USN :

CMR Institute of Technology, Bangalore
DEPARTMENT OF ELECTRICAL & ELECTRONICS ENGINEERING
III - INTERNAL ASSESSMENT

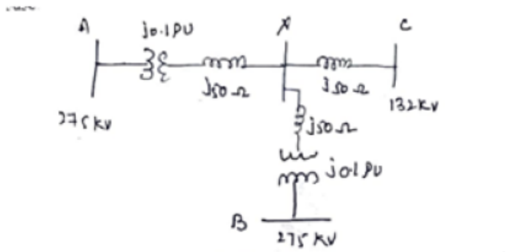
Semester: 8-CBCS 2017
Subject: POWER SYSTEM OPERATION & CONTROL (17EE81)
Faculty: Ms Sanitha

Date: 18 Jul 2021
Time: 10:00 AM - 11:30 AM
Max Marks: 50

Instructions to Students :

Answer any 5 questions .Each carries 10 marks.

Answer any 5 question(s)

Q.No		Marks	CO	PO	BT/CL
1	Explain about generation and absorption of reactive power in electrical power systems	10	CO5	PO3	L2
2	3 generating units are connected to a common busbars X,as shown in fig. for a particular system load,the line voltage at the bus bar falls by 2 kV. Calculate the reactive power injection required to bring back the voltage to the original value.All pu values are on 500 MVA base. 	10	CO5	PO4	L4
3	With the help of flow chart explain contingency analysis.	10	CO6	PO1,PO2	L1
4	Explain about linear sensitivity factors.	10	CO6	PO2	L2
5	Explain about P1Q method for contingency ranking. Also explain contingency processing using AC load flow analysis with a flowchart.	10	CO6	PO1	L3
6	Explain voltage control using : tap changing transformers, booster transformers and phase shifting transformers	10	CO5	PO2	L2

5.2 The Generation and Absorption of Reactive Power

In view of the findings in the previous section, a review of the characteristics of a power system from the viewpoint of reactive power is now appropriate.

5.2.1 *Synchronous generators*

These can be used to generate or absorb reactive power. The limits on the capability for this can be seen in Figure 3.14. The ability to supply reactive power is determined by the short-circuit ratio (1/synchronous reactance) as the distance between the power axis and the theoretical stability-limit line in Figure 3.14 is proportional to the short-circuit ratio. In modern machines the value of this ratio is made low for economic reasons, and hence the inherent ability to operate at leading power factors is not large. For example, a 200 MW 0.85 p.f. machine with a 10 per cent stability allowance has a capability of 45 MVAr at full power output. The var capacity can, however, be increased by the use of continuously acting voltage regulators, as explained in Chapter 3. An overexcited machine, i.e. one with greater than normal excitation, generates reactive power whilst an underexcited machine absorbs it. The generator is the main source of supply to the system of both positive and negative vars.

5.2.2 *Overhead lines and transformers*

When fully loaded, lines absorb reactive power. With a current I amperes for a line of reactance per phase $X(\Omega)$ the vars absorbed are I^2X per phase. On light loads the shunt capacitances of longer lines may become predominant and the lines then become var generators.

Transformers always absorb reactive power. A useful expression for the quantity may be obtained for a transformer of reactance X_T p.u. and a full-load rating of $3V \cdot I_{rated}$.

The ohmic reactance

$$= \frac{V \cdot X_T}{I_{rated}}$$

Therefore the vars absorbed

$$= 3 \cdot I^2 \cdot \frac{V \cdot X_T}{I_{rated}}$$

$$= 3 \cdot \frac{I^2 V^2}{(IV)_{rated}} \cdot X_T = \frac{(VA \text{ of load})^2}{\text{Rated } VA} \cdot X_T$$

5.2.3 Cables

Cables are generators of reactive power owing to their high shunt capacitance. A 275 kV, 240 MVA cable produces 6.25–7.5 MVAr per km; a 132 kV cable roughly 1.9 MVAr per km; and a 33kV cable, 0.125 MVAr per km.

5.2.4 Loads

A load at 0.95 power factor implies a reactive power demand of 0.33 kVAr per kW of power, which is more appreciable than the mere quoting of the power factor would suggest. In planning a network it is desirable to assess the reactive power requirements to ascertain whether the generators are able to operate at the required power factors for the extremes of load to be expected. An example of this is shown in Figure 5.2, where the reactive losses are added for each item until the generator power factor is obtained.

2

The line diagram and equivalent single-phase circuit are shown in Figures 5.4 and 5.5.

It is necessary to determine the value of $\partial Q/\partial V$ at the node or busbar M; hence the current flowing into a three-phase short-circuit at M is required.

The base value of reactance in the 132 kV circuit is

$$\frac{132^2 \times 1000}{500\,000} = 35\,\Omega$$

Therefore the line reactances

$$= \frac{j50}{35} = j1.43 \text{ p.u.}$$

The equivalent reactance from M to N $= j0.5$ p.u.

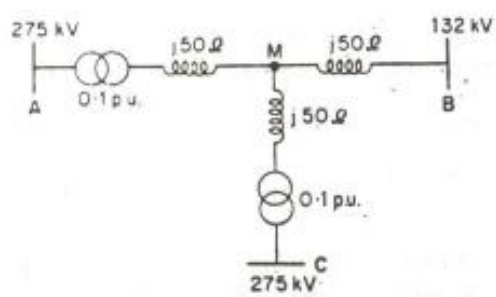


Figure 5.4 Schematic diagram of the system for Example 5.2

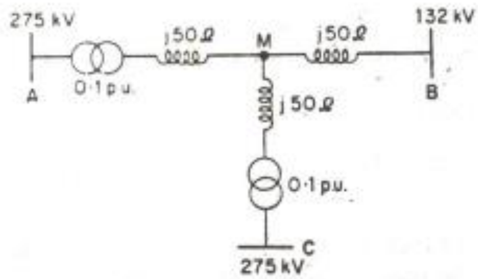
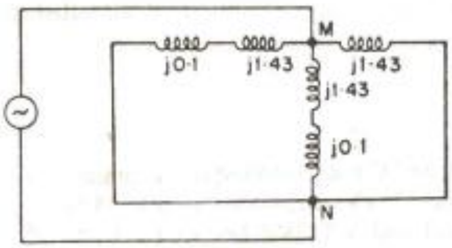


Figure 5.4 Schematic diagram of the system for Example 5.2



Hence the fault MVA at M

$$= \frac{500}{0.5} = 1000 \text{ MVA}$$

and the fault current

$$= \frac{1000 \times 10^6}{\sqrt{(3)} \times 132\,000}$$

$$= 4380 \text{ A} \quad \text{at zero power factor lagging}$$

It has been shown that $\partial Q_M/\sqrt{(3)}\partial V_M$ = three-phase short-circuit current when Q_M and V_M are three-phase and line values

$$\therefore \frac{\partial Q_M}{\partial V_M} = 7.6 \text{ MVAr/kV}$$

The natural drop at M =2 kV.therefore the value of the injected vars required =7.6*2=15.2MVAr

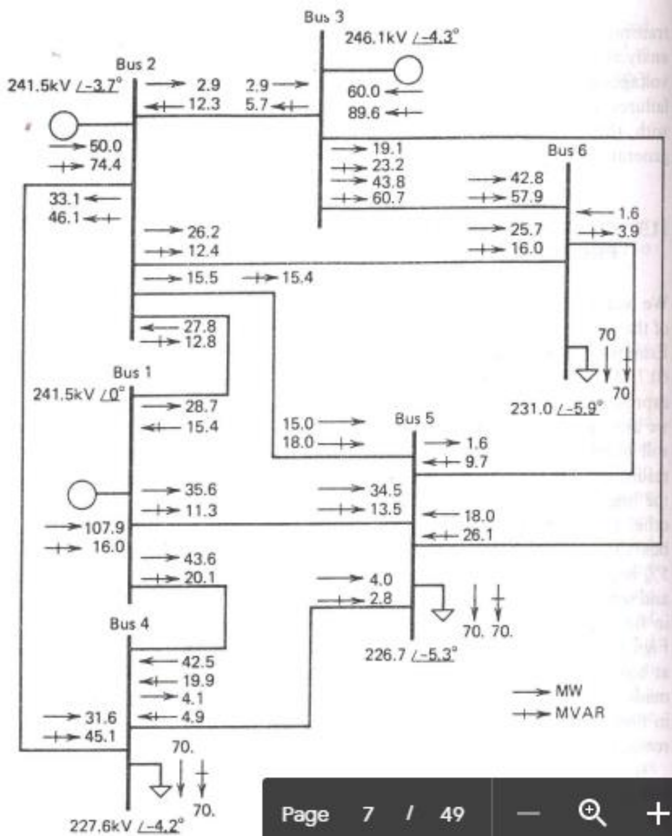


FIG. 11.1 Six-bus network base case AC power flow (see Example 4A).

contingency analysis techniques are used. Contingency analysis procedures model single failure events (i.e., one-line outage or one-generator outage) or multiple equipment failure events (i.e., two transmission lines, one transmission line plus one generator, etc.), one after another in sequence until "all credible outages" have been studied. For each outage tested, the contingency analysis procedure checks all lines and voltages in the network against their respective limits. The simplest form of such a contingency analysis technique is shown in Figure 11.5.

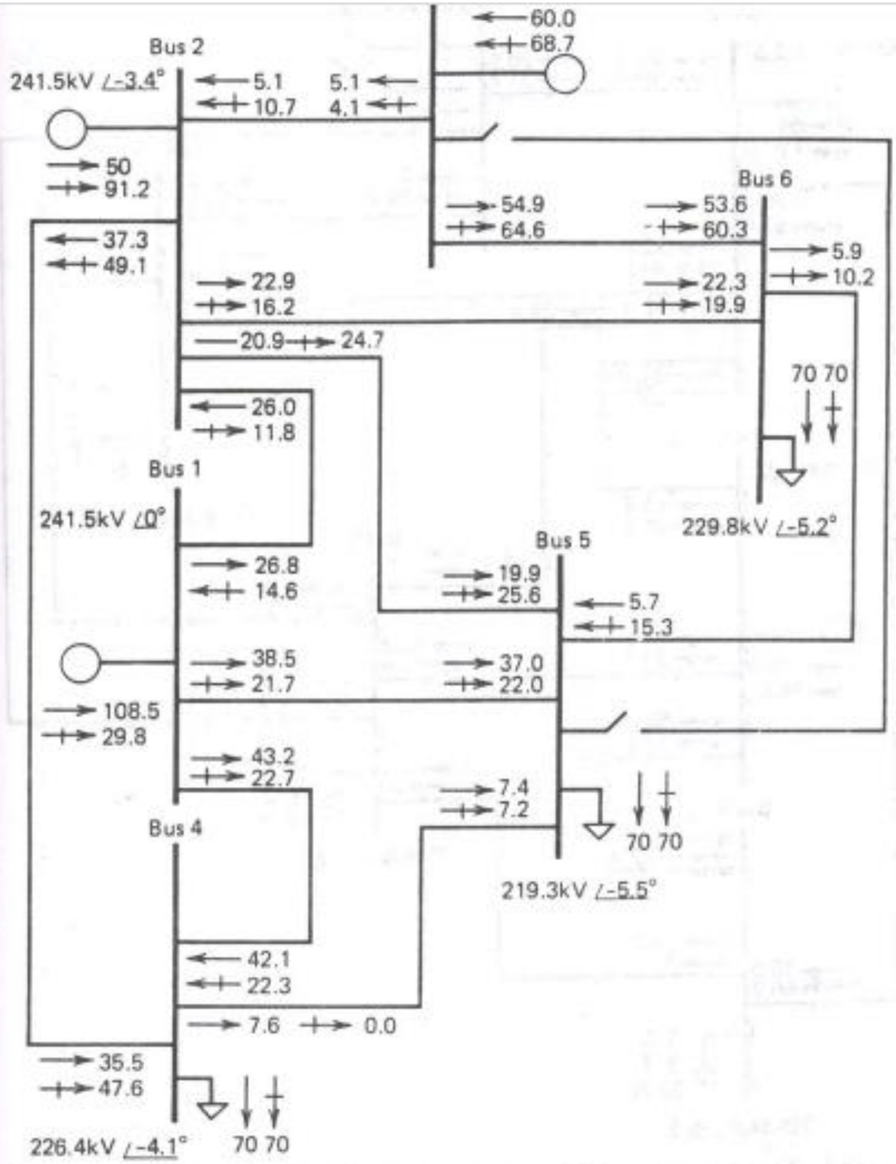


FIG. 11.2 Six-bus network line outage case; line from bus 3 to bus 5 opened.

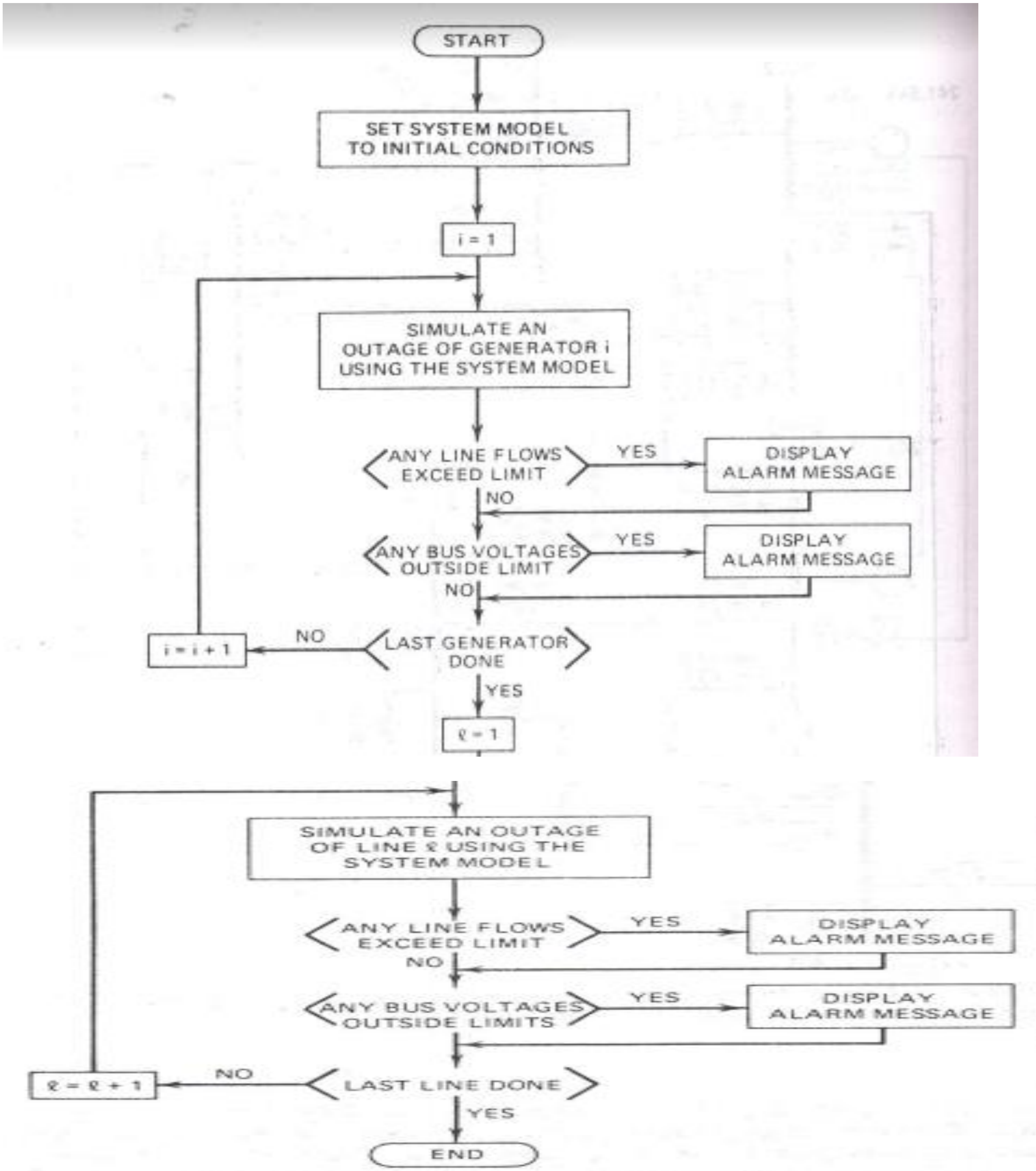


FIG. 11.5 Contingency analysis procedure.

11.3.1 An Overview of Security Analysis

A security analysis study which is run in an operations center must be executed very quickly in order to be of any use to operators. There are three basic ways to accomplish this.

- Study the power system with approximate but very fast algorithms.
- Select only the important cases for detailed analysis.
- Use a computer system made up of multiple processors or vector processors to gain speed.

The first method has been in use for many years and goes under various names such as "D factor methods," "linear sensitivity methods," "DC power flow methods," etc. This approach is useful if one only desires an approximate analysis of the effect of each outage. This text presents these methods under the name linear sensitivity factors and uses the same derivation as was presented in Chapter 4 under the DC power flow methods. It has all the limitations attributed to the DC power flow; that is, only branch MW flows are calculated and these are only within about 5% accuracy. There is no knowledge of MVAR flows or bus voltage magnitudes. Linear sensitivity factors are presented in Section 11.3.2.

If it is necessary to know a power system's MVA flows and bus voltage magnitudes after a contingency outage, then some form of complete AC power flow must be used. This presents a great deal of difficulty when thousands of cases must be checked. It is simply impossible, even on the fastest processors in existence today (1995) to execute thousands of complete AC power flows quickly enough. Fortunately, this need not be done as most of the cases result in power flow results which do not have flow or voltage limit violations. What is needed are ways to eliminate all or most of the nonviolation cases and only run complete power flows on the "critical" cases. These techniques go under the names of "contingency selection" or "contingency screening" and are introduced in Section 11.3.4.

introduced in Section 11.3.4.

Last of all, it must be mentioned that there are ways of running thousands of contingency power flows if special computing facilities are used. These facilities involve the use of many processors running separate cases in parallel, or vector processors which achieve parallel operation by "unwinding" the looping instruction sets in the computer code used. As of the writing of this edition (1995), such techniques are still in the research stage.

11.3.2 Linear Sensitivity Factors

The problem of studying thousands of possible outages becomes very difficult to solve if it is desired to present the results quickly. One of the easiest ways to provide a quick calculation of possible overloads is to use *linear sensitivity factors*. These factors show the approximate change in line flows for changes in generation on the network configuration and are derived from the DC load flow presented in Chapter 4. These factors can be derived in a variety of ways and basically come down to two types:

1. Generation shift factors.
2. Line outage distribution factors.

Here, we shall describe how these factors are used. The derivation of sensitivity factors is given in Appendix 11A.

The generation shift factors are designated $a_{\ell i}$ and have the following definition:

$$a_{\ell i} = \frac{\Delta f_\ell}{\Delta P_i} \tag{11.1}$$

where

ℓ = line index

i = bus index

Δf_ℓ = change in megawatt power flow on line ℓ when a change in generation, ΔP_i, occurs at bus i

ΔP_i = change in generation at bus i

It is assumed in this definition that the change in generation, ΔP_i, is exactly compensated by an opposite change in generation at the reference bus, and that all other generators remain fixed. The $a_{\ell i}$ factor then represents the sensitivity of the flow on line ℓ to a change in generation at bus i. Suppose one wanted to study the outage of a large generating unit and it was assumed that all the generation lost would be made up by the reference generation (we will deal with the case where the generation is picked up by many machines shortly). If the generator in question was generating P_i^0 MW and it was lost, we would represent ΔP_i as

$$\Delta P_i = -P_i^0 \tag{11.2}$$

and the new power flow on each line in the network could be calculated using a precalculated set of "a" factors as follows:

$$\hat{f}_\ell = f_\ell^0 + a_{\ell i}\Delta P_i \quad \text{for } \ell = 1 \ldots L \tag{11.3}$$

where

$\hat{f}_\ell$ = flow on line ℓ after the generator on bus i fails

f_ℓ^0 = flow before the failure

The "outage flow," $\hat{f}_\ell$, on each line can be compared to its limit and those exceeding their limit flagged for alarming. This would tell the operations personnel that the loss of the generator on bus i would result in an overload on line

The generation shift sensitivity factors are linear estimates of the change in flow with a change in power at a bus. Therefore, the effects of simultaneous changes on several generating buses can be calculated using superposition. Suppose, for example, that the loss of the generator on bus i were compensated by governor action on machines throughout the interconnected system. One frequently used method assumes that the remaining generators pick up in proportion to their maximum MW rating. Thus, the proportion of generation pickup from unit j ($j \neq i$) would be

$$\gamma_{ji} = \frac{P_j^{\max}}{\sum\limits_{\substack{k \\ k \neq i}} P_k^{\max}} \tag{11.4}$$

where

$P_k^{\max}$ = maximum MW rating for generator k

γ_{ji} = proportionality factor for pickup on generating unit j when unit i fails

Then, to test for the flow on line ℓ, under the assumption that all the generators in the interconnection participate in making up the loss, use the following:

$$\hat{f}_\ell = f_\ell^0 + a_{\ell i}\Delta P_i - \sum_{j \neq i} [a_{\ell j}\gamma_{ji}\Delta P_i] \tag{11.5}$$

Note that this assumes that no unit will actually hit its maximum. If this is apt to be the case, a more detailed generation pickup algorithm that took account of generation limits would be required.

The line outage distribution factors are used in a similar manner, only they apply to the testing for overloads when transmission circuits are lost. By definition, the line outage distribution factor has the following meaning:

$$d_{\ell,k} = \frac{\Delta f_\ell}{f_k^0} \tag{11.6}$$

where

$d_{\ell,k}$ = line outage distribution factor when monitoring line ℓ after an outage on line k

Δf_ℓ = change in MW flow on line ℓ

f_k^0 = original flow on line k before it was outaged (opened)

If one knows the power on line ℓ and line k, the flow on line ℓ with line k out can be determined using "d" factors.

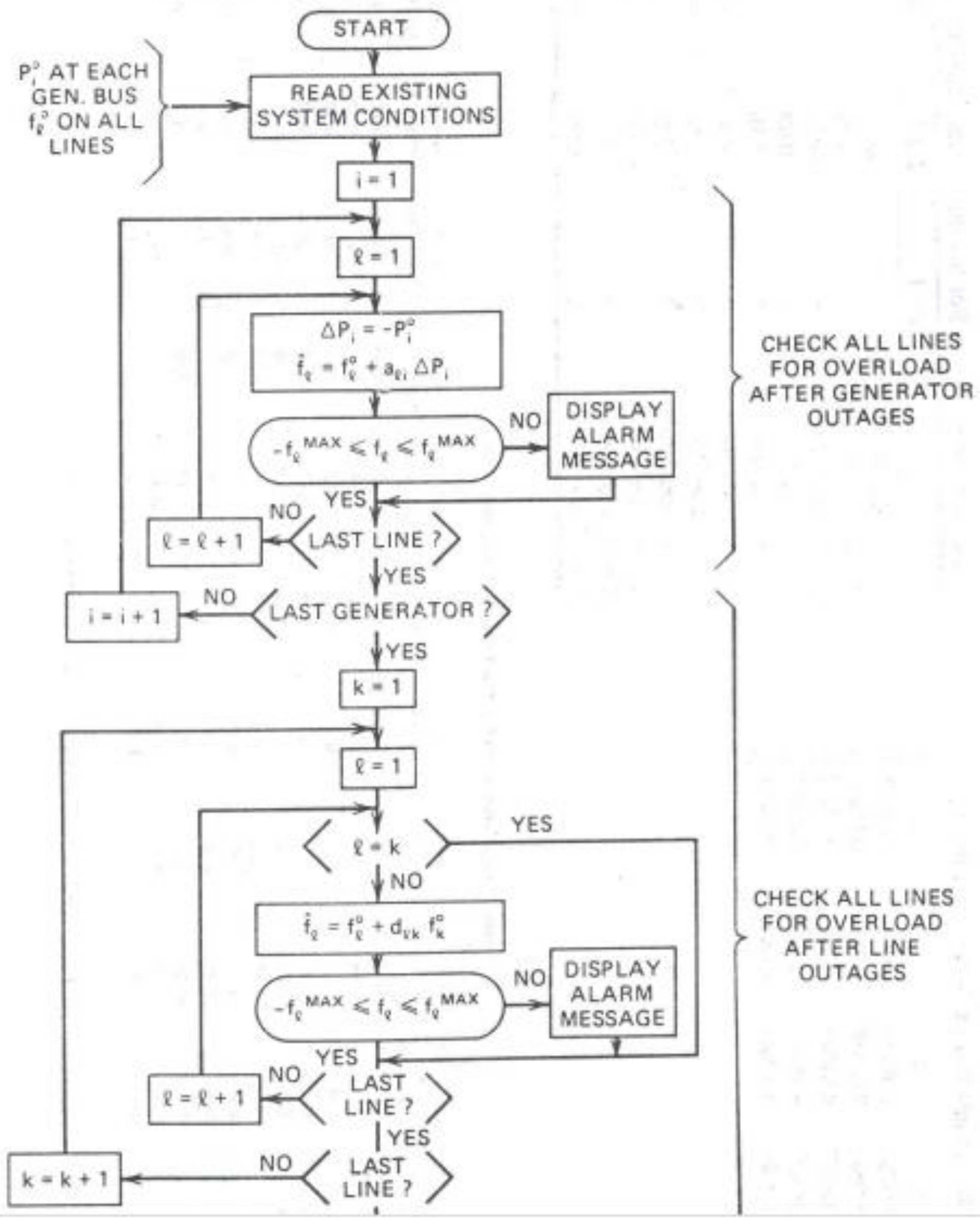
$$\hat{f}_\ell = f_\ell^0 + d_{\ell,k} f_k^0 \tag{11.7}$$

where

f_ℓ^0, f_k^0 = preoutage flows on lines ℓ and k, respectively

$\hat{f}_\ell$ = flow on line ℓ with line k out

By precalculating the line outage distribution factors, a very fast procedure can be set up to test all lines in the network for overload for the outage of a particular line. Furthermore, this procedure can be repeated for the outage of each line in turn, with overloads reported to the operations personnel in the form of alarm messages.


START
P AT EACH GEN. BUS
f ON ALL LINES
READ EXISTING SYSTEM CONDITIONS
i = 1
ℓ = 1
ΔP = -P
f = f + a ΔP
NO
DISPLAY ALARM MESSAGE
YES
NO
ℓ = ℓ + 1
LAST LINE ?
YES
i = i + 1
NO
LAST GENERATOR ?
YES
k = 1
ℓ = 1
ℓ = k
YES
NO
f = f + d f
NO
DISPLAY ALARM MESSAGE
YES
NO
ℓ = ℓ + 1
LAST LINE ?
YES
k = k + 1
NO
LAST LINE ?
CHECK ALL LINES FOR OVERLOAD AFTER GENERATOR OUTAGES
CHECK ALL LINES FOR OVERLOAD AFTER LINE OUTAGES

11.3.4 Contingency Selection

We would like to get some measure as to how much a particular outage might affect the power system. The idea of a performance index seems to fulfill this need. The definition for the overload performance index (PI) is as follows:

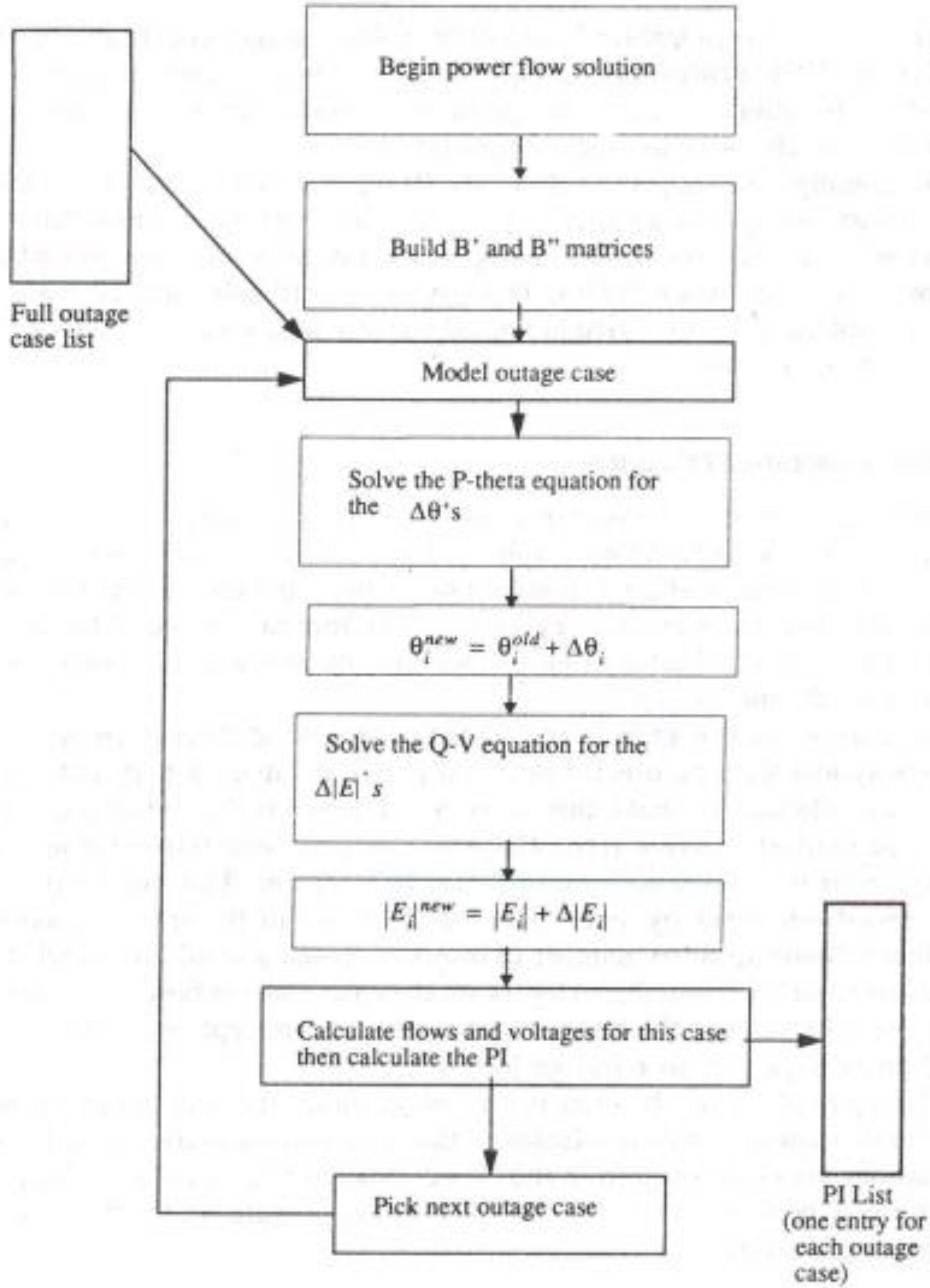
$$\mathrm{PI} = \sum_{\substack{\text{all branches} \\ l}} \left(\frac{P_{\text{flow } l}}{P_l^{\max}} \right)^{2n} \tag{11.8}$$

If n is a large number, the PI will be a small number if all flows are within limit, and it will be large if one or more lines are overloaded. The problem then is how to use this performance index.

Various techniques have been tried to obtain the value of PI when a branch is taken out. These calculations can be made exactly if $n = 1$; that is, a table of PI values, one for each line in the network, can be calculated quite quickly. The selection procedure then involves ordering the PI table from largest value to least. The lines corresponding to the top of the list are then the candidates for the short list. One procedure simply ordered the PI table and then picked the top N_c entries from this list and placed them on the short list (see reference 8).

However when $n = 1$, the PI does not snap from near zero to near infinity as the branch exceeds its limit. Instead, it rises as a quadratic function. A line that is just below its limit contributes to PI almost equal to one that is just over its limit. The result is a PI that may be large when many lines are loaded just below their limit. Thus the PI's ability to distinguish or detect bad cases is limited when $n = 1$. Ordering the PI values when $n = 1$ usually results in a list that is not at all representative of one with the truly bad cases at the top. Trying to develop an algorithm that can quickly calculate PI when $n = 2$ or larger has proven extremely difficult.

One way to perform an outage case selection is to perform what has been called the *1P1Q method* (see references 9 and 10). Here, a decoupled power flow is used. As shown in Figure 11.10, the solution procedure is interrupted after one iteration (one $P - \theta$ calculation and one $Q - V$ calculation; thus, the name 1P1Q). With this procedure, the PI can use as large an n value as desired, say $n = 5$. There appears to be sufficient information in the solution at the end of


Begin power flow solution
Full outage case list
Build B' and B" matrices
Model outage case
Solve the P-theta equation for the Δθ's
$\theta_i^{new} = \theta_i^{old} + \Delta\theta_i$
Solve the Q-V equation for the Δ|E|'s
$|E_i|^{new} = |E_i| + \Delta|E_i|$
Calculate flows and voltages for this case then calculate the PI
PI List (one entry for each outage case)
Pick next outage case

the first iteration of the decoupled power flow to give a reasonable PI. Another advantage to this procedure is the fact that the voltages can also be included in the PI. Thus, a different PI can be used, such as:

$$\mathrm{PI} = \sum_{\substack{\text{all branches} \\ l}} \left(\frac{P_{\text{flow } l}}{P_l^{\max}} \right)^{2n} + \sum_{\substack{\text{all buses} \\ i}} \left(\frac{\Delta |E_i|}{\Delta |E|^{\max}} \right)^{2m} \tag{11.9}$$

where $\Delta|E_i|$ is the difference between the voltage magnitude as solved at the end of the 1P1Q procedure and the base-case voltage magnitude. $\Delta|E|^{\max}$ is a value set by utility engineers indicating how much they wish to limit a bus voltage from changing on one outage case.

To complete the security analysis, the PI list is sorted so that the largest PI appears at the top. The security analysis can then start by executing full power flows with the case which is at the top of the list, then solve the case which is second, and so on down the list. This continues until either a fixed number of cases is solved, or until a predetermined number of cases are solved which do not have any alarms.

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5.5 Methods of Voltage Control: (ii) Tap-Changing Transformers

The basic operation of the tap-changing transformer has been discussed in Chapter 3; by changing the transformation ratio, the voltage in the secondary circuit is varied and voltage control is obtained. This constitutes the most popular and widespread form of voltage control at all voltage levels.

Consider the operation of a radial transmission system with two tap-changing transformers, as shown in the equivalent single-phase circuit of

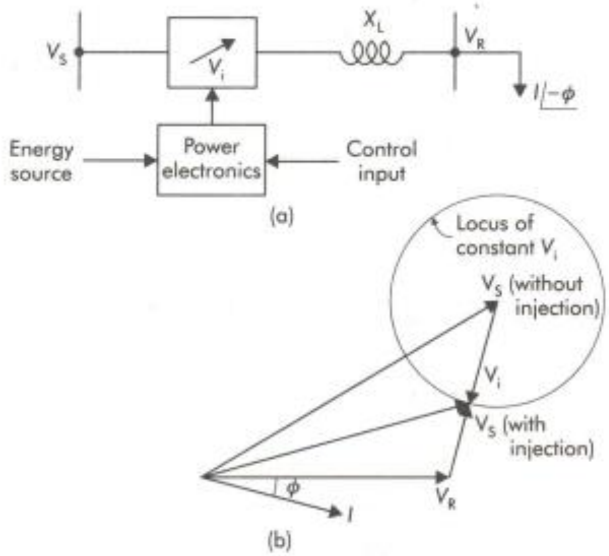

Figure 5.9 Principle of Universal Power Controller for series injection. (a) System diagram. (b) Phasor diagram

Figure 5.10. Here, t_s and t_r are fractions of the nominal transformation ratios, i.e. the tap ratio/nominal ratio. For example, a transformer of nominal ratio 6.6 to 33 kV when tapped to give 6.6 to 36 kV has a $t_r - 36/33 = 1.09$. V_1 and V_2 are the nominal voltages; at the ends of the line the actual voltages are $t_s V_1$ and $t_r V_2$. It is required to determine the tap-changing ratios required to completely compensate for the voltage drop in the line. The product $t_s t_r$ will be made unity; this ensures that the overall voltage level remains in the same order and that the minimum range of taps on both transformers is used.

Transfer all quantitites to the load circuit. The line impedance becomes $(R + jX)/t_r^2$; $V_s = V_1 t_s$ and, as the impedance has been transferred, $V_r = V_1 t_s$. The input voltage to the load circuit becomes $V_1 t_s / t_r$ and the equivalent circuit is as shown in Figure 5.10(c). The arithmetic voltage drop

$$= (V_1 t_s / t_r) - V_2 \approx \frac{RP + XQ}{t_r^2 V_2}$$

When $t_r = 1/t_s$,

$$t_s^2 V_1 V_2 - V_2^2 = (RP + XQ)t_s^2$$

and

$$V_2 = \tfrac{1}{2}[t_s^2 V_1 \pm t_s(t_s^2 V_1^2 - 4(RP + XQ))^{\frac{1}{2}} \tag{5.7}$$

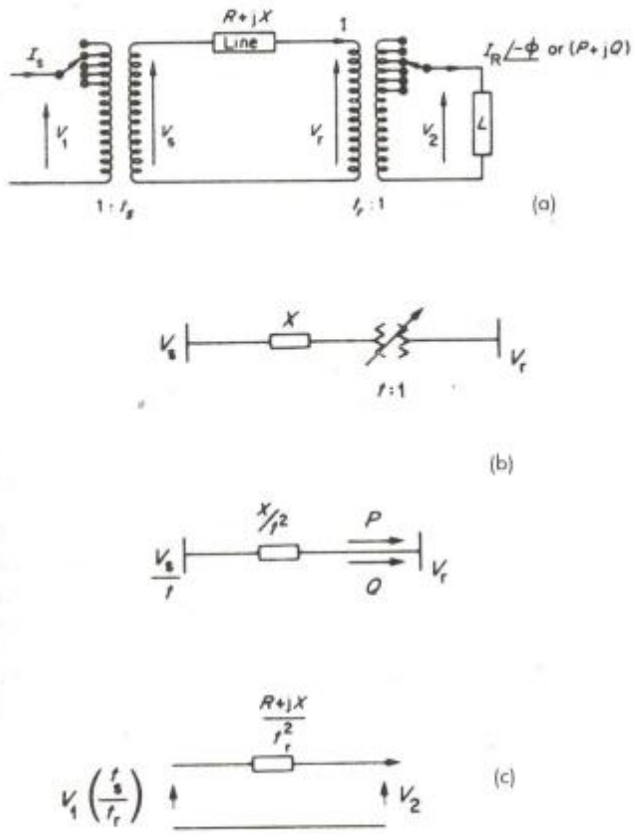

Figure 5.10 (a) Coordination of two tap-changing transformers in a radial transmission link (b) and (c) Equivalent circuits for dealing with off-nominal tap ratio. (b) Single transformer. (c) Two transformers

5.6 Combined Use of Tap-Changing Transformers and Reactive-Power Injection

The usual practical arrangement is shown in Figure 5.12, where the tertiar winding of a three-winding transformer is connected to a compensator. Fo given load conditions it is proposed to determine the necessary transformatio ratios with certain outputs of the compensator.

The transformer is represented by the equivalent star connection and a line impedance from V_1 or V_2 to the transformer can be lumped together wi the transformer branch impedances. Here, V_n is the phase voltage at the st point of the equivalent circuit in which the secondary impedance (X_s) is usual

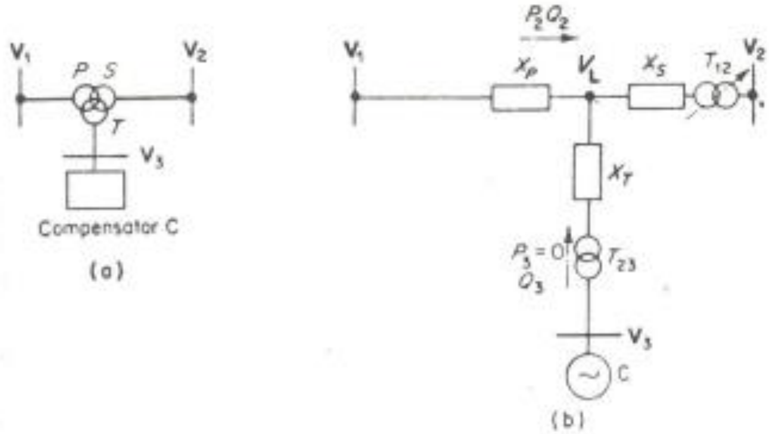

Figure 5.12 (a) Schematic diagram with combined tap-changing and synchronous compensation. (b) Equivalent network

approaching zero and hence is neglected. Resistance and losses are neglected. The allowable ranges of voltage for V_1 and V_2 are specified and the values of P_2, Q_2, P_3, and Q_3 are given; P_3 is usually taken as zero.

The volt drop V_1 to V_L

$$= \Delta V_p \approx X_p \frac{Q_2/3}{V_n}$$

or

$$\Delta V_p = X_p \frac{Q_2}{V_L\sqrt{3}},$$

where V_L is the line voltage $= \sqrt{(3)}V_n$, and Q_2 is the total vars. Also,

$$\Delta V_q = X_p \frac{P_2}{V_L\sqrt{3}}$$

$$\therefore (V_n + \Delta V_p)^2 + (\Delta V_q)^2 = V_1^2$$

(see phasor diagram of Figure 2.22; phase values used) and

$$\left(V_n + X_p \frac{Q_2}{V_L\sqrt{3}}\right)^2 + X_p^2\left(\frac{P_2^2}{3V_L^2}\right) = V_1^2$$

$$\therefore (V_L^2 + X_p Q_2)^2 + X_p^2 P_2^2 = V_{1L}^2 V_L^2$$

where V_{1L} is the line voltage $= \sqrt{(3)} V_1$

$$\therefore V_L^2 = \frac{V_{1L}^2 - 2X_p Q_2}{2} \pm \tfrac{1}{2}\sqrt{[V_{1L}^2(V_{1L}^2 - 4X_p Q_2) - 4 \cdot X_p^2 P_2^2]}$$

Once V_L is obtained, the transformation ratio is easily found. The procedure is best illustrated by an example.

5.7 Booster Transformers

It may be desirable, on technical or economic grounds, to increase the voltage at an intermediate point in a line rather than at the ends as with tap-changing transformers, or the system may not warrant the expense of tap-changing. Here, booster transformers are used as shown in Figure 5.15. The booster can be brought into the circuit by the closure of relay B and the opening of A, and vice versa. The mechanism by which the relays are operated can be controlled from a change in either the voltage or the current. The latter method is the more sensitive, as from no-load to full-load represents a 100 per cent change in current, but only in the order of a 10 per cent change in voltage. This booster gives an in-phase boost, as does a tap-changing transformer. An economic advantage is that the rating of the booster is the product of the current

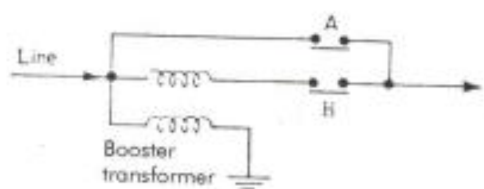

Figure 5.15 Connection of in-phase booster transformer. One phase only shown

5.7.1 Phase-shift transformer

A quadrature phase shift can be achieved by the connections shown in Figure 5.17(a). The booster arrangement shows the injection of voltage into one phase only; it is repeated for the other two phases. In Figure 5.17(b), the corresponding phasor diagram is shown and the nature of the angular shift of the voltage boost V'_{YB} indicated. By the use of tappings on the energizing transformer, several values of phase shift may be obtained.