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INTRODUCTION

Ever tightening environmental regulations have changed the way utility and non-utility electric generation providers currently view their fuels choices. While coal is still, by far, the major fuel utilized in power production, the general trend over the past 20 years has been to switch to low-sulfur coal and/or make costly modifications to existing coal-fired facilities to reach environmental compliance. Unfortunately, this approach has led to fragmented solutions to balance our energy and environmental needs. All too often, consideration is given merely to meeting the minimum requirements of environmental regulations. Talented scientists and technicians have been able to dissect any particular problem leading to individual "black boxes" for each particular pollution emission level requirement. Coal-fired power plants have, hence, become a series of mechanical devices. Each device has a very specific purpose, each has its own set of integration associated costs, but each is individually the low-cost temporary solution to a current or new emissions requirement. Periodically, the environmental ratchet again tightens, instigating a whole new round of additional piecemeal pollution control solutions.

In keeping with the theme of this meeting, integrated environmental control (IEC) is seen as a potential solution to the aforementioned, sometimes "penny wise and pound foolish," mentality.

A prime example of a potential industry where IEC makes sense for development is coal gasification technology. Coal has been successfully gasified by a whole host of utility industry equipment suppliers since early in this century. So gasification technology is not the problem. Cost-effective integration of it into an existing power generation infrastructure with its indigenous, justifiably conservative, technological viewpoint is really the issue. To date, few integrated gasification combined-cycle (IGCC) suppliers have been able to compete with the cost of other more conventional technologies or fuels. One need only look at the complexity of many IGCC approaches to understand that unless a view toward IEC is adopted, the widespread application of such otherwise potentially attractive technologies will be unlikely in our lifetime.

Jacobs-Sirrine Engineers and Riley Stoker Corporation are working in partnership with the Department of Energy's Morgantown Energy Technology Center to help demonstrate an innovative coal gasification technology called "PyGas™," for "pyrolysis-gasification" (Figure 1). This hybrid variation of fluidized-bed and fixed-bed gasification technologies is being developed with the goal to efficiently produce clean gas at costs competitive with more conventional systems by incorporating many of the principles of IEC within the confines of a single-gasifier vessel.

Our project is currently in the detailed design stage of a 4 ton-per-hour gasification facility to be built at the Fort Martin Station of Allegheny Power Services. By locating the test facility at an existing coal-fired plant, much of the facility infrastructure can be utilized saving significant costs. Successful demonstration of this technology at this new facility is a prerequisite to its commercialization.

INTEGRATED GASIFICATION COMBINED CYCLE CONCEPT

It is well recognized that the most efficient combined-cycle power plants fire fuel gas in a gas turbine (Brayton thermodynamic cycle) and recover exhaust gas waste heat in an unfired heat recovery steam generator (HRSG) to drive a conventional steam power system (Rankine thermodynamic cycle). However, it is often overlooked that very high efficiency gains, attributable to dual-fired (fully fired) combined-cycle plants, can be in the 20 to 25 percent range. The unfired combined cycle maximizes efficiency by minimizing the proportion of the Rankine cycle by minimizing the condenser heat loss. The dual-fired combined cycle maximizes efficiency by minimizing overall excess oxygen and by maximizing the Rankine cycle operating pressure and temperature.

Economies of scale of coal-fired power plants favor large utility applications. To be cost effective for industrial power use, the standardized IGCC gasifier module must be compatible with shop fabrication, redundant module sizing, and simplified field installation requirements.

Recognizing that cost would be the single most relevant barrier to both utility and industrial application of IGCC's, it was decided to simplify the cycle and subsystems to the limits of practicality. The criteria used to evaluate IGCC's for utility and industrial power application were as follows:

- Operates as an air-blown gasifier.
- Operates with run-of-mine coal.
- Operates at high pressure (400 lb/in^2 (psi)).
- Exceeds 40 percent cycle efficiency in new applications.
- Maximizes Brayton cycle sensible heat.

In addition to efficiency and cost considerations, efforts were undertaken to integrate as many known environmental control processes as possible into a single-pressure vessel. Specific technological solutions for each particular pollutant are often dealt with individually and are seemingly integrated piecemeal. Examples include low-nitorgen oxide (NO_X) burners, catalytic NO_X reduction systems, wet scrubbers, electrostatic precipitators, and sometimes baghouses, all in series. PyGas™ has integrated many environmental control strategies, forming a coal gasification process with potential operational and emissions reduction benefits.

BASIC GASIFIER TRAITS

The first stage in the PyGas™ gasifier is to de-cake eastern bituminous coals within a fluidized-bed pyrolyzer. This process overcomes the capacity reductions and operational difficulties commonly associated with agglomerating tendencies of caking coals in conventional fixed-bed gasifiers.

It is now apparent that even highly caking coals can be rendered noncaking in such a pyrolyzer[1,2]. This stage also offers the additional benefit of tar destruction due to a combination of residence time, elevated temperatures, and steam injection.

Once rendered noncaking, the coal char overflows the pyrolyzer tube and falls onto a fixed-bed below. As is commonly done in fixed-bed gasifier applications using low-swelling coals, coke, and char; gasification is achieved by introducing air and steam via a rotating grate. Bottom ash carbon content can thus be controlled to the low levels acceptable to industry and the environment.

In this hybrid dual-stage gasifier, virtually all of the hydrogen and carbon in the coal is converted into fuel gas, which can then be combusted in highly efficient gas turbines or conventional boilers arranged in a combined-cycle configuration.

In Situ Sulfur Removal

The fluidized bed processing of coals having 3 to 5 percent sulfur content in the presence of limestone and dolomite has demonstrated capture of 88 to 95 percent of all sulfur released[1,2]. Much of the captured sulfur is in the form of calcium sulfide (CaS). Retention of sulfur in this form has proven much more difficult within fixed-bed processes, probably due to the release of sulfur dioxide at elevated temperatures. Studies on the oxidation of CaS by Lynch and Elliot[3,4] and Tones-Ordannes[5] demonstrate that at high temperatures (greater than 2,500 °F), complete oxidation occurs releasing sulfur dioxide (SO_2) and producing calcium oxide (CaO). At temperatures below 2,000 °F, sulfate was produced in small amounts. In the intermediate range (2,100 to 2,300 °F), the conversion of CaS oscillated rapidly between the formation of the oxide and the sulfate. Rehmat[6] conducted a study of these reactions for dolomite and limestone over the range of 1,500 to 1,900 °F and up to 400 psi. Greater levels of sulfation were reported for dolomite (83 to 100 percent) than for limestones (18 to 34 percent). Fixed-bed combustion process in the PyGas™ process will be carefully controlled as a test objective to minimize sulfur release, and substantial sulfur retention is anticipated within the PyGas™ process.

Control of Fuel Nitrogen Release

The volatile fraction of coal-bound nitrogen is known to be released as hydrogen cyanide and ammonia in coal gasification processes[7]. Control of the amounts of these compounds which are formed will be attempted by the utilization of controlled combustion within the gasifier vessel and this investigation will be a test objective. It is known that elevated temperatures reduce these species[8]. The extent of molecular nitrogen formation from fuel-bound nitrogen must be weighed against the inherent inefficiencies brought about by adding air to the pyrolysis gas before such operation can be considered sufficiently effective for commercial viability.

Solid Waste Toxicity

CaS is a toxic chemical and solids waste that can leach this chemical can only be disposed as hazardous waste. The environment that the CaS must go through prior to exiting any fixed-bed gasifier is a highly oxidizing atmosphere where substantial sulfation is desired. The likelihood that surface sulfate will result in some "blinding" within a larger CaS crystal has prompted the project team to incorporate a wet oxidation process[9] to ensure complete sulfation prior to bottom ash disposal. Conventional sulfide to sulfate wet oxidation processes operate at temperatures of 120 to 260 °C and pressures of 5 to 50 atm.

Zero Wastewater Discharge
All process wastewater is consumed and ash dust controlled with the wet oxidation system, and there is no wastewater discharge stream from this process. Unlike some limestone desulfurization processes that produce large quantities of dry lime during the fluidized-bed calcination process, the wet oxidation system hydrates any available excess lime, eliminating caustic fumes commonly associated with dry ash, dedusting, water-spray type systems.

Water is sprayed into the hot coal gas to control temperatures to protect piping materials. The combined water consumption by chemical reaction, hydration in the wet oxidation system, and evaporation in the gas cooling system eliminates the need for costly and cumbersome water quench treatment systems. Such quench systems are sometimes used in coal gasification processes and are followed by conventional Claus and Stretford sulfur capture technologies.

THE PYGAS™ PROCESS

The "PyGas™" process was separated into four discreet zones to allow for individual parametric studies of the specific requirements of each zone. Then the zones were integrated into a single process to be completed within a single-pressure vessel.

Zone 1 -- Pyrolyzer
Many references[9-14] to rapid devolatilization of granular coal in a variety of fluidized-bed regimes are available in the literature. The common denominator is that granular coal devolatilization is much more driven by the rate of solid particle heat transfer than any other parameter. In all cases, operation at elevated temperatures resulted in greater devolatilization. The design for the pyrolyzer tube, therefore, became a heat transfer problem. While it is expected that most of the coal's volatile content will be rapidly driven off within the confines of the pyrolyzer tube, significant gasification is not expected at normal pyrolyzer operating temperatures. Several investigators have successfully exceeded 50 percent devolatilization[1,2] conversion of solids. Since PyGas™ includes a cracking zone immediately downstream of the pyrolyzer tube, whatever volatiles escape pyrolysis are expected to become converted either in the high-temperature top air injection zone or within the co-current annulus.

Zone 2 -- Top Air Injection
The primary purpose of the top air injection zone is to raise coal gas temperature sufficiently to crack any gaseous tars remaining after pyrolysis. One investigator[2] has completely cracked tars through the use of steam and carbonization temperatures in excess of those used by previous explorers. Therefore, raising temperature and using steam at high temperature are at least two methods available for tar cracking. The PyGas™ top air method results in higher heating value gas than the steam introduction method, but heating value of this gas is lower than if no cracking was needed. The tradeoff is between lowered gas British thermal unit (Btu) value in exchange for eliminating operational difficulties due to caking coal agglomeration and tar production. Side benefits of raising the coal gas temperature in zone 2 to approximately 2,300 °F include potential reductions of fuel-bound nitrogen to molecular nitrogen and enhancement of char gasification within the inner annulus.

Zone 3 -- Inner Annulus
The down-draft zone provides a third chance for tar destruction; however, the primary function of the co-current inner annulus zone is to gasify char. Since the solids residence time far exceeds that of the coal gases flowing in parallel, and since coal gasification reaction rates[15] are very fast at 2,300 °F, the coal gas exiting the zone 2 will undergo endothermic gasification reactions within the inner annulus, thus producing hydrogen and carbon monoxide. The process is similar to gasification which occurs immediately above the combustion region of the fixed-bed gasifier, which is also driven by high temperatures. A final benefit of the inner annulus is the potential reactions of volatilized alkali with "getters,"[16,17] either existing in the coal ash or added to the system with the coal feed. If a portion of volatilized alkali can be removed with the coal ash while within the PyGas™ gasifier vessel, it would minimize alkali compound formation on combustion turbine blades at temperatures below approximately 1,800 °F, where significant corrosion and deposition damage can occur.

Zone 4 -- Fixed-Bed Gasifier
The fourth discrete zone is the fixed-bed gasifier[18]. This zone was designed using coke gasification parameters since the char on the PyGas™ grate is expected to be less reactive than coal[19]. A good portion of the coal will have already been gasified prior to accumulating in the fixed-bed combustion/ gasification zone. For this reason, considerably less air and steam flows will be needed through the grate in contrast to conventional fixed-bed gasifiers. This is significant where steam/carbon ratios are their highest. Air/steam velocities are expected to be only in the range of 0.2 ft per second at 1 foot above the grate, and only 0.3 ft per second at the peak temperature combustion zone in the fixed bed.

Integration of Gasifier Zones
Owing to the fact that many carbonizers have been designed and operated at a variety of superficial velocities throughout the range of fluidized-bed flow regimes, integrating the pyrolyzer into the PyGas™ vessel, in theory, is not expected to pose significant operating problems. Most carbonizers merely use air to feed coal, proportioning air and coal flow, to control operating temperature. Pyrolyzer steam and nitrogen will be available for additional temperature and velocity control. The pyrolyzer tube is being designed to ensure that all solids fed into the bottom eventually leave by overflowing the top.

The following test data (Figure 2) illustrates the flexibility of the pyrolysis stage of the PyGas™ coal gasification process. The operating temperature of the pyrolyzer section is controlled by the quantity of air flow to it. The anticipated operating temperature range is from 1,300 to 1,600 °F and requires from approximately 14 to 27 percent of stoichiometric air for pyrolysis.

C. Y. Wen stated[20] that the understanding of coal pyrolysis is very important in view of the potential of the process to take advantage of (1) the phenomena of rapid pyrolysis, and (2) obtaining higher yields of gaseous hydrocarbons by the application of high-pressure hydrogen. It was also stated that pilot plant studies of Union Carbide showed that generation of gaseous hydrocarbons has improved significantly under high partial pressure of hydrogen. Since hydrogen partial pressure is increased due to steam gasification and water-gas-shift reactions, the gasifier design will introduce steam into the pyrolysis section of the gasifier along with the coal, limestone, and air.

In 1973, Menster[21] illustrated "rapid pyrolysis" as a method of carbonizing many different U.S. coals. Others[1,2] have shown similar results when operating carbonizers on caking bituminous coal with air, as shown in the devolatilization versus % stoichiometric air (operating temperature) in Figure 2.

Pyrolyzer turndown tests[1] have confirmed that very high rates of organics can be driven into gaseous state (approximately 50 percent by weight) over a very wide operating range, while holding operating temperature constant, by simply varying air flow to the pyrolyzer.

These developments show that adding a pyrolyzer, such as the one employed by the PyGas™ gasifier, increases the gasifier yield by avoiding liquid phase tars, while quickly converting 35 to 70 percent of the coal to gaseous fuel in a relatively small fluidized-bed vessel operated in the "slug flow" regime.

While admission of air into the top zone provides the elevated temperature required for fuel nitrogen reduction, tar cracking, and carbon dioxide (CO_2) gasification kinetics[22], its use is optional in the sense that it can be placed into service after the dual-bed processes are fully established. The temperature in the top zone will be controlled the same way as in the pyrolyzer, except that it will also include flame scanning to further ensure safe operation when in service.

The performance of the inner annulus zone will mainly depend on two things: solids inventory will determine pressure drop and gasification effectiveness, and top air injection zone operating gas temperatures will control gasification kinetics. Employing the char inventory in the inner annulus will be optional. While some of the aforementioned benefits of the top air injector and inner annulus are lost if char solids level in the fixed-bed zone are maintained below the inner annulus, it is anticipated that good coal gas quality and complete gasification can be achieved in either scenario.

The fixed bed's performance may depend upon how well the granular char is distributed on the bed. If good char size distribution is maintained on the fixed bed, it can be expected that the gasification process will proceed without the operational difficulties common to traditional fixed-bed gasifiers on lump tar-laden caking coal.

Typical fixed-bed coal gasifiers cannot control their raw gas exiting temperatures due to the evaporative process of the entering coal's moisture, which can vary daily with coal moisture content. Since the last stage of the PyGas™ coal gasification process is that of carbon gasification, the raw gas exit temperature will always be very close to the optimum for zinc ferrite types of hot gas cleanup systems[23-24], in the 1,100 to 1,600 °F range. This would be a decided advantage over either the molten slag bottom and entrained-bed gasifier types, which produce raw gas much too hot for hot gas cleanup systems, and conventional fixed-bed gasifiers whose raw gas product is often too cold. This may become a significant sensible heat advantage over the very hot slagging gasifiers, which must either quench their gas (very inefficient), or indirectly cool their gas, which shifts more heat to the less efficient Rankine thermodynamic cycle and away from the more efficient Brayton thermodynamic cycle.

The PyGas™ gasifier forces all of the incoming coal to pass entirely through the entire pyrolyzer and gasifier sections before it can leave the gasifier. This assures that no coal fines can bypass the gasifier as is commonly the case for many countercurrent fixed-bed gasifiers with gasifier top coal feed and raw gas removal in close proximity. This allows much more flexibility to the mechanical hardware design of the hot gas cleanup system, which has had to be concerned with coal fines and condensible tar carryover.

C. Y. Wen[12] concluded from entrained-bed coal gasification modeling that the effect of total pressure increased carbon conversion at any steam-to-fuel ratio. Wen also concluded that at an optimum steam-to-coal ratio, increasing oxygen-to-fuel ratios increased carbon conversion at any operating pressure. One can obtain the same carbon conversion at a lower oxygen feed by maintaining optimal steam-to-fuel ratios in the 0.4 to 0.5 range. Moreover, Wen's carbon conversion efficiencies considerably exceeded that required by the pyrolyzer section of the PyGas™ gasifier, indicating that acceptably high carbon utilization may be expected.

There exist significant data to support the viability of the two major components that comprise the PyGas™ gasifier, and the use of dolomite or limestone as a sulfur capture agent. C. Lowell[1] demonstrated retention of pyritic sulfur as high as 95 percent by injecting limestone with the coal into a "slug flow" pyrolyzer operated at 1,600 °F and of the same geometry as the one used within the PyGas™ gasifier vessel. Since the PyGas™ coal gasifier operates at from 1,500 to 1,800 °F in its rapid devolatilization pyrolyzer section, dolomite and limestone will calcine, and a portion will subsequently combine with available sulfur to form CaS (while in the pyrolyzer). Once CaS is formed, further increasing the temperature to 2,300 °F at the top of the gasifier will not result in significant release since it will rapidly cool to about 1,600 °F due to endothermic gasification reactions. Similarly, thermodynamic calculations indicate that the CaS can be oxided to calcium sulfate ($CaSO_4$) in the lower PyGas™ gasifier solids-bed region if the peak temperatures are maintained using 30 atmospheres below 2,000 °F.

E. J. Nemeth's[25] pilot-scale results showed that the desulfurization of coal-derived gas at 1,500 to 1,770 °F is feasible. This study found that desulfurization of the hot reducing gas initially exceeded 97 percent removal of hydrogen sulfide (H_2S) with dolomite.

Since the PyGas™ gasification process destroys tars, it is expected to result in significantly less sulfur bypass of the hot gas cleanup system, and far less potential for plugging due to tar and carbon-black thermalphorises downstream of the gasifier than for most fixed-bed gasifiers.

The release of volatile alkali represents a very substantial technological problem. Tests will investigate sorption of volatilized alkali onto aluminosilicate, either added or in the coal ash, within the PyGas™ gasifier where it can be stabilized.

Low-Btu coal gasification processes have been demonstrated in the area of NO_X control using off-stoichiometric combustion techniques[26]. Less ammonia conversion to NO_X was reported for low-Btu gas combustion than for medium-Btu gas. When combusted in a rich/lean mode, as much as 95 percent NO_X reduction resulted. When low-Btu gasifier coal gas is combusted in the burners of an existing retrofit/repowered boiler with turbine exhaust gas, a significant amount of NO_X can be reduced by "reburning[27-28]." Conventional combined-cycle utility power plants have demonstrated a 50 percent reduction[29] in the NO_X production by the gas turbine when operated in the fired gas turbine and fired boiler combined-cycle mode.

Therefore, the process goals of the PyGas™ gasifier coal gasification process are as follows:

- Operate on eastern high-caking bituminous coals.
- Crack tars, avoid thermalphorises.
- Avoid significant raw gas cooling (sensible heat retention).
- Capture sulfur (90 percent) using limestone and dolomite sorbent.
- Condense and capture volatilized alkali with in-bed ash-aluminosilicates.
- Maintain raw gas exit temperatures consistent with the needs of hot gas cleanup systems.
- Liberate tar sulfur promoting higher hot gas cleanup system sulfur capture.
- Maintain less than 0.1 lb/million Btu of NO_X emissions when coal gas is fired in IGCC applications.

REPOWERING COAL-FIRED POWER PLANTS

When repowering with a fully fired combined cycle[30,31], the optimum ratio of gas turbine to steam turbine occurs when stack gas excess oxygen is minimized. This occurs[32] at approximately 30 percent Brayton (gas turbine) and 70 percent Rankine (steam turbine) cycle (Figure 3). There is a thermodynamic and an economic reason for this. Thermodynamically, minimizing oxygen in the stack gas maximizes cycle efficiency since less unused oxygen exits the system above ambient temperature. Economically, full utilization of the existing boiler (Rankine cycle) utilizes the sunk value of the most costly system in any coal-fired power plant, namely the boiler island.

Two cost factors weigh heavily in the consideration of utility and industrial power plants as logical implementors of IGCC technology considering both new installations or repowering old facilities.

1) Utilities, cogenerators, and independent power producers (IPP's) will not be interested in new IGCC installations until high projected costs are substantially reduced in the relatively smaller size ranges of current interest to them.

2) Although the "N'th" IGCC plant may eventually become cost effective, the high cost of the first plant must be mitigated by utilizing existing coal plants that have most of the needed equipment. Old inefficient coal plants are excellent retrofit/repowering candidates because IGCC improves their cycle efficiency by 20 percent or more. Repowering appears to be the best near-term application potential for IGCC technologies in the coal-fired electric power market.

To effectively evaluate a repowering strategy as applied to a coal-fired utility power plant, a 38-megawatt electrical (MWe) class combustion turbine combined-cycle plant was utilized to retrofit a 100-MWe coal-fired utility power plant using IGCC technology. This arrangement simultaneously accomplished several important technical triumphs by--

- A very efficient Brayton cycle (gas turbine) at 2,300 °F combustion temperature combined with a relatively inefficient Rankine cycle at 1,250 psig/950 °F superheat resulted in a combined-cycle, overall efficiency improvement in excess of 20 percent net based on coal higher heating value[33].

- Consistent with this study's objective of achieving NO_X emission values of less than 0.1 lb/MBtu, the firing of low-Btu coal gas in the existing coal boiler proved to be positive NO_X control strategy using staged firing NO_X reburn techniques[16].

- Firing supplemental low-Btu gas in the existing boiler minimized the oxygen content in the turbine exhaust gas, which maximized cycle efficiency by lowering the dry stack gas losses[28].

- Adding coal gasifiers and an external combustion turbine to an existing coal-fired power plant with its inherent limitations, consumes and converts a considerable percent of the available energy, and results in less than full-load firing with the existing coal boiler. This should be looked upon as an inherent advantage since it alleviates the operating conditions of the existing coal boiler, which is sometimes overstressed at full load.

- Switching from pulverized coal to low-Btu coal gas fuel overcomes high furnace exit gas temperature (FEGT) by firing the existing coal boiler at a reduced capacity[34]. In this manner, any existing boiler's FEGT can be matched such that boiler performance can be maintained at design conditions that are close to the original. To recover from the impact of expected reduced furnace absorptivity, a conventional unfired heat recovery steam generator (HRSG) section replaces the original air heater (or furnace waterwall platens may be added).

- Adding an unfired HRSG augments the existing air heater (assumed tubular) and reduces the boiler exiting flue gas temperature to an acceptable stack exit temperature of 350 °F. Since turbine exhaust gas provides considerable sensible heat and excess oxygen in the converted coal boiler, a separate steam loop and small low-pressure steam turbine/generator may also be required (as in the case of any combined-cycle plant) due to multiple-feed water heaters that raise the feed water temperature above 400 °F, thereby precluding its use as a cooling medium for the boiler exit gases. This potential was found not to be required for the case reported in Figure 3.

CONCLUSIONS

The projected heat rate of one unit studied went from the highest of all the coal-fired units owned by a mid-western utility at 10,137 Btu/kilowatt hour (kWh) to the lowest at 8,430 Btu/kWh. Owing to its current high heat rate, this unit's dispatch rate is less than 10 percent annually. Were it to be repowered as illustrated in Figure 3, its improved efficiency would escalate its dispatch rate to the highest in the system. The utility commented that these older units tend to be more reliable than their newer ones, which are designed for higher pressures and temperatures. If the cycle efficiency of this older unit could be increased as suggested, they would feel comfortable operating it at a high load factor.

Innovative gasification technology is likely to be one of many technologies that will directly benefit from this concept. The results will be more affordable commercial systems which will be more likely to receive wider utility and industrial application.

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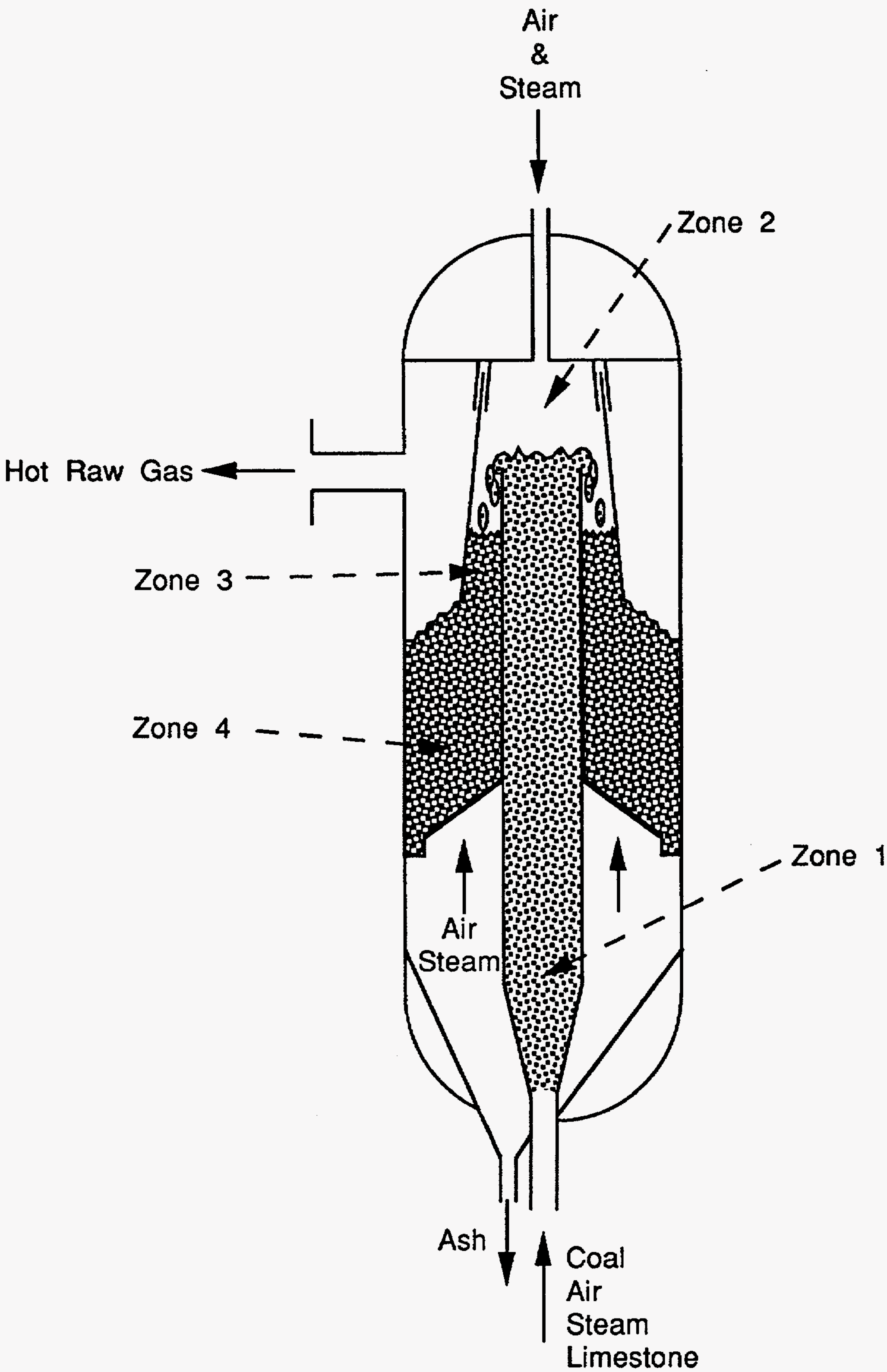

Figure 1. PyGas™ coal gasification apparatus.

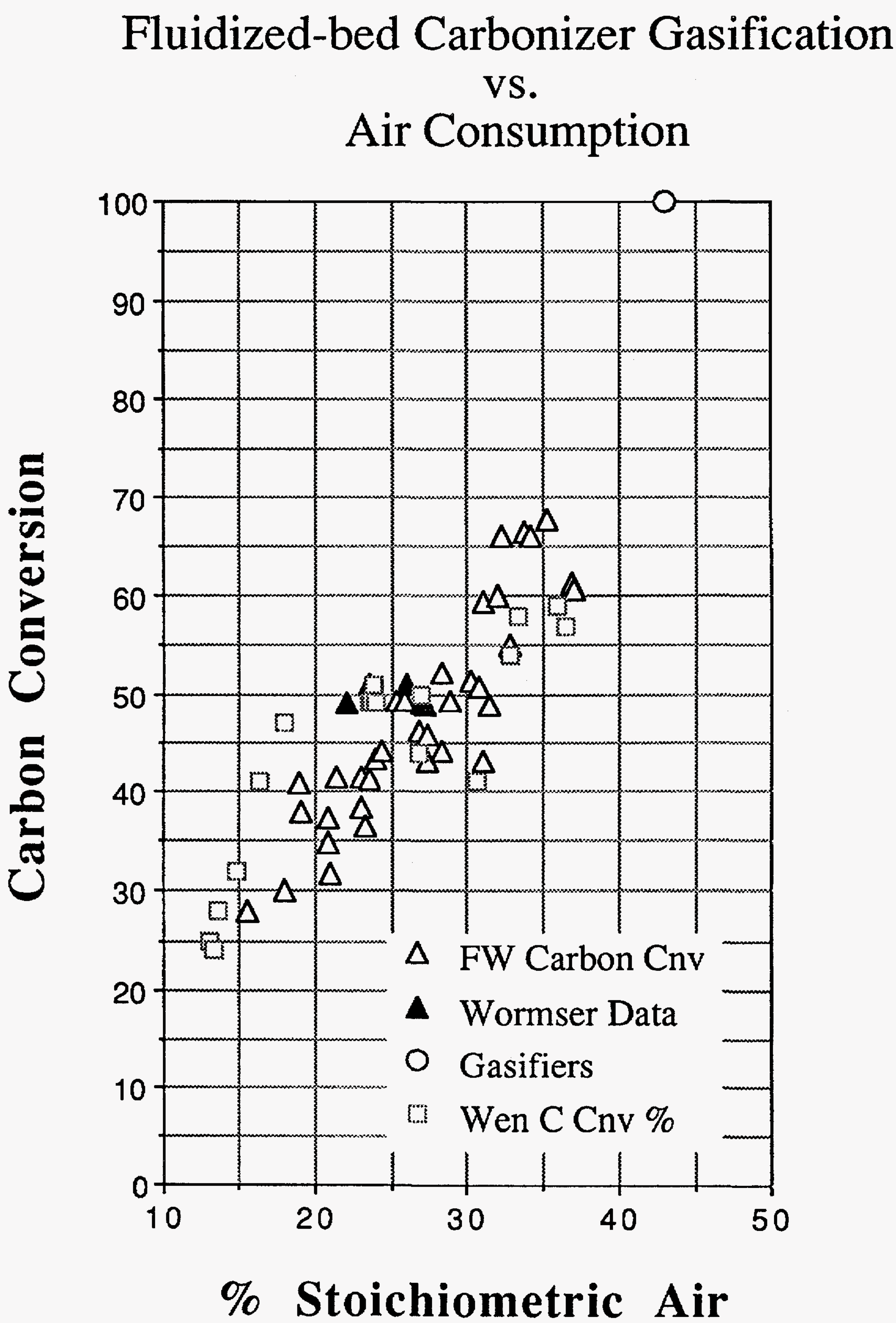

Figure 2. Carbonizer gasification versus air consumption.

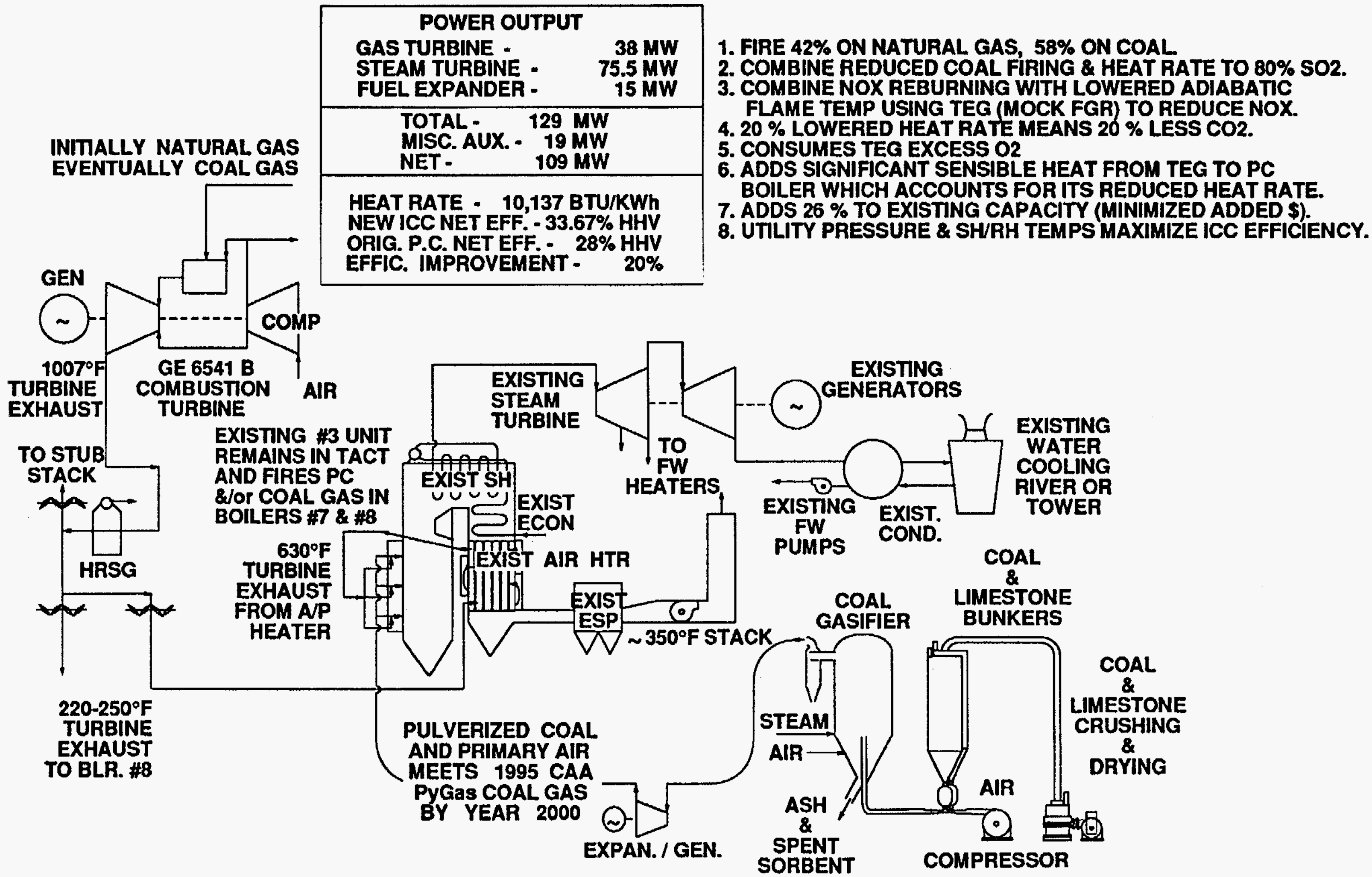

Figure 3. Repowered coal-fired power plant.