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

Semester: 8-CBCS 2017	Date: 23 May 2021
Subject: POWER SYSTEM OPERATION & CONTROL (17EE81)	Time: 11:00 AM - 12:30 PM
Faculty: Ms Sanitha	Max Marks: 50

Answer any 5 question(s)

Q.No			Marks	CO	PO	BT/CL
1		Explain the priority list method with the help of algorithm.	10	CO1	PO1	L2
2		With a neat diagram ,explain the general configuration and major components of SCADA .	10	CO1	PO2	L1
3		Explain the operating states of power system, with a neat diagram showing the transition between the states.	10	CO1	PO3	L2
4		Draw and explain the flow chart of forward dynamic programming algorithm	10	CO1	PO1	L2
5	a	Two prime mover generator sets are paralleled . Both have 3 % droop. The frequency is 50 Hz on full load .Plot the speed droop characteristics and comment on the load sharing if the total load is 400 MW and generator A has a rating of 500 MW and generator B 300 MW.	5	CO2	PO3	L3
	b	What are the functions of AGC?	5	CO2	PO2	L1
6		Explain about the constraints to be considered in unit commitment	10	CO2	PO1	L2
7		Two generators rated 200 MW and 400 MW are operating in parallel. The droop characteristics of their governors are 4 % and 5 % respectively from no load to full load.The speed set points are such that the governors operate at 50 Hz when sharing the full load of 600 MW in proportion to their ratings.(i)If the load reduces to 400 MW, how is it shared ?At what frequency will the system operate ?(ii)If now the speed changers are reset so that the load of 400 MW is shared at 50 Hz in proportion to their rating .What are the no load frequencies now?	10	CO2	PO1	L4

1

4.3.6 Capacity Limits of Generations

The limits of the generators may vary over the period of the day. This has to be considered while committing a unit.

$$P_{G\min,i} \le P_{i,k} \le P_{G\max,i} \quad (4.7)$$

where $P_{i,k}$ is the generation of unit i at period k.

4.3.7 Fuel Constraints

Some units have a limit on the fuel consumption. This is more of a challenge in the recent power systems which include a number of micro grids operating with different fuels.

4.3.8 Security Constraints

These include the breach of security associated with a condition of insufficient generating capacity. This can be simply modeled mathematically[16] as

$$S(t) = \sum_i p_i(t) q_i(t)$$

where

$S(t)$ = probability that the system has insufficient generating capacity at time t

$p_i(t)$ = probability that the system is in state i at time t

$q_i(t)$ = probability that the state i is a condition for which the load exceeds the generation at time t

t = time in future measured from the hour at which the system is in a known state.

A feasible solution would be the one that will have sufficient capacity to supply the load with an acceptable security, which can be measured by having reliability values for $S(t)$.

4.3.9 Hydel Plant Constraints

Hydel plants do not have operational expenses. These are not included in this chapter and have been dealt with in hydrothermal coordination presented in Chapter 5.

As we have seen in the discussion in the last section, the real barrier to an optimized solution of the unit commitment problem is the high dimensionality of the feasible solution space. In the next sections, we will discuss some of the popular techniques for the solution of the unit commitment problem.

4.4 Priority List Method

This is the simplest unit commitment solution method. It consists of creating a priority list of units. In Example 4.1, we saw that shutting down a unit is more advantageous under certain conditions. When a unit is shut down, the load it carried must be transferred to the other units. By shutting down an inefficient unit, the no-load running cost of the unit is eliminated. Once a unit is shut down, it will have to be started at a later hour when the next peak load approaches (see Fig. 4.3). The saving gained by shutting down the inefficient unit may, at times, be offset by the cost of starting up the unit again when needed.

To determine the optimum shutdown rule for a group of generating units, the units are ordered according to a *priority* rule. A simple method is to prepare the priority list based on the full-load average production cost of each unit. The total production cost for a period is the hourly production costs plus the cost of

shutting-down and starting-up units during the period. All units will be started up and shut down in a strict priority order, depending on the load at that hour. Let us consider an example.

Example 4.4 Construct a priority list for three units whose data are given below:

Unit	Full-Load Average Production Cost Rs./MWh	$P_{G\min}$ (MW)	$P_{G\max}$ (MW)
1	1,000	150	500
2	850	100	500
3	1,040	125	200

Solution

A priority order for these units prepared based on their average production costs is as follows:

Priority	Unit	Rs./MWh
1	2	850
2	1	1,000
3	3	1,040

It is important to note that the unit *with the least priority number is the most economical one*. Hence, it is always committed first. Higher number units are inefficient and uneconomical.

Ignoring start-up cost, the commitment scheme for different combinations is as follows:

Unit Combination	Min MW from Combination	Max MW from Combination
2 (priority 1)	100	500
2 + 1 (priority 1 and 2)	250	1,000
2 + 1 + 3	375	1,200

The commitment rule is simple:

1. $P_{DT} \le 500$ MW, run unit 2 only (Priority 1)
2. $500 < P_{DT} < 1{,}000$ MW, run units 2 and 1 (Priorities1 and 2)
3. $1{,}000 < P_{DT} < 1{,}200$ MW, run units 2,1 and 3

P_{DT} includes load demand + spinning reserve.

Let us now consider the reverse case. Assume the demand is 1,200 MW. To meet this demand, all the three units need to be committed. Now, unit 3 is shut down only when the demand drops to 1,000 MW. Similarly, when the demand falls below 500 MW, unit 1 is next shutdown. A simple algorithm to implement the priority list method is given as follows:

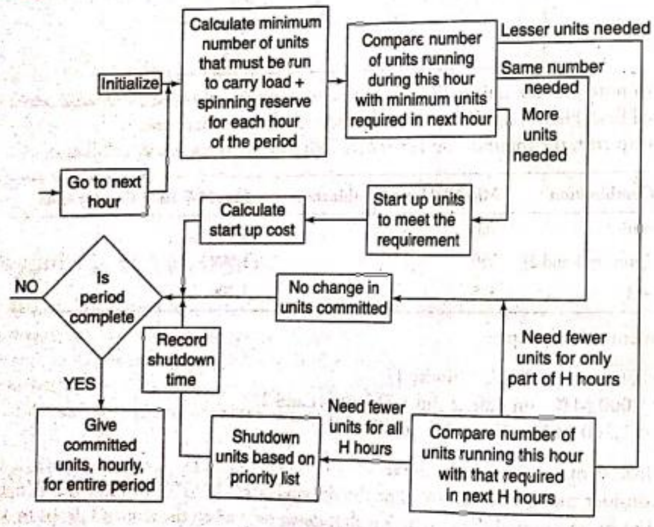
Algorithm Priority List Method

1. Determine the hourly load forecast for next 24 h (or any other period).
2. Prioritize the units based on their production costs and prepare a table based on unit combination to meet required load.
3. For the first hour, determine the minimum number of units necessary to carry the maximum predicted load and the spinning reserve.

4. Compare the number of units running in the present hour with the minimum number required for the next hour.
5. If the number required in the next hour is greater than the number of units in the present hour, startup the units according to the priority list.
6. If the minimum number of units required in the next hour is lesser than those running in the present hour, then determine whether dropping the unit with the highest priority number (least efficient) in the present group will leave sufficient generation to supply the load + spinning reserve. If not, do not shut down the unit.
7. Else, determine the number of H hours, before which the unit would be needed again.
8. If H is less than the minimum downtime of the unit, continue with the present commitment.
9. Else, calculate two costs.
   - Sum of the hourly production costs for the next H hours with unit up.
   - Hourly production costs with unit shut down + the start-up cost of the unit (which is the minimum of cooling or banking cost).

   If there is significant saving from shutting down the unit, shut it down.
10. Repeat the procedure hour by hour for the next 24 h.

The flowchart for the algorithm is given in Fig. 4.5.



* The load is dispatched to commited units using economic dispatch algorithm.
** The period is usually between 24 and 120 hours (1–5 days).

Figure 4.5 Flowchart for priority list method for UC

The priority list may be reordered as and when necessary if

1. Some units are unavailable due to breakdowns/maintenance.
2. Spinning reserve requirement is changed.
3. Running of some units for area protection to improve reliability is mandatory.

3. *EMS:* Energy management systems incorporate all features of SCADA and also includes other computations, such as load flows, state estimation, contingency analysis, etc. It includes extensive capabilities of record keeping and data exchange.
4. *DMS:* Distribution management systems are meant to monitor and control distribution feeder loads. DMS today includes topology analysis and load flow programs that allow identification of problems and restoration of services.
5. *LMS:* Load management system is meant to manage the peak load and is useful for demand-side management. It can be a stand-alone program or integrated into EMS or DMS.
6. *AMR:* Automatic meter reading is incorporated into LM systems.

12.1.2 Telemetry

Telemetry refers to the technique used in transmitting and receiving information or data over a medium. Typical data in a power system are the measurements of voltage, power flows, circuit breaker status, etc. The information is transmitted over a medium, such as cable, telephone, internet or radio. The information can come from multiple locations.

12.1.3 Data Acquisition

It refers to the method used to access and control the information or data from the equipment that is being controlled or monitored. The data are then forwarded via the telemetry system. The information can be either in an analog or in a digital form. It is the data obtained from sensors, meters, actuators, control equipment like relays, valves, etc.

With the above definitions, we can now define SCADA as *a collection of equipment that will provide an operator at a remote location with enough information to determine the status of a particular piece of equipment or an entire substation/power system, and cause actions to take place regarding that equipment or facility without being physically present at the location of the fault*[1].

12.2 Components of SCADA System

The general configuration is shown in Fig. 12.1[2]. Basically, SCADA systems collect information from the site (field) of the equipment, transfer it to a central computer facility and display the information to the operator to facilitate the control of the entire system from the central control center. In a SCADA system, the geographically dispersed sites contain either a remote terminal unit (RTU), which is a computer, or a programmable logic controller (PLC), which controls local actuators and monitor the sensors. The communication equipment allows transfer of information or data from the RTU/PLC to the central control center which houses a master terminal unit (MTU). The communication could be via telephone, radio, cable or satellite. The software of the SCADA system is programmed to tell the system what to monitor, what are the operating ranges, when to initiate alarms, controls, etc. Further, the system may consist of intelligent electronic devices (IEDs) that are smart sensors, at times combining a sensor, low level intelligent control, a communication system and program memory in one device. The IEDs can communicate directly with the MTU. Other components are the human–machine interface(HMI), also called the man–machine interface (MMI)that allows the operator to monitor the state of a process under control, modify

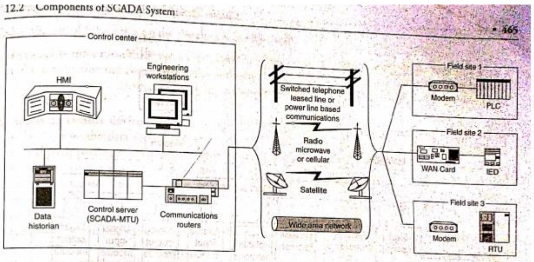


Figure 12.1 General SCADA configuration.

control settings if necessary, and permits the operator to override any automatic control previously set, should an emergency arise. The HMI is also responsible for displays, reports, historical information, status information, etc.

The major components of a SCADA system are thus classified as:

1. Field instrumentation,
2. Remote stations,
3. Communication network,
4. Central monitoring station and
5. Software.

12.2.1 Field Instrumentation

This refers to all the sensors and actuators that are interfaced directly to the equipment. They generate the analog and digital signals that are monitored by the remote station. The generated signals are conditioned to be compatible with the RTU/PLC at the remote station. The analog outputs of sensors have standard industry values like 0–5 V, 0–10 V, 0–20 mA, etc. Digital outputs of sensors are used to define the status of the equipment like On-OFF, Full-Empty, Open-Closed, etc.

12.2.2 Remote Station

Field instrumentation connected to the plant/substation/equipment which is being monitored and controlled is interfaced to the remote station to allow manipulation at a remote site. The remote station may be an RTU or a PLC. The RTU is a computer with good interfacing for communication and flexible programmability. The PLC is used mostly in industries. It has very good programmability. Modern PLCs also have extensive communication features and radio units for use with SCADA systems. A typical RTU unit is shown in Fig. 12.2.

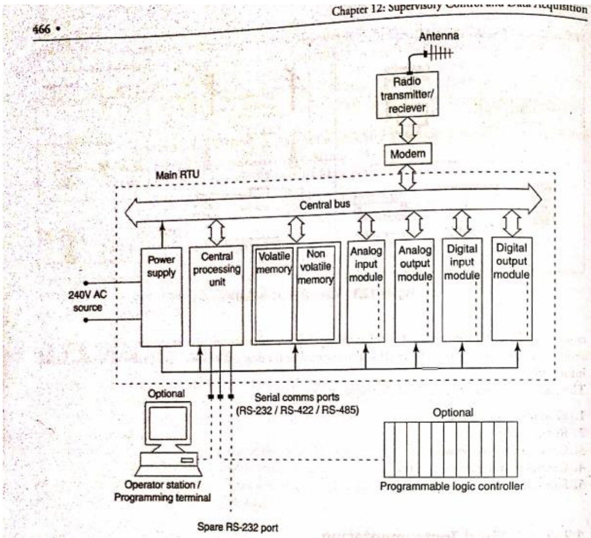


Figure 12.2 RTU unit.

12.2.3 Communication Network

This refers to the communication equipment needed to transfer data to and from different sites. Commonly used communication media are RS-232/RS-442/RS-485, dial-up telephone lines or dedicated landline, microwave, satellite, X.25 packet protocols and radio via trunked/VHF/UHF. Cables are normally used in factories and are not practical for systems spread over wide geographical areas due to the high cost of cables. The use of radio lines is common. Dial-up telephone lines are used for connecting remote stations economically. This is shown in Fig. 12.3.

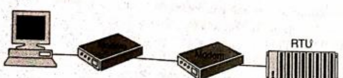


Figure 12.3 Use of telephone lines for communication.

Today, the use of Ethernet is on the rise since it is very cheap.

1. **Internal communication** is for server–client or server–server communication. In general, this is on a publish-subscribe and event-driven basis and uses the standard TCP/IP protocol. A server owns a parameter subscribed by a client, and when this parameter changes, the information is communicated to the subscriber client.
2. **Access to remote devices** is done through a polling system or through an interrupt system. In the *polling system*, the data servers poll the controllers at a defined polling rate which could be different for different parameters. The controller/RTU/slave responds by sending parameters to the master only when it receives a request. Each of these units will have a unique address. The parameters are generally time-stamped. Communication drivers are via field buses, the most common ones being Modbus, Profibus, Worldfip, etc. Some of the drivers are given in the appendix. A single data server can support multiple communication protocols. The advantages of polling are that the process of data gathering is fairly simple, collisions are avoided and link failure can be easily detected. The disadvantage is that immediate action is not possible, waiting time increases if the slaves increase. In the *interrupt system*, the slave monitors its inputs and when it exceeds a limit, it initiates communication to the master and transfers data. In such a system, collisions are common and the system has to be equipped with error detection and recovery process to cope with it. This facilitates detection of urgent status information.

12.2.4 Central Monitoring Station

The central monitoring station (CMS) is the master unit of a SCADA system. It is in charge of information collection from remote stations, generating control actions for any event and generating reports. It could be just a single computer or a network of workstations to allow sharing of information. The CMS in general has the following components:

1. An MMI or HMI program
2. A mimic diagram of the whole system or plant displayed on screen for the operator
3. Display of RTUs with present I/O reading
4. Window for alarms
5. Trending display

These have been discussed in subsequent sections.

12.2.5 Software for SCADA

Software for SCADA is based on real-time database (RTDB). SCADA software is of two types: *proprietary* and *open*. Proprietary software is developed by companies to communicate with their own hardware. Vendors sell the system as a turnkey solution. This makes the customer heavily dependent on the vendor. Open software systems have gained popularity because of interoperability capabilities and the ability to mix different equipment manufactured by different vendors on the same system. Some of the key features of SCADA software are user interface, graphics displays, alarms, trends, RTU/PLC interface, scalability, redundancy, networking and distributed processing.

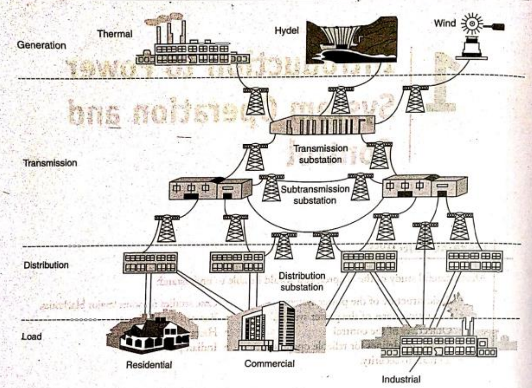


Figure 1.1 Basic structure of a power system.

industrial loads are also of three phase. Single-phase commercial and residential loads are distributed equally between the three phases so as to form a balanced system. The structure of the power system is shown in Fig. 1.1.

The transmission system interconnects all major generating stations. Normally, the generated voltage is 11 kV or 22 kV. The transmission voltages are 220 kV and above. The voltage level is stepped down at the distribution substations and transferred to the industrial consumers at voltages between 4 and 35 kV. The secondary distribution feeders supply to the residential and commercial suppliers at 230 V. Thus, the network is really large, consisting of a number of generating stations, several transmission interconnections and the distribution network. Obviously, it is not a simple task to run such a massive structure without failures and disruptions in service!!

1.2 Operating States of a Power System

DyLiacco[1] and Fink and Carlson[2] have classified a system operation into five states as shown in Fig. 1.2.

The system operation is governed by equality and inequality constraints. The equality constraints are nothing but the power balance between generation and load. The inequality constraints set the limits on

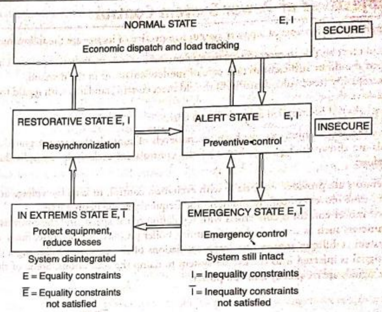


Figure 1.2 Operating states of a power system.

different operating parameters, such as voltage, generation limits, currents, etc. The system states are classified as follows:

1. ***Normal operating state:*** In this state, the equality constraints (E) and inequality constraints (I) are both satisfied. The generation is adequate to meet the demand, without any equipment being overloaded. Further, the reserve margins are sufficient to provide security for normal stresses.
2. ***Alert state:*** In this state also, the equality and inequality constraints are satisfied. However, the reserve margins are reduced. Therefore, there is a possibility that some inequality constraints (limits on equipment) may be violated in the event of disturbances. Preventive control will lead the system from the alert state to the normal state.
3. ***Emergency state:*** Due to severe disturbances, the system may enter an emergency state. This could be because of imbalance between generation and loads, either at the system level or at the local level. This could also be because of instability due to energy built-up in the system after a fault. Some strong control measures, such as direct or indirect load shedding, generation shedding, shunt capacitor or reactor switching, network splitting, called *emergency control measures* are to be taken. If these measures are not taken on time, the system stability may be under threat and the system may eventually break down and go to the *In Extremis state.*
4. ***In extremis state:*** In this state, both the equality and the inequality constraints are violated. The violation of the equality constraints implies that the generation and the load demand do not match. This means that some part of the system load is lost. Emergency measures must be taken to prevent a total grid collapse.
5. ***Restorative state:*** This is a transitional state, where the inequality constraints are satisfied by the emergency control actions taken, but the system has still not come to normalcy in terms of the equality constraints. We can have a transition either to the alert state or to the normal state.

4

4.5 Dynamic Programming

4.5.1 Dynamic Programming Methods for Unit Commitment

Dynamic programming (DP) methods applied to unit commitment became popular since the 1970s. The DP methods resort to creation of a priority list using DP search. They are characterized by forward and back path operations. The essence of the DP approach is that the problem of finding the optimum outputs of various units for a given load is replaced by the problem of finding the optimum outputs of the various units for all loads between the minimum output and the maximum capacity of the units. The big advantage of this approach is that knowing the optimum way of operating K units, we determine the optimum way of operating $K+1$ units.

Commitment of units progress 1h at a time and combination of schedulable units are calculated for each hour. The most economical schedule is obtained by backtracking from the combination with the least total cost at the final hour through the optimal path to the combination at the initial hour. The problem boils down to searching the feasible solutions, for the optimal solution. This is far from simple.

Assume there are 10 schedulable units, every hour. Then there are 2^{10} combinations to be tried, which is impractical. Hence, DP is clubbed with heuristic methods to generate combinations. One method is the dynamic programming sequential combination (DP-SC). The DP-SC method generates a subset of combinations by turning each unit on one by one, in the order given by the priority list sequence. Thus, if we have 10 units, we try 11 combinations. These are all units OFF, priority 1 unit ON, Priority 1 and 2 units ON, priority 1, 2 and 3 units ON, and so on, to all units ON. Note that we do not try all 2^{10} combinations in this method. Hence, the solution will be sub-optimal, but the dimensionality problem is well handled. It is simple and suited under a rapidly varying load.

Another method is the dynamic programming truncated combination (DP-TC). This method generates a subset of the combinations by selecting a fixed number of schedulable units and then trying out all combinations of the subset. This method is suitable for small changes in the system load. For a system with four units, generation of combinations for different DP methods is depicted in Table 4.5.

Table 4.5 Generation of combinations for different DP methods

Combination Number	DP Units 4321	DP-SC Units 4321	DP-TC Units 321
0	0000	0000	000
1	0001	0001	001
2	0010	0011	010
3	0011	0111	011
4	0100	1111	100
5	0101		101
6	0110		110

(Continued)

Table 4.5 (Continued)

Combination Number	DP Units	DP-SC Units	DP-TC Units
	4321	4321	321
7	0111		111
15	1111		

1. In DP, all combinations are generated. So we have 0000, 0001, 0010,……, 1111 giving 16 combinations.
2. In DP-SC, we have only 5 (4+1) combinations. The units are turned on one by one in priority order.
3. In DP-TC, we use a subset of three units (if the sum of their capacities is sufficient to meet the load) and try all combinations of the three units (2^3-1). The condition is that three units should have capacity to meet the demand. The higher priority number units are not considered.

4.5.2 DP Algorithm

Let us now see the step-by-step procedure for applying the DP algorithm for unit commitment. The priority list order is prepared by arranging the units in order of the full-load average cost rate. The algorithm described now would result in correct commitment only if:

1. No-load costs are not considered.
2. Unit input–output characteristics are linear between zero output and full load.
3. No other constraints are considered.
4. Start-up costs do not vary and are fixed amounts.

The assumptions made in this approach are as follows:

1. Individual production costs are known a priori for all units.
2. The load cycle is known a priori.
3. The load on each unit changes in small steps.
4. The start-up and shutdown costs are neglected.
5. There is a strict priority order specified.

The DP-SC algorithm is illustrated in detail, wherein we commit the units one by one and choose the most optimal path. In this approach, having obtained the optimal way of loading *K* units, it is easy to determine the optimal loading of ($K+1$) units. This is a forward DP approach. We start with an initial *state* and move forward to decide the units to be committed. A *state is an array of units* where specified units are committed and operating while rest is off-line. A feasible state is the one in which the units that are committed are sufficient to meet the required load. The DP algorithm essentially picks up the optimal state from the set of feasible states. We define two quantities:

1. $f_N(y)$ is the cost of generating y MW with the N^{th} unit operating alone. For example, $f_3(50)$ is the cost of generating 50 MW with unit three operating alone.
2. $F_N(x)$ is the cost of generating x MW with N units. For example, F_2 (80) is the cost of generating 80 MW with two units committed. The application of dynamic program results in a recursive formula given by

$$F_N(x) = min_y[f_N(y) + F_{N-1}(x-y)] \tag{4.8}$$

In the above formula, x MW are generated by N units. Out of x MW, y MW are generated by the N^{th} unit at a cost of $F_N(y)$ and ($x-y$)MW are generated by the other (N−1) units. From the above recursive formula, we can determine the combination of units, which yields minimum operating costs for various loads in convenient steps, from the minimum permissible load of the smallest unit, to the sum of the capacities of all available units. Consider a plant with four units, which has to supply say 40 MW and the load is allowed to vary in steps of 10 MW. Given the production costs of all the units, the algorithm is applied as follows:

Step 1: Arrange the units in priority order.

Step 2: Assume unit 1 is committed based on their production costs. Find the cost of generating 10, 20, 30 and 40 MW with unit 1.

Step 3: Assume units 1 and 2 are committed. To supply 40 MW, we have the following options:

Load Supplied by Unit 1 (MW)	Load Supplied by Unit 2 (MW)	Total Load (MW)
40	0	40
30	10	40
20	20	40
10	30	40
0	40	40

For each of the above allocations, determine the cost of production which yields lowest cost for producing 40 MW. This yields the optimum commitment for a load of 40 MW. Now determine the best option to produce 30 MW with units 1 and 2. The options available are:

Load Supplied by Unit 1 (MW)	Load Supplied by Unit 2 (MW)	Total Load (MW)
30	0	30
20	10	30
10	20	30
0	30	30

Similarly, determine the best option to produce 20 MW and 10 MW with units 1 and 2.

Step 4: Now assume units 1, 2 and 3 are committed. To meet 40 MW with three units we have the following options.

Load Supplied by Unit 3 (MW)	Load Supplied by Units 1 and 2 (MW)	Total Load (MW)
40	0	40
30	10	40
20	20	40
10	30	40
0	40	40

In the cost for load supplied by units 1 and 2, we choose the optimum allocation obtained from step 3 for the load. We compute the production cost with each of the above combinations and choose the best option to produce 40 MW with three units. Similarly, determine the best option to generate 30, 20 and 10 MW with three units.

5A

Solution

The speed droop is 3%. Therefore, the frequency at no load is 3% more than at full load which is 51.5 Hz. The characteristic is shown in Fig. 6.8.

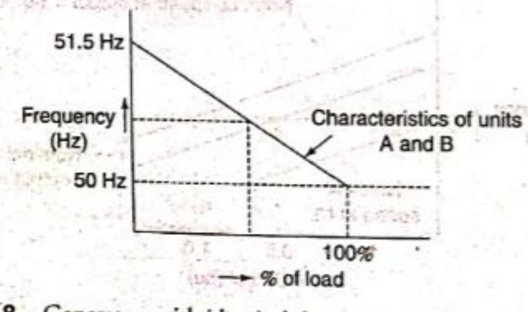
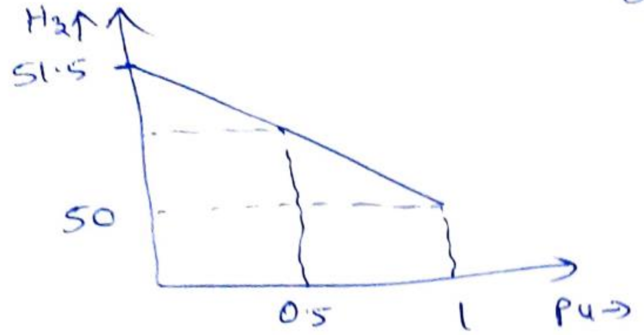


Figure 6.8 Generators with identical droop characteristics: Example 6.1.



$0.03\% \Rightarrow 50 \times 0.03$

$= 1.50$

At No load freq

$= 50 + 1.5$

$= 51.5\ Hz$

$$R = \frac{\Delta f(pu)}{\Delta P(pu)} \quad \text{ie)} \quad 0.03 = \frac{\frac{51.5 - x}{50}}{0.5 - 0}$$

$\therefore x = 50.75$

ii) freq $= 50.75\ Hz$

Load Sharing

A's capacity $= 500$ mw

B's capacity $= 300$ mw

If they have to share a load of 400mw

A's share $= 400/800 \times 500 = 250$ mw

B's share $= 400/800 \times 300 = 150$ mw

5B

In a power system the loads and losses are sensitive to frequency. If a generating unit is tripped or the load on the system is increased, the power mismatch is initially compensated by extracting the kinetic energy from system inertial storage causing a decline in system frequency. As the frequency decreases, the power taken by the loads also decreases. Equilibrium in larger systems is generally obtained when the reduction in frequency sensitive load balances the output of the tripped generator or the load increase at the new frequency. If equilibrium is reached it is in less than 2 s.

If the mismatch is large, then the governor action has to increase the generation of the units such that equilibrium is reached, when the reduction in the power taken by the loads plus the increase in generation makes up for the mismatch. Such equilibrium is reached in 10–15 s after tripping of a unit or connection of additional load. The main requirement of the AGC is to ensure the following:

1. The frequency of the various bus voltages are maintained at the scheduled frequency.
2. The tie-line power flows are maintained at the scheduled levels.
3. The total power is shared by all generators economically (economic dispatch).

The first two functions are realized using the ALFC, whereas the third has been extensively dealt with in Chapter 3. Apart from this, modern AGC strategies[2] include many more functions. Some of them are listed here.

1. Yield a generation trend acceptably matching the trend required to serve the changing load at the scheduled frequency, over the selected time frame.
2. Schedule generation to accumulate lower fuel cost over the selected time frame, which includes recognizing undesirable generation ranges in different units and avoiding sustained operation in these ranges.
3. Maintain a sufficient level of reserved control range and sufficient level of control rate.
4. Operate the system with higher security margins.
5. Provide timely recommendations for changing of outputs of units which are manually controlled.
6. Provide meaningful alarms such as display in control center for deviation from desired generation, unit not responding to AGC control signal, anticipated future generation, etc.

The design of AGC system depends on the way the units respond to AGC signals. The response characteristics of units vary widely and depend on many factors such as:

1. Type of generating unit: fossil-fired, nuclear hydro, combined cycle, etc.
2. Type of fuel used: coal, oil, uranium, gas, etc.
3. Type of plant control.
4. Type of plant: once-through boiler, drum-type boiler, pressurized-water nuclear reactor, pumped storage hydro, etc.
5. Operating point of units.
6. Manual control by operators.

In multi-area control, tie-line power deviation dictates the AGC control. This is dealt with in Chapter 7.

4.3 Constraints in Unit Commitment

Constraints on the unit commitment problem are unique to the power system under consideration. The constraints depend on the composition of the generator units (thermal, hydel, renewable, etc.), the load curve, the operational requirements of the utility, etc. However, there are some constraints to be considered, irrespective of the unique configuration.

4.3.1 Spinning Reserve

In any power system, some amount of active power generation capability has to be kept in reserve to re-establish the balance between load and generation at all times, even under the eventuality of a unit failing. Different types of reserves are required to respond to different types of events over different time frames. *Spinning reserve* is defined in various ways:

1. "Generators online, synchronized to the grid, that can increase output immediately in response to a major outage and can reach full capacity within 10 minutes," by Hirst and Kirby[1].
2. "The additional output which a part-loaded generating plant is able to supply and sustain within 5 minutes," by British Electricity International[2].
3. "The total synchronized capacity, minus the load and the losses," by Wood and Wollenberg[3].
4. "Unloaded generation that is synchronized and ready to serve additional demand," by NERC[4].

A broad definition would be, "*the unused capacity which can be activated on decision by the system operator and which is provided by generators synchronized to the grid and capable of supplying active power.*"

Spinning reserve = (sum of the capacities of all units synchronized at a time)−(load + losses in the system at that time). A *negative spinning reserve* is also defined as the capacity that can be switched off quickly to compensate for a dip in energy demand (shutting down a unit).

Spinning reserve is necessary so that the loss of a generating unit does not lead to a drop in system frequency. There should be ample reserve in the system so that in the event of loss of a unit, the other units can take up the load within a specified time period. It must be sufficient to meet the loss of the most heavily loaded unit in the system or it can be specified as a percentage of the forecasted peak demand. A more complicated approach is to calculate the reserve as a function of the probability of not having sufficient generation to meet the load. The constraints can be mathematically stated as follows:

$$\sum_{i=1}^{N} P_{\max i,t} U_{i,t} \geq P_{D,t} + SR_t ; 1 \leq t \leq T \tag{4.3}$$

where

$P_{\max i,t}$ = power generation limit of unit i at time t

$U_{i,t}$ = 1 if unit i is committed at time t (ON)

$P_{D,t}$ = demand at time t

SR_t = spinning reserve at time t (MW).

The spinning reserve must be allocated among fast-responding units and slow-responding units to allow the automatic generation control (AGC) to restore frequency quickly.

Apart from spinning reserve we also have scheduled or *off-line reserve*. These are units which are not connected on-line, but which can be started on quickly. Gas turbines are used for this. Pumped hydro plants

4.3.2 Thermal Unit Constraints

Thermal units can respond only to gradual changes in temperature, which translates into a minimum time period (of some hours) required to bring the unit online (commit the unit). This poses some constraints on the unit commitment problem, such as:

1. ***Minimum uptime:*** This is the minimum time for which a unit once committed should run. It should not be turned off immediately. Mathematically,

$$T_{\mathrm{ON},i} \geq T_{\mathrm{UP},i} \tag{4.4}$$

where

$T_{\mathrm{ON},i}$ is the duration for which unit i is continuously ON (in hours)

$T_{\mathrm{UP},i}$ is the minimum uptime of unit i.

2. ***Minimum downtime:*** A unit which has been shut down (de-committed) cannot be started up before a minimum time has elapsed. Mathematically,

$$T_{\mathrm{OFF},i} \geq T_{\mathrm{DOWN},i} \tag{4.5}$$

where

$T_{\mathrm{OFF},i}$ is the duration for which unit i is continuously OFF

$T_{\mathrm{DOWN},i}$ is the minimum downtime (in hours) of unit i.

In addition to the time constraints in thermal units, we have to consider the start-up costs for these units as well.

4.3.3 Start-Up Costs of Thermal Units

Start-up costs are the costs incurred in starting a thermal unit. There is a need to balance the start-up costs and the running costs. In the total cost calculation, we need to calculate the hourly production cost of running the committed units (based on equal incremental costs) to meet the demand plus spinning reserve and the total cost of shutting down and starting up units during the period.

When the load is removed from a unit, the boiler will either be shut down or allowed to cool, or it will be *banked*. In the banking mode, the *boiler is isolated from the steam system at no load* and kept at the system operating pressure and temperature by intermittent firing of either the igniters or by a main burner. The costs of the two options (cooling and banking) must be compared before choosing the best option. The start-up cost when the boiler is cooled can be given by[5]

$$\text{Start-up cost} = C_c[1 - e^{-\alpha(t-1)}] + K \tag{4.6}$$

where

C_c is the cost of starting boiler cold in Rs/h. ($/h),

t is the number of hours unit has been shut down (or cooled),

K includes maintenance and operation cost and cost of starting the turbine alone and

α is the cooling time constant of the boiler.

In the expression for start-up cost, $(t-1)$ hours is used, assuming that the boiler takes 1h to start up. The start-up cost when banking is given by

$$\text{Start-up cost} = C_c'(t-1) + K$$

where C_c' is the cost of banking the boiler for 1h. The start-up cost is shown in Fig. 4.2.

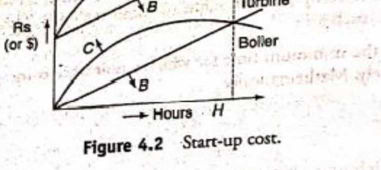


Figure 4.2 Start-up cost.

Up to a certain number of hours (H), banking will cost less than cooling. It depends on the unit under consideration. Hence, at times if it needs to be commissioned before H hours, it is more economical to run the unit on no load rather than shut it down. This will determine whether or not a unit will be shut down. Let us illustrate this with an example.

4.3.4 Network Constraints

The transmission network may have an effect on the commitment of the units. Consider Fig. 4.4. Assuming that the cost of production for G_3 is higher than G_1 and G_2, the transfer of power from G_1, G_2 to the load is limited by the transmission capacity of the lines. Hence, it is probable that the more expensive unit G_3 is committed, even though cheaper units (G_1 and G_2) are available. Similarly, network interconnections dictate that some units must be run to provide voltage support. Such units are called ***must-run units.*** Such network constraints will also affect the decision of the units to be committed.

4.3.5 Emission Constraints

Emission constraints pose a challenge today, as the emission norms are stringent in view of GHG (greenhouse gases) emissions and global warming. This limits the pollutants (such as SO_2, NO_X) which the generating units may emit. The constraints are modeled in various ways, such as:

1. Limit on each plant at each hour.
2. Limit on the plant over a year.
3. Limit on a group of plants (a pool) over a period.

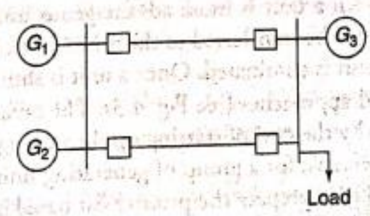


Figure 4.4 Network constraints.

4.3.6 Capacity Limits of Generations

The limits of the generators may vary over the period of the day. This has to be considered while committing a unit.

$$P_{Gmin,i} \leq P_{i,k} \leq P_{Gmax,i} \tag{4.7}$$

where $P_{i,k}$ is the generation of unit i at period k.

4.3.7 Fuel Constraints

Some units have a limit on the fuel consumption. This is more of a challenge in the recent power systems which include a number of micro grids operating with different fuels.

4.3.8 Security Constraints

These include the breach of security associated with a condition of insufficient generating capacity. This can be simply modeled mathematically[6] as

$$S(t) = \sum_i p_i(t) q_i(t)$$

where

$S(t)$ = probability that the system has insufficient generating capacity at time t
$p_i(t)$ = probability that the system is in state i at time t
$q_i(t)$ = probability that the state i is a condition for which the load exceeds the generation at time t
t = time in future measured from the hour at which the system is in a known state.

A feasible solution would be the one that will have sufficient capacity to supply the load with an acceptable security, which can be measured by having reliability values for $S(t)$.

4.3.9 Hydel Plant Constraints

Hydel plants do not have operational expenses. These are not included in this chapter and have been dealt with in hydrothermal coordination presented in Chapter 5.

As we have seen in the discussion in the last section, the real barrier to an optimized solution of the unit commitment problem is the high dimensionality of the feasible solution space. In the next sections, we will discuss some of the popular techniques for the solution of the unit commitment problem.

7

(i) The droop characteristics are drawn as in Example 6.4. Since 600 MW is shared in proportion to their rating, unit 1 supplies 200 MW and unit 2 supplies 400 MW, which is their capacity, respectively. Therefore, both the units operate at 100% full-load when supplying 600 MW. We take 100 MW to be the base power. The characteristics are drawn as shown in Fig. 6.12. Unit 1 has a frequency change from 1.04 pu to 1.0 pu from no-load to full-load (2 pu) and unit 2 has a frequency change from 1.05 pu to 1.0 pu from no-load to full-load (4 pu). Thus at $f = 1$ pu, total load is $2 + 4 = 6$ pu. The load now changes to 400 MW. Let x pu be the output of unit 1. Total load is 400 MW = 4 pu. Therefore, the output of unit 2 is $4 - x$ pu. From the figure,

$$\frac{BC}{BO} = \frac{CC_1}{OO_1} \Rightarrow \frac{0.04 - \Delta f}{0.04} = \frac{x}{2} \tag{i}$$

$$\frac{AC}{AO} = \frac{CC_2}{OO_2} \Rightarrow \frac{0.05 - \Delta f}{0.05} = \frac{4 - x}{4} \tag{ii}$$

$$\text{From (i)} \quad \frac{\Delta f}{0.04} = 1 - 0.5x \tag{iii}$$

$$\text{From (ii)} \quad \frac{\Delta f}{0.05} = 0.25x \tag{iv}$$

$$\text{solving we get } \frac{0.05}{0.04} = \frac{1-0.5x}{0.25x}$$

$$\text{or } 0.0125x = 0.04 - 0.02x$$

$$x = 1.23077\text{ pu}$$

$$= 123.077\text{ MW}$$

$$4 - x = 2.7692 \quad \text{pu} = 276.923\text{ MW}$$

$$\Delta f = (0.25x)0.05 = 0.01538\text{ pu}$$

$$\text{Frequency } f_1 = 1 + \Delta f = 1.01538\text{ pu}$$

$$= 50.769\text{ Hz}$$

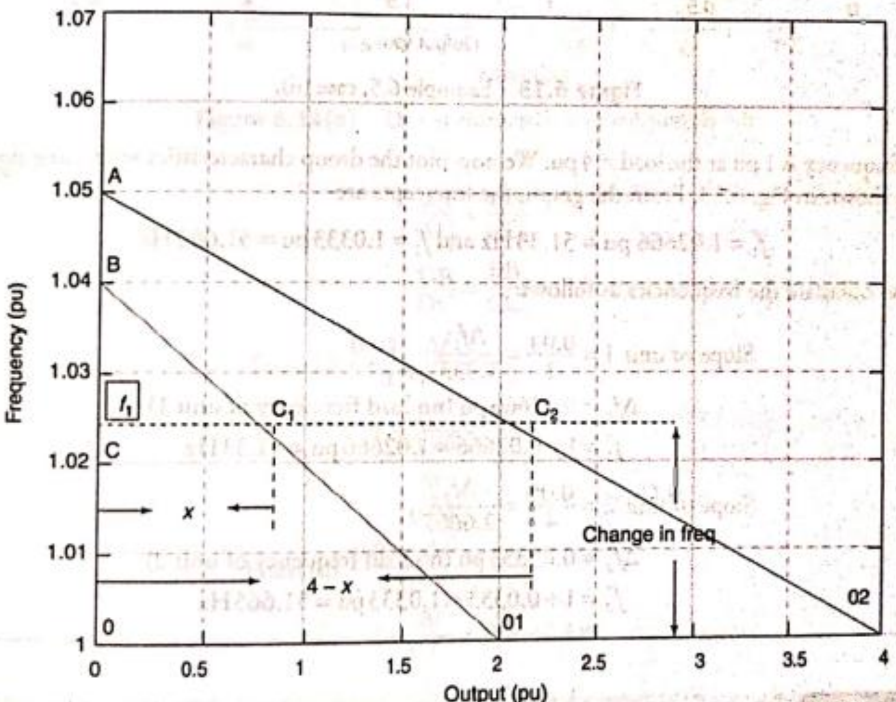


Figure 6.12 Example 6.5, case (i).

(ii) Now the governor settings are changed such that they share 400 MW in proportion to their rating at 50 Hz.

$$\therefore \text{ Output of unit } 1 = 400 \times \frac{2}{6} = 133.33\text{ MW}$$

$$= 1.3333\text{ pu}$$

$$\text{Output of unit } 2 = 266.67\text{ MW}$$

$$= 2.6667\text{ pu}$$

The characteristics are as shown in Fig. 6.13.

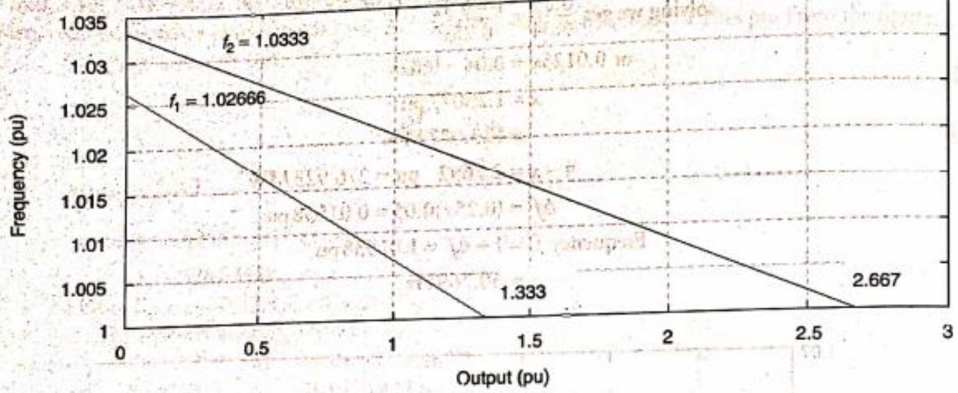


Figure 6.13 Example 6.5, case (ii).

Here, the frequency is 1 pu at the load = 4 pu. We now plot the droop characteristics with same slopes of 4% and 5% as shown in Fig. 6.13. From the graph, the intercepts are

$$f_1 = 1.02666\text{ pu} = 51.33\text{ Hz and } f_2 = 1.0333\text{ pu} = 51.665\text{ Hz}$$

We can also calculate the frequencies as follows:

$$\text{Slope of unit } 1 = \frac{0.04}{2} = \frac{\Delta f_1}{1.333}$$

$$\Delta f_1 = 0.02666\text{ pu (no load frequency of unit 1)}$$

$$f_1 = 1 + 0.02666 = 1.02666\text{ pu} = 51.33\text{ Hz}$$

$$\text{Slope of unit } 2 = \frac{0.05}{4} = \frac{\Delta f_2}{2.6667}$$

$$\Delta f_2 = 0.03333\text{ pu (no load frequency of unit 2)}$$

$$f_2 = 1 + 0.0333 = 1.0333\text{ pu} = 51.665\text{ Hz}$$