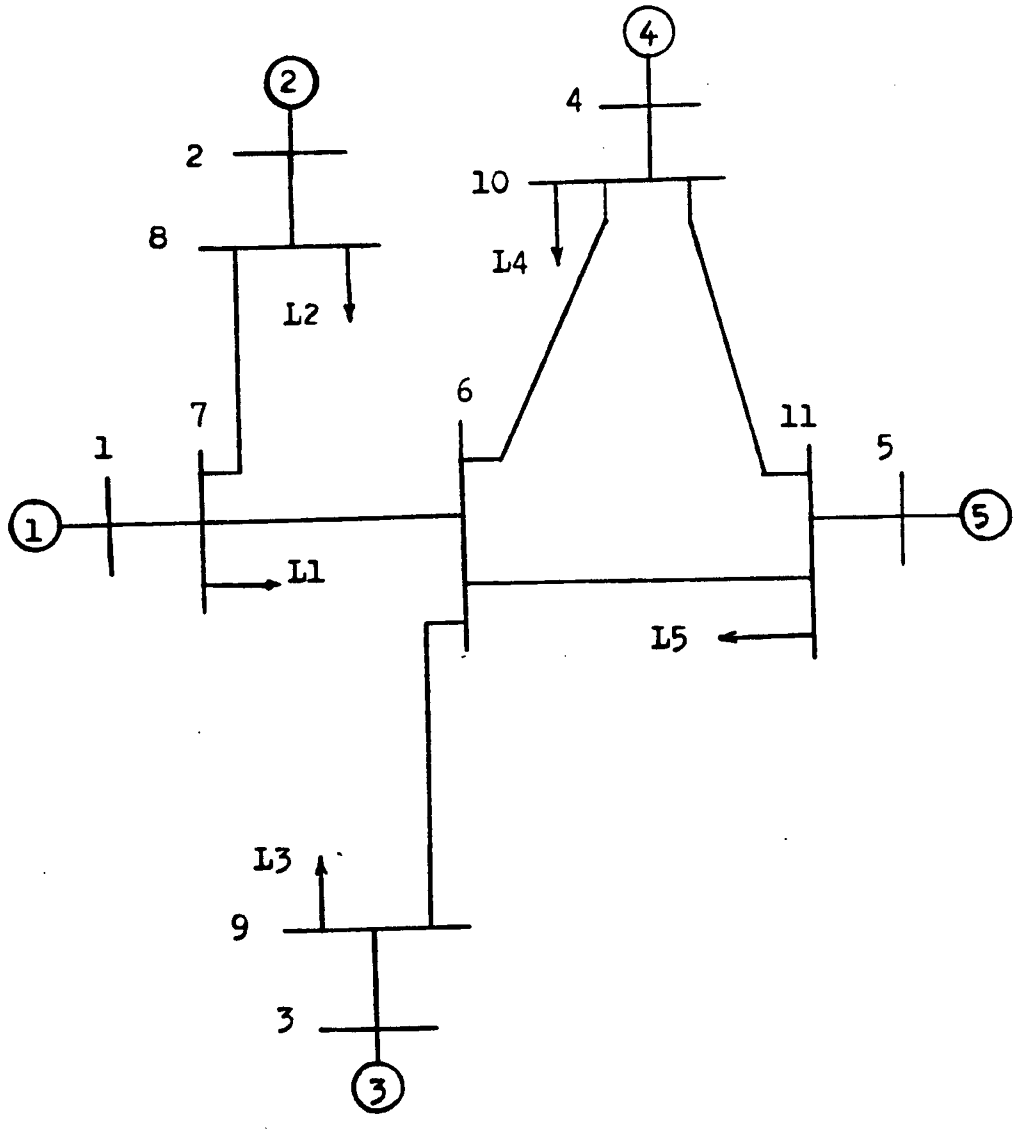


Fig 3. 4 The five-machine system

Table 3.3 Transmission line parameters and loads of the five-machine test system.

Transmission line (impedances)			Load (Admittance) pu		
Line	R(pu)	X(pu)	Load No	G(pu)	B (pu)
7-8	.12	2.397	L1	.0098	-.0049
7-6	.03	.597	L2	.0192	-.0092
9-6	.032	.639	L3	1.088	-.5271
10-11	.15	2.996	L4	.6598	-.3195
10-6	.186	3.71	L5	1.269	-.6144
11-6	.24	4.79			

Table 3.3 Generator data and initial conditions of the five-machine system.

Generator data			Initial conditions		
Gen No.	M (pu)	X'_d (pu)	P_{mo} (pu)	E (pu)	(degree)
1	.46	3.2	.0498	.981	37.6
2	1.1	1.6	.069	1.032	41.24
3	7.41	.25	1.138	1.171	40.9
4	.28	.799	.6998	1.397	37.6
5	.32	.89	1.269	2.08	31.8

CHAPTER 4

STUDIES OF GENERATOR VARIABLES AVAILABLE FOR LOCAL STABILITY ASSESSMENT

In this chapter we will discuss the studies carried out to investigate the suitability of available machine variables for assessing transient stability.

The angle swing curves will be used to distinguish between stable and unstable cases, then a comparison will be made with local variable curves to assess the transient stability. The local variables that will be investigated are angle, speed, acceleration and rate of change of acceleration.

4.1 Accelerating Power

Accelerating power is the difference between the mechanical power input and the electrical power output during the transient period.

Recalling the swing equation

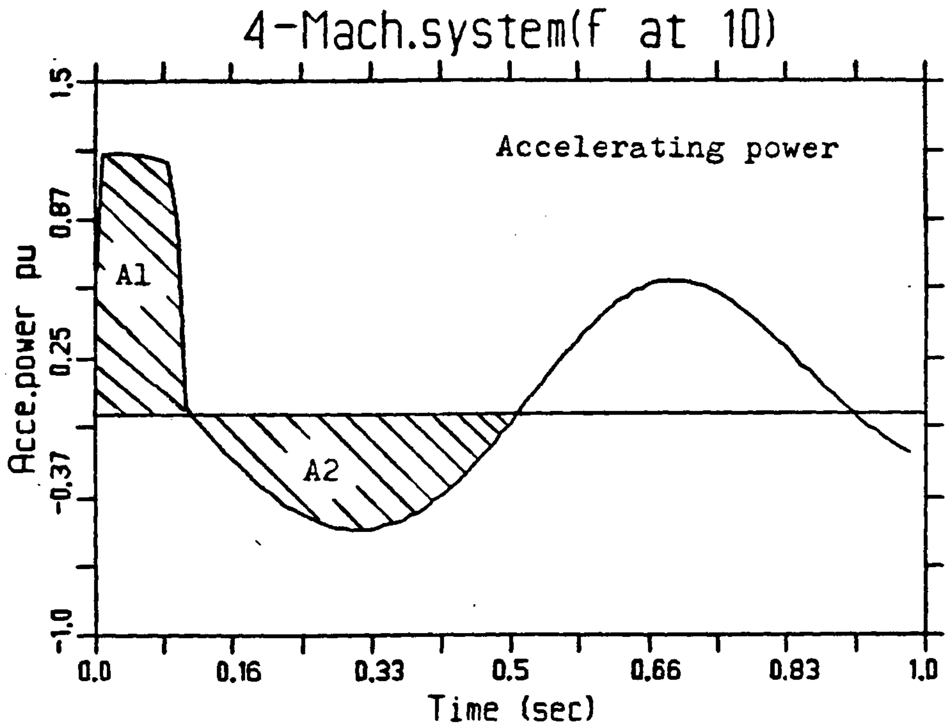
$$M \frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad \text{pu}$$

Where M is the inertia constant, δ is the rotor angle, P_m is the mechanical power input, P_e is the electrical power output and P_a is the accelerating power. P_a is one of the most important quantities at the generator terminal during transients. Because the value of P_a can give a valuable indication of the severity of the fault and the stability condition of the generator.

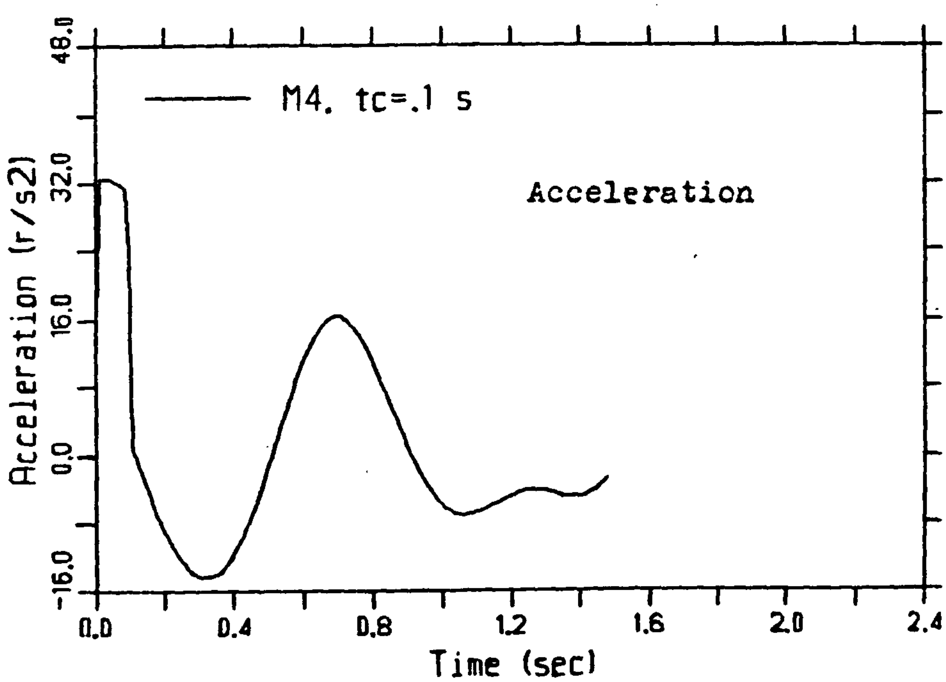
Since M is approximately constant for any generator undergoing small speed deviations, therefore the accelerating power is directly proportional to the acceleration. Practically both accelerating power and acceleration can be measured locally at the generator site [3,4]. Also both accelerating power and acceleration have the same waveshape, the only difference between them is the manner of measurement, where acceleration can be measured mechanically [4] and the accelerating power can be measured electrically [3].

Figure 4.1 shows both accelerating power and acceleration for a three-phase fault at bus 10 of the four-machine system (see Chapter 3) cleared at .1 second, for machine 4. The accelerating power curve of Fig 4.1 can represent the kinetic and potential energy, where the area under the curve before clearing represents the power gained during the fault which accelerates the machine rotor. The negative area under the curve after clearing represents the power absorbed by the system after fault clearing. Machine 4 is the only machine in the four-machine system that may lose synchronism for a fault at bus-10. It can be considered as a single-machine-infinite-bus system, or the critical machine [11] for a fault at bus-10. Therefore the area A_1 and A_2 under the accelerating power of Fig 4.1 can be compared to find the stability of machine 4 (for machine 4 to be stable A_1 must be less than or equal to A_2).

If we move the fault from bus-10 to bus-8 then it is very hard to apply the equal area criterion, because machine 4 is not



(a)



(b)

Fig 4.1 (a) accelerating pwer , (b) acceleration , of machine 4 for a fault at bus 10 cleared at .1s the only machine that may lose synchronism. In this case machine 3 and machine 2 may also lose synchronism. The equal area criterion can be applied to the whole system to find global system stability but it cannot be applied to a single machine in an interconnected system. Therefore we need to know which machine loses synchronism first and which machine we should trip first to maintain system stability if possible. These questions cannot be answered when using a global stability criterion. The answer is to search for another criterion based upon analyzing and tracking each machine variable individually.

4.2 Speed and Acceleration

It has been found [10] that all of the fault kinetic energy contributing to instability is imbedded in the unstable machine. Critical machines are easy to define [10] for a certain fault in any power system, then transient stability can be predicted for those critical machines by using the two-machine equivalent technique [12]. Recalling equation (2.15) for energy function of an individual machine

$$V_i = \frac{1}{2} M_i \tilde{\omega}_i^2 - P_i(\theta_i - \theta_{is}) + \sum_{\substack{j=1 \\ j \neq i}}^{n} E_i E_j Y_{ij} \int_{\theta_{is}}^{\theta} \cos(\theta_{ij} - \theta_i + \theta_j) d\theta_i$$

$$+ (M_i/M_t) \int_{\theta_{is}}^{\theta_i} P_{coi} \, d\theta_i \qquad (2.15)$$

For the critical machine of a certain fault the first term of equation (2.15) is the most effective [10] term when calculating the individual machine energy V_i. This shows the importance of speed deviation in transient stability of the critical machine during and after a fault. The first term in equation (2.15) during the fault period represents the kinetic energy injected to the system and after the fault is cleared it represents the potential energy being absorbed by the system. Tracking the speed curves for different fault locations shows a slow response to the fault applied. Fig 4.2 shows speed deviations for machine 4 for different fault locations.

The acceleration signal can be picked up from the speed signal [4] instantaneously in a very short period of time. The acceleration of the critical machine for a certain fault shows an instantaneous response for any fault and for any mismatch that takes place in the system, Fig 4.3 shows the acceleration and the swing curve of machine-4 for a fault at bus-10, the rapid response of the acceleration occurs much earlier than the first peak of the first swing.

4.3 Acceleration Stability "Limits"

When plotting acceleration versus time for different fault locations it is noticed that the first peak of the acceleration curves is different from one location to another depending on fault severity, i.e., the most severe fault results in a maximum first peak of acceleration. Fig 4.4 shows the acceleration for different fault locations for machine 4. When the first peak of the acceleration exceeds a certain maximum limit it is found that the machine loses synchronism right away.

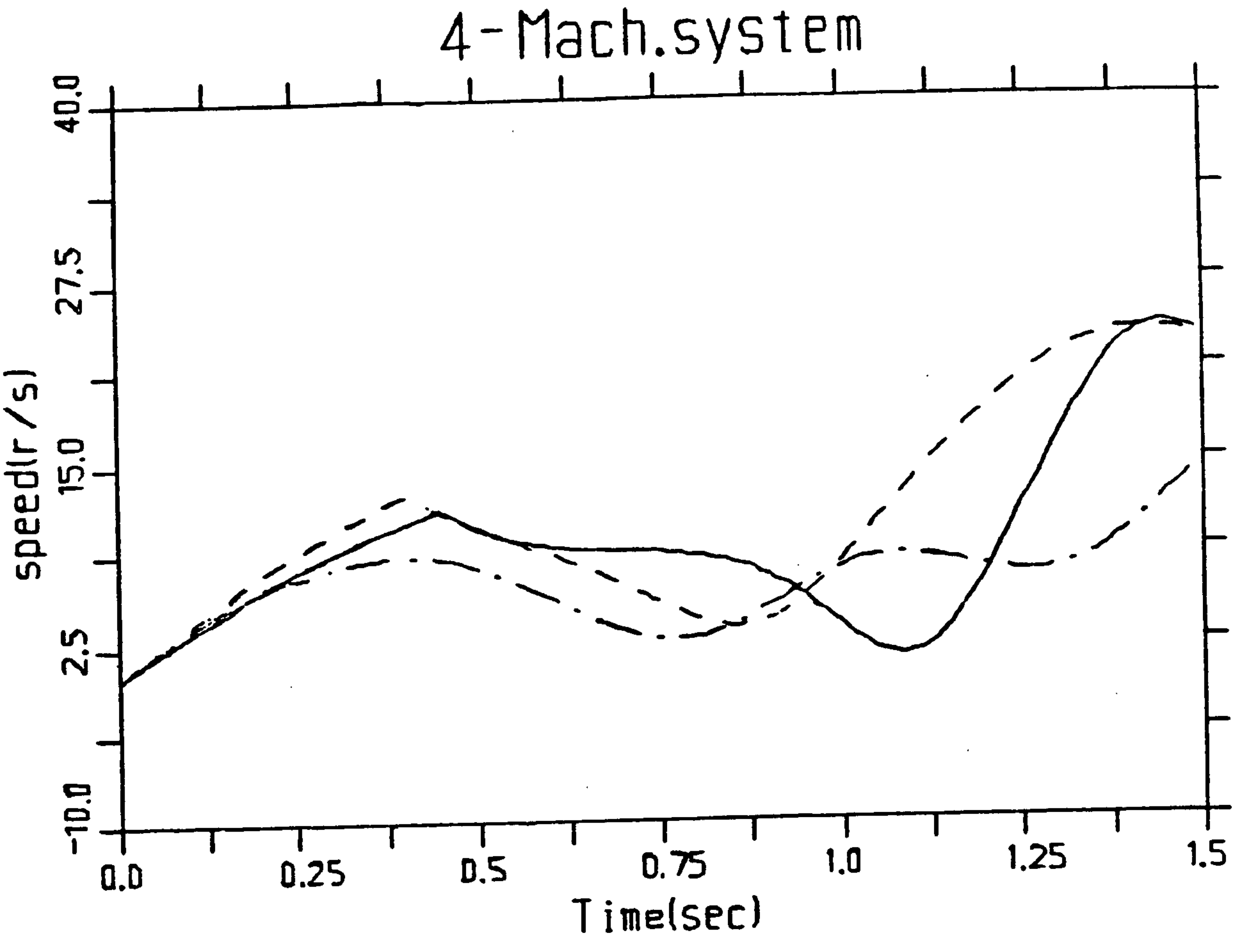


Fig 4.2

Fig 4.2 speed deviation of machine 4 for different fault locations.

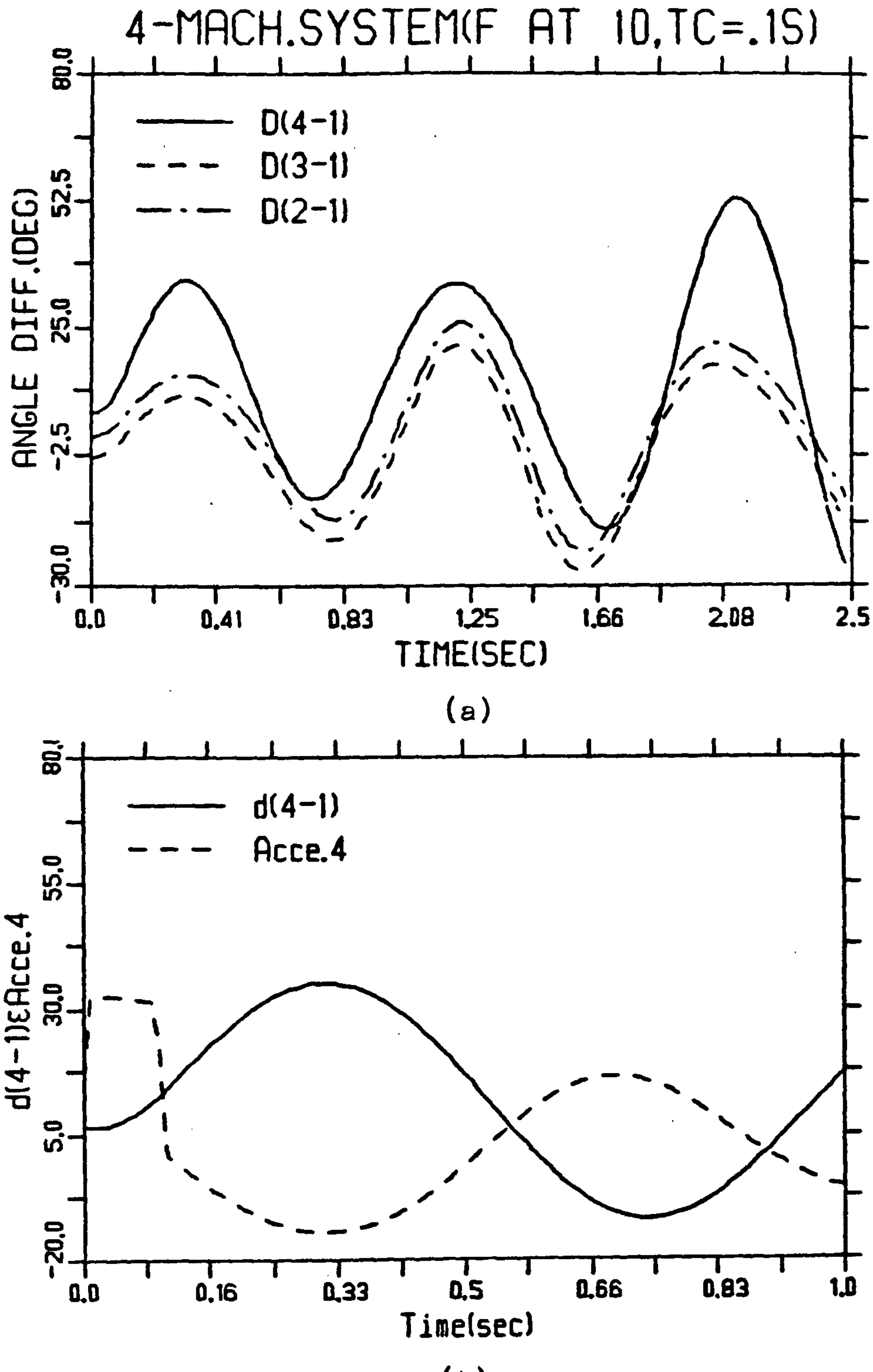


Fig 4.3 (a) swing curve of machines 4,3 and 2 ,

(b) swing curve and acceleratian of machine 4.

For afault at bus 10 cleared at .1s.

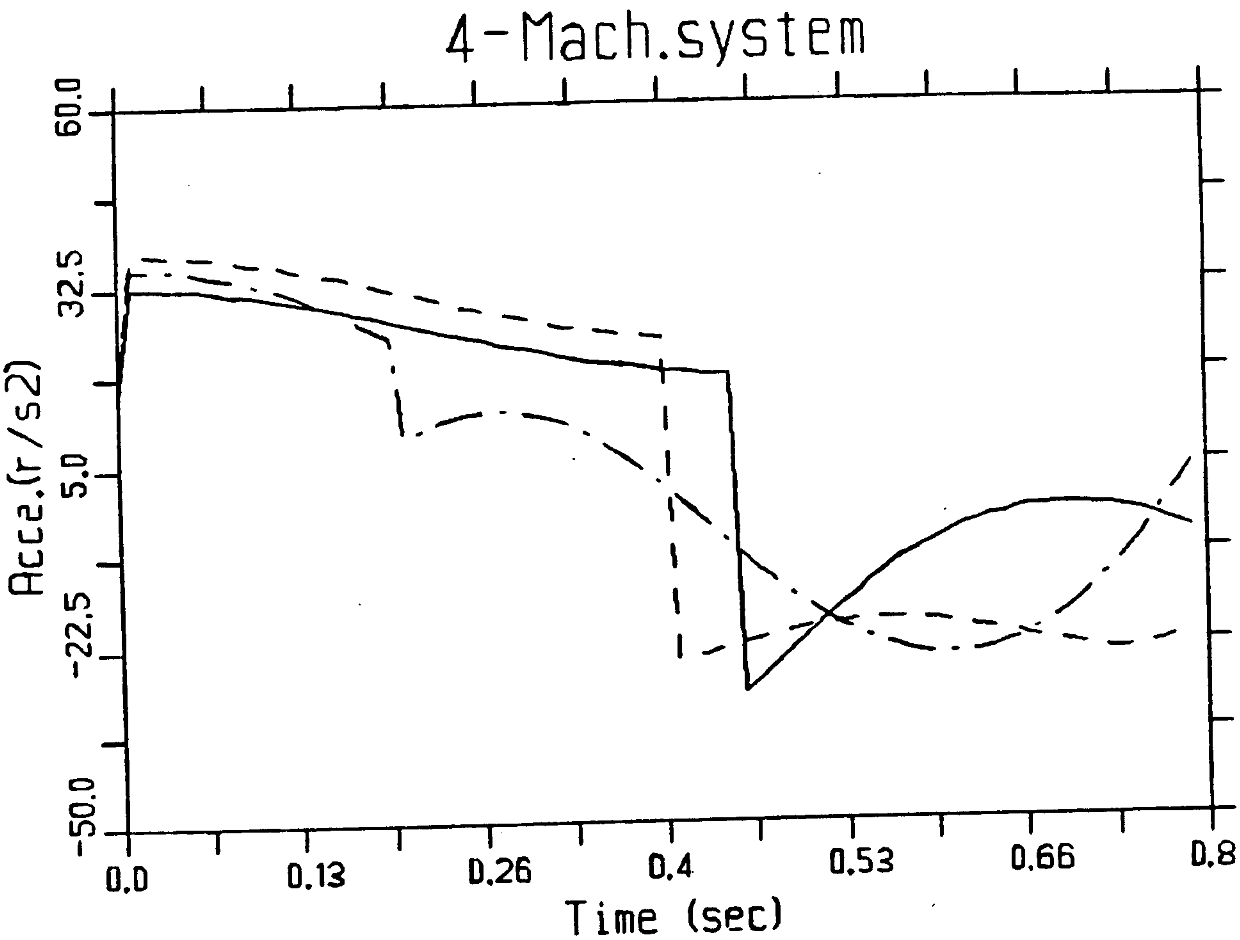


Fig 4.4

Acceleration of machine 4 for different fault locations.

Also for some fault locations far away from the machine it is found that the machine never loses synchronism even for a sustained fault, i.e., there is a minimum value of the acceleration (kinetic energy) that contributes to instability.

From the above discussion we can define two important acceleration limits. A maximum limit can be defined as the maximum value of the first peak of acceleraton for any fault for which the machine can critically maintain synchronism, i.e., if the first peak exceeds the maximum limit the machine will lose synchronism. Second, a minimum limit, can be defined as the minimum value of the first peak above which the machine could lose synchronism, i.e., if the first peak of the acceleration for any fault is less than this minimum value, the machine will never lose synchronism.

For any fault location it is found that each machine has some constant first peak of acceleration regardless of the fault duration, that is because this peak depends on the machine operating conditions. Fig 4.4 shows the different levels of acceleraiton for different fault locations for machine 4, the lowest level of the first peak of acceleration can be considered as the minimum limit, while the maximum level of the first peak of acceleraion is the maximum limit for machine 4. Fig 4.5 and Fig 4.6 show the acceleration limits for machine 2 and machine 3 for different fault locations in the 4-machine system.

Since the acceleration has the property of showing the fault severity before the fault is cleared, therefore it will

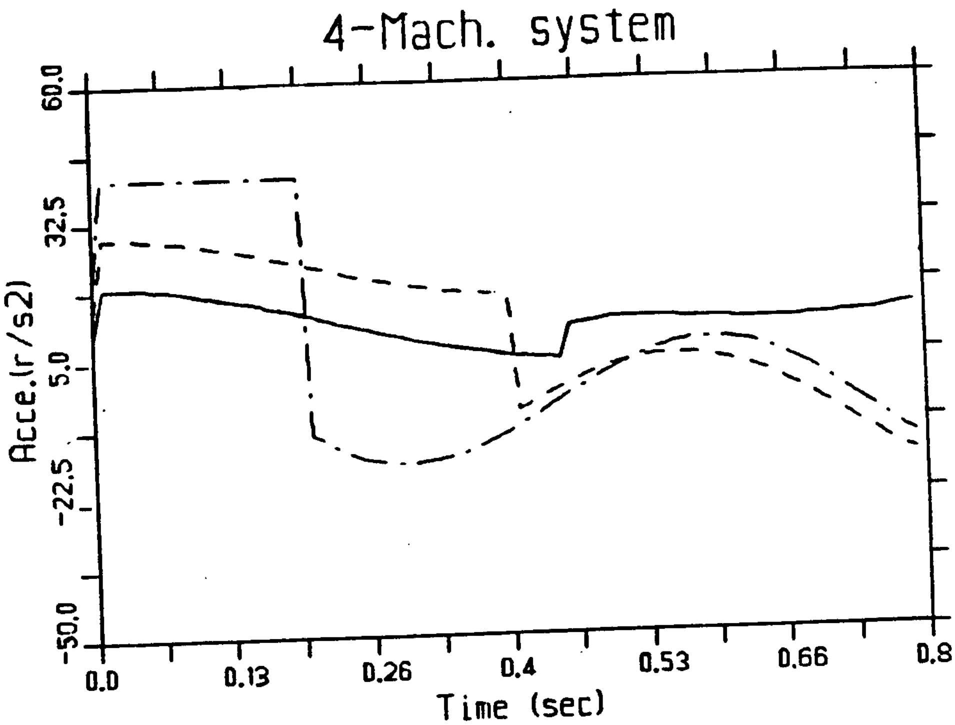


Fig 4.5

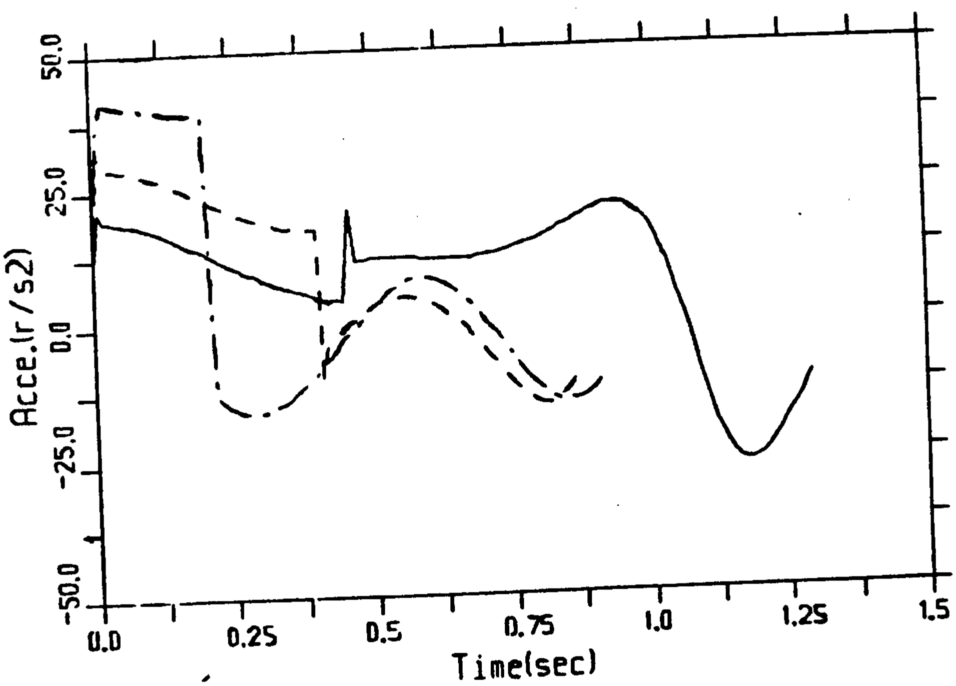


Fig 4.6

Acceleration for different fault locations of machines 2 and 3.

likely reveal the strength of the power system after the fault is cleared. In other words, the acceleration may indicate whether the machine is stable or not.

Several case studies have been carried out to demonstrate the importance of acceleration and to come up with valuable information about the stability of the disturbed machines.

4.4 Case Studies

4.4.1 The Three-machine System

A number of cases were studied with a three-phase fault applied at different locations in the three-machine system as shown in Fig 4.7. Swing curves and acceleration of each machine for each case were plotted and the stable and unstable cases were determined from the swing curves.

For each fault location the critical clearing time was found and then the critically stable curves of acceleration were plotted with the swing curve on the same figure. Also the critically unstable curves were plotted for each machine.

Case 1:

With a three phase fault on line 5-4 near bus-4, the critical clearing time is .3 sec, the fault being cleared by disconnecting line 5-4. Figures 4.8 to 4.10 show the swing curve and the acceleration of the machines 1, 2 and 3 for stable and unstable cases. For the stable cases the fault is cleared at .3 seconds, and for the unstable cases the fault is cleared

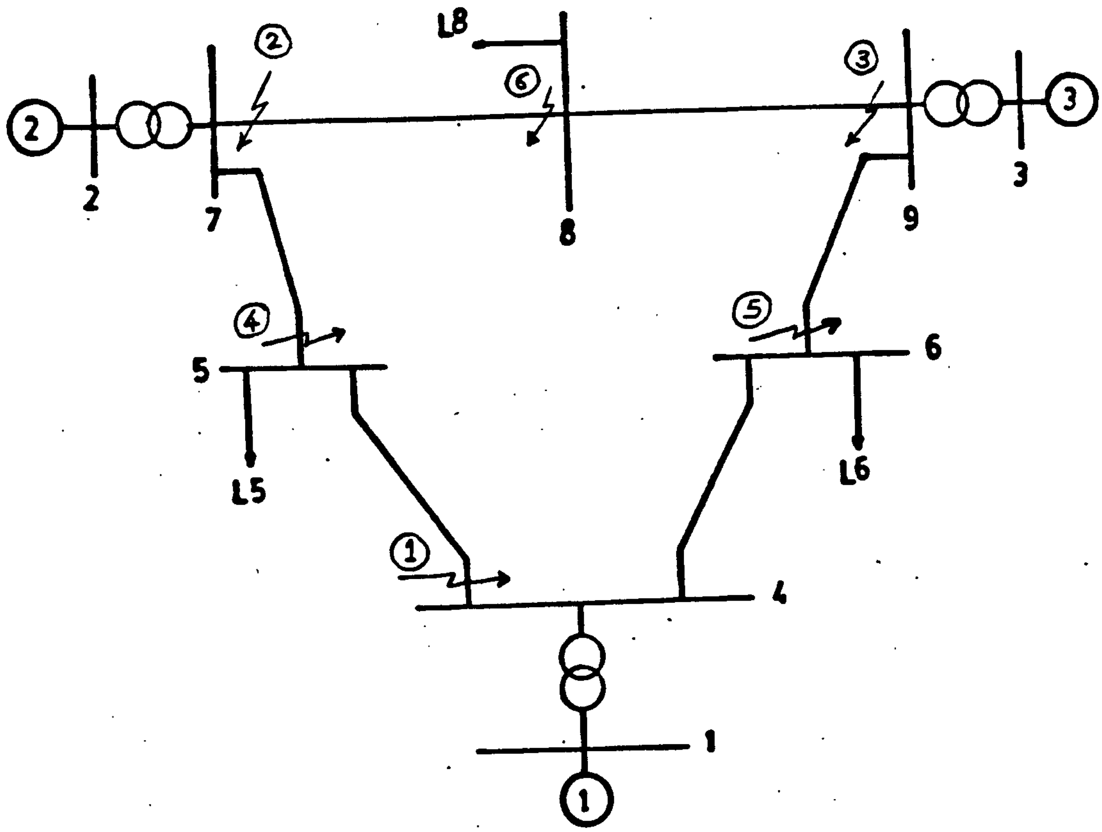


Fig. 4.7 The three-machine system case studies

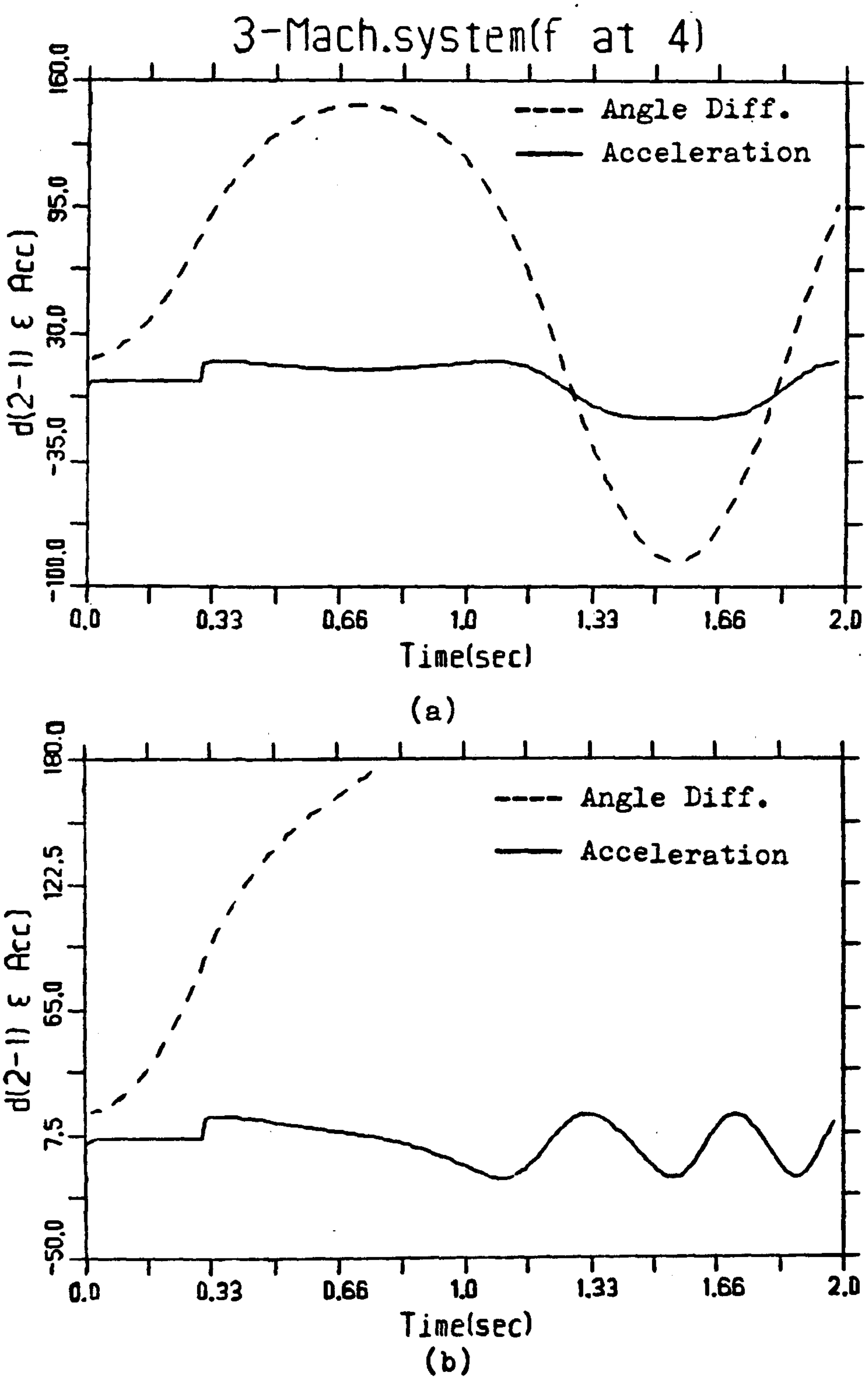
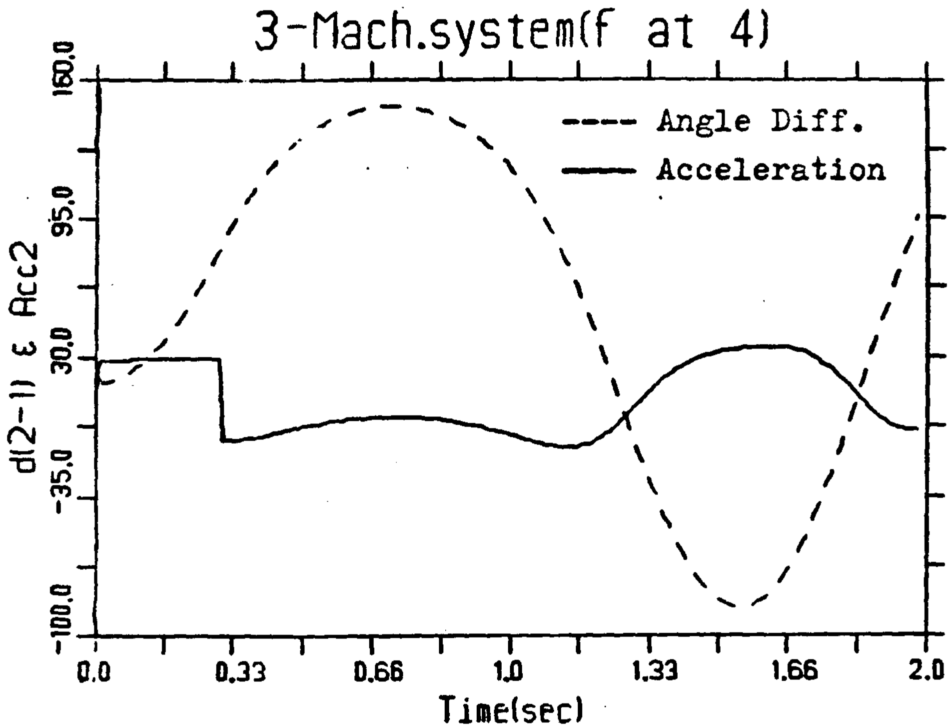


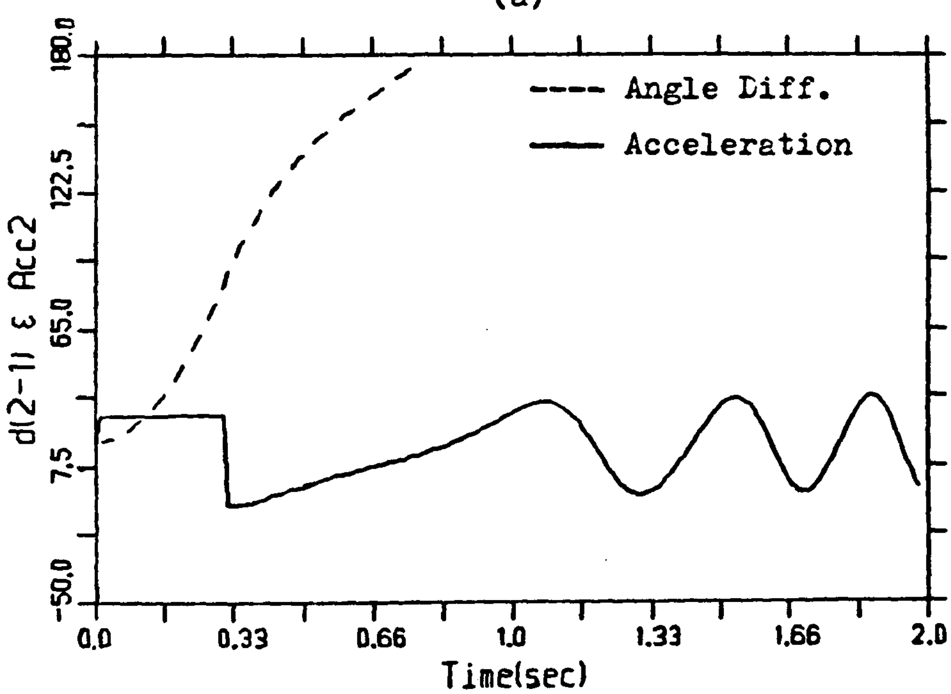
Fig 4.8 Angle diff. and acceleration of machine 1 for a fault at bus 4;

(a) stable case (Tc=.30 sec).

(b) unstable case (Tc=.31 sec).



(a)

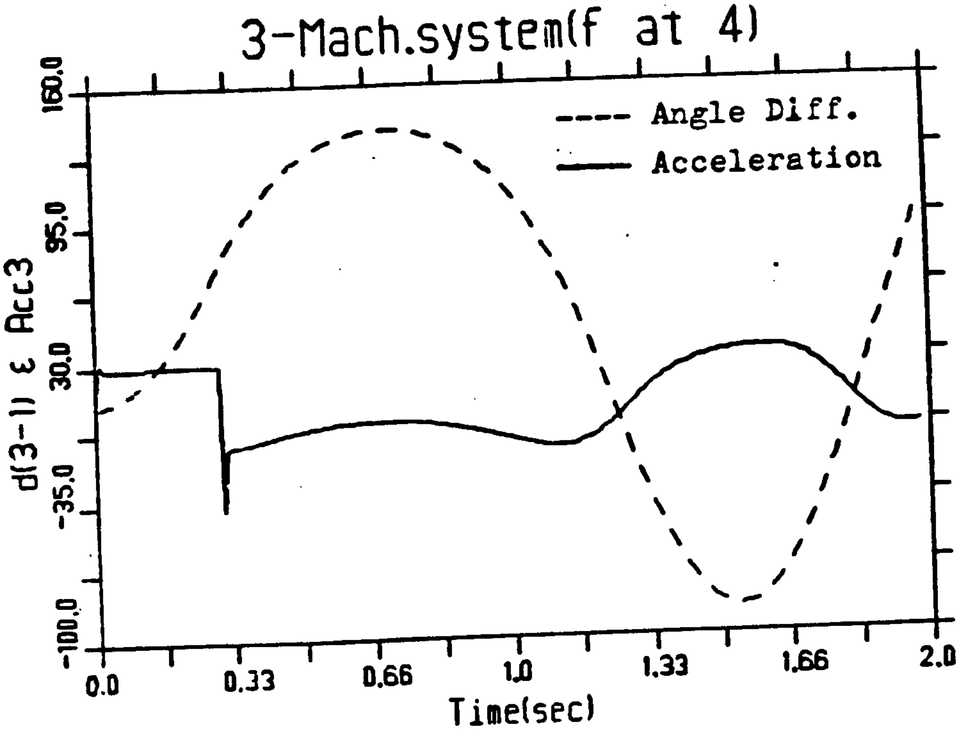


(b)

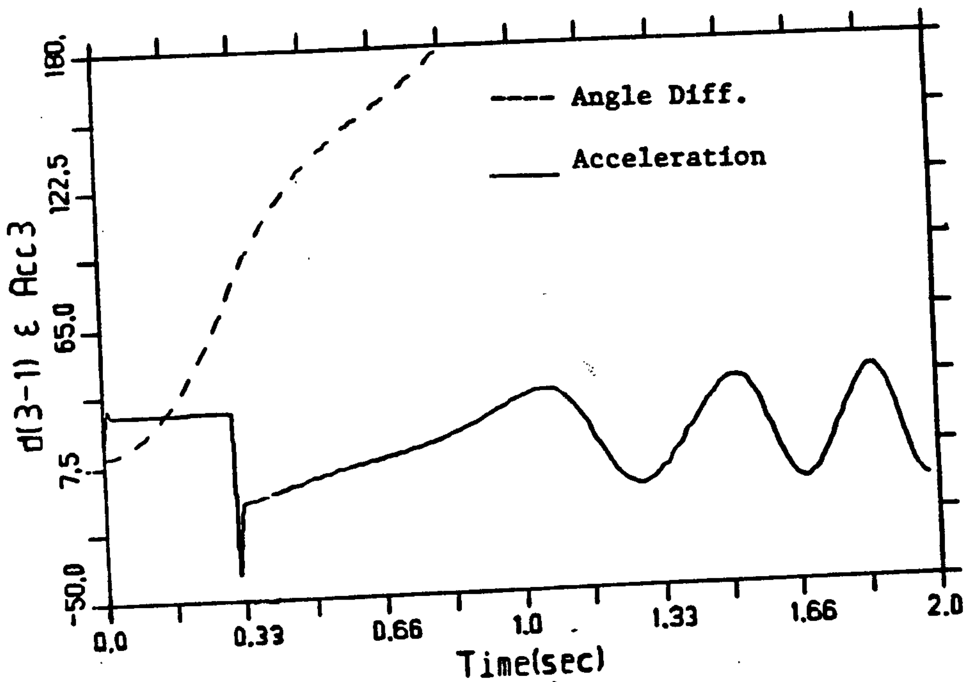
Fig 4.9 Angle diff. and acceleration of machine 2 for a fault at bus 4 ;

(a) stable case (Tc=.30 sec).

(b) unstable case (Tc=.31 sec).



(a)



(b)

Fig 4.10 Angle diff. and acceleration of machine 3 for a fault at bus 4 ;

(a) stable case(Tc=.30 sec).

(b) unstable case (Tc=.31 sec).

at .31 seconds. The peak of the acceleration after clearing is lower than the first peak before clearing for the stable cases at t_c = .3 seconds for all the three machines. It can be noted that machine 1, which is the closest machine to the fault, is not the critical machine, because it accelerated very slowly to this fault and also most of the kinetic energy has been generated by machines 2 and 3. So machine 1 will not be tripped for such a case. For the unstable case at t_c = .31 seconds the peak of the acceleration after clearing is higher than the peak before clearing for all the machines, it means that all the three machines are accelerating more after clearing and the system breaks up.

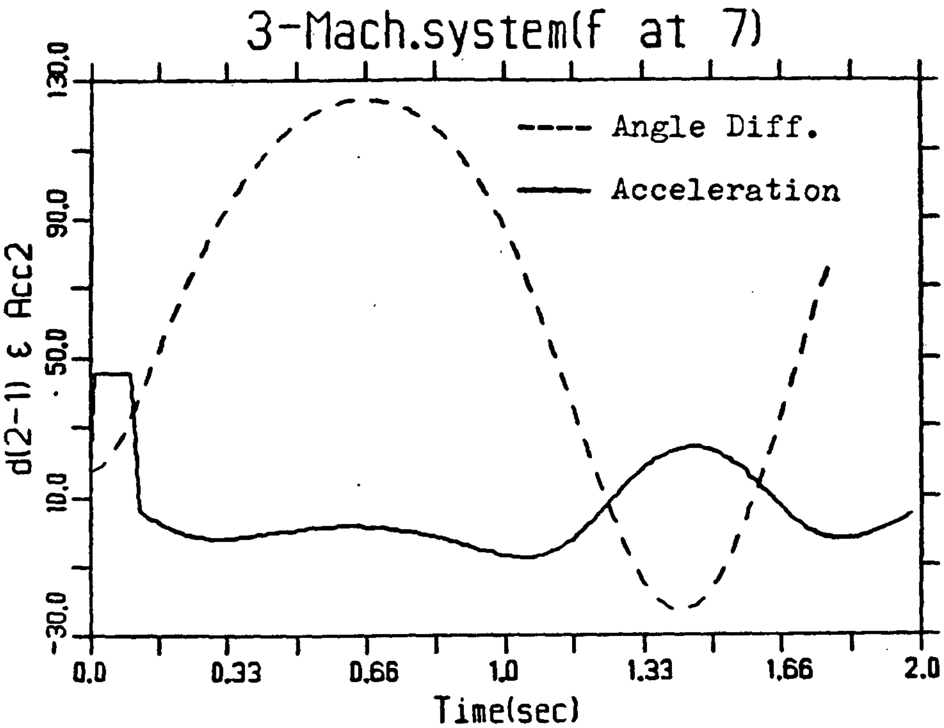
Case 2:

A three-phase fault on line 7-8 near bus 7, cleared at .11 seconds for the stable case and .12 seconds for the unstable case. Fig 4.11 and Fig 4.12 show the swing curve and acceleration for machines 2 and 3 for the stable and unstable cases.

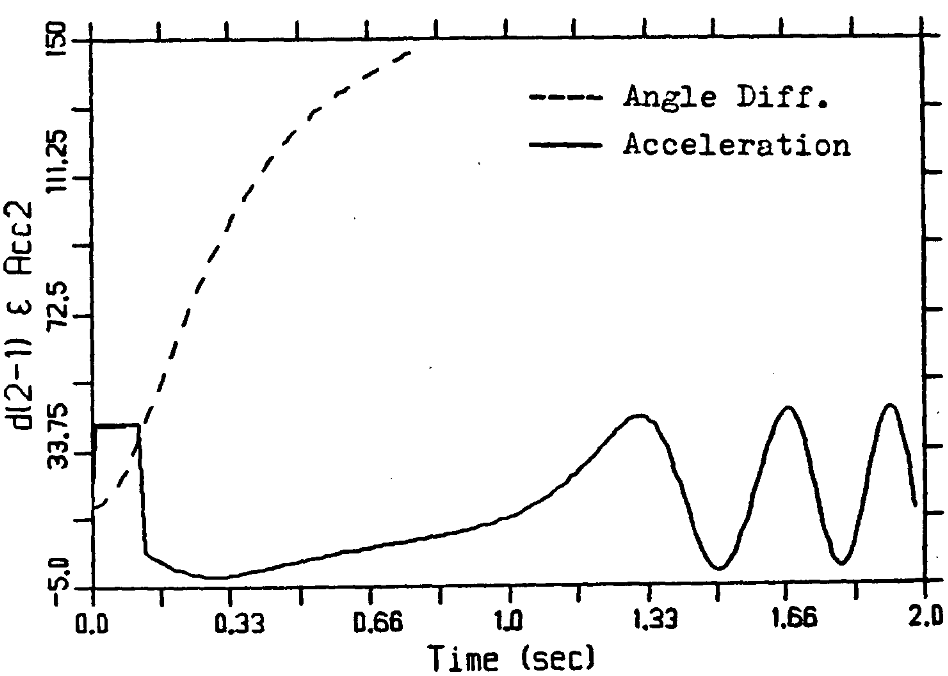
Case 3:

A three-phase fault on line 9-8 near bus-9. The fault cleared by disconnecting line 9-8. The critical clearing time for this fault is .41 seconds.

Figures 4.13 and 4.14 show the swing curve and acceleration for machines 2 and 3. For the stable case the



(a)

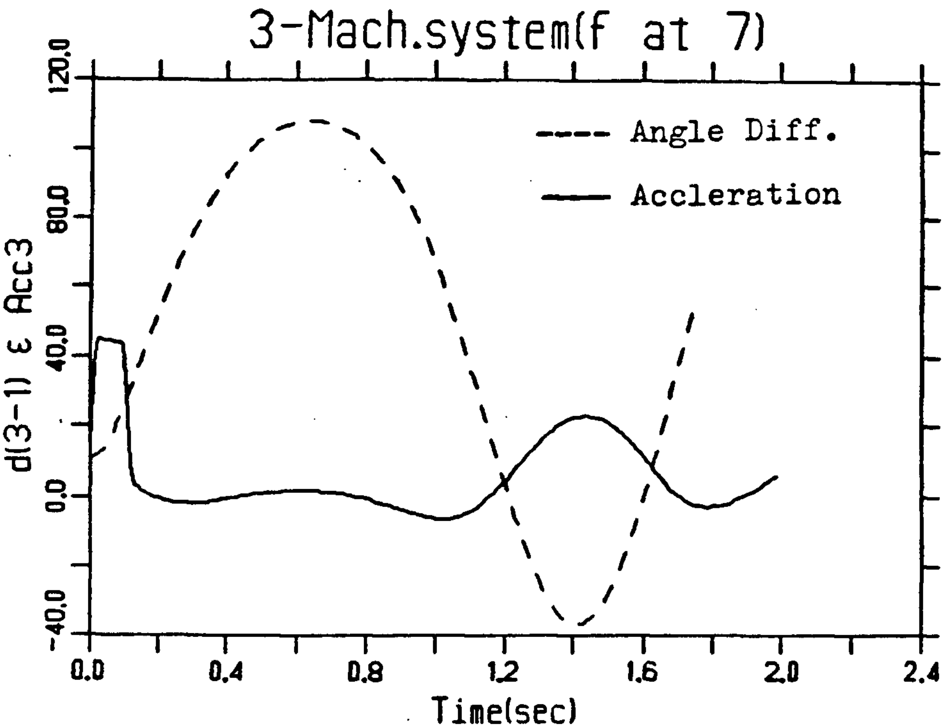


(b)

Fig 4.11 Angle diff. and acceleration of machine 2 for a fault at bus 7 ;

(a) stable case (Tc=.11 sec).

(b) unstable case (Tc=.12 sec).



(a)

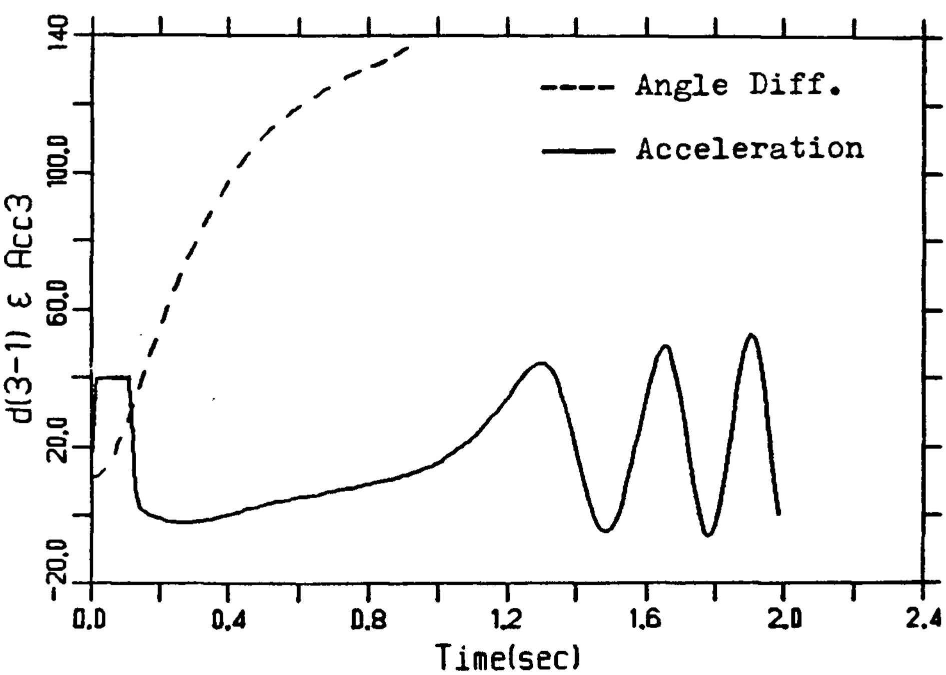


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Fig 4.12 Angle diff. and acceleration of machine 2 for fault at bus 7 ;

(a) stable case (Tc=.11 sec).

(b) unstable case (Tc=.12 sec).

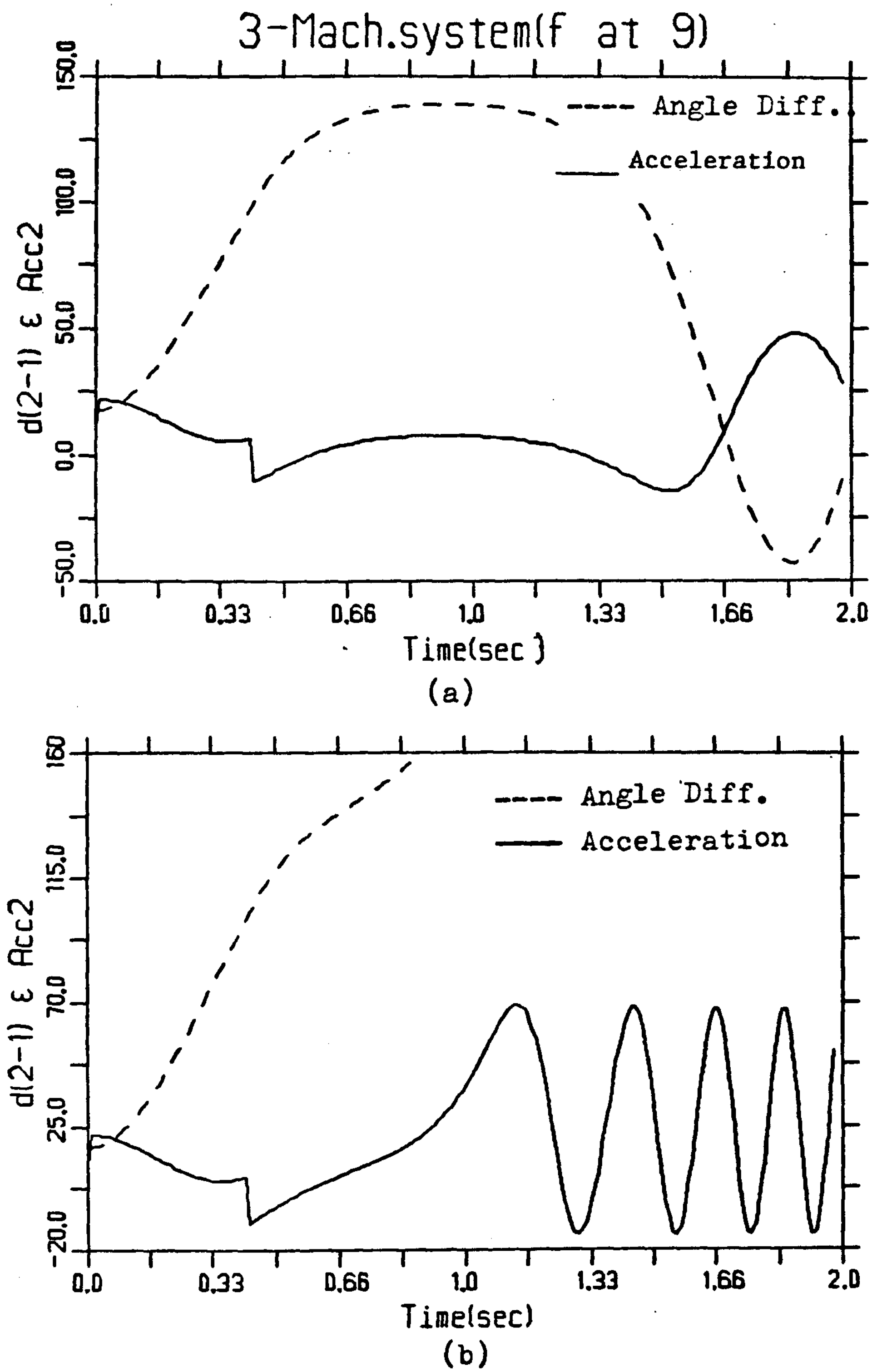


Fig 4.13 Angle diff. and acceleration of machine 2 for a fault at bus 9 ;

(a) stable case (Tc=.41 sec).

(b) unstable case (Tc=.42 sec).

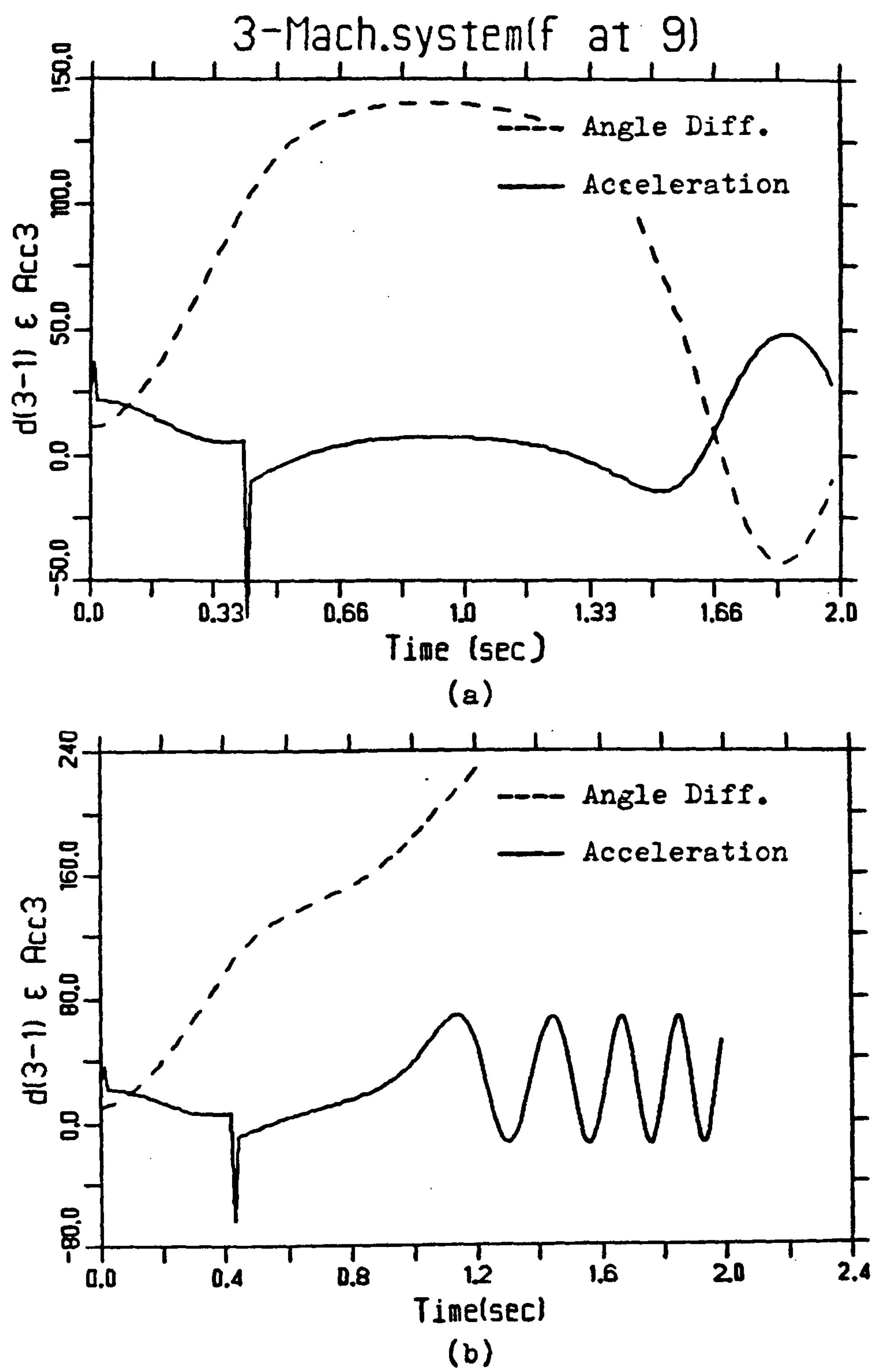


Fig 4.14 Angle,diff. and acceleration of machine 3 for a fault at bus 9 ;

(a) stable case (Tc=.41 sec).

(b) unstable case (Tc=.42 sec).

fault is cleared at .41 seconds and for the unstable case t_c = .42 seconds.

Similar results are seen in the following cases:

Case 4:

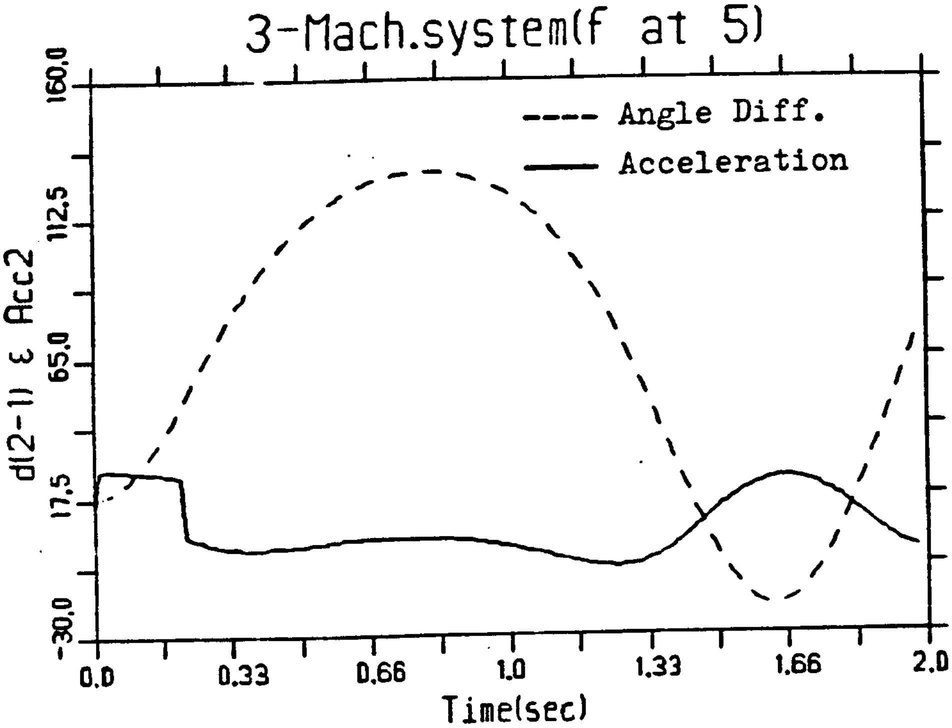
A three-phase fault on line 7-5 near bus-5 is cleared by disconnecting line 7-5. See Fig 4.15 and Fig 4.16.

Case 5:

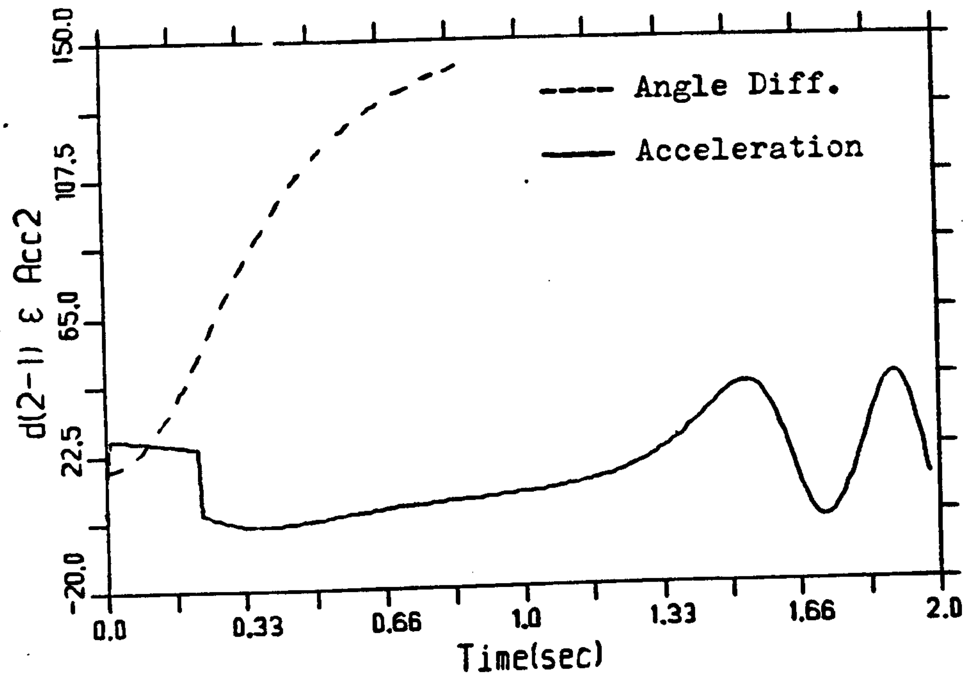
A three-phase fault on line 9-6 near bus-6, is cleared by disconnecting line 9-6. See Fig 4.17 and Fig 4.18.

Case 6:

A three-phase fault on line 7-8 near bus-8, is cleared by disconnecting line 7-8. See Fig 4.19 and 4.20.



(a)

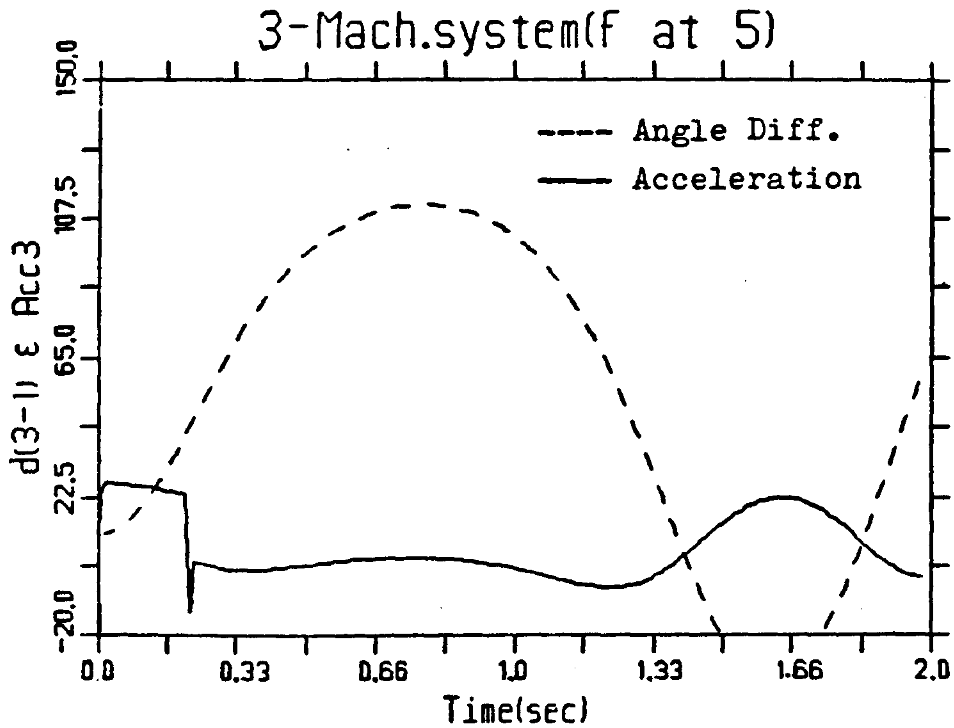


(b)

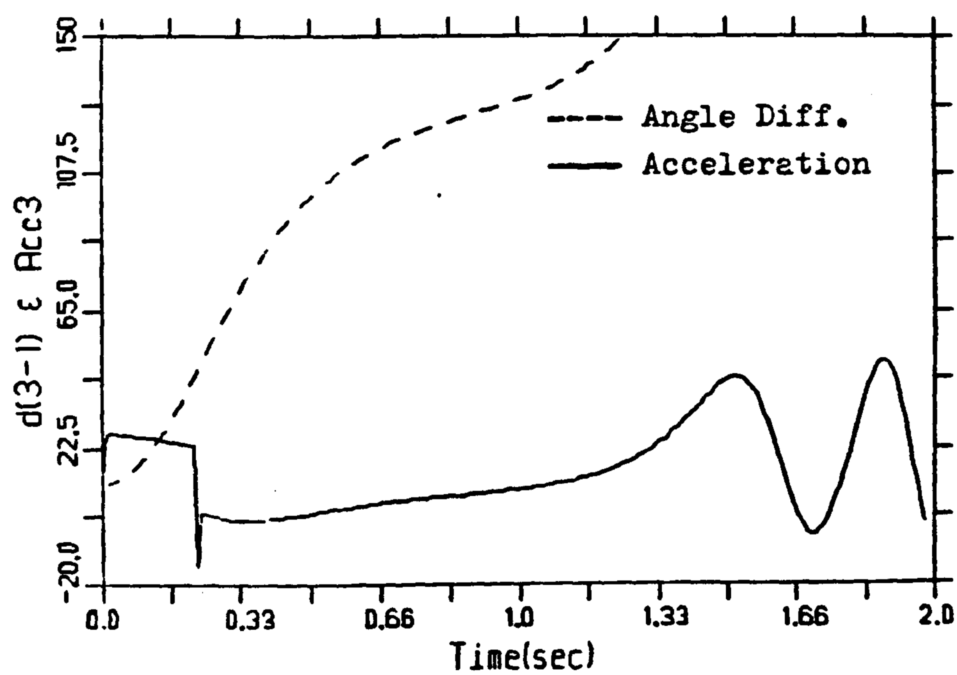
Fig 4.15 Angle diff. and acceleration of machine 2 for a fault at bus 5 ;

(a) stable case (Tc=.21 sec).

(b) unstable case (Tc=.22 sec).



(a)

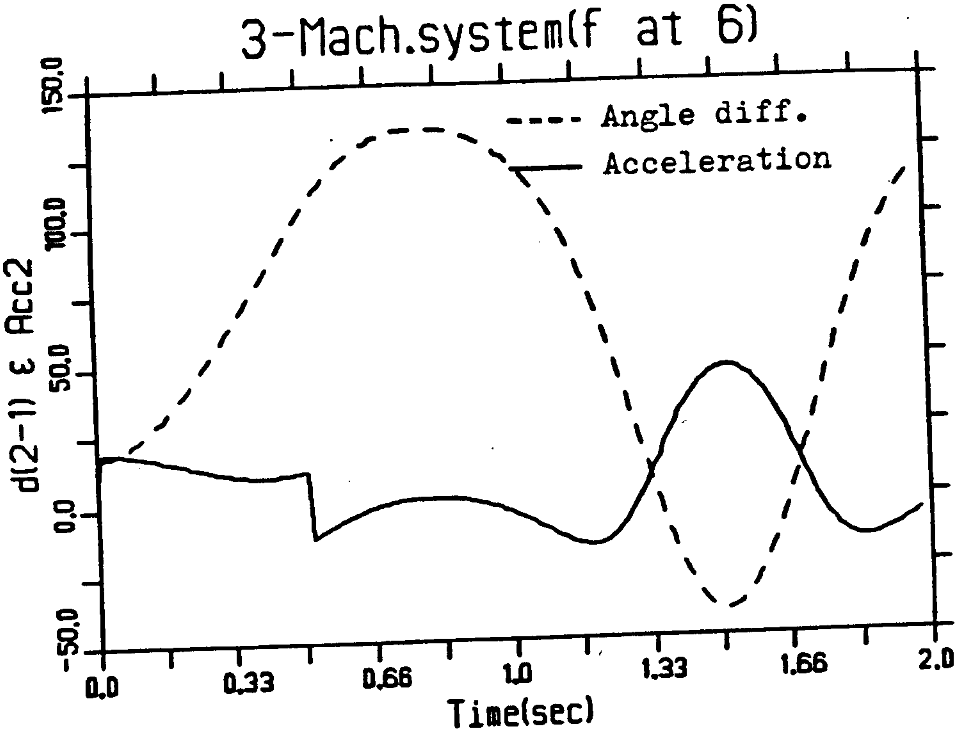


(b)

Fig 4.16 Angle diff.and acceleration of machine 3 for a fault at bus 5 ;

(a) stable case (Tc=.21 sec).

(b) unstable case (Tc=.22 sec).



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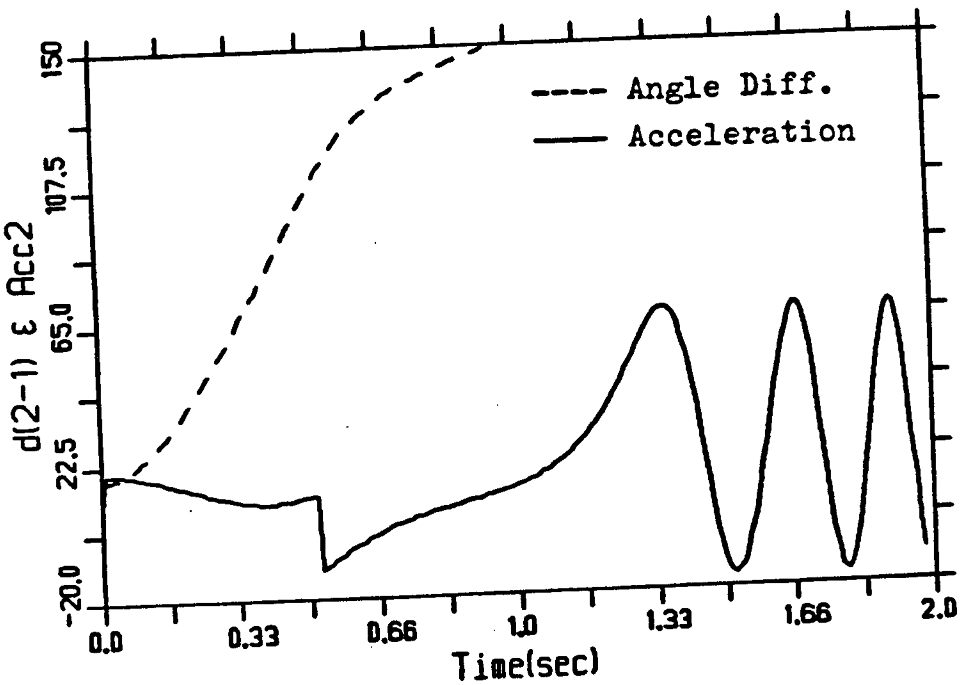
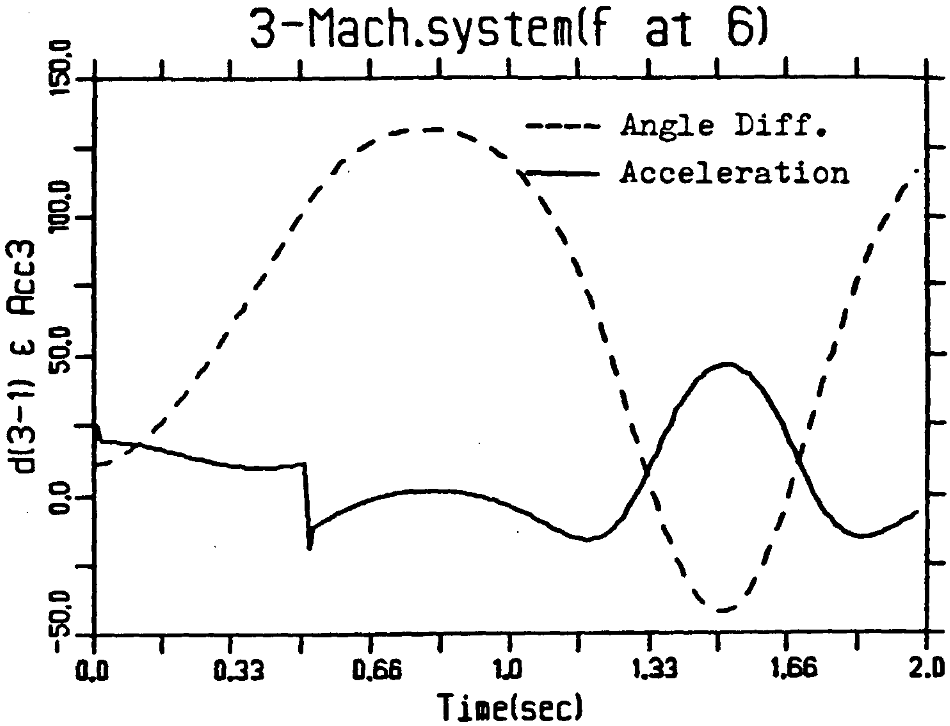


(b)

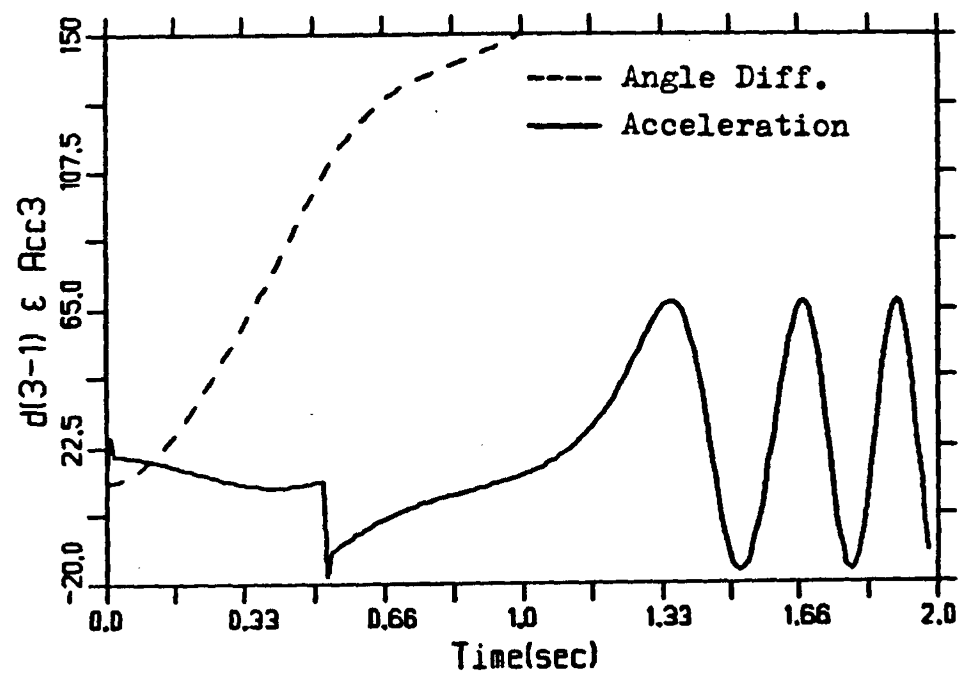
Fig 4.17 Angle diff. and acceleration of machine 2 for a fault at bus 6 ;

(a) stable case (Tc=.51 sec).

(b) unstable case (Tc=.52 sec).



(a)

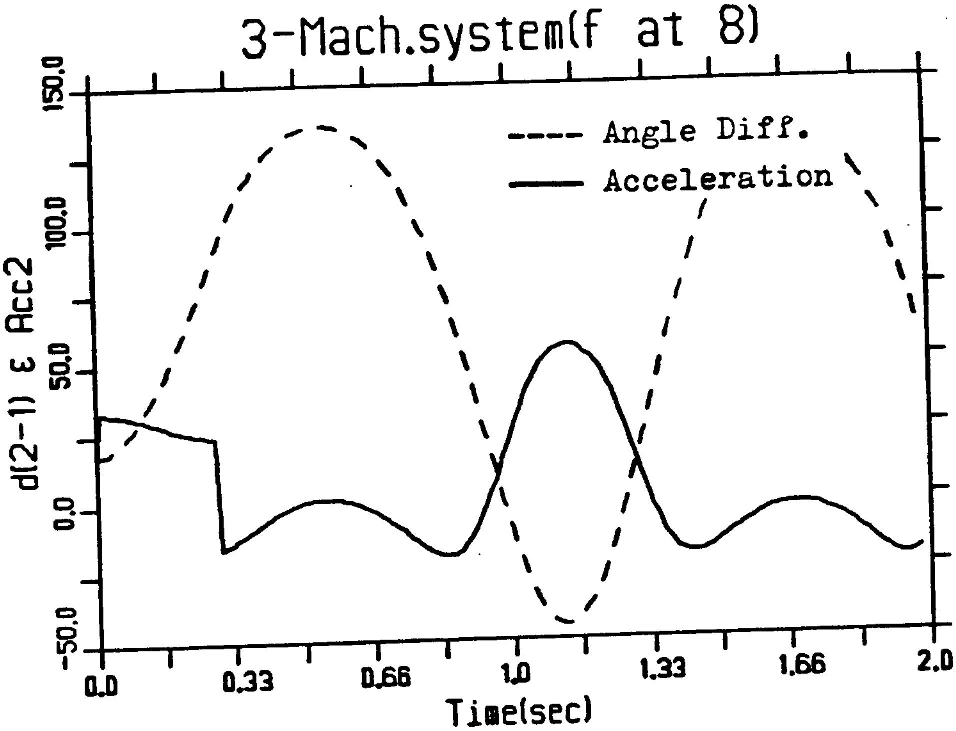


(b)

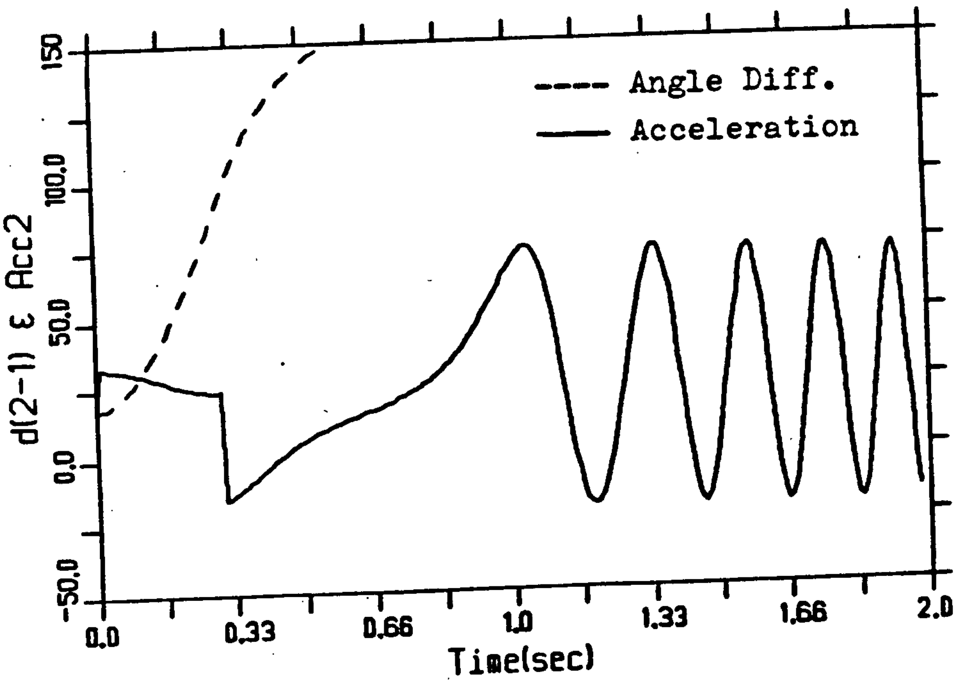
Fig 4.18 Angle diff. and acceleration of machine 3 for a fault at bus 6 ;

(a) stable case (Tc=.51 sec).

(b) unstable case (Tc=.52 sec).



(a)

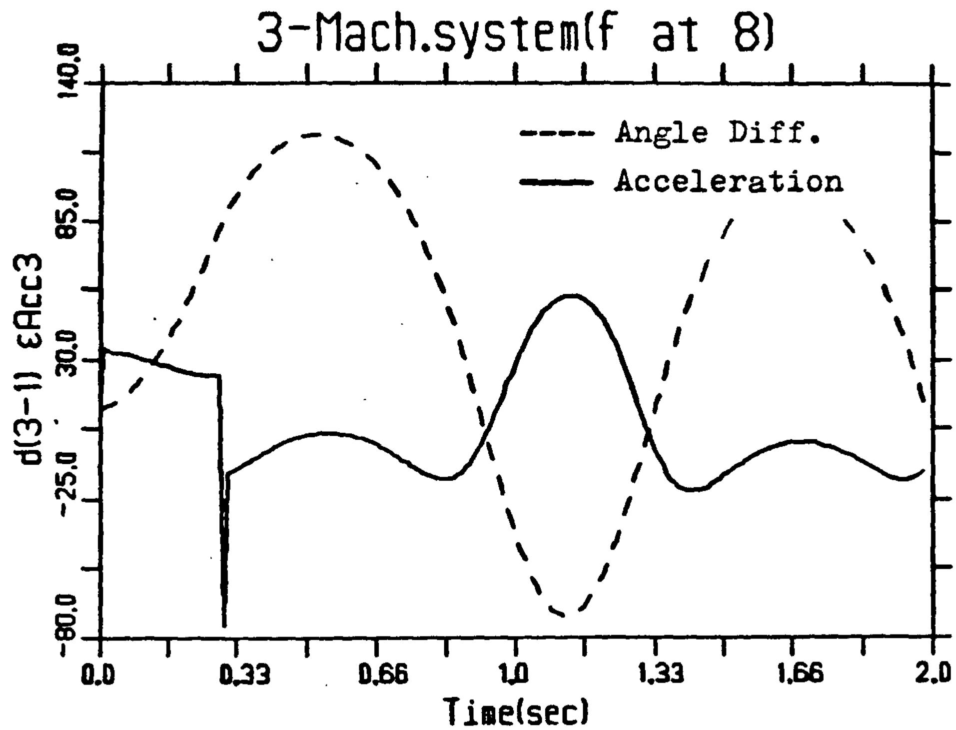


(b)

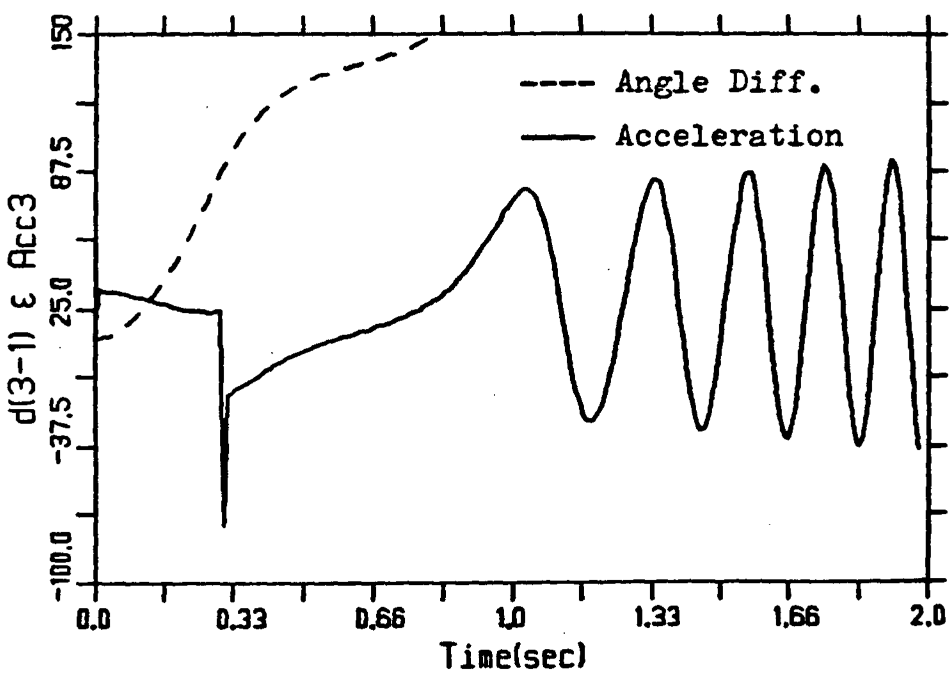
Fig 4.19 Angle diff. and acceleration of machine 2 for a fault at bus 8 ;

(a) stable case(Tc=.29 sec).

(b) unstable case (Tc=.30 sec).



(a)



(b)

Fig 4.20 Angle diff. and acceleration of machine 3 for a fault at bus 8 ;

(a) stable case (Tc=.29 sec).

(b) unstable case (Tc=.30 sec).

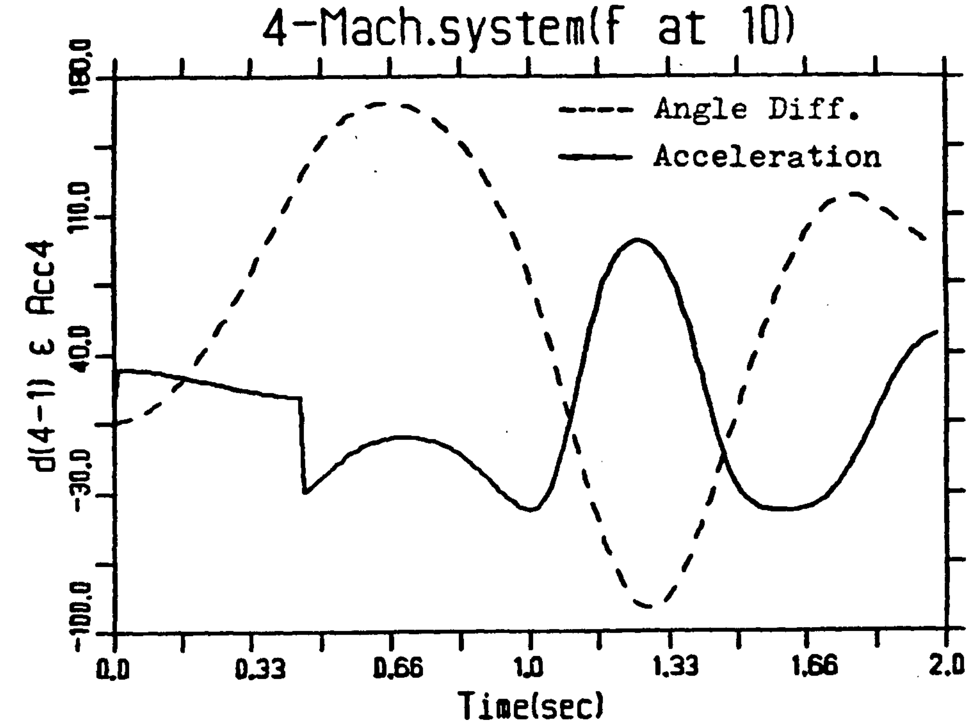
4.4.2 The Four-machine System Case Studies

The four-machine system is the same as the three-machine system except for a fourth machine connected to bus-4 through a double circuit transmission line. A load flow study was carried out to find the initial operating conditions of the machines. A three-phase fault was considered at each bus of the system, and by looking at the acceleration response of each machine it is clear that the acceleration of a machine indicates whether it is stable or not.

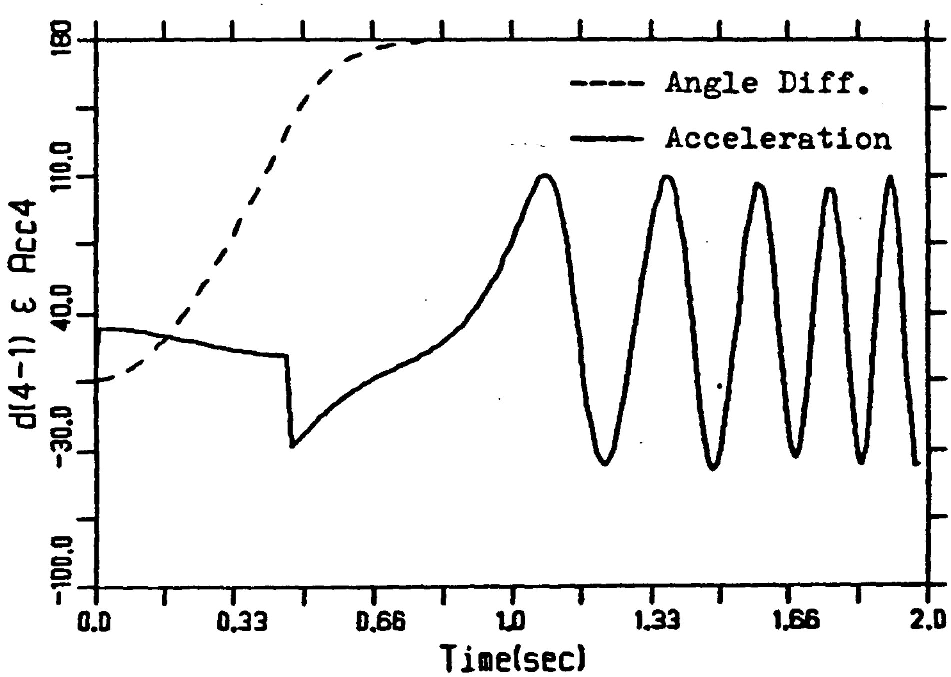
A number of studies were carried out on the system. A typical case of a three-phase fault near bus-10 will be considered here. The fault is cleared by disconnecting the faulted line between bus-8 and bus-10. The other three machines in the system never lose their stability even if machine-4 loses stability. This means that most of the kinetic energy produced by the machine rotors came from the rotor of machine-4. In this case, also, the first peak of acceleration of machines 1, 2 and 3 is less than the minimum limit of acceleration. Fig 4.21 to Fig 4.23 show the behavior of machines 4, 3 and 2 for stable and unstable cases of machine 4.

4.4.3 The Five Machine System Case Studies

Two cases are considered for this system (see Fig 3.3), Case 1; a three-phase fault near bus-11, Case 2; a three-phase fault near bus-6. The critical machine for both cases is



(a)

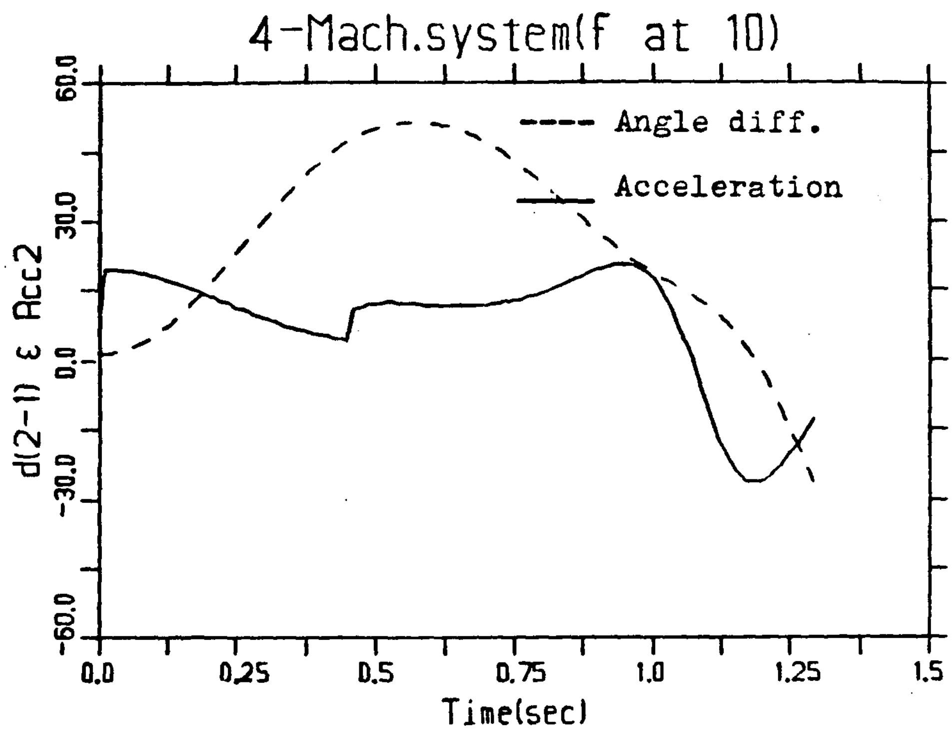


(b)

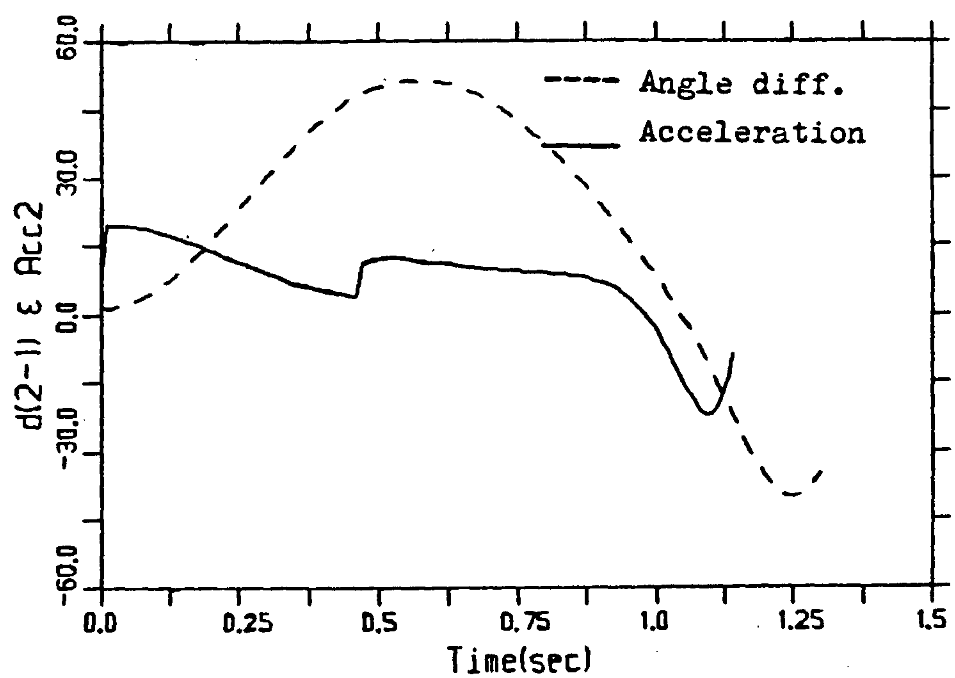
Fig 4.21 Angle diff. and acceleration of machine 4 for a fault at bus 10 ;

(a) stable case(Tc=.45 sec).

(b) unstable case (Tc = .46 sec).



(a)



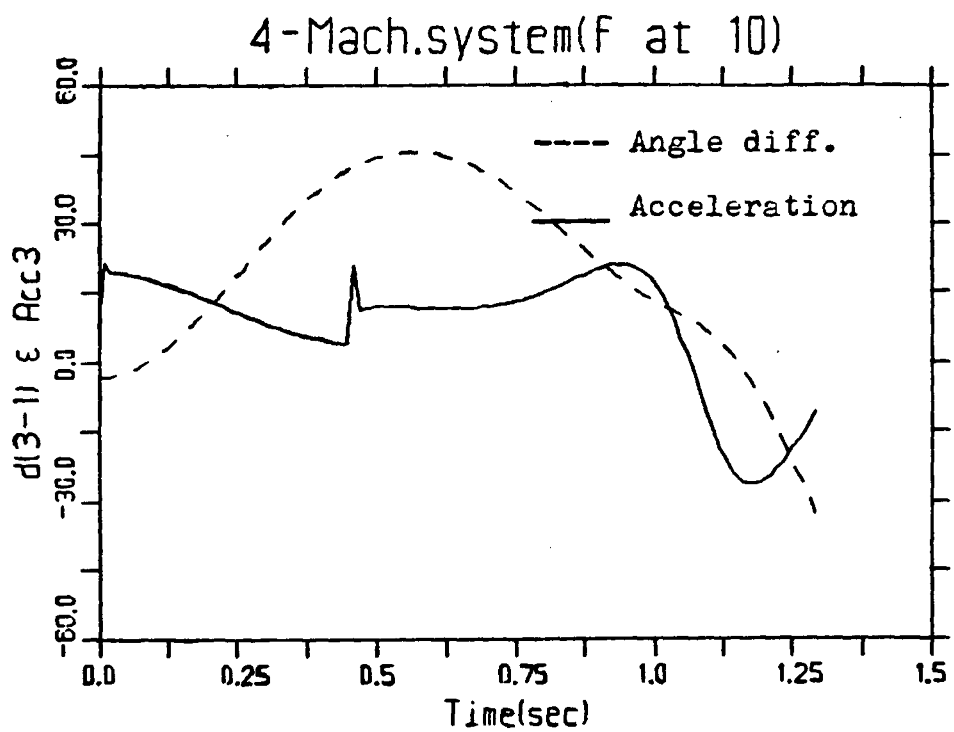
(b)

Fig 4.22 Angle diff. and acceleration of machine 2 for a fault at bus 10;

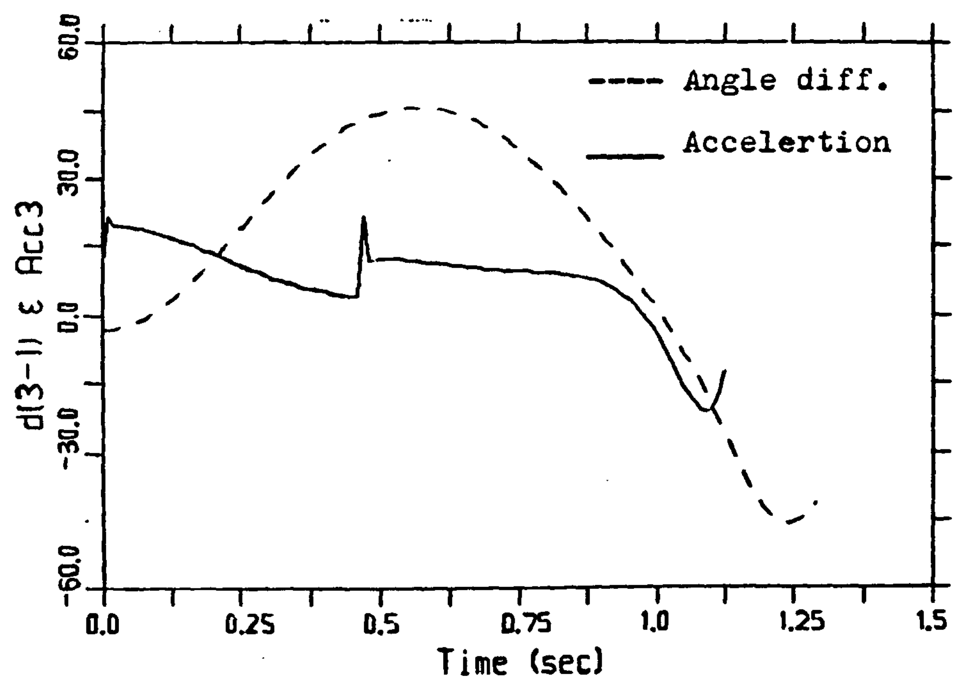
(a) stable (Tc=.45 sec).

(b) stable (Tc=.46 sec).

Note that the acceleration is lower than the min. limit.



(a)



(b)

Fig 4.23 Angle diff. and acceleration of machine 2 for a fault at bus 10 ; (a) and (b) are stable for Tc=.45,.46 sec.

machine 5, the other four machines did not show any signfiicant response to both faults (because each machine is locally loaded). The behavior of machine 5 is shown in Fig 4.24.

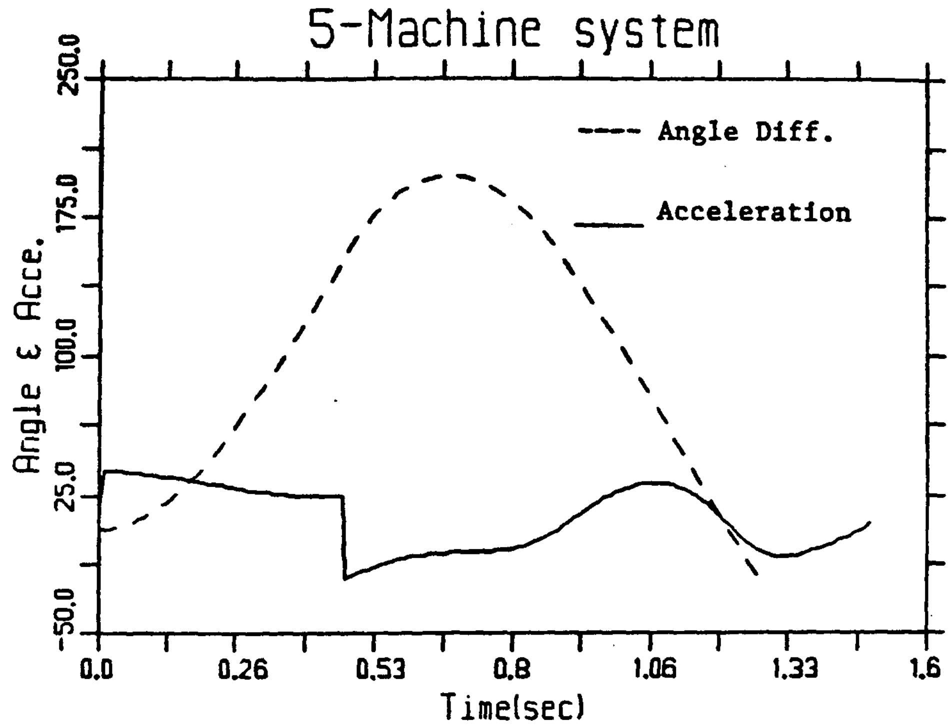
4.5 Case Studies Discussion

From the cases studied, for any fault considered it is found that if the first peak of acceleration lies between the previously defined maximum and minimum levels of acceleration, then the machine may lose synchronism unless the rest of the system is capable of handling the power flow after fault clearing.

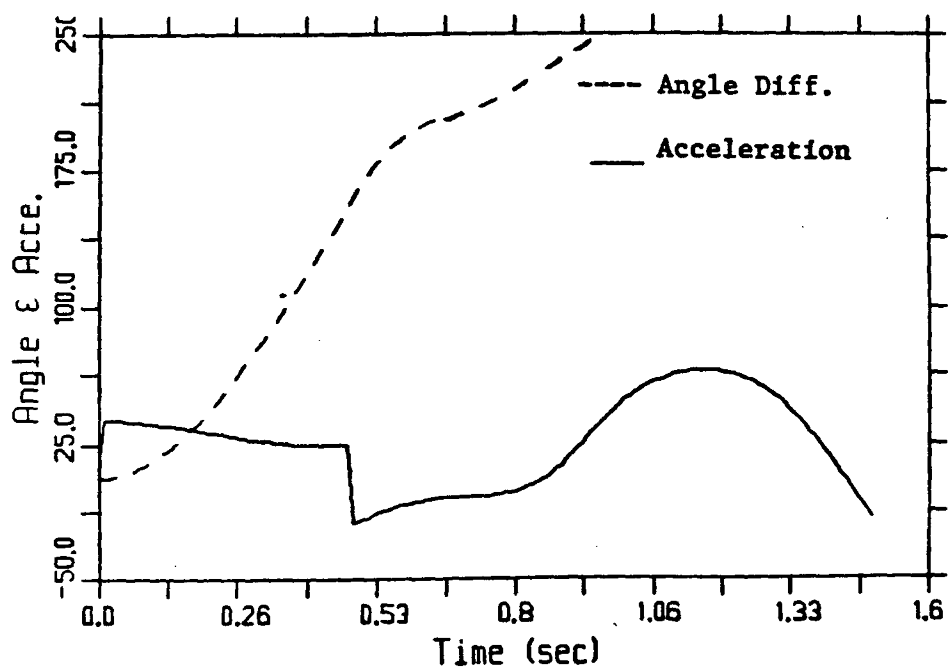
When we examine closely the acceleration curves for the stable cases we notice that the peak of the acceleration after fault clearing is less than the first peak before clearing. On the other hand we see the opposite for the unstable cases, where the peak of the acceleration after fault clearing is always higher than the peak of acceleraiton before fault clearing.

For any disturbed machine in the tested systems, if the acceleration is higher than the minimum limit, then it indicates that the machine is one of the critical machines for a specific disturbance.

The acceleration response is different for each machine in a power system when it is subjected to a fault. Some machines are accelerating and some decelerating. Usually the machines which are close to the fault location are accelerating and most probably one or more of these machines may lose



(b)



(b)

Fig 4.24 Angle difference and acceleration of machine 5 for a fault at bus 11 ; (a) stable case (Tc=.47 sec).
(b) unstable case (Tc= .48 sec).

synchronism. Also when the fault is cleared, most of the accelerating machines decelerate (depending upon the system configuration after fault clearing and the remaining loads). If a machine is stable then the maximum acceleration after clearing should be less than that before clearing, which means that this machine is converging toward a new stable operating point. For an unstable machine, the peak of the acceleration after clearing is higher than that before clearing which means that this machine is accelerating higher after clearing and diverging from stability.

Sometimes clearing the fault causes a second severe disturbance that may break up the system. In this case the machines continue to accelerate or decelerate until they lose synchronism. This can be monitored by looking at their acceleration curves. This happens only if the rest of the system is not capable of absorbing the fault kinetic energy and meeting the demand of the new operating conditions.

4.6 Transient Stability Criterion Based on Acceleration Measurements

This criterion relies on the instantaneous measurements of the acceleration of the synchronous machine during the transient period. The instantaneous acceleration can be measured by keeping track of time and sensing speed by monitoring the passage of teeth on a toothed wheel bolted to the machine's rotor [4]. Then the speed and the acceleration can be calculated by the use of specially designed micro- computers. Very good measurements have been achieved using such a system by the Montana Power Company.

The procedure for transient stability assessment using this criterion is outlined in the following steps:

1. Find the maximum and minimum limits of acceleraiton to indicate the severity of the fault for each machine in the power system, then adjust the tripping system to:

    (a) ignore the acceleration signal if the first peak is less than the minimum limit, because nothing serious has occurred, i.e., the machine is stable.

    (b) release immediately a trip signal to the relay to disconnect the generator if the first peak of the acceleration exceeds the maximum limit.

    (c) ready (but not release) a tripping signal for transmission to the relay if the first peak of the acceleration passes the minimum limit but does not exceed the maximum limit.

2. When the fault is cleared (this is clearly indicated by the rate of change of acceleration) and the peak of the acceleration after clearing is higher than that before clearing, then a trip signal must be issued to trip the generator as it is going to be unstable. But if the peak of the acceleration after clearing the fault is lower than that before the fault clearing

then the generator is stable and the trip signal must be blocked.

The criterion needs three important measurements to decide the transient stability: first acceleration peak, fault clearing indication, and acceleration peak after fault clearing.

The total time to issue a trip should be of the order of one second for case (c) of step 1. But for cases (a) and (b) the decision to issue a trip signal must occur immediately after the fault occurs.

The rate of change of acceleration can be used to indicate the occurrence and clearing of any fault because it shows two sharp jumps for these two incidents, as shown in Fig 4.25.

There are some special cases where some machines in the faulted system are decelerating instead of accelerating. The criterion is applicable to these cases also, but usually those machines are not the critical machines for such cases, and usually do not contribute to instability of the power systems.

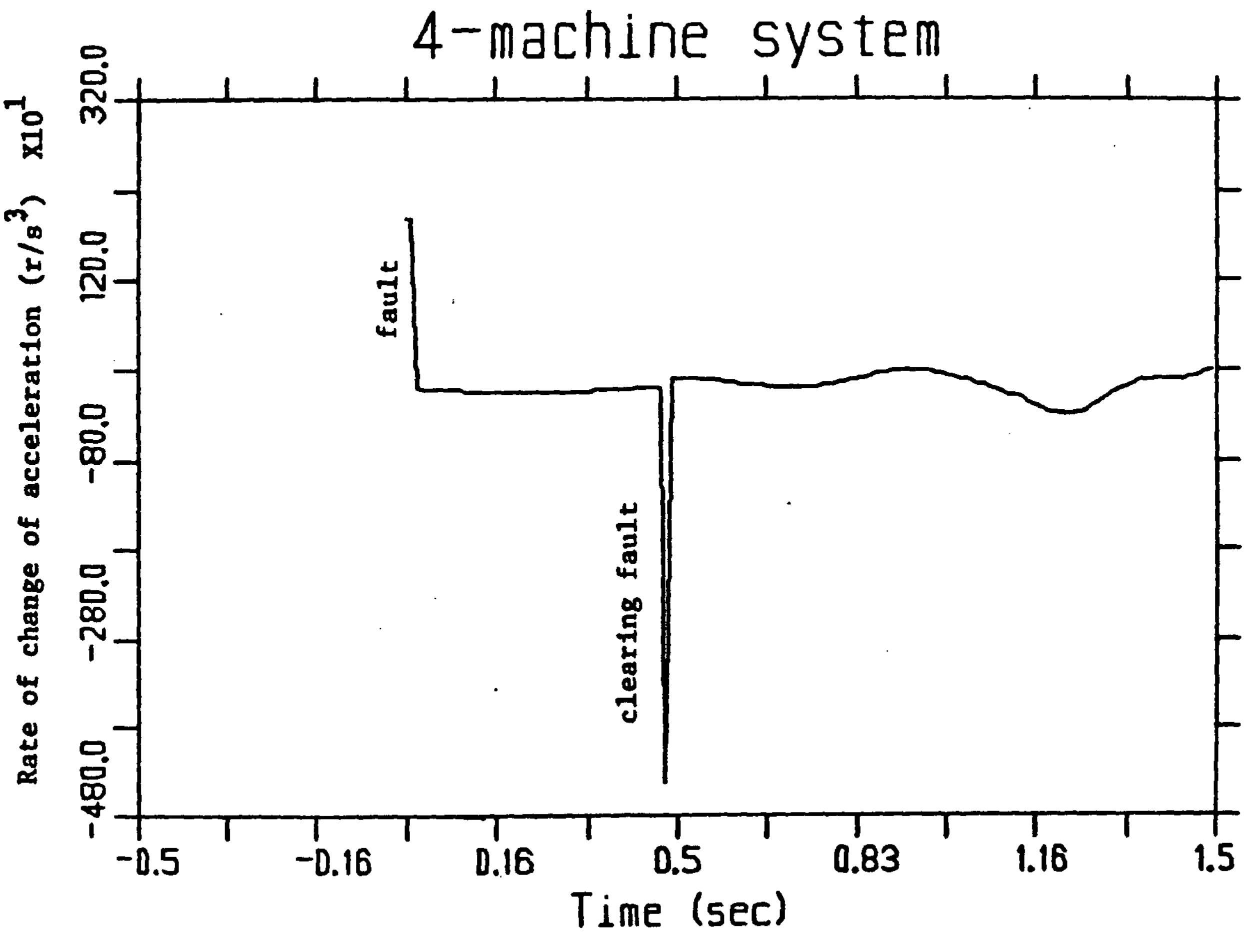


Fig 4.25 Rate of change of acceleration of machine 4 for a fault at bus 8, the two jerks at fault and clearing can be used to detect both events.

CHAPTER 5

CONCLUSION AND FUTURE WORK

Transient stability of power systems is conventionally studied many years in advance by the use of digital computer programs. The main factor used in deciding the transient stability of any machine is its angle differences with respect to other machines in the system.

It is clear from the investigations discussed in Chapter 4 that the local acceleration of each machine can give the essential information needed to assess the transient stability of that machine. The information provided by the local acceleration of a machine, about its transient stability is sufficient and definite for the tested systems, just like the angle difference between machines.

The transient stability criterion developed in Chapter 4 is simple and practical for locally assessing transient stability.

Generally the benefits of this new criterion can be summarized as follows:

1. The criterion can be used for automatic switching of some stability controls such as dynamic brakes, shunt capacitors and fast valving, where the instantaneous acceleration provides valuable information about the severity of the fault.
2. A great deal of time and money can be saved since large

system studies need not be made for different contingencies.

3. The criterion works regardless of how many disturbances are taking place and what changes have occurred in the transmission system at the same time, because it depends only upon local acceleration measured at each machine.

4. Since no information is needed from other machines in the system to assess the stability of a particular machine, control of the machines can be decentralized.

5. The criterion deals with real quantities and hence with the real situation of any machine in the system during transients. This will prevent any errors in the choice of tripping. Only the unstable machine or machines will be tripped.

Future Work

Based on this new criterion of transient stability we can think of new automatic protection systems for large generators to prevent instability of power systems. This protection system can be used to switch on some stability controls to maintain stability or to disconnect the unstable generators from the rest of the power system.

Future work could investigate the following:

1. Design of a device to measure the instantaneous acceleration quickly and accurately.

2. Design of a micro-computer that can process the

information from the measuring device and provide the right decision in a reasonable time about the state of stability of the disturbed machine.

3. Design of a relaying system, with blocking ability, to ensure system stability.

Such a protection system will go a long way to solve the transient stability problem, and to give more reliable and continuous power service.

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