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INTRODUCTION

1.1 PURPOSE OF THE COURSE

The objectives of a first-year, one-semester graduate course in electric power generation, operation, and control include the desire to:

1. Acquaint electric power engineering students with power generation systems, their operation in an economic mode, and their control.
2. Introduce students to the important "terminal" characteristics for thermal and hydroelectric power generation systems.
3. Introduce mathematical optimization methods and apply them to practical operating problems.
4. Introduce methods for solving complicated problems involving both economic analysis and network analysis and illustrate these techniques with relatively simple problems.
5. Introduce methods that are used in modern control systems for power generation systems.
6. Introduce "current topics": power system operation areas that are undergoing significant, evolutionary changes. This includes the discussion of new techniques for attacking old problems and new problem areas that are arising from changes in the system development patterns, regulatory structures, and economics.

Power Generation, Operation, and Control, Third Edition. Allen J. Wood, Bruce F. Wollenberg, and Gerald B. Sheblé.

1.2 COURSE SCOPE

Topics to be addressed include

1. Power generation characteristics
2. Electric power industry as a business
3. Economic dispatch and the general economic dispatch problem
4. Thermal unit economic dispatch and methods of solution
5. Optimization with constraints
6. Optimization methods such as linear programming, dynamic programming, nonlinear optimization, integer programming, and interior point optimization
7. Transmission system effects
   a. Power flow equations and solutions
   b. Transmission losses
   c. Effects on scheduling
8. The unit commitment problem and solution methods
   a. Dynamic programming
   b. Lagrange relaxation
   c. Integer programming
9. Generation scheduling in systems with limited energy supplies including fossil fuels and hydroelectric plants, need to transport energy supplies over networks such as pipelines, rail networks, and river/reservoir systems, and power system security techniques
10. Optimal power flow techniques
11. Power system state estimation
12. Automatic generation control
13. Interchange of power and energy, power pools and auction mechanisms, and modern power markets
14. Load forecasting techniques

In many cases, we can only provide an introduction to the topic area. Many additional problems and topics that represent important, practical problems would require more time and space than is available. Still others, such as light-water moderated reactors and cogeneration plants, could each require several chapters to lay a firm foundation. We can offer only a brief overview and introduce just enough information to discuss system problems.

1.3 ECONOMIC IMPORTANCE

The efficient and optimum economic operation and planning of electric power generation systems have always occupied an important position in the electric power industry. Prior to 1973 and the oil embargo that signaled the rapid escalation in fuel prices, electric utilities in the United States spent about 20% of their total revenues on fuel for the production of electrical energy. By 1980, that figure had risen to more than 40% of the total revenues. In the 5 years after 1973, U.S. electric utility fuel costs escalated at a rate that averaged 25% compounded on an annual basis. The efficient use of the available fuel is growing in importance, both monetarily and because most of the fuel used represents irreplaceable natural resources.

An idea of the magnitude of the amounts of money under consideration can be obtained by considering the annual operating expenses of a large utility for purchasing fuel. Assume the following parameters for a moderately large system:

Annual peak load: 10,000 MW

Annual load factor: 60%

Average annual heat rate for converting fuel to electric energy: 10,500 Btu/kWh

Average fuel cost: \$3.00 per million Btu (MBtu), corresponding to oil priced at 18\$/bbl

With these assumptions, the total annual fuel cost for this system is as follows:

Annual energy produced: 10^7 kW $\times$ 8760 h/year $\times$ 0.60 = 5.256 $\times$ 10^{10} kWh

Annual fuel consumption: $10,500$ Btu/kWh $\times$ 5.256 $\times$ 10^{10} kWh = 55.188 $\times$ 10^{13} Btu

Annual fuel cost: 55.188 $\times$ 10^{13} Btu $\times$ 3 $\times$ 10^{-6} \$/Btu = \$1.66 billion

To put this cost in perspective, it represents a direct requirement for revenues from the average customer of this system of 3.15 cents/kWh just to recover the expense for fuel.

A savings in the operation of this system of a small percent represents a significant reduction in operating cost as well as in the quantities of fuel consumed. It is no wonder that this area has warranted a great deal of attention from engineers through the years.

Periodic changes in basic fuel price levels serve to accentuate the problem and increase its economic significance. Inflation also causes problems in developing and presenting methods, techniques, and examples of the economic operation of electric power generating systems.

1.4 DEREGULATION: VERTICAL TO HORIZONTAL

In the 1990s, many electric utilities including government-owned electric utilities, private investor–owned electric utilities were “deregulated.” This has had profound effects on the operation of electric systems where implemented. This topic is dealt with in an entire chapter of its own in this text as Chapter 2.

1.5 PROBLEMS: NEW AND OLD

This text represents a progress report in an engineering area that has been and is still undergoing rapid change. It concerns established engineering problem areas (i.e., economic dispatch and control of interconnected systems) that have taken on new importance in recent years. The original problem of economic dispatch for thermal systems was solved by numerous methods years ago. Recently there has been a rapid growth in applied mathematical methods and the availability of computational capability for solving problems of this nature so that more involved problems have been successfully solved.

The classic problem is the economic dispatch of fossil-fired generation systems to achieve minimum operating cost. This problem area has taken on a subtle twist as the public has become increasingly concerned with environmental matters, so "economic dispatch" now includes the dispatch of systems to minimize pollutants and conserve various forms of fuel, as well as to achieve minimum costs. In addition, there is a need to expand the limited economic optimization problem to incorporate constraints on system operation to ensure the "security" of the system, thereby preventing the collapse of the system due to unforeseen conditions. The hydrothermal coordination problem is another optimum operating problem area that has received a great deal of attention. Even so, there are difficult problems involving hydrothermal coordination that cannot be solved in a theoretically satisfying fashion in a rapid and efficient computational manner.

The post–World War II period saw the increasing installation of pumped-storage hydroelectric plants in the United States and a great deal of interest in energy storage systems. These storage systems involve another difficult aspect of the optimum economic operating problem. Methods are available for solving coordination of hydroelectric, thermal, and pumped-storage electric systems. However, closely associated with this economic dispatch problem is the problem of the proper commitment of an array of units out of a total array of units to serve the expected load demands in an "optimal" manner.

A great deal of progress and change has occurred in the 1985–1995 decade. Both the unit commitment and optimal economic maintenance scheduling problems have seen new methodologies and computer programs developed. Transmission losses and constraints are integrated with scheduling using methods based on the incorporation of power flow equations in the economic dispatch process. This permits the development of optimal economic dispatch conditions that do not result in overloading system elements or voltage magnitudes that are intolerable. These "optimal power flow" techniques are applied to scheduling both real and reactive power sources as well as establishing tap positions for transformers and phase shifters.

In recent years, the political climate in many countries has changed, resulting in the introduction of more privately owned electric power facilities and a reduction or elimination of governmentally sponsored generation and transmission organizations. In some countries, previously nationwide systems have been privatized. In both these countries and in countries such as the United States, where electric utilities have been owned by a variety of bodies (e.g., consumers, shareholders, as well as government agencies), there has been a movement to introduce both privately owned generation companies and larger cogeneration plants that may provide energy to utility customers. These two groups are referred to as independent power producers (IPPs). This trend is coupled with a movement to provide access to the transmission system for these nonutility power generators as well as to other interconnected utilities. The growth of an IPP industry brings with it a number of interesting operational problems. One example is the large cogeneration plant that provides steam to an industrial plant and electric energy to the power system. The industrial-plant steam demand schedule sets the operating pattern for the generating plant, and it may be necessary for a utility to modify its economic schedule to facilitate the industrial generation pattern.

Transmission access for nonutility entities (consumers as well as generators) sets the stage for the creation of new market structures and patterns for the interchange of electric energy. Previously, the major participants in the interchange markets in North America were electric utilities. Where nonutility, generation entities or large consumers of power were involved, local electric utilities acted as their agents in the marketplace. This pattern is changing. With the growth of nonutility participants and the increasing requirement for access to transmission has come a desire to introduce a degree of economic competition into the market for electric energy. Surely this is not a universally shared desire; many parties would prefer the status quo. On the other hand, some electric utility managements have actively supported the construction, financing, and operation of new generation plants by nonutility organizations and the introduction of less-restrictive market practices.

The introduction of nonutility generation can complicate the scheduling–dispatch problem. With only a single, integrated electric utility operating both the generation and transmission systems, the local utility could establish schedules that minimized its own operating costs while observing all of the necessary physical, reliability, security, and economic constraints. With multiple parties in the bulk power system (i.e., the generation and transmission system), new arrangements are required. The economic objectives of all of the parties are not identical, and, in fact, may even be in direct (economic) opposition. As this situation evolves, different patterns of operation may result in different regions. Some areas may see a continuation of past patterns where the local utility is the dominant participant and continues to make arrangements and schedules on the basis of minimization of the operating cost that is paid by its own customers. Centrally dispatched power pools could evolve that include nonutility generators, some of whom may be engaged in direct sales to large consumers. Other areas may have open market structures that permit and facilitate competition with local utilities. Both local and remote nonutility entities, as well as remote utilities, may compete with the local electric utility to supply large industrial electric energy consumers or distribution utilities. The transmission system may be combined with a regional control center in a separate entity. Transmission networks could have the legal status of "common carriers," where any qualified party would be allowed access to the transmission system to deliver energy to its own customers, wherever they might be located. This very nearly describes the current situation in Great Britain.

What does this have to do with the problems discussed in this text? A *great deal*. In the extreme cases mentioned earlier, many of the dispatch and scheduling methods we are going to discuss will need to be rethought and perhaps drastically revised. Current practices in automatic generation control are based on tacit assumptions that the electric energy market is slow moving with only a few, more-or-less fixed, interchange contracts that are arranged *between interconnected utilities*. Current techniques for establishing optimal economic generation schedules are really based on the assumption of a single utility serving the electric energy needs of its own customers at minimum cost. Interconnected operations and energy interchange agreements are presently the result of interutility arrangements: all of the parties share common interests. In a world with a transmission-operation entity required to provide access to many parties, both utility and nonutility organizations, this entity has the task of developing operating schedules to accomplish the deliveries scheduled in some (as yet to be defined) "optimal" fashion within the physical constraints of the system, while maintaining system reliability and security. If all (or any) of this develops, it should be a fascinating time to be active in this field.

1.6 CHARACTERISTICS OF STEAM UNITS

In analyzing the problems associated with the controlled operation of power systems, there are many possible parameters of interest. Fundamental to the economic operating problem is the set of input–output characteristics of a thermal power generation unit. A typical boiler–turbine–generator unit is sketched in Figure 1.1. This unit consists of a single boiler that generates steam to drive a single turbine–generator set. The electrical output of this set is connected not only to the electric power system, but also to the auxiliary power system in the power plant. A typical steam turbine unit may require 2–6% of the gross output of the unit for the auxiliary power requirements necessary to drive boiler feed pumps, fans, condenser circulating water pumps, and so on. In defining the unit characteristics, we will talk about *gross* input versus *net* output. That is, gross input to the plant represents the total input, whether measured in terms of dollars per hour or tons of coal per hour or millions of cubic feet of gas per hour, or any other units. The net output of the plant is the electrical power output available to the electric utility system. Occasionally, engineers will develop gross input–gross output characteristics. In such situations, the data should be converted to net output to be more useful in scheduling the generation.

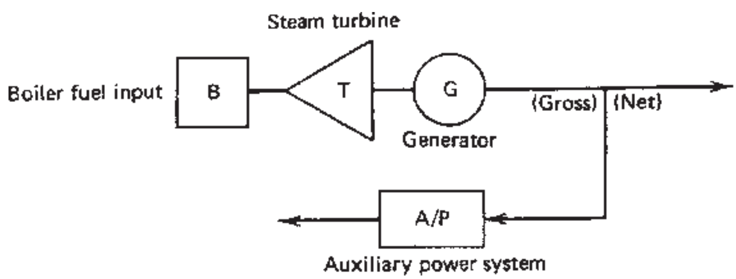


FIGURE 1.1 Boiler–turbine–generator unit.

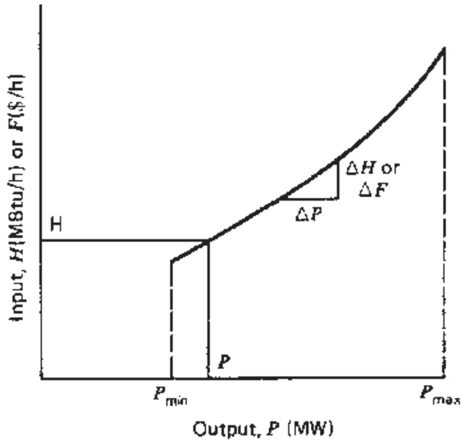


FIGURE 1.2 Input–output curve of a steam turbine generator.

In defining the characteristics of steam turbine units, the following terms will be used:

$$H = \text{Btu per hour heat input to the unit } (\text{or MBtu / h})$$
$$F = \text{Fuel cost times } H \text{ is the \$ per hour } (\$/\text{h}) \text{ input to the unit for fuel}$$

Occasionally, the $/h operating cost rate of a unit will include prorated operation and maintenance costs. That is, the labor cost for the operating crew will be included as part of the operating cost if this cost can be expressed directly as a function of the output of the unit. The output of the generation unit will be designated by P, the megawatt net output of the unit. Figure 1.2 shows the input–output characteristic of a steam unit in idealized form. The input to the unit shown on the ordinate may be either in terms of heat energy requirements [millions of Btu per hour (MBtu/h)] or in terms of total cost per hour ($/h). The output is normally the net electrical output of the unit. The characteristic shown is idealized in that it is presented as a smooth, convex curve.

These data may be obtained from design calculations or from heat rate tests. When heat rate test data are used, it will usually be found that the data points do not fall on a smooth curve. Steam turbine generating units have several critical operating constraints. Generally, the minimum load at which a unit can operate is influenced more by the steam generator and the regenerative cycle than by the turbine. The only critical parameters for the turbine are shell and rotor metal differential temperatures, exhaust hood temperature, and rotor and shell expansion. Minimum load limitations are generally caused by fuel combustion stability and inherent steam generator design constraints. For example, most supercritical units cannot operate below 30% of design capability. A minimum flow of 30% is required to cool the tubes in the furnace of the steam generator adequately. Turbines do not have any inherent overload

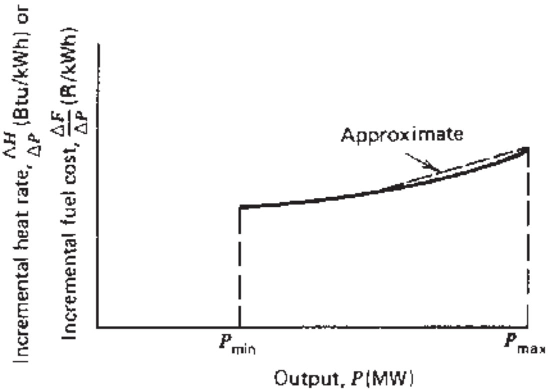


FIGURE 1.3 Incremental heat (cost) rate characteristic.

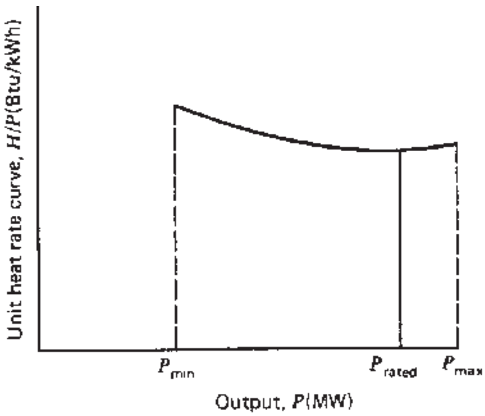


FIGURE 1.4 Net heat rate characteristic of a steam turbine generator unit.

capability, so the data shown on these curves normally do not extend much beyond 5% of the manufacturer's stated valve-wide-open capability.

The incremental heat rate characteristic for a unit of this type is shown in Figure 1.3 This incremental heat rate characteristic is the slope (the derivative) of the input–output characteristic ($\Delta H/\Delta P$ or $\Delta F/\Delta P$). The data shown on this curve are in terms of Btu/kWh (or $/kWh) versus the net power output of the unit in megawatts. This characteristic is widely used in economic dispatching of the unit. It is converted to an incremental fuel cost characteristic by multiplying the incremental heat rate in Btu per kilowatt hour by the equivalent fuel cost in terms of $/Btu. Frequently, this characteristic is approximated by a sequence of straight-line segments.

The last important characteristic of a steam unit is the unit (net) heat rate characteristic shown in Figure 1.4. This characteristic is H/P versus P. It is proportional to the reciprocal of the usual efficiency characteristic developed for

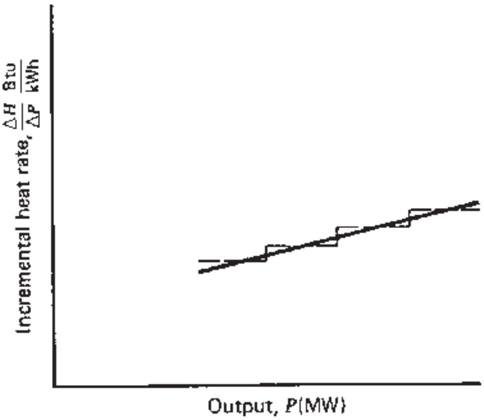


FIGURE 1.5 Approximate representations of the incremental heat rate curve.

machinery. The unit heat rate characteristic shows the heat input per kilowatt hour of output versus the megawatt output of the unit. Typical conventional steam turbine units are between 30 and 35% efficient, so their unit heat rates range between approximately 11,400 Btu/kWh and 9,800 Btu/kWh. (A kilowatt hour has a thermal equivalent of approximately 3412 Btu.) Unit heat rate characteristics are a function of unit design parameters such as initial steam conditions, stages of reheat and the reheat temperatures, condenser pressure, and the complexity of the regenerative feed-water cycle. These are important considerations in the establishment of the unit's efficiency. For purposes of estimation, a typical heat rate of 10,500 Btu/kWh may be used occasionally to approximate actual unit heat rate characteristics.

Many different formats are used to represent the input–output characteristic shown in Figure 1.2. The data obtained from heat rate tests or from the plant design engineers may be fitted by a polynomial curve. In many cases, quadratic characteristics have been fit to these data. A series of straight-line segments may also be used to represent the input–output characteristics. The different representations will, of course, result in different incremental heat rate characteristics. Figure 1.5 shows two such variations. The solid line shows the incremental heat rate characteristic that results when the input versus output characteristic is a quadratic curve or some other continuous, smooth, convex function. This incremental heat rate characteristic is monotonically increasing as a function of the power output of the unit. The dashed lines in Figure 1.5 show a stepped incremental characteristic that results when a series of straight-line segments are used to represent the input–output characteristics of the unit. The use of these different representations may require that different scheduling methods be used for establishing the optimum economic operation of a power system. Both formats are useful, and both may be represented by tables of data. Only the first, the solid line, may be represented by a continuous analytic function, and only the first has a derivative that is nonzero. (That is, $\mathrm{d}^2F/\mathrm{d}^2P$ equals 0 if $\mathrm{d}F/\mathrm{d}P$ is constant.)

At this point, it is necessary to take a brief detour to discuss the heating value of the fossil fuels used in power generation plants. Fuel heating values for coal, oil, and gas are expressed in terms of Btu/lb or joules per kilogram of fuel. The determination is made under standard, specified conditions using a *bomb calorimeter*.

This is all to the good except that there are *two* standard determinations specified:

- The higher heating value of the fuel (HHV) assumes that the water vapor in the combustion process products condenses and therefore includes the latent heat of vaporization in the products.
- The lower heating value of the fuel (LHV) does not include this latent heat of vaporization.

The difference between the HHV and LHV for a fuel depends on the hydrogen content of the fuel. Coal fuels have a low hydrogen content with the result that the difference between the HHV and LHV for a fuel is fairly small. (A typical value of the difference for a bituminous coal would be of the order of 3%. The HHV might be 14,800 Btu/lb and the LHV 14,400 Btu/lb.) Gas and oil fuels have a much higher hydrogen content, with the result that the relative difference between the HHV and LHV is higher; typically on the order of 10 and 6%, respectively. This gives rise to the possibility of some confusion when considering unit efficiencies and cycle energy balances. (A more detailed discussion is contained in the book by El-Wakil, [reference 1].)

A uniform standard must be adopted so that everyone uses the same heating value standard. In the United States, the standard is to use the HHV *except that engineers and manufacturers that are dealing with combustion turbines* (*i.e., gas turbines*) *normally use* LHVs *when quoting heat rates or efficiencies*. In European practice, LHVs are used for all specifications of fuel consumption and unit efficiency. In this text, HHVs are used throughout the book to develop unit characteristics. Where combustion turbine data have been converted by the authors from LHVs to HHVs, a difference of 10% was normally used. When in doubt about which standard for the fuel heating value has been used to develop unit characteristics—*ask*!

1.6.1 Variations in Steam Unit Characteristics

A number of different steam unit characteristics exist. For large steam turbine generators the input–output characteristics shown in Figure 1.2 are not always as smooth as indicated there. Large steam turbine generators will have a number of steam admission valves that are opened in sequence to obtain ever-increasing output of the unit. Figure 1.6 shows both an input–output and an incremental heat rate characteristic for a unit with four valves. As the unit loading increases, the input to the unit increases and the incremental heat rate decreases between the opening points for any two valves. However, when a valve is first opened, the throttling losses increase rapidly and the incremental heat rate rises suddenly. This gives rise to the discontinuous type of incremental heat rate characteristic shown in Figure 1.6. It is possible to use this

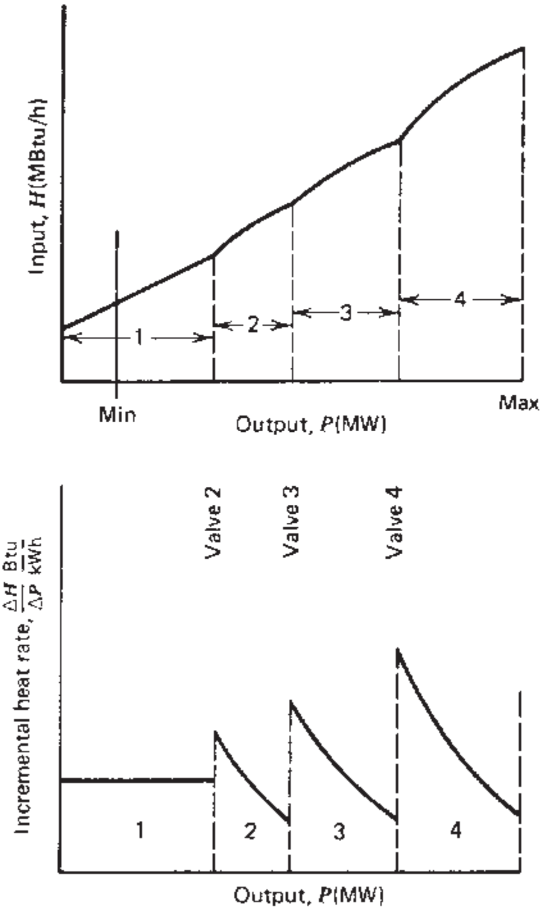


FIGURE 1.6 Characteristics of a steam turbine generator with four steam admission valves.

type of characteristic in order to schedule steam units, although it is usually not done. This type of input–output characteristic is nonconvex; hence, optimization techniques that require convex characteristics may not be used with impunity.

Another type of steam unit that may be encountered is the *common-header plant*, which contains a number of different boilers connected to a common steam line (called a common header). Figure 1.7 is a sketch of a rather complex common-header plant. In this plant, there are not only a number of boilers and turbines, each connected to the common header, but also a "topping turbine" connected to the common header. A *topping turbine* is one in which steam is exhausted from the turbine and fed not to a condenser but to the common steam header.

A common-header plant will have a number of different input–output characteristics that result from different combinations of boilers and turbines connected to the header. Steinberg and Smith (reference 2) treat this type of plant quite extensively. Common-header plants were constructed originally not only to provide a large

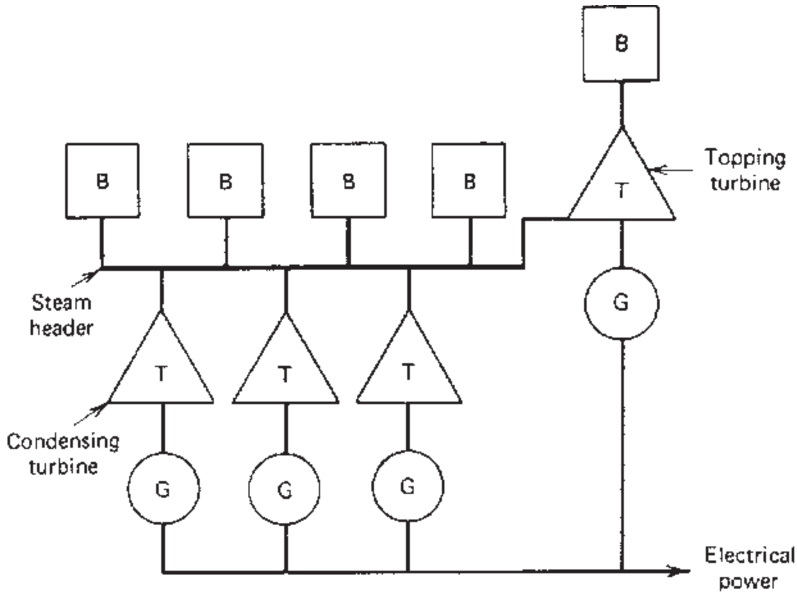


FIGURE 1.7 A common-header steam plant.

electrical output from a single plant but also to provide steam sendout for the heating and cooling of buildings in dense urban areas. After World War II, a number of these plants were modernized by the installation of the type of topping turbine shown in Figure 1.7. For a period of time during the 1960s, these common-header plants were being dismantled and replaced by modern, efficient plants. However, as urban areas began to reconstruct, a number of metropolitan utilities found that their steam loads were growing and that the common-header plants could not be dismantled but had to be expected to provide steam supplies to new buildings.

Combustion turbines (gas turbines) are also used to drive electric generating units. Some types of power generation units have been derived from aircraft gas turbine units and others from industrial gas turbines that have been developed for applications like driving pipeline pumps. In their original applications, these two types of combustion turbines had dramatically different duty cycles. Aircraft engines see relatively short duty cycles where power requirements vary considerably over a flight profile. Gas turbines in pumping duty on pipelines would be expected to operate almost continuously throughout the year. Service in power generation may require both types of duty cycle.

Gas turbines are applied in both a simple cycle and in combined cycles. In the simple cycle, inlet air is compressed in a rotating compressor (typically by a factor of 10–12 or more) and then mixed and burned with fuel oil or gas in a combustion chamber. The expansion of the high-temperature gaseous products in the turbine drives the compressor, turbine, and generator. Some designs use a single shaft for the turbine and compressor, with the generator being driven through a suitable set of

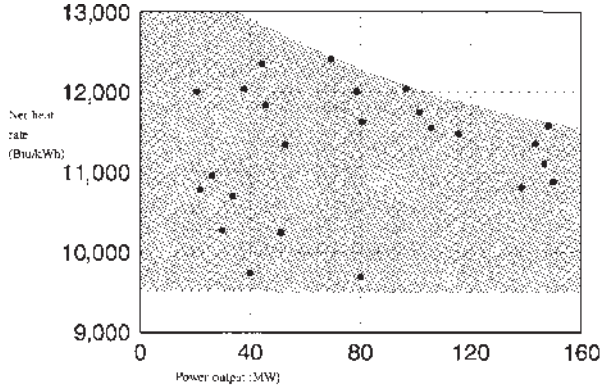


FIGURE 1.8 Approximate net heat rates for a range of simple cycle gas turbine units. Units are fired by natural gas and represent performance at standard conditions of an ambient temperature of 15°C at sea level. (Heat rate data from reference 1 were adjusted by 13% to represent HHVs and auxiliary power needs).

gears. In larger units the generators are driven directly, without any gears. Exhaust gases are discharged to the atmosphere in the simple cycle units. In combined cycles, the exhaust gases are used to make steam in a heat-recovery steam generator (HRSG) before being discharged.

The early utility applications of simple cycle gas turbines for power generation after World War II through about the 1970s were generally to supply power for peak load periods. They were fairly low-efficiency units that were intended to be available for emergency needs and to insure adequate generation reserves in case of unexpected load peaks or generation outages. Full-load net heat rates were typically 13,600 Btu/kWh (HHV). In the 1980s and 1990s, new, large, and simple cycle units with much improved heat rates were used for power generation. Figure 1.8 shows the approximate, reported range of heat rates for simple cycle units. These data were taken from a 1990 publication (reference 3) and were adjusted to allow for the difference between lower and higher heating values for natural gas and the power required by plant auxiliaries. The data illustrate the remarkable improvement in gas turbine efficiencies achieved by the modern designs.

1.6.2 Combined Cycle Units

Combined cycle plants use the high-temperature exhaust gases from one or more gas turbines to generate steam in HRSGs that are then used to drive a steam turbine generator. There are many different arrangements of combined cycle plants; some may use supplementary boilers that may be fired to provide additional steam. The advantage of a combined cycle is its higher efficiency. Plant efficiencies have been reported in the range between 6600 and 9000 Btu/kWh for the most efficient plants. Both figures are for HHVs of the fuel (see reference 4). A 50% efficiency would correspond to a net heat rate of 6825 Btu/kWh. Performance data vary with specific

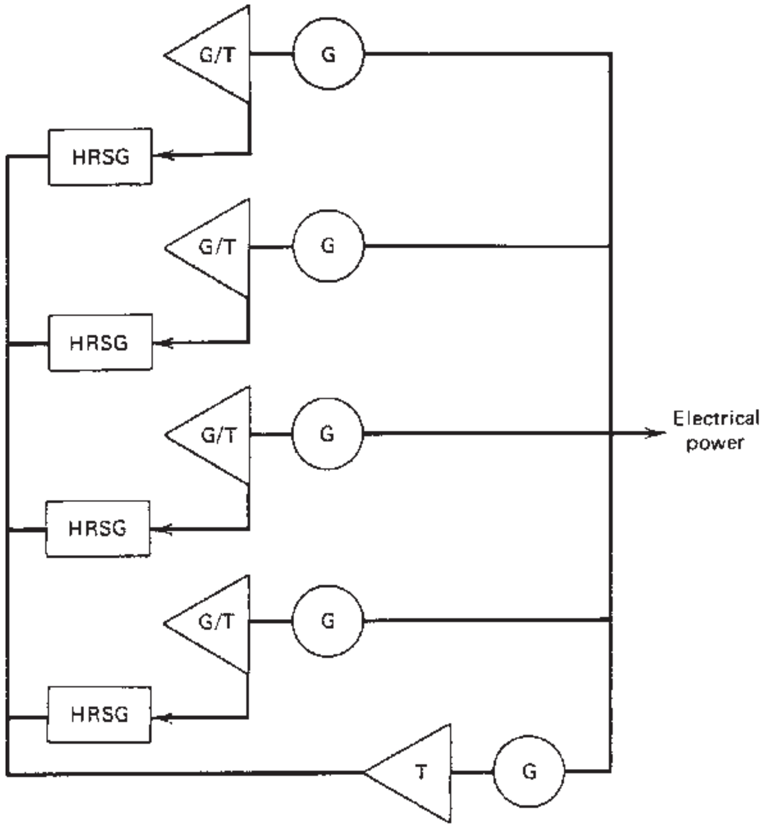


FIGURE 1.9 A combined cycle plant with four gas turbines and a steam turbine generator.

cycle and plant designs. Reference 2 gives an indication of the many configurations that have been proposed.

Part-load heat rate data for combined cycle plants are difficult to ascertain from available information. Figure 1.9 shows the configuration of a combined cycle plant with four gas turbines and HRSGs and a steam turbine generator. The plant efficiency characteristics depend on the number of gas turbines in operation. The shape of the net heat rate curve shown in Figure 1.10 illustrates this. Incremental heat rate characteristics tend to be flatter than those normally seen for steam turbine units.

1.6.3 Cogeneration Plants

Cogeneration plants are similar to the common-header steam plants discussed previously in that they are designed to produce both steam and electricity. The term "cogeneration" has usually referred to a plant that produces steam for an industrial process like an oil refining process. It is also used to refer to district heating plants. In the United States, "district heating" implies the supply of steam to heat buildings

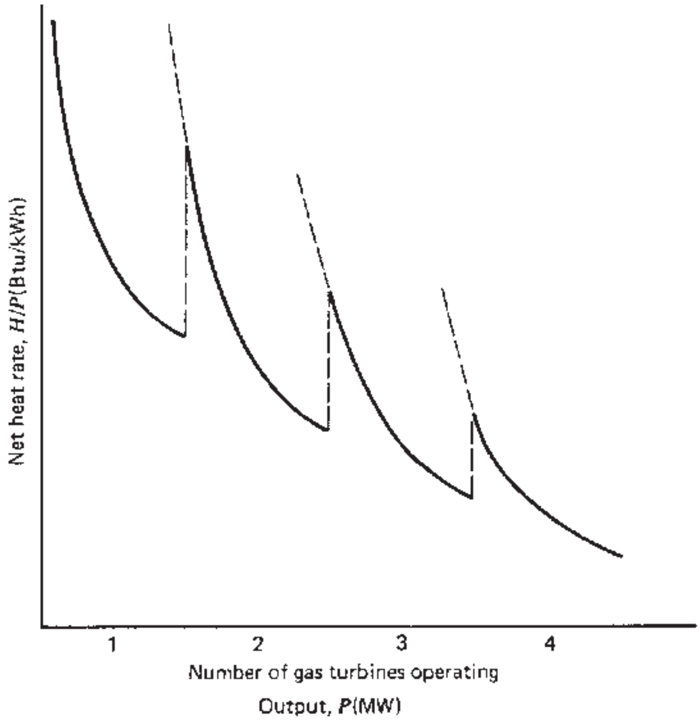


FIGURE 1.10 Combined cycle plant heat rate characteristic.

in downtown (usually business) areas. In Europe, the term also includes the supply of heat in the form of hot water or steam for residential complexes, usually large apartments.

For a variety of economic and political reasons, cogeneration is assuming a larger role in the power systems in the United States. The economic incentive is due to the high-efficiency electric power generation "topping cycles" that can generate power at heat rates as low as 4000 Btu/kWh. Depending on specific plant requirements for heat and power, an industrial firm may have large amounts of excess power available for sale at very competitive efficiencies. The recent and current political, regulatory, and economic climate encourages the supply of electric power to the interconnected systems by nonutility entities such as large industrial firms. The need for process heat and steam exists in many industries. Refineries and chemical plants may have a need for process steam on a continuous basis. Food processing may require a steady supply of heat. Many industrial plants use cogeneration units that extract steam from a simple or complex (i.e., combined) cycle and simultaneously produce electrical energy.

Prior to World War II, cogeneration units were usually small sized and used extraction steam turbines to drive a generator. The unit was typically sized to supply sufficient steam for the process and electric power for the load internal to the plant.

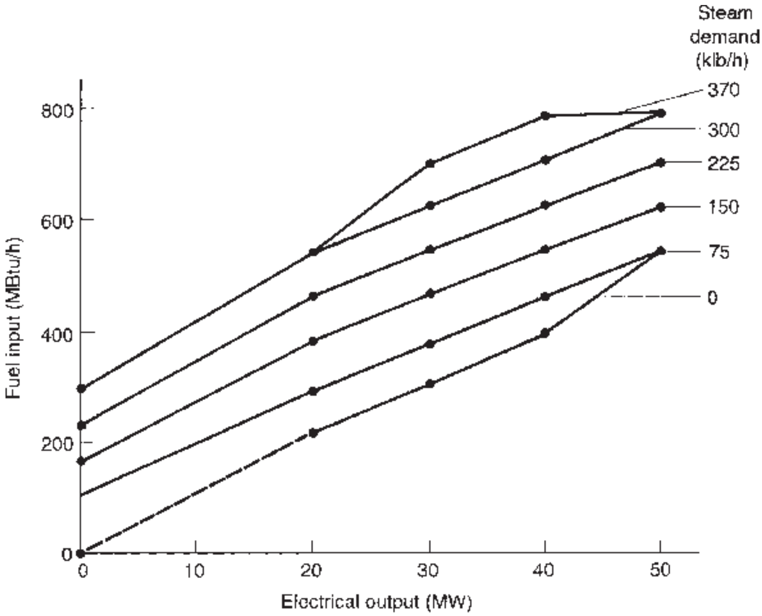


FIGURE 1.11 Fuel input required for steam demand and electrical output for a single extraction steam turbine generator.

Backup steam may have been supplied by a boiler, and an interconnection to the local utility provided an emergency source of electricity. The largest industrial plants would usually make arrangements to supply excess electric energy to the utility. Figure 1.11 shows the input–output characteristics for a 50-MW single extraction unit. The data show the heat input required for given combinations of process steam demand and electric output. This particular example is for a unit that can supply up to 370,000 lb/h of steam.

Modern cogeneration plants are designed around combined cycles that may incorporate separately fired steam boilers. Cycle designs can be complex and are tailored to the industrial plant's requirements for heat energy (see reference 2). In areas where there is a market for electric energy generated by an IPP, that is a non-utility-owned generating plant, there may be strong economic incentives for the industrial firm to develop a plant that can deliver energy to the power system. This has occurred in the United States after various regulatory bodies began efforts to encourage competition in the production of electric energy. This can, and has, raised interesting and important problems in the scheduling of generation and transmission system use. The industrial firm may have a steam demand cycle that is level, resulting in a more-or-less constant level of electrical output that must be absorbed. On the other hand, the local utility's load may be very cyclical. With a small component of nonutility generation, this may not represent a problem. However, if the IPP total generation supplies an appreciable portion of the utility load demand, the utility may have a complex scheduling situation.

1.6.4 Light-Water Moderated Nuclear Reactor Units

U.S. utilities have adopted the light-water moderated reactor as the "standard" type of nuclear steam supply system. These reactors are either pressurized water reactors (PWRs) or boiling water reactors (BWRs) and use slightly enriched uranium as the basic energy supply source. The uranium that occurs in nature contains approximately seven-tenths of 1% by weight of ^{235}U. This natural uranium must be enriched so that the content of ^{235}U is in the range of 2–4% for use in either a PWR or a BWR.

The enriched uranium must be fabricated into fuel assemblies by various manufacturing processes. At the time the fuel assemblies are loaded into the nuclear reactor core, there has been a considerable investment made in this fuel. During the period of time in which fuel is in the reactor and is generating heat and steam, and electrical power is being obtained from the generator, the amount of usable fissionable material in the core is decreasing. At some point, the reactor core is no longer able to maintain a critical state at a proper power level, so the core must be removed and new fuel reloaded into the reactor. Commercial power reactors are normally designed to replace one-third to one-fifth of the fuel in the core during reloading.

At this point, the nuclear fuel assemblies that have been removed are highly radioactive and must be treated in some fashion. Originally, it was intended that these assemblies would be reprocessed in commercial plants and that valuable materials would be obtained from the reprocessed core assemblies. It is questionable if the U.S. reactor industry will develop an economically viable reprocessing system that is acceptable to the public in general. If this is not done, either these radioactive cores will need to be stored for some indeterminate period of time or the U.S. government will have to take over these fuel assemblies for storage and eventual reprocessing. In any case, an additional amount of money will need to be invested, either in reprocessing the fuel or in storing it for some period of time.

The calculation of "fuel cost" in a situation such as this involves economic and accounting considerations and is really an investment analysis. Simply speaking, there will be a total dollar investment in a given core assembly. This dollar investment includes the cost of mining the uranium, milling the uranium core, converting it into a gaseous product that may be enriched, fabricating fuel assemblies, and delivering them to the reactor, plus the cost of removing the fuel assemblies after they have been irradiated and either reprocessing them or storing them. Each of these fuel assemblies will have generated a given amount of electrical energy. A pseudo-fuel cost may be obtained by dividing the total net investment in dollars by the total amount of electrical energy generated by the assembly. Of course, there are refinements that may be made in this simple computation. For example, it is possible by using nuclear physics calculations to compute more precisely the amount of energy generated by a specific fuel assembly in the core in a given stage of operation of a reactor.

Nuclear units will be treated as if they are ordinary thermal-generating units fueled by a fossil fuel. The considerations and computations of exact fuel reloading schedules and enrichment levels in the various fuel assemblies are beyond the scope of a one-semester graduate course because they require a background in

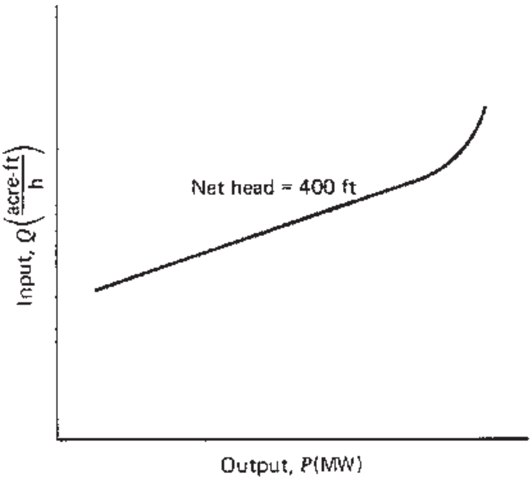


FIGURE 1.12 Hydroelectric unit input–output curve.

nuclear engineering as well as detailed understanding of the fuel cycle and its economic aspects.

1.6.5 Hydroelectric Units

Hydroelectric units have input–output characteristics similar to steam turbine units. The input is in terms of volume of water per unit time; the output is in terms of electrical power. Figure 1.12 shows a typical input–output curve for hydroelectric plant where the net hydraulic head is constant. This characteristic shows an almost linear curve of input water volume requirements per unit time as a function of power output as the power output increases from minimum to rated load. Above this point, the volume requirements increase as the efficiency of the unit falls off. The incremental water rate characteristics are shown in Figure 1.13. The units shown on both these curves are English units. That is, volume is shown as acre-feet (an acre of water a foot deep). If necessary, net hydraulic heads are shown in feet. Metric units are also used, as are thousands of cubic feet per second (kft^3/s) for the water rate.

Figure 1.14 shows the input–output characteristics of a hydroelectric plant with variable head. This type of characteristic occurs whenever the variation in the storage pond (i.e., forebay) and/or afterbay elevations is a fairly large percentage of the overall net hydraulic head. Scheduling hydroelectric plants with variable head characteristics is more difficult than scheduling hydroelectric plants with fixed heads. This is true not only because of the multiplicity of input–output curves that must be considered, but also because the maximum capability of the plant will also tend to vary with the hydraulic head. In Figure 1.14, the volume of water required for a given power output decreases as the head increases. (That is, dQ/d head or dQ/d volume is negative for a fixed power.) In a later section, methods are discussed that have been

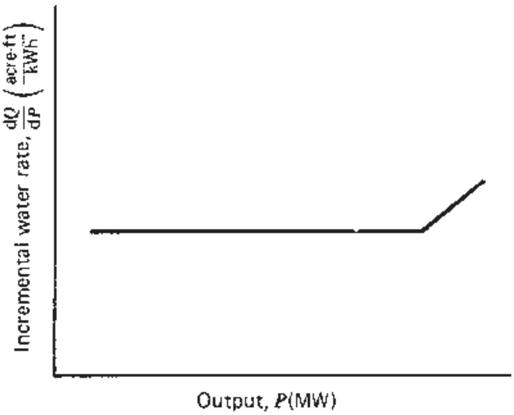


FIGURE 1.13 Incremental water rate curve for hydroelectric plant.

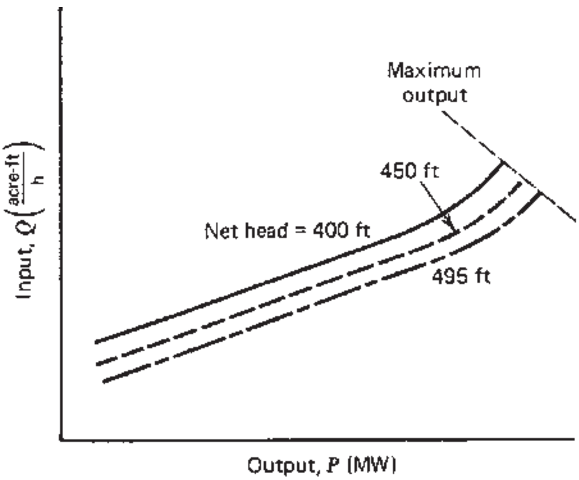


FIGURE 1.14 Input–output curves for hydroelectric plant with a variable head.

proposed for the optimum scheduling of hydrothermal power systems where the hydroelectric systems exhibit variable head characteristics.

Figure 1.15 shows the type of characteristics exhibited by pumped-storage hydroelectric plants. These plants are designed so that water may be stored by pumping it against a net hydraulic head for discharge at a more propitious time. This type of plant was originally installed with separate hydraulic turbines and electric-motor-driven pumps. In recent years, reversible, hydraulic pump turbines have been utilized. These reversible pump turbines exhibit normal input–output characteristics when utilized as turbines. In the pumping mode, however, the efficiency of operation tends to fall off when the pump is operated away from the rating of the unit. For this reason, most plant operators will only operate these units in the pumping mode at a fixed

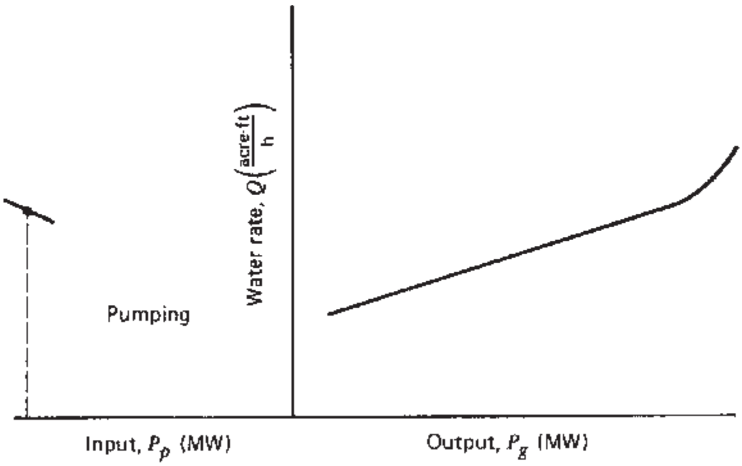


FIGURE 1.15 Input–output characteristics for a pumped-storage hydroplant with a fixed, net hydraulic head.

pumping load. The incremental water characteristics when operating as a turbine are, of course, similar to the conventional units illustrated previously.

The scheduling of pumped-storage hydroelectric plants may also be complicated by the necessity of recognizing the variable-head effects. These effects may be most pronounced in the variation of the maximum capability of the plant rather than in the presence of multiple input–output curves. This variable maximum capability may have a significant effect on the requirements for selecting capacity to run on the system, since these pumped-storage hydroplants may usually be considered as spinning-reserve capability. That is, they will be used only during periods of highest cost generation on the thermal units; at other times, they may be considered as readily available ("spinning reserve"). That is, during periods when they would normally be pumping, they may be shut off to reduce the demand. When idle, they may be started rapidly. In this case, the maximum capacity available will have a significant impact on the requirements for having other units available to meet the system's total spinning-reserve requirements.

These hydroelectric plants and their characteristics (both the characteristics for the pumped-storage and the conventional-storage hydroelectric plants) are affected greatly by the hydraulic configuration that exists where the plant is installed and by the requirements for water flows that may have nothing to do with power production. The characteristics just illustrated are for single, isolated plants. In many river systems, plants are connected in both series and in parallel (hydraulically speaking). In this case, the release of an upstream plant contributes to the inflow of downstream plants. There may be tributaries between plants that contribute to the water stored behind a downstream dam. The situation becomes even more complex when pumped-storage plants are constructed in conjunction with conventional hydroelectric plants. The problem of the optimum utilization of these resources involves the complicated problems associated with the scheduling of water as well as the optimum operation of the electric power system to minimize production cost. We can only touch on these matters in this text and introduce the subject. Because of the importance of the hydraulic coupling between plants, it is safe to assert that no two hydroelectric systems are exactly the same.

1.6.6 Energy Storage

Electric energy storage at the transmission system level where large amounts of electric energy can be stored over long time periods is very useful. When the prices of electric energy are low (for example at night), then it is useful to buy electric energy and then sell it back into the system during high-priced periods. Similarly, if you are operating renewable generation sources such as wind generators that cannot be scheduled, then it would be useful to store electric energy when the wind is blowing and then release it to the power system when most advantageous. Last of all, if there are seasonal variations such as in hydro systems, we would like to store energy during high runoff periods and then use it later when runoff is lower.

Parameters of electric energy storage (reference 5)

- *Available energy capacity*, W_{op}: The quantity of stored energy that is retrievable as electric power.
- *Rated power*, P_{rated}: The nameplate value for the rate at which electric energy can be continually stored or extracted from the storage system, usually given in kilowatts (kW) or megawatts (MW). Also referred to as the discharge capacity.
- *Discharge time*, $t_{storage}$: The duration of time that the energy storage system can supply rated power, given as $t_{storage} = (W_{op}/P_{rated})$.
- *Energy density*: Available energy capacity per unit mass, given in Wh/kg.
- *Power density*: Rated power per unit mass, given in W/kg.
- *Round-trip efficiency*, $\eta_{round\text{-}trip}$: The overall efficiency of consuming and later releasing energy at the point of common coupling with power grid. Also known as AC–AC efficiency, round-trip efficiency accounts for all conversion and storage losses and can be broken into charging and discharging efficiencies: $\eta_{round\text{-}trip} = \eta_{charge}\eta_{discharge} \cong \eta^2_{one\text{-}way}$.
- *Cycle life*: The maximum number of cycles for which the system is rated. The actual operating lifespan of the battery is either the cycle life or the rated lifespan, whichever is reached first.

List of technologies used in electric power energy storage:

- Pumped hydro
- CAES (compressed air energy storage)
- Flywheel
- SMES (superconducting magnetic energy storage)
- Lead-acid battery

- NaS battery
- Li-ion battery
- Metal-air battery
- PSB flow battery
- VRB flow battery
- ZnBr flow battery
- Fuel cells
- Ultra capacitors

Applications grouped by storage capacity and response time

Very short	0–20 s (1–4 MW or >20 MW)	End user protection
Short	10 min to 2 h (up to 2 MW)	End use reserves
Long	1–8 h (greater than 10 MW)	Generation, load leveling, ramp following
Very long	1–7 days (greater than 1 MW)	Seasonal and emergency backup, renewable backup

For this text, we are mainly interested in the last two for large transmission system applications. The types of storage technologies that make up the long and very long storage time categories are pumped storage, compressed air storage, as well as some of the battery types. However, for this text we shall deal mainly with pumped storage and compressed air since they are proven technologies that have scaled to large installations that can be used on the transmission system itself.

1.7 RENEWABLE ENERGY

Renewable energy is energy that comes from natural resources such as sunlight, wind, rain, tides, and geothermal heat, which are renewable (naturally replenished).[1] A renewable resource is a natural resource with the ability of being replaced through biological or natural processes and replenished with the passage of time.[2]

Renewable fuels are those fuel sources that can be burned in conventional generation systems such as boiler–turbine–generators, gas turbine generators, and diesel generators.

Organic plant matter, known as biomass, can be burned, gasified, fermented, or otherwise processed to produce electricity.[3]

Geothermal energy extracts steam directly from the earth and uses it to power turbine–generator units.

[1] http://en.wikipedia.org/wiki/Renewable_energy
[2] http://en.wikipedia.org/wiki/Renewable_resource
[3] http://www.acore.org/what-is-renewable-energy/

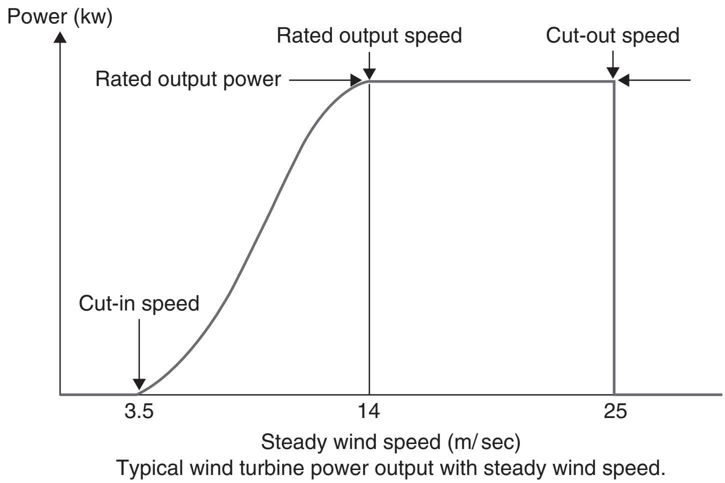


FIGURE 1.16 Typical wind turbine power output with steady wind speed.

Ocean energy can also be used to produce electricity. In addition to tidal energy, energy can be produced by the action of ocean waves, which are driven by both the tides and the winds. Because of their link to winds and surface heating processes, ocean currents are considered as indirect sources of solar energy.[4] In this case, ocean energy is converted through direct action of water on a turbine in the same manner as a hydroelectric plant turbine, although the shape and characteristics of the turbine for extracting energy from the oceans is different.

1.7.1 Wind Power

By far the most common renewable electric generation system is the wind generator. In the past 10 years, wind generation has advanced to the point that it is now quite economical to build and operate large sets of wing generators often called wind farms. In addition, wind generators are now being developed specifically to be placed in the ocean near the shore where strong and almost constant winds blow.

Figure 1.16 shows a sketch a how the power output from a wind turbine varies with steady wind speed. (This figure and the following paragraphs up to the equation for available power are taken from http://www.wind-power-program.com/turbine_characteristics.htm)

1.7.2 Cut-In Speed

At very low wind speeds, there is insufficient torque exerted by the wind on the turbine blades to make them rotate. However, as the speed increases, the wind turbine will begin to rotate and generate electrical power. The speed at which the turbine first

[4] ibid

starts to rotate and generate power is called the cut-in speed and is typically between 3 and 4 m/s.

1.7.3 Rated Output Power and Rated Output Wind Speed

As the wind speed rises above the cut-in speed, the level of electrical output power rises rapidly as shown. However, typically somewhere between 12 and 17 m/s, the power output reaches the limit that the electrical generator is capable of. This limit to the generator output is called the rated power output and the wind speed at which it is reached is called the rated output wind speed. At higher wind speeds, the design of the turbine is arranged to limit the power to this maximum level and there is no further rise in the output power. How this is done varies from design to design but typically with large turbines, it is done by adjusting the blade angles so as to keep the power at the constant level.

1.7.4 Cut-Out Speed

As the speed increases above the rate output wind speed, the forces on the turbine structure continue to rise and, at some point, there is a risk of damage to the rotor. As a result, a braking system is employed to bring the rotor to a standstill. This is called the cut-out speed and is usually around 25 m/s.

1.7.5 Wind Turbine Efficiency or Power Coefficient

The available power in a stream of wind of the same cross-sectional area as the wind turbine can easily be shown to be

$$\text{Available power in watts} = \frac{1}{2}\rho U^3 \frac{\pi d^2}{4}$$

where

U is the wind speed in m/s
ρ is the density of air in kg/m^3
d is the rotor diameter in m

We will talk in later chapters on the problems that wind generation presents due to its "nondispatchable" nature—simply meaning that we cannot order wind generation to be "on" during certain hours or "off" during others since it depends on the wind, which we do not have control over. The result is a strong interest in programs that use metrological data to predict wind speed, direction, location, and time of day.

In addition, it is apparent from recent data that large numbers of wind generators do have the ability to produce a smoother wind generation output than a single wind generator. Figure 1.17 shows this quite clearly.

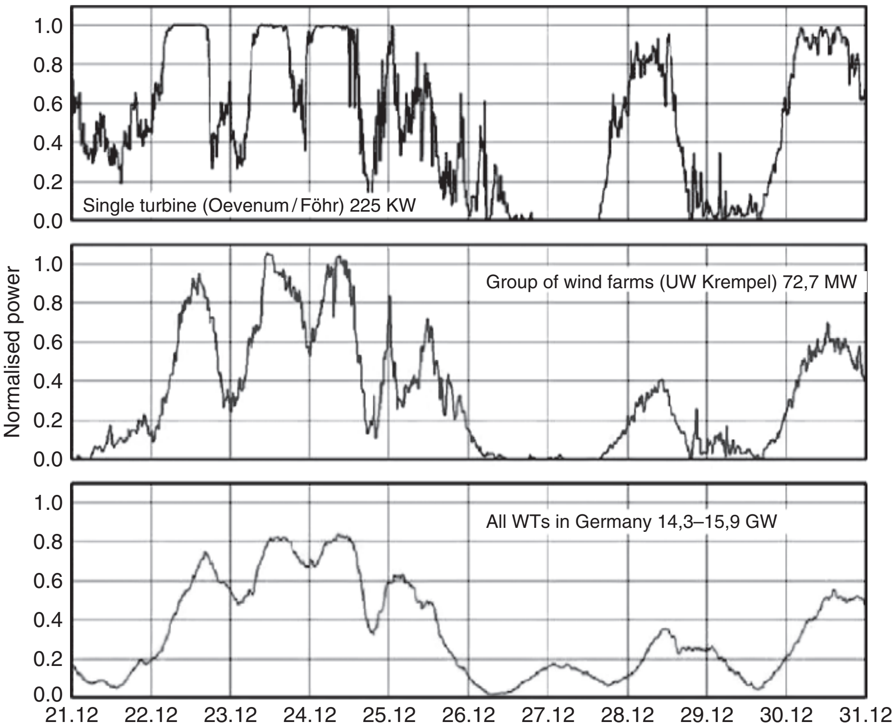


FIGURE 1.17 Example of time series of normalized power output from a single wind generator, a group of wind generators and all wind generators in Germany (21–31.12.2004) (reference 6).

This figure is taken from reference 6 and shows the output of a single wind generator (top), a group of wind farms (center), and the entire fleet of wind generators in Germany (bottom). Obviously, the wind generators taken as a large group overcome the very unpredictable and noisy output of a single wind generator.

1.7.6 Solar Power

Solar power comes in two varieties with respect to generation of electricity: photovoltaic and concentrated solar power.

Photovoltaic sources use cells that depend on the "photovoltaic" effect to convert incident sunlight into direct current (DC) electric power. The DC power is then converted to AC electric power at the system frequency where this is connected by power electronics converters. Small arrays of photo cells can be placed on the roof of a single home and supply electric power to that home or large numbers of arrays can be arranged in fields and wired to supply power directly to the electric system.

Concentrated solar power (also called *concentrating solar power*, *concentrated solar thermal*, and *CSP*) systems use mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. Electrical power is produced when the concentrated light is converted to heat, which drives a heat engine (usually a steam turbine) connected to an electrical power generator.[5]

Obviously, both of these sources depend on the availability of sunlight and like wind generators cannot be dispatched. However, the CSP units can produce some electric energy after the sun has gone down due to the storage of heat in its steam generators.

APPENDIX 1A
Typical Generation Data

Up until the early 1950s, most U.S. utilities installed units of less than 100 MW. These units were relatively inefficient (about 950 psi steam and no reheat cycles). During the early 1950s, the economics of reheat cycles and advances in materials technology encouraged the installation of reheat units having steam temperatures of 1000°F and pressures in the range of 1450–2150 psi. Unit sizes for the new design reheat units ranged up to 225 MW. In the late 1950s and early 1960s, U.S. utilities began installing larger units ranging up to 300 MW in size. In the late 1960s, U.S. utilities began installing even larger, more efficient units (about 2400 psi with single reheat) ranging in size up to 700 MW. In addition, in the late 1960s, some U.S. utilities began installing more efficient supercritical units (about 3500 psi, some with double reheat) ranging in size up to 1300 MW. The bulk of these supercritical units ranged in size from 500 to 900 MW. However, many of the newest supercritical units range in size from 1150 to 1300 MW. Maximum unit sizes have remained in this range because of economic, financial, and system reliability considerations.

Typical heat rate data for these classes of fossil generation are shown in Table 1.1. These data are based on U.S. federal government reports and other design data for U.S. utilities (see *Heat Rates for General Electric Steam Turbine-Generators* 100,000 *kW and Larger*, Large Steam Turbine Generator Department, G.E.).

The shape of the heat rate curve is based on the locus of design "valve-best-points" for the various sizes of turbines. The magnitude of the turbine heat rate curve has been increased to obtain the unit heat rate, adjusting for the mean of the valve loops, boiler efficiency, and auxiliary power requirements. The resulting approximate increase from design turbine heat rate to obtain the generation heat rate in Table 1.1 is summarized in Table 1.2 for the various types and sizes of fossil units.

Typical heat rate data for light-water moderated nuclear units are as follows:

Output (%)	Net Heat Rate (Btu/kWh)
100	10,400
75	10,442
50	10,951

[5] http://en.wikipedia.org/wiki/Concentrated_solar_power

TABLE 1.1 Typical Fossil Generation Unit Heat Rates

Fossil Unit—Description	Unit Rating (MW)	100% Output (Btu/kWh)	80% Output (Btu/kWh)	60% Output (Btu/kWh)	40% Output (Btu/kWh)	25% Output (Btu/kWh)
Steam—coal	50	11,000	11,088	11,429	12,166	13,409[a]
Steam—oil	50	11,500	11,592	11,949	12,719	14,019[a]
Steam—gas	50	11,700	11,794	12,156	12,940	14,262[a]
Steam—coal	200	9,500	9,576	9,871	10,507	11,581[a]
Steam—oil	200	9,900	9,979	10,286	10,949	12,068[a]
Steam—gas	200	10,050	10,130	10,442	11,115	12,251[a]
Steam—coal	400	9,000	9,045	9,252	9,783	10,674[a]
Steam—oil	400	9,400	9,447	9,663	10,218	11,148[a]
Steam—gas	400	9,500	9,548	9,766	10,327	11,267[a]
Steam—coal	600	8,900	8,989	9,265	9,843	10,814[a]
Steam—oil	600	9,300	9,393	9,681	10,286	11,300[a]
Steam—gas	600	9,400	9,494	9,785	10,396	11,421[a]
Steam—coal	800–1,200	8,750	8,803	9,048	9,625[a]	
Steam—oil	800–1,200	9,100	9,155	9,409	10,010[a]	
Steam—gas	800–1,200	9,200	9,255	9,513	10,120[a]	

[a]For study purposes, units should not be loaded below the points shown.

TABLE 1.2 Approximate Unit Heat Rate Increase over Valve-Best-Point Turbine Heat Rate

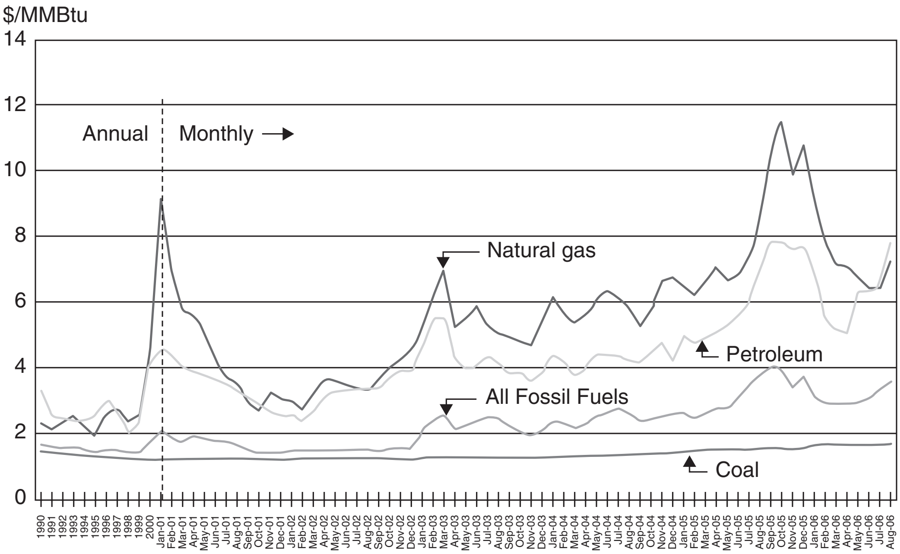
Unit Size (MW)	Coal (%)	Oil (%)	Gas (%)
50	22	28	30
200	20	25	27
400	16	21	22
600	16	21	22
800–1200	16	21	22

These typical values for both PWR and BWR units were estimated using design valve-best-point data that were increased by 8% to obtain the net heat rates. The 8% accounts for auxiliary power requirements and heat losses in the auxiliaries.

Typical heat rate data for newer and larger gas turbines are discussed earlier. Older units based on industrial gas turbine designs had heat rates of about 13,600 Btu/kWh. Older units based on aircraft jet engines were less efficient, with typical values of full-load net heat rates being about 16,000 Btu/kWh.

APPENDIX 1B
Fossil Fuel Prices

As can be seen in Figure 1.18, the prices for petroleum and natural gas have varied over time, sometimes peaking for short periods of times (several months). The price of coal is relatively constant over the past two decades.



Data Source: DOE/EIA

FIGURE 1.18 Fossil fuel prices 1990–August 2006 [reference 7].

APPENDIX 1C
Unit Statistics

In North America, the utilities participate in an organization known as the North American Electric Reliability Council (NERC) with its headquarters in Princeton, New Jersey. NERC undertakes the task of supporting the interutility operating organization that publishes an operating guide and collects, processes, and publishes statistics on generating units. NERC maintains the *Generating Availability Data System* (GADS) that contains over 25 years of data on the historical performance of generating units and related equipment. This information is made available to the industry through special reports done by the NERC staff for specific organizations and is also issued in an annual report, the *Generating Availability Report*. These data are extremely useful in tracking unit performance, detecting trends in maintenance needs, and in planning capacity additions to maintain adequate system generation reserves. The GADS structure provides standard definitions that are used by the industry in recording unit performance. This is of vital importance if collected statistics are to be used in reliability and adequacy analyses. Any useful reliability analysis and prediction structure requires three essential elements:

- Analytical (statistical and probability) methods and models,
- Performance measures and acceptable standards,
- Statistical data in a form that is useful in the analysis and prediction of performance measures.

In the generation field, GADS performs the last two in an excellent fashion. Its reputation is such that similar schemes have been established in other countries based on GADS.

Table 1.3 contains typical generating unit data on scheduled maintenance requirements, the "equivalent forced outage rate" and the "availability factor" that were taken from an NERC summary of generating unit statistics for the period 1988–1992. For any given, specified interval (say a year), the NERC definitions of the data are:

$$\begin{aligned}\text{Equivalent forced outage rate} &= (\text{forced outage hours} + \text{equivalent forced}\\ &\quad \text{derated hours}) \div (\text{forced outage hours} + \text{hours}\\ &\quad \text{in service} + \text{equivalent forced derated hours}\\ &\quad \text{during reserve shutdown})\\ \text{Availability factor (AF)} &= \text{available hours} \div \text{period hours}\end{aligned}$$

Scheduled maintenance requirements were estimated from the NERC data using the reported "scheduled outage factor," the portion of the period representing scheduled outages.

TABLE 1.3 Typical Maintenance and Forced Outage Data

Unit Type	Size Range (MW)	Scheduled Maintenance Requirement (Days/Year)	Equivalent Forced Rate (%)	Availability Factor (%)
Nuclear	All	67	18.3	72
Gas turbines	All	22	—	91
Fossil-fueled steam	1–99	31	7.2	88
	100–199	42	8.0	85
	200–299	43	7.2	85
	300–399	52	9.5	82
	400–599	47	8.8	82
	600–799	45	7.6	84
	800–999	40	5.8	88
	≥1000	44	9.0	82

From *Generating Unit Statistics* 1988–1992 issued by NERC, Princeton, NJ.

	Effective Outage Rates (%)		
	EFOR	EFOR′	Service Factor = (service hours) ÷ (period hours) (%)
All fossil units	5.7	4.1	60.5
All gas turbines	55.5	3.4	2.6

The reported, standard equivalent forced outage rate for gas turbines has been omitted since the low duty cycle of gas turbines in peaking service biases the value of effective forced outage rate (EFOR). Using the standard definition earlier, the reported EFOR for all sizes of gas turbine units was 58.9%. This compares with 8.4% for all fossil-fired units. Instead of the aforementioned definition of EFOR, let us use a different rate (call it the EFOR′) that includes reserve shutdown hours and neglects all derated hours to simplify the comparison with the standard definition:

$$\text{EFOR} = \text{forced outage hours} \div (\text{forced outage hours} + \text{hours in service})$$

or

$$\text{EFOR}' = \text{forced outage hours} \div (\text{forced outage hours} + \text{available hours})$$

where the available hours are the sum of the reserve shutdown and service hours. The effect of the short duty cycle may be illustrated using the NERC data.

The significance is not that the NERC definition is “wrong”; for some analytical models it may not be suitable for the purpose at hand. Further, and much more important, the NERC reports provide sufficient data and detail to adjust the historical statistics for use in many different analytical models.

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FURTHER READING

The following books are suggested as sources of information for the general area covered by this text. Since the publishing of the first edition of this text there has been a great increase in the number of specialized textbooks aimed at specific topics that are covered in this book. Due to this availability, we have entered only a few references to journals and other articles in each chapter.

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