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Engineering Systems Analysis
of Pressurized Fluidized-Bed-
Combustion Power Systems

R. L. Graves
F. P. Griffin
M. E. Lackey

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Engineering Technology Division

ENGINEERING SYSTEMS ANALYSIS OF PRESSURIZED
FLUIDIZED-BED-COMBUSTION POWER SYSTEMS

Task I Report

R. L. Graves
F. P. Griffin M. E. Lackey

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ENGINEERING SYSTEMS ANALYSIS OF PRESSURIZED FLUIDIZED BED COMBUSTION POWER SYSTEMS

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ABSTRACT

This effort was conducted to provide supporting data for the research and development program on pressurized fluidized bed combustor (PFBC) systems being continued under the auspices of the Office of Coal Utilization of DOE. This report deals with the first phase of the effort, designated Task 1, which was scoped to be a somewhat broad review of PFBC technology and a analysis to determine its potential and sensitivity to key development needs.

The report includes background information pertaining to the application of PFBC to the market for coal-fired technology. The status of development is reviewed and the deficiencies in data are identified. Responses to a survey of PFBC developers are reviewed with emphasis on the high risk areas of the PFBC concept. Some of these problems are:

1. uncertainty of life of gas turbine components,
2. lack of demonstration of load following, and
3. hot solids handling.

Some high risk areas, such as the gas cleanup or gas turbine systems, can be relieved by reducing the severity of design conditions such as the turbine inlet temperature. Alternate turbine designs or plant configurations are also possible solutions. Analyses were performed to determine whether the advantages held by PFBC systems in cost, efficiency, and emissions would be nullified by measures taken to reduce risk. In general, the results showed that the attractive features of the PFBC could be preserved.

1. EXECUTIVE SUMMARY

1.1 Introduction and Scope of This Work

The pressurized fluidized bed combustion (PFBC) combined cycle power plant has been developed to a point where it appears to offer high efficiency and high environmental performance. Many PFBC power cycles have

been proposed with projected thermal efficiencies of about 40%. However, all PFBC concepts have several common development challenges which do not exist or are lesser in magnitude in the atmospheric fluidized bed combustion (AFBC) power plant, for example. Some of these characteristic development needs are:

1. A gas turbine to operate on coal combustion gas,
2. A hot gas cleanup system to help protect the turbine,
3. Ability to feed solids to a vessel operating at up to 1.6 MPa pressure,
4. A ducting system to carry hot, corrosive, and particulate laden gas.

These problems, although not insurmountable, will require considerable effort to completely resolve. With the advantage for PFBC projected in previous studies as being only 10% cheaper power when compared to conventional plants with scrubbers (CPWS) meeting the NSPS, the incentive for a strong, federally funded development program is not obvious. However, if the New Source Performance Standards (NSPS) were to change or were not adequate to maintain a regional air quality standard, then the advantage held by the PFBC would be expected to be greater. Therefore, a major thrust of this analytical study is to quantify the change in relative costs of several technologies (PFBC, AFBC, CPWS) with tighter limits for SO₂ control.

The quantities of solid wastes and NO_x emissions are compared for the different technologies also.

Another matter which must be considered is the comparison of a PFBC system with many development areas yet undemonstrated to an AFBC which is relatively near term or to the CPWS which is a commercial product. This analysis attempts to address this issue by performing sensitivity studies on current PFBC concepts to determine the importance of the development of equipment labeled as high-risk.

A high-risk component may be thought of as one which presents a high challenge to engineering development. In reality, however, there may be little risk involved if the component has little effect on the plant feasibility or economics. Hence, for the purpose of this study, a high-risk

component is one which is believed to present substantial development problems and one whose development is very important to the overall feasibility or attractiveness of the power plant concept.

The most challenging development problems were identified in this study through a survey of the PFBC researchers. The economic importance of these features was quantified by examining the impact on the overall plant cost, efficiency, and emissions. By looking at the historical development progress, some projections were made as to the time which might elapse during resolution of the remaining areas of uncertainty in the PFBC. Hence, the study addresses the two ways to lower risk in the PFBC concept:

1. Alter the design conditions,
2. Complete development of high-risk components.

1.2 Status of Technology

In the 1978-1980 period over 5000 h of operation were accumulated on PFBC test units in this country and the United Kingdom. A number of encouraging results were produced but a number of data gaps still exist and several principles are in need of proof-tests. Endurance testing of turbine materials at Exxon, CURL, and Curtiss-Wright generally revealed that small cyclone particle separators could provide reasonable performance in the critical 10 μ particle size range. Possible improvements to conventional cyclones have also been identified. The endurance tests also revealed that coated turbine blades could offer superior life over uncoated blades. Unfortunately, the absolute life of a turbine blade is as yet undetermined since the PFBC test units have generally not been operated at conditions (temperature, pressure, excess air, etc.) representative of a commercial PFBC plant.

The cyclone separators which have provided the highest efficiency in PFBC tests have been of small physical size (less than 0.5 m diam) and low flow capacity. Conventional cyclones are less efficient in larger sizes which means that the cleanup train in a commercial plant might require a

stage of several hundred small cyclones operating in parallel. This arrangement leads to complicated manifolding and also the greater possibility of individual cyclone malfunction. Hence, investigations are under way on other cleanup devices and also on cyclones which maintain high performance in larger flow capacities.

The PFBC test units have also demonstrated that, with good engineering, solids feeding can be accomplished into a 0.7 to 1.0 MPa vessel. Some further development is desirable here, however, to reduce the coal pre-treatment requirements and reduce cost.

The report on the findings of the analysis is preceded by a review of the PFBC technology and an assessment of the problems which are unresolved. The current development activities and facilities are also described, along with some of the more significant efforts in recent years. Further background information pertaining to the role of advanced power systems in displacing oil with coal is presented in Sect. 2.

A serious deficiency in the recent testing is that none of the PFBC units operate as closed turbine-compressor systems. Only NASA and Curtiss-Wright have performed tests on rotating machinery in recent times and even so the turbine was not used to generate power for supplying pressurized air. Therefore, starting procedures, control, and off-design performance and emissions, are unproven at this time. Control schemes can affect the basic feasibility of the PFBC since most likely the gas cleanup system performance would be influenced by operation at part-load. The last PFBC unit to operate as a closed loop system was the Combustion Power Company facility which, due to gas cleanup problems, did not achieve intended goals and has not operated since 1975.

Although SO_2 retention and sorbent utilization are still not completely understood, there is adequate data to demonstrate the high potential for PFBC to generate very low SO_2 and NO_x , well below the NSPS. The effect of pressure on SO_2 , for example, is not clearly defined in the 0.5 to 1.0 MPa range but some data indicate a gradual increase in sorbent requirements to maintain SO_2 as the combustor pressure increases beyond 1.0 MPa. NO_x emissions have been related to combustor temperature and pressure, bed depth, and excess air but completely defensible correlations have not been derived.

1.3 Identification and Treatment of High-Risk Areas of PFBC Systems

The survey of PFBC research, development, and engineering teams, along with the technology review and analyses of this study, have identified a number of items in PFBC design and operation which offer high technical risk. Some of the risk areas are:

1. combined erosion/corrosion degradation in gas turbine,
2. hot solids pressure letdown and transport,
3. instrumentation to detect gas cleanup system malfunction quickly,
4. undemonstrated load-following for PFBC systems, and
5. deposits on hot gas ducting and turbine and their removal.

Several of these technical risks can be reduced by altering the design conditions of the PFBC concept. For example, it is generally accepted that the gas turbine life can be extended by lower design inlet temperatures, but at the expense of lower plant efficiency. Deposition also becomes a less likely problem at lower temperatures. In another case, the air-cooled PFBC offers ease of control relative to the steam-cooled versions. The question of whether these different designs or more conservative operating conditions greatly detract from the economic and environmental advantages of the PFBC is a valid one and is addressed in this study.

Other risk areas can only be reduced by continuing development efforts. The hot solids handling and solids feeding are common systems to all PFBC concepts and do not change appreciably by alternate design conditions. These areas affect the basic feasibility of the PFBC concept. Deposition may be a similar problem in that even soft deposits must be periodically removed from the turbine to prevent complete loss of power. The rate of deposition may require cleaning every few hundred hours which makes on-line deposit removal almost essential for normal operations.

1.4 Sensitivity of PFBC Advantages and Potential to Key Development Needs and Risk Areas

This part of the analyses was performed to determine how design conditions intended to reduce risk would affect the economics and

environmental performance of the PFBC. Several air- and steam-cooled PFBC plants were evaluated and their design conditions are summarized in Table 1.1. The configurations of the plants are shown in simplified form in Figs. 1.1 and 1.2.

Table 1.1. Characteristics of PFBC plants evaluated

	Steam cooled			Air cooled	
	Low risk			Low risk	
	A	B	C	A	B
Net power, MWe	712	677	642	450	373
Overall efficiency, %	37.9	38.8	40.0	38.1	35.1
Gas turbine inlet temperature, °C					
Clean air				843	760
Flue gas	621	760	900	899	815
Turbine inlet pressure, kPa	531	531	930	630	630
Steam cycle peak pressure, MPa	16.7	16.7	16.7	5.86	3.10
Steam cycle peak temperature, °C	538	538	538	441	388
Number of gas turbines	4 ^a	4 ^a	3 ^b	6 ^b	6 ^b

^aFluidized cat-cracker (FCC) turboexpanders.

^bConventional heavy duty industrial gas turbines.

1.4.1 SO₂ control potential

The ability to achieve SO₂ retention of 98% was found to be negligibly influenced by PFBC design condition. All PFBC plants evaluated showed only moderate increases in power cost as SO₂ control was increased (Fig. 1.3).

1.4.2 NO_x emissions

Low risk design conditions, as defined in this study, were found to result in moderate increases in NO_x (on the basis of mass per unit power output) relative to some of the more high performance PFBC concepts. The NO_x levels, however, are much less than from AFBC systems.

Fig. 1.1. Schematic of typical steam-cooled PFBC combined cycle.

Fig. 1.2. Diagram of air-cooled PFBC power system.

Fig. 1.3. Effect of SO_2 control on the cost of power for AFBC, CPWS, and several PFBC plants.

1.4.3 Solid wastes

The solid waste for all PFBC concepts was found to be substantially less than AFBC and CPWS and insensitive to SO_2 control and not greatly dependent on the PFBC configuration or design condition (Fig. 1.4).

1.4.4 Plant thermal efficiency

The steam-cooled PFBC plants displayed modest sensitivity to lower turbine inlet temperatures and gas turbine efficiencies. The air-cooled PFBC plants displayed a considerably higher sensitivity to these parameters (see Table 1.1) but the sensitivity could be reduced by supplemental firing in the waste heat boiler. In fact, the efficiency of the air-

Fig. 1.4. Comparison of solid waste from power plant concepts.

cooled cycle can be made to surpass that of the steam PFBC by upgrading the steam part of the air cycle. Combustor pressure has little impact on the plant efficiency in either system in the range of 0.6 to 1.0 MPa. Thermal efficiency was found to be mildly dependent on SO₂ control (Fig. 1.5).

1.4.5 Cost of power

The cost of power for steam-cooled plants varied by only about 3% over the range of design conditions summarized in Table 1.1. The air-cooled plant, although evaluated over a narrower temperature range, displayed a 3% variation also. In both cases the high turbine inlet temperature system was estimated as having the slight advantage if optimistic values for turbine blade life were used.

Fig. 1.5. Effect of sulfur control and plant design conditions on overall efficiency, GT = gas turbine conditions at inlet, eastern coal.

The effect of the gas turbine stage life was calculated as representing from less than 1% of the cost of power, for lifetimes over 30,000 h, to over 10% at 3000 h (the 3000 h value does not account for additional downtime which would actually be required for replacement more frequently than once per year). Hence, the turbine life is important to PFBC economics and a minimum goal of about 8000 h seems to be mandated. Trends, shown in Fig. 1.6, show the turbine economics to be of greater importance for the air-cooled PFBC systems.

Fig. 1.6. Influence of turbine stage life on PFBC cost of power. Gas turbine repair is \$500,000 per stage and expander repair is \$200,000 per stage.

2. BACKGROUND

2.1. The Market for Coal in Utilities

In the United States, coal is abundant, accessible, and relatively cheap. It is so abundant, in fact, that in some parts of the country all you have to do is remove a little soil to reach large deposits. Today, as the world's largest coal producer, the United States mines 770 million tons of coal a year, but that fact is not so impressive when you consider that we mined 700 million tons per year sixty years ago (1920). Why have we been turning away from coal and what is coal's future in the American energy market? We can obtain a fairly good perspective of our predicament if we understand how and why we got into it.

Sixty years ago coal was the primary purchased fuel; about 80% of the energy used in 1920 came from coal. At that time there were basically only two fuel sources — coal and wood. The supply of wood was limited and coal was seemingly inexhaustible, so coal won by default.

When oil and gas were first introduced, these fuels won rapid acceptance. Unlike today, when the oil price more closely represents its value, past pricing reflected production costs plus profit. Since 1915, gas has been a favorite of industry. Demand was so high that two-thirds of the early industrial gas supply was synthesized from coal since the natural gas fields in Pennsylvania and Ohio (which were the first developed and were close to the industrial market) were inadequate to meet the needs. By World War II, a transportation network was constructed that could move the gas long distances from the large fields in Texas and Louisiana, so the consumption of gas escalated. Gas proved to be the perfect fuel for industrial and residential heating because it is clean, easily handled by modest equipment, and was inexpensive. In fact, except for the last few years, natural gas has always been cheaper than coal, although regulation of natural gas price at artificially low values has been a major factor. Because gas and oil were cheap, easy to use, and met the eventual environmental restrictions better than coal, coal took a back seat to gas and oil. However, national energy policy now calls for a reduction of imported oil and replacements for gas. Other energy sources

that must fill the void which will result from restricted use of oil and gas are nuclear energy, conservation, and coal.

Production of electric power is one of the most attractive applications of coal because most electric power plants are large enough to take advantage of an economy of scale, and in such plants coal is used to generate steam, a technically developed application for coal. Coal presently plays a major role in the production of electricity with 45% of United States electric power coming from coal-fired plants. In recent years, however, coal has received less attention due to the emergence of less expensive nuclear power, continually tightening emissions standards, and greater use of oil and natural gas (see Fig. 2.1).

The demand for coal by the utilities is characterized by a retrofit market and an expansion market. The existing oil- and gas-fired power plants constitute the retrofit market -- that is, the plants whose boilers and other components must be replaced with proper equipment so that they can burn coal. The retrofit market represents six quads of energy, about half of which is oil (16% of imported oil). By the year 2000, however, the annual fuel use by utilities is predicted to increase by about 27 quads, making the expansion market the real target for coal.

Fig. 2.1. Historic trends in fuel use in the utility sector.

The geographic distribution of utilities that are largely dependent on oil may have a pronounced effect on the retrofit market for coal. About 60% of the oil consumed by utilities is used in California, the Northeast, and the deep South. Questions concerning the logistics and cost of moving coal to these areas have not been resolved.

One of the best ways to evaluate the role of direct coal combustion in the utility sector is to examine the economic incentives. Although a utility considering new expansion has a number of alternatives and load patterns to consider, this preliminary analysis limited the discussion to large base load expansion. Capital costs for various coal technologies vary somewhat from region to region throughout the country, changing with local labor rates and the types of coal available. Further, the cost of conventional coal technology is based on experience while the costs for advanced systems are derived from design studies and are, therefore, more disputable. Using the available data, some preliminary studies in 1979 at ORNL led to some interesting perspectives.

The options considered were conventional pulverized-coal systems with flue gas desulfurization, atmospheric fluidized bed combustion, combined cycle gasification, pressurized fluidized bed combustion, and a conventional oil-fired boiler. The results of this comparison are shown in Fig. 2.2. For the retrofit market, it is assumed that the choices are to either continue burning oil or build a new coal-fired system. Therefore, the costs of the oil-fired system represent only the operating costs. This comparison is shown in Fig. 2.3.

The implications from these comparisons are clear. First, development of advanced technologies will most likely have very little impact on the major energy problem — oil consumption. The economics of power generation so strongly favor new coal-fired plants over new oil-fired plants that the conversion to coal in the utilities will take place in the expansion market even in the absence of advanced technologies. Secondly, the incentives are there even if a utility chooses to scrap an oil-fired system and build a new coal-fired one. Thirdly, since a rapid change is not taking place, economic incentives alone do not appear to be sufficient.

Fig. 2.2. Preliminary economic comparison for new power plants.

Fig. 2.3. Preliminary economic comparison for existing power plants.

2.2 Role of advanced systems in retrofit market

Regional distribution by fuel use has major implications as to the problems associated with a wholesale conversion from oil to coal. Tables 2.1 and 2.2 list the utility companies that are major oil and gas users and their respective dependence on these fuels. This relatively short list of companies represents more than 4 quads of annual oil and gas use.

Not only is the use of oil and gas concentrated in specific power systems, but these companies in general are totally dependent on these fuels. The point is that even if there are economic incentives to shift to coal, the financing requirements for a utility to replace its entire generating capacity are staggering.

This predicament of the utility companies indicates that the development of advanced coal-fired systems which can be built with minimal investment, and/or which can be used for repowering, may result in a more

Table 2.1. Utilities highly dependent on oil — 1977

Utility	Annual oil consumption (Thousands of bbl)	Percent oil and gas	Percent oil
Southern California Edison	57,843	81	64
New England Electric System	19,046	100	100
Boston Edison	14,286	100	100
Niagara Mohawk Power	13,833	55	55
Long Island Lighting	20,687	100	99
Pacific Gas & Electric	35,918	100	50
Florida Power	15,574	86	72
Florida Power & Light	31,717	100	69
Middle South Utilities	35,895	100	50
Public Service Electric & Gas (New Jersey)	20,877	65	62
Virginia Electric & Power	28,000	60	60
Consolidated Edison	41,618	100	100

Source: Ref. 1.

Table 2.2. Utilities highly dependent
on natural gas - 1977

Utility	Annual gas consumption (Millions of ft ³)	Percent oil and gas	Percent gas
Houston Lighting & Power	470,668	100	100
Central & South West	380,000	94	91
Pacific Gas & Electric	215,907	100	50
Oklahoma Gas & Electric	168,223	95	95
Middle South Utilities	206,947	100	50
Texas Utilities	362,119	55	53
Gulf States Utilities	193,656	100	75
Southwestern Public Service	105,710	82	81

Source: Ref. 1.

rapid retrofit to coal. Current endeavors in advanced systems development strongly emphasize the plant efficiency and overall cost of power in lieu of minimizing capital investment (although capital cost and efficiency are interrelated).

Environmental regulations may also prove to stymie the retrofit to coal. The use of oil and gas in concentrated areas is, again, important because the conversion to coal on a large scale would result in a substantial reduction in air quality even if the coal-fired plants meet the NSPS for particulates and SO₂. Hence advanced coal-fired plants which are capable of performing beyond the NSPS without losing their economic advantage can enhance the acceptance of coal into a historically noncoal utility area.

2.3 Role of advanced power systems in expansion market

As previously mentioned, the future market for coal in the utilities is very large, and a great deal of effort is being expended in determining the most suitable technologies to fill this need.

In any event, the expanded use of oil in utilities is not economically justifiable in most instances and will not probably be considered in

future utility expansion plans unless there are influential factors other than economics, such as air quality. With air quality in mind, the geographic distribution of the future market is of great importance in determining the applicability of coal. Referring to the regional electric reliability council geographic areas shown in Fig. 2.4, according to DOE the projections for the increase in peak demand for power are as presented in Table 2.3. One can deduce from these data that the largest growths are to occur in the SERC, ECAR, WSCC, and, to a lesser extent, in the SWPP regions. The close proximity to coal sources and the present existence of some coal-fired plants make the ECAR and SERC regions appear to be likely candidates for coal utilization in the future. However, coal is generally not used and not readily available in parts of the WSCC (California) and, therefore, direct combustion of coal is perhaps less feasible in this area.

The problems of burning coal in areas which may already be near non-compliance for a particular atmospheric pollutant weigh as heavily in the expansion market as in the retrofit market. Many parts of the ECAR and

Table 2.3. Projections in peak power demand
by region, 1978-1987

Region	Percent increase over period		1978 summer peak (MW)	1978 winter peak (MW)
	Summer peak	Winter peak		
ECAR	5.23	5.58	66,055	65,863
ERCOT	5.38	5.43	28,949	19,893
MAAC	3.77	4.33	32,713	28,866
MAIN	5.24	5.93	35,003	28,842
MARCA	5.66	6.03	18,651	16,879
NPCC	3.52	3.74	35,710	35,520
SERC	5.96	6.05	84,400	86,885
SWPP	6.21	6.26	38,946	27,810
WSCC	4.72	4.72	71,937	69,983

NATIONAL ELECTRIC RELIABILITY COUNCIL

Fig. 2.4. Regional electric reliability council areas.

WSSC regions, for example, already have air quality problems, even without a substantial increase in coal use. Hence, as in the retrofit market, coal use in the expansion market should be enhanced by the availability of advanced power systems with the potential for high environmental performance at reasonable cost.

Emphasis on plant efficiency is, of course, justifiable but must be viewed with the proper perspective. The median overall power generation efficiency in the United States is only 32% and has been declining since 1975. Therefore, even the introduction of the AFBC steam power plant, a relatively near-term option with 34 to 35% efficiency, represents an opportunity to reverse the current trend in heat rates.

2.4 Overview of PFBC Concept

The most obvious effect of pressurizing a fluidized bed coal combustion furnace is the reduction in physical size per heat release. At a first approximation, the cost of the furnace would also be expected to be reduced as a result of the size reduction especially with the added possibility of shop fabrication.

The power required for compressing the combustion air flow is large and can be most efficiently accomplished by expanding the hot, pressurized, combustion gases through a power recovery gas turbine which drives the compressor which provides the pressurized air to the furnace. The incorporation of the gas turbine also provides an opportunity to increase power plant efficiency. By appropriate design conditions in the furnace, considerable power may be obtained from the power recovery turbine in excess of that required to drive the compressor. This results in a version of the familiar combined gas- and steam-turbine cycle with potential for efficiencies over 40%.

The gases which drive the power recovery turbine are particle laden and corrosive and most attempts to operate such a turbine system have met with limited success. The development of PFBC power plants, thus, faces this problem and several others. A brief discussion of the major PFBC advantages and disadvantages follows.

2.4.1 Principal advantages of the PFBC

One principal advantage of the pressurized fluidized bed combustor is a reduced size for a specific thermal output. The heat release in an atmospheric fluidized bed combustor is limited by the maximum achievable mass flow rate and, hence, the superficial velocity of the combustion air which causes excessive elutriation of the bed materials. Unless the sorbent particles are made so large that their conversion is too incomplete, the maximum superficial velocity for current AFBC design parameters is about 4 m/s (13 ft/s). As the pressure of the combustion air is increased to several atmospheres, the concentration of oxygen per unit volume is proportionally increased; an equivalent heat release can be achieved at much lower superficial velocities, resulting in increased gas residence time and improved combustion efficiency and sorbent utilization. A higher heat release per unit volume can be obtained at higher velocities as limited by elutriation or the inability to remove all of the heat released. In fact, the heat release in a PFBC can be increased to the point where its limiting factor is determined by the amount of heat transfer surface which can be physically packed into the bed. Deepening the bed allows more volume for heat transfer surface and can be done in a pressurized bed without incurring excessive pumping power losses due to the use of the power recovery turbine. Hence, the PFBC can indeed generate the same power as the AFBC in a smaller plan area which also implies that the number of coal feed points will be reduced. A deep bed also has the advantage that it gives a greater transit time for the fine coal particles and gases passing through the bed if a bottom coal feed location is employed, and this in turn increases both the combustion efficiency and the sulfur retention. NO_x emissions are also believed to be inversely proportional to pressure.

The greater bed depth permissible if the furnace is pressurized has a number of subtle but important advantages from the standpoint of control. The greater bed depth, for example, makes possible a larger space between the air tuyeres and the bottom of the boiler tube matrix, this gap being only a small fraction of the total bed depth at full power. The pumping power associated with such an increment in bed depth is small, while the

gap improves mixing of the fuel and air before it reaches the heat transfer matrix so that it reduces the possibility for boiler tube corrosion arising from local regions in which a reducing atmosphere might prevail. Further, the use of a fairly generous plenum between the air tuyeres and coal feed points on the one hand and the bottom of the tube matrix on the other, makes it possible to start-up the fluidized bed with its level a little below the boiler tube matrix so that there would be no boiler tubes immersed in the bed under start-up conditions, and hence, no large heat losses to these tubes. Further, with a fluidized bed depth of the order of 3.7 m (12 ft) at full power, the problems of sensing and controlling bed depth are eased because a change in bed depth represents a much smaller fraction of the total depth than for a typical atmospheric bed. Also, by using bed depth as the prime mechanism for controlling the boiler furnace output, one has a reasonably linear relationship between bed depth and furnace output because the amount of heat transfer surface area immersed in the bed is directly proportional to the bed depth above the bottom of the heat transfer matrix. The exposed tube matrix above the bed will remove some heat from the flue gas which in turn will reduce the flue gas turbine output. The combination of reduced bed heat transfer surface and reduced turbine output can be utilized as a plant load control mechanism.

In applying PFBC to utility power plants the potentially high efficiencies resulting from the combined cycle configuration must be included near the top of a list of advantages. Overall efficiencies of over 40% (relative to AFBC steam plant at 34 to 35%) are achievable in a PFBC with design conditions that are not totally unreasonable from a materials standpoint.

In applying PFBC to industrial boilers (no net power from turbo-compressor) the principal advantage is the size reduction. The small size is important because of the larger steaming rate of coal-fired boilers which could be shop fabricated and shipped by rail. Shop fabricated boilers can be built and delivered for perhaps one-half the cost of a field-erected boiler of the same steaming rate. The size advantage which would be held by an industrial PFBC boiler is illustrated in Fig. 2.5.

Fig. 2.5. Illustration of the advantage of pressurizing industrial coal-fired boilers (120,000 lb/h steam rate for boilers shown here).

2.4.2 PFBC disadvantages

In addition to the principal problems of turbine erosion, corrosion, and deposits (discussed in detail in Sect. 4 of report), pressurizing a fluidized bed poses some problems in feeding the coal and sorbent into the bed against a relatively high furnace pressure. If an atmospheric bed is employed, the feed systems need to operate against a pressure of perhaps 0.014 MPa (2 psig), but if the furnace is pressurized, the feed systems must deliver the materials against a pressure of 0.3 to 1.0 MPa (3 to 10 atm). This can be accomplished with lockhoppers, but these have proved to be a source of mechanical troubles in the many types of chemical process system in which they have been employed. Other methods of introducing granular solids through some sort of a pressure lock have all given difficulties so that a substantial set of development problems must be overcome in the development of reliable coal and sorbent feed systems for pressurized fluidized beds.

Another important disadvantage of pressurized fluidized beds stems from the fact that there is considerably less operating experience with units of this type than with atmospheric fluidized bed coal combustion systems. It is not clear just how serious this disadvantage will prove to be, but it certainly is a factor in the thinking of many people. No PFBC systems are operating which would permit meaningful control studies since none incorporate a gas turbine to drive the air pressurization device.

3. DESCRIPTIONS OF PFBC TEST FACILITIES

The PFBC test units which have been in operation recently or are still operating are described in this section. The areas of research most emphasized at each facility are identified also.

3.1 NASA PFBC Facility

The conical PFBC test unit at the NASA Lewis Research Center in Cleveland, Ohio was operated from 1977 to 1980 and is currently being dismantled.²⁻⁴ The bed had a cylindrical combustion section for the lower end which is 91 cm (3 ft) high and has a 23 cm (9 in.) inside diameter. This section contained horizontal water-cooled tubes which could be replaced with solid test specimens. The upper part of the furnace was conical varying from a 23 cm (9 in.) inside diameter at the bottom to a 53 cm (21 in.) inside diameter at the top. This section had a vertical length of 203 cm (6.5 ft). The purpose of this design was to make the upper section of the fluidized bed tend to be only slightly fluidized, thereby becoming a granular bed filter of sorts. Bed height was maintained at 61 to 244 cm (2 to 8 ft) by a water cooled auger type solids removal device which can be placed at numerous levels. There was also a television type camera in the top of the combustor as well as a gas sampling probe. A schematic drawing for the system is shown in Fig. 3.1.

The NASA rig burned up to 36 kg/h (80 lb/h) of coal in the presence of about 9 kg/h (20 lb/h) of sorbent. The pressure of the combustor varied from 0.14 to 0.69 MPa (1.4 to 6.9 atm) and the bed operated at temperatures up to 1100°C (~2000°F) producing combustion gases at about 870°C (1600°F).

Coal and sorbent were fed after blending to a lockhopper. A high pressure screw feeder metered the solids from the lockhopper into a pneumatic transport line which carried the solids into the combustor.

The combustor was equipped for either stationary or rotating turbine materials testing. The stationary specimens can be subjected to a high velocity gas stream on the so-called carousel wedge test unit. This unit

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Fig. 3.1. Schematic drawing of NASA combustor and auxiliary components (Ref. 2).

was located directly on top of the furnace and was not preceded by a gas cleanup device.

The turbine used was a modified single stage Chrysler automotive turbine. The rotor was 14 cm (5.5 in.) in diameter and had 53 blades. Since the turbine was designed to accommodate much more flow than the combustor generated, it operated with partial admission and produces 3.7 to 6.0 kW (5 to 8 hp). Rotational speed at test conditions was 38,000 rpm. Speed was regulated by a dual purpose air starter and brake operated with pressurized air. A special seal installed by the NASA engineers allowed the turbine to operate with the inlet pressure essentially that of the combustor.

The gas cleanup system consisted of a single Aerodyne cyclone mounted above the combustor. Some modification had been made to this unit to enhance performance.

The major efforts at the NASA Lewis facility were related to characterizing the effluents from the PFBC under a wide range of operating conditions. Turbine materials testing with stationary specimens were conducted next followed by the small gas turbine operation.

3.2 Argonne National Laboratory (ANL)

The Argonne National Laboratory (ANL) has been conducting a basic research and development program since early 1969 to demonstrate the feasibility of the combustion of coal in a pressurized fluidized bed combustor. A 15-cm (6.0-in.) diam, pressurized, fluidized bed combustor capable of operating to 1.0 MPa (10 atm) pressure and temperatures in the range of 775 to 975°C (1427 to 1787°F) was used to investigate sulfur retention, combustion efficiency, additive utilization, and heat transfer coefficients.^{5,6}

A series of eleven experiments were performed in 1974 to demonstrate the effects of the bed temperature, fluidizing velocity, and the Ca/S mole ratio upon the sulfur retention, nitrogen oxide levels in the flue gas and the combustion efficiency.

The bed is water-cooled and incorporates a bubble-cap distributor plate. The combustor is about 3.4 m (11 ft) tall and is enclosed in an outer shell of 30 cm (12 in.) diam. A flow diagram is shown in Fig. 3.2.

Since 1974, the 15-cm (6-in.) diam combustor has been operated in conjunction with a lime regeneration system. Recent experiments have involved characterizing the particle size distribution from the combustor. The performance of granular bed filters and some types of cyclones have been evaluated also.

3.3 Exxon Miniplant

The Exxon PFBC facility is located at the Exxon Research and Engineering Company facilities in Linden, New Jersey, and has been in operation since 1974. The PFBC miniplant was constructed with EPA funds with initial emphasis placed on obtaining data on sulfur emissions and sorbent utilization. Recently a series of tests on turbine and heat exchanger materials were sponsored by DOE.⁷⁻¹⁰

The combustor is a 10 m (32 ft) tall vessel which is 61 cm (24 in.) in diam. Refractory lining brings the inside diameter down to 33 cm (13 in.). The combustor is cooled by vertically oriented serpentine coils through which water is circulated. The coils are fabricated from type 316 stainless steel, 1.2 cm (0.5 in.) in diam (Schedule 40 pipe). Each coil covers a vertical distance of 46 cm (18 in.).

The system operates at pressures to 1.0 MPa (10 atm), bed velocities to 3.05 m/s (10 ft/s), and temperatures up to 982°C (1800°F). Solids feeding rate is as high as 180 kg/h (400 lb/h). Coal and dolomite are premixed and are injected through the side of the shell at a distance of 30 cm (11 in.) above the air tuyere plate. The feeding system is a modified Petrocarb unit. Two stages of cyclone collectors plus one tertiary cleanup device constitute the particulate removal equipment for the miniplant. Granular bed filters, ceramic bag filters and cyclones were tested as the tertiary device with the cyclone providing the most satisfactory operation. Solids collected in the first stage cyclone are recycled back to the combustor. The test unit is diagrammed in Fig. 3.3. The bed depth in the combustor can be varied from 2.3 to 6.1 m (7.5 to 20 ft).

Fig. 3.2. Schematic flow sheet of ANL PFBC system (Ref. 10).

Fig. 3.3. Schematic of Exxon miniplant.

The turbine blade test section was supplied by GE and contains four rows of turbine blades which direct the flow through four 90° turns. The first three cascades consist of impulse blades while the last is a reaction stage. The rectangular duct containing the cascades is 1.6 cm (0.625 in.) deep and 6.66 cm (2.625 in.) wide. Chord length of the airfoil specimens is 2.54 cm (1.0 in.). The combustion gas must be supplementally heated with methane to maintain temperature at the turbine test section.

The experiments at the miniplant have been directed toward a number of areas:

1. SO₂ emissions,
2. NO_x emissions,
3. sorbent regeneration,
4. turbine and heat exchanger materials evaluation.

The combustor had operated for over 3300 h in runs of up to 260 h before EPA funding ran out in August 1979 and the facility was shut down.

3.4 Leatherhead — National Coal Board (NCB)

The PFBC at Leatherhead, England, is operated by the Coal Utilization Research Laboratory (CURL) which was formerly British Coal Utilization Research Association (BCURA). Tests at this facility have been carried out since 1972 which, at that time, were funded by the Office of Coal Research (OCR). ERDA continued support as is DOE. The Mark II combustor was operable in 1972 but was modified slightly around 1975 to a Mark III configuration and was modified again in 1978.¹¹⁻¹⁴ The Mark III version is shown in Fig. 3.4. This combustor consisted of a refractory-lined rectangular casing situated inside a cylindrical pressure shell. The fluidized bed in the casing is 0.6 m × 0.91 m (2 ft × 3 ft) in cross section. Water-cooled horizontal tubes traverse the bed over a 2.1 m (6.9 ft) vertical distance. The air distributor plate has multiple tubes attached to plate which extend about 3.8 cm (1.5 in.) into the bed. The layer of unfluidized material below the air ports serves as insulation for the distributor plate. Material removal is accomplished via a tube which drains through a distributor plate.

Fig. 3.4. Schematic layout of the Leatherhead Mark III PFBC facility (Ref. 20).

Four water-cooled coal feed nozzles penetrate the sides of the combustor. The solids transport system is a Petrocarb lockhopper system. Control of the coal feed rate is accomplished by adjusting the pressure differential between the coal feeder and the combustor. Dolomite is fed from a small, separate lockhopper system.

Tests during 1976 to 1977 saw the combustor operating at 866 to 899°C (1590 to 1650°F) and 0.44 to 0.50 MPa (4.4 to 5.0 atm) with a bed height of about 2.4 m (8 ft). Test durations were typically 70 to 100 h. Excess air was varied from 25 to 120%.

Corrosion test specimens are located in the fluidized bed. The Mark III system was also equipped with a turbine blade cascade test section. Two stages of cyclone separators precede the cascade. Behind the cascade are located some pin specimens.

In 1978 the combustor was modified to a Mark VI configuration which incorporate cascades and cleanup systems provided by GE and Stal-Laval.¹⁴ American Electric Power's (AEP's) PFBC plant concept utilizes the Stal-Laval turbine and three stages of cyclones similar to those being tested at Leatherhead. The GE supplied cleanup system incorporates an electrostatically enhanced cyclone plus two stages of conventional cyclones.

These latest tests involved simultaneous turbine materials and gas cleanup experiments with AEP, Stal-Laval, GE and Combustion Systems Ltd. as the principal participants. DOE and EPRI also supplied funding or materials. For these tests the internal parts of the combustor were completely reworked. The bed has a top cross-section of 4 ft x 2 1/4 ft (1.2 m x 0.69 m). The bed depth is ~9 ft (2.74 m) and tapered in one plane to a bottom cross section of ~2 ft x 2 1/4 ft (0.61 m x 0.69 m). The bed heat is removed by a tapered water cooled tube bank that extends from 2 ft (0.61 m) to 8 ft (2.4 m) above the base of the fluidized bed. The general heat exchanger design is representative of that being considered for the AEP/Stal-Laval plant.

The gas stream is split into two flows which feed into turbine material test sections monitored by GE and Stal-Laval, respectively. The Stal-Laval section has three sections of first stage turbine blades from a Stal-Laval GT-120 gas turbine. The GE section has four cascades each having six small blades with a chord length of ~1 in. (2.5 cm). The Stal-Laval test section was operated at a temperature of ~1430°F (1050°K) and the GE section at a temperature of ~1500°F (1089°K). The additional

temperature in the GE section was obtained through supplemental firing with propane.

A 50 h commissioning test was performed in June, 1979 followed by five tests of 150 to 200 h duration. A total of 1801 h of operation had been accumulated by December 1979.

A rotary valve solids metering system that was installed to replace the Petrocarb feeders used in the previous experiments resulted in a very close control of bed temperature throughout the 1000 h of operation.

A simplified schematic of the Mark VI modification to the Leatherhead facility is shown in Fig. 3.5.

3.5 Grimethorpe — International Energy Agency (IEA)

The PFBC test unit at Grimethorpe, England, is a venture involving principally the National Coal Board (NCB) and the IEA. Under their management in 1975 an agreement to build the facility was reached among the United Kingdom, United States, and Germany. Construction costs have been borne in part by each country. Shakedown testing of the facility was scheduled to start in early 1980.¹⁵ This date has slipped to early 1981 due to a host of procurement and contractual delays.

The system diagram is presented in Fig. 3.5. The combustor has a capacity of about 80 MW operating at pressures of 0.6 to 1.2 MPa (6 to 12 atm) with off-gas temperature of 800 to 950°C (1472 to 1742°F). Maximum design temperature is 1100°C (2012°F). The pressure shell, built in Germany, is about 4 m (13.1 ft) in diam and 14 m (46 ft) in height. The shell is constructed of shaped steel plates butt welded together. Power for air compression is supplied by a steam turbine which utilizes the steam generated in the combustor. Excess steam is to be exported to an adjacent power plant.

A 2 m (6.6 ft) square cross section furnace is situated within the shell. Water walls are used for heat absorption and containment for the fluidized bed. The distributor plate is a bubble cap design. The water-cooled tube bundles lie in a horizontal orientation. The combustor is illustrated in Fig. 3.6.

Fig. 3.5. Simplified schematic of the Leatherhead Mark VI facility.

Fig. 3.6. Grimethorpe Experimental Facility plant layout-elevation.

The solids injection system was built by Petrocarb and feeds nine nozzles which penetrate the distributor plate. Coal is dried and mixed with dolomite prior to injection.

The flue gas leaving the top of the combustor is divided among four primary cyclones arranged circumferentially around the combustor. The gases then pass through a second and third bank of cyclones before entering the cascade test section. The facility will provide important information since its gas flow of 39 kg/s (85 lb/s) is large enough to permit testing of full-size turbine blade cascades or rotors. The schedule as presented in the summer of 1980 called for start of the experimental program early in 1981.

3.6 Curtiss-Wright

The Curtiss-Wright Small Gas Turbine (SGT) test rig is located at the Curtiss-Wright plant in Wood-Ridge, New Jersey. This PFBC test unit is among the largest in existence and has been operating since early 1978. The SGT unit was to provide a technology base for a larger pilot plant demonstration which to date is in early stages of construction.¹⁶⁻¹⁸

The combustor is 0.91 m (3 ft) in diam and has an expanded bed height of 9.7 m (16 ft) and a 4.6 m (15 ft) freeboard. The bed is aircooled by vertical tubes which are 10.2 cm (4 in.) in diam and 9.7 m (16 ft) long. The tubes are of the bayonet or reentry type and have external vertical fins. The entire rig is about 23 m (75 ft) tall. A schematic flow diagram is shown in Fig. 3.7.

The combustor operates with a pressure of about 0.65 MPa (6.5 atm) and produces hot air at a maximum temperature of 899°C (1650°F); bed temperature during testing ranges up to 911°C (1672°F). Combustion is maintained with 30% excess air. The maximum coal flow rate is about 266 kg/h (585 lb/h) accompanied by about 114 kg/h (250 lb/h) of dolomite. Coal and dolomite are injected in to the combustor separately. Both systems employ lockhoppers followed by pneumatic transport. The solids are fed through the side of the combustor shell.

The Curtiss-Wright concept for a combined cycle power plant incorporates an air-cooled combustor where the heated clean air is mixed with the

Fig. 3.7. Curtiss-Wright SGT technology rig.

combustion gas after the gas is subjected to extensive cleanup. The SGT rig utilizes this same approach. The ratio of clean air to flue gas is about 2/1 on a mass basis. The latest version of the gas cleanup system consists of 3 stages of conventional cyclones followed by an Aerodyne cyclone which uses a small portion of the clean air to generate a high rotational velocity of the gas in the cyclone. The matter collected in the first stage cyclone is recycled to the combustor.

A Rover gas turbine is driven by a small fraction of the air and gas mixture. The turbine is a single stage wheel with impulse blading and is

about 17.8 cm (7 in.) in diam. Normal operational speed is about 40,000 rpm. The design of the turbine is not conducive to long life when operating on dirty gas, and the test results would therefore be rather conservative with respect to erosion resistance.

As of December 1979 about 3000 h of operation had been accumulated on the test unit with the gas turbine in operation for 1000 h. A complete report on the 1000 h turbine test was not available at the time of this writing.

Curtiss-Wright and DOE have developed plans for a pilot plant to be located at the same site. The coal feed rate for this unit would be about 4545 kg/h (10,000 lb/h) and the maximum gas turbine output would be about 7000 kWe. The engineering for the pilot plant is essentially complete. Some preconstruction activity has been started such as procuring a limited amount of equipment.

3.7 New York University (NYU) PFBC Facility

Under DOE sponsorship, a 76 cm (30 in.) PFBC unit is being constructed at NYU. The facility is intended to incorporate sufficient flexibility for a number of types of research activities. A panel of industrial and laboratory personnel acting in an advisory capacity has been formed to ensure the versatility of the test unit.

The combustion air system can supply air at pressures of 0.1 to 1.0 MPa and flows up to about 10,000 kg/h. The air compressors are diesel driven. Combustion air can be preheated for start-up by gas or kerosene heaters. The combustor is refractory lined and uses a water-cooled perforated plate air distributor.

Solids metering is to be accomplished by a rotary valve operating in conjunction with a lockhopper system. Isolation of the lockhoppers is accomplished by gate knife valves. Design flow rates cover the range of 91 to 1800 kg/h of coal and 12 to 280 kg/h of sorbent.

Two stages of cyclones are used for particle cleanup. The primary cyclone is 61 cm (24 in.) in diam (inside) and the secondary unit's diameter is 25 cm (10 in.). Inlet gas velocities of about 25 m/s (83 ft/s)

are to be used in the cyclones. The flue gas can be monitored for emissions of SO_2 , CO, CO_2 , and NO_x .

A research program is being planned with industrial applications in view. A summary of the proposed activities at the NYU facility is shown in Table 3.1. Construction was scheduled for completion near the end of 1981. A decision was made to terminate plans for the large combustor and build a smaller unit of about 30 cm (1.0 ft) diam.

3.8 GE Long Term Materials Test Facility (LTMTF)

The LTMTF is currently under construction at GE facilities in Schenectady, New York. The combustor is about 30 cm (12 in.) inside diam and is to operate at pressures of about 1.0 MPa and combustion temperatures of 955°C (1750°F). The coal feed rate is expected to be 60 kg/h (132 lb/h) and sorbent feed is to be 19 kg/h (42 lb/h). The facility is to have two materials test sections, one low velocity [8.0 m/s (26 ft/s)] and one high velocity [240 to 420 m/s (800 to 1400 ft/s)]. The combustor is designed to run with 20% excess air. The expanded bed depth will normally be about 1.6 m (5.3 ft) using a superficial air velocity of just under 1.0 m/s (3.3 ft/s). The combustor vessel is refractory lined. The distributor plate utilizes air nozzles to provide for a non-fluidized layer of solid material that will rest on the bed plate and insulate it from the combustion zone. Propane is to be used to start the combustor. The combustor is cooled by water passing through horizontal, serpentine heat exchanger tubes.

Gas cleanup is accomplished by three stages of conventional cyclones. The first stage is about 20 cm (8 in.) in diam and the latter two stages are 15 cm (6 in.) cyclones.

The high velocity test section is to be a refurbished version of the cascade used at the CURL facility in 1979 for the 1000 h materials test. Unfortunately, the total pressure at the inlet to this cascade will be only about 30% of the combustor pressure.

The solids feeding system is made up of lockhoppers and a rotary valve metering device. A single coal feed line supplies fuel to the combustor. An illustration of the facility is shown in Fig. 3.8.

Table 3.1. NYU pressurized fluidized bed combustion (PFBC) facility research program

Operating characteristics.				
Coal		Sorbent	Operating range	
1. Pennsylvania bituminous	1. New Jersey Newton Limestone No. 2 and 3		Bed pressure: 1 to 10 atm	
2. Montana sub-bituminous	2. Chas Pfizer dolomite No. 6 and 10		Bed temperature: 760-980°C	
3. Texas lignite	3. Texas limestone		Fluidizing velocity: 1.2-3.0 m/s	
			Excess air: 10-30%	
			Expanded bed height: up to 3.0 m	
			Initial mean sorbent size: 1.2 to 2.4 mm	
Research areas				
Bed material performance	Heat transfer	Sulfur adsorption	Attrition and elutriation	Scaling parameters
1. Combustion performance and operational limitations of coal	1. Immersed horizontal and vertical heat exchanger	1. Sulfur retention and Ca/S ratio as a function of pressure, temperature, particle size, excess air, precalcination, gas and solids residence time	1. Particle shrinkage rate	Will be developed for heat transfer, bed expansion and sulfur adsorption in conjunction with data from other units
2. Utilization and attrition behavior of sorbents	2. Parametric effects of pressure, temperature, fluidizing velocity, bed depth, particle size, HX solidity, fins	2. Comparison with sulfur retention models	2. Rate of fines production	
	3. Develop experimental correlations	3. Experimental correlation	3. Elutriation rate	
	4. Comparison with correlation and theoretical models		4. Comparison with attrition models	
	5. HX tube vibration and stress

Fig. 3.8. Long-term materials test facility.

Instrumentation for the system includes analyzers for O_2 , SO_2 , CO, and NO_x . An alkali sampling train is to be used at the facility also.

Preliminary operation of the facility was to have begun early in 1981.

4. REVIEW OF PFBC DATA BASE

This section relates the current understanding of a number of important aspects of the PFBC concept. The data and information described in this section served as the foundation for the analytical work described later in the report. The subject areas covered are:

1. Emissions
2. Combustion efficiency
3. Solids feeding
4. Gas cleanup
5. Turbine degradation modes
6. Materials performance in PFBC
7. Turbine life estimates
8. Heat transfer

4.1 Emissions

4.1.1 Sulfur capture

The sulfur contained in coal is captured by a calcium-rich sorbent which forms the majority of the bed material in a PFB combustor. The sorbent is usually limestone or dolomite. Limestone is principally composed of calcium carbonate, CaCO_3 , while dolomite is an aggregate consisting of practically equal parts of magnesium carbonate, MgCO_3 , and CaCO_3 . The overall sulfur capture reaction for limestone or dolomite is

where the product calcium sulfate, CaSO_4 , is a dry solid. The MgCO_3 component of dolomite does not react with sulfur in a PFB. However, at most PFB operating conditions the MgCO_3 will calcine to MgO . The calcining of MgCO_3 increases the porosity of the dolomite solid which enhances the sulfur capture reaction.

In atmospheric fluidized bed combustors the sulfur capture reaction is usually assumed to occur in the following steps:

where the third reaction is the slow, rate-determining step. The first step is the calcination of CaCO_3 to CaO . The calcination reaction is very sensitive to temperature and CO_2 partial pressure. If the actual CO_2 partial pressure from coal combustion in the fluidized bed exceeds the calcination equilibrium CO_2 partial pressure, the reaction will proceed in the reverse direction. This condition can actually occur in a PFB operating at high total pressure and low temperature and excess air. Some calcination numerical examples are shown in Table 4.1.

PFB experimental data have been produced at operating conditions on both sides of the calcination equilibrium point. The data show that sulfur is easily captured using dolomite even when the calcination of CaCO_3 is not favored. Therefore sulfur capture mechanisms other than the reaction of SO_2 with CaO must also be important. One hypothesis is direct sulfation without calcination

A thorough understanding of reaction mechanisms will be necessary to fully interpret the effects of PFB operating conditions on sulfur capture.

The type of sorbent has a large influence on the sulfur retention in a PFB. Most dolomites are more effective PFB sorbents than limestones, on both molar and weight bases. This trend is shown in Figs. 4.1 and 4.2. However there are some exceptions to this tendency. Westinghouse²¹ has performed pressurized thermogravimetric measurements on many types of

Table 4.1. Effects of pressure, temperature and excess air on the calcination of calcium carbonate. Equilibrium data are from Ref. 19. Actual CO₂ partial pressure estimated for coal combustion gases of an average composition.

Type of combustor	Total pressure (atm)	Bed temperature (°C)	Excess air (%)	Ratio of actual to equilibrium CO ₂ partial pressure	Direction of calcination	
					CaCO ₃	CaO + CO ₂
AFB	1	850	20	0.28		forward
PFB	5	800	20	3.00		reverse
			100	1.81		reverse
		900	20	0.70		forward
			100	0.42		forward
PFB	10	800	20	6.00		reverse
			100	3.63		reverse
		900	20	1.40		reverse
			100	0.85		forward

Fig. 4.1. Retention of sulfur in the CURL 0.6 × 0.9 m pressurized fluidized bed combustor (Ref. 11).

dolomite and found that a large grained crystalline structure results in a dolomite with very poor sulfur capture properties. The explanation presented by Westinghouse indicates that sulfur capture is almost entirely concentrated at the dolomite grain boundaries. Therefore larger grains mean less sulfur capture.

Fig. 4.2. Sulfur retention capabilities of additives compared, mass basis (ANL) (Ref. 20).

The calcium to sulfur molar feed ratio (Ca/S) is the most influential PFB operating condition affecting sulfur capture. The stoichiometry of the reaction requires that the fraction of sulfur captured²² during steady state combustion is related to Ca/S and U_t (fraction of calcium which is utilized in the sulfur capture reaction) in the following manner,

$$E = U_t (\text{Ca/S}) .$$

The effect of Ca/S is shown in Figs. 4.3 and 4.4 which present data measured at Exxon's miniplant. Exxon's most recent data (Fig. 4.4) were produced to define the relationship between E and Ca/S at higher sulfur retention levels.

The effects of expanded bed depth and superficial velocity on sulfur capture in a PFB are usually lumped together into the single parameter, gas residence time (t). Both Exxon²⁴ and Westinghouse²⁵ have derived a simple, first order, PFB reaction expression which assumes the SO_2 reaction rate is proportional only to SO_2 concentration and where all

Fig. 4.3. SO₂ retention using dolomite sorbent (Exxon) (Ref. 22).

Fig. 4.4. Recent SO₂ retention data at high sulfur capture levels using dolomite sorbent (Exxon) (Ref. 23).

SO_2 is assumed to be produced at the bottom of the bed. The following expression was obtained

$$E = 1 - e^{-kt}$$

where k is the first order rate constant. Exxon (also in Ref. 24) correlated PFB sulfur capture data for dolomite sorbent from ANL, NCB and their own miniplant using the first order rate expression and they determined that the rate constant was only a function of calcium utilization as shown in Fig. 5. Exxon also published the following curve fit of Fig. 4.5

$$k = 10.11 - 23.4 (U_t) + 14.0 (U_t)^2$$

where U_t is the fractional calcium utilization and k has units of sec^{-1} .

Temperature, in the range of interest in this study, appears to have a small to negligible influence on sulfur capture in PFB's using dolomite

Fig. 4.5. Measured first order rate constant for sulfur capture using dolomite sorbent (Exxon) (Ref. 24).

sorbent. Data produced at the Leatherhead facility are shown in Fig. 4.6. Similar data for dolomite sorbent were also measured by ANL²⁶ in both their VAR and NOX-II series of combustion studies. Exxon²⁷ has concluded that sulfur retention is only affected by combustor temperature when the temperature is less than 800°C. Data from their miniplant using dolomite sorbent are shown in Fig. 4.7.

The effects of pressure, excess air and sorbent particle size on sulfur retention in a PFB are not well defined relationships. This problem is due to insufficient data generated at the experimental facilities and also difficulties in comparing data from different facilities because of

Fig. 4.6. Effect of combustor temperature on sulfur retention with Ca/S mole ratio = 2. Fluidizing velocity 0.6 to 0.75 m/s, bed depth 1.14 to 2.44 m and freeboard pressure 0.35 to 0.60 MPa (CURL) (Ref. 11).

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Fig. 4.7. Effect of low combustor temperatures on sulfur capture using dolomite sorbent (Exxon) (Ref. 27).

differences in sorbent types, operating conditions and combustor configurations (location of heat transfer surface, solids feeding, etc.). Understanding the relationship between pressure and sulfur retention can obviously be very important to the development of PFB power plants. Unfortunately the available data are both limited and conflicting. The general

tendency of the data appears to be that sulfur capture using dolomite sorbents decreases slightly as pressure increases. Data from the ANL NOX-II series of experiments²⁶ support this trend in the range from 1 to 8 atm. Thermogravimetric measurements of dolomite sorbents performed by Westinghouse²⁸ also support this tendency in the range from 10 to 20 atm as is shown in Fig. 4.8. However Westinghouse²⁹ has also generated data between 1 and 10 atm of pressure which indicate that sulfur capture using dolomite sorbents either remains stable or improves slightly as pressure increases. Additional PFB experimental studies will be necessary in order to fully resolve this conflicting information.

4.1.2 NO_x emissions

NO_x concentrations emitted from PFB combustors are usually higher than equilibrium concentrations from the dissociation of gaseous N₂.

Fig. 4.8. The effect of combustor pressure on sulfur retention performance in a PFB using dolomite sorbents (Westinghouse) (Ref. 28).

This indicates that a large portion of the nitrogen oxides are formed from nitrogen contained in the coal. However, the relatively low combustion temperatures in PFBs hold down the NO_x emissions to levels which are generally well below the new source performance standard of $0.6 \text{ lb NO}_2 / 10^6 \text{ Btu}$ (bituminous coal). The composition of NO_x emissions is about 95% NO and 5% NO_2 .¹¹

Excess combustion air has a large effect on NO_x concentrations in PFB flue gases. A correlation of Exxon miniplant data is shown in Fig. 4.9. Measurements produced by NASA-Lewis are presented in Fig. 4.10. Excess air influences the amount of oxygen which is available for reaction with nitrogen to form nitrogen oxides. Sometimes the actual O_2 concentration in the flue gas is a more appropriate NO_x correlation parameter. This is particularly true for data measured during unsteady PFB operating conditions as is shown by the NRDC measurements in Fig. 4.11.

Comparison of AFB with PFB experimental data indicates that NO_x emissions are higher at atmospheric pressure. This tendency is supported by ANL data from their NOX-II series of experiments as is shown in Fig. 4.12. One possible explanation of this pressure effect is based on the assumption that most NO_x emissions are produced from coal nitrogen in the following reaction:

This reaction is suppressed at increased pressures because 2 moles of gaseous product are produced from 1 mole of gaseous reactant.

Temperature appears to have only a small effect on NO_x concentration. The NASA-Lewis data in Fig. 4.10 shows a slight increase in NO_x when the temperature is raised 110°C (200°F). Insufficient data is available to determine any significant influences on NO_x emissions from other operating conditions, such as expanded bed depth, superficial velocity, or type of sorbent.

4.1.3 Trace element emissions

Release of trace elements or their vapors from coal combustion produces undesirable atmospheric pollution and creates serious corrosion and

Fig. 4.9. NO_x emissions from the 9 atm miniplant PFB combustor (Exxon) (Ref. 23).

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Fig. 4.10. Effect of excess air on NO_x emissions from a 5.2 atm PFB combustor (NASA-Lewis) (Ref. 30).

ORNL-DWG 81-16555 ETD

Fig. 4.11. Correlation of oxygen and nitrogen oxide concentrations in the flue gas (CURL) (Ref. 11).

ORNL-DWG 81-16556 ETD

Fig. 4.12. Effect of pressure on NO_x emissions from a PFB combustor (ANL) (Ref. 26).

deposition problems in a gas turbine driven by the coal combustion gases. Some effort has been made to characterize these emissions, and examples of the available data are presented here. Discussion relevant to turbine erosion and corrosion is found in a later section. Data on the trace element content of coal combustion gas have been documented by NRDC, CPC, and ANL.

The alkali metals are very active in the corrosion mechanism for the gas turbine materials, and their concentrations are emphasized over other trace elements. These metals form sulfates and chlorides with the SO_2 and chlorine in the combustion products. The sulfates and chlorides have been identified as promoting corrosion and deposition in gas turbines. According to studies performed by GE, the combustion temperature and

chlorine content of the coal are the most important in determining the amount of alkali metal vapor in the flue gas (Fig. 4.13).

The GE analytical model predicts a weight concentration of about 10 ppm for sodium and potassium in the combustion products of a PFBC operating at 954°C (1750°F) on a typical U.S. coal (0.1% Cl content). The concentration is about 30 times greater than current limits suggested for petroleum (residual)-fired turbines. The data from the NRDC combustor in Table 4.2 provide an order of magnitude confirmation of the calculations of GE. Numerous other factors such as the dolomite feed rate and sulfur retention have influence on the alkali vapor emissions.

Fig. 4.13. Alkali vapor concentration variation with temperature based on thermochemical equilibrium calculations.

Table 4.2. Measured alkali vapor concentrations in NRDC PFBC at Leatherhead

Test No.	1 ^a	2 ^b	3.2 ^c	4.2 ^d	6.1 ^e	7A ^f
Na (weight ppm)	5.2	1.7	3.0	1.5	1.4	0.8
K (weight ppm)	2.7	1.2	2.5	1.3	0.6	0.3

^a0.09% Cl in coal, bed temperature — 888°C (1630°F).

^b0.09% Cl in coal, bed temperature — 952°C (1745°F).

^c0.04% Cl in coal, bed temperature — 902°C (1655°F).

^d0.04% Cl in coal, bed temperature — 949°C (1740°F).

^e0.04% Cl in coal, bed temperature — 871°C (1600°F).

^f0.04% Cl in coal, bed temperature — 877°C (1650°F).

Sources: (1) National Research Development Corporation, *Pressurized Fluidized Bed Combustors*, R&D Report 85, Interim No. 1, prepared for Office of Coal Research, Department of the Interior (1974). (2) A. G. Roberts et al., *Pressurized Fluidized Bed Combustion Annual Report July 1976–June 1977*, FE-1511-43 (September 1977).

Data from ANL have shown alkali vapor emission to be proportional to combustor temperature with a notable increase occurring at about 816°C (1500°F).²⁶

Some attempts to measure alkali vapor concentrations have been made in conjunction with the CC programs also. The concentrations of sodium were on the order of 3 ppm. It should be noted that the data presented in this section emphasize the alkali in vapor phase which is generally not readily removed for the gas stream.

4.2 Combustion efficiency

The most important PFBC operating conditions which influence the combustion efficiency of coal particles are temperature, excess air, bed depth, superficial velocity, amount of carbon fines recycled from the gas cleanup system, and amount of carbon fines removed from the coal prior to

combustion. Data generated at the NASA-Lewis facility⁴ show that efficiency is also affected by pressure. However most of the published data do not cover an adequate range of pressures to support or disprove this conclusion.

The greatest amount of combustion efficiency data have been produced by Exxon in their miniplant. Data from 55 miniplant runs were used in a multiple regression analysis²⁷ to determine the following correlation:

$$\text{C.E.}(\%) = 161.3 = 1.62 \times 10^{-1} (T) + 1.0 \times 10^{-4} (T^2) +$$

$$7.51 \times 10^{-5} (T) (EA) - 4.62 \times 10^{-4} (EA)^2 + 1.73 \times 10^{-2} (t)^3$$

where the temperature T is in $^{\circ}\text{C}$, excess air EA in % and time t in seconds. A plot of this equation versus experimentally measured combustion efficiency is shown in Fig. 4.14. Efficiency measurements taken by Exxon¹⁰ since they reported the above correlation have been consistently

Fig. 4.14. Comparison of calculated and measured combustion efficiencies (Exxon) (Ref. 27).

higher than the predicted values by an average of 0.8 combustion efficiency units. It is important to note that the Exxon miniplant collected carbon fines in the first stage cyclone and recycled them back to the combustor in order to improve the combustion efficiency.

Combustion efficiency data have also been reported by ANL and NRDC. The effects of temperature, excess air, superficial velocity and bed depth on efficiency are seen in Figs. 4.15 through 4.17. The three plots indicate combustion efficiency is a function of temperature, excess air and superficial velocity with no definite dependence on bed depth. Both the ANL and NRDC data were measured in combustors which did not recycle carbon fines.

Fig. 4.15. Combustion efficiency as a function of bed temperature (ANL) (Ref. 20).

Fig. 4.16. Effects of combustor temperature on combustion efficiency with 17% excess combustion air (CURL) (Ref. 11).

Fig. 4.17. Effect of operating parameters on combustion efficiency (CURL) (Ref. 13).

4.3 Solids Handling Systems

4.3.1 Basic requirements

The handling of solids for a PFBC presents one of the more critical and difficult mechanical design problems associated with the system. In general, the system must be designed to process run-of-mine material to the desired particle size and to convey the feed to the combustor. After the completion of combustion, the ash and spent sorbent materials must be removed from the system and transported to a disposal site.

The coal and sorbent handling and preparation systems will generally include equipment for receiving, storing, crushing, and conveying the coal and sorbent to the plant storage hoppers. From the storage hoppers the solids are fed to the combustor. The bulk of the elutriated material from the furnace is separated from the gas streams with cyclone separators and the remainder removed by either electrostatic precipitators or bag filters. The solids from the cyclones can be either recycled or added to the solids disposal stream after being cooled.

Uncertainties in the design of the solids handling systems are related not only to the mechanical aspects of the systems but also to their effect on system performance, particularly in regard to sulfur retention, combustion efficiency, and component integrity.

4.3.1.1 Coal/sorbent feed handling system. The function of the coal/sorbent feed system is to introduce a metered amount of coal and sorbent to the furnace in such a manner that combustion takes place predominantly within the bed. In-bed combustion affords maximum contact of the SO_2 generated during combustion with the sorbent (usually CaO). To minimize materials corrosion problems, the coal and sorbent must also be fed in a manner that prevents reducing zones or alternating reducing and oxidizing zones in the volume of the bed containing the boiler or steam tubes.

Coal/sorbent can be fed to the bottom of a fluidized bed either through ports in the bottom support plate or through tubes, or lances, from the sides of the furnace. One question concerning either of these feeding methods is the number of feed points required. One "rule of thumb" (derived from AFBC experience) often quoted states that one feed

point should be provided for each 9 ft^2 (0.8 m^2) of bed area, which would lead to approximately one feed point for each 10 to 20 MW(t) in a commercial-scale PFBC system. It should be noted that the experimentally tested power level for FBC's is ~ 1 to 2 MW(t) per feed point. These tests were run in the B&W $6 \text{ ft} \times 6 \text{ ft}$ and the Rivesville plant both of which are AFBCs. It is not known if the radial mixing in a PFBC is great enough to handle 10 times the coal flow rates tested in the AFBCs. If the mixing rate is not adequate, this will lead to areas of the bed that are in a reducing zone. The Grimethorpe experiment is planned to operate at ~ 5 times the AFBC coal rate and 4.5 ft^2 (0.4 m^2) per feed point.

The number of feed points required probably depends on many factors. The basic criterion, however, is that coal should be burned in such a manner that local hot zones or reducing zones are not produced in the tube matrix volume of the bed. For example, if the size of coal particles fed to the bed is very small, very rapid combustion of the volatiles could occur near the feed point and give rise to the local reducing zones. Conversely, if very large lumps of coal are fed to the bed, the coal does not fluidize readily and this, in turn, could lead to reducing conditions near the feed points. Another factor to be considered is the vertical distance between a feed point and the tube matrix. Increases in this distance favor dispersion of the coal throughout the bed material before it contacts the tube matrix and reduce the probability of a reducing zone in the matrix.

An attempt to avoid local in-bed reducing zones can be made by over-design (i.e., by providing more feed points than are deemed essential). However, the resulting solids feed system will be expensive, and the larger number of feed points can cause operation and maintenance problems. To minimize the cost of the feed system, most designs use a system whereby a metered coal stream is split several times before entering the furnace. This splitting system could lead to an unacceptably nonuniform feed rate or particle size distribution of coal to various sections of the bed. For example, if the coal feed is split three times with an accuracy of $\pm 5\%$ each time, the resulting coal feed rate to the feed points could vary by as much as $\pm 16\%$.

Precautions are also required in the design of lines supplying coal to the feed points, especially if long pipes are used to carry the coal through the furnace wall and the bed to the feed points. In this case, the coal may be heated to a temperature which could cause coking of the coal and result in eventual plugging of the feed lines.

An overbed feed system that employs a spreader stoker to spread the coal over the surface of a bed is presently being tested at the Georgetown AFBC as an alternate to underbed feeding. The main advantage of this approach is a dramatic reduction in the number of feed points and, therefore, a simplification in the fuel distribution system. A secondary advantage of overbed feeding is that the spreader stokers utilize larger coal sizes than are currently used with the underbed feed systems. The success of this method applied to a PFBC will probably require that coal fines be eliminated or kept to a small fraction of the coal fed since the fines might burn in the freeboard above the fluidized bed with possible escape of most of the resulting SO_2 from the furnace. This system could also result in excessive carryover or elutriation of unburned carbon from the bed. Another possible problem that may arise from the use of larger coal sizes is the accumulation of "rocks" in lower sections of the bed that could interfere with the overall bed performance.

4.3.1.2 Wet coal feeding. Fluidized-bed combustors containing in-bed heat transfer surfaces require uniform fuel distribution to ensure adequate life for the metal comprising the heat exchange surfaces. To prevent excessive corrosion, the heat exchange environs must be maintained in an oxidizing condition. This condition is usually satisfied in most AFBC installations today by underbed fuel feeding systems with each fuel feed point located to serve $\sim 9 \text{ ft}^2$ (0.8 m^2) of bed surface. For the PFBC with a higher burning rate than the AFBC's this area will probably have to be reduced.

Using the design criteria of one feed point per 4.5 ft^2 (0.4 m^2) of bed area requires that a large number of feed points be used in a commercial-sized PFBC [approximately one point per 5 MW(e) of steam generation]. Economics require that metered streams of feedstock ($\sim 1/4 \times 0$ in.) be subdivided and transported pneumatically through multiple small feed pipes. Excess moisture in the coal, combined with the fines,

promotes agglomeration, which ultimately may result in plugging of the feed lines and/or the feed splitters. Excess moisture in the coal feed can also lead to problems in other parts of the feed systems, such as bridging and ratholing in the storage bunkers, which can result in nonuniform fuel flow to the section of bed supplied by the bunkers.

The amount of moisture that can be allowed in the feedstock fed to the underbed feeding system cannot be generally specified, as it depends on the top size of the feed material, its porosity and its fines fraction. Coal handling experience would indicate that coal in the $1/4 \times 0$ in. (6.4×0 mm) range can be handled in the distribution system with a surface moisture in the 4 to 5% range.

Uniform distribution of wet fuel (5 to 15% moisture) fed to a fluidized combustor may be accomplished through the use of a spreader stoker to spread the coal over the surface of the bed. The success of this method will probably require that the coal fines be eliminated or kept to a small fraction of the coal fed since the fines that burn in the freeboard above the fluidized bed will contribute disproportionately to the SO_2 that escapes the furnace. This system could also result in excessive carryover or elutriation of unburned carbon from a bed. The main attraction of this fuel feeding system is lower cost and the probable elimination of coal dryers.

4.3.1.3 Ash and spent sorbent removal. Coal ash and spent sorbent material are removed from the bed through use of bed let-down extraction points and by elutriation from the bed and subsequent transport from the freeboard by the flue-gas stream. In addition to the coal ash and spent sorbent, unburned carbon and unreacted sorbent are also removed from the bed as part of these streams. The location of the bed let-down point should be as remote from the coal/sorbent feed points as possible to avoid short circuiting these streams.

The material removed from the bed let-down points is at a temperature of about $1500^\circ F$ ($800^\circ C$). This material should be cooled to eliminate the necessity of using high-temperature handling methods, and the sensible heat recovered from the solids should be returned to the system economically to contribute to the overall thermal efficiency. Cooling can be accomplished either by direct or indirect heat exchange; the material can be

cooled in a fluidized-bed heat exchanger with the hot gas being fed to the combustor, or the material can be cooled by a water-walled heat exchanger with the hot water being used as boiler feed water.

Potentially, the direct air-cooled system may reduce the carbon concentration in the bed let-down material and thereby improve the furnace combustion efficiency. To offset this advantage, however, the power requirements of the air-cooled system would probably be greater than for the water-cooled system.

The cooled ash and spent sorbent can be depressurized with a lock hopper arrangement and transported pneumatically to a storage silo. From the storage silo, the spent material will normally be sent to a disposal area or may be recycled to the fluidized bed for start up.

The majority of the material elutriated from the bed is removed from the flue gas by a cyclone separator and recycled either to the main bed or a separate bed to allow a more nearly complete combustion of the carbon contained in the elutriated material. The solids remaining in the flue-gas stream are removed by mechanical control devices.

4.3.1.4 Recycle and utilization of fines and spent-bed material.

The total amount of solids to be removed from a bed depends on the ash and sulfur content of the coal, the amount and type of sorbent material required for sulfur retention, the physical properties of the solids fed to the system, and the operating conditions of the fluidized-bed combustor. The solids are removed from the combustion system at three locations: the furnace, the cyclone separators, and the final stack-gas cleanup system. These streams contain thermal energy in the form of sensible heat, unburned carbon, and unreacted CaO.

Although many factors affect the potential sensible heat loss in the rejected solids, this loss can be reduced to well under 0.5% of the heating value of the coal by cooling the solids to 250 to 400°F (120 to 200°C) and returning the recovered heat to the system. Without any sensible heat recovery, this loss would probably be in the range of 1 to 2% of the heating value of the coal.

Energy is also lost from the system in the form of unburned carbon. Carbon can be lost by two paths: in solids drained from the furnace and in particulate material elutriated from the bed. The solids drained from

the beds will contain about the same fraction of carbon as that existing in the bed during normal operation. This carbon fraction is probably in the range of 0.1% of the bed weight, and the energy lost by this path would be a few tenths of 1% of the heating value of the coal.

The amount of carbon elutriated from the bed depends strongly on the velocity of the combustion gases leaving the bed, the depth of the bed, and the method of feeding the bed (under or overbed). For under bed fed systems operating with a bed depth in the 6 ft (2 m) range and a superficial velocity in the range of 3 ft/s (1 m/s), the amount of carbon carried from the bed may reach 5% of the coal feed rate. Losses of this magnitude impose a significant penalty, and the elutriated material must be collected by cyclone-type mechanical collection equipment and the particles recycled to improve combustion efficiency. Recycling to the main combustor may result in overall carbon burnup efficiencies in the 98 to 77% range with the added advantage of potentially greater sorbent utilization if incompletely sulfated sorbent is contained in the recycled material.

In general, the inherent susceptibility to elutriation at process conditions determines the amount and composition of the material elutriated from the bed. The particle size distribution, density, and other factors determine the susceptibility of an individual particle to collection.

4.3.1.5 Conclusions and recommendations on solids handling systems.

The performance and reliability of the feed and waste handling systems are essential for the operation of the PFBC process. Major uncertainties in this area involve not only the mechanical difficulties of the systems but also their effects on process performance (i.e., sulfur retention, combustion efficiency, component integrity, and corrosion resistance of the internals).

Experience in handling the feed and waste materials for fluidized-bed combustors has been limited to small beds. The systems have proven adequate in the size ranges employed in the laboratory environment. Under-bed feeding through nozzles requires the capability to split a feed stream into multiple feed lines with uniformity and minimal pluggage. This has yet to be demonstrated for large-scale PFBC operations. Overbed feeders

present problems in the area of freeboard combustion of fines, reduced inbed sulfur capture, and increased unburned carbon elutriation from the bed. More economical and simpler feed systems with improved uniformity of feed distribution throughout the bed must be developed for large commercial installations. Problems may also arise in large commercial systems that do not occur in the small laboratory equipment if the spreader stoker is used, such as contamination of the bed by large-sized "rock" fractions in the coal feed. Systems for cleaning a large bed of oversized material with a minimum loss of bed material and thermal energy need to be developed.

Moisture associated with the fluidized combustor feedstock can cause problems in the solids transport system. The solids are usually transported pneumatically through multiple piping systems. Excess moisture in the solids, in the presence of fines, changes the flow characteristics of the materials in an unpredictable manner. Development work should be conducted to examine the effects of particle size, and distribution on the allowable moisture content of the coal-sorbent feedstock in various designs.

The fluidized combustor requires the handling of hot waste material [650 to 1550°F (340 to 840°C)]. The temperature of these solids introduces problems of material selection, valves design, carbon ignition, and transport equipment. A possible solution to the problem of hot transport probably would be precooling the solids before they enter the transport equipment.

4.3.2 Solids feeding equipment

The PFBCs built to date have employed a lock-hopper type system to raise the pressure above the solids from atmospheric to the combustor operating pressure. These lock-hopper systems have been of two basic types. One is the Petrocarb type system employed in the Curtiss Wright, the Exxon, the early CURL and the planned Grimethorpe facilities. The other is a simple two tank system employed in the present CURL facility. Descriptions of these systems and others follow here.

4.3.2.1 Type 1 - fluidized lock hopper. The Petrocarb type system is essentially a fluidized bed feeder which depends upon a pressure

differential between the feeder and the combustor to control the solids flow rate to the combustor. The system is widely used in the ore processing industry for the controlled flow of solids to furnaces and smelters.³¹ A Petrocarb feeder was tested by the Bureau of Mines in the early 1960's at an operating pressure of 100 psig (0.78 MPa) and a coal flow rate of 33 lb/s (15.2 kg/s).³² The system performed satisfactorily for the complete series of tests which lasted about four months. Another Petrocarb unit designed to operate at 1000 psig (6.9 MPa) was also tested at the Pittsburgh Energy Research Center for use with the SYNTHANE gasifier.³³ This test also reported satisfactory operation of the feeder for the design range. A fluctuation of $\pm 5\%$ of the coal flow rates was reported.

Both of the above tests were conducted with dry pulverized coal. Difficulties with plugging from wet coal were experienced in the SYNTHANE feeder. Steam from the char cooler entered the lock hoppers and the dry coal storage bin through the vent valves and condensed in these vessels, wetting the coal. The maximum amount of surface moisture allowable was not determined in these experiments.

The operators of the Exxon miniplant indicate that bottom screening of the coal is necessary to prevent plugging of the Petrocarb feeders with surface moisture contents above 3%.¹⁰ It was reported that plugging of the feeder would occur if the coal was fed with a combination of high moisture and high fines content. Satisfactory feedings of 11% moisture coal (size 6 $\times$ 40 U.S. mesh) and 3% moisture coal (size 6 $\times$ 50 U.S. mesh) were reported.

4.3.2.2 Type 2 — nonfluidized lock hopper. Lock hopper feeding systems that operate without fluidizing air have been used for feeding solids to pressurized system such as gasifiers and fluidized bed combustors.^{32,34,14} The lock hopper system employs a storage bin, means of conveying coal into a lock hopper at atmospheric pressure, means for pressurizing to operating pressure, means for discharging into a feed vessel, and a means of reducing the lock hopper pressure back to atmospheric conditions. Two vessels are normally used alternately to supply the feed vessel so as to allow a continuous feed of solids to the processing equipment. To protect the isolating valves from jamming with solids, they are

usually preceded with full flow slide valves. This type system is considered to be the state-of-the-art method of feeding high pressure systems with dry solids. At pressure levels in the range of 10 atm (1 MPa) the solids flow rate from the feed vessel is controlled with a pressure balanced rotary valve.

4.3.2.3 Linear pocket feeder (LPF). A linear pocket feeder (LPF) is under development by Forster-Miller Associates, Inc. for the Department of Energy as part of the Coal Gasification program.³⁵⁻³⁹ This feeder is mechanically sealed and is designed to continuously supply fine to coarse coal into pressurized vessels operating at pressures up to 1500 psig (10 MPa).

A description of the linear pocket feeder from reference 37 is given below:

"Fixed and stirred bed gasification processes generally require a coarse coal feed, with little or no fines. The feed size for a Lurgi stirred bed gasifier is typically 1-3/4 in. by 1/4 in. The linear pocket feeder has been developed for coarse coal feed applications, such as the Lurgi gasifier but it is capable of feeding essentially any coal size distribution. At present, the lock hopper is the only feed system suitable for feeding lump coal to gasifiers operating above 50 psi.

The linear pocket feeder system (LPF) is shown schematically in Fig. 4.18. It is essentially a tubular conveyor in which pistons are connected together with spaces or "pockets" between them. These pistons form a continuous "chain," the pockets of which are filled with coal and then emptied.

Referring to Fig. 4.18, coal enters the feeder through the hopper, is then pulled along through the close tolerance sealing section, and is then dumped into a pressurized vessel. Within the pressure vessel, the chain "exchanges" coal for high pressure gas and then moves to the gas-water transfer station where high pressure water is used to displace the gas. The high pressure water moves to the water discharge station where it is dumped into the water reservoir. The chain now moves over the drive sprocket and through the return tubes, where it is air

Fig. 4.18. Schematic of linear pocket feeder (Ref. 37).

dried. It then moves over the idler sprocket and back to the hopper section where the feeding cycle begins again."

A prototype of the LPF was designed for operation at 500 psig (3.5 MPa) with $3/4 \times 0.1$ in. (19 $\times$ 0 mm) coal at a rate of 5 tons/h (1.26 kg/s). The unit was constructed and tested. After 200 h of operation the piston seals which were the area of greatest initial concern were operating with only minor wear. The major problem uncovered during the early operation of the feeder was heavy wearing of the connecting links between the pistons. A bench scale development of these curbs is presently under way.

4.3.2.4 Fuller-Kinyon pump. The Fuller-Kinyon Pump is essentially a screw feeder that is designed for injecting materials into pressurized pneumatic conveying lines. In its "normal" applications, the materials are dry, pulverized, free flowing, and have a fineness of at least 100% passing 50 mesh, 75% passing 100 mesh, 60% passing 200 mesh, and 45% passing 325 mesh screens. A test of the ability of the pump to handle $-1/4$ in. (64 mm) coal was conducted in 1976 by the Fuller company for the Electrical Power Research Institute (EPRI).⁴⁰ Consistent successful operation

of the pump was obtained with a pressure differential of 25 to 30 psi (1.7 to 2 atm) across the pump. It was concluded that further testing and modification of the pump would be required to attain higher pressure differentials in the range of 100 psi (6 to 7 atm).

4.3.2.5 Kinetic extruder. A kinetic extruder uses centrifugal force to compact coal particles and move them through a channel from a low pressure to a higher pressure zone. A kinetic extruder has been designed and tested by the Lockheed Space and Missiles Co. for the DOE.⁴¹ The system operating with pulverized coal delivered coal against back pressures up to 150 psig (~9 atm).

The performance of this type of coal feeder depends upon a seal produced by a coal plug located near the pump discharge. The effectiveness of the seal is proportional to the compressibility of the coal. This sealing principle is very similar to the sealing arrangements for the Fuller-Kinyon pump described above. It would therefore not be expected that a kinetic extruder would develop a discharge pressure much in excess of 25 to 30 psi (1 to 2 atm) when operating with -1/4 in. (64 mm) coal.

4.3.2.6 Piston feeder-single acting. Single acting piston feeders are currently under development by Ingersoll-Rand Research, Inc.⁴² and Conspray Construction Systems, Inc. for the DOE.⁴³ The feeder utilizes two co-axial delivery pistons. As described by Ingersoll, there are six steps in the piston feeder cycle: load, advance, delivery, volume reduction, retreat, and open for reloading. The system offers several advantages as compared to other feeders. The use of pressurizing gas is greatly reduced as compared to a pressurized lock hopper feed systems. Since the system does not depend upon the coal to provide a seal as in the kinetic and Fuller-Kinyon type feeders, there should be little restriction upon the size of coal feedstock. As a further advantage there can be no "blow back" through the feeder in case of a power failure or other problems that might result in feeder stoppage. The Ingersoll device has been tested successfully against back pressures to 3.4 MPa (34 atm). Tests on the Conspray machine were scheduled for the summer of 1981.

4.3.2.7 Screw feeder. A screw feeder, based on a modified injection molding machine, has been designed and tested by the Ingersoll-Rand Company for DOE.⁴² Effective sealing, achieved by coal particle compaction,

has been demonstrated while operating against back pressures to 750 psi (51 atm). The coal is discharged from the screw feeder in the form of a continuous, homogeneous "plug" and is reduced to feed-stock size by an extrudate break-up device.

4.4 Gas Cleanup Equipment

Most of the recent designs of PFBC plants incorporate cyclone particle collectors at least as a part of the gas cleanup train. These devices are relatively inexpensive and recent tests have shown them to be capable of providing adequate removal efficiency. This is in contrast to experience with granular bed filters, for example, which were found to be quite expensive and somewhat inconsistent in achieving their purported high efficiency.

In response to the increased emphasis on cyclones, discussion is presented on their basic characteristics. A following section describes briefly other gas cleanup devices.

4.4.1 Characteristics of conventional cyclone separators

Numerous authors have published correlations and theoretical models for estimating the performance of tangential-entry, reverse-flow cyclones.⁴⁴⁻⁴⁶ The theories all predict an increase in collection efficiency for the following conditions:

1. increase in particle diameter,
2. increase in particle density,
3. decrease in cyclone size (proportional decrease in all dimensions),
4. increase in tangential inlet velocity,
5. decrease in temperature (which causes a decrease in gas viscosity).

The theoretical model of W. Licht et al.⁴⁶ is the most detailed with respect to the effect of relative cyclone dimensions on cyclone performance. This theoretical model was tested against the limited data that is readily available with the agreement in absolute separation efficiency being somewhat inconsistent. This is hardly surprising, however, due to the difficulty in accurately measuring mass quantities of particles in discrete

size ranges, especially for particles smaller than 10μ . The following discussion is based on this theory.

Two very important cyclone design parameters are the ratio of inlet to outlet duct areas (A_{in}/A_{out}) and the ratio of inlet area to cyclone cross sectional area (A_{in}/A_{cyc}). The pressure drop across a cyclone is directly proportional to A_{in}/A_{out} and the square of the inlet velocity (U_{in}^2). The A_{in}/A_{out} ratios of cyclones are generally less than 0.8 in order to maintain pressure drops at reasonable levels.

The parameter A_{in}/A_{cyc} determines the volume flow rate ($\dot{V}$) of dirty gases which can be cleaned in a cyclone of specified diameter (D_{cyc}) and inlet velocity,

$$\dot{V} = \frac{A_{in}}{A_{cyc}} \frac{\pi}{4} D_{cyc}^2 U_{in} .$$

A reduction in the volume flow rate (caused by a decrease in A_{in}/A_{cyc}) produces increases in both the average residence time of particulates in a cyclone and collection efficiency. Therefore the ratio A_{in}/A_{cyc} must be selected carefully in order to balance the dual objectives of high collection efficiency and high volume flow rate per cyclone. Typical cyclone designs use values of A_{in}/A_{cyc} which are in the range from 0.1 to 0.2.

Gas cleanup systems which perform identically will have the same overall particulate collection efficiencies and they will be capable of cleaning the same volume flow rates of gases. The ideal cleanup system will satisfy both conditions while minimizing the overall pressure drop and equipment costs. The sample values shown in Table 4.3 indicate that the choice of cyclone size is complicated by changes in pressure drop. A large cyclone can only attain the same collection efficiency as a smaller cyclone when the inlet velocity and pressure drop of the large cyclone are higher. The example in Table 4.3 shows that 10 small cyclones connected in parallel can be replaced by one larger cyclone if a 320% increase in pressure drop is acceptable.

Large cyclones can also achieve the same overall collection efficiency as small cyclones by cleaning gases in two stages instead on one.

Table 4.3. Effect of cyclone size
on single stage cleanup systems
with identical performance
(Estimated for 800°C, 800 kPa)

	Cyclone diameter (m)	
	0.5	1.1
Collection efficiency of 10 μ particles, %	86.3	86.3
Tangential inlet velocity, m/s	20.0	41.1
Total volume flow rate, m^3/s	5.0	5.0
No. of parallel cyclones per stage	10	1
Overall pressure drop, %	0.31	1.31

The example in Table 4.4 shows that this type of configuration can actually reduce the overall pressure drop. The disadvantage of this arrangement is the large increase in cyclone dimensions. The sample values in Table 4.4 indicate that 20 small cyclones connected in parallel can be exchanged for 2 cyclones connected in series if the cyclone diameter is increased 500%.

4.4.2 Development of new gas cleanup equipment

Although cyclones have been found to provide reasonable performance in the PFBC technology unit tests there are certain incentives to developing higher performance systems, especially if they are low cost systems. For example, cyclone collectors would benefit from improvements which would enable them to maintain high efficiency in the larger sizes. The cleanup requirements generally require that cyclone collectors be small in diameter to achieve sufficiently high efficiency. The result is usually a

Table 4.4. Effect of multiple cyclone stages on cleanup systems with identical performance
(estimated for 800°C, 800 kPa)

	No. of cyclone stages in series	
	1	2
Cyclone diameter, m	0.5	3.0
Overall correction efficiency of 10 μ particles, %	92.1	92.1
Tangential inlet velocity, m/s	40.0	22.4
Total volume flow rate, m ³ /s	20.0	20.0
No. of parallel cyclones per stage	20	1
Overall pressure drop, %	1.25	0.78

stage of cyclones consisting of a large number of small, efficient cyclones operating in parallel to provide adequate flow capacity. This complicates the piping and headering with probable higher cost.

The previous engineering analyses have shown that a definite trade-off exists between the cost of installing an advanced cleanup system and the cost of replacing turbine blades. Other than extending turbine life, more efficient gas cleanup will reduce the overall particle loading and should reduce deposition rates. In general, both deposition and erosion worsen as the gas turbine inlet temperature increases and, therefore, improved cleanup devices will probably be necessary if the peak cycle temperature of PFBC plants is gradually pushed up to 950°C and beyond to give overall efficiencies of over 40%.

This section gives brief descriptions of some of the developmental gas cleanup devices under investigation at this time. Table 4.5 provides a summary of developmental gas cleanup devices. More detailed descriptions of cleanup processes and equipment can be found in Ref. 47 and 48.

Table 4.5. Developmental gas cleanup devices

Type of gas cleaning device	Principal research or development team ^a	Principal advantage	Principal disadvantages	Other comments
Conventional cyclone	GE	Simple, inexpensive, adequate efficiency	Efficiency inversely proportional to flow capacity	See Ref. 49 and 53
Rotary flow cyclone	GE Westinghouse	Efficiency possibly less sensitive to flow capacity	Some require secondary air flow; may be no efficiency advantage over conventional	See Ref. 53 and 54
Cyclo centrifuge	MTI	Very high efficiency	High pressure drop, may suffer erosion	See Ref. 55
Granular bed filter	Combustion Power Company Ducon	Very high efficiency	Large size, high cost	See Ref. 50
Electrostatically enhanced cyclone	GE	Very high efficiency at large flow capacities		See Ref. 52
Ceramic "bag" filter	Accurex Exxon	High efficiency	Requires back flush, mechanical strength	
Ceramic panel filter	Westinghouse	High efficiency	Low face velocity, mechanical strength	See Ref. 51
Electrostatic precipitator	Research-Cottrell	High efficiency, low pressure drop	Large size, temperature sensitive performance	

^aNot necessarily active at time of writing.

4.4.2.1 Cyclone separators. Cyclones collect particles through inertial separation and are simple devices (see Fig. 4.19). The characteristics are described in detail elsewhere in this report and in other works (Ref. 45). Cyclones are generally far more effective in capturing large particles ($>20\ \mu$) and moderately effective in capturing particles of $10\ \mu$ size or smaller. An "air shield" cyclone (Fig. 4.20) is being

Fig. 4.19. Typical cyclone collector.

Fig. 4.20. Schematic of uniflow cyclone upstream of air-shield cyclone (Ref. 49).

evaluated by GE and shows some improvement over more conventional designs by preventing bypassing of the cyclone vortex by the dirty gas.

4.4.2.2 Granular bed filters. Granular beds separate particles from a gas stream by impingement on larger pellets. These filter devices are usually very efficient but also very large, physically, and have been

found to be rather expensive for the needs of PFBC systems. A typical schematic of a granular bed arrangement is shown in Fig. 4.21.

4.4.2.3 Ceramic bag filters. Flexible ceramic material has been evaluated as a filter by Exxon and others. This is a positive filtration device and has been found to be very efficient. Caking on the bag would require a backflushing operation.

Fig. 4.21. Moving bed granular filter, counterflow (screenless) configuration (Combustion Power Co.) (Ref. 50).

4.4.2.4 Ceramic panels. The ceramic panel is a rigid porous ceramic material. A ceramic monolith has been under investigation by Westinghouse. The ceramic panel generally offers higher efficiency than cyclones but would probably also require backflushing. Furthermore, the face velocity is usually low to reduce pressure drop and improve collection which would result in a very large array of panels. The ceramic monolith is depicted in Fig. 4.22.

4.4.2.5 Electrostatically augmented cyclone. In particular General Electric is pursuing development of an electro-cyclone. This device, illustrated in Fig. 4.23, requires that a charge be imposed on the gas stream and particles before entering the collection vessel. Theoretical analyses indicate that electrostatics will allow cyclones to maintain high efficiency in large flow capacity sizes. Tests on the small cyclones at CURL showed no appreciable improvement in efficiency with the electrostatics on.

4.4.2.6 Rotary flow cyclones. These devices are sometimes found in series with a conventional cyclone as seen in Fig. 4.24. They are inertial separation devices which utilize vanes and perhaps secondary flow streams to provide swirl to the dirty gas instead of simple tangential entry into a vessel as in the more conventional cyclone. There are conflicting reports as to whether the collection efficiency of a rotary flow

Fig. 4.22. Crossflow ceramic monolith (Ref. 51).

Fig. 4.23. Advanced inertial separation with electrostatic enhancement and outlet skimming (Ref. 52).

cyclone will be influenced by the flow capacity of the unit.^{53, 54} Analysis by Westinghouse indicates a trend similar to conventional cyclones but experiments by GE show little variation in efficiency volume flow for a particular size of unit.

4.4.2.7 Cyclocentrifuge. Experiments on a cyclone which uses a turbine-type rotor to increase swirl have been performed by Mechanical Technology Incorporated (MTI).⁵⁵ Testing has been done with the gas itself providing the power to drive the rotor which has resulted in rather high pressure drop. An alternate approach would be to drive the rotor with an auxiliary steam turbine which would help preserve the efficiency

Fig. 4.24. Aerodyne tornado cyclone (Ref. 48).

of a PFBC system which is sensitive to gas-side pressure drop. A diagram of the cycloentrifuge is presented in Fig. 4.25.

4.4.2.8 Electrostatic precipitators. These devices are in widespread use for removal of particles from stack gas. Their use for high temperature gas purification has been limited due to the difficulty in assuring proper particle resistivity for high collection efficiency among other design problems and operational instabilities. They are particularly poorly suited to collection of particles with a high carbon content. Generally, the electrostatic precipitator remains relatively untried for

Fig. 4.25. Cross section of laboratory cyclocentrifuge (Ref. 55).

application in PFBC systems with turbine inlet temperatures of 650 to 760°C (1200 to 1400°F). The advantages of precipitators warrants further research especially if PFBC systems at these moderate temperatures appear to be attractive.

4.4.2.9 Alkali removal techniques. Various schemes to remove alkali metal vapor from the PFBC flue gas or to prevent its formation have been proposed. A few ideas are being evaluated under the sponsorship of DOE. Various forms of clay, alumina, or diatomaceous earth act as getters for alkali vapor and can be added to the bed to prevent release. This has been demonstrated as feasible by ANL.⁵⁶ Similar materials can be added to granular bed filters for postcombustion alkali removal. Most concepts for alkali removal are variations of these two schemes.

The trade-off between equipment cost and turbine maintenance costs should be recognized and evaluated, particularly in light of the conclusions reached in the analyses described in this report. Further increases in plant efficiency via higher temperature may be the most valid driving force behind advancing the state-of-the-art of gas purification.

4.5 Gas Turbine Degradation Modes

This section presents recent developments and findings related to turbine materials for PFBC systems. A summary of most of the previous attempts to operate coal-fired turbines has been published recently^{57, 58} so the earlier programs are not reexamined here.

Brief descriptions of mechanisms for erosion, corrosion, and deposition are presented here. The parameters which significantly influence the rates of the mechanisms are discussed with supporting data.

4.5.1 Erosion

A loss of blade material in gas turbines can result from the impingement of small particles in the gas stream on the turbine blades. Excessive erosion of the blade causes the airfoil to lose its effectiveness which lowers the turbine efficiency. Data are available to demonstrate the important factors which determine rates of erosion.

The loading of particles in the gas stream is known to directly affect erosion rates. Although dust loading is often quoted as a weight per standard cubic foot, the loading per actual cubic foot is a better reference. Lower pressure air streams, therefore, have a lighter dust load per cross-sectional area of the duct for a given particle mass per standard unit volume.

Catastrophic loss of blade material has been experienced recently in cascades with particle concentrations of 2260 mg/m^3 (1.0 grains/scf) when operating at over 760°C (1400°F) and when using typical turbine gas velocities.⁵⁹ Turbine life under such conditions would probably be on the order of 50 h. The NASA turbine test series also revealed unacceptable rates of erosion with loadings of 3390 mg/m^3 (1.5 grains/scf) after about 12 h (Ref. 2). With average particle concentrations as low as 678 mg/m^3 (0.3 grains/scf) the NASA investigators still found severe pitting and erosion after 164 h of running.³

In recent Curtiss-Wright tests with their SGT unit, minor erosion was evident after 150 h of operation with a particle loading of 339 mg/m^3 (0.15 grains/scf). Not until the loading was reduced to 136 mg/m^3 (0.06 grains/scf) did visible erosion decline to an insignificant level for runs of 500 to 700 h. Note, however, that a desirable turbine life is about 25,000 h between replacing airfoils. The NASA experience has been similar. Runs of about 400 h produced no significant erosion with a dust loading of about 45 mg/m^3 (0.02 grains/scf).⁶⁰ Cascade tests at Exxon also showed very minor erosion on certain blade materials for particles in the gas stream at about 70 mg/m^3 (0.03 grains/scf) after a test duration of about 800 h.

Particle size distribution and particle concentration cannot be decoupled when discussing erosion. Generally, larger particles are responsible for most of the erosion, and particles below 5μ in size are often said to be of no consequence. Particles as small as 2μ , however, are reported to have produced erosion.

The dependence of erosion on the particle velocity has been documented by NASA and others. The NASA carousel wedge tests were performed recently on their PFBC test unit and showed erosion to increase by a factor of 4 with a factor of 2 increase in particle velocity. Erosion seen

as a power function of velocity is common and suggests that erosion may be drastically reduced by a decrease in turbine blade speed. The angle of impingement is a related variable which also influences erosion rate.

The effect of temperature on erosion has been investigated by NASA, Combustion Power Company, and the University of Cincinnati among others. The NASA results were inconclusive showing both increase and decrease in erosion with temperature, depending on the blade material.² The dust loading in these tests was very high, however, and may have masked the effects of other parameters. The Combustion Power data indicate a temperature at which erosion is overtaken by deposition.⁶¹ At about 450°C (840°F) they found that deposition rates were about equal to erosion resulting in a fairly constant test specimen weight. At higher temperature, deposition became dominant.

The University of Cincinnati has performed erosion tests using a simulated PFBC exhaust gas stream. The tests at this facility revealed a clearly defined rapid increase in erosion (Fig. 4.26) as the metal specimen temperature was increased beyond 649°C (1200°F).⁶² The particle loading for the tests was high at about 7 g/m³ (3 grains/ft³) and velocities ranged from 100 to 300 m/s (328 to 985 ft/s).

Fig. 4.26. Effect of metal temperatures on erosion rate (Ref. 62).

The University of Cincinnati work has also been instrumental in showing the importance of particle hardness and size on erosion rates. The particle size experiments reinforced previous results that indicate that particles larger than 5 to 10 μ are responsible for most of the erosion damage in a turbine (Fig. 4.27) (Ref. 63). This phenomenon is reflected in the cleanup requirements recommended by turbine vendors as presented in this report.

The particle hardness or abrasiveness depends on its composition. The characteristic hardness should be considered when attempting to estimate the durability of a turbine in a PFBC system by extrapolating data generated in a cat-cracker or blast furnace system. For example, catalyst dust is primarily an alumino-silicate and is substantially harder than a

Fig. 4.27. Erosion vs particle size at 900°F (experimental results) (Ref. 63).

composit dust generated in a PFBC as pointed out by Tabakoff. Using the Exxon PFBC fly ash as an example, it has about one-third the silicates of fly ash from a pulverized coal furnace and about the same alumina. In comparing the erosivity of the Exxon material to the other ash samples as in Fig. 4.28 the different mean particle sizes must be considered. The erosivity of the PFBC dust should be increased by a factor of about 9 or 10 if its mean size were 25 μ instead of 3.9. The conclusion is that the PFBC dust is really as erosive as the other ash materials. The compositions of the ashes (Table 4.6) would indicate this since they all contain about the same amounts of alumina. The PFBC dust is lower in silicates by about 50%. It is likely, however, that the larger particles of the PFBC sample were coal ash (which contains the alumina and silicates) whereas the smaller particles were probably the dolomite (CaO and MgO) which tends to produce fine particles in the fluidized bed.

Table 4.6. Chemical analysis of fly-ash

Substance	Amount present (%)		
	Kingston fly-ash	CC&E fly-ash	Exxon fly-ash
Si	54.39	48.08	15.40
Al	28.58	21.16	25.40
Fe	10.08	20.05	5.53
Ca	1.28		7.20
Ti	0.47		
Mg	1.04	0.93	3.84
Na	0.20	0.64	0.59
K	2.09		1.16
S	1.03	1.20	0.05
P ₂ O ₅	0.06		
SO ₄			22.4
Cl			0.14
PO ₄			0.25
C			1.2
F			0.02
Undetermined	0.78	7.94	16.82
Total	100.00	100.00	100.00

Fig. 4.28. Erosion by different ashes of different particle sizes (Ref. 63).

Therefore, one can apply Tabakoff's findings to the PFBC dust as well as the others. The application of the finding that the alumina and silicate contents are the most relevant to erosion leads to the conclusion that PFBC exhaust should be about 50 to 70% as erosive as the catalyst dust ingested in an FCC turbo-expander.

4.5.2 Deposition

The build-up of deposits on gas turbine blades reduces the flow area resulting in loss of power and efficiency. It is also possible that cooling air passages could become blocked which would reduce the life of the turbine.⁶⁴ Deposition and erosion are intimately related as mentioned previously and depend somewhat on the same parameters. A significant difference is that deposition can be caused by particles of very small size on the order of $1\ \mu$.

The rate of deposition is basically determined by the (1) rate of arrival of particles on the blade and (2) the fraction of these particles which stick to the blade. Particles arrive at the blade surface through several mechanisms:

1. Inertial impaction — responsible for arrival of most particles larger than $1\ \mu$.
2. Turbulent eddy diffusion — particles swept toward blade when entrained in eddies of the turbulent boundary layer. Affects particles generally larger than $1\ \mu$.
3. Brownian diffusion — transport of particles to surface via random collisions with high temperature gas molecules (high molecular velocity). Largest influence on particles less than $0.1\ \mu$ in diam.
4. Thermophoresis — due to thermal gradients in boundary layer.

This mechanism has significant effect on particles 0.01 to $0.10\ \mu$ in size and is believed to have negligible impact on deposition in PFBC due to scarcity of particles of this size and also due to minor thermal gradients (Ref. 65).

The gas stream and blade temperatures seem to have a large effect on the fraction of particles which stick to the blade. Alkali's which condense on the blade are suspected of behaving as "glue" for small particles. The gas and blade temperatures partially determine the alkali

content of the PFBC exhaust gas and the alkali condensation rate. Temperature will also influence the "stickiness" of the particles themselves.

Results of tests in Australia using coal ash and other salt mixtures showed a well-defined maximum deposition rate at 700 to 900°C (1300 to 1650°F).⁵⁵ As noted already, Combustion Power found deposition to increase continually between 400 to 750°C (750 to 1380°F). A compilation of data reported in Ref. 45 showed that the higher temperatures resulted in the formation of deposits by progressively smaller particles as seen in Fig. 4.29. Documentation is also available indicating fouling to be proportional to particle loading in the gas stream.⁵⁵

The PFBC turbine inlet pressure affects deposition in two ways:

1. Influencing the spacial particle loading and arrival rate at the blade,
2. Influencing the alkali condensation temperature in the gas stream.

Data brought forward by NASA⁶⁶ indicate a strong dependence on pressure, at least for levels of alkali in the gas stream generally less than 1 ppm by weight. The alkali vapor content in PFBC effluent is generally several times this value and may result in a less notable effect of pressure. The basis for the pressure effect is associated with its influence on the condensing temperature of alkali vapors in the gas stream.

Recently, Westinghouse investigators have presented predicted deposition rates in a PFBC environment.⁶⁷ Particle arrival rates were calculated from aerodynamic modeling and an adherence factor was backed out of the Exxon cascade data. Based on particle size distributions shown in Fig. 4.30, probable turbine cleaning intervals were derived and the data reproduced here in Fig. 4.31. Further discussion of the theories and mechanisms of deposition can be found in the Westinghouse report and elsewhere in the literature.⁶⁶

4.5.3 Corrosion

4.5.3.1 Possible mechanisms. Erosion is a relatively peculiar problem to coal-fired turbines but corrosion is evident in gas turbines operating on practically any fuel, natural gas being perhaps the least

Fig. 4.29. Dependence of deposition phenomena in turbine on variations in particle size and inlet gas temperature (Ref. 47).

Fig. 4.30. Estimated turbine inlet particle loadings used to calculate deposition rates (Ref. 67).

Fig. 4.31. Estimated cleaning frequency for deposit removal (Ref. 67).

offensive (although there are recorded instances of hot corrosion involving a gas-fired turbine where the fuel was contaminated with H_2S and was used near the sea coast). Volumes have been published on corrosion in gas turbines and all of the theories and data cannot be presented here. Those data and theories which seem to relate best to the coal-fired turbine are discussed briefly. Significant effort has been expended with corporate funds in developing corrosion resistance airfoil materials to allow turbines to operate on crude oil, for example. However, there is still not a consensus on the corrosion mechanisms, and models for predicting the rate or even the conditions for the onset of corrosion do not exist.

Oxidation and sulfidation are the two most prominent modes of corrosion of interest in gas turbines. The character of oxidation is seen in Fig. 4.32 as an actual weight gain by the blade material as an oxide layer grows. Depending on the material, this oxide layer may spall and give rise to a continual loss of blade material. Growth of the oxide layer is obviously temperature dependent. A similar trend with temperature has been reported by General Electric with the rate of oxidation increasing by a factor of 3 resulting from increasing firing temperature from 871 to 982°C (1600 to 1800°F).

Fig. 4.32. Oxidation of In 792 (Ref. 68).

Sulfidation is a corrosion mode generally involving levels of sodium and sulfur. For over 25 years General Electric has conducted programs to improve turbine life in the presence of compounds of sodium, potassium, vanadium and lead which enter the machine via fuel and air.

Hot corrosion involves two competing mechanisms.

1. Condensation of corrosive deposits is increased by lower temperature and higher pressure.
2. Chemical reaction rates increase with temperature.

The typical sequence of hot corrosion as reported by General Electric is as follows:⁶⁹

1. Hot corrosion begins with the presence of Na and S which form Na_2SO_4 in a hot atmosphere which condenses on the turbine material surface.
2. Na_2SO_4 reacts in such a way that the protective oxide layer formed by superalloys is destroyed. Sulfur then penetrates the metal forming chromium sulfides.
3. Diminishing level of chromium retards the formation of the protective oxide film.
4. Decreased capacity for forming oxide accelerates the attack on the metal.

This scenario of corrosion has somewhat wide acceptance except that in some experiments deposited Na_2SO_4 or K_2SO_4 failed to initiate corrosion. Although the Na_2SO_4 is still involved, some complications are brought forth by a METC task force report.⁷⁰

"Impurities, either in the Na_2SO_4 condensate or in the alloy which are believed to enhance corrosive attack include SO_3 , carbon, chlorides, other metal oxides, silica, and miscellaneous unidentified reductants. SO_3 is known to be unusually soluble in molten Na_2SO_4 , and has been identified electrochemically as an active reagent in corrosion at temperatures in the vicinity of 1000–1200 K. It is possible that molten sulfate serves only as a solvent-reservoir for SO_3 ."

The portion of the scenario where Na_2SO_4 condenses onto the blade from a vapor state may also be faulty based on the conclusions reached by

investigators at NASA. According to a deposition model they are developing, the Na_2SO_4 condensate growth on a surface occurs primarily via transport of gaseous NaOH , NaCl , and Na and not Na_2SO_4 . Hence gaseous Na_2SO_4 need not be present in the gas stream to appear on the blade surface. In general, though, increased levels of SO_2 and Na compounds in the gas stream will increase deposition rate at a particular temperature.

Also discussed in the literature is the influence that oxides and slags such as SiO_2 , Al_2O_3 and Cr_2O_3 may have on corrosion. These compounds may serve to dissociate the Na_2SO_4 whereupon the products of dissociation serve as the corrosive agents which remove the protective metal oxide layers on the alloy surfaces. A reductant such as carbon could have a similar effect.

Direct gas/solid corrosion reactions have been observed and reported.⁷⁰ Apparently the presence of gaseous SO_2 alone, without condensed alkali sulfates, can initiate sulfidation attack on a turbine blade. Interaction of gaseous NaCl with the blade material and condensed phases of Na_2SO_4 have also been noted. The so-called crevice corrosion seen in parts of turbines where gas stagnation occurs, may be a product of gas/solid reactions. Of particular importance is the find that gaseous NaCl can reduce the protective characteristic of coatings which form an Al_2O_3 scale.

A relatively recently observed and unexplained corrosion phenomena is the low-power corrosion seen usually in geographic areas where the sea-salt is likely.⁷⁰ The corrosion appears to be worst at near 650°C (1200°F) and the CoCrAlY coatings seem to be particularly susceptible to this type of attack. Some coatings with higher chromium content have shown improved resistance.

4.5.3.2 Dependence of corrosion on pressure and temperature. The temperature and pressure of the gas flowing in the turbine rotor affect the composition of the gas, especially in a PFBC exhaust. The blade temperature influences the form of species which deposit on the blades and the rate of reactions occurring between the deposits and the blade material.⁷⁰

Presumably, the corrosion mechanisms involving Na_2SO_4 should cease when

1. The metal temperature is too high to allow a liquid melt of Na_2SO_4 to exist, perhaps 1300°C (1880°F).
2. The metal temperature is low enough that Na_2SO_4 exists as a solid and is inactive. The melting point for Na_2SO_4 is about 884°C (1623°F).

Avoiding corrosion by the first means of avoiding a Na_2SO_4 deposit is impractical due to metal oxidation and low alloy strength at temperatures that high. The low temperature limit for corrosion is a point of great uncertainty. There are many citations of corrosion at temperatures below the melting point of Na_2SO_4 .^{71,72} However, a liquid salt can exist on the blade if the Na_2SO_4 is mixed with another substance which possibly exists on the blade surface. The melting points of some possible mixtures are provided in Table 4.7. The presence of small amounts of vanadium also result in a molten salt deposit with a lower melting point 500 to 677°C (932 to 1250°F) than the Na_2SO_4 alone.

Table 4.7. Melting points of sulfates and sulfate eutectic mixtures

System	Melting point eutectic mixture	Melting point pure phase
$\text{Fe}_2(\text{SO}_4)_3\text{-Na}_2\text{SO}_4$	620°C (1148°F)	$\text{Fe}_2(\text{SO}_4)_3$ 680°C (1256°F)
$\text{CuSO}_4\text{-Na}_2\text{SO}_4$	523°C (974°F)	CuSO_4 771°C (1420°F)
$\text{CoSO}_4\text{-Na}_2\text{SO}_4$	565°C (1049°F)	CoSO_4 800°C (1472°F)
$\text{NiSO}_4\text{-Na}_2\text{SO}_4$	671°C (1240°F)	NiSO_4 948°C (1738°F)
$\text{ZnSO}_4\text{-Na}_2\text{SO}_4$	472°C (882°F)	ZnSO_4 730°C (1346°F)
$\text{PbSO}_4\text{-Na}_2\text{SO}_4$	741°C (1366°F)	PbSO_4 1000°C (1832°F)

Source: Ref. 74.

Assessing the influence of gas temperature on corrosion is difficult because in burner rig tests the gas temperature is usually controlled by the fuel-to-air mass ratio. Hence the excess oxygen as well as the temperature influence the composition of the gas. Investigators at NASA documented the effect of fuel-to-air ratio on corrosion rates of Mar-M 509

while maintaining the sample temperature at 900°C (1652°F). NaCl was injected into the burner to give a 3 ppm (wt) concentration in the gas. Corrosion rates were found to increase dramatically with increasing fuel-to-air ratio (increasing flame and gas temperature). This was observed in spite of the fact that deposition rates of Na_2SO_4 did not change appreciably with fuel-to-air ratio. Furthermore, equilibrium gas composition calculations predict that the gaseous Na_2SO_4 species would decrease with increasing temperature. The gaseous species which did increase in quantity and thus may have perpetrated the increased corrosion were found to be CO, SO_2 , HCl, NaOH, Na, Cl, and NaO.

Data are available which show the effect of temperature on corrosion where the fuel-to-air ratio was held constant and the temperature changed via preheating the combustion air to different degrees. The results of these tests were unpredictable with the corrosion rate sometimes increasing and sometimes decreasing in the range of (1350 to 1600°F) metal temperature.⁷³ No single major trend could be seen in varying the fuel salt and sulfur or the material.

However, even an extremely simple corrosion rate model would indicate that varying trends with temperature are possible. The NASA deposition model for Na_2SO_4 predicts the formation of a condensate to behave with temperature as in Fig. 4.33.^{66,75} Also, recent furnace tests have

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Fig. 4.33. General influence of temperature on Na_2SO_4 deposit formation rate.

shown that the corrosion rate of materials covered with a salt solution behaves as an Arrhenius reaction. Now if one assumes that the corrosion rate is proportional to the product of the deposition rate and reaction rate, the result is

$$R = (C - K_2 T^n) e^{-K_1/T}$$

where

R = corrosion rate

n, C, K, K_2 = constants

T = absolute temperature

The values of C and K_2 depend primarily on the amount of Na_2SO_4 forming species in the gas stream whereas K_1 is material dependent. This oversimplified model predicts corrosion rate as shown in Fig. 4.34. According

Fig. 4.34. Estimated behavior of corrosion rate as influenced by temperature and type of material.

to the model, in a particular temperature range, the rate may be increasing or decreasing depending on the gas composition and material. A report of experiments recently published by NASA shows corrosion behavior with temperature to be very similar to the predicted trends.⁷⁶ The new NASA data, generated on a burner rig with contaminants injected into the combustion chamber, clearly show unique temperatures for maximum corrosion. This temperature, as well as the absolute level of corrosion, are also shown as dependent on the blade material. The temperature for maximum rate can be found by setting

$$\frac{dR}{dT} = 0 .$$

One finds that the temperature of maximum rate is a function of the constants K_1 and K_2 . This model obviously does not attempt to treat the other possible corrosion mechanisms and oxidation at the higher temperatures. Higher pressure in this model would increase the rate of Na_2SO_4 deposit. This is probably the foremost effect of pressure on corrosion. The effect on deposits formation is shown in Fig. 4.35.⁷⁷

Fig. 4.35. Na_2SO_4 deposition and dew point increase with pressure (Ref. 77).

Dependence of corrosion on material composition. For many years most of the materials development focused on increasing their high-temperature strength so that the turbine inlet temperature and overall efficiency could be increased. Although a discussion of metallurgy is not in order here, succinctly, to increase the strength of the Ni-based alloys the chromium content had to be reduced. Co-based alloys, which were developed and used in the 1940s, remained underdeveloped due to the superior strength of the Ni based alloys. The advance in high-temperature strength has been documented by Felix as in Fig. 4.36.⁷⁸ Note that the Cr content of the Co-based alloys (Mar-M-509, WI-52, X-40) does not follow the same trend as the others. There has been no need to reduce the Cr content of Co-based alloys because they derive their strength through a different

Fig. 4.36. High-temperature resistance typical blade materials in relation to their year of introduction.

Arbitrary measure of strength is the temperature at which a life of 100 h is attained when subjected to a tensile stress of $142 \text{ N/mm}^2 = 20,000 \text{ lb/in}^2$ (5).

Chromium content in parentheses. Brown Boveri Review, January 1977.

mechanism than the Ni-based materials. For the reader's convenience Table 4.8 relates the composition of most alloys discussed.

The attempts to use heavier fuels coupled with increasing temperature resulted in increased corrosion problems. Hence high-temperature strength is not the only goal in materials development at this time. Renewed interest in the Co-based alloys is evident for several reasons as discussed

Table 4.8. Composition of superalloys for gas turbines

Alloy	Cr	Co	Ni	Ti	Al	Mo	Other
A286	15		26	2.0		1.25	Fe Balance
Waspaloy	19.5	13.5	Balance	3.0	1.4	4.0	
In738	16	8.5	Balance	3.4	3.4	1.7	2.6 W 1.8 Ta
In792	12.7	9.0	Balance	4.2	3.2	2.0	3.9W 3.9 Ta
Mar-M-509	23	Balance	10	0.2			7.0 W 3.5 Ta
U-700	14.2	15.5	Balance	3.3	4.2	4.4	
In713	13.0		Balance	0.75	6.0	4.5	2.3 Ta
X-40	25.12	Balance	10.0				7.5 W
B-1900	8	10	Balance	1.0	6.0	6.0	4.0 Ta
U-500	19	19	Balance	3.0	3.0	4.0	
Hast. X	21.5	1.3	Balance			9.1	18.2 Fe 0.4 W
X-45	23.9	Balance	10.2				7.0 W 1.4 Fe
FSX-414	29.3	Balance	10.4				7.2 W
Rene 77	14.7	14.5	Balance	3.5	4.2	4.2	
GTD111	14.0	9.5	Balance	4.9	3.0	1.5	3.8 W
Nimonic 90	19.5	18	Balance	2.4	1.4		
Nimonic 80A	20		Balance	2.3	1.4		
Mar-M-432	15.5	20	Balance	4.3	2.8		Nb-2, W-3,
Mar-M-246	9.0	10	Ni	1.5	5.5		10 W
WI-52	21.0	Balance					11 W
IN 100	10.0	15.0	Balance	4.5	5.5	3.0	
Mar-M-302	21.5	Balance					10.0 W 9.0 Ta
SM-200	8.8	10.2	Balance	1.8	4.9		12.3 W
Mar-M-200	9.0	10.0	Balance	2.0	5.0		12.5 W 2.0 Hf
U-500	18.8	19.4	Balance	3.0	3.0	4.0	
GE2541*	25.0				4.0		Fe Bal 1Y
ECY-768	24.0	Balance	10.0		0.1		Ti, Fe, W, Ta
IN671	48.0		Balance				Fe
S-57*	25.0	Balance	10		3.0		5-Ta
PFB-6*	25	Balance	10		5.0		0.15 Y
ATD-2*	23	Balance			12.0		0.35Y
ATD-14	30	Balance			5.0		0.4 Y
ATD-17	25				4.0		Fe Base 0.3 Y
GT-21	23	Balance			12.0		0.35 Y

*Primarily used as coating.

by Stringer:

1. Co alloys have flatter stress rupture/time-temperature profile.
2. Corrosion resistance appears to be higher even when accounting for higher Cr content relative to Ni alloys.

Felix has correlated the corrosion resistance to a parameter including the Cr, Al, and Ti content of the alloy.⁷⁸ A plot of the historical trend is shown in Fig. 4.37. Recent burner rig tests have reinforced this correlation as shown in Fig. 4.38.⁷⁹ The cobalt-based alloys developed some time ago were shown to be even superior to coated or clad Ni-based materials.

In determining the material requirements for the PFBC gas turbine there is possibly a trade-off between strength and corrosion resistance. Obviously 100,000 h of stress limited life is not necessary where corrosion may render the blade useless in 15,000 h. The lower temperature of the PFBC gas turbine relative to conventional aircraft or industrial gas

Fig. 4.37. Resistance to high-temperature corrosion by typical blade materials in relation to their year of introduction. The content of Cr-Ti-Al is taken as a measure of the resistance to corrosion.

Brown Boveri Review, January 1977.

ORNL-DWG 81-16576 ETD

Fig. 4.38. Relative corrosion resistance of turbine materials - laboratory data.

turbine raises questions of whether the Ni-based alloys are actually necessary from a strength standpoint especially since it appears that a coating or cladding might be necessary to provide adequate corrosion protection.

4.5.3.3 Corrosion protection via coatings and claddings. A number of coating and cladding processes exist which have been discussed collectively by Grey et al.⁵⁶ A brief description of the coatings applied to turbines is repeated here. The general purpose of the coatings is to provide corrosion protection for a high strength material by using a coating which will form the protective Cr_2O_3 or Al_2O_3 and contains

levels of Cr, Al, and other elements which are not feasible in the base material due to strength considerations.

Aluminum and chromium-aluminum coatings for turbine alloys were applied by the pack-cementation method in the early 1960s. This type of coating is called a diffusion coating because the bonding is caused by diffusion of the coating material into the substrate material and vice versa. Currently, General Electric uses a Pt-Cr-Al coating on some of its commercial machines which is applied by electroplating plus pack diffusion. Al_2O_3 is the protective substance. Due to the diffusion of the substrate material the coating actually becomes Ni-Al with Pt and Cr in solid solution. These coatings are about 75 to 113 μ (0.0030 to 0.0045 in.) thick. Overlay coatings differ from diffusion coatings in that the substrate material is not relied upon to be a constituent of the coating. These coatings are applied by different methods including electron beam vapor deposition and plasma spraying. Since these coatings do not rely on the substrate for formation their composition is more flexible and they can be applied in thicker layers, perhaps 230 μ (0.009 in.). General Electric reports that overlay coatings applied by plasma spraying are being evaluated in gas turbines for commercialization in the near-term. Some CoCrAlY overlay coatings are reportedly in use in aircraft engines.

A sheet-cladding represents another type of overlay coating. In this case a corrosion resistant sheet of metal is bonded to the substrate under high pressure and temperature. The cladding is 250 to 500 μ (0.010 to 0.020 in.) thickness providing more protection for the substrate which supplies the required strength for the blade. Claddings are in the development process and are undergoing field evaluation.

Laboratory tests generally show advantages in corrosion protection using coatings but, again, the results are not entirely consistent. Referring to the burner rig test data shown in Fig. 4.38 it is evident that the coatings improved the resistance of the nickel alloys but yet did not surpass the state-of-the-art cobalt based materials.

Earlier data from Westinghouse demonstrated that the method by which the coating is applied is very influential on its corrosion performance.⁷² There is considerable research in this subject at this time.

The data also showed that, in general, the coating were competitive with or slightly better than uncoated cobalt alloys.

An important result has been produced by researchers at Pratt and Whitney aircraft concerning combined erosion, corrosion testing.⁸⁰ Their tests showed more conclusively that the coated nickel based materials offered superior protection over uncoated nickel- or cobalt-based alloys (Fig. 4.39). These tests were also run on a burner rig (see Fig. 4.40).

More recent Westinghouse work has included laboratory evaluations of diffusion and overlay coatings of several different compositions.⁸¹ The overlay type coatings were CoCrAlY and NiCrAlY and the diffusion type were Al-Pt-Cr and Pt-Rh-Al-Cr. Base and bare metals included X-45, Mar-M 509, ECY768, and U-500. The coated alloys generally performed better than bare metal although a few of the coatings failed rather quickly. The fuels used in the tests were salt contaminated sour gas and crude oil containing

Fig. 4.39. Weight change vs time data showing severe attack of metallic materials by erosion-hot corrosion interactions.

Fig. 4.40. Schematic diagram of ducted burner rig used for Pratt and Whitney tests.

sodium and vanadium. Test temperature on the metal was 843 to 900°C (1550 to 1650°F).

Field testing on rotating machinery is necessary to verify the suitability of coatings since one would anticipate possible problems in a stressed operating environment more so than on a laboratory rig. Results of such field tests have been recently reported by General Electric. Materials were tested in a MS5000 turbine using contaminated fuel. Two separate programs are reported in Ref. 82.

The fuel used in the Lynn Turbine program had levels of vanadium of about 100 ppm in the fuel with Na + K less than 2 ppm after washing. A summary of the blade condition at 10,000 h and 19,000 h is provided in Table 4.9. During the tests, deposits were routinely removed by nutshell-ing.

The GE/ARAMCO program used sour gas as fuel which contained over 3% H₂S. Sodium was available as a contaminant in the combustion air. The firing temperature was not reported other than being less than 955°C (1750°F). The first stage bucket metal temperature would normally be

Table 4.9. Results of laboratory visual examination after 19,000 fired hours
(Lynn Turbine Rainbow Rotor)

Coating	Appearance
Uncoated IN-738	Some surface roughening particularly along suction face leading edge; corrosion estimated to be 125 to 200 microns
Fe-Cr-Al-Y cladding	Moderate surface roughening along upper suction face leading edge; elsewhere in excellent condition
Ni-50Cr cladding	Some localized roughening; generally good condition
Aluminided Co-Cr-Al-Y (2961) electron beam coating	Excellent condition
Aluminided Co-35Cr electron beam coating	Slight roughening on localized suction face area; otherwise excellent condition.
Cr-Al pack diffusion coating (RT-21)	Moderate to heavy corrosion on leading edge half of bucket. Coating exhibits worse performance of group
Pt-Cr-Al pack diffusion coating (LDC-2)	Excellent condition

about 815°C (1500°F) in the General Electric MS5000 series unit with the normal firing temperature of (1730°F). Results are summarized in Table 4.10.

Table 4.10 . GE/ARAMCO field test results for
Phase II, 13,000 h

Blade	Condition
Uncoated IN738	Serious attack, 180 μ penetration
Pack diffusion coatings	
Pt-Cr-Al	No evident attack. 65 μ coating thickness.
Cr-Al	Poor performance. Coating completely penetrated at some locations
Pt(Rh)-Cr-Al	Poorer performance than Pt-Cr-Al
Overlay coatings	
CoCrAlY (plasma sprayed)	Good condition. About 25% of coating depth penetrated.
CoCrAlY (electron beam)	Some penetration. Believed due to coating technique.
Ni-50 Cr (sheet cladding)	Significant attack. Substrate penetrated.
FeCrAlY (sheet cladding, 2541)	Virtually no attack.

4.6 Turbine Materials Performance in FBC Environment

There have been several significant materials related programs which have generated data in the last two years. They carry special significance since they were actual fluidized bed tests. The tests and results are briefly described in this section. Discussion on the accomplishments and short-comings of the tests is presented also.

The tests and some of the significant operating parameters are included in Table 4.11. Although each test has produced some meaningful results caution should be exercised in extrapolating because none of these tests have been performed with the operating conditions the same as those design conditions proposed for commercial PFBC power plants.

Table 4.11. Summary of recent turbine materials test in fluidized bed combustors

	Exxon cascade 1978-79	NASA wedge 1977	NASA turbine ^a 1979	CURL cascade 1979 (GE stream)	C-W turbine 1979	CURL AFB 1977	CURL cascade 1979 (Stal-Laval)
Combustor temperature °C	925-955	800	935-1022	849-863	900	900	849-863
Combustor pressure, atm	9.0	5.0	6.0	5.0	7.0	1.0	6.0
Excess air, %	15-34	high 100	high $\approx$ 100	90-108	$\sim$ 33	10-20	90-108
SO ₂ in gas, ppm	100-300	250-450	300	100-400	80	350	100-400
Velocity relative to samples m/s	291	152-271	259-335	$\leq$ 427	365 (estimate)	$\leq$ 50	230-518
Cascade or turbine inlet pressure atm	5.0	5.0	5.0	5.5	2.0	1.0	5.5
Alkali in gas Na + K ppm	2.0-3.5			0.07 aerosol ^b			
Sample metal temperature °C	$\approx$ 843	720-800	765 777 (stator)	732-802	$\sim$ 750 rotor, $\sim$ 843 stator	721 804	750-780
Dust loading g/m ³	0.032-0.128	2.3-4.6	0.09 0.46	0.32	0.14		0.13
CO in gas, ppm	50-200	20	3-16	5-50	6		5-50
Materials tested	<u>Bare</u> IN738, U700, FSX414, <u>Coated</u> 738-RT22 (Pt-Al) <u>Clad</u> 738-2541 414-2541 738-671 738-357/Al 738-6/Al 414-6/Al	IN792, Mar-M-509 U700 IN-100	IN792+Hf	<u>Bare</u> IN738 <u>Coated</u> (IN738 Base on all) PFB-6-clad PFB-6/Al clad 2541 clad ATD2 PVD coat ATD14 PVD coat ATD17 PVD coat GT21 plasma spray coat RT22 diffusion coat- ing Pt-Al	<u>Stator</u> IN738 & FSX414 with coatings Al diffusion Pt-Al diffusion Pt-Al diffusion Rh-Al diffusion NiCrAlY-PVD coat CoCrAlY-PVD coat FeCrAlY-PVD coat <u>Rotor</u> U720 U720/Al diffusion U720/Pt-Al diffu- sion	U-500 IN-738 (1st 1,000 h) IN-738 (2nd 1,000 h) IN-738 IN-738/Pt-Al IN-738/BC-29E (electron beam) IN-738/BC-21P (plasma) GE2541 Inconel 617 GTD-111 X-40 (2nd 1,000 h) X-40 FSX-414 FSX-414/Pt-Al U-700 IN-713C (1st 1,000 h) IN-713C (2nd 1,000 h) INCO-713C HAST. X INCONEL 671 HA 188	U-500 bare and with FeCrAlY and CoCrAlY PVD coatings IN 671 IN 713

^aBest results, last 400 h.^bMuch lower than previous tests.

4.6.1 Exxon cascade

The Exxon tests closely approximate the design conditions of a commercial plant except for the lack of rotating turbomachinery. Parameters such as excess air, pressure, and temperature were close to plant design conditions. However, the cascade inlet pressure was only about 0.5 MPa (5.0 atm) and therefore the rate of alkali deposition and erosion would be changed. The pressure drop at the inlet to the turbine test section would also lower the spatial loading of particulate matter and reduce the erosion rate.

The attack on the materials was about 100 to 175 μ (4 to 7 mils) for the bare alloys with the coated alloys performing better at only 25 to 100 μ (1 to 4 mils) penetration.⁸³ The uncoated materials showed corrosion and erosion damage as did the thin Pt-Al diffusion coating. The overlay coatings and claddings showed some erosion damage but had not been breached.⁵⁶ During the 1000 h test at Exxon there was a malfunction in the cleanup train for a few hours which allowed a high dust loading to hit the cascade. It is uncertain as to the magnitude of damage which resulted.

The size of the cascade blade is also not representative of commercial machines. In summary these tests were effective in screening candidate materials for the PFBC system. Also, the effectiveness of small cyclones was demonstrated. Little can be concluded, though, with regard to absolute rates of corrosion and erosion.

4.6.2 NASA wedge tests

These tests were very severe due to the high particulate loading.² At the higher temperatures both oxidation and sulfidation were evident on all alloys. Sulfidation was not found at 720°C. Some deposition was also found on the specimens. The NASA combustor operated with an air/fuel ratio of about 20, indicating a high level of excess air which would tend to influence the composition of the gases and the deposition rates of alkalis in such a way as to lessen the severity of the tests.

4.6.3 NASA turbine tests

The NASA engineers designed their experiment to operate the turbine with an inlet pressure of 0.5 MPa (5.0 atm) to retain more resemblance to commercial design conditions.^{3,60} Even at relatively low metal temperatures (the rotor would run at below the gas temperature at the stator inlet) sulfidation was observed. The best results still showed an erosion rate of about 1.3 mm/1000 h (50 mils/1000 h) which is quite severe considering the partial admission operation of the turbine. Although the excess air during the tests was rather high, the conditions were reasonable and there was no cooling/reheating in the the gas stream. Unfortunately, only one material was tested and this experimental facility is no longer in operation. These NASA tests are probably more representative of what would be experienced in a viable commercial PFBC system than any test performed to date.

4.6.4 CURL cascade tests

The recent 1000 h CURL cascade run again demonstrated the advantage of using an overlay coating or cladding. The materials were generally attacked less at CURL than at Exxon. Several explanations are offered:⁸³

1. Malfunction of Exxon cleanup system
2. Lower alkalis in CURL
3. Higher excess air at CURL
4. Lower CO at CURL (result of higher excess air)
5. Lower metal temperature at CURL.

The alkalis were much lower at CURL than had been seen previously and no concrete explanation is offered in the summary report for the tests.¹⁴ The high excess air, low alkalis, and cooling/reheating of the gas stream are bothersome in attempting to draw conclusions from these tests with regard to performance of commercial systems. The sequence of cooling, cleaning and then reheating the gas leads to the possible elimination of much of the aerosol alkali metals which would tend to condense on the particles as the gas cooled. It should also be noted that a PFBC system operating at the conditions of these test would have an efficiency of 39%, below the goal of near 40%.

The coated materials performed the best in both the GE and AEP/Stal-Laval streams. There was very little corrosion attack on the coated specimens in either stream after 1000 h. The high effectiveness of small cyclone separators was, again, demonstrated.

4.6.5 Curtiss-Wright turbine tests

The Curtiss-Wright combustor has accumulated 2600 h of operating time. A 1000 h small turbine test was conducted in 1979.⁸⁴ The combustor conditions typified those of the commercial air-cooled PFBC plant as proposed by Curtiss-Wright. The turbine is, of course, much smaller than those proposed for commercial plants but the relative velocities between the gas and the blade are similar. In fact the tip speed of the rotor and gas velocities are somewhat similar to a larger conventional turbine. The small diameter of the Curtiss-Wright turbine rotor therefore promotes higher centrifuging action of the particles which might induce some accelerated localized erosion. The effect would probably have been more pronounced had the turbine been a two-stage machine.

A major shortcoming of the Curtiss-Wright test was the 0.2 MPa (2.0 atm) turbine inlet pressure. The effects of pressure on erosion and corrosion have been noted previously. Figure 4.41 is presented to reiterate the change in corrosion and deposition characteristics which can accompany changes in pressure. The need for flue gas reheating was present in the Curtiss-Wright test unit also.

The test results are valid in indicating that the Pt-Al diffusion coating was superior to the bare alloys and the plain Al coating. Some corrosion was seen on the bare stator and rotor materials. The plain Al coating also suffered considerable damage but the Pt-Al coating performed better. The FeCrAlY overlay coating on the vanes was penetrated only to a depth of about 12 μ (0.5 mil) after 1000 h. The ability of small cyclones to remove particles 10 μ and larger was demonstrated. Conclusions regarding the life of full-sized turbines in a PFBC environment can probably not be drawn from these tests, however.

Fig. 4.41. Calculated effect of pressure on deposition rates, after Rosner et al. (Ref. 60).

4.6.6 CURL AFB tests

These tests were performed at atmospheric pressure and low gas velocity to study the corrosion on turbine materials in the gas stream.⁸⁵ Bare, diffusion coated and overlay coated materials were evaluated. Bare metals such as IN738, FSX414, and X-40 suffered penetration of 25 to 50 μ (1 to 2 mils). The coatings did not perform better but it appeared that the coatings had not been applied well. The GE 2541 suffered the least attack, about 10 μ (0.4 mils). This material, intended for use as a blade cladding, has consistently shown the least erosion, corrosion damage in the FBC tests.

4.7 Estimates for Gas Turbine Rotor Life

The estimates for turbine blade life which have been published or which were submitted in the survey response are reviewed in this section. The replacement interval for the turbine rotor or blades is shown as a significant economic consideration especially if the life of the part is less than about 6000 h. The component life is more important for the

air-cooled PFBC systems primarily because these plants rely on the gas turbine for a higher portion of the total output than with the steam-cooled PFBC systems. The loss in performance which results from turbine degradation is also a significant factor, again more so for the air-cooled PFBC plants.

4.7.1 Factors affecting turbine blade life

4.7.1.1 Loading of particles and particle size. The effect of particle loading and size distribution has been presented elsewhere in this report. The hardness of the particles is also significant and was considered in estimating the life of a turbo-expander operating on PFBC effluent rather than catalytic cracker exhaust.

4.7.1.2 Gas temperature. The gas temperature influences the composition of the gas and therefore its corrosiveness. See the section on corrosion in this report for further discussion.

4.7.1.3 Blade and vane temperature. The temperature of the metal affects the reaction rate of the corrosion on the blade surface and also the deposition rate. See section on corrosion for other discussion.

4.7.1.4 Pressure ratio per stage. The pressure drop across a turbine stage will partially determine the gas and particle velocities relative to the rotor. Higher velocities are generally seen in industrial gas turbines which may have stage pressure ratios of about 2.2. Turbo-expanders with two stages will be similar if developing pressure ratios over 5.0. High impulse stages, which give high vane exit velocities, will generally produce higher relative velocities and more erosion damage. However, the impulse stage is beneficial by having a lower gas temperature at the first rotor inlet than a comparable reaction stage.

4.7.1.5 Blade design. As discussed elsewhere in this report, blades with a longer chord length should lessen the accelerations required for a particle to follow the gas flow and therefore should lessen the impact frequency. The thickness of the trailing edge, a high impact frequency area, may be increased as in turbo-expanders to extend life with some loss in efficiency. An axial inlet to the turbine stage is desirable to assure that the particles are evenly distributed across the flow area instead of concentrated as might occur with a curved inlet path.

4.7.1.6 Inlet pressure. The spatial particle loading and deposition increase with pressure. A more efficient gas cleanup system would be necessary to maintain a constant loading per volume flow if the design inlet pressure were increased.

4.7.1.7 Type of coal. The amount of ash, alkali, and the ash composition will influence the blade life for any particular particle loading. Ashes which are high in alumina or silicates will be more erosive. Furthermore, high ash coals will probably shift the composition of the particles into the turbine toward higher fractions of ash instead of the usually softer calcium oxide and magnesium oxide. Higher alkali content will, of course, increase the corrosion and deposition potential. The data in Fig. 4.42 clearly show the influence of the amount of alkali released during combustion.

Fig. 4.42. Quantitative data on turbine life in presence of alkalis derived from GE data presented in Ref. 86 and elsewhere.

4.7.2 Baseline clean fuel turbine blade life

The life of a blade operating on clean fuel is usually limited by the stress creep, or erosion by dust in the combustion air. When discussing life as influenced by temperature, distinction should be made among turbine inlet temperature, firing temperature, and blade temperature.

The turbine inlet temperature refers to the mean gas temperature at the inlet to the first set of vanes before any pressure drop takes place. This temperature is used for thermodynamic calculations in determining cycle efficiency.

The firing temperature is a term used by some manufacturers in the gas turbine industry and is defined as the mean temperature of the gas at the exit of the first set of vanes. The expansion through the vanes converts thermal energy to kinetic energy such that the gas temperature may drop by 100 to 150°C relative to the turbine inlet temperature.

The blade temperature is self-explanatory. Blade cooling is used to maintain the average metal temperature usually at about 820°C or less to preserve the strength of the material. The metal temperature will vary with location on the blade and depth into the blade.

The data in Fig. 4.43 have been derived from several sources to show a typical relation among the temperatures which might be present in a modern, high-performance gas turbine engine. The blade temperature is the life-limiting factor and the life shown as dependent on inlet and firing temperature is shown only for illustrative purposes. The blade material has characteristics similar to IN738 which is among the highest strength blade materials in widespread use today.

4.7.3 Turboexpander rotor life in PFBC

Estimates for the life of a turbo-expander operating on PFBC exhaust gases have been derived from vendor data and other projections. The projections made by vendors do not consider the effect of corrosion on the blade and generally reflect experience in the cat-cracker environment. These life estimates are shown in Fig. 4.44. The ORNL estimate was derived from cat-cracker experience and projections by GE which account for

Fig. 4.43. Approximate relation between blade, firing, and turbine inlet temperature. Blade temperature is most suitable for reference to blade life.

corrosion. At temperatures less than 650°C erosion is expected to be the dominant blade degradation mechanism. Using data generated by Tabakoff, the relative hardness of the PFBC effluent was estimated as about 50 to 70% of that of catalyst dust and the baseline turbo-expander life was increased accordingly. At higher temperatures around 750°C the expander blade material will probably be IN738 or Waspaloy. At this temperature corrosion should be important and erosion somewhat worse and the life is expected to fall close to the projections made by GE. Ref. 52. Turbo-expanders use little or no blade cooling so the inlet temperature is reasonably close to the rotor blade temperature aside from the temperature drop in the vanes. A portion of the temperature drop is reversed however, as the gas stagnates at the blade surface and its temperature increases.

The particle loading and size distribution required to attain these projected lifetimes are shown in Fig. 4.45. The particle loadings were provided by turboexpander vendors.

4.7.4 Industrial gas turbine stage life in PFBC

The estimates for stage life in this section (Fig. 4.46) have been derived from vendor estimates in various reports and in the survey

Fig. 4.44. Estimated life of turboexpander rotor blades.

responses. In spite of minor differences in assumptions for gas cleanup performance the band of curves for stage life is reasonably narrow. The PFBC power plant model used in the sensitivity analyses incorporated sufficient cooling air to keep the turbine metal temperature below about 815°C (1500°F) at which point the stress oxidation, and corrosion would tend to produce very short usable lifetimes. According to these estimates, then, the PFBC systems which utilize inlet temperatures higher than about 1650°F could require repair of one or more stages every 3,000 to 10,000 h even with clad blades. More cooling for the blades could extend

Fig. 4.45. Allowable particle loadings into turbines.

the life but there is, of course, an efficiency penalty associated with increasing the turbine cooling air bleed flow.

The particle loadings for the industrial gas turbine are shown in Fig. 4.45 also. These estimated allowable loadings were obtained in the survey response and from recent GE papers. On an actual volume flow basis, the loadings for expanders and gas turbines show little difference, indicating that cleanup systems required for either would not differ greatly.

Fig. 4.46. Summary of estimated life times for stage of industrial gas turbine.

4.8 Recent Heat Transfer Data in a PFBC

Heat transfer data is not as abundant for the PFBC as in the AFBC although differences should not be great. Most correlations for heat transfer coefficient show a weak dependence on gas density at the most. Some typical data from the NRDC PFBC facility are shown in Fig. 4.47.

Curtiss-Wright's vertical finned tubes have been tested in the CURL facility also and with results in the 228 to 285 W/m²·°C (40 to 50 Btu/h·ft²·°F) range.^{16,84} The bed material was rather coarse but the

Fig. 4.47. Heat transfer data from NRDC.

fluidizing velocity was 0.7 to 1.1 m/s (2.3 to 3.7 ft/s). A seven tube bundle was used in these tests with three tubes cooled by air, two by water and two by steam. These tubes were about 10 cm (4.0 in.) in diameter and 2.4 m (8 ft) long. The tubes were spaced on 20 cm (8 in.) centers.

5. TECHNICAL RISK IN PFBC SYSTEMS

5.1 Identification of Risk Areas

A questionnaire was sent to a number of organizations either currently or previously involved in PFBC development. The questionnaire deals with high risk technical features of the PFBC concept and how the risk might be avoided or reduced. This section of the report discusses the responses received. The recipients of the questionnaire are listed below:

EPRI	Elliot
TVA	NASA-Lewis
METC	Exxon
Curtiss-Wright	Babcock & Wilcox
Westinghouse	CURL
General Electric	Gilbert Associates
Ingersoll-Rand	Burns & Roe
Foster-Wheeler	Argonne National Laboratory
American Electric Power/Stal-Laval	

Twelve responses had been received as of January 25, 1981. Each question is repeated here, followed by a discussion of the responses to that question.

1. What is the maximum bed temperature which should be used considering boiler materials as the limiting factor? If materials are not limiting on the bed temperature, what is the limiting factor? Do you consider the air-cooled in-bed tubes (per Curtiss-Wright) as presently lower/higher risk than a steam cooled-bed? Why?

Most responses indicated that factors other than boiler materials would limit the bed temperature. Based on the metal temperature of an evaporator tube submerged in the bed a maximum temperature of 955°C (1750°F) was suggested in most cases. The same upper limit was suggested for the other limiting factors such as:

1. Ash clinkering
2. Poor SO₂ capture
3. Volatilization of very high levels of alkali
4. NO_x emissions.

Although not unanimous, most responses indicated that air-cooled tubes would represent a higher risk due to the higher metal temperature which occurs resulting in more potential for corrosion. Other responses indicated structural risk with the long bayonet tubes proposed in the Curtiss-Wright designs due to possible vibration (this has not appeared as a problem to date in the Curtiss-Wright Test Facility). An advantage of the air-cooled tube approach cited in several cases was that the consequences of a tube failure would be less than for a steam-cooled system. The air-cooled tubes also operate at lower pressure and if properly-designed might be less likely to fail during a system upset which caused tubes to overheat.

2. Do you see solids feeding as potentially troublesome at 10 atm? 15 atm? Do you anticipate that feeding to a lower pressure vessel (3 to 7 atm) would be less costly and/or more reliable? What are the assumptions and/or performance data leading to your answer? Do you feel that solids feeding presents a high or low engineering challenge?

Approximately half of the responses categorized solids feeding as presenting a high engineering challenge and a higher fraction indicated a need for more engineering development in this area which partially determines the basic feasibility of the PFBC. Improvements to the Petrocarb system were recommended due to its high cost and sensitivity of operation to coal condition (size, moisture, etc.). Maintaining a consistent feed rate to multiple coal guns and the solids handling valves were the most often mentioned trouble sources. Most responses indicated that the feed pressure would have little impact on the reliability or cost of the coal feed system unless a new design such as the Fuller-Kinyon pump were perfected.

3. Please sketch your estimate of gas turbine stage life (time between blade replacement) versus inlet temperature. Responses to this question are included in this report in the section on estimating the lifespans of gas turbine stages.

Do you anticipate advantage/disadvantage in turbine life for the air-cooled bed as opposed to steam-cooled? Why?

Several responses indicated that the alkali levels would still be beyond current practical limits even with the combustion gas dilution used

in the Curtiss-Wright cycle. Regarding erosion damage, the air-cooled system should have an advantage from the dilution provided that the clean-up train performs at the same level as in a steam-cooled PFBC plant. In general the diluted combustion gas was considered to be less offensive to the gas turbine.

Do you predict any variation of your plot with turbine inlet pressure? Why? With combustion temperature?

The effects of these parameters on turbine tube are discussed elsewhere in this report. Most responses indicated a dependence on both parameters.

What gas cleanup train system would you recommend to achieve your estimate of life?

Based on the experience in cat-cracker system operation and at Exxon and CURL, cyclone systems were favored for the gas cleanup train. Other types of high temperature filters, presumably granular beds or ceramic felts, were considered as possibly necessary for some types of coal.

Do you expect deposition to be a problem? If so, in what temperature range? How would you recommend handling the problem?

The responses indicated that deposition could present substantial problems at temperatures higher than 820 to 870°C because the deposits formed at these temperatures would be too adherent to remove with soft abrasives with the turbine assembled. Reports of deposits formed at much lower temperatures in the vicinity of 705°C (1300°F) were also discussed. For mildly tenacious deposits, a modified "nutshelling" was suggested as an acceptable means of deposit control.

Would you predict any different life for a cat-cracker, turbo-expander in contrast with an industrial gas turbine? Why?

Most responses indicated that a life span advantage would exist for the turbo-expander provided that the temperature was low enough to avoid high rates of corrosion. The effect of turbine life on design is discussed elsewhere in this report.

4. What level of engineering challenge does system control present? High, medium, low? Why?

The majority of respondents believed that system control had not been sufficiently demonstrated but that it presented only a moderate engineering challenge.

5. Please list other high risk features and how, in your opinion, the problems should be approached.

This part of the survey was intended to be a catch-all for subjects not included in the previous questions. The high-risk problems included in responses to this question are itemized below.

1. Unknown effects of combined erosion and corrosion.
2. Hot solids letdown and transport.
3. Safety equipment for explosion hazard in pressure vessel.
4. Need for development of instrumentation, especially to detect malfunction in gas cleanup system.
5. Demonstration of load following.
6. Demonstration of duct and turbine deposit removal.

A possible explosion-related safety hazard with operation at pressure was also brought forward by one group and may be a concern that deserves further study.

5.2 Reduction of Risk in PFBC Systems

The technical and economic risk and uncertainty in PFBC systems can be reduced in two basic manners:

1. The problem areas and uncertainties can be surmounted by carrying research and demonstration programs through to completion.
2. Design conditions for PFBC plants can be limited to levels where the risk and uncertainty are less and the operating experience is higher.

There are several problem areas in need of development, as identified in the survey, which are not readily resolved by changing design conditions and are common to all types of PFBC systems. For example, the hot ash letdown and handling systems are universal to all PFBC concepts. Similarly, the control of an integrated PFBC is a subject of uncertainty which will be resolved only by demonstration of a large pilot plant or demonstration unit, complete with gas and steam turbine systems. Solids metering and feeding is also a common problem and it affects the basic feasibility of the PFBC, in addition to the economic attractiveness of the concept.

The recent developments in gas cleanup and turbine materials CURL and Curtiss-Wright have demonstrated a probable feasibility of operating a gas turbine on coal combustion gases. The limited successes in previous efforts such as the Locomotive Development Committee have also indicated the basic feasibility of this operation. The uncertainties lie in whether a suitable, economical combination of gas cleanup system and turbine durability can be achieved. For example, the uncertainty in achieving long turbine lifetime could be reduced by operating a PFBC at cat-cracker design conditions which would be about 2.5 to 3.0 atm and 620°C since single stage turbo-expanders have been in widespread use and have demonstrated high durability. PFBC systems designed on these conditions have not been evaluated, however, for their economic and environmental attractiveness.

Another topic of uncertainty is the effect of tighter SO₂ control standards on PFBC systems. Does tighter SO₂ control degrade the advantages held by PFBC over plants with scrubbers? Do design conditions which favor the turbine durability influence the potential environmental performance of the PFBC? Uncertainties such as these can be treated through engineering analysis provided that there is a sufficient data base. On the other hand, the development needs which partially determine the fundamental feasibility of the PFBC and are purely technical in nature require a concerted research and demonstration effort.

6. SENSITIVITY OF THE POTENTIAL ADVANTAGES OF PFBC SYSTEMS TO KEY DEVELOPMENTS AND DESIGN CONDITIONS

In the preceding sections of this report the key problem areas of the PFBC have been identified and discussed at length. Many of the potential problem areas have been shown to be amenable to alternate design conditions but there has been considerable uncertainty as to how alternate design conditions, if necessary, would affect the economic viability and environmental performance potential of PFBC system. The following sections describe the results of analyses intended to quantify the effect of alternate design conditions on these features of the PFBC.

Five PFBC plant configurations have been evaluated and are discussed. These plants and their major design parameter are summarized in Table 6.1. Simplified flow diagrams of the air- and steam-cooled systems are presented in Figs. 6.1 and 6.2. A number of other PFBC power plant configurations have been analyzed in various levels of detail by other organizations and could have possibly been included in this study. However, the time constraints placed limitations on the number of cycles which could be studied and so the choice was made to study variations of the cycles being recommended by the two major PFBC development contractors, GE and Curtiss-Wright.

6.1 Plant Efficiency

6.1.1 Sensitivity to sulfur control

Tighter control of SO_2 decreases plant efficiency generally because of:

1. net loss in calcination/sulfation reaction,
2. more sensible heat loss in disposed solids,
3. higher CO_2 generation and stack loss, and
4. more efficient gas cleanup requirements (higher pressure drop).

The change in efficiency for the PFBC plants is shown in Fig. 6.3 in comparison to an AFBC system. The net loss is small in every case with the loss in any of the PFBC systems less than the AFBC. These results are sensitive to the utilization efficiency of the sorbent and for example, a

Table 6.1. Major design parameters

	Steam-cooled			Air-cooled	
	A	B	C	A	B
<u>Cycle performance</u>					
Gross power, MW _e	728.0	692.3	660.3	458.0	383.3
Auxiliary power, MW _e	18.0	17.0	16.6	11.2	9.6
Net power, MW _e	710.0	675.3	643.7	446.8	373.7
Coal flow (fired), lbm/h	950,296	511,957	472,834	347,510	313,325
Net plant efficiency, %	37.8	38.7	39.9	37.7	35.0
<u>Selected design parameters</u>					
<u>steam turbine</u>					
Main steam throttle pressure, psia	2,415	2,415	2,415	659	396
Main steam throttle temperature, °F	1,000	1,000	1,000	828	735
Main steam flow, lbm/h	4,394,355	3,907,455	3,203,707	1,300,564	1,170,066
Reheat temperature, °F	1,000	1,000	1,000		
Secondary steam pressure, psia				152	108
Secondary steam temperature, °F				718	585
Secondary steam flow, lbm/h				325,142	292,516
Condenser pressure, in. HgA	2.5	2.5	2.5	2.5	2.5
Steam turbine power, MW _e	659.6	596.8	517.3	188.5	150.8
<u>Gas turbine/turboexpander</u>					
Compressor pressure ratio	6.0	6.0	10.1	7.1	7.1
Compressor air flow, lbm/h	5,854,796	5,446,888	5,295,418	13,337,343	13,892,694
Compressor efficiency, %	85.0	85.0	85.0	85.0	85.0
Turbine inlet temperature, °F					
Combustion gases	1,150	1,400	1,652	1,650	1,500
Clean air				1,550	1,400
Turbine pressure ratio	5.2	5.1	9.0	6.1	6.1
Turbine inlet mass flow, lbm/h	6,360,334	5,917,205	5,467,248	13,231,843	14,171,319
Turbine efficiency, %	85.0	85.0	89.0	89.0	89.0
Turbine cooling air, %	0	0	5.0	3.1	0
Gas turbine power, MW _e	50.4	78.5	126.4	258.3	222.9
<u>Selected design parameters pressurized fluidized bed combustor</u>					
Excess air, %	20	20	20	30	30
Air flow, lbm/h	5,854,796	5,446,888	5,030,649	4,005,389	3,611,379
Coal flow, lbm/h	549,747	511,446	472,362	347,162	313,012
Dolomite flow, lbm/h	200,200	186,253	172,020	101,613	91,618
Bed temperature, °F	1,500	1,500	1,750	1,650	1,500
Ca/S mole ratio	1.38	1.38	1.38	1.11	1.11
Combustion efficiency, %	98.8	98.8	99.6	99.7	99.6
Radiant heat loss, %	0.5	0.5	0.5	0.5	0.5
Total pressure loss-Δp, psi	7.3	7.3	7.3	10.3	10.3

Fig. 6.1. Schematic of typical steam-cooled PFBC combined cycle.

Fig. 6.2. Diagram of air-cooled PFBC power system (Curtiss-Wright).

Fig. 6.3. Estimated efficiency losses caused by higher control of SO_2 .

different, more reactive limestone might swing the results in favor of the AFBC plant. Other variables, such as the rate of recycle of elutriated material, can have a similar effect. Improved SO_2 capture in a PFBC can be effected not only by increasing the sorbent feed rate but also by increasing the residence time of the gases in the bed. The residence time, in turn, can be increased by utilizing a deeper bed or by lowering the superficial air velocity. A series of calculations were performed to determine the combined effects of bed depth and Ca/S ratio on the SO_2 capture and plant efficiency. The results in Figs. 6.4 to 6.6 reveal that there is an optimum combination of bed depth and Ca/S with regard to preserving high efficiency at high levels of SO_2 retention. Furthermore, the optimum bed depth is seen to be relatively shallow for the air-cooled PFBC. The air-cooled system, deriving over 50% of its power from the gas

Fig. 6.4. Effect of sulfur capture, expanded bed depth (H) and Ca/S ratio on air-cooled PFBC efficiency.

turbine loop, is naturally sensitive to the pressure drop in the combustion air loop that is very much dependent on the bed depth. The effect of pressure drop is discussed singly later in this section. The air-cooled system also utilizes a lower combustion air velocity (recommended in Curtiss-Wright design).

The two steam-cooled plants that were analyzed in this manner show about the same sensitivity to bed depth and, therefore, have about the same optimum bed depth. Intuitively, one would expect the cycle with the lower turbine inlet temperature (Fig. 6.6) to be less sensitive to the bed depth and the accompanying pressure drop because of the lesser contribution by the gas turbine to the plant output (only 8% of total plant output). However, the lower turbine inlet pressure in the cycle means that changes in bed pressure drop cause a relatively large change in the $\Delta P/P$

Fig. 6.5. Effect of sulfur capture, expanded bed depth (H) and Ca/S ratio on high temperature steam-cooled PFBC efficiency.

Fig. 6.6. Effect of sulfur capture, expanded bed depth (H) and Ca/S ratio on low-temperature steam-cooled PFBC plant efficiency.

parameter that has substantial influence on the output of a gas turbine cycle. A safe conclusion is that for reasonably reactive sorbents, neither PFBC nor AFBC will suffer a substantial performance penalty in order to achieve lower SO_2 output based on current data.

6.1.2 Sensitivity to turbine inlet temperature

Both air- and steam-cooled PFBC plants were evaluated for sensitivity to the peak cycle temperature. The data shown in Fig. 6.3 reveal that the steam-cooled plants are much less sensitive to turbine inlet temperature than a Curtiss-Wright type of air-cooled plant (see also Fig. 6.8). The high sensitivity of the air-cooled concept is common to all power cycles of a topping/ bottoming configuration. One reason is that the steam cycle must be degraded as well as the gas cycle when the peak temperature is reduced. Note that the steam cycle does not change appreciably when the turbine inlet temperature is reduced in a steam-cooled PFBC concept. Table 6.2 presents some data for comparison which demonstrates these characteristics for air- and steam-cooled cycles.

Table 6.2. Comparison of variation in steam cycle performance for air- and steam-cooled PFBC plant

	High temperature systems		Low temperature systems	
	Air (A)	Steam (C)	Air (B)	Steam (B)
Gas turbine inlet temperature, °C	~870	900	~780	760
Overall efficiency, %	38.1	40.0	35.1	38.77
Fraction gas turbine power	57	20	60	12
Fraction steam turbine power	43	80	40	88
Steam cycle efficiency	31.1	40.7	28.2	41.4

The air-cooled plant can be made more efficient and less sensitive to turbine inlet temperature by upgrading the steam bottoming cycle. The steam cycle can be upgraded through supplemental firing which would be equivalent to cooling the PFBC with steam in addition to air. Supplemental firing also reduces the fraction of the plant output generated by

the gas turbine which would also lessen the sensitivity of plant performance to the gas turbine and compressor efficiency. A power cycle employing supplemental firing on the steam cycle is depicted in Fig. 6.7. The supplemental firing in the air-cooled PFBC can be accomplished by putting steam generator tubes in the furnace in addition to the air-cooled tubes. The resulting system could be termed a hybrid in that the PFBC furnace is both air- and steam-cooled. The affect that this alteration has on the performance of the air-cooled cycle is quite notable as shown in Fig. 6.8. The hybrid PFBC system shows high potential efficiencies which are retained at modest design turbine inlet temperatures.

Fig. 6.7. Schematic of air/steam-cooled PFBC power cycle illustrating concept of supplemental firing.

Fig. 6.8. Effect of upgrading steam cycle in an air-cooled PFBC plant by generating steam in the furnace.

6.1.3 Sensitivity to pressure

Data on the effect of pressure ratio on the efficiency of the steam-cooled and air-cooled has been previously compiled (Ref. 87). Generally, in the range of 6 to 10, the pressure ratio has little effect as seen in Fig. 6.9.

6.1.4 Sensitivity to gas turbine efficiency

The gas turbine in a PFBC system will most certainly gradually degrade from erosion and corrosion. The loss in performance of the entire plant associated with gas turbine degradation was calculated for air- and steam-cooled PFBC systems. The general trend is that the systems which have the small fraction of plant output from the gas turbine tend to be less sensitive to the turbine efficiency. The importance of gas turbine efficiency is shown in Fig. 6.10.

Fig. 6.9. Effects of gas turbine inlet temperature and pressure ratio on steam-cooled PFBC overall efficiency.

Gas turbine efficiency is 83% at pressure ratio of 5, 85% at 7 and 88% at 10.

This trend carries the implication that the air-cooled concepts currently receiving the greatest emphasis may be poor choices for first generation commercial PFBC plants since anything going awry with the cleanup system might damage the turbine and significantly reduce the power producing capacity of the plant, certainly more so than would be experienced in a steam-cooled PFBC system.

6.1.5 Sensitivity to pressure drop in gas cleanup device

The plant performance analyses revealed that the gas cleanup system's pressure drop generally accounted for less than half of the total gas side pressure drop. The model used to calculate pressure drop was used for all plants compared. Samples of the cleanup system pressure loss are provided in Table 6.3.

The estimates for the cyclone pressure drop are believed to be reasonably accurate, perhaps slightly high. Since the cleanup system pressure drop is only a part of the total pressure drop, it could, therefore, be increased by a significant fraction without seriously degrading the

Fig. 6.10. Effect of gas turbine efficiency on the overall efficiency of several PFBC configurations. Values noted refer to turbine inlet conditions.

Table 6.3. Comparison of pressure drops of gas cleanup systems

Plant	Cleanup ΔP -% of compressor outlet pressure	Bed Δ -%
Steam-cooled B	3.83	9.20
Steam-cooled C	4.07	5.33
Air-cooled A	2.34	9.87

plant efficiency. The impact on plant efficiency that would result from increasing the pressure drop in the combustion gas stream is illustrated in Fig. 6.11. As previously mentioned, the air-cooled cycle suffers the greater penalty.

Fig. 6.11. Increased pressure drop in the combustion gas stream will have notable impact on plant efficiency.

6.1.6 Effect of deposition

Deposition in the gas turbine is expected to occur in PFBC systems and, regardless of whether they can be removed, they will influence the plant performance and operation between cleaning intervals. As deposits

build on the gas turbine blades a number of events occur at gradual rates.

1. The adiabatic gas turbine efficiency will drop.
2. The operating characteristics of the turbine will change.
3. The operating point of both turbine and compressor will change.

The overall result of a change in gas turbine efficiency has been noted previously. The change in operating characteristics is best explained by referring to Fig. 6.12. As the turbine begins to lose flow area its flow would tend to drop, provided that its inlet pressure remained constant. The assumption is made here that the turbine and compressor must operate at constant speed. The change in geometry of the turbine, which is caused by the deposits, will shift its constant speed operating line from line A in Fig. 6.12(b) to line B. The turbine would probably be choked or nearly so and a reduction in flow area will therefore mean that the quantity, $\dot{m}/P_{04}$, will drop as the turbine inlet temperature, T_{04} , is held constant. The compressor map indicates that the pressure ratio would increase slightly and that the mass flow rate would decrease. The compressor operating point thus moves closer to the surge line (OP_1 to OP_2) and its efficiency would more than likely decrease [Fig. 6.12(c)]. The loss in the swallowing capacity of the gas turbine would mandate that the entire plant be turned down, whereas the loss in turbine efficiency would decrease the plant efficiency according to the trends established earlier in this section.

Gas turbines which have two shafts and separate turbine wheels to drive the compressor and generator would not have fixed compressor speeds. Deposits would have a similar effect, however, by driving the compressor towards the surge line. The proposed Curtiss-Wright PFBC commercial plant utilizes a two-shaft gas turbine.

The frequency of cleaning will be determined by what is viewed to be an acceptable power drop or by operation too close to the surge line. The method of determination will depend somewhat on the operating characteristics of the particular turbomachine which are generally regarded as proprietary by the manufacturer.

The power loss and efficiency loss must be considered as additional to the normal degradation caused by erosion and corrosion. In general,

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Fig. 6.12. Compressor and turbine performance maps.

on-line cleaning will probably not restore the full performance potential that the machine had prior to the deposition. This nature of a deposition/cleaning cycle is shown in Fig. 6.13. The degree of restoration of power through cleaning, of course, depends on the tenacity of the deposits.

Fig. 6.13. Power output of Beznau heavy oil fired gas turbine, without additive A and with silicon additive B - Brown-Boveri Review (Ref. 88).

6.2 The Influence of Design Conditions on Major Components in PFBC

The designs, configurations, and materials for many parts of the PFBC plant change considerably when major parameters such as combustor pressure and turbine inlet temperature are changed. Some of these changes for major components are described here. Major effects on the cost of equipment are also discussed where appropriate.

6.2.1 Effect of pressure and turbine inlet temperature on furnace

The furnace shell size is primarily influenced by the combustor pressure, and the amount of steam generator surface is influenced mainly by the combustion temperature and turbine inlet temperature. The amount of combustor plan area generally varies inversely proportional to pressure whereas the thickness of the pressure vessel is proportional to pressure. Hence the cost of the shell is not substantially reduced by increasing its pressure.

Larger plan areas dictate more (not larger) pressure vessels in general because even at 10 atm, the power generation can be only about 300 MWe per vessel if one limits the vessel diameter to a practical size of about 10 m. Larger area requirements simply require multiple vessels which do not offer significant economies of scale. However, in a detailed analysis, fewer vessels may offer cost savings in the ducting systems, thereby favoring higher pressure combustors.

The gas turbine inlet design temperature is controlled by cooling of the combustion gases with steam generator or air heater convection passes. Due to the poor heat transfer in the convection zone relative to the fluidized bed, it is desirable to attempt to minimize the convection heat transfer. This can be accomplished by reducing the bed combustion temperature. A net savings should result as long as combustion efficiency and sulfur capture are not sacrificed an appreciable amount. In the evaluations in this study a combustion temperature of 815°C was used for turbine inlet temperatures less than 800°C and a combustion temperature of 954°C was used for the turbine inlet temperatures around 900°C.

In a steam-cooled PFBC, the exhaust of the gas turbine is used for feedwater heating in an economizer. The feedwater flow through the economizer is parallel to the flow through the feedwater heaters. Increasing the turbine inlet temperature will generally increase the heat duty of the economizer. For example, the economizer of steam-cooled plant C has roughly 40% more heat transfer than the economizer in plant A. Due to the respective temperature differences, however, the two economizers are about the same size.

6.2.2 Effect of design conditions on gas turbine configuration

The combustor pressure and turbine inlet temperature affect aspects of the turbine design such as:

1. number of stages,
2. blade materials,
3. specific power, and
4. degree of blade cooling.

A turbine stage pressure ratio of about 2.25 is a reasonable maximum although higher is attainable but usually with sacrifice of efficiency. Although each stage of a turbine may not have the same pressure ratio the total number of stages can be estimated by

$$n = \frac{\ln (\text{Total Pressure Ratio})}{\ln (\text{Stage Pressure Ratio})}$$

Two turbine stages or less can be incorporated into an expander with an overhung (cantilever) shaft which permits easy maintenance. More stages make this type of design less feasible.

For the turboexpander PFBC systems, the blade material required for strength and corrosion resistance will vary with temperature in the 620 to 750°C temperature range. The Elliot Company provided the following materials recommendations in Table 6.4. The Elliot Company projected a 60 to 100% increase in expander cost at the upper bound of inlet temperature.

Table 6.4. Recommended materials for turboexpander applications

Turbine inlet temperature (°C)	Blade material
<620	A286
700 735	Inconel or Incoloy
735 760	Waspaloy

If the inlet temperature is increased much beyond 760°C vane and blade cooling become necessary, adding more expense to the machine. Blades with cooling passages would also be more expensive to replace and are more susceptible to damage since deposits might block the cooling air channels.

6.2.3 Effect of pressure and turbine inlet temperature on steam bottoming cycle configuration

The steam cycle configuration for a steam-cooled PFBC changes very little even with major changes in gas turbine inlet conditions as evaluated in this study. Basically, only the feedwater heater train must change due to the additional energy available in the turbine exhaust at higher inlet temperatures. More heat transfer in the economizer (which cools the turbine exhaust) reduces the amount of regenerative feedwater heating in the steam bottoming cycle and therefore reduces its thermal efficiency slightly. However, another result is that the power output per mass flow of steam (at the HP turbine inlet) increases. Table 6.5 presents data demonstrating this characteristic.

Table 6.5. Relation between economizer heat duty and steam cycle efficiency

Steam-cooled plant	Economizer heat load (kW)	Steam cycle efficiency (%)	Steam cycle specific power (kWh/kg)
A	155,884	41.7	0.33
C	220,999	40.7	0.36

Changing the turbine inlet temperature on the air-cooled PFBC combined cycle mandates significant changes in the steam cycle configuration. The waste heat boiler conditions for air-cooled plants A and B were considerably dissimilar as shown in Fig. 6.14 although both are dual pressure systems. When lowering the gas turbine inlet temperature, the exhaust temperature will drop, of course, unless the design pressure ratio is reduced. The characteristics of combined cycles shown in Fig. 6.15 indicate

Fig. 6.14. Effect of high (and low) gas turbine inlet temperature on waste heat boiler conditions.

Fig. 6.15. Effect of lowering the design gas turbine inlet temperature on plant efficiency - with and without change in turbine pressure ratio.

that the efficiency loss from dropping inlet temperature can be minimized by maintaining a high turbine exhaust temperature which would necessitate lowering the gas turbine pressure ratio.⁸⁹

On the other hand, if gradual development permits higher gas turbine inlet temperatures ($>900^{\circ}\text{C}$), the steam cycle configuration must also undergo significant change in order to achieve the largest possible improvement in efficiency. Steam pressure would have to increase as well as peak temperature. The addition of a steam reheat may also be advisable at gas turbine inlet temperatures greater than 1000°C .

This is contrary to the steam-cooled PFBC which could retain the same basic steam cycle at higher gas turbine inlet temperatures than currently envisioned for PFBC systems. A supercritical steam cycle is seen as the only practical improvement over the subcritical cycle used throughout the analyses in this effort.

Although its importance may be questionable, the implication is that the steam cycle configuration would have to be completely reworked for the air-cooled plant for each step in an evolutionary development process. This would not be necessary with the steam-cooled concepts.

6.2.4 Effects of pressure and temperature on hot gas ducting

Increasing pressure and density of the hot gas will reduce the volume flow rate and the number of parallel pipes required to transport the gases between the combustors, cleanup devices, and gas turbine. Since multiple pipe streams must be used, the cost is proportional to the volume flow rate or pipe flow area.

At relatively low temperatures, 650°C, either insulated alloy piping or refractory lined mild steel piping can be utilized. The refractory might require an internal liner to prevent damage to the refractory but could be made of low alloy material since its strength requirements are low and corrosion is minimal. The cost difference between these two designs is not large as long as a modest alloy (not stainless steel) can be used for the internal shroud. At higher temperatures the shrouded refractory ducting apparently offers the lowest cost. The use of mild steel for the outer pressure containment tends to reduce the sensitivity of the pipe to pressure since the stainless or Hastelloy shroud necessary at high temperature dominates the cost of the pipe. The outer pipe will also have to withstand thermal stresses which are not directly related to the gas pressure. Succinctly, the process gas temperature will have considerable effect on the ducting cost and the pressure will have minimal effect.

The 3M Company has developed a new type of hot gas pipe which employs a tough, hard ceramic tile for the inner shroud which is backed by a resilient tile insulation. The hard tiles interlock in a manner to allow for thermal expansion but still protect the insulation and pipe. This type of pipe may be a less expensive option for very high temperatures which would otherwise require a Hastelloy or stainless steel shroud.

6.2.5 Effect of pressure on solids feeding

This topic is covered more thoroughly in a previous section of this report. The presumption has been that high pressure and reduced combustor plan area would allow simplification of the solids feeding by reducing the number of coal feed points. The previous discussion casts some doubt as to the validity of this trend.

The survey of feeding equipment indicates that lockhoppers will be necessary for PFBC systems of 6 to 10 atm. The Fuller-Kinyon pump, which would not require a complex lockhopper feed system, is yet undemonstrated at these pressure levels. Hence the conclusion here, as in many of the survey responses, is that solids feeding will present equal challenge at either 5 or 10 atm pressure.

6.3 Cost of Power

6.3.1 Sensitivity to sulfur control

The cost of power for all PFBC plants studied is relatively insensitive to sulfur control level (Fig. 6.16). This favorable characteristic

Fig. 6.16. Influence of sulfur capture on plant cost of power.

is evident even though the plant parameters were not adjusted to minimize the COE at a particular sulfur capture level. For example, the superficial combustion air velocity could be reduced or bed depth increased which would reduce the dolomite feed rate required (at a particular value of SO_2 capture) but might change the size of the pressure vessel. Optimization studies of this nature for the PFBC were performed on a limited basis in this task. Alternate bed depths were evaluated for impact on the overall COE.

Two PFBC concepts were studied with the results shown in Figs. 6.17 and 6.18. On these graphs, the Ca/S ratio required for 90% sulfur capture is shown as a function of bed depth. The combination of bed depth and

Fig. 6.17. Optimum bed depths for cost and efficiency in air-cooled PFBC.

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Fig. 6.18. Optimum bed depths for cost and efficiency in steam-cooled PFBC.

Ca/S ratio were then used as inputs for calculating the plant efficiency and overall COE. Although the efficiency of the air-cooled plant peaks at a rather shallow bed depth, the overall COE is minimized at a bed depth close to that proposed in earlier design studies. Similarly, most economical bed depth for the steam-cooled plant is predicted as being somewhat deeper than the values used in most design studies. However, at some depth one would expect to see some step increases in furnace costs which were not predicted in this analysis.

The air-cooled PFBC displayed the smallest increase in COE when increasing the sulfur capture from 90 to 98%. A number of factors contribute to this trend such as:

1. The overall efficiency of the air-cooled system is less sensitive to SO₂ control than the other PFBC concepts.
2. The dolomite cost increase associated with increasing SO₂ capture from 90 to 98% is smaller for the air-cooled PFBC. This is mainly because the air-cooled bed is designed with a relatively low superficial air velocity which promotes sorbent utilization but makes the pressure shell larger and more expensive.

In comparison to the baseline AFBC model, the COE of all PFBC concepts shows less dependence on the degree of SO₂ control. The difference is not overwhelming, however, and use of a better sorbent in the AFBC or less reactive sorbent in the PFBC could alter the conclusion.

The increase in COE of the CPWS is primarily due to the larger size and higher capital cost of the scrubber necessary to achieve SO₂ capture in excess of 90%. The auxiliary energy requirements of the scrubber also increase at higher efficiencies and reduce the net output (and efficiency) of the plant. The rate of increase for the CPWS is, again, higher than the PFBC plants but a dramatic increase in the COE is not seen even with conventional technology.

6.3.2 Sensitivity to turbine life

Succinctly, the cost of turbine maintenance can be of greater influence on COE than the sulfur control requirements. The importance of the turbine life depends on the type of PFBC plant as much as the stage life itself. For plants employing the turboexpander, the turbine maintenance is practically an insignificant part of the COE for a stage life >10,000 h. The turboexpander is anticipated to have a longer life with little uncertainty at the operating conditions of steam-cooled plant "A." The 900°C steam-cooled plant shows more sensitivity to turbine life for the single reason that the turbines are more expensive to repair. Data are shown in Fig. 6.19.

Fig. 6.19. Influence of turbine stage life on PFBC Busbar power cost.

The turbine maintenance becomes a large part of the COE of an air-cooled PFBC for lifetimes less than 10 to 20,000 h depending on whether one or two (perhaps even three) stages require replacement. The greater number of gas turbines in the air-cooled system, relative to steam-cooled, requires that the turbine blades last longer to keep down the repair costs. The long turbine life would probably be assured by using a high performance gas cleanup system in addition to the clean air mixed with the flue gas. Hence, it is unlikely that substantial cost savings could be realized in the gas cleanup system for an air-cooled system.

On the other hand, the results indicate that for a low temperature turboexpander plant the turbine life could be sacrificed for a less expensive gas cleanup system with probably a net reduction in cost of power.

The results, of course, depend on the actual cost of repairing the turbo-machinery which carries some uncertainty in the case of a turboexpander but even more uncertainty for the industrial gas turbine with coated or clad blades.

6.3.3 Effect of turbine inlet temperature

In the case of the steam-cooled PFBC, the effect of the peak cycle temperature is best determined by examining cases A and B which are practically identical in all design conditions other than turbine inlet temperature. Steam-cooled plant B has a higher plant efficiency but the overall COE is about the same as plant A with the 620°C peak temperature. The reason lies in the capital costs of the respective plants and a breakdown of the costs. Table 6.6 reveals where the trade-offs between efficiency and capital cost appear.

Table 6.6. Comparison of capital cost components for steam-cooled plants A (620°C) and B (760°C)

Account No.	Description	Cost (\$/kWe)	
		A	B
3.0	Gas turbine system	39.4	51.1
4.2	Gas cleanup equipment	65.3	74.6
4.4	Hot gas pipe	15.9	20.4
4.1 and 6.1	PFBC combustor/steam generator	63.4	53.8
7.0	Steam turbine/generator	68.0	65.8

The increased turbine inlet temperature in plant B decreases the density of the flue gas and therefore the gas handling equipment must be larger. This affects the gas turbines, piping, and gas cleanup systems. As expected, the steam generator for the higher temperature system is less costly due to the lesser convection heat exchanger surface required. The cost increase for high temperature turbine alloys is also factored into the higher cost of the gas turbine as well as the reduction in mass flow

which accompanies the increase in inlet temperature. A key factor is that the plant output is increased by lowering the turbine inlet temperature because a higher mass flow could therefore be handled by the four turbo-expanders. The increased output is instrumental in reducing the cost per kilowatt (electric).

In the case of the air-cooled plant, however, lowering the peak cycle temperature reduces the power output of a plant (based on six gas turbines) as well as reducing the overall efficiency a greater degree than in the steam-cooled plants. The combined cycle configuration in the air-cooled plant requires that the steam cycle be downgraded when the peak temperature is lowered and the gas turbine pressure ratio is not altered. Table 6.7 summarizes the change in plant performance.

Table 6.7. Effect of turbine inlet temperature on air-cooled plant

	Plant B	Plant A
Gas turbine inlet temperature, °C	~780	~870
Gas turbine inlet gas mass flow, kg/h	6.43×10^6	6.19×10^6
Gas turbine power, MW	222	258
Steam turbine power, MW	152	192
Steam turbine power per unit mass flow of steam, kWh/kg	0.23	0.26
Overall efficiency, %	35.1	38.1

Basically, less power is obtained from the same equipment and for the same cost. These data imply that the fall-back design conditions, if needed, will be more detrimental to the overall economics for the air-cooled system than for the steam-cooled concepts. On the other hand, the air-cooled plant would receive greater benefit from increasing the turbine inlet temperature.

The overall influence of turbine inlet temperature on COE includes changes in plant efficiency, design, and turbine maintenance. These individual contributors to COE were combined in Fig. 6.20 to illustrate the

Fig. 6.20. Estimated net effect on COE by increasing turbine inlet temperature.

probable trends in the overall COE with increasing turbine inlet temperatures. The turbine maintenance costs are based on the data shown in Fig. 6.19, Fig. 4.44, and Fig. 4.46. Due to the larger number of gas turbines utilized in the plant, the air-cooled PFBC shows a much higher uncertainty in COE, despite a potentially substantial benefit from increasing the turbine inlet temperature. The steam-cooled PFBC is predicted to have a lesser benefit at higher temperatures, but also lesser uncertainty in COE.

6.3.4 Effect of pressure (and further turbine inlet temperature increase)

A number of parameters other than pressure are different between steam-cooled plants B and C. Among these differences are:

1. turbine inlet temperature and
2. turbine efficiency.

Some of the pressure effects can be ascertained, however. For example, three gas turbines at 10 atm inlet pressure can handle roughly the same gas flow as four turboexpanders at 6 atm. Furthermore, the reduced gas volume flow at high pressure tends to cancel out the ducting cost increase associated with temperatures over 820°C. The cost analysis also revealed no appreciable difference in the combustor shell cost for the two plants although the steam generator for plant C was found to be less expensive since almost all heat exchanger surface is submerged in the fluidized bed. The cost of the large cyclone vessels did not show a great difference although the volume flow is reduced, since the shell wall thickness must increase for higher pressure.

The cumulative trade-offs resulted in overall capital costs for the two plants differing by less than 10%. The advantage in efficiency for plant C resulted in a slightly lower COE depending, of course, on the assumed turbine maintenance cost.

7. OVERALL COMPARISON OF PFBC CONCEPTS, AFBC, AND CONVENTIONAL PULVERIZED COAL PLANT WITH WET SCRUBBERS (CPWS) — EMISSIONS

The environmental intrusion of power plants depends on the combustion characteristics and efficiency, among other things. Solid wastes and gaseous emissions of the various technologies are compared in the following sections.

The emissions data have been presented in terms of the amount per power output of the plant which appears to be more sound in comparing options than looking at emissions based on fuel consumed. Comparing emissions on an output basis provides due credit to the more efficient plants as shown in Fig. 7.1. The more efficient plants obviously generate less SO_2 for any particular power generating capacity.

Fig. 7.1. Illustration of lesser environmental impact for more efficient power plants.

7.1 Solids disposal

Although the solids disposal is a relatively small part of the overall COE it is receiving increasing attention as an environmental hazard. The solid wastes from various power systems are compared in Fig. 7.2. Any of the PFBC systems are superior to the AFBC. The air-cooled system has the least solids because the furnace is designed with a high gas residence time, lowering the Ca/S mole ratio required for SO_2 control (this design condition is not necessarily optimum in terms of cost, however).

Over the range of SO_2 capture shown, the molar Ca/S ratio varied from 3.0 to 4.4 for the AFBC and from about 1.4 to 1.8 for the PFBC plants. These differences, in addition to the efficiency advantage for PFBC, combine to give the difference in solids disposal between AFBC and PFBC. The PFBC advantage exists in spite of the lower CaCO_3 content of

Fig. 7.2. Comparison of solid waste from power plant concepts.

dolomite relative to limestone. The ash in the coal, of course, represents a substantial fraction of the solid wastes.

Improvements in the AFBC may be forthcoming upon the optimization of recycling during combustion. The data shown for the PFBC, however, are not optimized either and solid wastes can certainly be reduced through use of different design conditions.

There are currently no EPA standards for the quantities of solid waste produced by power plants and, therefore, the COE vs solid waste control has not been presented. At the expense of higher capital cost, the solid wastes from the PFBC plants could be reduced somewhat by increasing the gas residence time in the combustor. The dolomite feed requirements would then be decreased. The ash in the coal, however, represents a considerable fraction of the solids and could not be eliminated.

7.2 Emissions of NO_x

The review of PFBC data on NO_x emissions revealed that pressure and excess air were the more important variables to consider. Additionally, the combustion efficiency has some influence. The Ca/S ratio has been claimed as affecting the NO_x emissions but no clear trends were found in the review of data. A correlation was developed to compare the NO_x emissions from the PFBC systems evaluated in this study. The results of the comparison are presented in Table 7.1.

Table. 7.1. NO_x emissions
from PFBC systems

Case	NO _x	
	[kg/kWeh (lb/10 ⁶ Btu)]	
Steam-cooled A	0.441	0.259
Steam-cooled B	0.431	0.259
Steam-cooled C	0.310	0.192
Air-cooled A	0.469	0.277
Air-cooled B	0.510	0.277
AFBC	1.33	0.707

By virtue of its higher operating pressure and highest efficiency of the PFBC systems, the steam-cooled plant C (930 kPa, 899°C) emits the lowest level of NO_x based on electric output. The air-cooled plant NO_x emissions were calculated as being slightly higher than the low pressure steam-cooled plants due to the higher combustion efficiency resulting from the deep bed and low air velocity called for in the air-cooled PFBC design (Curtiss-Wright design conditions).

8. ADVANCED POWER SYSTEMS — FROM DEVELOPMENTAL TO COMMERCIAL PRODUCT — A PERSPECTIVE

The widespread notion that a whole set of advanced energy systems will soon be serving the public stems from difficulties most people have in appreciating two major problem areas, i.e., the serious uncertainties in both the research and the development phases, and the time spans required for not only these two phases but a third phase, that for commercialization to the point where the system makes a significant contribution to the economy as a whole. These three phases must be conducted in series, and the time required for each depends in part on the difficulty of basic technical problems such as corrosion, in part on the size of the system required for commercial viability (and hence the time required for construction), and in part on the competition. Pocket size solid state electronic calculators, for example, represent a dramatic case in which a technical innovation was developed and virtually took over the market from its predecessor (slide rules) in less than 10 years because the basic R&D on silicon chip microcircuits was well in hand, the units were small, inexpensive, and quickly manufactured, and they were much superior to the product they displaced. Advanced systems for producing electricity present vastly different problems. Conventional steam power plants are highly developed so that it is difficult to compete with them, and the economics of scale strongly favor very large units each of which costs roughly a billion dollars, takes 5 to 10 years to build, and — because of its size — introduces environmental effects which in turn make for political problems that often dominate technical considerations. Thus it is a formidable task indeed to carry a new concept for an advanced energy system through to commercialization, the time required is probably two decades, and there is no assurance of success. In fact, it is a bit like a horse race — only a few of the entrants can be expected to win or even place.

An illustration of the nature of the situation is given by an historical review of the time required for the research, development, and commercialization phases for fission power reactors. Fifteen different reactor types were under development in the 1945 to 1970 period, but by 1980

only four types had reached a stage of commercialization such that each was represented by at least a half dozen units in commercial operation. One or a few units of each of four other types had produced substantial amounts of electricity, but only one of these, the LMFBR, was under active development in 1980, and all R&D work on 7 of the 15 types had been terminated.

Probably the first point is that all four of the successful reactor types operate at relatively low temperatures — around 300°C (575°F) — and make use of fairly conventional materials that, from the standpoints of both extensive experience and from basic chemical thermodynamics, one would expect to be compatible and relatively free of corrosion difficulties. No scientific or technological "breakthroughs" were required for their development, and — in particular — the materials problems (except for radiation damage) were largely in hand in 1945. Yet even in the most successful types, the pressurized and boiling water reactor systems, the most serious troubles have been with corrosion of stainless steel systems by nominally pure water. Even one of the lowest temperature reactor concepts was dropped from development because of a materials problem — the organic coolant (whose low vapor pressure would have avoided the need for the massive and expensive pressure vessels of the water reactors) was subject to polymerization under intense irradiation, and the resulting gummy solids fouled the vital heat transfer surfaces in the reactor core making the system completely unacceptable.

A second major factor affecting system acceptability has been the costs for both the capital investment and for the fuel. Of the reactor concepts requiring an expensive moderator, i.e., Be, BeO, or D₂O, only the D₂O reactor has reached commercialization. D₂O reactors entail a high capital investment for the D₂O, but they have the important advantage that the extremely low neutron absorption cross-sections of D and O make the neutron economy of the D₂O reactors the best of any of the thermal reactors.

A third major factor affecting commercialization is the sensitivity of the system to small leaks and the consequent maintainability and reliability. However thorough the design work, and however stringent the quality control in the course of fabrication, occasional leaks are bound

to occur. The PWR and BWR systems have shown themselves to be the least sensitive to leaks.

The sodium-cooled reactors are very sensitive to leaks. This was particularly true for the sodium-cooled graphite reactor because sodium reacts with graphite causing it to swell. To prevent this, the graphite blocks were canned in sheet stainless steel which had to be thin in order to avoid excessive neutron losses. As predicted by critics of the concept, when a reactor was built and operated, the cans cracked in the wrinkles upon thermal cycling, the sodium got into the graphite, and swelling occurred. The graphite swelling closed the gaps between graphite blocks in which the control plates operated, rendering first one and then another control plate inoperative. This forced termination of reactor operation after relatively little running, and terminated the development program.

The aqueous homogeneous and molten salt reactors are also inherently sensitive to small leaks and was a major factor in terminating support for these two programs, though experimental reactors of both types were operated for periods of a year or more.

A fourth major factor is system stability and controllability. The steam bubbles in a boiling water reactor are voids in the water moderator, and increasing their volume reduces the reactivity. The control problems that this posed in the initial design studies appeared formidable, but clever design followed by successful reactor operating experience demonstrated that these control problems were tractable, and in the event they did not hold up the development program. Similarly, the short neutron lifetime of fast reactors appeared to present such serious control problems that their development was delayed until extensive analyses supported by tests of small experimental reactors demonstrated that satisfactory control could be achieved. On the other hand, various attempts to design water reactors that would serve as both boilers and superheaters proved unsuccessful because local fuel burn-out conditions could be induced by either potential boiling instabilities or shifts in the heat load distribution between boiling and superheating caused by changes in load or system pressure. As a consequence, development of this type of reactor

was abandoned at one stage or another in every country in which it was considered.

In reviewing the above it is apparent that some reactor concepts presented relatively few technological problems and hence their development proceeded fairly rapidly with only ~15 years required for R&D before commercialization could begin, and another 15 years was required to penetrate ~5% of the market. At the other extreme, many of the concepts presented such serious materials or basic stability problems that they were abandoned. A few concepts have been pursued to the point where one or a small number of reactors produce commercial electric power, but because of slowness in development, costs, and/or maintenance problems, these types are not widely used and seem unlikely to take over a larger segment of the market. Only one concept, the LMFBR is under active development. This stems from the fact that in spite of high capital costs and a marked sensitivity to system leaks, there is a strong incentive to proceed with the breeder development because the price of natural uranium is expected to rise enough by the early 21st century so that the much lower fuel costs obtainable by breeding fissionable material will more than offset the higher capital costs.

In applying the lessons implicit in fission reactor development to FBC power systems one finds that several of the currently envisioned concepts satisfy one or more of the four guidelines. For example, the low-temperature steam-cooled PFBC (sometimes termed an evolutionary PFBC) clearly offers the lowest potential for corrosion in the turbine, ducting, and boiler. It also appears to require no breakthrough provided that solids handling systems currently available can be engineered to high reliability.

Low capital cost may be an advantage held by the AFBC. This study shows, however, the advantage in overall COE which results from improved efficiency at the expense of modest increases in capital outlay.

The air-cooled PFBC, as noted by respondents to the survey, probably offers the least sensitivity to minor leaks of any of the PFBC concepts. Furthermore, the air-cooled bed has control advantages over steam-cooled beds since the overall heat transfer coefficient can be altered by changing the power cycle air-flow. Although not actually a stability problem

as in reactors, the system control for PFBC plants is generally undemonstrated and the ease of control will probably influence the acceptance of the concept.

Other data on commercializing new concepts can be found for a power device somewhat more related to the PFBC — the gas turbine. The gas turbine engine was developed from a proof-of-principle experiment in 1904 to a limited production technology in the early 1940s. However, not until the 1960s was the gas turbine considered practical for widespread use by utilities. Many of the developments which made this application of gas turbines practical can be attributed to the major research efforts aimed at military aircraft engines. Since that time gas turbines have continually undergone fine tuning with gradual improvements in:

1. compressor and turbine aerodynamics
2. control methods
3. turbine cooling
4. materials
5. combustor design
6. efficiency, due to a number of the above.

Development of new and unique concepts are rare and probably considered unnecessary. New gas turbine models are generally representative of older designs but are scaled to larger sizes and utilize improvements such as those mentioned above. A good example of the time required to put a new gas turbine model into production is seen in the GE MS6001 which required about three years to take from conceptual studies to a field test unit. This model incorporates a number of improvements over its predecessors but certainly does not represent a new concept. This development period, however, might be representative of that required to put a gas turbine into reality which incorporated features to reduce susceptibility to damage due to particle ingestion.

Other examples of the time required to put new concepts into practical use can be reviewed. The rotary internal combustion engine (Wankel) was hardly more than an experiment about 25 years ago and it took until about 10 years ago for it to become a reliable automotive engine. It has since been following the path of the gas turbine, i.e., continually being

improved and being scaled to different sizes (Ingersoll-Rand markets 500 to 1000 bhp models).

In summary, the 15 to 20 years required to commercialize new concepts is a typical average even with large expenditure for development. Furthermore, due to the great expense and long construction time, it takes considerably longer for a new electric power system to have substantial impact on the environment or cost of power to the consumer.

If one takes 1970 as a starting date for serious PFBC experimentation then this concept would appear to be on schedule quite similar to the other examples cited in this discussion with large scale demonstration in the mid-1980s and perhaps a commercial product by 1990.

APPENDIX

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PFB COMPUTER MODEL

The coal combustion and gas power cycle calculations were performed by a large Fortran computer model. The model was used to simplify the tedious mass and energy balances of the 5 gas constituents (N_2 , O_2 , CO_2 , H_2O , SO_2) and 5 solid constituents (dolomite, coal, spent dolomite, char, ash). A summary of the major correlations used in the PFB Fortran model is provided in Table A.1. The performance of the steam power cycles was predicted using Syntha Corporation's Syntha-II Powerplant Design and Surveillance computer code.

Features of the PFB Combustor and Gas Power Cycle Fortran Model

The Fortran model for predicting the performance of steam-cooled PFB combustors includes the following capabilities.

1. Combustion mass and energy balances which compute the amount of energy available for steam production in both the fluidized bed and convection areas of the combustor. Radiant thermal losses from the combustor are accounted for.
2. Economizer energy balance which calculates the amount of energy in the gas turbine exhaust gases that is available for feedwater heating.
3. Air heater energy balance which automatically omits combustion air heating when the temperature difference between the gas turbine and compressor outlets falls below a specified value.
4. Mass balances for a recycle cyclone and up to 3 additional cyclone stages. An iterative procedure is used to determine the cyclone inlet velocities and diameters required for adequate gas cleanup. Secondary air flow from the compressor is allowed for in the final cyclone.
5. Solids cooler mass and energy balances which calculate the amount of ambient air needed for the cooling of solids collected in the cyclone and bed overflow lock hoppers.
6. Solids feeding mass balance which determines the amount of combustion air needed for pneumatic feeding. An intercooler energy balance is automatically included when it is necessary to calculate the amount of ambient air needed to maintain coal feeding temperatures at safe levels.

Table A.1. Major correlations used in the PFB combustor and gas power cycle model

Correlation	Computed values	Functional dependence
Thermal properties of gases (air, N ₂ , O ₂ , CO ₂ , H ₂ O, SO ₂)	Temperature averaged constant pressure heat capacity	1. Low temperature 2. High temperature
Thermal properties of coal and dolomite	Heat capacity evaluated at 50°C	None
Thermal properties of combustion solids (spent dolomite, char, ash)	Heat capacity averaged between 0°C and 850°C	None
Combustion efficiency	Fraction of carbon in the coal that is burned	1. Fraction excess air 2. Combustor temperature 3. Gas residence time
Sulfur capture	Calcium to sulfur mole ratio	1. Fraction of sulfur in coal which is captured 2. Gas residence time
Nitrogen oxides emissions	Mass of NO _x emitted per unit energy input (based on HHV)	1. Fraction excess air 2. Combustor pressure 3. Fraction combustion efficiency
Gas turbine cooling air	Fraction of compressor flow which is used for gas turbine cooling	1. Gas turbine inlet temperature
Elutriation (dolomite, char, ash)	Fraction of total solids leaving PFB which are entrained in the flue gas leaving the recycle cyclone	1. Superficial velocity
Cyclone efficiencies	Fraction of solids entering cyclone which are captured	1. Particle diameter 2. Cyclone diameter 3. Cyclone inlet velocity 4. Temperature
Cyclone pressure drops	Fractional pressure loss	1. Cyclone inlet velocity 2. Temperature
Bed pressure drop	Actual pressure loss	1. Expanded bed depth 2. Superficial velocity
Convection heat exchanger pressure drop	Fractional pressure loss	1. Ratio of heat transfer rate to mass rate of gases

7. Mass and energy balances for the drying and grinding of coal and dolomite. The amount of hot air needed from the solids cooler and inter-cooler is computed. Excess hot air from the coolers is used for stack gas reheating.
8. Energy balance which determines the net electrical output from the gas turbine-compressor unit. Power for the electric auxiliary motors (associated with the drying/grinding equipment, solids cooler, etc.) are deducted from the net output. Other plant auxiliaries are accounted for in a percent loss term. Generator and motor efficiencies are also accounted for.

The Fortran model for estimating the performance of air-cooled PFB combustors and gas power cycles is almost identical to the steam-cooled model explained above. The few exceptions are listed below.

1. The combustion mass and energy balance determines the amount of clean air which is heated in the bed tubes. The clean air is mixed with the flue gases after the particulate removal system.
2. The economizer energy balance computes the amount of energy which is available for waste heat boiling.

Steam Power Cycle Computer Code for Steam-Cooled PFB Power Plants

The Syntha-II computer code for predicting the performance of steam-cooled PFB steam cycles is modeled from TVA's Widow's Creek Unit No. 7 power plant. Unit No. 7 uses a conventional, subcritical, single reheat steam power system with eight regenerative feedwater heaters. The PFB economizer is located in parallel with five or six (depending on gas turbine exhaust temperatures) of the feedwater heaters. The effect of the economizer is to reduce the overall steam power cycle efficiency as more feedwater flow is diverted away from the regenerative heaters. Some features of the Syntha-II computer code are listed below.

1. Steam turbine efficiencies are estimated using the published correlations and procedures of the General Electric Company.
2. Pressure losses are accounted for in heat transfer components and long pipes.

3. Steam seal flows and a gland steam condenser for energy recovery are included.
4. Losses due to auxiliary feed-pump turbines, electric feed-pump motors, generator and motor efficiencies are all included.

Steam Power Cycle Computer Code
for Air-Cooled PFB Power Plants

The Syntha-II computer code for estimating the performance of air-cooled PFB steam cycles is patterned after Curtiss-Wright's PFB commercial plant design. The power plant design uses a dual pressure boiler in order to reduce the temperature differences between the steam and gas turbine exhaust gases in the waste heat boiler. High pressure steam generated in the boiler is expanded through a high pressure turbine and then is mixed with low pressure steam before expansion continues in a low pressure turbine. The air-cooled PFB Syntha-II computer model is less detailed than the steam-cooled model explained above. Some of the simplifications are listed below.

1. Steam turbine efficiencies are specified.
2. Steam seal flows are not included.
3. All boiler feed-pumps are driven by electric motors.

Coal Properties

A single eastern coal was used throughout all analyses. Properties of the coal are given in Table A.2.

SOURCES AND ASSUMPTIONS FOR COST DATA

The 1978 Burns and Roe (B-R) study (Ref. 90) was used as the basis for costing the PFBC concepts in this study. There are several attractive aspects of the B-R effort which made their data appear to be the best choice to use as a starting point:

1. The B-R study included a sub-critical, steam-cooled PFBC system.
2. The B-R study included air-cooled PFBC cycles, one of which is very similar to the Curtiss-Wright system.

Table A.2. Characteristics of coal
used in this study

Source: Western Kentucky Seam No. 9 (unwashed)

HHV (wet basis): 10,900 Btu/lb

HHV (dry basis): 12,000 Btu/lb

Size received: 3 by 0 in.

Proximate analysis (% by wt)	Wet basis	Dry basis
Fixed carbon	43.3	47.6
Volatile matter	33.6	36.9
Ash	14.1	15.5
Moisture	9.0	
	100.0	100.0

Ultimate analysis (% by wt)	Dry basis
Carbon	66.7
Ash	15.5
Oxygen	7.3
Hydrogen	4.5
Sulfur	4.5
Nitrogen	1.5
	100.0

Ash fusion temperature, °F	Reducing	Oxidizing
Initial	1990	2400
Softening	2070	2450
Fluid	2150	2550

3. The B-R published volumes include a very detailed breakdown of the components costs.

The B-R costs were modified to reflect data from the other design studies such as the ECAS Ref. 91, new GE Ref. 92, and Curtiss-Wright programs Ref. 17. These areas of modification included primarily the components which might change in cost due to changes in emission control, operating pressure, turbine inlet temperature, and gas turbine design.

The costing procedures used for the modified areas are discussed below. All costs were adjusted to 1980 dollars assuming 8% escalation.

Combustor

The steam generator surface area varies with the turbine inlet temperature due to the convection heat transfer required to cool the flue gases. The following costs were used for the fabricated heat transfer surface:

Economizer	(\$13.00/ft ²)
Superheater	\$63.00/ft ²
Reheater	\$43.00/ft ²
Air preheater	\$6.00/ft ²
Evaporator	\$16.00/ft ²

The heat exchanger costs are roughly twice the tubing cost. These costs would be somewhat higher for a super critical steam generator.

The shell cost was derived from a correlation used by Westinghouse in ECAS II. A basic cost of (4000 \$/ft²) of bed area was used for a 10 atm system. This cost was adjusted inversely proportional to operating pressure to account for changes in the thickness of the shell wall. No scaling factor was used on the bed area since larger areas result in more combustors, not larger single combustors. The coal and sorbent pneumatic transport system is included in the combustor account and was costed at \$14/kg/h of solids. This value was derived from the Westinghouse work and was scaled proportional to (solids flow)^{0.7}. From the same source, structural steel and balance of plant materials and labor were assumed to be 26% of the shell plus pressure parts. The resulting costs agreed reasonably well with the Westinghouse total combustor cost on the basis of

dollars per steaming rate, bed area, and combustion air flow rate. The Westinghouse data, in turn, was also comparable to the GE estimates on similar bases.

The air-cooled combustor is of such a different configuration that the above methods are not applicable. The published data from Curtiss-Wright was drawn upon for the combustor cost. The Curtiss-Wright estimate is very similar to the B-R value on both a cost/bed area and cost/gas flow basis. The Curtiss-Wright cost included the ash return and removal system which was accordingly dropped from the B-R account, 4.0.

Solids Handling

These accounts (5.2 and 5.3) include the solids metering and distribution system. The cost found in several studies was about (\$14.00/lb/h) and was used in this study. The solids stackout and preparation are not sensitive to the flow rate in the range of plant sizes studied. The cost of the system was scaled to the 0.7 power from the base value.

Gas Turbine

The conventional industrial gas turbine cost was taken as 185 \$/kWe, installed and including the generator. Turbo-expander costs were obtained from vendors.

Hot Gas Ducts

The costs for hot gas piping in the previous design studies ranged from (\$11 to \$38/ACFM) with more recent estimates being higher. A value of (\$30/ACFM) was selected as an average for the high temperature systems.

An analysis was performed to determine how the cost might change with gas temperature. Estimates by Foster-Wheeler placed the cost of large gas pipe (internally insulated) at almost \$3000/ft when a Hastelloy liner, required at over 815°C (1500°F), was used. The liner represents over half the pipe cost when Hastelloy is used according to our analysis. By using stainless steel for the liner the duct cost drops by a factor of about

two. This ducting was assumed to be suitable for less than 815°C (1500°F). At lower temperatures an even milder material can be used for the liner resulting in a slightly less expensive duct.

Based on these findings, the following were used as duct costs:

\$30/ACFM for 815°C ($\geq$ 1500°F)

\$15/ACFM for 815°C (<1500°F)

\$14/ACFM for 650°C ($\leq$ 1200°F)

The clean air ducting in the air-cooled plants was assumed to have no liner inside the refractory.

Cyclone Particle Separators

The model used to calculate cyclone performance has been described elsewhere. Variations of the conventional cyclone were used for costing purposes for the sake of consistency. Aerodyne cyclones are specified in several design studies with the cost being put at (22 to 27 \$/ACFM). However, there is apparently some disagreement as to how the performance of these cyclones varies with capacity and therefore for consistency, they were not used in the analysis described in this report. The Aerodyne cyclones require a secondary stream of clean air for best results and as such are better suited to the air-cooled system.

Costs found for installed conventional cyclones ranged from (8 to 15 \$/ACFM). Personal communication with Buell placed the estimate for a high efficiency conventional cyclone system at the higher end of this range. A multiclone separator, similar to the 3rd stage separator in a cat-cracker system, also was found to cost about 20 \$/ACFM. To account for the varying degrees of complexity in the cyclones the following costs were used:

Low performance, first stage, recycle \$10/ACFM

High performance \$15/ACFM

Multiclone or multiple cyclones \$20/ACFM

The multiclone cost was adjusted to account for the number of multiple tubes using a 6 in. tube for the base cost. Hence the adjusted cost is

$$\text{Cost/flow} = (\text{Base cost/flow}) (\text{diameter}/6 \text{ in.})^{-0.2}$$

Steam Turbine and Steam Flow Components

The steam carrying component costs are those of B-R. Component costs are adjusted on the basis of steam flow rate to the 0.7 power. In the case of the air-cooled system, the Curtiss-Wright estimate for the waste heat boiler is used.

AFBC Costs

The AFBC costs were based on the GE-ECAS values for the most part. Cost correlations were established to allow variation of capital cost for components which would be influenced by the level of sulfur control. The thermodynamic and cost models are integrated into a single computer code. A more detailed description of this model and its capabilities has been published elsewhere (Ref. 93). The boiler materials costs were the same as those used in the steam-cooled PFBC. Other AFBC data are shown in Table A.3.

Table A.3. Summary performance data and COE for AFBC plants

	Sulfur capture (%)		
	90	94	98
Net power, MWe	812.9	812.9	812.7
Net plant efficiency, %	34.2	34.0	33.6
Bed superficial velocity, ft/s	8.0	8.0	8.0
Static bed depth, ft	4.0	4.0	4.0
Bed temperature, °F	1550	1550	1550
Combustion efficiency, %	93.1	93.1	93.1
Ca/S mole ratio	3.04 ^a	3.50	4.41
Total capital cost, \$ × 10 ⁶	584.3	587.3	593.7
COE, mills/kWh	52.6	53.5	55.6

^a2.5 Probable with improved solids recycle.

CPWS Costs

Most of the data for the conventional plants was derived from cost and performance data published by TVA (Ref. 94). Both TVA and EPRI data were reviewed on the cost of the scrubber component itself. The different flow requirements and vessel sizes were calculated for each level of sulfur control and the costs were scaled appropriately from the baseline cost. The efficiency of the plant was also adjusted at the various levels of SO₂ control. The steam plant used was the same basic configuration used in the AFBC and steam-cooled PFBC models. Cost data that are graphically presented in the body of the report are shown in Table A.4 and A.5.

Table A.4. Capital breakdown
for scrubber on CPWS

	\$/kW(e) 90% removal	% of total
Limestone handling	6.9	3.6
Absorbers	43.8	22.5
Pumps	5.4	2.8
Tanks	10.1	5.2
Ducts	14.5	7.4
Piping	38.7	19.9
Electrical	11.4	5.9
Erection cost	15.7	8.1
Civil	36.2	18.7
Miscellaneous	11.4	5.9
TOTAL	194.1	100

Table A.5. Cost and performance data for CPWS

Cost categories	Sulfur removal			
	84%	90%	93%	99%
FGD capital (10 ⁶ \$)	138	154.4	163	207
Total capital (10 ⁶ \$)	691	707.4	716	760
Annual capital (10 ⁶ \$)	124.4	127.3	128.9	136.8
Coal cost (10 ⁶ \$)	125.1	125.1	125.1	125.1
Limestone cost (10 ⁶ \$)	7.5	8	8.3	8.8
Disposal cost (10 ⁶ \$)	11.3	11.9	12.3	13.1
Other O&M (10 ⁶ \$)	28.2	28.9	29.3	31
Total annual cost (10 ⁹)	296.5	301.2	303.9	314.8
Power produced [10 kWh(e)]	4.887	4.875	4.869	4.826
Overall plant efficiency, % HHV	33.0	32.9	32.85	32.55
Bus bar cost mills/kWh(e)	60.1	61.8	62.4	65.2

Other Costs

The B-R data is used for other plant costs such as instrumentation, auxiliary equipment, and land improvements. An appropriate scaling factor was used to adjust the costs to reflect the correct plant size. Other economic analysis ground rules are shown in Table A.6.

Table A.6. Economic analysis parameters

Project life, year	30
Fixed charge rate	18% of total capital outlay
Project contingency	20% of direct capital
AE fee	10% of direct capital
Interest during construction	16.6% of total investment
Coal cost, \$/ton	30
Dolomite cost, \$/ton	10
Ash disposal cost, \$/ton	5
Levelizing factor for fuel	1.93
Leveling factor for non-fuel O&M	1.88
Capacity factor	0.7

Limitations on Cost Accuracy

The costs developed in this study are not of sufficient detail to account for anomalies in design which may exist from one case to another. This is especially true for a low-temperature steam-cooled PFBC system since no detailed design has been performed. For instance, the configuration of the steam generator and type of ducting could be quite different from previous conceptual designs and could cause a notable perturbation in cost trends. Uncertainties of this nature can be resolved through more detailed engineering studies. Samples of the computer model output, including cost estimates, are included on the following pages.

STEAM COOLED A (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000
 FRACTION EXCESS AIR = 0.20000
 EXPANDED BED HEIGHT = 4.00000 M
 SUPERFICIAL VELOCITY = 1.50000 M/S
 RESIDENCE TIME = 2.66667 S
 COAL SULFUR FRACTION = 0.04400

CALCIUM SULFUR RATIO = 1.3785
 COMBUSTION EFFICIENCY = 0.98849
 BED AREA = 279.24 M2
 SO2 EMISSIONS = 0.32452 G/MJ
 NOX EMISSIONS = 0.05971 G/MJ
 PARTICULATE EMISSIONS = 0.06934 G/MJ

SPENT SOLIDS TEMP = 131.81 DEG C
 DRYER BYPASS AIR = 0. KG/HR
 CYC AUX AIR FRAC = 0.0
 GT COOL AIR FRAC = 0.0
 PUMP MOTORS = 3543.74 KW
 SOLIDS OVERFLOW = 83445.1 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL OUTPUT (KW)	THERMAL EFFICIENCY
				GASSES	SOLIDS			
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	254.59	608.66		2655691.		COMPRESSOR		0.85000
BED INLET	320.28	606.51		2655693.		GAS TURBINE	50357.	0.85000
CONVECTION INLET	815.00	556.11		2884999.	203029.	STEAM TURBINE	659649.	0.41668
RECYCLE EXIT	621.00	556.11		2884999.	27417.9	OVERALL	710005.	0.37838
GAS TURBINE INLET	621.00	531.00		2884999.	138.09			
GAS TURBINE EXIT	375.28	103.03		2884999.	138.09			
ECONOMIZER INLET	325.63	102.40		2878990.	138.09			
ECONOMIZER EXIT	146.88	101.30		2878990.	138.09			
STACK	140.00	101.30		3131400.	468.38			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.57	266068.	97970.	681021.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	249610.	90900.	704549.	0.03000	0.03000	27063.0	0.66746
BED INLET	65.00		249361.	90809.		0.03000	0.03000	27063.0	

	SUBMERGED BED		ABOVE BED		STEAM CONDITIONS	
	HT TRANS (KW)	LMTD (DEG C)	HT TRANS (KW)	LMTD (DEG C)	MASS RATE (KG/HR)	OUTLET TEMP (DEG C)
EVAPORATOR	710117.	460.20	10607.	455.19	1993246.	354.80
SUPERHEATER	480483.	361.00	0.	266.20	1993246.	537.80
REHEATER	66392.	304.75	191957.	314.19	1802782.	537.80
ECONOMIZER			155844.	46.01	711615.	279.10

STEAM COOLED A (PAGE 2 OF 2)

	HT TRANS	LMTD	HOT MASS RATE (KG/HR)		COLD
	(KW)	(DEG C)	GASSES	SOLIDS	AIR RATE
					(KG/HR)
AIR HEATER	44865.	62.68	2884999.	138.09	2315521.
SOLIDS COOLER	19889.	226.00		110725.	222863.
INTERCOOLER	0.	1.00	340170.		0.

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET	PARALLEL	DIAM	INLET	PRESS
	DOL	CHAR	ASH	SOLIDS (G/ACH)	STREAMS	(M)	VELOCITY (M/S)	DROP (KPA)
RECYCLE ELUTRIATION	0.09500	0.22500	0.54000					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	20.1615	8.	4.5811	15.0000	1.7996
FIRST STAGE					8.	4.8998	26.2237	3.8961
SECOND STAGE					8.	4.2434	34.9649	6.9264
THIRD STAGE				0.1015	800.	0.4243	34.9649	6.9264
TOTALS	0.99496	0.99496	0.99496					25.1096

	CAPITAL COSTS (\$1000S)		CAPITAL COSTS (\$1000S)		ANNUAL COSTS (\$1000S)
LAND AND LAND RIGHTS	1285.	ENGINEERING FEE	33148.	CAPITAL	93931.
STRUCTURES AND IMPROVEMENTS	18460.	CONTINGENCY	66296.	COAL	104131.
GAS TURBINE GENERATORS	26942.	CONSTRUCTION INTEREST	71533.	SORBENT	12452.
PFB COMBUSTORS	80921.	ALTERATIONS	8618.	SOLIDS DISPOSAL	7033.
SOLIDS HANDLING EQUIPMENT	33208.	WORKING CAPITAL	4979.	NORMAL MAINTENANCE	10623.
BOILER PLANT EQUIPMENT	68078.	STARTUP COSTS	5786.	GAS TURB MAINTENANCE	229.
STEAM TURBINE GENERATORS	53716.				
ACCESSORY ELECTRICAL EQUIPMENT	29629.	INDIRECT SUBTOTAL	190360.	TOTAL ANNUAL COSTS	228398.
MISCELLANEOUS PLANT EQUIPMENT	631.				
INSTRUMENTATION AND CONTROLS	8183.	TOTAL CAPITAL COSTS	521837.	ANNUAL ELECTRICITY	4353749. MW-HR
JOB DISTRIBUTABLES	10425.				
DIRECT SUBTOTAL	331478.	DIRECT COSTS (\$/KWE)	466.87	COST OF ELECTRICITY	52.4601 MIL/KW-HR
		TOTAL COSTS (\$/KWE)	734.98	ADJUSTED COE (800 MW)	51.7014 MIL/KW-HR

STEAM COOLED B (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000	CALCIUM SULFUR RATIO = 1.3785	SPENT SOLIDS TEMP = 131.81 DEG C
FRACTION EXCESS AIR = 0.20000	COMBUSTION EFFICIENCY = 0.98849	DRYER BYPASS AIR = 4961. KG/HR
EXPANDED BED HEIGHT = 4.00000 M	BED AREA = 260.59 M2	CYC AUX AIR FRAC = 0.0
SUPERFICIAL VELOCITY = 1.50000 M/S	SO2 EMISSIONS = 0.32452 G/MJ	GT COOL AIR FRAC = 0.0
RESIDENCE TIME = 2.66667 S	NOX EMISSIONS = 0.05971 G/MJ	PUMP MOTORS = 3193.09 KW
COAL SULFUR FRACTION = 0.04400	PARTICULATE EMISSIONS = 0.07148 G/MJ	SOLIDS OVERFLOW = 77631.4 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL	
				GASSES	SOLIDS		OUTPUT (KW)	THERMAL EFFICIENCY
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	255.09	610.56		2470667.		COMPRESSOR		0.85000
BED INLET	429.38	604.79		2470669.		GAS TURBINE	78534.	0.85000
CONVECTION INLET	815.00	554.39		2683999.	188884.	STEAM TURBINE	596750.	0.41437
RECYCLE EXIT	760.00	554.39		2683999.	25507.7	OVERALL	675284.	0.38682
GAS TURBINE INLET	760.00	531.00		2683999.	141.95			
GAS TURBINE EXIT	484.38	104.27		2683999.	141.95			
ECONOMIZER INLET	353.47	102.58		2683999.	141.95			
ECONOMIZER EXIT	146.50	101.30		2683999.	141.95			
STACK	140.00	101.30		2923865.	449.22			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.63	247531.	91145.	633574.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	232220.	84567.	655462.	0.03000	0.03000	27063.0	0.66120
BED INLET	65.00		231988.	84483.		0.03000	0.03000	27063.0	

	SUBMERGED BED		ABOVE BED		STEAM CONDITIONS	
	HT TRANS	LMTD	HT TRANS	LMTD	MASS	OUTLET
	(KW)	(DEG C)	(KW)	(DEG C)	RATE (KG/HR)	TEMP (DEG C)
EVAPORATOR	631000.	460.20	9868.	455.19	1772392.	354.80
SUPERHEATER	427245.	361.00	0.	405.20	1772392.	537.80
REHEATER	188275.	359.39	44213.	444.96	1622324.	537.80
ECONOMIZER			168920.	58.52	771325.	279.10

STEAM COOLED B (PAGE 2 OF 2)

	HT TRANS	LMTD	HOT MASS RATE (KG/HR)		COLD
	(KW)	(DEG C)	GASSES	SOLIDS	AIR RATE
					(KG/HR)
AIR HEATER	112221.	74.60	2683999.	141.95	2154197.
SOLIDS COOLER	19452.	236.55		102997.	217968.
INTERCOOLER	0.	1.00	316470.		0.

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET SOLIDS (G/ACH)	PARALLEL STREAMS	DIAM (M)	INLET VELOCITY (M/S)	PRESS DROP (KPA)
	DOL	CHAR	ASH					
RECYCLE ELUTRIATION	0.09500	0.22500	0.54000					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	17.4486	8.	4.7497	15.0000	1.5527
FIRST STAGE					8.	5.0021	27.0490	3.5763
SECOND STAGE					8.	4.3319	36.0654	6.3579
THIRD STAGE				0.0971	800.	0.4332	36.0654	6.3579
TOTALS	0.99443	0.99443	0.99443					23.3886

	CAPITAL COSTS (\$1000S)		CAPITAL COSTS (\$1000S)		ANNUAL COSTS (\$1000S)
LAND AND LAND RIGHTS	1285.	ENGINEERING FEE	32369.	CAPITAL	91641.
STRUCTURES AND IMPROVEMENTS	18003.	CONTINGENCY	64738.	COAL	96876.
GAS TURBINE GENERATORS	34583.	CONSTRUCTION INTEREST	69853.	SORBENT	11584.
PFB COMBUSTORS	84945.	ALTERATIONS	8416.	SOLIDS DISPOSAL	6542.
SOLIDS HANDLING EQUIPMENT	31571.	WORKING CAPITAL	4632.	NORMAL MAINTENANCE	10104.
BOILER PLANT EQUIPMENT	55635.	STARTUP COSTS	5418.	GAS TURB MAINTENANCE	400.
STEAM TURBINE GENERATORS	49477.				
ACCESSORY ELECTRICAL EQUIPMENT	29187.	INDIRECT SUBTOTAL	185426.	TOTAL ANNUAL COSTS	217147.
MISCELLANEOUS PLANT EQUIPMENT	625.				
INSTRUMENTATION AND CONTROLS	8061.	TOTAL CAPITAL COSTS	509118.	ANNUAL ELECTRICITY	4140837. MW-HR
JOB DISTRIBUTABLES	10321.				
	-----	DIRECT COSTS (\$/KWE)	479.34	COST OF ELECTRICITY	52.4404 MIL/KW-HR
DIRECT SUBTOTAL	323692.	TOTAL COSTS (\$/KWE)	753.93	ADJUSTED COE (800 MW)	51.3433 MIL/KW-HR

STEAM COOLED C (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000	CALCIUM SULFUR RATIO = 1.3785	SPENT SOLIDS TEMP = 131.81 DEG C
FRACTION EXCESS AIR = 0.20000	COMBUSTION EFFICIENCY = 0.99578	DRYER BYPASS AIR = 96951. KG/HR
EXPANDED BED HEIGHT = 4.00000 M	BED AREA = 154.84 M2	CYC AUX AIR FRAC = 0.0
SUPERFICIAL VELOCITY = 1.50000 M/S	SO2 EMISSIONS = 0.32452 G/MJ	GT COOL AIR FRAC = 0.05000
RESIDENCE TIME = 2.66667 S	NOX EMISSIONS = 0.05971 G/MJ	PUMP MOTORS = 3505.54 KW
COAL SULFUR FRACTION = 0.04400	PARTICULATE EMISSIONS = 0.06756 G/MJ	SOLIDS OVERFLOW = 70916.8 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL OUTPUT (KW)	THERMAL EFFICIENCY
				GASSES	SOLIDS			
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	343.01	1026.54		2401961.		COMPRESSOR		0.85000
BED INLET	416.53	1022.23		2281864.		GAS TURBINE	126367.	0.89000
CONVECTION INLET	954.00	971.83		2479902.	170816.	STEAM TURBINE	517284.	0.40728
RECYCLE EXIT	900.00	971.83		2479902.	23331.3	OVERALL	643651.	0.39921
GAS TURBINE INLET	900.00	930.00		2479902.	108.38			
GAS TURBINE EXIT	471.53	103.72		2599999.	108.38			
ECONOMIZER INLET	418.68	103.03		2599999.	108.38			
ECONOMIZER EXIT	139.79	101.30		2599999.	108.38			
STACK	140.00	101.30		2922190.	392.17			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.89	228615.	84179.	585157.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	214474.	78105.	605373.	0.03000	0.03000	27063.0	0.64086
BED INLET	65.00		214260.	78027.		0.03000	0.03000	27063.0	

	SUBMERGED BED		ABOVE BED		STEAM CONDITIONS	
	HT TRANS (KW)	LMTD (DEG C)	HT TRANS (KW)	LMTD (DEG C)	MASS RATE (KG/HR)	OUTLET TEMP (DEG C)
EVAPORATOR	516151.	599.20	9294.	594.21	1453177.	354.80
SUPERHEATER	350296.	502.15	0.	545.20	1453177.	537.80
REHEATER	157482.	498.95	40745.	582.76	1383250.	537.80
ECONOMIZER			222039.	78.39	1013877.	279.10

STEAM COOLED C (PAGE 2 OF 2)

	HT TRANS	LMTD	HOT MASS RATE (KG/HR)		COLD
	(KW)	(DEG C)	GASSES	SOLIDS	AIR RATE
					(KG/HR)
AIR HEATER	44113.	64.79	2599999.	108.38	1989577.
SOLIDS COOLER	21467.	279.43		94140.	240553.
INTERCOOLER	4533.	131.66	292286.		61414.

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET SOLIDS (G/ACH)	PARALLEL STREAMS	DIAM (M)	INLET VELOCITY (M/S)	PRESS DROP (KPA)
	DOL	CHAR	ASH					
RECYCLE ELUTRIATION	0.09500	0.22500	0.54000					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	26.6529	6.	4.2440	15.0000	2.3979
FIRST STAGE					6.	4.2876	29.3932	6.5220
SECOND STAGE					6.	3.7132	39.1910	11.5947
THIRD STAGE				0.1238	900.	0.3032	39.1910	11.5947
TOTALS	0.99536	0.99536	0.99536					41.8275

	CAPITAL COSTS (\$1000S)		CAPITAL COSTS (\$1000S)		ANNUAL COSTS (\$1000S)
LAND AND LAND RIGHTS	1285.	ENGINEERING FEE	30092.	CAPITAL	85189.
STRUCTURES AND IMPROVEMENTS	17576.	CONTINGENCY	60183.	COAL	89473.
GAS TURBINE GENERATORS	25537.	CONSTRUCTION INTEREST	64938.	SORBENT	10699.
PFB COMBUSTORS	88601.	ALTERATIONS	7824.	SOLIDS DISPOSAL	5980.
SOLIDS HANDLING EQUIPMENT	29862.	WORKING CAPITAL	4278.	NORMAL MAINTENANCE	9630.
BOILER PLANT EQUIPMENT	47443.	STARTUP COSTS	5039.	GAS TURB MAINTENANCE	1338.
STEAM TURBINE GENERATORS	43056.				
ACCESSORY ELECTRICAL EQUIPMENT	28770.	INDIRECT SUBTOTAL	172354.	TOTAL ANNUAL COSTS	202308.
MISCELLANEOUS PLANT EQUIPMENT	619.				
INSTRUMENTATION AND CONTROLS	7946.	TOTAL CAPITAL COSTS	473270.	ANNUAL ELECTRICITY	3946868. MW-HR
JOB DISTRIBUTABLES	10223.				
	-----	DIRECT COSTS (\$/KWE)	467.51	COST OF ELECTRICITY	51.2579 MIL/KW-HR
DIRECT SUBTOTAL	300916.	TOTAL COSTS (\$/KWE)	735.29	ADJUSTED COE (800 MW)	49.8948 MIL/KW-HR

AIR COOLED A (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000
 FRACTION EXCESS AIR = 0.30000
 EXPANDED BED HEIGHT = 4.60000 M
 SUPERFICIAL VELOCITY = 0.80000 M/S
 RESIDENCE TIME = 5.75000 S
 COAL SULFUR FRACTION = 0.04400

CALCIUM SULFUR RATIO = 1.1080
 COMBUSTION EFFICIENCY = 0.99745
 BED AREA = 331.85 M2
 SO2 EMISSIONS = 0.32452 G/MJ
 NOX EMISSIONS = 0.06468 G/MJ
 PARTICULATE EMISSIONS = 0.08717 G/MJ

SPENT SOLIDS TEMP = 131.81 DEG C
 DRYER BYPASS AIR = 16146. KG/HR
 CYC AUX AIR FRAC = 0.0
 GT COOL AIR FRAC = 0.03110
 PUMP MOTORS = 2155.53 KW
 SOLIDS OVERFLOW = 52698.3 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL OUTPUT (KW)	THERMAL EFFICIENCY
				GASSES	SOLIDS			
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	281.30	717.44		6049717.		COMPRESSOR		0.85000
BED INLET	281.30	717.44		1816814.		GAS TURBINE	258240.	0.89000
CONVECTION INLET	899.00	646.60		1957095.	73402.	STEAM TURBINE	188512.	0.30517
RECYCLE EXIT	898.90	646.60		1957095.	10581.6	OVERALL	446752.	0.37702
GAS CLEANUP EXIT	898.90	630.00		1957095.	174.23			
BED TUBE EXIT	843.30	630.00		4044768.				
GAS TURBINE INLET	862.20	630.00		6001863.	174.23			
GAS TURBINE EXIT	489.60	103.36		6190000.	174.23			
ECONOMIZER INLET	489.60	103.36		6190000.	174.23			
ECONOMIZER EXIT	151.70	101.30		6190000.	174.23			
STACK	150.00	101.30		6356455.	371.88			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.19	168021.	49726.	407531.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	157628.	46138.	421512.	0.03000	0.03000	27063.0	0.66023
BED INLET	65.00		157470.	46091.		0.03000	0.03000	27063.0	

	HT TRANS	LMTD	HOT MASS RATE (KG/HR)		COLD
	(KW)	(DEG C)	GASSES	SOLIDS	AIR RATE
					(KG/HR)
AIR TUBES IN BED	711932.	233.58			4044768.
WASTE HEAT RECOVERY	630342.		6190000.	174.23	
AIR HEATER	0.	1.00	6190000.	174.23	5658021.
SOLIDS COOLER	13607.	266.70		63106.	152470.
INTERCOOLER	0.	1.00	203562.		0.

AIR COOLED A (PAGE 2 OF 2)

	SUPERHEATER EXIT CONDITIONS			MIDDLE
	(DEG C)	(KPA)	(KG/HR)	SH TEMP (DEG C)
LOW PRESSURE STEAM	381.103	1044.18	147482.	228.289
HIGH PRESSURE STEAM	442.396	4539.96	589926.	

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET SOLIDS (G/ACH)	PARALLEL STREAMS	DIAM (M)	INLET VELOCITY (M/S)	PRESS DROP (KPA)
	DOL	CHAR	ASH					
RECYCLE ELUTRIATION	0.05900	0.14300	0.34800					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	3.4073	6.	4.5862	15.0000	1.5917
FIRST STAGE					6.	5.3676	21.9006	0.0
SECOND STAGE					6.	4.6485	29.2007	4.2727
THIRD STAGE				0.0561	600.	0.4649	29.2007	4.2727
TOTALS	0.98353	0.98353	0.98353					16.6031

	CAPITAL COSTS (\$1000S)		CAPITAL COSTS (\$1000S)		ANNUAL COSTS. (\$1000S)
LAND AND LAND RIGHTS	1285.	ENGINEERING FEE	32919.	CAPITAL	92588.
STRUCTURES AND IMPROVEMENTS	14971.	CONTINGENCY	65839.	COAL	65758.
GAS TURBINE GENERATORS	51057.	CONSTRUCTION INTEREST	71040.	SORBENT	6320.
PFB COMBUSTORS	106882.	ALTERATIONS	8559.	SOLIDS DISPOSAL	4008.
SOLIDS HANDLING EQUIPMENT	23273.	WORKING CAPITAL	3077.	NORMAL MAINTENANCE	6684.
BOILER PLANT EQUIPMENT	51701.	STARTUP COSTS	3752.	GAS TURB MAINTENANCE	2676.
STEAM TURBINE GENERATORS	24944.				
ACCESSORY ELECTRICAL EQUIPMENT	30791.	INDIRECT SUBTOTAL	185186.	TOTAL ANNUAL COSTS	178035.
MISCELLANEOUS PLANT EQUIPMENT	575.				
INSTRUMENTATION AND CONTROLS	11835.	TOTAL CAPITAL COSTS	514379.	ANNUAL ELECTRICITY	2739484. MW-HR
JOB DISTRIBUTABLES	11878.				
		DIRECT COSTS (\$/KWE)	736.86	COST OF ELECTRICITY	64.9885 MIL/KW-HR
DIRECT SUBTOTAL	329194.	TOTAL COSTS (\$/KWE)	1151.37	ADJUSTED COE (800 MW)	59.5687 MIL/KW-HR

AIR COOLED B (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000
 FRACTION EXCESS AIR = 0.30000
 EXPANDED BED HEIGHT = 4.60000 M
 SUPERFICIAL VELOCITY = 0.80000 M/S
 RESIDENCE TIME = 5.75000 S
 COAL SULFUR FRACTION = 0.04400

CALCIUM SULFUR RATIO = 1.1080
 COMBUSTION EFFICIENCY = 0.99631
 BED AREA = 278.62 M2
 SO2 EMISSIONS = 0.32452 G/MJ
 NOX EMISSIONS = 0.06468 G/MJ
 PARTICULATE EMISSIONS = 0.08988 G/MJ

SPENT SOLIDS TEMP = 131.81 DEG C
 DRYER BYPASS AIR = 0. KG/HR
 CYC AUX AIR FRAC = 0.0
 GT COOL AIR FRAC = 0.0
 PUMP MOTORS = 1912.73 KW
 SOLIDS OVERFLOW = 47603.9 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL OUTPUT (KW)	THERMAL EFFICIENCY
				GASSES	SOLIDS			
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	280.92	715.81		6301620.		COMPRESSOR		0.85000
BED INLET	280.92	715.81		1638094.		GAS TURBINE	222943.	0.89000
CONVECTION INLET	815.60	644.97		1764471.	66421.	STEAM TURBINE	150776.	0.28032
RECYCLE EXIT	815.50	644.97		1764471.	9555.7	OVERALL	373720.	0.34979
GAS CLEANUP EXIT	815.50	630.00		1764471.	167.50			
BED TUBE EXIT	760.00	630.00		4663531.				
GAS TURBINE INLET	775.91	630.00		6428002.	167.50			
GAS TURBINE EXIT	437.55	103.03		6427999.	167.50			
ECONOMIZER INLET	437.55	103.03		6427874.	167.50			
ECONOMIZER EXIT	151.91	101.30		6427874.	167.50			
STACK	150.00	101.30		6563341.	345.71			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.19	151493.	44834.	367442.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	142122.	41599.	380048.	0.03000	0.03000	27063.0	0.66051
BED INLET	65.00		141980.	41557.		0.03000	0.03000	27063.0	

	HT. TRANS (KW)	LMTD (DEG C)	HOT MASS RATE (KG/HR)		COLD AIR RATE (KG/HR)
			GASSES	SOLIDS	
AIR TUBES IN BED	694312.	211.66			4663531.
WASTE HEAT RECOVERY	548843.		6427874.	167.50	
AIR HEATER	0.	1.00	6427999.	167.50	6118083.
SOLIDS COOLER	10953.	240.86		56992.	122735.
INTERCOOLER	0.	1.00	183537.		0.

AIR COOLED B (PAGE 2 OF 2)

	SUPERHEATER EXIT CONDITIONS			MIDDLE SH TEMP	
	(DEG C)	(KPA)	(KG/HR)	(DEG C)	
LOW PRESSURE STEAM	307.085	742.91	132683.	208.627	
HIGH PRESSURE STEAM	390.351	2726.27	530733.		

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET SOLIDS (G/ACM)	PARALLEL STREAMS	DIAM (M)	INLET VELOCITY (M/S)	PRESS DROP (KPA)
	DOL	CHAR	ASH					
RECYCLE ELUTRIATION	0.05900	0.14300	0.34800					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	3.1040	6.	4.1969	15.0000	1.7092
FIRST STAGE					6.	5.2927	18.8642	0.0
SECOND STAGE					6.	4.5836	25.1523	3.4041
THIRD STAGE				0.0544	600.	0.4584	25.1523	3.4041
TOTALS	0.98247	0.98247	0.98247					14.9671

CAPITAL COSTS (\$1000S)		CAPITAL COSTS (\$1000S)		ANNUAL COSTS (\$1000S)	
LAND AND LAND RIGHTS	1285.	ENGINEERING FEE	29853.	CAPITAL	83965.
STRUCTURES AND IMPROVEMENTS	13693.	CONTINGENCY	59705.	COAL	59289.
GAS TURBINE GENERATORS	44218.	CONSTRUCTION INTEREST	64422.	SORBENT	5698.
PFB COMBUSTORS	9746.	ALTERATIONS	7762.	SOLIDS DISPOSAL	3620.
SOLIDS HANDLING EQUIPMENT	21646.	WORKING CAPITAL	2774.	NORMAL MAINTENANCE	5592.
BOILER PLANT EQUIPMENT	50354.	STARTUP COSTS	3432.	GAS TURB MAINTENANCE	1287.
STEAM TURBINE GENERATORS	23165.				
ACCESSORY ELECTRICAL EQUIPMENT	29186.	INDIRECT SUBTOTAL	167948.	TOTAL ANNUAL COSTS	159452.
MISCELLANEOUS PLANT EQUIPMENT	555.				
INSTRUMENTATION AND CONTROLS	11218.	TOTAL CAPITAL COSTS	466475.	ANNUAL ELECTRICITY	2291647. MW-HR
JOB DISTRIBUTABLES	11462.				
DIRECT SUBTOTAL	298527.	DIRECT COSTS (\$/KWE)	798.80	COST OF ELECTRICITY	69.5796 MIL/KW-HR
		TOTAL COSTS (\$/KWE)	1248.19	ADJUSTED COE (800 MW)	62.0999 MIL/KW-HR

AIR AND STEAM COOLED HYBRID (PAGE 1 OF 2)

FRACTION SULFUR CAPTURE = 0.90000
 FRACTION EXCESS AIR = 0.20000
 EXPANDED BED HEIGHT = 5.00000 M
 SUPERFICIAL VELOCITY = 1.50000 M/S
 RESIDENCE TIME = 3.33333 S
 COAL SULFUR FRACTION = 0.04400

CALCIUM SULFUR RATIO = 1.2873
 COMBUSTION EFFICIENCY = 0.99300
 BED AREA = 155.23 M2
 SO2 EMISSIONS = 0.32452 G/MJ
 NOX EMISSIONS = 0.05971 G/MJ
 PARTICULATE EMISSIONS = 0.07363 G/MJ

SPENT SOLIDS TEMP = 131.81 DEG C
 DRYER BYPASS AIR = 84265. KG/HR
 CYC AUX AIR FRAC = 0.0
 GT COOL AIR FRAC = 0.03691
 PUMP MOTORS = 3554.32 KW
 SOLIDS OVERFLOW = 71562.6 KG/HR

	TEMP (DEG C)	PRES (KPA)	RELATIVE HUMIDITY	MASS RATE (KG/HR)			ELECTRICAL OUTPUT (KW)	THERMAL EFFICIENCY
				GASSES	SOLIDS			
AMBIENT	25.00	101.30	0.60000					
COMPRESSOR EXIT	342.95	1026.18		4792991.		COMPRESSOR		0.85000
BED INLET	342.95	1026.18		2373605.		GAS TURBINE	223404.	0.89000
CONVECTION INLET	899.00	963.18		2576610.	174900.	STEAM TURBINE	462762.	0.40023
RECYCLE EXIT	898.90	963.18		2576610.	24095.4	OVERALL	686166.	0.40913
GAS CLEANUP EXIT	898.90	930.00		2576610.	154.62			
BED TUBE EXIT	843.00	930.00		2242509.				
GAS TURBINE INLET	873.81	930.00		4819119.	154.62			
GAS TURBINE EXIT	443.39	103.15		4995999.	154.62			
ECONOMIZER INLET	443.39	103.15		4995999.	154.62			
ECONOMIZER EXIT	140.46	101.30		4995999.	154.62			
STACK	140.00	101.30		5310476.	444.53			

	TEMP (DEG C)		MASS RATE (KG/HR)			FRACTION MOISTURE		COAL HHV (KJ/KG)	RELATIVE HUMIDITY
	SOLIDS	GASSES	COAL	DOLOMITE	GASSES	COAL	DOLOMITE		
DRYER INLET	25.00	158.76	237806.	81766.	597924.	0.09000	0.10000		
DRYER OUTLET	65.00	65.00	223097.	75865.	618534.	0.03000	0.03000	27063.0	0.63952
BED INLET	65.00		222874.	75789.		0.03000	0.03000	27063.0	

AIR AND STEAM COOLED HYBRID (PAGE 2 OF 2)

	HT TRANS	LMTD	HOT MASS RATE (KG/HR)		COLD
	(KW)	(DEG C)	GASSES	SOLIDS	AIR RATE
					(KG/HR)
AIR TUBES IN BED	353467.	217.84			2242509.
WASTE HEAT RECOVERY	457002.		4995999.	154.62	
AIR HEATER	0.	1.00	4995999.	154.62	4317443.
SOLIDS COOLER	20627.	266.70		95503.	231140.
INTERCOOLER	4628.	131.65	298663.		62720.

	TEMP (DEG C)			STEAM	ENTHALPY
				RATE	CHANGE
				(KG/HR)	(KJ/KG)
ECONOMIZER:	GAS	WATER			
HP HOT END	443.39	354.80	REHEATER	1216518.	515.90
HP PINCH POINT	300.00	260.00	SUPERHEATER	1223862.	867.80
HP COLD END	140.46	101.40	EVAPORATOR	1118779.	815.70
LP HOT END	140.46	101.40	HP ECONOMIZER	1223862.	1344.24
LP COLD END	140.46	101.40	LP ECONOMIZER	1223862.	0.0

	FRACTION ELUTRIATION OR CYCLONE EFFICIENCY			TOTAL OUTLET SOLIDS (G/ACH)	PARALLEL STREAMS	DIAM (M)	INLET VELOCITY (M/S)	PRESS DROP (KPA)
	DOL	CHAR	ASH					
RECYCLE ELUTRIATION	0.09500	0.22500	0.54000					
RECYCLE CYCLONE	0.93750	0.93750	0.76920	14.2391	6.	4.3249	15.0000	2.3778
FIRST STAGE					6.	4.7457	24.9149	4.6467
SECOND STAGE					6.	4.1099	33.2199	8.2608
THIRD STAGE				0.0914	600.	0.4110	33.2199	8.2608
TOTALS	0.99358	0.99358	0.99358					33.1780

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