

Chapter 2

Literature Survey

2.1 Structure of an Electrical Power System

Electrical power systems are large, complex structures consisting of power sources, transmission networks, distribution networks and a variety of consumers (Fig. 2.1). Only the generation and transmission levels are considered in power system analysis; the distribution networks are not usually modelled as-such, but replaced by equivalent loads—composite loads [6]. **Appendix-A** demonstrates the modeling of the power system's main power corridor—transmission lines and transformers with a two-port network.

With regard to the power system engineering, in general, load can be considered as:

- A device connected to the power system that consumes power;
- The total active or reactive power consumed by all devices connected to the power system;
- The power output of a particular generator plant;
- A portion of the system that is not explicitly represented in the system model, but as if it were a single power-consuming device—composite load [**Appendix-B**].

2.2 Power System Stability

Stability of a power system can be defined as: The ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact [7].

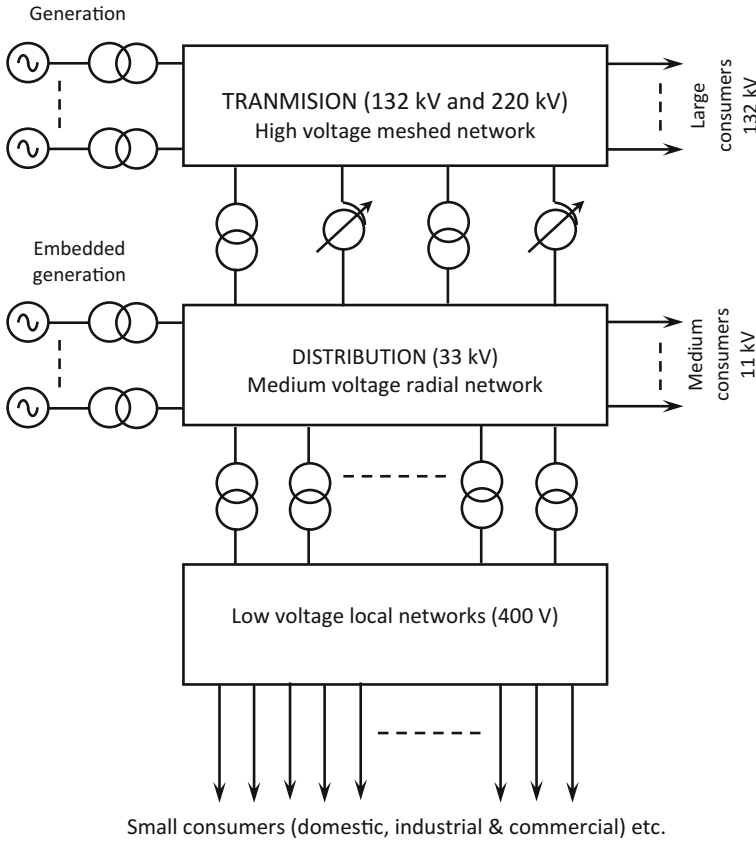


Fig. 2.1 Structure of an electrical power system

2.3 Why Power System Instability Situations Occur?

Power system is a highly nonlinear system that operates in a constantly changing environment. Because of the interconnection of different elements that form a large, complex and dynamic system capable of generating, transmitting and distributing electricity, in a power system, a large variety of dynamic interactions are possible. The main causes of PS dynamics are:

- changing power demand
- various types of disturbances

A changing power demand introduces a wide spectrum of dynamic changes into the system each of which occurs on a different time scale.

- The fastest dynamics are due to sudden changes in demand—which associates with the transfer of energy between the rotating masses in the generators and the loads.
- Slightly slower are the voltage and frequency control actions needed to maintain system operating conditions
- very slow dynamics which corresponds to the way in which the generation is adjusted to meet the slow daily demand variations

The way in which the system responds to disturbances also covers a wide spectrum of dynamics and associated time frames.

- The fastest dynamics are those associated with the very fast wave phenomena that occur in high-voltage transmission lines.
- Slightly slower are the electromagnetic changes in the electrical machines which occur before the relatively slow electromechanical rotor oscillations occur
- The slowest are the prime mover and automatic generation control actions

For reliable service, a PS must remain intact and be capable of withstanding a wide variety of disturbances [6, 8–10].

2.4 Disturbances

The disturbances which are experienced by the Power System may be small or large. They vary in both magnitude and character. A disturbance is defined as ‘Disturbance (General): An undesired variable applied to a system that tends to affect adversely the value of a controlled variable’ [4]. Therefore, it is essential that the system be designed and operated so that the more probable contingencies can be sustained with no loss of load (except that is connected to the faulted element) and the most adverse possible contingencies do not result in uncontrolled, widespread and cascading power interruptions [3, 11, 12]. Disturbance types and characteristics can be categorized into two major categories. They are:

- Load disturbances
 - Small random fluctuations super imposed on slowly varying loads
- Event disturbances
 - Faults on transmission lines due to equipment malfunctions or natural phenomena such as lightening.
 - Cascading events due to protective relay action following severe overloads or violation of operating limits.
 - Generation outages due to loss of synchronism or malfunction.

2.4.1 Effects of the Disturbances on the Power System

The PS responds to these disturbances with the involvement of different equipment:

- A short circuit on a critical element followed by its isolation by protective relays will cause variations in power transfers, machine rotor speeds, and bus voltages;
- The voltage variations will actuate both generator and transmission system voltage regulators; the speed variations will actuate prime mover governors;
- The change in tie line loadings may actuate generation controls;
- The changes in voltage and frequency will affect loads on the system in varying degrees depending on their individual characteristics.
- Devices used to protect individual equipment may respond to variations in system variables and thus affect the system performance.

The most large-power systems install equipment to allow operations personnel to monitor and operate the system in a reliable manner. Some of such major types of failures are:

- Generation-unit failures
- Transmission-line outages.

Effects on Power System Due to Generation Unit Failures

When a generator experiences a failure/outage, there will be a great impact on performance of other generators and transmission lines of the PS.

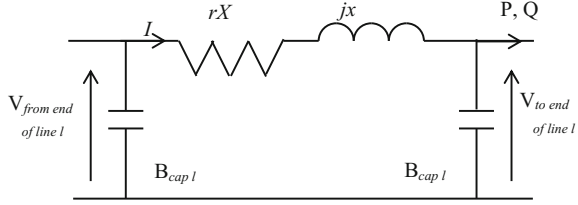
Due to the imbalance between total load plus losses and generation, a drop in frequency is resulted. This must be restored back to its nominal value (50 Hz or 60 Hz). This must be made up either by the balance set of generators or by shedding a sufficient amount of load from the system. The proportion of the lost power made up by each generator is strictly determined by its governor droop characteristic, (**Appendix-C**); [6, 13]. Further, due to generation outage, much of the made up power will come from tie lines and other transmission lines. This can make line flow limit or bus voltage limit violations [13].

Effect on PS Due to Transmission Line Outages

When a transmission line or transformer fails and is disconnected, the flow on that line goes to zero and all flows nearby will be affected. The result can be a line flow limit or bus voltage limit violation [13].

The reactive losses in the transmission system (an equivalent π -model is shown in Fig. 2.2) have a big effect on the voltage at the buses. Reactive losses may be due to two reasons:

Fig. 2.2 π -model of a transmission-line



- The MVAR consumed by the line
- Transformer inductive reactance

$$\text{Reactive loss, (i)} = \sum_{\text{all lines } l} I_l^2 x_l \quad (2.1)$$

Since,

Reactive power consumed by the transmission line \propto square of the line current, when the transmission lines become heavily loaded this term goes up and more reactive power must be supplied from some other resource.

Due to capacitive charging of the transmission line, reactive power is injected back into the PS.

$$\text{Reactive loss, (ii)} = - \sum_{\text{all lines } l} \left(V_{\text{from end of line } l}^2 B_{\text{cap } l} + V_{\text{to end of line } l}^2 B_{\text{cap } l} \right) \quad (2.2)$$

There can be fixed capacitors injecting reactive power into buses.

$$\text{Reactive loss, (iii)} = - \sum_{\text{all lines } l} \left(V_l^2 B_{\text{fixed cap at bus } l} \right) \quad (2.3)$$

The total reactive loss = Reactive loss, (2.1) + Reactive loss, (2.2) + Reactive loss, (2.3)

$$\begin{aligned} \text{Reactive power loss} &= - \sum_{\text{all lines } l} I_l^2 x_l - \sum_{\text{all lines } l} \left(V_{\text{from end of line } l}^2 B_{\text{cap } l} + V_{\text{to end of line } l}^2 B_{\text{cap } l} \right) \\ &\quad - \sum_{\text{all lines } l} \left(V_l^2 B_{\text{fixed cap at bus } l} \right) \\ \text{Reactive power loss} &= \sum_{\text{all lines } l} I_l^2 r_l \end{aligned}$$

2.5 Reliability of a Power System

According to NERC (North American Electric Reliability Council), reliability of power system has been defined as a combined process of,

- Transmission adequacy—The ability of the electric system to supply the aggregate demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements/components.
- Transmission security—The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits, unanticipated loss of system components or switching operations [9].

2.6 Quality of a Power System

Fundamental requirements concerning the quality of (power) generation equilibrium operation are:

- Network frequency should be at its “nominal” value (the choice of the nominal value is a technical and economic compromise among design and operating characteristics of main components, with specific regard to generators, transformers, lines, and motors);
- Voltage magnitudes (positive sequence) should match their nominal values, within a range, e.g., of $\pm 5\%$ or $\pm 10\%$ at each network bus-bar, particularly at some given load bus-bars [14].

2.6.1 *Addressing Instability Situations Due to Perturbations in the Power System*

Facing the effects of perturbations, especially of those lasting longer, and maintaining the system at satisfactory steady-state conditions can be done with two fundamental controls. They are:

- f/P control (frequency and active power control)—acts on control valves of prime movers, to regulate frequency and dispatch active power generated by each plant. Frequency regulation is the modulation of driving powers which must match, at steady-state conditions, the total active load (apart from some deviations due to mechanical and electrical losses, or contributions from non-mechanical energy sources). After a perturbation, the task of frequency regulation is not only to make net driving powers and generated active powers

coincide but, moreover, to return frequency to the desired value. Therefore, even the regulation itself must cause transient unbalances between the powers until the frequency error returns to zero.

- V/Q control (voltages and reactive power control)—acts on the excitation circuit of synchronous machines and on adjustable devices (e.g., reactors, capacitors, static compensators, under-load tap-changing transformers), to achieve acceptable voltage profiles with adequate power flows in the network.

f/P and V/Q controls are different from each other with regard to the power system stability concern.

- Regulated frequency is common to the whole system and can be affected by all the driving powers. Therefore, the f/P control must be considered with respect to the whole system, as the result of different contributions (to be suitably shared between generating plants). In other words, the f/P control must present a “hierarchical” structure (as shown in Figs. 2.1 and 2.6) in which local controls (also named “primary” controls) on each turbine are coordinated through a control at the system level (named “secondary” control).
- Regulated voltages are instead dissimilar from each other (as they are related to different network points), and each control predominantly acts on voltages of the nearest nodes. Consequently, the V/Q control problem can be divided into more primary control problems (of the local type), which may be coordinated by a secondary control (at the system level) or simply coordinated at the (unit) scheduling stage [14].

2.6.2 Classification of Power System Dynamics

Dynamic relations among variables that characterize a generic model of a generator system can be presented as in the block diagram of Fig. 2.3.

- Subsystem (a): Predominantly a mechanical type, consists of generating unit rotating parts (specifically, inertias) and supply systems (thermal, hydraulic, etc.).
- Subsystem (b): Predominantly an electrical type, consists of the remaining parts, i.e., generator electrical circuits, transmission, and distribution systems, and users (and possible energy sources of the non-mechanical type), with the latter possibly assimilated with electrical equivalent circuits. Subsystem (b) includes mechanical rotating parts of synchronous compensators and electro-mechanical loads. The mechanical parts of synchronous compensators and of synchronous motors—the latter including their loads—can be considered, if worthy, in subsystem (a) without any particular difficulties [14].

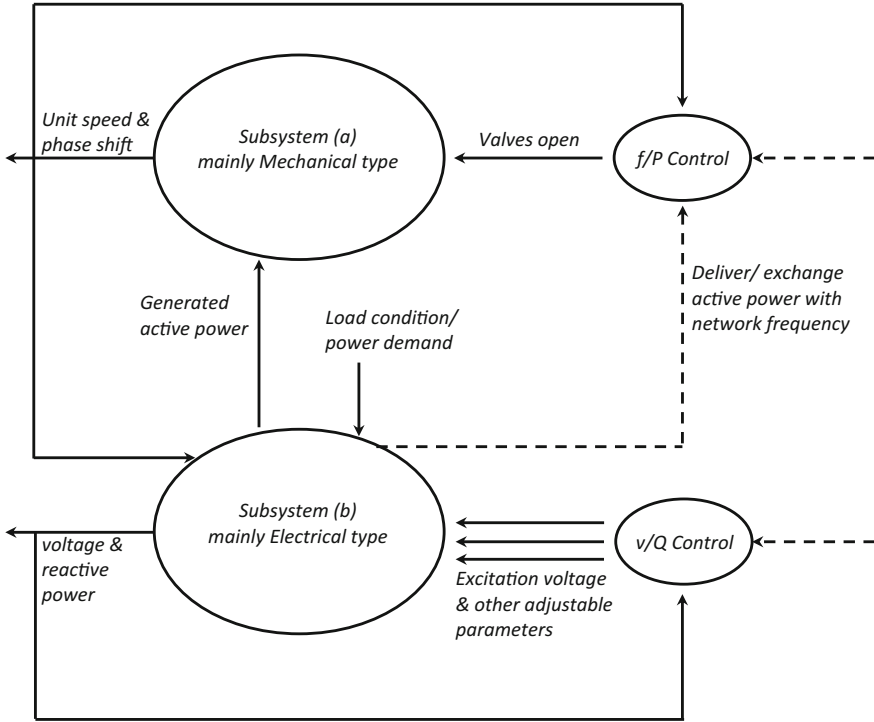


Fig. 2.3 A generic model of a generator system [14]

As demonstrated by the Fig. 2.3, the input variables to the system are essentially,

- openings of prime mover valves, which “enter” into subsystem (a), affecting driving powers (at given operating conditions of the supply systems, e.g., set points of the boiler controls, water stored in reservoirs);
- excitation voltages of synchronous machines, which “enter” into subsystem (b), affecting the amplitude of emfs applied to the three-phase electrical system;
- different parameters that can be adjusted for control purposes (specifically, for the V/Q control): capacitances and inductances of reactive components (of the static type), transformer ratios of under-load tap-changing transformers, etc.;
- load conditions dictated by users, which are further inputs for the subsystem (b), in terms of equivalent resistances (and inductances) or in terms of absorbed mechanical powers, etc.

With reference to the Fig. 2.3, the f/P control is achieved through acting on valves’ opening, while the V/Q control is achieved through acting on excitation voltages and the adjustable parameters mentioned above. The load conditions instead constitute “disturbance” inputs for both types of control.

Subsystems (a) and (b) interact with each other, specifically through:

- generated active powers;
- electrical speeds of generating units (or, more generally, of synchronous machines) and (electrical) shifts between their rotors.

With reference to [14], typical time intervals for analysis and control of the most important dynamic phenomena are shown in Fig. 2.4. Regarding response times, subsystem (a) generally presents much slower “dynamics” than subsystem (b) (except with torsional phenomena on turbine-generator shafts), primarily because of:

- the effects of rotor inertias,
- limits on driving power rate of change,
- delay times by which (because of the dynamic characteristics of supply systems) driving powers match opening variations of the valves.

With the help of above facts various simplifications can be done that are useful in,

- identifying the most significant and characterizing factors of phenomena,
- performing dynamic analyses with reasonable approximation, and
- selecting the criteria and implementing on the significant variables, on which the real-time system operation (control, protection, supervision, etc.) should be based.

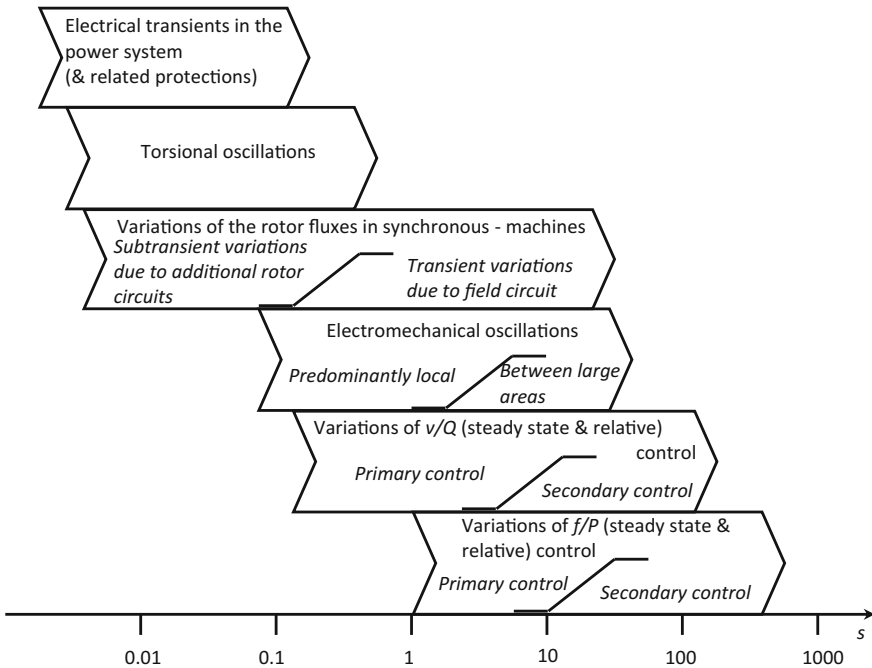


Fig. 2.4 Typical time intervals for analysis and control of the most important power system dynamic phenomena [14]

Accordingly, dynamic phenomena can be categorized as below [14].

• <i>Predominantly</i> Mechanical phenomena	<ul style="list-style-type: none"> – caused by perturbations in subsystem (a) and in f/P control, – slow enough to allow rough estimates on the transient response of subsystem (b), up to the adoption of a purely “static” model (an example is the case of phenomena related to frequency regulation)
• <i>Predominantly</i> Electrical phenomena	<ul style="list-style-type: none"> – caused by perturbations in subsystem (b) and in V/Q control, – fast enough that machine speeds can be assumed constant (for instance, the initial part of voltage and current transients following a sudden perturbation in the network) or which are such to produce negligible variations in active powers, again without involving the response of subsystem (a) (for instance, phenomena related to voltage regulation, in case of almost purely reactive load)
• <i>Strictly</i> Electromechanical- phenomena	<ul style="list-style-type: none"> – Caused by interaction between subsystems (a) and (b) – acceptable to simplify the dynamic models of components according to the frequencies of the most important electromechanical oscillations (e.g., oscillation of the rotating masses of the generators and motors that occur following a disturbance, operation of the protection system [6])

2.7 Process for Generation-Load Balance

An electrical power system consists of many generating units and many loads while its total power demand varies continuously throughout the day in a more or less anticipated manner. It is very important for the utilities to ensure that the power system can be catered with sufficient generation whenever it is on demand. There are four main time frames in ensuring that they can supply their loads as shown in Fig. 2.5, [9].

They are:

- Long term planning—ensures that the most optimal generation portfolio is invested into supply the forecasted load
- Operations planning—deals with changes in transmission or generation that will need to take place for maintenance purposes in the coming months. The unit function that deals with the optimum selection of the units that need to go online to supply the load may fall in this time frame as well, depending on their type, generating units need different preparation time for going live spanning from months to days.

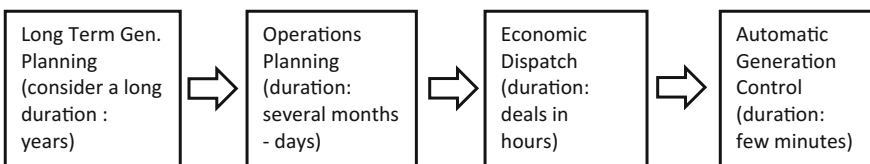


Fig. 2.5 Generation load balance in different time horizons [9]

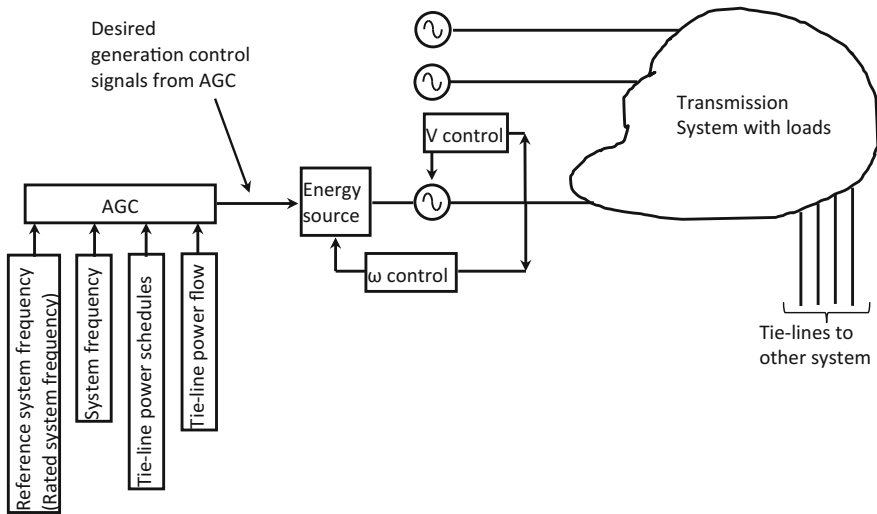


Fig. 2.6 Power system automatic generation control [9]

- Economic dispatch—deals with the selection of the most economic units to supply the load in the next few hours.
- Automatic Generation Control, AGC—balance generation and load on a minute-to-minute basis when operators do not have sufficient time to control generators. With reference to AGC, Load Frequency Control is demonstrated in Fig. 2.6, considering one generator in the system.

According to [15], Load frequency control is described in the “UCTE Operation Handbook” as “the continuous balance between supply and demand that must be maintained for reliability and economic operational reasons.” The system frequency, which should not vary significantly from its set point of 50 Hz, is an indication of the quality of “balance”. The load frequency control can be identified with five control levels. They are:

- Primary control
- Secondary control
- Tertiary control
- Time control
- Measures for emergency conditions.

2.7.1 Primary Control (Is by Governors)

The action of turbine governors due to frequency changes when reference values of regulators are kept constant is referred to as primary frequency control. According

to [15], the time for starting the action of primary control is in practice a few seconds starting from the incident (although there is no intentional time delay for governor pickup), the deployment time for 50% or less of the total primary control reserve is at most 15 s and from 50 to 100% the maximum deployment time rises linearly to 30 s.

When the total generation is equal to the total system demand (including losses) then the frequency is constant, the system is in steady state condition. As discussed in Appendices A–C [6], system loads are frequency dependent. In order to obtain a linear approximation of the frequency response characteristic of the total system load, a similar expression similar to Eq. (2.2) (in Appendix-C) can be written as,

$$\frac{\Delta P_L}{P_L} = K_L \frac{\Delta f}{f_n} \quad (2.4)$$

where,

K_L frequency sensitivity coefficient of the power demand of the total system

From Eq. (2.2) (in Appendix-C),

$$\frac{\Delta P_T}{P_L} = -K_T \frac{\Delta f}{f_n} \quad (2.5)$$

Tests conducted on actual systems indicate that the generation response characteristic is much more frequency dependent than the demand response characteristic.

Typically,

$$K_L = \text{between } 0.5 \text{ and } 3$$

$$K_T \approx 20(\rho = 0.05).$$

In Eqs. (2.2) and (2.4) the coefficients K_T and K_L have opposite signs so that an increase in frequency corresponds to a drop in generation and an increase in electrical load.

In the (P, f) plane the intersection of the generation and the load characteristic, Eqs. (2.2) and (2.4), defines the system equilibrium point.

A change in the total power demand ΔP_L corresponds to a shift of the load characteristic in the way shown in Fig. 2.7, so that the equilibrium point is moved from position 1 to position 2. The increase in the system load is compensated in two ways:

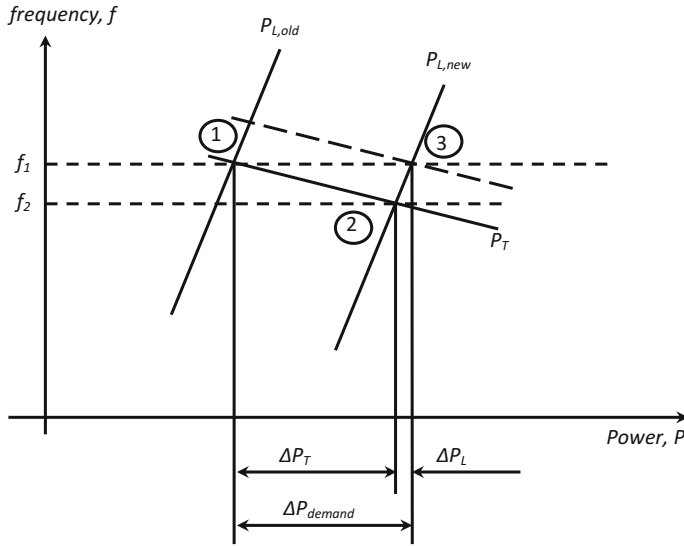


Fig. 2.7 Equilibrium points for an increase in the power demand [6]

- 1st by the turbines increasing the generation by ΔP_T .
- 2nd by the system loads reducing the demand by ΔP_L from that required at position 3 to that required at position 2

$$\Delta P_{\text{demand}} = \Delta P_T - \Delta P_L = -(K_T - K_L)P_L \frac{\Delta f}{f_n} = K_f P_L \frac{\Delta f}{f_n} \quad (2.6)$$

where,

K_f stiffness of a given area or power system.

A reduction of the demand by ΔP_L is due to the frequency sensitivity of demand. An increase of generation by ΔP_T is due to turbine governors. **The action of turbine governors due to frequency changes when reference values of regulators are kept constant is referred to as primary frequency control.**

2.7.2 Secondary Control (Is by Automatic Generation Controls)

This maintains a balance between generation and consumption (demand) of the power system as well as the system frequency, without disturbing the primary control that is operated in the corresponding power system in parallel, but by a margin of seconds. Secondary control makes use of a centralized Automatic

Generation Control, modifying the active power set points/adjustments of generator sets. Secondary control is based on secondary control reserves that are under automatic control [15].

Traditionally, distribution networks have been passive, that is, there was little generation connected to them. Because of the rapid growth in distributed and renewable generation,

- Power flows in distribution networks may no longer be unidirectional, that is from the point of connection with the transmission network down to customers. In many cases the flows may reverse direction when the wind is strong and wind generation high, with distribution networks even becoming net exporters of power [6].
- Most of the solar plants here in Sri Lanka are photovoltaic (PV) with an inverter. Since the intensity of sun varies from time to time, the power generation also changes accordingly [16, 17].
- Mini-hydro Power Plants are designed with a plant factor of around 40% because of the uncertainty in power generation associated with it, as it totally depends on rain fall [5].
- Hydro Power generation depends on the stored energy (reserved water) in corresponding reservoirs [5, 6, 16, 18].

Therefore, the direction of the current flow in transmission mesh network varies from time to time [19].

Further, with the state-of-the-art wind forecasting methods, the hour ahead forecast errors for a single wind power plant are still around 10–15% with respect to its actual outputs [20].

That situation has created many technical problems with respect to settings of protection systems, voltage drops, congestion-management etc.

Hence, the main Duties performed by Automatic Generation Control are:

- maintain frequency at the scheduled value (frequency control);
- maintain the net power interchanges with neighboring control areas at their scheduled values (tie-line control);
- Maintain power allocation among the units in accordance with area dispatching needs (energy market, security or emergency).

In certain systems, one or two of the above objectives may be handled by the AGC. For example, tie-line power control is only used where a number of separate power systems are interconnected and operate under mutually beneficial contractual agreements [6].

This is clearly demonstrated in Fig. 2.6, where AGC measures,

- Actual system frequency
- Interchange flows

From which it calculates,

- the frequency and
- interchange flow deviations,

by using the reference frequency and scheduled interchange values. The frequency and interchange deviation are then used to balance load and generation on a minute-to-minute basis.

Different Automatic Generation Control applications such as:

- Governor Control System
- Interconnected Operation

are implemented [6, 9].

Governor Control System

The slope of the curve shown in Fig. 2.8 is known as the governor droop. That is:

$$\text{Governor droop} = \frac{(f_0 - f_1)}{(G_0 - G_1)}$$

In general,

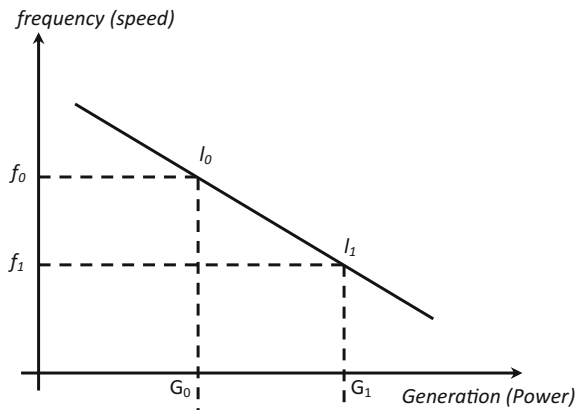
$$\text{Governor droop} = -\frac{\Delta f}{\Delta G} \text{ Hz/MW} \quad (2.7)$$

$$\text{p.u. Governor droop \%} = -\frac{\Delta f/f_0}{\Delta G/G_R} \quad (2.8)$$

where,

f_0 rated frequency
 Δf system frequency change
 G_R rated generation capacity
 ΔG system generation change

Fig. 2.8 A typical speed power characteristic of a governor system



∴ when the droop increases, the generation response is less sensitive to a frequency change. As the system frequency is a constant all over a given system, from the Eqs. (2.8) and (2.9) it can be understood that, for a Δf change in system frequency, response from different generating units are:

$$\frac{\Delta G_i}{G_R} = \frac{-\Delta f/f_0}{GD_i} \Rightarrow \Delta G_i = -(\Delta f) \frac{G_R/f_0}{GD_i} \quad (2.9)$$

where,

ΔG_i generation change

GD_i governor—droop of the i th generator

As a result of the frequency change, total generation change in an n generator system is:

$$\text{Total generation change in MW} = \sum_{i=1}^n \Delta G_i = \sum_{i=1}^n -(\Delta f) \frac{G_{Ri}/f_0}{GD_i} \quad (2.10)$$

As a result of the frequency change the system load also changes due to load sensitivity to frequency.

$$\Delta L_i = D\Delta f \quad (2.11)$$

where,

ΔL_i Load change (MW)

Δf frequency change (Hz)

D Load frequency variation factor (MW/Hz)

From Eqs. (2.10) and (2.11),

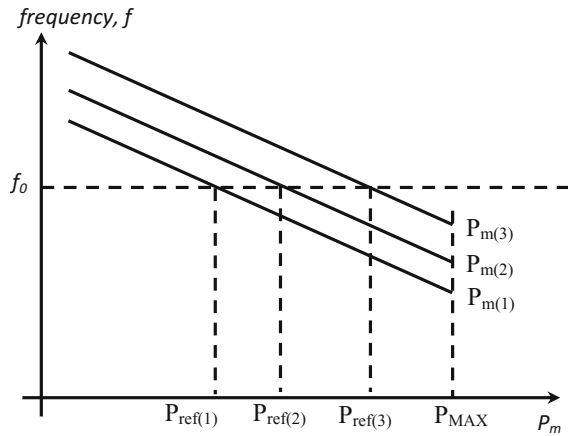
$$\text{Total generation change in MW} = \sum_{i=1}^n \Delta G_i - \Delta L_i = \sum_{i=1}^n -(\Delta f) \frac{G_{Ri}/f_0}{GD_i} - D\Delta f \quad (2.12)$$

$$\text{Total generation change in MW} = \sum_{i=1}^n \Delta G_i - \Delta L_i = -(\Delta f) \left(\sum_{i=1}^n \frac{G_{Ri}/f_0}{GD_i} + D \right) \quad (2.13)$$

Hence due to a frequency change of Δf , there will be an adjustment in both load and generation as given in Eq. 2.13.

As shown in Fig. 2.9, changes in the settings $P_{\text{ref}(1)}$, $P_{\text{ref}(2)}$ and $P_{\text{ref}(3)}$ enforce a corresponding shift of the characteristic to the positions $P_{m(1)}$, $P_{m(2)}$ and $P_{m(3)}$. A turbine cannot be forced to exceed its maximum power rating P_{MAX} with change

Fig. 2.9 Turbine speed–droop characteristics for various settings of P_{ref}



of settings. Further Changing in settings P_{ref} of individual governors will move upwards the overall generation characteristic of the system. Eventually this will lead to the restoration of the rated frequency but now at the required increased value of power demand. Such **control action on the governing systems of individual turbines is referred to as secondary control.**

Interconnected Operations

Power systems interconnections are put in place for different systems to be able to

- Perform exchange of electricity and enjoy the economic benefits of diversity in generation and load
- Provide support under contingencies

Since load and generation in each system change instantaneously, it is important to have proper controls on interties. These controls ensure that the undesirable tie-line flows do not show up as the systems try to mitigate frequency deviations. In other words, each system provides its share of frequency correction without impacting another system's generation load balance inadvertently [6, 9].

In interconnected power systems, AGC is implemented in such a way that each area, or subsystem, has its own central regulator. As shown in Fig. 2.10, the power system is in equilibrium if, for each subsystem satisfy the condition,

$$P_T - (P_L + P_{tie}) = 0 \quad (2.14)$$

2.7.3 Tertiary Control

This action restores secondary control reserve by rescheduling generation and is put into action by the responsible undertakings. The task of tertiary control depends on

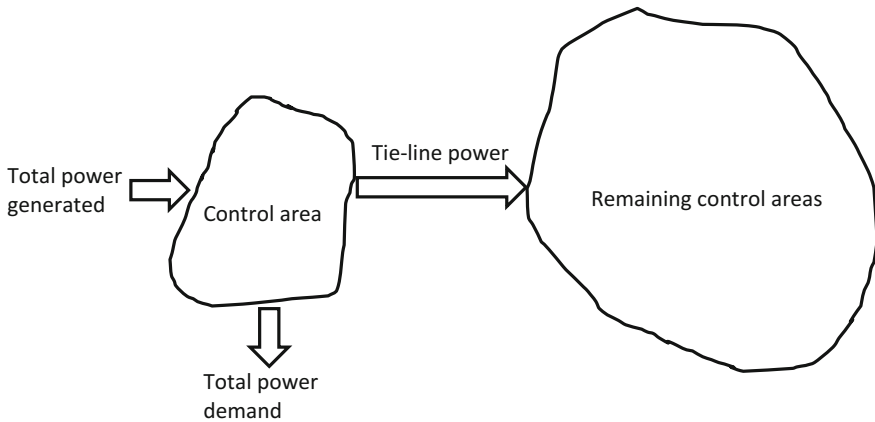


Fig. 2.10 Power balance of a control area [6]

the organizational structure of a given power system and the role that power plants play in this structure. Tertiary control is an additional frequency control procedure to primary and secondary frequency control. This is slower than, primary and secondary frequency control [6, 15].

Under the vertically integrated industry structure (see Fig. 2.1), the system operator sets the operating points of individual power plants based on the economic dispatch, or more generally Optimal Power Flow, which minimizes the overall cost of operating plants subject to network constraints. Hence tertiary control sets the reference values of power in individual generating units to the values calculated by optimal dispatch in such a way that the overall demand is satisfied together with the schedule of power interchanges.

In many parts of the world, electricity supply systems have been liberalized. Gradually, private owned power plants are added to the power system of Sri Lanka too [21, 22]. These privately owned power plants are not directly controlled by the system operator. Instead, according to their mutual agreements with the government or utility, the generation of electricity is practiced by them. Hence the economic dispatch is executed through an energy market.

The main task of the system operator is then to adjust the contracts to make sure that the network constraints are satisfied and to supply the required amount of primary and secondary reserve from individual power plants. In such a market structure the task of tertiary control is to adjust, manually or automatically, the set points of individual turbine governors in order to ensure,

- Adequate spinning reserve in the units participating in primary control.
- Optimal dispatch of units participating in secondary control.
- Restoration of the bandwidth of secondary control in a given cycle.

(The sum of regulation ranges, up and down, of all the generating units active in secondary control is referred to as the **bandwidth of secondary control**. The positive value of the band-width, that is, from the maximum to the actual operating point, forms the reserve of secondary control [6].)

Tertiary control is supervisory with respect to the secondary control that corrects the loading of individual units within an area. Tertiary control is executed through,

- Automatic change of the reference value of the generated power in individual units.
- Automatic or manual connection or disconnection of units that are on the reserve of the tertiary control [6].

Usually control areas are grouped in large interconnected systems with the central regulator of one area (usually the largest) regulating power interchanges in the given area with respect to other areas. In such a structure the central controller of each area regulates its own power interchanges while the central controller of the main area additionally regulates power interchanges of the whole group.

2.7.4 Time Control

This action corrects global time deviations of the synchronous time in the long term as a joint action of all undertakings.

It is considered that each utility's load is composed of,

- its native load and
- the scheduled transactions with other utilities.

Two numbers of system measurements are used to reflect the degree of generation-load imbalance. They are [9],

- the system frequency—which is constant in the whole system and reflects whether the native load is balanced. By removing the frequency error, the AGC control ensures that the generation and load are balanced out.
- the total interchange obligation the utility has to other utilities—if a number of interconnected utilities all attempt to remove the system frequency deviations, they will end up balancing load and generation for the whole interconnected system, except that the final outcome may not fulfill their interchange obligations to each other.

Area Control Error (ACE)

As discussed above AGC controller should minimize both the frequency and interchange deviations as its objective function in its control design. Hence, Area

Control Error (ACE) is defined for a system. Within each control area, continuously, this ACE should be controlled to zero.

$$ACE = -10 \cdot \beta_f \cdot (f_{\text{Actual}} - f_{\text{Desired}}) + (T_{\text{Actual}} - T_{\text{Scheduled}}) \quad (2.15)$$

where,

f_{Desired}	desired frequency (e.g. 50 Hz)
f_{Actual}	actual frequency in Hz
T_{Actual}	actual interchange schedule or tie-line flow with a positive sign for export, in MW
$T_{\text{Scheduled}}$	scheduled interchange or tie-line flow with a positive sign for export, in MW
β_f	area bias with a negative value, MW per 0.1 Hz

AGC achieves its objective by minimizing or bounding ACE. It is important to note that ACE only considers the status of a snapshot of the system disregarding the frequency deviations in the previous time periods and the accumulated frequency and interchange flow mismatches. This creates other issues associated with accumulated frequency and interchange deviations as shown in Fig. 2.7. These frequency deviation and interchange deviation can be reduced to zero by AGC.

Time Error

All electric clocks operates on the main system, are based on system frequency. As shown in Fig. 2.11, the error with time can be considered as a function of accumulated frequency deviation, which is reflected by the area under the frequency deviation curve.

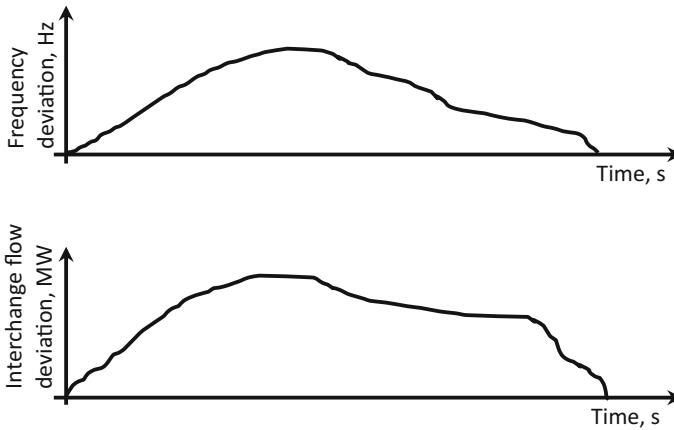


Fig. 2.11 Frequency and interchange flow deviations for one area [1]

To ensure that the time shown by electric clocks is correct, system operators should correct the accumulated time error by scheduled actions. The time error resulting from frequency deviation can be calculated by,

$$Time\ error = \int \left(\frac{f_{Actual} - f_{Desired}}{f_{Desired}} \right) .dt \quad (2.16)$$

where,

$f_{Desired}$ desired frequency in Hz

f_{Actual} actual frequency in Hz

The time error adjustment is not accomplished by AGC. It is sometimes added to the ACE Eq. 2.16 for the sake of completeness, as given in Eq. 2.17:

$$ACE = -10.\beta_f.(f_{Actual} - f_{Desired}) + (T_{Actual} - T_{Scheduled}) + \beta_t.(Time\ error) \quad (2.17)$$

β_t the time error bias in MW/s

In any given situation, the responses of only a limited amount of equipment may be significant. Therefore, using assumptions, usually it is made to simplify the problem and to focus on factors influencing the specific type of stability problem [11]. Further, in analyzing more complex cases where simplifications may not seem acceptable, computer simulations can become necessary [14].

2.8 Under-Frequency Load Shedding

AGC as a “secondary control” has been used by power systems for several decades for bringing up the system frequency to its nominal value, with its actions usually slower than the “primary control” which is done by turbine governors. In any event, the first seconds of frequency dip and recovery after a major generator trip is essentially be accomplished by governor control. When the power system’s self-regulation is insufficient to establish a stable state, the system frequency will continue to drop until it is arrested by automatic under-frequency load shedding (UFLS) to re-establish the load-generation balance within the time constraints necessary to avoid system collapse.

This can be considered as one of the most possible contingencies that may lead the Power System unstable. Events that can be identified as critical signals are:

- Open Circuit of generator feeder or grid transformer Circuit Breaker;
 - OC of a bus-coupler feeder or tie line Circuit Breaker;
 - Protection lock-out function operation of a critical Circuit Breaker;
- (In LS functionality, grid or generator or network Circuit Breakers are referred to as critical Circuit Breakers.);

- Hidden failures in protection systems [3, 12, 23, 24].

The problem of optimal LS has been extensively investigated and many publications on the utility implementation are presented in the literature over the past, [3, 10, 12, 23, 25, 26]. Selection of a suitable LS strategy depends on the application scenario.

- In large scale and wide area Power Systems, typically the adopted methods are based on voltage measurement. This helps in determining the perturbation location so that the area affected by the power deficiency can be addressed by implementing a Load Shedding action confined to that particular area.
- In local power systems, detection of the location of the contingency is trivial. For such situations, LS actions are implemented mainly based on frequency and its derivatives [3, 10, 27].

As demonstrated in Fig. 2.12, LSS acts whenever it identifies a situation of danger for the PS. The most initiative method of checking the level of danger is measuring the average frequency of the grid: when the frequency falls below a certain threshold it is possible to obtain an indication on the risk for the system and consequently to shed a certain amount of load. Although this approach is effective in preventing inadvertent LS in response to small disturbances with relatively longer time delays and low frequency thresholds, it is not capable of distinguishing the difference between normal oscillations and large disturbances in the power system. Thus, this approach is prone to shed lesser loads at large disturbances.

During a load and generation imbalance situation that occurred due to a generation deficiency, the amount of over-load is not known. Therefore the load is shed in blocks until the frequency stabilizes. The three main categories of LS methodologies are: Traditional, semi-adaptive and adaptive.

- Traditional LS scheme is mostly implemented because of its simplicity and less requirement of sophisticated relays. It sheds a certain amount of load when the system frequency falls below a threshold. If this load drop is sufficient, the frequency will stabilize or increase. This process continues until the overload relays get operated. The value of the threshold and the relative amount of load to

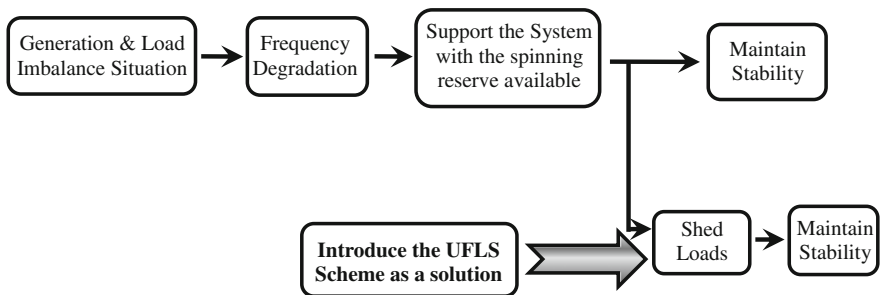


Fig. 2.12 Power system responses due to a load-generation imbalance situation

be shed are decided off line based on experience and simulation. Although this approach is effective in preventing inadvertent LS in response to small disturbances with relatively longer time delay and lower frequency threshold, it is not able to distinguish between normal oscillations and large disturbances of the power system. Thus, this approach is prone to shed lesser loads at large disturbances [8, 28].

- The semi-adaptive LS scheme uses the frequency decline rate as a measure of the generation shortage. In this scheme, the rate of change of frequency thresholds and the size of load blocks to be shed at different thresholds are decided off-line on the basis of simulation and experience [8, 28].
- Adaptive LS scheme is the one that can prevent black-outs through controlled disintegration of a power system into a number of islands together with generation tripping and/or LS [8, 28, 29]. In [29], a linear System Frequency Response (SFR) model is developed which is based on the frequency derivative of the Power System. According to [28, 29], from the reduced order SFR model it is possible to obtain a relation between the initial value of the ROCOF and the size of the disturbance P_{step} , which caused the frequency decline. This relation is:

$$\left. \frac{df}{dt} \right|_{t=0} = \frac{P_{step}}{2H}$$

where,

F expressed in per unit, on base of the nominal system frequency (50 Hz)
 P_{step} in per unit on the total MVA of the whole system

The initial value of the ROCOF is proportional, through the inertia constant H , to the size of the disturbance. Thus, assuming that the inertia of the system is known, the measure of the initial ROCOF is—through H —a backward estimate of the disturbance and consequently an adequate countermeasure in terms of load-shedding can be operated. A drawback of this method is that, if generators or large synchronous motors are disconnected during the disturbance, the inertia of the system should be accordingly adapted. For large systems, this can be overcome by the consideration that only a small percentage of the total inertia has been lost [28, 29]. For small systems such as Power system of Sri Lanka, this may generate an under estimation of the actual perturbation.

Different methodologies have been introduced to implement LS actions based on frequency [8, 12, 23, 25, 26, 30, 31]. With reference to them, it is possible to understand an intelligent and adaptive, control and protection system for wide-area disturbance is needed, to make possible full utilization of the power network, which will be less vulnerable to a major disturbance.

Adaptive settings of frequency and frequency derivative (ROCOF) relays, based on actual system conditions, may enable more effective and reliable implementation

of LSSs [10, 27, 32]. A major component of adaptive protection systems is their ability to adapt to changing system conditions. Thus, relays which are going to participate in the process of control and protection must necessarily be adaptive. In precise, this must be a relay system that allows communication with the outside world. These communication links must be secure, and the possibility of their failure must be considered in designing the adaptive relays [27].

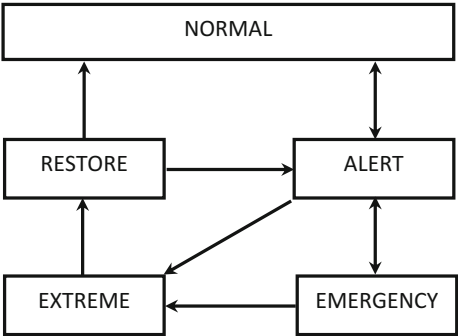
The problem of optimal load shedding has been extensively investigated. As the power systems are dynamic and difficult to model in advance, control schemes should be capable of adjusting their decision criteria/parameters adaptively and independently. In [12], the ‘Reinforcement learning method’ has been introduced to provide suitable basis for the adaptation and the ‘Temporal difference learning method’ has been implemented for the Load Shedding Scheme to provide the reinforcement function. A methodology to develop a reliable load shedding scheme for power systems with high variability and uncertainty, under any abnormal condition, has been introduced, to prevent black-outs while maintaining its stability in [23]. The technique proposes the sequence and conditions of applications of different load shedding schemes and islanding strategies. Another load shedding scheme is proposed in [33] which Develops an algorithm for the selection of Load circuits to shed in periods of reduced generation, that may occur owing to industrial action or if the installed generation capacity is insufficient to meet demand. In [32], an adaptive centralized under-frequency load shedding scheme is described. The frequencies measured by Phasor Measurement Unit are used for calculating the rate of change of frequency as well as the magnitude of the disturbance in the power system. This method can estimate the magnitude of overload occurring from different disturbances and accordingly to determine the necessary amount of load to be shed as well as the size and frequency setting of each shedding step. Since balancing of frequency of an islanded system is still an issue to be solved, especially when the demand exceeds the generation in the power island, a strategy to shed an optimal number of loads in the island to stabilize the frequency is presented in [25]. In [27], Miroslav Begovic et al. explore special protection schemes and new technologies for advanced, wide-area protection. There it has been high-lighted that there is a great potential for advanced wide-area protection and control systems, based on powerful, flexible and reliable system protection terminals, high speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in cooperation. Some of the basic principles which should be considered in the application of a load shedding and load restoration program are presented in [34]. The philosophy which led to the frequency actuated load shedding and load restoration program being implemented on the American Electric Power System are also discussed. In [26], a new approach to adaptive UFLS based on frequency and rate of change of frequency is presented, which are estimated by non-recursive Newton type algorithm. A load shedding scheme for the power system of Sri Lanka considering a coal power plant with 300 MW generation capacity is suggested in [30]. Draw backs of the then load shedding scheme are also presented. In [28], several load-shedding schemes for under-frequency operation are examined. Both traditional schemes,

based only on frequency thresholds, and adaptive schemes, based on frequency and on its rate of change, are considered. An IEEE test system for reliability analysis is used to compare the behavior of the proposed schemes when selecting different thresholds and percentages of load to be disconnected. Results are reported in detail; considerations on possible advantages and drawbacks are also related to the framework provided by the electricity market. M. Giroletti et al., propose a new hybrid Load Shedding method, which combines the most significant features of frequency-based and power-based LS approaches in their publication [10]. A solution technique is described for designing a load shedding scheme using under frequency relays to limit the effect of system over loads and a description of each necessary design decision is also presented in [31]. In their literature, the improvements done in calculating the tripping frequency of a given load shedding step, using the clearing frequency of the previous step and the use of a per-unit relative efficiency ratio are also presented. This method guarantees co-ordination between load-shedding steps. In [25], a technique to develop a frequency dependent auto load-shedding and islanding scheme to bring a power system to a stable state and also to prevent blackouts under any abnormal condition is described. The technique incorporates the sequence and conditions of the application of different load shedding schemes and islanding strategies. The technique is developed based on the international current practices. It uses the magnitude and the falling rate of change of frequency in an abnormal condition to determine the relay settings offline. The paper proposes to implement the technique using only Frequency Sensitive and Frequency Droop relays. For developing countries located in the South Asian region such as Sri Lanka and India (which have poor power systems) may experience equal types of power system instability situations which lead for catastrophic events as in Bangladesh. So the above technique would be a good solution to eliminate power system black-outs while maintaining the stability of the power system. But,

- the traditional LS scheme incorporated with the above technique suggests some time-delay and these time-delays vary from one step to another; hence deciding a correct time delay for corresponding LS stage may be a practically difficult task,
- even though it suggests to disintegrate the power system and to operate in the islanding mode if the frequency decline rate exceeds a particular threshold, power system instability situations can be occurred during the disintegration of the system [12, 23].
- Further when a disturbance occurs, it takes some time to reach particular frequency degradation (df/dt). So during that period, a load shedding action can be taken place (based on traditional load shedding), before this df/dt action gets activated. This may lead for excessive load shedding.

One can look at the system operation as explained in Fig. 2.13, which has been introduced by Fink and Carlsen. In this model, conventional protection and control is likely to be effective in the ‘alert’ and ‘emergency’ states where the load capacity

Fig. 2.13 Fink and Carlsen diagram [35]



and generating capacity remain matched. In the ‘extreme’ state, they are no longer matched and system integrity protection schemes are required [35].

Hence, as a solution for the above requirements, the proposed methodology is presented. It is a combination of all three basic-categories of load shedding schemes mentioned above. Thereby it is aimed to provide a quality and reliable power supply for the consumer while supporting the economy of the country.

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