POWER SYSTEM OPERATION AND CONTROL (18EE81)

MODULE – 1: Introduction:

Electricity is a converted form of energy and is used extensively in industrial, commercial, residential agricultural and transportation sectors. It can be generated and transmitted in bulk, economically, over long distances. AC systems have become the most popular system for use, over DC, for the following reasons:

1. AC generators are simpler than DC generators.
2. Transformation of voltage levels is simple, providing great flexibility of different voltage levels at generation, transmission and distribution.
3. AC motors, widely used, are simpler and more economical than DC motors.

In modern power systems, the grids are interconnected and vary widely in size and structure. However, they comprise three phase systems, at both generation and transmission. Synchronous generators are used for generation. The prime movers act to convert mechanical energy into electric energy. Thermal plants use coal as the primary fuel and hydel plants use water to run the turbine. The generated power is transmitted over a wide geographical area, at voltage levels higher than the generated voltage. At the consumer end, the voltage is stepped down and distributed to various consumers. Consumers of different types need voltages of different levels.

The transmission system interconnects all major generating stations. Normally, the generated voltage is 11 kV or 22 kV. The transmission voltages are 220 kV, 400kV and above. The voltage level is stepped down at the distribution substations and transferred to the industrial consumers at voltages between 4kV and 35 kV. The secondary distribution feeders supply to the residential and commercial consumers at 230 V. Thus, the network is really large, consisting of a number of generating stations, several transmission interconnections and the distribution network.

Operating States of Power System:

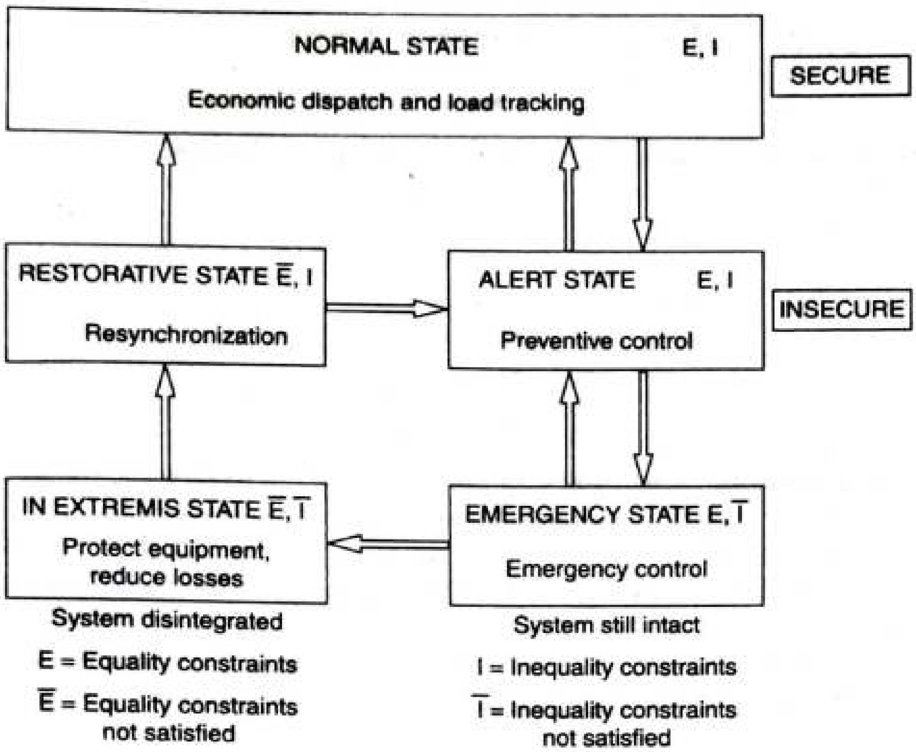

Fig.1 Operating states of a power system

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 different operating parameters, such as voltage, generation limits, currents, etc.

For purposes of analysing power system security and designing appropriate control systems, it is helpful to conceptually classify the system-operating conditions into five states:

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. The system operates in a secure manner and is stable to withstand a contingency without violating any of the constraints.

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 may be violated in the event of disturbances that places the system in an emergency state. If the disturbance is very severe, the in-extremis (or extreme emergency) state may result directly from the alert state. Preventive action, such as generation shifting (security dispatch) or increased reserve, can be taken to restore 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, fault clearing, excitation control, fast-valving, 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 cascading outages, total grid collapse and widespread blackout.

5. Restorative state: This is a transitional state, where the inequality constraints are satisfied by the emergency control actions taken, i.e., reconnect all the facilities and to restore system load, but the system has still not come to normalcy in terms of the equality constraints. The transition either to the alert state or to the normal state.

Objectives of Control:

The fundamental requirements of a power system irrespective of its size are the following:

1. The system must be able to meet the continually changing load demand for active and reactive power. Unlike other types of energy, electricity cannot be conveniently stored in sufficient quantities. Therefore, adequate spinning reserve of active and reactive power should be maintained to take care of sudden variation in the load demand.
2. The power quality should meet certain standards with regard to frequency, amplitude and wave shape of generated voltage and level of reliability.
3. The system should supply energy at a minimum cost.

To achieve the above objectives, several levels of controls that are integrated in a complex way. Some of the controls on individual components are as follows:

1. The generators are provided essentially with excitation control, to keep the voltage and reactive power at the desired levels, and with prime mover control, to maintain the frequency and real power at the desired levels.
2. The prime mover control is concerned with regulation of the speed, and the controls are for the associated parameters such as water discharge quantity, boiler pressure, temperature, flows, etc.
3. Power system stabilizers are used to damp oscillations of the generator following a disturbance. A stabilizing signal is injected into the exciter system to damp the oscillations. Some of the commonly used feedback signals are terminal voltage, frequency and real power.
4. The system generation control maintains the required active power balance in the system. The Automatic Generation Control (AGC) is responsible for maintaining this balance, which in turn is required to hold the frequency around the nominal value. The AGC also maintains the scheduled power flows in tie-lines, which are responsible for power transfer between different control areas.
5. The transmission controls include power and voltage control devices, which help maintain the voltage levels within limits, maintain system stability, protect the system and result in reliable operation of the system. The control devices are tap changing transformers, Flexible AC Transmission (FACTS) controllers, shunt reactors, shunt capacitors, phase-shifting transformers and HVDC controls.

6. Distribution level controls such as capacitors, wave shaping circuits, etc., are used to provide quality power to the consumer. These devices maintain the system voltage at the correct frequency and amplitude, and also help in removing harmonics injected into the load or the system.

The operation and control of the system should ultimately maintain the following:

1. **Stability:** Continued intact operation of the system, following a disturbance. This depends on the operating condition and the nature of the disturbance.
2. **Security:** It is the degree of risk in the power system's ability to survive contingencies without interruption to the customer. It is related to the robustness of the system.
3. **Reliability:** It is the probability of satisfactory operation over a long period. It denotes the ability of the system to supply adequate service on a nearly continuous basis, with a few intermittent interruptions over an extended time period.

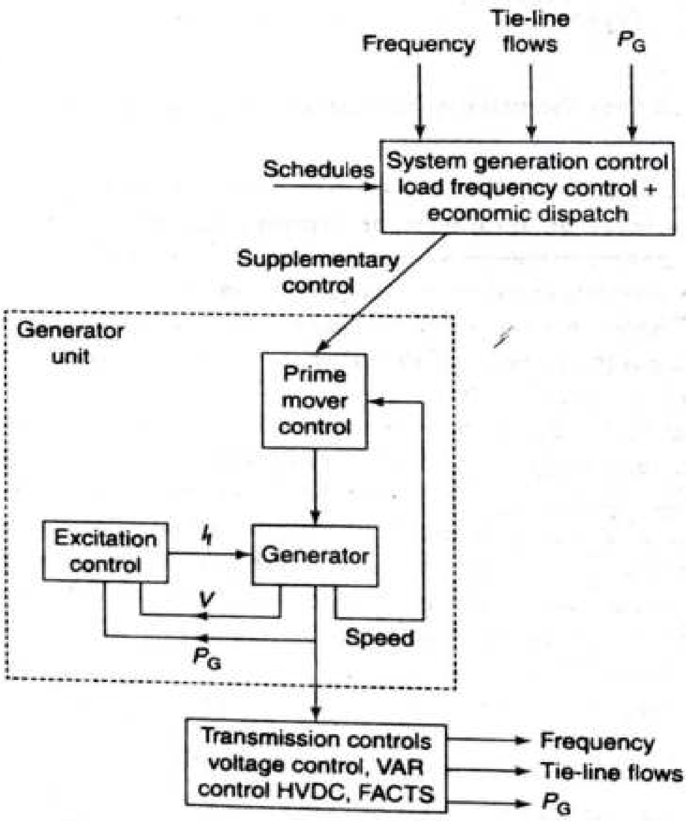

Fig.2 Various controls in a power system

Key Concepts of Reliable Operation:

The North American Electric Reliability Corporation (NERC) has proposed seven key concepts for reliable operation of the power system. These are:

1. **Balance the generation and the load:** The load on the power system is dynamic and changing all the time. The production by the generators must be scheduled to meet this constantly changing load. The AGCs are used to match the generation with the demand. The demand is predictable and a load prediction is done, to keep the appropriate generation and reserve on hand. Failure to match the generation with the demand will cause frequency deviation from the nominal value. The frequency increases if the generation exceeds the demand and frequency drops if the demand exceeds the generation. Over-frequency and under-frequency relays operate when the frequency deviations cross the preset values.
2. **Balance reactive power generation and demand:** This balance is required to maintain the scheduled voltages. Reactive power sources are generators and capacitor banks. They must be constantly adjusted to maintain the voltages at all levels, within permissible range, to protect the equipment. The generator automatic voltage regulators control the voltage level of the generators. FACTS controllers are commonly used for reactive power control.
3. **Ensure thermal limits are not exceeded:** The heating limits of the overhead lines must not be exceeded; otherwise, the lines will sag into the objects given below. There are many critical blackouts which have resulted due to sagging of lines, leading to short circuits, relay tripping and ultimately grid collapse.
4. **Maintain system stability:** Power system stability is 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. If a system loses stability, the grid may face a total collapse. The stability limits will specify the maximum power that can be transferred over the lines. Angle stability is the ability of the generators connected to the grid to remain in synchronism. Voltage stability is the ability of the system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and also after a disturbance.
5. **Meet N – 1 reliability criteria:** This means that the system should remain operational and secure even after the loss of the largest generator in the system. (N is the number of generators, N - 1 indicates loss of one generator). Further after a contingency, the operators must assess the health of the system in the eventuality of another contingency, and take suitable control actions to maintain system security, if it were to occur.

6. **Plan, design and maintain to operate reliably:** The planning, design and maintenance should be such that the system should be operated reliably and within safe limits at all times. Planning involves both short-term and long-term planning.
7. **Prepare for emergencies:** In spite of thorough planning and good design, emergencies such as weather fluctuations, operator error, software failure, equipment failure, etc., can occur. Operators must be trained to prepare for such emergencies.

Preventive and Emergency Controls:

Preventive control is meant to keep the system in the normal state or bring it back to the normal state from the alert state. Automatic controls are provided for frequency and voltage control. Preventive control measures commonly used are as follows:

1. Rescheduling of active power generated by various units, to match the changing load.
2. Scan-up of generation units and providing adequate spinning reserve.
3. Switching of shunt elements for reactive power control and to maintain the voltage within desired limits.
4. Change of reference points of controllable devices such as FACTs controllers, phase-shifting transformers, etc.
5. Change in the voltage reference points of generators and voltage control devices.
6. Change of substation configuration, like bus-bar splitting, etc.

Emergency control measures are taken to stop worsening of the situation, prevent degradation of the system and cascading failure effects and to bring back the system to the alert state. Under-frequency and under-voltage load shedding schemes are used. Some of the common emergency control measures are as follows:

1. Tripping of generators.
2. Load shedding.
3. Fast valving or fast water diversion which leads to a fast reduction in generation.
4. Controlled disconnection of interconnected systems to prevent spreading of frequency problems.
5. Controlled islanding to create local generation-load balance.
6. Blocking of tap changers of transformers.
7. Fast HVDC power transfer control.
8. Application of braking resistors.

Energy Management Centres:

The control of the modern power system is extremely complex. Modern energy management centres are embedded a number of functions. They comprise both hardware and software to monitor and control the system. Monitoring is fully automated. Controlling is a combination of automated and manual operations. Sophisticated computing machines have enhanced the system operation and control facilities. A hierarchical structure is used for control. The functions of energy centre can be divided into three subsystem blocks as follows:

1. The dispatch subsystem: This subsystem would involve the functions of unit commitment, economic dispatch, automatic generation control and demand forecasting.
2. Data subsystem: This subsystem is essentially for data acquisition and processing. It contains the units of SCADA, state estimation and all the associated alarms and displays.
3. Security subsystem: This subsystem is basically to oversee the secure operation of the power system. The functions included are security monitoring, contingency analysis, decision on control actions based on the state of the system, such as preventive control / emergency control / restorative control, etc., and decision on the VAR support to be provided in the system for the voltage profile to be maintained.

The hierarchical control can be broadly classified into three levels:
Level 1: Load forecasting, unit commitment and trading (longer duration)
Level 2: Economic dispatch, optimal power flow, interchange evaluation (duration 5 -10 min)
Level 3: Automatic generation control, voltage control, state estimation (time in seconds)

(Level 1 functions require statistical data and hence probabilistic methods are used. The results of level 1 are used in level 2 and level 3 functions. These are mainly deterministic in nature).

Major components of Energy Centres

The four major components of the energy management centres are as follows:

1. SCADA: The SCADA system consists of two subsystems - the supervisory control and the data acquisition. The supervisory subsystem is responsible for: (a) display at the central location, the status of circuit breakers and other devices such as tap changers, capacitor switching, generator voltage regulators; and (b) facilitating remote tripping of breakers, tap changing of transformers, etc. The dispatcher at the control centre will initiate actions to switch circuit breakers, change taps, etc. The data acquisition subsystem consists of the Remote Terminal Units (RTUs) to interface the power system instrumentation with the control devices and interface communication channels (wireless communication and Power Line Carrier Communication (PLCC) systems) and control centre.

2. Computers: Modern computers are having great capabilities in terms of memory and speed. The structure of energy management centres has changed with advent of fast computing facilities. Since the applications are crucial, redundancy is built in the hardware. Different schemes are available for backup. The main functions of the computing facilities at the control centre are as follows:

- Real-time monitoring and control,
- User interface
- Operating studies,
- Maintenance and testing
- Simulation studies

3. User interface (with extensive GUI and display facilities): The user interface consists of consoles, data loggers, display units and screen projections to alert operators. Since there is extensive interaction with human beings, modern interfaces use techniques of animation and extensive graphics to make it more user friendly.

4. Application software: It is to implement the various functions such as, unit commitment (UC), economic dispatch, state estimation, optimal power flow, contingency analysis, etc.

Supervisory Control and Data Acquisition (SCADA)

Introduction: Automation is used in a variety of applications ranging from the gas and petroleum industry, power system automation, building automation, to small manufacturing unit automation. The terminology SCADA is generally used when the process to be controlled is spread over a wide geographic area, like power systems. SCADA systems are undergoing drastic changes by the addition of new technologies and devices. SCADA is a combination of supervisory control and data acquisition, along with the associated telemetry. It consists of both hardware and software. SCADA is only for supervisory control and does not include a full control system. The complete automation of a process can be achieved by automating the monitoring and the control actions. In electric power systems, most supervisory systems are meant to provide operators with sufficient information and control capabilities to operate the power system in a safe and secure manner.

- **Supervisory Control System:** The intention of supervisory control is to control a specific device to make it perform in accordance with a directed action. Some typical supervisory systems used in power systems are: SCADA, AGC, EMS (Energy Management System), DMS (Distribution Management System), LMS (Load Management System) and AMR (Automatic Meter Reading).

- **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.

- **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.

Thus, SCADA can be defined 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.

Automating the monitoring process will involve the following steps:

- Collect the data from the field.
- Convert the data into transmittable form.
- Bundle the data into packets.
- Transmit the packets of data over the communication media.
- Receive the data at the control centre.
- Decode the data.
- Display the data at the appropriate points on the display screens of the operator.

Automating the control process will involve the following steps:

- The operator initiates the control command.
- Bundle the control command as a data packet.
- Transmit the packet over the communication media.
- The field device receives and decodes the control command.
- Control action is initiated in the field using the appropriate device actuation or cause to operate.

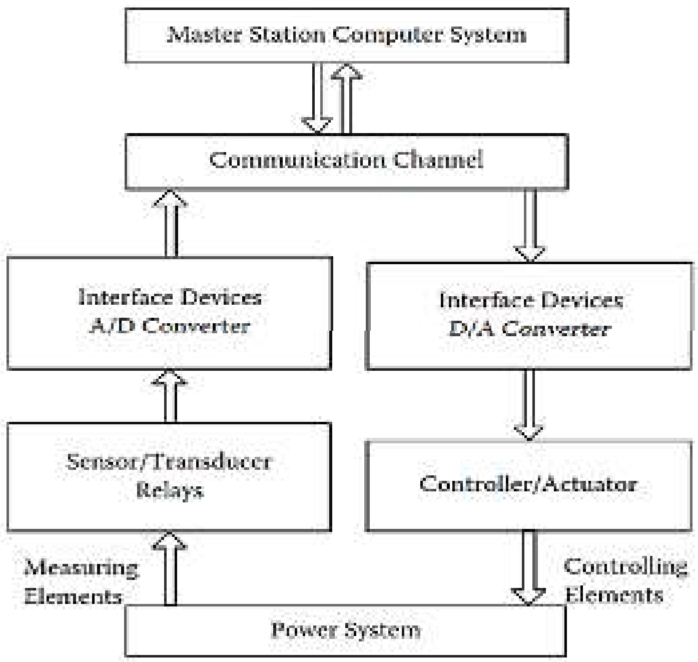

Fig.3 The monitoring and control process

Components of SCADA System:

Fig.4 Components of SCADA system

The four major components of a SCADA system are as follows:

1. RTU: Remote Terminal Unit (RTU) serves as the eyes, ears, and hands of a SCADA system. The RTU acquires all the field data from different field devices, as the human eyes and ears monitor the surroundings, process the data and transmit the relevant data to the master station. At the same time, it distributes the control signals received from the master station to the field devices, as the human hand executes instructions from the brain. Today, Intelligent Electronic Devices (IEDs) are replacing RTUs.

2. Communication System: This refers to the communication channels employed between the field equipment and the master station. The bandwidth of the channel limits the speed of communication.

3. Master Station: This is a collection of computers, peripherals, and appropriate input and output (I/ O) systems that enable the operators to monitor the state of the power system (or a process) and control it.

4. Human-Machine Interface (HMI): HMI refers to the interface required for the interaction between the master station and the operators or users of the SCADA system.

Application in Power System:

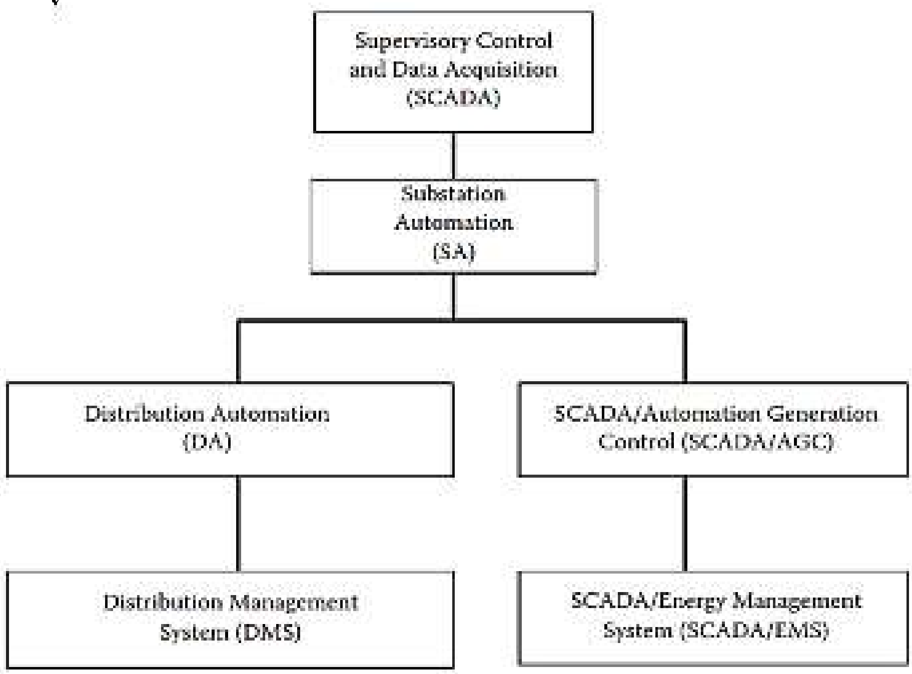

Fig.5 Use of SCADA in power systems

SCADA systems are extensively used in a large number of industries for their monitoring and control. Applications in power industry, oil and gas industry, water treatment, water distribution, and wastewater management systems, control the heating, ventilation, and air conditioning of buildings, steel, plastic, paper, and other major manufacturing industries, mining industry, etc.

The use of SCADA systems in the power industry, including generation, transmission, distribution and utilization of electrical energy is widespread. The SCADA functions can be classified as basic and advanced application functions.

- **Basic functions:** The basic SCADA functions include data acquisition, remote control, human-machine interface, historical data analysis, and report writing, which are common to generation, transmission, and distribution systems.
- **Advanced application functions**:
  Generation SCADA application functions (SCADA/AGC)
  1. Automatic Generation Control (AGC): a collection of equipment and computer programs implementing closed-loop feedback control of frequency and tie-line net interchange.
  2. Economic Dispatch Calculation (EDC): the scheduling of power from all available sources in such a way to minimize cost within some security limit.
  3. Interchange Transaction Scheduling (ITS): ensures that sufficient energy and capacity are available to satisfy load energy and capacity requirements.
  4. Transaction Evaluation (TE): evaluates economy of transactions using the unit commitment results as the base condition.
  5. Unit Commitment (UC): produces the hourly start-up and loading schedule which minimizes the production cost for up to one week in the future
  6. Short- Term Load Forecasting (STLF): produces the hourly system load for up to one week into the future and is used as input to the unit commitment program.
  7. Hydrothermal coordination: the scheduling of power from all available hydro generation in such a way to minimize cost within constraints (e.g., reservoir levels).

Transmission SCADA application functions (SCADA/EMS)

1. Network Configuration/Topology Processor: analyses the status of circuit breakers as well as measurements to automatically determine the current model of the power system.
2. State Estimation: provides a means of processing a set of redundant information to obtain an estimate of the state variables of the system.
3. Contingency Analysis: simulates outages of generating units and transmission facilities to study their effect on bus voltages, power flows, and the transient stability of the power system as a whole.
4. Three- Phase Balanced Power Flow: obtains complete voltage angle and magnitude information for each bus in a power system for specified load and generator real power and voltage conditions.
5. Optimal Power Flow: optimize some system objective function, such as production cost, losses, and so on, subject to physical constraints on facilities and the observation of the network laws.

Distribution automation application functions (DA/DMS): They include substation automation, feeder automation, and customer automation. The additional features incorporated in distribution automation will be

1. Fault identification, isolation, and service restoration
2. Network reconfiguration
3. Load management/demand response
4. Active and reactive power control
5. Power factor control
6. Short-term load forecasting
7. Three-phase unbalanced power flow
8. Interface to customer information systems (CISs)
9. Interface to geographical information systems (GISs)
10. Trouble call management and interface to outage management systems (OMSs).

Advantages of SCADA in power systems:

1. Increased reliability, as the system can be operated with less severe contingencies and the outages are addressed quickly.
2. Lower operating costs, as there is less personnel involvement due to automation.
3. Faster restoration of power in case of a breakdown, as the faults can be detected faster and action taken.
4. Better active and reactive power management, as the values are accurately captured in the automation system and appropriate action can be taken.
5. Reduced maintenance cost, as the maintenance can be more effectively done (transition from time based to condition-based maintenance) with continuous monitoring of the equipment.
6. Reduced human influence and errors, as the values are accessed automatically, and the meter reading and related errors are avoided.
7. Faster decision making, as a wealth of information is made available to the operator about the system conditions to assist the operator in making accurate and appropriate decisions.
8. Optimized system operation, as optimization algorithms can be run and appropriate performance parameters chosen.

Building Blocks of SCADA System:

The SCADA system has four components, the first component is the remote terminal unit (RTU) or data concentrator, which is the link of the control system to the field, for acquiring the data from the field devices and passing on the control commands from the control station to the field devices. Modern SCADA systems are incomplete without the data concentrators and intelligent electronic devices (IEDs) which are replacing the conventional RTUs with their hardwired input and output (I/O) points. Legacy systems with only RTUs, hybrid systems with RTUs and IEDs, and new systems with only IEDs have to be handled with ease by the SCADA system designer.

The second component is the communication system that carries the monitored data from the RTU to the control centre and the control commands from the master station to the RTU or data concentrator to be conveyed to the field. The communication system is of great significance in SCADA generally and in power automation specifically, as the power system field is widely distributed over the landscape, and critical information that is time bound is to be communicated to the master station and control decisions to the field.

The third component of the SCADA system is the master station where the operator monitors the system and makes control decisions to be conveyed to the field.

The fourth component is the user interface (UI) also referred to as the human-machine interface (HMI) which is the interaction between the operator and the machine.

All automation systems essentially have these four components, in varied proportions depending on the process requirements. Power system SCADA systems are focused on the master stations and HMI is of great significance, whereas process automation is focused on controllers, and master station and the HMI has less significance.

Components of RTU:

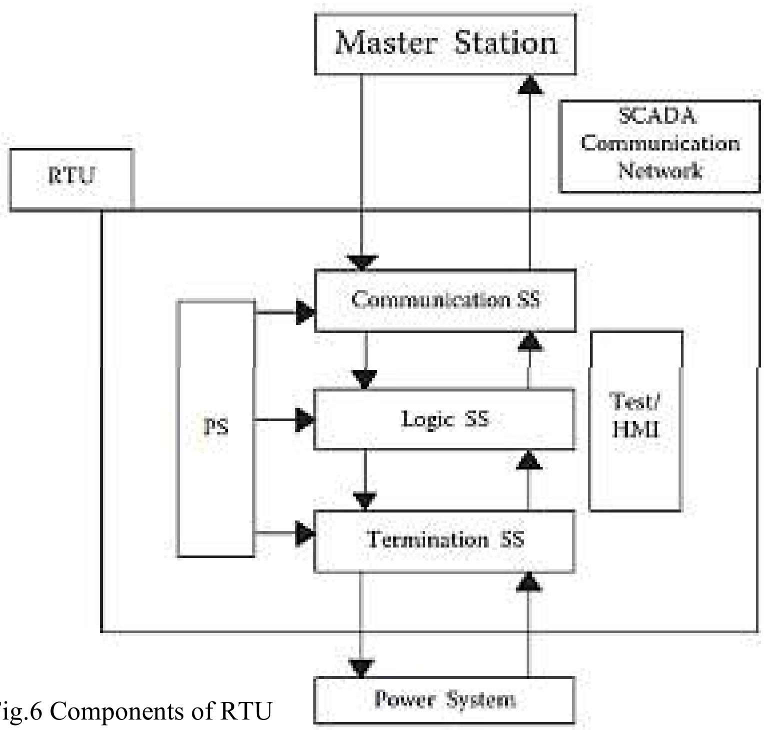

Fig.6 Components of RTU

RTU has the following major components to complete the tasks of monitoring and controlling the field devices:

1. Communication Subsystem: It is the interface between the SCADA communication network and the RTU internal logic. This subsystem receives messages from the master, interprets the messages, initiates actions within the RTU which in turn initiates some action in the field. RTU also sends an appropriate message to the master station on the completion of the task. It also collects data from the field, and processes and conveys relevant data to the master station. RTU may report to a single master or multiple masters.
2. Logic Subsystem: It consists of the main processor and database and handles all major processing - time keeping, and control sensing. The logic subsystem also handles the analog-to-digital conversions and computational optimization, in most of the cases.
3. Termination Subsystem: It provides the interface between RTU and external equipment such as the communication lines, primary source, and substation devices. RTU logic needs to be protected from the harsh Environment of the substation.
4. Power Supply Subsystem: The power supply converts primary power, usually from the substation battery, to the supply requirements of the other RTU subsystems.
5. Test/ HMI Subsystem: This subsystem covers a variety of components, built- in hardware/firmware tests, and visual indicators, within the RTU, and built-in or portable test/maintenance panels or displays.

Communication Subsystem:

It is the interface between the SCADA communication network and the RTU internal logic. Messages from the master station are received and interpreted by the communication subsystem, and the required action is initiated within the RTU. The RTU then initiates the requisite control action in the field, on the completion of which an appropriate message is transmitted to the master station. The communication subsystem receives data from the field, processes the data, bundles the relevant data in the appropriate protocol, and conveys the data to the master station, via the SCADA communication network.

The RTU communication subsystem handles the following functions

1. Communication protocols: A large variety of communication protocols exist in the power system, and the RTU communication system is designed to format and interpret the data in the required protocol. SCADA communication protocols generally report by exception or give information on the points that have changed since the last scan, to reduce the communication system load.

2. Message security: The data handled by the SCADA system are critical, and any corruption in the data can lead to serious consequences. Parity check and Cyclic redundancy check (CRC) are error-checking methods used. The message will have a fixed length preamble of overhead characters, depending on the protocol used, the station address, the function code, and other details. CRC code is calculated separately for the preamble and the data block.

3. Multi-port communication: Modern RTUs have to communicate to the higher SCADA hierarchy to more than one master station, and at the same time, communicate with peer RTUs and IEDs in a variety of protocols. The communication subsystem should be designed to handle this capability.

IED Functional Block Diagram:

External Communication	Data Processing	Input/Output Measurement
Selectable Protocol	Protection*	Discrete Inputs
Selectable Protocol	Metering	Analog Inputs*
Rapid Response	Event Recording	Discrete Outputs*
Real-Time Data*	Fault Recording	Analog Outputs*
Multiple Ports	Application Logic	Selectable Ratings

Fig.7 Modern IED with the functional blocks

- The modern IED architecture ensures that the device is multipurpose, modular in nature, flexible and adaptable, and has robust communication capabilities which include multiple selectable protocols, multi-drop facilities with multiple ports, and rapid response for real-time data.
- IEDs have great data-processing capability for a variety of functions, for various applications like protection and metering.
- IEDs have event recording capability that can be very useful for post-event analysis, for fault waveform recording, and for power quality measurements. This eliminates additional digital fault recorders and power quality monitors.
- IEDs can also accept and send out analog and digital signals with selectable ratings, thus making the IEDs able to adapt different functions.
- The IED brings a relay panel with many single-function electromechanical relays, control switches, extensive wiring, and much more into a single box.
- IED handles additional features like self and external circuit monitoring, real- time synchronization of the event monitoring, local and substation data access, programmable logic controller functionality, and an entire range of software tools for commissioning, testing, event reporting, and fault analysis.

Classification of SCADA System:

SCADA systems can be classified into four categories depending on the complexity, the number of RTUs, master stations present in the system, number of points at each RTU and the required update rates, location of the RTUs, communication facilities, and equipment available.

1. Single master-single remote
It is the simplest configuration, utilized for simple systems where small numbers of points are involved, since it requires one master station and one communication channel per RTU. This one-on-one configuration generally has one indicator or display at the master station for each remote data point.
Example- Control centre of a generating station with one RTU to collect data.

2. Single master-multiple RTU
In this configuration, one master station is shared by several RTUs. Generally, the master station communicates in turn to each RTU using serial digital data messages. This configuration has the advantage over the one-on-one of sharing the master station communications logic among a number of RTUs. These are generally off-the-shelf systems that can be procured easily, and the number of RTUs is generally restricted to 25. The communication configuration could be radial or shared line.
Example- Power distribution system with one master station controlling a number of substations with RTUs.

Fig.8 Single master-single remote configuration

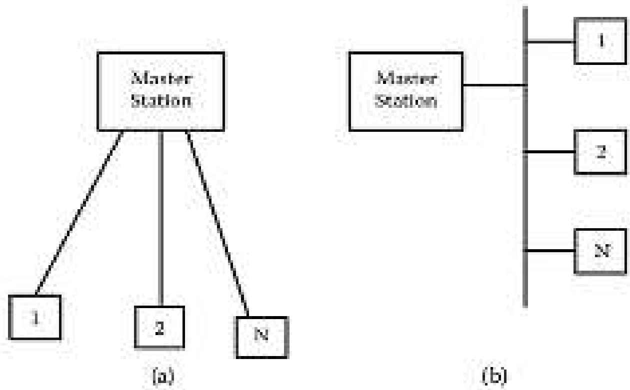

Fig.9 Single master-multiple RTU (a) Radial and (b) Shared line

3. Multiple master-multiple RTUs
In this configuration, there will be sub-masters available with multiple RTUs reporting to each master. These systems will have a large number of RTUs connected to it, and extensive engineering and customization are required for commissioning of the system. It is also characterized by a sizable number of application programs. These systems will take a longer time to execute and implement.
Example- Generation and transmission utility with multiple distribution members, where each member has its own SCADA system.

4. Single master, multiple sub-master, multiple remote
In this system there is a single master, with additional sub-masters, with each sub-master reporting to the master station. The remote RTUs/IEDs will typically be connected to the sub-masters. A typical system would be the hierarchical transmission SCADA used. The multiple sub-masters represent the five regional control centres and also state load dispatch centres. The RTUs are located in the substations around the country.

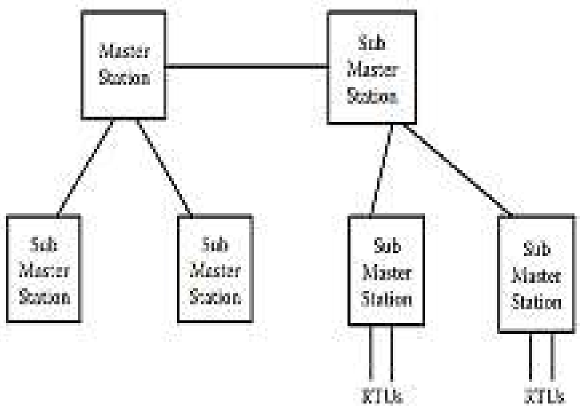

Fig.10 Multiple master-multiple remote configuration

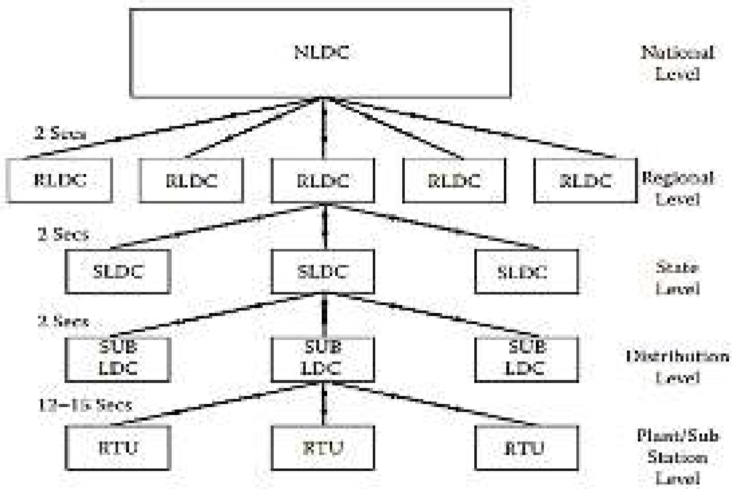

Fig.11 Practical system (National Control Centre for the transmission SCADA in India)

POWER SYSTEM OPERATION AND CONTROL (18EE81)

MODULE – 2: Automatic Generation Control (AGC)

Introduction: Two important parameters in the power system are system voltage and system frequency. These two have to be continuously controlled to maintain them within acceptable limits. Frequency deviations occur due to imbalance between generation and load. The load on the system being dynamic, the voltage and frequency continuously change. These changes must be detected in real time and the automatic control system should initiate control actions and bring the system back quickly to its original state. Hence, generation has to be controlled to keep track of the load variations. This is the problem of automatic generation control (AGC).

Schematic Diagram of Load Frequency and Excitation Voltage Regulators of Turbo Generators

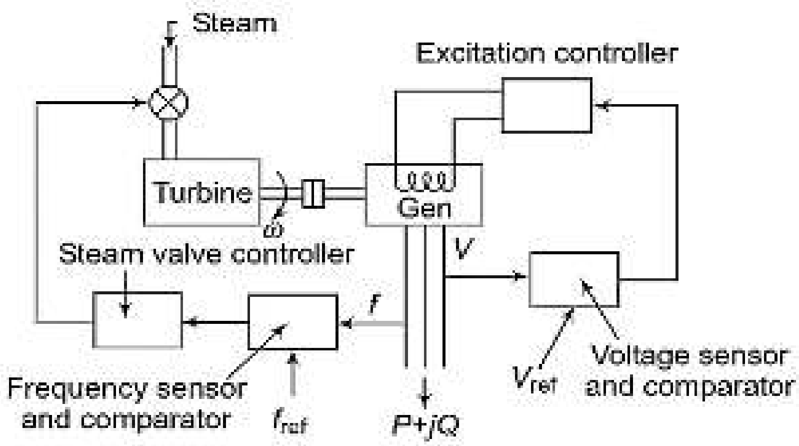

Fig.2.1 Schematic diagram of load frequency and excitation voltage regulators of turbo generators

In the power systems, both active and reactive power demands are never steady and they continually change with the rising or falling trend. Power input to generators must be continuously regulated to match the active power demand, otherwise the machine speed will vary with consequent change in frequency which may be highly undesirable (maximum permissible change in power frequency is ± 0.5 Hz). Also the excitation of generators must be continuously regulated to match the reactive power demand with reactive generation, otherwise the voltages at various system buses may go beyond the prescribed limits. In modern large interconnected systems, manual regulation is not feasible and therefore automatic generation and voltage regulation equipment is installed on each generator. Fig. 2.1 gives the schematic diagram of load frequency and excitation voltage regulators of a turbo-generator.

The controllers are set for a particular operating condition and they take care of small changes in load demand without frequency and voltage exceeding the prescribed limits. With the passage of time, as the change in load demand becomes large, the controllers must be reset either manually or automatically.

For small changes active power is dependent on internal machine angle δ and is independent of bus voltage; while bus voltage is dependent on machine excitation, therefore on reactive power generation and is independent of machine angle δ. Change in angle δ is caused by momentary change in generator speed. Therefore, load frequency and excitation voltage controls are non-interactive for small changes and can be modelled and analysed independently.

The excitation voltage control is fast acting in which the major time constant encountered is that of the generator field; while the power frequency control is slow acting with major time constant contributed by the turbine and generator moment of inertia. This time constant is much larger than that of the generator field. Thus, the transients in excitation voltage control vanish much faster and do not affect the dynamics of power frequency control.

Changes in load demand can be identified as: (i) slow varying changes in mean demand, and (ii) fast random variations around the mean. The regulators must be designed to be insensitive to fast random changes, otherwise the system will be likely to suffer from hunting, resulting in excessive wear and tear of rotating machines and control equipment.

Load Frequency Control: Single Area Case

Consider the problem of controlling the power output of the generators of a closely coupled electric area so as to maintain the scheduled frequency. All the generators in such an area constitute a coherent group so that all the generators speed up and slow down together maintaining their relative power angles. Such an area is defined as a control area. The boundaries of a control area will generally coincide with that of an individual electricity board.

To understand the load frequency control problem, consider a single turbo-generator system supplying an isolated load.

1. Turbine Speed Governing System:

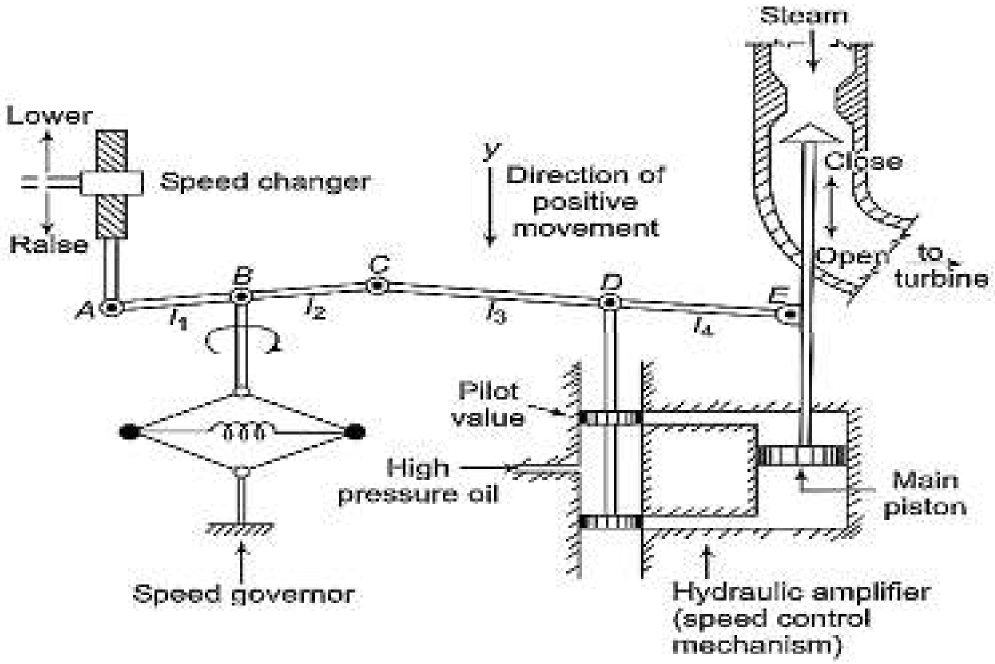

Fig.2.2 Speed governing system of a steam turbine

Fig. 2.2 shows schematically the speed governing system of a steam turbine. The system consists of the following
components:

Fly ball speed governor: This is the heart of the system which senses the change in speed or frequency. As the speed increases the fly balls move outwards and the point B on linkage mechanism moves downwards. The reverse happens when the speed decreases.

Hydraulic amplifier: It comprises a pilot valve and main piston arrangement. Low power level pilot valve movement is converted into high power level piston valve movement. This is necessary in order to open or close the steam valve against high pressure steam.

Linkage mechanism: ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. This link mechanism provides a movement to the control valve in proportion to change in speed. It also provides a feedback the steam valve movement (link 4).

Speed changer: It provides a steady state power output setting for the turbine. Its downward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions. The reverse happens for upward movement of speed changer.

Model of Speed Governing System:

Assume that the system is initially operating under steady conditions - the linkage mechanism stationary and pilot valve closed, steam valve opened by a definite magnitude, turbine running at constant speed with turbine power output balancing the generator load. Let the operating conditions be characterized by

f^0 = system frequency (speed)

P_G^0 = generator output = turbine output (neglecting generator loss)

y_E^0 = steam valve setting

To obtain a linear incremental model around these operating conditions, the point A on the linkage mechanism be moved downwards by a small amount Δy_A. It is a command which causes the turbine power output to change and is given by

$$\Delta y_A = k_C \ \Delta P_C \qquad \rightarrow (2.1)$$

where ΔP_C is the commanded increase in power.

The command signal ΔP_C (i.e. Δy_E) sets into motion a sequence of events - the pilot valve moves upwards, high pressure oil flows on to the top of the main piston moving it downwards; the steam valve opening consequently increases, the turbine generator speed increases, i.e. the frequency goes up.

To model these events mathematically, two factors contribute to the movement of C:

i) Δy_A contributes $-\left(\frac{l_2}{l_1}\right)\Delta y_A$ or $-k_1 \ \Delta y_A$ (i.e., upwards) or $-k_1 \ k_C \ \Delta P_C$

ii) Increase in frequency Δf causes the fly balls to move outwards so that the point B move downwards by a proportional a amount $k_2^{'} \ \Delta f$. The consequent moment of C with A remaining fixed Δy_A is

$$+\left(\frac{l_1 + l_2}{l_1}\right)k_2^{'} \ \Delta f = + \ k_2 \Delta f \quad \text{(i.e., downwards).}$$

Then the net moment of C is $\Delta y_C = -k_1 \ k_C \ \Delta P_C + k_2 \ \Delta f$ $\rightarrow$ (2.2)

The moment of D (Δy_D) is the amount by which the pilot valve opens. It is contributed by Δy_C and Δy_E can be written as

$$\Delta y_D = \left(\frac{l_4}{l_3 + l_4}\right)\Delta y_C + \left(\frac{l_3}{l_3 + l_4}\right)\Delta y_E$$

$$\Delta y_D = k_3 \ \Delta y_C + k_4 \ \Delta y_E \qquad \rightarrow (2.3)$$

The movement Δy_D depending upon its sign opens one of the ports of the pilot valve admitting high pressure oil into the cylinder thereby moving the main piston and opening the steam valve by Δy_E. Certain justifiable simplifying assumptions can be made, at this stage, are:

(i) Inertial reaction forces of main piston and steam valve are negligible compared to the forces exerted on the piston by high pressure oil.

(ii) Because of (i) above, the rate of oil admitted to the cylinder is proportional to port opening Δy_D.

The volume of oil admitted to the cylinder is thus proportional to the time integral of Δy_D. The movement Δy_E is obtained by dividing the oil volume by the area of the cross-section of the piston. Thus

$$\Delta y_E = k_5 \int_0^t (-\Delta y_D) dt \qquad \rightarrow (2.4)$$

It can be verified from the schematic diagram that a positive movement causes negative (upward) movement Δy_E accounting for the negative sign used in Eq. (2.4)

Taking the Laplace transform of Eqs. (2.2), (2.3) and (2.4), gives

$$\Delta Y_C(s) = -k_1 \ k_C \ \Delta P_C(s) + k_2 \ \Delta F(s) \qquad \rightarrow (2.5)$$

$$\Delta Y_D(s) = k_3 \ \Delta Y_C(s) + k_4 \ \Delta Y_E(s) \qquad \rightarrow (2.6)$$

$$\Delta Y_E(s) = -k_5 \frac{1}{s} \Delta Y_D(s) \qquad \rightarrow (2.7)$$

Eliminating, $\Delta Y_C(s)$ and $\Delta Y_D(s)$, then

$$\Delta Y_E(s) = \frac{k_1 k_3 k_C \ \Delta P_C(s) - k_2 k_3 k_C \ \Delta F(s)}{\left(k_4 + \dfrac{s}{k_5}\right)} = \left[\Delta P_C(s) - \frac{1}{R}\Delta F(s)\right] \times \left[\frac{K_{sg}}{1 + T_{sg}\, s}\right] \quad \rightarrow (2.8)$$

where $R = \dfrac{k_1 k_C}{k_2}$ = speed regulation of the governor, $K_{sg} = \dfrac{k_1 k_3 k_C}{k_4}$ = gain of the speed governor

$T_{sg} = \dfrac{1}{k_4 k_5}$ = time constant of the speed governor

Eq. (2.8) is represented in the form of block diagram shown in Fig. 2.3.

In the speed governing system of a hydro-turbine, an additional feedback loop provides temporary droop compensation to prevent instability. This is necessitated by the large inertia of the penstock gate which regulates the rate of water input to the turbine.

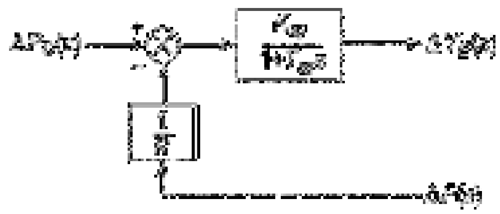

Fig.2.3 Block diagram of speed governing system

Turbine Model:

The dynamic response of a steam turbine is related in terms of changes in power output ΔP_t to changes in steam valve opening Δy_E. Fig. 2.4a shows a two stage steam turbine with a reheat unit. The dynamic response is largely influenced by two factors, (i) entrained steam between the inlet steam valve and first stage of the turbine, (ii) the storage action in the reheater which causes the output of the low pressure stage to lag behind that of the high pressure stage. Thus, the turbine transfer function is characterised by two time constants. For ease of analysis it will be assumed here that the turbine can be modelled to have a single equivalent time constant. Fig. 2.4b shows the transfer function model of a steam turbine. Typically, the time constant T_t lies in the range 0.2 to 2.5 sec.

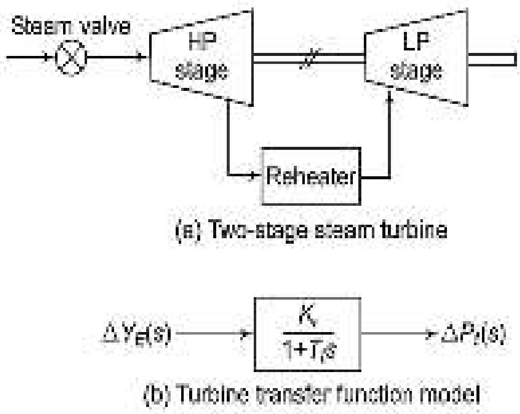

Fig.2.4 Block diagram of steam turbine

Generator Load Model:

The increment in power input to the generator-load system is $\Delta P_G - \Delta P_D$, where $\Delta P_G = \Delta P_t$, incremental turbine power output (assuming generator incremental loss to be negligible) and ΔP_D is the load increment. This increment in power input to the system is accounted for in two ways:

(i) Rate of increase of stored kinetic energy in the generator rotor. At scheduled frequency (f^0), the stored energy is

$$W_{ke}^0 = H \times P_r \ \text{ kW-sec (kilojoules)}$$

where P_r is the kW rating of the turbo-generator and H is defined as its inertia constant.

The kinetic energy being proportional to square of speed (frequency), the kinetic energy at a frequency of $(f^0 + \Delta f)$ is given by

$$W_{ke} = W_{ke}^0 \left(\frac{f^0 + \Delta f}{f^0}\right)^2 = \left(1 + \frac{2\,\Delta f}{f^0} + \left(\frac{\Delta f}{f^0}\right)^2\right) \approx H \times P_r \times \left(1 + \frac{2\,\Delta f}{f^0}\right) \quad \rightarrow (2.9)$$

Rate of change of kinetic energy is

$$\frac{d}{dt}(W_{ke}) = \frac{2\,H\,P_r}{f^0}\frac{d}{dt}(\Delta f) \quad \rightarrow (2.10)$$

(ii) As the frequency changes, the motor load changes being sensitive to speed, the rate of change of load with respect to frequency, $\frac{\partial P_D}{\partial f}$ can be regarded as nearly constant for small changes in frequency Δf and can be expressed as

$$\frac{\partial P_D}{\partial f}\ \Delta f = B\ \Delta f \qquad \rightarrow (2.11)$$

where the constant B can be determined empirically. B is positive for a predominantly motor load.

Then the power balance equation is

$$\Delta P_G - \Delta P_D = \frac{2\,H\,P_r}{f^0}\frac{d}{dt}(\Delta f) + B\ \Delta f$$

Dividing both sides by P_r and rearranging the above equation,

$$\Delta P_G\,(pu) - \Delta P_D\,(pu) = \frac{2\,H}{f^0}\frac{d}{dt}(\Delta f) + B(pu)\ \Delta f \qquad \rightarrow (2.12)$$

Taking Laplace transform, and write $\Delta F(s)$ as

$$\Delta F(s) = \frac{\Delta P_G(s) - \Delta P_D(s)}{\frac{2\,H}{f^0}s + B} = \left[\Delta P_G(s) - \Delta P_D(s)\right] \times \left[\frac{K_{ps}}{1 + T_{ps}\,s}\right] \qquad \rightarrow (2.13)$$

where $T_{ps} = \frac{2\,H}{B\,f^0}$ = time constant of the power system,

$K_{ps} = \frac{1}{B}$ = gain of the power system.

Eq. (2.13) is represented in the form of block diagram shown in Fig. 2.5.

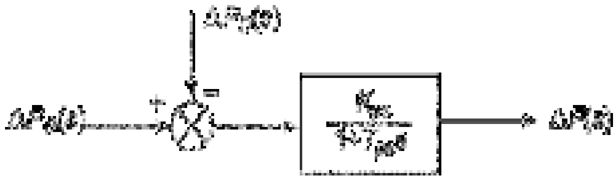

Fig.2.5 Block diagram of generator-load

Complete Block Diagram of Representation of Load Frequency Control of an Isolated Power System:

A complete block diagram representation of an isolated power system comprising turbine, generator, governor and load is easily obtained by combining the block diagrams of individual components. The complete block diagram with feedback loop is shown in Fig. 2.6.

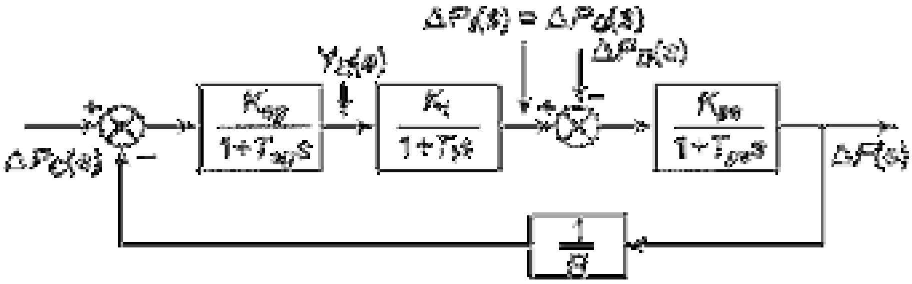

Fig.2.6 Block diagram of load frequency control of an isolated power system

Steady State Analysis:

The model of isolated power system (Fig. 2.6) shows that there are two important incremental input to the load frequency control system- ΔP_C, the change in speed changer setting and ΔP_D, the change in load demand. Consider a situation in which the speed changer has a fixed setting so that $\Delta P_C = 0$ and the load demand changes. This is known as a free governor operation. For such an operation, steady state change in frequency for a sudden change in load demand by an amount ΔP_D (i.e., $\Delta P_D(s) = \frac{\Delta P_D}{s}$) is obtained as follows:

From the block diagram, the transfer function $G(s) = \dfrac{\Delta F(s)}{-\Delta P_D(s)} = \dfrac{\left[\dfrac{K_{ps}}{1+T_{ps}\,s}\right]}{1+\left[\dfrac{K_{ps}}{1+T_{ps}\,s}\right]\left[\dfrac{1}{R}\times\dfrac{K_{sg}}{1+T_{sg}\,s}\times\dfrac{K_t}{1+T_t\,s}\right]}$

$$\Delta F(s) = \frac{K_{ps}\times\left[\dfrac{-\Delta P_D}{s}\right]}{\left(1+T_{ps}\,s\right)+\left[\dfrac{K_{ps}\,K_{sg}\,K_t}{R\left(1+T_{sg}\,s\right)\left(1+T_t\,s\right)}\right]} \qquad \rightarrow (2.14)$$

Using the final value theorem, the steady state change in frequency,

$$\Delta f = \lim_{s\to 0}\left(\left(s\,\Delta F(s)\right)\right) = \lim_{s\to 0}\left(\frac{s\times K_{ps}\times\left[\dfrac{-\Delta P_D}{s}\right]}{\left(1+T_{ps}\,s\right)+\left[\dfrac{K_{ps}\,K_{sg}\,K_t}{R\left(1+T_{sg}\,s\right)\left(1+T_t\,s\right)}\right]}\right) = -\,\frac{K_{ps}\,\Delta P_D}{1+\dfrac{K_{ps}\,K_{sg}\,K_t}{R}} \qquad \rightarrow (2.15)$$

While the gain K_t is fixed for the turbine and K_{ps} is fixed for the power system, K_{sg}, the speed governor gain is easily adjustable by changing lengths of various links. Let it be assumed for simplicity that K_{sg} is so adjusted that $K_{sg}K_t = 1$. Also, $K_{ps} = \dfrac{1}{B}$, where $B = \dfrac{\partial P_D}{\partial f}/P_r$ (in pu MW/ unit change in frequency), then

$$\Delta f = -\frac{\left(\dfrac{1}{B}\right)\Delta P_D}{1+\dfrac{\left(\dfrac{1}{B}\right)\times 1}{R}} = -\left(\frac{\Delta P_D}{B+\dfrac{1}{R}}\right) \qquad \rightarrow (2.16)$$

Eq. (2.16) gives the steady state changes in frequency caused by changes in load demand. Speed regulation R is naturally so adjusted that changes in frequency are small (of the order of 5% from no load to full load). Therefore, the linear incremental relation (Eq.2.16) can be applied from no load-to-full load. The two plots in Fig. 2.7 shows the linear relationship between frequency and load for free governor operation with speed changer set to give a scheduled frequency of 100% at full load and to give the same frequency at 60% rated load because of same slope.

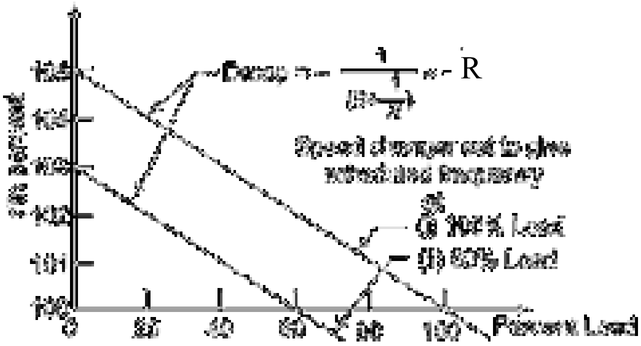

Fig.2.7 Steady state load frequency characteristic of a speed governing system

The droop or slope of this relation is $-\left(\dfrac{1}{B+\dfrac{1}{R}}\right)$

Power system parameter B is generally much smaller than 1/R (a typical value is B = 0.01 pu MW/Hz and 1/ R = 1/3) so that B can be neglected in comparison. Eq. (2.16) then simplifies to

$$\Delta f = -R\,\Delta P_D \qquad \rightarrow (2.17)$$

The droop of the load frequency curve is thus mainly determined by R, the speed governor regulation. It is also observed that increase in load demand (ΔP_D) is met under steady conditions partly by increased generation (ΔP_G) due to opening of the steam valve and partly by decreased load demand due to drop in system frequency. From the block diagram of Fig. 2.6 (with $K_{sg}K_t = 1$), the increase in generation is, $\Delta P_G = -\frac{1}{R}\Delta f = \left(-\frac{1}{R}\right)\left(-\frac{\Delta P_D}{B+\frac{1}{R}}\right) = \frac{\Delta P_D}{BR+1}$

and the decrease in system load $= -B\Delta f = -B\left(-\frac{\Delta P_D}{B+\frac{1}{R}}\right) = \left(\frac{BR\,\Delta P_D}{BR+1}\right)$

Of course, the condition of decrease in system load is much less than the increase in generation. For typical values of B = 0.01 pu MW/Hz and 1/ R = 1/3,

$\Delta P_G = \frac{\Delta P_D}{BR+1} = \frac{\Delta P_D}{\left(0.01\times\frac{1}{3}\right)+1} = 0.9966\ \Delta P_D$ and the decrease in system load $= \left(\frac{\left(0.01\times\frac{1}{3}\right)\Delta P_D}{\left(0.01\times\frac{1}{3}\right)+1}\right) = 0.0033\ \Delta P_D$

Consider now the steady effect of changing speed changer setting ($\Delta P_C(s) = \frac{\Delta P_C}{s}$) with load demand remaining fixed ($\Delta P_D = 0$). The steady state change in frequency is obtained as follows:

From the block diagram, the transfer function $G(s) = \frac{\Delta F(s)}{\Delta P_C(s)} = \frac{\left[\frac{K_{ps}}{1+T_{ps}\,s}\right]\left[\frac{K_{sg}}{1+T_{sg}\,s}\times\frac{K_t}{1+T_t\,s}\right]}{1+\frac{1}{R}\left[\frac{K_{ps}}{1+T_{ps}\,s}\right]\left[\frac{K_{sg}}{1+T_{sg}\,s}\times\frac{K_t}{1+T_t\,s}\right]}$

$$\Delta F(s) = \frac{K_{ps}K_{sg}K_t\times\left[\frac{\Delta P_C}{s}\right]}{(1+T_{ps}\,s)(1+T_{sg}\,s)(1+T_t\,s)+\left[\frac{K_{ps}\,K_{sg}\,K_t}{R}\right]} \qquad \rightarrow (2.18)$$

Using the final value theorem, the steady state change in frequency,

$$\Delta f = \lim_{s\to 0}\left((s\,\Delta F(s))\right) = \lim_{s\to 0}\left(\frac{s\times K_{ps}K_{sg}K_t\times\left[\frac{\Delta P_C}{s}\right]}{(1+T_{ps}\,s)(1+T_{sg}\,s)(1+T_t\,s)+\left[\frac{K_{ps}\,K_{sg}\,K_t}{R}\right]}\right) = \frac{K_{ps}\,\Delta P_C}{1+\frac{K_{ps}\,K_{sg}\,K_t}{R}} \qquad \rightarrow (2.19)$$

Let it be assumed for simplicity that K_{sg} is so adjusted that $K_{sg}K_t = 1$. Also, $K_{ps} = \frac{1}{B}$, where $B = \frac{\partial P_D}{\partial f}/P_r$ (in pu MW/ unit change in frequency), then

$$\Delta f = \frac{\left(\frac{1}{B}\right)\Delta P_C}{1+\frac{\left(\frac{1}{B}\right)\times 1}{R}} = \left(\frac{\Delta P_C}{B+\frac{1}{R}}\right) \qquad \rightarrow (2.20)$$

If the speed changer setting is changed by ΔP_C, while the load demand changes by ΔP_D, the steady frequency change is obtained by superposition, i.e.,

$$\Delta f = \left(\frac{(\Delta P_C - \Delta P_D)}{B+\frac{1}{R}}\right) \qquad \rightarrow (2.21)$$

According to Eq. (2.21) the frequency change caused by load demand can be compensated by changing the setting of the speed changer, i.e., $\Delta P_C = \Delta P_D$, for $\Delta f = 0$.

Control Area Concept:

Consider now a practical system with a number of generating stations and loads. It is possible to divide an extended power system (national grid) into subareas (State Electricity Boards) in which the generators are tightly coupled together so as to form a coherent group (holding synchronism together), i.e. all the generators respond in unison (simultaneous action) to changes in load or speed changer settings. The individual control loops have the same regulation parameters and the individual generator turbines tend to have the same response characteristics. Such a coherent area is called a control area in which the frequency is assumed to be the same throughout in static as well as dynamic conditions.

For purposes of developing a suitable control strategy, a control area can be reduced to a single speed governor, turbo-generator and load system.

Proportional Plus Integral Controller:

It is clear that with the speed governing system installed on each machine, the steady load frequency characteristic for a given speed changer setting has considerable droop from no load to full load (1 pu load). System frequency specifications are rather stringent (precise) and, therefore, so much change in frequency cannot be tolerated. It is expected that the steady change in frequency will be zero. While steady state frequency can be brought back to the scheduled value by adjusting speed changer setting, the system could undergo intolerable dynamic frequency changes with changes in load. It leads to the natural suggestion that the speed changer setting be adjusted automatically by monitoring the frequency changes. For this purpose, a signal from Δf is fed through an integrator to the speed changer resulting in the block diagram configuration shown in Fig. 2.8. The system now modifies to a proportional plus integral controller, which, as is well known from control theory, gives zero steady state error or $\Delta f = 0$.

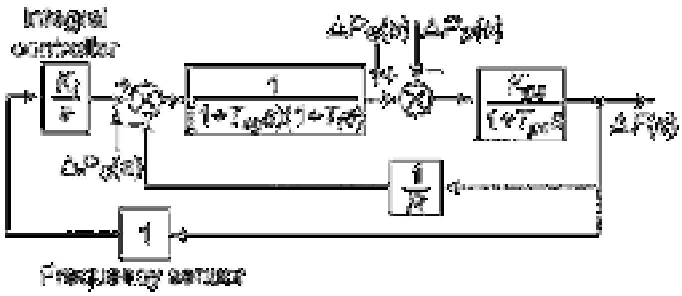

Fig.2.8 Proportional plus integral load frequency control

The signal $\Delta P_C(s)$ generated by the integral control must be of opposite sign to $\Delta F(s)$ which accounts for negative sign in the block for integral controller. For a step change in load, with $K_{sg}K_t = 1$,

$$\Delta F(s) = \frac{K_{ps}}{(1+T_{ps}\,s)+\left[\frac{1}{R}+\frac{K_i}{s}\right]\left[\frac{K_{ps}}{(1+T_{sg}\,s)(1+T_t\,s)}\right]} \times \left[\frac{-\Delta P_D}{s}\right]$$

$$\Delta F(s) = \frac{s\;R\,K_{ps}\;(1+T_{sg}\,s)(1+T_t\,s)}{s\;R\,(1+T_{sg}\,s)(1+T_t\,s)(1+T_{ps}\,s)+(s+R\,K_i)\,K_{ps}} \times \left[\frac{-\Delta P_D}{s}\right] \quad \rightarrow (2.22)$$

According to the final value theorem,

$$\Delta f = \lim_{s\to 0}\left((s\,\Delta F(s)\right) = \lim_{s\to 0}\left(s \times \frac{s\;R\,K_{ps}\;(1+T_{sg}\,s)(1+T_t\,s)}{s\;R\,(1+T_{sg}\,s)(1+T_t\,s)(1+T_{ps}\,s)+(s+R\,K_i)\,K_{ps}} \times \left[\frac{-\Delta P_D}{s}\right]\right) = 0 \quad \rightarrow (2.23)$$

From the Eq. 2.23, it is clear that the steady state change in frequency has been reduced to zero by the addition of the integral controller. Δf reaches steady state (a constant value) only when $\Delta P_C = \Delta P_D$ = constant. Because of the integrating action of the controller, this is only possible if $\Delta f = 0$.

In central load frequency control of a given control area, the change (error) in frequency is known as Area Control Error (ACE). The additional signal fed back in the modified control scheme presented above is the integral of ACE. In the above scheme ACE being zero under steady conditions, a logical design criterion is the minimization of $\int ACE \;\; dt$ for a step disturbance. This integral is indeed the time error of a synchronous electric clock run from the power supply. The modern power systems keep track of integrated time error all the time. A corrective action (manual adjustment ΔP_C, the speed changer setting) is taken by a large (preassigned) station in the area as soon as the time exceeds a prescribed value.

The dynamics of the proportional plus integral controller can be studied numerically only, the system being of fourth order - the order of the system has increased by one with the addition of the integral loop. The dynamic response of the proportional plus integral controller and without controller is shown in Fig. 2.9

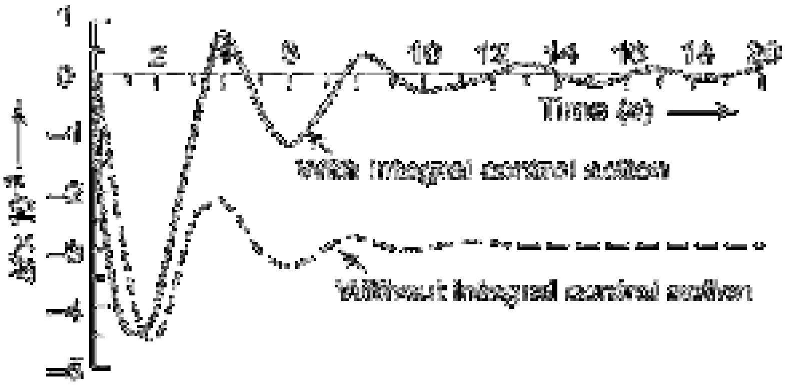

Fig.2.9 Dynamic response of load frequency controller with & without integral control action

Problem-1: A 100 MVA synchronous generator operates on full load at frequency of 50 Hz. The load is suddenly reduced to 50 MW. Due to time lag in governor system, the steam valve begins to close after 0.4 seconds. Determine the change in frequency that occurs in this time. Given, H = 5 kW-sec/kVA of generator.

Solution:

Kinetic energy stored in rotating parts of generator and turbine = $5 \times 100 \times 1000 = 5 \times 10^5$ kW-sec.

Excess power input to generator before the steam valve begins to close = 50 MW

Excess energy input to rotating parts in 0.4 sec = $50 \times 1000 \times 0.4 = 20000$ kW-sec

Stored kinetic energy $\propto$ (frequency)^2 or frequency $\propto \sqrt{\text{stored kinetic energy}}$

$\therefore$ Frequency at the end of 0.4 sec. $= 50 \times \sqrt{\frac{500000+20000}{20000}} = 50.99 \approx 51$ Hz

Problem-2: 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. Assuming that the generators are operating at 50 Hz at no load, how would a load of 600 MW be shared between them? What will be the system frequency at this load? Assume free governor operation. Repeat the problem if both governors have a droop of 4%.

Solution:

Since the generators are in parallel; they will operate at the same frequency at steady load. Let the load supplied by generator-1 (200MW) be x MW and by generator-2 (400MW) will be (600 – x) MW.

Let the frequency deviation be Δf from the no-load frequency, then

$$R_1 = 4\% = \frac{0.04 \times 50}{200} = 0.01\ \frac{Hz}{MW} = \frac{\Delta f}{\mathrm{x}} \quad and \quad R_2 = 5\% = \frac{0.05 \times 50}{400} = 0.00625\ \frac{Hz}{MW} = \frac{\Delta f}{600 - \mathrm{x}}$$

Equating Δf from the above two equations, $0.01\,(x) = 0.00625\,(600 - x)$

$$\therefore\ 0.01625\,x = 3.75 \ \rightarrow\ x = 230.77\ MW$$

Load supplied by generator-1= x = 230.77 MW

Load supplied by generator-2= 600 - x = 600 – 230.77 = 369.23 MW

$$\text{From,}\quad \frac{\Delta f}{\mathrm{x}} = 0.01 \ \rightarrow\ \frac{\Delta f}{230.77} = 0.01 \ \rightarrow\ \Delta f = 2.3077\ Hz$$

The new frequency f = 50 - Δf = 50 – 2.3077 = 47.6923 Hz

It is observed here that due to difference in droop characteristics of governors, generator-1 gets overloaded while generator-2 is under loaded.

If both governors have a droop of 4%, they will share the load as

$$R_1 = 4\% = \frac{0.04 \times 50}{200} = 0.01\ \frac{Hz}{MW} = \frac{\Delta f}{\text{x}} \quad and \quad R_2 = 4\% = \frac{0.04 \times 50}{400} = 0.005\ \frac{Hz}{MW} = \frac{\Delta f}{600 - \text{x}}$$

Equating Δf from the above two equations, $0.01\,(x) = 0.005\,(600 - x)$

$$\therefore\ 0.015\,x = 3 \ \rightarrow\ x = 200\ MW$$

Load supplied by generator-1= x = 200 MW

Load supplied by generator-2= 600 - x = 600 – 200 = 400 MW

They are loaded corresponding to their ratings. Hence it is advantageous for droops of all governors to be equal.

Problem-3: Two machines operate in parallel to supply a load of 400 MW. The capacities of each machine are 200 MW and 500 MW. Each has a droop characteristic of 4%. Their governors are adjusted so that the frequency is 100% on full load. Calculate the load supplied by each unit taking base power of 100 MW and frequency at this load. The system frequency is 50 Hz.

Solution: Full load output of unit – 1 in pu, $P_1 = \frac{200}{100} = 2\ pu$

Full load output of unit – 2 in pu, $P_2 = \frac{500}{100} = 5\ pu$

System frequency in pu = $\frac{50}{50} = 1\ pu,$ Load in pu = $\frac{400}{100} = 4\ pu$

Speed droops, $R_1 = R_2 = R = 4\%\ or\ 0.04$ (at full-load). The no-load speed is 4% greater than full-load speed. Therefore, when the load is thrown off, the frequency raises from 100% to 104% or 1.04 pu. Let the load supplied by unit -1 be x pu and by unit -2 will be (4 – x) pu. Let the frequency deviation be Δf from the no-load frequency of 1.04 pu, then,

$$\frac{\Delta f}{R_1} = \Delta P_1 = \frac{x}{P_1} \quad and \quad \frac{\Delta f}{R_2} = \Delta P_2 = \frac{4 - x}{P_2}$$

$$\frac{\Delta f}{0.04} = \Delta P_1 = \frac{x}{2} \quad and \quad \frac{\Delta f}{0.04} = \Delta P_2 = \frac{4 - x}{5}$$

$$\therefore\ \frac{x}{2} = \frac{4 - x}{5} \ \rightarrow\ 5\,x = 8 - 2\,x \ \rightarrow\ 7\,x = 8$$

$$\therefore\ x = \frac{8}{7} = 1.14285\ pu = 1.14285 \times 100 = 114.285\ MW$$

$$\text{From,}\quad \frac{\Delta f}{0.04} = \frac{x}{2} = \frac{1.14285}{2} \ \rightarrow\ \Delta f = 0.022857\ pu$$

The new frequency f = 1.04 - Δf = 1.04 – 0.022857 = 1.017143 pu or 1.017143×50 = 50.5871 Hz

Load supplied by unit -1 = x = 1.14285 pu or 114.285 MW

Load supplied by unit -2 = (4 – x) = (4 – 1.14285) = 2.85715 pu or 285.715 MW

Problem-4: Two identical machines 1 and 2 have droop characteristics with 5% and 2% speed regulation respectively. They share an initial load of 100 MW equally, operating at nominal frequency. If now there is an increase of 35 MW in the load, how would the additional load be shared?

Solution: Assume nominal frequency = 50Hz. Speed droops, $R_1 = 5\%$, $R_2 = 2\%$

Initial load P_1= 100 MW, increased load P_2= 35 MW, ∴ new load $P_1 + P_2$= 135 MW

When the load is increased by 35 MW, the machines slows down, the governor increases the output until machines seek a new common operating frequency (<50 Hz). Then the additional load shared by the machines (ΔP_1& ΔP_2):

$$\Delta P_1 + \Delta P_2 = 35\ MW, \quad and \quad \frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$
$$\frac{\Delta P_1}{35 - \Delta P_1} = \frac{2}{5}$$
$$5\ \Delta P_1 = 70 - 2\Delta P_1$$
$$7\Delta P_1 = 70 \quad \rightarrow \quad \therefore\ \Delta P_1 = 10\ MW$$
$$10 + \Delta P_2 = 35\ MW \quad \rightarrow \quad \therefore\ \Delta P_2 = 35 - 10 = 25\ MW$$

Problem-5: Two generators rated 1000 MW and 500 MW are operating in parallel with a droop of 5% and 4% respectively. The frequency is 1 pu (50 Hz) at no-load. How is a load of 800 MW shared between them? At what frequency?

Solution:

Let the load supplied by unit -1 be x MW and by unit -2 will be (800 – x) MW.

Let the frequency deviation be Δf from the no-load frequency, then

$$R_1 = 5\% = \frac{0.05 \times 50}{1000} = 2.5 \times 10^{-3}\ \frac{Hz}{MW} = \frac{\Delta f}{\mathrm{x}} \quad and \quad R_2 = 4\% = \frac{0.04 \times 50}{500} = 4 \times 10^{-3}\ \frac{Hz}{MW} = \frac{\Delta f}{800 - \mathrm{x}}$$

Equating Δf from the above two equations, we get

$$2.5 \times 10^{-3}\ (x) = \ 4 \times 10^{-3}\ (800 - x)$$
$$\therefore\ \ 6.5 \times 10^{-3}\ x = 3.2 \quad \rightarrow \quad x = 492.3076\ MW$$

Load supplied by unit -1= x = 492.3076 MW

Load supplied by unit -2= 800 - x = 800 – 492.3076 = 307.6924 MW

$$From, \quad \frac{\Delta f}{\mathrm{x}} = 2.5 \times 10^{-3} \quad \rightarrow \quad \frac{\Delta f}{492.3076} = 2.5 \times 10^{-3} \quad \rightarrow \quad \Delta f = \ 1.2307\ Hz$$

The new frequency f = 50 - Δf = 50 – 1.2307 = 48.7693 Hz

Problem-6: A 100 MW generator is operating onto an infinite network. The regulation parameter R is 3 %. By the how much will the turbine power increase if the frequency drops by 0.2 Hz with reference unchanged. The system frequency is 50 Hz.

Solution: Turbine power will increase 100 MW for a 0.03 pu or 1.5 Hz drop in frequency. Thus, regulation parameter R is,

$$R = \frac{\Delta f}{\Delta P} \quad \rightarrow \quad R = \frac{\left(\frac{3}{100} \times 50\right)}{100} = \frac{1.5}{100} = 0.015\ \ Hz/MW$$

For a frequency change of Δf= - 0.2 Hz, the turbine power will experience a static change of

$$\Delta P_t = -\frac{\Delta f}{R} = -\ \frac{1}{0.015} \times (-0.2) = 13.33\ MW$$

Increase in turbine power = 13.33 MW if reference power setting is unchanged.

Problem-7: A 500 MW generator has a speed regulation of 3%. The frequency drops by 0.1 Hz due to increased load. Find the increase in turbine power if reference power setting is unchanged. What would be the change in reference power setting if turbine power is to remain unchanged?

Solution: $R = \frac{\Delta f}{\Delta P} \ \rightarrow \ R = \frac{\left(\frac{3}{100} \times 50\right)}{500} = 0.003\ Hz/MW$

For a frequency change of Δf= - 0.1 Hz, the turbine power will experience a static change of

$$\Delta P_t = -\frac{\Delta f}{R} = -\ \frac{1}{0.003} \times (-0.1) = 33.33\ MW$$

Increase in turbine power = 33.33 MW if reference power setting is unchanged.

If this increase has to be blocked, then the reference setting should be changed such that

$\Delta P_C + \frac{\Delta f}{R} = 0$ $\quad\quad\quad$ $\therefore\ \Delta P_C = -\frac{\Delta f}{R} = -33.33\ MW$. This would leave the turbine power unchanged.

Problem-8: Two generators of ratings 40 MW and 400 MW, respectively supplying power to a system. The frequency is 50 Hz and each generator is half-loaded. The system load increases by 110 MW and as a result the frequency drops to 49.5 Hz. What must be the individual regulations if the two generators should increase their turbine powers in proportion to their ratings?

Solution: The two generators should pick up 10 MW and 100 MW respectively.

Regulation for smaller unit, $R = -\frac{\Delta f}{\Delta P} = -\left(\frac{-0.5}{10}\right) = 0.05\ \frac{\text{Hz}}{\text{MW}}$

Regulation for larger unit, $R = -\frac{\Delta f}{\Delta P} = -\left(\frac{-0.5}{100}\right) = 0.005\,\frac{\text{Hz}}{\text{MW}}$

or $\quad R = -\frac{-0.5/50}{10/40} = -\frac{-0.5/50}{100/400} = 0.04$ pu or 4% for both units.

Problem-9: Two generators are supplying power to a system. Their ratings are 50MW and 500MW respectively. The frequency is 60Hz and each generator is half-loaded. The system load increases by 110 MW and as a result the frequency drops to 59.5Hz. What must the individual regulations be if the two generators should increase their turbine powers in proportion to their ratings?

Solution: The two generators should pick up 10 MW and 100 MW respectively.

Regulation for smaller unit, $R = -\frac{\Delta f}{\Delta P} = -\left(\frac{-0.5}{10}\right) = 0.05\ \frac{\text{Hz}}{\text{MW}}$

Regulation for larger unit, $R = -\frac{\Delta f}{\Delta P} = -\left(\frac{-0.5}{100}\right) = 0.005\,\frac{\text{Hz}}{\text{MW}}$

or $\quad R = -\frac{-0.5/60}{10/50} = -\frac{-0.5/60}{100/500} = 0.0417\ \text{p.u}$ or 4.17% for both units.

Problem-10: Determine K_{ps}, T_{ps}, and B, the primary automatic load frequency control parameters for a control area having the following data: Total rated capacity = 1000 MW, Inertia constant H = 5 kWs/kVA, Regulation R = 2 Hz/pu MW (all generators) and normal operating load = 500 MW at 50 Hz. Assume that the change in load 1% for 1% change in frequency. Also find the static frequency drop following a 1% load increase.

Solution: Change in load = 1% of 500 = 5 MW, change in frequency = 1% of 50 = 0.5 Hz, $P_r = 1000\ MW$

$$B = \left(\frac{\partial P_D}{\partial f}\right)/P_r = \left(\frac{5}{0.5}\right)/1000 = 0.01\ pu\ MW/Hz$$

$$K_{ps} = \frac{1}{B} = \frac{1}{0.01} = 100\ \ Hz/pu\ MW \qquad \text{and} \qquad T_{ps} = \frac{2\,H}{B\,f^0} = \frac{2\times5}{0.01\times50} = 20\ sec$$

$$\Delta f = -\left(\frac{1}{B+\frac{1}{R}}\right)\Delta P_D = -\left(\frac{1}{0.01+\frac{1}{2}}\right)\times 0.01 = -0.0196\ Hz\ \ or\ -0.0392\%\ \ of\ 50\ Hz.$$

Problem-11: Determine the primary load frequency control loop parameters for a control area having the following data: Total rated area capacity P_r = 2000 MW, Normal operating load = 1000 MW at 60 Hz, Inertia constant H = 5.0 sec, Regulation R = 2.4 Hz/pu MW (all area generators). Assume that the old load would increase 1% for 1% frequency increase. Also find the static frequency drop following a 1.5% load increase.

Solution: Change in load = 1% of 1000 = 10 MW, change in frequency = 1% of 60 = 0.6 Hz, $P_r = 2000\ MW$

$$B = \left(\frac{\partial P_D}{\partial f}\right)/P_r = \left(\frac{10}{0.6}\right)/2000 = 0.00833\ pu\ MW/Hz$$

$$K_{ps} = \frac{1}{B} = \frac{1}{0.00833} = 120.05\ \ Hz/pu\ MW \qquad \text{and} \qquad T_{ps} = \frac{2\,H}{B\,f^0} = \frac{2\times5}{0.00833\times60} = 20.01\ sec$$

$$\Delta f = -\left(\frac{1}{B+\frac{1}{R}}\right)\Delta P_D = -\left(\frac{1}{0.00833+\frac{1}{2.4}}\right)\times 0.015 = -0.0353\ Hz\ \ or\ -0.0588\%\ \ of\ 60\ Hz.$$