COAL CONVERSION PROCESSES, CLEANING AND DESULFURIZATION

Coal(qv) is a primary source of energy for the United States and is expected to continue to be so into the twenty-first century (see Fuel resources). However, combustion of raw coal directly in the furnace of an electric power generating plant yields flue gases containing sulfur oxides (SO_x), nitrogen oxides (NO_x), and compounds of toxic metals (see Power generation). These materials, which are principally derived from impurities in the coal feed, may be reduced below permissible emission levels by various processes (1): the coal can be cleaned before it is fed to the furnace; the contaminants can be captured in a solid sorbent during, or immediately following, combustion as the hot product gases pass through the boiler; or the cool flue gases can be cleaned after leaving the heat exchange region (see Air pollution control methods; Exhaust control, industrial; Fuels, synthetic, gaseous fuels; Sulfur removal and recovery).

1. Coal Cleaning

In 1990 coal production in the United States reached 0.9 billion metric tons (2) and worldwide production was estimated to be over four billion metric tons. In 1982 it was estimated that at least 50% of the world coal production was cleaned in some manner before use (3). As higher quality coal reserves are depleted and more stringent environmental regulations on pollutants, particularly sulfur oxides, are enacted, this percentage is expected to increase.

1.1. Impurities

The three categories of potential pollutants in coal are sulfur, nitrogen, and ash. Sulfur and ash are associated with both the mineral and organic portions of coal, whereas nitrogen is mainly associated with the organic matter (4).

Most commercial coals of the eastern United States contain 0.5–4.0 wt % sulfur; most western coals contain less than 1 wt % sulfur. Sulfur is present in coal as sulfate, pyrite, and organic sulfur. Sulfate sulfur is of minor concern as its concentration in coal is much less than 1 wt %. Furthermore, sulfate compounds can be easily removed by washing because of their high solubility in water. No definite relationship between the organic and pyritic sulfur coal contents has been established. In the United States, both the organic and pyritic sulfur content in raw coal may vary from 20–80% of the total sulfur. Theoretically, organic sulfur cannot be removed from coal unless chemical bonds are broken or the organic sulfur compound is extracted. Thus the amount of organic sulfur present sets the lowest limit to which a coal can be cleaned by physical methods. The pyritic particles may be macroscopic or microscopic in size. For some coals, pyritic sulfur is finely dispersed in the coal matrix and removal of this form of sulfur by physical cleaning methods can be difficult.

Nitrogen, unlike pyritic sulfur, is mostly chemically bound in organic molecules in the coal and therefore not removable by physical cleaning methods. The nitrogen content in most U.S. coals ranges from 0.5–2.0 wt %.

Minor elements	Trace elements
Pollutant	
sulfur	
nitrogen	beryllium
	fluorine
Ash-forming	arsenic
	selenium
sodium	cadmium
potassium	mercury
iron	lead
	calcium
magnesium	manganese
silica	copper
alumina	chromium
titania	

Table 1. Effect of Coal Cleaning on Trace Elements[a]

Coal	Trace element content, ppm							
	Cd	Cr	Cu	F	Hg	Mn	Ni	Pb
feed	3.15	55	25	156	0.20	53	26	18
product[b]	0.05	28	10	71	0.09	7.9	11	3.0
reduction, %	98	49	60	54	55	85	58	83

[a]Upper Freeport Coal, W.Va., 0.075 mm top size, ie, all particles $\leq$0.075 mm.
[b]Float at 1.40 specific gravity.

Coal ash is derived from the mineral content of coal upon combustion or utilization. The minerals are present as discrete particles, cavity fillings, and aggregates of sulfides, sulfates, chlorides, carbonates, hydrates, and/or oxides. The key ash-forming elements and compounds are (4, 5):

Minor elements contribute $\geq$1 wt % to the ash; trace elements contribute $\leq$0.1 wt %. The degree of de-ashing achievable by physical cleaning depends on the distribution of mineral matter in the coal. In some cases, a considerable amount of the mineral matter can be removed; in other cases, especially where the mineral matter is distributed throughout the coal as microscopic particles, deashing by physical cleaning is not practical.

Concern over the release of hazardous trace elements from the burning of coal has been highlighted by the 1990 Clean Air Act Amendments. Most toxic elements are associated with ash-forming minerals in coal (5). As shown in Table 1, levels of many of these toxic metals can be significantly reduced by physical coal cleaning (6).

1.2. Conventional Coal Preparation Plants

Coal cleaning (preparation) is based principally on size and density differences, with the exception of flotation (qv). In this manner physical impurities, ie, ash and pyrite, may be removed from coal. Four general categories of coal preparation plants can be defined based on levels or degrees of cleaning (7): level 1 involves crushing and screening only; level 2, coarse coal cleaning only; level 3, coarse coal and partial fine coal cleaning; and level 4, total cleaning, ie, all size fractions are cleaned. At each successive level, the process design becomes increasingly more sophisticated.
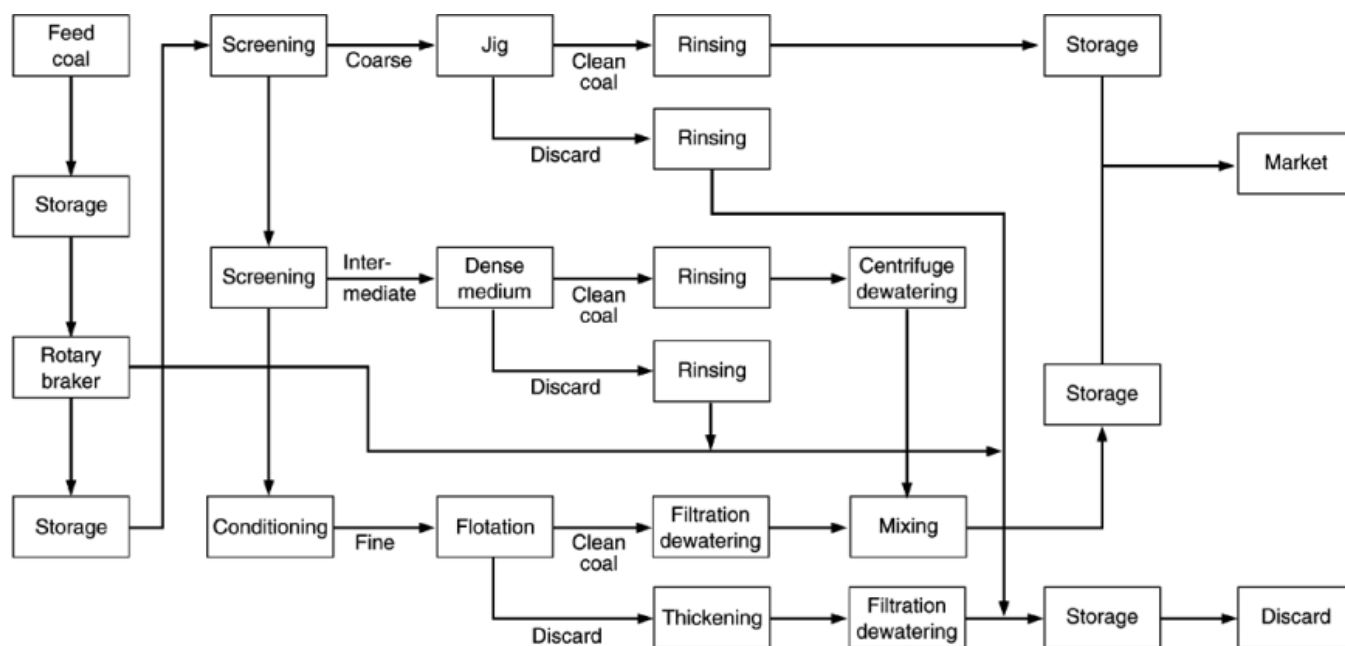
Fig. 1. Coal preparation plant flowsheet (7).

In a typical modern coal preparation plant, shown in Figure 1, coal is subjected to (*1*) size reduction (qv) and screening; (*2*) separation of impurities; and (*3*) dewatering (qv) and drying (qv). Size reduction is accomplished in rotary or roll crushers. More impurities are liberated as the coal size is reduced. Then, coal is screened, either wet or dry, to separate the various size fractions. Before treatment, the crushed raw coal is divided into coarse (>10 mm), intermediate (0.6–10 mm), and fine (<0.6 mm) sizes. Coarse coal is cleaned using one or more pieces of equipment based on gravity separation, such as jigs, or dense-medium baths. The intermediate size coals are usually cleaned using dense-medium baths/cyclones, jigs, concentrating tables, or spirals. Fine size coals can only be effectively treated by nongravimetric washing methods, such as froth flotation.

The product of any wet-separation process must be dewatered or dried depending on the mode of transportation and use. Coarse coal can be easily dewatered by natural drainage using screens. Intermediate size coal is dewatered using sieve bends or centrifuges. For fine coal, dewatering may require not only more complicated mechanical devices, such as centrifuges and vacuum filters, but also thermal drying, to achieve an acceptable moisture content.

In 1992 there were more than 400 physical coal cleaning plants throughout the United States having a total capacity of over 400 million metric tons of raw coal per year. Table 2 shows the types of coal cleaning equipment used in these plants. Historically, jigs are the equipment of choice and remain the most popular device for cleaning coal. The use of dense-medium baths and cyclones has been increasing steadily however, particularly where difficult-to-clean coals are involved and where the relative density differences between coal and refuse are small. Concentrating tables, eg, Deister shaking tables, have been employed by many plants. These provide good separation, especially in removing pyrite from coal. Pneumatic-dry-separation processes are less likely to be used because of the inability to achieve sharp separations, partly because of changes in mining laws requiring large quantities of water to be sprayed on the coal during mining and handling to suppress dust. The efficiency of pneumatic processes is severely impeded by added moisture.

Table 2. Mechanical Cleaning of U.S. Coal by Equipment Type

Equipment	Annual percentage						
	1940	1950	1960	1970	1975	1978	1983[a]
jigs	46.0	47.4	50.0	43.0	46.6	46.6	39.3
dense medium vessels	6.5	14.6	24.3	31.4	32.6	33.2	37.6
concentrating tables	2.3	2.4	11.3	13.6	10.7	10.5	10.5
classifiers[b]	7.6	9.1	4.0	1.1	2.3	2.7	5.7
launders	15.9	5.8	2.8	1.6	1.0	0.6	0.8
others[c]	21.7	20.7	7.0	5.5	2.5	1.9	1.3
flotation			0.6	3.3	4.3	4.5	4.8
Total cleaned, %[d]	*22.2*	*38.5*	*65.7*	*53.6*	*41.2*	*33.8*	*42.6*

[a]1983 is the last year for which these data were collected.
[b]Includes cyclones.
[c]Includes pneumatic separation.
[d]As percentage of total production.

Table 3. Effects of Physical Cleaning on Sulfur Reduction in Coal[a]

Cleaning level	Products, 10^6 t[b]		Sulfur reduction	
	Coal	Sulfur	10^6 t	%
no cleaning	95	2.69		
nominal cleaning, 100% particle top size	89	1.82	0.87	32
3.8 cm[c]	88	1.73	0.96	36
1.0 cm[c]	87	1.50	1.19	44
0.14 cm[d]	85	1.15	1.54	57

[a]Northern Appalachian Region Coals.
[b]Tonnage necessary to produce a heating value of 2.87×10^{12} MJ.
[c]At specific gravity = 1.40.
[d]At specific gravity = 1.3.

Conventional coal cleaning processes can remove about 50% of pyritic sulfur and 30% of total sulfur. For northern Appalachian region coals it has been shown that a greater sulfur reduction can be achieved by applying physical coal cleaning to finer size coals (Table 3) (8).

1.3. Advanced Coal Cleaning Technologies

As the easy-to-remove relatively clean coals are gradually mined out and as fuel specifications become more stringent in order to meet environmental regulations, the need for advanced fine coal cleaning processes has grown. For any fine coal cleaning process, two characteristics tend to dominate. As coal particles are crushed into finer size, the specific surface area increases and the mass of each particle becomes smaller. This leads to the development of surface force-controlled processes or advanced density-based processes that are quite different from the specific gravity-controlled processes found in coarse coal cleaning. In general, advanced processes are capable of producing a deep-cleaned coal product having low ash and low sulfur content. However, as of this writing, most of these processes are in the small-scale demonstration stage and have not been tested on a commercial scale.

1.3.1. Flotation

The application of flotation (qv) to coal cleaning is a relatively new development in the United States. In 1960, only 0.6% of the clean coal produced came from flotation. However, by 1983 flotation accounted for about 5% of the clean coal production (Table 2). Utilization of the flotation process is expected to grow rapidly because more fine size coal is produced as a result of beneficiation schemes that require significant size reduction of the raw coal prior to cleaning to enhance the liberation of pyrite and ash minerals.

The flotation process usually involves three steps: (*1*) the conditioning of the coal surface in a slurry with reagents, (*2*) adhesion of hydrophobic coal particles to gas bubbles, and (*3*) the separation of the coal-laden bubbles from the slurry. In the conventional flotation process, when the coal particles become attached to air bubbles, the particles are allowed to rise to the top of the flotation cell and form a stable froth layer (9). A mechanical scraper is used to remove the froth layer and separate the clean coal product from the refuse-laden slurry.

Reverse flotation is a two-stage process (10). The first stage is a conventional froth flotation in which most of the high ash refuse and some of the coarser or liberated pyrite are rejected as tailings. The coal froth concentrate and some dilution water is fed to a second stage flotation where a hydrophilic colloid, such as starch or dextrine, is added to depress the coal, followed by a xanthate collector to float the pyrite. This process has been successfully tested at 90 kg/h. The process is specifically designed for pyritic sulfur removal. When tested on a Ohio No. 9 seam coal sample, this process achieved a 93.8% reduction of pyritic sulfur.

Although froth flotation is recognized as the best available fine coal cleaning technique, it becomes ineffective when the particle size is much smaller than 0.1 mm or when the feed contains a large amount of clay, resulting in low coal recovery or poor selectivity. A solution to these problems is the use of modified flotation devices.

The KEN-FLOTE column (11) is one of several column flotation processes based on a countercurrent principle. The feed slurry containing reagents is introduced into the column just below the froth zone. Air is injected at the bottom of the column via an air sparger. Wash water is sprayed within the froth zone to reject the entrained impurities from the froth. Test results on this column indicate that a 6% ash product coal having a combustible-recovery of 75–80% can be obtained. A 70–80% pyrite reduction is also claimed. Figure 2 shows the operation of such a column.

The packed-bed flotation column (12) utilizes a stack of corrugated plates as the packing elements arranged in blocks positioned at right angles to each other. These stacked corrugated plates provide a tortuous flow path to attain intimate particles–bubbles contact and limit impurity entrainment. It also features countercurrent flow of air and pulp in the column. It is reported that less than 1% ash in product coal has been attained for a two-stage cleaning.

Another modification is the use of microbubble column flotation (13). In this process, smaller bubbles are generated to enhance the recovery of micrometer-sized particles. A countercurrent flow of feed slurry is also used to further enhance the bubble–particle attachment. The process is capable of producing ultraclean coals containing less than 0.8% ash.

Similarly, small (0.2–0.6 mm) air bubbles are introduced into a 2.6-m Deister Flotaire column at an intermediate level allowing rapid flotation of readily floatable material in the upper recovery zone. The bottom air permits longer retention time of the harder-to-float particles in the presence of micrometer-sized bubbles at a reduced downward velocity. The first commercial unit went on stream in 1986. It was used to improve the recovery of <0.6 mm (−28 mesh) coal in the plant's tailings. An average of 5.5% increase in coal recovery resulted from its use (14). The second commercial use processed <0.15 mm (−100 mesh) coal feed.

A new flotation cell developed by AFT, Inc. (15) is designed to promote a "skin" flotation process for deep cleaning of fine size coal. In this process plant fines are slurried and then treated with flotation reagents to enhance the natural hydrophobicity of the coal. The conditioned feed slurry is sprayed through nozzles onto the surface of the Sprayflot flotation cell. This operation provides excellent opportunity for air bubble attachment
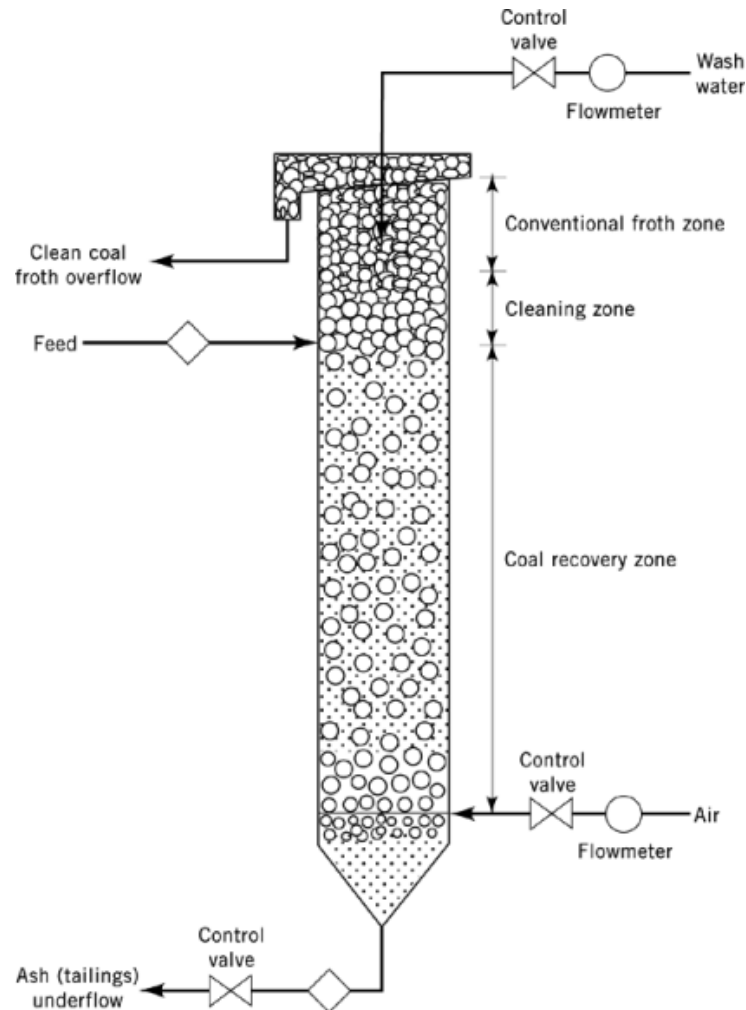
Fig. 2.   Diagram of KEN-FLOTE column flotation cell.Courtesy of CAER, University of Kentucky (14).

by the air-avid coal particles, which remain on the surface of the cell. The associated hydrophilic impurities remain dispersed in the slurry throughout the cell. The feed to flotation cell contains flocs that form during the conditioning of the feed slurry prior to beneficiation. Such flocs are normally contaminated with entrained mineral matter. The shearing action of the slurry being induced through the spray nozzles is designed to eliminate such flocs and thus provide an improved clean coal product. The froth generated is shown to be drier than a normal flotation froth, thus providing a significant cost advantage during the clean coal dewatering operation.

In 1981, a novel flotation device known as the air-sparged hydrocyclone, shown in Figure 3, was developed (16). In this equipment, a thin film and swirl flotation is accomplished in a centrifugal field, where air sparges through a porous wall. Because of the enhanced hydrodynamic condition, separation of fine hydrophobic particles can be readily accomplished. Also, retention times can be reduced to a matter of seconds. Thus, this device provides up to 200 times the throughput of conventional flotation cells at similar yields and product qualities.
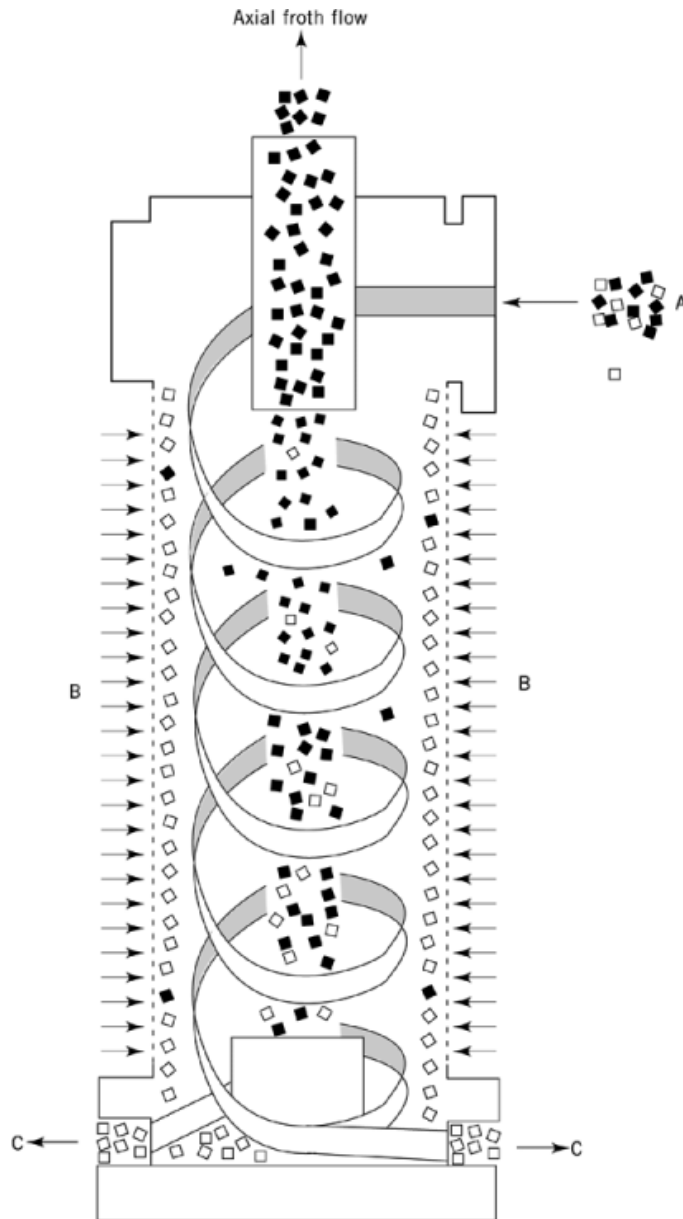
Fig. 3. Air-sparged hydrocyclone, where A represents the tangential feed that establishes swirl flow; B, the area of small bubbles formed by high shear at the porous wall; and C, the outlet for the (□) hydrophilic particles rejected by the swirl flow. The (■) hydrophobic particles are in the axial froth flow. Courtesy of Professor J. D. Miller, University of Utah (16).

1.3.2. Agglomeration-Based Fine Coal Cleaning

Most recently a search for nonaqueous collectors or reagents for fine coal cleaning has been undertaken. A number of liquids have been tested and found to be suitable as agglomeration agents. These include heavy oil, Freon, pentane, hexane, heptane, 2-methylbutane, methyl chloride, and liquid carbon dioxide.

The use of a water-immiscible liquid to separate coal from impurities is based on the principle that the coal surface is hydrophobic and preferentially wetted by the nonaqueous medium whereas the minerals, being hydrophilic, remain suspended in water. Hence, separation of two phases produces a clean coal containing a small amount of a nonaqueous liquid, eg, oil, and an aqueous suspension of the refuse. This process is generally referred to as selective agglomeration.

One of the best known examples is the spherical agglomeration process, developed by the National Research Council of Canada (17, 18). This is a two-stage fine coal cleaning process using No. 2 fuel oil as the agglomerant at a rate of about 6% on a dry solid basis. A typical flow diagram is shown in Figure 4. In the first stage, fine coal–oil agglomerates are formed under high shear agitation condition. The formed agglomerates are then fed to the second-stage low shear contractor where the agglomerate size increases. The agglomerated product is in turn separated from fine clay and other high ash material on a Vor-Siv screen. The screen oversize material is further dewatered in high speed screen-bowl centrifuges to about 12% moisture. The product coal is pelletized using a lignin binder prior to storage.

The Otisca-T process (19) is a three-step selective agglomeration process. First, the coal is ground to minus 0.002 mm in a controlled environment. Then, the finely ground coal is agglomerated using a low molecular-weight hydrocarbon such as pentane, leaving the associated pyrite and mineral matter in the water phase. Finally, the agglomerant (pentane) is recovered for reuse. In this process, heating value recovery has been achieved in the range of 93–98% with pyritic sulfur reductions up to 90%. Product coal ash contents less than 1% are routinely obtained.

The LICADO process based on *li*quid *car*bon *dio*xide (20, 21), is a novel non-aqueous process for fine coal cleaning. Liquid CO_2 is used both as an agglomerant and a transport agent. The process relies on selective agglomeration of coal particles and transport of coal—liquid CO_2 agglomerates from the aqueous phase to the CO_2 phase to achieve the desired separation. It was reported that >90% pyritic sulfur rejection and over 85% clean coal recovery have been achieved. A principal advantage of the LICADO process is that the product coal contains very little moisture and requires no further dewatering. A continuous research unit of the LICADO process is shown in Figure 5.

1.3.3. Heavy-Medium and Heavy-Liquid Cycloning Processes

Heavy-medium cyclones are widely used for cleaning intermediate size coals and application has been extended to fine coal cleaning by using very fine magnetite particles to provide the desired specific gravity of the processing medium. For example, the MicroMag process (22) uses a magnetite medium ground to less than 0.01 mm top size. An alternative method to handle very fine size coal particles is to use heavy-liquids as media for the cyclone separators. Examples of these heavy-liquids include: Freon-113, methylene chloride, sulfuric acid, zinc chloride, calcium chloride, and sugar solutions. All heavy-liquid cycloning processes are capable of effecting separation down to about 0.04 mm (325 mesh) coal particles. Unfortunately, most of these liquids cannot be used in commercial applications because of the potential hazards to workers or the environment and high cost.

1.3.4. Dry Coal Cleaning

Developments in the areas of magnetic and electrostatic separation as a means of cleaning coals in the dry state include high gradient magnetic separation (HGMS), triboelectrostatic separation (TESS), and dry coal purifier (D-CoP).

Several coal cleaning processes have been developed based on the differences in magnetic properties of coal, which is diamagnetic, and pyrite, which is paramagnetic, and some of the ash-forming minerals which are weakly magnetic. The best known example is the HGMS technique which can be used for both dry and wet coal cleaning (23). A magnetic field as strong as 2 Tesla has been employed to capture fine-sized feebly magnetic particles more efficiently. The separation efficiency can be further increased by using a matrix column
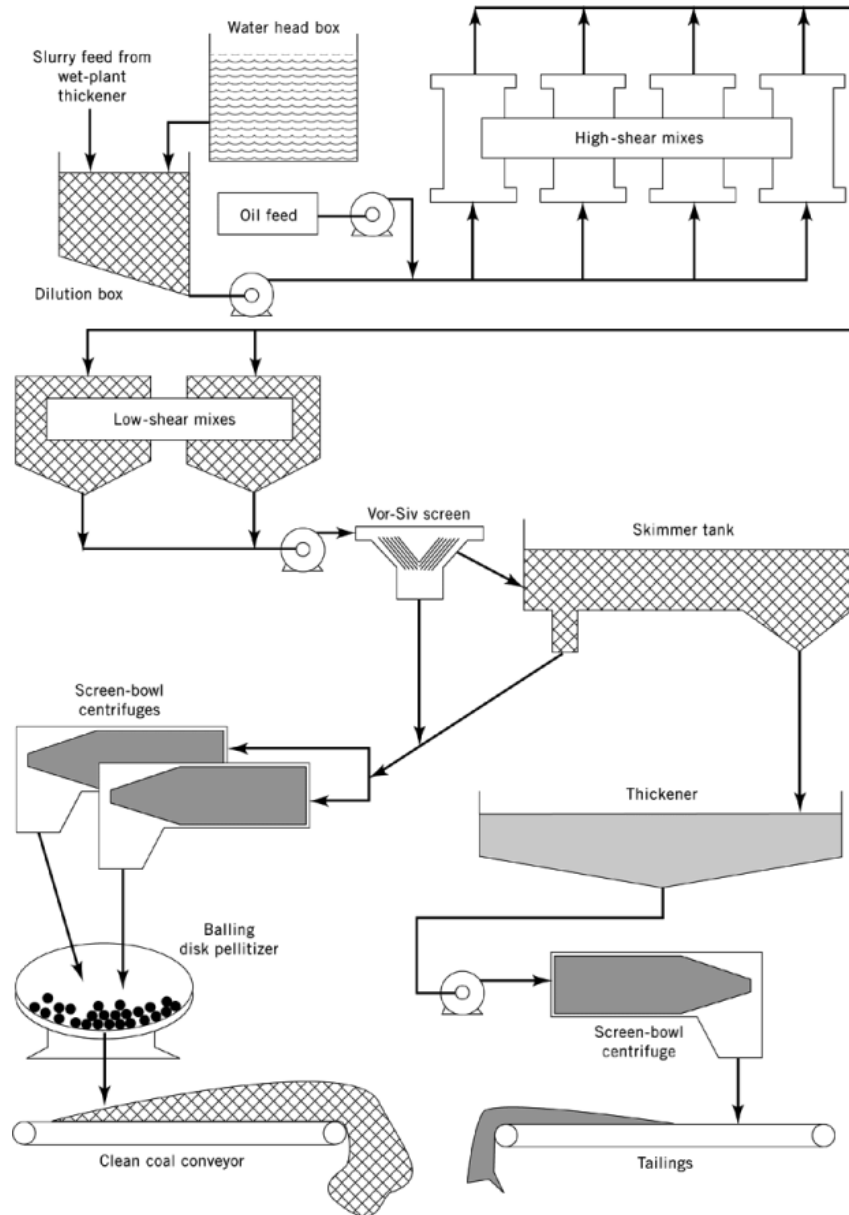
Fig. 4.   Flowsheet of Florence Mining Co. oil agglomeration process (7).

filled with fine filaments made of ferromagnetic materials, such as stainless steel wool. The HGMS process is usually operated in a cyclic mode. In the first cycle, pyrite and other impurities are captured in the filament matrix. The trapped particles are then flushed out by high pressure air in the next cycle before returning to the first cycle. This technique has been tested on a variety of coals having ash contents in the range of 10–28% and sulfur contents up to 6.5%. The pyrite rejection ranged from 14–94%. The high rejections were usually associated with low clean coal recoveries (see Separation, magnetic).
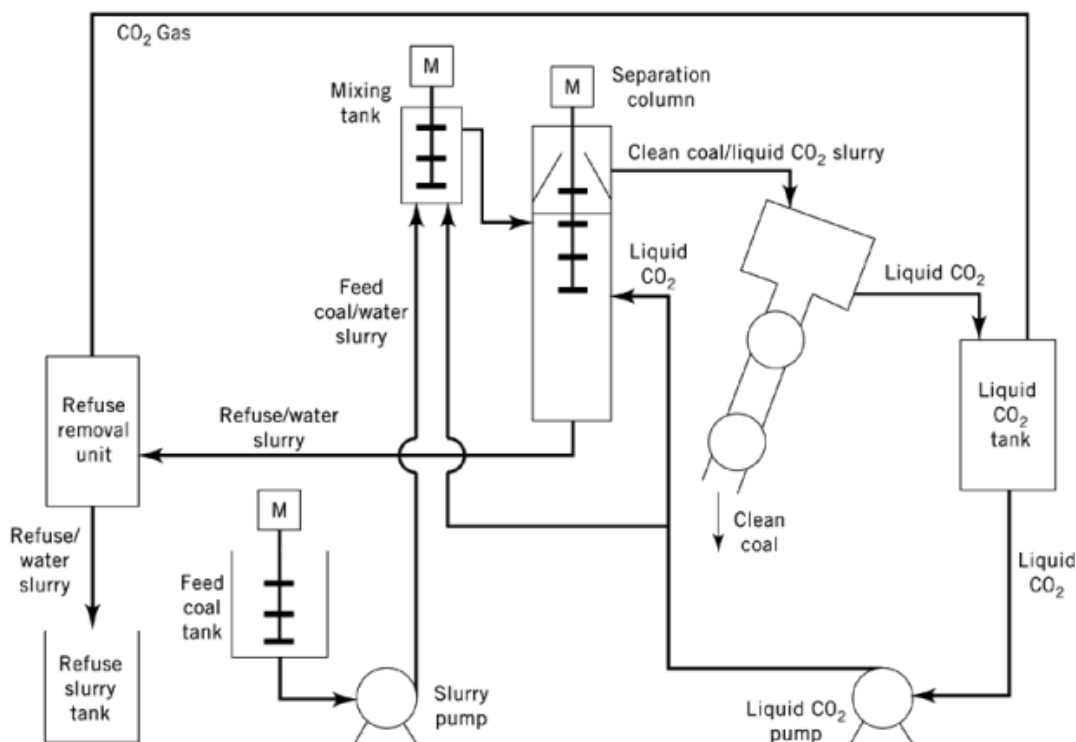
Fig. 5. LICADO continuous research unit where M represents motor-driven mixer (21).

In the TESS process, dry pulverized coal is blown rapidly past a copper baffling device that imparts a positive charge on the coal particles and a negative charge on the pyrite and mineral matter particles (24). The charged particles are immediately introduced into an electrostatic separator where negatively charged plates attract the positively charged coal and positively charged plates attract the pyrite and mineral matter. Ash reductions of up to 93% and pyritic sulfur reductions greater than 95% were obtained in processing minus 0.037 mm coal in a two-stage configuration. However, the yield was as low as 40%.

Another dry coal cleaning process is the dry coal purifier (D-CoP) (25). This technique processes crushed coal in an air-fluidized bed with magnetite particles. When a fluidized bed contains particles of different densities and sizes, there is a tendency at near minimum bubbling conditions for the solids to stratify in the vertical direction according to density, and to a lesser extent, size. In a case of a bed consisting of magnetite particles and crushed coal, the clean fraction of the coal segregates at the top of the bed, the liberated minerals settling toward the bottom. As a consequence, the ash content of the coal at the top of the bed is lowered, thereby permitting recovery of coal having significantly reduced amounts of pyrite and other materials. Because it is a dry process and involves fine coal particles, D-CoP can be integrated directly into a pulverized coal power plant.

1.4. Chemical and Biological Coal Cleaning

Whereas physical coal cleaning is capable of removing most of the ash (mineral matters) and inorganic (pyritic) sulfur, it cannot be used to remove organic sulfur. For most bituminous coals in the United States, 40 to 60% of the sulfur content is bound in organic matter. Organic sulfur can be classified into four types (26): thiols,

sulfides, disulfides, and heterocyclic thiophenes, such as dibenzothiophene [132-65-0], $C_{12}H_8S$. The sulfur from these compounds can only be removed using chemical or biological methods. Some of these processes have progressed to the miniplant stage. However, most are still at laboratory scale.

1.4.1. Oxidative Desulfurization Process

Oxidative desulfurization of finely ground coal, originally developed by The Chemical Construction Co. (27, 28), is achieved by converting the sulfur to a water-soluble form with air oxidation at 150–220°C under 1.5–10.3 MPa (220–1500 psi) pressure. More than 95% of the pyritic sulfur and up to 40% of the organic sulfur can be removed by this process.

The applicability of a nitrogen dioxide oxidative cleaning process for 10 coals on the laboratory scale has been examined via a pilot-plant program (29). In this process, dry pulverized coal is treated with gaseous NO_2, to convert the sulfur to an alkali-soluble form at about 120°C and 342 kPa (496 psi). The coal is then washed using aqueous sodium hydroxide solution to dissolve the sulfur compounds. The waste effluent is treated with lime to regenerate the caustics for reuse and the gypsum formed in the process goes to disposal. The generated gaseous sulfur dioxide and sulfur trioxide are removed by a gas scrubbing system. The process is capable of removing essentially all of the pyrite sulfur and up to 40% of the organic sulfur from a Lower Kittanning coal (29).

1.4.2. Coal Cleaning by Reactive Leaching

During World War II, Germany developed the first chemical coal cleaning technique to produce ultraclean coal (30). A run-of-mine bituminous coal (26 t/h) was cleaned by multistage flotation to less than 1% ash, and then leached using a mixture of 0.4% hydrofluoric acid and 1.4% hydrochloric acid to obtain 0.5% ash coal. This development reached the pilot-plant stage. A flotation product assaying 0.8% ash was cleaned to 0.28% ash and 10% moisture.

More recently, the molten caustic leaching (MCL) process developed by TRW, Inc. has received attention (28, 31, 32). This process is illustrated in Figure 6. A coal is fed to a rotary kiln to convert both the mineral matter and the sulfur into water- or acid-soluble compounds. The coal cake discharged from the kiln is washed first with water and then with dilute sulfuric acid solution countercurrently. The effluent is treated with lime to precipitate out calcium sulfate, iron hydroxide, and sodium–iron hydroxy sulfate. The MCL process can typically produce ultraclean coal having 0.4 to 0.7% sulfur, 0.1 to 0.65% ash, and 25.5 to 14.8 MJ/kg (6100–3500 kcal/kg) from a high sulfur, ie, 4 wt % sulfur and ca 11 wt % ash, coal. The moisture content of the product coal varies from 10 to 50%.

Based on the same principle, several other chemical leaching processes, including the promoted oxidative leaching, wet-oxygen leaching, hydrothermal leaching, and hydrogen peroxide–sulfuric acid leaching processes have been developed and exhibited promising desulfurization characteristics (28).

1.4.3. Microwave Desulfurization

Microwave desulfurization of coal is another modification of the alkali leaching method. A mixture of coal and sodium hydroxide is heated at about 250°C to promote reaction of the sodium hydroxide with the sulfur contained in the coal. The wet-coal cake is then irradiated with microwaves for 25 to 45 seconds under an inert atmosphere. The coal is washed with water and acid to remove soluble sulfide, usually Na_2S, and other solubilized mineral matter. The entire process can be repeated several times to obtain a desired level of sulfur and ash removal. In tests using an Illinois No. 6 coal containing 15.4 wt % ash and 3.4 wt % sulfur, nearly all of the pyritic sulfur, 75% of the organic sulfur, and 87% of the ash were removed, resulting in a clean coal product having less than 2% ash and 0.7% sulfur by weight (33) (see Microwave technology).
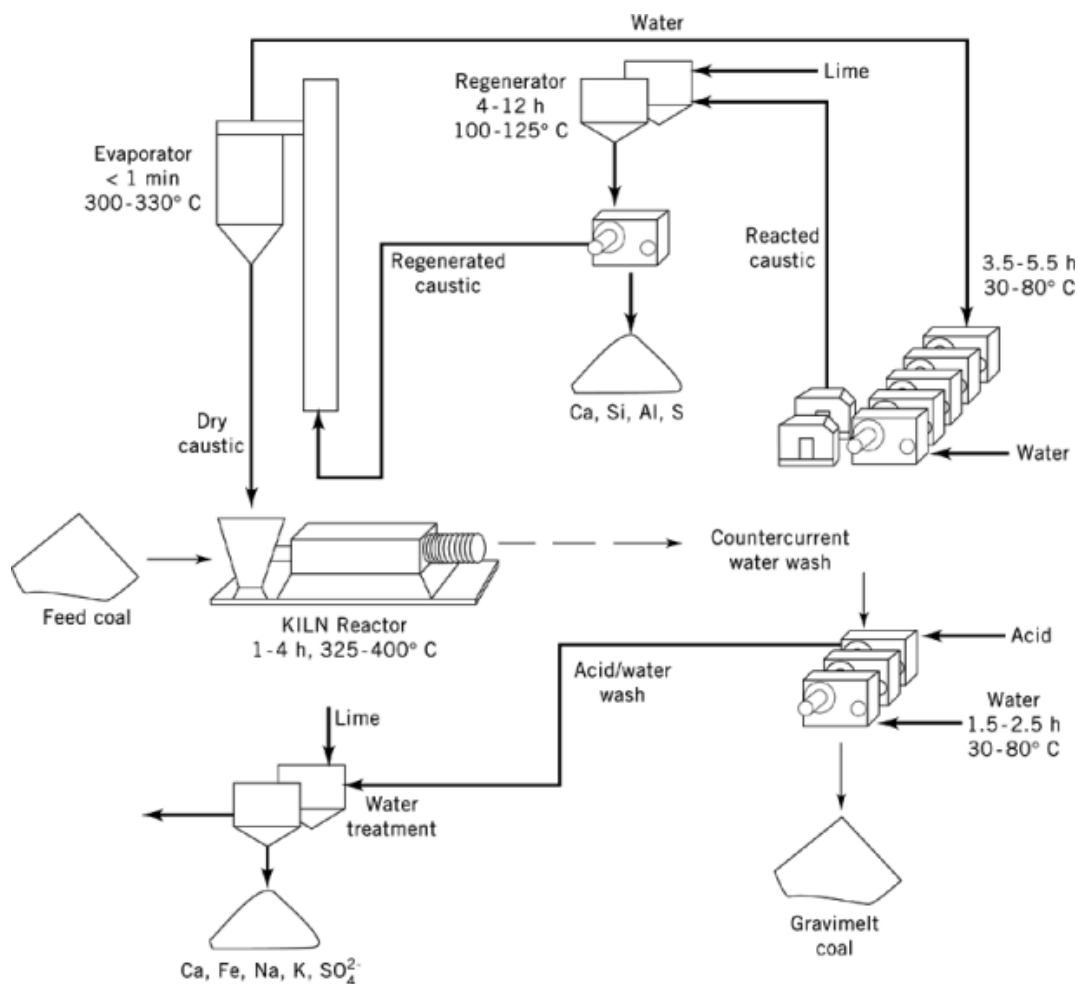
Fig. 6. Flowsheet for TRW's molten caustic leaching process (7).

1.4.4. Chlorinalysis

Chlorine can be used to remove the sulfur from coal. The coal is contacted with chlorine gas in methylchloroform at about 75°C (34). After separation of the coal from the slurry, the solvent is recovered by distillation. The chlorinated coal is washed with water and finally dechlorinated by heating at about 300–350°C. The process is capable of extracting about 90% of the pyritic sulfur and up to 70% of the organic sulfur from some coals. This process could thus expand the availability of low sulfur solid fuels by making a greater portion of the high organic sulfur coals available as a clean source of energy. However, much research and development is needed to overcome several technical problems, including chlorine retention by the coal, chlorine regeneration, and recycling.

1.4.5. Self-Scrubbing Coal

A novel coal cleaning process marketed by Custom Coal International (35) is designed to produce a self-scrubbing coal. In this process, crushed run-of-mine coal is first cleaned by using a heavy-medium bath to
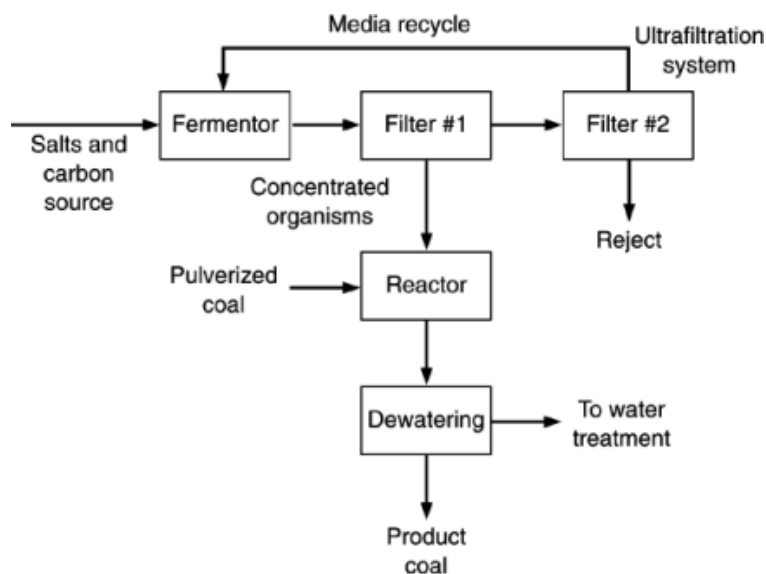
Fig. 7.   Flowsheet for ARC's microbial coal cleaning process (7).

remove noncombustible material, including 90% of the pyritic sulfur content of the coal. Limestone-based additives then are mixed with the beneficiated coal to produce a clean coal product. These additives react with the remaining organic sulfur, which is released during combustion, to remove an additional 70–80% of resulting SO_2 from the coal, effecting a reduction of 80–90% of total sulfur.

1.4.6. Microbial Coal Cleaning

Some of the organic sulfur compounds, such as thiophene and dibenzothiophene (DBT), can be degraded by a variety of microorganisms that often proliferate in petroleum-saturated soil. A strain of *Pseudomonas*, named CB-1, that can convert thiophenic sulfur to sulfate has been isolated (36), as have a number of other microbes including CB-2, which is an *Acinetobacter*. Both CB-1 and CB-2 have been tested in a continuous bench-scale unit. The coal slurry can contain as high as 26 wt % solids. The organisms are grown in continuous fermenters at 25 to 35°C and then fed to the reactor as a thick broth. A process flowsheet is depicted in Figure 7. Organic sulfur removal is in the neighborhood of 25% and the combined use of microbes, either simultaneously or sequentially, could potentially improve organic sulfur rejection. The limiting factors appear to be those of accessibility and residence time. Therefore, finer size coal should be used not only to improve accessibility of microbes to coal particle surfaces but also to reduce the overall retention time in the bioreactor. Additional information and a detailed review of conventional and advanced coal cleaning technologies may be found in Chapters 7 and 14 of Reference 7.

1.5. Combustion of Synthetic Fuels

Sulfur may also be removed from coal before combusting the coal for energy production by converting to a synthetic gaseous fuel (syngas) (see Coal conversion processes, gasification; Fuels, synthetic, gaseous fuels), then removing the H_2S from the syngas (see Sulfur removal and recovery). Rather than simply combusting the syngas in a boiler, this clean, hot-burning fuel can first be burned in a gas turbine. The hot exit gases from the gas turbine can be fed to a conventional boiler and steam turbine. This combined cycle technique, ie, gas turbine cycle plus steam cycle, integrated with coal gasification, is denoted as gasification combined cycle (GCC) (37).

The GCC process provides a significant boost in overall thermal efficiency over other commercially available systems for deriving power from coal. GCC projects include an early conceptual one using the Westinghouse coal-gasification technology (38), and one being planned to meet the requirements of the 1990 Clean Air Act is the repowering by Public Service of Indiana of Unit 1 at its Wabash River Station (39).

2. Coal Desulfurization in the Furnace and Ductwork

Sulfur dioxide in the hot gases from a coal-fired combustor may be transferred to a solid reaction product that usually contains the calcium ion, at any point in the furnace. In a fluidized-bed combustor the SO_2-sorbent is intimately mixed with the coal throughout the region where combustion occurs. In entrained-bed systems the sorbent is introduced in finely divided form into the hot exhaust gases as they pass through the heat exchange system inside the boiler or through the ductwork leading to the particulate removal equipment following the boiler.

2.1. Fluidized-Bed Combustion

Fluidized-bed combustors are able to burn coal particles effectively in the range of 1.5 mm to 6 mm in size, which are floating in place in an expanded bed (40). Coal and limestone for SO_2 capture can be fed to the combustion zone, and ash can be removed from it, by pneumatic transfer. Very little precombustion processing is needed to prepare either the coal or the sorbent for entry into the furnace (41).

     In the 1970s commercial fluidized-bed combustors were limited to the atmospheric, bubbling-bed system, called the atmospheric fluidized-bed combustor (AFBC). In the late 1970s the circulating fluidized combustor (CFC) was introduced commercially, and in the 1980s the new commercial unit was the pressurized fluidized-bed combustor (PFBC).

2.1.1. *Atmospheric Fluidized-Bed Combustors*

By the late 1970s coal-fired AFBCs such as those shown in Figure 8 were offered having single units up to 230×10^3 t/h of steam (60 megawatts-electric and denoted as MWe) and fluidizing velocities up to 3 m/s (41). By 1991 the largest fluidized-bed unit in operation had grown in size to 160 MWe at the Shawnee Station of the Tennessee Valley Authority (43). A brief report of a 1990 survey of seven manufacturers of fluidized-bed combustors with regard to boiler statistics and problems generally common to the systems may be found in Reference 43. Three projects of particular interest are the fluidized-bed cogeneration system at the Europoort Tank Farm of Shell Nederland Raffinadeij (SNR) (44); the retrofit conversion at the Black Dog Station of Northern States Power (NSP) Co. (45); and the relocation, repowering, and reconfiguration of the power plant of Florida Crushed Stone (FCS) Corp. at its quarry near Brooksville, Florida (46).

     SNR's fluidized-bed cogeneration system is an early example of the commercial development of AFBC technology. Foster Wheeler designed, fabricated, and erected the coal-fired AFBC/boiler, which generates 6.6 MWe and 37 MW thermal (also denoted as MWt) of heat energy. The thermal energy is transferred via medium-pressure hot water to satisfy the heat demand of the tank farm. The unit burns 6.4 t/h of coal and uses a calcium to sulfur mole ratio of 3 to set the limestone feed rate. The spent bed material may be reinjected into the bed as needed to maintain or build bed inventory. The fly ash, collected in two multicyclone mechanical collectors, may also be transferred pneumatically back to the combustor to increase the carbon burnup efficiency from 93%, without fly ash reinjection, to 98%.

     NSP's retrofit conversion is the electric utility industry's demonstration of the use of AFBC to repower an aging pulverized-coal furnace using a clean combustor, capable of burning fuel of lower quality. Partly funded by the Electric Power Research Institute (EPRI), the 130 MWe FBC unit was constructed in 1985 by Foster Wheeler Energy Corp. The new unit is expected to provide a 25-year unit life extension and it has already
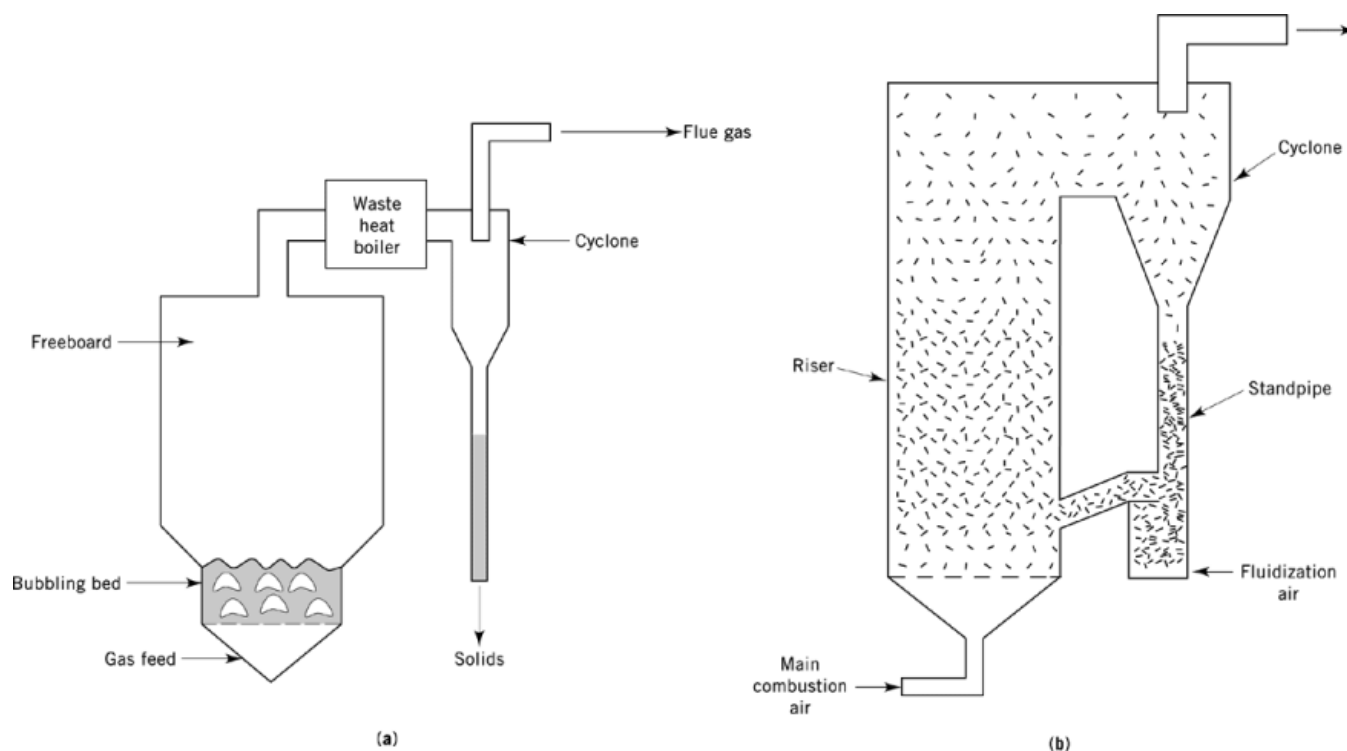
Fig. 8. (**a**) A bubbling fluidized bed; (**b**) a circulating fluidized bed. Reproduced by permission of the American Institute of Chemical Engineers, 1990 (42).

reduced emissions per unit of electric power produced. Details of startup and equipment performance during the first eight months of operation are provided in Reference 45. Another smaller retrofit project, in which two bubbling-bed units were installed in 1990 by Energy Products of Idaho in the 25 MWe Stream Plant No. 2 of Tacoma City Light, can burn coal, wood (qv), refuse-derived fuel (see Fuels from waste), or a mixture of all three fuels in a cost effective, efficient, and environmentally clean manner (43).

In FCS's 1986 repowering project Babcock and Wilcox (B&W) constructed a bubbling-bed section to FCS's existing 125 MWe pulverized-coal furnace to produce 31.3 t/h of lime, using crushed coal as the source of heat to calcine limestone in the fluidized bed. A portion of the lime is drawn from the bed as bottom ash and a portion is collected as fly ash. Both portions are transferred to a cement (qv) plant adjacent to the boiler. The hot flue gas from the FBC flows into the existing main pulverized-coal furnace, in which a B&W LIMB system was also installed to absorb sulfur dioxide during those times when the FBC is not operating.

2.1.2. Circulating Fluidized-Bed Combustors

Commercialization of the circulating fluidized-bed combustor (CFBC) began in the late 1970s (42). CFBCs operate with fluidizing velocities up to 10 m/s, which greatly increases elutriation from the bed within the main vessel, or riser (Fig. 8**b**). The effluent from the riser passes to a cyclone, where particulates are separated from the combustion gases and returned to the riser through an enlarged dipleg, or standpipe. The CFBC can handle feeds having many more fine particles than can an AFBC. This leads to more rapid burnout of the carbon content of the feed than for AFBCs and allows the firing of a larger size range of fuels.

By the late 1980s six principal commercial CFBC technologies were available (42). In 1993 the largest CFBC in operation is expected to be the Pyropower Corporation's 165 MWe reheat coal-fired unit, under construction since 1991 at the Point Aconi Station of Nova Scotia Power Corp. (43). Combustion and SO_2 control in this unit is to be carried out in the water-cooled riser. The unit is expected to operate at 870°C to optimize sulfur capture. The cyclone separators are refractory-lined and are supported approximately 30 m above grade.

An earlier Pyropower CFBC installation was completed in 1987 at the 110 MWe Nucla Station of the Colorado-Ute Electric Association (47). During shakedown, ie, the first year of its operation, beginning July 1, 1987, coal was fed to the unit for 37% of the time. A number of significant problems were identified and solved during this period, including several associated with a significant overheating incident, which shut the unit down for 74 days during Fall 1987. Following acceptance of the unit in Fall 1988, an extensive two-year test, sponsored by EPRI, provided a successful demonstration of the Pyropower technology (43).

Another of the six CFBC technologies, the multisolid fluidized-bed combustor (MSFBC), has been under development by Battelle Memorial Institute since 1974 (48). In an MSFBC a CFBC is superimposed on an AFBC in the combustor section. An early 15 MWt commercial version of MSFBC was designed and constructed by Struthers Thermo-Flood Corp. for Conoco.

2.1.3. Pressurized Fluidized-Bed Combustors

By 1983 the pressurized fluidized-bed combustor (PFBC) had been demonstrated to have capacities up to 80 MWt (49). PFBCs operate at pressures of up to 1500 kPa (220 psi) and fluidization velocities of 1–2 m/s. Compared to an AFBC of the same capacity, a PFBC is smaller, exhibits higher combustion efficiencies with less elutriation of fine particles, and utilizes dolomite, $CaCO_3 \cdot MgCO_3$, rather than limestone to capture SO_2.

Considerable development work on PFBCs was carried out in the United States, the United Kingdom, and Sweden through the 1980s (50). By the beginning of the 1990s two PFBCs were commercially available: ASEA Babcock's bubbling-bed technology and Pyropower Corp.'s circulating-bed system (51). A 70-MWe version of the ASEA Babcock technology has been installed at the Tidd Station of Ohio Power Co. and a 40-MWe version of the Pyropower system is planned for the Alma Station of Dairyland Power Cooperative.

The PFBC at the Tidd Station operates at 1200 kPa (170 psi) and a bed temperature of 860°C (51). A pressure vessel, 13.4 m in diameter by 20.7 m high, houses the combustor and its ancillaries. Coals, which contain ash contents less than about 25%, are blended with dolomite and pumped to the combustor as a paste having a total water content of 20–25%. Coals, which contain ash contents higher than 25%, and dolomite are individually fed pneumatically via separate lock hoppers. Both coal and dolomite are crushed to 3-mm top size before being fed to the unit.

Second-generation PFBC, currently being developed by Foster Wheeler Development Corp. places a pressurized carbonizer ahead of a circulating-bed PFBC (CPFBC) (52). The carbonizer produces a low heating-value fuel gas and a char, which are burned separately in a topping combustor and in the CPFBC respectively. This technology promises higher electrical power generating efficiencies (45%) than is obtained with first-generation PFBC systems (40%) (51).

2.2. Entrained-Bed Combustion

Entrained-bed combustors burn coal particles finer than 100 μm, which are carried rapidly through the flame by the combustion gases (40). To obtain particles of this size, larger pieces of coal are fed to pulverizers and thence to the burners, giving rise to the designation of these devices as pulverized coal (PC) furnaces. Flame temperatures are frequently above the ash fusion temperature of the coal, ie, $>1200°C$. In contrast to FBCs, little significant sulfur capture is possible by cofeeding calcium-based sorbents into the combustion zone, because calcium sulfite and calcium sulfate are unstable above 1200°C. Thus sorbents for sulfur removal from
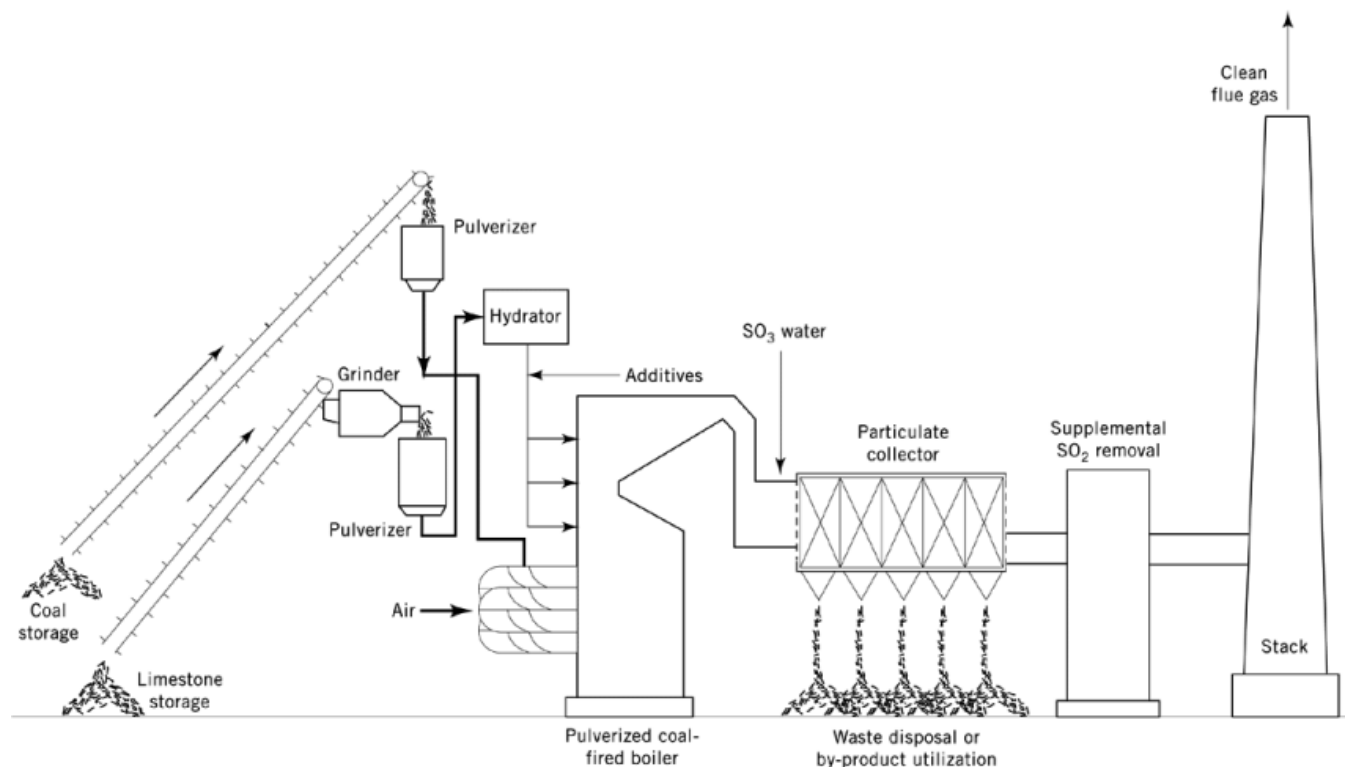
Fig. 9. Integrated LIMB system. Reproduced by permission of the American Institute of Chemical Engineers, 1985 (55).

PC furnaces are injected as the combustion gases are being cooled. This can be accomplished in the upper region of the furnace or in the ductwork leading from the furnace to the particulate removal system (53).

2.2.1. *Sulfur Removal Above the Furnace Combustion Zone*

The first full-scale demonstration of injecting sorbent into a furnace above the combustion zone came in 1970, when fine limestone and pulverized coal were cofed to one of the units at the Shawnee Station of the Tennessee Valley Authority (54). Whereas this test disappointingly provided less than 30% removal of SO_2, the research that emerged showed that relocating the limestone feed point could significantly increase SO_2 capture. As a result, in the early 1980s the U.S. Environmental Protection Agency (EPA) initiated a program for limestone injection with multistage burners (LIMB) to develop and demonstrate processes to remove SO_2 from the upper region of PC furnaces (55). In the LIMB process finely-divided limestone is injected into the furnace at the 1300°C level, which is just above the furnace outlet plane and ahead of the pendent superheaters as shown in Figure 9. There, after being flash-calcined to lime, the sorbent reacts with SO_2 in the presence of O_2 to form $CaSO_4$. The temperature regime, where the sulfate is both stable and formed at reasonable rates, lies between 1200 and 900°C.

Three demonstrations of the LIMB technology have been carried out. The first was a privately funded project in the 75 MWt Boiler 405 at the No. 4 AC Station of Inland Steel Industries, Inc. (56). By injecting 70 wt % minus 200 mesh (74 μm) limestone, approximately 40% SO_2 removal was achieved at a Ca:S ratio of 3. This rose to 50% removal when the Ca:S ratio was increased to 4. The second LIMB demonstration was the

backup desulfurization system installed by B&W as part of the relocation, repowering, and reconfiguration of the FCS power plant (46).

The third, and most significant LIMB, was the installation at the 105 MWe wall-fired Unit 4 Boiler at Ohio Edison's Edgewater Station (57). Three rows of eight sorbent injector nozzles each were installed on the front wall at elevations of 55.2, 57.0, and 58.2 m (54). The row at the 57.0 m level extends for two additional nozzles on each of the two adjacent side walls. All nozzles can be tilted through a 30° arc and are designed to achieve a momentum flux, which permit the pneumatically-transported sorbent to penetrate the flue gas from the wall. Problems associated with sorbent feeding, increased soot blowing, electrostatic precipitator (ESP) operation, and handling of increased ash have been corrected since the LIMB system was started up at the Edgewater Station in July 1987 (58). The problem associated with the ESP was the production of a back corona, caused by the high electrical resistivity of the sulfate-containing fly ash. The solution was simply to install a 18.3-m horizontal duct having a 4.3-m by 4.3-m cross section, containing an array of 100 water-spray nozzles, to humidify the flue gas before it passed to the ESP. The B&W LIMB process has proven technically very successful: SO_2 removals of 55 to 60% were obtained at a Ca:S stoichiometry of 2 and the goal of 50% removal at a stoichiometry of 1.6 was anticipated before the conclusion of the demonstration program (54). As of this writing sorbent injection in the upper portion of three additional commercial boilers in Illinois is being carried out in conjunction with gas reburning tests for NO_x reduction (59).

2.2.2. Removal in the Ductwork

For that portion of the furnace where temperatures drop from 900 to 150°C, both thermodynamics and kinetics prevent effective desulfurization using calcium-based sorbents. However, below 150°C humidification of the flue gas reestablishes a supportive environment for SO_2 removal, just as it improves ESP performance. At least six processes, based on the addition of a sorbent in conjunction with humidification of the flue gas downstream of the preheater, are being developed as of this writing (60). Three are funded as part of the U.S. Department of Energy's program to develop duct injection technology, and a fourth is an extension of the LIMB demonstration at the Edgewater Station.

The Bechtel confined zone dispersion (BCZ) process involves the injection of a fine slurry mist of pressure hydrated dolomitic lime or calcitic lime, using two-fluid atomizing nozzles. A demonstration at the 70 MWe Seward Station of the Pennsylvania Electric Co., performed in 15.2 m of ductwork with a 2.4-m by 3.4-m cross section, achieved a 50% removal of SO_2 at a Ca:S ratio around 1.1.

The General Electric in-duct scrubbing (IDS) process involves the atomization of a slaked lime slurry, using a rotary disk atomizer. A test at the 12 MWe scale at the Muskingum River Station of Ohio Power, performed in a duct with a 4.3-m^2 cross section, achieved 50% SO_2 removal with good lime utilization.

The Dravo hydrate addition at low temperature process involves a two-step injection of water and dry sorbent in a rectangular 19.8-m duct having a cross section of 2 m^2. In one step water is injected through atomization nozzles to cool the flue gas from 150°C to approximately a 15°C approach to adiabatic saturation. The other step involves the dry injection of hydrated lime, either downstream or upstream of the humidification nozzles. Typical SO_2 removals were 50–60% at a Ca:S ratio of 2.

The Coolside process of Consolidation Coal Co. (Consol) (Fig. 10) involves injecting hydrated lime upstream of flue gas humidification. A second sorbent, initially sodium hydroxide, may be added to the water spray, using two-fluid atomizing nozzles. Being tested in a 17-m duct having a 19.8-m^2 cross section at the Edgewater Station of Ohio Edison, the process is projected to remove 70% SO_2 at a Ca:S ratio of 2 and a Na:Ca ratio of 0.185, based on pilot-plant tests (61). Considerable work has been carried out by Consol (62–64) and a team from Acurex Corp. and EPA (65) to seek process improvements by studying the characteristics of sorbents, developing sorbent modifications, and examining new substances for this purpose.
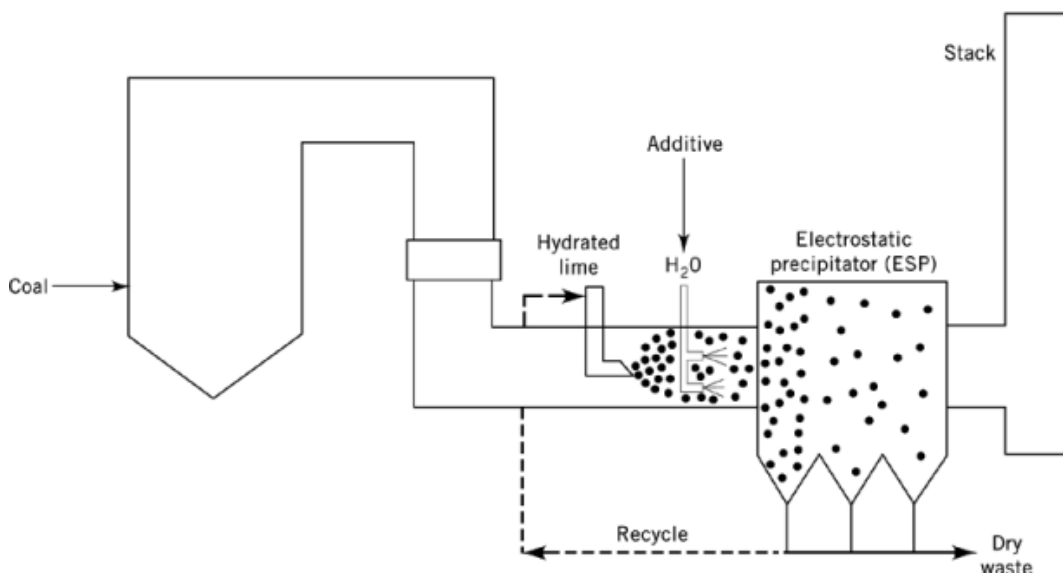
Fig. 10.   Coolside hydrated lime injection. Reproduced by permission of the American Institute of Chemical Engineers (61).

3. Sulfur Removal from Flue Gases

In 1983 there were 116 flue-gas desulfurization (FGD) systems in service, representing 47 gigawatts-electric of power generation capacity (66). As of 1992, more than 150 coal-fired boilers in the United States operated with FGD systems. The total electrical generating capacity of these plants has risen to 72 gigawatts (67). FGD processes are classified into (*1*) wet-throwaway, (*2*) dry-throwaway, (*3*) wet-regenerative, and (*4*) dry-regenerative processes (68).

3.1. Wet-Throwaway Processes

By 1978, three wet-throwaway systems were in commercial operation: lime scrubbing, limestone slurry scrubbing, and dual alkali (1). Lime/limestone wet scrubbing (Fig. 11) remains the most common post-combustion control technique applied to utility boilers (67). The waste product from the scrubbers can either be sent to a landfill or be upgraded by oxidation to become saleable gypsum.

Whereas it is not precisely a lime/limestone wet scrubber because it uses alkali already present in the coal ash, the Colstrip FGD system has been most expansively described (69). Three scrubber modules, operating in parallel, are used on two 360 MWe coal-fired boilers at the Colstrip Station of the Montana Power Co. and the Puget Sound Power and Light Co. Each module consists of a downflow venturi scrubber, centered within an upflow spray tower contactor, and is designed to clean 120 MWe of equivalent gas flow under normal conditions and 144 MWe under emergency conditions. Thus, when one module is off line, the boilers can still operate at 80% capacity, using the remaining two modules to clean the generated flue gas. Test data show that the levels of pollutants in the plant emissions are well below the vendor guarantee and the applicable federal standards. Scrubber availability and plant load for a 22-month period shortly after startup and a number of operating details for the FGD system may also be found in Reference 69.

In the design of a lime/limestone scrubber, there are numerous considerations to be evaluated, including particulate removal (if any), ash removal, scrubber type and configuration, scaling prevention, absorbent feed
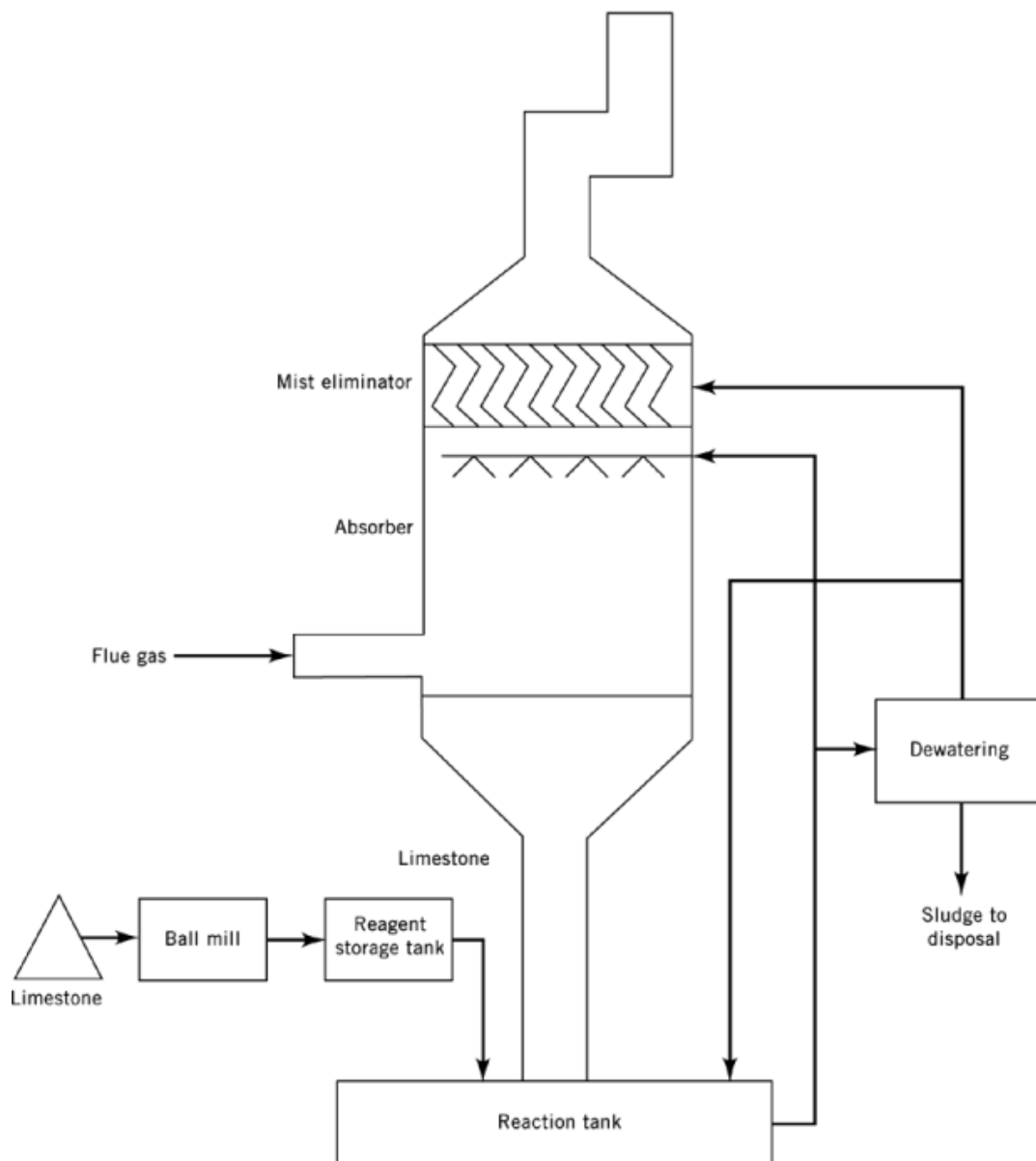
Fig. 11.   Limestone FGD system. Reproduced by permission of the American Institute of Chemical Engineers (67).

control, water balance, mist elimination, reheat, and sludge disposal (70). In addition, the size of the boiler is a factor. FGD systems for smaller industrial coal-fired boilers can be purchased as packages, as opposed to the large specially engineered systems for field construction at utility stations (71). These latter systems are typically designed as vertical towers and use either lime or limestone as the sorbing agent. If the sulfur content is high or liquid waste is not permitted, the double alkali process may be used, where the sodium ion is replaced by a calcium ion to form an insoluble precipitate of the sulfur compounds. The precipitate is then
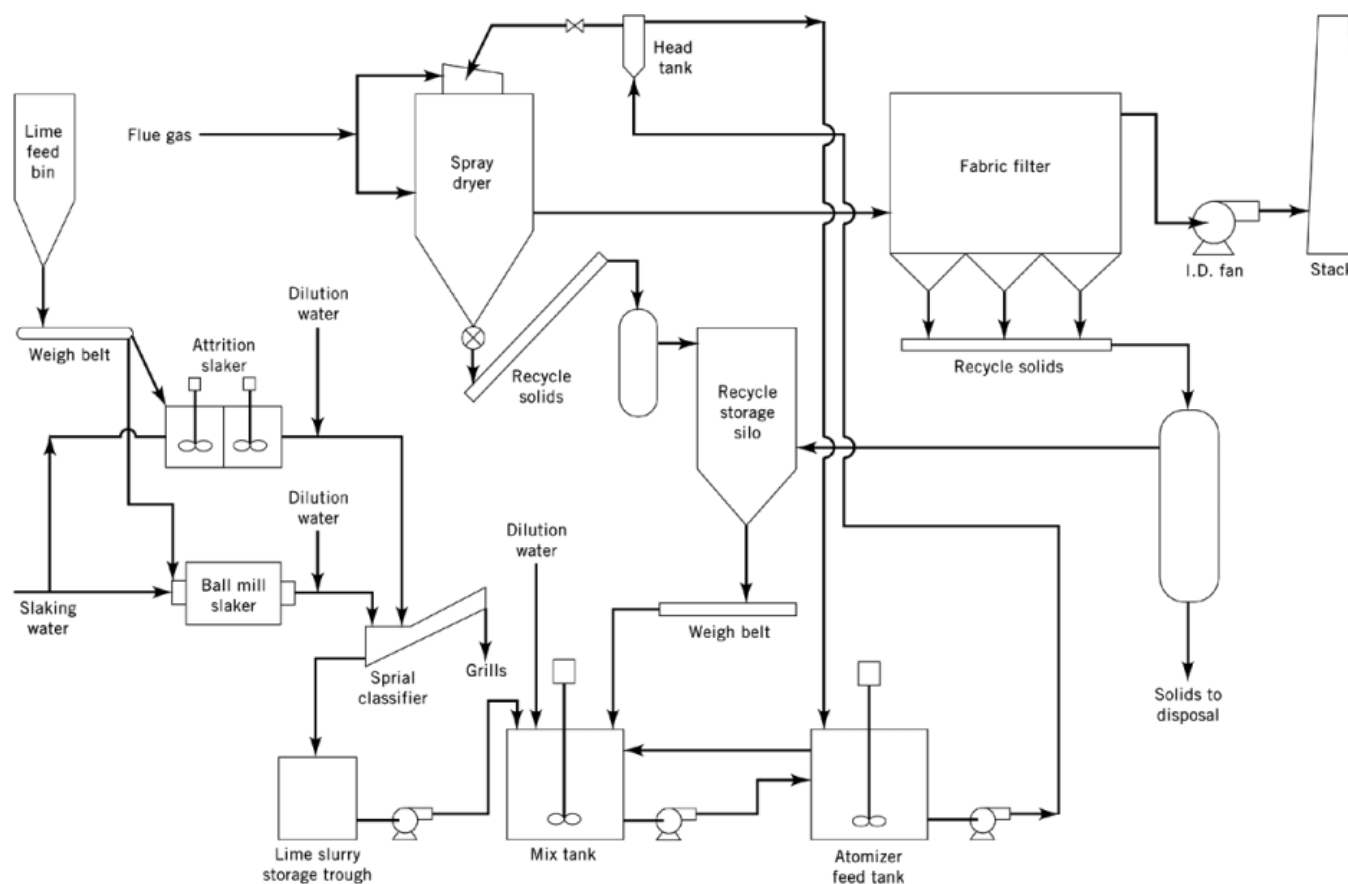
Fig. 12.   Lime spray dryer process flow diagram. Reproduced by permission of the American Institute of Chemical Engineers, 1991 (67).

filtered from the liquid stream and the regenerated liquid, containing the original sodium ions, is returned to the scrubber.

3.2. Dry-Throwaway Processes

Dry-throwaway systems were the precursor of processes that removed SO_2 in the ductwork, eg, the BCZ and IDS processes. Here, however, the device is a spray chamber similar to the wet scrubbers such as the three modules of the Colstrip installation (Fig. 12). Into the upper portion of the chamber a slurry or clear solution containing sorbent is sprayed. Water evaporates from the droplets, the sorbent reacts with SO_2 both before and after drying, and the dry product is removed in a downstream baghouse or ESP (72). Unfortunately, dry scrubbing is much less efficient than wet scrubbing and lime, instead of the much less expensive limestone, is required to remove SO_2 effectively. Consequently, a search has been conducted for more reactive sorbents (72–75).

One commercial dry-scrubbing process is the system designed and installed by MikroPul Corp. at Strathmore Paper Company's 3.2 MWe PC cogeneration boiler in Woronoco, Massachusetts (76). The system consists of a slaked-lime spray drier reactor and a fabric filter. The stainless-steel spray drier is 4.4 m in diameter and

8.5 m tall. Four flue gas/sorbent slurry diffusers, containing two-fluid, external-mix-type nozzles, are installed at the top of the chamber. Early modifications to the chamber included changes in its aerodynamics to improve mixing and changes in the slurry feed and distribution system. The unit generally removes 80% SO_2 at a Ca:S ratio of 1.8.

3.3. Regenerative Processes

By 1984 two commercial regenerative processes, the Davy McKee Wellman-Lord system and the United Engineers & Constructors Magnesium Oxide [1309-48-4] system were in operation in five generating stations, for a total of eleven units, in the United States (77). The Wellman-Lord process, of which only one unit is still in operation and which is no longer offered commercially, uses an aqueous solution of sodium sulfite to absorb SO_2 and form sodium bisulfite. The sodium bisulfite is thermally decomposed in the regenerator to reform sodium sulfite and release SO_2 and the sulfite is returned to the absorber. The SO_2 is converted to either sulfur or sulfuric acid.

The MgO system shown in Fig. 13 uses an aqueous solution of $Mg(OH)_2$ to absorb SO_2, forming crystalline $MgSO_3\cdot3H_2O$. After removal by centrifugation the $MgSO_3\cdot3H_2O$ is dried in a direct-fired rotary kiln to produce anhydrous magnesium sulfite [7757-88-2], $MgSO_3$, which may then be shipped to a fluidized-bed calciner. In the calciner $MgSO_3$ is decomposed to magnesium oxide [1309-48-4], MgO, and SO_2. MgO absorbers were installed at Units 1 and 2 of the Eddystone Station and Unit 1 of the Cromby Station of Philadelphia Electric Co., and regenerators were built at sulfuric acid plants in Delaware and New Jersey by Allied Corp. and Essex Chemical, respectively. By February 1984 about 23,800 t of sulfuric acid had been made from by-product SO_2 and the scrubbers had consistently reached 96–98% removal of sulfur dioxide. The MgO system continues to operate well, but the regenerative process market has moved toward other systems, particularly the NOXSO process, which provides combined NO_x/SO_2 removal.

The NOXSO process has many of the elements of a traditional dry scrubber (78–80). The sorbent for both NO_x and SO_2 is sodium carbonate impregnated on a high surface-area gamma alumina. From a fluidized-bed absorber the sorbent is first heated from 120 to 600°C, driving off the NO_x and loosely-bound SO_2. The sorbent then passes to the first chamber of a regenerator where it is contacted with natural gas to remove most of the sulfur (about 70%), which it carries into that chamber. In the second chamber of the regenerator steam drives off the remaining sulfur. The sulfur-laden gases from both chambers are combined and processed to yield products for sale. A contract to construct a 5 MWe proof-of-concept plant for the NOXSO process at either Boiler 10 or Boiler 11 of Ohio Edison's Toronto Station was signed in 1989. A full-scale demonstration is in operation at Ohio Edison's Niles Station.

Development efforts regarding regenerative processes have also focused on higher temperature sorption using fluidized beds of metals supported on porous solids. The most advanced of these developments is the WSA-SNOX cleaning technology, offered by Haldor Topsoe, Inc. (81). After NO_x removal by selective catalyst reduction (SCR), the SO_2 in the flue gas is oxidized to SO_3 over a conventional sulfuric acid catalyst. Upon cooling, the SO_3 is hydrated to sulfuric acid, which is condensed, concentrated, and stored for sale. In 1988 several WSA-SNOX units were in operation in Europe and the first one in the United States was being planned by Ohio Edison for Boiler No. 2 of the Niles Station.

At a much earlier stage in the research and development cycle, fluidized-bed processes use porous sorbents containing copper oxide (82), cerium oxide (83), and other metal oxides (84).

4. Clean Coal Choices

When the Clean Air Act of 1990 was signed into law, electric utilities were required to establish plans and initiate projects to comply with that Act's Title IV. Each utility had to evaluate how the various commercial and
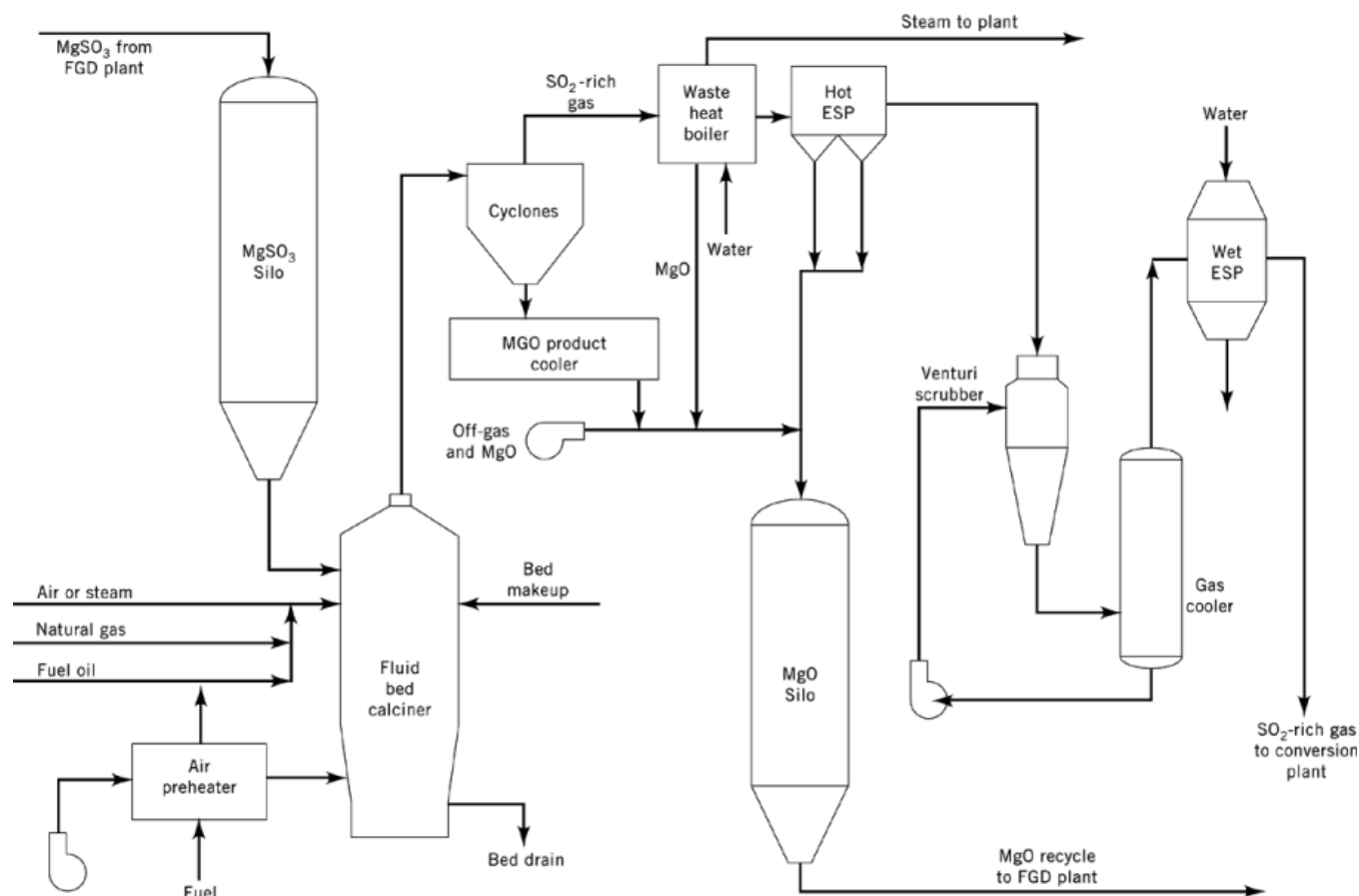
Fig. 13.   The MgO desulfurization system: regeneration. Reproduced by permission of the American Institute of Chemical Engineers, 1984 (77).

emerging clean coal systems fit into the utility's technical and business environment resulting in strategies to utilize fuel switching and wet throwaway FGD processes almost exclusively (38, 85, 86).

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