1.18

The dry, pulverized coal is fed by a pressurizing feedder (kinetic extruder) and a fluidizing feeder to the gasifier. The gasifier consists of a bottom combustion section and a top reduction section. The coal is fed into both sections. The molten slag flows into a water-quench tank. Sulfur is removed from the hot gas by two processes: *in situ* and final desulfurization. *In situ* desulfurization is achieved by limestone injection. Final desulfurization is performed by a moving bed, zinc ferrite system downstream of the gasifier. The cleaned, low heating value gas is used in a combined cycle system to generate 65 MW of electricity. The construction is planned to start by the end of 1992.

1.3. FLUIDIZED BEDS

1.3.1 Combustion

(i) *Processes.* Combustion of coal in fluidized beds is becoming increasingly common. The atmospheric, fluidized bed combustion (AFBC) technology has been commercialized in the last two decades; the pressurized, fluidized bed combustion (PFBC) is in the demonstration phase. The fluidized bed technologies are among the most important recent development in coal combustion. Today, the fluidized bed boilers compete with the stoker boilers in small sizes and with the pulverized coal fired boilers in large sizes. Only a decade ago the stokers dominated in small sizes and the pulverized coal fired boilers in larger sizes, with little overlap (ref. 48). The fluidized bed boilers, as more important, are emphasized here; the fluidized bed furnaces are similar.

A fluidized bed consists of a bed of particles set in vigorous, turbulent motion by the combustion air blowing upward through the bed, illustrated earlier in Fig. 1.3. The particles are mostly inert materials such as coal ash or sand, or sulfur sorbents such as limestone or dolomite. The coal particles make up only around 1% of the bed mass. At low air velocities, the air flows through the bed without disturbing the particles and the bed remains fixed. At velocities greater than the minimum fluidizing velocity, the bed is fluidized and the air flows through the bed in bubbles; thus the bubbling fluidized bed (BFB). At velocities approaching or greater than the free fall velocity of the particles, the particles become entrained in the air and are carried out of the furnace. The entrained particles are separated from the combustion gases in a cyclone and circulated back to the bed; thus the circulating fluidized bed (CFB) (ref. 49).

The basic aspects of the atmospheric, bubbling fluidized bed are illustrated in Fig. 1.19. The run-of-mine coal is crushed to less than 3.2 cm (1 1/4 in.) top size for overbed feed systems. For underbed feed systems the coal is crushed to less than 0.6 to 2.5 cm (1/4 to 1 in.) top size and it must be dried to less than 6% surface moisture for pneumatic conveying (ref. 50). If the run-of-mine limestone is used then it must also be crushed. The crushed coal and limestone are fed to the fluidized bed of coal ash and limestone particles. To start combustion, the bed is preheated to 700 to 811 K (800 to

1000°F) depending on the particular coal properties. The coal particles, introduced in the fluidized bed, heat, dry, devolatilize, ignite, and burn leaving ash; the residence time of the coal particles in the bed is typically around 1 min. and usually sufficient for 80 to 90 % burnout. The temperature of the bed is increased to the operating temperature, usually 1120 K (1550°F); it is maintained at this relatively low level by removing enough heat, usually 40 to 45% of the heat input, with an in-bed heat exchanger. The limestone particles, introduced into the bed, heat and calcine; the calcium oxide then reacts with sulfur dioxide to form calcium sulfate. Due to intensive mixing, the heat transfer rates in the bed are high and the temperature of the bed is uniform. For the same reason, the heat transfer rate between the bed and the in-bed heat exchanger is high in spite of the low bed temperature. The low bed temperature prevents formation of the thermal nitric oxides and helps reduce the fuel nitric oxides. It also helps reduce slagging and fouling.

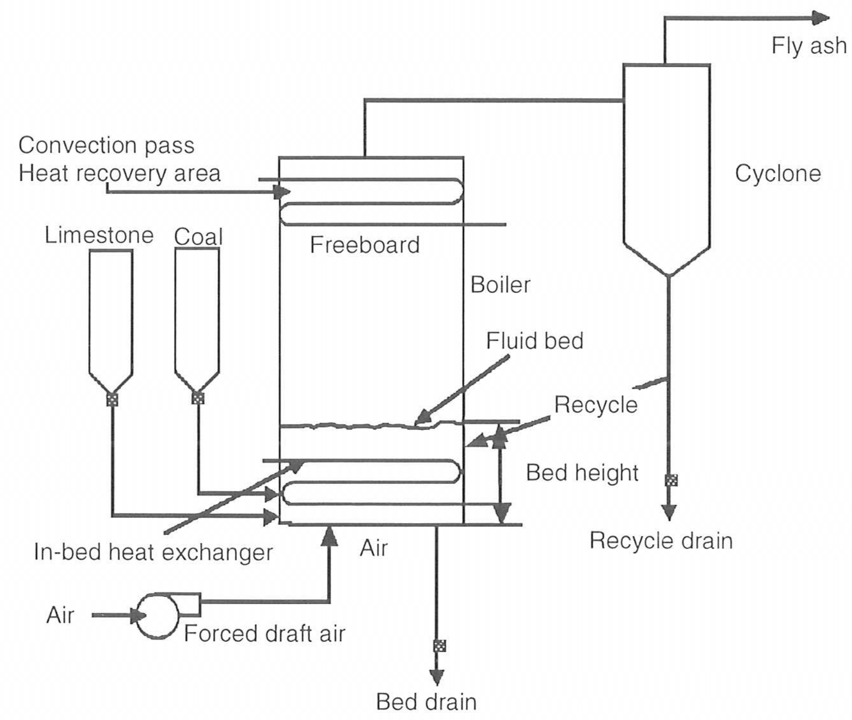

Fig. 1.19 Bubbling fluidized bed schematic (published with permission from ref. 50).

Some coal, coal ash, and limestone particles are thrown out of the bed in a freeboard zone. The freeboard zone provides additional space and time to complete coal combustion, increase sulfur dioxide capture, and destroy a portion of the nitrogen oxides released in the bed. An additional 10 to 20% burnout is achieved. The large particles decelerate and return to the bed; the small particles are entrained and must be removed in a cyclone. The unburnt carbon and the unreacted limestone contents in the separated particles are usually high and justify recycling to the bed. The remaining fly ash is removed in an electrostatic precipitator or a fabric bag filter.

The atmospheric, circulating fluidized beds, developed more recently, are becoming increasingly important for the large units. The circulating fluidized bed is similar to the bubbling bed; the differences stem from smaller coal and limestone particle sizes and higher gas velocities. The bed fills the entire furnace volume although most of the mass is still in the lowest third of the bed. A large portion of the solids is carried out of the furnace, separated in the cyclone, and recirculated to the furnace. Thus combustion takes place throughout the furnace as well as in the cyclone.

Chemical and physical processes in the fluidized beds are similar as in the entrained beds. The main distinguishing features of the fluidized beds are: more complex flow of solids dependent but very different from the flow of gases, desulfurization in the bed, and the increased dependence of the reaction rates on diffusion. At atmospheric pressure, limestone is the preferred sorbent. The limestone calcines to form the calcium oxide and to develop pores:

$$CaCO_3 = CaO + CO_2 \tag{1.9}$$

The sulfur dioxide penetrates the pores and reacts with the calcium oxide to form the calcium sulfate:

$$CaO + SO_2 + 1/2\ O_2 = CaO_4 \tag{1.10}$$

which can be removed with the ash. At high pressure limestone may not calcine because the carbon dioxide partial pressure is greater than the equilibrium dissociation pressure (ref. 51); dolomite is the preferred sorbent. The calcination of the dolomite proceeds as follows:

$$Ca\,CO_3 \cdot Mg\,CO_3 = Ca\,CO_3 \cdot MgO + CO_2 \tag{1.11}$$

The partially calcined dolomite reacts with the sulfur dioxide according to:

$$Ca\,CO_3\ MgO + SO_2 + 1/2\ O_2 = Ca\,SO_4\ MgO + CO_2 \tag{1.12}$$

The magnesium oxide does not form the magnesium sulfate because the magnesium sulfate is not stable at typical fluidized bed temperatures. Its role is to open up pores for the calcium carbonate reaction (ref. 49).

The main advantages of fluidized bed combustion are:

1. the substantial reduction of SO_X during combustion eliminating the need for post-combustion SO_X control processes; NO_X is also somewhat lower;
2. the high heat transfer rates in the bed resulting in compact furnaces and heat transfer exchangers and
3. the low combustion temperature reducing slagging and fouling and the dependence on coal ash properties.

The fluidized bed boilers can burn a wide variety of coals, including high sulfur coal, cleanly and efficiently. However, there are also some disadvantages (ref. 48):

1. the increased erosion of virtually all components handling solid because of the high solids loading;
2. the refractory failures particularly for the circulating fluidized beds;
3. the increased quantities of the solid waste because of the sorbent; for 90% SO_2 removal, the fluidized bed boilers require Ca: S ratios of 2:1 to 5:1, the wet scrubbers around 1, and the spray dryers around 1.2 to 1.5;
4. the increased emission of the nitrous oxide, N_2O, with respect to pulverized coal and stoker firing; the nitrous oxide has been implicated as a greenhouse gas and an ozone layer depleter and
5. the reliability of the large units has to be proven in the industrial and the utility practice.

(ii) *Technologies.* Fluidized bed combustion technologies are still in the state of intensive development: there are many different overall and component designs but not much unification yet. The technologies will only be illustrated by describing several important fluidized bed projects. The atmospheric, fluidized bed technology has been demonstrated for utility boilers in units up to 100-150 MW (ref. 48). Two such boilers will be presented in this section. However, utility boilers are often in much larger units of 300-400 MW and, sometimes, even in units up to or exceeding 800 MW (ref. 27). For these larger units the pulverized coal combustion technology is still the technology of choice. The pressurized, fluidized bed technology for utility-size boilers is presently being demonstrated. An example for this technology will be presented in the section on developments.

An example of the bubbling atmospheric fluidized bed combustion technology is the Northern States Power Company's Black Dog Unit 2 (ref. 50). The plant burned a blend of the Illinois No. 6, high volatile, bituminous coal and a low sulfur, western subbituminous coal to meet the emission limits for sulfur. The switch from the original design coal, the Illinois No. 6 coal, to the western coal blend resulted in increasing furnace deposits and derating from 100 MW to 85W. The unit was retrofitted with a bubbling AFBC boiler to increase the rating with the western coal to 130 MW while

Fig 1.20 cont on next page

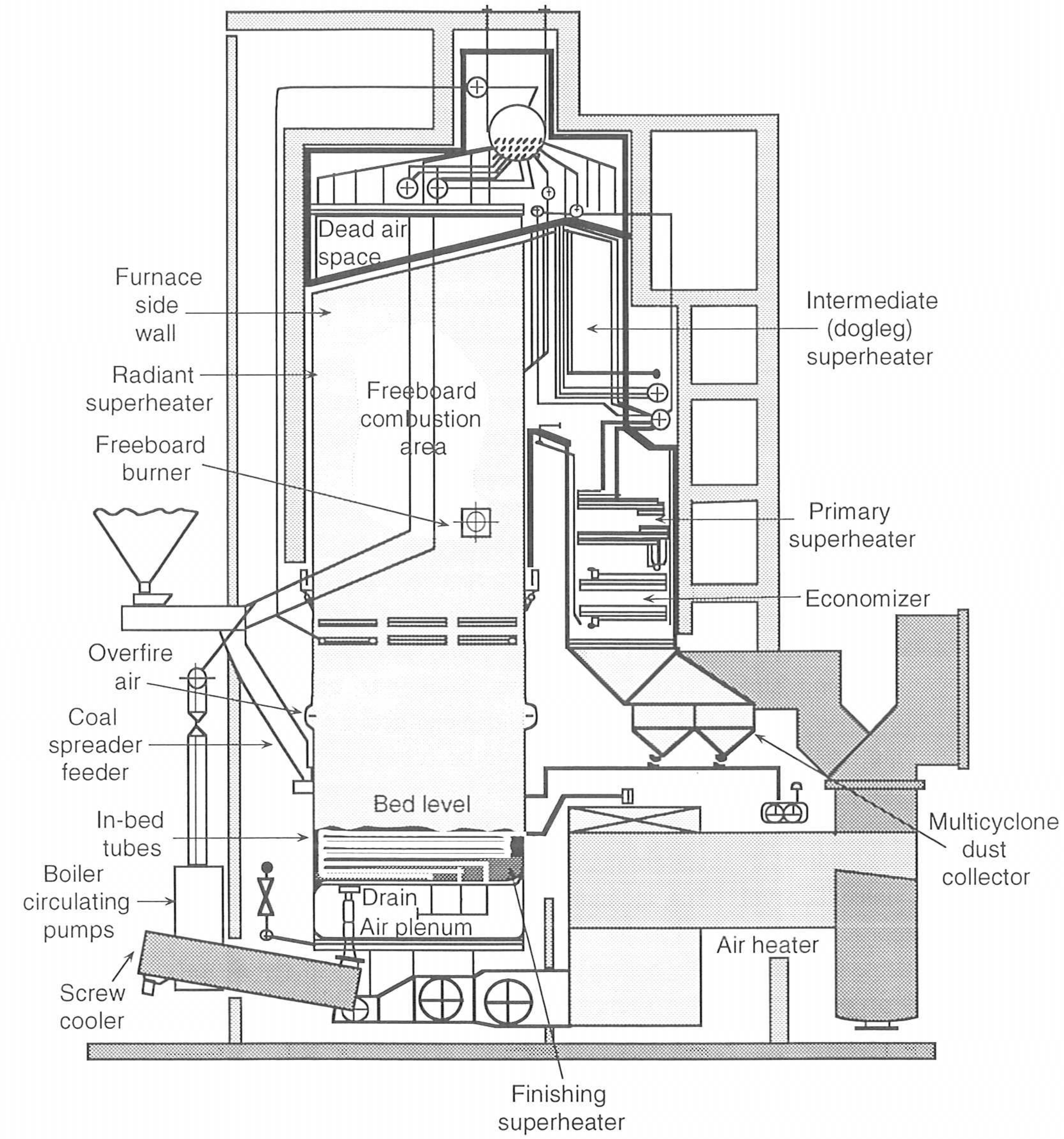

Fig. 1.20 Black Dog bubbling AFBC boiler (published with permission from ref. 50).

preserving low emissions. The design emission limits were 17.2 mg/MJ for particulates and 516 mg/MJ for SO_2. The boiler is shown in Fig. 1.20.

A system was added for storage, crushing, transporting, and feeding the limestone. The fluidized bed area is divided into the center cell and two side cells, separated by water-cooled walls. The independent operation of cells provides turndown to 25% of the maximum rated capacity. The center cell has 6 overbed spreader/feeders, 2 limestone ports, and 12 recycle ports. The steam side includes in-bed superheaters. The convection pass is similar to the convection passes for the pulverized coal boilers. Multicyclones collect the larger particles of fly ash containing the unburned carbon and the unreacted limestone. The collected material is recycled to the fluidized bed. The existing electrostatic precipitator was upgraded to accommodate the greater capacity.

The Black Dog Unit 2, retrofitted with the bubbling AFBC boiler, was placed in commercial operation in 1986. The plant performance was rated in terms of availability, boiler operating statistics, and on-line startups. The availability for a test period in 1988, including outages to prepare for the boiler performance tests, was 58.3%. The boiler performance tests indicated that the boiler efficiency at full load was 86.8%. The cold starts required approximately 8 hours; the hot restarts required around 1 hour.

One of the important features of bubbling, fluidized beds is the feeding method. There are two in use:

1. The overbed feeders (spreader stokers) feed the coal and the limestone over the bed surface; they are simpler but may result in lower coal and limestone utilization efficiency.
2. The underbed feeders feed the coal and the limestone through many feeder pipes into the bottom of the bed; the current practice requires a coal feed point for every 0.9 to 1.9 m^2 (10 to 20 ft^2) of the bed area; they are more complex and costly but yield better coal and limestone utilization efficiency.

The circulating AFBC boilers are similar in many respects to the bubbling AFBC boilers. Some of the important differences are listed below:

1. The circulating AFBC boilers are taller and have smaller cross section because of higher gas velocities.
2. The circulating AFBC boilers usually do not include the in-bed heat exchangers because of potential high velocity erosion.
3. The cyclone in the circulating AFBC boilers is located before the convection pass to protect the convection surfaces from erosion due to high solids loading and velocity; the cyclone thus operates at high temperatures.
4. The feeding system in the circulating AFBC boilers, because of enhanced solids mixing, requires an order of magnitude fewer feed points.

An example of the circulating atmospheric fluidized bed combustion technology is the Colorado-Ute Electric Associations's Nucla Power Station (ref. 50). The station used to burn a local coal in three stoker-fired boilers. It was repowered with a circulating AFBC boiler to produce 110 MW at low emission levels. The design emission limits were 12.9 mg/MJ for particulates, 172 mg/MJ for SO_2, and 215 mg/MJ for NO_x. The boiler is shown in Fig. 1.21.

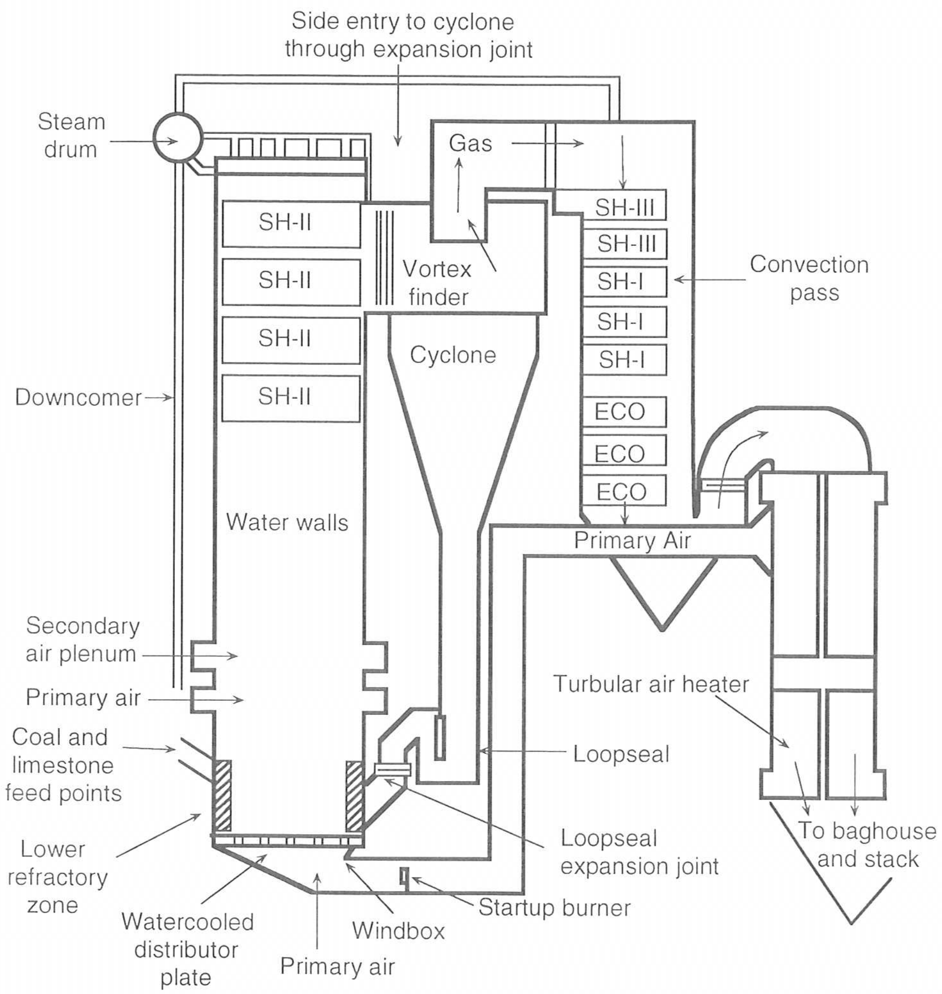

Fig. 1.21 Nucla circulating AFBC boiler (published with permission from ref. 50).

The furnace consists of two combustion chambers. The coal is fed to each combustion chamber through 3 ports. The limestone is injected at 4 points in each chamber. The NO_x production is reduced by two-stage combustion using primary and secondary air supplied to combustion chambers. The hot gases and particulates are separated in two cyclones and particulates are returned to the combustion chambers. The hot gases and remaining fly ash flow through the convection pass. The convection pass is similar to the convection passes for the pulverized coal boilers. The fly ash is collected in four fabric filters-baghouses.

The Nucla Power Station, repowered with the circulating AFBC boiler, was brought to full load in 1988. The results of acceptance testing indicated boiler efficiency of 88.5% and sulfur retention of 70% at Ca/S ratio of 1.73. The particulates were under 5% opacity. The NO_x emission was approximately at one half of the design limit of 129 mg/MJ. The SO_2 emission was maintained at the compliance level of 172 mg/MJ.

One of the important design features of the circulating fluidized beds is the location of heat transfer surfaces. There are two approaches:

1. The external heat exchanger for the solids returning from the hot cyclone.
2. The heat exchangers in the upper part of the furnace.

The first one is more complex; the second is simpler but it exposes the high temperature heat exchanger tubes to a strongly erosive environment.

(iii) *Developments.* Fluidized bed combustion technologies are being developed in many countries of the world. These technologies are attractive for developed countries because of their ability to control and reduce pollution during combustion and for developing countries because of their ability to burn a wide variety of low quality fuels effectively. Some of these technologies being developed in Europe were listed in Tables 1.8 and 1.9. The fluidized bed combustion technologies being developed and demonstrated in the United States under the Clean Coal Technologies Demonstration Program were presented in Table 1.11.

The project "Tidd PFBC Demonstration Project" at the Ohio Power Company's Tidd Plant, Fig. 1.22, is described in more detail as a representative of these developments (ref. 31). The project objectives are: to demonstrate PFBC at a 70 MW scale, to verify PFBC in a combined cycle application, to achieve more than 90% SO_2 removal and less than 86 mg/MJ NO_x, and to attain an overall power plant efficiency of 38% using the existing steam system.

The pressurized, bubbling fluidized bed is operating at 1.2 MPa; the combustion air is supplied by the gas turbine compressor. The coal-water paste is fed to the bed of coal ash and dolomite sorbent. The hot combustion gases and entrained particles pass through the cyclones to remove 98% of the particles. The hot gases are then expanded in the gas turbine to generate 16 MW of electricity. The gases exiting the gas turbine are further cooled in the waste heat exchanger heating the boiler feedwater. The gases are cleaned in the electrostatic precipitator prior to being discharged. The feedwater is converted to superheated steam in the PFBC boiler. The steam passes through the steam turbine to produce an additional 58 MW of electricity. The three year operation and testing phase started in 1991.

1.3.2 Gasification

(i) *Processes.* Physical and chemical processes in fluidized bed gasification are similar to processes in fluidized bed combustion. The main differences, including a short discussion of gasification reactions, are outlined in Section 1.22 and will not be

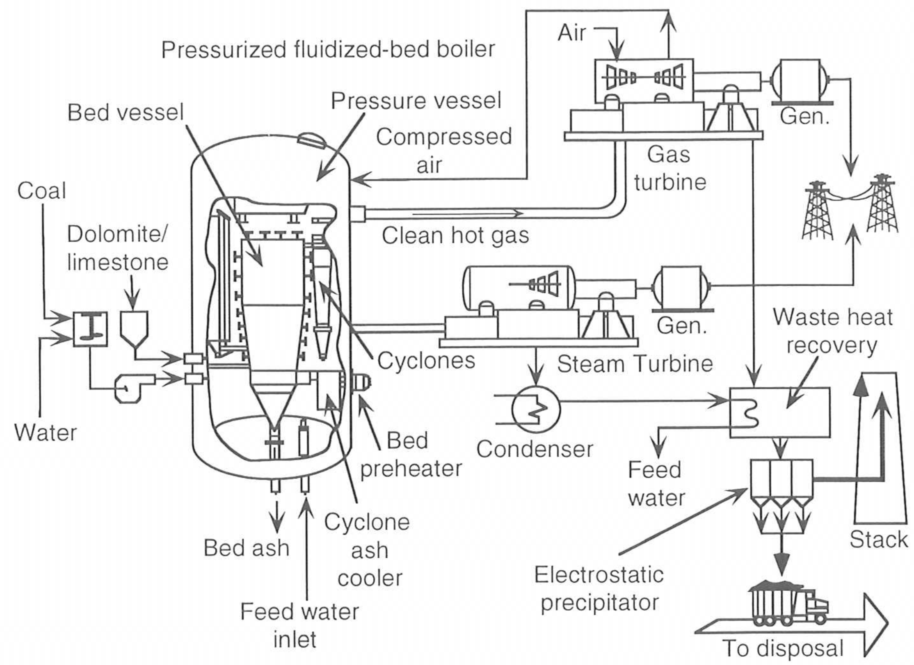

Fig. 1.22 Tidd PFBC demonstration project (published with permission from ref. 31).

repeated here. In the fluidized bed gasifiers, just as in the entrianed bed gasifiers, the devolatilization products are released in the region of high temperature and excess oxygen. Thus, tars, oils, phenols and hydrocarbon gases are cracked and oxidized to carbon monoxide, hydrogen, carbon dioxide and steam.

The main charactertisics of fluidized bed gasification are: high char recycling rate, uniform and moderate temperature, moderate oxygen and steam requirements, difficulties in handling caking coals, and difficulties in obtaining high carbon conversion for high rank coals (ref. 28).

(ii) *Technologies.* Fluidized bed gasification technologies, just like fluidized bed combustion technologies, are still in the state of development. They will be illustrated by describing a commercially proven gasifier: the Winkler gasifier.

The Winkler gasifier, shown in Fig. 1.23, is an atmospheric pressure, fluidized bed gasifier. The gasifier is also offered at pressures up to four atmospheres. The feed coal is crushed to less than 9.5 mm size and fed through a variable speed screw feeder to a fluidized bed in the lower portion of the gasifier. The gasifier is a refractory-lined, steel-shell cylinder. The fluidized bed occupies around one third of the gasifier volume; the remainder is a freeboard. Steam and oxygen or air are blown through a grate at the bottom of the gasifier fluidizing the bed and reacting with the coal.

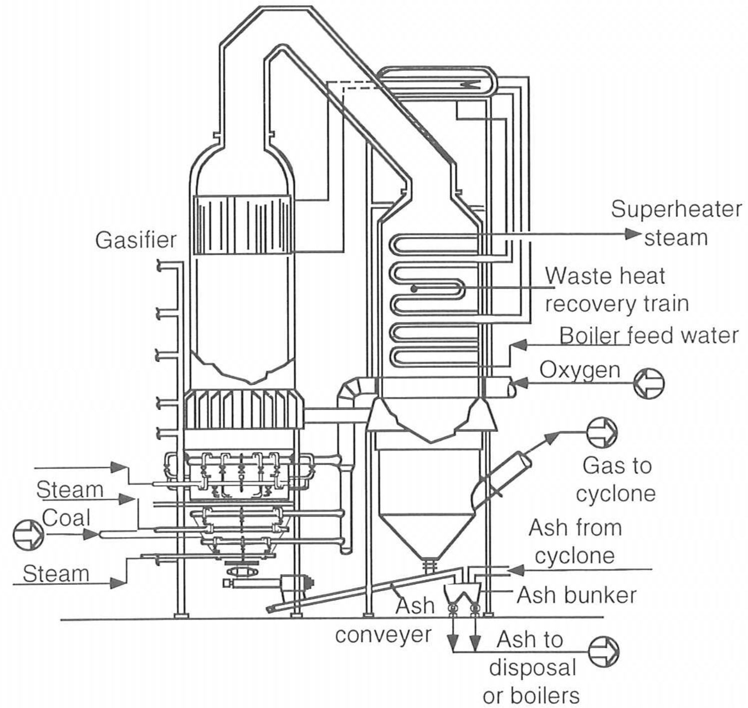

Fig. 1.23 Winkler gasifier (published with permission from ref. 45).

The coal bed temperature is usually kept between 1070 and 1370 K to avoid ash fusion. At these temperatures, the coal is converted primarily to CO, H_2, and CO_2 and small amounts of CH_4; no tars or other heavy hydrocarbons are present. These relatively low temperatures restrict the Winkler gasifier to more reactive lignites and subbituminous coals. The reactivity of higher rank coals is, as a rule, insufficient at these temperatures. The heavier ash particles are removed from the bottom of the gasifier by a water-cooled screw conveyor. The lighter particles are entrained in the gas and carried over to the freeboard. The unconverted carbon from these particles reacts with steam and oxygen or air, blown in the freeboard; some of the ash particles melt. To solidfy these molten ash particles, the gas is cooled by approximately 200 to 220 K in a radiant steam boiler installed inside the gaisifer at the top. The product gas is further cooled in a waste heat boiler and cleaned in a cyclone, a wet scrubber, and an electrostatic precipitator. The cooled and cleaned gas is then desulfurized in a sulfur removal system. A typical commercial Winkler gasifier is 5.5 m in diameter and

23 m in height. It can gasify approximately 110 t/d of coal at atmospheric pressure and 1800 t/d of coal at four atmosphers (refs. 45, 52).

More recently, the Winkler process seems to be evolving into the High Temperature Winkler (HTW) process. This process is designed to operate at higher pressures and temperatures (ref. 53).

(iii) *Developments.* Fluidized bed gasification technologies are being developed in the United States, Europe, and Japan. Some of the important technologies in demonstration or development are: Coal Mining Research Center, Japan; Exxon (Exxon Catalytic); Institute of Gas and Technology (U-GAS), Kellog/Rost/Westinghouse (KRW); Rheinische Braunkohlenwerke (HTW), Germany. Some of these technologies being developed in Europe were listed in Table 1.8 and 1.9. The fluidized bed gasification technologies being developed and demonstrated under the Clean Coal Technologies Demonstration Program were presented in Table 1.11.

The "Pinon Pine IGCC Power Project," Fig. 1.24, at Sierra Pacific Power's Tracy Station in Reno, Nevada is described as a representative of these development (ref. 31). The project objectives are: to demonstrate an air-blown, fluidized bed gasification technology incorporating hot gas cleanup; to evaluate a low-heating value gas combustion turbine, and to assess reliability, availability, and maintainability at commercial scale.

The dried, crushed coal is fed into a KRW pressurized, air-blown, fluidized bed gasifier through a lock hopper system. The coal bed is fluidized by blowing air and steam through special nozzles into the bed. Crushed limestone is also fed into the gasifier to absorb sulfur and to inhibit conversion of fuel nitrogen into ammonia. The product gas passes thorugh cyclones to remove particulates and through a hot gas cleanup system, a fixed bed of zinc ferrite sorbent, to remove remaining sulfur. The cleaned, low-heating value gas is used in a combined cycle system, a gas turbine and a steam turbine, to produce 80 MW of electricity. The project was selected by the Department of Energy at the end of 1991.

1.4 FIXED BEDS

1.4.1 Combustion

(i) *Processes.* Combustion of coal in fixed beds (*e.g.,* in stokers) is the oldest method of coal use and it used to be the most common. In the last two decades stokers have lost part of their traditional market to fluidized beds. In the lower range of capacities the market had been lost to gas years ago.

The basic aspects of fixed bed combustion are illustrated in Fig. 1.25. The run-of-mine coal is crushed typically to 95% less than 3.2 cm (1 1/4 in) and 20-60% less than 0.6 cm (1/4 in) (refs. 37, 55). The crushed coal is fed-pushed, dropped, or thrown-on a slowly moving bed of coal particles on a grate. The raw coal is heated, dried, devolatilized, and burned, leaving ash. The layer of ash protects the grate from

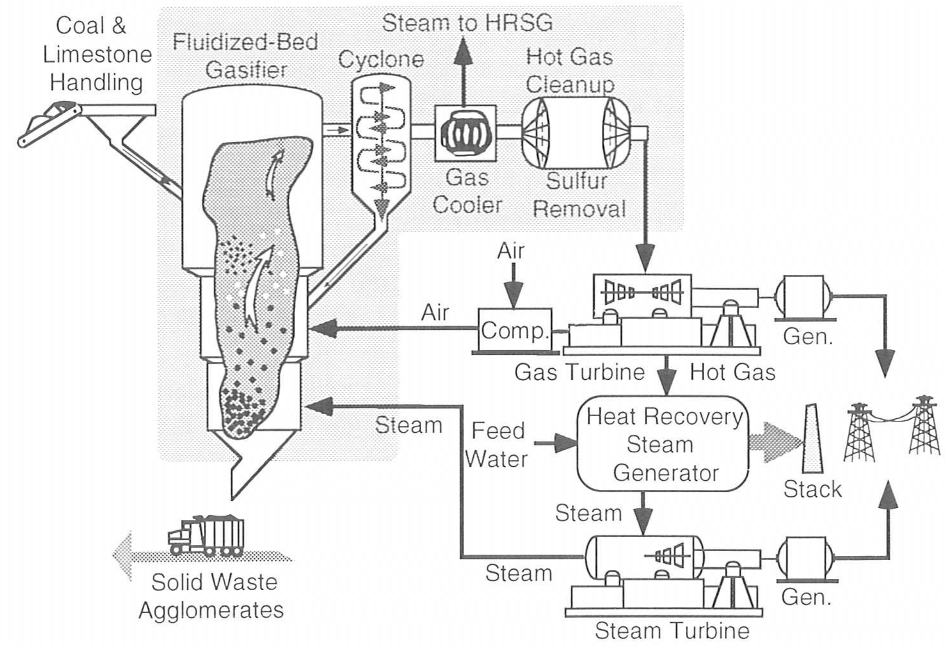

Fig. 1.24 Pinon Pine IGCC power project (published with permission from ref. 31).

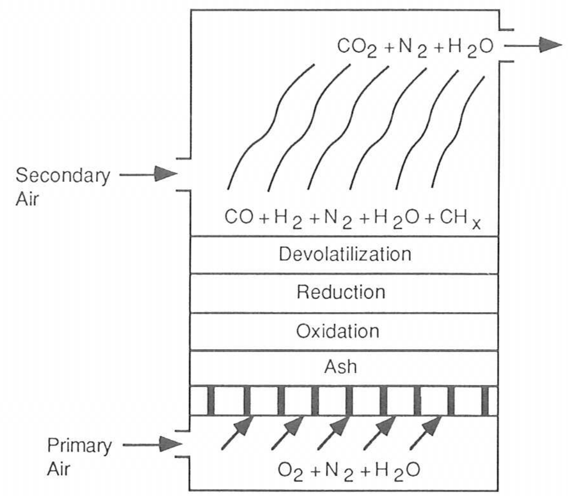

Fig. 1.25 Fixed bed schematic (adapted with permission from ref. 54).

excessive heat. The primary air flows upward through the grate and through the bed of coal particles. It is heated in the ash zone and reacts with the char in the oxidation zone. The char burns to carbon monoxide and carbon dioxide but, in the presence of oxygen, most of the carbon monoxide is converted to carbon dioxide. Most of the oxygen is consumed in the oxidation zone. In the reduction zone, a part of the carbon dioxide reduces to carbon monoxide. More combustible gases are added in the devolatilization zone. The combustible gases from the reduction and the devolatilization zones must be burned in the space above the bed. The burning is facilitated by introducing secondary or overfire air. The fixed bed processes may be classified according to the flow patterns of coal and air as countercurrent, crosscurrent, and cocurrent processes.

Chemical and physical processes in the fixed beds are similar to those in entrained and fluidized beds. The main distinguishing features of the fixed beds are: the flow of solids almost independent from the flow of gases and the increased dependence of the reaction rates on diffusion.

(ii) *Technologies.* The fixed bed combustion technologies are well established technologies, and a great variety of stokers is in use today. They are commonly classified, based on the way in which coal is fed onto the grate, as spreader stokers, overfeed stokers, and underfeed stokers (ref. 55). These categories are, in general, equivalent to countercurrent, crosscurrent and cocurrent processes, respectively. Within each category, the stokers differ according to the way in which the grate handles the ash. Each category will be discussed and illustrated.

Spreader stokers are the most commonly used type of stokers. A traveling grate spreader stoker is shown in Fig. 1.26. The coal is thrown and spread over the entire grate surface by mechanical feeders. There is some burning of the suspended coal fines above the bed. It is this suspension burning, coupled with a very thin coal bed, which allows fast response to load changes. The smaller spreader stokers use the dumping grates while the larger ones use the continuous discharge grates. The most common type is the traveling grate shown in Fig. 1.26; the reciprocating and the vibrating grates are less common. The spreader stoker can fire a wide range of coals. It has high availability, simplicity of operation, and high operating efficiency, but it also has high fly-ash carry-over and high fly-ash combustible heat loss (ref. 55).

A traveling grate overfeed stoker is shown in Fig. 1.27. The coal is fed onto the grate from a coal hopper. The coal depth is adjusted by a coal gate. The coal is burned as it passes slowly through the furnace. The ash is discharged continuously into an ash pit. The overfeed stokers use the chain grate, the traveling grate, and the water-cooled vibrating grate. The overfeed stokers are characterized by low fly-ash carry-over. They burn most coals but high coking coals can be a problem. Their response time is longer than that of the spreader stokers. The overfeed stokers require larger grate sizes than the spreader stokers of the same capacities (ref. 55).

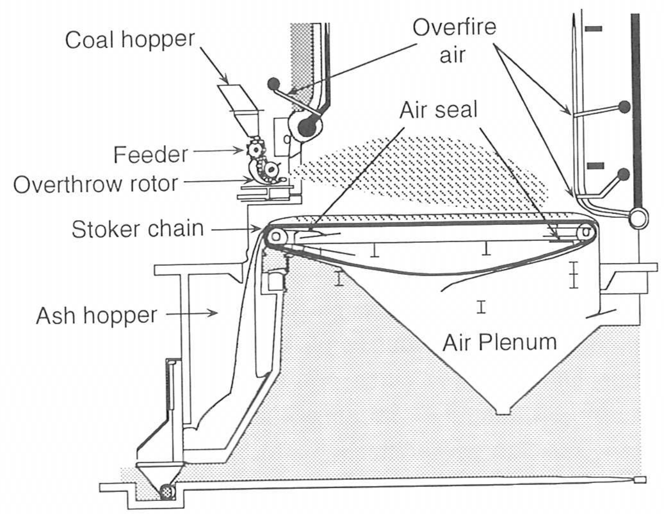

Fig. 1.26 Traveling grate spreader stoker (published with permission from ref. 35).

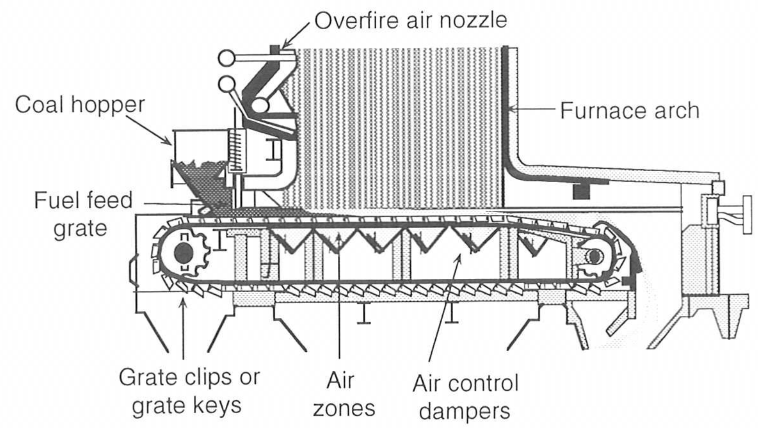

Fig. 1.27 Traveling grate overfeed stoker (published with permission from ref. 56).

A multiple retort, underfeed stoker is shown in Fig. 1.28. The coal is introduced through long retorts below the level of air tuyeres. Thus, the raw coal is at the bottom, the ash moves away from the retort at the top, and combustion takes place in between. The smallest underfeed stokers use the single and the double retort. The coal is fed by a screw or a ram. The ash is usually discharged with the side-dumping grates. The larger underfeed stokers are the multiple retorts inclined at an angle of 25° to 30° to aid the flow of coal and ash. The ash is discharged either intermittently or continuously. The underfeed stokers operate with very thick coal beds causing a high thermal intertia and a slow response to load changes. They have trouble burning high coking coals, low ash bituminous coals, and loose ash subbituminous coals because of the grate overheating. On the other hand, the underfeed stokers have a clean smokeless combustion and low fly-ash carry-over (ref. 55). The smokeless combustion comes from feeding the coal under the combustion zone. The volatiles escape from the raw coal, flow upward through the combustion zone, and burn almost completely while passing through the zone.

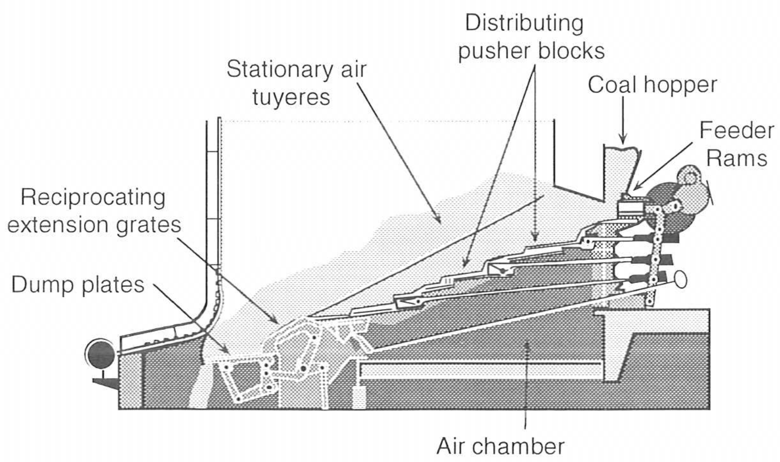

Fig. 1.28 Multiple retort underfeed stoker (published with permission from ref.56).

(iii) *Developments*. There has been little research or development of the fixed bed combustion technologies recently. The last major effort was funded by the American Boiler Manufacturers Association (ABMA), the U.S. Department of Energy (DOE), and the U.S. Environmental Protection Agency (EPA) between 1977 and 1979 (refs. 55, 57, 58). The main objective of this extensive test program was to reduce emissions and improve efficiency of stoker boilers. The measurements were performed on eighteen stoker boilers, six spreader stokers, seven overfeed stokers, and five underfeed stokers. The spreader stokers were all with the traveling grates. Of

the overfeed stokers one had the vibrating grate, three the traveling grate, and one the chain grate. All but one of the underfeed stokers used the multiple retorts; one had the single retort. The operating variables included heat release rate, excess air, overfire air, fly-ash reinjection, and coal properties. The measurements included both uncontrolled and controlled particulate loading, nitrogen oxides, sulfur oxides, oxygen, carbon dioxide, carbon monoxide, unburned hydrocarbons, combustibles in the fly-ash and bottom-ash, particle size distribution, and boiler efficiency. The particulate loading was found to be largely dependent on stoker type and degree of fly-ash reinjection. It increased with the heat release rate but, in many cases, it could be controlled with the overfire air. The nitric oxide increased with the excess air and the grate heat release rate. The overfire air, as it existed in the boilers at that time, did not affect the nitric oxide. The results also addressed other relationships between the operating variables and the measured emissions and efficiency. Based on these tests, the guidelines for clean and efficient operation of stoker boilers were also prepared (ref. 55).

The improved overfire air systems for nitric oxide reduction were discussed by Lisauskas and McHale (ref. 59). The overfire air, the limestone addition, and the flue gas recirculation for the reduction of nitrogen and sulfur oxides were discussed by Angleys (ref. 60). Two flue gas recirculation systems for stokers were described in a recent review of systems for controlling nitric oxides from coal combustion (ref. 61).

1.4.2 Gasification

(i) *Processes*. Fixed bed gasification is an important commercial gasification process. Eighty-nine percent of the coal gasified in the world is gasified by the fixed bed, ten percent by the entrained bed, and only one percent by the fluidized bed process. The fixed bed process is also a process of chioce for mild gasification. Fixed bed gasification processes, just like fixed bed combustion processes, may be classified according to the flow patterns of coal and air as countercurrent, cocurrent, and crosscurrent presses.

The countercurrent process is the most common fixed bed gasification process. The coal is fed to the top of the reactor and moved downward under gravity, countercurrent to the rising gas stream. The dry or slagging ash is removed from the bottom of the reactor. The feed gas is commonly composed of air or oxygen and steam. The excess steam is supplied to the gasifier to control the ash temperature. As the coal slowly descends, the hot gases produced in the gasification and combustion zones exchange energy with the colder solid. The water vapor and subsequently the volatile matter are released when the coal reaches sufficiently high temperatures. After the drying and the devolatilization zones, the char enters the gasification zone where carbon reacts with steam, carbon dioxide, and hydrogen. The endothermic reactions in this section produce carbon monoxide and hydrogen. The slightly exothermic reaction of hydrogen with carbon produces methane. Differentiation between the "gasification zone" and the "combustion zone" is based on the presence or absence of free oxygen. Combustion and gasification reactions can occur simultaneously in the "combustion zone." Combustible gases such as carbon monoxide or hydrogen may react with oxygen. The exothermic combustion reactions provide the necessary energy for the endothermic gasification reactions and drying. The blast gas, which is composed of steam and air or oxygen, is heated by the hot ash.

The solid residence times in the drying, devolatilization, gasification, and oxidation zones may be on the order of several hours. The residence time in the ash zone may be even higher depending on the thickness of this zone. The gas residence time is on the order of seconds. The solid and gas temperature gradients are highest in the devolatilization and oxidation zones. In the countercurrent fixed bed gasifiers, as opposed to the entrained and the fluidized bed gasifiers, the devolatilization products are released in the region of relatively low temperature and lack of free oxygen. Thus, tars, oils, and heavier hydrocarbon gases are neither cracked nor oxidized, but added to the product gas. This may be a disadvantage but it may also be used to advantage as in the mild gasification processes.

The concept of the cocurrent fixed bed gasifiers is not new but the gasifiers of this type have never reached a commercial status for processing coal; the cocurrent gasifiers have been successfully applied for processing biomass materials. The crosscurrent gasification processes are less common: the rotary kiln gasifiers are the best known example.

Physical and chemical processes in fixed bed gasification are similar to processes in fixed bed combustion. The main differences are outlined in Section 1.2.2 and will not be repeated here. The main characteristics of fixed bed gasification are: minimal pretreatment of feed coal; high thermal efficiency; low oxidant requirements; relatively high methane content in the product gas; tars, oils, and heavy hydrocarbon gases in the product gas; difficulties in handling coking coals; and difficulties in handling coal fines (ref. 28).

(ii) *Technologies*. Fixed bed gasification technologies have been applied extensively. They will be illustrated by describing a commercially proven, fixed bed gasifier: the Lurgi gasifier.

The Lurgi gasifier, shown in Fig. 1.29, is a dry-ash, oxygen-blown, fixed bed gasifier. The feed coal, typically sized from 5 to 50 mm, enters the top of the bed through a lock hopper and moves downward under gravity. The coal movement is controlled by a distributor or a stirrer and a rotary grate. The ash falls from the grate and is removed through another lock hopper. Steam and oxygen enter the gasifier below the grate, move upward, and react with the coal. The dry-ash Lurgi gasifier requires a large quantity of steam to reduce the combustion zone temperature below the ash fusion temperature. Some of this steam is generated in a water jacket around the gasifier. Only a small part of steam reacts with the coal. The temperatures are very non-uniform because of the countercurrent flow. Near the bottom, in the combustion

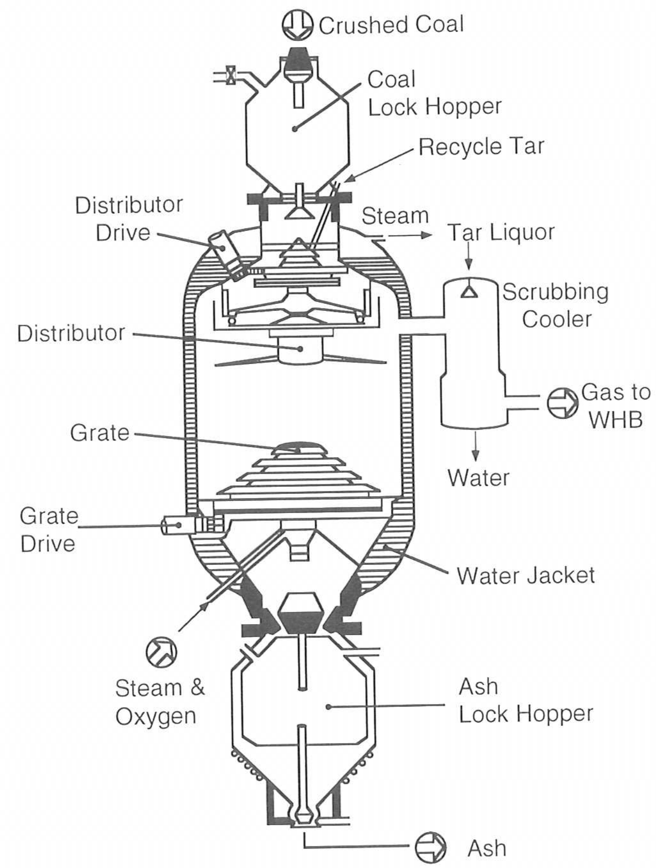

Fig. 1.29 Dry-ash Lurgi gasifier (published with permission from ref. 62).

zone, the temperatures are around 1400 K. Near the top, after leaving the devolatilization and drying zone, the temperatures are around 800 K. For a high moisture coal, the gasifier exit temperature may be as low as 600 K (ref. 28). Because of the low temperature and the lack of oxygen in the devolatilization zone, the product gas shows high content of hydrocarbon liquids such as tars, oils, and phenols. The product gas is water-quenched to condense and remove hydrocarbon liquids and cooled to generate additional steam. The cleaned and cooled gas is then desulfurized in a sulfur removal system. A typical Lurgi gasifier is 4 m in diameter. It has a nominal dry gas capacity of 55,000 m^3/hr at standard conditions. This is equivalent to approximately 590 t/d of MAF coal. A larger Lurgi gasifier is 5 m in diameter. Its nominal dry gas capacity is 85,000 m^3/hr at standard conditions, which is equivalent to approximately 910 t/d of MAF coal (ref. 28).

The most important application of the Lurgi gasification technology so far has been in the SASOL plants in Sasolburg and Secunda, South Africa. The three SASOL plants, SASOL I, III, and III, produce nearly 90 percent of the total world production of gas from coal. The synthesis gas is used primarily to produce liquid transportation fuel by the Fisher-Tropsh synthesis. However, a broad product slate includes gasoline, distillate fuel oil, light olefins, light alcohols, waxes, phenols, tars, and town gas. The three SASOL plants have a total of more than 90 Lurgi gasifiers and consume approximately 90,000 t/d of subbituminous coal.

Another important application of the dry-ash Lurgi gasification technology is the Great Plains Coal Gasification project near Beulah, North Dakota. The plant has 14 gasifiers (12 on stream and two on standby at any time). It is designed to produce 162,000 m^3/hr of pipeline quality synthetic natural gas (SNG) from 12,900 t/d of lignite (ref. 63).

The dry-ash Lurgi gasifier was originally designed for sized, non-caking coals. It cannot readily handle caking coals and coals with fines. In addition, the operating temperature is kept low to prevent ash melting and agglomeration. The low gas temperature results in high content of tars, oils, and phenols in the product gas.

In order to overcome these and some other limitations, a slagging Lurgi gasifier is being developed by British Gas Corporation and Lurgi (BGC/Lurgi). The BGC/Lurgi gasifier, shown in Fig. 1.30, is a slagging, oxygen-blown, pressurized, fixed bed gasifier. The gasifier operates at elevated temperatures so that the ash melts and forms liquid slag. As in a conventional Lurgi gasifier, the coal is fed to the gasifier through a lock hopper system and a distributor. A fluxing agent is added to some coals to reduce slag viscosity. The coal reacts while moving downward through the gasifier. The coal ash melts and passes through a slag tap hole. The slag is then water-quenched and removed through a slag lock hopper. Steam and oxygen are injected through tuyeres at the bottom of the bed. The temperatures in the raceway zone are above the ash melting temperature. The steam requirement is reduced to only about 15% of that for the dry-ash Lurgi gasifier when gasifying bituminous coal. The product gas passes through a water-quench scrubber into a waste heat boiler. The particulates and the condensed tars, oils, and phenols are recycled to the top of the gasifier or reinjected through the tuyeres. Coal fines can also be fed through the tuyeres. The cleaned and cooled product gas is then desulfurized in a sulfur removal system (refs. 28, 45, 64).

(iii) *Developments*. Fixed bed gasification technologies are being developed in the United States and Europe. The important technologies in various phases of demonstration or development include: Allis-Chalmers (KILnGAS rotary kiln); British Gas and Lurgi (Slagging BGC/Lurgi), Great Britain and Germany; Energy and Environmental Research Center, University of North Dakota; General Electric

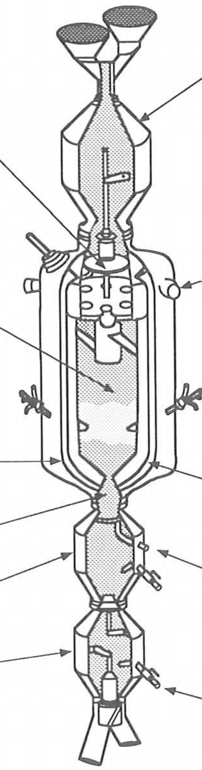

Fig. 1.30 British Gas Corporation/Lurgi slagging gasifier (published with permission from ref. 28).

(GEGAS); Kohlegas Nordrhein (KGN), Germany; Lurgi (Dry Ash Lurgi), Germany; Morgantown Energy Technology Center, Department of Energy (METC); and Ruhrgas/Ruhrkohle/Steag (RUHR 100), Germany. Several mild gasification technologies are also being developed in the United States by Coal Technology Corp. (CTC), Institute of Gas Technology (IGT), Western Research Institute/AMAX/Riley and ENCOAL Corporation. Some of the fixed bed technologies being developed in Europe were listed in Tables 1.8 and 1.9. The fixed bed gasification technologies being developed and demonstrated under the Clean Coal Technologies Demonstration Program were presented in Table 1.11.

The "Air-Blown/Integrated Gasification Combined-Cycle Project," Fig. 1.31, at Tampa Electric Company's Polk Power Station in Lakeland, Florida is described as a representative of these developments (ref. 31). The project objectives are: to demonstrate an air-blown, fixed bed, integrated gasification combined-cycle

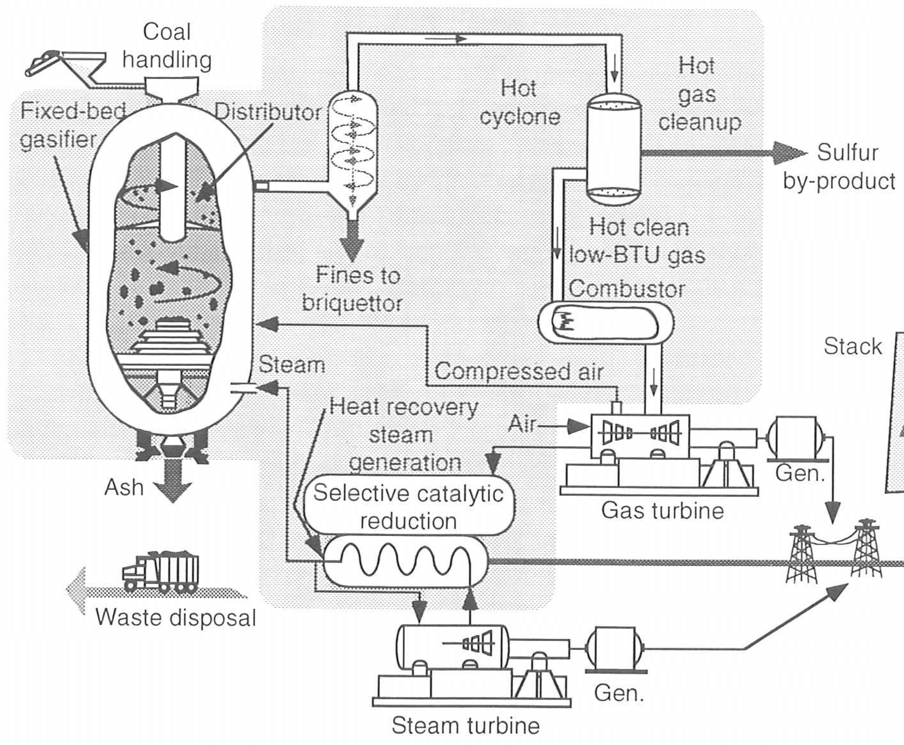

Fig. 1.31 Air-blown/integrated gasification combined-cycle project (published with permission from ref. 31).

technology and to assess reliability, availability, and maintainability at commercial scale. The coal is gasified in a pressurized, air-blown, fixed bed gasifier. The low heating value gas leaves the gasifier at approximately 810 K and goes to a hot gas cleanup system. The removal of sulfur compounds is accomplished in a moving bed of solid sorbent. Approximately 1,270 t/d of high sulfur Illinois bituminous coal is converted to a low heating value gas. The cleaned gas is used in a combined-cycle system, a gas turbine and a steam turbine, to produce 120 MW of electricity. The cooperative agreement was awarded at the beginning of 1991.

The "ENCOAL Mild Coal Gasification Project" near Gillette, Wyoming is another CCT project (ref. 31). The project objective is to demonstrate the production of two higher value fuel forms, liquid and solid, through mild gasification in staged, rotary, fixed beds. The plant start-up was scheduled for mid-1992.

1.5 OTHER PROCESSES

1.5.1 Underground Coal Gasification

(i) *Processes.* The underground coal gasification (UCG) processes are similar to the coal gasification processes in the fixed bed gasifiers. The principles are illustrated in Fig. 1.32. Boreholes for blast injection and gas removal are drilled through the overburden of a coal field. Linkings between the blast injection and the gas removal boreholes are provided within the coal seam. Blast air or oxygen with steam, are injected in one borehole and gas is removed from the other. Three overlapping zones are established between the blast and the gas boreholes: combustion, gasification, and devolatilization zones. In the combustion zone, carbon dioxide and steam are generated. Additional steam comes from the blast and from the coal moisture. Carbon dioxide and steam are reduced in the gasification zone to carbon monoxide and hydrogen. More carbon monoxide and hydrogen, as well as light hydrocarbons and tar, are added in the devolatilization zone. Air injection yields a low heating value gas; a medium heating value gas is produced with oxygen.

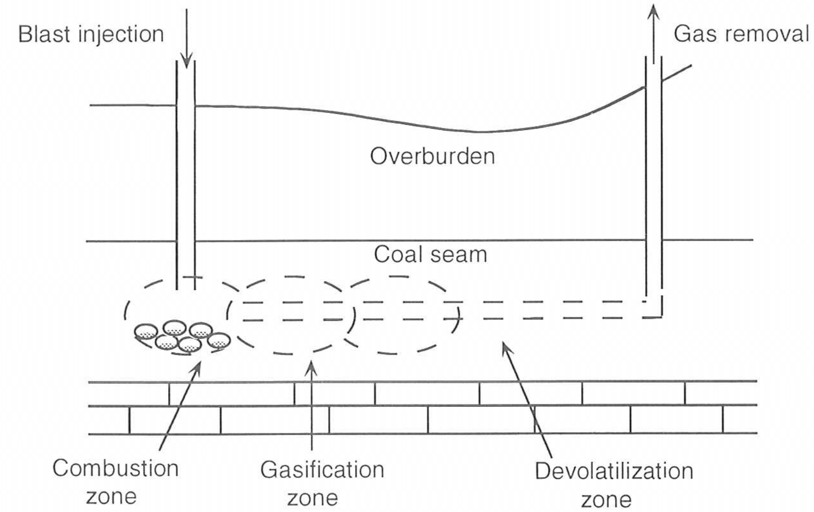

Fig. 1.32 Underground coal gasification.

The UCG combines extraction and conversion of coal into a single step. Thus the need for mining equipment and gasification reactors is eliminated. It is a promising technology for coal deposits that are not economically or technically feasible to recover by conventional mining technologies, particularly by shaft mining (refs. 65, 66). The UCG can also eliminate some of the health, safety, and environmental problems associated with conventional shaft mining of coal (ref. 66). The UCG is expected to have much smaller environmental impact than surface mining or shaft mining of coal, but it is not without problems. Particularly important is the potential for ground water contamination (ref. 65).

(ii) *Technologies and Developments.* The natural permeability of coal seams is not sufficient for the UCG processes. The permeability of the coal seam must be enhanced to provide a sufficiently high initial permeability and to prevent loss in permeability due to the condensation of tars and other heavier hydrocarbons. This step is referred to as "linking." It can be accomplished by directional drilling, countercurrent combustion, electrolinking, and hydraulic fracturing. By all these methods, narrow, highly permeable, nearly cylindrical channels are formed between the blast injection and the gas removal boreholes. The countercurrent combustion linking has been most extensively tested.

For horizontal coal seams holes are drilled typically in a rectangular pattern directly over the coal to be gasified. The boreholes are vertical and the linking channels are formed at the bottom of the seam. To accommodate thick coal seams, two modifications are usually made. First, either the blast injection or the gas removal boreholes are placed along the side of the gasification zone with the remaining holes drilled directly over the gasification zone. Second, all holes are drilled at a slant to keep them out of the subsidence region. For steeply dipping coal beds, a stream method with its modifications is more appropriate. In the stream method, the blast injection and the gas removal holes are drilled from the surface along the dipping coal seam and connected at the bottom by the linking channels. To reduce air leaking and combustion channeling, the air injection holes are sometimes drilled vertically from the surface to the bottom of the seam. For thick coal seams, the injection holes are drilled at a slant under the seam to avoid the subsidence region. To minimize the pressure drop along the seam and improve the flow control, a number of additional holes are drilled along the seam dip.

The nature of the UCG processes is such that laboratory scale tests are of limited use; costly and time-consuming field tests are needed. In the United States, several such field test studies have been conducted under funding from the Department of Energy: the Hanna field test study (ref. 67), the Hoe Creek field test study (ref. 68), and the large block underground coal gasification study (ref. 69). Several more have been funded by private companies and state governments (refs. 70, 71). At present, there is no commercial utilization of the UCG processes in the United States.

The UCG research and development in the USSR has been extensive. Several relatively large industrial scale installations operated successfully for many years (ref. 72).

1.5.2 Magnetohydrodynamic Generators

(i) *Processes.* A magnetohydrodynamic (MHD) generator works in a way similar to a conventional electric generator: a conducting gas, instead of a rotating solid conductor, cuts a magnetic field, generating electricity (refs. 73, 74). The conducting gas is provided by seeding high temperature combustion products with a

species of low ionization potential, typically potassium. Temperatures of around 2700 K are sufficient to produce adequate conductivity. When the ionized gas passes through the magnetic field an electric field is generated. If electrodes are added and an external load is connected to the electrodes, free electrons flow through the load, performing work. The MHD generator produces direct current which must be converted into alternating current.

The main advantage of the MHD generator is very high conversion efficiency: a typical commercial MHD generator is expected to achieve efficiency in the range of 80 to 90 percent. The main disadvantage is very high operating temperature and related materials problems. An additional advantage of the MHD generator is an inherent SO_2 control system. The potassium, added to improve conductivity, also reacts with sulfur. The resulting potassium sulfate, which condenses as a solid, is collected in an electrostatic precipitator or a baghouse. Almost 100 percent SO_2 can be removed at 50 percent excess potassium (refs. 73, 75, 76). With the MHD combustor operating fuel-rich, NO_x control can be accomplished in a heat recovery furnace. It is expected that NO_x emissions can be kept below 17% of the current U.S. New Source Performance Standards (refs. 73, 75, 76).

(ii) *Technologies and Developments.* The MHD generator can be used only when the gas temperature is high enough to maintain thermal ionization, *i.e.*, higher than around 2300 K (refs. 74, 75). Thus, the MHD generator can be used as a topping cycle in a combined cycle power plant. The remainder of the energy in the hot gases will be used in a bottoming cycle. The United States developent has centered around a boiler/steam turbine bottoming cycle. The topping cycle components are: a high temperature coal combustor, a nozzle for near sonic expansion of the combustion gases through a magnetic channel, a superconducting magnet, a diffuser after the magnetic channel, a regeneration plant to recover the potassium seed and return it to the combustor, and a power-conditioning system to collect power from the electrodes and to convert direct current into alternating current. The bottoming cycle components are conventional but will operate at substantially higher temperatures and with the combustion gas chemistry changed by the potassium seed. The MHD combined cycle power plants are expected to achieve fuel-to-busbar efficiency of around 50 percent in the first commercial versions and up to 60 percent in the advanced versions.

Much of the MHD technology development in the United States has taken place at two facilities: the 20 MW_t Coal Fired Flow Facility (CFFF) at Tullahoma, Tennessee and the 50 MW_t Component Development and Integration Facility (CDIF) at Butte, Montana, both funded by the Department of Energy. The CFFF team focuses on bottoming cycle components while the work at the CDIF concentrates on topping cycle development (ref. 77). The current, proof-of-concept test program is scheduled to be completed by the end of 1993. Two conceptual designs for retrofitting an MHD topping cycle to an existing coal-fired power plant have been prepared. It is expected that one of these designs will go into construction, possibly under the Clean Coal Technology Demonstration Program (ref. 73).

The MHD technology development in the USSR has been extensive. It is reported that a 500 MW MHD power plant, fired with natural gas, has been under construction since the late 1980's (ref. 75).

1.5.3 Fuel Cells

(i) *Processes.* A fuel cell, like a battery, converts chemical energy directly into electrical energy. Electrodes, in contact with an electrolyte, are sites of electrochemical reactions releasing or absorbing electrons. In the battery, the electrodes provide fuel for these reactions and thus are eventually depleted. In the fuel cell, the electrodes are catalysts for the reactions of a hydrogen-rich fuel with an oxidant. The fuel and the oxidant are fed continuously and separately to the anode and to the cathode where electrochemical reactions take place. The electrodes are separated by electrolyte serving as a transport medium for the ions. By physically separating the oxidation of the fuel at the anode from the reduction of the oxidant at the cathode, the electrochemical reactions are set to produce electricity directly (refs. 32, 78-81). Fig. 1.33 illustrates these processes for a typical fuel cell. The oxidation of the fuel at the anode releases electrons while the reduction of the oxidant at the cathode absorbs electrons, creating a potential difference between the electrodes. When an external load is connected to the electrodes, the electrons flow through the loading, performing work. In the electrolyte, the ions flow from one electrode to the other, completing the electric circuit (ref. 78). The fuel cell generates direct current which must be converted into alternating current.

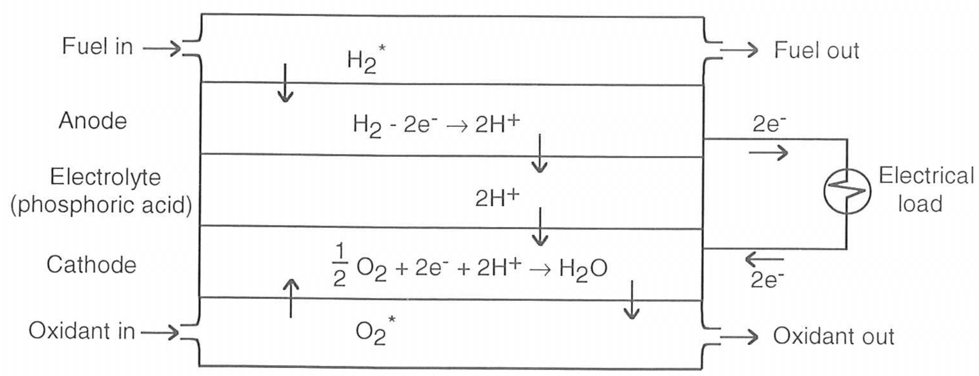

Fig. 1.33 Fuel cell processes.

The advantages of the fuel cell stem from the direct conversion of chemical energy into electrical energy (ref. 81). The fuel cell efficiency is not limited by the Carnot cycle and it may eventually reach 60%. Further, the pollutant emissions, in the absence of combustion, are extremely low. The fuel cell potentially offers the highest efficiency and the lowest emissions of any coal-based process (ref. 32). However, there are also some disadvantages (ref. 81):

1. The fuel cell needs a clean, hydrogen-rich fuel. Thus, the coal must be gasified, the coal gas reformed by steam into a hydrogen-rich gas, and the hydrogen-rich gas treated to remove impurities. This is likely to be expensive.
2. Some components of the fuel cell are made of rare or expensive materials such as platinum, nickel, strontium-doped lanthanum manganite, calcia-stablizied zirconia, yttria-stabilized zirconia, and magnesium-doped lanthanum chromite.
3. These materials are not only expensive but also susceptable to premature failures with respect to the fuel cell operating life.

(ii) *Technologies and Developments.* Three types of fuel cells are being developed for utility, industrial, and commercial applications. They are classified by the type of electrolyte as phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC) fuel cells. Phosphoric acid (PAFC) and polymer electrolyte (PEFC) fuel cells are also being developed for transportation uses. The operating temperatures are around 480 K for PAFC, around 920 K for MCFC and around 1260 K for SOFC (ref. 79).

Fuel cell technologies are being developed in many countries of the world but the research and development programs in the United States and Japan seem to be the largest (ref. 82). In the United States, PAFC systems for electric utilities are on the verge of commercialization (refs. 32, 80, 81, 83, 84). PAFC systems, in sizes ranging from 10 kw to 4.5 MW, were demonstrated in the mid-1980's. An 11 MW PAFC power plant is planned for demonstration in the early 1990's. MCFC systems are currently receiving the most attention. A 100 kW MCFC unit will go on-line in the early 1990's and 2 MW MCFC systems will be demonstrated in the mid-1990's (ref. 32, 84). There are three SOFC configurations now under development: tubular, monolithic, and planar. For the tubular configuration, units up to 5 kW have been tested (ref. 83).

In Japan, PAFC systems are also in the final stages of development (refs. 85, 86). 1 MW PAFC units for the central utility power plants were demonstrated in the late 1980's. Testing of 200 kW PAFC units for on-site power plants and commercial applications is in progress. MCFC stacks in 10 kW size range were demonstrated in the mid-1980's. 100 kW stacks are being developed for a 1 MW power plant scheduled for demonstration in the mid-1990's. SOFC stacks in 100 W size range are planned for testing in the early 1990's.

1.6 SUMMARY

Coal is the world's most abundant fuel. Recoverable world coal resources are estimated to be in excess of 1 trillion short tons. World coal production increased from 4.2 billion short tons in 1980 to 5.2 billion short tons in 1988. At this level of production the recoverable world coal reserves would last for 200 years. Coal is also the most abundant fuel in the United States. Coal resources represent 90 percent of all known fossil energy resources. Recoverable reserves are estimated to be 291 billion short tons with total resources far in excess of this amount. The United States coal production was 981 million short tons in 1989. At this production level, the United States recoverable coal reserves would last almost 300 years. Coal represents a smaller fraction of the United States energy consumption than of its energy production because of heavy reliance on imported oil for transportation. In 1989, coal accounted for 23 percent of total energy consumption but its share is expected to increase in the future. Electric utilities are the largest coal consuming sector by far and account for most of the growth in coal consumption. In 1989, 86 percent of coal consumption went into generating electricity and about 55 percent of the electricity was produced from coal.

Most of the coal presently being consumed is by direct combustion of finely pulverized coal in large-scale utility furnaces for generation of electric power, and this is likely to remain the way through the end of this century. However, many other processes for the conversion of coal into other products or for the direct combustion of coal are being developed and demonstrated, including various coal combustion and gasification processes. Several other processes and technologies such as underground coal gasification, magnetohydrodynamic generators, and fuel cells are also being developed.

Increasing the use of coal presents many technical problems, particularly in protecting environment while maintaining or increasing efficiency. In order to solve these problems and increase the use of coal, many countries in the world are supporting research and development of clean coal technologies. It is imperative for new coal technologies to reach the market in a timely manner with minimal environmental impact, and at a competitive cost. It was against this background that the International Energy Agency ministers decided in 1985 that the first area of emphasis for international collaboration in energy research, development, and demonstration should be the clean use of coal.

The most important goal of the United States National Energy Strategy is to maintain coal as competitive and to establish it as clean fuel. The resulting Clean Coal Technology Demonstration Program is a major effort in this direction. A multiyear effort consisting of five separate solicitations is underway. As a result of four solicitations through September 1991, the CCT program currently comprises 42 demonstration projects. Of these projects, 11 are in advanced electric power generation systems, 21 in high-performance pollution control devices, 6 in coal processing for clean fuels, and four in industrial applications. Several of these projects were described in this chapter.

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