Power Plant System Design

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Preface

This textbook is the outgrowth of our consulting engineering work and teaching in electric power generation. It was written to meet the needs of mechanical engineering students and engineers. In the last 20 years, the changes in technology include substantial growth in unit size (from approximately 200 MW in the 1950s to 1100 MW in the 1970s) and the use of different steam conditions (from subcritical in the 1950s to supercritical conditions in the 1970s). In addition, the plant capital and fuel costs have escalated so rapidly that the plant system design has become a subject of increasing importance in the power industry.

The aim of this book is the design of optimum power plant systems. There are two basic concepts in power plant design that will be embodied in this book: component design and system design. The system generally consists of one or more components related to each other to perform one particular task. In power plants the system may be very simple, such as a section of steam pipe between the superheater and the high-pressure turbine, or very complex, such as the turbine cold-end system, which may consist of the turbine exhaust end, condenser, and cooling tower. This book will emphasize systems rather than components. The selection of components will be made in terms of its impacts on the system. However, basic knowledge of the components is a necessary ingredient for understanding the system.

Design is a decision-making process. The design process frequently results in a set of drawings, or a report that may include calculations and descriptions of equipment. In this textbook attention will be focused on the system design rather than the component design; on the thermal design rather than the mechanical design. When we write "thermal design" we mean that the calculations or decisions are based on the principles of thermodynamics, heat transfer, and fluid mechanics. The system design procedures will generate several optional solutions. Apparently, not all these solutions are equally acceptable. Some are better than others. The final decision as to which solution to use will be made by utilizing various simulation and optimization techniques.

This book serves as an introduction to power plant system design. Since the electric power generating system is complex, we do not intend to cover all aspects. Rather, attention is focused on the steam turbine, steam supply systems, condenser, and cooling tower, as well as their combined system. However, the design methodology introduced here is so general that it can be easily adapted to other system design problems.

The use of the digital computer in power plant design is another feature of this textbook. Several computer programs are introduced and may be obtained from us. These programs have been thoroughly verified and tested in a Boston consulting firm. The reason for including these programs is to provide students with an opportunity to use them for system design. Without them, students may have to spend a lot of time in design calculation and not have enough time to appreciate the effects of various design parameters. These computer programs may also serve as models for the further development of computer programs for power plant system design. However, the computer materials were presented in such a way that omitting them would not in any way disturb the continuity of the text.

The book is intended for use at the undergraduate and beginning graduate levels. It should provide sufficient materials, including homework problems, for one four-credit course in universities and colleges. The prerequisites are the first course of thermodynamics, heat transfer, and fluid mechanics. This book is also suitable as a reference for engineers in consulting engineering firms and in utility and manufacturing companies.

The subject matter included in this text is arranged to provide the instructor with a certain degree of flexibility in developing a particular engineering course. When the text is used in a system course (such as power plant system design or thermal system design in general), some background and component materials should be omitted. For this purpose it is suggested that Chapters 2, 5, and 6 be quickly reviewed or entirely omitted. When the text is used in a low-level course such as "Energy Conversion" or "Introduction to Power Plant Systems," the design materials presented in the text should be de-emphasized to some extent. In either case the instructor must select the material to be covered according to the background of the student and the purpose of the course.

During the preparation of this book students were foremost in the our minds. The objective was to develop in students an awareness and understanding of the relationship between the power plant system design and thermal science courses. Efforts were made to demonstrate by examples the use of the principles and working procedures in system design. The book has been tested for two years at North Dakota State University. In 1982 it was also used as a text for the short course "Power Plant System Simulation and Design Optimization" at the Center for Professional Advancement in New Brunswick, New Jersey. We appreciated very much the constructive criticisms both from the practicing engineers and university students.

No claim is made for complete originality of the text. We have been influenced by the excellent publications of many organizations and individuals, especially *Steam/Its Generation and Use* by Babcock & Wilcox, *Combustion*, *Fossil Power Systems* by Combustion Engineering, and those by General Electric and Westinghouse. We feel that these excellent publications should be acknowledged separately in addition to their being listed in the reference sections in the text.

We are indebted to Northern States Power Company (Minneapolis), Chas. T. Main, Inc. (Boston), and North Dakota State University for the assistance rendered in their professional development. We also thank North Dakota State's Department of Mechanical Engineering and Applied Mechanics for their support in preparing the manuscript and to Brenda Stotser and Debbie Coon for their typing.

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Contents

CHAPTER ONE

Introduction

1.1 INTRODUCTION

As civilization has evolved, energy consumption has increased. Table 1-1 shows a rapid increase in the recent decades of world energy consumption. For the last 80 years the consumption increased more than tenfold. Energy consumption is mainly in the form of coal, oil, natural gas, and hydroelectric and nuclear energy. The electric power generated by these natural resources is the most convenient form in which this energy can be used. In 1970 the total world generation of electricity was about 5×10^{12} kWh, which was about 10% of the world energy consumption in that year. If the average conversion efficiency was roughly one-third, then approximately 30% of the world energy consumption was devoted to the production of electricity. This percentage is expected to increase gradually in the years to come.

The demand for electrical energy is not constant. Figure 1-1 shows the typical daily load curve for a metropolitan area. The ratio of valley to peak (minimum daily output to maximum daily output) is between 0.5 to 0.8. If we include weekends, when the demand from the industries is greatly reduced, and consider the maximum annual demand, we will find an even smaller ratio of annual minimum to annual maximum. This relationship becomes apparent in the annual load duration curve shown in Fig. 1-2. Any point on the load duration curve will indicate the number of hours in a given period during which the given load and higher loads prevail. The hatched area can be interpreted as the electrical energy generated in the year by the network system, while the remaining area represents the unused capacity. The ratio of the hatched area to the total area is frequently called the annual system capacity factor, which is generally around 60%. It follows then that sufficient power generating units must be available to meet the highest load, but for most of the year some of these units will be at a standstill. To satisfy the load variation, the power industry must have different generating systems. The generating systems can be classified into three groups as presented in Table 1-2.

The peak-load generating units are for use during the load peaks. Accordingly, they can be started and shut down several times every day. The number of operation hours per year varies from a few hundred to about 2500 hours. Because of the ease in startup, these units are also used as standby or emergency units. These units are generally characterized by a low capital investment and high fuel costs.

The base-load generating units are operated at full load as long as possible during the year. They have high conversion efficiency and can generate electric power at the lowest cost. These units are generally characterized by high capital investment and low fuel cost. Because of the complexity in the generating system, the base-load

Table 1-1
World Energy Consumption [3]

Year	Annual Consumption (10^{18} J)	Annual Consumption (10^{15} Btu)	Average Annual Growth Rate (%)	Annual Consumption per Capita (10^{9} J)	Annual Consumption per Capita (10^{6} Btu)
1900	22	20.8	2.9	14	13.2
1925	45	42.6	2.2	23	21.8
1950	80	75.8	4.0	32	30.3
1960	118	111.9	5.5	40	37.9
1965	155	147.0	5.4	55	52.1
1970	201	190.5	5.3	58	54.9
1972	218	206.6	3.3	60	56.9
1974	233	220.8	3.1	60	57.2
1976	264	250.4	6.5	65	61.8
1978	279	264.8	2.8	66	62.7
1980	289	274.1	1.7	66	62.3
1981	294	278.3	1.5	65	62.0

Note: The data in this table have been supplemented with additional data from the United Nations report, "World Energy Supplies, 1929 to 1981."

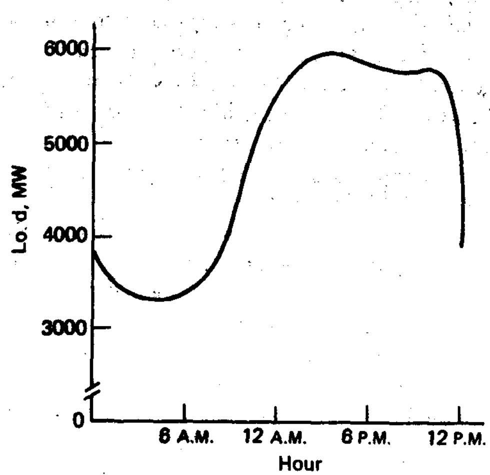

Figure 1-1. Typical daily load curve for a metropolitan area.

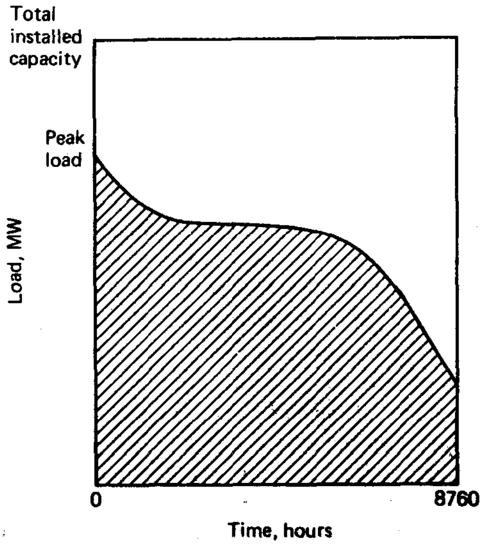

Figure 1-2. Typical annual load duration curve.

generating units have a poor load change capability. In other words, they take more time to respond to load demand than the peak-load generating units.

The medium-load generating units are operated predominantly on weekdays and shut down at night and on the weekend. The number of operation hours per year varies between 2000 and 5000 hr. These units have operation and economic characteristics somewhere between those of base-load and peak-load generating units. The conversion efficiency is higher than that of peak-load plants, but lower than that of base-load plants.

Table 1-2
Classification of Electric Power Generation Units

1. Peak-load generating units
   - Gas turbine
   - Diesel engine
   - Hydropumped storage plant
   - Old simple steam turbine plant
2. Base-load generating units
   - Nuclear plant
   - High-performance steam turbine plant
   - Advanced combined gas and steam turbine plant
   - Hydroelectric plant
3. Medium-load generating units
   - Simple steam turbine plant
   - Old base-load plant
   - Combined gas and steam turbine plant

Electric power generation is a capital-intensive business. In 1978 it costs around \$600 to \$1000 to build one kilowatt of generating facility. For a 1000 MW plant, this means a capital investment of 600 million to 1 billion dollars. The cost of operating a power plant is equally expensive. For instance, a 1000 MW coal-fired power plant would consume fuel at a rate of 58.34 trillion Btu per year (capacity factor 70% at plant net heat rate 9513 Btu/kWh), or 2.03 million tons of coal per year (coal heating value 12851 Btu/lb). At the price of \$0.7 per million Btu, the annual fuel cost for this 1000 MW plant would be \$40.833 million. One percent of fuel saving resulting from improved engineering design would mean a savings of \$408,330 every year. These capital-intensive characteristics and high operating costs make the engineering design of power plants extremely important and challenging.

Power plant design is a complex process. The general design objective is to produce a reliable facility that can generate electric power at the lowest cost and with acceptable impacts on the environment. The designer must take into account the progress in technology and the availability and economics of fuels. In the last 20 years, the changes in technology include exponential growth in unit size (from approximately 200 MW in 1960s to 1100 MW in 1970s) and the use of different inlet steam conditions (from subcritical conditions in the 1960s to supercritical conditions in the 1970s). Because of increasing fuel cost, plant efficiency has become a matter of greater significance.

Power plant construction is also a complicated and time-consuming process. In recent years it took 12 years or more to complete a nuclear generating unit and seven to eight years for a coal-fired generating unit. This long lead time is mainly due to regulatory processes and occasionally materials shortage. It follows therefore that load forecasting and long-range planning are especially important in the electric utility. There are also many other reasons for forecasting and long-range planning. One of these is the scheduling of financing by the utility company on a long-term basis. In general, system planning is carried out on a 10- to 20-year basis. Rates are affected by changes that may take place in the company's service area. Sales programs, devised to improve the company's position, are based on long-term forecasts.

Environmental impact of power plant operation is another concern to the plant designer. The magnitude of waste heat is significant. For every kilowatt of electricity generated, there are approximately two kilowatts of waste heat. The availability of cooling water is frequently considered to be one of the important factors for the plant site selection. The plant cooling system affects not only the plant performance but also the plant environment.

Air pollution problems associated with fossil-fuel power plant operation are serious. Of the air pollutants emitted from fossil-fuel power plants, SO_2 is the most serious one. Table 1-3 shows the effects of SO_2 on health by level of exposure. In general, illness from SO_2 may be acute (short-lived) or chronic (usually permanent and irreversible). Chronic bronchitis may develop in persons exposed to even moderate levels of SO_2 over many years—an exposure range of 100 to 350 $\mu g/m^3$ with associated particulate levels of 66 to 365 $\mu g/m^3$. In the past few years various methods of controlling SO_2 concentration levels have been proposed. These methods

Table 1-3
Some Observed Health Effects of SO_2 and Particulates [3]†

Concentration of SO_2		Concentration of Particulates		
$\mu g/m^3$	Measured as	$\mu g/m^3$	Measured as	Possible Effect
1500	24-hr average			Increased mortality
715	24-hr mean	750	24-hr mean	Increased daily death rate; a sharp rise in illness rates among bronchitis over age 54
300–500	24-hr mean	Low	24-hr mean	Increased hospital admissions of elderly respiratory disease cases; increased absenteeism among older workers
600	24-hr mean	300	24-hr mean	Symptoms of chronic lung disease cases accentuated
105–265	Annual mean	185	Annual mean	Increased frequency of respiratory symptoms and lung disease
120	Annual mean	100	Annual mean	Increased frequency and severity of respiratory diseases among schoolchildren
115	Annual mean	160	Annual mean	Increased mortality from bronchitis and lung cancer

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seem to group themselves into categories ranging from fuel selection to intermittent control of emitted SO_2. More progress, including fluidized bed combustion, is expected in the near future.

1.2 COAL-FIRED POWER PLANTS

Coal-fired plants make up slightly over one-half of the electric power generation in the United States and in most other parts of the world. There are vast recoverable reserves of coal in the United States, estimated at over 5000 quads (one quad is 10^{15} Btu). Approximately 16 quads were consumed in the United States in 1981, 75% of which was in electricity generation.

Coals are generally classified by geological age, beginning with peat, then lignite, subbituminous, bituminous, semianthracite, and anthracite. There are meta-anthracite reserves in New England, but the ability to burn it in power plants has not been developed, because of its hardness.

The percentage of oxygen and volatile matter are greatest in peat and lignite, and decrease through subbituminous, to the lowest percentage in anthracite. Conversely, the percentage of fixed carbon is greatest in anthracite and decreases through the bituminous grades to the lowest percentage in lignite and peat.

The lignite and subbituminous coals appear more abundantly in the western area and the Gulf Coast areas. The bituminous coals are more abundant in the central and eastern areas. There is relatively little anthracite, which is found chiefly in eastern Pennsylvania.

Coal is usually hauled from the mines to the power plant by railroad. In some cases the coal may be shipped partly by river barge or ocean ship. If shipped by rail, each rail car will contain up to 100 tons, which will fuel a 220 MW plant at full load for approximately one hour.

Coal is usually prepared for shipment in one of several ways, such as by reducing the lump size to a maximum of approximately $1\frac{1}{4}$ inches. At the plant site, the coal is further crushed to approximately a $\frac{3}{4}$ inch maximum. In some cases the coal is washed at the mine site to reduce pyrites and sulphur.

Rail cars may be unloaded at the power plant, either by opening doors at the bottom of the cars, dumping into a hopper, or the cars may be turned upside-down in a rotary trunnion over the hopper. In some cases a mechanical shaking device must be applied to the car to facilitate the removal of coal from the bottom hopper doors. In colder climates thawing facilities must be provided if the coal is frozen in the cars.

From the unloading hopper the coal is conveyed by moving inclined rubber belts mounted on steel-frame galleries to a crusher tower and to the storage yard or to the elevated coal bunkers, or silos, above the pulverizer mills. Plant coal storage is usually divided into two parts; a small area for "ready" use to be used, if required, between coal deliveries, and a "dead" storage area sufficient to serve the plant for an extended period, possibly 90 days, in the event of a major stoppage of coal delivery. The "dead" storage coal must be compacted and coated with a bitumastic material to prevent erosion and possible spontaneous combustion.

Deciding on the location of the plant site also requires a comprehensive engineering study. The site should be large enough for sufficient coal storage and should be accessible to coal delivery. It should also be suitable for condenser cooling water, either from river, or water body, or by cooling towers.

The plant should be supplied with an elevated coal bunker above each pulverizer mill, each sized for several hours of storage. Coal will flow by gravity to the coal feeders at each mill. A pulverizer mill has a grinding capacity of up to 60 tons of coal per hour. An extra or spare mill is usually supplied with each boiler unit.

Coal "grindability" is an important factor in selecting coal for a plant, and also for selecting and sizing pulverizer mills. Grindability is an index of the coal's relative ease of being pulverized. The index is named the Hardgrove Index for the man who developed it. The index covers the most grindable at approximately 40 to over 100. Anthracite coals have the higher indices.

Steam generators designed to burn coal must be "tailored" for the specific coal analysis. The amount of ash and the analysis of the ash are very important. The softening temperature of the ash determines its tendency to slag (deposit on metal surfaces). Softening temperatures of 2600 F or above are more suitable for "dry-bottom" furnaces in which the large ash particles drop to the bottom of the furnace in a solid form (approximately 15–20% of the total ash) and the smaller particles are carried out in the combustion gases in dry form called "fly-ash" (approximately 80–85%). Coals with ash-softening temperatures of less than 2500 F may be more suitable for "wet-bottom" furnaces or "cyclone" furnaces, which will be described in greater detail in Chapter 5. The chemical composition of the ash is also very important. The corrosive qualities of the ash have caused boiler designers and operators many problems.

The suitable coals are usually selected by the utility company. However, the suitable coals may be more expensive and may require greater hauling distance. In most cases all local coal available in the required quantities should be used even if some coal qualities are objectionable.

The boiler designer can, to some extent, compensate for undesirable coal qualities. The geometry of the furnace and the size and placement of coal burners should be such as to prevent flame impingement on furnace walls. Superheater tubes near the top of the furnace section should be at a suitable distance above the topmost coal burners. Superheater and reheater tube sections should have adequate free spacing for gas passage so that slag will not be trapped between the tubes. All tubes in the gas passages should be "bare." The use of "finned" tubes will increase heat transfer but also form traps for slag and fouling. Economizer tubes in the rear boiler pass may be "finned" for boilers firing natural gas, but not for those using coal.

The generous application of soot blowers will help to remove the fouling of slag, which inevitably will occur. Soot blowers consist of jets of high-pressure air or steam, which is intended literally to blow the molten stag off the tubes and wall surfaces. Soot blowers are of two general types; the "wall" blowers, which penetrate the water walls at intervals and are operated by entering the furnace for a few feet and "blowing" in sequence, then withdrawn from the furnace for protection; another type of soot blower is the "long-retractable" units for blowing convection surface sections. These long-retractable blowers, on large, wide boilers may extend from each side to the midpoint of the boiler (as much as 24 or 25 ft). These blowers are withdrawn when not in use and rest on hangers with access platforms. When in use these blowers, with their air or steam nozzles, are traversed into the boiler for sequential blowing of superheater and reheater surfaces. The reason for sequential blowing is to minimize the air compressor and air storage tank size required, or the steam consumption demand. Soot-blower access platforms and furnace wall penetrations should be designed into the boiler initially, because it is either impossible, or very expensive, to discover later that more are needed. This very frequently has happened with coal-fired boilers. Boilers that were designed for oil or natural gas fuel can seldom be satisfactorily converted to use coal fuel. For example the furnaces are usually too small, the burners are not spaced properly, the tube spacing is too "tight," the tube surfaces may be "finned" in some places, and there is no space for soot-blower installation.

After the combustion gases pass through all the heat transfer surfaces, they must be passed through dust precipitators, and then possibly through "scrubbers" to remove sulphur compounds before the gas is discharged into the atmosphere. The dust collector consists of electrostatically charged plates or wires installed in a large boxlike structure. These devices are described in detail in Chapter 5.

Waste disposal is a major concern in coal-fired generating plants. Coal fly ash must be collected in electrostatic precipitators. Fly ash is ash that is carried in the combustion gases. Heavier ash will fall to the bottom of the boiler furnace, where it is collected in a hopper. Facilities must be provided to remove the dry fly ash from the precipitator hoppers, and the bottom ash from the boiler bottom hopper. The fly ash is usually removed by pneumatic conveyors to a storage silo system, from which it may be trucked away. In many cases the dry ash may be used in concrete construction. The boiler bottom ash may be water sluiced to a storage area, or the dewatering facility, from which it may be trucked to a landfill area.

Steam turbines for power generation have grown significantly in size in the last 30 years. Single-shaft units operating at the generator synchronous speed of 3600 rpm for 60 Hz generation, were limited in capacity to approximately 100,000 kW in 1950. Higher capacities were available at lower speeds. The largest earlier units were designed for 1200 and 1800 rpm. At lower speeds, such as 1800 rpm, the last stage diameter can be approximately twice that at 3600 rpm. There is a substantial economic advantage to the 3600 rpm unit, which has substantially reduced weight, stage diameters and, consequently, manufacturing cost. However, the principal effect of the higher speed has been that designers must now cope with higher pressures and temperatures.

The steam loading on the last row of turbine blades was limited earlier to 12,000 lb per hour and per square foot of exhaust annulus area. Later design and metallurgical improvements permitted an increase in allowable loading to 15,000 lb/hr-ft^2. This limit has remained in effect up to the present time.

Increasing the maximum capacity of the 3600 rpm turbine has been achieved over the years by: (1) doubling the capacity of the low-pressure section by using a "double-flow" exhaust (and even more than one double-flow exhaust section); (2) developing metallurgy and design to permit increasing the maximum length of the last stage blades from 23 to 25–26 in., then to 28–30 in., and finally to $33\frac{1}{2}$ in.; (3) increasing the throttle pressure from the 1450–1800 psig level to 2400 and 3500 psig; (4) increasing throttle steam temperature to 1000 F from the 900 to 950 F temperatures used more frequently in the 1930s and 1940s; (5) returning a portion of the steam after partial expansion to the boiler to be reheated and returned to the turbine. Reheating is a common practice now. The steam expands to approximately 500–700 psig, with a temperature of approximately 600 F, is reheated to 1000 F, and is returned to the turbine to continue its expansion. Such reheating increases the turbine efficiency and the maximum available capability for a specific last stage blade length.

At the present time the maximum capability that can be developed on a single shaft (tandem-compound) is approximately 1,100,000 kW. This is achieved by using three double-flow exhaust sections, each with maximum length last-row blades, a separate casing for the reheated steam intermediate-pressure section, and a separate casing for the high-pressure steam. Very few units of this type are in service, and most of these units were designed for lower capability at high efficiency.

Cross-compound (two shafts) turbine units have been employed occasionally to achieve greater capability and higher efficiency. Maximum capabilities have ranged from 500 to 1300 MW. Steam turbines are discussed further in Chapter 7.

Condensers are usually located below the turbine floor. Steam from each turbine exhaust section is discharged from the bottom. This arrangement usually requires two separate condenser shells, one below each exhaust section. This is done because the turbine must be supported by foundations between the two exhaust sections, and these foundations are made more economically and structurally sound if the condensing function is in two separate shells. In such an installation, the condenser tubes are perpendicular to the axis of the turbine, and access to the water boxes and tube installation is from one side of the unit.

Condensers have been designed for installation with the tubes parallel to the turbine axis, with the foundation structures "straddling" the longitudinal condenser. Such a condenser has tubes that are somewhat longer than in the perpendicular condenser.

In years prior to the 1970s, the large power plant units were nearly always located adjacent to available rivers, harbors, lakes, or on manmade lakes, so that cooling water could be pumped through the condensers from the body of water and discharged back to the source (with intake and discharge separated a sufficient distance to prevent recirculation of the heated water). This method of condensing water became known as the "once-through" arrangement.

The quality of condenser water required for a large turbine-generator could be around 400,000 to 500,000 gallons of water per minute (gpm). A power plant consisting of four 600 to 800 MW units would require 1,600,000 to 2,000,000 gpm of water.

The water used would be pumped through the condenser tubes and condense the steam, which would be exposed to the outside of the tubes. The water temperature would be increased by as much as 20 F. Environmentalists have claimed that variations in water temperature have adverse effects upon marine life. This has resulted in the application of cooling towers and other systems to many new power plants. (See Chapter 8 for a discussion of cooling towers.)

1.3 OTHER ELECTRIC POWER GENERATING SYSTEMS

While coal-fired plants constitute most of generating systems used in the United States and in most other parts of the world, other systems such as oil-fired and nuclear plants are available and frequently used. This section contains a brief description of several electric power generating systems.

Oil-Fired Power Plants

The use of fuel oil as a power plant fuel of prime importance began in the late 1950s when the price of crude oil dropped to around $2 per barrel. Prior to that time fuel oil was a relatively minor fuel. Light distillates were used in diesel engines, gas turbines, and smaller installations. The heavier grades of oils such as No. 6 were used for marine applications and emergency back-up for gas- and coal-fired power plants. Fuel oil did not play a major role in large power generation.

When the price of oil dropped, it became highly competitive with coal. The increased use of refined grades of gasoline for automobiles made available large amounts of all grades of residuals from the refining process. Beginning around 1960 many large central station coal-fired power plants were converted for oil firing. The conversions were feasible because the boiler internals, which were designed for coal, were more than ample for oil firing. The conversions consisted primarily of installing the oil burners, or gun, usually within the frame of the coal burners, and adding the necessary piping, pumps, tankage, and other equipment. In many cases the old coal-handling equipment was partially or completely dismantled, and over a period of years became difficult to reconvert to coal firing.

During the early and mid-1970s the oil-producing nations (OPEC) increased the price of crude oil, first to $12.00 per barrel, and later to $30.00 or higher. The oil price later receded to $25.00 per barrel.

In addition to the conversion of existing coal-fired plants to burn oil, many new plants were designed and built to burn only oil. The boiler designed for burning oil cannot be converted to burn coal without substantial derating. There are several reasons for this: (1) Furnace volumes and tube spacing can be "tighter" for oil firing. Coal firing would cause considerable "slagging" of surfaces; (2) Space for coal-handling facilities were not provided in the initial design of the oil-fired unit.

At the present time approximately 10% of the power generation in the United States is oil fired (down from 17% in 1974). It is expected that the percentage of oil fuel will continue to decline, because there is no long-range prospect of oil price declining, in comparison to coal. It is not expected that any new large oil-fired central stations will be built in the foreseeable future.

Fuel oil for power generation consists, basically, of two grades, both of which are by-products of the oil-refining process. No. 2 distillate oil is a light oil (specific gravity 0.8654 at 50 F) and usually contains 0.4 to 0.7% sulphur. It is used for gas turbines, diesels, and small industrial boilers. No. 6 residual oil is much heavier (specific gravity 0.9861 at 60 F) and contains up to 2.8% sulphur. No. 6 oil is the grade that generally has been used in large central station boilers. This latter grade of oil has a viscosity of up to 3000 SUS (Saybolt universal seconds) at 122 F, and must be heated to approximately 200 F to become free-flowing and suitable for atomizing in the burners.

Oil facilities at an oil-fired power plant must include storage tanks (with containing dikes), unloading pumps, and steam heaters. Storage tanks usually are sized to provide several weeks, or months, of storage capacity. Smaller tanks are usually installed near the boilers to provide flexibility in operation. These latter tanks are called "day-tanks."

Turbine system and other parts of oil-fired plant are similar to those in a coal-fired unit.

Natural Gas-Fired Plants

Natural gas-fired plants made up approximately 15% of the electric generation in the United States in 1981. Gas plants are located principally in the west southcentral