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Improvement Test

Sub:	Power System Operation and Control							Code:	10EE82
Date:	25/5/2017	Duration:	90 mins	Max Marks:	50	Sem:	8	Branch:	EEE
Answer any FIVE Full Questions									

		Marks	OBE	
			CO	RBT
1	Derive the exact coordination equation for optimum loading of thermal power plants considering line losses.	[10]	CO5	L2
2	Explain the dynamic programming method to solve unit commitment problem.	[10]	CO5	L2
3	Explain security constrained optimal power flow with the help of typical power system one line diagram.	[10]	CO6	L2
4	Explain the contingency analysis for detection of network problems using a suitable flow chart	[10]	CO6	L2
			CO5	L2
			CO6	L2
5	Explain about unit commitment problems and its solution methods.	[10]		
6	Explain about the factors affecting power system security.	[10]		

Solutions:

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... due to start-up considerations.

7.5 OPTIMUM GENERATION SCHEDULING

From the unit commitment table of a given plant, the fuel cost curve of the plant can be determined in the form of a polynomial of suitable degree by the method of least squares fit. If the transmission losses are neglected, the total system load can be optimally divided among the various generating plants using the equal incremental cost criterion of Eq. (7.10). It is, however, unrealistic to neglect transmission losses particularly when long distance transmission of power is involved.

A modern electric utility serves over a vast area of relatively low load density. The transmission losses may vary from 5 to 15% of the total load, and therefore, it is essential to account for losses while developing an economic load dispatch policy. It is obvious that when losses are present, we can no longer use the simple 'equal incremental cost' criterion. To illustrate the point, consider a two-bus system with identical generators at each bus (i.e. the same IC curves). Assume that the load is located near plant 1 and plant 2 has to deliver power via a lossy line. Equal incremental cost criterion would dictate that each plant should carry half the total load; while it is obvious in this case that the plant 1 should carry a greater share of the load demand thereby reducing transmission losses.

In this section, we shall investigate how the load should be shared among various plants, when line losses are accounted for. The objective is to minimize the overall cost of generation

$$C = \sum_{i=1}^{k} C_i(P_{Gi}) \tag{7.7}$$

at any time under equality constraint of ...

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Equation (7.23) can also be written in the alternative form

$$(IC)_i = \lambda[1-(ITL)_i] \quad i = 1, 2, ..., k \tag{7.25}$$

This equation is referred to as the *exact coordination equation*.

Thus it is clear that to solve the optimum load scheduling problem, it is necessary to compute ITL for each plant, and therefore we must determine the functional dependence of transmission loss on real powers of generating plants. There are several methods, approximate and exact, for developing a transmission loss model. A full treatment of these is beyond the scope of this book. One of the most important, simple but approximate, methods of expressing transmission loss as a function of generator powers is through B-coefficients. This method is reasonably adequate for treatment of loss coordination in economic scheduling of load between plants. The general form of the loss formula (derived later in this section) using B-coefficients is

$$P_L = \sum_{m=1}^{k}\sum_{n=1}^{k} P_{Gm}B_{mn}P_{Gn} \tag{7.26}$$

where

P_{Gm}, P_{Gn} = real power generation at m, nth plants

B_{mn} = loss coefficients which are constants under certain assumed operating conditions

If $P_G s$ are in megawatts, B_{mn} are in reciprocal of megawatts*. Computations, of course, may be carried out in per unit. Also, $B_{mn} = B_{nm}$.

Equation (7.26) for transmission loss may be written in the matrix form as

$$P_L = P_G^T B P_G \tag{7.27}$$

where

$$P_G = \begin{bmatrix} P_{G1} \\ P_{G2} \\ \vdots \\ P_{Gk} \end{bmatrix} \text{ and } B = \begin{bmatrix} B_{11} & B_{12} & \cdots & B_{lk} \\ B_{21} & B_{22} & \cdots & B_{2k} \\ \vdots & & & \vdots \\ B_{k} & B_{k2} & \cdots & B_{kk} \end{bmatrix}$$

It may be noted that B is a symmetric matrix.

For a three plant system, we can write the expression for loss as

$$P_L = B_{11}P_{G1}^2 + B_{22}P_{G2}^2 + B_{33}P_{G3}^2 + 2B_{12}P_{G1}P_{G2} + 2B_{23}P_{G2}P_{G3} + 2B_{31}P_{G3}P_{G1} \tag{7.28}$$

With the system power loss model as per Eq. (7.26), we can now write

$$\frac{\partial P_L}{\partial P_{Gi}} = \frac{\partial}{\partial P_{Gi}}\left[\sum_{m=1}^{k}\sum_{n=1}^{k} P_{Gm}B_{mn}P_{Gn}\right]$$

*B_{mn} (in pu) = B_{mn} (in MW^{-1}) × Base MVA

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$$= \frac{\partial}{\partial P_{Gi}}\left[\sum_{\substack{n=1\\n\neq i}}^{k} P_{Gi}B_{in}P_{Gn} + \sum_{\substack{m=1\\m\neq i}}^{k} P_{Gm}B_{mi}P_{Gi} + P_{Gi}B_{ii}P_{Gi}\right] \tag{7.29}$$

It may be noted that in the above expression other terms are independent of P_{Gi} and are, therefore, left out.

Simplifying Eq. (7.29) and recognizing that $B_{ij} = B_{ji}$, we can write

$$\frac{\partial P_L}{\partial P_{Gi}} = \sum_{j=1}^{k} 2B_{ij}P_{Gj} \tag{7.30a}$$

Assuming quadratic plant cost curves as

$$C_i(P_{Gi}) = \frac{1}{2}a_iP_{Gi}^2 + b_iP_{Gi} + d_i$$

We obtain the incremental cost as

$$\frac{dC_i}{dP_{Gi}} = a_iP_{Gi} + b_i \tag{7.30b}$$

Substituting $\partial P_L/\partial P_{Gi}$ and dC_i/dP_{Gi} from above in the coordination Eq. (7.22), we have

$$a_iP_{Gi} + b_i + \lambda\sum_{j=1}^{k} 2B_{ij}P_{G_j} = \lambda \tag{7.31}$$

Collecting all terms of P_{Gi} and solving for P_{Gi}, we obtain

$$(a_i + 2\lambda B_{ii})\,P_{Gi} = -\,\lambda\sum_{\substack{j=1\\j\neq i}}^{k} 2B_{ij}P_{Gj} - b_i + \lambda$$

$$P_{Gi} = \frac{1 - \dfrac{b_i}{\lambda} - \displaystyle\sum_{\substack{j=1\\j\neq i}}^{k} 2B_{ij}P_{Gj}}{\dfrac{a_i}{\lambda} + 2B_{ii}};\ i = 1, 2, \ldots, k \tag{7.32}$$

For any particular value of λ, Eq. (7.32) can be solved iteratively by assuming initial values of P_{Gi}s(a convenient choice is $P_{Gi} = 0$; $i = 1, 2, \ldots, k$). Iterations are stopped when $P_{Gi}s$ converge within specified accuracy.

Equation (7.32) along with the power balance Eq. (7.19) for a particular load demand P_D are solved iteratively on the following lines:

1. Initially choose $\lambda = \lambda_0$.
2. Assume $P_{Gi} = 0$; $i = 1, 2, \ldots, k$.
3. Solve Eq. (7.32) iteratively for $P_{Gi}s$.

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4. Calculate $P_L = \sum_{i=1}^{k}\sum_{j=1}^{k} P_{Gi} B_{ij} P_{Gj}$.

5. Check if power balance equation (7.19) is satisfied, i.e.

$$\left| \sum_{n=1}^{k} P_{Gi} - P_D - P_L \right| < \varepsilon \quad \text{(a specified value)}$$

If yes, stop. Otherwise, go to step 6.

6. Increase λ by $\Delta\lambda$ (a suitable step size); if $\left(\sum_{i=1}^{k} P_{Gi} - P_D - P_L \right) < 0$ or

decrease λ by $\Delta\lambda$ (a suitable step size); if $\left(\sum_{i=1}^{k} P_{Gi} - P_D - P_L \right) > 0$,

repeat from step 3.

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5.2.2 Dynamic-Programming Solution

5.2.2.1 *Introduction*

Dynamic programming has many advantages over the enumeration scheme, the chief advantage being a reduction in the dimensionality of the problem. Suppose we have found units in a system and any combination of them could serve the (single) load. There would be a maximum of $2^4 - 1 = 15$ combinations to test. However, if a strict priority order is imposed, there are only four combinations to try:

Priority 1 unit
Priority 1 unit + Priority 2 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

The imposition of a priority list arranged in order of the full-load average-cost rate would result in a theoretically correct dispatch and commitment only if

1. No load costs are zero.
2. Unit input–output characteristics are linear between zero output and full load.
3. There are no other restrictions.
4. Start-up costs are a fixed amount.

In the dynamic-programming approach that follows, we assume that:

1. A *state* consists of an array of units with specified units operating and the rest off-line.
2. The start-up cost of a unit is independent of the time it has been off-line (i.e., it is a fixed amount).
3. There are no costs for shutting down a unit.
4. There is a strict priority order, and in each interval a specified minimum amount of capacity must be operating.

A feasible state is one in which the committed units can supply the required load and that meets the minimum amount of capacity each period.

5.2.2.2 *Forward DP Approach*

One could set up a dynamic-programming algorithm to run backward in time starting from the final hour to be studied, back to the initial hour. Conversely, one could set up the algorithm to run forward in time from the initial hour to the final hour. The forward approach has distinct advantages in solving generator unit commitment. For example, if the start-up cost of a unit is a function of the time it has been off-line (i.e., its temperature), then a forward dynamic-program approach is more suitable since the previous history of the unit can be computed at each stage. There are other practical reasons for going forward. The initial conditions are easily specified and the computations can go forward in time as long as required. A forward dynamic-programming algorithm is shown by the flowchart in Figure 5.4.

The recursive algorithm to compute the minimum cost in hour K with combination I is,

$$F_{\text{cost}}(K, I) = \min_{\{L\}} [P_{\text{cost}}(K, I) + S_{\text{cost}}(K-1, L: K, I) + F_{\text{cost}}(K-1, L)] \quad (5.1)$$

where

$F_{\text{cost}}(K, I)$ = least total cost to arrive at state (K, I)

$P_{\text{cost}}(K, I)$ = production cost for state (K, I)

$S_{\text{cost}}(K-1, L: K, I)$ = transition cost from state $(K-1, L)$ to state (K, I)

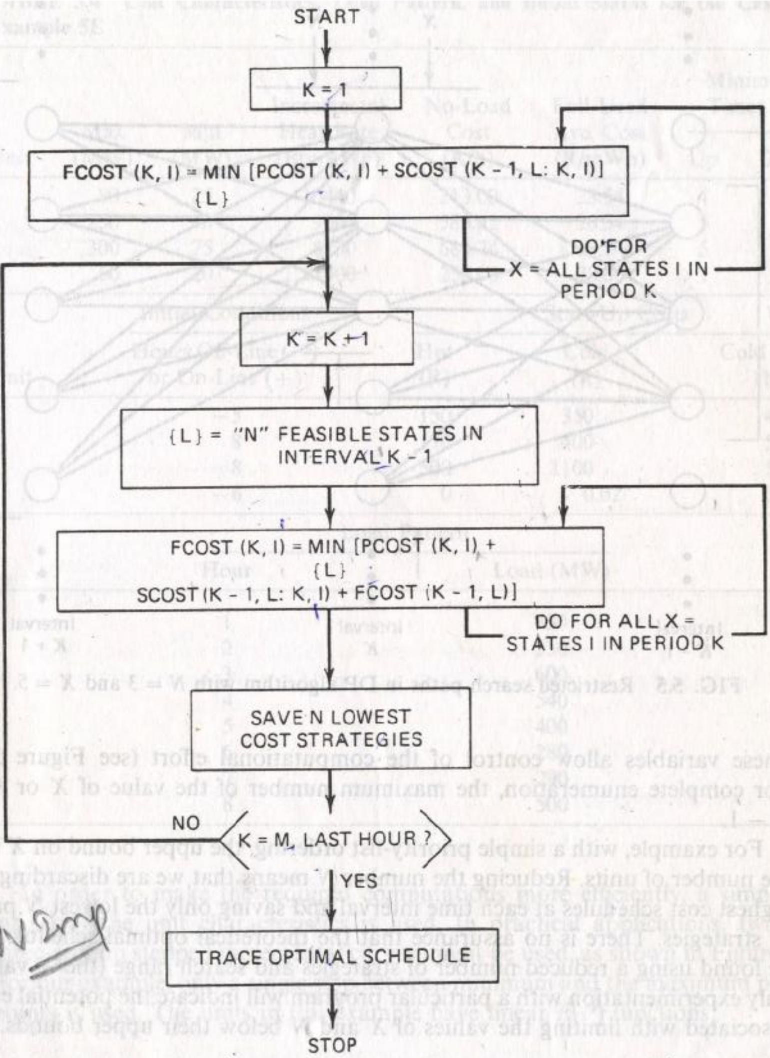

FIG. 5.4 Unit commitment via forward dynamic programming.

State (K, I) is the I^{th} combination in hour K. For the forward dynamic-programming approach, we define a *strategy* as the transition, or path, from one state at a given hour to a state at the next hour.

Note that two new variables, X and N, have been introduced in Figure 5.4.

$$X = \text{number of states to search each period}$$

$$N = \text{number of strategies, or paths, to save at each step}$$

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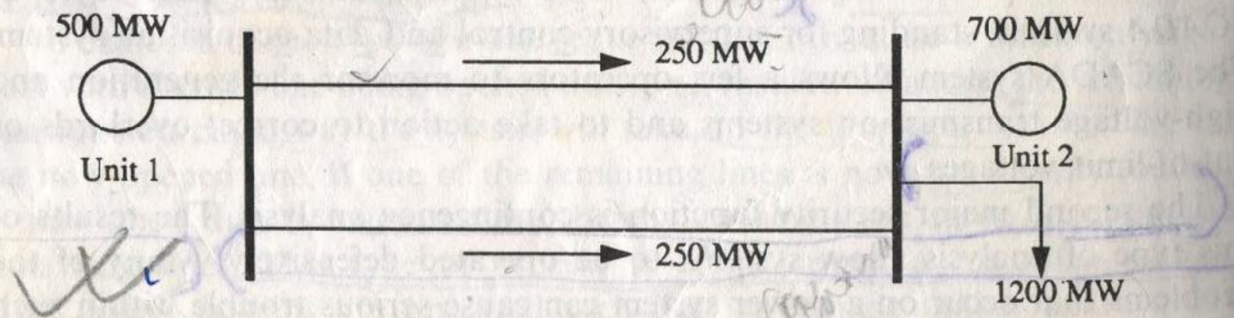
- **Optimal dispatch:** this is the state that the power system is in prior to any contingency. It is optimal with respect to economic operation, but it may not be secure.
- **Post contingency:** is the state of the power system after a contingency has occurred. We shall assume here that this condition has a security violation (line or transformer beyond its flow limit, or a bus voltage outside the limit).
- **Secure dispatch:** is the state of the system with no contingency outages, but with corrections to the operating parameters to account for security violations.
- **Secure post-contingency:** is the state of the system when the contingency is applied to the base-operating condition—with corrections.

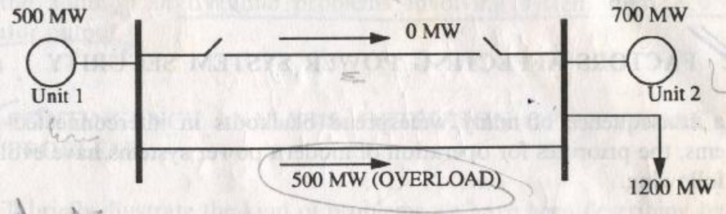
We shall illustrate the above with an example. Suppose the trivial power system consisting of two generators, a load, and a double circuit line, is to be operated with both generators supplying the load as shown below (ignore losses):



OPTIMAL DISPATCH

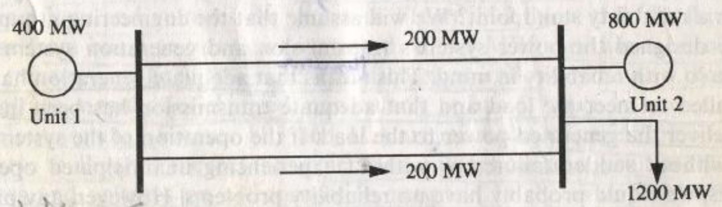
We assume that the system as shown is in economic dispatch, that is the 500 MW from unit 1 and the 700 MW from unit 2 is the optimum dispatch. Further, we assert that each circuit of the double circuit line can carry a maximum of 400 MW, so that there is no loading problem in the base-operating condition.

Now, we shall postulate that one of the two circuits making up the transmission line has been opened because of a failure. This results in



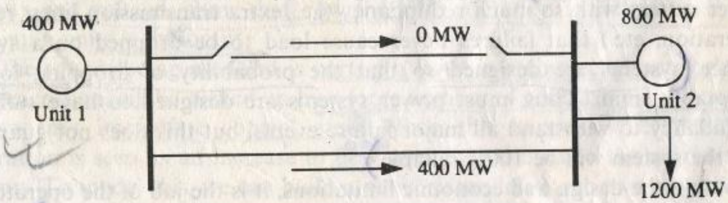
POST CONTINGENCY STATE

Now there is an overload on the remaining circuit. We shall assume for this example that we do not want this condition to arise and that we will correct the condition by lowering the generation on unit 1 to 400 MW. The secure dispatch is



SECURE DISPATCH

Now, if the same contingency analysis is done, the post-contingency condition is



SECURE POST CONTINGENCY STATE

By adjusting the generation on unit 1 and unit 2, we have prevented the post-contingency operating state from having an overload. This is the essence of what is called "security corrections." Programs which can make control adjustments to the base or pre-contingency operation to prevent violations in the post-contingency conditions are called "security-constrained optimal power flows" or SCOPF. These programs can take account of many contingencies and calculate adjustments to generator MW, generator voltages, transformer taps, interchange, etc. We shall show how the SCOPF is formed in Chapter 13.

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11.3 CONTINGENCY ANALYSIS: DETECTION OF NETWORK PROBLEMS

We will briefly illustrate the kind of problems we have been describing by use of the six-bus network used in Chapter 4. The base-case power flow results for Example 4A are shown in Figure 11.1 and indicate a flow of 43.8 MW and 60.7 MVAR on the line from bus 3 to bus 6. The limit on this line can be expressed in MW or in MVA. For the purpose of this discussion, assume that we are only interested in the MW loading on the line. Now let us ask what will happen if the transmission line from bus 3 to bus 5 were to open. The resulting flows and voltages are shown in Figure 11.2. Note that the flow on the line from bus 3 to bus 6 has increased to 54.9 MW and that most of the other transmission lines also experienced changes in flow. Note also that the bus voltage magnitudes changed, particularly at bus 5, which is now almost 5% below nominal. Figures 11.3 and 11.4 are examples of generator outages and serve to illustrate the fact that generation outages can also result in changes in flows and voltages on a transmission network. In the example shown in Figure 11.3, all the generation lost from bus 3 is picked up on the generator at bus 1. Figure 11.4 shows the case when the loss of generation on bus 3 is made up by an increase in generation at buses 1 and 2. Clearly, the differences in flows and voltages show that how the lost generation is picked up by the remaining units is imporant.

If the system being modeled is part of a large interconnected network, the lost generation will be picked up by a large number of generating units outside the system's immediate control area. When this happens, the pickup in generation is seen as an increase in flow over the tie lines to the neighboring systems. To model this, we can build a network model of our own system plus an equivalent network of our neighbor's system and place the swing bus or reference bus in the equivalent system. A generator outage is then modeled so that all lost generation is picked up on the swing bus, which then appears as an increase on the tie flows, thus approximately modeling the generation loss when interconnected. If, however, the system of interest is not interconnected, then the loss of generation must be shown as a pickup in output on the other generation units within the system. An approximate method of doing this is shown in Section 11.3.2.

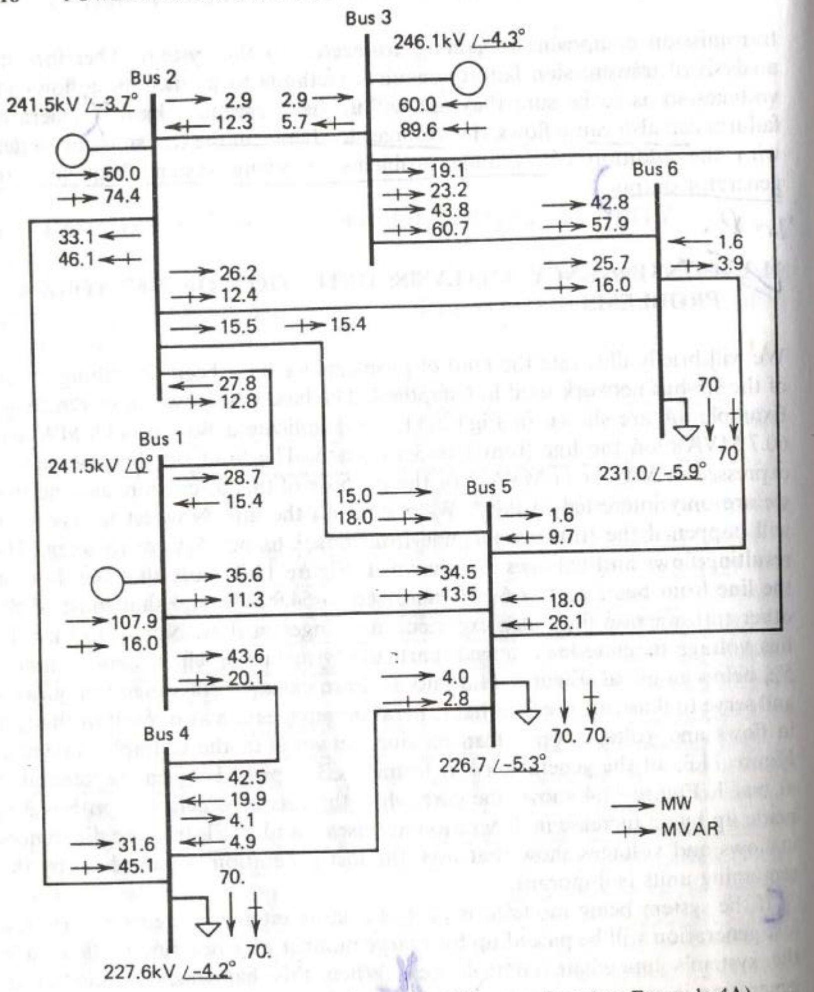

FIG. 11.1 Six-bus network base case AC power flow (see Example 4A).

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.

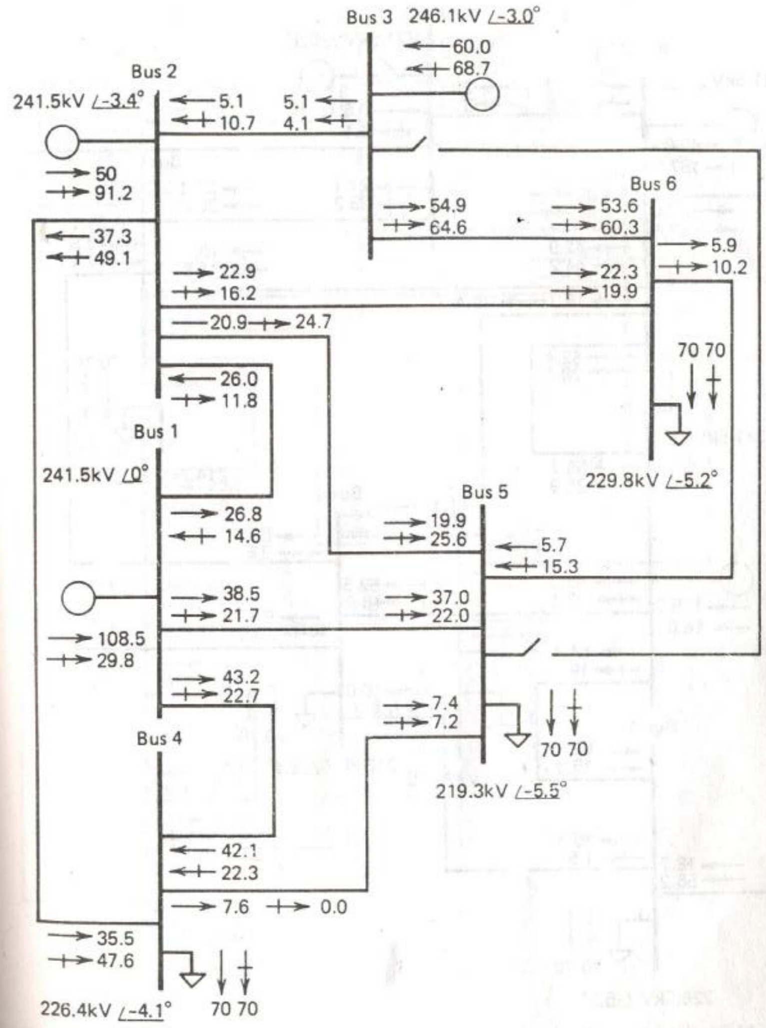

FIG. 11.2 Six-bus network line outage case; line from bus 3 to bus 5 opened.

The most difficult methodological problem to cope with in contingency analysis is the speed of solution of the model used. The most difficult logical problem is the selection of "all credible outages." If each outage case studied were to solve in 1 sec and several thousand outages were of concern, it would take close to 1 h before all cases could be reported. This would be useful if the system conditions did not change over that period of time. However, power

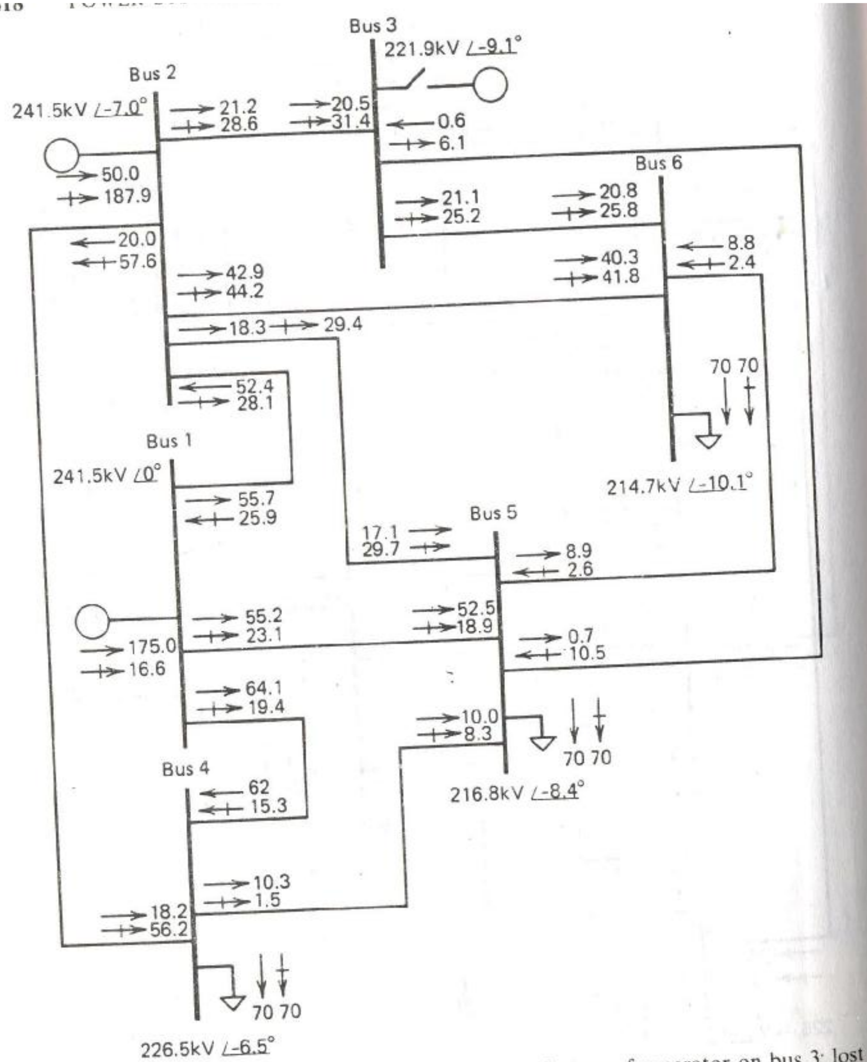

FIG. 11.3 Six-bus network generator outage case. Outage of generator on bus 3; lost generation picked up on generator 1.

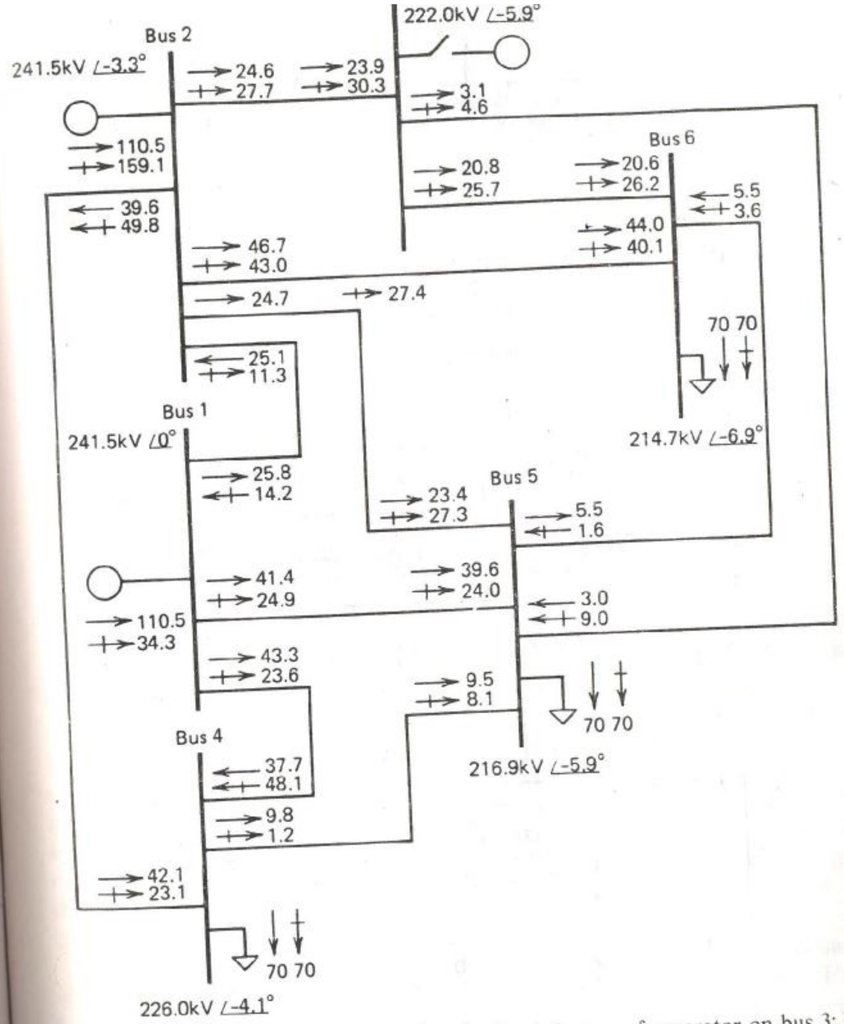

FIG. 11.4 Six-bus network generator outage case. Outage of generator on bus 3; lost generation picked up on generator 1 and generator 2.

systems are constantly undergoing changes and the operators usually need to know if the present operation of the system is safe, without waiting too long for the answer. Contingency analysis execution times of less than 1 min for several thousand outage cases are typical of computer and analytical technology as of 1995.

One way to gain speed of solution in a contingency analysis procedure is to use an approximate model of the power system. For many systems, the use of DC load flow models provides adequate capability. In such systems, the voltage magnitudes may not be of great concern and the DC load flow provides sufficient accuracy with respect to the megawatt flows. For other systems, voltage is a concern and full AC load flow analysis is required.

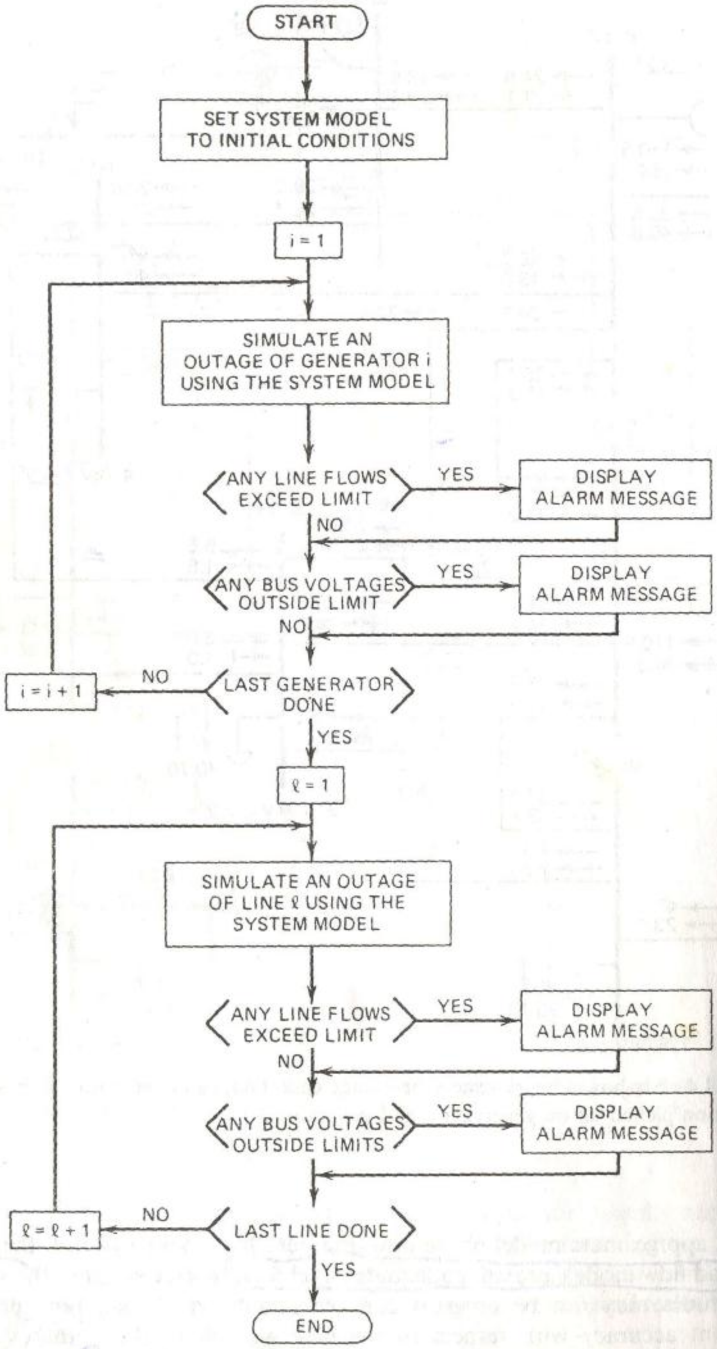

FIG. 11.5 Contingency analysis procedure.

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TABLE 5.2 "Shut-down Rule" Derivation for Example 5B

	Optimum Combination		
Load	Unit 1	Unit 2	Unit 3
1200	On	On	On
1150	On	On	On
1100	On	On	On
1050	On	On	On
1000	On	On	Off
950	On	On	Off
900	On	On	Off
850	On	On	Off
800	On	On	Off
750	On	On	Off
700	On	On	Off
650	On	On	Off
600	On	Off	Off
550	On	Off	Off
500	On	Off	Off

Figure 5.1b shows the unit commitment schedule derived from this shut-down rule as applied to the load curve of Figure 5.1a.

So far, we have only obeyed one simple constraint: *Enough units will be committed to supply the load.* If this were all that was involved in the unit commitment problem—that is, just meeting the load—we could stop here and state that the problem was "solved." Unfortunately, other constraints and other phenomena must be taken into account in order to claim an optimum solution. These constraints will be discussed in the next section, followed by a description of some of the presently used methods of solution.

5.1.1 Constraints in Unit Commitment

Many constraints can be placed on the unit commitment problem. The list presented here is by no means exhaustive. Each individual power system, power pool, reliability council, and so forth, may impose different rules on the scheduling of units, depending on the generation makeup, load-curve characteristics, and such.

5.1.2 Spinning Reserve

Spinning reserve is the term used to describe the total amount of generation available from all units synchronized (i.e., spinning) on the system, minus the present load and losses being supplied. Spinning reserve must be carried so that the loss of one or more units does not cause too far a drop in system frequency (see Chapter 9). Quite simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time period.

Spinning reserve must be allocated to obey certain rules, usually set by regional reliability councils (in the United States) that specify how the reserve is to be allocated to various units. Typical rules specify that reserve must be a given percentage of forecasted peak demand, or that reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time. Others calculate reserve requirements as a function of the probability of not having sufficient generation to meet the load.

Not only must the reserve be sufficient to make up for a generation-unit failure, but the reserves must be allocated among fast-responding units and slow-responding units. This allows the automatic generation control system (see Chapter 9) to restore frequency and interchange quickly in the event of a generating-unit outage.

Beyond spinning reserve, the unit commitment problem may involve various classes of "scheduled reserves" or "off-line" reserves. These include quick-start diesel or gas-turbine units as well as most hydro-units and pumped-storage hydro-units that can be brought on-line, synchronized, and brought up to full capacity quickly. As such, these units can be "counted" in the overall reserve assessment, as long as their time to come up to full capacity is taken into account.

Reserves, finally, must be spread around the power system to avoid transmission system limitations (often called "bottling" of reserves) and to allow various parts of the system to run as "islands," should they become electrically disconnected.

EXAMPLE 5C

Suppose a power system consisted of two isolated regions: a western region and an eastern region. Five units, as shown in Figure 5.2, have been committed to supply 3090 MW. The two regions are separated by transmission tie lines that can together transfer a maximum of 550 MW in either direction. This is also shown in Figure 5.2. What can we say about the allocation of spinning reserve in this system?

The data for the system in Figure 5.2 are given in Table 5.3. With the exception of unit 4, the loss of any unit on this system can be covered by the spinning reserve on the remaining units. Unit 4 presents a problem, however. If unit 4 were to be lost and unit 5 were to be run to its maximum of 600 MW, the eastern region would still need 590 MW to cover the load in that region. The 590 MW would have to be transmitted over the tie lines from the western region, which can easily supply 590 MW from its reserves. However, the tie capacity of only 550 MW limits the transfer. Therefore the loss of unit 4 ...

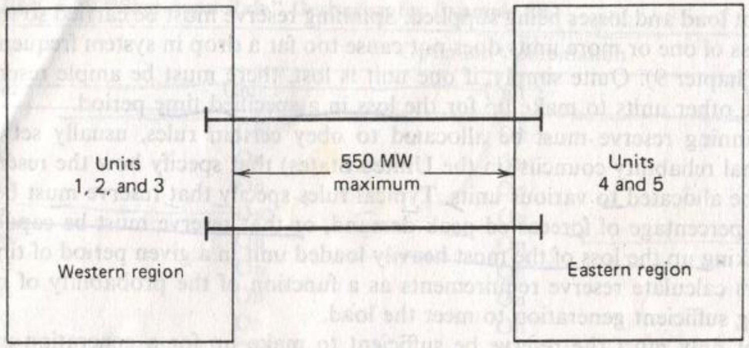

FIG. 5.2 Two-region system.

TABLE 5.3 Data for the System in Figure 5.2

Region	Unit	Unit Capacity (MW)	Unit Output (MW)	Regional Generation (MW)	Spinning Reserve	Regional Load (MW)	Interchange (MW)
Western	1	1000	900		100		
	2	800	420	1740	380	1900	160 in
	3	800	420		380		
Eastern	4	1200	1040	1350	160	1190	160 out
	5	600	310		290		
Total	1–5	4400	3090	3090	1310	3090	

be covered even though the entire system has ample reserves. The only solution to this problem is to commit more units to operate in the eastern region.

5.1.3 Thermal Unit Constraints

Thermal units usually require a crew to operate them, especially when turned on and turned off. A thermal unit can undergo only gradual temperature changes, and this translates into a time period of some hours required to bring the unit on-line. As a result of such restrictions in the operation of a thermal plant, various constraints arise, such as:

- **Minimum up time:** once the unit is running, it should not be turned off immediately.
- **Minimum down time:** once the unit is decommitted, there is a minimum time before it can be recommitted.

- **Crew constraints:** if a plant consists of two or more units, they cannot both be turned on at the same time since there are not enough crew members to attend both units while starting up.

In addition, because the temperature and pressure of the thermal unit must be moved slowly, a certain amount of energy must be expended to bring the unit on-line. This energy does not result in any MW generation from the unit and is brought into the unit commitment problem as a *start-up cost*.

The start-up cost can vary from a maximum "cold-start" value to a much smaller value if the unit was only turned off recently and is still relatively close to operating temperature. There are two approaches to treating a thermal unit during its down period. The first allows the unit's boiler to cool down and then heat back up to operating temperature in time for a scheduled turn on. The second (called *banking*) requires that sufficient energy be input to the boiler to just maintain operating temperature. The costs for the two can be compared so that, if possible, the best approach (cooling or banking) can be chosen.

$$\text{Start-up cost when cooling} = C_c(1 - \varepsilon^{-t/\alpha}) \times F + C_f$$

where

C_c = cold-start cost (MBtu)

F = fuel cost

C_f = fixed cost (includes crew expense, maintenance expenses) (in R)

α = thermal time constant for the unit

t = time (h) the unit was cooled

$$\text{Start-up cost when banking} = C_t \times t \times F + C_f$$

where

C_t = cost (MBtu/h) of maintaining unit at operating temperature

Up to a certain number of hours, the cost of banking will be less than the cost of cooling, as is illustrated in Figure 5.3.

Finally, the capacity limits of thermal units may change frequently, due to maintenance or unscheduled outages of various equipment in the plant; this must also be taken into account in unit commitment.

5.1.4 Other Constraints

5.1.4.1 *Hydro-Constraints*

Unit commitment cannot be completely separated from the scheduling of hydro-units. In this text, we will assume that the hydrothermal scheduling (or "coordination") problem can be separated from the unit commitment problem.

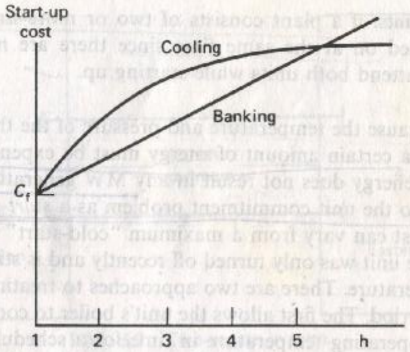

FIG. 5.3 Time-dependent start-up costs.

5.1.4.2 *Must Run*

Some units are given a must-run status during certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.

5.1.4.3 *Fuel Constraints*

We will treat the "fuel scheduling" problem briefly in Chapter 6. A system in which some units have limited fuel, or else have constraints that require them to burn a specified amount of fuel in a given time, presents a most challenging unit commitment problem.

5.2 UNIT COMMITMENT SOLUTION METHODS

The commitment problem can be very difficult. As a theoretical exercise, let us postulate the following situation.

- We must establish a loading pattern for M periods.
- We have N units to commit and dispatch.
- The M load levels and operating limits on the N units are such that any one unit can supply the individual loads and that any combination of units can also supply the loads.

Next, assume we are going to establish the commitment by enumeration (brute force). The total number of combinations we need to try each hour is,

$$C(N, 1) + C(N, 2) + \ldots + C(N, N-1) + C(N, N) = 2^N - 1$$

where $C(N, j)$ is the combination of N items taken j at a time. That is,

$$C(N, j) = \left[\frac{N!}{(N-j)!\,j!}\right]$$

$$j! = 1 \times 2 \times 3 \times \ldots \times j$$

For the total period of M intervals, the maximum number of possible combinations is $(2^N - 1)^M$, which can become a horrid number to think about.

For example, take a 24-h period (e.g., 24 one-hour intervals) and consider systems with 5, 10, 20, and 40 units. The value of $(2^N - 1)^{24}$ becomes the following.

N	$(2^N - 1)^{24}$
5	6.2×10^{35}
10	1.73×10^{72}
20	3.12×10^{144}
40	(Too big)

These very large numbers are the upper bounds for the number of enumerations required. Fortunately, the constraints on the units and the load-capacity relationships of typical utility systems are such that we do not approach these large numbers. Nevertheless, the real practical barrier in the optimized unit commitment problem is the high dimensionality of the possible solution space.

The most talked-about techniques for the solution of the unit commitment problem are:

- Priority-list schemes,
- Dynamic programming (DP),
- Lagrange relation (LR). X (not in syllabus.

5.2.1 Priority-List Methods

The simplest unit commitment solution method consists of creating a priority list of units. As we saw in Example 5B, a simple shut-down rule or priority-list scheme could be obtained after an exhaustive enumeration of all unit combinations at each load level. The priority list of Example 5B could be obtained in a much simpler manner by noting the full-load average production cost of each unit, where the full-load average production cost is simply the net heat rate at full load multiplied by the fuel cost.

EXAMPLE 5D

Construct a priority list for the units of Example 5A. (Use the same fuel costs as in Example 5A.) First, the full-load average production cost will be calculated:

Unit	Full Load Average Production Cost (R/MWh)
1	9.79
2	9.48
3	11.188

A strict priority order for these units, based on the average production cost, would order them as follows:

Unit	R/MWh	Min MW	Max MW
2	9.48	100	400
1	9.79	150	600
3	11.188	50	200

and the commitment scheme would (ignoring min up/down time, start-up costs, etc.) simply use only the following combinations.

Combination	Min MW from Combination	Max MW from Combination
2 + 1 + 3	300	1200
2 + 1	250	1000
2	100	400

Note that such a scheme would not completely parallel the shut-down sequence described in Example 5B, where unit 2 was shut down at 600 MW leaving unit 1. With the priority-list scheme, both units would be held on until load reached 400 MW, then unit 1 would be dropped.

Most priority-list schemes are built around a simple shut-down algorithm that might operate as follows.

- At each hour when load is dropping, determine whether dropping the next unit on the priority list will leave sufficient generation to supply the load plus spinning-reserve requirements. If not, continue operating as is; if yes, go on to the next step.
- Determine the number of hours, H, before the unit will be needed again. That is, assuming that the load is dropping and will then go back up some hours later.
- If H is less than the minimum shut-down time for the unit, keep commitment as is and go to last step; if not, go to next step.
- Calculate two costs. The first is the sum of the hourly production costs for the next H hours with the unit up. Then recalculate the same sum for the unit down and add in the start-up cost for either cooling the unit or banking it, whichever is less expensive. If there is sufficient savings from shutting down the unit, it should be shut down, otherwise keep it on.
- Repeat this entire procedure for the next unit on the priority list. If it is also dropped, go to the next and so forth.

Various enhancements to the priority-list scheme can be made by grouping of units to ensure that various constraints are met. We will note later that dynamic-programming methods usually create the same type of priority list for use in the DP search.

5.2.2 Dynamic-Programming Solution

5.2.2.1 *Introduction*

Dynamic programming has many advantages over the enumeration scheme, the chief advantage being a reduction in the dimensionality of the problem. Suppose we have found units in a system and any combination of them could serve the (single) load. There would be a maximum of $2^4 - 1 = 15$ combinations to test. However, if a strict priority order is imposed, there are only four combinations to try:

Priority 1 unit
Priority 1 unit + Priority 2 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit
Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

The imposition of a priority list arranged in order of the full-load average-cost rate would result in a theoretically correct dispatch and commitment only if:

11.2 FACTORS AFFECTING POWER SYSTEM SECURITY

As a consequence of many widespread blackouts in interconnected power systems, the priorities for operation of modern power systems have evolved to the following.

- Operate the system in such a way that power is delivered reliably.
- Within the constraints placed on the system operation by reliability considerations, the system will be operated most economically.

The greater part of this book is devoted to developing methods to operate a power system to gain maximum economy. But what factors affect its operation from a reliability standpoint? We will assume that the engineering groups who have designed the power system's transmission and generation systems have done so with reliability in mind. This means that adequate generation has been installed to meet the load and that adequate transmission has been installed to deliver the generated power to the load. If the operation of the system went on without sudden failures or without experiencing unanticipated operating states, we would probably have no reliability problems. However, any piece of equipment in the system can fail, either due to internal causes or due to external causes such as lightning strikes, objects hitting transmission towers, or human errors in setting relays. It is highly uneconomical, if not impossible, to build a power system with so much redundancy (i.e., extra transmission lines, reserve generation, etc.) that failures never cause load to be dropped on a system. Rather, systems are designed so that the probability of dropping load is acceptably small. Thus, most power systems are designed to have sufficient redundancy to withstand all major failure events, but this does not guarantee that the system will be 100% reliable.

Within the design and economic limitations, it is the job of the operators to try to maximize the reliability of the system they have at any given time. Usually, a power system is never operated with all equipment "in" (i.e., connected) since failures occur or maintenance may require taking equipment out of service. Thus, the operators play a considerable role in seeing that the system is reliable.

In this chapter, we will not be concerned with all the events that can cause trouble on a power system. Instead, we will concentrate on the possible consequences and remedial actions required by two major types of failure