Ramakumar, Rama “Electric Power Generation: Conventional Methods”
The Electric Power Engineering Handbook
Ed. L.L. Grigsby
Boca Raton: CRC Press LLC, 2001

2

Electric Power Generation: Conventional Methods

Rama Ramakumar
Oklahoma State University

2

Electric Power Generation: Conventional Methods

Steven R. Brockschink
Pacific Engineering Corporation

James H. Gurney
BC Hydro

Douglas B. Seely
Pacific Engineering Corporation

Paul I. Nippes
Magnetic Products and Services, Inc.

Kenneth H. Sebra
Baltimore Gas and Electric Company

John R. Kennedy
Georgia Power Company

2.1 Hydroelectric Power Generation

Steven R. Brockschink, James H. Gurney, and Douglas B. Seely

Hydroelectric power generation involves the storage of a hydraulic fluid, normally water, conversion of the hydraulic energy of the fluid into mechanical energy in a hydraulic turbine, and conversion of the mechanical energy to electrical energy in an electric generator.

The first hydroelectric power plants came into service in the 1880s and now comprise approximately 22% (660 GW) of the world's installed generation capacity of 3000 GW (Electric Power Research Institute, 1999). Hydroelectricity is an important source of renewable energy and provides significant flexibility in base loading, peaking, and energy storage applications. While initial capital costs are high, the inherent simplicity of hydroelectric plants, coupled with their low operating and maintenance costs, long service life, and high reliability, make them a very cost-effective and flexible source of electricity generation. Especially valuable is their operating characteristic of fast response for start-up, loading, unloading, and following of system load variations. Other useful features include their ability to start without the availability of power system voltage ("black start capability"), ability to transfer rapidly from generation mode to synchronous condenser mode, and pumped storage application.

Hydroelectric units have been installed in capacities ranging from a few kilowatts to nearly 1 GW. Multi-unit plant sizes range from a few kilowatts to a maximum of 18 GW.

Planning of Hydroelectric Facilities

Siting

Hydroelectric plants are located in geographic areas where they will make economic use of hydraulic energy sources. Hydraulic energy is available wherever there is a flow of liquid and head. Head represents potential energy and is the vertical distance through which the fluid falls in the energy conversion process. The majority of sites utilize the head developed by fresh water; however, other liquids such as salt water and treated sewage have been utilized. The siting of a prospective hydroelectric plant requires careful evaluation of technical, economic, environmental, and social factors. A significant portion of the project cost may be required for mitigation of environmental effects on fish and wildlife and re-location of infrastructure and population from flood plains.

Hydroelectric Plant Schemes

There are three main types of hydroelectric plant arrangements, classified according to the method of controlling the hydraulic flow at the site:

1. Run-of-the-river plants, having small amounts of water storage and thus little control of the flow through the plant.
2. Storage plants, having the ability to store water and thus control the flow through the plant on a daily or seasonal basis.
3. Pumped storage plants, in which the direction of rotation of the turbines is reversed during off-peak hours, pumping water from a lower reservoir to an upper reservoir, thus "storing energy" for later production of electricity during peak hours.

Selection of Plant Capacity, Energy, and Other Design Features

The generating capacity of a hydroelectric plant is a function of the head and flow rate of water discharged through the hydraulic turbines, as shown in Eq. (2.1).

$$P = 9.8\ \eta\ Q\ H \tag{2.1}$$

where P = power (kilowatts)
η = plant efficiency
Q = discharge flow rate (meter^3/s)
H = head (meter)

Flow rate and head are influenced by reservoir inflow, storage characteristics, plant and equipment design features, and flow restrictions imposed by irrigation, minimum downstream releases, or flood control requirements. Historical daily, seasonal, maximum (flood), and minimum (drought) flow conditions are carefully studied in the planning stages of a new development. Plant capacity, energy, and physical features such as the dam and spillway structures are optimized through complex economic studies that consider the hydrological data, planned reservoir operation, performance characteristics of plant equipment, construction costs, the value of capacity and energy, and discount rates. The costs of substation, transmission, telecommunications, and remote control facilities are also important considerations in the economic analysis. If the plant has storage capability, then societal benefits from flood control may be included in the economic analysis.

Another important planning consideration is the selection of the number and size of generating units installed to achieve the desired plant capacity and energy, taking into account installed unit costs, unit availability, and efficiencies at various unit power outputs (American Society of Mechanical Engineers Hydro Power Technical Committee, 1996).

Hydroelectric Plant Features

Figures 2.1 and 2.2 illustrate the main components of a hydroelectric generating unit. The generating unit may have its shaft oriented in a vertical, horizontal, or inclined direction depending on the physical

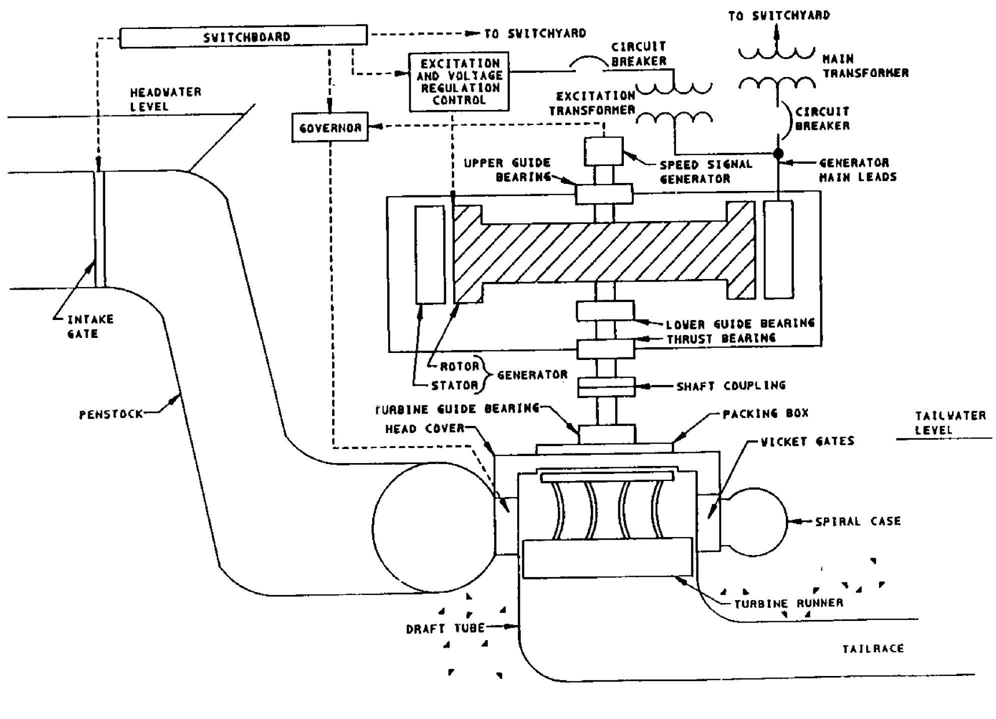


FIGURE 2.1 Vertical Francis unit arrangement. (*Source:* IEEE Standard 1020-1988 (Reaff 1994), *IEEE Guide for Control of Small Hydroelectric Power Plants,* 12. Copyright 1988 IEEE. All rights reserved.)

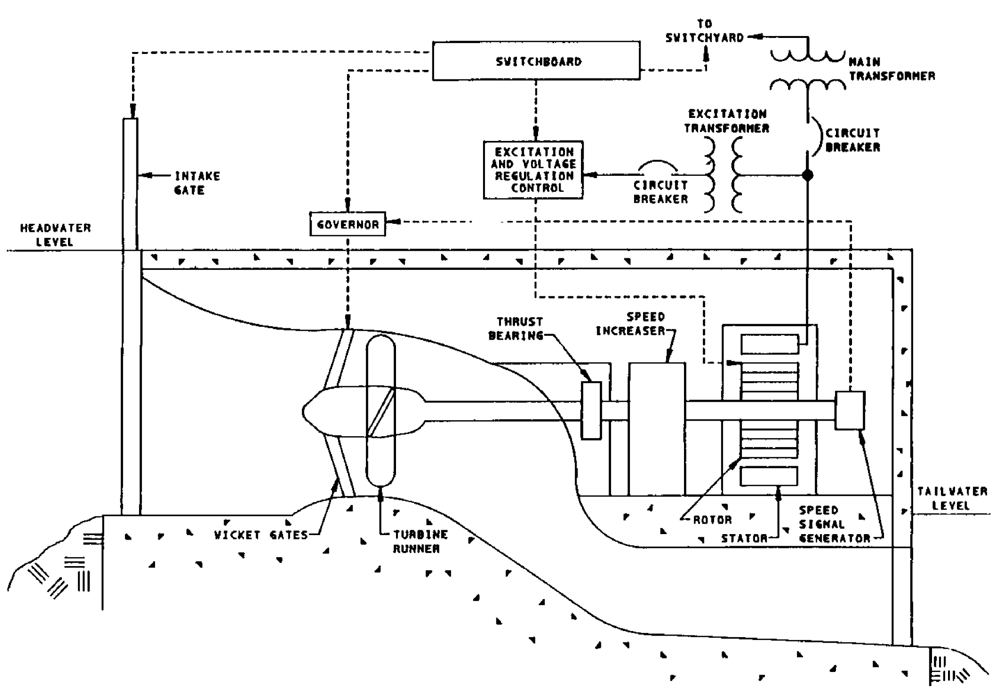


FIGURE 2.2 Horizontal axial-flow unit arrangement. (*Source:* IEEE Standard 1020-1988 (Reaff 1994), *IEEE Guide for Control of Small Hydroelectric Power Plants,* 13. Copyright 1988 IEEE. All rights reserved.)

conditions of the site and the type of turbine applied. Figure 2.1 shows a typical vertical shaft Francis turbine unit and Fig. 2.2 shows a horizontal shaft propeller turbine unit. The following sections will describe the main components such as the turbine, generator, switchgear, and generator transformer, as well as the governor, excitation system, and control systems.

Turbine

The type of turbine selected for a particular application is influenced by the head and flow rate. There are two classifications of hydraulic turbines: impulse and reaction.

The impulse turbine is used for high heads — approximately 300 m or greater. High-velocity jets of water strike spoon-shaped buckets on the runner which is at atmospheric pressure. Impulse turbines may be mounted horizontally or vertically and include perpendicular jets (known as a Pelton type), diagonal jets (known as a Turgo type) or cross-flow types.

In a reaction turbine, the water passes from a spiral casing through stationary radial guide vanes, through control gates and onto the runner blades at pressures above atmospheric. There are two categories of reaction turbine — Francis and propeller. In the Francis turbine, installed at heads up to approximately 360 m, the water impacts the runner blades tangentially and exits axially. The propeller turbine uses a propeller-type runner and is used at low heads — below approximately 45 m. The propeller runner may use fixed blades or variable pitch blades (known as a Kaplan or double regulated type) which allows control of the blade angle to maximize turbine efficiency at various hydraulic heads and generation levels. Francis and propeller turbines may also be arranged in slant, tubular, bulb, and rim generator configurations.

Water discharged from the turbine is directed into a draft tube where it exits to a tailrace channel, lower reservoir, or directly to the river.

Flow Control Equipment

The flow through the turbine is controlled by wicket gates on reaction turbines and by needle nozzles on impulse turbines. A turbine inlet valve or penstock intake gate is provided for isolation of the turbine during shutdown and maintenance.

Spillways and additional control valves and outlet tunnels are provided in the dam structure to pass flows that normally cannot be routed through the turbines.

Generator

Synchronous generators and induction generators are used to convert the mechanical energy output of the turbine to electrical energy. Induction generators are used in small hydroelectric applications (less than 5 MVA) due to their lower cost which results from elimination of the exciter, voltage regulator, and synchronizer associated with synchronous generators. The induction generator draws its excitation current from the electrical system and thus cannot be used in an isolated power system. Also, it cannot provide controllable reactive power or voltage control and thus its application is relatively limited.

The majority of hydroelectric installations utilize salient pole synchronous generators. Salient pole machines are used because the hydraulic turbine operates at low speeds, requiring a relatively large number of field poles to produce the rated frequency. A rotor with salient poles is mechanically better suited for low-speed operation, compared to round rotor machines which are applied in horizontal axis high-speed turbo-generators.

Generally, hydroelectric generators are rated on a continuous-duty basis to deliver net kVA output at a rated speed, frequency, voltage, and power factor and under specified service conditions including the temperature of the cooling medium (air or direct water). Industry standards specify the allowable temperature rise of generator components (above the coolant temperature) that are dependent on the voltage rating and class of insulation of the windings (ANSI, C50.12-1982; IEC, 60034-1). The generator capability curve, Fig. 2.3, describes the maximum real and reactive power output limits at rated voltage within which the generator rating will not be exceeded with respect to stator and rotor heating and other limits. Standards also provide guidance on short circuit capabilities and continuous and short-time current unbalance requirements (ANSI, C50.12-1982; IEEE, 492-1999).

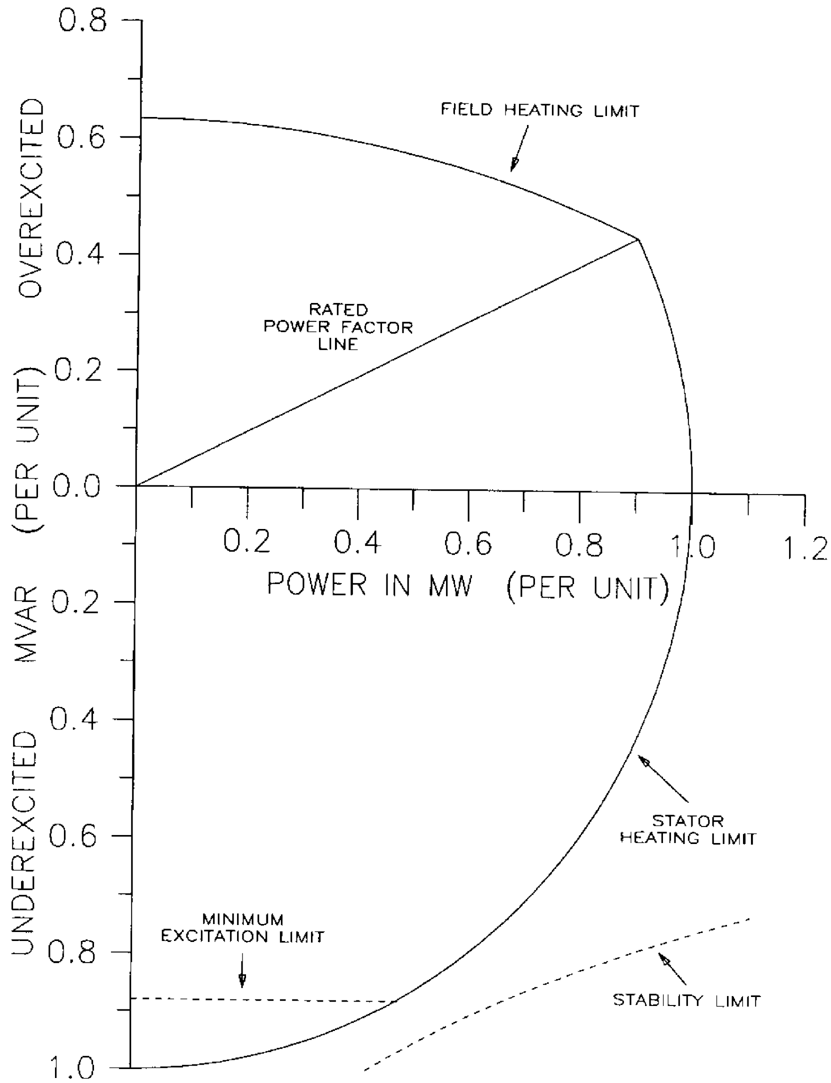


FIGURE 2.3 Typical hydro-generator capability curve (0.9 power factor, rated voltage). (*Source:* IEEE Standard 492-1999, *IEEE Guide for Operation and Maintenance of Hydro-Generators,* 16. Copyright 1999 IEEE All rights reserved.)

Synchronous generators require direct current field excitation to the rotor, provided by the excitation system described in Section entitled "Excitation System". The generator saturation curve, Fig. 2.4, describes the relationship of terminal voltage, stator current, and field current.

While the generator may be vertical or horizontal, the majority of new installations are vertical. The basic components of a vertical generator are the stator (frame, magnetic core, and windings), rotor (shaft, thrust block, spider, rim, and field poles with windings), thrust bearing, one or two guide bearings, upper and lower brackets for the support of bearings and other components, and sole plates which are bolted to the foundation. Other components may include a direct connected exciter, speed signal generator, rotor brakes, rotor jacks, and ventilation systems with surface air coolers (IEEE, 1095-1989).

The stator core is composed of stacked steel laminations attached to the stator frame. The stator winding may consist of single turn or multi-turn coils or half-turn bars, connected in series to form a three phase circuit. Double layer windings, consisting of two coils per slot, are most common. One or more circuits are connected in parallel to form a complete phase winding. The stator winding is normally

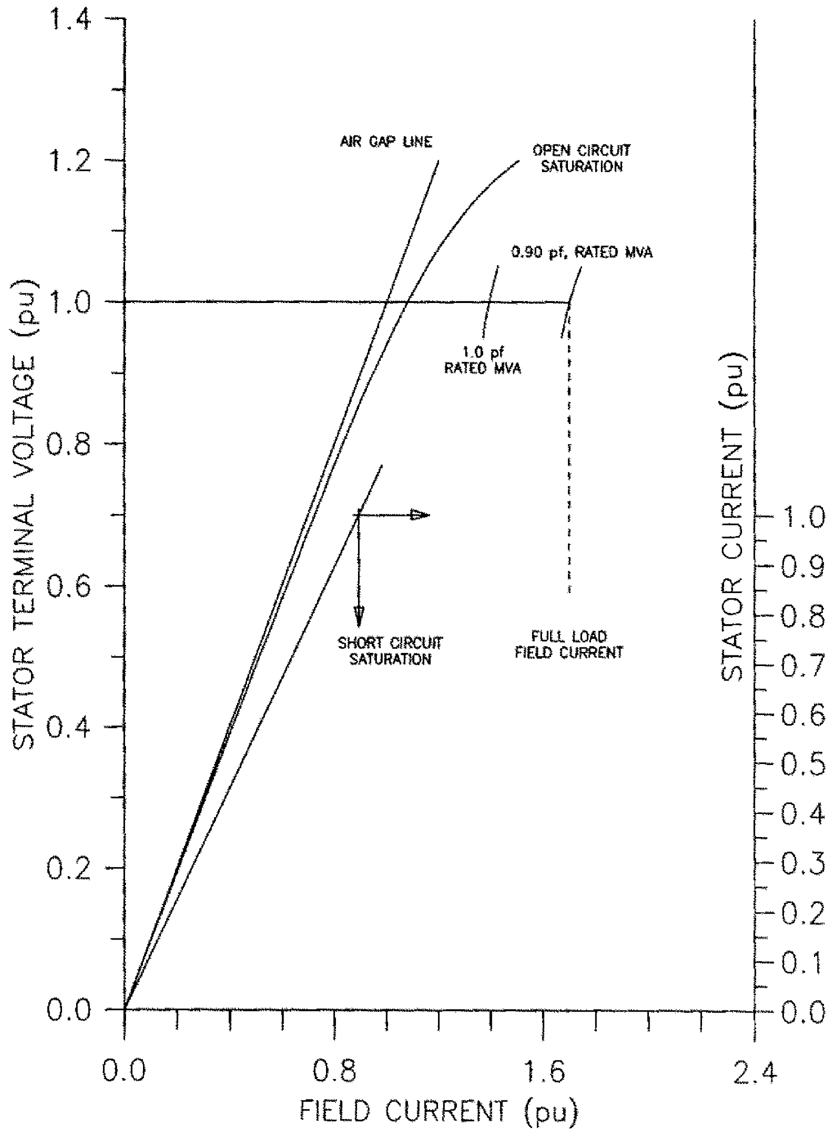


FIGURE 2.4 Typical hydro-generator saturation curves. (*Source:* IEEE Standard 492-1999, *IEEE Guide for Operation and Maintenance of Hydro-Generators,* 14. Copyright 1999 IEEE. All rights reserved.)

connected in wye configuration, with the neutral grounded through one of a number of alternative methods which depend on the amount of phase-to-ground fault current that is permitted to flow (IEEE, C62.92.2-1989; C37.101-1993). Generator output voltages range from approximately 480 VAC to 22 kVAC line-to-line, depending on the MVA rating of the unit. Temperature detectors are installed between coils in a number of stator slots.

The rotor is normally comprised of a spider attached to the shaft, a rim constructed of solid steel or laminated rings, and field poles attached to the rim. The rotor construction will vary significantly depending on the shaft and bearing system, unit speed, ventilation type, rotor dimensions, and characteristics of the driving hydraulic turbine. Damper windings or amortisseurs in the form of copper or brass rods are embedded in the pole faces, for damping rotor speed oscillations.

The thrust bearing supports the mass of both the generator and turbine plus the hydraulic thrust imposed on the turbine runner and is located either above the rotor ("suspended unit") or below the rotor ("umbrella unit"). Thrust bearings are constructed of oil-lubricated, segmented, babbit-lined shoes. One or two oil lubricated generator guide bearings are used to restrain the radial movement of the shaft.

Fire protection systems are normally installed to detect combustion products in the generator enclosure, initiate rapid de-energization of the generator and release extinguishing material. Carbon dioxide and water are commonly used as the fire quenching medium.

Excessive unit vibrations may result from mechanical or magnetic unbalance. Vibration monitoring devices such as proximity probes to detect shaft run-out are provided to initiate alarms and unit shutdown.

The choice of generator inertia is an important consideration in the design of a hydroelectric plant. The speed rise of the turbine-generator unit under load rejection conditions, caused by the instantaneous disconnection of electrical load, is inversely proportional to the combined inertia of the generator and turbine. Turbine inertia is normally about 5% of the generator inertia. During design of the plant, unit inertia, effective wicket gate or nozzle closing and opening times, and penstock dimensions are optimized to control the pressure fluctuations in the penstock and speed variations of the turbine-generator during load rejection and load acceptance. Speed variations may be reduced by increasing the generator inertia at added cost. Inertia can be added by increasing the mass of the generator, adjusting the rotor diameter, or by adding a flywheel. The unit inertia also has a significant effect on the transient stability of the electrical system, as this factor influences the rate at which energy can be moved in or out of the generator to control the rotor angle acceleration during system fault conditions [see Chapter 11 — Power System Dynamics and Stability and (Kundur, 1994)].

Generator Terminal Equipment

The generator output is connected to terminal equipment via cable, busbar, or isolated phase bus. The terminal equipment comprises current transformers (CTs), voltage transformers (VTs), and surge suppression devices. The CTs and VTs are used for unit protection, metering and synchronizing, and for governor and excitation system functions. The surge protection devices, consisting of surge arresters and capacitors, protect the generator and low-voltage windings of the step-up transformer from lightning and switching-induced surges.

Generator Switchgear

The generator circuit breaker and associated isolating disconnect switches are used to connect and disconnect the generator to and from the power system. The generator circuit breaker may be located on either the low-voltage or high-voltage side of the generator step-up transformer. In some cases, the generator is connected to the system by means of circuit breakers located in the switchyard of the generating plant. The generator circuit breaker may be of the oil filled, air-magnetic, air blast, or compressed gas insulated type, depending on the specific application. The circuit breaker is closed as part of the generator synchronizing sequence and is opened (tripped) either by operator control, as part of the automatic unit stopping sequence, or by operation of protective relay devices in the event of unit fault conditions.

Generator Step-Up Transformer

The generator transformer steps up the generator terminal voltage to the voltage of the power system or plant switchyard. Generator transformers are generally specified and operated in accordance with international standards for power transformers, with the additional consideration that the transformer will be operated close to its maximum rating for the majority of its operating life. Various types of cooling systems are specified depending on the transformer rating and physical constraints of the specific application. In some applications, dual low-voltage windings are provided to connect two generating units to a single bank of step-up transformers. Also, transformer tertiary windings are sometimes provided to serve the AC station service requirements of the power plant.

Excitation System

The excitation system fulfills two main functions:

1. It produces DC voltage (and power) to force current to flow in the field windings of the generator. There is a direct relationship between the generator terminal voltage and the quantity of current flowing in the field windings as described in Fig. 2.4.
2. It provides a means for regulating the terminal voltage of the generator to match a desired set point and to provide damping for power system oscillations.

Prior to the 1960s, generators were generally provided with rotating exciters that fed the generator field through a slip ring arrangement, a rotating pilot exciter feeding the main exciter field, and a regulator controlling the pilot exciter output. Since the 1960s, the most common arrangement is thyristor bridge rectifiers fed from a transformer connected to the generator terminals, referred to as a "potential source controlled rectifier high initial response exciter" or "bus-fed static exciter" (IEEE, 421.1-1986; 421.2-1990; 421.4-1990; 421.5-1992). Another system used for smaller high-speed units is a brushless exciter with a rotating AC generator and rotating rectifiers.

Modern static exciters have the advantage of providing extremely fast response times and high field ceiling voltages for forcing rapid changes in the generator terminal voltage during system faults. This is necessary to overcome the inherent large time constant in the response between terminal voltage and field voltage (referred to as T'_{do}, typically in the range of 5 to 10 sec). Rapid terminal voltage forcing is necessary to maintain transient stability of the power system during and immediately after system faults. Power system stabilizers are also applied to static exciters to cause the generator terminal voltage to vary in phase with the speed deviations of the machine, for damping power system dynamic oscillations [see Chapter 11 — Power System Dynamics and Stability and (Kundur, 1994)].

Various auxiliary devices are applied to the static exciter to allow remote setting of the generator voltage and to limit the field current within rotor thermal and under excited limits. Field flashing equipment is provided to build up generator terminal voltage during starting to the point at which the thyristors can begin gating. Power for field flashing is provided either from the station battery or alternating current station service.

Governor System

The governor system is the key element of the unit speed and power control system (IEEE, 125-1988; IEC, 61362 [1998-03]; ASME, 29-1980). It consists of control and actuating equipment for regulating the flow of water through the turbine, for starting and stopping the unit, and for regulating the speed and power output of the turbine generator. The governor system includes set point and sensing equipment for speed, power and actuator position, compensation circuits, and hydraulic power actuators which convert governor control signals to mechanical movement of the wicket gates (Francis and Kaplan turbines), runner blades (Kaplan turbine), and nozzle jets (Pelton turbine). The hydraulic power actuator system includes high-pressure oil pumps, pressure tanks, oil sump, actuating valves, and servomotors.

Older governors are of the mechanical-hydraulic type, consisting of ballhead speed sensing, mechanical dashpot and compensation, gate limit, and speed droop adjustments. Modern governors are of the electro-hydraulic type where the majority of the sensing, compensation, and control functions are performed by electronic or microprocessor circuits. Compensation circuits utilize proportional plus integral (PI) or proportional plus integral plus derivative (PID) controllers to compensate for the phase lags in the penstock — turbine — generator — governor control loop. PID settings are normally adjusted to ensure that the hydroelectric unit remains stable when serving an isolated electrical load. These settings ensure that the unit contributes to the damping of system frequency disturbances when connected to an integrated power system. Various techniques are available for modeling and tuning the governor (Working Group, 1992; Wozniak, 1990).

A number of auxiliary devices are provided for remote setting of power, speed, and actuator limits and for electrical protection, control, alarming, and indication. Various solenoids are installed in the hydraulic actuators for controlling the manual and automatic start-up and shutdown of the turbine-generator unit.

TABLE 2.1 Summary of Control Hierarchy for Hydroelectric Plants

Control Category	Sub-Category	Remarks
Location	Local	Control is local at the controlled equipment or within sight of the equipment.
	Centralized	Control is remote from the controlled equipment, but within the plant.
	Off Site	Control location is remote from the project.
Mode	Manual	Each operation needs a separate and discrete initiation; could be applicable to any of the three locations.
	Automatic	Several operations are precipitated by a single initiation; could be applicable to any of the three locations.
Operation (supervision)	Attended	Operator is available at all times to initiate control action.
	Unattended	Operation staff is not normally available at the project site.

Source: IEEE Standard 1249-1996, *IEEE Guide for Computer-Based Control for Hydroelectric Power Plant Automation*, 6. Copyright 1997. All rights reserved.

Control Systems

Detailed information on the control of hydroelectric power plants is available in industry standards (IEEE, 1010-1987; 1020-1988; 1249-1996). A general hierarchy of control is illustrated in Table 2.1. Manual controls, normally installed adjacent to the device being controlled, are used during testing and maintenance, and as a backup to the automatic control systems. Figure 2.5 illustrates the relationship of control locations and typical functions available at each location. Details of the control functions available at each location are described in (IEEE, 1249-1996). Automatic sequences implemented for starting, synchronizing, and shutdown of hydroelectric units are detailed in (IEEE, 1010-1987).

Modern hydroelectric plants and plants undergoing rehabilitation and life extension are utilizing increasing levels of computer automation (IEEE, 1249-1996; 1147-1991). The relative simplicity of hydroelectric plant control allows most plants to be operated in an unattended mode from remote control centers.

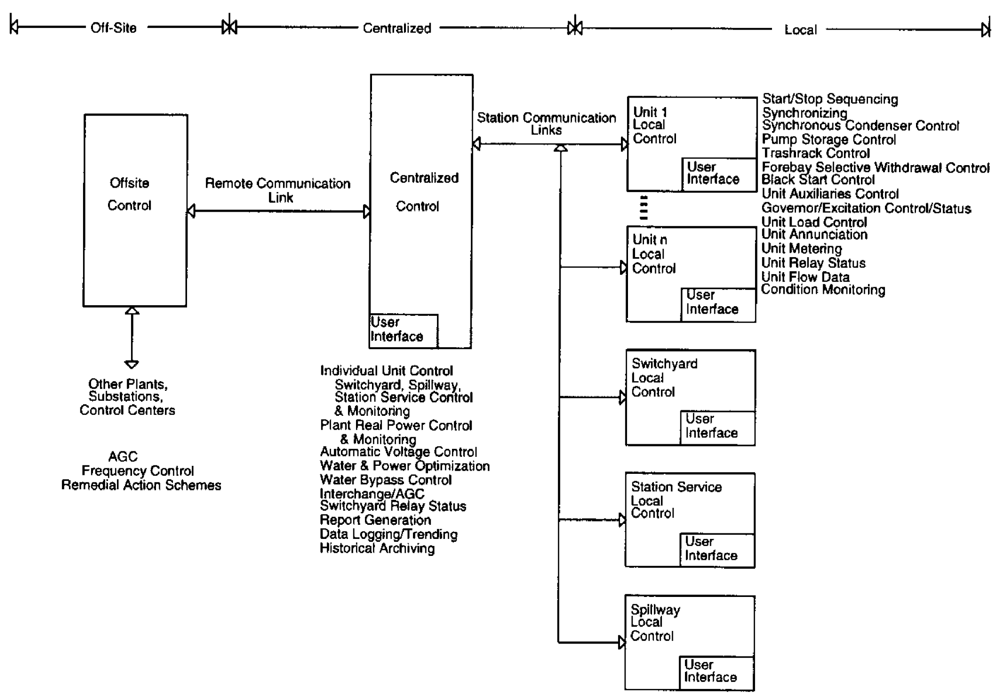


FIGURE 2.5 Relationship of local, centralized and off-site control. (*Source:* IEEE Standard 1249-1996, *IEEE Guide for Computer-Based Control for Hydroelectric Power Plant Automation*, 7. With permission.)

An emerging trend is the application of automated condition monitoring systems for hydroelectric plant equipment. Condition monitoring systems, coupled with expert system computer programs, allow plant owners and operators to more fully utilize the capacity of plant equipment and water resources, make better maintenance and replacement decisions, and maximize the value of installed assets.

Protection Systems

The turbine-generator unit and related equipment are protected against mechanical, electrical, hydraulic, and thermal damage that may occur as a result of abnormal conditions within the plant or on the power system to which the plant is connected. Abnormal conditions are detected automatically by means of protective relays and other devices and measures are taken to isolate the faulty equipment as quickly as possible while maintaining the maximum amount of equipment in service. Typical protective devices include electrical fault detecting relays, temperature, pressure, level, speed, and fire sensors, and vibration monitors associated with the turbine, generator, and related auxiliaries. The protective devices operate in various isolation and unit shutdown sequences, depending on the severity of the fault.

The type and extent of protection will vary depending on the size of the unit, manufacturer's recommendations, owner's practices, and industry standards.

Specific guidance on application of protection systems for hydroelectric plants is provided in (IEEE, 1010-1987; 1020-1988; C37.102-1995; C37.91-1985).

Plant Auxiliary Equipment

A number of auxiliary systems and related controls are provided throughout the hydroelectric plant to support the operation of the generating units (IEEE, 1010-1987; 1020-1988). These include:

1. Switchyard systems (see Chapter 5 — Substations).
2. Alternating current (AC) station service. Depending on the size and criticality of the plant, multiple sources are often supplied, with emergency backup provided by a diesel generator.
3. Direct current (DC) station service, normally provided by one or more battery banks, for supply of protection, control, emergency lighting, and exciter field flashing.
4. Lubrication systems, particularly for supply to generator and turbine bearings and bushings.
5. Drainage pumps, for removing leakage water from the plant.
6. Air compressors, for supply to the governors, generator brakes, and other systems.
7. Cooling water systems, for supply to the generator air coolers, generator and turbine bearings, and step-up transformer.
8. Fire detection and extinguishing systems.
9. Intake gate or isolation valve systems.
10. Draft tube gate systems.
11. Reservoir and tailrace water level monitoring.
12. Synchronous condenser equipment, for dewatering the draft tube to allow the runner to spin in air during synchronous condenser operation. In this case, the generator acts as a synchronous motor, supplying or absorbing reactive power.
13. Service water systems.
14. Overhead crane.
15. Heating, ventilation, and air conditioning.
16. Environmental systems.

Special Considerations Affecting Pumped Storage Plants

A pumped storage unit is one in which the turbine and generator are operated in the reverse direction to pump water from the lower reservoir to the upper reservoir. The generator becomes a motor, drawing its energy from the power system, and supplies mechanical power to the turbine which acts as a pump. The motor is started with the wicket gates closed and the draft tube water depressed with compressed air. The motor is accelerated in the pump direction and when at full speed and connected to the power system, the depression air is expelled, the pump is primed, and the wicket gates are opened to commence pumping action.

Pump Motor Starting

Various methods are utilized to accelerate the generator/motor in the pump direction during starting (IEEE, 1010-1987). These include:

1. Full voltage, across the line starting. Used primarily on smaller units, the unit breaker is closed and the unit is started as an induction generator. Excitation is applied near rated speed and machine reverts to synchronous motor operation.
2. Reduced voltage, across the line starting. A circuit breaker connects the unit to a starting bus tapped from the unit step-up transformer at one third to one half rated voltage. Excitation is applied near rated speed and the unit is connected to the system by means of the generator circuit breaker. Alternative methods include use of a series reactor during starting and energization of partial circuits on multiple circuit machines.
3. Pony motor starting. A variable speed wound-rotor motor attached to the AC station service and coupled to the motor/generator shaft is used to accelerate the machine to synchronous speed.
4. Synchronous starting. A smaller generator, isolated from the power system, is used to start the motor by connecting the two in parallel on a starting bus, applying excitation to both units, and opening the wicket gates on the smaller generator. When the units reach synchronous speed, the motor unit is disconnected from the starting bus and connected to the power system.
5. Semi-synchronous (reduced frequency, reduced voltage) starting. An isolated generator is accelerated to about 80% rated speed and paralleled with the motor unit by means of a starting bus. Excitation is applied to the generating unit and the motor unit starts as an induction motor. When the speed of the two units is approximately equal, excitation is applied to the motor unit, bringing it into synchronism with the generating unit. The generating unit is then used to accelerate both units to rated speed and the motor unit is connected to the power system.
6. Static starting. A static converter/inverter connected to the AC station service is used to provide variable frequency power to accelerate the motor unit. Excitation is applied to the motor unit at the beginning of the start sequence and the unit is connected to the power system when it reaches synchronous speed. The static starting system can be used for dynamic braking of the motor unit after disconnection from the power system, thus extending the life of the unit's mechanical brakes.

Phase Reversing of the Generator/Motor

It is necessary to reverse the direction of rotation of the generator/motor by interchanging any two of the three phases. This is achieved with multi-pole motor operated switches or with circuit breakers.

Draft Tube Water Depression

Water depression systems using compressed air are provided to lower the level of the draft tube water below the runner to minimize the power required to accelerate the motor unit during the transition to pumping mode. Water depression systems are also used during motoring operation of a conventional hydroelectric unit while in synchronous condenser mode. Synchronous condenser operation is used to provide voltage support for the power system and to provide spinning reserve for rapid loading response when required by the power system.

Commissioning of Hydroelectric Plants

The commissioning of a new hydroelectric plant, rehabilitation of an existing plant, or replacement of existing equipment requires a rigorous plan for inspection and testing of equipment and systems and for organizing, developing, and documenting the commissioning program (IEEE, 1248-1998).

References

American Society of Mechanical Engineers Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design*, HCI Publications, Kansas City, KA, 1996.

ANSI Standard C50.12-1982 (Reaff 1989), *Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications*.

ASME PTC 29-1980 (R1985), *Speed Governing Systems for Hydraulic Turbine Generator Units*.

Electricity Technology Roadmap — 1999 Summary and Synthesis, Report C1-112677-V1, Electric Power Research Institute, Palo Alto, July, 1999, pp. 74, 83.

IEC Standard 60034-1 (1996-12), *Rotating Electrical Machines — Part 1: Rating and Performance*.

IEC Standard 61362 (1998-03), *Guide to Specification of Hydraulic Turbine Control Systems.*

IEEE Standard C37.91-1985 (Reaff 1990), *IEEE Guide for Protective Relay Applications to Power Transformers.*

IEEE Standard 421.1-1986 (Reaff 1996), *IEEE Standard Definitions for Excitation Systems for Synchronous Machines*.

IEEE Standard 1010-1987 (Reaff 1992), *IEEE Guide for Control of Hydroelectric Power Plants*.

IEEE Standard 125-1988 (Reaff 1996), *IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.*

IEEE Standard 1020-1988 (Reaff 1994), *IEEE Guide for Control of Small Hydroelectric Power Plants.*

IEEE Standard C62.92.2-1989 (Reaff 1993*), IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II — Grounding of Synchronous Generator Systems.*

IEEE Standard 1095-1989 (Reaff 1994), *IEEE Guide for Installation of Vertical Generators and Generator/Motors for Hydroelectric Applications*.

IEEE Standard 421.2-1990, *IEEE Guide for Identification, Testing and Evaluation of the Dynamic Performance of Excitation Control Systems*.

IEEE Standard 421.4-1990, *IEEE Guide for the Preparation of Excitation System Specifications*.

IEEE Standard 1147-1991 (Reaff 1996), *IEEE Guide for the Rehabilitation of Hydroelectric Power Plants*.

IEEE Standard 421.5-1992*, IEEE Recommended Practice for Excitation Systems for Power Stability Studies*.

IEEE Standard C37.101-1993, *IEEE Guide for Generator Ground Protection.*

IEEE Standard C37.102-1995*, IEEE Guide for AC Generator Protection.*

IEEE Standard 1249-1996, *IEEE Guide for Computer-Based Control for Hydroelectric Power Plant Automation*.

IEEE Standard 1248-1998, *IEEE Guide for the Commissioning of Electrical Systems in Hydroelectric Power Plants*.

IEEE Standard 492-1999, *IEEE Guide for Operation and Maintenance of Hydro-Generators.*

Kundur, P., *Power System Stability and Control*, McGraw-Hill, New York, 1994.

Working Group on Prime Mover and Energy Supply Models for System Dynamic Performance Studies, Hydraulic turbine and turbine control models for system dynamic studies*, IEEE Trans. Power Syst.*, 7(1), February 1992.

Wozniak, L., Graphical Approach to Hydrogenerator Governor Tuning, *IEEE Trans. Energy Conv.*, 5(3), September 1990.

2.2 Synchronous Machinery

Paul I. Nippes

General

Synchronous motors convert electrical power to mechanical power; synchronous generators convert mechanical power to electrical power; and synchronous condensers supply only reactive power to stabilize system voltages.

Synchronous motors, generators, and condensers perform similarly, except for a heavy cage winding on the rotor of motors and condensers for self-starting.

A rotor has physical magnetic poles, arranged to have alternating north and south poles around the rotor diameter which are excited by electric current, or uses permanent magnets, having the same number of poles as the stator electromagnetic poles.

The rotor RPM = 120 × Electrical System Frequency/Poles.

The stator winding, fed from external AC multi-phase electrical power, creates rotating electromagnetic poles.

At speed, rotor poles turn in synchronism with the stator rotating electromagnetic poles, torque being transmitted magnetically across the "air gap" power angle, lagging in generators and leading in motors.

Synchronous machine sizes range from fractional watts, as in servomotors, to 1500 MW, as in large generators.

Voltages vary, up to 25,000 V AC stator and 1500 V DC rotor.

Installed horizontal or vertical at speed ranges up to 130,000 RPM, normally from 40 RPM (waterwheel generators) to 3600 RPM (turbine generators).

Frequency at 60 or 50 Hz mostly, 400 Hz military; however, synthesized variable frequency electrical supplies are increasingly common and provide variable motor speeds to improve process efficiency.

Typical synchronous machinery construction and performance are described; variations may exist on special smaller units.

This document is intentionally general in nature. Should the reader want specific application information, refer to standards: NEMA MG-1; IEEE 115, C50-10 and C50-13; IEC 600034: 1-11,14-16,18, 20, 44, 72, and 136, plus other applicable specifications.

Construction (See Fig. 2.6)

Stator

Frame

The exterior frame, made of steel, either cast or a weldment, supports the laminated stator core and has feet, or flanges, for mounting to the foundation. Frame vibration from core magnetic forcing or rotor unbalance is minimized by resilient mounting the core and/or by designing to avoid frame resonance with forcing frequencies. If bracket type bearings are employed, the frame must support the bearings, oil seals, and gas seals when cooled with hydrogen or gas other than air. The frame also provides protection from the elements and channels cooling air, or gas, into and out of the core, stator windings, and rotor. When the unit is cooled by gas contained within the frame, heat from losses is removed by coolers having water circulating through finned pipes of a heat exchanger mounted within the frame. Where cooling water is unavailable and outside air cannot circulate through the frame because of its dirty or toxic condition, large air-to-air heat exchangers are employed, the outside air being forced through the cooler by an externally shaft-mounted blower.

Stator Core Assembly

The stator core assembly of a synchronous machine is almost identical to that of an induction motor. A major component of the stator core assembly is the core itself, providing a high permeability path for magnetism. The stator core is comprised of thin silicon steel laminations and insulated by a surface coating minimizing eddy current and hysteresis losses generated by alternating magnetism. The laminations are stacked as full rings or segments, in accurate alignment, either in a fixture or in the stator frame, having ventilation spacers inserted periodically along the core length. The completed core is compressed and clamped axially to about 10 kg/cm^2 using end fingers and heavy clamping plates. Core end heating from stray magnetism is minimized, especially on larger machines, by using non-magnetic materials at the core end or by installing a flux shield of either tapered laminations or copper shielding.

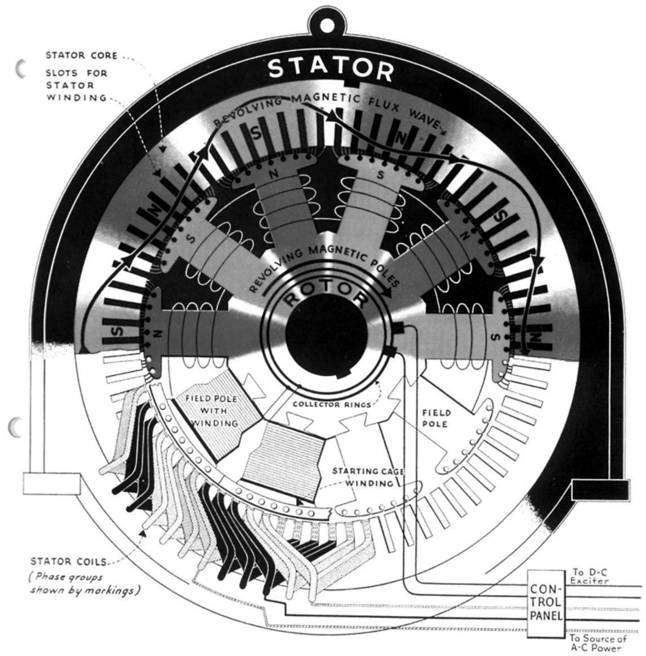


FIGURE 2.6 Magnetic "skeleton" (upper half) and structural parts (lower half) of a ten-pole (720 rpm at 60 cycles) synchronous motor. (From *The ABC's of Synchronous Motors*, 7(1), 5, 1944. The Electric Machinery Company, Inc. With permission.)

A second major component is the stator winding made up of insulated coils placed in axial slots of the stator core inside diameter. The coil make-up, pitch, and connections are designed to produce rotating stator electromagnetic poles in synchronism with the rotor magnetic poles. The stator coils are retained into the slots by slot wedges driven into grooves in the top of the stator slots. Coil end windings are bound together and to core-end support brackets. If the synchronous machine is a generator, the rotating rotor pole magnetism generates voltage in the stator winding which delivers power to an electric load. If the synchronous machine is a motor, its electrically powered stator winding generates rotating electromagnetic poles and the attraction of the rotor magnets, operating in synchronism, produces torque and delivery of mechanical power to the drive shaft.

Rotor

The Rotor Assembly

The rotor of a synchronous machine is a highly engineered unitized assembly capable of rotating satisfactorily at synchronous speed continuously according to standards or as necessary for the application. The central element is the shaft, having journals to support the rotor assembly in bearings. Located at the rotor assembly axial mid-section is the rotor core embodying magnetic poles. When the rotor is round it is called "non-salient pole", or turbine generator type construction and when the rotor has protruding pole assemblies, it is called "salient pole" construction.

The non-salient pole construction, used mainly on turbine generators (and also as wind tunnel fan drive motors), has two or four magnetic poles created by direct current in coils located in slots at the rotor outside diameter. Coils are restrained in the slots by slot wedges and at the ends by retaining rings on large high-speed rotors, and fiberglass tape on other units where stresses permit. This construction is not suited for use on a motor requiring self-starting as the rotor surface, wedges, and retaining rings overheat and melt from high currents of self-starting.

A single piece forging is sometimes used on salient pole machines, usually with four or six poles**.** Salient poles can also be integral with the rotor lamination and can be mounted directly to the shaft or fastened to an intermediate rotor spider. Each distinct pole has an exciting coil around it carrying excitation current or else it employs permanent magnets. In a generator, a moderate cage winding in the face of the rotor poles, usually with pole-to-pole connections, is employed to dampen shaft torsional oscillation and to suppress harmonic variation in the magnetic waveform. In a motor, heavy bars and end connections are required in the pole face to minimize and withstand the high heat of starting duty.

Direct current excites the rotor windings of salient, and non-salient pole motors and generators, except when permanent magnets are employed. The excitation current is supplied to the rotor from either an external DC supply through collector rings or a shaft-mounted brushless exciter. Positive and negative polarity bus bars or cables pass along and through the shaft as required to supply excitation current to the windings of the field poles.

When supplied through collector rings, the DC current could come from a shaft-driven DC or AC exciter rectified output, from an AC-DC motor-generator set, or from plant power. DC current supplied by a shaft-mounted AC generator is rectified by a shaft-mounted rectifier assembly.

As a generator, excitation current level is controlled by the voltage regulator. As a motor, excitation current is either set at a fixed value, or is controlled to regulate power factor, motor current, or system stability.

In addition, the rotor also has shaft-mounted fans or blowers for cooling and heat removal from the unit plus provision for making balance weight additions or corrections.

Bearings and Couplings

Bearings on synchronous machinery are anti-friction, grease, or oil-lubricated on smaller machines, journal type oil-lubricated on large machines, and tilt-pad type on more sophisticated machines, especially where rotor dynamics are critical. Successful performance of magnetic bearings, proving to be successful on turbo-machinery, may also come to be used on synchronous machinery as well.

As with bearings on all large electrical machinery, precautions are taken with synchronous machines to prevent bearing damage from stray electrical shaft currents. An elementary measure is the application of insulation on the outboard bearing, if a single-shaft end unit, and on both bearing and coupling at the same shaft end for double-shaft end drive units. Damage can occur to bearings even with properly applied insulation, when solid-state controllers of variable frequency drives, or excitation, cause currents at high frequencies to pass through the bearing insulation as if it were a capacitor. Shaft grounding and shaft voltage and grounding current monitoring can be employed to predict and prevent bearing and other problems.

Performance

Synchronous Machines, in General

This section covers performance common to synchronous motors, generators, and condensers.

Saturation curves (Fig. 2.7) are either calculated or obtained from test and are the basic indicators of machine design suitability. From these the full load field, or excitation, amperes for either motors or generators are determined as shown, on the rated voltage line, as "*Rated Load*." For synchronous condensers, the field current is at the crossing of the zero P.F. saturation line at 1.0 V. As an approximate magnetic figure of merit, the no-load saturation curve should not exceed its extrapolated straight line by more than 25%, unless of a special design. From these criteria, and the knowledge of the stator current and cooling system effectiveness, the manufacturer can project the motor component heating, and thus insulation life, and the efficiency of the machine at different loads.

Vee curves (Fig. 2.8) show overall loading performance of a synchronous machine for different loads and power factors, but more importantly show how heating and stability limit loads. For increased hydrogen pressures in a generator frame, the load capability increases markedly.

The characteristics of all synchronous machines when their stator terminals are short-circuited are similar (see Fig. 2.9). There is an initial subtransient period of current increase of 8 to 10 times rated, with one phase offsetting an equal amount. These decay in a matter of milliseconds to a transient value of 3 to 5 times rated, decaying in tenths of a second to a relatively steady value. Coincident with this, the field current increases suddenly by 3 to 5 times, decaying in tenths of a second. The stator voltage on the shorted phases drops to zero and remains so until the short circuit is cleared.

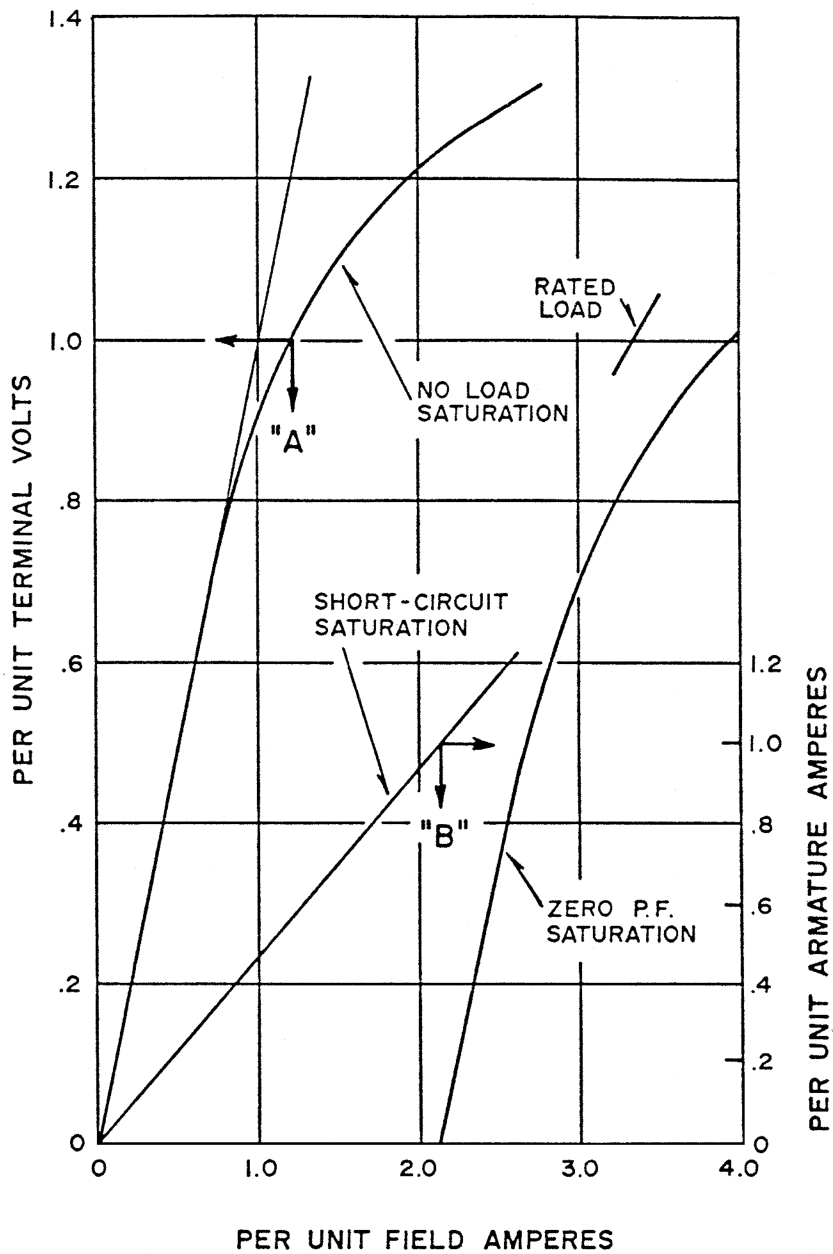


FIGURE 2.7 Saturation curves.

Synchronous Generator Capability

The synchronous generator normally has easy starting duty as it is brought up to speed by a prime mover. Then the rotor excitation winding is powered with DC current, adjusted to rated voltage, and transferred to voltage regulator control. It is then synchronized to the power system, closing the interconnecting circuit breaker as the prime mover speed is advancing, at a snail's pace, leading the electric system. Once on line, its speed is synchronized with the power system and KW is raised by increasing the prime mover KW input. The voltage regulator adjusts excitation current to hold voltage. Increasing the voltage regulator

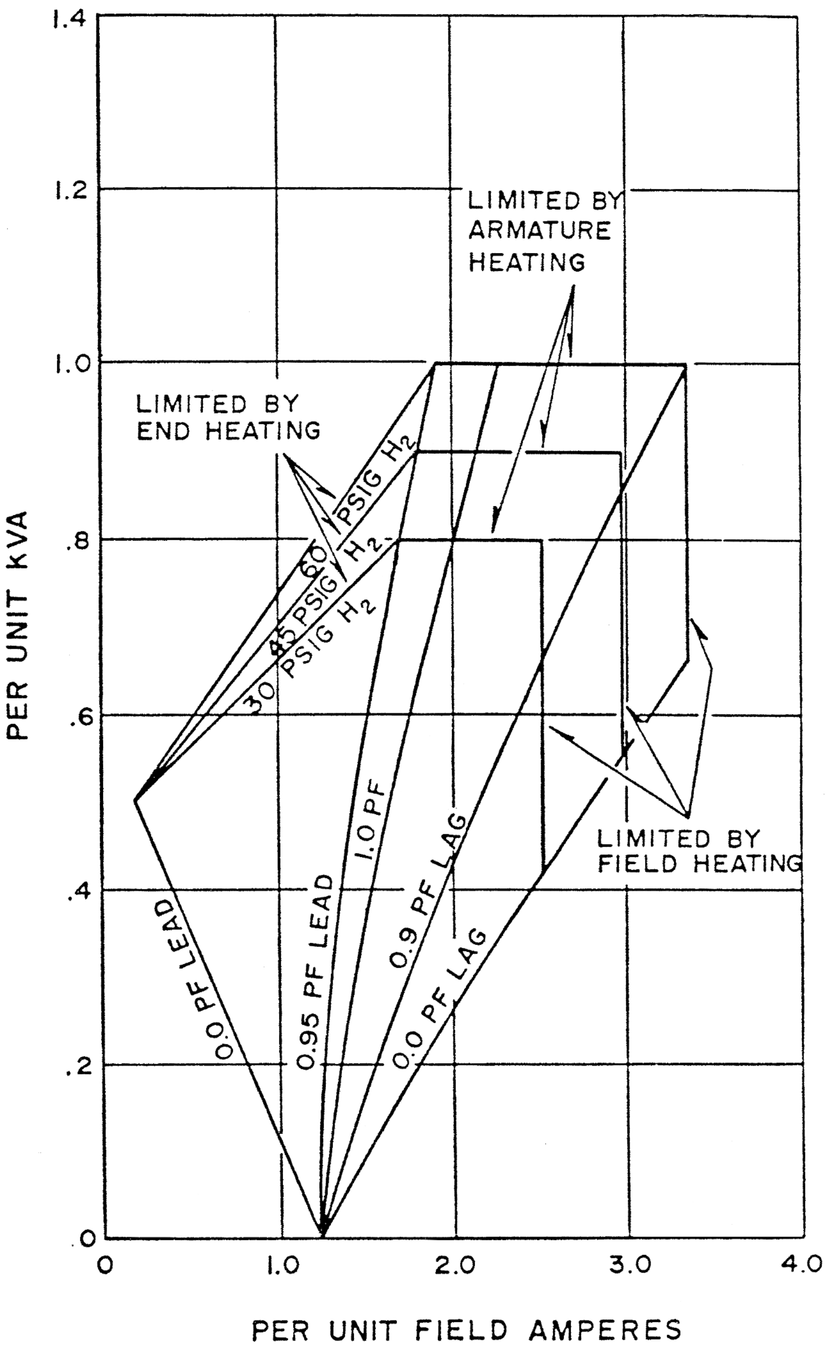


FIGURE 2.8 Vee curves.

set point increases KVAR input to the system, reducing the power factor toward lagging and vice versa. Steady operating limits are provided by its Reactive Capability Curve (see Fig. 2.10). This curve shows the possible kVA reactive loading, lagging, or leading, for given KW loading. Limitations consist of field heating, armature heating, stator core end heating, and operating stability over different regions of the reactive capability curve.

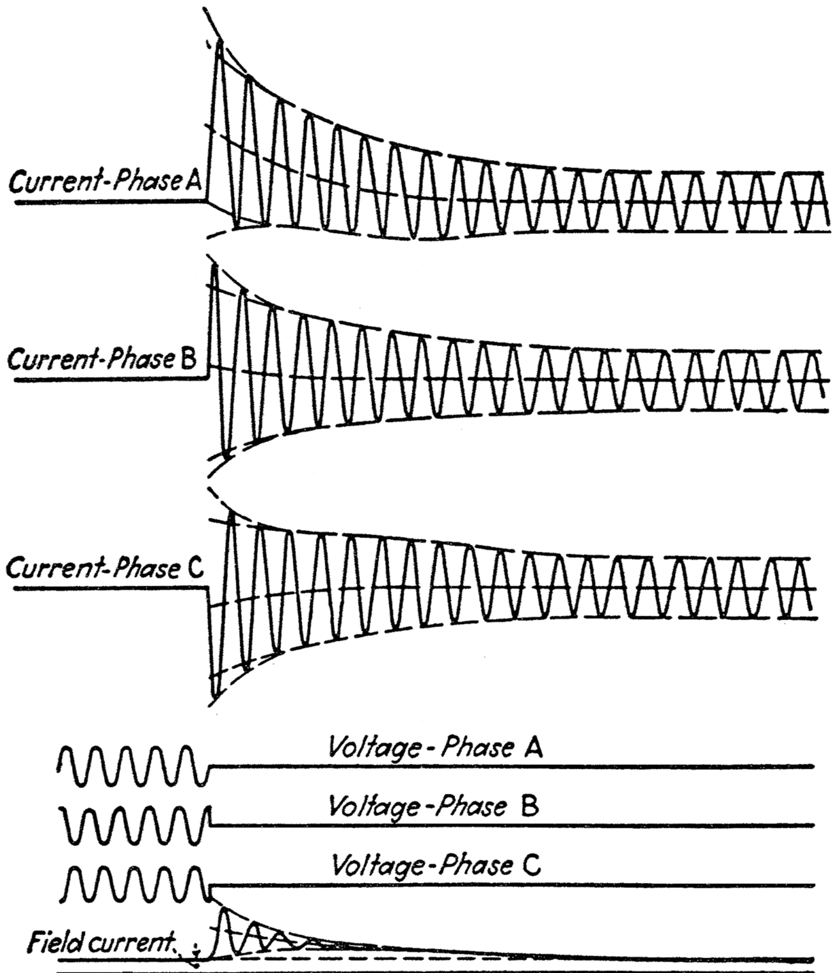


FIGURE 2.9 Typical oscillogram of a sudden three-phase short circuit.

Synchronous Motor and Condenser Starting

The duty on self-starting synchronous motors and condensors is severe, as there are large induction currents in the starting cage winding once the stator winding is energized (see Fig. 2.11). These persist as the motor comes up to speed, similar to but not identical to starting an induction motor. Similarities exist to the extent that extremely high torque impacts the rotor initially and decays rapidly to an average value, increasing with time. Different from the induction motor is the presence of a large oscillating torque. The oscillating torque decreases in frequency as the rotor speed increases. This oscillating frequency is caused by the saliency effect of the protruding poles on the rotor. Meanwhile, the stator current remains constant until 80% speed is reached. The oscillating torque at decaying frequency may excite train torsional natural frequencies during acceleration, a serious train design consideration. An anomaly occurs at half speed as a dip in torque and current due to the coincidence of line frequency torque with oscillating torque frequency. Once the rotor is close to rated speed, excitation is applied to the field coils and the rotor pulls into synchronism with the rotating electromagnetic poles. At this point, stable steady-state operation begins.

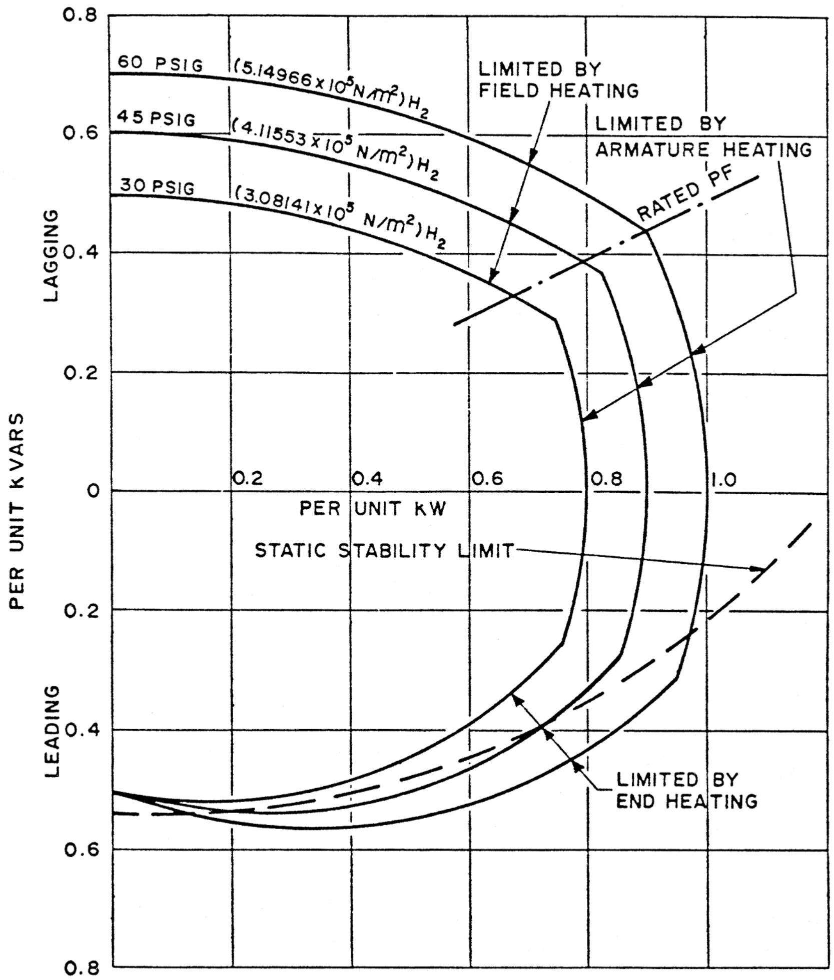


FIGURE 2.10 Typical reactive capability curve.

Increasingly, variable frequency power is supplied to synchronous machinery primarily to deliver the optimum motor speed to meet load requirements, improving the process efficiency. It can also be used for soft-starting the synchronous motor or condenser. Special design and control are employed to avert problems imposed, such as excitation of train torsional natural frequencies and extra heating from harmonics of the supply power.

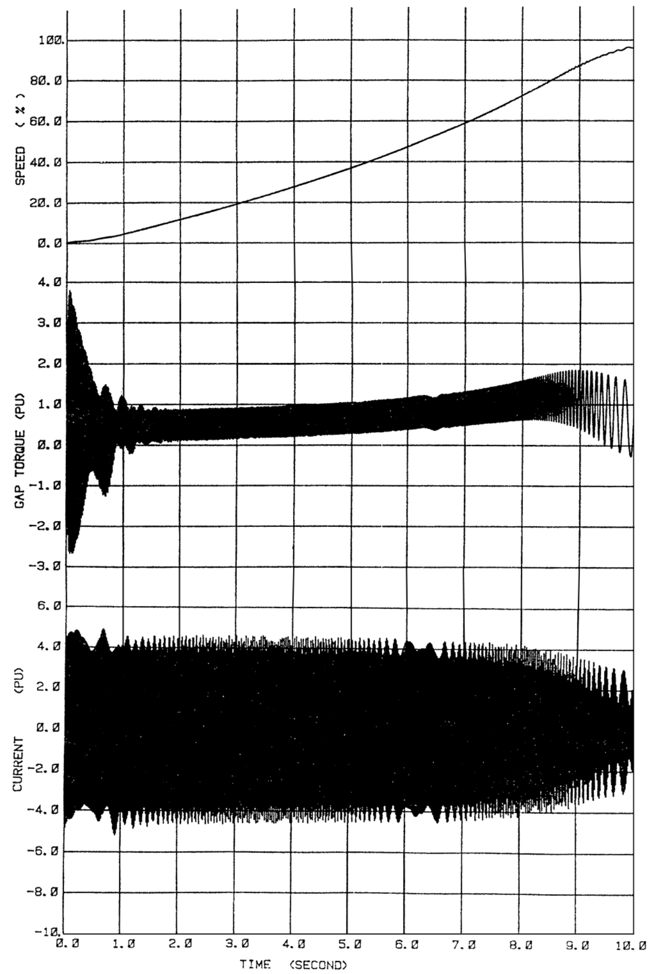


FIGURE 2.11 Synchronous motor and condensor starting.

2.3 Thermal Generating Plants

Kenneth H. Sebra

Thermal generating plants are designed and constructed to convert energy from fuel (coal, oil, gas, or radiation) into electric power. The actual conversion is accomplished by a turbine-driven generator. Thermal generating plants differ from industrial plants in that the nature of the product never changes. The plant will always produce electric energy. The things that may change are the fuel used (coal, oil, or gas) and environmental requirements. Many plants that were originally designed for coal were later converted to oil, converted back to coal, and then converted to gas. Environmental requirements have changed, which has required the construction of air and water emissions control systems. Plant electrical systems should be designed to allow for further growth. Sizing of transformers and buses is at best a matter of guesswork. The plant electrical system should be sized at 5 to 10% the size of the generating unit depending on the plant configuration and number of units at the plant site.

Plant Auxiliary System

Selection of Auxiliary System Voltages

The most common plant auxiliary system voltages are 13,800 V, 6900 V, 4160 V, 2400 V, and 480 V. The highest voltage is determined by the largest motor. If motors of 4000 hp or larger are required, one should consider using 13,800 V. If the largest motor required is less than 4000 hp, then 4160 V should be satisfactory.

Auxiliary System Loads

Auxiliary load consists of motors and transformers. Transformers supply lower level buses which supply smaller motors and transformers which supply lower voltage buses. Generation plants built before 1950 may have an auxiliary generator that is connected to the main generator shaft. The auxiliary generator will supply plant loads when the plant is up and running.

Auxiliary System Power Sources

The power sources for a generating plant consist of one or more off-site sources and one or more on-site sources. The on-site sources are the generator and, in some cases, a black start diesel generator or a gas turbine generator which may be used as a peaker.

Auxiliary System Voltage Regulation Requirements

Most plants will not require voltage regulation. A load flow study will indicate if voltage regulation is required. Transformers with tap changers, static var compensators, or induction regulators may be used to keep plant bus voltages within acceptable limits. Switched capacitor banks and overexcited synchronous motors may also be used to regulate bus voltage.

Plant One-Line Diagram

The one-line diagram is the most important document you will use. Start with a conceptual one-line and add detail as it becomes available. The one-line diagram will help you think about your design and make it easier to discuss with others. Do not be afraid to get something on paper very early and modify as you get more information about the design. Consider how the plant will be operated. Will there be a start-up source and a running source? Are there on-site power sources?

Plant Equipment Voltage Ratings

Establish at least one bus for each voltage rating in the plant. Two or more buses may be required depending on how the plant will be operated.

Grounded vs. Ungrounded Systems

A method of grounding must be determined for each voltage level in the plant.

Ungrounded

Most systems will be grounded in some manner with the exception for special cases of 120-V control systems which may be operated ungrounded for reliability reasons. An ungrounded system may be allowed to continue to operate with a single ground on the system. Ungrounded systems are undesirable because ground faults are difficult to locate. Also, ground faults can result in system overvoltage, which can damage equipment that is connected to the ungrounded system.

Grounded

Most systems 480 V and lower will be solidly grounded.

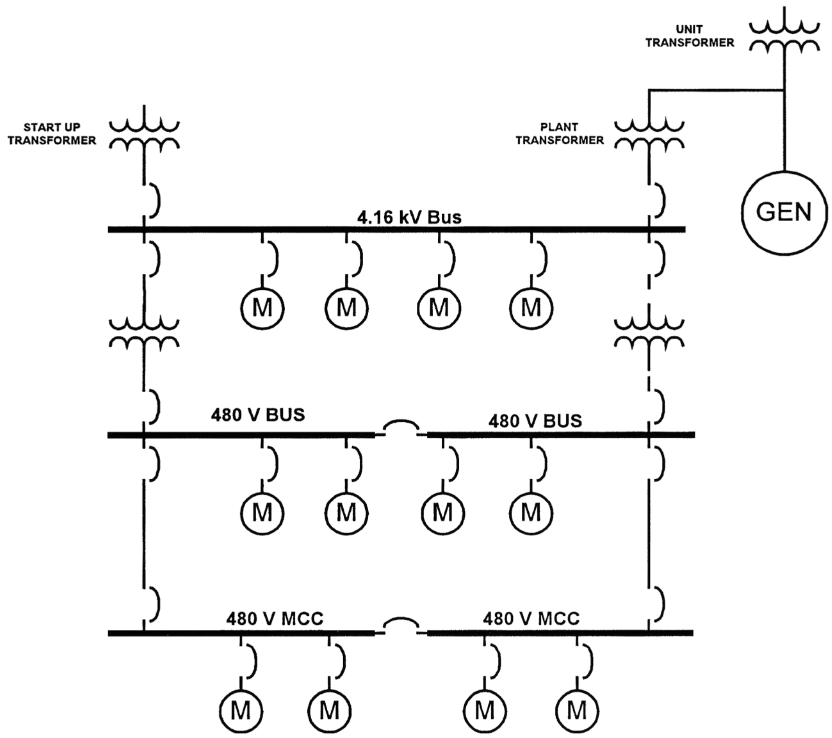


FIGURE 2.12 Typical plant layout.

Low-Resistance Grounding

Low-resistance grounding systems are used at 2400 V and above. This system provides enough ground fault current to allow relay coordination and limits ground fault current to a value low enough to prevent equipment damage.

High-Resistance Grounding

High-resistance grounding systems limit ground fault current to a very low value but make relay coordination for ground faults difficult.

Miscellaneous Circuits

Essential Services

Essential services such as critical control required for plant shutdown, fire protection, and emergency lighting should be supplied by a battery-backed inverter. This is equipment that must continue to operate after a loss of off-site power. Some of these loads may be supplied by an on-site diesel generator or gas turbine if a delay after loss of off-site power is acceptable.

Lighting Supply

Lighting circuits should be designed with consideration to emergency lighting to the control room and other vital areas of the plant. Consideration should be given to egress lighting and lighting requirements for plant maintenance.

DC Systems

The plant will require at least one DC system for control and operation of essential systems when off-site power is lost. The required operating time for the emergency equipment that will be operated from the DC systems must be established in order to size the batteries. The installation of a diesel generator may reduce the size of the battery.

125-V DC

A 125-V DC system is supplied for circuit breaker and protective relaying. The system voltage may collapse to close to zero during fault conditions and would not be capable of supplying relay control and breaker trip current when it is needed to operate.

250-V DC

A 250-V DC system may be required to supply turbine generator emergency motors such as turning gear motors and emergency lube oil motors.

Power Plant Switchgear

High-Voltage Circuit Breakers

High-voltage circuit breakers of 34.5 kV and above may be used in the switchyard associated with the generating plant, but are rarely used in a generating plant.

Medium-Voltage Switchgear

Medium-voltage breakers are 2.4 to 13.8 kV. Breakers in this range are used for large motors in the plant. The most prevalent is 4.16 kV.

Medium-Voltage Air Circuit Breakers

Air circuit breakers were the most common type of breaker until about 1995. Due to large size and high maintenance requirements of air circuit breakers, they have been replaced by vacuum breakers.

Medium-Voltage Vacuum Circuit Breakers

Vacuum circuit breakers are the most common type of circuit breaker used in new installations. Vacuum circuit breakers are being used to replace air circuit breakers. Vacuum breakers are smaller and can provide additional space if the plant needs to be expanded to meet new requirements. Before using vacuum circuit breakers, a transient analysis study should be performed to determine if there is a need for surge protection. If required, surge protection can be supplied by the installation of capacitors and/or surge suppressors can be used to eliminate voltage surge problems.

Medium-Voltage SF6 Circuit Breakers

SF6 circuit breakers have the same advantages as vacuum circuit breakers but there is some environmental concern with the SF6 gas.

Low-Voltage Switchgear

Low voltage is 600 V and below. The most common voltage used is 480 V.

Low-Voltage Air Circuit Breakers

Air circuit breakers are used in load centers that may include a power transformer. Air circuit breakers are used for motors greater than 200 hp and less than about 600 hp. Low-voltage circuit breakers are self-contained in that fault protection is an integral part of the breaker. Low-voltage devices, which do not contain fault protection devices, are referred to as low-voltage switches. Low-voltage breakers may be obtained with various combinations of trip elements. Long time, short time, and ground trip elements may be obtained in various combinations.

Low-voltage breakers manufactured before 1970 will contain oil dashpot time delay trip elements. Breakers manufactured after the mid-1970s until about 1990 will contain solid-state analog trip elements. Breakers manufactured after 1990 will contain digital trip elements. The digital elements provide much more flexibility.

A circuit that may be large enough for a load center circuit breaker but is operated several times a day should not be put on a load center circuit breaker. The circuit breaker would be put through its useful life in a very short time. A motor starter would be a better choice.

Motor Control Centers

Motor control centers are self-contained and may include molded case breakers or combination starters. Molded case breakers are available as either magnetic or thermal-magnetic. The magnetic trip breakers are instantaneous trip only and the thermal-magnetic trip breakers are time delay with instantaneous trip. Magnetic breakers can be used with a contactor to make a combination starter. Time delay trip is provided by overload relays mounted on the contactor. Solid-state equipment is available to use in motor control centers and allows much greater flexibility

Circuit Interruption

The purpose of a circuit breaker is to provide a method of interrupting the circuit either to turn the load on and off or to interrupt fault current. The first requirement is based on the full load current of the load. The second requirement is based on the maximum fault current as determined by the fault current study. There is no relationship between the load current and the fault current. If modifications are made to the electric power system, the fault interrupting current requirement may increase. Failure to recognize this could result in the catastrophic failure of a breaker.

Auxiliary Transformers

Selection of Percent Impedance

The transformer impedance is always compromised. High transformer impedance will limit fault current and reduce the required interrupting capability of switchgear and, therefore, reduce the cost. Low impedance will reduce the voltage drop through the transformer and therefore improve voltage regulation. A careful analysis using a load flow study will help in arriving at the best compromise.

Rating of Voltage Taps

Transformers should be supplied with taps to allow adjustment in bus voltage. Optimum tap settings can be determined using a load flow study.

Motors

Selection of Motors

Many motors are required in a thermal generating plant and range in size from fractional horsepower to several thousand horsepower. These motors may be supplied with the equipment they drive or they may be specified by the electrical engineer and purchased separately. The small motors are usually supplied by the equipment supplier and the large motors specified by the electrical engineer. How this will be handled must be resolved very early in the project. The horsepower cut-off point for each voltage level must be decided. The maximum plant voltage level must be established. A voltage of 13.8 kV may be required if very large horsepower motors are to be used. This must be established very early in the plant design so that a preliminary one-line diagram may be developed.

Types of Motors

Squirrel Cage Induction Motors

The squirrel cage induction motor is the most common type of large motor used in a thermal generating plant. Squirrel cage induction motors are very rugged and require very little maintenance.

Wound Rotor Induction Motors

The wound rotor induction motor has a rotor winding which is brought out of the motor through slip rings and brushes. While more flexible than a squire cage induction motor, the slip rings and brushes are an additional maintenance item. Wound rotor motors are only used in special applications in a power plant.

Synchronous Motors

Synchronous motors may be required in some applications. Large slow-speed, 1800 rpm or less may require a synchronous motor. A synchronous motor may used to supply VARs and improve voltage regulation. If the synchronous motor is going to be used as a VAR source, the field supply must be sized large enough to over-excite the field.

Direct Current Motors

Direct current motors are used primarily on emergency systems such as turbine lube oil and turbine turning gear. Direct current motors may also be used on some control valves.

Single-Phase Motors

Single-phase motors are fractional horsepower motors and are usually supplied with the equipment.

Motor Starting Limitations

The starting current for induction motors is about 6 times full load current. This must be taken into account when sizing transformers and should be part of the load flow analysis. If the terminal voltage is allowed to drop too low, below 80%, the motor will stall. Methods of reduced voltage starting are available, but should be avoided if possible. The most reliable designs are the simplest.

Main Generator

The turbine generator will be supplied as a unit. The size and characteristics are usually determined by the system planners as a result of system load requirements and system stability requirements.

Associated Equipment

Exciters and Excitation Equipment

The excitation system will normally be supplied with the generator.

Electronic exciters — Modern excitation systems are solid state and, in recent years, most have digital control systems.

Generator Neutral Grounding

The generator neutral is never connected directly to ground. The method used to limit the phase to ground fault current to a value equal to or less than the three-phase fault current is determined by the way the generator is connected to the power system. If the generator is connected directly to the power system, a resistor or inductor connected between the neutral of the generator and ground will be used to limit the ground fault current. If the generator is connected to the power system through a transformer in a unit configuration, the neutral of the generator may be connected to ground through a distribution transformer with a resistor connected across the secondary of the transformer. The phase-to-ground fault current can be limited to 5 to 10 A using this method.

Isolated Phase Bus

The generator is usually connected to the step-up transformer through an isolated phase bus. This separated phase greatly limits the possibility of a phase-to-phase fault at the terminals of the generator.

Cable

Large amounts of cable are required in a thermal generating plant. Power, control, and instrumentation cable should be selected carefully with consideration given to long life. Great care should be given in the installation of all cable. Cable replacement can be very expensive.

Electrical Analysis

All electrical studies should be well-documented for use in plant modifications. These studies will be of great value in evaluating plant problems.

Load Flow

A load flow study should be performed as early in the design as possible even if the exact equipment is not known. The load flow study will help in getting an idea of transformer size and potential voltage drop problems.

A final load flow study should be performed to document the final design and will be very helpful if modifications are required in the future.

Short-Circuit Analysis

Short-circuit studies must be performed to determine the requirements for circuit breaker interrupting capability. Relay coordination should be studied as well.

Surge Protection

Surge protection may be required to limit transient overvoltage caused by lightning and circuit switching. A surge study should be performed to determine the needs of each plant configuration. Surge arrestors and/or capacitors may be required to limit transient voltages to acceptable levels.

Phasing

A phasing diagram should be made to determine correct transformer connections. An error here could prevent busses from being paralleled.

Relay Coordination Studies

Relay coordination studies should be performed to ensure proper coordination of the relay protection system. The protective relay system may include overcurrent relays, bus differential relays, transformer differential relays, voltage relays, and various special function relays.

Maintenance and Testing

A good plant design will take into account maintenance and testing requirements. Equipment must be accessible for maintenance and provisions should be made for test connections.

Start-Up

A start-up plan should be developed to ensure equipment will perform as expected. This plan should include insulation testing. Motor starting current magnitude and duration should be recorded and relay coordination studies verified. Voltage level and load current readings should be taken to verify load flow studies. This information will also be very helpful when evaluating plant operating conditions and problems.

References

General

Beeman, D., Ed., *Industrial Power Systems Handbook,* McGraw-Hill, New York.

Electrical Transmission and Distribution Reference Book, Westinghouse Electric Corporation.

IEEE Standard 666-1991, IEEE Design Guide for Electric Power Service Systems for Generating Stations.

Grounding

IEEE 665-1955, IEEE Guide for Generating Station Grounding.

IEEE 1050-1996, IEEE Guide for Instrumentation and control Grounding in Generating Stations.

DC Systems
IEEE 485-1997, IEEE Recommended Practice for Sizing Lead-Acid Batteries for Station Applications.
IEEE 946-1992, IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations.

Switchgear
IEEE Standards Collection: Power and Energy-Switchgear, 1998 Edition.

Auxiliary Transformers
IEEE Distribution, Power and Regulating Transformers Standards Collection, 1998 Edition.

Motors
IEEE Electric Machinery Standards Collection, 1997 Edition.

Cable
IEEE 835-1994, IEEE Standard Power Cable Ampacity Tables.

Electrical Analysis
Clarke, E., *Circuit Analysis of AC Power Systems,* General Electric Company, 1961.
Stevenson, W. D., *Elements of Power Systems Analysis,* McGraw-Hill, New York, 1962.
Wager, C. F. and Evans, R. D., *Symmetrical Components,* McGraw-Hill, New York, 1933.

2.4 Distributed Utilities

John R. Kennedy

Distributed utilities (sometimes referred to as DU) is the current term used in describing distributed generation and storage devices operating separately and in parallel with the utility grid. In most cases, these devices are small in comparison to traditional utility base or peaking generation, but can range up to several megawatts. For the purposes of this section, DU will be limited to devices 5 MW and below applied at either the secondary voltage level, 120 V single phase to 480 V three phase, and at the medium voltage level, 2.4 kV to 25 kV, although many of the issues discussed would apply to the larger units as well.

In this section, we will give an overview of the different issues associated with DU, including available technologies, interfacing, a short discussion on economics and possible regulatory treatment, applications, and some practical examples. Emerging technologies discussed will include fuel cells, microturbines, and small turbines. A brief discussion of storage technologies is also included. Interfacing issues include general protection, overcurrent protection, islanding issues, communication and control, voltage regulation, frequency control, fault detection, safety issues, and synchronization. In the applications section, deferred investment, demand reduction, peak shaving, ancillary services, reliability, and power quality will be discussed. Economics and possible regulatory treatment will be discussed briefly.

Available Technologies

Many of the "new" technologies have been around for several years, but the relative cost per kilowatt of small generators compared to conventional power plants has made their use limited. Utility rules and interconnect requirements have also limited the use of small generators and storage devices to mostly emergency, standby, and power quality applications. The prospect of deregulation has changed all that. Utilities are no longer assured that they can recover the costs of large base generation plants, and stranded investment of transmission and distribution facilities is a subject of debate. This, coupled with improvements in the cost and reliability of DU technologies, has opened an emerging market for small power plants. In the near future, these new technologies should be competitive with conventional plants, providing high reliability with less investment risk. Some of the technologies are listed below. All of the

Technology	Size	Fuel Sources	AC Interface Type	Applications
Fuel Cells	.5Kw – Larger units With Stacking	Natural Gas Hydrogen Petroleum Products	Inverter type	Continuous
Microturbines	10Kw-100Kw Larger sizes	Natural Gas Petroleum Products	Inverter type	Continuous Standby
Batteries	.1Kw-2Mw+	Storage	Inverter type	PQ, Peaking
Flywheel	>.1Kw - .5Kw	Storage	Inverter type	PQ, Peaking
PV	>.1Kw- 1Kw	Sunlight	Inverter type	Peaking
Gas Turbine	10Kw – 5Mw+	Natural Gas Petroleum Products	Rotary type	Continuous, Peaking Standby

FIGURE 2.13 Distributed generation technology chart.

energy storage devices and many of the small emerging generation devices are inverter/converter based. Figure 2.13 is a listing of different technologies, their size ranges, fuel sources, and AC interface type, and most likely applications.

Fuel Cells

Fuel cell technology has been around since its invention by William Grove in 1839. From the 1960s to the present, fuel cells have been the power source used for space flight missions. Unlike other generation technologies, fuel cells act like continuously fueled batteries, producing direct current (DC) by using an electrochemical process. The basic design of all fuel cells consists of an anode, electrolyte, and cathode. Hydrogen or a hydrogen-rich fuel gas is passed over the anode, and oxygen or air is passed over the cathode. A chemical combination then takes place producing a constant supply of electrons (DC current) with by-products of water, carbon dioxide, and heat. The DC power can be used directly or it can be fed to a power conditioner and converted to AC power (see Fig. 2.14).

Most of the present technologies have a fuel reformer or processor that can take most hydrocarbon-based fuels, separate out the hydrogen, and produce high-quality power with negligible emissions. This would include gasoline, natural gas, coal, methanol, light oil, or even landfill gas. In addition, fuel cells can be more efficient than conventional generators. Theoretically they can obtain efficiencies as high as 85% when the excess heat produced in the reaction is used in a combined cycle mode. These features, along with relative size and weight, have also made the fuel cell attractive to the automotive industry as an alternative to battery power for electric vehicles. The major differences in fuel cell technology concern the electrolyte composition. The major types are the Proton Exchange Membrane Fuel Cell (PEFC) also called the PEM, the Phosphoric Acid Fuel Cell (PAFC), the Molten Carbonate Fuel Cell (MCFC), and the Solid Oxide Fuel Cell (SOFC) (Fig. 2.15).

Fuel cell power plants can come in sizes ranging from a few watts to several megawatts with stacking. The main disadvantage to the fuel cell is the initial high cost of installation. With the interest in efficient and environmentally friendly generation, coupled with the automotive interest in an EV alternative power source, improvements in the technology and lower costs are expected. As with all new technologies, volume of sales should also lower the unit price.

Microturbines

Experiments with microturbine technology have been around for many decades, with the earliest attempts of wide-scale applications being targeted at the automotive and transportation markets. These experiments

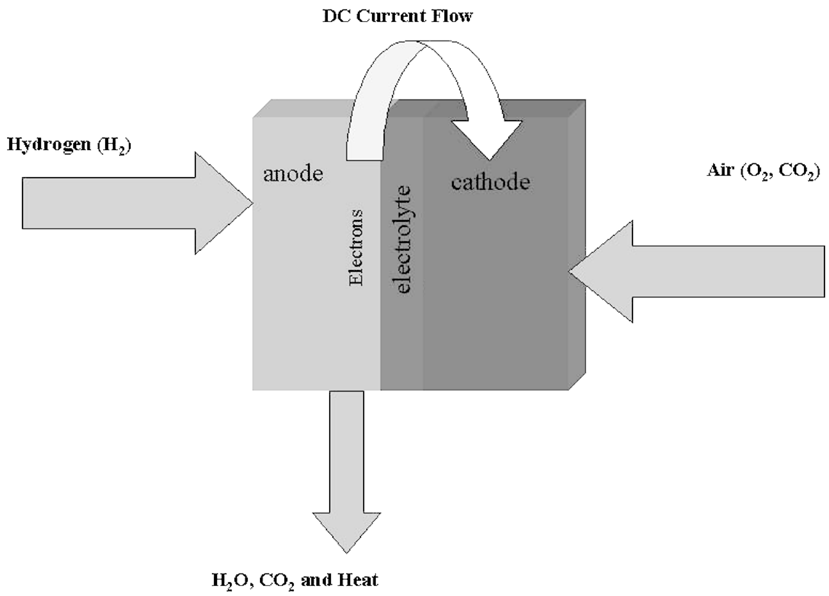


FIGURE 2.14 Basic fuel cell operation.

	PAFC	MCFC	SOFC	PEMFC
Electrolyte	Phosphoric acid	Molten carbonate salt	Ceramic	Polymer
Operating Temperature	375°F (190°C)	1200°F (650°C)	1830°F (1000°C)	175°F (80°C)
Fuels	Hydrogen (H_2)	H_2/CO	$H_2/CO_2/CH_4$	H_2
	Reformate	Reformate	Reformate	Reformate
Reforming	External	External	External	External
Oxidant	O_2/Air	CO_2/O_2/Air	O_2/Air	O_2/Air
Efficiency (HHV)	40–50%	50–60%	45–55%	40–50%

FIGURE 2.15 Comparison of fuel cell types. (*Source:* DoD Website, www.dodfuelcell.com/fcdescriptions.html.)

later expanded into markets associated with military and commercial aircraft and mobile systems. Microturbines are typically defined as systems with an output power rating of between 10 kW up to a few hundred kilowatts. As shown in Fig. 2.16, these systems are usually a single-shaft design with compressor, turbine, and generator all on the common shaft, although some companies are engineering dual-shaft systems. Like the large combustion turbines, the microturbines are Brayton Cycle systems, and will usually have a recuperator in the system.

The recuperator is incorporated as a means of increasing efficiency by taking the hot turbine exhaust through a heavy (and relatively expensive) metallic heat exchanger and transferring the heat to the input air, which is also passed through parallel ducts of the recuperator. This increase in inlet air temperature helps reduce the amount of fuel needed to raise the temperature of the gaseous mixture during combustion to levels required for total expansion in the turbine. A recuperated Brayton Cycle microturbine can operate at efficiencies of approximately 30%, while these aeroderivative systems operating without a recuperator would have efficiencies in the mid-teens.

Another requirement of microturbine systems is that the shaft must spin at very high speeds, in excess of 50,000 RPM and in some cases doubling that rate, due to the low inertia of the shaft and connected components. This high speed is used to keep the weight of the system low and increase the power density

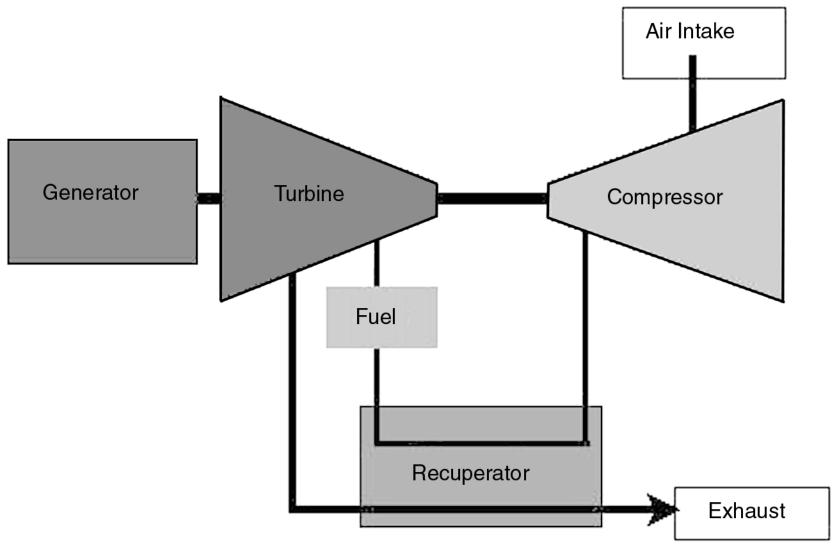


FIGURE 2.16 Turbine block diagram configuration with recuperator.

over other generating technologies. Although many of the microturbines are touted as having only a single moving part, there are numerous ancillary devices required that do incorporate moving parts such as cooling fans, fuel compressors, and pumps.

Since the turbine requires extremely high speeds for optimal performance, the generator cannot operate as a synchronous generator. Typical microturbines have a permanent magnet motor/generator incorporated onto the shaft of the system. The high rotational speed gives an AC output in excess of 1000 Hz, depending on the number of poles and actual rotational speed of the microturbine. This high-frequency AC source is rectified, forming a common DC bus voltage that is then converted to a 60-Hz AC output by an onboard inverter.

The onboard electronics are also used to start the microturbine, either in a stand-alone mode or in grid parallel applications. Typically, the utility voltage will be rectified and the electronics are used to convert this DC voltage into a variable frequency AC source. This variable frequency drive will power the permanent magnet motor/generator (which is operating as a motor), and will ramp the turbine speed up to a preset RPM, a point where stabile combustion and control can be maintained. Once this preset speed is obtained and stabile combustion is taking place, the drive shuts down and the turbine speed increases until the operating point is maintained and the system operates as a generator. The time from a "Shaft Stop" to full load condition is anywhere from 30 sec to 3 min, depending on manufacturer recommendations and experiences.

Although things are in the early stages of commercialization of the microturbine products, there are cost targets that have been announced from all of the major manufacturers of these products. The early market entry price of these systems is in excess of $600 per kW, more than comparably sized units of alternative generation technologies, but all of the major suppliers have indicated that costs will fall as the number of units being put into the field increases.

The microturbine family has a very good environmental rating, due to natural gas being a primary choice for fuel and the inherent operating characteristics, which puts these units at an advantage over diesel generation systems.

Combustion Turbines

There are two basic types of combustion turbines (CTs) other than the microturbines: the heavy frame industrial turbines and the aeroderivative turbines. The heavy frame systems are derived from similar

	Heavy Frame	Aeroderivative
Size (Same General Rating)	Large	Compact
Shaft Speed	Synchronous	Higher Speed (coupled through a gear box)
Air Flow	High (lower compression)	Lower (high compression)
Start-up Time	15 Minutes	2-3 minutes

FIGURE 2.17 Basic combustion turbine operating characteristics.

models that were steam turbine designs. As can be identified from the name, they are of very heavy construction. The aeroderivative systems have a design history from the air flight industry, and are of a much lighter and higher speed design. These types of turbines, although similar in operation, do have some significant design differences in areas other than physical size. These include areas such as turbine design, combustion areas, rotational speed, and air flows.

Although these units were not originally designed as a "distributed generation" technology, but more so for central station and large co-generation applications, the technology is beginning to economically produce units with ratings in the hundreds of kilowatts and single-digit megawatts. These turbines operate as Brayton Cycle systems and are capable of operating with various fuel sources. Most applications of the turbines as distributed generation will operate on either natural gas or fuel oil. The operating characteristics between the two systems can best be described in tabular form as shown in Fig. 2.17.

The combustion turbine unit consists of three major mechanical components: a compressor, a combustor, and a turbine. The compressor takes the input air and compresses it, which will increase the temperature and decrease the volume per the Brayton Cycle. The fuel is then added and the combustion takes place in the combustor, which increases both the temperature and volume of the gaseous mixture, but leaves the pressure as a constant. This gas is then expanded through the turbine where the power is extracted through the decrease in pressure and temperature and the increase in volume.

If efficiency is the driving concern, and the capital required for the increased efficiency is available, the Brayton Cycle systems can have either co-generation systems, heat recovery steam generators, or simple recuperators added to the combustion turbine unit. Other equipment modifications and improvements can be incorporated into these types of combustion turbines such as multistage turbines with fuel re-injection, inter-cooler between multistage compressors, and steam/water injection.

Typical heat rates for simple cycle combustion turbines vary across manufacturers, but are in a range from 11,000 to 20,000 BTU/kWh. However, these numbers decrease as recuperation and co-generation are added. CTs typically have a starting reliability in the 99% range and operating reliability approaching 98%. The operating environment has a major effect on the performance of combustion turbines. The elevation at which the CT is operating has a degradation factor of around 3.5% per 1000 ft of increased elevation and the ambient temperature has a similar degradation per 10° increase.

Figure 2.18 shows a block diagram of a simple cycle combustion turbine with a recuperator (left) and a combustion turbine with multistage turbine and fuel re-injection (right).

Storage Technologies

Storage technologies include batteries, flywheels, ultra-capacitors, and to some extent photovoltaics. Most of these technologies are best suited for power quality and reliability enhancement applications, due to their relative energy storage capabilities and power density characteristics, although some large battery installations could be used for peak shaving. All of the storage technologies have a power electronic converter interface and can be used in conjunction with other DU technologies to provide "seamless" transitions when power quality is a requirement.

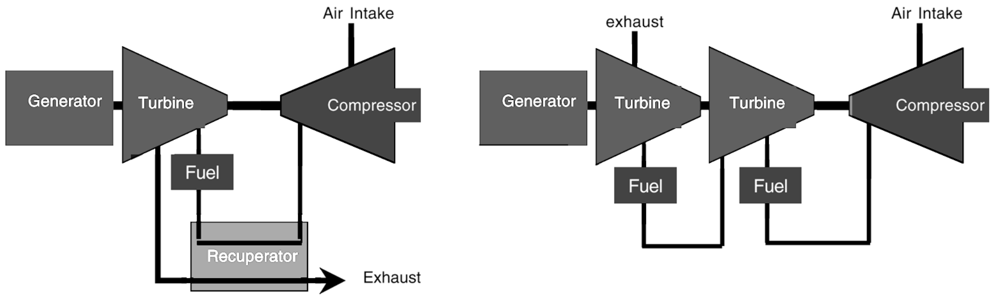


FIGURE 2.18 Basic combustion turbine designs.

Interface Issues

A whole chapter could be written just about interface issues, but this discussion will touch on the highlights. Most of the issues revolve around safety and quality of service. We will discuss some general guidelines and the general utility requirements and include examples of different considerations. In addition to the interface issues, the DU installation must also provide self-protection to prevent short circuit or other damage to the unit. Self-protection will not be discussed here. The most important issues are listed in Table 2.2.

In addition to the interface issues identified in Table 2.2, there are also operating limits that must be considered. These are listed in Table 2.3.

Utility requirements vary but generally depend on the application of a distributed source. If the unit is being used strictly for emergency operation, open transition peak shaving, or any other stand-alone type operation, the interface requirements are usually fairly simple, since the units will not be operating in parallel with the utility system. When parallel operation is anticipated or required, the interface requirements become more complex. Protection, safety, power quality, and system coordination become issues that must be addressed. In the case of parallel operation, there are generally three major factors that determine the degree of protection required. These would include the size and type of the generation, the location on the system, and how the installation will operate (one-way vs. two-way). Generator sizes are generally classified as:

Large: Greater than 3 MVA or possibility of "islanding" a portion of the system
Small: Between large and extremely small
Extremely small: Generation less than 100 kVA

TABLE 2.2 Interface Issues

Issue	Definition	Concern
Automatic reclosing	Utility circuit breakers can test the line after a fault.	If a generator is still connected to the system, it may not be in synchronization, thus damaging the generator or causing another trip.
Faults	Short circuit condition on the utility system.	Generator may contribute additional current to the fault, causing a miss operation of relay equipment.
Islanding	A condition where a portion of the system continues to operate isolated from the utility system.	Power quality, safety, and protection may be compromised in addition to possible synchronization problems.
Protection	Relays, instrument transformers, circuit breakers.	Devices must be utility grade rather than industrial grade for better accuracy. Devices must also be maintained on a regular schedule by trained technicians.
Communication	Devices necessary for utility control during emergency conditions.	Without control of the devices, islanding and other undesirable operation of devices.

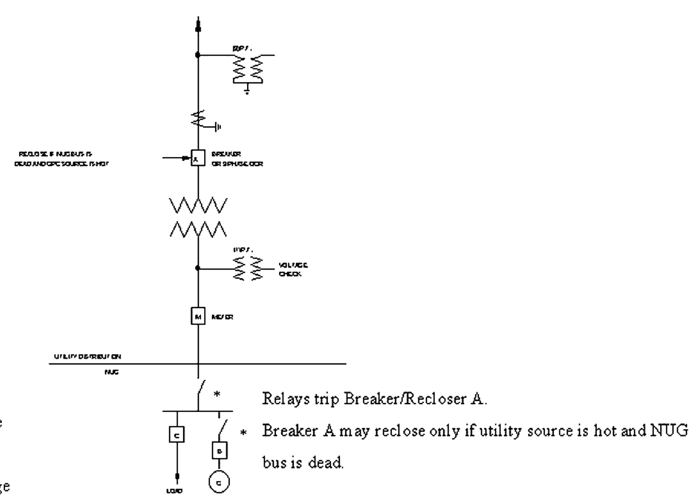
TABLE 2.3 Operating Limits

1. Voltage — The operating range for voltage must maintain a level of ±5% of nominal for service voltage (ANSI C84.1), and have a means of automatic separation if the level gets out of the acceptable range within a specified time.
2. Flicker — Flicker must be within the limits as specified by the connecting utility. Methods of controlling flicker are discussed in IEEE Std. 519-1992, 10.5.
3. Frequency — Frequency must be maintained within ±0.5 Hz of 60 Hz and have an automatic means of disconnecting if this is not maintained. If the system is small and isolated, there might be a larger frequency window. Larger units may require an adjustable frequency range to allow for clock synchronizaton.
4. Power factor — The power factor should be within 0.85 lagging or leading for normal operation. Some systems that are designed for compensation may operate outside these limits.
5. Harmonics — Both voltage and current harmonics must comply with the values for generators as specified in IEEE Std. 519-1992 for both total and individual harmonics.

Location on the system and individual system characteristics determine impedance of a distribution line, which in turn determines the available fault current and other load characteristics that influence "islanding" and make circuit protection an issue. This will be discussed in more detail later.

The type of operation is the other main issue and is one of the main determinants in the amount of protection required. One-way power flow where power will not flow back into the utility has a fairly simple interface, but is dependent on the other two factors, while two-way interfaces can be quite complex. An example is shown in Fig. 2.19. Smaller generators and "line-commutated" units would have less stringent requirements. Commutation methods will be discussed later. Reciprocating engines such as diesel and turbines with mass, and "self-commutating" units which could include microturbines and fuel cells, would require more stringent control packages due to their islanding and reverse power capabilities.

Most of the new developing technologies are inverter based and there are efforts now in IEEE to revise the old Standard P929 *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems* to include other inverter-based devices. The standards committee is looking at the issues with inverter-based devices in an effort to develop a standard interface design that will simplify and reduce the cost, while not sacrificing the safety and operational concerns. Inverter interfaces generally fall into two classes: line-commutated inverters and self-commutated inverters.



Device No.	Function
59/27	Overvoltage/Undervoltage
81	Over/Underfrequency
59G	Zero Sequence Overvoltage
50/51	Phase Overcurrent
50/51N	Ground Overcurrent

FIGURE 2.19 Example of large generator interface requirements for distribution. (*Source: Georgia Power Bulletin,* 18-8, generator interface requirements.)

Line-Commutated Inverters

These inverters require a switching signal from the line voltage in order to operate. Therefore, they will cease operation if the line signal, i.e., utility voltage, is abnormal or interrupted. These are not as popular today for single-phase devices due to the filtering elements required to meet the harmonic distortion requirements, but are appearing in some of the three-phase devices where phase cancellation minimizes the use of the additional components.

Self-Commutated Inverters

These inverters, as implied by the name, are self-commutating. All stand-alone units are self-commutated, but not all self-commutated inverters are stand-alone. They can be designed as either voltage or current sources and most that are now being designed to be connected to the utility system are designed to be current sources. These units still use the utility voltage signal as a comparison and produce current at that voltage and frequency. A great deal of effort has gone into the development of non-islanding inverters that are of this type.

Applications

Applications vary and will become more diverse as utilities unbundle. Listed below are some examples of the most likely.

Ancillary Services

Ancillary services support the basic electrical services and are essential for the reliability and operation of the electric power system. The electrical services that are supported include generating capacity, energy supply, and the power delivery system. FERC requires six ancillary services, including system control, regulation (frequency), contingency reserves (both spinning and supplemental), voltage control, and energy imbalance. In addition, load following, backup supply, network stability, system "black-start", loss replacement, and dynamic scheduling are necessary for the operation of the system. Utilities have been performing these functions for decades, but as vertically integrated regulated monopoly organizations. As these begin to disappear, and a new structure with multiple competing parties emerges, distributed utilities might be able to supply several of these.

The distributed utilities providing these services could be owned by the former traditional utility, customers, or third-party brokers, depending on the application. The main obstacles to this approach are aggregation and communication when dealing with many small resources rather than large central station sources.

"Traditional Utility" Applications

Traditional utilities may find the use of DU a practical way to solve loading and reliability problems if each case is evaluated on a stand-alone individual basis. Deferring investment is one likely way that DU can be applied. In many areas, substations and lines have seasonal peaks that are substantially higher than the rest of the year. In these cases, the traditional approach has been to increase the capacity to meet the demand. Based on the individual situation, delaying the upgrade for 2 to 5 years with a DU system could be a more economical solution. This would be especially true if different areas had different seasonal peaks and the DU system was portable, thus deferring two upgrades. DU could also be used instead of conventional facilities when backup feeds are required or to improve reliability or power quality.

In addition, peak shaving and generation reserve could be provided with strategically placed DU systems that take advantage of reducing system losses as well as offsetting base generation. Again, these have to be evaluated on an individual case basis and not a system average basis as is done in many economic studies. The type of technology used will depend on the particular requirements. In general, storage devices such as flywheels and batteries are better for power quality applications due to their fast response time, in many cases half a cycle. Generation devices are better suited for applications that require more than 30 min of supply, such as backup systems, alternate feeds, peak shaving, and demand deferrals. Generation sources can also be used instead of conventional facilities in certain cases.

Customer Applications

Individual customers with special requirements may find DU technologies that meet their needs. Customers who require "enhanced" power quality and reliability of service already utilize UPS systems with battery backup to condition the power to sensitive equipment, and many hospitals, waste treatment plants, and other emergency services providers have emergency backup systems supplied by standby generator systems. As barriers go down and technologies improve, customer-sited DU facilities could provide many of the ancillary services as well as sell excess power into the grid. Fuel cell and even diesel generators could be especially attractive for customers with requirements of heat and steam. Many of the fuel cell technologies are now looking at the residential market with small units that would be connected to the grid but supply the additional requirements for customers with special power quality needs.

Third-Party Service Providers

Third-party service providers could provide all the services listed above for the utilities and customers, in addition to selling power across the grid. In many cases, an end user does not have the expertise to operate and maintain generation systems and would prefer to purchase the services.

Conclusions

Disbursed generation will be a part of the distribution utility system of the future. Economics, regulatory requirements, and technology improvements will determine the speed at which they are integrated.

References

ANSI/IEEE Std. 1001-1998, *IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems*, IEEE Standards Coordinating Committee 23, Feb. 9, 1989.

Davis, M. W. *Microturbines — An Economic and Reliability Evaluation for Commercial, Residential, and Remote Load Applications*, IEEE Transactions PE-480-PWRS-0-10-1998.

Delmerico, R. W., Miller, N. W., and Owen, E. L. *Power System Integration Strategies for Distributed Generation*, Power Systems Energy Consulting GE International, Inc., Distributed Electricity Generation Conference, Denver, CO, Jan. 25, 1999.

Department of Defense Website, www.dodfuelcell.com/fcdescriptions.html.

Goldstein, H. L. *Small Turbines in Distributed Utility Application Natural Gas Pressure Supply Requirements*, NREL/SP-461-21073, May, 1996.

Hirschenhofer, J. H. DOE Forum on Fuel Cell Technologies, IEEE Winter Power Meeting, Parsons Corporation Presentation, Feb. 4, 1999.

Kirby, B. *Distributed Generation: A Natural for Ancillary Services,* Distributed Electric Generation Conference, Denver CO, Jan. 25, 1999.

Oplinger, J. L. *Methodology to Assess the Market Potential of Distributed Generation*, Power Systems Energy Consulting GE International, Inc., Distributed Electric Generation Conference, Denver, CO, Jan. 25, 1999.

Recommended Practice for Utility Interface of Photovoltaic (PV) Systems, IEEE Standard P929, Draft 10, Feb. 1999.

Southern Company Parallel Operation Requirements, Protection and Control Committee, Aug. 4, 1998.

Technology Overviews, DOE Forum on Fuel Cell Technology, IEEE Winter Power Meeting, Feb. 4, 1999.