After entering the cell plenums, air passes through an air distribution grid to enter the fluidized bed. This grid consists of tee nozzles installed in the fin section of a water tube cooled grid plate. This design allows the grid to operate at a controlled temperature thereby eliminating sealing problems caused by thermal expansion.

The tee nozzles provide uniform air distribution throughout both cells and allow the formation of a layer of unfluidized bed material which acts as an insulating layer to protect the grid plate.

Protection of the grid is further insured by providing insulation on the plenum side of the tubes and fins in the start-up sections. During start-up, the use of a water-cooled gridplate permits warming up each cell with 815°C (1500°F) air without elaborate special design considerations to account for thermal expansion. The floor and walls of the air plenum in the start-up segments are insulated to minimize cooling of the air in the plenum. A steel plate located in each plenum separates the two segments. Because of the small dimensions of this plate (1500 x 2400mm) thermal expansion can be accommodated. This steel plate is insulated on the face exposed to the start-up zone (refer to Figure 4).

Within the fluidized bed, air mixes with the coal and lime to effect coal combustion and sulfur capture. Flue gases and elutriated fines leave each fluidized bed and are combined in an extended freeboard in Cell A. Sufficient freeboard height is provided to permit burnout of elutriated coal fines and combustible gases.

After leaving the freeboard, flue gases pass over the finishing superheater surface located above Bed A, through a waterwall screen separating Cell A and Cell B, down through a bare tube economizer located above Cell B, and through a waterwall screen in the rear wall to mechanical dust collecting cyclones. The cyclones remove approximately 85% of the flyash for reinjection into Cell A. The flue gases and remaining fines pass through a tubular air heater and then to a baghouse for final particulate control. Flue gases exiting the baghouse are routed to the ID fans which discharge into an existing stack. The ID fans have inlet vanes to control furnace draft and discharge isolation dampers.

The coal, and inert refractory bed materials for the boiler enter the plant by totally enclosed conveyor trucks (refer to Figure 5). These materials are conveyed by bucket elevator to a diverter valve located above all the storage silos. They are then distributed by gravity to their respective storage silos. Limestone may also be delivered to the storage silo in this manner. However, the preferred method is to have it pneumatically conveyed from the delivery truck directly to the limestone storage silo. Coal and limestone leave their silos on a common belt conveyor which connects the silos to a bucket elevator and a conveyor which discharges through a diverter valve directly to the coal day bin or, if limestone, by a conveyor to the day bin. The inert material is transported to the boiler pneumatically.

The coal feed system delivers coal from day bins to the boiler. One day bin for each cell supplies coal to a mass flow extraction screw conveyor and through a stream spreader to a rotor flipper. Coal is distributed across the fluidized bed by the rotor flipper. Foster Wheeler has successfully pioneered the use of overbed feed for fluidized bed combustion as a means of avoiding the problems often encountered with underbed feed systems using injection nozzles.

The rate of coal feed is controlled by the speed of the mass flow extraction screw conveyor. The rotor flipper operates at a low speed when distributing coal across half the bed during segmental fluidization and at a higher speed for full cell operation. Weigh cells on the coal day bin provide a means for totalizing coal usage. Identical coal feed systems are provided for both A cell and B cell.

To take advantage of the fluidized bed's ability to burn a variety of fuels, the SNR unit has also been designed with provision for feeding alternate fuels, both liquid and solid.

The limestone feed system takes limestone from the limestone day bin and delivers it to the boiler cells at the required flow rate.

One limestone day bin is located along the side of Cell B opposite the coal rotor flipper and supplies limestone through two discharge hoppers. Each hopper feeds one cell through an isolation slidegate valve and a single rotary feeder which regulates the flow. For Cell A, the limestone falls by gravity through a pipe to an injection point located in the side wall just above the fully expanded fluidized bed level. For Cell B, the

FIGURE 4 ***ARRANGEMENT OF START-UP ZONE***

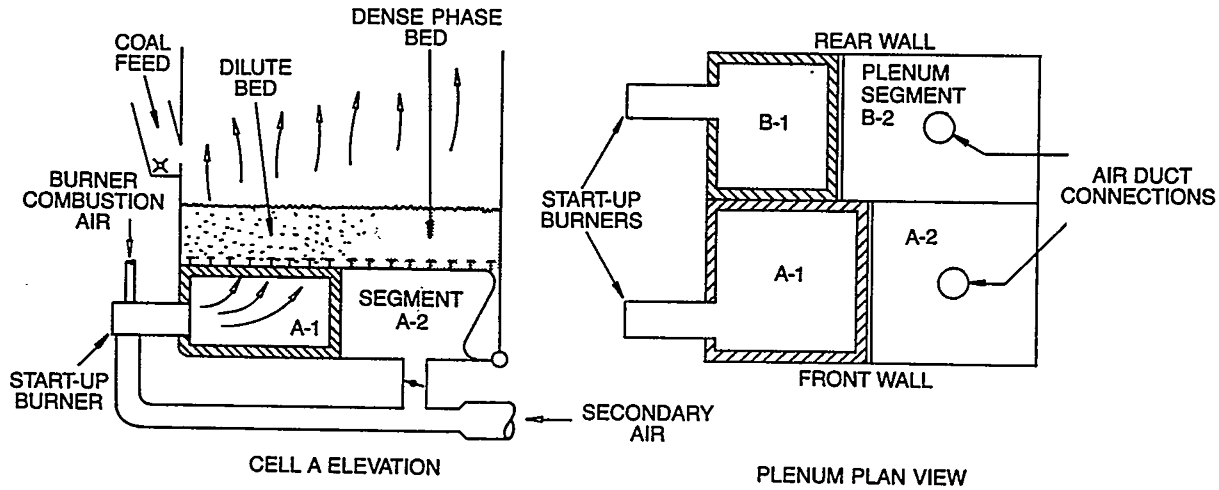


FIGURE 5 ***MATERIAL RECEIVING AND HANDLING SYSTEM***

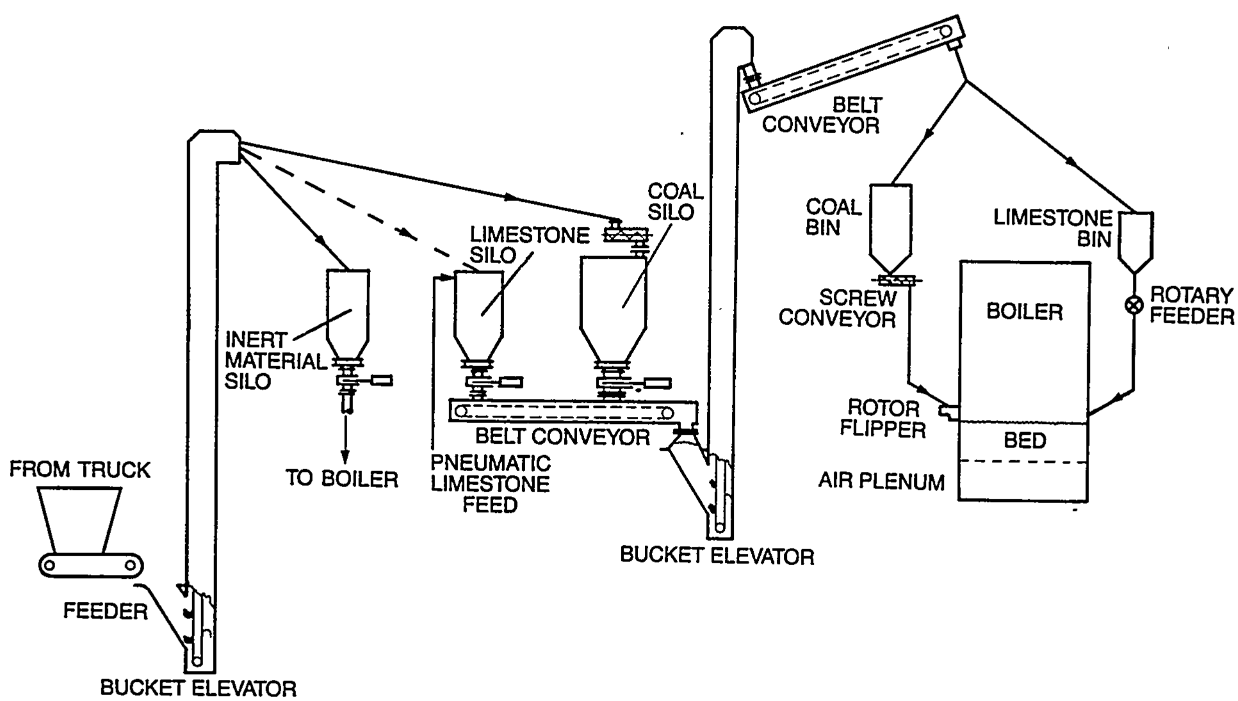


FIGURE 6 *BED REMOVAL AND RECYCLE SYSTEM*

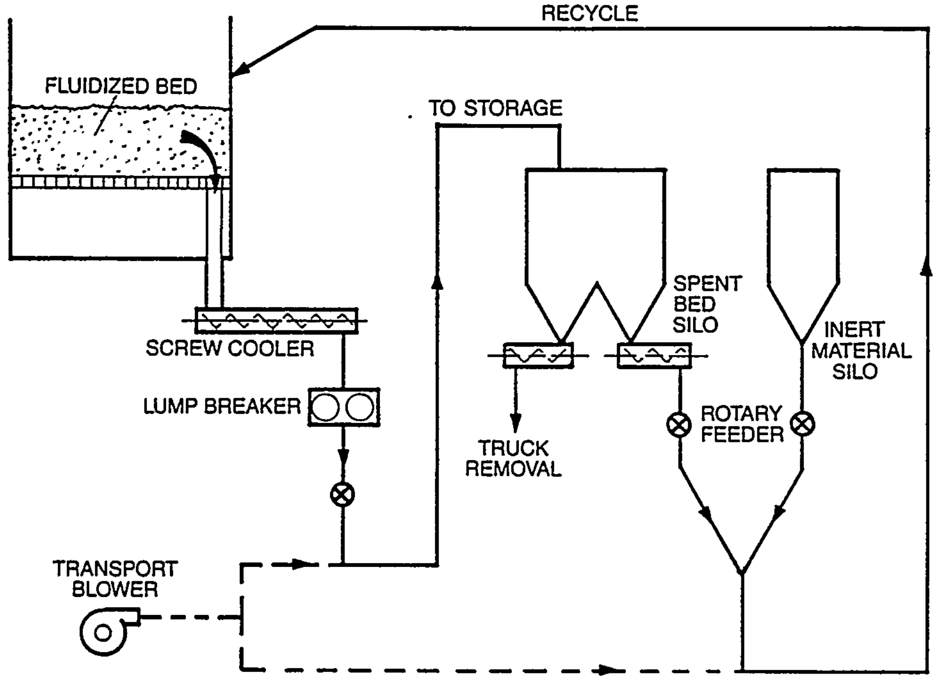
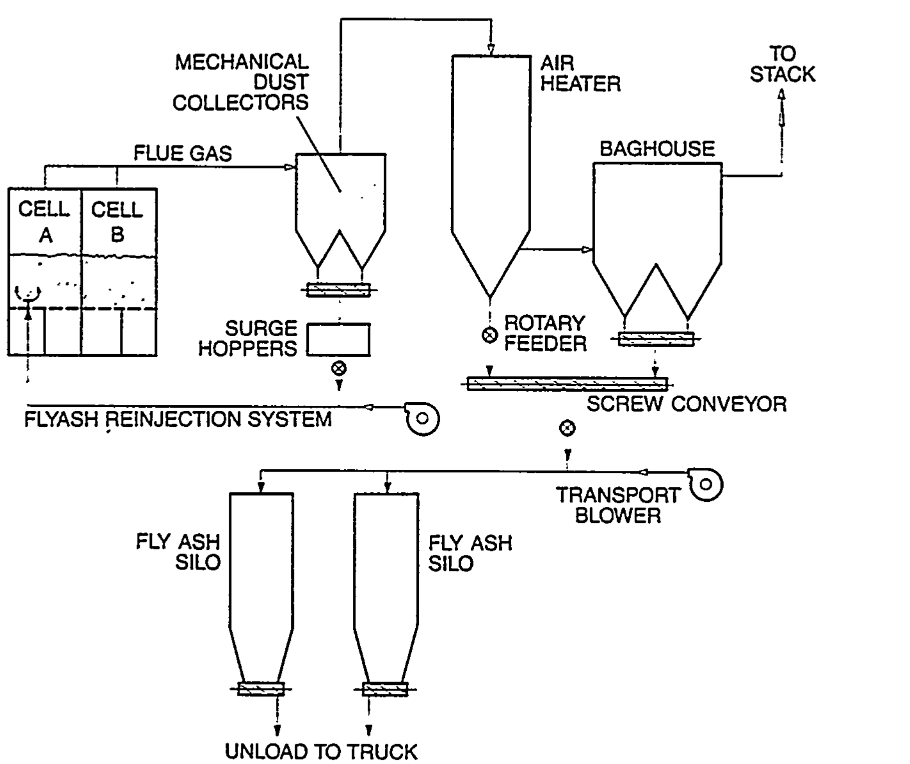


FIGURE 7 *FLY ASH SYSTEM*



limestone enters the unit through one of two paths. When the entire cell is fluidized, the path is identical to that described for Cell A. During segmental fluidization, limestone is diverted to a transport screw conveyor for injection into the bed through a pipe located on the coal rotor flipper wall of the cell which discharges the limestone just above the fully expanded fluidized bed level. To safeguard working mechanisms in the rotary feeder, each injection chute is provided with a seal air system. In addition, the limestone feed system from the day bin outlet to the boiler penetration is completely sealed.

Due to the good mixing characteristics in the bed only one feed point is required per cell. This simplification eliminates the need for limestone driers, pneumatic injection systems, and flow splitters to multiple injection points, thereby reducing possible hangup problems associated with small diameter lines.

The spent bed material removal system extracts and cools bed material from each of the cells independently at a rate required to maintain a constant bed material inventory regardless of coal ash content or reinjection rate (refer to Figure 6).

Flexibility of this system has been maximized by providing two slidegates in the partition wall between Cell A and Cell B so that all material can be extracted through one cooler. Operating experience may prove this to be the preferred mode of operation when firing low sulfur coal.

As the spent bed material passes through the screw cooler, its temperature is reduced to approximately 60°C (140°F). Material leaving the screw cooler is fed through a lump breaker and a rotary air lock prior to pneumatic transport to the spent bed material storage silo. Once in the storage silo, spent bed material can be either unloaded for truck removal or reinjected into the bed as needed to maintain or build bed inventory.

Pilot plant testing has indicated that under certain circumstances, depending on the coal and limestone being used, bed material may elutriate at a faster rate than fresh limestone would be added to control SO_2 emissions. If this situation develops, there would be a gradual reduction in bed level and consequent reduction in the rate of steam generation. In order to provide for this eventuality, a spent bed/inert material reinjection system capability has been included in the overall system design. By using that system, bed level can be controlled independent of the limestone feed rate, or spent bed cooler withdrawal rate, thereby providing additional operating flexibility and conserving limestone.

Separate storage silos are provided for spent bed material, flyash and inert material. In this way, stored spent bed material can be removed periodically since extended storage of that material is not recommended.

In operation, when material needs to be added to a cell to either maintain or increase bed inventory, the material can be taken from either the spent bed storage silo or the inert material storage silo. A variable speed feeder controls the rate of material withdrawal and a rotary valve acts as an air lock to the pneumatic transport line. A pneumatic transport line is used for spent bed and inert material injection. Near the steam generator a diverter valve in the pneumatic transport line directs material to either Cell A or Cell B. The injection point in each cell is located in the side wall above the fully expanded bed.

Previous experience has verified that some of the coal and limestone fed into the bed elutriates without taking part in the combustion or SO_2 capture processes. To recover and use this elutriated material, the SNR unit has been fitted with a flyash reinjection system which is shown schematically on Figure 7.

Flyash is collected in two 50% capacity multicyclone mechanical dust collectors. The gas inlet of one multicyclone has a damper which is closed below 50% gas flow to maintain collector efficiency and the material outlet has an actuated slidegate to prevent gas bypass during single collector operation.

A common collecting screw under both mechanical dust collectors has a single discharge into an upper weigh hopper which batch feeds a lower surge hopper. A variable speed rotary feeder on the outlet of the lower surge hopper continuously feeds material into a pneumatic transport line. Valves and piping are arranged to permit the lower surge hopper to operate continuously at a pressure equal to the pneumatic transport line pressure while the upper weighing hopper cycles between the transport line pressure and the pressure in the mechanical dust collectors. The rate of material collection in the upper surge hopper is used to control the speed of the rotary feeder. One blower supplies the required transport air. Splitter tees, located in the transport piping are used to generate eight individual streams of flyash. The flyash reinjection nozzles penetrate through the gridplate of Cell A in segment A-1. This configuration has been selected because this segment of Cell A is the first to go into operation.

By reinjecting the captured flyash, carbon burnup efficiency is expected to increase by approximately 5% to a total of 98%.

A baghouse downstream of the mechanical dust collector provides final cleaning of the flue gases before they are discharged through the stack into the atmosphere.

This unit has been designed with a two-part control system. The first part automatically controls sequential and modulating operations for the entire plant by using a microprocessor based distributed control system (DCS) employing cathode-ray tube (CRT) displays. It has the capability to automatically light-off and shutdown Cell B, without operator assistance, as the steam load demand changes.

The second part of the control system is a hard wired fail-safe system which operates independent of the DCS. Its purpose is to interlock critical components thereby ensuring a safe sequence of operation during startup, normal operation and shutdown.

TABLE 2

Steaming Rate	No. of Cells in Service
30%— 50% MCR	1
42%— 70% MCR	1½
60%—100% MCR	2

The normal bed operating temperature range is 771°C to 899°C (1420°F to 1650°F).

During normal operation, a change in steam generating rate can be accomplished by varying bed temperature and by the slumping or fluidizing cells or cell segments as indicated in Table 2. By using this method, bed inventory may be held constant.

Each boiler cell is provided with an in-plenum start-up section and an oil fired start-up burner as shown in Figure 4. The burner is fired to warm the unit and preheat the bed material to the coal ignition temperature. Since the plenum and gridplate are watercooled, they can withstand the burner exhaust gas temperatures that occur in the start-up zone.

As an alternate start-up method, if one cell is on line, it is possible to allow the hot bed material from that cell to flow into the adjoining cell by opening the slidegate valves in the partition wall that separates the two boiler cells.

If the present trend continues, the price of premium fuel will rise while emission limits become increasingly restrictive. The Shell plant at Europoort is demonstrating that fluidized bed combustion is a viable option when addressing those trends. It is providing a means of burning high sulfur coal in an environmentally acceptable manner. In addition, by the application of cogeneration techniques, overall cycle efficiencies as high as 80% can be achieved. Based on these advantages, it is expected that fluidized bed combustion will become an increasingly important contributor in meeting future steam generation needs throughout the world.

APPENDIX AB-9-6

COAL BENEFICIATION — THE CINDERELLA TECHNOLOGY *

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COAL BENEFICIATION — THE CINDERELLA TECHNOLOGY *

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ABSTRACT

A brief introduction to coal beneficiation processes is given. The paper includes brief summaries of current commercial practices and several developmental coal cleaning methods. Coal beneficiation economics and research needs are also discussed.

It is felt that coal beneficiation can play a significant role in the increased usage of coal to meet the nation's future energy needs. Fertile areas for coal beneficiation research and development are suggested, such as increased automation of coal cleaning circuits and novel coal cleaning methods to increase the recovery of higher quality coal from the mine product.

*Research sponsored by the Fossil Energy Office, U.S. Department of Energy under contract W-7405-eng-26 with the Union Carbide Corporation.

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INTRODUCTION

Raw coal as it comes from the mine ranges in size from large rocks (often 24 in.) to dust. In addition to the organic coal matter, the mine product contains shale from mine partings, stray machine parts, pieces of lumber, water, ash, and other mineral impurities such as pyrites. The raw mine product is often referred to as run-of-mine (ROM) or as-mined coal. ROM coal is seldom used as is; it is beneficiated to make it more suitable for the end-use application.

Coal beneficiation is a generic term that is used to designate the various operations performed on the coal to make it more suitable for its end-use application (e.g., feed to a coal-fired boiler or a coke oven, or a coal conversion process such as gasification or liquefaction). Coal beneficiation is also referred to as coal preparation, coal cleaning, or coal washing. In the past, when the need arose for lump coal, coal beneficiation consisted of operations such as hand-picking of coal lumps from the mine product. In recent years, however, coal beneficiation has come to encompass the entire spectrum of operations, ranging from the relatively simple crushing and size classification operations (that are almost routinely performed on all coals used today) to rather elaborate chemical and microbiological processes that are used or are being developed to render the ROM coal more suitable for the end-use process. Coal beneficiation processes prepare the ROM coal for its end use by removing the undesirable constituents associated with the coal without destroying the physical identity of the coal. However, liquefaction-type processes (such as the solvent-refined coal process) that upgrade the coal to yield a clean fuel product are generally not regarded as coal beneficiation processes primarily because they alter the physical identity of the coal; that is, the coal is liquefied, upgraded, and then resolidified to yield a coal-like product called solid SRC (solvent refined coal).

Beneficiating the coal has several advantages, including the following:

1. The cleaned coal is more uniform in size, composition, calorific value, and moisture content. When the cleaned coal is burned, it results in more uniform and steady combustion.

2. By reducing the ash and sulfur impurities in the coal, beneficiation contributes to reduced slagging and fouling in the furnace. This leads to increased boiler on-stream availability, decreased maintenance, and lower overall operating costs.

3. Removal of the associated mineral matter from the ROM coal results in lower transportation costs, higher combustion efficiency, and reduced ash disposal and flue-gas desulfurization (FGD) requirements for obtaining the same calorific value at the furnace.

4. The moisture content of the cleaned coal can be controlled (generally, the coal moisture content is reduced), which can result in improved coal handling and burning characteristics. This procedure leads to more efficient fuel use because less energy is wasted in drying the coal.

5. Beneficiation can be used to "tailor" the coal to more closely meet customer specifications, thereby resulting in a higher value for

the product. This takes on greater significance when one considers the potentially lucrative export market for U.S. coals.

6. Beneficiation can make it possible to use many of the high-sulfur and high-ash coals which could not otherwise be used, thereby increasing the usable resource base.

As with any technology, coal beneficiation has its disadvantages too, especially from the viewpoint of the beneficiation plant owner/operator. These disadvantages are the following:

1. Beneficiating the coal results in reduced marketable coal output from the mine product because some of the coal is discarded with the refuse. Current cleaning processes result in a significant fraction of the coal calorific value being lost to the plant refuse stream.

2. Capital must be invested to beneficiate the coal, thereby necessitating a higher price for the product coal because the invested capital must be recovered.

3. The beneficiation plant operator is confronted with the problems and the cost of disposal of the plant refuse in an environmentally acceptable manner. This cost (and concern) is absent (or, at least significantly reduced) if as-mined coal is shipped to the consumer.

As can be seen from the above, the advantages of beneficiating coal appear to far outweigh the disadvantages. A study by Hoffman et al.[1] indicated that coal beneficiation combined with FGD appeared to offer the most economical means of achieving sulfur oxides emission control for coal burning facilities. The study further stated that for some coals, beneficiation could even eliminate the need for FGD systems in order to economically achieve acceptable sulfur oxides emission control.

If, as projected:

1. coal is to provide an increasing share of the national energy needs,

2. future coal utilization plants will be required to meet increasingly stringent environmental constraints, and

3. the supply of acceptable coal is limited,

then coal beneficiation will be called upon to play an increasingly important role in meeting the nation's future energy needs.

The remainder of this paper will cover briefly the following topics related to coal beneficiation: current commercial practices, novel coal beneficiation processes, coal beneficiation economics, and coal beneficiation research activities. Large portions of the material to follow have been extracted from previous publications by Singh et al.[2,3] These publications may be consulted for additional information.

COAL BENEFICIATION PROCESSES

Coal beneficiation at present is more an art than a science. The beneficiation processes may be broadly classified into one of three areas:

1. physical or mechanical,
2. chemical, or
3. microbial.

Physical beneficiation processes rely on physical principles such as gravity separation, centrifugal action, surface tension, magnetic separation, etc. to separate the coal from the refuse. These processes will be discussed in somewhat greater detail later in the paper under current commercial practices.

Chemical beneficiation processes rely on the action of certain chemical reagents such as acids, alkalis, etc. to separate the ROM coal into clean coal and refuse. The chemical reagents used essentially affect only the sulfur and the ash impurties present in the coal, not the basic coal matrix.

Microbial beneficiation processes, as the name implies, rely primarily on the use of bacterial strains such as Thiobacillus ferrooxidans (also known as Ferrobacillus ferrooxidans) and Thiobacillus thiooxidans to remove some of the impurities from the coal. Microbial processes are known to occur in nature during the weathering of coal and mine wastes and are responsible for acid mine drainage. While earlier studies were directed at devising methods to minimize acid mine drainage (primarily because of environmental concern), it is only recently that the same bacterial process has been investigated as a potential beneficiation process.

Up to the present, commercial practice has relied primarily on physical coal-cleaning processes to beneficiate coals. Chemical, microbial, and other novel coal beneficiation processes are of recent origin and are still at various levels of process development. The microbial beneficiation processes are still in their infancy, for example. The chemical beneficiation processes (though generally capable of producing a higher yield of a cleaner coal product from the ROM coal) have not been used on a commercial scale, primarily because they have not yet proven to be economical.

CURRENT COMMERCIAL PRACTICES

Currently in the United States and other coal-producing countries, the ROM coal is prepared by a physical beneficiation process. The degree of preparation can vary from no beneficiation to a very thorough treatment of the raw coal. The process(es) used and the degree of cleaning employed are very dependent on the type of coal and the product coal specifications desired. However, in general, commercial beneficiation processes rely on the use of gravitational and/or centrifugal forces to effect the separation of the clean coal from the accompanying impurties. Physical coal cleaning generally consists of dry or wet beneficiation methods. In 1975, only 2.5% of the coals cleaned in the United States were beneficiated using dry separation methods; the other 97.5% were cleaned by using wet beneficiation methods.[4]

In general, physical beneficiation processes consist of various combinations of some or all of the following unit operations.

1. Size reduction. This operation consists of reducing the size of the coal received from the mine (often 24 in. x 0) to more manageable sizes. Size reduction is usually accomplished by using equipment such as rotary breakers, impact mills, and single and double roll crushers. Sketches of some typical size reduction equipment are given in Figure 1.

2. Size classification. This operation consists of segregating the coal into various size fractions to facilitate downstream processing. Both the ROM coal and the crushed product may be classifed into different size fractions. Equipment for size classification includes stationary, vibrating, and cross-flow screens and classifying cyclones. Figure 2 shows some sketches of typical size classification equipment.

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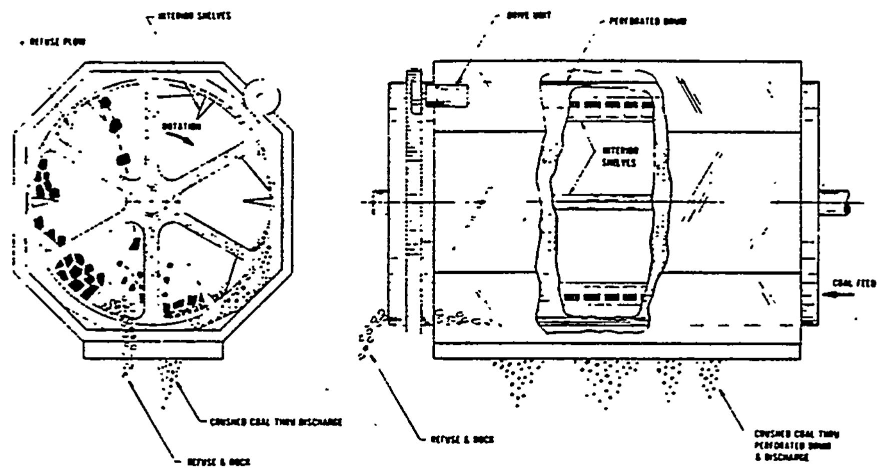

(a) Rotary breaker

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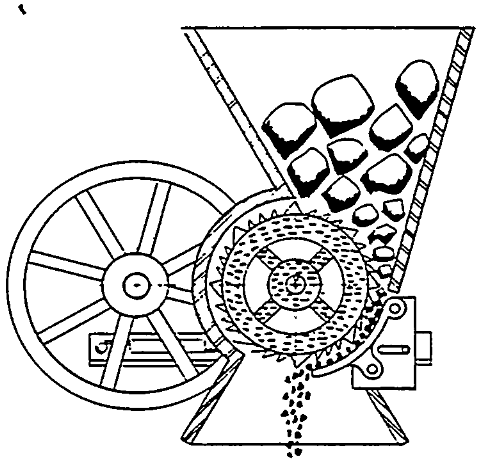

(b) Single roll crusher

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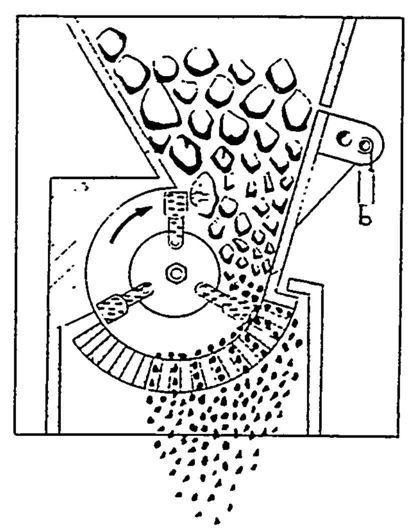

(c) Hammer impact mill

Figure 1. Sketches of typical size reduction equipment used in coal preparation plants.

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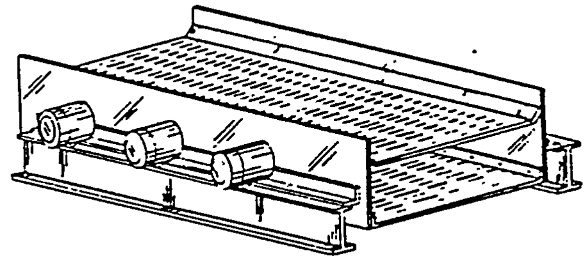

(a) Double deck mechanically vibrated screen

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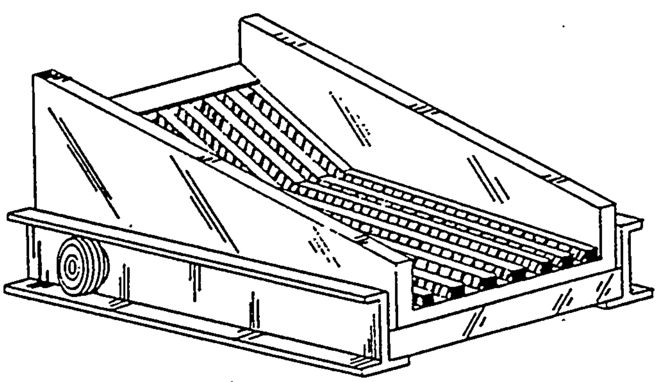

(b) Mechanically vibrated bar grizzly

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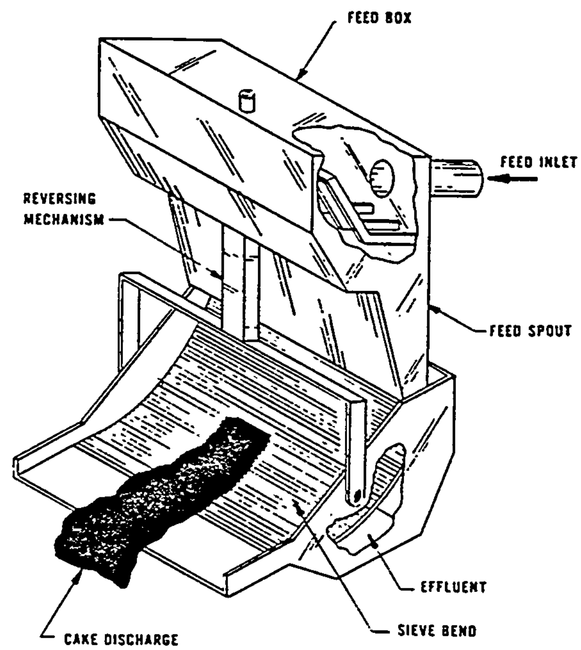

(c) Sieve bend

Figure 2. Sketches of typical size classification equipment used in coal preparation plants.

3. Cleaning. This operation is the heart of many coal beneficiation (preparation) plants. It involves mainly the separation of the physically attached sulfur and/or mineral impurties of higher specific gravities from the coal of lower specific gravity. This step is often accomplished by using jigs, cyclones, and concentration tables, which utilize a combination of frictional and/or gravity or centrifugal forces to effect an apparent density differential separation between the coal and its sulfur and mineral impurities. Schematics of typical equipment used in coal preparation plants are given in Figure 3. Another commonly used cleaning method is the heavy-medium separation, which employs an intermediate specific gravity suspension of fine heavy minerals (such as magnetite or sand) in water to effect the desired separation. In general, heavy-medium separation results in a fairly high recovery of the clean coal, although the clean coal has to be separated from the heavy medium before it can be either used or processed further. Because of this additional processing step required, heavy-medium separation incurs higher operating costs than similar beneficiation processes using only clear water. Finally, froth flotation processes are generally used to beneficiate very fine-size (28 mesh x 0) fractions. In froth flotation, the coal is beneficiated in a liquid medium (usually water) by air bubbles (injected into the coal bath) that float the very fine clean coal particles to the liquid surface, where the coal particles are mechanically skimmed. A surfactant is generally added to the coal bath to render the coal more hydrophobic and thereby facilitate the flotation of the coal. The impurities associated with the coal sink to the bottom of the vessel from where they are removed for eventual disposal.

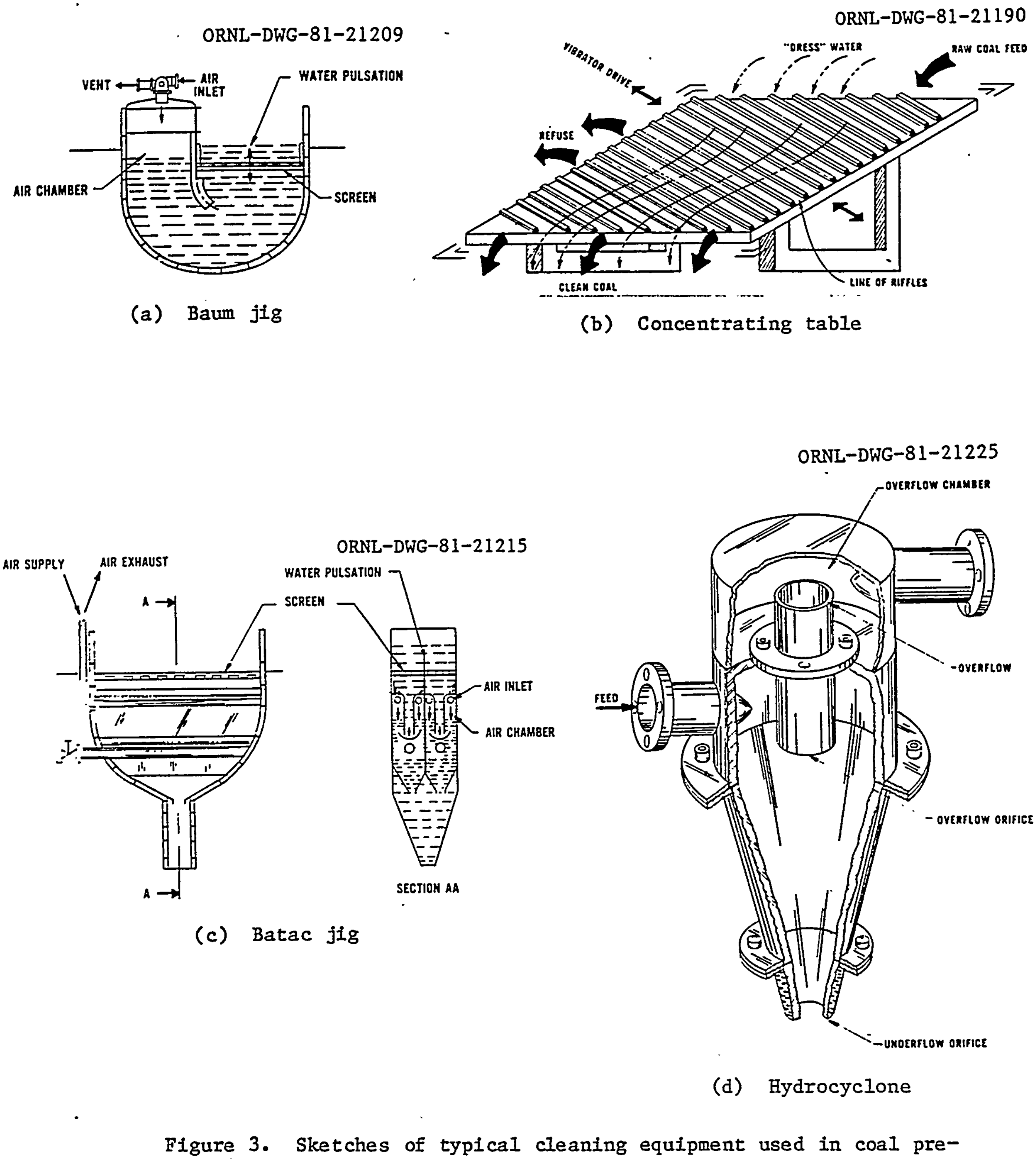

Figure 3. Sketches of typical cleaning equipment used in coal preparation plants.

4. Drying. This unit operation involves the reduction of the moisture content in the coal to the desired value. Various types of equipment such as screens, filters, centrifuges, and thermal dryers are used to dry the coal, depending upon the desired moisture content in the product coal. Figure 4 is a sketch of a fluidized-bed coal dryer installation.

In general, coal beneficiation plants use various combinations of all or some of the above unit operations to beneficiate different size fractions of the raw coal, depending upon the level of beneficiation desired. The latter is greatly dependent on the desired specifications of the coal to be produced. The various levels of coal beneficiation are discussed below.

LEVELS OF COAL BENEFICIATION

ROM coal may be beneficiated at various levels ranging from level 1, which involves essentially no beneficiation, up to level 4, which implies a very thorough beneficiation of the coal. Of course, the cost of beneficiation also increases correspondingly from level 1 to level 4. Level 4 cleaning is generally intended for coals to be used in metallurgical operations (coke production, for example), although some Eastern and Interior Basin coals (intended for steam production) may also require this thorough level of beneficiation in order to meet environmental restrictions. The four levels of coal beneficiation are described briefly below.

Level 1. This level is a very basic stage of beneficiation, consisting of size reduction and classification with some attendant removal

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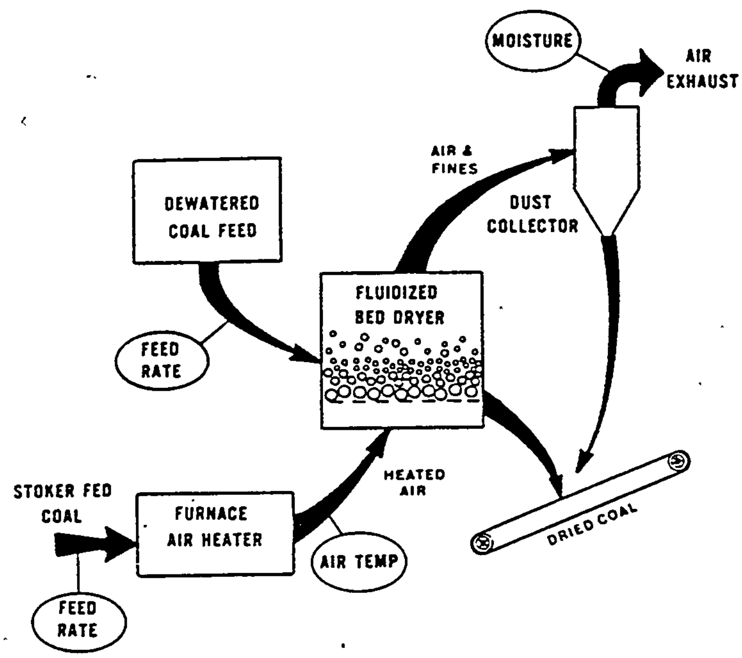

Figure 4. Sketch of a fluidized-bed coal dryer installation.

of refuse and mine dilutions such as pieces of timber, stray machine parts, etc., which can cause problems with downstream processing equipment. Level 1 beneficiation is practiced essentially on all coal burned. Calorific recovery or recovery of the ROM coal heating value is about 100%. However, there is essentially no reduction in the mineral impurities present in the coal.

Level 2. This level involves level 1 preparation plus wet beneficiation of the coarse coal (generally larger than 3/8 in. in size) fraction only. The fines fraction generated in the process is usually collected and shipped as part of the product coal. Calorific recovery at this level of treatment is generally high (>90%), but there is relatively little to no reduction in the mineral impurities in the coal. Figure 5 is a sketch of a conceptual level 2 coal beneficiation plant.

Level 3. This level involves level 2 preparation plus further beneficiation of all coal down to +28-mesh size fraction. The -28-mesh coal is either dewatered and shipped with the plant product or disposed of as refuse, provided environmental regulations permit such disposal. Calorific recovery is generally good (>80%), and there is a significant reduction in the sulfur and mineral impurties in the product coal.

Level 4. This level involves a full-scale or thorough beneficiation of the coal. Figure 6 is a sketch of one version of a conceptual level 4 coal beneficiation plant. In the version shown, only one product stream is shown for simplicity. However, level 4 cleaning can usually yield several coal product streams that contain varying levels of sulfur and mineral matter. The ultraclean fraction with the lowest level of sulfur and ash may be routed to metallurgical operations. This

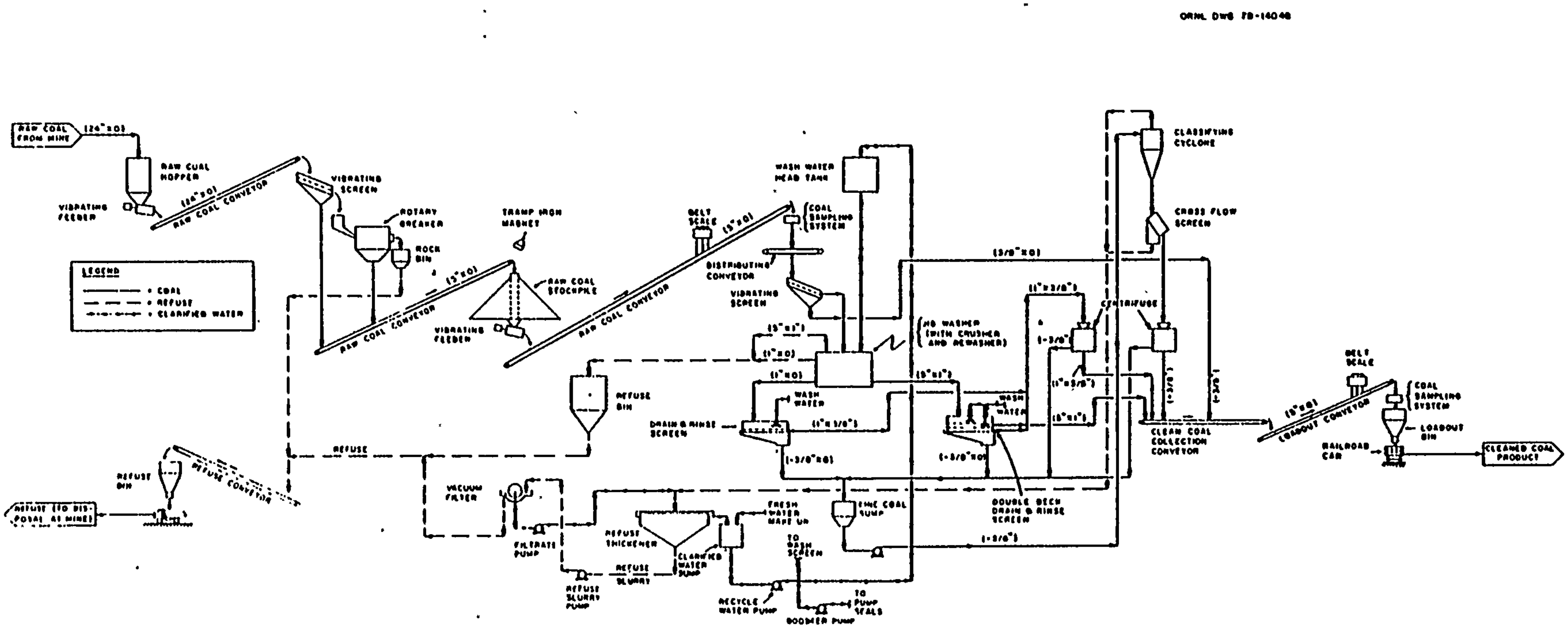

Figure 5. Process flow diagram of one version of a conceptual level 2 wt mechanical coal beneficiation plant.

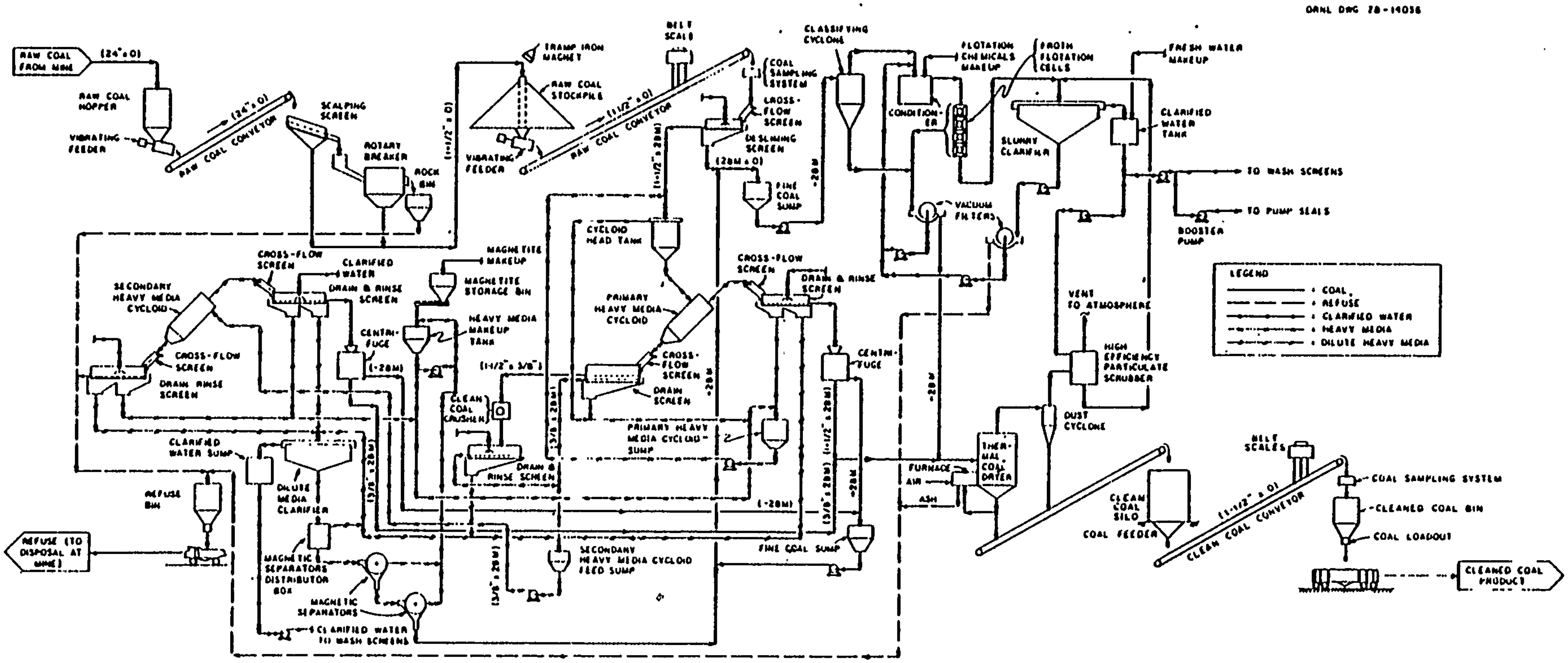

Figure 6. Process flow diagram of one version of a conceptual level 4 wt mechanical coal beneficiation plant.

stream may amount to as little as 25% of the raw coal feed to the plant.[5] Several intermediate fractions are also produced which contain coal with significantly reduced sulfur and ash levels but not low enough to meet metallurgical coal specifications. These intermediate streams are often referred to as "middlings" and are usually suitable for steam generation purposes. Material yields at this level of beneficiation typically range between 60 to 80%, while calorific recovery is generally between 85 and 95% of the incoming coal.[5]

Regardless of the levels of cleaning achieved, physical coal beneficiation processes have limitations in that they can remove only the inorganic sulfur (mainly the pyritic sulfur) and the extraneous mineral impurities from the ROM coal. These processes are unable to reduce the organic sulfur content of the coal. Inorganic sulfur reductions by conventional physical beneficiation processes can range between 0 and 60 wt %. This generally corresponds to a 0 to 50 wt % reduction of the total sulfur content of the coal. Material recoveries or clean coal yields for the currently used beneficiation processes generally vary between 60 to 80 wt % of the feed coal.

NOVEL COAL BENEFICIATION PROCESSES

Historically, coals (other than those intended for metallurgical operations) were given perfunctory beneficiation, with the objective of recovering as much lump coal as possible. The fines generated during the upgrading operations were often discarded as plant refuse. However, during the past few years, the needs of the coal markets have greatly changed because of the following factors:

1. the increased emphasis to use coal instead of oil or natural gas to generate electric power;
2. The increasingly stringent environmental controls being promulgated for the burning of coal and for the disposal of refuse from coal processing plants;
3. increased mechanization in the coal mines, which results in higher volumes of fines in the ROM coal; and
4. current coal economics, which almost mandates that as much clean and marketable coal be recovered from every ton of raw product mined.

As a result, more and more emphasis is being placed on processing the fine-size (generally -1/4-in.) coal to recover usable coal and minimize the amount discarded as refuse. In particular, considerable research effort is currently being expended on developing new processes that either minimize the production of fines during the cleaning operations (such as the chemical comminution process) or clean the fine coal to yield a marketable product and thereby concurrently reduce the refuse to be processed from the beneficiation plant.

To overcome the limitations of the physical beneficiation processes and to better serve the changing needs of the coal markets, several novel beneficiation processes have recently been (and are being) developed. These include several novel physical beneficiation processes, as well as new chemical and microbial beneficiation processes.

Table 1 is a listing of novel physical beneficiation processes that have been developed. Brief descriptions of the processes and references for additional information regarding these processes are also given.

Table 1. Novel physical coal beneficiation process

Process name	Process developer	References	Typical operating conditions: Temp. (°F)	Pressure (psig)	Particle size U.S.S.[a] mesh size	Impurities reduction potential, %: Pyritic sulfur	Ash	Clean coal yield (%)	Comments
Dry Beneficiation Processes									
1. Magnex Process	Hazen Research, Inc.	6, 7	338	Ambient	-14	~85	67	85	Magnetic separation process; uses iron carbonyl [$Fe(CO)_5$] vapors to render the pyrites and the ash impurities magnetic; an 8- to 12-kilogauss magnetic field is used to separate the clean coal from the impurities; process has been tested in a 200-lb/h pilot plant.
2. High-gradient Magnetic Separation (HGMS) Process	Auburn University/ Oak Ridge National Laboratory	8-10	Ambient	Ambient	-28 + 325	87	52	~80	Magnetic separation process; impurities separated from the clean coal by subjecting a fluidized bed of finely pulverized coal to a high-intensity (20 kilo-oersted) magnetic field; process has been developed up to one ton/h pilot scale.
3. Dry table separator	FMC Corp.	11	Ambient	Ambient	1/8 in. to 8 in.	<50	<74	72	Clean coal is separated from the impurities by the action of vibratory and gravity forces; pyrite and ash reduction is very dependent on the type of coal processed and the extent of pyrite liberation in the feed coal; best used as a "rougher;" equipment has been field-tested; preferred top size to bottom size ratio of feed coal per pass = 4:1.
4. Microwave coal cleaning process	G.E. Laboratories	12	392-572	Ambient	-30 + 100	40-50[b]	N.A.[c]	N.A.	Process uses microwave heating to remove sulfur from coal; process can remove pyritic and organic sulfur (for organic sulfur removal, the feed coal is mixed with NaOH); process has negligible effect on coal volatiles; process has been developed up to a laboratory bench-scale unit.

Table 1. (continued)

Process name	Process developer	References	Typical operating conditions: Temp. (°F)	Pressure (psig)	Particle size U.S.S.[a] mesh size	Impurities reduction potential, %: Pyritic sulfur	Ash	Clean coal yield (%)	Comments
Wet Beneficiation Processes									
5. Two-stage froth flotation	U.S. Bureau of Mines	13	Ambient	Ambient	-28	<90	N.A.	N.A.	Similar to conventional froth flotation except that the clean coal from the first stage is subjected to reverse froth flotation in the second stage (i.e., in the second stage, the clean coal is permitted to sink while the impurities are floated and collected); process development has proceeded up to laboratory bench-scale unit.
6. Wet HGMS process	Auburn University, Indiana University, Sala Magnetics, Inc., Oak Ridge National Laboratory	14-16	Ambient	Ambient	-200	80-90	35-45	95	Pyritic sulfur and ash impurities are removed from finely pulverized coal slurried in water by subjecting the coal slurry to a high-intensity (20 kilo-oersted) magnetic field in a specially designed separator; process is based upon proven technology used in the kaolin industry; process has been developed up to a small pilot-plant-scale unit.
7. Otisca process	Otisca Industries Ltd.	17	60-68	1 to 2 in. of H_2O	1/2 in. x 0	~44	~50	>73	Process is a heavy-media separation process that uses a halogenated hydrocarbon fluid as the heavy media. No water (other than that associated with the coal) is used in the process; hence, dewatering costs are reduced substantially. Process operates at a high vacuum. Process has been developed up to a 20-ton/h pilot plant.
8. Oil agglomeration	National Research Council of Canada (NRCC)	18, 19	Ambient	Ambient	-28	56	76	90[d]	Process beneficiates coal by forming micro-agglomerates or flocs of the coal particles; process uses light hydrocarbon liquids (such as kerosine or fuel oil) to preferentially wet the coal particles to form flocs; the flocs are separated from the impurities and then pelletized to form large balls to improve their mechanical handling properties; process is especially suited to beneficiating fine sized coal particles; it has been devel- up to pilot-plant-scale level by NRCC.

Table 1. (continued)

Process name	Process developer	References	Typical operating conditions: Temp. (°F)	Pressure (psig)	Particle size U.S.S.[a] mesh size	Impurities reduction potential, %: Pyritic sulfur	Ash	Clean coal yield (%)	Comments
Wet Beneficiation Processes									
9. Chemical comminution process	Syracuse University Research Center (SURC)	20, 21	-30 to 75	15-120	3 in. x 0	~73	~55	>95	The process uses anhydrous liquid or gaseous ammonia instead of mechanical grinding to reduce the size of the ROM coal and to liberate the pyrites; the comminuted coal is then separated by conventional sink-float methods into clean coal and reject fractions; the process has been developed up to a small pilot-plant-scale level.

[a]U.S.S. = U.S. Sieve Series.

[b]Total sulfur reduction potential reported.

[c]N.A. = not available.

[d]Yield reported is the calorific value recovery potential of the process. This value is generally higher than the material yield from the process.

Table 2 is a similar listing for the novel chemical beneficiation processes. Several of the chemical beneficiation processes under development claim to be able not only to reduce the pyritic (and inorganic) sulfur, but also to remove a fraction of the organically bound sulfur without incurring a significant loss in the heating value of the coal.

The microbial beneficiation processes, as mentioned earlier, are still at the bench-scale level of development.

Additional details on the novel beneficiation processes may be obtained from the references indicated in Tables 1 and 2 and from refs. 34-35. Some general characteristics primarily related to the commercial potential of these processes in coal beneficiation operations are summarized below.

1. All of the novel processes are developmental in nature. The processes are at various levels of process development ranging from bench-scale to pilot-plant stages. None of the novel processes have been used in a commercial plant yet, though some efforts are being made to commercialize some of the processes such as the HGMS process, for example.

2. All of the processes exhibit high recoveries, ranging up to 90 to 95% of the incoming coal. These recoveries, if achieved in commercial practice, indicate significant improvements over current coal beneficiation processes.

3. The new processes offer significantly higher sulfur and/or ash reductions than can be achieved even by the highest level of the conventional wet beneficiation processes practiced today. Inorganic sulfur

Table 2. Novel chemical coal beneficiation process

	Process name	Process developer	References	Typical operating conditions			Chemical reagent used	Impurities reduction potential, %		Clean coal yield (%)	Comments
				Temp. (°F)	Pressure (psig)	Particle size U.S.S.[a] mesh size		Pyritic sulfur	Ash		
1.	TRW-Meyers Coal Desulfurization Process	TRW, Inc.	22, 23	194-266	<120	-14	Ferric sulfate[b]	<95	10-30	82-92	Process only removes the pyritic sulfur from the coal; it does not affect the organic sulfur present in the coal; ferric sulfate used in the process is generated from the pyrites liberated from the coal; free sulfur is formed in the process; process requires oxygen and lime as chemicals; process has been developed up to an 8-tons/day process design unit.
2.	Battelle Hydrothermal Coal Process	Battelle Columbus Laboratories	24, 25	430-650	350-2500	-200	Sodium hydroxide	90-98 plus 24-70% of the organic sulfur present in the coal	c	97-100 for battery-limits plant; 49-60 for grassroots plant	Process has the capability of reducing the pyritic, organic sulfur, and the free swelling index of the coals tested; increase in the ash content of the coal is due to NaOH impregnation of the product coal; product coal may be de-ashed by acid treatment; yield is lower for the grassroots plant because a significant fraction of the clean coal is used to provide the plant energy requirement.
3.	Ledgemont Oxygen Leaching (LOL) Process	Ledgemont Laboratory Kennecott Copper Corp.	26, 27	212-266	<300	-100	Oxygen, water	>90	N.A.[d]	N.A.[d]	Process removes only pyritic sulfur formed in the process; process has been developed up to a laboratory bench-scale unit.
4.	Ledgmont Ammonia Oxygen-Water Process	Ledgemont Laboratory Kennecott Copper Corp.	28	212-266	<300	-100	Ammonia, oxygen	>90 plus up to 25% organic sulfur removal	N.A.	N.A.	Process is similar to the LOL process except that organic sulfur is also removed from the coal; however, process can result in an 8-13% loss in the coal heating value. Process has been developed up to a laboratory bench-scale unit.

Table 2. (continued)

Process name	Process developer	References	Typical operating conditions: Temp. (°F)	Pressure (psig)	Particle size U.S.S.[a] mesh size	Chemical reagent used	Impurities reduction pontential, %: Pyritic sulfur	Ash	Clean coal yield (%)	Comments
5. KVB Coal Desulfurization	KVB Engineering, Inc.	29, 30	100-500	15-300	-14 + 28	gaseous NO_2	<90[e]	N.A.	N.A.	Process claims to be able to remove pyritic and organic sulfur from coal; reaction is performed in a fluidized-bed reactor; no free sulfur is formed in the process; process at bench-scale level of development.
6. PERC Oxidative	Pittsburgh Energy Technology Center	31, 32	~300-430	220-1500	-200	H_2SO_4[b]	>95 plus <40% of the organic sulfur in the coal	N.A.	90f	Process claims to be able to reduce the pyritic and the organic sulfur present in the coal; process requires air and water as reagent chemicals; process has been developed up to a laboratory bench-scale unit.
7. Low-Temperature Chlorinolysis	Jet Propulsion Laboratory, California Institute of Technology	33	165	15	-200	Chlorine	<90 plus <70 organic sulfur removal	N.A.	98f	The finely pulverized coal is slurried in methylchloroform; the coal slurry is then treated with chlorine gas for 1-4 h; the treated coal is then dechlorinated by heating to 644°F; process has been developed up to a laboratory bench-scale unit.

[a]U.S.S. = U.S. Sieve Series.

[b]The chemical reagent is generated in the process from the pyrites present in the coal.

[c]The ash content of the product coal increases due to NaOH impregnation in the coal.

[d]N.A. = not available.

[e]Total sulfur reduction potential reported.

[f]Yield reported is the calorific value recovery potential of the process. This value is generally higher than the material yield from the process.

reductions >90 wt % and significant organic sulfur reductions have been reported for some coals when using some of the chemical beneficiation processes (see Table 2).

4. Most of the new physical coal cleaning methods achieve the high sulfur reductions mentioned above by beneficiating the fine and ultra-fine-sized coal (-28 mesh and smaller). This procedure appears to be acceptable commercially since most of the coal used in utility boilers today is fired in pulverized coal-fired boilers. However, this trend may necessitate that these beneficiation processes be located near the end-use facility to avoid either the excessive losses of coal in fine-coal transportation or the increased costs associated with briquetting operations.

5. The application of the novel beneficiation processes, though potentially yielding higher recoveries of cleaner coal, will undoubtedly raise the price of the cleaned coal. However, the increase may well be less than the additional costs of providing FGD processes to meet statutory gaseous emission regulations.

6. Most of the novel processes can be considered to be add-on-type processes which could be added to conventional coal beneficiation plants to clean, for example, the fine coal fraction. However, many of the novel processes can also be designed to clean the entire raw coal feed to the preparation plant.

COAL BENEFICIATION ECONOMICS

The economics of coal beneficiation are equivocal in nature primarily because they are very project and coal specific. Coal preparation plants today are by and large customized for each application. The costs developed for one situation may not be directly applicable to another. However, bearing in mind the above caveat, Roman[36] (quoting Phillips[5]) indicates that the cost estimates for physically cleaning coal (in 1977 dollars) can range from ~\$0.80 per ton of cleaned coal for rudimentary beneficiation to ~\$15 per ton for full-scale coal beneficiation.

Also, especially for power plant applications, beneficiation economics need to be examined in concert with FGD economics. Ehrlich[37] speculated that it may cost ten times as much money to remove a pound of sulfur with FGD as it does with coal cleaning. Hoffman and Holt[38] report that assessments conducted on new power plants using cleaned coal indicate savings of 2 to 112% as compared to meeting the emission limitations by using FGD alone. They further report that the above type of savings are even more impressive for existing power plants (ranging between 13 and 140%) when they used cleaned or beneficiated coal.

Of course, the application of the novel beneficiation processes will tend to increase coal cleaning costs. However, using the novel technologies should produce increased yields of a higher quality product which may well lower the overall cost to power plants of meeting increasingly stringent emission regulations. To illustrate the likely costs of using some of the novel coal beneficiation processes, the results of an assessment conducted at ORNL are reported in Table 3. The potential costs for level 2 and level 4 conventional wet beneficiation plants are included in Table 3 for comparative purposes. The above

Table 3. Comparison of the material recoveries and beneficiation costs for the five conceptual coal beneficiation processes (second-quarter 1978 costs)

Process	Material recovery[a] (%)	Beneficiation cost per ton coal processed,[b,c] ($/ton)	Incremental cost over wet mechanical beneficiation: Level 2 ($/ton)	Incremental cost over wet mechanical beneficiation: Level 4 ($/ton)
Wet magnetic beneficiation	85	20.42	13.17	10.12
Chemical comminution	89	14.46	7.21	4.16
Meyers process	86	28.23	20.98	17.93
Level 2 wet mechanical	72	7.25		-3.05
Level 4 wet mechanical	74	10.30	3.05	

[a]Derived as tons of cleaned product coal per ton of ROM coal feed.

[b]Derived as (product price per ton - feed coal cost per ton of product coal) x material recovery, %/100.

[c]The values reported are for $20/ton ROM coal, 100% equity financing, and 15% annual after-tax rate of return (AARR) on equity.

assessments were performed for conceptual battery-limits facilities processing 200 tons per h of feed coal and operating 14 h/d for 329 d/year. Further details of the assessment may be obtained from ref. 2.

As can be seen from Table 3, use of some of the novel processes may tend to double and even triple the beneficiation cost. However, these costs have to be examined against the likely larger decrease in power plant and FGD costs associated with burning a higher quality coal to appreciate their true significance.

No conclusions regarding the potential benefits of using the newer technologies can be derived based on the above assessments. A much more detailed analysis (preferably for an actual plant situation) will have to be performed to determine the merit of using some of the newer technologies. However, it seems fairly certain that any improvements in coal preparation technology will likely translate into sizable benefits, especially for the utility industry.

COAL BENEFICIATION RESEARCH ACTIVITIES

Most coal cleaning plants (including some of the newer facilities) today still use rather simple cleaning techniques and manual control methods. This leads to considerable loss of otherwise usable coal. Until recently, there was little incentive to improve coal cleaning efficiencies because (1) supplies of high-quality coals were plentiful, (2) environmental constraints were minimal to nonexistent, and (3) economics did not warrant anything beyond perfunctory beneficiation except for metallurgical coals. However, the energy crises and the increased environmental activism of the seventies together changed all that. Coal was looked upon as the near-term energy savior of the industrial nations, yet it was a "dirty" fuel. Because of the above, several initiatives were undertaken in the seventies to improve and develop environmentally acceptable coal conversion technologies including coal beneficiation.

Coal beneficiation research activities proposed were to be conducted along these three broad fronts:

1. Improve existing technologies — seeking improvements in recovery and separation efficiencies of coal cleaning unit operations such as coal comminution, coal washing, and froth flotation.

2. Improve preparation plant operations — the development and incorporation of advanced instrumentation and process controls to operate the plants so as to produce more cleaned coal of a consistent quality at a lower cost.

3. Develop newer cleaning technologies — the development of processes with the potential of recovering more clean coal containing less ash and sulfur impurities than current practices. Some of the novel beneficiation processes are summarized in Tables 1 and 2.

An off-shoot of this category is the development of novel technologies to ultra-clean fine coal for use in coal-water mixtures. These coal-water mixtures could hopefully be burned like oil in existing oil-fired units.

Although the economic downturn of the early eighties has taken the bloom off coal usage, coal beneficiation research still flourishes (albeit with reduced vigor) at several locations. Two examples of ongoing research activities are given below:

1. EPRI in 1981 completed their $15.2 million Coal Cleaning Test Facility near Homer City, Pennsylvania. The objectives of the facility[39] are (1) to characterize coal cleanability on a national basis, (2) to develop and test new equipment and processes, (3) to train coal-preparation engineers and operators, and (4) to be one of the major sources of near-term R&D in coal beneficiation.

2. ORNL and TVA are building a 1-ton/h HGMS pilot plant at TVA's newest 2000-tons/h Coal Preparation Plant (feeding TVA's adjacent power plant) at Paradise, Kentucky, to compare the performances of the HGMS and froth flotation processes. The pilot plant is expected to be in operation by the summer of 1983. The 2000-tons/h plant is a conventional wet beneficiation plant using heavy-media processing and froth flotation to clean an ~5.5 wt % sulfur and ~15 wt % ash Kentucky No. 9 coal to produce a 3.5 wt % sulfur and an ~8.5 wt % ash cleaned coal. The design calorific recovery and mass yield are ~90% and ~84%, respectively.

CONCLUSIONS

A very brief introduction to coal beneficiation has been presented in this paper. References have been given for further details. Some conclusions that can be drawn regarding coal beneficiation are summarized below:

1. It is evident that coal preparation can play a significant role in increasing coal use to meet future energy needs in an environmentally acceptable manner. However, beneficiation is not a panacea for the use of the nation's high-sulfur and/or high-ash coals. It has limitations.

Present technology can at best remove only a fraction of the pyritic sulfur and mineral matter from coal, and much usable coal is often discarded with the refuse. Nonetheless, coal beneficiation can certainly mitigate the problems associated with using the high-sulfur and high-ash coals, and (for some coals) it can even obviate the need for downstream FGD processes.

2. Present commercial beneficiation technologies can often be economically superior compared to FGD processes, when burning certain high-sulfur coals in a utility boiler.

3. Current preparation plants rely too heavily on manual process control methods, resulting in a significant loss of saleable coal in the refuse. Improved instrumentation and process controls are needed in these plants to provide higher yields of a more consistent quality product.

Several foreign coal-producing countries (especially England) have recognized this deficiency and have begun to incorporate advanced process controls in their newer preparation plants. In the United States, however, many coal preparation plant operators are too small to be able to support an extensive R&D program, with the result that automation and process controls have not been widely used in the industry. This is an area where a Federal (or state-supported) R&D program can yield significant benefits.

4. Novel coal beneficiation technologies are required that will increase the yield of cleaned coal containing much less sulfur and ash than currently practiced. These technologies are being developed, and some of them show considerable promise of achieving the above goals. The further development of these technologies should be encouraged.

The new technologies will very likely cost more than current methods, with the costs appearing to increase with the degree of processing. However, the new technologies also promise higher yields of better quality (coal with less impurities) product which could translate into larger benefits with downstream processes, such as greater boiler availability and lower (to nonexistent) FGD costs.

5. R&D should be encouraged in novel coal cleaning technologies that go even beyond the capabilities of current novel processes and can produce a very low-sulfur and low-ash coal (the so-called "ultra-clean" coal) with the goal of developing coal-water mixtures that can be used directly (with minor modifications) as a replacement fuel in present day oil-fired units.

6. In spite of the current oil-glut, many forecasters still feel that coal will be the near-term energy savior of the industrial nations. Any increased coal use will greatly benefit from improved coal beneficiation.

7. Coal beneficiation is truly a Cinderella technology because its potential significance has been overshadowed by the attention given to other emission control technologies such as flue-gas desulfurization, yet it is a technology that is basic to all coal conversion processes.

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COAL-METHANOL SLURRY

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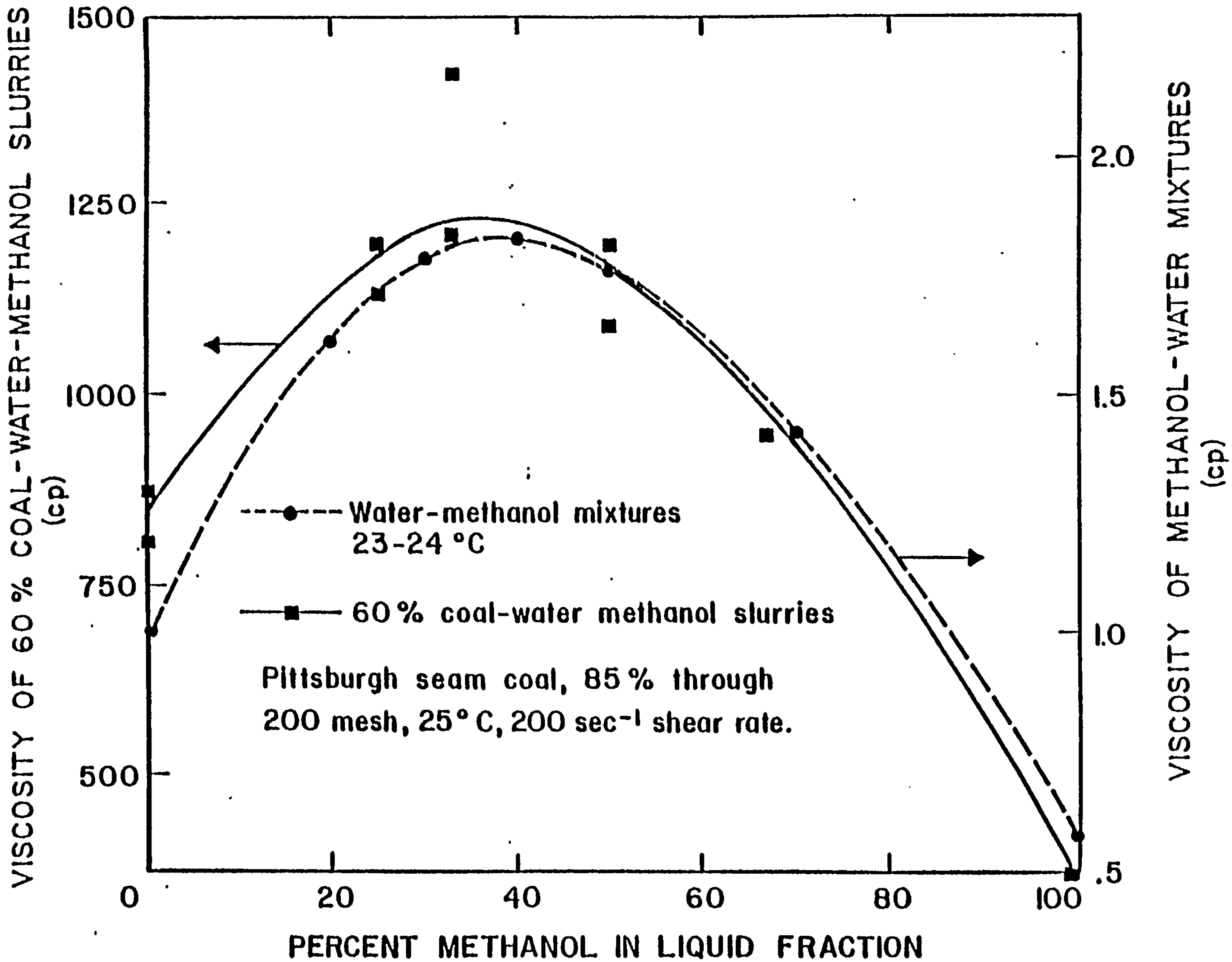
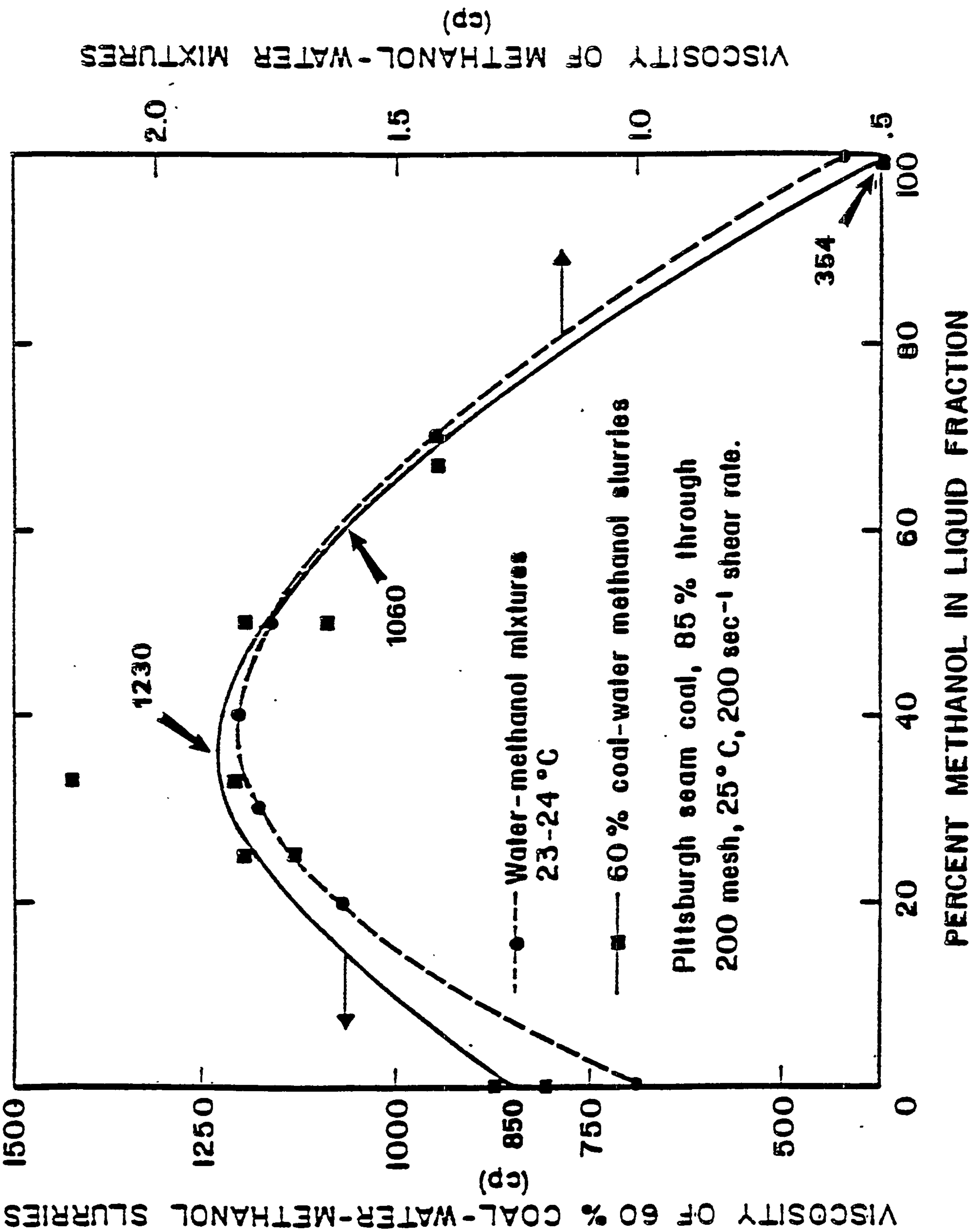


VISCOSITY vs PERCENT METHANOL



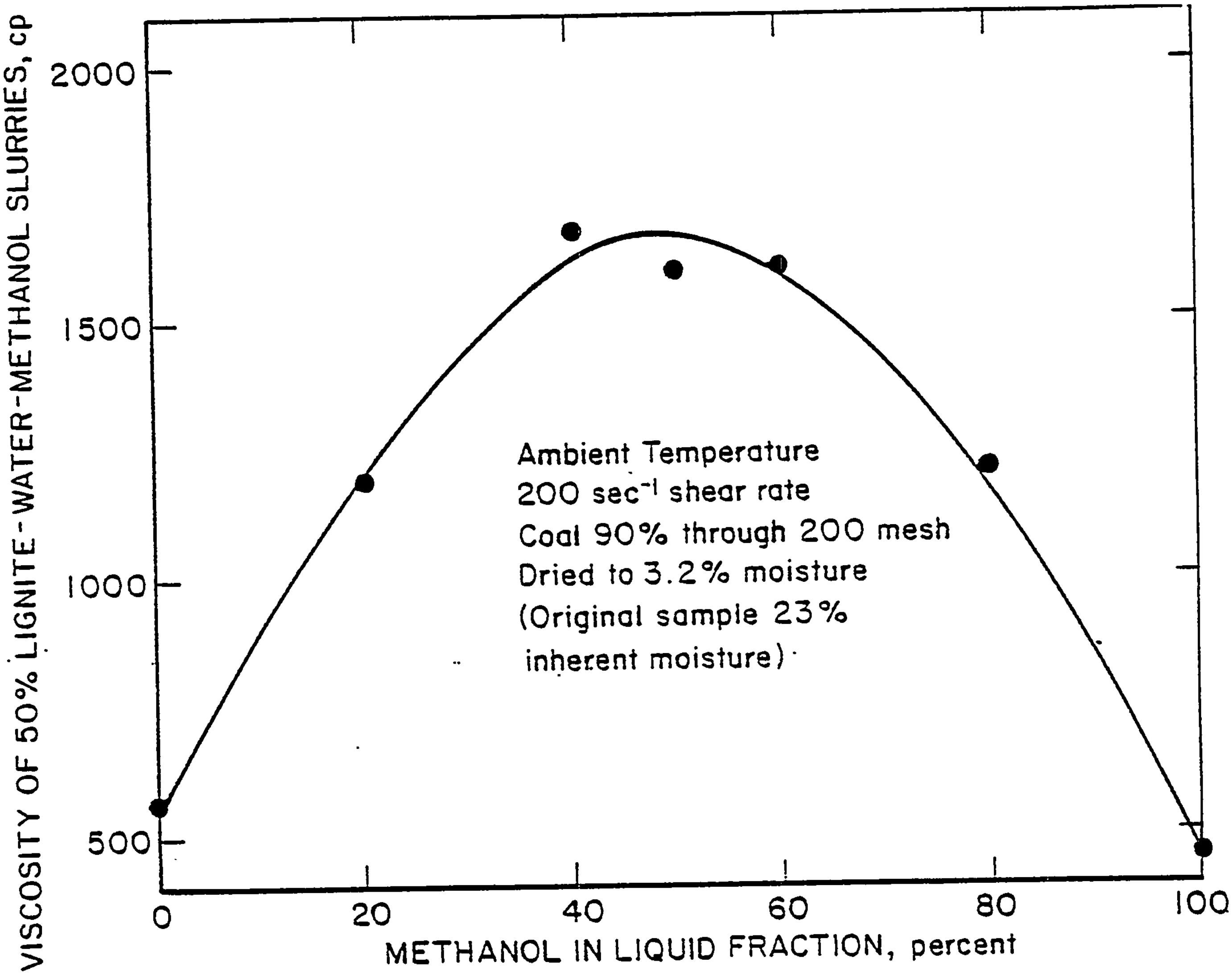
VISCOSITY vs PERCENT METHANOL

VISCOSITY OF DRIED MONTANA ROSEBUD IN METHANOL[1/]

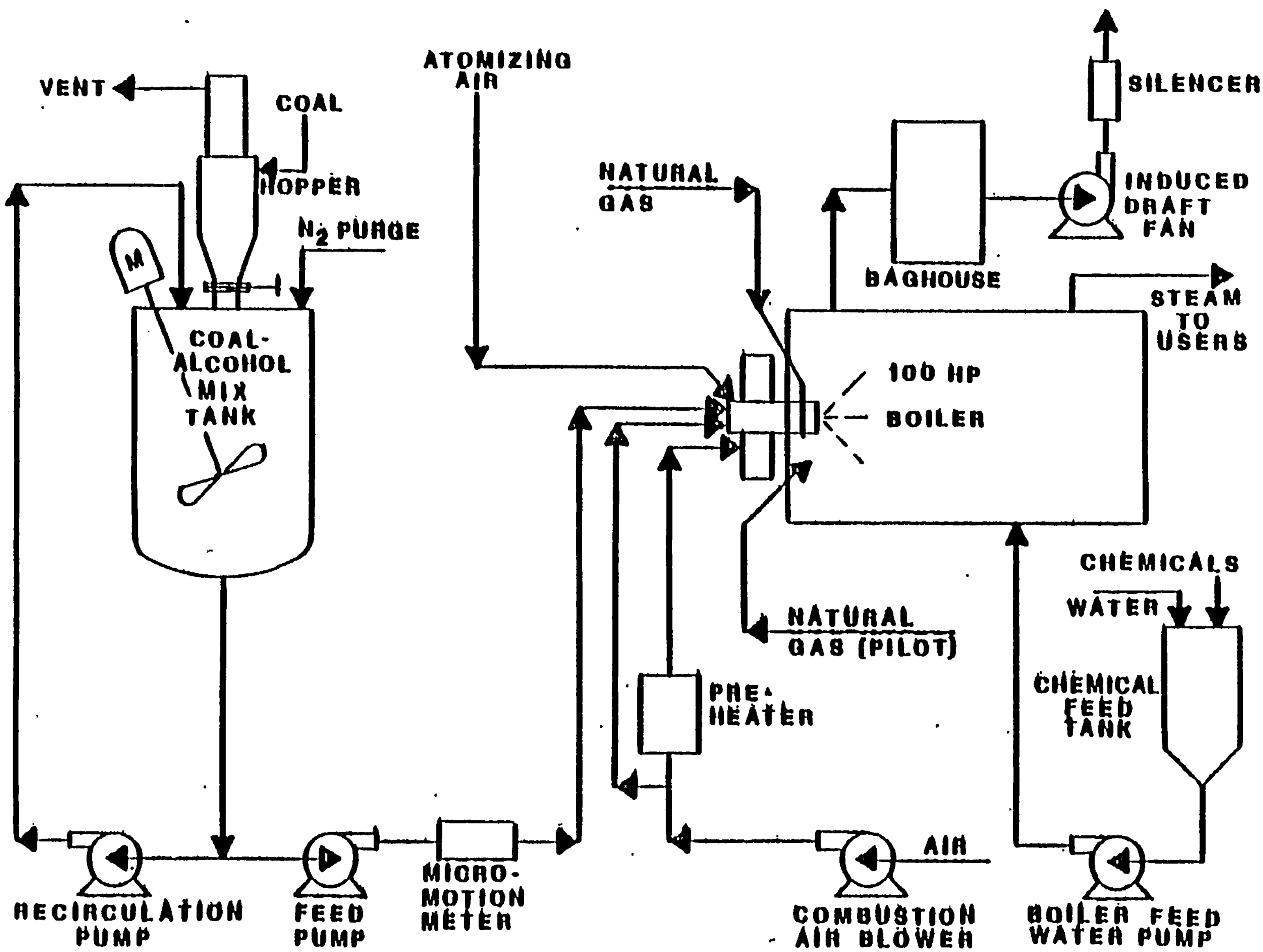
COAL CONC., wgt %	VISCOSITY, Cp*
45.0	46
47.5	251
50.0	652
52.5	2360
(60% PGH SEAM COAL	354)

*AFTER 50 SEC AT SHEAR RATE OF 200^{-1} sec

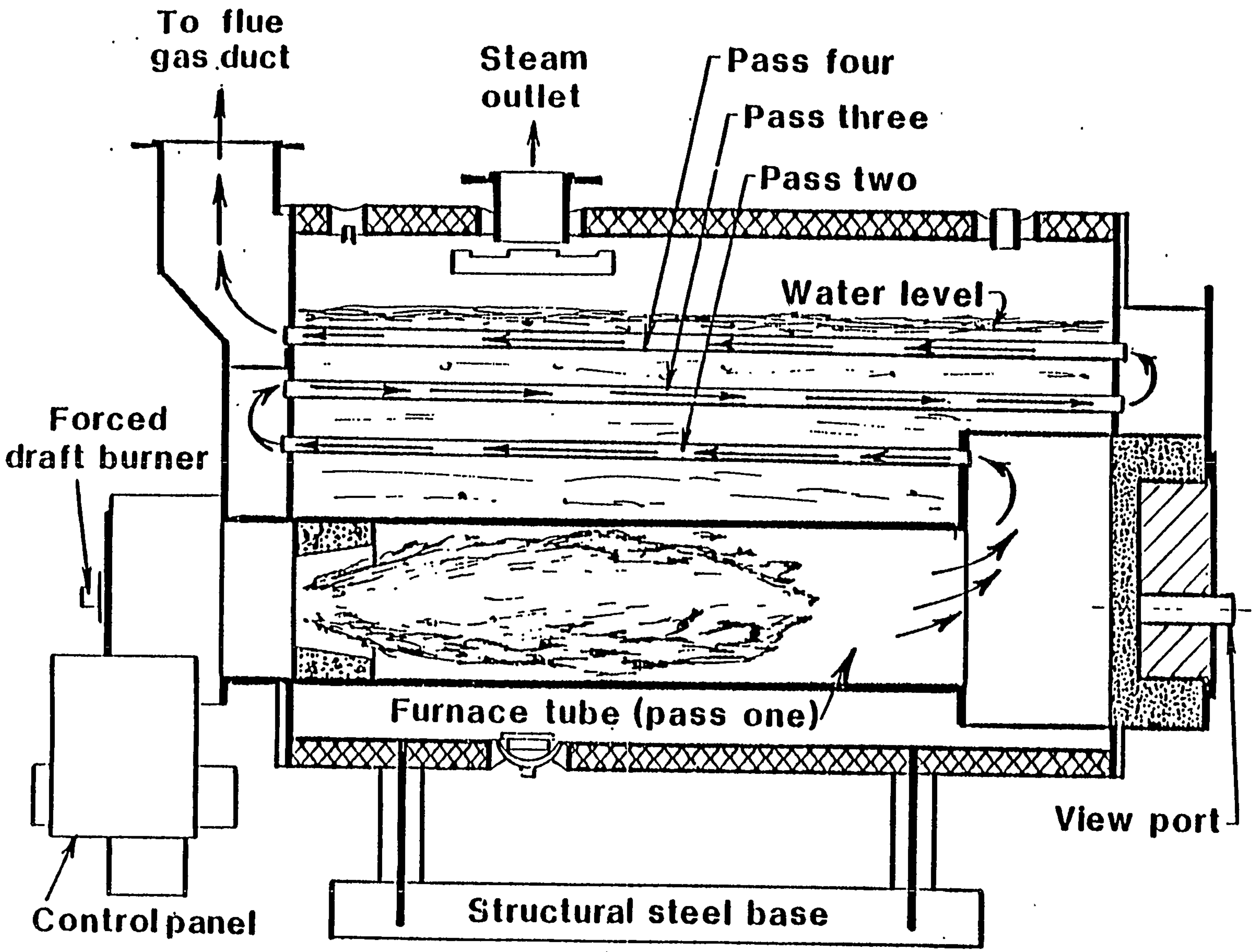
[1/] J. M. Ekmann, Pittsburgh Energy Technology Center



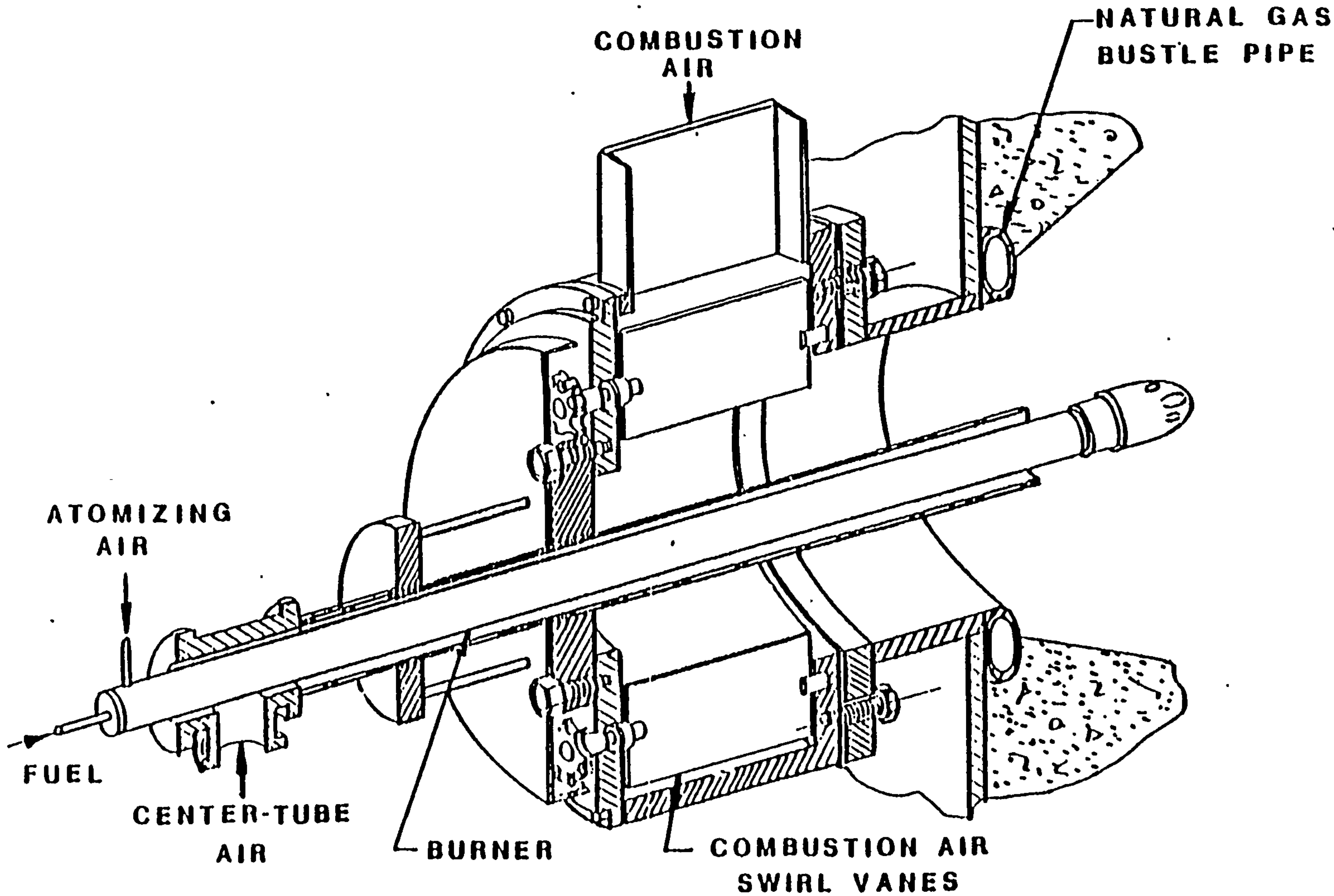
VISCOSITY vs PERCENT METHANOL IN LIGNITE-WATER-METHANOL MIXTURES



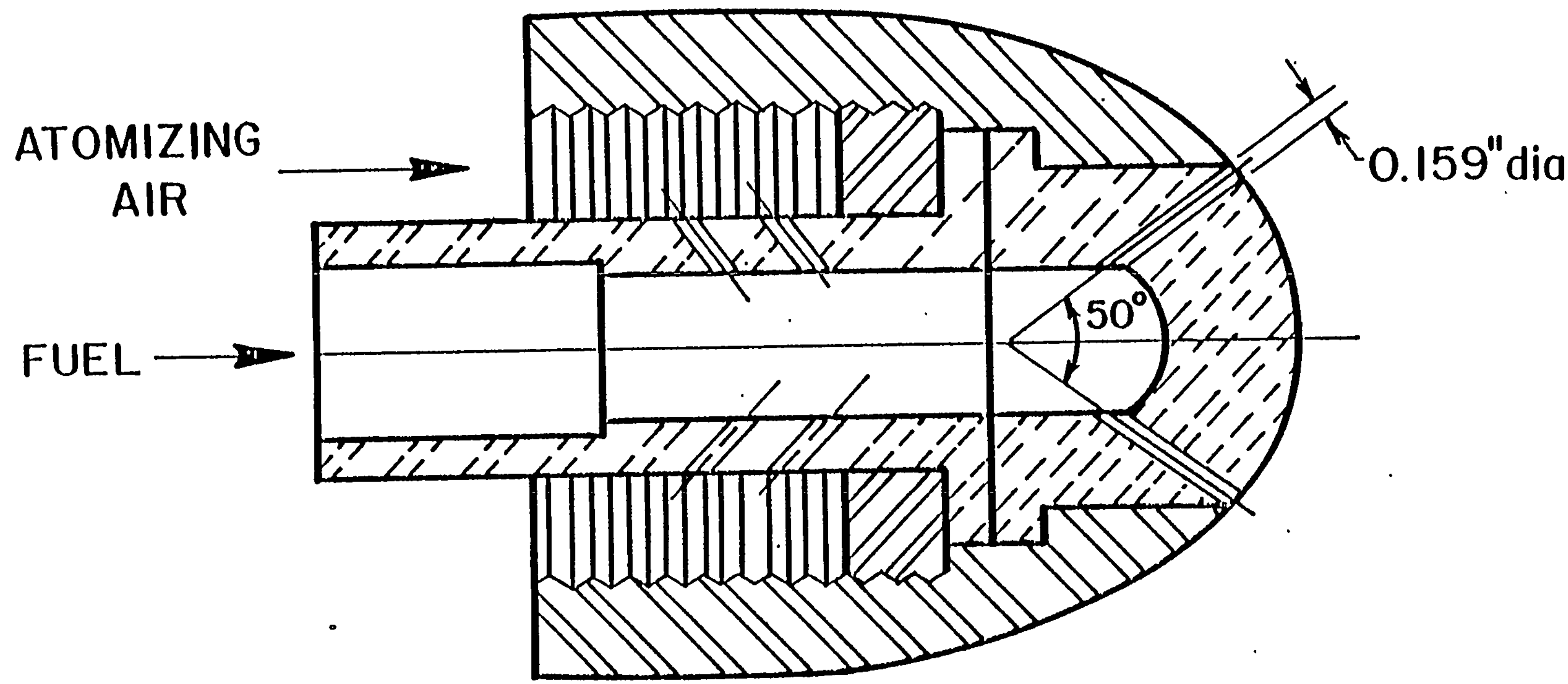
Flow Diagram of the 100-hp Combustion Test Facility as Arranged for Coal-Methanol Combustion Tests



Vertical Cross-Section View of the 100-hp Firetube Boiler



Air Register and Burner Nozzle Arrangement in the 100-hp Boiler



BURNER NOZZLE USED FOR CWM AND CMM TESTS IN THE 100-HP BOILER

COAL SLURRY TESTS IN 100-HP BOILER(1)

	NO. 6 OIL	CWM	CMM	CMM	CMM	CMM
FUEL COMPOSITION, %						
COAL (MOISTURE FREE)		60.0	61.0	55.9	54.9	56.0
METHANOL		----	39.0	26.0 } 60/40	17.8 } 40/60	8.7 } 20/80
WATER		40.0	0	18.1	27.3	35.3
HEATING VALUE (BTU/LB)	18530	7810	11649	9639	8710	7960
FLUE GAS O_2, %	2.3	3.3	3.0	5.0	4.2	3.6
EXCESS AIR, %	11.6	2.5	8.3	20.0	14.8	5.4
COMBUSTION AIR TEMP., °F	75	528	79	79	66	428
CARBON CONVERSION EFF., %	99.8	85.2	92.2	85.9	90.2	88.8
BOILER EFFICIENCY, %	82.9	69.3	77.2	69.9	72.0	72.4
HEAT LOSS, %						
H_2O IN FUEL	0	5.72	0.11	2.24	3.75	5.02
HYDROGEN IN FUEL	6.04	3.79	7.17	6.59	6.00	4.80
CO IN FLUE GAS, PPM	98	106	53	124	105	50
NO_X IN FLUE GAS, PPM	255	712	564	407	429	684
LB/MBTU	0.32	0.85	0.67	0.53	0.55	0.81
FLY ASH EMISSIONS, #/HR	0.9	81.9	34.0	75.8	63.7	62.8
LB/MBTU	0.19	15.67	7.94	14.41	12.82	12.64

(1)Y.S. PAN ET AL PRESENTED AT 4TH INT'L. SYMPOSIUM ON COAL SLURRY COMBUSTION, MAY 10-12, 1982, ORLANDO, FLORIDA.

FUEL COSTS

	$/MBTU
NO. 6 OIL	4.90
60 COAL, 40 MeOH	4.84*
55 COAL, 18 MeOH, 27 H_2O	3.64*
45 COAL, 55 OIL	3.60
56 COAL, 9 MeOH, 35 H_2O	2.63*
60 COAL, 39.5 H_2O/0.5% ADDITIVE	2.08*

*CORRECTED FOR LOWER BOILER EFFICIENCY

		$/MBTU
COAL	$30/ton	1.20
NO. 6 OIL	$30/BBL	4.90
MeOH	$0.70/GAL	10.90
ADDITIVE	$0.80/LB	—

FUEL COST COMPARISON OF METHACOAL AND COAL-WATER MIXTURES

70 COAL, 30 H_2O

ADDITIVE RANGE 0.5-1.0 wgt% (80¢/lb)

$1.96-2.49/MBTU

56 COAL, 9 MeOH, 35 H_2O

METHANOL RANGE 50-70¢/GAL.

$2.23-2.63/MBTU

CANADA-JAPAN COAL METHANOL SLURRY PROJECT*

- FINANCED:

  1/3 - PROVINCE OF ALBERTA

  1/3 - WEST COAST TRANSMISSION CO.

  1/3 - CHIEFTAIN DEVELOPMENT LTD.

- AGREEMENT SIGNED WITH 15 MITSUI COMPANIES

- SLURRY TO BE MADE IN ALBERTA WHERE COAL FIELDS AND NATURAL GAS ARE PLENTIFUL. SHIPMENT BY PIPELINE OF 55 COAL-45 MeOH, 750 MILES TO COAST, THEN BARGED TO JAPAN. FUEL CAN BE DELIVERED TO JAPAN AT 65% OF FUEL OIL COST. IN JAPAN, PART OF METHANOL WILL BE REPLACED BY WATER.

- PREPARATION COST OF METHANOL U.S. $165/METRIC TON = $0.50/GAL.

  POSTED PRICE OF METHANOL $0.76/GAL.

*INFORMATION OBTAINED 11/16/82 FROM R. M. RUTHERFORD, PROJECT MANAGER, CHIEFTAIN CONSORTIUM, AND N. A. LAWRENCE, DIRECTOR, CHIEFTAIN DEVELOPMENT

KBW

METHANOL FROM COAL:

	EASTERN PLANT	WESTERN PLANT
TECHNOLOGY EMPLOYED	INDIRECT LIQUEFACTION	INDIRECT LIQUEFACTION
METHANOL PRODUCTION CAPACITY	22,000 BBL/DAY	45,000 BBL/DAY
COAL CONSUMPTION	6,000 TONS/DAY	15,000 TONS/DAY
COAL COST	$35/TON ($1.50/MILLION BTU)	$9/TON ($0.50/MILLION BTU)
LOCATION	TENNESSEE	WYOMING
ANNUAL OPERATING COSTS 1982 DOLLARS	$130 MILLION (43¢/GALLON)	$170 MILLION (27¢/GALLON)
PLANT INVESTMENT, 1982 DOLLARS	$1.1 BILLION	$2.0 BILLION
PLANT GATE METHANOL COST, 1982 DOLLARS	75-85¢/GALLON	60-70¢/GALLON

COAL-WATER-METHANOL

A COAL-WATER SLURRY CONTAINING SOME METHANOL MAY PROVIDE THE BEST COMPROMISE OF PERFORMANCE AND ECONOMICS.

1. LOWER COST OF PIPELINE TRANSPORT. A 50/50 MIXTURE OF COAL/MEOH HAS 60% MORE ENERGY THAN AN EQUAL VOLUME OF 50/50 COAL/H_2O.

2. COAL/MEOH PIPELINE AND COAL/H_2O/MEOH PROCESS FEED LINES NEED NOT BE HEATED OR PLACED UNDERGROUND. 6.4% MEOH PROTECTS TO 0°F, 11% PROTECTS TO -40°F.

3. CARBON CONVERSION AND BOILER EFFICIENCY HIGHER.

4. COMBUSTION AIR PREHEAT PROBABLY NOT NECESSARY.

5. FUEL COSTS ARE APPROXIMATELY 10% HIGHER.

DISCUSSIONS ON COAL RESEARCH AT TRW*
(December 13, 1982)

S. S. Penner visited TRW on December 13, 1982. Discussions related to coal beneficiation and the TRW entrained slagging coal combustor.

A. Coal Beneficiation

The TRW work on the Gravimelt Process by R. A. Meyers and his associates is summarized in Appendix AB-10-1, which is reproduced from a paper presented at the 17th Intersociety Energy-Conversion and Engineering Conference, August 1982. In the Gravimelt Process, fused caustics are used for sulfur removal. Bench-scale tests (5 lbs of coal/hr) have been performed, although not for sufficiently long periods of time to reach steady-state conditions. The beneficiated coal has not yet been used in combustion tests. Caustic regeneration represents about one half of the total cost, with sodium sulfide dissolved in NaOH representing the main products.

Performance data and capital cost estimates are summarized, respectively, in Tables 1 and 2 of Appendix AB-10-1. Ash removal for a single pass is seen to fall in the range 95-99% for mine-cleaned coals containing up to $\sim$23% of ash; SO_2 removals fall in the range 83-92%. Total costs are estimated to amount to about $25 per ton of coal cleaned, with additional savings possible when larger scale tests are performed.

B. The TRW Entrained, Slagging Combustor

The TRW entrained, slagging combustor was described by Albert Solbes. A readable description of this development is reproduced

*Prepared by S. S. Penner.

in Appendix AB-10-2. This combustor has applications in MHD power conversion [6 atm. pressure, $T_{oxidizer} > 2500^{o}F$, the oxidizer is oxygen-enriched air, and the equivalence ratio (ϕ) ranges from 0.5 to 0.7], in low-Btu gasifiers (4 to 25 atm., pure O_2, $\phi = 0.4$), and in retrofits for industrial and utility boilers (1 atm, $T_{oxidizer} = 750^{o}F$, air is used as oxidizer).

For the third application, tests have been conducted in a 17 in. combustor at about the 3-MW_t level. About 350 hrs. of operation were completed. In general, the TRW combustor will be interposed between the coal-inlet section and the existing (oil-firing) boiler in retrofits for conversion to the use of PC or CWM. The slagging operation will remove about 90% of the coal ash.

Scale-up to a 34 in. i.d. unit (50×10^6 Btu/hr) is being proposed. A 10×10^6 Btu/hr burner is currently in operation at TRW's Capistrano Beach facility.

The modeling program developed by A. Solbes appears to provide and excellent example of current work in this field and may be reviewed at the March meeting of CCAWG in La Jolla.

APPENDIX AB-10-1

PRECOMBUSTION EXTRACTION OF 90% OF THE SULFUR AND 95% OF THE MINERAL MATTER FROM COAL

R. A. Meyers, W. D. Hart and L. C. McClanathan

TRW Electronics and Defense - Energy Development Group

The Gravimelt Process, which results in near complete removal of sulfur and mineral matter from coal consists of treatment with fused caustic to remove the sulfur and a subsequent series of water and dilute sulfuric acid washes to remove the remaining mineral matter. Preliminary engineering design and economic studies indicate that the process will add approximately $30 per ton to the cost of coal. This is significantly lower than the cost of scrubbing exhaust from existing burners in order to meet air pollution regulations and is consistent with the currently paid premium for coal which can contain as much as 1% sulfur and 10% ash. Major applications for Gravimelt coal can include coal water and coal oil slurries for retrofit boiler and furnace systems, coking coal for steel, aluminum and silicon carbide industries and transportation fuel for automotive turbine engines.

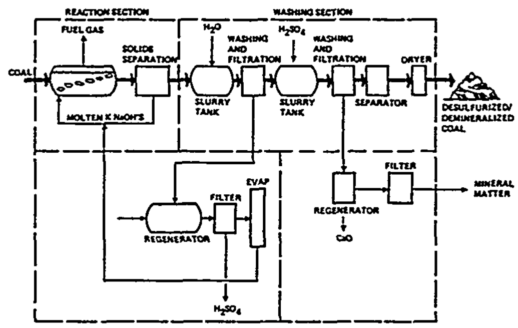


Figure 1. Gravimelt Conceptual Process Flow Diagram

The near complete desulfurization and demineralization of coal has been demonstrated in the laboratory via the TRW proprietary Gravimelt Process (1). Subsequently, the process was further laboratory-tested at TRW under the sponsorship of the U.S. Department of Energy (Contract No. DE-AC22-80PC30141) and TRW is supporting testing and assessing a proprietary regeneration method and scale up to large batch reactor size to provide samples for potential Gravimelt coal users. The process is currently being tested under D.O.E. sponsorship in a 5-10 lb/hr continuous bench scale unit at our San Juan Capistrano California Chemical Test Facility (Contract No. DE-AC-81PC42295).

The TRW Gravimelt Process (Figure 1) involves the treatment of mine-cleaned coal with molten potassium and or sodium hydroxide to chemically extract both organic and pyritic sulfur into the molten alkali. The coal mineral content is broken down to forms mainly insoluble in water but highly soluble in dilute acids such as sulfuric acid. The high density of the melt causes the desulfurized coal to float to the surface, where it is skimmed off. The coal is then washed with water to recover the alkali metals and product sulfur compounds. The coal is next washed with a dilute sulfuric acid where the mineral matter is extracted into the solution.

The caustic wash water is treated to recover the extracted coal sulfur as sulfuric acid and the caustic solution is reconcentrated in an evaporator system for recycle to the reactor. The acidic wash water is neutralized with lime to produce a clay, silica and gypsum material.

TEST RESULTS

A summary of typical results, obtained under standardized conditions, for a range of U.S. coals is presented in Table 1. All of the samples were reduced to well below 1 lb of $SO_2/10^6$ Btu and less than 0.4 lbs of ash/10^6 Btu which corresponds to 83-93% removal of sulfur and 95-99% removal of ash. When sulfur and ash reduction due to cleaning at the mine is added to these results, sulfur reduction approaches an average of 90-95% and ash removal approaches 99% for all of the samples. The standardized removal results shown above can be improved by the use of longer reaction times and by multiple pass extractions to give residual sulfur and ash at 0.1% concentrations.

ENGINEERING

Preliminary engineering design and cost studies indicate that the total installed capital cost of a 10 x 10^9 Btu/hr (approximately 400 ton/hr input coal) Gravimelt plant can be estimated at about $80,000,000 which corresponds to a total invested capital cost of $115,000,000. Table 2 indicates the percentages of these costs associated with each process section.

TABLE 1. TRW GRAVIMELT PROCESS RESULTS* FOR U.S. COALS

Coal		Analysis, dry basis S,%	Ash,%	Heat content, Btu	lbs SO_2/10^6 Btu	lbs Ash/10^6 Btu	SO_2 removal %	Ash removal %
W. Ky. No. 9	Feed	3.93	22.85	10795	7.28	21.2		
	Product	0.37	0.27	13359	0.55	0.20	92	99
W. Ky. No. 11	Feed	3.51	7.26	13182	5.33	5.50		
	Product	0.52	0.21	13530	0.77	0.16	86	97
Ill. No. 6	Feed	3.45	11.92	12342	5.60	9.66		
	Product	0.28	0.14	13518	0.40	0.10	93	99
Lucas No. 5	Feed	2.17	8.29	13116	3.30	6.32		
	Product	0.25	0.41	13334	0.38	0.31	88	95
Pittsburgh No 8	Feed	3.12	10.68	12907	4.83	8.28		
	Product	0.55	0.40	13801	0.80	0.32	83	96
Lower Kittaning	Feed	5.24	13.60	12931	8.11	10.52		
	Product	0.64	0.39	14420	0.89	0.27	89	97

*coal treated for 30 mins at 370°C with a 1:1 wt mixture of fused NaOH/KOH, washed with water, then with aqueous sulfuric acid, then with water and dried.

TABLE 2. GRAVIMELT PROCESS CAPITAL COSTS

Reaction Section	
Solids handling and storage, fused caustic reactor, filtration, pumps, etc.	25%
Coal Recovery and Mineral Rejection	
Slurry tanks, filtration neutralization, storage, etc.	25%
Caustic Regeneration	
Regenerators, evaporator system, centrifuges, sulfuric acid plant, etc.	50%
Total Installed Capital Cost	$ 80,000,000
Total Invested Capital	$115,000,000

Total non-capitalized operating costs are estimated to be approximately $46,000,000 (includes coal for process heat, caustic loss, power, process and cooling water, labor, supervision, general overhead, maintenance, taxes and insurance and operating supplies, etc.). Annual capital charges of 20% of the total plant investment or $23,000,000 brings the total amortized operating costs to near $70,000,000 which corresponds to $25 per ton of coal product as a cost to be added to the price of coal. Since the process is in an early stage of development, it is believed that this processing cost has an upside potential of about 25%. Thus, it is recommended that a potential price (in 1980 dollars) of $30 per ton should be utilized when assessing the Gravimelt Process for various applications.

APPLICATIONS

The Gravimelt coal could offer major advantages for use as a boiler fuel either in its solid form or as a coal water or coal oil slurry. These advantages are as follows:

1) low sulfur and ash content will comply with the majority of governmental regulations for pollution control,

2) the low sulfur and ash content will reduce boiler downtime due to corrosion and erosion and would allow production of smaller boilers due to the elimination of slag and ash handling,

3) as a coal water or coal oil slurry ingredient, the Gravimelt coal will have the previous two advantages and will not erode or corrode in plant boiler equipment or furnace nozzles,

4) the Gravimelt coal may have use as a transportation fuel for turbine and diesel engines where engine component erosion due to coal ash is presently a limiting factor, and

5) coke made from Gravimelt coal could have premium qualities due to low ash and sulfur.

REFERENCE

1) Meyers, R. A. and W. D. Hart, Patents Pending.

APPENDIX AB-10-2

TRW'S ENTRAINED SLAGGING COAL COMBUSTOR

J. C. Stansel and R. B. Gerding
TRW Energy Development Group
Redondo Beach, California

1.0 Abstract

For the past seven years TRW has been engaged in the development of an advanced coal combustor which can be used to retrofit coal-, oil- and gas-fired boilers, furnaces and process heaters. We have conducted over 700 tests on four entrained slagging coal combustors ranging in power level from 1 MBTU/hr to 70 MBTU/hr. The extensive data base generated in these tests has been combined with an engineering computer program specifically developed to predict combustor scaling, design parameters, and performance. The design is based upon technology developed through company-sponsored programs using as a baseline TRW's experience in rocket propulsion, low NO_x burners, and Magnetohydrodynamic (MHD) coal combustors. A demonstration is planned in 1983-84 to obtain life, reliability and maintenance information.

2.0 Introduction

TRW is developing three related coal conversion systems:

1. A combustor for retrofit/replacement of exisiting coal-, oil- and gas-fired burners on kilns, process heaters and industrial and utility boilers.

2. A compact gasifier for producing fuel gas and higher grade chemical feedstock gas from coal.

3. A high temperature combustor for Magnetohydrodynamic (MHD) power generation when coupled to fluid flow/electrical conversion equipment.

This paper overviews the chronological development of TRW's coal conversion systems while rapidly focusing on the retrofit combustor device which the company plans to commercially manufacture, sell and service beginning in 1985. Combustor hardware and test results are described followed by our plans for a field demonstration program in 1983-84.

3.0 Coal Combustion Technology Evolution

TRW's entry into coal combustion was a natural continuation of years of successful work in combustion research, rocket propulsion, and low NO_x burner development. In 1975, we initiated coal combustor design activities. Continuing into 1976, we fabricated a small scale test unit (1 MBTU/hr) and conducted both atmospheric and pressurized combustion tests. We demonstrated that powdered coal could be fluidized at 10/1 mass ratio of coal to transport fluid and successfully injected into the combustion chamber using an injector concept derived from our Lunar Module Descent

Engine. A 10/1 throttling ratio was required in this engine to maintain high performance across the entire range of thrust levels. The rocket propulsion concepts of aeroballistically controlling combustion ratio and fuel particle trajectories were incorporated into the small scale coal combustor design. Good ignition and stable combustion were achieved with slag being centrifugally driven to the wall by the aerodynamic swirling flows.

We next scaled the combustor design to 10-30 MBTU/hr. The specific power level achieved for the fixed design depended upon the mass throughput at an operating pressure in the range of one to six atmospheres. A feasibility test unit was constructed and an extensive combustion test series was performed in 1977-78 using preheated air and coal flow rates in the range of one half to two tons/hr. Good combustion and acceptable slag removal conditions were achieved during this company sponsored test series in each of the three regimes of interest for retrofit combustors, low BTU gasifiers, and MHD combustors.

DOE sponsored further testing of the feasibility unit in 1978 in the MHD application regime; i.e., high air preheat and/or oxygen enrichment, three to six atmosphere combustor pressures, potassium carbonate seeding to enhance gas electrical conductivity and exit gas temperatures in excess of 4000°F. After these tests, the combustor was loaned to Argonne National Laboratory for heat recovery/seed recovery experiments. Based on the feasibility unit test results, the combustor was scaled to 70 MBTU/hr. A test unit at this scale was designed and fabricated. Over 100 tests were conducted on this unit at TRW's Fossil Energy Test Site during 1979-80. These tests were performed with air preheat conditions of 1100°F to 3700°F, combustor pressures of 3 to 6 atms and coal flow rates of 2 to 3.5 T/hr. A final demonstration series was successfully conducted at 6 atms and 2900°F air preheat conditions, after which TRW was selected as DOE's MHD combustor developer. Since the demonstration, we have conducted a 140 cumulative hour MHD combustor life test and performed integrated combustor/channel testing using the 70 MBTU/hr hardware. We have also completed the preliminary design of a 170 MBTU/hr MHD field test unit and expect to build and test this unit within the next year.

More recently, we have concentrated on testing a second 10 MBTU/hr combustor at the one atmosphere, 400-750°F air preheat conditions characteristic of existing industrial, commerical and utility plants. During 1981-82, over 200 tests were conducted under company sponsorship with good combustion, low NO_x emission and acceptable slagging results. We expect to complete the design of a 40 MBTU/hr combustor by year end. This unit will be fabricated and tested in our facility during 1983 to provide the design of a 40 MBTU/hr combustor by year end. This unit will be fabricated and tested in our facility during 1983 to provide the design basis for a commercial type 40 MBTU/hr combustor which will be used in an industrial boiler plant demonstration program planned to begin in late 1983.

4.0 Coal Combustor Description

The TRW Entrained Slagging Combustor is shown in Figure 1. The design is based upon the extensive development effort described in the previous section. The configuration consists of a water-cooled right circular cylinder with a simple baffle located in the aft region to promote the appropriate mixing/combustion reactions and slag flow patterns. Powdered coal (70% through 200 mesh) is transported to the pintle in a dense-phase fluidized condition, conically injected into the combustor and then burned inflight in the cylindrical volume with slag impinging on the wall and being driven to the slag tap by a combination of aerodynamic and gravity forces. The slag is removed from the combustor by flowing into a water-filled slag tank where slag fracture and size reduction are accomplished. Coal water mixtures (70% powdered coal, 30% water) have also been burned in the combustor by substituting an air atomized injector for the powdered coal pintle previously discussed.

Generally the combustor is operated at an equivalence ratio in the range of 0.7-0.9. The resulting hot product gas which is rich in CO and H_2 is ducted to the heat utilization equipment interface where secondary air is added. Combustion of the product gas is completed within the furnace volume of the heat utilization equipment resulting in a staged combustion process which minimizes NO_x formation. Sufficient temperature and heat flux must be generated within the coal combustor volume to achieve liquid slag flow conditions but the classical high NO_x formation regime can be avoided by the combination of temperature and gas composition control. The product gas can be delivered to the heat utilization equipment either via a deswirl section aft of the baffle as shown in Figure 1 or by allowing the swirling flows to continue axially into the secondary furnace volume. The approach to be used depends upon the specific application.

The combustor offers significant advantages when compared to competitive retrofit technologies including simplicity and compactness of design, refractory free construction, highly efficient combustion, and high ash removal. These characteristics, combined with low NO_x operation, small particulate carryover and high turndown ratio, allow operational flexibility with low maintenance and high reliability. A more definitive listing of the principle characteristics of the combustor is given in Table 1.

The combination of simplicity and compactness make the device ideal for retrofitting existing oil- and gas-fired kilns, furnaces and boilers within the available space. Note that a combustor 2'D X 4'L produces up to 20 MBTU/hr and when scaled by a factor of over twelve to 250 MBTU/hr grows to only 7'D X 11'L.

TABLE 1

CHARACTERISTICS OF TRW COMBUSTOR

• SIMPLE CONFIGURATION	CYLINDER WATER COOLED	LOW MAINTENANCE
• SMALL SIZE	2'D x 4' - 7'D x 11' (20-250 MBtu/HR) 1 MBtu/HR-FT^3	FITS AVAILABLE SPACE
• NO REFRACTORY LINER	∿1" SLAG ON WALL	AVOIDS FAILURE, DOWN-TIME
• HIGH SLAG REMOVAL	80 - 90%	MINIMIZES CARRYOVER
• HIGH CARBON BURNOUT	>99.5%	EFFICIENT COMBUSTION
• LOW NO_x	250 - 450 ppm	STAGED COMBUSTION
• LOW HEAT REJECTION	5 - 8%	EFFICIENT SYSTEM OPERATION
• FLEXIBLE DEVICE	ADJUSTABLE AIR AND COAL FEED	ACCOMMODATES RANGE OF COALS
• TEST PROGRAM	SHORT DURATION	MANY CYCLES
• STATE OF DEVELOPMENT	FEASIBILITY SHOWN	SPECIFIC RUN CONDITIONS, SCALING AND LONG DURATION DEMO REQUIRED

Since no refractory materials are used within the slagging combustor, refractory erosion, failure and replacement downtime are avoided. The continually generated slag on the walls of the combustor acts as an effective thermal and hot gas barrier allowing the water-cooled walls to operate at a conservative temperature of approximately 600°F. Heat transferred to the cooling water is calculated to be only 5-8% of the total heat released in commercial combustor designs. This heat can be effectively utilized in boiler feedwater circuits or for air preheating, thus contributing to the overall thermodynamic efficiency of the heat utilization system.

The high slag removal characteristic minimizes particulate carryover into heat utilization equipment; e.g., for a 10% ash coal only about 1%-2% particulates would carryover. Additionally, the carryover material typically consists of slag particles less than 10-15μ which tend to follow the flue gas streamlines rather than eroding or depositing out on any internal structures within the heat utilization equipment; e.g., convective pass tube bundles. The major advantage sought from the current and proposed test program is the ability to convert existing heat utilization equipment designed for oil-/gas-firing to coal firing without any significant derating of the equipment.

Stable, well-anchored flames are produced in the combustor with gas residence times on the order of 100 milliseconds. This leads to efficient combustion with carbon burnout values in excess of 99.5% as measured by the amount of carbon remaining in the slag waste material. The staged combustion feature of the TRW retrofit system leads to low NO_x production, in the range of 250 to 450 ppm. We are attempting to demonstrate NO_x values at the stack outlet consistent with present oil fired standards (approximately 250 ppm) while simultaneously obtaining high slag removal and carbon conversion values. Since both coal and air flow rates are adjustable and the air inlet momentum can be varied by use of a movable damper valve, combustor turndown values in the range of two to four are possible. Three western and two eastern coals have been successfully burned in the feasibility unit.

To date, our combustor test program has yielded data over a wide range of operating conditions. The hardware has experienced numerous thermal cycles without failure. Test durations have typically been 1 to 2 hours in length with some runs up to eight hours. We have also subjected the pintle to hundreds of hours of simulated erosion tests in our laboratories. This approach has provided data on the combustor geometry/run conditions which are applicable to retrofit applications in general. The basic feasibility of the combustor has been shown at 10 MBTU/hr. We are now focusing on specific run conditions for kilns, furnaces and boilers while at the same time scaling a test unit to 40 MBTU/hr. After confirming tests at our Fossil Energy Test Site (FETS) with the larger scale hardware, we will be ready to implement a long duration field demonstration with a commercial 40 MBTU/hr combustor integrated with an existing industrial boiler located in our Cleveland Aircraft Parts Plant. The field demonstration will provide essential data on combustor performance, life and reliability as well as the combustor's exhaust interaction with the boiler.

5.0 Combustion Research Activities

A continuing combustion research program undergirds TRW's hardware development efforts. For example, coal devolatilization rate information is acquired in a special inert gas chamber where an infrared laser is used to simulate combustion heat fluxes to the coal particles. Turbulent mixing information is obtained using the laboratory flow visualization equipment shown on left side of Figure 2. During operation, different density gases, some of which are seeded with fine particulates, are injected into the volume and visible low power lasers are used to produce images to study the mixing effects as shown on the right of Figure 2.

Prior to final hardware fabrication, a full scale plastic model of a proposed combustor test unit is constructed for detailed aerodynamic flow visualization as shown in Figure 3. Heated air enters the model through the horizontal wrapped duct on the left side of the figure. Entrance Reynolds numbers are thus simulated. Fine particulates are injected through the pintle at the right end of the combustor model and high speed photographs are taken to establish particle trajectories and distribution, as well as the nature of the internal swirling flows and their sensitivities to model geometry changes. Key model pressures are measured and recorded via pressure transducers and the Manometer bank, shown in the background. Using this approach, much insight into combustor geometry optimization can be obtained before actual combustors are built and hot firing tests conducted.

In parallel with the above laboratory and engineering studies, an analytical model has been developed and computerized. It utilizes five subroutines to analytically model thermochemistry, aerodynamics, combustion, heat transfer and slag flow phenomenon. The model functions in much the same way as a test is conducted; i.e., combustor geometry, orientation, pressure, coal type and flow rate and oxidizer type and flow rate are input. The model then computes expected gas compositions, temperatures, carbon burnout, pressure drop, heat transfer to coolant and slag removal/losses. The model is anchored with test data from actual combustor firings and used in combustor scaling and test prediction/analysis efforts. It is very useful as a means of improving our understanding of the internal workings of the entrained slagging combustor.

6.0 Combustor Scaling

The first small scale combustor hardware fabricated and tested in 1975-76 is shown in Figure 4. Coal injection experiments were first conducted to establish fluidization, flow and injection parameters. Combustion chamber components were fabricated and initial coal-fired combustion tests using both swirling and tangential preheated air injection were performed at atmospheric and pressurized conditions. We achieved acceptable mixing and combustion conditions with slag being centrifuged to the chamber wall.

The next hardware designed and fabricated was the feasibility unit shown in Figure 5. This unit employed a 17" internal diameter chamber scaled from the analysis and test data previously obtained from the small scale experiment. The hardware was designed so that the chamber geometry could be varied in length by the addition or deletion of spool sections. The positions of the coal pintle, tangential air inlet, internal baffle and slag tap with its accompanying slag tank could also be varied from run to run as appropriate. Each major section was individually flanged to accommodate repositioning and water cooled so that axial calorimetry information could be obtained. The feasibility unit was designed to produce 10 MBTU/hr at a combustor pressure of one atmosphere and slightly over 30 MBTU/hr when operated at about six atmospheres. The hardware was horizontally mounted with the slag tank vertical as shown in Figure 5. The hot, swirling combustor gases exited the unit axially into a chamber where more air was added to complete combustion. After testing at TRW, the unit was loaned to Argonne National Laboratory for MHD heat recovery/seed recovery experiments. The combustor is still in use at their facility.

To accommodate larger sized combustors, TRW constructed a major new capital facility in 1978, the Fossil Energy Test Site (FETS), at our Capistrano Test location as shown in Figure 6. Two test bays separated by a coal storage/feed area were built. Each bay can accommodate two combustors. Cooling water is pumped in a closed loop through the combustor flow channels and then to the cooling tower shown at the right of the figure. Liquid oxygen and liquid nitrogen storage vessels are also visible. Test control and instrumentation functions are performed within the control center building located in front of the test bays as shown in Figure 6. The automated control panel and instrumentation setups are shown in Figure 7.

The next combustor designed and fabricated by TRW is shown in Figure 8. This unit is 24" in diameter and operates at 70 MBTU/hr in the 3 to 6 atmospheres pressure regime associated with the MHD application. The second stage air injector and slag tank are also shown in the figure. Primary air is preheated to very high temperatures and tangentially injected into the combustor. Powdered coal is introduced via the pintle located on the combustor axis and potassium carbonate seed material is injected to enhance the electrical conductivity properties of the high temperature exit gas.

A photograph of the internal slag layer adhering to the combustor walls after a test is shown in Figure 9. Note the pintle injector located on axis and the tangential air inlet in the upper left of the picture. The slag layer uniformly covers the combustor wall to a depth of 3/8" to 3/4" and has the appearance of a black glassy material. It acts as an efficient thermal and hot gas barrier as previously discussed.

The MHD combustor is currently undergoing additional tests to obtain the design and scaling information necessary to finalize the 170 MBTU/hr combustor configuration.

In parallel with the 70 MBTU/hr hardware development program discussed above, a second feasibility unit was constructed so TRW could concentrate on the commercial retrofit combustor operating regime. The combustor hardware was installed in the Fossil Energy Test Facility as shown in Figure 10. The combustor was elevated at 30° to the horizontal thus adding a gravity vector to aid slag flow. A deswirl section was used in the aft region of the combustor. Hot combustion gas laden with some fine particulates exits the combustor at right angles to its axis entering a circular duct in which secondary air is added to complete combustion of the CO and H_2 rich gas. A water deluge and cyclone scrubber, shown outside the open test cell, is used to provide the required pollution control in the test facility. A closeup of the feasibility test unit is shown in Figure 11. As in the first feasibility unit, this combustor is assembled from flanged sections providing flexibility in combustor length and specific geometry. Each section is individually water-cooled allowing axial calorimetry data to be taken during testing. A vitiator shown in the figure near the test technician is used to preheat the incoming air stream. This system is being used to explore the low preheat, low pressure operating regime characteristic of retrofit applications.

7.0 Test Results

Test results from the first feasibility test unit and the 70 MBTU/hr combustor are summarized in Table 2. Note the wide range of operating conditions explored with the first feasibility test unit as indicated by the values listed for operating pressure, air preheat temperature and equivalence ratio range. Up to 86% of the total ash contained in mine-mouth coals has been captured as slag. Coal ash contents have varied from 5% to 24%. Carbon burnout has consistently exceeded 99.5% as measured by quantitative analyses of carbon contained in the slag. Outlet temperatures vary with the type of coal used and the operating equivalence ratio. Very high values are desired for the MHD operating conditions. Heat rejection to the cooling water in these experimental devices is generally higher than expected in commercial design hardware due to the large number of joints, flanges, etc. The total number of tests on the first feasibility unit have exceeded 300, leading to extensive thermal cycling of the hardware. However, individual tests have been of relatively short duration; i.e., long enough to obtain equilibrium conditions.

Similar data for the 70 MBTU/hr unit is also shown in Table 2. Note that slag recoveries up to 91% were obtained with the larger hardware while at the same time achieving the high carbon burnout values accomplished with the smaller feasibility hardware. In general, both air preheat and exhaust gas temperatures are higher in this unit due to the MHD operating requirements. Test durations were similar to those used in the feasibility test series, except a life test was accomplished on the 70 MBTU/hr unit where continuous operating periods of 22 hours were obtained with accompanying exit gas temperatures in excess of 4400°F.

A summary of the tests performed on the second feasibility test unit operating at approximately 10 MBTU/hr using powdered coal is given in Table 3. These tests were designed to provide information primarily in the retrofit regime. Combustor L/D ratios varied from 1.5 to 4; the combustor orientation was inclined 30° to the horizontal. Operating pressures were consistent with commercially available fans and the air preheat temperature was maintained in the range achievable with conventional waste heat recovery systems, except for some excursions designed to provide complete parametric data. The maximum slag capture and carbon burnout values achieved were consistent with the first feasibility unit. The outlet temperature was generally in the range of 2300 to 2900°F with some parametric excursions to higher values.

TABLE 2

TRW COAL COMBUSTOR TEST SUMMARY

COMBUSTOR TYPE	FIRST FEASIBILITY	MHD
POWER LEVEL (MBTU/HR)	10 - 30	70
INSIDE DIAMETER (INCH)	17	24
OPERATING PRESSURE (ATM.)	1.0 - 6.0	3.2 - 6.0
AIR PREHEAT TEMPERATURE (°F)	800 - 2900	1100 - 2950
EQUIVALENCE RATIO RANGE	0.4 - 1.3	0.5 - 1.2
MAXIMUM SLAG CAPTURE (%)	86	91
CARBON BURNOUT (%)	>99.5	>99.5
OUTLET TEMPERATURE (°F)	2300 - 4070	3600 - 4430
HEAT REJECTION TO COOLING WATER (%)	8 - 15	>10
TOTAL NUMBER FIRINGS	314	173
TOTAL RUN DURATION ON COAL (HRS)	128	191
INDIVIDUAL RUN (HRS)	1 - 2	1 - 22

TABLE 3

TRW COAL COMBUSTOR TEST SUMMARY
Second Feasibility Unit (10 MBTU/hr)

DIAMETER (INCH)	17
LENGTH (INCH)	26 - 62
ORIENTATION	INCLINED AT 30°
OPERATING PRESSURE (ATMS)	1.05 - 1.2
AIR PREHEAT TEMPERATURE (°F)	500 - 1500
EQUIVALENCE RATIO RANGE	0.4 - 1.2
MAXIMUM SLAG CAPTURE (%)	86
CARBON BURNOUT (%)	>99.5
OUTLET TEMPERATURE (°F)	2300 - 3700
HEAT REJECTION TO COOLING WATER (%)	8 - 15
TOTAL NUMBER OF FIRINGS TO DATE	184
TOTAL RUN DURATION ON COAL (HRS)	323
INDIVIDUAL RUN (HRS)	1 - 8

Because of growing interest in making logistical improvements in coal delivery systems, a brief test series using coal water mixtures (CWM) was recently accomplished. Four tons of ARC 70% coal, 30% water CWM was used. The results are summarized in Table 4. The operating conditions were similar to those used with powdered coal. A specially designed atomizing slurry injector replaced the powdered coal pintle previously used. Atomization air mass flow was about 2% of the incoming primary air as indicated by atomization ratios in the range of .01 to .03. Somewhat higher equivalence ratios and a stronger ignition source were required in the CWM tests, but once ignited, the flame was well-anchored and stable. Good combustion was achieved as evidenced by high carbon burnout and stable flame conditions. Maximum slag capture of 75% was accomplished in the limited test series. It appears that comparable slag capture values to those achieved using powdered coal are obtainable. In general, the CWM test results were very encouraging and more testing is planned in the near future.

TABLE 4

TRW CWM COMBUSTOR TEST SUMMARY
Second Feasibility Unit (10 MBTU/hr)

DIAMETER (INCH)	17
LENGTH (INCH)	26
ORIENTATION	30°
OPERATING PRESSURE (ATMS)	1.05 - 1.2
AIR PREHEAT TEMPERATURE (°F)	700 - 1900
EQUIVALENCE RATIO RANGE	0.7 - 1.2
ATOMIZATION RATIO RANGE	0.01 - 0.03
MAXIMUM SLAG CAPTURE (%)	75
CARBON BURNOUT (%)	>99.5
OUTLET TEMPERATURE (°F)	2800 - 3700
HEAT REJECTION TO COOLING WATER (%)	8 - 10
TOTAL NUMBER OF FIRINGS TO DATE	6
TOTAL RUN DURATION ON COAL (HRS)	9
INDIVIDUAL RUN (HRS)	1 - 2

The basic feasibility of burning powdered and water slurried mine-mouth coal has been established by TRW at 10 MBTU/hr. Efficient combustion and high ash removal as molten slag have been demonstrated. We are now focusing on specific run conditions for kilns, furnaces and boilers. In parallel, we are designing a 40 MBTU/hr engineering test unit which will be fabricated and tested in 1983 to verify scaling and provide the basic data for final design and construction of a commercial type combustor to be used in a field demonstration program.

8.0 Field Demonstration

TRW believes that the final step prior to commercialization involves a field demonstration program using a representative commercial combustor integrated with typical heat utilization equipment. We have structured such a program and are now seeking interested sponsors to assist in funding this effort. The participants will probably include utilities, potential industrial users and other organizations interested in seeing advanced coal combustion technology commercialized.

TRW's demonstration program will provide combustor life, reliability and maintenance data through the conduct of a 4000-hour long-term test under continuous plant operating conditions. It will also provide quantitative data on the performance of heat utilization equipment under the influence of combustor exhaust products. The program has been designed to take full advantage of TRW's prior development work; the engineering services of Stone & Webster, a company with 90 years experience in engineering design and construction; and the operating steam plant in TRW's TAPCO (Thompson Aircraft Parts Company) facility shown in Figure 12.

The industrial boiler selected for this test series was originally designed for stoker coal firing and converted to oil and gas firing in 1969. Much of the required coal receiving and handling capability is still in place as shown in Figure 13 and will be used in the demonstration.

The demonstration will involve the following sequence of activities:

- Modifications to the existing boiler plant which are necessary to accommodate the combustor equipment including the addition of coal crushing/grinding, cooling water, air preheating, stack gas particulate removal, and slag disposal systems.

- Design and fabrication of a 40 MBTU/hr commercial type coal combustor system consisting of an entrained slagging combustor, dense phase coal feed system, slag removal equipment, a secondary burner which interfaces with the boiler, and appropriate instrumentation.

- Brief hot-fired acceptance test of the combustor system at FETS.

- Integration of the combustor system with the 30,000 lb/hr Keeler boiler and necessary support systems at the TAPCO boiler plant as shown in the artist's rendering of Figure 14.

- Short duration test series to check out integrated combustor system-boiler performance.

- 4000-hour test conducted during a six-month period using a selected low sulfur coal to obtain key information on durability, maintenance and long-duration operation of the combustor system and boiler when exposed to combustor exhaust products. The latter data will be used to evaluate the expected performance of various types of oil-fired heat utilization equipment when coupled to the TRW combustor.

- Three-month test series using coals of particular interest to our sponsors.

This demonstration will be followed by specific field applications in customer facilities and the sale of commercial coal combustion retrofit systems by 1985. We will also further scale the device to larger sizes after the technology is demonstrated.

9.0 Conclusion

The retrofit of oil- and gas-fired commercial heat utilization equipment with TRW combustors will result in a substantial fuel savings and provide a much more secure fuel supply. Also since the combustor hardware costs will be modest and most of the existing heat utilization equipment already in place could be used, the capital investment required will be much smaller than for replacement of competing coal-fired equipment.

TRW is firmly committed to the development and commercialization of the coal combustor system as evidenced by the continuing expenditure of millions of dollars of its own funds. We are now seeking interested organizations who will directly benefit from the application of the developed unit to assist in sponsoring the TAPCO Demonstration Program as a final step prior to commercialization.

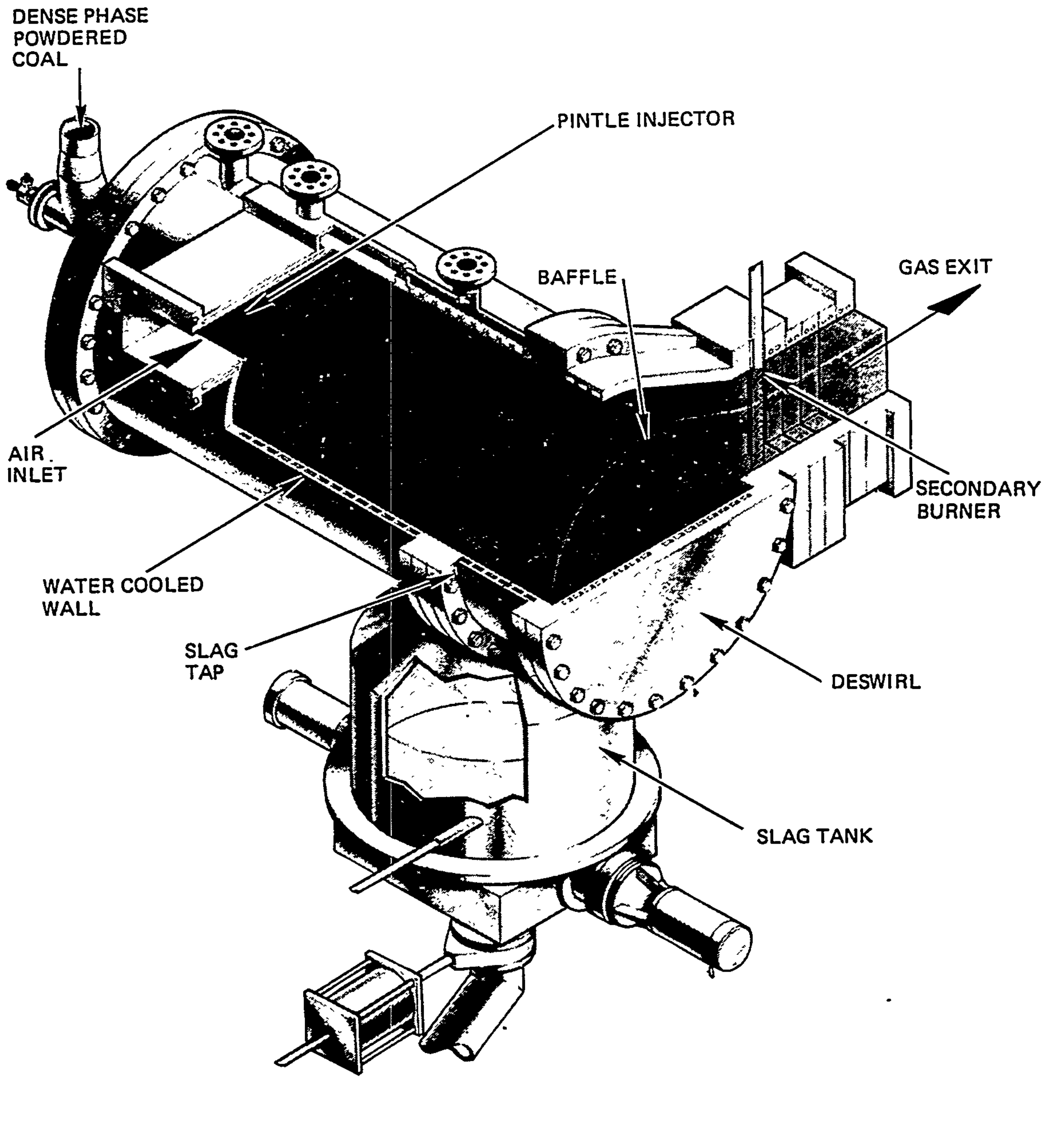


FIGURE 1. TRW COAL COMBUSTOR

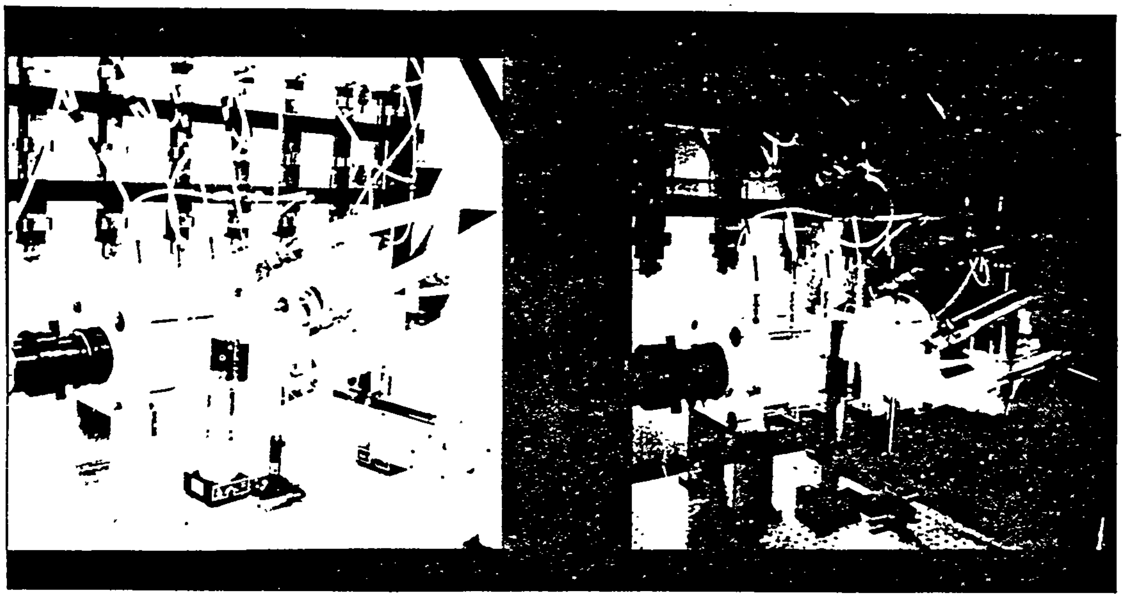


FIGURE 2. COMBUSTION RESEARCH

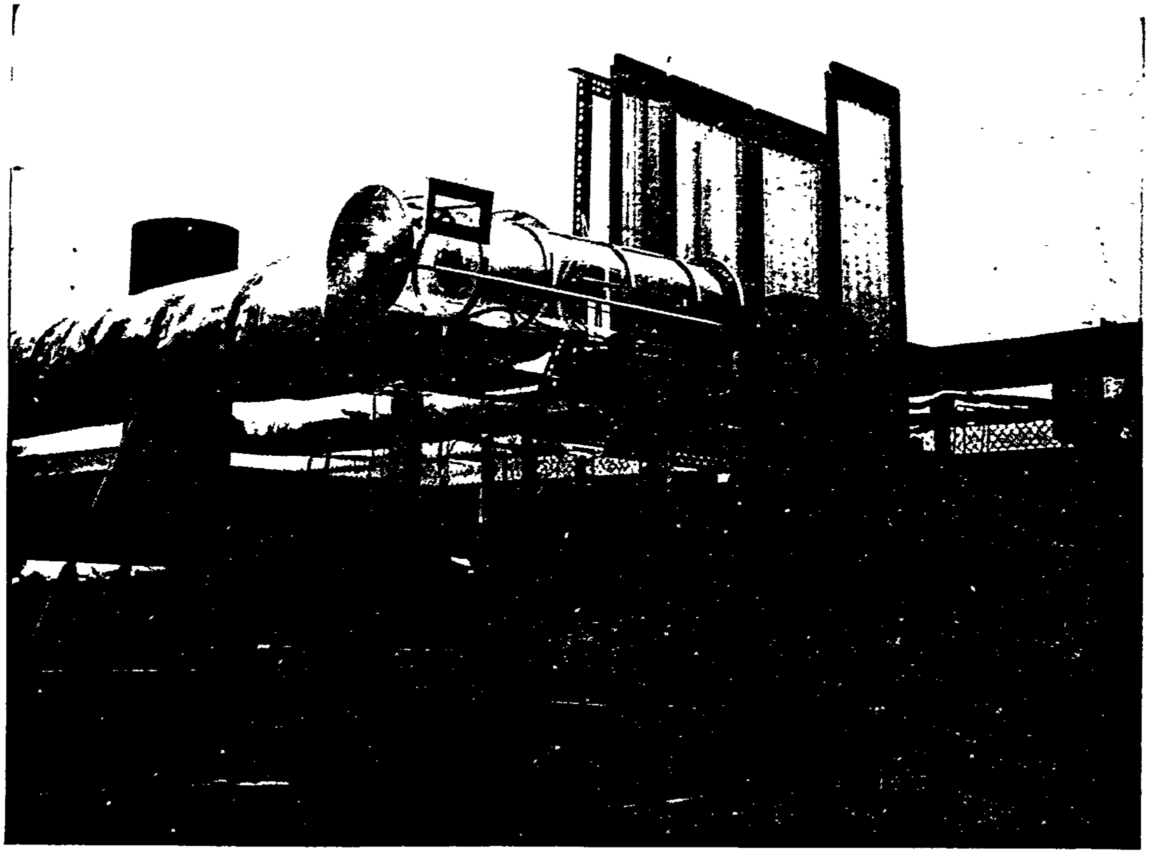


FIGURE 3. COMBUSTOR AIR FLOW MODEL

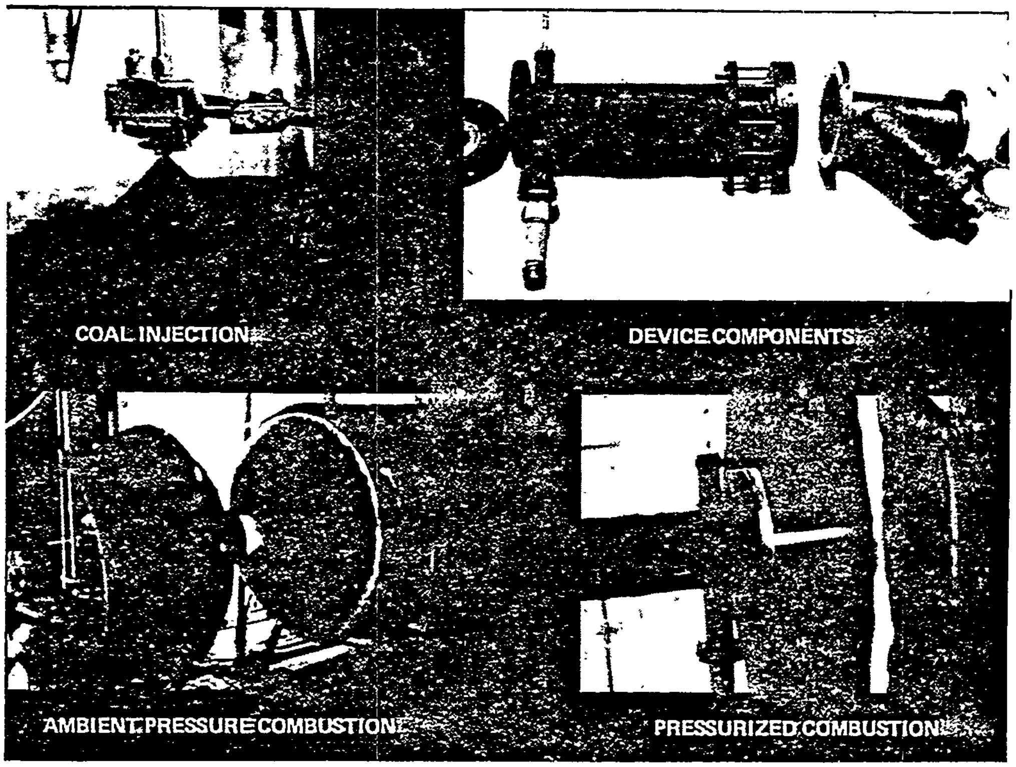


FIGURE 4. SMALL SCALE DEVICE (1 MBTU/HR)

FIGURE 5. FEASIBILITY UNIT (10-30 MBTU/HR)

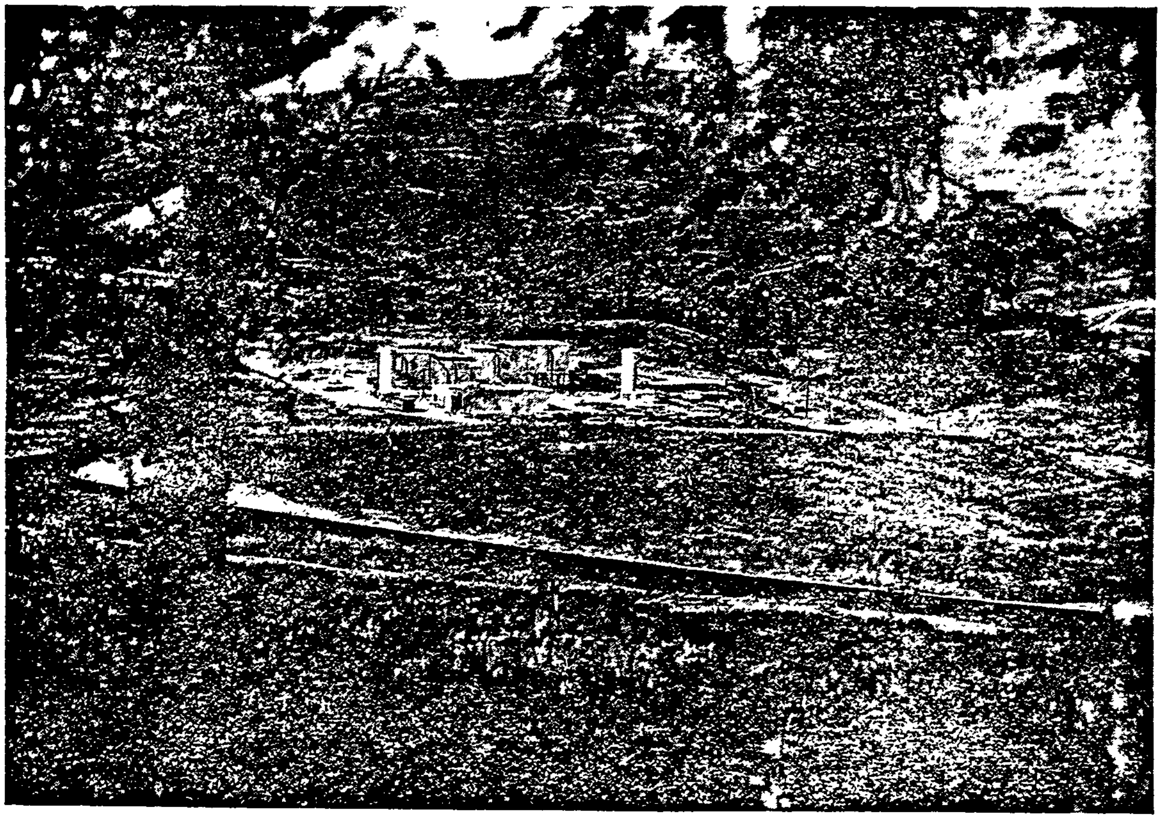


FIGURE 6. FOSSIL ENERGY TEST SITE (FETS)

CONTROL PANEL

INSTRUMENTATION SETUP

FIGURE 7. FETS CONTROL/INSTRUMENTATION CENTER

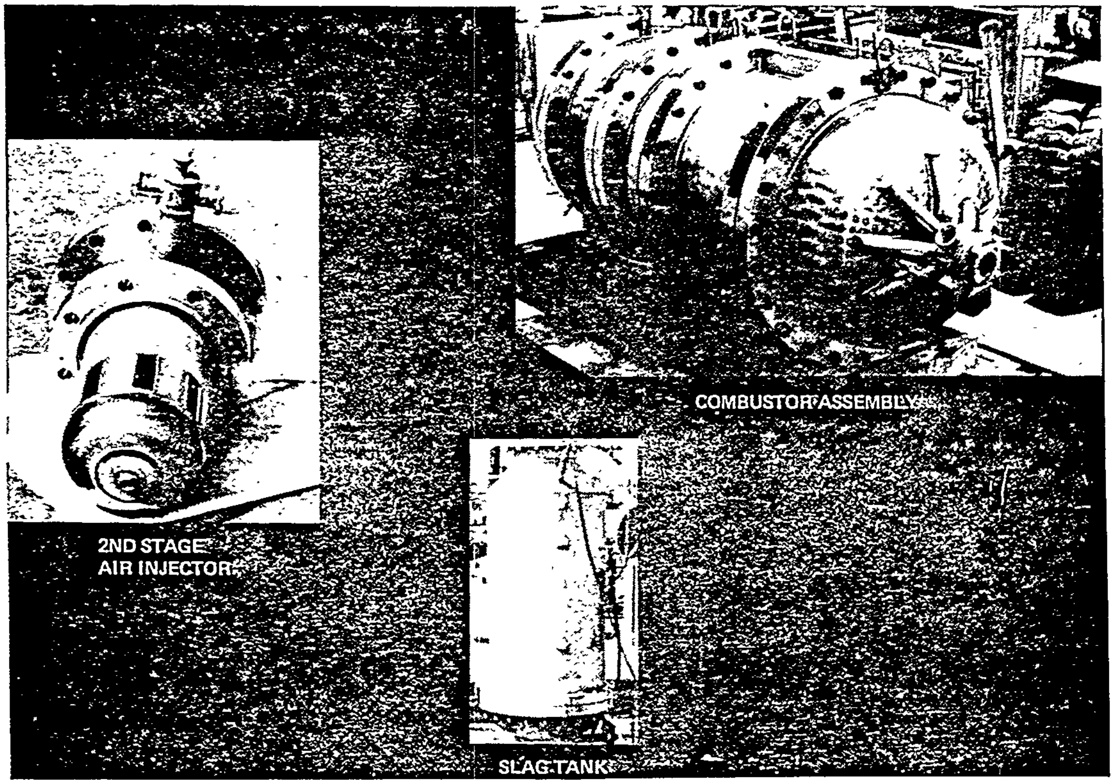


FIGURE 8. 70 MBTU/HR COAL COMBUSTOR HARDWARE

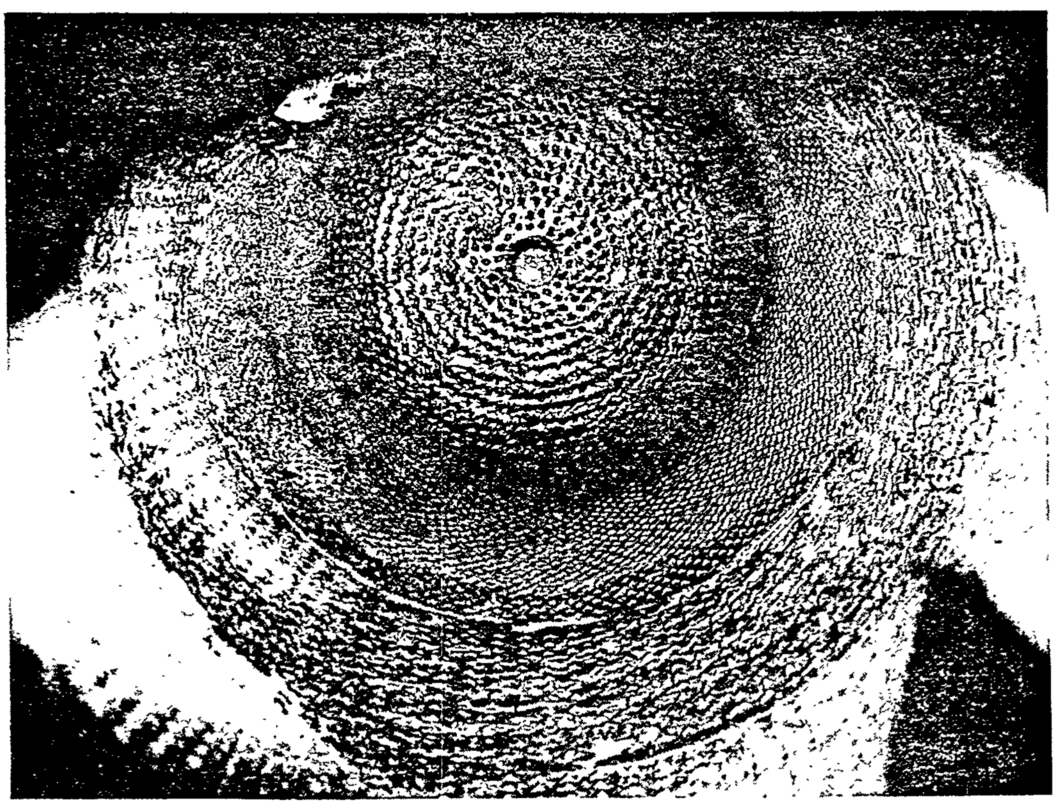


FIGURE 9. EQUILIBRIUM SLAG LAYER

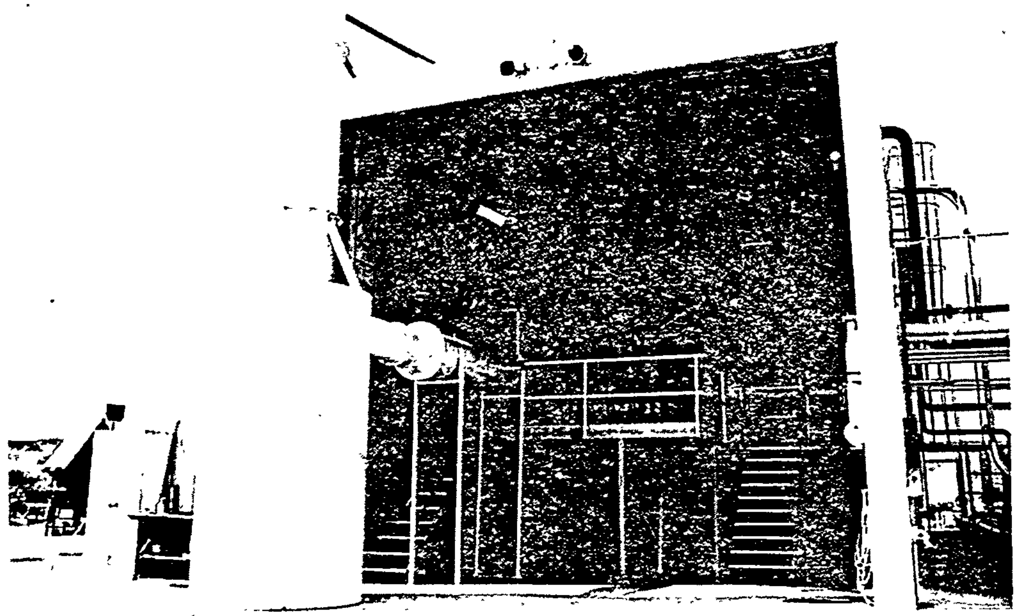


FIGURE 10. SECOND FEASIBILITY UNIT ON TEST STAND AT FETS (10 MBTU/HR)

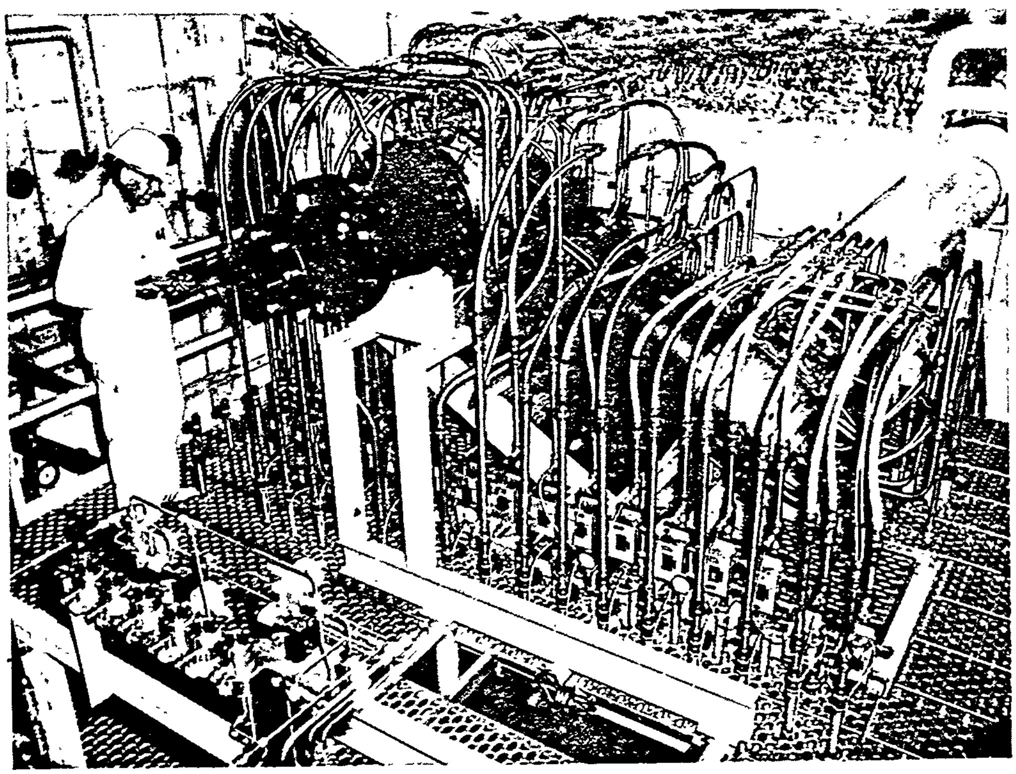


FIGURE 11. 10 MBTU/HR FEASIBILITY TEST UNIT

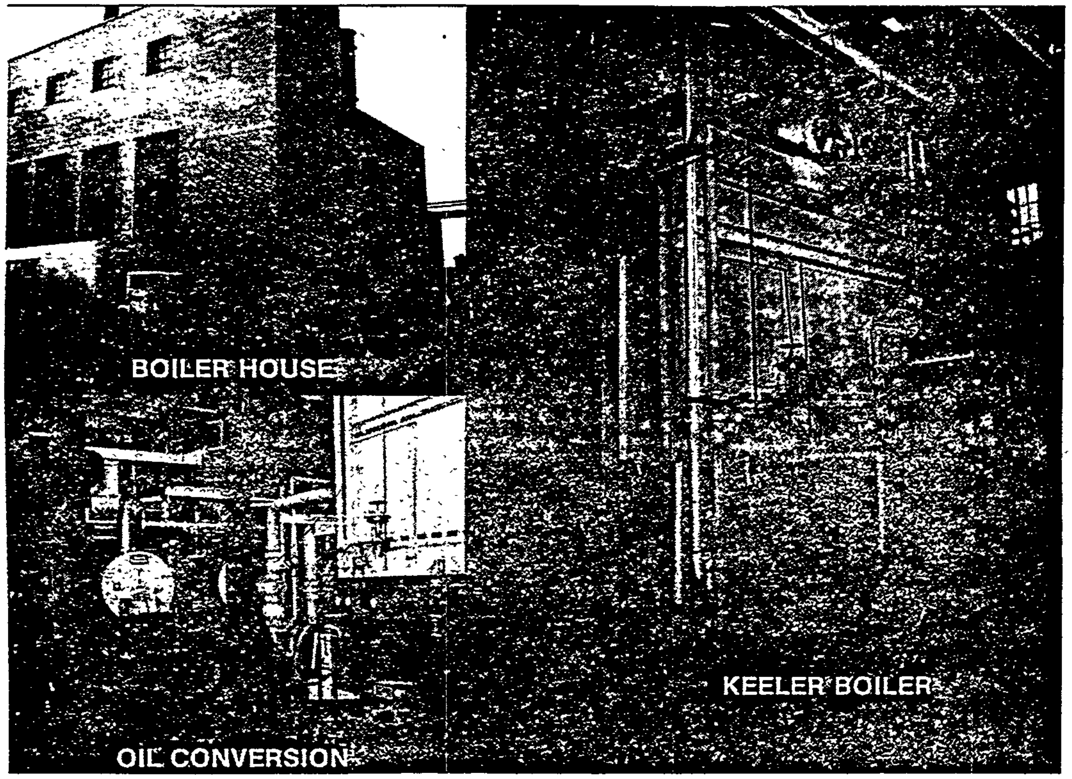


FIGURE 12. TAPCO BOILER FACILITY

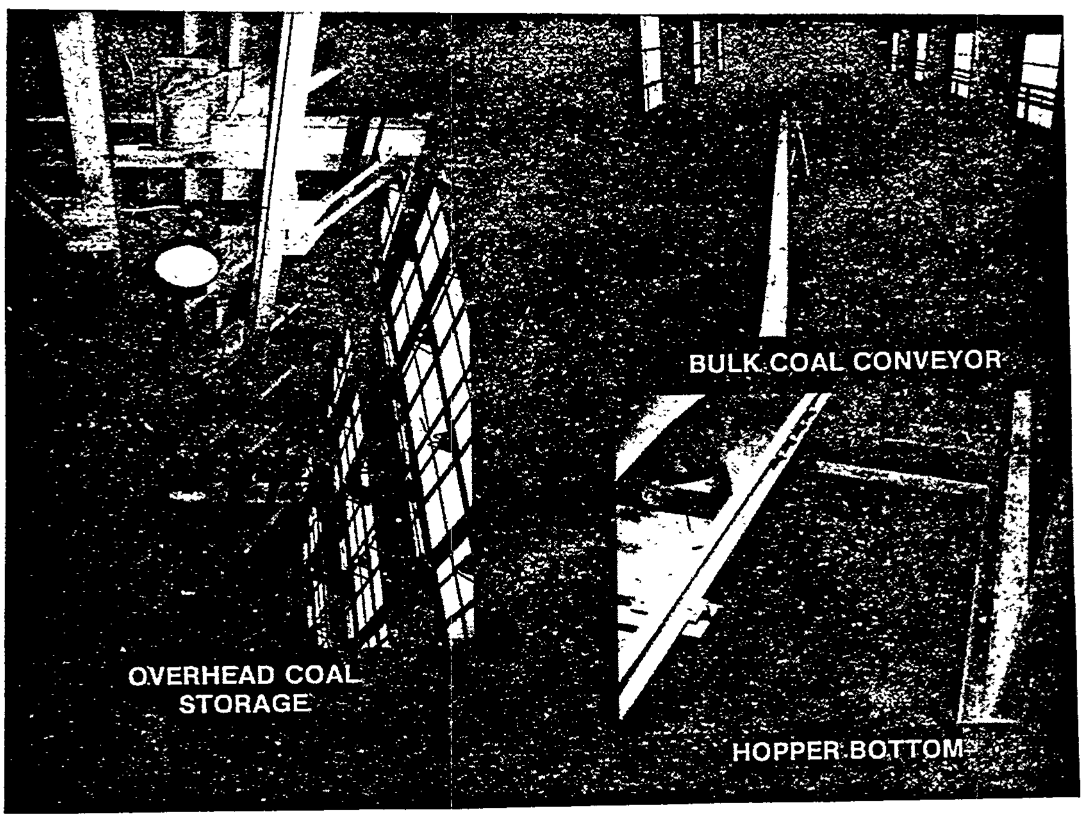


FIGURE 13. TAPCO COAL HANDLING/STORAGE

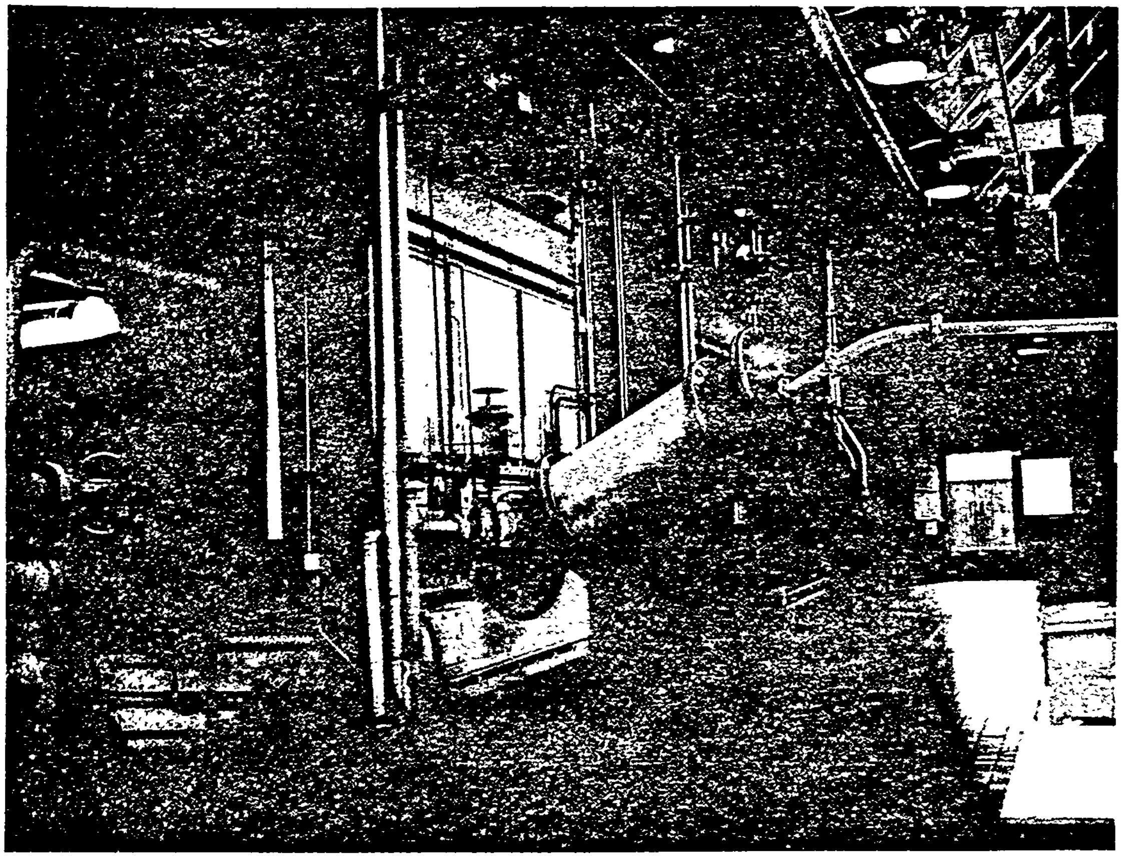


FIGURE 14. ARTIST'S RENDERING OF TRW COMBUSTOR
INTEGRATED WITH KEELER BOILER

STUDIES ON COAL UTILIZATION AT THE ENERGY AND ENVIRONMENTAL RESEARCH CORPORATION (EER), 18 MASON, IRVINE, CALIFORNIA 92714 (January 1983)*

EER has been involved in a broad program on coal utilization for some years. Funding for the current year runs at a level of about $\$6 \times 10^6$, with support from EPA, EPRI, DOE, and private companies. The EER co-founders are M. A. Heap and T. Tyson, who serve as principal officers. The larger experimental facilities are located in Irvine, California, at a test site developed during the fifties by Philco-Ford for rocket and cannon testing.

A. Current Programs

EER has served as primary consultants to the EPA on a fundamental combustion research program, for which support levels have recently been reduced from about $\$4 \times 10^6$/year to $\$1 \times 10^6$/year. These studies have included work on kinetic models for reaction processes involving fuel-derived nitrogen in flames, dry additives for SO_2 control, characterization of sorbents for SO_2 removal under conditions of high heating rates, and downstream reburning with fuel injection to achieve NO_x and SO_2 control. Successful correlations have been derived for the volatile materials and nitrogen contents of fuels with total NO_x concentrations remaining in the exhaust flows.

Bartlesville/DOE is supporting experimental studies on coal utilization in a diesel engine. A high-intensity cyclone combustor is under development, with primary burning occurring in the suspension phase. A fundamental program on coal-particle ignition and combustion of particles in jets is supported by NSF. The EPRI program on coal-quality control and its effects on utility-boiler

*Prepared by S. S. Penner

performance has recently included funding for EER. A DOE program is in progress on retrofitting gas-fired burners for the use of pulverized coals. There are also current studies on fuels evaluations, programs with boiler manufactures on second generation NO_x control (to about 0.3 lb/10^6 Btu), and the design (for Bechtel Corp.) of a dry-scrubber bag house with sorbent injection for SO_2 control.

Studies on slagging and fouling are viewed as representing an especially challenging area. While qualitative performance predictions can be made on the basis of small-scale tests, quantitative predictions for new coal types are not yet feasible and development of the needed understanding represents a special challenge. Fundamental work to characterize the chemical compositions and size distributions of particles reaching and then adhering to the boiler walls are needed in order to obtain insights into the governing processes.

B. Publications

The following is a listing of some recent publications by EER personnel, which are available at UCSD:

1. M. P. Heap and W. Richter, "Einfluß der Brennstoffart auf die Wärmeübertragung in Feuerungen," VDI-Berichte 423, 225-234 (1981).

2. W. Richter and M. P. Heap, "The Impact of Heat Release Pattern and Fuel Properties on Heat Transfer in Boilers," The American Society of Mechanical Engineers Paper No. 81-WA/HT-27 (1981).

3. W. Richter, "Anwendung von Berechnungsmodellen für Feuerräume," VGB Kraftwerkstechnik 62, Heft 10, 845-852 (1982).

4. Energy and Environmental Research Corporation, "Evaluation of Time/Temperature History of Gases and Particles in the Radiant Furnace Zone of Pulverized Coal-Fired Steam Generators," November 1982.

5. Energy and Environmental Research Corporation, "Evaluation of In-Furnace NO_x Reduction and Sorbent Injection on NO_x/SO_x Emissions of U.S.-Designed Pulverized-Coal-Fired Boilers," November 1982.

6. Energy and Environmental Research Corporation, "Development of Limestone-Injected, Internally Staged Low-NO_x/SO_x Retrofit Coal Burners," November 1982.

7. Energy and Environmental Research Corporation, "Prototype Evaluation of Second-Generation Low NO_x Burner Performance and Sulfur Capture Performance," December 1982.

8. J. E. Broadwell, P. E. Dimotakis, T. J. Tyson, C. J. Kau, and W. R. Seeker, "The Structure of Turbulent Diffusion Flames and Nitric Oxide Formation," Energy and Environmental Research Corporation, 1982.

9. S. L. Chen, W. C. Clark, M. P. Heap, D. W. Pershing, and W. R. Seeker, "NO_x Reduction by Reburning with Gas and Coal— Bench Scale Studies," Energy and Environmental Research Corporation,1982.

10. W. R. Seeker, W. D. Clark and G. S. Samuelson, "The Influence of Scale and Fuel Properties on Fuel-Oil Atomizer Performance," Energy and Environmental Research Corporation, 1982.

11. S. L. Chen, M. P. Heap, and D. W. Pershing, "Bench-Scale Emissions Testings of Non-U.S. Coals: Influence of Particle Size and Thermal Environment," Energy and Environmental Research Corporation, 1982.

12. G. England, M. Heap, Y. Kwan, R. Payne, and D. Pershing, "Development of a Low NO_x Burner for Enhanced Oil Recovery," paper presented at the Joint Symposium on Stationary Combustion NO_x Control (1982).

13. J. H. Pohl, S. L. Chen, M. P. Heap, and D. W. Pershing, "Correlation of NO_x Emissions with Basic Physical and Chemical Characteristics of Coal," Energy and Environmental Research Corporation,1982.

14. P. L. Case, M. P. Heap, R. Payne, and D. W. Pershing, "Limb Testing: The Use of Dry Sorbents to Reduce Sulfur Oxide Emissions from Pulverized-Coal Flames Under Low-NO_x Conditions," Energy and Environmental Research Corporation, 1982.

15. B. Folsom, A. Abele, J. Reese, and J. Vatsky, "NO_x Emissions Control with the Distributed Mixing Burner - Part I. Field Evaluation of an Industrial Size Boiler"; B. Folsom, R. Payne, A. Abele, and P. Nelson, "Part II. Thermal Environment and Heat Release Capacity Scaling," Energy and Environmental Research Corporation, 1982.

16. S. L. Chen, D. W. Pershing, and M. P. Heap, "Bench-Scale Evaluation of Non-U.S. Coals for NO_x Formation Under Excess Air and Staged Combustion Conditions," Energy and Environmental Research Corporation, Report No. IERL-RTP-1367, December 1981.

17. M. P. Heap, B. A. Folsom, and R. Payne, "Effects of Coal Quality on Power Plant Performance and Costs," Energy and Environmental Research Corporation Monthly Progress Report No. 1, November 1982.

C. Research and Facility Descriptions

We have available at UCSD the 1982 EER report on "Research, Development, Applications." Also, it is expected that M. A. Heap will describe the EER programs at a future meeting of CCAWG.

AB-12

CCAWG MEETING AT EPRI*
(Tuesday, February 1, 1983)

The following CCAWG members participated in an excellent overview of EPRI programs arranged by K. Yeager: S. B. Alpert, J. M. Beér, C. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, L. D. Smoot, R. E. Sommerlad, C. L. Wagoner, I. Wender, and K. Yeager. The meeting was also attended by ex officio members J. F. Kaufmann and R. E. Roberts and by EPRI speakers (see Table AB-12-1) and others (J. Maulbetch, S. Dalton, et al). A copy of the meeting agenda is attached (see Table AB-12-1).

1. Overview

Appendix AB-12-1 contains three papers that provide overviews of EPRI's work on coal combustion and applications. K. Yeager's paper is reprinted from the Public Utilities fortnightly and summarizes R&D priorities for EPRI. Related policy issues and studies are presented in the mid-1982 summary of EPRI programs on advanced pulverized coal power plants. A brief summary of an EPRI study mission to Japan is contained in the third paper.

The EPRI work on coal combustion systems has projected funding of \$361 x 10^6 for the period 1983-87 (i.e., an average funding level of about \$72 x 10^6/yr).

T. Armor emphasized the importance of powerplant availability and performance for which 1983 EPRI expenditures are \$13 x 10^6. Important availability problem areas involve blade failures and solid-particle erosion in the steam turbine, failure of waterwall tubes and fouling and slagging in the boilers. Improved powerplant performance can be achieved through monitoring and utilization of

*Prepared by S. S. Penner.

Table AB-12-1 CCAWG Meeting at EPRI, Palo Alto, CA (February 1, 1983)

9:00	Welcome and Introduction	K. Yeager
9:30	Availability and Performance Program - Advanced Coal Plant - Plant Diagnostics - Japanese Technical Transfer	T. Armor
10:30	Retrofitting Utility Power Plants for Coal	R. Manfred
11:15	Environmental Control Systems - EPRI Program Overview	G. Preston
12:00	Lunch	
12:30	Impact of Environmental Issues on Coal-Fired Power Generation	K. Yeager
1:30	Utility Particulate Emission Control	M. McElroy
2:15	Combustion Control of NO_x - Retrofit Low NO_x Burners - Furnace Limestone Injection SO_2/Low NO_x	M. McElroy
3:00	Coal Gasification/Combined Cycle - Coolwater Project Status	S. B. Alpert
4:00	Adjourn	

measures such as direct [illegible]

appropriate plant diagnostics. An advanced PC design shows a 3% increase in efficiency, corresponding to about a 10% decrease in heat rate (i.e., heat rates reduced from about 9100 Btu/kW-hr to 8200 Btu/kW-hr). The next generation of powerplants is being designed to operate under supercritical conditions. Supercritical plants have been found to have the same availability as subcritical plants. The Japanese are planning to construct 40,000 MW_e of supercritical capacity by the year 2000. These advanced PC units are expected to be economically competitive with IGCC and PFBC plants.

R. Manfred discussed retrofitting of existing boilers for coal use. He noted that no one has as yet constructed a PC plant adjacent to an existing oil-fired unit and used the existing balance of plant. Boilers originally designed for coal use have been reconverted to coal use. Retrofitting of two 200-MW_e oil burners in Australia required derating to 60% capacity, i.e., to 120 MW_e. Actual derating of oil-fired burners depends on the boiler design. COM appears to be uneconomical; CWM production in the U.S. is growing and is expected to reach 1×10^6 TPY by 1984, which should be sufficient for one large utility demonstration plant. The required differential between oil and CWM costs must be greater than about $\$1.5/10^6$ Btu at derating of less than 30% for CWM to represent an economically attractive option. Modeling of CWM tests has not been supported by EPRI in the past but may now constitute an appropriate activity.

G. Preston described environmental control systems and performance, including the use of bag houses, regenerable FGD, combustion and post-combustion control of NO_x, zero-discharge cooling towers, wet and dry cooling. EPRI does not develop improved control technologies for the purpose of producing tighter regulatory measures. Major problem areas include scrubber corrosion, materials specifications, waste disposal. It appears that all of the environmental control technologies could profit from research and improved understanding of the fundamental processes involved.

K. Yeager gave an excellent overview of problem areas involved in acid precipitation. He noted that, whereas total NO_x levels are expected to grow to the year 2000, SO_2 levels are expected to remain level. Rapid restoration of acidified lakes can only be achieved through implementation of active remedial measures such as direct lime additions.

M. McElroy discussed particulate emission controls using filter bag houses or ESP and NO_x control using combustor modifications and post-combustion clean-up. A low-NO_x, staged-combustion burner now marketed by Mitsubishi is based on principles clearly defined by U.S. researchers during the sixties. NO_x control to 0.2 lb/10^6 Btu is achievable at moderate costs ($\sim$0.13 to 0.34 mills/kW-hr with capital costs of $5 to 12/kW). It was noted that EPRI has not supported a significant level of fundamental combustion research.

Limestone injection into or above the burner region may be a preferred SO_2-removal technology in accord with the fact that chemical conversions are generally implemented more quickly and efficiently at elevated than at low temperatures, as has been repeatedly emphasized especially by A. K. Oppenheim. Unresolved clean-up issues relate to the interplay between systems design and SO_2 removal, ESP performance, ash disposal and utilization, slagging and fouling, soot blowing, tube erosion, and the formation of backpass deposits.

The EPRI presentations were concluded by S. B. Alpert with an overview of the Coolwater IGCC demonstration plant. This important facility (100 MW_e net output) represents a milestone in advanced engineering applications on coal utilization. It could not have come to fruition without Alpert's dedication, knowledge and skill. Coolwater is being built by EPRI, Texaco, SCE, JCDC, and others (without DOE support). Many if not all of the participants concurred with Alpert's view that the U.S. will become a third-rate power unless we take the high risks represented by advanced technological implementations of the type represented by Coolwater.

Along the Technical Front in Coal Utilization

By KURT E. YEAGER

How the electric utility industry and its suppliers respond in this decade to declining demand growth rates, uncertainty over petroleum availability and pricing, stringent environmental controls, lessened capital investment capability, loss of momentum for the nuclear option, decreased governmental funding of technology development, and increased emphasis by domestic coal suppliers on their international market will have important consequences for the industry's power generation capability and structure in the next century. The following article describes technological advances in direct coal utilization which effectively address those challenges.

THE past decade brought new constraints that are reshaping the technical approach of the U. S. utility industry to coal utilization. In the 1970s, increasing electrical rates, restrictive environmental controls, uncertainty over petroleum availability, and skyrocketing fuel costs caused the industry to consider a variety of new coal-based generating options.

Now, in the 1980s, these constraints are compounded by declining demand growth rates, restricted capital investment capability, loss of public confidence in the nuclear initiative, withdrawal of government funding in technology development, and increased emphasis by domestic suppliers on the international market.

Coal now provides over 50 per cent of the electricity generated in the United States. Its importance will continue to grow over the remainder of this century, providing about two-thirds of the nation's energy growth. How the U. S. utility industry and its suppliers respond in this decade to those constraints will have important consequences for the nation's power generation capability and structure into the next century. Certain trends seem clear. For example:

Generation capacity will depend increasingly on direct coal combustion. Private sector responsibility for technology improvements will encourage lower-risk, nearer-term options. Priority will be placed on improving the reliability and longevity of existing generating coal capacity to minimize investment.

Technological advances in direct coal utilization which effectively address these challenges are (1) coal quality improvement, (2) improved pulverized coal technology, and (3) fluidized bed combustion (FBC).

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Coal Quality

Traditionally, the U. S. utility industry has not given high priority to quality control of its coal feedstock. The general decline in plant reliability and efficiency has, however, led to a reexamination of the entire power generating system from coal supply to ash disposal. The sensitivity of pulverized coal-fired power plant performance and reliability to coal quality has particularly emerged as a major industry concern. As a result utilities are learning that the cheapest coal does not necessarily produce the lowest cost electricity.

A principal facility for assessing the effects of coal quality on power plants is the new Electric Power Research Institute-sponsored coal cleaning test facility

(CCTF) located at the Homer City power station of Pennsylvania Electric Company and New York State Electric and Gas Corporation. Based on commercial scale equipment, the CCTF has a coal handling rate of 20 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can simulate more than 50 commercial cleaning plant designs. Participating utilities and suppliers deliver 1,000 ton coal samples to the CCTF for cleaning characterization. The results provide a reliable estimate of the commercial cleanability potential of the coal, the effect of cleaning on fouling and slagging, as well as verification of cleaning plant design and cost meeting the company's specific needs.

Coal Quality Assessment

New apparatus to determine coal quality has been developed with the support of the Electric Power Research Institute and is being applied in full-scale utility tests. Called CONAC (for "continuous nuclear analysis of coal"), the method blends the principles of nuclear physics with the practicalities of coal technology. CONAC instrumentation is based on a technique called prompt neutron activation analysis. The technique is already accepted in a wide variety of industrial applications.

CONAC uses a small specimen of radioactive californium (Cf-252) to bombard a coal stream with neutrons. When a neutron is captured by an atomic nucleus, gamma rays are emitted that have a frequency characteristic of the elements involved. CONAC uses radiation detectors to count the number of gamma rays at each characteristic frequency. The number of each is proportional to the abundance of the element associated with that frequency.

CONAC's application range includes determining coal quality at the mine, coal blending, control of coal washing and beneficiation, prediction and avoidance of slagging and fouling, heat management around a boiler, real time heat rate determination, optimal load dispatch, and compliance with flue gas emission limits.

Coal Slurries

Continued oil and gas cost escalation, as well as potential supply interruption, are strong incentives for the conversion of oil-fired power plants to coal. EPRI has conducted studies examining the technical and economic considerations in the several options for achieving this conversion. Based on the results, EPRI is conducting research to develop, demonstrate, and commercialize coal-water slurries (CWS) as a cost-effective, oil replacement fuel for oil-fired utility boilers.

Coal slurries may substantially lower the cost of conversion. The advantage of these slurries over pulverized coal is that they can be transported, stored, and handled with less extensive changes to existing oil-firing facilities.

EPRI, therefore, is focusing its future projects on the rapid development and demonstration of CWS. Various coal feedstocks, coal treatment processes, grinding methods, and stabilizing processes are being studied so that selection and use guidelines can be prepared for the broad range of utility conditions. Combustion tests have been performed in small furnaces and development projects are under way to demonstrate stable and reliable combustion in larger boilers. Utility scale demonstration of CWS combustion is planned by EPRI for 1984-85.

Improved Pulverized Coal Technology

In the next twenty years, the utility industry will be faced with maintaining the integrity of power generation and supply with only a limited number of new plant additions. The difficulty of financing new plants, the cancellation and deferment of many nuclear orders, and the uncertain rate of growth of the industry place increasing emphasis on the availability of existing generation. In particular, many fossil units are approaching the limit of their design lives (typically thirty to forty years) and present a challenge to utilities in extending life without impacting availability.

It is in this current climate that the techniques of incipient failure detection are beginning to flourish. Early warning of component deterioration is seen as an essential part of any predictive maintenance program for fossil plants. Conversely, the absence of such techniques leads to sudden, and often catastrophic, equipment failure causing extended outages for repair and replacement. Even when faced with only one day of additional downtime on a large unit, it is apparent that the capital cost of monitoring equipment is quickly justified.

Diagnostic monitoring is advancing for all areas of the power plant: boilers, turbines, generators, fans, pumps, heat exchangers, but the degree of sophistication of the techniques is not uniform. Some monitoring techniques — vibration signature analysis for example — are well developed and can be implemented into utility maintenance procedures. Others, such as boiler stress and condition analyzers, will require further development and field qualification before across-the-board application to aging fossil plants.

The average station heat rate decreased continuously until the early 1960s. Subsequently, there was little incentive to continue the effort because of the expected increase in nuclear power generation for base-load application and the availability of relatively inexpensive fossil fuels; also additional environmental restrictions required flue gas treatment which had a significant adverse effect on heat rate. A further negative impact resulted from the need to cycle many large fossil plants and run the units at other than base load. This mode of operation typically results in lower component efficiencies and increased heat rate of the units.

EPRI believes that it is important to reverse this trend and has recently carried out a study on the design of fossil plants. As a result, a substantial improvement in heat rate appears possible in new fossil plants. For existing units, EPRI is pursuing a program of on-line performance monitoring and improved instrumentation and testing. The cumulative effect of this effort on the close to 1,000 fossil units currently in service can be a significant reduction in fuel usage as well as immediate economic benefits to the operating utilities.

The trend in unit availability and capacity factor suggests that reserve margins will continue to be of concern in the future. Improved heat rate will be one factor which will assist in improving system reserve margins.

The evaluation of the benefits of higher steam conditions and innovative design concepts must include critical consideration of their impact on unit reliability. Traditional opinion has suggested that supercritical steam-electric plants cannot be expected to produce reliability levels equivalent to those of subcritical plants. Further, the fuel cost savings from high efficiency plants may be more than offset by their increased capital cost and reduced reliability. The EPRI studies concluded that this is unlikely.

U. S. utility experience indicates there is now no statistically significant difference between once through (supercritical) and drum-type (subcritical) unit reliability. Furthermore, we find nothing inherent in the design of supercritical plants which should contribute to lower reliability. The total forced outage hours are about the same for once through and drum units. While, on average, the first large, supercritical power plants achieved poorer availability during the 1960s, the plants built in the 1970s demonstrated results superior to those of drum units. In fact, for plants in the 600- to 825-megawatt-electric range with supercritical pressure and double reheat average availabilities over 80 per cent have been maintained in recent years.

Integrated Environmental Control

Today, environmental regulatory requirements on coal-fired plants involve continuous control of air, water, solid waste, and thermal discharges. This has become a major cost factor in construction and operation, typically 30 to 40 per cent of a coal plant's investment cost. The high-cost, poor reliability, and reduced operational flexibility resulting from the add-on, piecemeal response to these rapidly changing environmental control requirements are changing the historical approach of user, designer, and supplier.

Environmental control in the 1980s has become as much an integral part of the coal-fired power plant system as the boiler or turbine. A design strategy which pursues a more systematic approach to control of all effluent streams may offer capital savings of $100 per kilowatt, increase plant availability by 5 per cent, and improve heat rate by up to 500 kilojoules per kilowatt-hour. These savings occur less from new technology than from assigning single point responsibility for environmental control system design and elevating its engineering priority to a level equivalent with its economic importance.

EPRI's integrated emission control pilot plant (IECPP) at the Arapahoe power station of Public Service Company of Colorado in Denver has the flexibility to test a very wide range of possible equipment configurations. Initially focusing on air, water, and solid waste control technologies, the pilot scale program represents a cost-effective means to obtain critical design and operation information. The overall goal is to produce engineering design guidelines for the selection, configuration, and operation of integrated environmental control equipment under the operating conditions a typical utility might encounter. Emphasis is on the emissions control capability and on the interface among the various components and the power plant to minimize operating, maintenance, and cost requirements.

The IECPP is the first coal-fired pilot system in the United States for investigating different integrated emission control systems and for providing environmental management services to the utility industry. The equipment options provide the unique advantage of sophisticated research flexibility at a size representative of large, commercial installations.

Fluidized Bed Combustion

The electric utility industry also is aggressively evaluating and developing technologies which may ultimately provide less costly and more reliable operation than current pulverized coal systems. These options are intended to carry utility coal utilization beyond the limits inherent in pulverized coal technology. The most important factor in commercial acceptance will be their *demonstrated* capability to be at least as reliable as pulverized coal-fired power plants. Accordingly, priority must be placed on reliability. This requires the construction and operation of large-scale, engineering prototype or pioneer plants over a range of designs and fuels at operating conditions which are representative of the using utility industry.

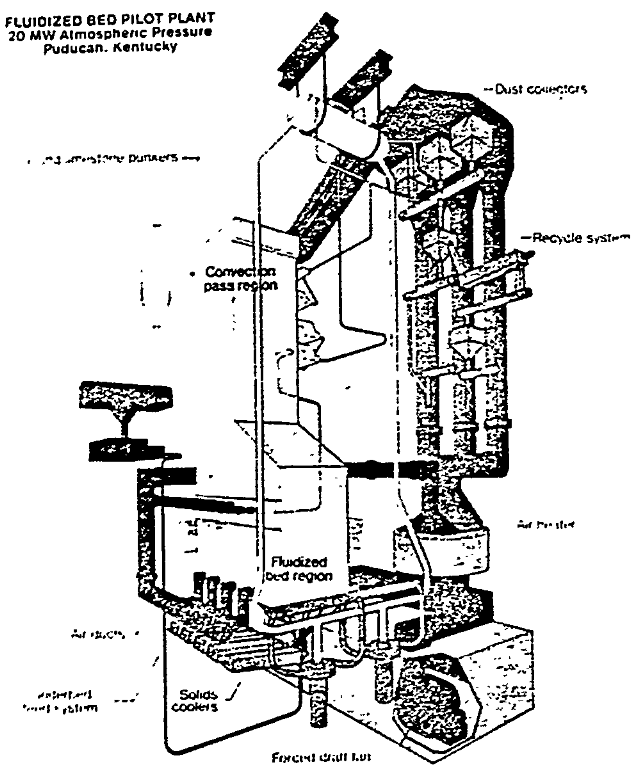
EPRI and the utility industry are accelerating the development and application of fluidized bed combustion as a further *evolutionary* improvement in coal utilization to meet the expanding needs for coal-fired power generation. The improvements which excite this utility interest include reduced sensitivity to fuel quality, thus permitting the use of a much broader fuel supply, from anthracite to municipal refuse, without suffering large losses in efficiency and reliability in a single boiler design. Less cost sensitivity to unit size in a period of load growth and siting restrictions may favor smaller FBC boilers rather than larger pulverized coal furnaces.

A third primary advantage of FBC that may lead to the displacement of pulverized coal boilers is environmental performance. Our experiments with fluidized combustion of coal confirm that it is possible to control sulfur and nitrogen oxides economically without parasitic postcombustion cleanup devices.

Atmospheric Fluidized Bed Combustion

The atmospheric fluidized bed combustion (AFBC) option shows its greatest initial advantage under low-grade or highly variable fuel conditions such as lignite, high-sulfur and high-ash content coal, mine and cleaning plant wastes, and municipal refuse. Since both private and federal projections indicate that a large portion of U. S. coal production growth over the rest of the century and beyond will occur in these low-grade fuels, the AFBC market potential appears substantial. For example, 40 per cent of new utility generating additions during the 1980s will use low-rank coal.

A cost-effective utility scale AFBC design is achievable, and the important hardware questions and alternatives are being resolved. To this end the Tennessee Valley Authority has implemented a 20-megawatt-electric engineering prototype at the Shawnee power station near Paducah, Kentucky. The prototype was built by Babcock and Wilcox. Operation began in May of this year and the EPRI-cosponsored test program will continue through at least 1986. This will provide the basis for 100- to 200-megawatt commercial utility AFBC demonstrations, operational this decade.



The Tennessee Valley Authority's new 20-megawatt atmospheric fluidized bed combustion pilot plant located at Paducah, Kentucky, features a boiler that burns coal and limestone mixed together.

Pressurized Fluid Bed Combustion

The new and dynamic utility climate also influences pressurized fluid bed combustion (PFBC) development goals. The influence arises from the trend toward smaller new unit size and growing utility interest in uprating the capacity of existing units to bring capacity on line at the lowest investment cost. As a result, development emphasis is being placed on turbocharged boilers which can provide shop-fabricated, barge transportable, steam generation modules. These can be rapidly field-erected to provide the desired uprating in unit sizes of 150 to 250 megawatts-electric. This approach will also use coal to replace and increase the capacity of existing oil- or gas-fired plants while minimizing space and environmental control requirements.

The primary physical difference between the turbocharged boiler and the PFBC-combined cycle that has been previously emphasized is the reduction in gas turbine operating temperature. This substantially reduces the development risk and cost, and improves the reliability of the boiler system.

Efforts are now being initiated by EPRI to design engineering prototypes of the turbocharged boiler based on results from operational pilot plants. This approach should permit commercial prototypes to be operational this decade, thus yielding important financial advantages to utilities during the current period of low-load growth and high-construction costs.

Summary

The emphasis in utility coal technology development is on near-term resolution of the reliability, cost, and environmental issues limiting domestic coal utilization. The focus is, therefore, on improvements in conventional pulverized coal power plants and fluidized bed combustion of coal. New apparatus for rapid analysis of coal composition and heat content is being applied to commercial utility installations. Coal quality control has become increasingly important as one element in improving power plant performance and reliability, reducing investment in new capacity, and complying with emission regulations.

EDITOR'S NOTE: *The foregoing article was adapted from a paper presented by the author at the 12th general meeting of the International Electric Research Exchange held earlier this year in San Francisco.*

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EPRI Program on Advanced Pulverized Coal Power Plants

1. Background

Coal-fired, steam-electric power plants currently produce over 50% of the electric power in the United States. Due to the cost and scarcity of oil and the slowdown in growth of nuclear power generation capacity, attention is still being focused on pulverized coal-fired power plants as a major energy resource for the nation's future. The development of conventional coal-fired power plants has been an evolutionary process, and from 1900 until the early 1960s there was a continuous trend toward lower heat rates. For the past twenty years, however, because there was little economic incentive to continue the effort, research and development to increase thermal efficiency has been relatively stagnant. The rapid escalation in fossil fuel costs during the 1970s has changed this view and warranted a re-examination of the potential for improving thermal efficiency.

During recent years, the U. S. utility companies have retreated from purchasing large power plants with high efficiency, supercritical pressure thermal cycles (once-through), and instead have chosen smaller, subcritical pressure plants (drum). In general, the rationale for this trend was based on the perception that drum units are more reliable and cost effective than supercritical units which were introduced in the early 1960s. Since that time, as a result of the natural design maturation process and increased operator experience, once-through units have proved as reliable as drum units. Furthermore, because of their inherent efficiency advantage, they are an economic choice for the industry.

EPRI Engineering Studies

In light of these considerations, EPRI sponsored two independent engineering studies to evaluate the potential for improving the thermal efficiency of coal-fired, steam-electric power plants. The specific objectives of the two teams, each of which comprised a turbine-generator manufacturer, boiler manufacturer, architect-engineer and utility, were to"

- o Assess the technical and economic feasibility of concept to increase thermal efficiency.
- o Identify critical research necessary to commercialize these concepts and maintain or improve plant availability.
- o Develop conceptual designs for "base" (reference case) and "advanced" plants.

- Evaluate the development, construction, and operating costs for the advanced plants as compared to the base plant.

- Assess the reliability of the advanced plant.

These studies have now been completed and have concluded that advanced pulverized coal power plants offer significant economic advantages to the utility industry for new capacity additions. It is also apparent that much of the technology outlined for the advanced plant has application, on a retrofit basis, to existing coal plants.

EPRI Advanced Plant Development, Phase I

It is the intention of EPRI to pursue the development efforts related to advanced plants through a series of tasks designed to bring new innovations into the utility industry. Phase I of this work will cover a detailed planning effort related to the development of advanced steam cycles and equipment improvements and will last 18 months. This Phase will also plan the orderly introduction of retrofittable features into existing fossil plants, so as to capitalize on the advanced plant development work. Phase II represents the development, qualification and testing efforts related to the next generation of supercritical steam plants, particularly covering material considerations at high temperatures. The output from Phase II will include a detailed specification for an advanced coal plant, designed to ~~improve heat~~ rate approximately 10% beyond what is currently available.

The objective of Phase I is to carry out the planning necessary for a major development effort on advanced pulverized coal power plants. It is an additional goal to plan the orderly introduction of advanced features into existing coal-fired plants so as to enhance existing plant heat rate. The R&D necessary to qualify these retrofit features is included in this effort.

The important aspects of the approach to the planned work are:

A. A review and consolidation of past studies in the U. S., Japan, and Europe.

B. A study on the state-of-the-art in high temperature materials.

C. A survey and assessment of existing test facilities, domestic and foreign.

D. An assessment and recommendation of retrofittable features to improve existing plant heat rate, including cost/benefit studies.

E. The development of an implementation plan for existing plant enhancement, including utilities, costs, milestones.

F. Development work related to retrofit application.

APPENDIX B: SITE VISIT REPORTS

ASSESSMENT OF RESEARCH NEEDS FOR COAL UTILIZATION

DOE COAL COMBUSTION AND APPLICATIONS WORKING GROUP
(CCAWG)

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Contract Sponsors: DOE Office of Energy Research and Fossil Energy. DOE Program Managers: Dr. Jorgen Birkeland, Mr. John Kaufmann, Dr. G. Jordy, Dr. R. Roberts. DOE Contract Number: DOE DE-FG03-82FE-60014.

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