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Reintroducing Coal to New England

by

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ABSTRACT

Reintroducing Coal to New England

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The New England region, adversely affected by O.P.E.C. price gouging and natural gas shortages is justifiably seeking alternative energy sources. Reintroduction of coal promises to offer security of supply, favorable economics, and energy independence.

This paper describes coal fired boiler development, dwelling mainly on contemporary methods, and on emerging coal utilization technologies.

Modern boilers for coal firing are of two major types. Smaller boilers with traveling grate stokers are suitable for a wide range of coals. They are economical and practical to operate.

For larger boilers or where efficiency is most important, pulverized coal boilers are available. Pulverized coal boilers are finding increasing usage for industrial applications in addition to the traditional electric utility steam generating plant application.

Sulfur dioxide emission limits, where required, are normally met by wet scrubbing of the flue gas. A new technology being developed right here in New England, referred to as "dry scrubbing", allows dry sulfur containing fly ash removal, a method preferred by many.

Fluidized bed combustion boilers offer a new alternative which can be attractive when high sulfur coal is used as a fuel. In-bed removal of sulfur can be accomplished in this type of boiler, eliminating the need for a flue gas desulfurization system. Development work has progressed sufficiently for commercialization of fluidized bed boilers for industrial applications.

Coal gasification is an old technology that went out of popular use as natural gas was discovered and made available by pipeline transmission. The threat of natural gas curtailment in the future makes coal gasification an attractive option for many process gas requirements. Producer gas can be used as a chemical feedstock or as synthesis gas. Practical low and intermediate BTU coal gasification methods are available for commercialization.

New England industry may be on the threshold of moving forward toward the greater utilization of the country's vast coal resources.

REINTRODUCING COAL TO NEW ENGLAND

INTRODUCTION

It is often helpful before describing equipment and designs currently available in the power industry to attempt to grasp the magnitude of coal utilization as it currently exists in America today.

It requires about 1 lb. of coal to produce 10 lbs. of steam in modern generating plants. In turn, this 10 lbs. of steam can generate 1 kw of electricity.

Forty years ago, electrical generating units in the 50 mw size range were considered large. By today's standards, units ten times larger are only considered average in size (Fig. 1).

A modern 500 mw steam turbine consumes nearly 11 million gallons of water every day. It is a bit difficult to imagine this quantity of water. It would fill a pond 5 acres in area to a depth of almost 7 feet. To supply the heat required, nearly 8,000 tons of coal must be burned every day. The coal is ground to talcum powder fineness in large pulverizers, and is then blown into the boiler furnace where it burns in suspension. It, therefore, requires some 80 carloads of coal every day just to satisfy this one single average sized boiler. This would be enough energy to heat the average New England home for over 500 years.

At today's rate of electricity generation (Fig. 2), we have in operation in America the equivalent of about 250 such plants, consuming the mind-boggling total of approximately 500 million tons of coal per year.

Industrial coal fired boiler applications add about another 40% to that figure.

Obviously, the direct combustion of coal represents the most formidable of its use options today.

COAL BOILER DESIGN

It is fair to ask what is so remarkable about boilers. It certainly doesn't take much know-how to boil water and make steam. Nero demonstrated steam generation for power in Alexandria, Egypt 150 years before Christ.

Coal has been a boiler fuel for a very long time, and for the past 100 years, there have been essentially three basic methods of firing this abundant fuel: by hand, by mechanical stoker, and by pulverization.

The hand firing method is illustrated by this sketch (Fig. 3) of a "modern" 1870 vintage coal fired boiler. Not shown is the teamster who replenished the coal piles after the fireman hand-stoked the furnace. In those days, labor was plentiful, unlicensed, non-union, and inexpensive. The system worked so well, this method of firing stayed with us for quite a while.

Toward the end of the century, when the demand for steam was increasing and labor costs rising, hand firing was replaced with stoker firing. This illustration (Fig. 4) shows an early 1900 boiler design, incorporating a first generation mechanical stoker for feeding coal to a stationary grate below the water vessel. I'm not certain if the mode of dress was typical of boiler operators in those days, or if the sketch was made to show how this "modern" machine, the stoker, had elevated the job of the fireman almost to a white collar status.

As the costs of fuels and operating labor increased and the need to burn coal more efficiently and more automatically became an important factor in our industrial economy, the traveling grate stoker was born. There have evolved many more types of stokers throughout the years, but the traveling grate is the most popular for a wide range of solid fuels and boiler sizes (shown in Fig. 5.)

The third conventional method of firing coal is by pulverizing it to better than talcum powder fineness and burning it in suspension by the use of specially-designed burners. There are many types of coal pulverizers available in today's market (shown in Fig. 6), among them the high speed impact type; the medium speed roll and race types; and the slow speed ball tube mill.

A typical Riley steam generator design incorporating a waterwall furnace and a traveling grate spreader stoker is shown in the next illustration (Fig. 7). This unit was one of several installed recently at an Oklahoma automotive plant. It produces 150,000 lbs. of steam per hour for general plant use. The furnace was designed with ample volume and heating surface to insure complete burn-out of fuel before the combustion gases leave the furnace and to maintain furnace exit gas temperatures below the ash fusion temperature of the coal being fired.

It is a top supported single gas pass design. Single pass means the combustion gases flow directly through and are not sent through a labyrinth path with baffles. The top supported single pass design has the following advantages:

1. Expansion is downward, with the drum remaining in a fixed position to minimize expansion provisions for upstream and downstream piping.

2. Differential expansion between the furnace and the convection section is minimized, resulting in a tighter setting.

3. Refractory work is kept to a minimum and gas flow baffles are eliminated.

4. Building steel and boiler support steel can often be combined, reducing total steel and foundation requirements.

5. With an open furnace design, multiple fuel firing provisions can be accommodated, and adequate space is available for overfire air and flyash reinjection systems.

6. External downcomers improve and maintain circulation.

The boiler section, which is the convection bank of boiler tubes between the drums, is designed to permit combustion gas to flow around the water tubes in a straight pass. This reduces erosion of tubes by dust and ash in the combustion gas to a minimum, and provides optimum heat transfer to the water in the tubes.

The drums are very large in diameter, to insure sufficient water holding capacity and steam release area and to assist in stabilizing water level when boiler load changes to meet varying steam demands in the plant.

This combination of stoker and boiler, together with its accessories, was designed to be energy efficient -- stoker power requirements are low and the total system draft loss and pressure drops in the gas and air circuits are kept at low values to reduce fan power requirements.

Because of the high cost of fuel, very few, if any, medium and large size boilers are sold today without heat recovery equipment. Heat recovery for a stoker fired boiler consists of either an economizer or an airheater, or both. An economizer heats the incoming water with exhaust gases. The preheater heats combustion air with exhaust gases. When the economizer water outlet temperature is at least 50°F. below the boiler drum saturation temperature, and the economizer is designed for about 350°F. exit gas temperature, Riley's choice is to provide an economizer only. Airheaters are not normally used with most stoker fired industrial boilers because of the added horsepower requirements, increased equipment costs, overall space requirements, and the limit on under-grate air temperature. On larger sized stoker fired boilers where size of economizer is limited by elevated feedwater temperatures, it is necessary to provide both an airheater and economizer to produce the most efficient boiler system.

The Oklahoma boiler in this illustration is provided with an economizer only.

The following chart (Table 1) shows the performance data for the stoker fired unit just illustrated. Furnace and grate heat release rates shown here are low and indicate conservative design for high availability and low maintenance. The efficiency shown is the thermal efficiency of the boiler itself, and not plant efficiency.

The next illustration (Fig. 8) shows one of two 180,000 lbs./hr. Riley water wall furnace, pulverized coal fired boilers installed in a Southeast plant of a leading beer brewer. These units utilize high speed impact type pulverizers. They also feature a unique single header hopper design that eliminates the need for an external ash hopper, reduces overall height requirements, and maintains a tight furnace enclosure. The boiler is top supported, and the convection section is a single gas pass design, chosen for the same reasons as stated previously for the stoker fired boiler.

Unlike stoker fired boilers, pulverized coal fired boilers usually include an airheater as a means of heat recovery, because of the pulverizer's requirement for hot primary air for coal drying. The airheater shown in this boiler illustration is the familiar rotating regenerative type, selected in this case for low gas and air side pressure drops resulting in reduced fan power requirements, equipment arrangement considerations, and low maintenance costs. The use of an airheater also permits designing for lower stack temperatures than would be possible with an economizer, because special corrosion resistant metals can be utilized in the airheater cold end sections. This results in gains in overall efficiency.

Table 2 shows the performance data for the pulverized coal fired unit just shown. Here, conservative furnace heat release rates are employed. Thermal efficiency is higher than for the stoker fired unit previously described. This is a normal relationship. Better thermal efficiency is offset somewhat by higher capital costs and higher horsepower requirements for pulverized coal installations.

Having reviewed both stoker firing and pulverized coal firing for boiler service, it is appropriate to examine the advantages and disadvantages of each method.

The next illustration (Fig. 9) lists various items that represent major differences between the two methods.

1. Based on current prices and generally similar equipment, the relative costs to the purchaser of a 200 - 250,000 PPH boiler would be:

Natural gas fired	\$10.00/# of steam
Oil fired	\$12.50/# of steam
Stoker fired coal	\$16.00/# of steam
Pulverized coal fired	\$20.00/# of steam

2. Particulate carryover is substantially less with stoker firing. A well-designed pulverized coal fired unit will have about 75% to 80% of the ash carried through the boiler as flyash, with 45% to 50% of that flyash being under 10 microns in size. A similarly well-designed stoker fired unit will have only about 25% to 30% of the ash carried through the boiler as flyash, much of it over 10 microns in size.

3. In some instances, the use of mechanical dust collectors with stoker firing will satisfy particulate air quality requirements. With pulverized coal firing, electrostatic precipitators on fabric filters are necessary to reduce the heavier concentration of small size flyash to acceptable emission limits. Precipitators and fabric filters have a higher first cost and operating cost than mechanical dust collectors.

4. As a rule, stoker fired boilers require less ground area and building volume than equivalent pulverized coal fired boilers. The furnace volume of the stoker fired boiler is only 2/3 the furnace volume of the pulverized coal fired boiler. The stoker is internal to the unit, whereas the pulverizers must be installed outside the boiler, requiring space not only for the equipment itself, but for fuel transport to the burners. Dust collecting equipment, as previously noted, is normally less sophisticated and smaller for the stoker fired boiler.

5. A stoker fired boiler of about 150,000 PPH size will require about 260 HP total for the feeder drive, grate drive, overfire air fan drive and forced draft fan drive. A 150,000 PPH pulverized coal fired boiler will require about 655 HP for the pulverizer drives, pulverizer feeder drives and forced draft fan drive.

6. Stoker maintenance is considerably less costly and time consuming than pulverizer and burner maintenance. We have no hard figures since most of our customers do not maintain accurate, detailed records of material and labor costs. A ball park estimate of 6 to 8 cents per ton in favor of the stoker may represent a reasonable difference.

7. Pulverizer control and burner management are higher in cost than stoker control. The essential difference is in burner management control; pulverized coal mixed with air is a highly explosive mixture and must be treated like a gaseous fuel requiring the same explosion control. The safety system sequencing and programming is made more complex by the use of multiple burners, pulverizers, and the requirements for scanners to read and discriminate both ignition flames and coal flames.

8. Being more sophisticated, a pulverized coal firing system requires a higher degree of operator skill to achieve optimum performance. However, in plants where operators are already familiar with pulverized coal fired boilers, this difference loses its significance.

   A. As mentioned earlier, it is possible to design for somewhat lower stack temperatures with pulverized coal fired boilers, but the most significant reduction in heat loss that favors the pulverized coal fired boiler is the loss due to unburned combustibles -- it is only about 0.5% with pulverized coal firing as compared to 2.5% or more, depending on coal characteristics, for stoker firing. This difference in efficiency, when converted to fuel savings for the anticipated useful life of the boiler, represents a major item to be considered.

   B. Stokers require more careful attention to coal supply than do pulverizers, and the purchase of suitable coals for stoker use may represent a sizeable increase in dollars per ton or per million BTU over coals for pulverizer use. Pulverizers can handle an extremely wide range of coals and will accept large quantities of fines, so coal sizing is not critical.

   C. Because pulverized coal firing is substantially like gaseous fuel firing, its response to load changes is very rapid. There is equally rapid response to demands for simultaneous changes in pulverizer feeder throughput and pulverizer output. Stokers react well to load change demands, but response time is slower.

   D. Stoker firing requires, as an average, 30% excess air, whereas only 20% is required for pulverized coal firing. Reduced air quantity results in less air and combustion gas flow through the boiler components, and, therefore, smaller comparative horsepower requirements for fans and small ductwork size, all in favor of the pulverized coal fired design.

Next, let us examine what factors must be considered for choosing the best type for a specific application.

The next illustration (Fig. 10) highlights some of the major points that should be taken into consideration.

1. While it is possible to design boilers of just about any capacity for pulverized coal firing, it is generally believed that stoker firing is the economic choice for capacities below 100,000 PPH, particularly where fast load change response is not a requirement. Since pulverizers and pulverized coal burners are not readily available in the small sizes required for low capacity boilers, it is necessary to provide oversized equipment for this duty, which further increases the price spread between pulverized coal and stoker designs, and reduces turndown capability.

2. The largest traveling grate stokers available today are of a size that will satisfy requirements for a boiler of about 450,000 PPH steam capacity. Experience has shown that it is not economical to design boilers around the extremely large grate area required for capacities above that figure.

3. It isn't possible to make such positive statements with regard to boilers in the capacity range between 100,000 PPH and 450,000 PPH. The choice can be made only after very careful analysis of all of the other factors involved for each specific application. We have listed some of the major ones that are involved:

   A. A basic consideration is the initial cost of the entire plant, including all accessory equipment, site preparation, foundations, electrical and mechanical work, buildings and the like. Coal handling and ash handling costs must be considered. Stoker firing is normally less costly than pulverized coal firing.

   B. Operating labor costs may vary, depending on type of equipment selected. More highly skilled labor is usually required for pulverized coal firing.

   C. Pulverized coal firing requires higher total power requirements and maintenance costs.

   D. Fuel costs are of vital importance. Boiler manufacturers will be able to provide comparative efficiency figures for stoker and pulverized coal firing, based on selected coals and boiler operating conditions.

   E. Since stoker firing generally requires a more careful selection of coal, long term availability of the proper fuel must be considered when analyzing the type of unit to purchase.

   F. Turndown capability, plant load swing requirements, and long term projection of average load must be considered.

   G. Pollution control requirements vary from site to site. It is difficult to generalize on the impact of such requirements when comparing stoker and pulverized coal firing. Also, the use of alternate fuels may complicate the picture.

   H. Pulverized coal fired boilers and accessories normally require more space than stoker fired arrangements. Availability of adequate space, therefore, is a consideration.

   I. In some plants, where either stoker or pulverized coal fired boilers are in use, operator familiarity can be a factor.

   J. Very few boilers are designed today to utilize only a single fuel. Availability, type, quantity, and frequency of use of fuels other than coal must be considered to insure that the design selected provides for the optimum use of those fuels and does not preclude such use. The range of fuel types should be practical -- too broad a range will raise equipment selection costs, resulting in higher initial cost.

The large pulverized coal fired utility boiler (Fig. 11) represents the epitome of mechanical equipment system design. Careful matching of tubing alloys from carbon steel through the various grades of chrome molybdenum types and stainless steel to the corrosive and thermal working environment insures cost effective metallurgy is applied to today's boiler designs.

Mechanical configurations optimize contemporary designs to the inorganic coal properties of the specific coal analysis anaticipated. Considerations are made to minimize the adverse effects of slagging, fouling, and erosion.

Utility boilers designed for many shutdowns and startups annually include drainable superheaters and sophisticated control systems, aimed at reducing boiler load transient times.

Inefficient means of maintaining superheat and reheat temperatures through wider turndown such as increased excess air have given way to multiple pass convection sections (Fig. 12) with damper control of flue gas proportions and increased radiant superheat surface.

Furnace implosions due to the high negative suction development capabilities of induced draft fans designed for sulfur dioxide scrubbing equipment have led to new code requirements governing furnace design and control systems (NFPA-85G).

Present day value evaluation factors for demand and energy requirements of power plant auxiliary equipment often exceeds $3,000 per Kilowatt, forcing boiler manufacturers to devise novel system designs which are energy efficient.

Current awareness of operating cost dollars has led the industry to also demand lower maintenance costs of power plant equipment. Pulverizer maintenance costs have sky-rocketed in recent years. This is partly due to the continual degradation of available coal stocks for utility use, but also due to the increased use of huge pulverizers which add disproportionately to maintenance labor requirements. Typically, vertical spindle and high speed pulverizers cost an average of 31 cents per ton of coal processed. For a 500 mw boiler, the mill maintenance cost exceeds $750,000 per year. Thus, mill maintenance costs far exceed mill power difference evaluations.

Systems which were once designed with primary air fans downstream of the airheater are giving way to "cold side" fans located upstream of the airheater. This saves horsepower, and increases fan useful wear life.

A recent industry demand to lower ignition oil use has resulted in the design of burners with more turndown capability and pulverized coal fired ignition and stabilization equipment. Cold boiler warm-ups utilizing pulverized coal are being achieved with encouraging success (Fig. 13).

Shop Assembled Modular Boilers

Shipping clearance restrictions in many New England communities poses a serious problem to the manufacturer of "package" type boilers. The added size constraints of solid fuel fired boilers further complicates the issue.

Riley took the best features of the package boiler, teamed them with a spreader stoker and came up with the Shop Assembled Modular Boiler. The result is a unique coal-fired "packaged modular" design available in twelve incremental sizes from 40,000 to 150,000 pounds of steam per hour. Pressures up to 1650 psig design are available (Fig. 14).

The basic "building blocks" are the boiler bank section, the superheater, the furnace section and the stoker. While the modular approach to boiler fabrication is relatively new, the Shop Assembled Modular Boiler actually is a re-arrangement of time-proven concepts. It has a maximum of shop-assembled components so field erection time is held to a minimum. There are no heat transfer unknowns. Each module has been specifically designed for rail shipment clearance capability to any New England location.

Shop assembly is less expensive and allows close quality control. Modules fit together better and quicker, requiring fewer manhours of field labor. This adds up to cost savings, making the Riley Shop Assembled Modular Boiler the first choice for coal-fired industrial requirements. Such boilers are available in pulverized coal, fluidized bed, and overfeed coal configurations, as well as spreader stoker.

In summarizing the coal fired boiler state of the art, relative to what might be considered emerging coal use technologies, it might simply be said it is fully developed with its novelties being in the optimization of system design areas.

ENVIRONMENTAL ASPECTS

Current federal new source performance standards applicable to industrial boilers cover units of 250,000,000 Btu/Hr. or above. This is about 220,000 PPH. These standards are:

Particulate .... 0.1 lbs./10^6 Btu
SO_2 .... 1.2 lbs./10^6 Btu
NO_x .... 0.7 lbs./10^6 Btu

Proposed new legislation could lower these figures to:

Particulate .... .03 to .05 lbs./10^6 Btu
SO_2 .... 1.2 lbs./10^6 Btu & 90% Reduction
NO_x .... .3 to .6 lbs./10^6 Btu

Ref: Impact Analysis of Selected Control Levels for New Industrial Boilers, EPA, June, 1980.

While stoker fired units firing coal with sulfur less than 0.8% can usually meet the current requirements with mechanical dust collection only, the proposed standards would require the use of electrostatic precipitators or baghouses, undeveloped stoker and pulverized coal combustion processes, and some form of sulfur dioxide removal equipment.

Although expensive and bulky, properly-designed electrostatic precipitators are capable of removing in excess of 99% of the particulate matter attendant with coal burning (Fig. 15).

Baghouses are fast becoming very popular, particularly in the industrial coal fired boiler market (Fig. 16). They are capable of extremely high efficiencies, require less space, and are cost competitive with precipitators.

Many manufacturers offer a variety of mechanical wet scrubbing devices for SO_2 removal. All require some form of alkali additive to react with the gaseous SO_2 and precipitate a disposable or reclaimable solid waste product. Fig. 17 shows one such wet scrubbing system applied to a 400 mw Illinois utility steam generator. The specific alkali utilized generally is dictated by corporate economics. Typically, utilities and large industrial users with adequate capital and space to invest in the larger and more costly scrubbers opt for additives such as limestone to keep operating costs down.

Smaller industries who are not in a position to invest large sums of capital in equipment usually choose smaller equipment and more expensive reactants, such as lime or sodium to achieve the requirement SO_2 removal efficiencies.

Flash dry absorbent spray towers such as that depicted in Fig. 18 find favor with those who would rather dispose of a dry, solid baghouse catch than deal with a wet sludge disposal concern.

Current research to evaluate the combined removal effect of introducing alkali into the furnace firing zone and entail end flash dry spray towers looks promising. Since spray towers alone do not appear to be capable of the high sulfur removal efficiencies mandated by the proposed federal legislation, such combined removal efforts must prove themselves successful for such an approach to be viable.

Solvent refining of coal has been proven to be technically feasible and may, in the long run, become a viable method of controlling pollutants. Economics may prove to be too high a hurdle for this approach for the immediate future.

Fig. 19 shows one popular current method of controlling the generation of oxides of nitrogen. It has been known for some time that this pollutant is formed by two phenomenon:

1. The thermal dissociation and recombination of nitrogen and oxygen diatomic molecules into NO (Thermal NO_x).

2. The release of nitrogen atoms from hetrocyclic hydrocarbon rings during the combustion process, and subsequent reformation with oxygen atoms to form NO (Fuel NO_x).

The staging of the combustion process results in initial combustion in a deficiency of oxygen. The intent is to force the freed nitrogen atoms to recombine with themselves to form molecular nitrogen (N_2).

It has been found that substoichiometric combustion is required to minimize initial NO formation. Since substoichiometric combustion results in incomplete combustion (by definition), additional or staged air must be introduced into the furnace to complete the combustion of the CO and gaseous hydrocarbons formed below. Care must be exercised in the placement of the staged air admission ports. If located too far from the initial combustion zone, insufficient heat may be available to complete combustion. On the other hand, if located too near the initial combustion zone, insufficient residence time for molecular nitrogen reformation may result, and unacceptable levels of NO may be generated at the staged level.

Low excess air combustion and burners which produce staged flame patterns have proven effective in reducing NO_x levels relative to uncontrolled levels. While these measures are generally adequate for meeting the current emission standard, it is doubtful that they will meet new tighter limits. For this reason, burner research continues today, aimed at developing more effective NO_x control methods.

In summary, coal fired steam boiler plant (Fig. 20) designs are available which enable the user to optimize cost and performance within air quality standard limits. The technology is developed and reasonably proven, and failure risk is low. Federal, state, and local environmental requirements in effect now and anticipated for the future are important factors in coal fired power plant sizing and design. Relative to emerging coal use technologies, the direct coal combustion approach represents what might be called the "base" of current technology to which all others must be compared, and with which they must be evaluated.

THE FLUIDIZED BED COMBUSTION PROCESS

Atmospheric pressure fluidized bed combustion (AFBC)(Fig. 21) widely hailed as an advanced technique, is ready for adoption by industry now. Fluidized bed combustion allows a wide range of fuels, including high ash, high sulfur coals, to be burned efficiently in an environmentally acceptable manner. Regulatory emission standards can be met without the need for stack gas scrubbing systems. Both are important advantages of the AFBC process.

THE PROCESS (Fig. 22)

A heated bed of thermally inert material, such as ash, limestone or sand, is fluidized by an air stream. Crushed fuel injected into this turbulent and suspended bed material is burned with the fluidizing air at high combustion efficiency. The fuel content of an operating fluidized bed is very small; when burning coal, the carbon content of the bed is typically 0.5%.

Steam generating or superheat surface immersed in the bed maintains bed temperature at approximately 1550°F. The hot gases leaving the bed are cooled by conventional water tube boiler surfaces. Well developed and demonstrated control systems provide good load-following characteristics.

OPERATING RANGE

Following extensive pilot and demonstration plant experience, AFBC boilers and boiler plants are now available (Fig. 23) for reliable and guaranteed operation for steam outputs of 50,000 to 500,000 lbs./hr. at steam conditions up to 1000°F. and 1600 psig when firing with coal of any grade. Heavy fuel oil, low calorific value gases, wood or refuse are among low grade fuels which can be fired as supplementary fuels.

Thermal efficiency, capital investment requirements, operability and reliability compare favorably with equivalent conventional steam generating systems.

COAL GASIFICATION

The need for alternate sources of fuel gases for industry has prompted a re-examination of the proven coal gasification process. Low-Btu gas can be substituted for natural gas in many industrial applications with only slight burner modifications. Gasifiers have had long and successful use in the steel, glass, chemical, refractory, ceramic, lime and cement industries. Today, uninterruptible on-site gas production is again coming into its own as natural gas supplies become expensive or scarce and industry faces cut-backs in its supply.

The first cylindrical gas producer used in the United States was built about 1880 by Charles Morgan in Worcester, Massachusetts. By 1941, when the need for manufactured gas diminished, his Morgan Construction Company had built and installed more than 9,000 gas producers throughout the world.

Riley Stoker Corporation, a leading manufacturer of steam generating and fuel burning equipment for utilities and industry, obtained the exclusive manufacturing rights to the Morgan Gas Producer and has completed an extensive program to redesign it to comply with modern safety and environmental standards (Fig. 24).

Fig. 25 describes the construction and operating features of the Riley gasifier. A refractory-lined cylinder and ash pan slowly revolve in a water seal, while the top remains stationary. Coal feeds at the top through a lock-purge hopper, which allows flow of fuel into the gasifier against system pressure without a migration of gas into the coal storage area.

Coal passes through a metering feeder and then across the radius of the revolving bed, providing uniform fuel distribution. Pivoting agitator arms, counter-balanced to achieve the proper depth of agitation, act to prevent large agglomerates and open channels from forming in the fuel bed.

Air and steam are distributed across the bottom of the bed by a blast hood. Gas leaves from an opening in the fixed cover of the gasifier. To remove ash, the plow, which normally rotates with the ash pan, is held stationary for a complete revolution. The ash rides up and over the plow to an ash removal system.

The Riley Gasifier is the product of five years of design improvements on this reliable unit at Riley's own Research and Development Center. Fuels ranging from sized anthracite to sized and run-of-mine coals having free-swelling indexes up to 8.5 have been studied on both a two-foot diameter process development unit and a 10½ foot diameter demonstration plant.

COALS TESTED AT RILEY STOKER GASIFICATION TEST FACILITY

Coal	Rank	Nominal Size	Free Swelling Index	Ash Fusion Temperature °F (Fluid-Reducing)
COALS TESTED IN 2-FOOT DIAMETER PROCESS DEVELOPMENT UNIT				
Anthracite, Pa.	AN	Pea	0	2700
Pocahontas Seam, Va.	LVB	3/4" x 1/2"	3	2700
Sewell Seam, W. Va.	HVAB	2" x 3/4"	8	2700
Egypt Valley, Ohio	HVCB	2" x 1/4"	4	2290
Illinois No. 6	HVCB	BRIQ	2.5	2160
Northern Plains	Lignite	2" x 3/4" 2" x 1/2" 2" x 1/4" ROM BRIQ	0	2100
COALS TESTED IN RILEY DEMONSTRATION PLANT				
Anthracite, Pa.	AN	Nut & Pea	0	2700
Upper Banner Seam, Va.	HVAB	1-1/4" x 1/4"	6	2630
Coronet No. 2, Va.	MVB	2-1/2" x 1"	8.5	2560
Hazzard No. 4, Ky.	HVAB	2-1/2" x 1"	4.5	2700
Elkhorn No. 3, Ky.	HVAB	2" x 1-1/2"	4.5	2660
Northern Plains	Lignite	2" x 1/2"	0	2050

Outputs from the Riley Gasifier for the above fuels have ranged from 30 to 70 million Btu per hour. Capacities for specific fuels may be obtained upon request.

CONCLUSION

The Federal Government already has legislation in place which allows for accelerated depreciation and tax credits for companies who convert to coal (H.R.8269). This year, Congress is expected to introduce a new bill which will extend these incentives even further (S-207).

The State of Massachusetts has enacted legislation to enable small municipals and utilities to finance the purchase of coal burning equipment which replaces oil and gas burning equipment. This law allows two-thirds of the fuel cost savings to be used to pay for the coal burning equipment.

Perhaps now is the right time for power engineers and New England Industries to get serious about re-introducing coal to our region.

ABOUT THE AUTHOR

RICHARD S. SADOWSKI

Currently serving as Industrial Sales Manager for Riley Stoker Corporation, Dick's career has spanned flue gas desulfurization to fuel burning engineering.

A 1968 graduate of Worcester Polytechnic Institute, having earned a BSME, he also graduated from its School of Industrial Management Program in 1977.

As an active A.S.M.E. member, Dick most recently served as Session Chairman for the last Fuels Division Session at the Industrial Power Conference in October.

Dick has considerable fuel burning experience, having served as an applications engineer for fuel burning systems some ten years ago. He spent seven years heading that same department prior to his current position.

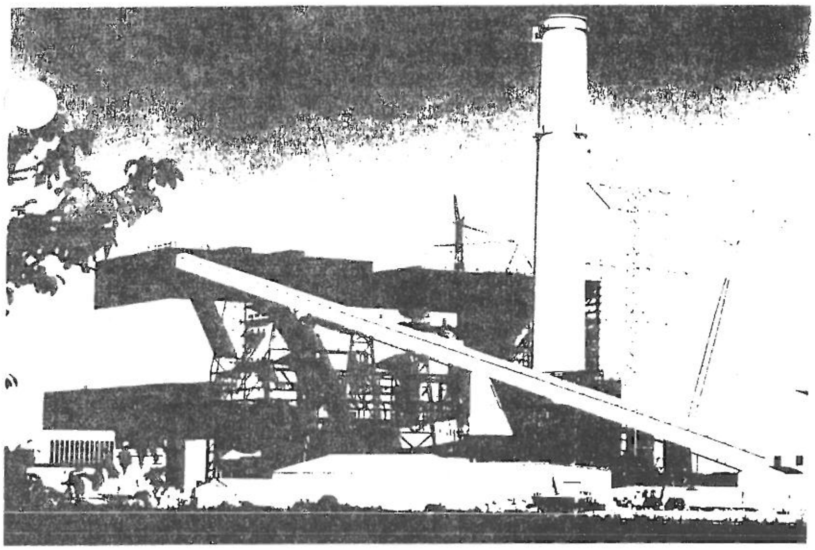


Fig. 1

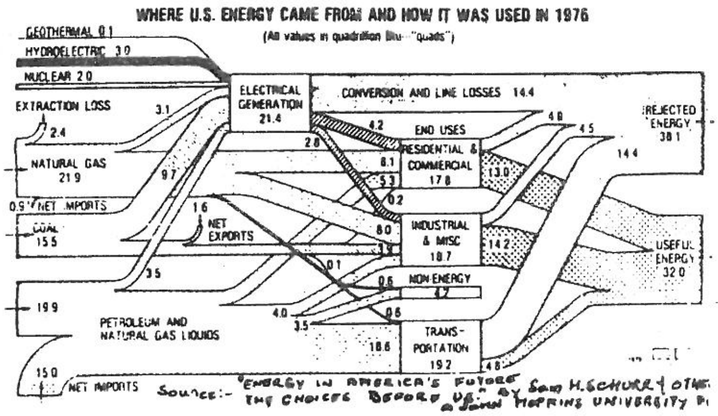
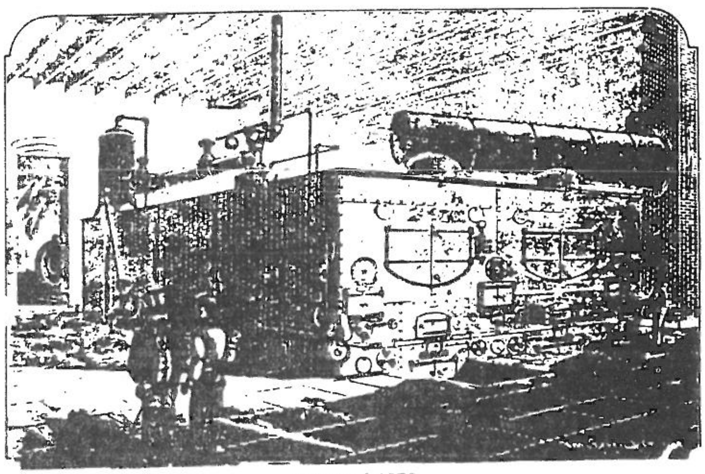
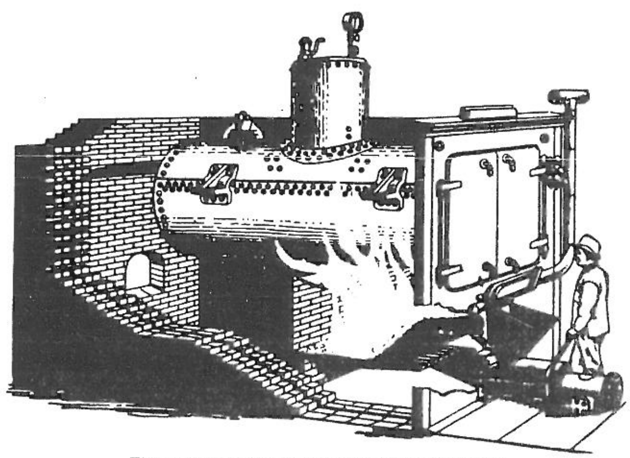


Fig. 2



Boiler of 1870

Fig. 3



The latest word in boilers seventy years ago

Fig. 4

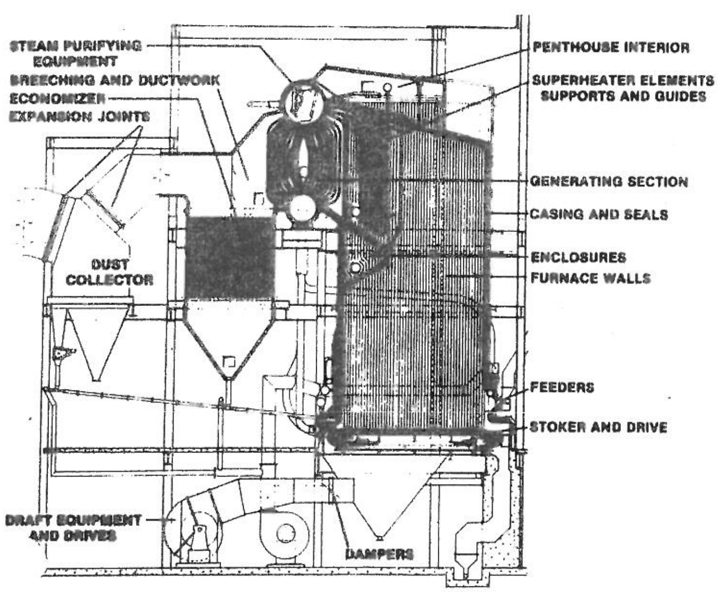
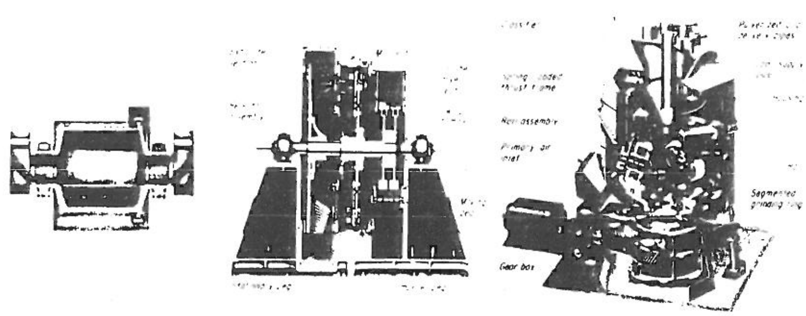


Fig. 5



Three common types of coal pulverizers

Fig. 6

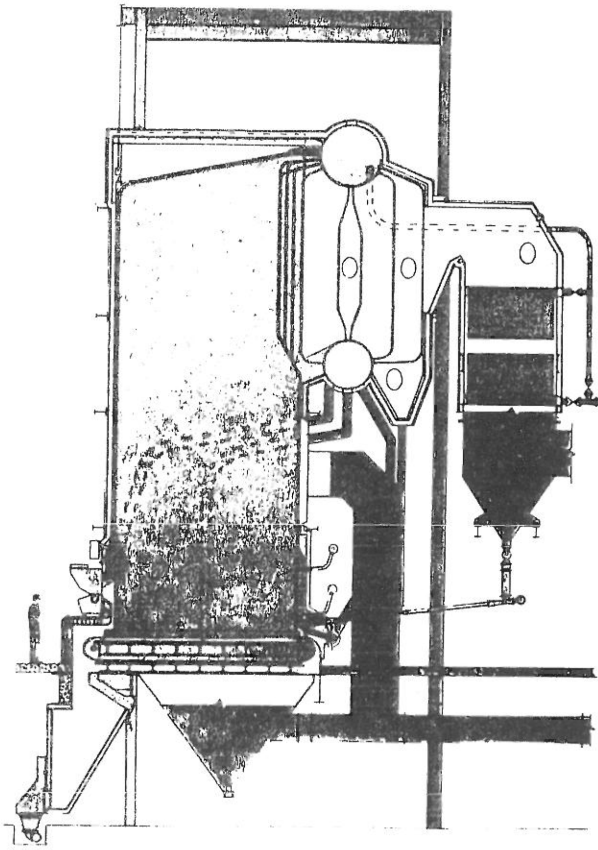


Fig. 7

PREDICTED PERFORMANCE DATA

One steam generating unit, 150,000 pounds of steam per hour maximum continuous capacity; 260 psig operating pressure; 260° F feedwater; saturated steam temperature.

Pounds of steam per hour actual evaporation	50,000	100,000	150,000
Operating pressure psig	260	260	260
Heat release in furnace Btu / cubic feet / hour	5,633	11,469	17,614
Heat release in furnace Btu / cubic feet / hour	22,546	45,906	70,500
Grate heat release Btu / square foot	219,995	447,928	653,537
Overall unit efficiency %	83.81	82.32	80.40

Table I

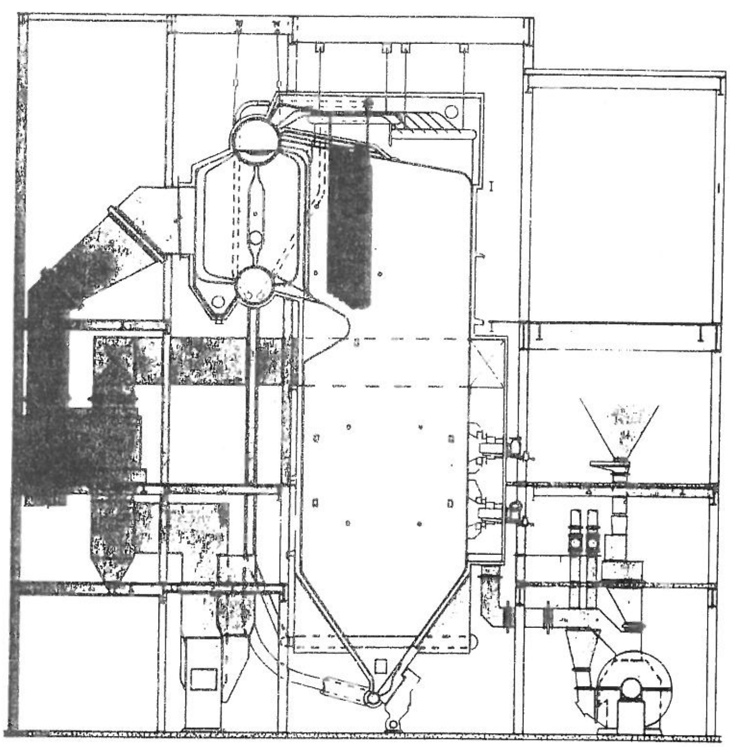


Fig. 8

PREDICTED PERFORMANCE DATA

One steam generating unit, 180,000 pounds of steam per hour maximum continuous capacity; 635 psig operating pressure; 259° F feedwater; steam temperature 750° F.

Pounds of steam per hour actual evaporation	35,000	100,000	180,000
Heat release in furnace Btu / cubic feet / hour	3,841	11,483	20,940
Overall unit efficiency %	88.55	88.48	87.14

Table 2

STOKER FIRED UNITS COMPARISON
VERSUS PULVERIZED COAL FIRED UNITS

Advantages:

1. Lower cost
2. Lower particulate carryover with a larger percent of particles greater than 10 microns
3. Simplified particulate removal equipment
4. Less overall space generally required
5. Lower horsepower requirements
6. Lower maintenance and wear
7. Less sophisticated auxiliary equipment and controls
8. Less skilled labor required

Disadvantages:

A. Efficiency 4 to 7% lower
B. Limited coal size flexibility
C. Limited load swing and pickup capability
D. Higher excess air

Fig. 9

POINTS TO CONSIDER IN SELECTING STOKER OR PULVERIZED COAL FIRING FOR A SPECIFIC APPLICATION

1. Stoker firing usually best choice for boilers 100,000 pph and less
2. Pulverized coal firing only choice for boilers above 450,000 pph
3. Between 100,000 and 450,000 pph:
   - (a) Installed cost of total plant
   - (b) Operating labor costs
   - (c) Operating power and maintenance costs
   - (d) Efficiency (fuel cost)
   - (e) Long term availability of suitable coal
   - (f) Plant load factors
   - (g) Pollution control requirements
   - (h) Space requirements
   - (i) Operator familiarity with similar boilers
   - (j) Alternate fuels

Fig. 10

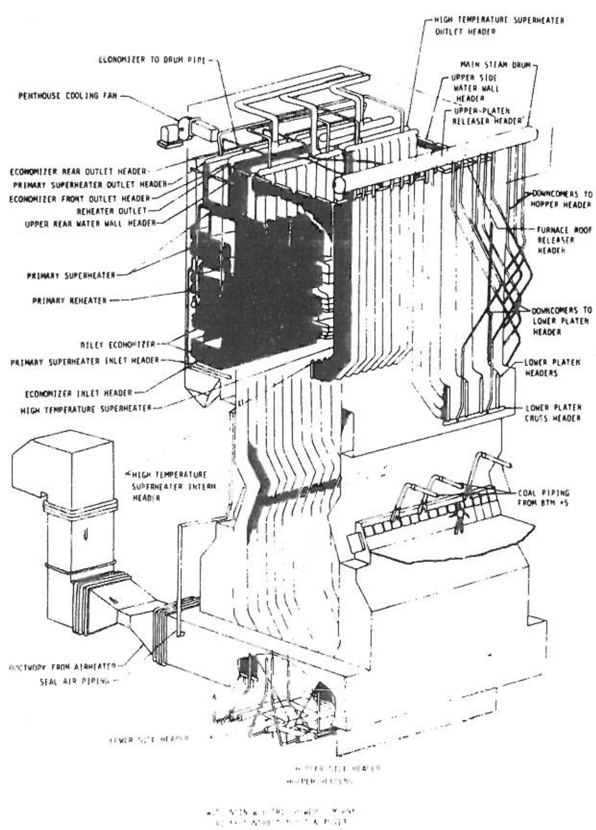


Fig. 11

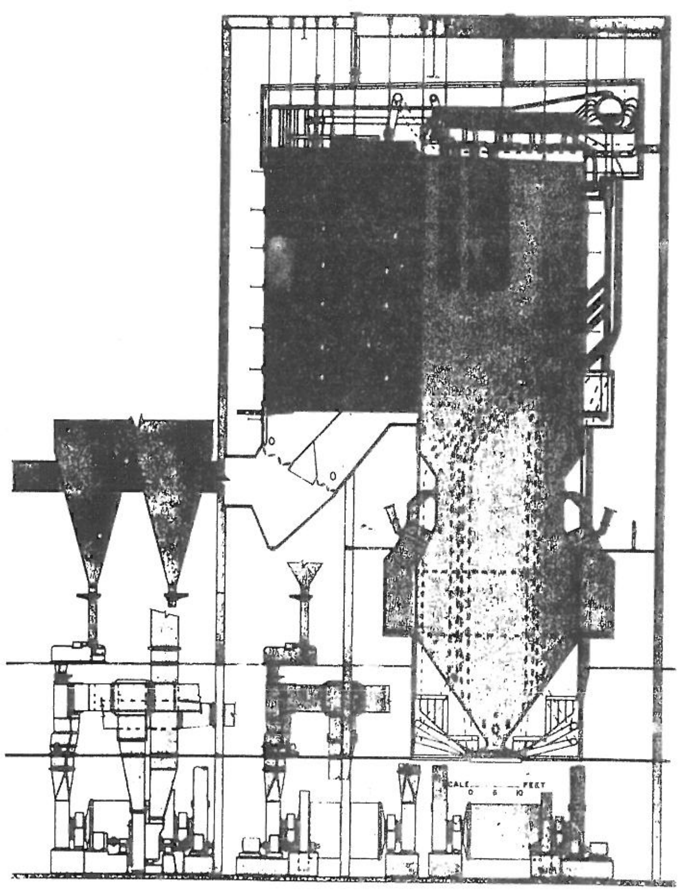


Fig. 12

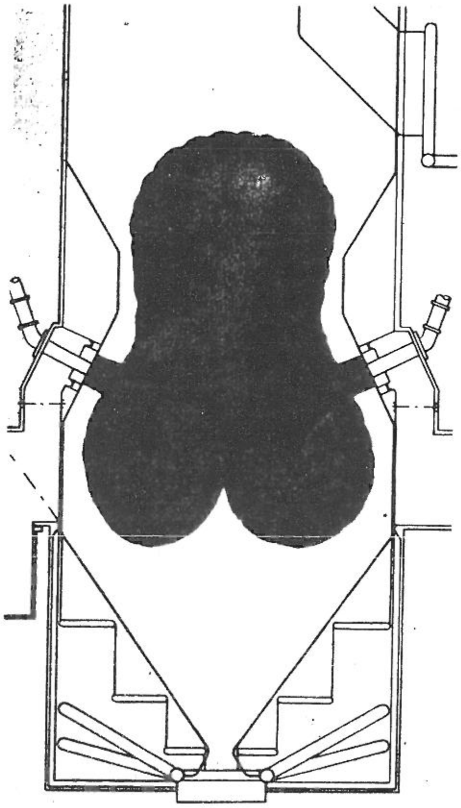
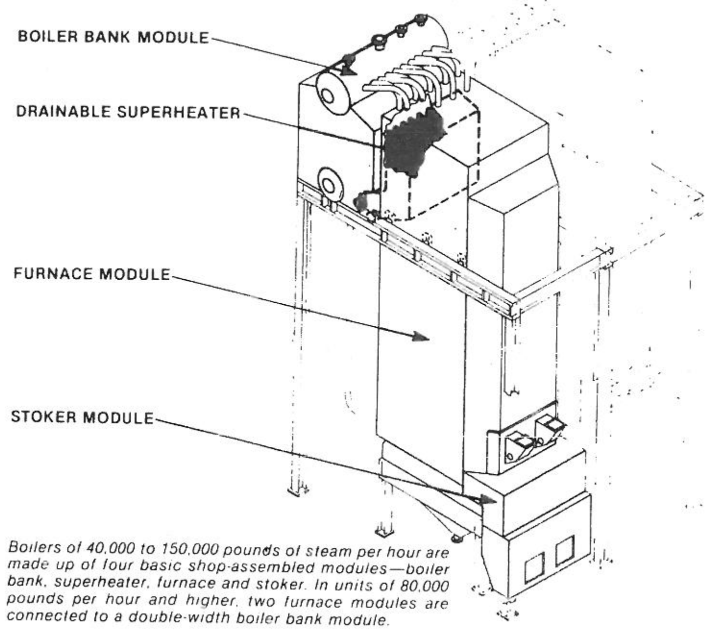


Fig. 13



Boilers of 40,000 to 150,000 pounds of steam per hour are made up of four basic shop-assembled modules—boiler bank, superheater, furnace and stoker. In units of 80,000 pounds per hour and higher, two furnace modules are connected to a double-width boiler bank module.

Fig. 14

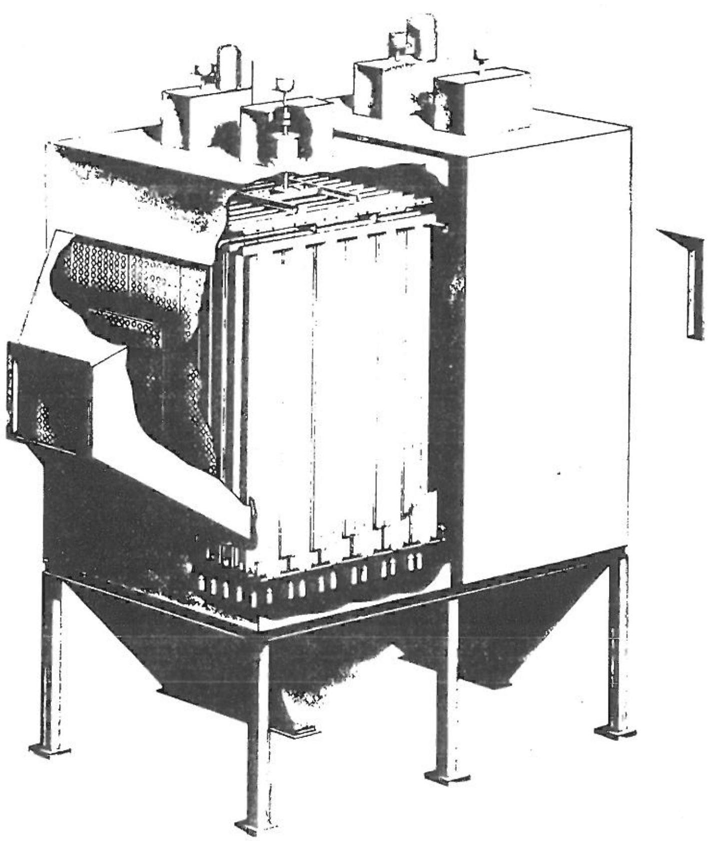


Fig. 15

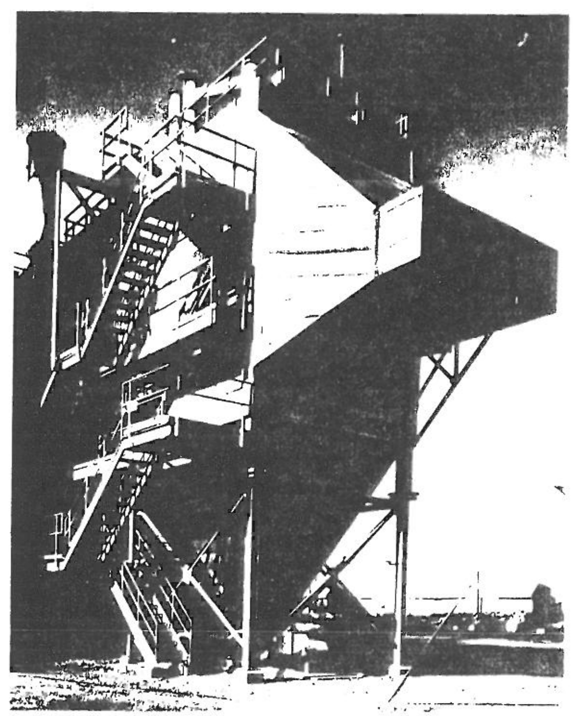


Fig. 16

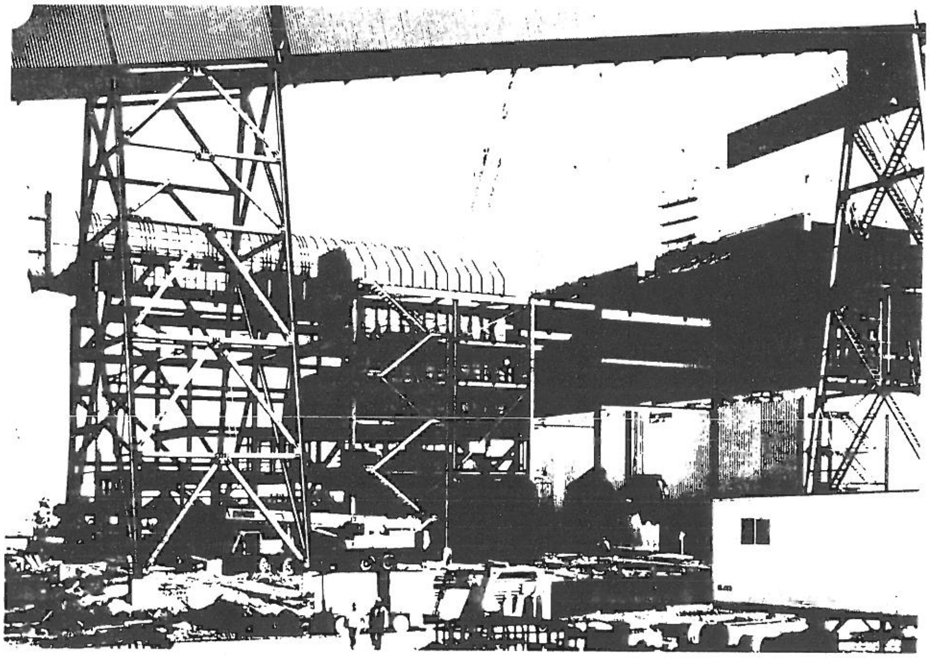


Fig. 17

Fig. 18

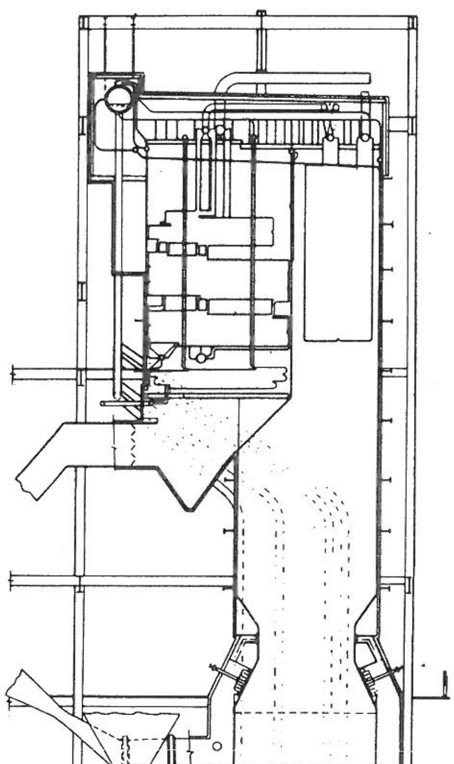


Fig. 19

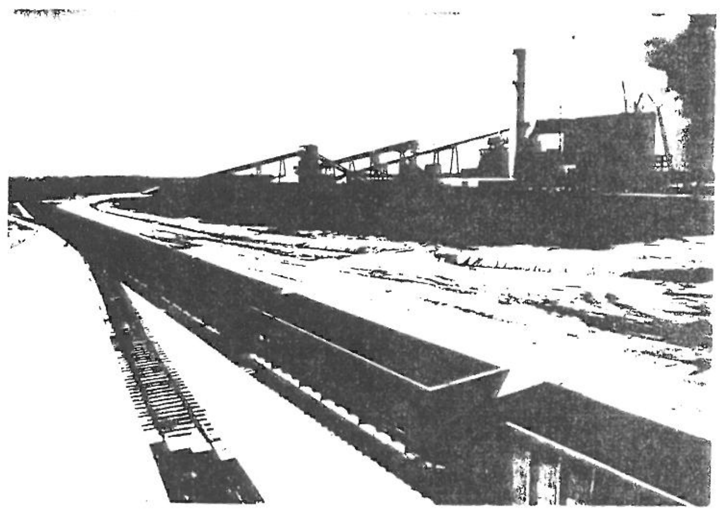


Fig. 20

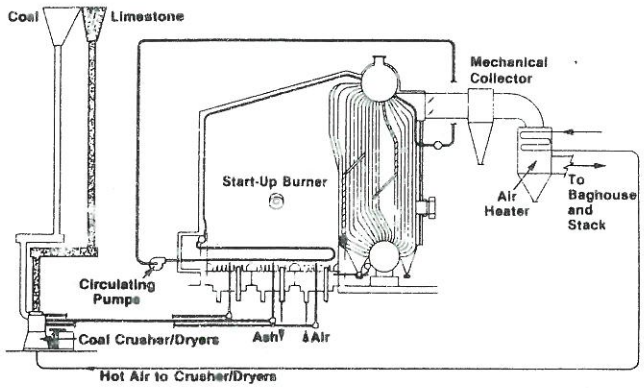


Fig. 21

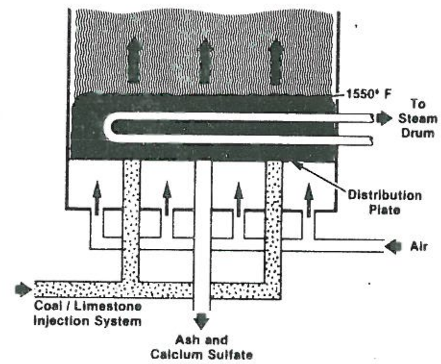


Fig. 22

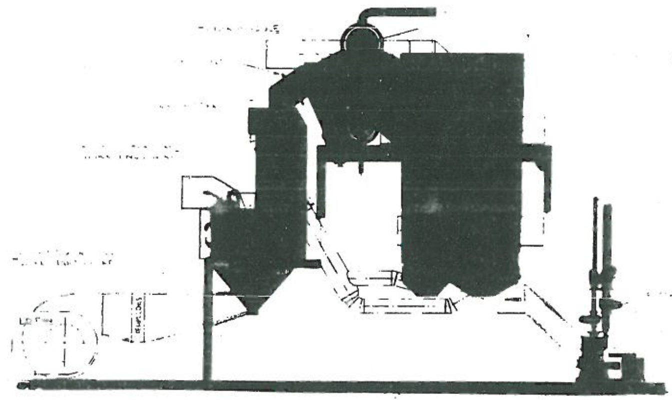


Fig. 23

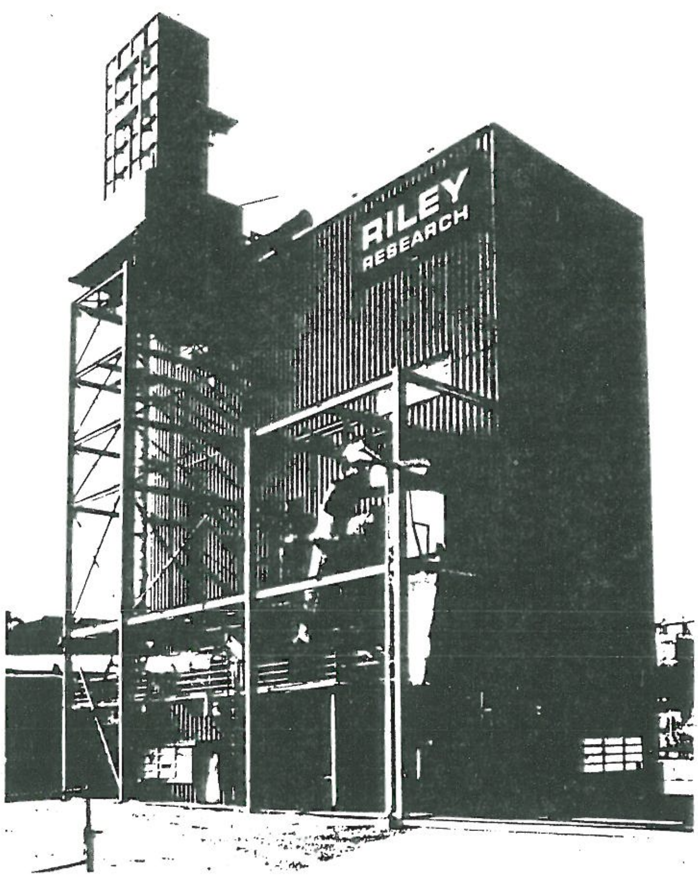
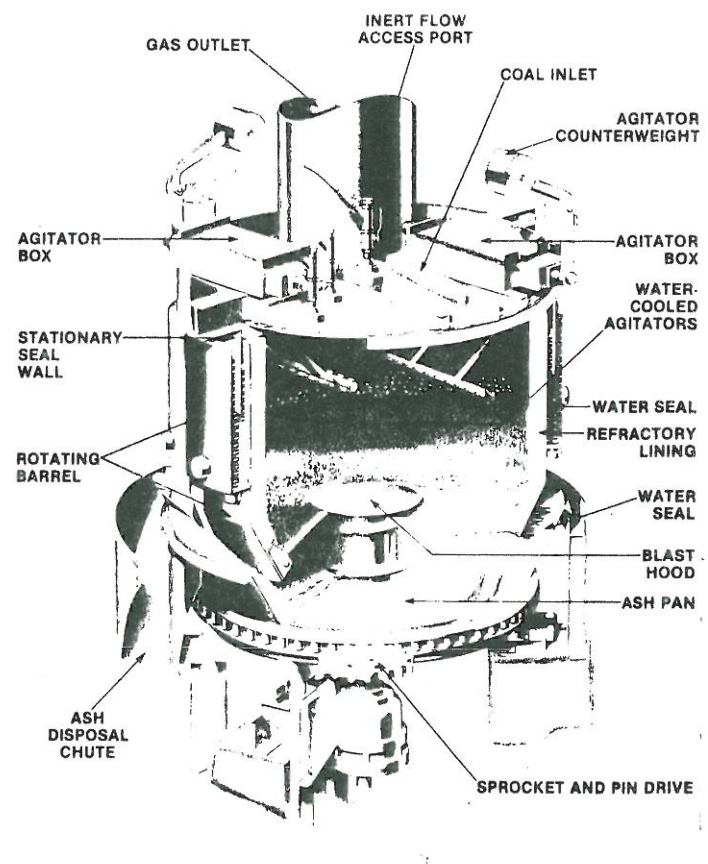


Fig. 24



The Riley Gasifier

Fig. 25