CHAPTER 2

GENERAL FEATURES OF HYDROELECTRIC DEVELOPMENT AND THE ROLE OF HYDROPOWER

2-1. Introduction. This chapter briefly describes the general concepts of power system operation, the use of hydro projects in power systems, the various types of hydroelectric development, the components of a typical hydro project, the components of a powerhouse, and the various types of turbines that are available.

2-2. Power System Operation. The purpose of this section is to describe power system operation. Topics include loads (demand for power), resources (types of powerplants), use of resources to meet loads, and the role of hydropower in power system operation.

a. Organization of the Power Industry.

(1) Electric Power Utilities. Most power generated in the United States is produced by the electric power utilities. Utilities can be divided into three categories: investor-owned utilities, which supply about 78 percent of the nation's electrical energy; publicly owned systems (municipalities, public utility districts, etc.), which provide about 15 percent; and the customer-owned rural electric cooperatives, which supply the remaining 7 percent. Most of the investor-owned systems, municipal systems and cooperatives produce their own power, but others purchase their power either from the generating utilities or from the Federal government.

(2) Federal Hydropower Projects. In 1982, about 120,000,000 MWh, or 5 percent of the nation's electrical energy requirements, was produced by Federal hydroelectric projects, operated by the Corps of Engineers, the Bureau of Reclamation, and the Tennessee Valley Authority. These projects are multiple-purpose projects, and power production is just one of the functions they serve. Under the terms of the 1944 Flood Control Act and related legislation, power from Corps and Bureau hydro projects is marketed to the utilities by the five regional Power Marketing Administrations (PMA's) of the Department of Energy (see Sections 3-5b and 3-12). In addition to marketing, some of the PMA's also provide transmission and dispatching services. The Tennessee Valley Authority is directly responsible for the marketing, dispatching, and transmission of power produced at its own plants. Legislation gives preference to publicly owned utilities and cooperatives in the purchase of power produced at Federal projects.

b. Definitions. Some of the basic definitions relating to power system operation follow. Figure 2-1 illustrates many of these parameters.

(1) Energy. Energy is that which is capable of doing work. Mechanical energy is expressed in foot-pounds, while electrical energy is expressed in kilowatt-hours (1 kWh = 2,656,000 ft-lbs.). The output of a hydroelectric plant is called electrical energy.

(2) Power. Power is the rate at which energy is produced or used, expressed in either horsepower or kilowatts. While this is the technical definition of power, the term is often used in a broad sense to describe the commodity of electricity, which includes both energy and power.

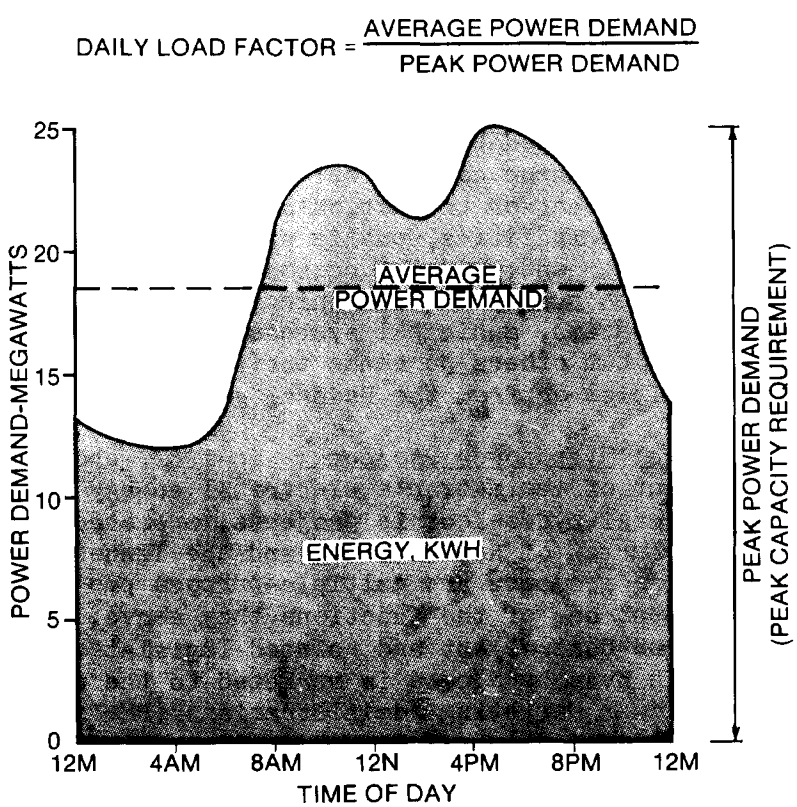

Figure 2-1. Daily load shape showing common power terms

(3) Capacity. Capacity is the maximum amount of power that a generating plant can deliver, expressed in kilowatts.

(4) Load. Load is demand for electricity. Load can be expressed in terms of energy demand (average power demand), or capacity demand (peak power demand). For planning purposes, capacity demand is measured in terms of the expected maximum annual capacity demand, or "annual peak load." Energy demand is normally measured in terms of average annual energy.

(5) Resources. Resources are sources of electrical power. A system's power resources could include both generating plants and imports from adjacent power systems.

(6) Load Factor. A load factor is the ratio of average power demand to peak power demand for the period being considered. Load factor can be computed on a daily, weekly, monthly, or annual basis. For example,

$$\text{daily load factor} = \frac{\text{(average power demand for day)}}{\text{(peak power demand for day)}}$$

c. Power Loads.

(1) General. An understanding of how loads are classified and how they vary with time is basic to an understanding of power system operation.

(2) Daily Load Shapes. Load or demand for electric power varies from hour to hour, from day to day, and from season to season in response to the needs and living patterns of the power users. The daily load shape in Figure 2-1 illustrates this concept. Demand for power is at a low point in the early morning hours, when most of the population is at rest. Demand increases markedly at 6 am, as people get up and begin going to work, and reaches a peak in the late morning hours. It remains high through the daytime hours, often reaching another peak about suppertime, and then decreases in the evening hours, as activity drops off.

(3) Weekly Load Shapes. Figure 6-1 (see Chapter 6) illustrates the weekly load pattern. Daytime loads, which are at a high level during the five weekdays, are somewhat lower on Saturdays and at their lowest levels on Sundays and holidays. This pattern reflects the impact of industrial and commercial activity on power demand.

(4) Seasonal Demand Pattern. The seasonal load pattern reflects the effects of weather and hours of daylight. Weather can cause two seasonal peaks, one due to winter heating loads and one due to summer air conditioning loads. Demand is usually highest in these seasons and relatively low in the spring and fall months. Winter peaks predominate in New England and the Pacific Northwest, while the Southern states, from California to the Carolinas, experience their highest loads in the summer months. Most of the rest of the country has high demand periods in both the summer and the winter. Figure 2-2 illustrates seasonal demand patterns for the Pacific Northwest, West North Central and South Central States.

(5) Load Types. The load shape is divided into three segments: base load, intermediate load, and peaking load (Figure 2-3). The base load is the minimum load in a stated period of time. The peaking load is that portion of the load which occurs eight hours per day or less. The intermediate load is the load between the base and peaking loads. Powerplants are often categorized as base load, intermediate (or cycling), and peaking, but operational definitions vary somewhat from load definitions (see Section 6-3). An intermediate load or cycling plant would operate 8 to 14 hours a day, and a base load plant would carry the portion of the load below the intermediate plant.

(6) Load Classes. Loads can also be classified by consumer. Following is a listing of the major load classes and the approximate portions of the total load that each comprises (nationally):

- industrial — 35 percent
- residential — 35 percent
- commercial — 25 percent
- irrigation and street lighting — 5 percent

(7) Load Forecasts. When planning future system construction and operation requirements, it is necessary to forecast loads for a number of years into the future. Load forecasts and their use in Corps planning reports are discussed in Chapter 3.

d. Power Resources.

(1) Introduction. Power resources are sources of electric power for meeting loads. A power system's resources could include powerplants, power supply contracts from outside the system (imports), and interruptible loads. A brief description of the major types of powerplants and other power resources currently being used in the United States follows. Approximate costs are presented in 1983 dollars for purposes of comparison.

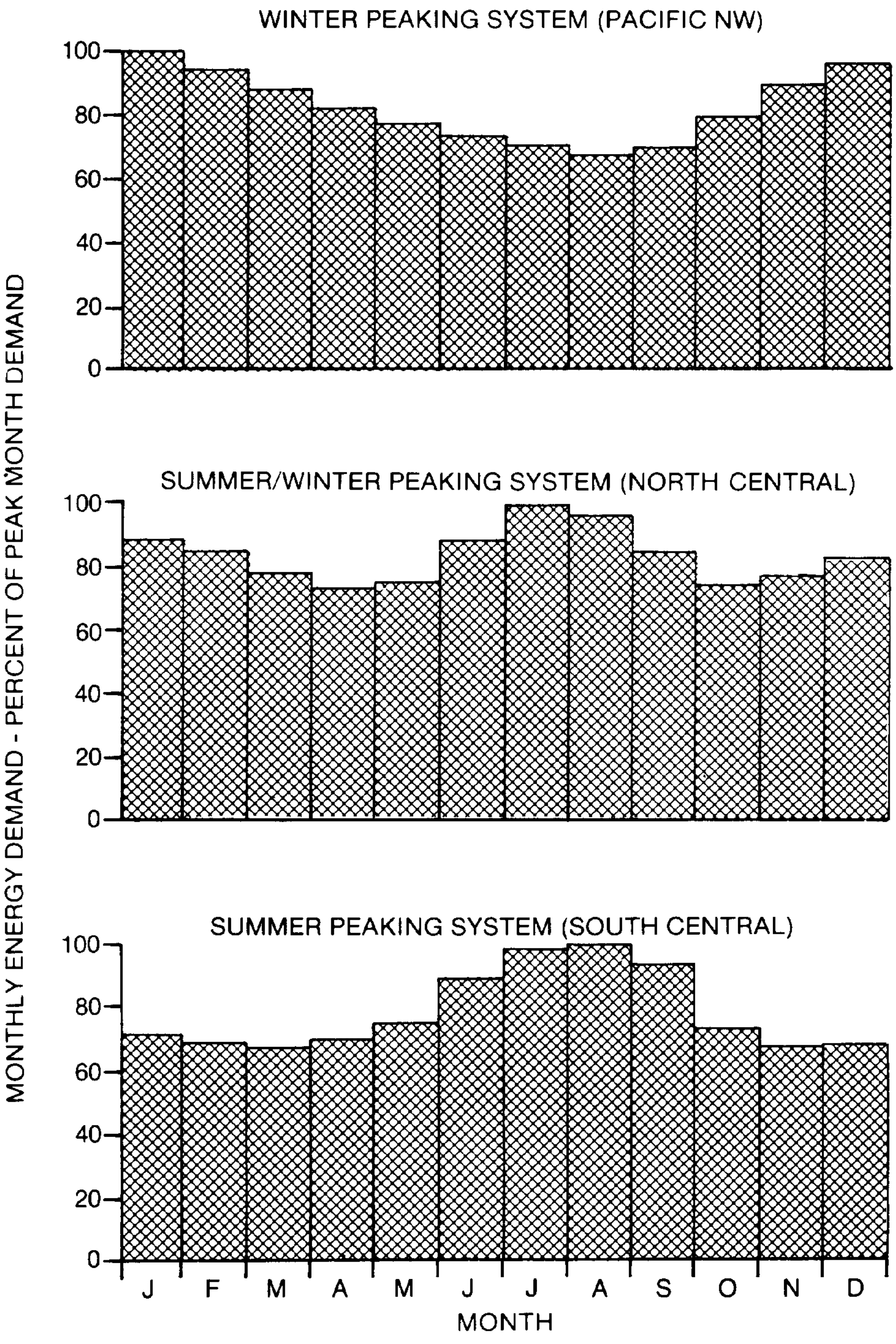

Figure 2-2. Seasonal demand patterns

(2) Fossil-Fuel Steam. Steam plants fired by fossil fuel (Figure 2-4) are the nation's largest single source of electric power. Fuel is burned in a steam plant's boiler to produce steam to drive a turbine. This process converts 30 to 40 percent of the energy content of the fuel to electrical energy. Steam plants may be designed to operate on coal, natural gas, oil, or a combination of fuels. Although smaller units have been constructed in the past, most modern steam plants have units in the 300 to 700 megawatt range. Most of the newer. more efficient units are used in base load service. Older, smaller units are typically used for cycling (intermediate loads),

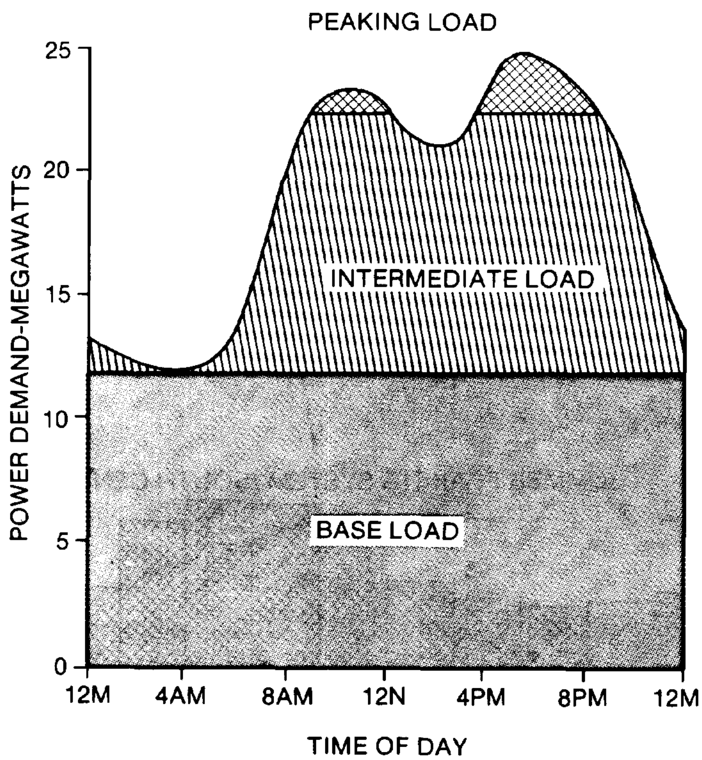

Figure 2-3. Daily load shape showing load types

although some new plants have been constructed in recent years for cycling service. Because of the complexity of their operating systems, steam plants require several hours for startup. While they have some peaking capability, they do not respond as rapidly to change in load as other types of plants. Capital costs are relatively high ($1000/kW or more in 1983). Fuel costs range from 5 to 20 mills/kWh for coal to 60 mills/kWh or more for oil. Coal plants require four to six weeks of maintenance each year and have forced outage rates (which vary with plant size) of 10 to 20 percent. The resulting overall availability (maximum possible plant factor) ranges from 65 to 85 percent, depending on plant size.

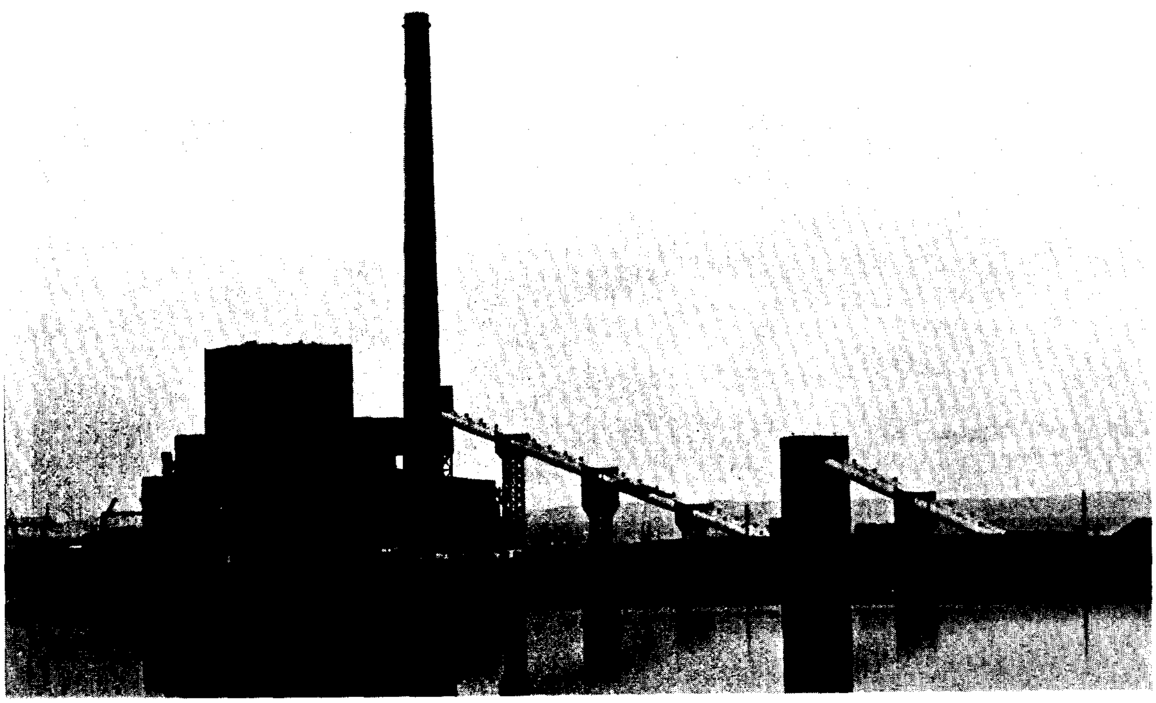

Figure 2-4. Boardman coal-fired steam plant
(Courtesy of Portland General Electric Company)

(3) Nuclear. Nuclear plants (Figure 2-5) are similar to fossil-fuel steam plants except that nuclear fission produces the heat required to generate the steam. Thermal efficiency, at about 33 percent, is somewhat lower than that of coal plants because nuclear steam systems operate at a lower pressure and temperature. Plant sizes are typically in the 800 to 1250 MW range. Because of their low fuel costs (5 to 10 mills/kWh) and high capital costs ($1200/kW or more), as well as other operational characteristics, nuclear plants are used almost exclusively for base load service. Nuclear plants are normally out of service for about eight weeks a year for scheduled maintenance and refueling. Forced outage rates average about 15 percent, which results in an overall availability of 65 to 70 percent.

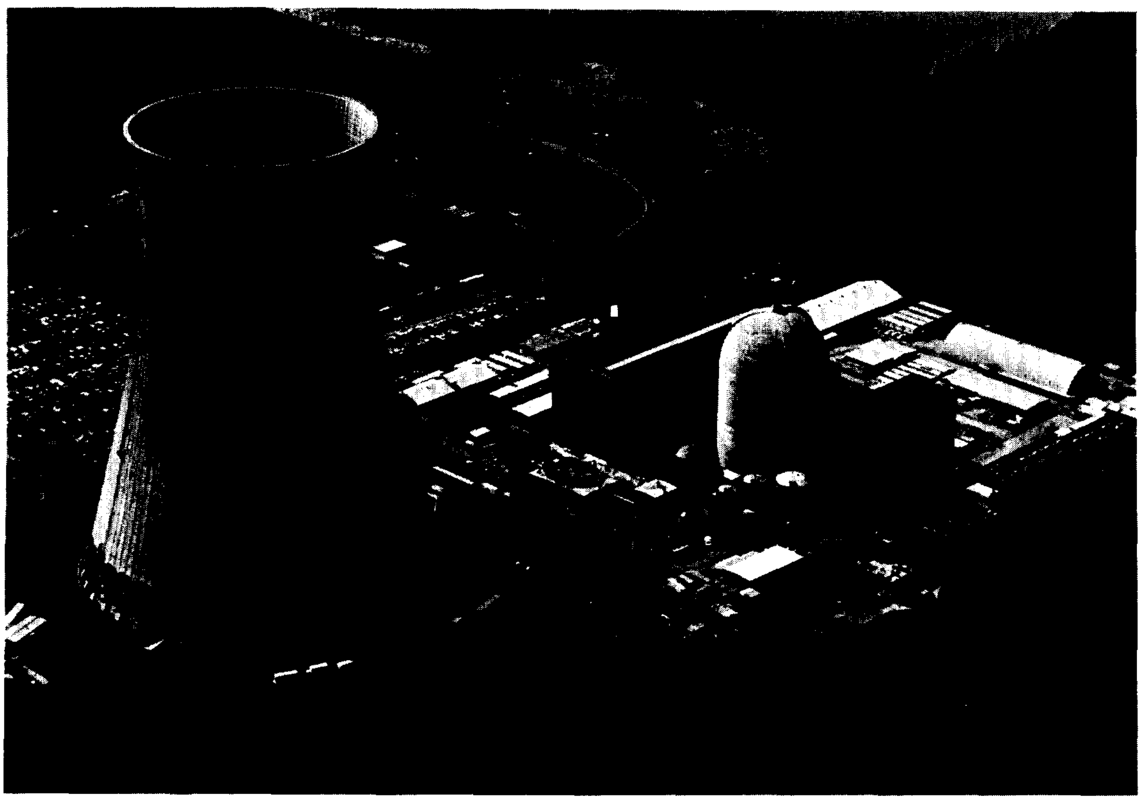

Figure 2-5. Trojan nuclear power plant
(Courtesy of Portland General Electric Company)

(4) Combustion Turbine. A combustion turbine (Figure 2-6) is basically a jet engine connected to a generator. Combustion turbines can run on natural gas or distillate oil, and their overall efficiency is between 25 and 30 percent. Sizes are in the 10 to 100 MW range. They are often constructed in pairs (two combustion turbines connected to a single generator), and installations may consist of several pairs of units. Capital costs are low (about $225/kW), and fuel costs are high (90 to 100 mills/kWh when fired by oil). Combustion turbines can be started in a matter of minutes and can be used for load-following by varying the number of units that are on line. Because of their high fuel costs and fast-start characteristics, combustion turbines are normally used for peaking and standby reserve service. Average annual plant factors are typically 10 percent or less, although in periods of power shortage, combustion turbines have operated at much higher plant factors. In Alaska, where low-cost natural gas is available, combustion turbines are the major source of electric power in some areas and operate at annual plant factors in excess of 50 percent.

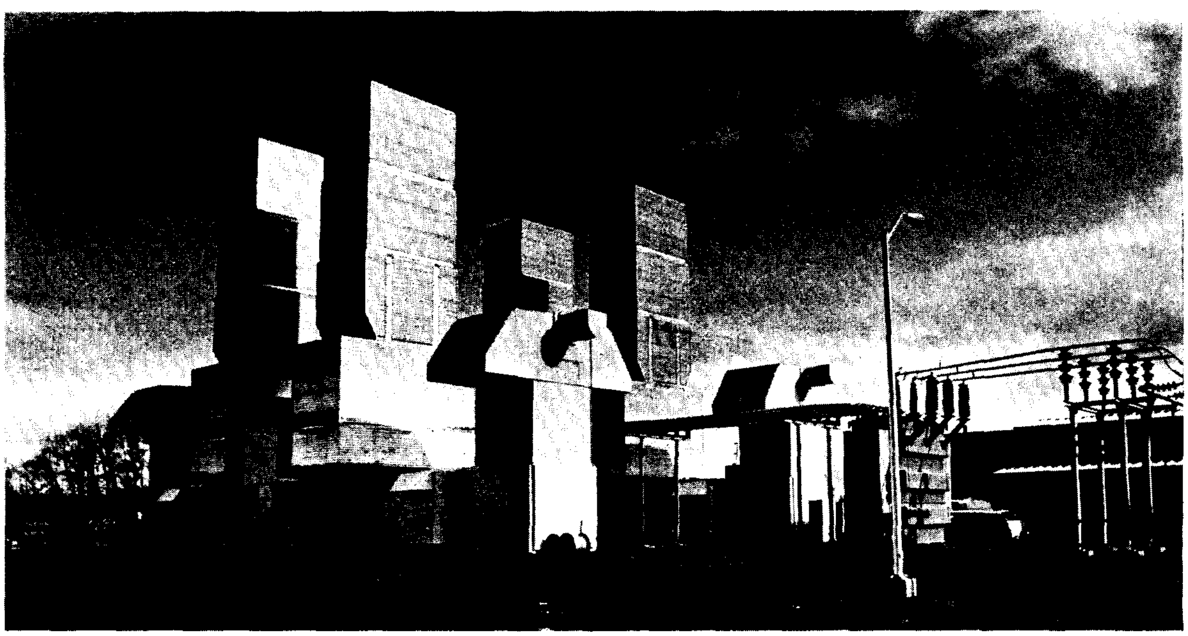

Figure 2-6. Bethel combustion turbine power plant
(Courtesy of Portland General Electric Company)

(5) Combined Cycle. A combined cycle plant (Figure 2-7) is a series of combustion turbines with heat extractors on their exhausts. Steam from the heat extractors is used to drive a conventional turbine-generator. The addition of the steam cycle increases overall efficiency to about 40 percent. Capital costs are higher than combustion turbines (about $500/kW), but due to their higher efficiency, fuel costs are lower (60 mills/kWh or more for oil). Combined cycle plants are designed primarily for cycling operation or extended operation in periods of high demand.

(6) Conventional Hydro. The various types of hydro plants are described in Section 2-3, but some of their basic operating characteristics will be summarized here. Hydro differs from other types of powerplants in that the quantity of "fuel" (i.e. water) that is available at any given time is fixed. Techniques such as seasonal storage or daily/weekly pondage can be used in many cases to make the distribution of streamflow better fit the power demand pattern, but the total amount of water that is available for power generation at a given site is fixed. Increasing plant size may, in some cases, increase the percentage of the potential energy that is utilized, but it cannot increase the total supply. On the positive side, fuel costs are essentially zero. However, capital costs are relatively high, ranging from $500 to $2,000/kW for new projects. Hydro has by far the

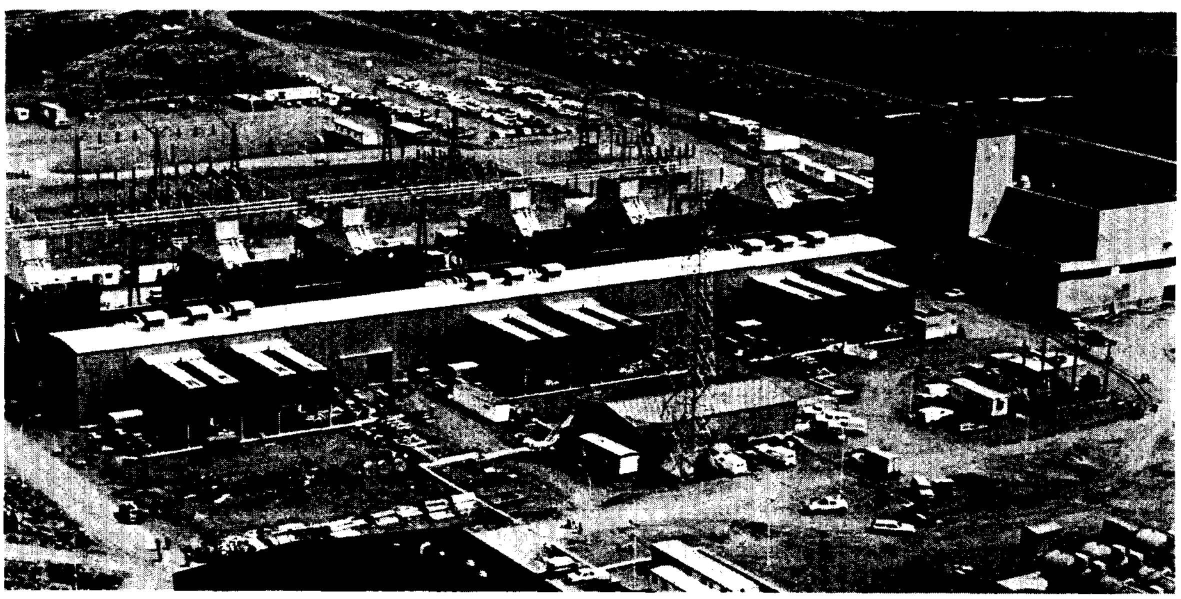

Figure 2-7. Beaver combined cycle power plant
(Courtesy of Portland General Electric Company)

highest energy conversion efficiency, at 80 to 90 percent. Hydropower units can be placed on-line rapidly and can respond quickly to changes in loading. Hydro is well-suited for peaking or load-following operation and is generally used for this service if storage or pondage is available and if river conditions permit. If the project has no controllable storage or if operating restrictions preclude load-following, hydro energy can be produced only when water is available (run-of-river operation). Forced outage rates on hydro are very low (2 to 4 percent), and average availability (which includes scheduled maintenence) is about 95 percent.

(7) Pumped-Storage Hydro. Pumped-storage hydro is a form of energy storage. Relatively low-cost electrical energy, usually from coal-fired steam plants, is used to pump water into an upper storage reservoir during periods of low power demand (nights and weekends). During high demand periods, when energy is most valuable, water is released to produce power. Further details on pumped-storage operation can be found in Section 2-3e and Chapter 7. Because of mechanical and electrical losses in the pumping and generating processes, overall efficiency is about 65 to 75 percent. Pumped-storage has quick-start capability, and because of its relatively high "fuel" cost (the cost of the off-peak pumping energy divided by the overall efficiency), it is normally used for peaking service. Construction costs are moderately high ($500 - $800/kW) and forced outage rates are about five percent.

(8) Other Types of Powerplants. Other types of powerplants are geothermal steam, wind, solar, and tidal. However, they are presently in limited use because they are in the developmental stage, or because the resource itself is limited. One additional type of powerplant, the diesel or internal combustion unit, is widely used to provide power in isolated areas where loads are relatively small or for emergency service, but such units are seldom operated in the larger power systems of the continental United States.

(9) Imports. An additional resource available to some power systems is the import of power from adjacent power systems. Imports fall into several categories. First, there are firm or assured sales contracts, which usually become available when a utility has a temporary surplus of generation. These contracts are normally of relatively short duration (one to ten years). Another category is the exchange contract, which is designed to take advantage of seasonal or daily diversity in load or resource capabilities. Exchange contracts are usually firm contracts and are of longer duration (10 years or more). The third major category is low-cost "dump" power, which may be available from outside the system on a short-term interruptible basis. This power can be used to cut system fuel costs, but it is not considered a firm power system resource.

(10) Interruptible Loads. A portion of the load in some systems can be interrupted during periods of high demand and this "interruptible" load serves in effect as a resource available to the operator to insure that firm system loads will be met. One example is the rotating short-term interruption of individual water heaters or air conditioners during the peak demand hours of the day. Another example is the long-term interruption of service to certain types of industrial customers during extended periods of shortage. The latter might include electro-process industries, which may pay relatively low power rates in exchange for allowing a portion of their loads to be interruptible.

e. Reserves. Having just enough resources to meet expected peak loads is not sufficient to guarantee a reliable service to customers. Additional capacity must be available to cover forced outages, maintenance outages, abnormal loads, and other contingencies. Typically, power system resource planning is based on providing about 20 percent reserve capacity above the expected annual peak load. This capacity is called the system planning reserve. In day to day system operation, an operating reserve of 5 to 10 percent of the load being carried must be maintained at all times. Half of this must be spinning reserve (capacity which is rotating but not under load) and the remainder is standby reserve, which must be available in a matter of minutes. The spinning reserve is used to handle moment-by-moment load changes, while standby reserve is used to cover unexpected powerplant outages.

f. Meeting Loads with Resources.

(1) This section shows how a given set of power resources is used to meet system loads. When planning a program of resource construction to meet expected future demands, both fixed (capital) and operating costs must be considered. However, to illustrate the principles of system operation, only operating costs (primarily fuel costs) will be considered. In order to simplify the discussion, the operation of an all-thermal system will be examined first. Section 2-2g will address the operation of power systems that include hydropower plants.

(2) A simplified example based on a single week of operation will illustrate these concepts. A load-duration curve is commonly used to describe system operation. Figure 2-8 shows the derivation of a load-duration curve from a weekly load curve. The example assumes that a 20 percent reserve margin must be maintained. When evaluating average system operating costs, the occasional use of reserve generation to cover forced outages must be accounted for. Since techniques for doing this are complex (see Section 6-9f), operation to cover forced outages will not be considered in this example.

(3) The expected peak load for the example system is assumed to be 5000 MW, so an additional 1000 MW of generating capacity is required to provide a 20 percent reserve margin. Table 2-1 lists the powerplants available for meeting this load and their respective operating costs.

(4) The basic objective of system operation is to minimize costs by placing the plants in the load in order of increasing cost. The plant with the lowest operating cost is NUKE-1 at 6 mills/kWh. It would be operated at the base of the load. The next lowest operating cost is 8 mills/kWh for COAL-2, so it would be loaded next. The other plants would be loaded in the weekly load-duration curve as shown in Figure 2-9, with CMBT-1 being loaded at the peak and CMBT-2 and -3 providing the reserve capacity. Costs would be computed for each plant by multiplying the plant capacity by the number of hours operated in the week and the energy cost in mills/kWh. Table 2-2 shows the computation of system costs for the week. Table 2-2 and Figure 2-9 show that this loading order produces the lowest system operating cost.

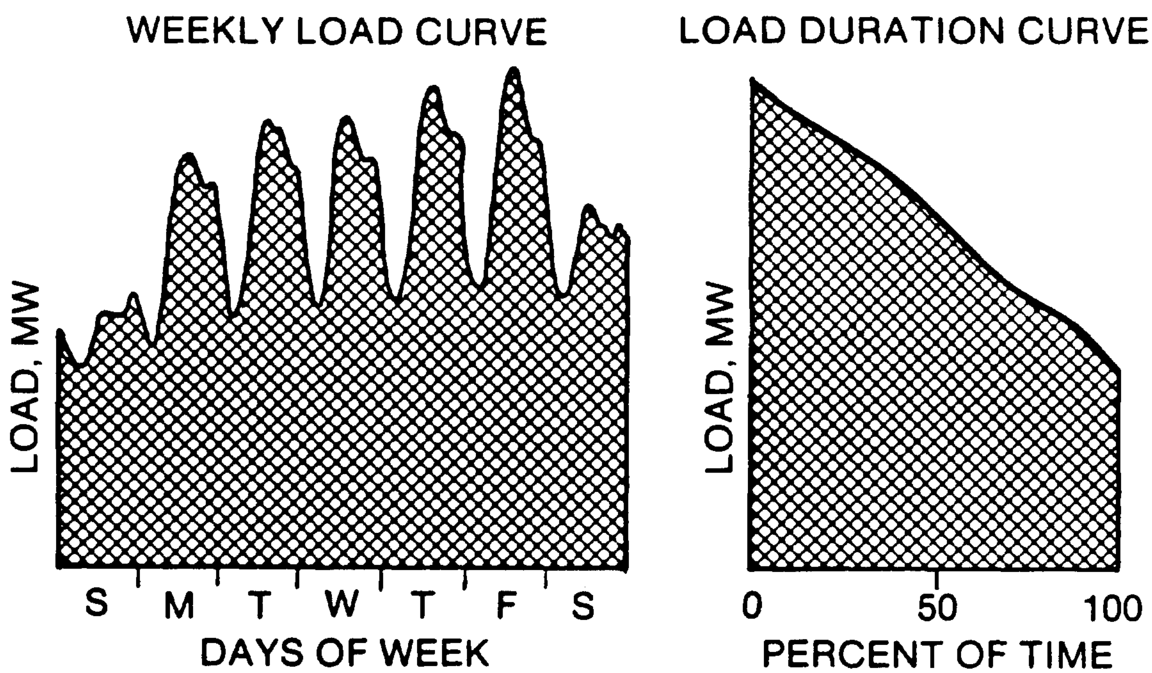

Figure 2-8. Derivation of load duration curve from weekly load curve.

TABLE 2-1
Generating Plants Available for Meeting Loads - Base Case

Plant	Symbol	MW	Mills/kWh
Base load coal	COAL-1	500	15
Base load coal	COAL-2	750	8
Base load coal	COAL-3	750	9
Cycling coal	CYCL-1	500	20
Cycling coal	CYCL-2	500	30
Combined cycle	CMCY-1	500	60
Combustion turbine	CMBT-1	500	80
Combustion turbine	CMBT-2	500	90
Combustion turbine	CMBT-3	500	100
Nuclear	NUKE-1	1000	6
TOTAL		6000	

(5) This simplified example ignores the costs of operation to cover forced outages. It fails to account for possible ramp rate and minimum down time constraints on plants operating in the variable portion of the load. It also does not reflect the fact that spinning reserve requirements are usually met by operating some plants at partial loading. However, the example does illustrate the general concept of system operation.

g. The Use of Hydropower.

(1) Hydropower can be used in a power system in several ways: for peaking, for meeting intermediate loads, for base load operation, or for meeting a combination of these loads. These alternative operations can best be illustrated by adding hydro to the system described in the preceding section. Given the same load shape and resources as shown in Figure 2-9 and a hydro project with an average power putput for the week of 250 MW (250 MW x 168 hours = 42,000 MWh), several possible system operations are considered.

(2) Hydro energy has a fuel cost of approximately zero mills/kWh. The best loading of hydro to minimize system operating cost would be in the peak of the load. A 1000 MW installation would fit almost in the peak of the load and would displace CMBT-1 at 80 mills/kWh and CMCY-1 at 60 mills/kWh (Figure 2-10). The resulting system cost for the week would be $5,306,000, saving $1,950,000

compared to the all-thermal system (Table 2-3). If the hydro plant were constructed as a base load plant, only 250 MW of capacity would be required to fully utilize the 42,000 MWh of energy which is available, and it would be loaded as shown in Figure 2-11. The system operating cost would be $6,159,000 and the savings only $1,097,000 (Table 2-4). Alternative hydro plant sizes could be tested by loading them at intermediate points in the loading order, but none would result in a lower system operating cost than loading the hydro in the peak.

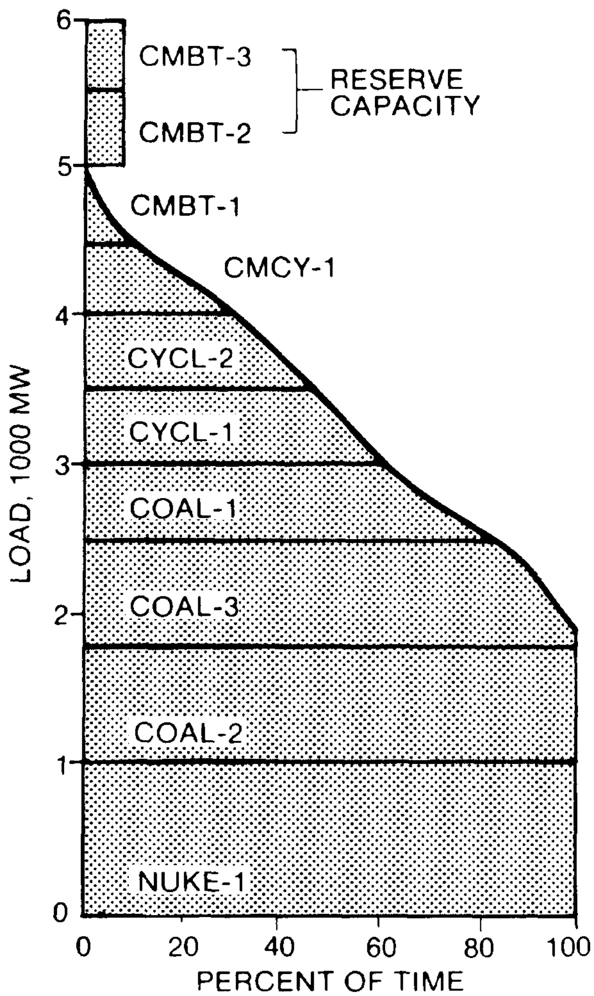

Figure 2-9. Duration curve showing operation of all-thermal power system

TABLE 2-2
Cost of Operating All-Thermal Base System for One Week
(From Figure 2-9)

Plant Symbol	Capacity (MW)	Plant Factor(%)	Energy (1000 MWh)	Unit Cost (Mills/kWh)	Cost ($1000)
CMBT-3	500	0	0	100	0
CMBT-2	500	0	0	90	0
CMBT-1	500	4	3	80	240
CMCY-1	500	21	18	60	1080
CYCL-2	500	40	34	30	1020
CYCL-1	500	55	46	20	920
COAL-1	500	72	60	15	900
COAL-3	750	95	120	9	1080
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
HYDRO	0	0	0	0	0
TOTALS	6000	68 2/	575	12.6	7256

1/ Energy = (capacity, MW)x(plant factor, %)x(168 hrs/wk)/100
2/ System load factor, based on 5000 MW peak load

(3) The above analysis considers only system operating costs, and does not account for the capital costs of the alternative hydro installations, which obviously increase with installed capacity. Nor does the analysis account for the displacement of an equivalent amount of thermal plant capacity by the hydro capacity. These points must be considered when determining the best plant size, and the economic evaluation procedures described in Chapter 9 are designed to do this.

(4) It is possible to make some general observations regarding the use of hydro. Much of the cost associated with the construction of a hydro plant is independent of plant size: i.e., the costs of the main dam, spillway, reservoir, relocations, and fish and wildlife protection and mitigation. The incremental costs of larger plant sizes at a given site are often relatively low. Because of this and hydro's ability to come on-line rapidly and respond quickly to load changes, it is traditionally viewed as a peaking resource.

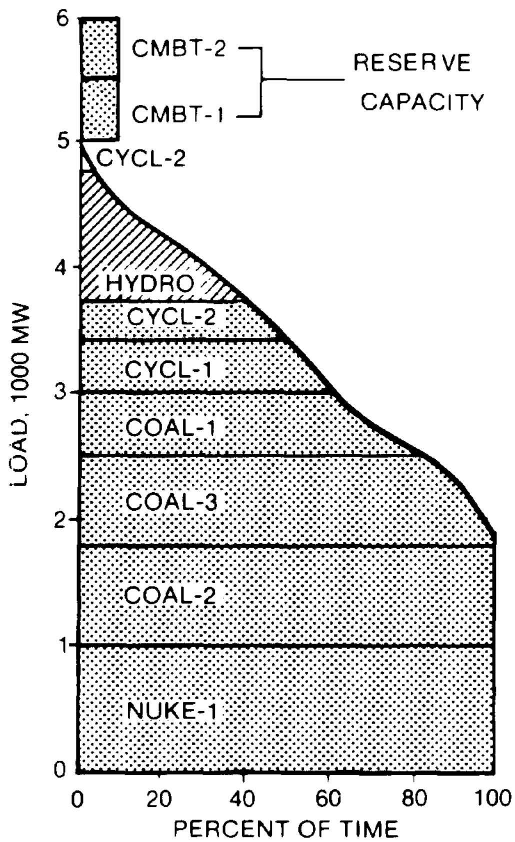

Figure 2-10. Duration curve showing operation of system with hydro plant in peaking mode

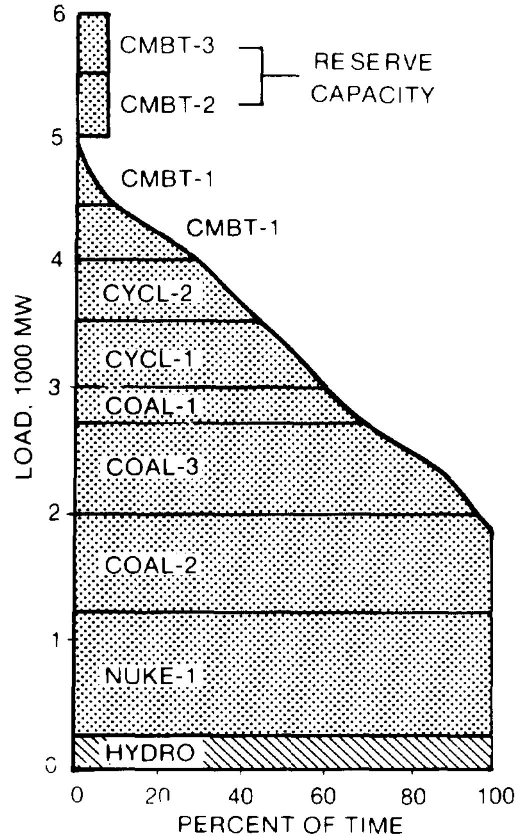

Figure 2-11. Duration curve showing operation of system with hydro plant as base load

(5) However. some potential hydro developments are constrained from peaking operation by operating limits designed to protect the environment and other project purposes (Section 6-5). Others are constrained from the daily and weekly shaping of power discharges to fit power demand by lack of storage or pondage. However, it is sometimes possible to do some load-following within those constraints. Figure 2-12 illustrates a case where a portion of the generation is operated base load in order to meet minimum flow requirements, and the remainder is used for peaking.

(6) The use of hydro is most limited where storage or pondage is not available. Where streamflow is dependable, the hydro plant may displace an increment of thermal capacity. Where it is not, the hydro energy may be usable only for displacement of the energy output of existing thermal plants (Figure 2-13). However, in some cases, the

TABLE 2-3
Cost of Operating System for One Week with Hydro Used for Peaking
(from Figure 2-10)

Plant Symbol	Capacity (MW)	Plant Factor (%)	Energy (1000 MWh)	Unit Cost (mills/kWh)	Cost ($1000)
CMBT-2	500	0	0	90	0
CMBT-1	500	0	0	80	0
HYDRO	1000	25	42	0	0
CYCL-2	500	15	13	30	390
CYCL-1	500	55	46	20	920
COAL-1	500	72	60	15	900
COAL-3	750	95	120	9	1080
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
TOTALS	6000	68 1/	575	10.5	5306

TABLE 2-4
Cost of Operating System for One Week with Hydro Used as Base Load
(from Figure 2-11)

Plant Symbol	Capacity (MW)	Plant Factor (%)	Energy (1000 MWh)	Unit Cost (mills/kWh)	Cost ($1000)
CMBT-3	500	0	0	100	0
CMBT-2	500	0	0	90	0
CMBT-1	500	1	1	80	80
CMCY-1	500	13	11	60	660
CYCL-2	500	33	28	30	840
CYCL-1	500	48	40	20	820
COAL-1	500	62	52	15	780
COAL-3	750	85	107	9	963
HYDRO	(250)	100	42	0	0
COAL-2	750	100	126	8	1008
NUKE-1	1000	100	168	6	1008
TOTALS	6000	68 1/	575	10.8	6159

1/ System load factor. based on 5000 MW peak load value of energy being displaced may be high. In California and New England, where a substantial portion of the generation is oil-fired steam, the benefits attributable to this type of operation may be substantial.

(7) The operation of pumped-storage hydro, which differs somewhat from conventional hydro, is discussed in Chapter 7.

2-3. Types of Hydropower Projects.

a. General. Hydropower projects can be classified by type of operation, which is in turn a function of the amount of storage available for the regulation of power output. The major types of

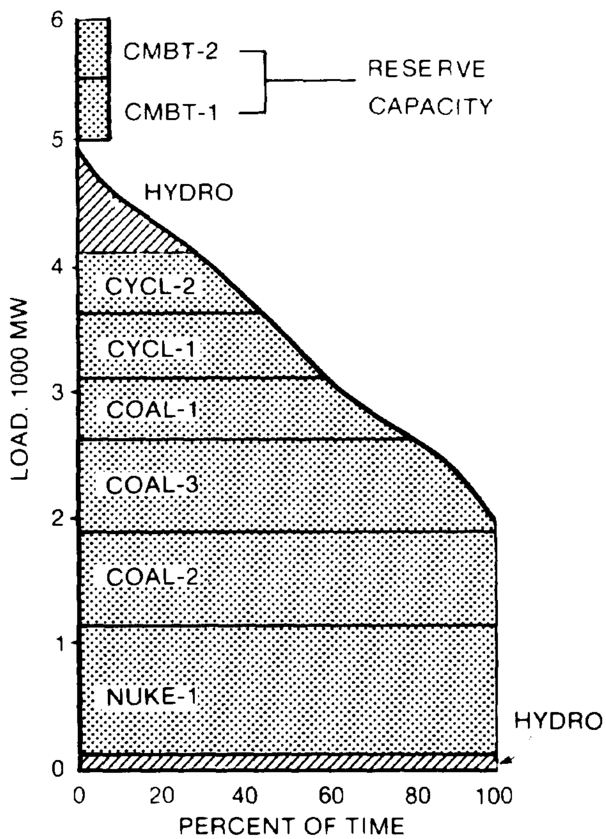

Figure 2-12. Duration curve showing operation of system with hydro plant carrying both base and peaking loads

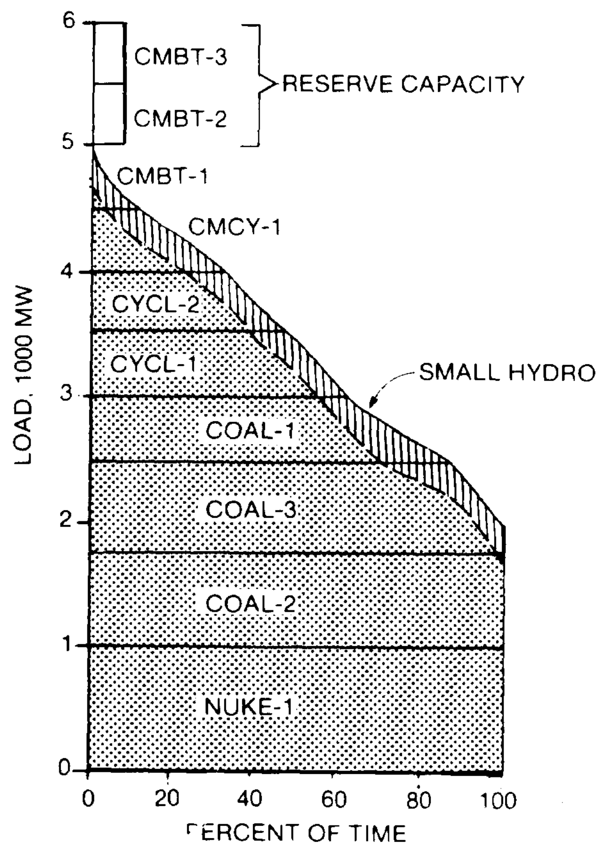

Figure 2-13. Duration curve showing operation of system with pure run-of-river hydropower plant

conventional hydro projects are run-of-river, pondage, storage, and reregulating. Pumped-storage projects can be categorized as off-stream or pump-back.

b. Run-of-River Projects.

(1) A pure run-of-river project (Figure 2-14) has no usable storage. Power output at any time is strictly a function of inflow. Typical run-of-river projects include navigation projects where the pool must be maintained at a constant elevation, irrigation diversion dams, and single-purpose hydro projects where the topography upstream from the dam site does not allow for pondage or seasonal storage. Powerplants on irrigation canals and water supply pipelines can also be classified as run-of-river projects.

(2) The term "run-of-river" also refers to an operating mode. A storage project can operate in the run-of-river mode if it is just passing inflow. Another example would be a powerplant installed at a project with storage regulated only for flood control and non-power conservation purposes such as water supply. No special regulation would be permitted for power. either on a daily/weekly or on a

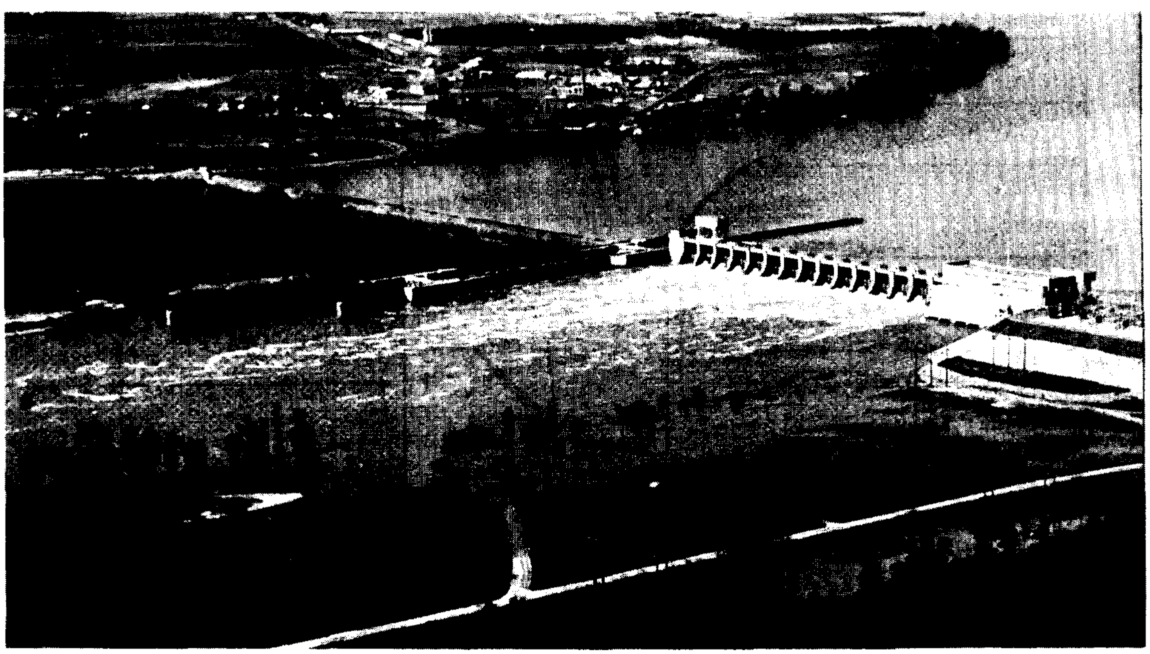

Figure 2-14. Jim Woodruff Dam and Reservoir, a pure run-of-river project (Mobile District)

seasonal basis. Discharges would be regulated for non-power purposes so that power production would use whatever flows happen to be available as a result of the non-power regulation. Run-of-river projects can be considered to be base load plants in terms of use in meeting loads.

c. Pondage Projects. Some projects have insufficient storage space for seasonal flow regulation. The storage can be used, however, to shape discharges to follow the daily and, in some cases, weekly load patterns. Daily/weekly storage is referred to as "pondage", and the use of pondage permits a project to serve intermediate and peaking loads. Some navigation projects are designed to permit fluctuations of several feet without adversely affecting navigation. Many of the small to medium-sized single-purpose power projects constructed in this country have pondage. These two types of projects are sometimes called run-of-river projects with pondage (Figure 2-15). Some flood control reservoirs with powerplants are designed with several feet of pondage. They are examples of projects with seasonal storage regulated strictly for non-power purposes, but with sufficient flexibility to permit fluctuation of daily releases for peaking

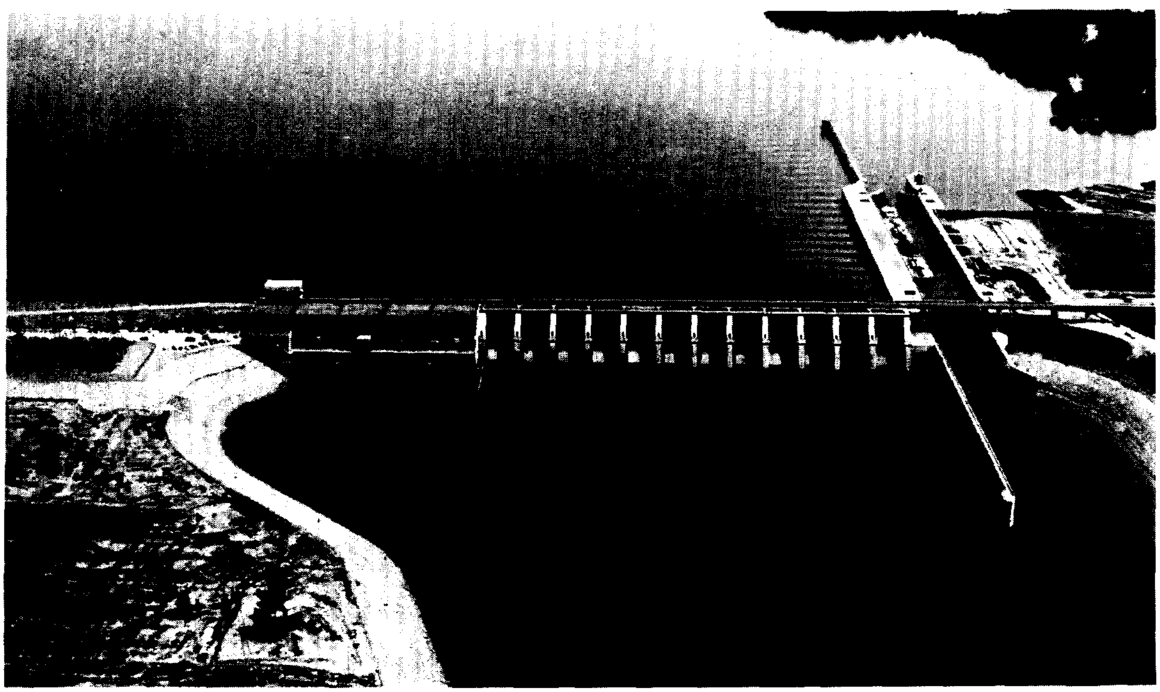

Figure 2-15. Barkley Lock and Dam, a run-of-river project with pondage (Nashville District)

operation. The amount of load following that can be accomplished at many pondage projects may be limited by the amount of pondage available or by operating constraints such as minimum discharge requirements.

d. Storage Projects. The term "storage" generally refers to projects which have seasonal regulation capability (Figure 2-16). A project with power storage can be used to regulate seasonal discharges in order to more closely follow the seasonal power demand pattern. Although there are some single-purpose power storage projects in this country, most storage projects are regulated for multiple purposes (see Section 5-12). While power storage can be used to benefit at-site power production, it is often used to improve production at downstream power projects (Section 5-14). Power storage projects inherently have pondage operation capability and thus can be used to serve intermediate and peaking loads as well as the base load if downstream conditions permit. Where operating restrictions prohibit large fluctuations in releases, a small reregulating reservoir can be constructed downstream of the main dam in order to maintain required discharge conditions.

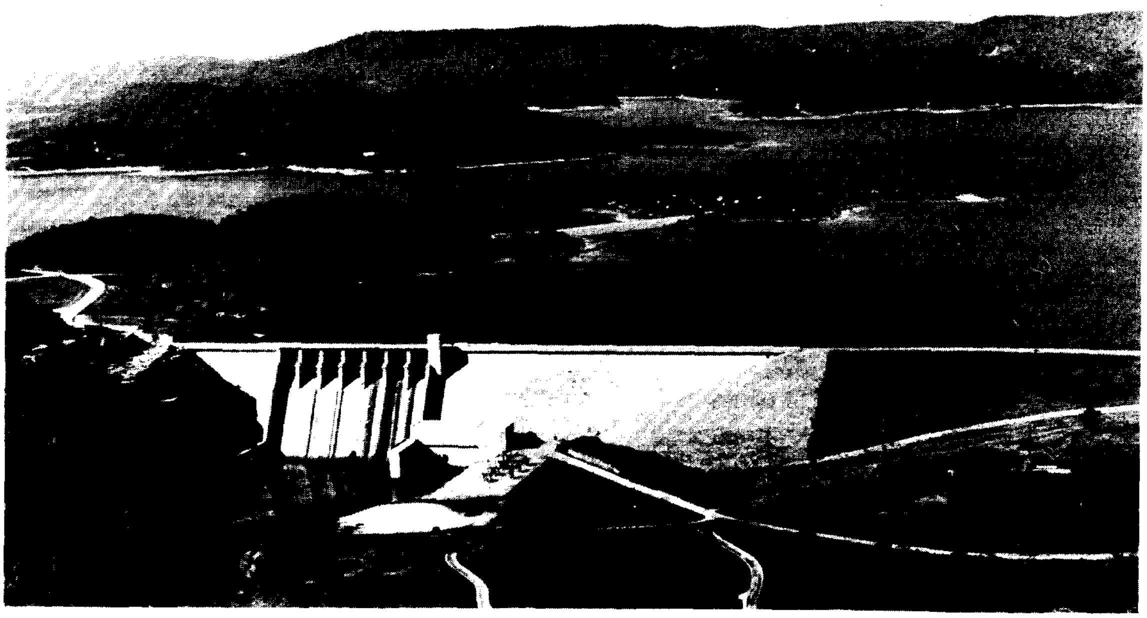

Figure 2-16. Beaver Lake Dam and Reservoir, a seasonal storage project (Little Rock District)

e. Pumped-Storage Projects.

(1) General. Pumped-storage projects are designed to convert low value off-peak energy to high value on-peak energy. Low cost energy is used to pump water to an upper reservoir at nights and on weekends, and the water is released during high demand hours to generate peaking power. There are two basic types of pumped-storage projects: off-stream and pump-back. Pump-back projects use two reservoirs in series to transfer energy, while an off-stream project uses an adjacent reservoir to store water. A brief description of each type follows, and Chapter 7 provides more detailed information on the planning and operation of pumped-storage projects.

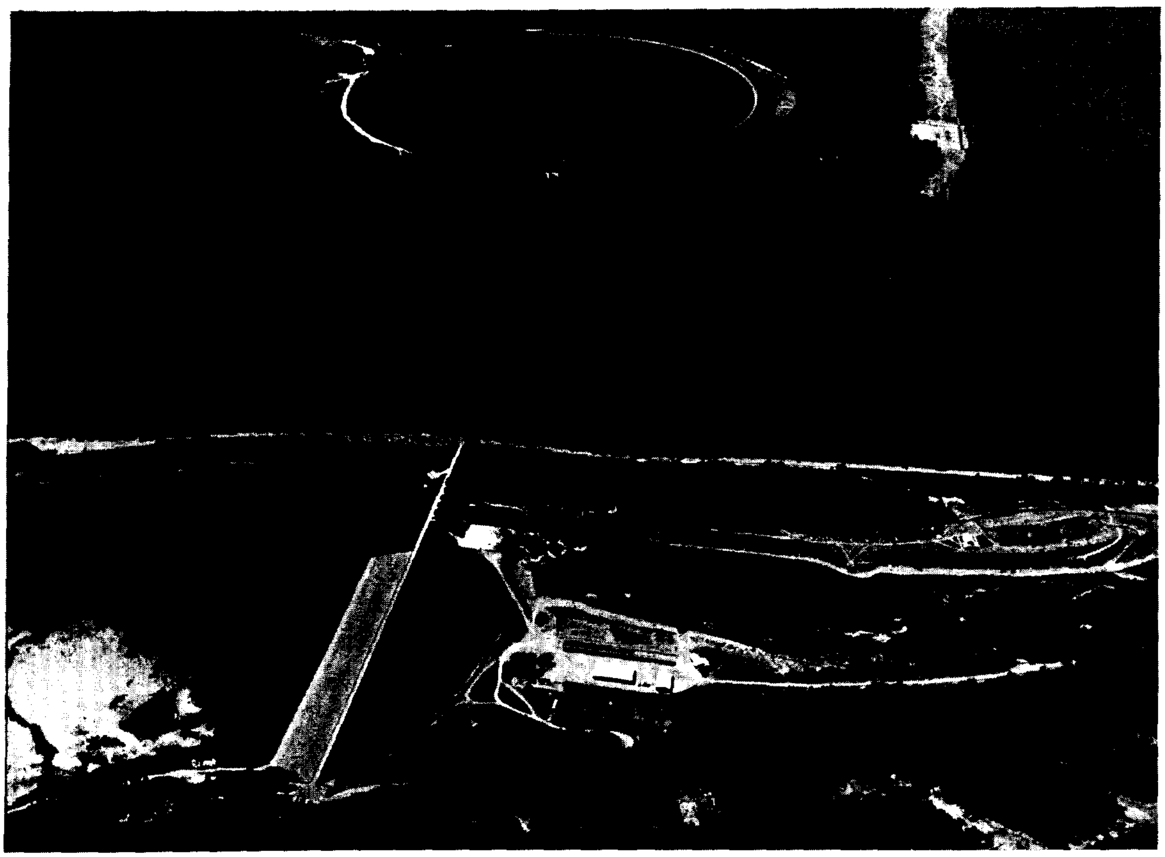

Figure 2-17. Seneca off-stream pumped-storage project, which uses the Allegheny Reservoir behind Kinzua Dam as its lower reservoir (Courtesy Pennsylvania Electric Company and Cleveland Electric Illuminating Company)

(2) Off-Stream. An off-stream pumped-storage project (Figure 2-17) consists of a lower reservoir on a stream or other water source and a reservoir located off-stream at a higher elevation. Water is pumped to the higher reservoir during periods of energy surplus and is released through the turbines during periods of energy demand. Off-stream pumped-storage projects are usually dependent exclusively on pumped water as their source of energy. They frequently utilize existing reservoirs as lower reservoirs, and because the resulting peaking operation does not have a major impact on the river downstream, installed capacities can often be very large.

(3) Pump-Back. A pump-back project, also known as on-stream or integral pumped-storage, consists of a conventional hydro project with a pumped-storage cycle superimposed on the normal power operation. As with off-stream pumped-storage, two reservoirs are involved, but both are located in tandem on the same stream (Figure 2-18). The main dam usually forms the upper reservoir, and the lower reservoir could be (a) another multiple-purpose project located immediately downstream or

Figure 2-18. Carters pump-back project (Mobile District)

(b) a special reservoir designed to serve as a combination pumped-storage afterbay and reregulating dam. The principal power installation would generally be located at the main dam, but the lower reservoir might have a powerplant also. The purpose of pump-back is to increase the firm peaking capability of the main dam. A given site may physically be ideal for a hydro project, but flows may be inadequate to support a large peaking installation. Recycling the limited amount of available water between the main reservoir and the lower reservoir would make it possible to install a larger plant. The project would operate as a conventional hydro plant part of the time, but when flows are low or when peak demands are high, the project would operate in the pumped-storage mode. Some water would normally be passed downstream, however, even during pumped-storage operation. All of the units at some pump-back projects are reversible. At others, only a portion of the generating units need to be reversible in order to firm up peaking capacity.

f. Reregulating Projects. Reregulating reservoirs (Figure 2-19) are designed to receive fluctuating discharges from large peaking plants and release them downstream in a pattern which meets downstream minimum flow and rate of change of discharge criteria. Reregulating

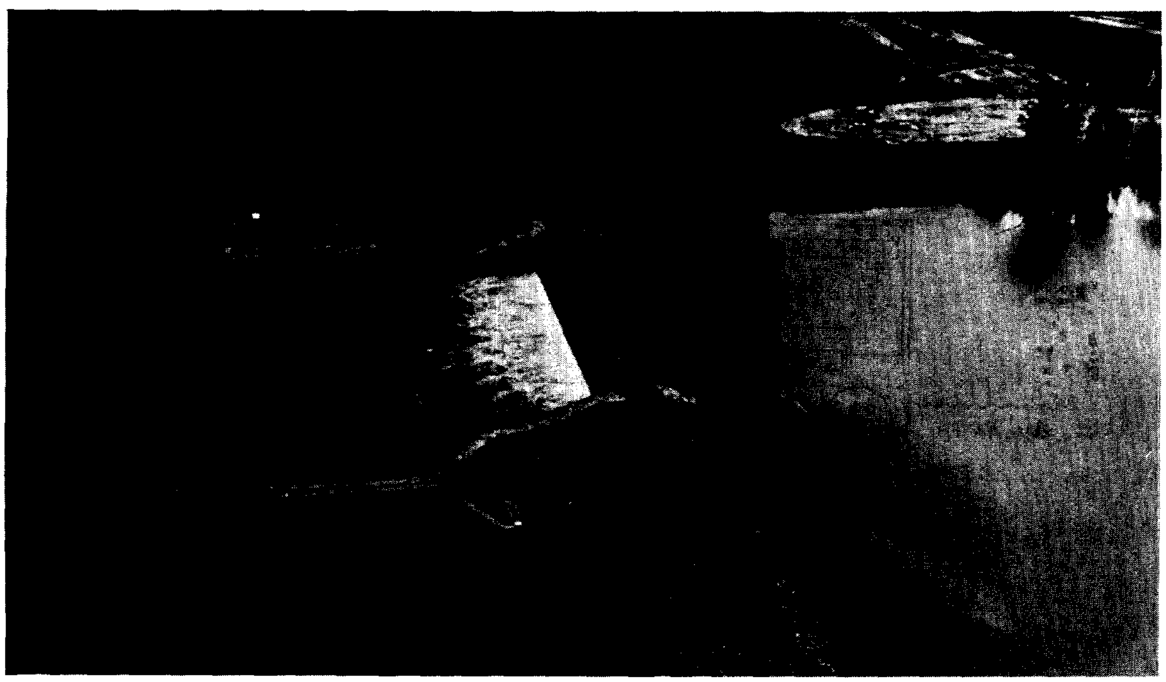

Figure 2-19. Reregulating dam for the DeGrey project (Vicksburg District)

projects (also sometimes known as afterbay reservoirs) may be constructed in conjunction with a conventional hydro peaking plant or a pump-back installation. A downstream project may serve as a reregulator for a series of hydro projects located on the same stream.

2-4. Components of Hydro Projects.

a. General. Three basic elements are necessary in order to generate power from water: a means of creating head, a conduit to convey water. and a powerplant. To provide these functions, the following components are used: dam. reservoir, intake, conduit or penstock, surge tank, powerhouse, draft tube, and tailrace (see Figure 2-20).

b. Dam. The dam performs two major functions. It creates the head necessary to move the turbines, and impounds the storage used to maintain the daily or seasonal flow release pattern. The height of

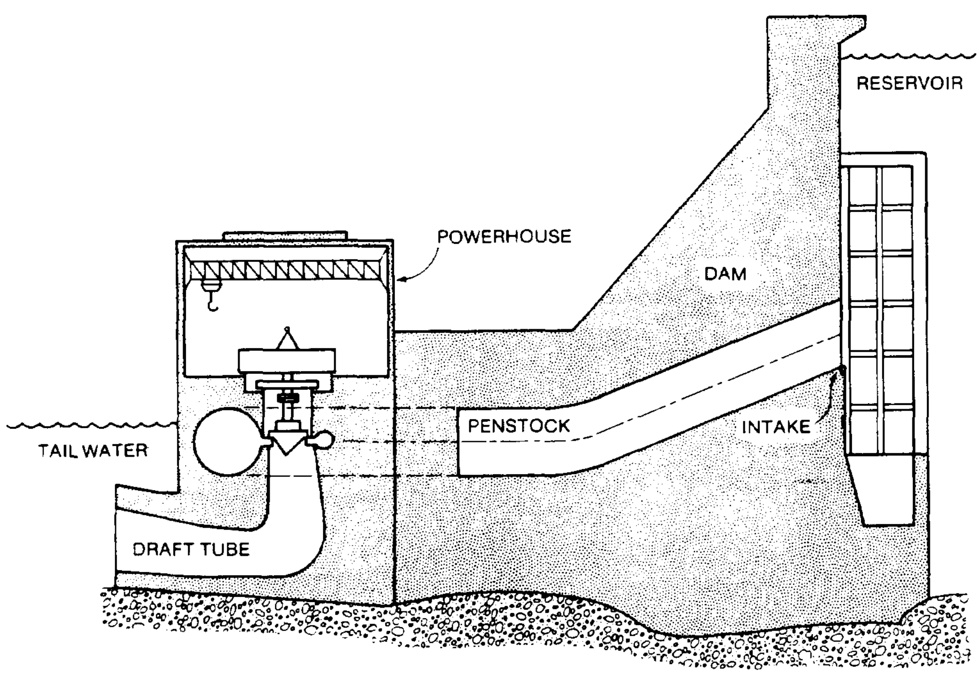

Figure 2-20. Components of a hydropower project

the dam establishes the generating head and the amount of water storage available for power plant operation. Power projects can utilize either existing or new dam structures. Fitting powerplants to existing dams is a task that must be undertaken carefully in order to prevent degradation of the dam's structural integrity. The publication, Feasibility Studies for Small Scale Hydropower Additions, (39) provides information on engineering and evaluation of some of the problems unique to powerplant retrofitting.

c. Reservoir. A reservoir consists of the water impoundment behind a dam. Storage capacity is the volume of a reservoir available to store water. This storage is divided into active and inactive storage. Active storage is that portion of the storage capacity in which water will normally be stored or withdrawn for beneficial uses. Inactive storage is that portion of the storage capacity from which water is not normally withdrawn, in accordance with operating agreements or restrictions. Inactive storage includes dead storage, which is storage that lies below the invert of the lowest outlet and thus cannot be evacuated by gravity. A pure run-of-river project would have no storage. Storage used for daily or weekly flow regulation is called pondage and storage used for seasonal regulation is called seasonal storage. Seasonal storage often serves other functions in addition to hydropower. The reservoir water surface at the power intake may be called the forebay, headrace, headwater, or simply the pool elevation.

d. Intake. Intake structures direct water from the reservoir into the penstock or power conduit (see Figure 2-21). Gates or valves are used to shut off the flow of water to permit emergency unit shutdown or turbine and penstock maintenance. Racks or screens prevent trash and debris from entering the turbine units. Where the powerhouse is integral with the dam, the intake is part of the dam structure. Where the powerhouse is not part of the dam, a separate intake structure must be provided. Projects that are required to use water at a selected temperature must have multi-level intakes in order to control inlet water quality by mixing waters obtained from different levels.

e. Penstock. The penstock conveys water from the intake structure to the powerhouse and can take many configurations, depending upon the project layout (see Figure 2-22). Where the powerhouse is an integral part of the dam, the penstock is simply a passage through the upstream portion of the dam. A canal, pipe, or tunnel is required where the powerhouse is separated from the intake. A penstock may be several miles long at diversion-type projects. Water may be conveyed most of the distance at an elevation close to the forebay elevation via an open canal or a low pressure pipe or tunnel. The remainder of the penstock, where most of the drop in elevation occurs, would be a pressurized tunnel or pipe. Because the cost of a pressurized tunnel or pipe is much greater than that of a low pressure tunnel or pipe, it is usually desirable to minimize the length of the high pressure penstock. When the powerhouse is located adjacent to the dam but is not an integral part of the structure, water would be conveyed through or around the dam via a pressure tunnel. For multi-unit installations, it is often desirable to serve several units with a single penstock, and manifolds or bifurcation structures are provided to direct flow to individual units. Guidance on penstock design can be found in EM 1110-2-3001.

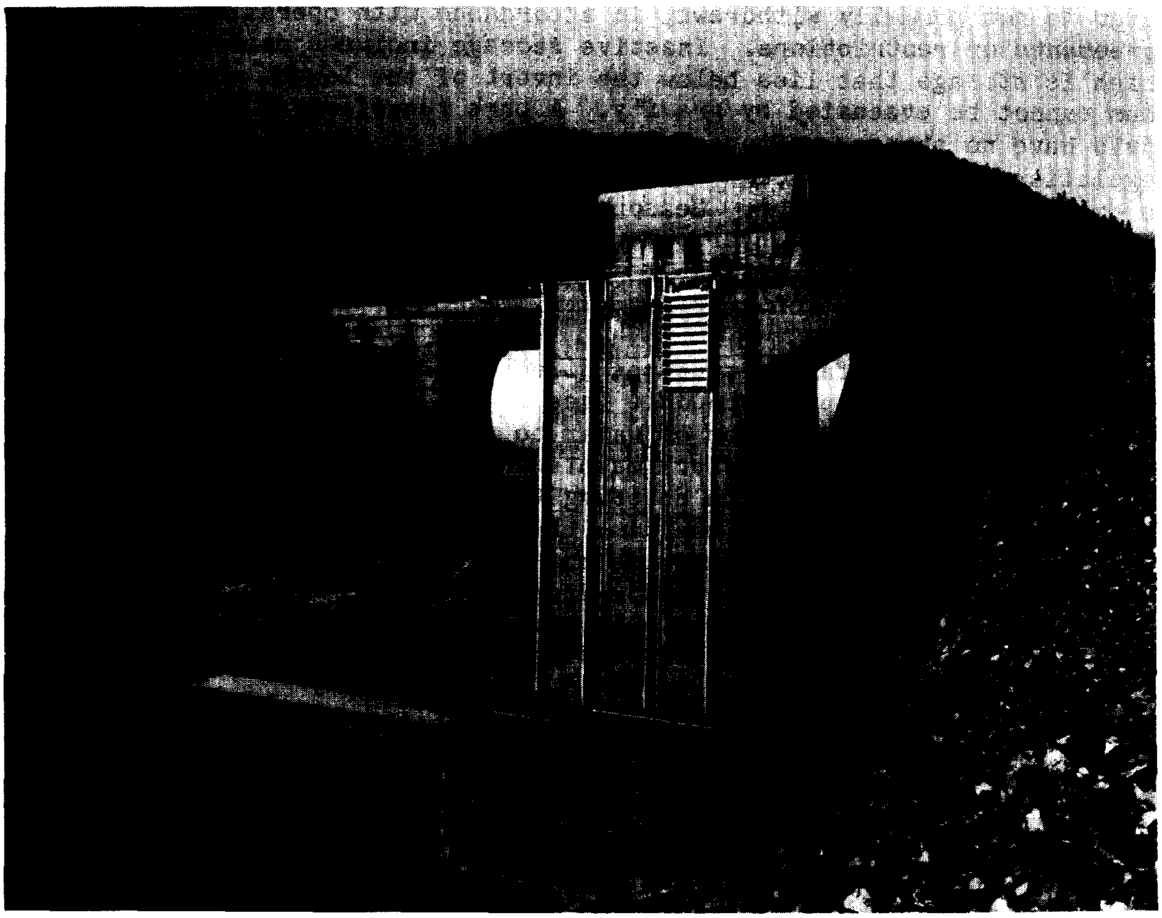

Figure 2-21. Intake tower, Hills Creek Dam. Power intake is on the left, regulating outlet intake is on the right. Trashracks are not yet in place (Portland District)

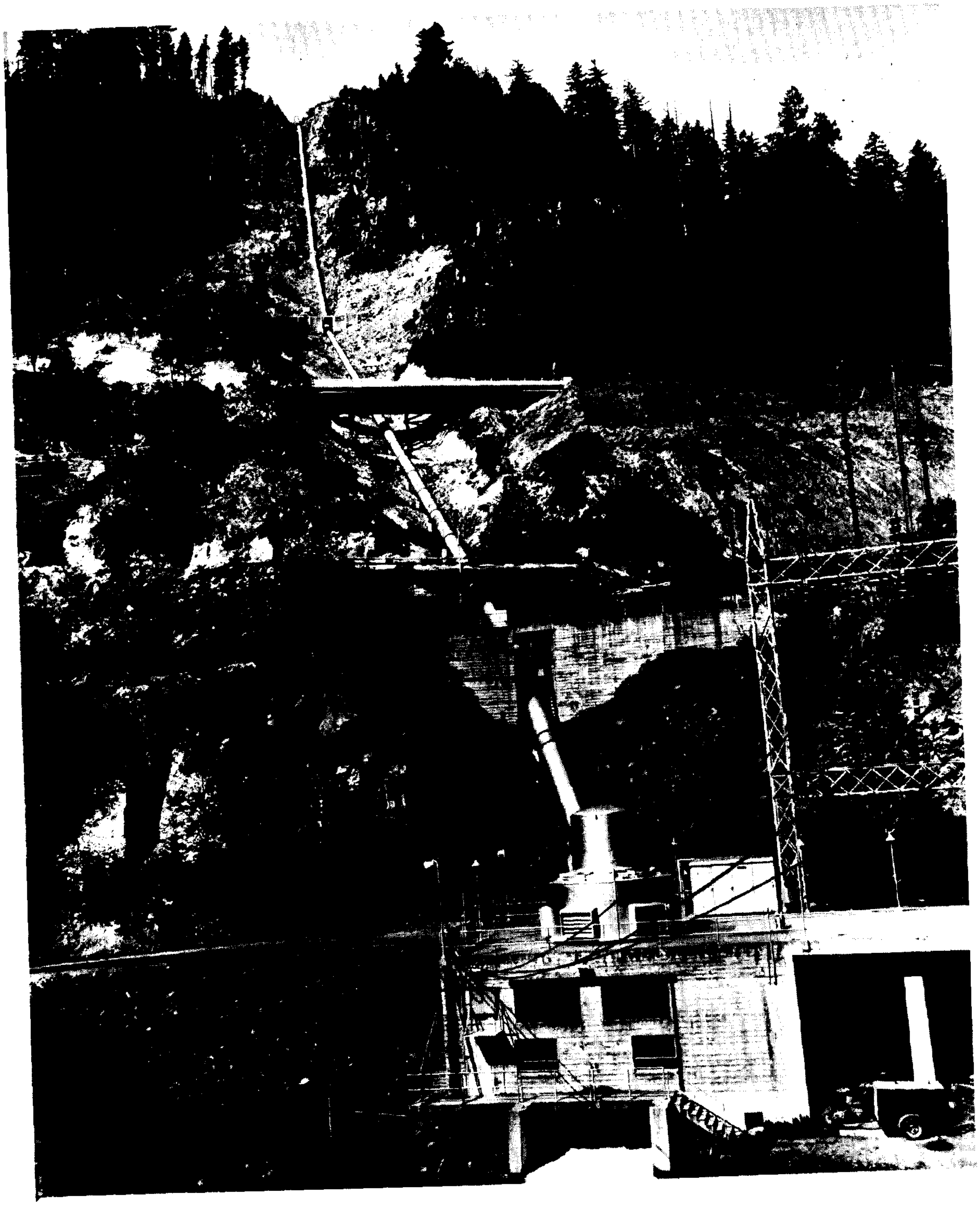

Figure 2-22. Penstock and outdoor powerhouse, Fish Creek Project (Courtesy of Pacific Power and Light Company)

f. Surge Tanks.

(1) Flow through a penstock can change rapidly during the operation of a power project. As long as flow is steady and constant, pressure changes on the conveyance conduit are minimal. However, pressure changes within the conduit become greater as the rate of change of flow increases. This phenomenon is known as water hammer and is caused by a change of momentum within the water column. When the changes in flow are gradual, water hammer problems are usually minor. However, when there are rapid changes in flow, water hammer effects can become serious. Surge tanks are sometimes constructed on the conduit to reduce momentum changes due to water hammer effects (see Figure 2-23).

(2) Water hammer effects start at the wicket gates, in response to a sudden change in loading on the generating unit, and travel up the penstock to the reservoir and then back to the turbine. Therefore, the penstocks must be designed for water hammer pressure waves. The conduit located above the surge tank also must be reinforced for water hammer effects, as well as surge from mass oscillation (rises in

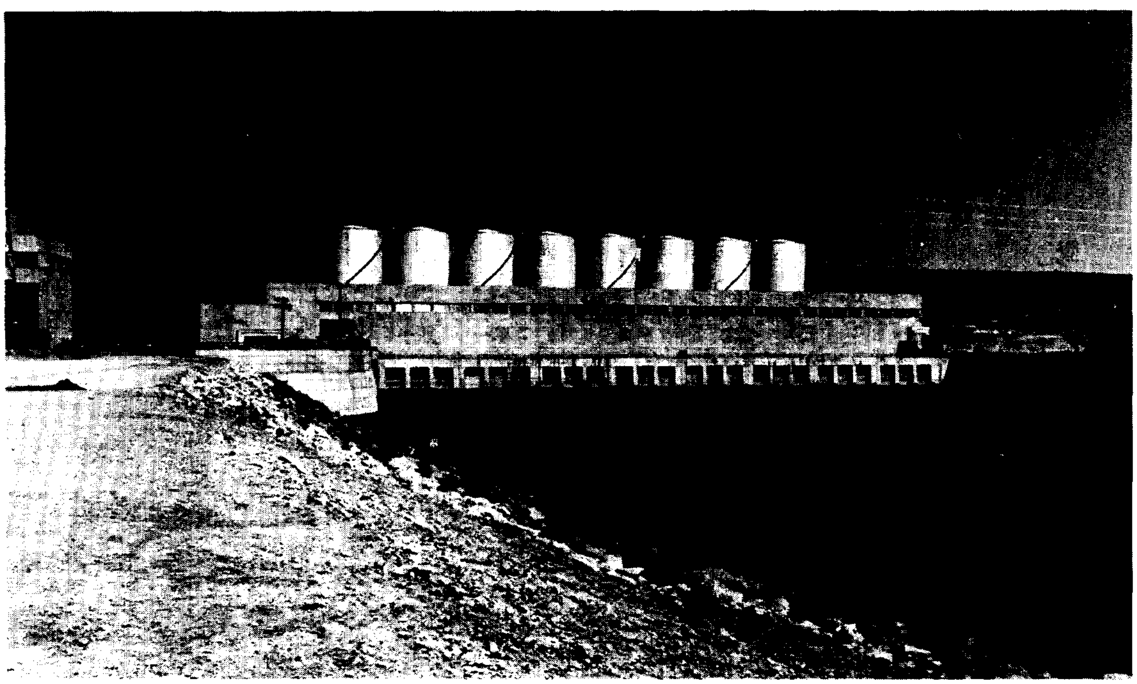

Figure 2-23. Surge tanks and indoor powerhouse, Fort Randall Dam (Omaha District)

surge tank water level). Surge tanks are often necessary in medium and high head hydropower projects, particularly where there is a considerable distance between the water source and power unit. Alternative measures, such as synchronous bypass valves, may be used for smaller installations. Surge tanks or chambers can also be provided on the draft tube where discharge conduits are very long. Additional guidance on this topic can be found in EM 1110-2-3001.

(3) A comprehensive computer program named WHAMO computes the effect of water hammer and mass oscillation at Corps of Engineers projects. Final design of powerplants should be verified by a Hydroelectric Design Center, using this program.

g. Powerhouse.

(1) General. The powerhouse shelters the turbines, generating units, control and auxiliary equipment, and sometimes erection and service areas. The powerhouse location and size is determined by site conditions and project layout. It could be located within the dam structure, adjacent to it, or some distance away from the dam. The powerhouse would be located to economically maximize available head while observing site physical and environmental constraints.

(2) Powerhouse Type. There are four types of powerhouse structures, three of which are classified according to how the main generating units are housed.

- Indoor. This type of structure encloses all of the powerhouse components under one roof (Figure 2-23).

- Semi-outdoor. This powerhouse has a fully enclosed generator room. The main hoisting and transfer equipment is located on the roof of the plant and equipment is handled through hatches located in the roof (see Figure 2-24).

- Outdoor. A generator room is not provided with this type of powerhouse structure. Generators are inclosed in weatherproof individual cubicles or enclosures and are recessed into the powerhouse floor (see Figure 2-22).

- Underground. This type of powerhouse is often used in mountainous areas where there is limited space available to locate a powerplant (Figure 2-25). It is also used to minimize penstock length in these areas because it can often be located directly below the reservoir. Pumped-storage powerhouses are often located underground in order to shorten the penstock and obtain deep settings on the turbines.

The selection of powerhouse structure should be based upon both fixed and operation and maintenance (O&M) costs. The lower capital cost associated with outdoor and semi-outdoor plants is often offset by increased equipment and O&M costs. The final selection of powerhouse type for any given site would be made after a detailed cost study, usually performed in the design memorandum stage.

(3) Erection Bay. The erection bay is an area provided for the assembly and disassembly of major generating components. It is often located at one end of the generator room, and generally at the same floor elevation. Erection areas at smaller powerplants are often built outside the powerhouse. The length of an erection bay is approximately equal to at least one generator bay. Its exact area is determined by providing space for all individual powerplant parts which may be removed during an overhaul period. Vertical clearance

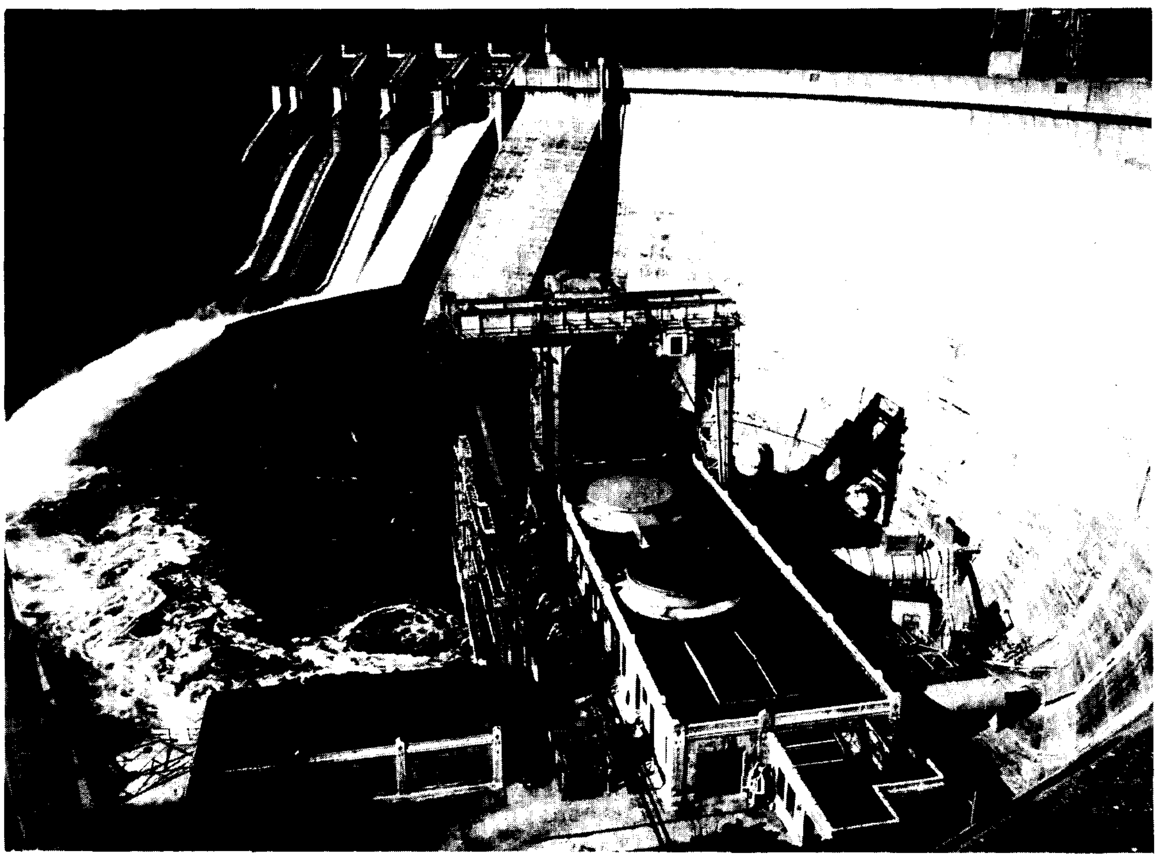

Figure 2-24. Semi-outdoor powerhouse and overhead crane, Merwin Dam (Courtesy of Pacific Power and Light Company)

should be sufficient to disassemble the turbines and generators. Erection bays at large power projects are usually constructed within the powerhouse.

(4) Service Areas. Service areas include offices, control and testing rooms, storage rooms, maintenance shops, auxiliary equipment rooms, and other areas for special uses. The amount of space required is a function of the size and location of the project, but space for service requirements is normally small at small hydropower installations. A separate service building can frequently be constructed at a cost savings due to flexibility in site location. However, space will still be required in the main powerhouse structure for the service equipment required by the generating unit.

Figure 2-25. Underground powerhouse, Snettisham Project (Alaska District)

h. Draft Tube and Tailrace. The powerhouse discharges water into the tailrace or tailwater. The draft tube conveys the water from the discharge side of the turbine to the tailrace. It is normally a part of the powerhouse structure, and is designed to minimize exit losses. The tailrace could be an open stream, the reservoir of a downstream project, a canal, or, in the case of an underground powerhouse, a tunnel. The primary function of the tailrace is to maintain a minimum tailwater elevation below the power plant and to keep the turbine's draft tube submerged. It is important to keep the draft tube submerged, even when there is no flow in the downstream channel or tailrace, in order to improve turbine startup performance. This can be done by excavating the channel immediately downstream of the powerplant so that an adequate water depth will be maintained, or by including a control structure to maintain tailwater at a constant elevation. Impulse or pelton turbines rotate in the open air, rather than underwater, so tailwater would not be maintained on the turbine discharge. At projects having a wide range of tailwater elevation, tailwater may at times encroach on the turbine runner. When this occurs, air under pressure is maintained in the turbine enclosure in order to keep the water level down.

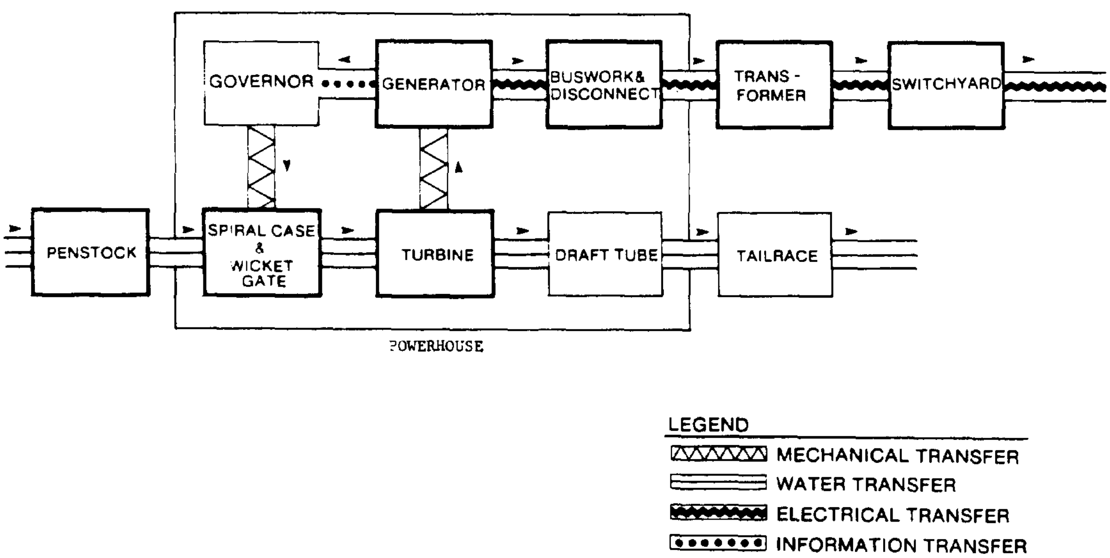

Figure 2-26. Powerhouse systems network

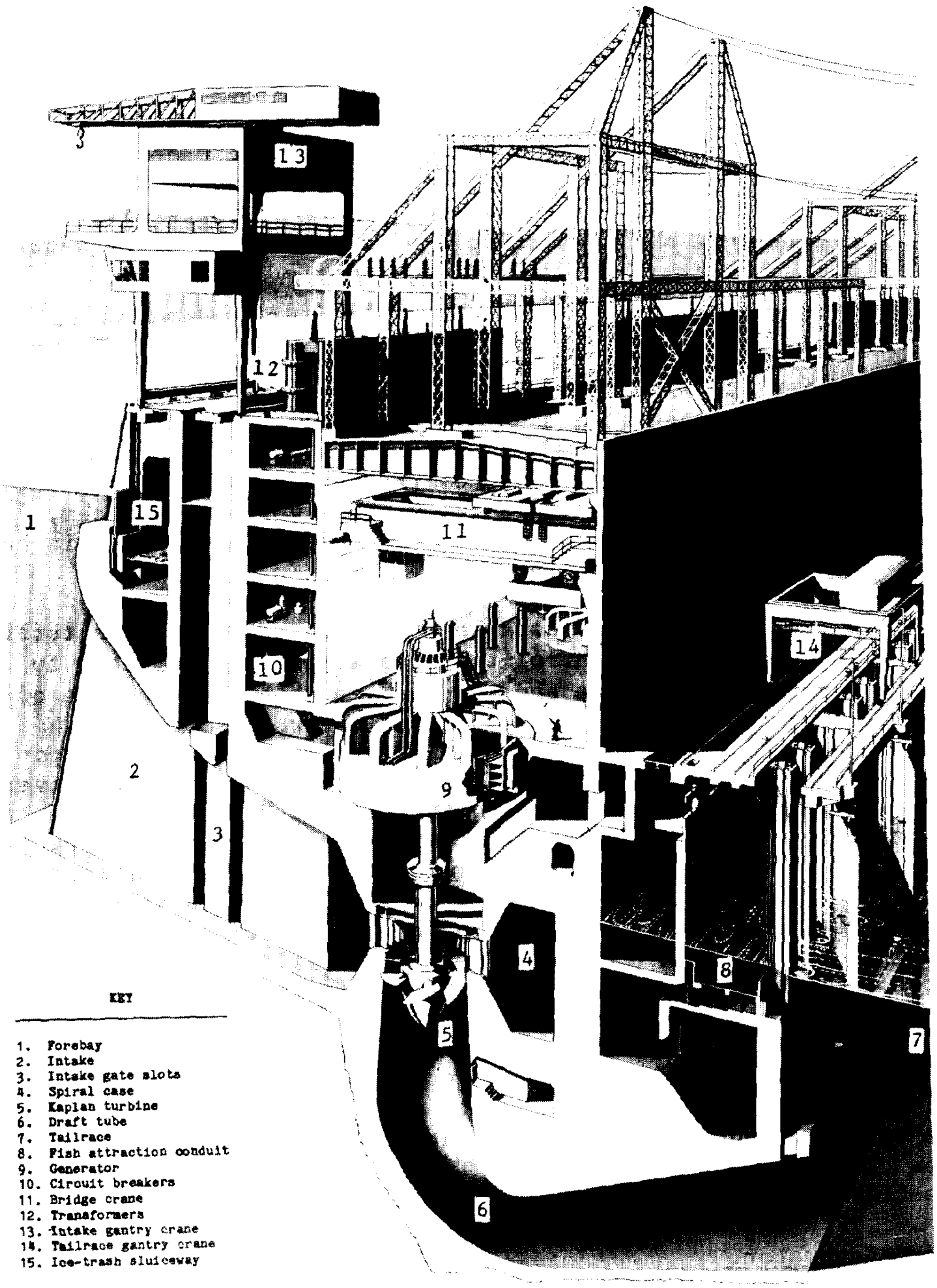

Figure 2-27. Cross-section of The Dalles powerhouse (Portland District)

2-5. Components of a Powerhouse.

a. General. Figure 2-26 shows the two major powerhouse systems and how they interrelate. The water-related (hydraulic) system is indicated by the lower level of boxes, and the electrical system is represented by the upper series of boxes. These two major systems are interconnected by mechanical transfers at the governor and generator. The primary flow of energy is represented by those boxes with a heavy outline. Figure 2-27 shows an example of a powerhouse cross section.

b. Spiral Case and Wicket Gates.

(1) The spiral case and wicket gates (Figure 2-28) are used in reaction turbines to direct and control the water entering the turbine runner. The spiral case is a steel-lined conduit connected to the penstock or intake conduit, and it distributes flow uniformly into the turbine. "Semi-spiral" cases, made of reinforced formed concrete, are used in powerhouses that pass relatively large volumes of water, usually at heads of 100 feet or less. The spiral case design is based upon the type and size of turbine used.

(2) Wicket gates are adjustable vanes that surround the turbine runner entrances and they control the area available for water to enter the turbine. This area and the head establish the volume of water that produces energy. The amount of water passing into the turbine at a specific wicket gate opening will vary depending upon the head on the unit. Wicket gate settings are controlled by the governor (or gate positioner, if frequency control is not required). When the wicket gates are fully open, the turbine is said to be operating at "full gate". Wicket gates in the form of pie-shaped radial segments control the flow tubular type axial-flow turbines (such as bulb, pit, and rim units) and units with "S" type draft tubes.

c. Turbine. The turbine converts the potential energy of water into mechanical energy, which in turn drives the generator. Water under pressure enters the turbine through the wicket gates and is discharged through the draft tube after its energy is extracted. The amount of power the turbine is able to produce depends upon the head on the turbine, the rate of flow of water passing through the unit, and the efficiency of the turbine. Types of turbines and their uses are described in Section 2-6.

d. Generator.

(1) General. The generator converts the mechanical power produced by the turbine into electrical power. The two major components of the generator are the rotor and stator. The rotor is the rotating assembly, which is attached by a connecting shaft to the

turbine, and the stator is the fixed portion of the generator (Figure 2-29). The generator is coupled as closely as possible to the turbine in order to minimize costs and mechanical problems. The two major types of generators are briefly described below.

Figure 2-28. Spiral case and wicket gates, Norris Dam. This is an older plant (1936) featuring riveted rather than welded construction, but the photo dramatically illustrates the shape of the water passageway (Courtesy of Tennessee Valley Authority)

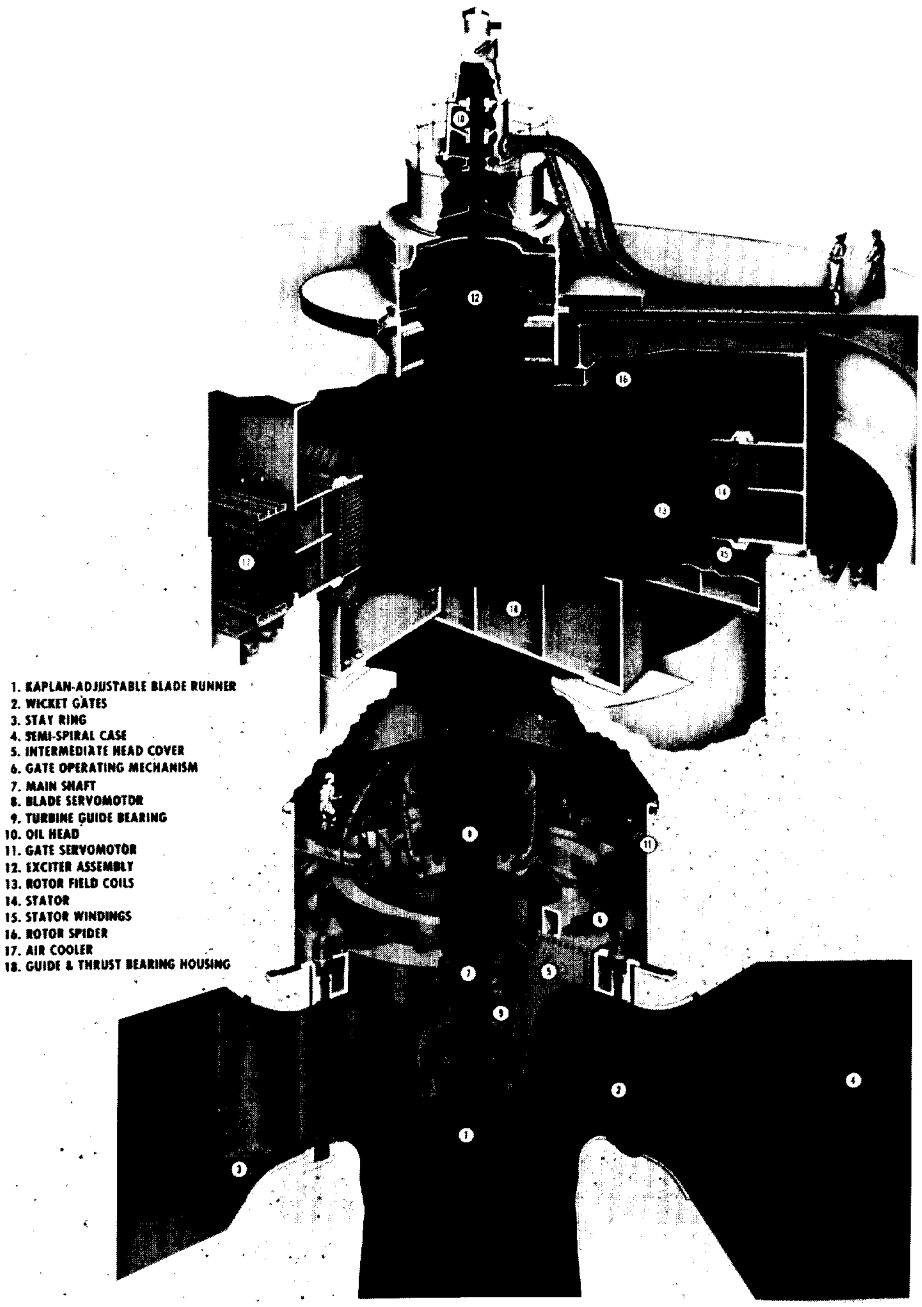

Figure 2-29. Turbine generator (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(2) Synchronous Generators. A synchronous generator is synchronized to the power system voltage, frequency, and phase angle before the generator is tied into the power grid. The generator excitation is direct current (DC). Sychronous generator excitation is controlled to provide lead and lag reactive power required by the power system for power factor correction. Synchronous generators are used in power systems where the generator output provides a significant portion of the power system load. Most generators larger than 2 MW are synchronous because they are capable of correcting the power factor of the system caused by inductive loads (motors).

(3) Induction Generators. The induction generator also consists of two parts, a rotor and a stator. The major difference between the induction and synchronous generators is that the induction generator cannot generate while disconnected from the power system, because it is incapable of providing its own excitation current. Induction generators and their associated electrical equipment are less expensive than synchronous generators but are generally limited to capacities of less than 5 MW. Induction generators cannot correct power factor.

(4) Cooling. The generator is usually cooled by passing air through the stator and rotor coils. This cooling can be assisted by passing the air through water-cooled heat exchangers. For both indoor and outdoor plants, the generator and associated cooling equipment are enclosed in a housing. Direct water cooled windings have also been successfully used on very large units. Some small units do not have an air housing, and they use powerhouse air for cooling.

e. Governor.

(1) Hydraulic turbine governors (Figure 2-31) are designed to regulate the speed and output of turbine-generator units by controlling the wicket gates to adjust water flow through the turbine. A Kaplan turbine governor also controls the turbine blade angle to maximize turbine efficiency. Governors for large units (or small units which produce a significant portion of their system's energy output) have both power and speed responsive elements. The governors sense changes in load (or speed) and respond with a movement of the wicket gates in order to maintain synchronous speed.

(2) If the turbine-generator is small compared to the size of the power system, gate and blade positioners can be used for control of the wicket gates and turbine blades.

(3) Figure 2-30 illustrates the basic governor operating sequence. If system load increases, the generator is no longer able to meet load with existing turbine inflow and the unit begins to slow

down. The governor speed sensor (3) receives a message from the speed signal generator (2), which is mounted on the generator shaft, and determines that turbine inflow must be increased so that the generator will be restored to the rotating speed required to maintain the desired system frequency. The speed sensor sends a signal to the pilot servo (4), which activates the main governor valve (5). This valve sends oil under pressure to the turbine servo motor (6), which

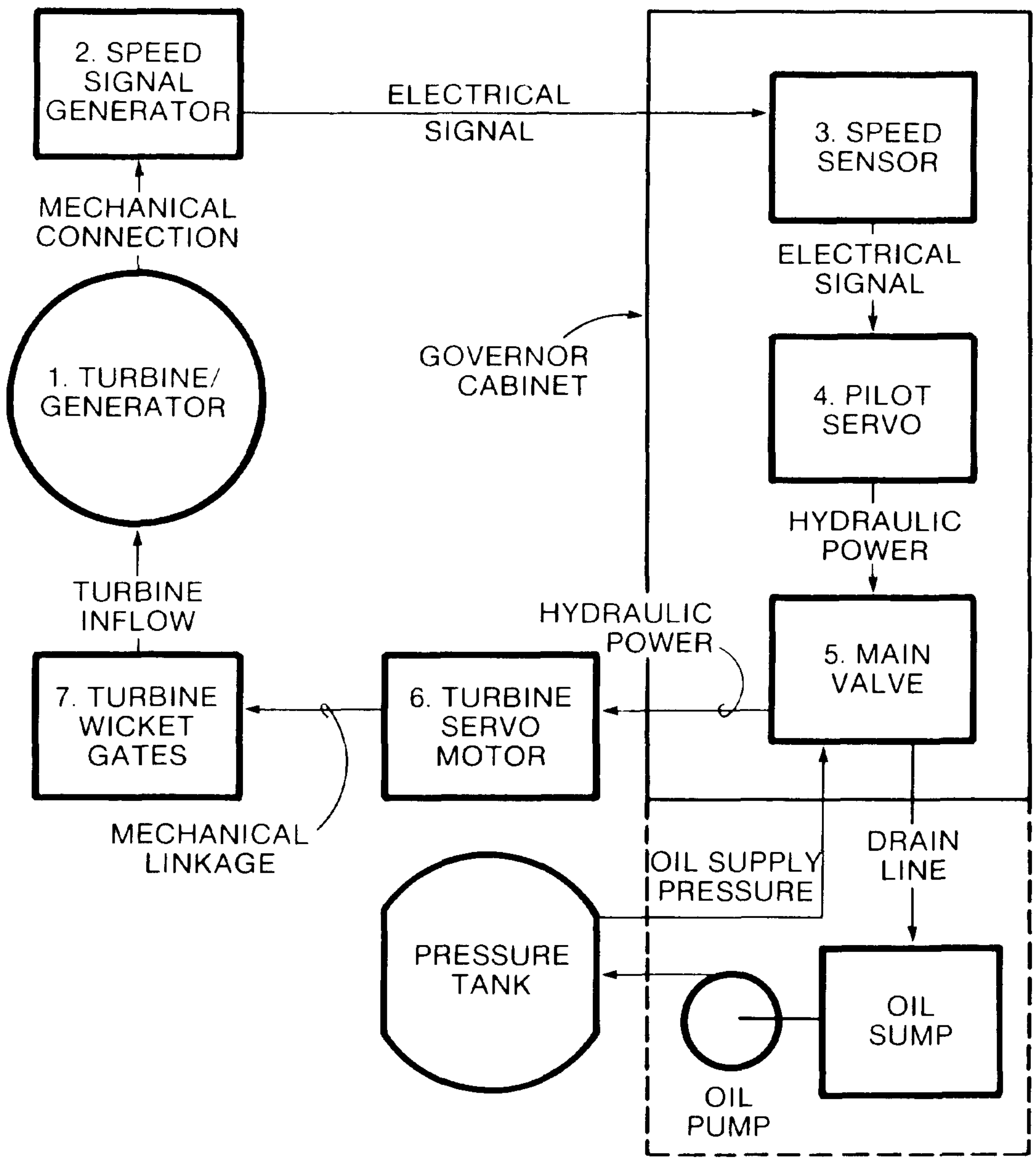

Figure 2-30. Simplified schematic diagram of governor system

operates a linkage opening the turbine wicket gates (7). With the gates open wider, more water passes into the turbine, thus generating the increased load while restoring the turbine/generator rotating speed to the level required to maintain system frequency. When the load decreases, the process serves to close the wicket gates, thus reducing turbine inflow.

(4) Most generators are synchronous and are connected to a relatively large power grid. While the turbine governors are sensitive to very small speed or load changes in the system, it is important that they be adjusted so that each governor does not attempt to correct the total system error by itself. Because of this adjustment, referred to as droop, the governor action alone does not

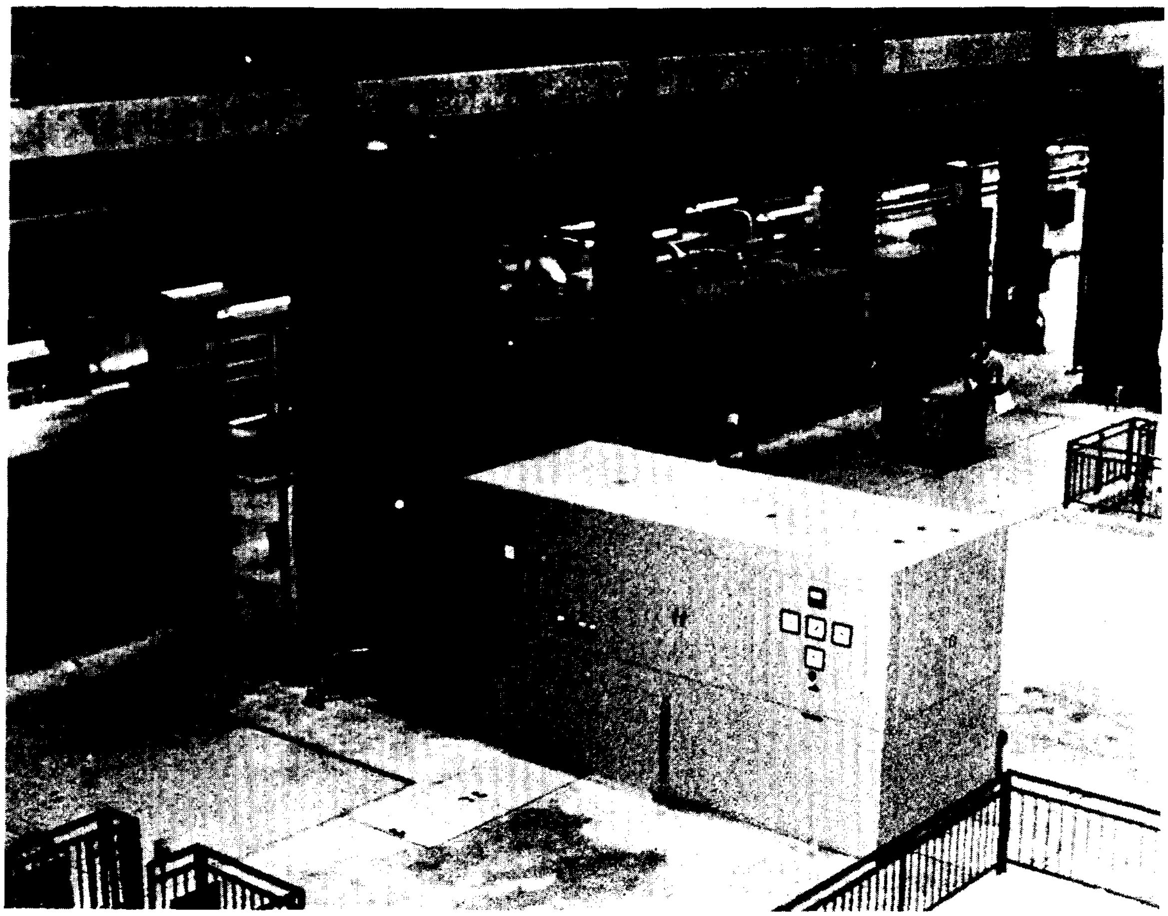

Figure 2-31. Turbine governor (Courtesy of Woodward Governor Company, Rockford, Illinois, U.S.A.)

return the system frequency exactly to the desired level. Automatic generation control (AGC) equipment is also used to readjust the speed set point at one or more of the system's large units or plants so that part of the effort needed to return the frequency to normal is supplied by some of the governors on droop. In an isolated system, droop is set at zero, and the governors alone maintain correct system frequency.

Figure 2-32. Generator buswork and circuit breakers (Bonneville second powerhouse, Portland District)

(5) In many cases, however, the amount of control that a governor has over the unit's power loading is limited. Most generators are synchronous and are connected to a relatively large power grid, and these large systems have frequency excursions which are usually too small for the governor's speed sensing elements (particularly the mechanical type) to detect. In this case, automatic generation control equipment monitors system frequency and controls generation to meet the load.

(6) A simpler governing device, such as a load or speed controller, can be used for small generation units on large, stable systems. These devices rely on the system for unit stability.

f. Buswork, Circuit Breakers, and Disconnects. Buswork, circuit breakers, and disconnects link the generator to the power grid. Buswork consists of the electrical conduits that transfer power output

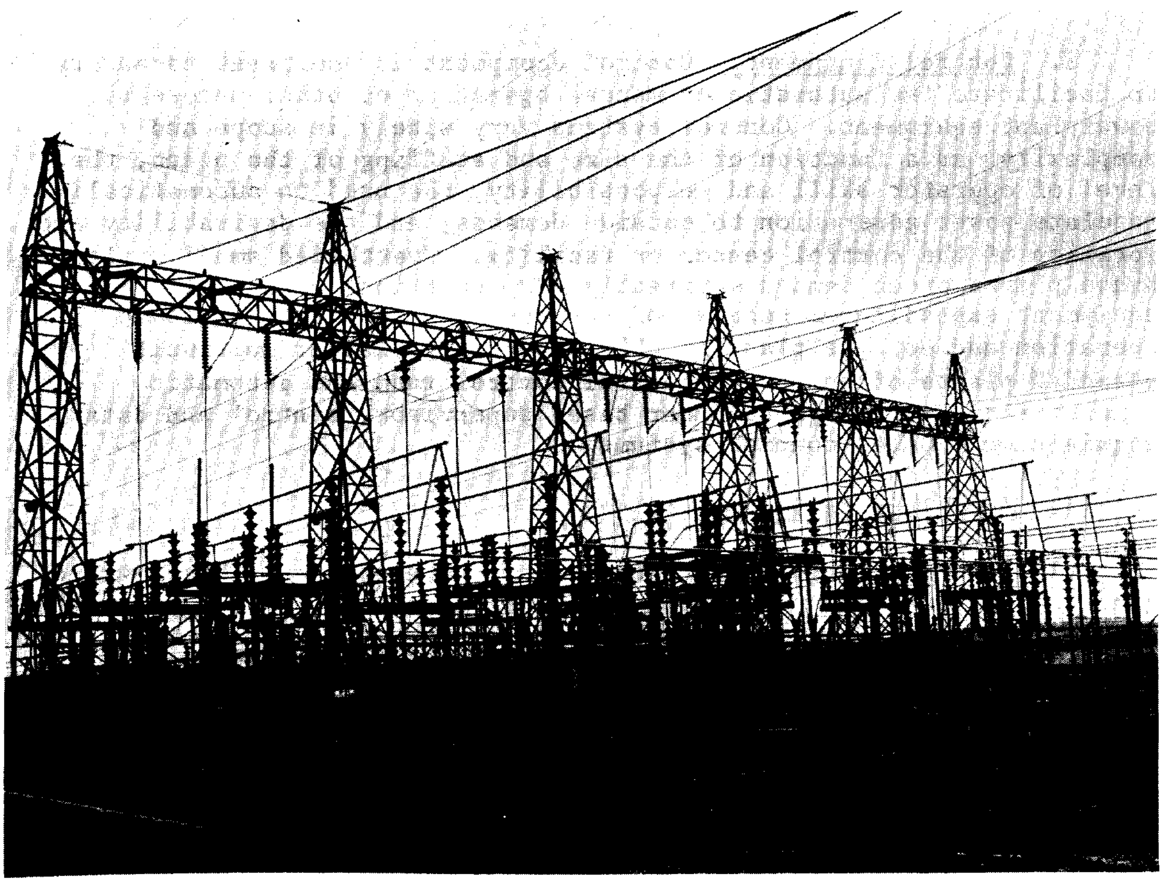

Figure 2-33. Switchyard, Fort Gibson Dam (Tulsa District)

from the generator to the step-up transformers (Figure 2-32). Disconnects or circuit breakers are switches that connect and disconnect the generator to the power grid. Circuit breakers interrupt the circuit when it is under load, and disconnects isolate equipment once the load has been interrupted.

g. Transformers. Transformers (Figure 2-34) are electrical devices that increase generator output voltage to match the voltage level of the transmission line. In most cases they are located close to the generators in order to minimize losses. Transformers are often cooled with oil-to-air fin type radiators. Fans alone or combined with oil circulating pumps may be employed to augment cooling.

h. Switchyard. The switching and delivering of power is the final link to the power grid. The switchyard (Figure 2-33) consists of line circuit breakers and disconnect switches. Often, in large powerplants, the switchyard can deliver power to a number of different transmission lines, sometimes at different line voltages.

i. Control Equipment. Control equipment is equipment necessary to facilitate the automatic or manual operation of other necessary powerplant equipment. Control systems vary widely in scope and complexity, as a function of the size and staffing of the plant, the level of operator skill and responsibility, the need to automatically regulate power generation to outside demands, and the desirability and location of the control center or facility. Unattended small scale hydro plants often demand apparently disproportionate control equipment expenditures because of the need for automatic failsafe operation and outside plant trouble reporting. Larger multiunit attended plants often have a central control room and automatic control requiring large computer based supervisory control and data acquisition (SCADA) control systems.

j. Auxiliary Equipment.

(1) Auxiliary equipment consists of the electrical, heating and ventilation, generator cooling, piping, fire protection, and drainage systems. These systems are necessary to support the primary function of the powerhouse and are located within the powerhouse. They can vary in complexity depending upon the size of powerplant. For power projects that are remotely operated, the heating, ventilating and plumbing systems are kept to a minimum. However, in plants where personnel are expected to be on duty throughout the day, these systems must be designed for human comfort.

(2) Another major piece of auxiliary equipment is the overhead crane, which is used to assemble and maintain the generating units (Figure 2-24). Permanent cranes at larger projects are included as a

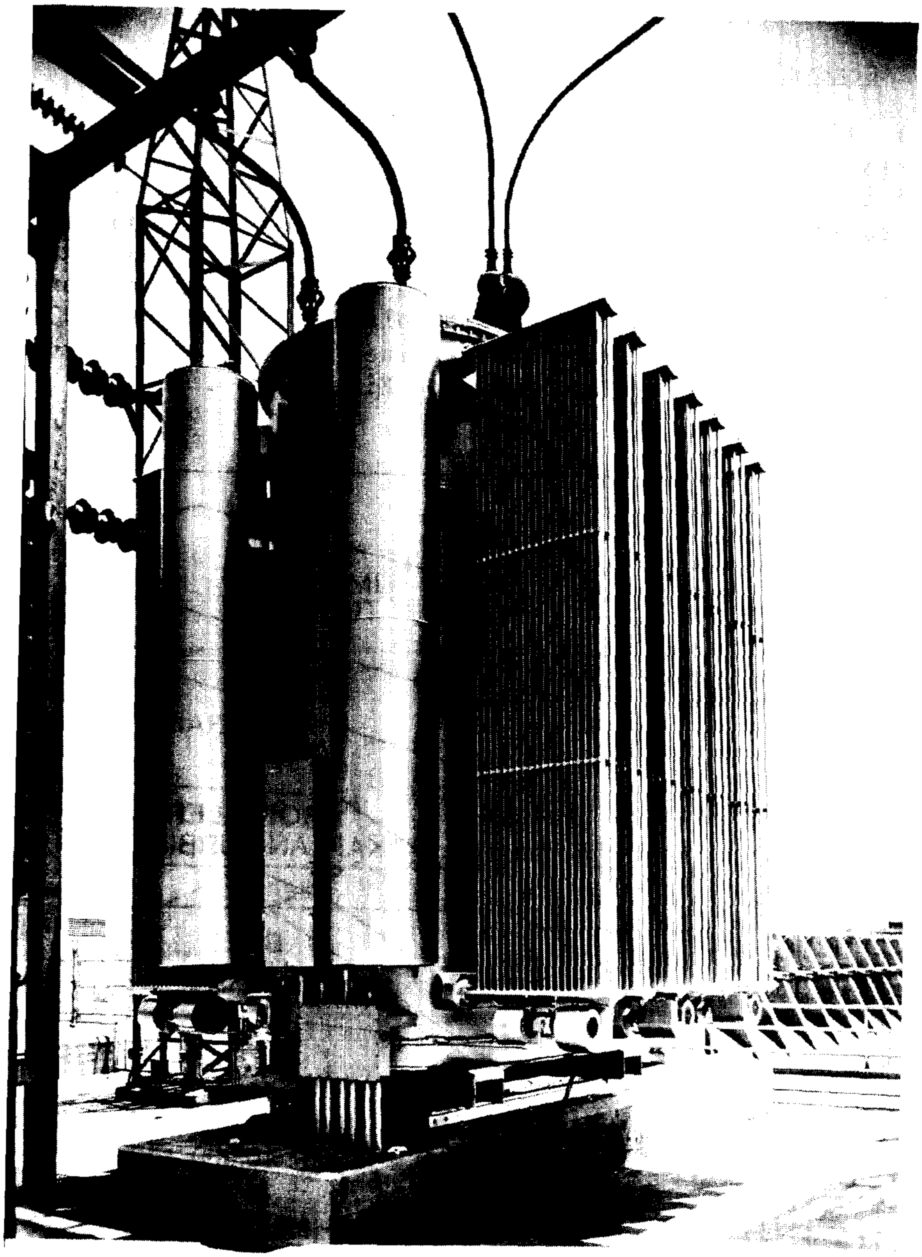

Figure 2-34. Power transformer
(Courtesy of Tennessee Valley Authority)

part of the powerhouse equipment. Mobile cranes may be brought into smaller installations when required.

2-6. Types of Turbines.

a. General.

(1) Modern turbines can develop power from almost any combination of head and flow. The many turbine models can be divided into two categories: impulse and reaction units. Impulse turbines extract power from the impact of water jets on their runners. Reaction units, in addition to extracting power from the kinetic energy of water, also are driven by the difference in pressure between the front and the back of each runner blade. The common application ranges for conventional hydraulic turbines are shown in Figure 2-35. Turbine efficiency curves are shown on Figure 2-36.

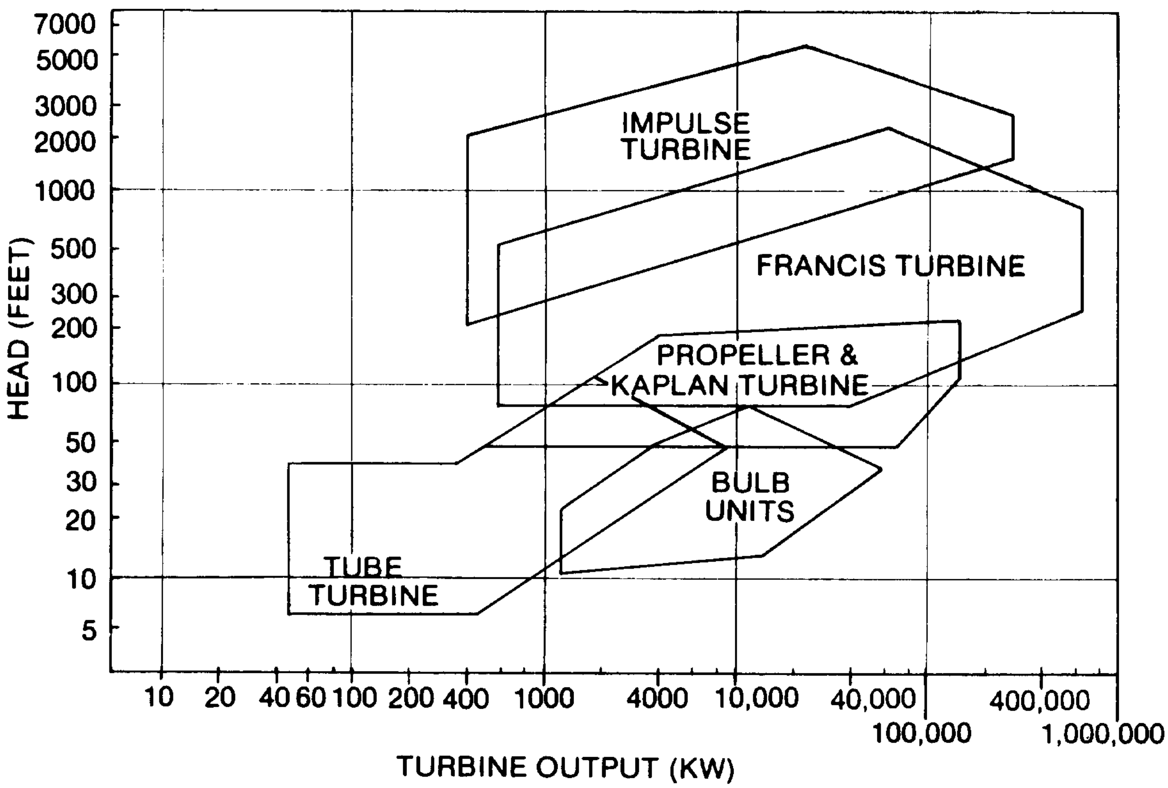

Figure 2-35. Application ranges for standard and custom hydraulic turbines (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(2) The characterisics of the major turbine types are described in the following sections, and generalized performance curves are presented for Francis, Kaplan, fixed-blade propeller, and tubular turbines. These curves are plotted in terms of percent of rated capacity, rated head, and rated discharge. As will be discussed in Section 5-5, a given turbine could be rated at any one of a variety of operating conditions. The rating points upon which Figures 2-39, 2-41, 2-43 and 2-45 are based are typical rating points for the respective types of turbines, but they do not represent the only

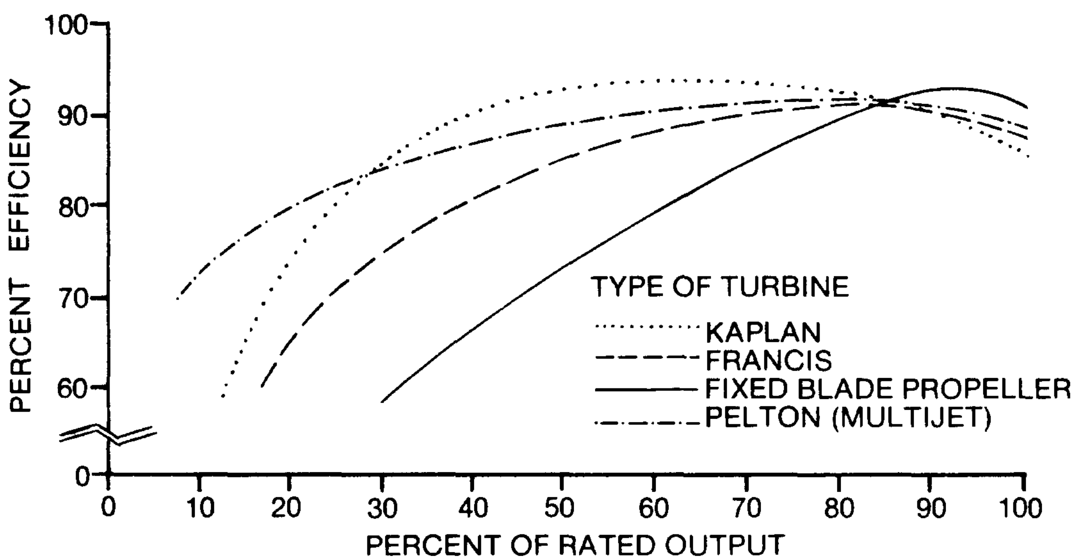

Figure 2-36. Turbine efficiency curves

points at which the units could be rated. To illustrate this, Section 5-5g describes three different ways in which a given Francis unit could be rated.

b. Impulse Turbines.

(1) The impulse turbine (commonly called Pelton turbine) has a runner with numerous spoon shaped "buckets" attached to its periphery. It is driven by one or more jets of water issuing from fixed or

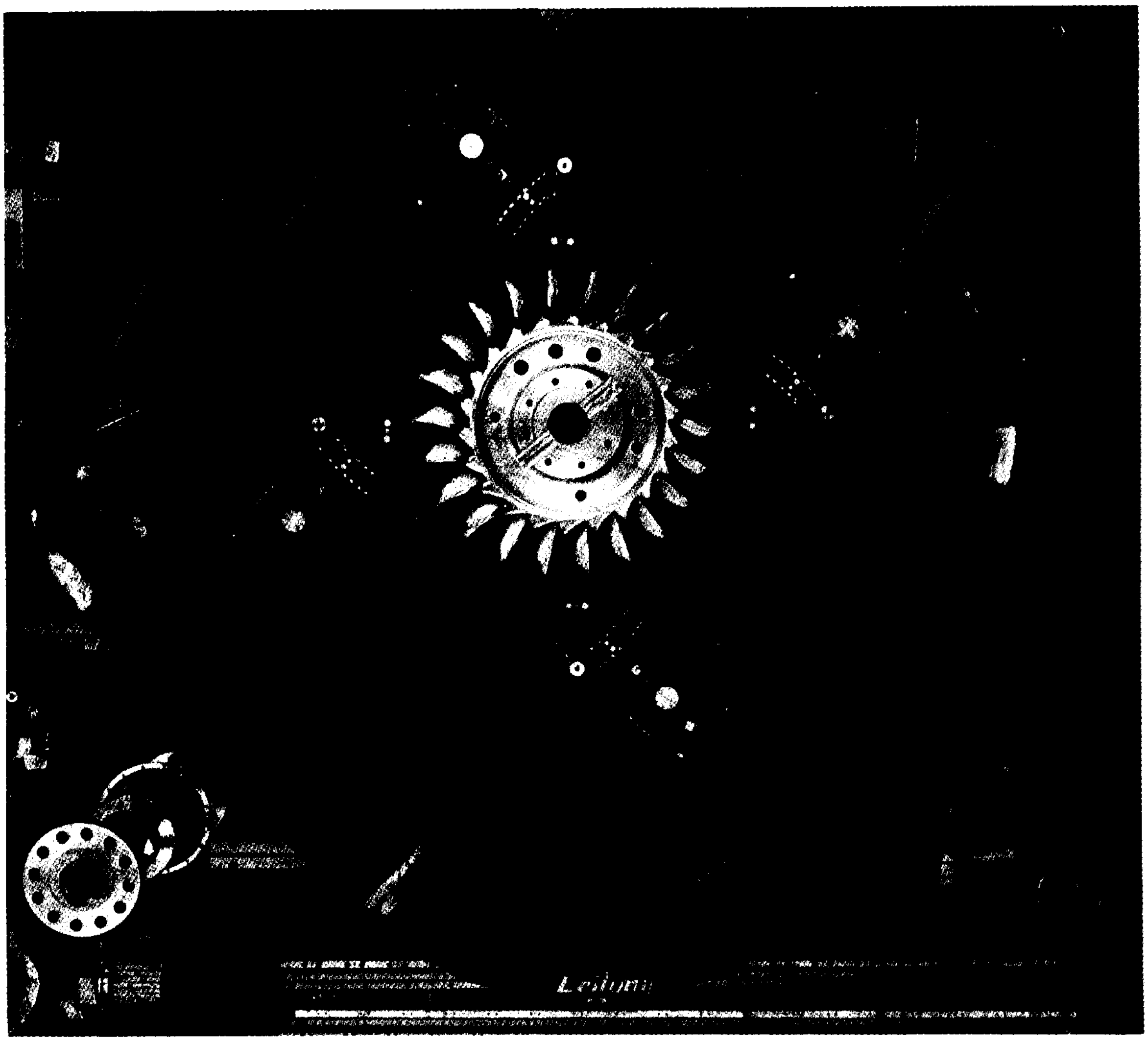

Figure 2-37. Pelton turbine and nozzle layout
(Courtesy of Sulzer-Escher Wyss Ltd.)

adjustable nozzles. A maximum of six jets can be used on vertical shaft units. A maximum of two jets may be used on horizontal shaft units in order to keep ejected water from re-entering the wheel, resulting in a loss of efficiency. A photograph of a Pelton turbine is shown in Figure 2-37.

(2) Large Pelton units are typically used at heads above 1,000 feet. Smaller "standardized" units can operate at reasonable efficiencies at heads of 100 feet and less. Impulse turbines operate best at nearly constant heads and have a relatively flat efficiency curve down to 20-25 percent of rated output, a useful characteristic where flow range is wide. Unit sizes range up to 300

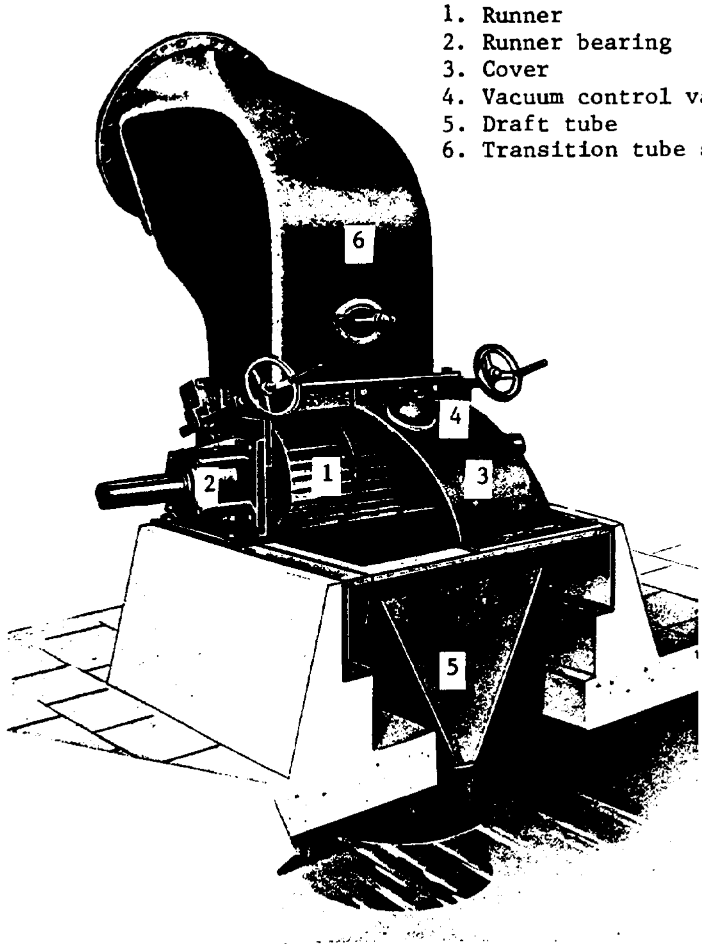

Figure 2-38. Detail view of crossflow (Ossberger) turbine (Courtesy of F. W. E. Stapenhorst, Inc., Pointe Claire, Quebec)

MW. A good source of information on estimating the size and speed of impulse turbines is the Bureau of Reclamation's Design Standards No. 6, "Turbines and Pumps."

(3) Turgo and crossflow units are also classified as impulse turbines. The Turgo is a side impulse type turbine with water jets passing through the wheel at an angle of less than 90 degrees to the shaft axis. The crossflow or Ossberger type resembles a "squirrel cage" fan. Water enters the wheel from one side, crosses through the middle, and discharges through the other side (Figure 2-38). It uses guide vanes instead of needle valves to control flow. Both of these turbines are used for lower heads than the Pelton type.

c. Reaction Turbines.

(1) Francis Turbines. The Francis turbine is constructed so that water enters the runner radially and then flows towards the center and along the turbine shaft axis. These units are most often applied under heads ranging from 100 to 1500 feet and are usually the economic choice in the 150 to 1000 foot head range. However, small Francis units can operate satisfactorily under heads as low as 20

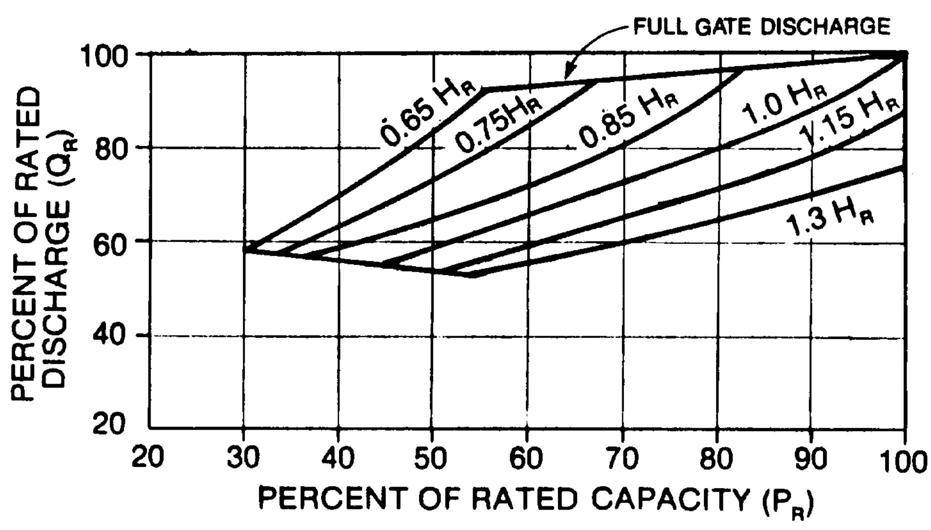

Figure 2-39. Francis turbine generalized performance curves

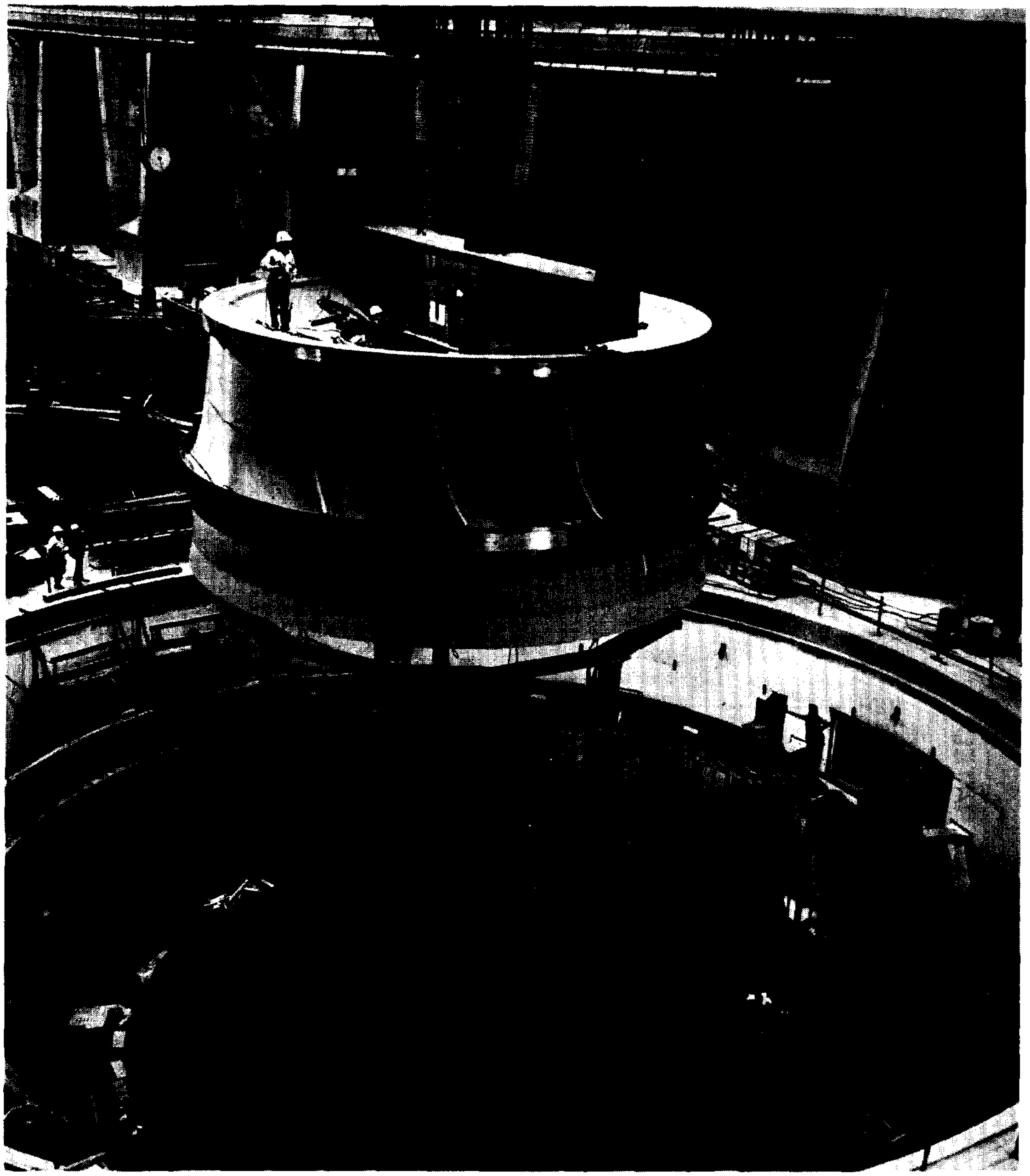

Figure 2-40. Francis turbine, Grand Coulee Dam
(Courtesy of the Bureau of Reclamation)

feet. Operational considerations limit minimum discharge to about 40 percent of rated capacity, and efficiency varies widely with head and discharge, ranging from 75 to 95 percent. The operating head range extends down to 50 percent of maximum head. Unit sizes range from 1 kW to 1000 MW. A photograph of a Francis turbine is shown in Figure 2-40 and generalized performance curves are shown in Figure 2-39.

(2) Fixed Blade Propeller Turbines. The propeller turbine passes water through its propeller blades in an axial direction. Propeller turbines can be designed for heads ranging from 10 to 200 feet but are usually an economic choice in the 50 to 150 foot head range. Units as small as 0.5 MW can be obtained, but most are 10 MW or larger (up to 150 MW). A fixed blade propeller turbine has a sharply peaked efficiency curve in comparison to Kaplan units (Figure 2-36) and operates efficiently over a limited range of output. Therefore, it is normally used where it can be operated close to its design discharge. Its normal head range varies down to 40 percent of maximum head, and the minimum discharge is typically 70 percent of full gate output. A photograph of a fixed-blade turbine is shown in Figure 2-42 and generalized performance curves are shown in Figure 2-41.

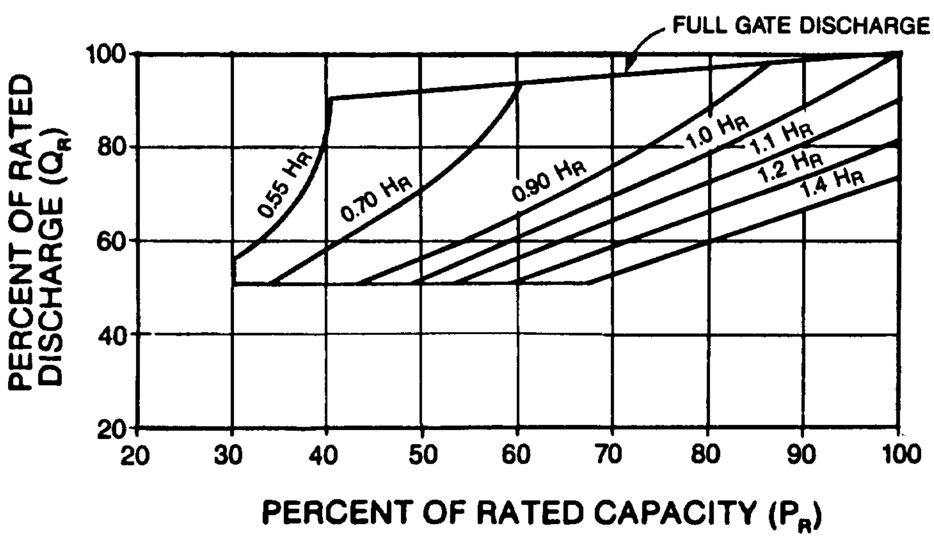

Figure 2-41. Fixed blade propeller turbine generalized performance curves

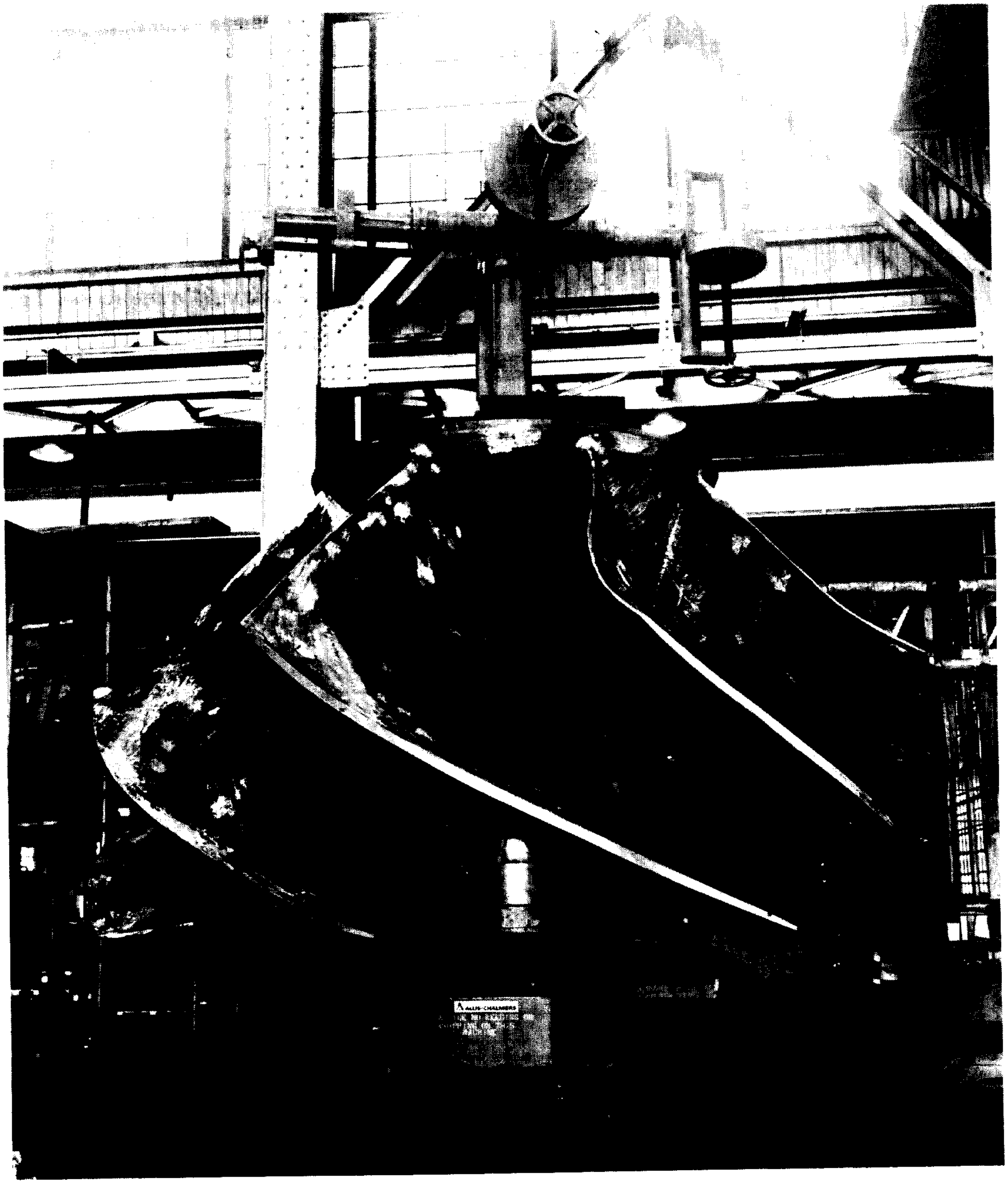

Figure 2-42. Fixed blade propeller turbine being manufactured for the Safe Harbor Project (Courtesy of Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(3) Kaplan Turbines. Kaplan turbines are propeller turbines with adjustable pitch blades which operate in the same general head range as propeller turbines. They are available in unit sizes ranging from 1 kW to 150 MW. Kaplan turbines have a relatively flat efficiency curve over a wide range of head and flow (Figure 2-36). Its normal head range varies down to 40 percent of maximum head, and its minimum discharge is about 40 percent of full gate output. Kaplan units are more expensive than fixed blade propeller units but are often the economic choice in the 50 to 150 foot head range where high efficiencies are important and where individual units must operate over a wide range of output. An example of this type of turbine is shown in Figure 2-44 and generalized performance curves are shown in Figure 2-43.

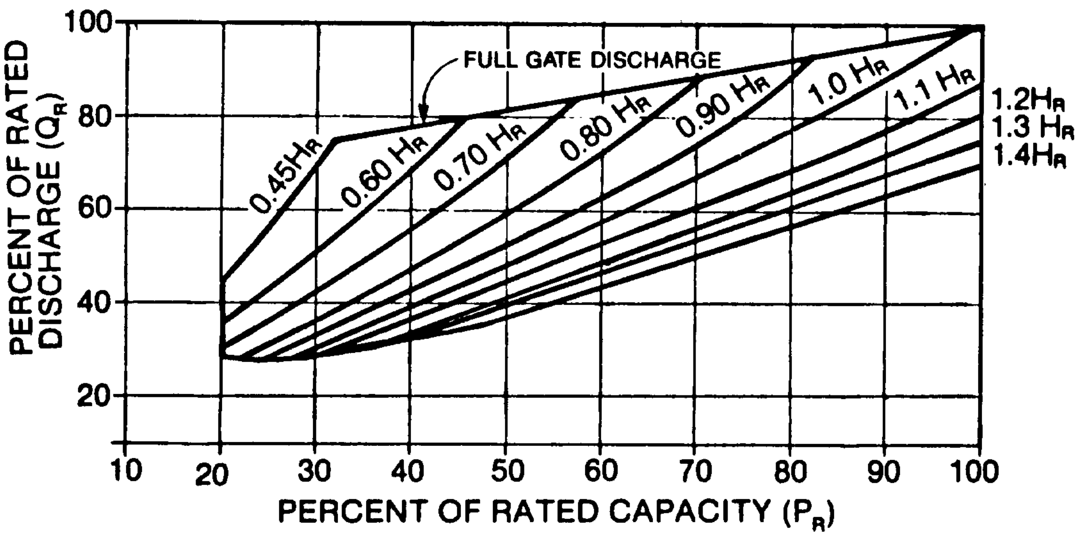

Figure 2-43. Kaplan turbine generalized performance curves

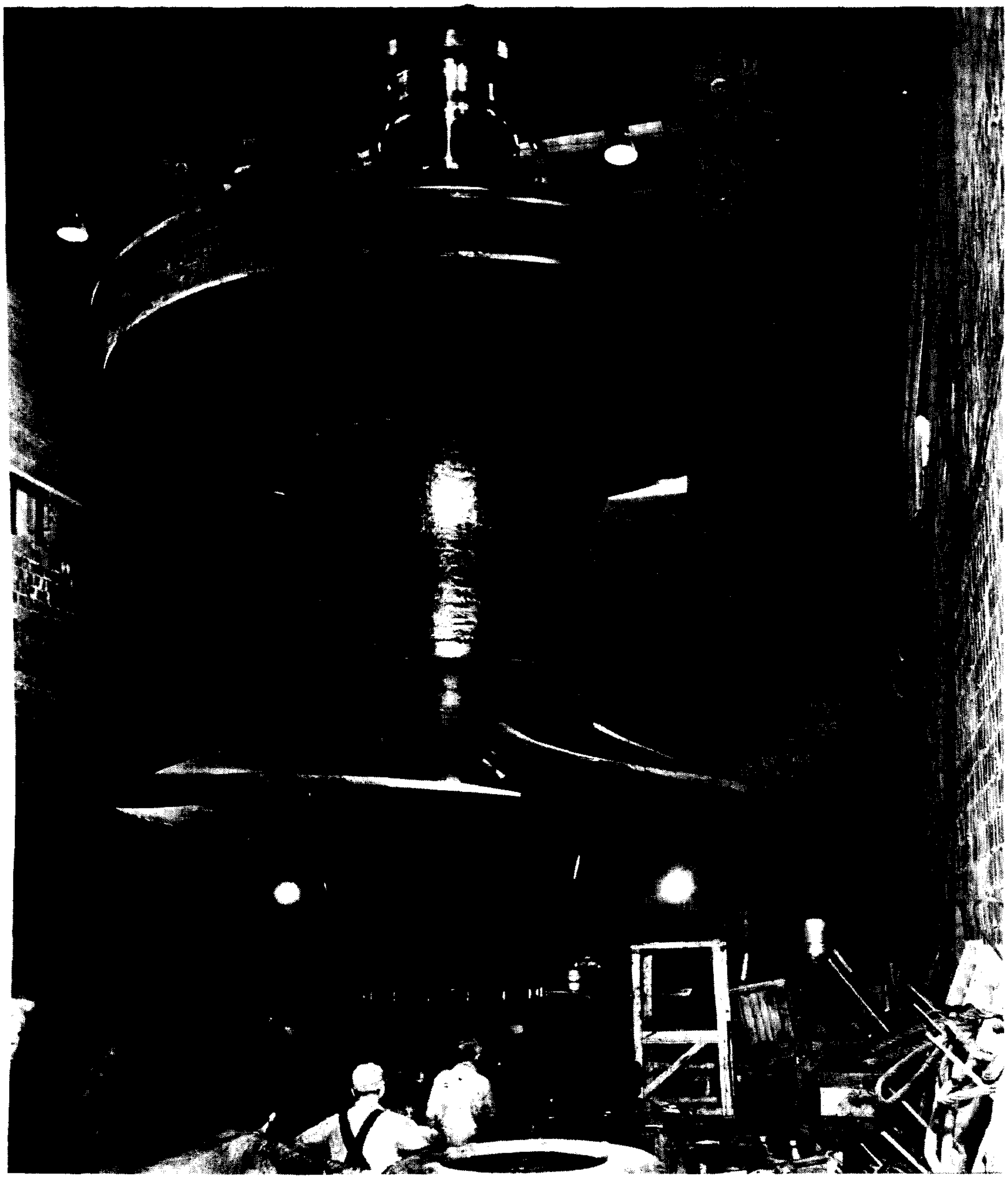

Figure 2-44. Kaplan turbine runner, Chickamauga Dam
(Courtesy of the Tennessee Valley Authority)

(4) Tubular Turbines. Tubular turbines may be vertical, horizontal, or slant-mounted axial flow units. The guide vane assembly is in line with the turbine and contributes to the tubular shape (Figure 2-46). Generators are located outside of the water passageway. Performance characteristics are similar to those of conventional propeller turbines, and both wicket gates and blades may be either adjustable or fixed in position for heads typically ranging from 10 to 50 feet and in sizes up to 10 MW. Smaller horizontal units with 'S' type draft tubes and vertical units with elbow draft tubes have been standardized to reduce costs. These turbines may have lower efficiencies than custom built units but also may be more cost effective. Tubular turbines are sometimes the economic choice for small units with heads of less than 50 feet. Generalized tubular turbine performance curves are shown in Figure 2-45.

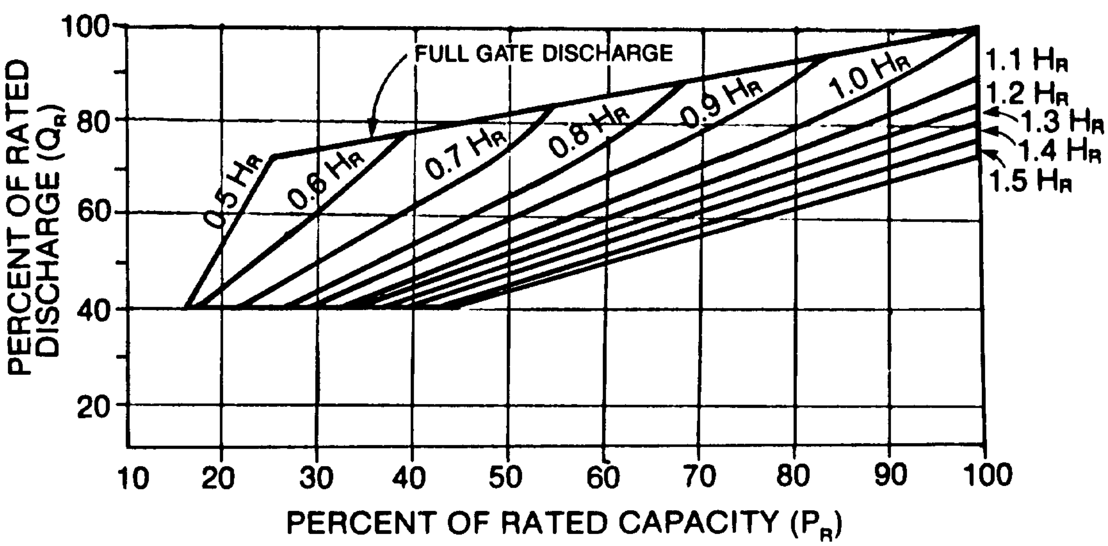

Figure 2-45. Tubular turbine generalized performance curves

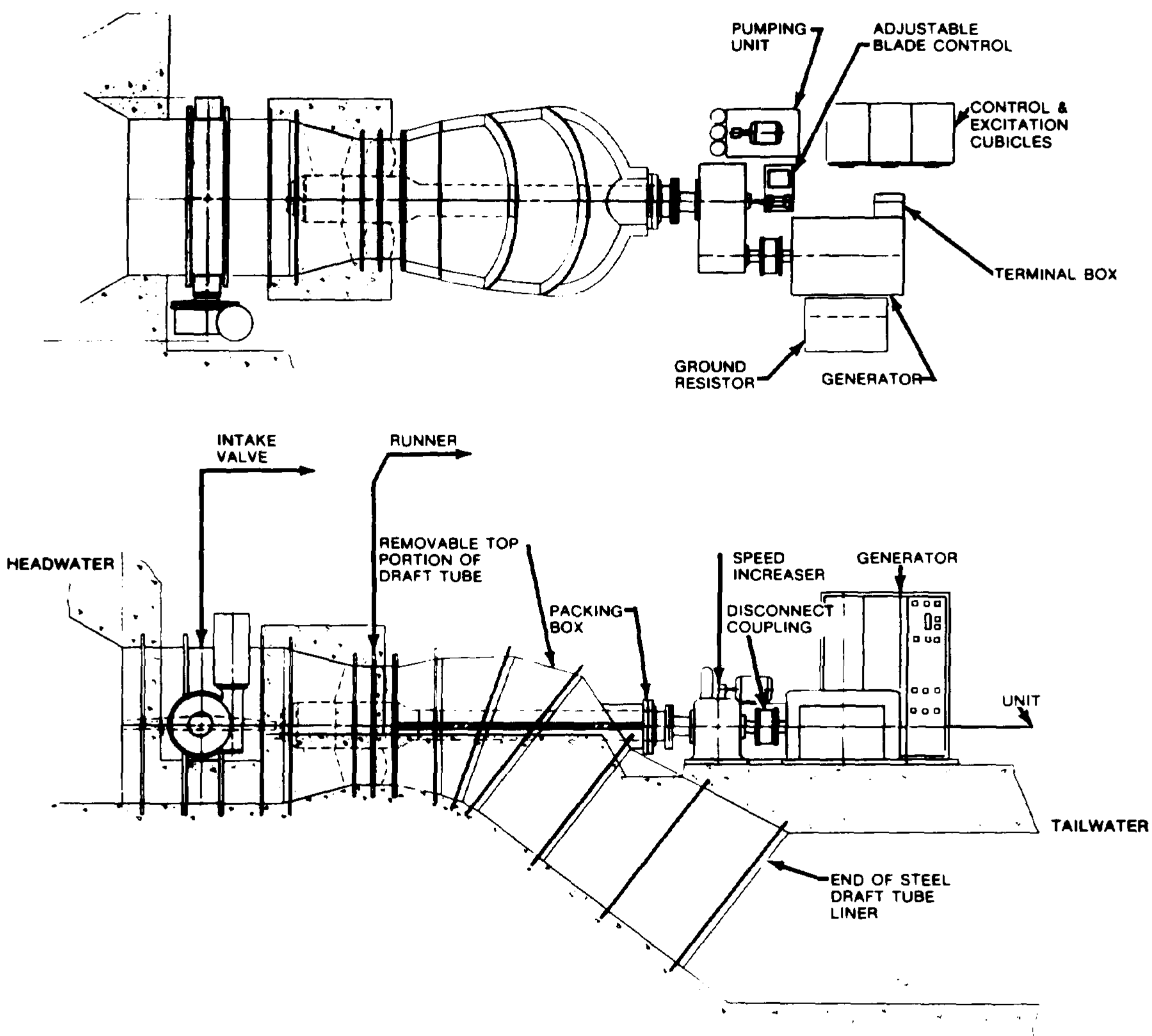

Figure 2-46. Plan and section of tubular turbine

(5) Bulb and Pit Turbines. Bulb Turbines (Figure 2-47) are horizontal axial-flow units with a turbine runner connected either directly to a generator or through a speed increasing gearbox (usually an epicyclic type). The generator and its appurtunances are housed in a water tight enclosure (or bulb) located in the water passageway. They can be considered to be a specialized, custom-built variation of the tubular turbine, but because of their shape, they have become more commonly known as bulb turbines. Fixed or variable pitch blades and wicket gates are available. Fitting a bulb turbine with a gearbox permits the generator to run at a higher speed. This results in a smaller bulb diameter and often permits the unit to be designed for easier disassembly. Performance is similar to propeller and tubular turbines, except that efficiency is increased approximately two percent over comparable propeller or Kaplan units because of an essentially straight water passageway. However, high trashrack and draft tube outlet velocities may in some cases reduce the overall system efficiency to less than that of a vertical unit. Heads of 10 to 75 feet can be utilized, and unit sizes range from 25 kW to 50 MW. Bulb turbines are frequently the best choice for large units at heads less than 50 feet due to savings in civil works costs. Some manufacturers have standardized their design of small bulb units. These units may have a right angle gear drive with the generator located outside the water passage. Pit turbines are similar to bulb turbines, except that the small upper access shafts are replaced by a single access shaft (or access "pit") large enough to permit removing some of the machinery without disassembling the bulb.

(6) Rim Turbines. The rim turbine (Figure 2-48) is similar to the bulb turbine except that the generator is mounted on the periphery of the turbine runner blades. A seal must be provided to prevent water from entering the generator. This seal is critical to the satisfactory operation of the units. Rim turbines are suitable for the 10 to 100 foot head range and sizes of up to about 20 MW. Performance characteristics are similar to those of bulb turbines. Wicket gates can be installed to regulate flow, and both fixed and adjustable pitch blades are available. The rim turbine provides the most compact powerhouse layout of any type of unit in this head range. However, the limited number of manufacturers that design and build this type of turbine may result in uncompetitive bids.

(7) Submersible Turbine-Generators. For very small plants, and/or where a unit is to be placed in a pipeline, standardized submersible axial-flow turbine-generators are available. They resemble a bulb turbine except for their size. Typical head ranges are from 20 to 50 feet and power ranges are from 20 to 500 kW are typical.

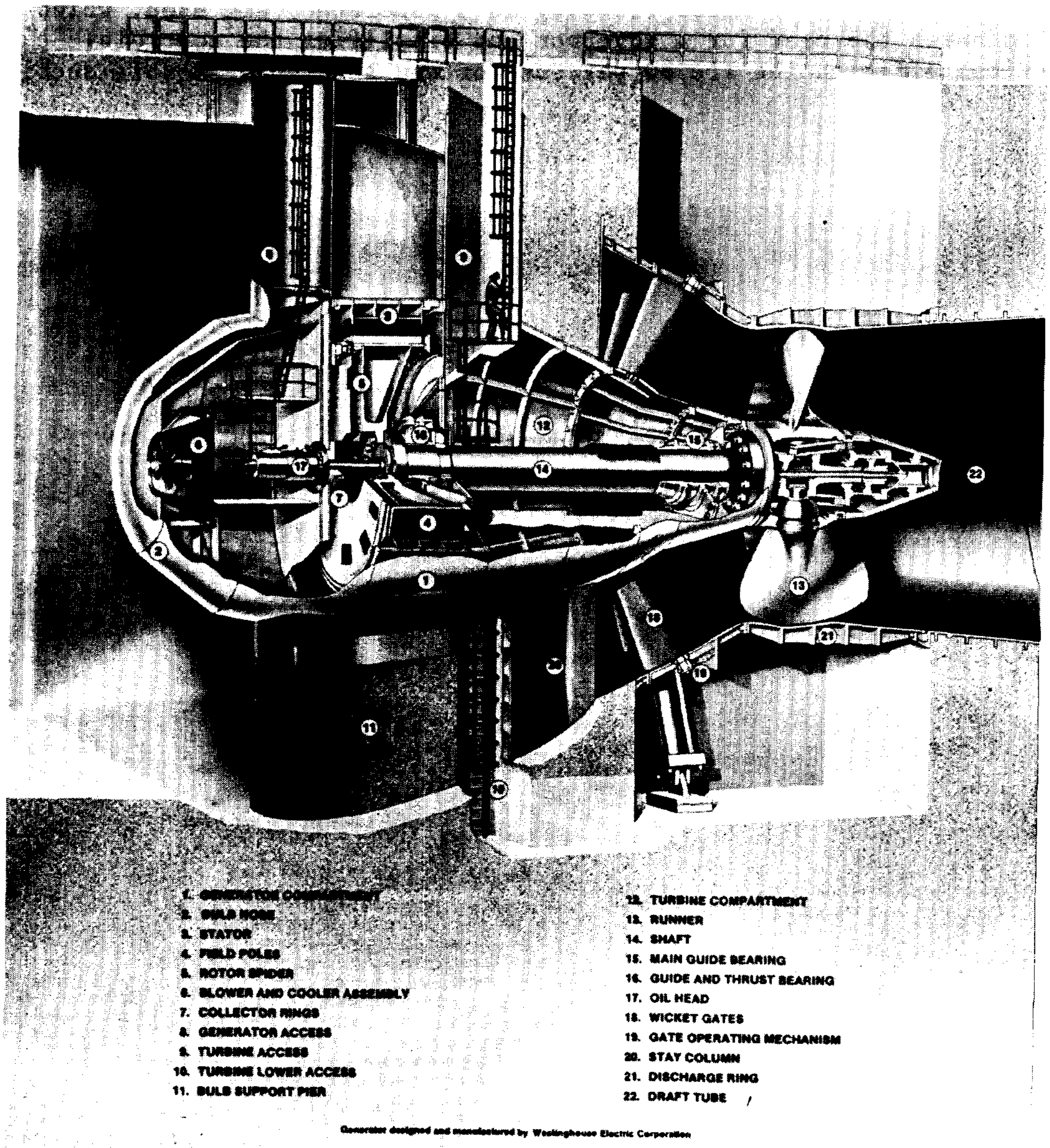

Figure 2-47. Detail view of bulb turbine (Courtesy Allis-Chalmers Corporation, Milwaukee, Wisconsin, U.S.A.)

(8) Pumps as Turbines. Pumps rotating in reverse and operating as turbines may be used for small plants where head is relatively constant. These units will deliver a fixed output of power and discharge at operating head, and multiple units of various sizes may be required to cover the available flow range. Usually a butterfly valve and induction motor (running as a generator) are used, which eliminates the need for a governor and simplifies the controls. Maximum efficiencies are 80 percent for end suction or double suction

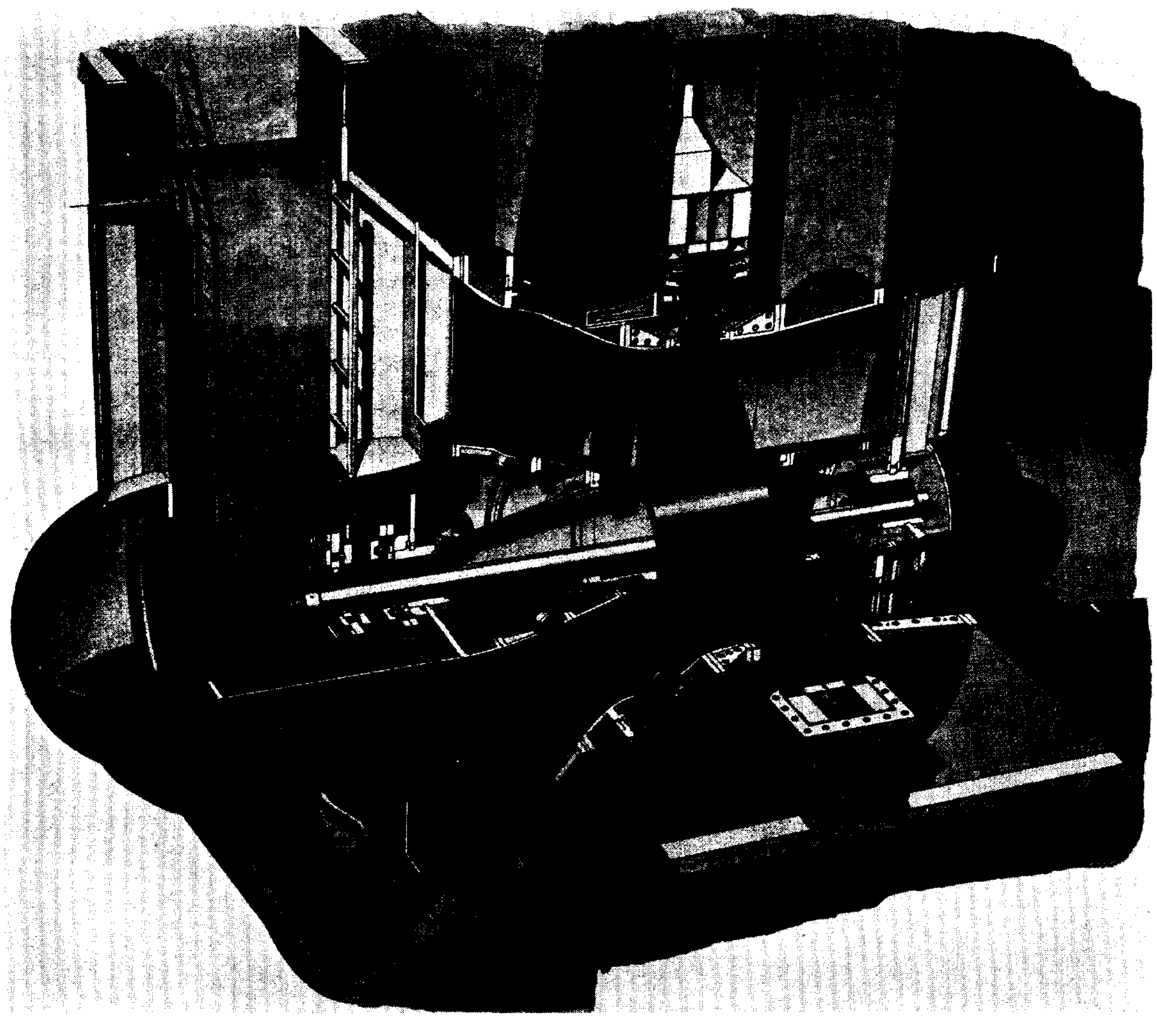

Figure 2-48. Rim turbine (Courtesy of Sulzer-Escher Wyss Ltd.)

pumps and 90 percent for axial flow propeller pumps. A diffuser cone (draft tube) is usually necessary. First costs of these turbines are quite low because they are regular pumps with minor modifications.

d. Turbine Selection. Figure 2-35 provides some general information on the types of turbines that are best suited to different operating conditions. However, it is not generally possible to apply "cookbook" procedures or rules of thumb to turbine selection because operational ranges overlap. The peculiarities of each site must be taken into account when selecting suitable turbine types. In advanced studies, it is usually desirable to consider all applicable types of units that could be adapted to the given head and plant size in order to determine which is most economical. These types of analyses should be made in conjunction with one of the Hydroelectric Design Centers. References (35), (36), (39), (60), and (64) provide further information on turbine selection and characteristics.

Figure 2-49. Fixed-blade propeller turbine being transported by bridge crane, Big Bend Dam (Omaha District)