Technical and Economic Assessment of Fluidized Bed Augmented Compressed Air Energy Storage System

**Volume II
Introduction and Technology Assessment**

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September 1981

**Prepared for
Pacific Northwest Laboratory
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TECHNICAL AND ECONOMIC ASSESSMENT
OF FLUIDIZED BED AUGMENTED COMPRESSED
AIR ENERGY STORAGE SYSTEM

VOL II - INTRODUCTION AND TECHNOLOGY
ASSESSMENT

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Foreword

Compressed air energy storage (CAES) is a technique for supplying electric power to meet peak load requirements of electric utility systems. A CAES plant uses low-cost power from base load plants during off-peak periods to compress air in an underground reservoir -- an aquifer, solution mined salt cavity or mined hard rock cavern. During subsequent daytime peak load periods, the compressed air would be withdrawn from storage, heated, and expanded through turbines to generate peak power.

Studies have shown that the CAES concept is technically feasible and, with a proper utility power generation mix is economically viable. Replacement of current oil-fired gas turbine peaking units by CAES systems could result in an annual savings of more than 100,000,000 barrels of oil. Already, a CAES plant is being operated by Nordwestdeutsche Kraftwerke AG. in Germany and other plants are being planned or considered by U.S. utilities.

In view of the potential benefits the CAES concept offers, the Department of Energy (DOE) has undertaken a comprehensive program in order to accelerate commercialization of this technology. The Pacific Northwest Laboratory (PNL) was selected by DOE as lead laboratory for the CAES Technology Program. As such, PNL is responsible for assisting the DOE in planning, budgeting, contracting, managing, reporting, and disseminating information. Under subcontract to PNL are a number of companies, universities and consultants that are responsible for various research tasks within the Program.

This report describes the results of a study subcontracted by PNL to the United Technologies Research Center on the engineering feasibility and economics of a CAES concept which uses a coal fired, fluidized bed combustor (FBC) to heat the air being returned from storage during the power production cycle. By burning coal instead of fuel oil, the CAES/FBC concept can completely eliminate the dependence of compressed air energy storage on petroleum fuels.

This study is a part of the "Second Generation CAES Systems" task of the CAES Technology Program. The general objective of the Second Generation task is to develop advanced CAES technologies that would reduce or eliminate the dependence of CAES systems on petroleum fuels. Other concepts receiving preliminary attention in this task are:

- Adiabatic CAES utilizing mined hard rock caverns for compressed air storage.

- Adiabatic CAES utilizing aquifers for storage of compressed air and part of the heat of compression
- CAES cycle integrated in a coal gasification plant
- Solar assisted CAES
- Combined CAES and coal-fired steam plant.

At the present time PNL is directing the limited research and development funding resources to advancement of CAES concepts utilizing thermal energy storage. The CAES/FBC concept appears technically feasible and economically competitive with conventional CAES. However, significant advancement is required in FBC technology before serious commercial commitment to CAES/FBC can be realized. At present, other elements of DOE, industrial groups, and other countries are performing the required R&D for advancement of FBC technology. The CAES/FBC will be reevaluated at a later date when FBC technology has matured and many of the concerns now plaguing FBC are resolved.

Foreword

This technical and economic assessment of fluidized bed combustion augmented compressed air energy storage systems was performed by United Technologies Research Center with subcontract assistance from Coal Processing Consultants Limited of the United Kingdom and Acres American Incorporated. The study program has been prepared under subcontract No. B-51299-A-L for Pacific Northwest Laboratory which is operated for the U.S. Department of Energy by Battelle Memorial Institute. The work described herein was initiated in November 1978 and completed in April 1980.

The results of this assessment effort are presented in three volumes. Volume I - Executive Summary provides a concise overview of all major elements of the assessment including the conclusions. Volume II - Introduction and Technology Assessment presents a discussion of program background and an in-depth coverage of both fluid bed combustion and turbomachinery technology pertinent to their application in a CAES power plant system. Volume III - Preconceptual Design contains the system analysis which led to the identification of a preferred component configuration for a fluidized bed combustion augmented compressed air energy storage system, the results of the effort which transformed the preferred configuration into preconceptual power plant design, and an introductory evaluation of the performance of the power plant system during part-load operation and while load following.

The United Technologies Research Center provided overall program management and major contributions in the areas of turbomachinery technology assessment, systems analysis, turbomachinery preconceptual design, power plant economics, part-load operation, and load following. This effort was performed under the general guidance of F. L. Robson, Chief, Utility Power Systems and involved the following people:

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Acres American Incorporated provided contributions in the areas of balance-of-plant preconceptual design and institutional factor identification. These efforts involved the following people:

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Additional assistance was provided by the Department of Energy, Electric Power Research Institute, and Potomac Electric Company in making available data and conceptual design information from their ongoing CAES assessment study.

The study program was conducted under the general direction of W. V. Loscutoff of Pacific Northwest Laboratory.

The support and assistance of all of the aforementioned individuals and organizations in contributing to the successful completion of this study program is acknowledged with sincere appreciation.

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FLUIDIZED BED COMBUSTION AUGMENTED COMPRESSED
AIR ENERGY STORAGE SYSTEMS

VOLUME II - INTRODUCTION AND TECHNOLOGY ASSESSMENT

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Introduction

The compressed air energy storage concept has been developed because it has the potential to supply competitively priced peaking energy, to reduce peak-load power plant dependence on petroleum-based fuels, and to provide a means of leveling the utility system load demand. The concept has evolved over the last decade to the point where a 290-MW gas-fired power plant is in operation. However, with the recent rampant escalation in fuel oil costs, it is timely to investigate novel compressed air energy storage system concepts which totally eliminate petroleum consumption. This report documents one such investigation - the assessment of coal-fired fluid bed combustion augmented compressed air energy storage systems.

Chapter 1

Introduction

UTILITY BACKGROUND

The load demands experienced by electric utilities undergo wide daily, weekly, and seasonal fluctuations. Because of these fluctuations, a very significant fraction of installed generating capacity is required to serve load demands of relatively short duration. Meeting these peak-load demands can be very expensive and introduce serious operational problems for utilities. Until recently, the traditional practice of utilities requiring additional peak-load capacity has been to: (1) install additional high-efficiency, fossil-fueled steam turbine units for base-load operation, (2) transfer older, less-efficient units to intermediate-load operation, and (3) relegate the oldest, least-efficient units to peaking service. This traditional approach for providing capacity is no longer adequate because of the increasing demand for electric power, increased cost of utility fossil fuels, and the installation of very large nuclear and coal-fired base-load stations which could not economically be transferred to intermediate-or peak-load operation in future years.

During the past decade, low-cost steam turbine and gas turbine units have been installed to generate peaking power. In addition, many utilities have been turning to energy storage as a means of leveling out load demand (see Fig. 1-1). During low-load periods, when the incremental cost of generating electricity is relatively low, electricity would be put into some type of energy storage system. Then during subsequent peak-load periods, electricity would be removed from storage to supplement that generated by the grid. The net effect is a leveling of electricity generation with time.

Pumped water storage is an economical and flexible energy storage method which has gained widespread acceptance, although some conflict has arisen recently over land use for large pumped storage reservoirs and the need to construct transmission lines through remote, unspoiled countryside. Other energy storage schemes being researched today include underground pumped hydro, high-energy storage batteries, electrolysis of water to produce hydrogen and oxygen which could be recombined in fuel cells, superconducting magnet coils, flywheels, and thermal storage. An alternative energy storage system which could be attractive for future peak power applications is a modified gas turbine power system utilizing underground storage of compressed air.

WEEKLY ELECTRIC UTILITY LOAD CURVE

CAES ALTERNATIVE

The compressed air energy storage (CAES) concept was first conceived and patented during the 1940's. The novel features of CAES systems (see Fig. 1-2) are the uncoupling of the compressor and turbine, so that they operate during different time intervals, and the incorporation of intermediate storage of the compressed air. During the low-load, off-peak periods, the turbine clutch would be disengaged, the compressor clutch engaged, and the electric generator used as a motor to drive the compressor. The compressed air would be stored in a large underground facility such as a mined, hard-rock cavern, an aquifer, or a salt cavity. The cavern could, if desired, be maintained at constant pressure by a water-filled shaft connected to a surface water reservoir while the aquifer or salt cavity would provide constant volume (variable pressure) storage. During subsequent peak-load periods the air would be withdrawn from storage, mixed with fuel, burned, and expanded through the turbine to generate power. During this expansion process, the compressor clutch would be disengaged and the entire output from the turbine would be available to drive the generator.

Since a major part of the gross power developed by the expansion turbine in a conventional gas turbine cycle is consumed to compress incoming air, uncoupling the compressor from the turbine would increase net turbine output by two to three times that obtainable from a conventional gas turbine with the same size components. Another advantage of CAES stems from the use of off-peak electricity for compression. This power would presumably be generated from coal or nuclear power stations. Since 50 to 70 percent of the basic energy consumption would be for compression, this means that 50 to 70 percent of the basic energy requirement would be transferred from imported petroleum products to low-cost indigenous energy resources. In oil-fired CAES schemes, the remaining 30 to 50 percent of the energy requirement would be from oil burned during the power generation mode.

Since its conception, the CAES concept has been studied for use in a number of countries, especially in Europe (Refs. 1-1 through 1-5). The world's first CAES plant has been constructed at Huntorf, West Germany by Nordwestdeutsche Kraftwerke, A. G. (Ref. 1-6). Despite some early equipment problems, this plant is now in daily operation and has accumulated over 600 hours of running time for electricity generation (Ref. 1-7).

In the U.S., two early federally supported programs were commissioned to investigate the viability of CAES for domestic applications. The Department of Energy (DOE, formerly the Energy Research and Development Administration) sponsored a study (Ref. 1-8) that dealt with air storage in hard-rock and aquifer formations. A follow-on study concerned with solution-mined salt caverns

SIMPLIFIED COMPRESSED AIR ENERGY STORAGE SYSTEM

FIG. 1-2

was conducted under Electric Power Research Institute (EPRI) sponsorship (Ref. 1-9). The National Science Foundation initiated an 18-month study which focused on hard-rock storage in the Northeast (Ref. 1-10). Three electric utilities (Northeast Utilities Service Company, New England Electric System, and Potomac Electric Power Company) also participated in the program by providing informal consulting assistance and appropriate utility and geological data. These studies generally concluded that there are no technical barriers to implementation of CAES plants, sufficient siting opportunities exist throughout most of the U.S., and the competitive position of CAES plants relative to conventional generation alternatives looks favorable, but is highly dependent on specific utility factors.

As a result of these promising conclusions, DOE and EPRI launched a major effort directed toward construction of the first CAES plant in the U.S with three CAES demonstration projects being co-funded by DOE and EPRI (Ref. 1-7). The primary objective for these projects is to bring the engineering, environmental, and economic assessments of CAES for utility applications to the point where design and outline specifications have been developed, cost estimates established, and associated risks assessed. The Potomac Electric Power Company is studying CAES systems using hard-rock caverns. This project is scheduled for completion in 1980. The Middle South Services, Inc., project is based on compressed air storage in salt cavities in the Gulf Coast region. This project is essentially complete. The third project by Public Service of Indiana is still in the early stages. This study deals with air storage in porous media formations. All three of these projects are based on CAES systems that use off-peak electricity for compression and consume petroleum during the power generation mode.

NONOIL-BURNING APPROACHES

A potential long-term weakness of the oil-fired CAES concept is its reliance on clean petroleum fuels which are in short supply. It seemed appropriate, therefore, to investigate advanced CAES concepts designed to completely eliminate consumption of oil during the power generation mode through replacement with coal or coal-derived fuels.

Historically, the principal deterrent to the use of coal in gas turbine based power plants, such as CAES plants, has been the incompatibility of gas turbines to the products of coal combustion. The feasibility of burning coal in an open cycle gas turbine was investigated as early as 1945 when a coal-fired competitor to the diesel engine for railroad applications was being sought (Ref. 1-11). In the intervening years, a number of organizations have attempted to design and test coal-fired gas turbines. However, problems with corrosion, erosion, and deposition on turbine blading due to the amount and nature of the coal ash passed through the high temperature combustion zone have prevented the development of a commercially viable system. Investigations in recent years have shown promise for two possible approaches to coal utilization in gas turbine based power systems -- coal gasification and fluidized bed coal combustion.

Coal gasification, followed by cleanup of the raw fuel gas, provides a means of producing a relatively clean sulfur- and ash-free fuel. The basic technology for production of fuel gas from coal is available (Ref. 1-12). Coal gasification has been in use since the early 1800's in a variety of industries. Also, a number of desulfurization processes have been developed for gas cleanup. In addition, to these existing processes, a number of advanced processes are in various stages of development. Most of this gasification technology is being developed for combined-cycle systems (Refs. 1-13 through 1-15).

The application of coal gasification technology to CAES systems was investigated recently (Ref. 1-16). Two gasifier operating schemes were considered during this investigation. In the cycling scheme, the gasifier would be operated only during the CAES power generation mode and would be banked at night. This scheme of operation could provide system load-leveling benefit, and it might have acceptable economics under some circumstances. Serious questions exist, however, regarding the feasibility of cycling gasifier systems to accommodate the frequent startups, shut downs, and rapid load following typically required of peaking plants. To avoid cycling the gasifier, a scheme featuring continuous gasifier operation was also examined. In this scheme, the gasifier would provide all the fuel energy required during both the CAES compression and power generation modes. This kind of operation offers no system load leveling benefit, and the economics appear to be unfavorable.

This leaves fluidized bed combustion as the sole promising coal-fired option for CAES systems.

FBC AUGMENTED CAES PROSPECTUS

Utilization of a fluidized bed combustor (FBC) is a sophisticated approach to direct coal combustion which offers the promise of solving some of the ash-related gas turbine problems previously mentioned. Basically, a fluidized bed comprises coal ash together with dolomite or limestone which may be added to absorb sulfur dioxide. By achieving efficient combustion while maintaining the mean bed temperature at a relatively low level (1350-1700 F (730-925 C))* compared to previous combustion techniques, the coal ash remains relatively soft and is much less destructive to the turbine. The low bed temperature also leads to low emission of nitrogen oxides. Another feature of FBC is the excellent heat transfer rate to submerged surfaces.

Fluid bed combustion technology is progressing at a rapid rate in conjunction with advanced steam, gas turbine, and combined-cycle power plants. Recent studies and research (Refs. 1-17 through 1-26) indicate that FBC systems operating at atmospheric (AFBC) or elevated pressure (PFBC) offer promise for use in advanced electric power plants having high performance, low cost, and low emission characteristics. The DOE has recognized the potential for fluid beds and is funding several multimillion dollar research and development programs. One of the largest programs, for \$25 million, (Ref. 1-21) is intended to lead to a 13-MW demonstration plant in which a gas turbine would be operated on a mixture of PFBC off-gas and compressor discharge air heated in tubes immersed in the bed. The United Technologies Corporation participated with Burns and Roe Industrial Services Corp. and Babcock & Wilcox Co. (Ref. 1-22) in preparation of a conceptual design for a PFBC combined-cycle power plant. Coal Processing Consultants, Ltd. together with the National Coal Board and Babcock Contractors, Ltd. is involved in the design of PFBC power plants for the American Electric Power Company (Ref. 1-23) and British Columbia Hydro and Power Authority (Ref. 1-24). According to present plans, the former project will be a combined-cycle plant rated at 170 MW, while the latter will be an air-cycle plant with an output of 70 MW. Other major programs (Ref. 1-25 and 1-26) deal with the development of an AFBC for use in steam power plants.

The magnitude of the aforementioned programs suggests that meaningful advances in FBC technology are possible, leading to their use in steam, gas turbine, and combined-cycle power systems. These systems can be considered for use in cycling applications such as those envisioned for CAES systems. However, all of the major FBC development programs currently in progress are directed toward base-load applications which can tolerate relatively slow startup and shut down. In order to achieve maximum performance, these base-load system designs incorporate combustors with massive steam or air heat

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* See Appendix A for factors to convert from English to SI units.

exchanger surfaces within the bed. Such designs severely limit the ability of the system to quickly follow load and to accomodate the numerous rapid startups and shut downs required for cycling duty. As a result, the specific combustor designs for combined-cycle applications are not necessarily suitable for consideration in CAES applications. New combustor designs could, presumably, be developed for CAES applications using the same basic technology and rapidly growing background data being generated for base-load applications.

SCOPE OF PRESENT STUDY

The objective of this study was to provide a preliminary technical and economic feasibility assessment of advanced, nonoil-burning CAES concepts for generating peak-load electric power by the use of coal-fired FBC air heaters to increase the temperature of air coming from storage before it enters the gas turbines. The principal tasks in this study were concerned with:

- 1) the required operating characteristics of FBC systems designed for CAES applications,
- 2) the interface compatibility between the FBC system and the gas turbine equipment,
- 3) identification of the most promising FBC/CAES system configuration,
- 4) preconceptual design of a prospective commercial electric power generation plant, and
- 5) the part load and load following characteristics of such a plant.

In order to keep the level of effort for this preliminary assessment to a minimum, extensive use was made of background and related information generated during previous studies. Specifically, the turbomachinery concepts presented are based on previous design efforts presented in Ref. 1-10 plus recent in-house studies of advanced single-shaft engines. Similarly, past efforts reported in Refs. 1-10 and 1-27 plus recent work for the Potomac Electric Power Company project were extensively used to define the air storage facilities, ancillary mechanical and electrical equipment, and the remaining balance of plant.

The detailed results of this preliminary assessment study are presented in the remainder of this report. The second chapter deals with FBC technology and covers the technology review and assessment for application to CAES systems. This chapter also contains a turbomachinery technology review and assessment, wherein particular emphasis was placed on the compatibility problems with the FBC. The third chapter presents the system analysis which starts with system configuration synthesis and proceeds through the screening analysis to select a system configuration which appears to have the greatest potential for early commercial application. The fourth chapter contains the resulting power plant preconceptual design for the selected FBC/CAES system configuration. This chapter also includes the detailed economic analysis for the preconceptual design. The last chapter provides an introduction to part load operation of FBC/CAES systems. It covers part load performance and addresses some transient considerations which limit the response of major system components. It also covers alternative part-load operating modes wherein the FBC would continue to operate near its full-load condition.

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Chapter 2

CAES Fluid Bed Combustor and Turbomachinery Technology Assessment

CAES Fluid Bed Combustor and Turbomachinery Technology Assessment

The goal of this technology assessment was to provide the data base necessary to perform the fluid bed combustor FBC/CAES turbomachinery integration studies. The scope of this effort included: a brief review of the current state of fluid bed combustion and turbomachinery technology; characterization of the fluid bed combustor and turbomachinery technology relative to the parameters pertinent to CAES application; an evaluation of the availability of the major equipment components for a commercial FBC/CAES power plant; and an indication of the research and development required to commercialize the fluid bed combustor and turbomachinery for CAES applications.

The purpose of the state-of-technology review was to indicate the current capabilities and limitations of both the fluid bed combustor and turbomachinery relative to application in a FBC/CAES power plant. It also provides an indication of potential future achievements by reflecting upon past progress and highlighting current programs.

The parametric characterization of the major equipment components is an essential prerequisite to any system analysis investigation. The impact on system performance of the major operating variables must be understood in order to synthesize power plant system configurations with the potential for high efficiency. For the fluid bed combustor, several key parameters were investigated. These included bed operating temperature; bed fluidizing velocity; bed operating pressure; heat transfer from the bed to immersed surfaces; bed and fuel particle size; bed particle elutriation rate; combustion efficiency; and sulfur dioxide, nitrogen oxide, and alkali emissions. In addition, the off-design characteristics and hot gas cleanup requirements for pressurized fluidized beds were investigated. For the turbomachinery, the only major area requiring an original characterization effort centered on the ability of the turbomachinery to accept the exhaust from a pressurized fluid bed combustor. Consequently, the erosion, corrosion, and combined erosion and corrosion capabilities of the turbomachinery were investigated.

Off-the-shelf fluid bed combustor plants or turbomachinery plants are not currently available for a FBC/CAES application. However, some of the major equipment items in these plants do exist. For the remaining items, the technology associated with materials, fabrication, control, etc. either have to be applied or extended to provide FBC/CAES power plant capability. These remaining major equipment items were identified and the R&D requirements discussed.

The elements of this technology assessment effort summarized above provide the basis for the commentary in this chapter of the report.

FLUID BED COMBUSTION TECHNOLOGY

Fluid bed combustion is a comparatively new technology, the first practical units appearing in the 1950's. Since that time, considerable interest in further developments of the technology has been generated.

Much of the early research (circa 1960) was performed in the United Kingdom (UK). This work stemmed from a desire to improve the utilization of coal resources to offset what was perceived at the time to be a lack of indigenous petroleum and natural gas resources. As a result of this research effort, there have been over 25,000 hours of running experience on small-scale atmospheric fluid bed combustor (AFBC) test rigs in the UK and approximately another 5000 hours of running experience on pressurized fluid bed combustors (PFBC).

In the US, FBC technology is progressing at a rapid rate in conjunction with advanced steam, gas turbine, and combined-cycle plants. Development work is now approaching the stage where commercial-scale fluid bed combustors can be engineered with confidence. In addition, the Department of Energy (DOE) has recognized the potential for fluid beds and is funding several multi-million dollar R&D programs on advanced FBC concepts.

The reason for this FBC-related activity is that fluid bed combustion offers a number of advantages over conventional firing systems, particularly for handling low-grade fuels, meeting current environmental requirements, and providing a new approach to the application of solid fuel firing in gas turbines. A fluid bed combustor permits versatility of fuel choice. This is because the performance of the FBC is relatively insensitive to the type of fuel used. The process is particularly well suited for the combustion of coals having high ash and moisture contents or fouling propensities.

Reduced SO_2 emissions are possible through the use of limestone or dolomite in the bed to absorb 90 percent or more of the SO_2 formed during combustion. Thus, liquid and solid fuels with high sulfur contents can be utilized without supplementary equipment such as stack gas scrubbing systems. Suppressed NO_x emission is also possible because the combustion temperature is lower than in conventional coal-fired systems.

Improved heat transfer to the immersed tube surfaces allows higher heat release rates for a given heat transfer area, thus reducing the amount of heat transfer tubing required. Fuel preparation costs are reduced compared with a pulverized coal-fired system. Carryover of volatile alkali metal salts are

reduced due to the lower combustion temperature. Lastly, less fouling of heat transfer tubes occurs because the combustion takes place below the ash sintering temperature.

In spite of this lengthy list of advantages, the coupling of a FBC with a gas turbine still poses a challenge. The incorporation of a FBC in a CAES introduces an additional challenge because of the cycling mode of operation envisioned for the system and the high operating pressure. A detailed discussion of these challenges is presented later in this chapter, nonetheless, they will be mentioned here so that the commentary on the FBC may be presented in context.

The upper operating temperature of the FBC/CAES power plant system is limited by ash sintering, metal temperature, and alkali emissions. Generally, bed temperature cannot exceed about 1652 F (900 C). In an open-bed PFBC configuration (no tubes immersed in the bed), the hot gas could be delivered to the gas turbine at essentially the bed temperature. If, however, the gas for the turbine is heated in tubes immersed in the bed (PFBC or AFBC), the hot gas temperature is limited by the maximum in-bed metal temperature of about 1202 F (650 C). This implies a maximum gas temperature of about 1022 F (550 C) to the turbine. This limitation is offset somewhat in an AFBC, however, by the ability to heat air indirectly in the freeboard section above the bed. Nevertheless, in either FBC the relatively low turbine inlet temperature will result in turbines with somewhat lower specific work and higher cost per unit of output power than is currently available in clean fuel-fired gas turbines.

A key uncertainty in a PFBC/CAES concerns the downstream turbine erosion caused by particulates from the bed. These particulates, especially the larger sizes, could cause unacceptable rates of erosion. Although the level of alkali metal salts from a PFBC would be below the level experienced from conventional methods of coal combustion because of the lower combustion temperature, the levels are still considerably above those experienced in current gas turbine operations. Consequently, corrosion resulting from alkali metal salts is also a potential problem. Cycling of the FBC as would be required in CAES operation can, in theory, be handled by the proper control system. However, the long-term effects of cycling on a FBC/CAES are still unknown.

These challenges are significant; nonetheless, the advantages attendant to meeting them are also significant. In addition, as the remarks in this chapter will indicate, they are not beyond solution with the proper R&D programs.

In this part of the report, a summary of the major features of atmospheric and pressurized fluid bed combustion pertinent to their application in a CAES system is presented. Because the detailed design of a fluid bed combustor is related closely to the operating conditions of bed temperature, fluidizing velocity, pressure and particle size, those conditions are discussed in detail. The effects of these parameters on the performance of the combustor in terms of heat transfer rates, elutriation, combustion efficiency, and sulfur retention are considered. Other factors discussed are those affecting the combustor design and applications technology such as the emission of nitrogen oxides, alkali emissions, materials of construction, load-following characteristics and hot gas cleanup. Detailed data are given on operating ranges and performance. These data were used in the Systems Analysis portion of the study (see Volume III) as a basis for selecting the preferred CAES configuration. Lastly, a summary of the R&D required to commercialize fluid bed combustion for CAES applications is provided, including an outline of the order of costs and time scales for the main development activities.

The FBC review has been restricted to published information and excludes proprietary information, particularly on plant design. For this reason, it has not been possible to quantify many of the relationships between the various design and operating parameters, nor to give detailed guidelines for plant design. Comprehensive design procedures are available and were utilized in the subsequent design phase of this project (see PFBC/CAES Preconceptual Design in Volume III).

General Description

The fluid bed combustion process could be one of the most significant advancements in combustion technology since the advent of pulverized coal firing. Not only is it versatile in being able to accommodate a range of solid and liquid fuels, but it can also utilize fuels of high sulfur content with minimum atmospheric pollution.

Fluid bed combustion, as discussed herein, involves the combustion of coal in a bed containing ash or another inert and a crushed sulfur acceptor which is in suspension (fluidized) by air. The characteristics of fluid beds enable coal, irrespective of ash and sulfur content, to be burned efficiently at relatively low combustion temperature. Pressurized fluid bed combustion is similar to atmospheric fluid bed combustion except that the process takes place under a pressure of several atmospheres such as would exist at the exhaust of a compressor of a gas turbine engine.

In the following paragraphs, a general description is provided of the fluidization phenomena and the fluid bed combustion process. Some of the advantages of fluid bed combustion are discussed. Potential applications are summarized and the present status reviewed.

Fluidization

A bed of particles is said to be fluidized by a gas when the gas velocity is sufficient to support the bed. The stages involved in fluidization are illustrated in Fig. 2-1. At low gas velocities (Fig. 2-1(i)), the gas permeates through the bed without disturbing the particles significantly. At higher velocities (Fig. 2-1(ii)), the force exerted on the particles by the upward passage of the gas becomes greater so that, eventually, the gas stream supports the total weight of the bed. This causes the particles to separate and the bed to expand, marking the onset of fluidization. The gas velocity at this stage is termed the minimum or incipient fluidizing velocity. At gas velocities greater than the minimum fluidizing velocity, bubbles form and rise up through the bed, as shown in Fig. 2-1 (iii).

In most commercial applications of fluidization (including fluid bed combustion), it is normal to operate with a gas velocity several times greater than the minimum fluidizing velocity. The passage of bubbles through the bed causes violent turbulent mixing of the bed particles, giving the bed the appearance of boiling liquid. The analogy is, however, more than superficial; a fluid bed possesses several of the properties of a boiling liquid, including good heat and mass transfer properties and a hydrostatic head.

The use of fluidization in a commercial process was described as long ago as 1921 in the Winkler coal gasification system. Probably the first widespread application was during the 1940's in catalytic processes for oil refining and the manufacture of chemicals. Later, the technique was used by metallurgical industries for heat treatment. The first application of fluidization to coal combustion occurred in the 1950's. A schematic diagram of a coal-fired fluid bed boiler is displayed in Fig. 2-2.

Fluid Bed Combustion Process

A fluid bed is generally comprised of particles of coal ash or a sulfur acceptor (limestone or dolomite), and is fluidized by the combustion air. The concentration of carbon in the bed is typically less than 1 percent. The fuel, typically coal crushed to 1/8 in. (3 mm), is fed to the bottom of the bed by pneumatic transport.

The reaction between coal and air is controlled by several factors, including:

- (i) the surface area of coal particles (or coal particle size),
- (ii) the coal particle residence time,
- (iii) the gas-solid contact,
- (iv) the gas residence time,
- (v) the combustion temperature, and
- (vi) the supply of air relative to that of coal.

EFFECT OF INCREASED GAS FLOW THROUGH A BED OF PARTICLES

(i) FIXED BED

(ii) INCIPIENTLY FLUIDIZED

(iii) FLUIDIZED

DIAGRAMMATIC LAYOUT OF FLUID BED BOILER INSTALLATION

FIG. 2-2

All coal combustion systems involve a compromise among the above factors. In terms of particle size and residence time, fluid bed combustion can be regarded as intermediate between the earlier fixed bed (lump coal) and pulverized fuel systems.

A characteristic feature of fluid bed combustion is the relatively low combustion temperature of 1427 to 1742 F (775 to 950 C). The bed temperature is maintained at the desired level by balancing the heat released by the combustion of the fuel against the heat removed by the combustion gases and heat transfer surfaces immersed in the bed.

Because the gas-solid contact is good, a combustion efficiency of more than 90 percent can be achieved in a single pass with 10 to 20 percent excess air. The combustion gases from a fluid bed are cleaned in cyclones and electrostatic precipitators. If the combustion efficiency obtained on a single pass were insufficient, part of the fines collected by the cyclone system can be recycled to the combustor. Alternatively, these fines can be fed to a separate fines burn-up bed. By employing a recycle system or a carbon burn-up cell, combustion efficiencies of up to 99 percent can be achieved.

Fluid bed combustors can operate either at atmospheric pressure or at elevated pressure. Atmospheric pressure combustors can be used for power generation or for a variety of industrial purposes. In the pressurized bed concept, the energy required to compress the combustion air is recovered by passing the combustion gases through a turbine. As a result, pressurized fluid bed combustion is generally limited to power generation applications.

Advantages of Fluid Bed Combustion

Fluid bed combustion has several advantages over conventional solid fuel combustion systems.

Thermal

The high and uniform rate of heat transfer to tubes in the bed reduces the amount of heat transfer surface area required. Heat transfer coefficients to bed tubing are typically in the range of 70 to 123 Btu/hr-ft²-F (400 to 700 W/m²-K). Less convective heat transfer surface is usually required than in a conventional boiler because of the lower gas exit temperature from the combustion chamber. The maximum proportion of the total heat release which can be extracted by tubes immersed in the bed is in the range of 40 to 60 percent. High combustion intensities (i.e., heat release per volume of combustor) can be achieved, resulting in smaller, cheaper installations. For atmospheric pressure combustion, heat release rates of 96.6×10^3 Btu/hr-ft³ (1 MW (th)/m³) of bed volume are typical, with several times this intensity being possible at elevated pressures.

Fuels

The system is capable of burning a wide range of fuels. Coals of high or variable ash content can be burned, as can low heating value slurries and other waste materials. This arises from the high thermal inertia of the bed and the absence of flame stability problems. Fuel preparation costs are reduced compared with a pulverized coal-fired system. For a fluid bed, a typical feed size is 100 percent below 1/4 in. (6 mm), compared with 70 percent below 80 micron for pulverized coal.

Reliability

The comparatively low combustion temperature decreases the release of corrosive alkali compounds from the ash. Because combustion takes place below the ash sintering temperature, less fouling of tubes in or above the bed will take place. This, together with the low release of alkali compounds results in greater operational reliability, lower maintenance costs, and reduced tubing requirements.

Emissions

The addition of limestone or dolomite to the bed enables 90 percent or more of the sulfur to be retained as sulfate, thus reducing SO₂ emissions to the atmosphere. As a result, liquid and solid fuels with high sulfur contents can be utilized without supplementary equipment such as stack gas scrubbing systems. This may reduce the capital cost by 20 to 30 percent compared with conventional systems, allowing for the additional solids handling equipment. The formation of oxides of nitrogen from atmospheric nitrogen is virtually eliminated, reducing the overall emissions of this pollutant. Typical NO_x emissions from a coal-fired atmospheric pressure fluid bed are 250 to 450 ppm(v).

Installation

Factory construction methods can be used, even for power station boilers, reducing construction time and interest charges during construction.

Pressurized Combustion

Pressurized combustion offers additional advantages over atmospheric pressure fluid bed combustion.

A higher electricity generation efficiency is possible by using gas turbines and steam turbines in a combined-cycle system. Design efficiencies up to 42 percent are expected, compared with 37.5 percent for present steam cycles. A reduction in the capital cost should follow from the smaller volume

of the combustor in a pressurized system and the comparatively low capital cost of gas turbines. Pressurized operation enhances some of the advantages possessed by atmospheric pressure fluid bed combustion. Emissions of nitrogen oxides are, for example, further reduced and, with dolomite as the sulfur acceptor, sulfur removal is more efficient.

Applications of Fluid Bed Combustion

Fluid bed combustors have found potential applications in industrial boilers and furnaces, waste incineration, power generation, and pressurized combustion.

Industrial Boilers and Furnaces

For all industrial applications, conventional coal-fired boilers are considerably larger than oil-fired or gas-fired units of equivalent output. This disadvantage is compounded by the need to adopt less favorable construction techniques for a specified size, for example, water tube instead of shell boilers or site construction instead of packaged (factory-fabricated) units. Furthermore, the cost of the ancillary equipment (including coal and ash handling), which accounts for approximately half of the total cost of a coal-fired system, is also considerably greater than for oil-fired and gas-fired systems.

The above factors combine to make the cost of a conventional coal-fired boiler system two to three times higher than the equivalent oil- or gas-fired system throughout the range of industrial boiler sizes. To overcome the additional capital cost of a coal-fired system, coal must be marketed at a significantly lower price on a thermal basis than the competitive fuels. However, at industrial sites where coal-fired boilers have already been installed and handling facilities for coal and ash exist, a coal-fired boiler can be economically competitive with oil- or gas-fired systems. Nonetheless, even here if a high premium were placed on space or amenity, it still may not be possible to offer sufficient incentive to make coal-firing attractive.

There is, therefore, a need to develop compact, low-cost industrial coal-fired boilers offering a greater degree of amenity to the customer. The incentives are particularly strong for boilers above 10 MW (th), where coal is at the greatest disadvantage compared with oil and gas. The high intensity of heat release and efficient heat transfer possible in a fluid bed combustor make this technology well suited to meeting the above requirements.

Developments of fluid bed combustion for the industrial boiler market could occur in several ways. Fluid bed combustion could be adapted to suit conventional coal-fired boilers. This would reduce the capital and operating

costs of new coal-fired boilers, and encourage the re-conversion of coal-fired boilers previously converted to oil or gas. Fluid bed combustion could be adapted to existing oil and gas boiler designs. This would make available highly compact coal-fired boilers and would allow the conversion of existing oil or gas-fired boilers to coal firing. Novel, low-cost boilers could be developed taking advantage of the features of fluid bed combustion. These would be mainly vertical shell and packaged water tube boilers.

Industrial fluid bed combustors can be considered to be grouped into two categories according to the size grading of the coal used.

Small coal size

The coal is dried and crushed to a top size of .04 in. to .20 in. (1 to 5 mm) before feeding to the fluid bed. This is the original design concept for atmospheric power generation boilers and is applicable to industrial water-tube boilers. Generally, the coal is fed pneumatically to the bottom of the bed, which is composed of coal ash, make-up refractory material, or limestone (if sulfur retention is required). The velocity of the fluidizing air is typically in the range 3.3 to 10 ft/sec (1 to 3 m/s), and the bed depth about 3.3 ft (1 m). Boiler tubes are immersed in the bed with further convective heat transfer taking place after the combustor.

Large coal size

The coal, generally up to 2 in. (50 mm) top size, is fed to the combustor as delivered. It has been found that with an appropriate choice of bed material and fluidizing velocity, the large coal particles can float in the bed. Segregation does not occur because of the turbulent conditions in the bed. In this system, the coal would usually be distributed onto the top of the bed.

The concept of large coal feeding is comparatively recent and has been developed mainly for sized and washed coal, although its application to smalls is an objective of current R&D. The use of large coal permits compact combustion systems based on shallow bed and high fluidizing velocities to be employed, while retaining a high combustion efficiency. However, it does not appear possible to obtain efficient sulfur retention by limestone addition in such systems. The efficiency of sulfur retention in other systems using large coal is uncertain.

Fluid bed combustion can also be applied to furnaces, for example for heating or drying materials. Either the crushed coal or the large coal technology can be used. For these applications, the bed is operated at a high excess air level so that it is unnecessary to place heat transfer tubes in the fluid bed.

Waste Incineration

The tolerance of fluid bed combustion to the properties of the fuel extends to waste materials and aqueous slurries, provided that self-sustaining combustion is possible at the design bed temperature. Liquid wastes, including suspensions, would generally be sprayed from the freeboard onto the bed. The combustible material burns, evaporating the water which passes (as steam) to the stack, leaving an inert residue. For example, the disposal of colliery tailings is an increasing environmental problem in many countries. However, by drying the tailings in a fluid bed incinerator, a stable mineral matter residue is produced, removing the potential hazard of tipping.

Fluid bed incineration has been applied to a wide range of industrial waste materials, including chemical wastes, and to the disposal of sewage sludge. In some cases, the waste materials may not be capable of supporting combustion alone and in these cases a supplementary fuel, such as coal, is required.

Further information on the application of fluid bed combustion to low-grade fuels is given in Refs. 2-1 to 2-4.

Atmospheric Pressure Combustion for Power Generation

The initial development of fluid bed combustion concentrated on steam raising for power generation as an alternative to pulverized fuel combustion. The main incentives were reduced boiler capital cost, the ability to use coal of low or variable quality, and cheap and effective control of environmental emissions. The technology of atmospheric pressure combustion for power generation is similar to that being developed for industrial water tube boilers. Crushed coal is generally used, and is fed pneumatically to the bottom of a bed of about 3.3 ft (1 m) deep, fluidized at 3.3 to 10 ft/sec (1 to 3 m/s). The bed contains immersed heat transfer tubes which extract up to 60 percent of the total heat released. Because of the large bed area required for power station applications, it may be desirable to use multiple beds stacked vertically. To simplify start-up and load control, most designs favor the use of separate beds for the evaporation, superheat and reheat duties. The heat in the gas leaving the beds is used for water preheating and for superheating with conventional convective heat transfer units.

Atmospheric pressure fluid bed combustion has a clear advantage over pulverized fuel systems in the comparative ease and cheapness with which sulfur can be retained. The capital cost of a pulverized fuel station with stack gas scrubbing to remove the sulfur is 20 to 30 percent more than that of an equivalent atmospheric pressure fluid bed combustor with limestone addition (Ref. 2-5). Other advantages include the possibility of reduced maintenance costs because of less fouling and corrosion of tubes and the ability to accept

coals of high and variable ash content. Because atmospheric pressure fluid bed combustion will operate with the same steam conditions as a conventional pulverized fuel boiler system, the thermodynamic cycle efficiency will be approximately the same. If sulfur is retained, however, the losses incurred in reheating the stack gas from a pulverized fuel system to obtain buoyancy after scrubbing will be avoided.

Pressurized Combustion

Fluid bed combustion can be used to supply hot gas to a gas turbine or a combined-cycle system by operating the combustor at elevated pressure. The adaption of pulverized fuel combustion for use with gas turbines has not been successful because of excessive erosion and corrosion of the turbine blades. Fluid bed combustion should overcome this problem because the comparatively low combustion temperature avoids sintering the ash and minimizes vaporization of alkali metal salts.

Pressurized fluid bed combustion can be employed in an number of thermodynamic cycles (see Ref. 2-6) using either combustion products, steam, air or any combination of these as the working medium. In the open-cycle gas turbine, the combustion takes place at elevated pressure and the gas is used to drive a gas turbine. In the open air-heat cycle, part of the air is used for fluidization/combustion and the rest is heated in tubes immersed in the bed. The resulting hot air and combustion products are mixed and used to power a gas turbine. In the closed-cycle gas turbine, air is compressed, heated indirectly in tubes in and above the fluid bed, and expanded through a turbine.

In the waste heat boiler combined cycle, the simplest combined cycle, an open-cycle gas turbine is combined with a waste heat boiler in the turbine exhaust gas stream to raise steam for a steam cycle. However, because the temperature of the turbine exhaust gases is low, the steam conditions are relatively poor. Several other schemes incorporating high-efficiency steam cycles in fluid bed combined-cycle systems have been proposed, the most common of which is a modification of the waste heat combined cycle in which heat for the steam cycle is extracted by a tube bundle immersed in the fluid bed (supercharged boiler cycle).

History and Present Status of Fluid Bed Combustion

The first applications of fluid bed technology to coal combustion took place in the 1950's, a notable example being the French Ignifluid system. This operated at a temperature sufficiently high to cause sintering of the ash which was then removed as a clinker on a traveling grate. Although high combustion intensities were attained, few of the other advantages of fluid bed combustion were exploited.

In the 1960's the main organizations interested in fluid bed combustion were in the UK and included the Central Electricity Generating Board (CEGB) and the National Coal Board (NCB). Most of the combustors of this period operated at atmospheric pressure, but the possibility of using a gas turbine encouraged the development of experimental pressurized combustors (Ref. 2-7). By 1969, a 3-MW(th) pressurized combustor was operating at the British Coal Utilization Research Association (BCURA) laboratories (now the Coal Utilization Research Laboratories), and to date this is the largest facility of its type in the world. The ability of fluid bed combustors to retain sulfur during the combustion process was also recognized at this stage, and several experimental investigations of the retention efficiency were carried out (Ref. 2-8).

In the early 1970's, development effort in the UK was directed towards the early commercial exploitation of fluid bed combustion in the industrial market (i.e., for industrial boilers, furnaces and waste incinerators). In 1974 a 1.1-ton/hr (1-t/h) demonstration plant for colliery tailings combustion was commissioned by the NCB at the Coal Research Establishment. In 1975, Combustions Systems Limited and Babcock and Wilcox (UK) Limited completed the conversion of a 13-MW(th) boiler at Renfrew, Scotland to fluid bed firing. On the basis of this work, Babcock and Wilcox (UK) Limited now offers large industrial fluid bed boilers with commercial guarantees. The technology for burning lump coal in industrial fluid bed combustors was also developed during the early 1970's (Ref. 2-9) and has been applied since 1974 in a number of operational commercial prototype boilers and furnaces of up to 6 MW(th) in the UK. The largest plant to use this technology is the NCB/ME Boilers 30-MW(th) unit at the River Don British Steel works, Sheffield. Commissioning is expected in the spring of 1980.

In the U.S., effort has concentrated mainly on power generation applications. The largest atmospheric pressure combustion facility is the Pope, Evans and Robins plant at Rivesville, West Virginia. This is rated at 30 MW(e) and can be regarded as a commercial prototype. For pressurized combustion, the most significant operational pilot plants are the Exxon 1 MW(th) unit at Linden, New Jersey and the Combustion Power 2-MW(th) unit at Menlo Park, California. A 13-MW(e) pressurized combustor incorporating a gas turbine is to be built by Curtiss-Wright Corporation under contract from the Department of Energy. The design will be based on an air heater cycle.

In the Federal Republic of Germany (FRG), another pressurized combustion pilot plant using the air heater cycle is under construction at Bergbau-Forschung. The unit is rated at 22 MW(th) and will also incorporate a gas turbine.

In addition to the national programs referred to above, a number of international development projects have been initiated.

Under the auspices of the International Energy Agency, the US, UK and FRG agreed in 1975 jointly to fund a pressurized combustor to be built by the NCB. This will be an 80-MW(th) unit, and will be sited at the NCB Grimethorpe colliery. The objective of the project is to provide a flexible experimental facility capable of obtaining basic data over a wide range of operating conditions, rather than to be a commercial prototype or demonstration unit for a particular application. The plant is expected to be commissioned in the summer of 1980.

Babcock and Wilcox (UK) and the NCB are studying systems using a pressurized fluid bed combustor with an existing 70 MW(e) Stal-Laval gas turbine. The technical and economic merits of the basic concept are being assessed for two applications (Ref. 2-10). Through Coal Processing Consultants Ltd., several advanced coal-fired power generation systems are being evaluated for the British Columbia Hydro and Power Authority. The 70 MW(e) design is the major fluid bed option in this study, the objective of which is to build a commercial prototype plant which will serve as a model for subsequent full-size stations. Babcock and Wilcox (UK) are also carrying out a detailed design and costing study jointly with Stal-Laval (Sweden) for the American Electric Power Co. The plant would have a total output of 170 MW(e), of which approximately 100 MW(e) would be provided by an existing steam turbo-generator at an American Electric Power Co. site.

A summary of the present status of development world-wide for atmospheric and pressurized fluid beds is given in Tables 2-1 through 2-3. More details of current work and the history of the technology are given in Refs. 2-11 to 2-16.

Operating Temperature

One of the distinguishing features of fluid bed combustion is the comparatively low bed temperature of 1427 to 1742 F (775 to 950 C). Because of the rapid solids mixing in a fluid bed, the temperature of the bed can be assumed to be uniform, unless agglomeration and segregation occur. The temperature of the burning coal particles is, however, higher than the bed temperature, typically by 180 to 360 F (100 to 200 C). This difference is accounted for by the requirements of heat transfer from the surface of the burning particles to the inert bed material.

The choice of bed temperature is influenced by several considerations, the most important of which are:

- (i) achieving a high combustion efficiency;
- (ii) avoiding ash sintering;
- (iii) maximizing sulfur retention;

TABLE 2-1

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Boiler

Organization	Location	Description	Size MW (th)	Objective	Status
NCB	Leatherhead UK	Vertical shell boiler	3.3	Operation and test plant	Operational since 1969
NCB/Combustion Systems Ltd./Johnston Boilers	Ferrysburgh, Michigan USA	Locomotive type boiler	4	Commercial design	Operational since 1977. A number of commercial orders for this design now being completed
DOE/Exxon Research and Engineering Co.	Linden USA	Industrial fluid bed boiler	4	Demonstration plant	Operation scheduled for 1979
DOE	Morgantown USA	Three-cell fluid bed combustor	4	Test unit to provide information for build- ing industrial plants	Operation scheduled to begin in 1979
NCB/ Babcock (Shell Boilers)	Cheltenham UK	Babcock Compo Boiler	4.3	Development boiler to prove new design	Commissioning 1980 for proving trials
NCB/ Vosper Thornycroft	Cheltenham UK	Vosper Thornycroft open hearth horizontal boiler	5	Development boiler to prove new design	Commissioning 1980 for proving trials
NCB/ Vosper Thornycroft	Edmonton UK	Vosper Thornycroft vertical boiler	5	Commercial prototype field proving trials	Commissioned 1980 6 further boilers ordered
Northern Engineering Industries	Annan UK	Horizontal shell boiler	5	Works test unit to obtain design data	Operational as a test unit 1978. (Two commercial units at 1.2 MW in manufacture for site installation 1980/81)

TABLE 2-1 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Boiler

Organization	Location	Description	Size MW (th)	Objective	Status
Ruhrkohle AG	Konig Ludwig FRG	Coal-fired power plant	5.8	Demonstration plant for district heating	Construction completed. Plant commissioned.
EPRI/Babcock & Wilcox Co.	Alliance USA	Fluid bed boiler	7	To collect information	Operational
NCB	Newcastle- under-Lyme, UK	Locomotive steam boiler	10	Testing distributor design	Commissioned 1978
Energy Equipment	Birmingham UK	Retrofit unit for water tube boiler	10	Commercial unit used for testing and demonstration	Operational 1979
Combustion Systems Ltd. /Babcock & Wilcox Ltd.	Renfrew UK	Babcock cross-type steam boiler	16	To obtain operating data	Operational since 1975. Results have confirmed advantages of FBC on commercial scale.
DOE	Morgantown USA	Fluid bed boiler, 0.1 t/h input	approx. 0.3	To burn anthracite waste	Operational
NCB	Cheltenham UK	Hot water boiler	0.6	To obtain design data	Commissioned 1974, used as test installation
DOE/Battelle	Columbus USA	Industrial fluid bed boiler	1	Demonstration plant	Operation scheduled for 1980
NCB	Dudley UK	Conversion of horizontal shell boiler designed for conventional coal firing	1.2	To demonstrate the application of fluid bed combustion to horizontal shell boilers	Commissioned 1975, used as test installation to obtain data for commer- cial design

TABLE 2-1 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Boiler

Organization	Location	Description	Size MW (th)	Objective	Status
NCB	Peterborough UK	Fluid bed test rig	1.5	Obtaining design data for 30 MW (th) boiler	Work completed, rig dismantled
Northern Engineering Industries	Derby UK	Horizontal shell boiler	1	Works test unit to obtain design data	Operational as test unit 1978
Energy Equipment	Olney UK	Horizontal shell boiler	1.5	Works testing before site installation	Operational as test unit 1979. Move to site with two similar boilers 1980
NCB	Bury UK	Vertical shell steam boiler	2.5	Field trial demon- stration. Used to develop alternative load control and start up systems	Commissioned 1977. Meeting factory heating requirements
NCB	Hereford UK	Vertical shell hot water boiler	2.5	Field trial demonstration. Used to develop load control systems and test distributor designs	Commissioned 1977. Meeting site heating requirements
NCB	Cheltenham UK	Horizontal oil-fired shell boiler (steam)	3	Further development for retrofit on gas- or oil-fired boilers	Commissioned 1979. Used as test installation to obtain data for commer- cial designs
Stone Platt Fluidfire	Keighley UK	Packaged water tube boiler	3	Demonstration and test installation on site	Operational 1980. Test program
Whites Combustion	Widnes UK	Vertical shell boiler	3	Works test unit to obtain design data	Operational 1979. Commercial units under manufacture

TABLE 2-1 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Boiler

Organization	Location	Description	Size MW (th)	Objective	Status
DOE/Combustion Engineering Co.	Great Lakes Naval Training Centre USA	Two industrial fluid bed boilers	16	Demonstration plant	Plant under construction. Operation scheduled to begin 1980.
Ohio dept. of administrative services/ Babcock & Wilcox Ltd.	Columbus, Ohio USA	Atmospheric fluid bed boiler, retrofit	18	Demonstration of Babcock Contractors design	Construction nearly complete Commissioning 1980.
AB Enkoepings Vaermeverk	Enkoeping SWEDEN	Coal & oil atmospheric pressure boiler	25	High pressure water for district heating scheme	Plant operational since February 1978
NCB/ME Boilers	Sheffield UK	High pressure steam unit using ME 'coil' type boiler	30	Demonstration plant for commercial production of high pressure steam	Construction nearly complete. Commissioning 1980.
DOE/ Georgetown University	Washington DC USA	Industrial fluid bed boiler	33	Demonstration plant	Commissioned 1979. Undergoing trials.
Ruhrkohle AG	Dusseldorf FRG Flingen	Coal-fired power plant	35	Demonstration plant for combined production of power and heat	Commissioned 1979. Undergoing trials.
DOE/Foster Wheeler/ Pope Evans & Robbins	Rivesville USA	Multiple chamber fluid bed combustor	100	To collect information for the construction of a 200 MW(e) plant planned for 1980	Operational since 1977

TABLE 2-2

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Size MW (th)	Objective	Status
NCB	Cheltenham UK	Materials testing facility	0.1	For corrosion/erosion tests of metallic components	Operational
Babcock-BSH	Essen FRG	Tailings combustor, 0.1 t/h input	0.2	To demonstrate combus- tion of pre-dried tailings	Operational
Fluidyne	Minneapolis USA	Atmospheric pressure furnace	0.3	Test unit	Operational
DOE/MIUS	Oak Ridge USA	Atmospheric fluid bed combustor heating air for closed cycle gas turbine	0.3-0.5	Test unit to provide information for the construction of commercial scale plant	Operation scheduled to begin in 1979
NCB	Cheltenham UK	Fluid bed tailings combustor, 1 t/h input	0.7	To demonstrate combus- tion and drying of colliery waste material	Commissioned 1974, still in operation
CSIRO	Glenlee AUSTRALIA	Tailings combustor, 2 t/h input	1.5	Demonstrate combustion of minestone and, later, colliery tailings to generate power	Operational

TABLE 2-1 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Boiler

Organization	Location	Description	Size MW (th)	Objective	Status
Saarbergwerke	Völklingen/Fenne FRG	Combined cycle fluid bed and pf fired boiler using air cooled bed coils to a gas turbine with supplementary coke oven gas firing. Flue gas desulfurisation plant in cooling tower. Also supplies heat to d.h. network.	667	Large scale demonstration plant	Under construction

TABLE 2-2 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Size MW (th)	Objective	Status
DOE/Fluidyne	USA	Industrial fluid bed air heater	6	Demonstration plant	Design and development testing completed
NCB/ G.P. Worsley & Co. Ltd.	Selby UK	Hot gas furnace for crop dryer	5	Commercial prototype demonstration crop dryer of alternative design	Commissioned 1976, in commercial use
NCB/ G.P. Worsley & Co. Ltd.	Newark UK	Hot gas furnace for crop dryer	5	As above	Commissioned 1977, in commercial use
NCB/ G.P. Worsley & Co. Ltd.	Okehampton Thetford (now closed) Lincoln UK	Three commercial furnaces	5	Third type commercial design	In commercial use
Energy Equipment	Essex UK	Grass drying furnace	10	Commercial plant	Commissioned 1980
Energy Equipment	Nottingham- shire UK	Grass drying furnace		Commercial plant	Commissioned 1980
NCB/ G.P. Worsley & Co. Ltd.	Lincoln- shire UK	Clay drying furnace	15	Commercial plant	Commissioned 1979
Lurgi-Gesellschaft Fir Chemie und Huttenwesen GmbH	Frankfurt FRG	'Turbulent layer' fluid bed furnace	33	Combustion of low-grade fuels	Operational

TABLE 2-2 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Size MW (th)	Objective	Status
Ruhrkohle AG	Gneisenau Coll. FRG	Fluid bed combustion plant for burning flotation tailings	35	Prototype plant	Completion 1980
Deborah Combustion	Avonmouth UK	Incinerator for acid tars		EEC demonstration plant	Commissioned 1980

TABLE 2-2 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Through- put t/h	Objective	Status
Dorr-Oliver Inc.	New Rochelle USA	Primary sewage sludge solids	0.1	Pilot plant	Operational since 1962
Dorr-Oliver Inc.	USA, UK, France, Germany, Italy, Japan and South Africa	73 plants operating 3 types of new fluosolids disposal system	0.1-1.5	Commercial plant	Operational since 1976
Dorr-Oliver Inc.	Green Bay USA	Dry waste liquor solids. Neutral Sulphite Semi Chemical Paper Mills	2.7-5.7	Commercial plant	Operational
Dorr-Oliver Inc.	Karlsruhe FDR	Aqueous refinery waste	1.0-1.2	Commercial plant	Operational since 1970
Dorr-Oliver Inc.	Lodi Italy	Aqueous refinery waste	0.4	Commercial plant	Operational since 1973
Dorr-Oliver Inc.	Livorno Italy	Aqueous refinery waste	3.5	Commercial plant	Operational since 1973
Dorr-Oliver Inc.	Bari Italy	Aqueous refinery waste	1.5	Commercial plant	As above
Dorr-Oliver Inc.	Whiting USA	Aqueous refinery waste	14	Commercial plant	Operational since 1972
Not known	Barstow USA	Dry solids mix of sewage sludge	0.22		
Not known	Bergen County, New Jersey USA	Dry solids mix of sewage sludge	0.5		

TABLE 2-2 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Through- put t/h	Objective	Status
US/DOE	MERC (Morgantown) USA	Anthracite waste		Pilot plant	
Several	IGT, Westinghouse City Univer- sity, others	Char from coal			
	Rocky Flats, California USA	Chemical and low level radio-active wastes	0.005-0.1	Pilot plant	
US EPA, City of St. Louis, Union Electric Co.	St. Louis, USA	Residential solid waste	300	Full scale testing	Operation scheduled for 1977
Nippon Zein Co. Ltd., Japan Gasoline Co. Ltd., Japanese Government	Tokoyama Japan	Waste tires	1		Operational
Heenan Environmental Systems	Caernarfon, UK	Sewerage sludge			Operational
Dorr-Oliver	Esher, UK	Sewerage sludge (wet)	2.3		Operational
Hydrasposal/Fibre- claim Black Clawson Co.	Franklin, Ohio USA	Solid refuse	6		Operational

TABLE 2-2 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Atmospheric Pressure Furnaces and Incinerators

Organization	Location	Description	Through- put t/h	Objective	Status
Copeland Process Ltd.	Great Lakes Paper Co. USA	Wood/paper waste		Commercial plant	Operational
Copeland Systems Inc. Copeland Process Ltd.	Several claimed	Pulping waste, pharmaceutical waste, distillery waste, chemical waste, municipal waste, plastic waste, agricultural waste, wood waste.		Commercial plant	Operational

TABLE 2-3

FLUID BED COMBUSTION R&D PROJECTS

Pressurized Combustors

Organization	Location	Description	Size MW (th)	Objective	Status
Bergbau-Forschung GmbH/ Vereinige Kesselwerke AG (Fluid bed combustion group)	Bottrop FRG	Pressurized fluid bed air heater with 2 MW(e) Sulzer gas turbine	22	To collect information for construction of a 100 MW(e) coal-fired power station using fluid bed combustion	Planning nearing completion
DOE/Curtiss-Wright	Wood Ridge USA	Open cycle gas turbine plant with pressurized fluid bed combustor	43	Information for construction of demonstration plant	Plant to be operational in 1980
NCB(IEA) Services Ltd. (supported by UK, USA, FRG governments)	Grimethorpe UK	Pressurized boiler, flue gases cooled in heat exchangers, expanded and removed via stack	85	To collect basic infor- mation for the operation and design of pressur- ized fluid bed combustors	Operation of test plant scheduled for 1980
America Electric Power/Stal Laval/ Babcock & Wilcox Ltd.	Pennsylvania USA	Open cycle gas turbine plant with pressurized fluid bed combustor	200	Demonstration plant for electricity generation	Design study
British Columbia Hydro/CPC	Vancouver CANADA	Air heater cycle	200	Demonstration plant	Conceptual design stage completed

TABLE 2-3 (Cont'd)

FLUID BED COMBUSTION R&D PROJECTS

Pressurized Combustors

Organization	Location	Description	Size MW (th)	Objective	Status
Rolls Royce	Ansty UK	Pressurized fluid bed operating with 0.1 MW(e) Rover gas turbine	0.3	To collect information on operation of pres- surized adiabatic fluid bed combustor	Program completed
EPA/Exxon	Linden USA	Pressurized fluid bed unit - 'Miniplant'	1	Test rig for combustion, heat transfer and acceptor regeneration	Test program believed completed
Curtiss-Wright	Wood-Ridge USA	Pressurized fluid bed air heater, coupled to a Rover gas turbine	2.3	Technology development unit	Operational
NCB	Leatherhead UK	Pressurized fluid bed boiler	5	Tests on corrosion and erosion of turbine blades	Operational since 1970
DOE/Combustion Power Co.	Menlo Park USA	Pressurized fluid bed combustion system	4	To test gas clean-up techniques and turbine blade erosion	Plant operated
DOE/Argonne National Laboratory	Argonne USA	Pressurized fluid bed component test and integration unit	10	To collect information for operation on larger scale. Investigate gas cleaning techniques	Recently suspended

- (iv) achieving high heat transfer rates to tubes in the bed;
- (v) limiting the temperature of heat transfer surfaces in the bed;
- (vi) increasing the proportion of the total heat release extracted by heat transfer surfaces in the bed;
- (vii) permitting part-load operation; and
- (viii) reducing emissions of alkali metal salts.

These factors are considered in the following sections.

Combustion Efficiency

The rate of reaction between coal particles and air increases with temperature, and the corresponding rate of carbon carryover is, therefore, reduced. As a result, operation at a high bed temperature increases the proportion of the coal burned in the bed in a single pass (see the section on Combustion Efficiency for details).

Ash Sintering

Sintering refers to the tendency of particles of coal ash to stick together to form agglomerates at high temperatures. The temperature below which sintering is avoided is referred to as the initial sintering temperature. Laboratory determination of this parameter under conditions relevant to fluid bed combustion is difficult. The ash characteristic most widely used to describe sintering behavior is the initial deformation temperature, but this is considerably higher than the initial sintering temperature. As a result, the bed temperature is usually limited to 360 F (200 C) below the initial deformation temperature.

Most fluid bed systems are designed to avoid sintering because sintering can form agglomerates which would interfere with the fluidization. If the agglomerates become too large, segregation of the bed and defluidization can result. Sintering can also lead to the formation of bonded deposits on heat transfer surfaces in and above the bed.

Fluid beds can, however, be operated above the initial sintering temperature, and such designs have been termed accreting fluid beds (Ref. 2-17). The high operating temperature of accreting fluid beds may make them attractive for use as carbon burn-up cells or for use with high-temperature gas turbines. To maintain stable fluidizing conditions in an accreting fluid bed, the fluidizing velocity must be sufficiently high to avoid excessive growth and segregation of the agglomerates. The relationship between fluidizing velocity and bed temperature for stable fluidization is illustrated in Fig. 2-3 for coal ash with a greater tendency to agglomerate than the Illinois No. 6 ash and sulfated limestone shown in Fig. 2-4.

FIG. 2-3

RELATIONSHIP BETWEEN FLUIDIZING VELOCITY AND BED TEMPERATURE

(REF. 2-17)

FIG. 2-4

RELATIONSHIP BETWEEN FLUIDIZING VELOCITY AND BED TEMPERATURE FOR ILLINOIS NO. 6 ASH AND SULFATED LIMESTONE

MEAN PARTICLE SIZE = 500 MICRONS

The initial sintering temperature appears to depend on particle size (Ref. 2-18), decreasing significantly for particles smaller than 50 microns. It has been suggested (Ref. 2-19) that bonded deposits on surfaces immersed in a fluid bed are caused by the sintering of fine ash particles at the bed temperature. The formation of such deposits with Illinois No. 6 coal has been observed at a bed temperature of 1652 F (900 C) yet the initial deformation temperature for this coal is 2120 F (1160 C).

Sulfur Retention

The chemical reactions by which sulfur is retained in the bed occur in two stages for both atmospheric pressure and elevated pressure combustors. First, calcination of the stone occurs when evolution of carbon dioxide opens up the pore structure and increases the reactivity of the stone. Then, absorption of sulfur dioxide occurs when sulfur dioxide released during combustion reacts with the calcined acceptor to form sulfate.

For effective sulfur retention using limestone, the bed temperature has to be above 1382 F (750 C) at atmospheric pressure to obtain an adequate rate of calcination. This is illustrated in Fig. 2-5 which shows the variation in the calcination time with particle size for limestone. Elevated pressure inhibits calcination, making limestone generally less suitable for such applications. Dolomite calcines more easily than limestone and is therefore preferred for pressurized applications.

For atmospheric pressure operation, the sulfur retention efficiency falls at high temperatures (Fig. 2-6) and may impose an upper limit on the bed temperature. Several mechanisms have been proposed to account for this effect, including thermal dissociation of the sulfate at high temperatures, and increased decrepitation of the stone resulting from the high rate of carbon dioxide evolution during calcination.

Both dissociation of the sulfate and calcination of the stone are inhibited by pressure, so that effective sulfur retention is possible at higher temperatures with elevated pressure operation (Fig. 2-6).

Heat Transfer

Operation at a high bed temperature leads to a large temperature differential between the bed and immersed heat transfer surfaces and, consequently, to a high heat flux per unit area of heat transfer surface. The size of the heat exchanger is therefore reduced. However, increasing the heat flux per unit area of heat transfer surface also implies an increase in the temperature differential between the tube metal and fluid. For the same fluid temperature, therefore, a high bed temperature results in a higher tube metal temperature.

EFFECT OF CALCINATION TEMPERATURE AND LIMESTONE SIZE
ON LIMESTONE CALCINATION RATE

(REF. 2-12)

FIG. 2-6

EFFECT OF BED TEMPERATURE ON SULFUR RETENTION

(REF. 2-20)

79-02-248-6

A further consideration is that, for a fixed combustion efficiency and excess air level, a low bed temperature results in a greater proportion of the total heat release being available in the bed and, correspondingly, less available for convective heat transfer after the bed. This may be either an advantage or disadvantage depending on the cost and temperature limitations (e.g., corrosion) of the heat transfer materials used.

The choice of bed temperature is also influenced by the requirements for part-load operation. One option for reducing the rate of heat transfer to surfaces immersed in the bed is to reduce the bed temperature. To avoid too low a bed temperature during turndown, the bed temperature at maximum rating must be sufficiently high. Part-load operation of fluid bed combustors are considered further in Volume III.

Alkali Metal Salts

The deposition of alkali metal salts in the gas turbine is likely to lead to catastrophic hot corrosion, especially in the presence of sulfur oxides. Because of the relatively low bed temperature, the emission levels of alkali vapor from a fluid bed combustor are lower than from conventional combustion systems. Because the volatility of the salts increases with temperature, it may be necessary to place an upper limit on the bed temperature for coals with a high alkali metal content. Emission levels are considered in more detail in a later section entitled Alkali Emissions.

Fluidizing Velocity

When a fluid is passed upwards through a fixed bed of particles, the pressure drop across the bed increases with the fluid velocity. When the pressure drop reaches a value equal to the bed weight per unit area of the distributor plate less buoyancy forces, no further increase in pressure drop occurs and the bed becomes fluidized. The velocity of the fluid at this point is called the fluidizing velocity.

Minimum Fluidizing Velocity

The relationship between fluid velocity and bed pressure drop is illustrated in Fig. 2-7 (from Ref. 2-21). As shown in the figure, the transition from a fixed bed to a fluid bed occurs gradually over a range of fluid velocities. It is usual to define the minimum fluidizing velocity (U_{mf}) by extrapolation from the fixed bed and fluid bed regions, as indicated. The minimum fluidizing velocity is less than that required for full bed support.

From the theory of flow through a fixed bed (Ref. 2-21 and 2-22), the minimum fluidizing velocity can be obtained from the following equation:

RELATIONSHIP BETWEEN BED PRESSURE DROP AND FLUID VELOCITY

(REF. 2-21)

FIG. 2-7

$$GaE_{mf}^3 = 150 Re_{mf}(1-E_{mf}) + 1.75 Re_{mf}^2 \quad (2-1)$$

$$\text{where } Ga = \text{Galileo number, } \rho(\rho_s - \rho)gd^3/\mu^2, \quad (2-2)$$

$$E_{mf} = \text{the void fraction,} \quad (2-3)$$

$$Re_{mf} = \text{particle Reynolds number, } \rho_s d U_{mf} / \mu,$$

$$\rho = \text{the fluid density,}$$

$$\rho_s = \text{the solid density,}$$

$$g = \text{acceleration due to gravity,}$$

$$d = \text{particle diameter,}$$

$$\mu = \text{fluid viscosity, and}$$

$$U_{mf} = \text{minimum fluidizing velocity}$$

with all the above defined in consistent units.

In Ref. 2-23 it is pointed out that it is difficult to define U_{mf} precisely because the value of E_{mf} is uncertain. For fluid bed combustion, however, the fluid velocities are usually several times the minimum fluidizing velocity and for many systems it is sufficiently accurate to take E_{mf} to be 0.5.

Minimum fluidizing velocities for typical fluid bed combustor conditions (coal ash at 1472 F (800 C) fluidized with air) are shown in Fig. 2-8. The minimum fluidizing velocity decreases with pressure and increases with bed particle size.

Maximum Velocity

The combustion rate per unit area of bed surface is limited by the availability of oxygen, which depends on the fluidizing velocity. A high fluidizing velocity is therefore necessary to achieve a high combustion rate and a small unit size. As the fluidizing velocity increases, however, so does the rate of removal of bed material through entrainment in the gas stream (elutriation). This has three consequences, each of which can impose an upper limit on the fluidizing velocity. The removal of carbon from the bed reduces the combustion efficiency per pass. The removal of unreacted acceptor reduces the sulfur retention efficiency per pass for a fixed rate of acceptor addition. The removal of inert bed material ultimately leads to loss of bed height. The prediction of the elutriation rate is considered in a later section entitled Elutriation.

An upper limit to the fluidizing velocity is given by the terminal velocity in free fall, U_t , of bed particles. This can be calculated from correlations of drag coefficient and Reynolds number (Ref. 2-24), which are based on the work in Ref. 2-25. The variation of the terminal velocity with particle size is illustrated for typical fluid bed combustor conditions in Fig. 2-9.

FIG. 2-ε

EFFECT OF BED PARTICLE SIZE AND BED PRESSURE ON MINIMUM FLUIDIZING VELOCITY

BED PARTICLE SPECIFIC GRAVITY = 2.5

LOOSE PACKED DENSITY = (87.4 lb/ft³ AT 1472 F (1400 kg/m³ AT 800 C)

FIG. 2-9

EFFECT OF BED PARTICLE SIZE AND BED PRESSURE ON TERMINAL VELOCITY

79-02-248-9

Operating Range

The range of velocities between U_{mf} and U_t is indicated by the relationship between U_t/U_{mf} and particle size (or, equivalently, Galileo number), shown in Fig. 2-10. For large particles, the allowable range is about $10 U_{mf}$, increasing to about $80 U_{mf}$ for fine particles (Ref. 2-21).

In practice, the conflicting requirements of avoiding segregation or poor mixing at low velocities and excessive elutriation or poor gas - solids contacting at high velocities leads to a compromise. A combination of conditions which leads to acceptable fluidization has been proposed in Ref. 2-26 in terms of the following dimensionless parameters:

$$V_n = U (\rho^2 / [g\mu(\rho_s - \rho)])^{1/3} \quad (2-4)$$

where V_n = velocity number, and
 U = fluidizing velocity; and
 $F_n = d[\rho g(\rho_s - \rho)/\mu^2]^{1/3}$

(2-5)

where F_n = fluidization number.

The suggested relationship between velocity number and fluidization number is shown in Fig. 2-11, together with the corresponding relationships for U_{mf} and U_t .

The velocity number and fluidization number can be expressed in terms of the Reynolds number and Galileo number as follows:

$$V_n = Re (\rho/\rho_s) Ga^{-1/3} \quad (2-4a)$$

$$F_n = Ga^{1/3} \quad (2-5a)$$

Operating Pressure

The main incentive to operate fluid bed combustors at elevated pressure has been to reduce the capital cost and improve the efficiency of power generation through combined cycle operation. The range of operating pressures considered for fluid bed combustors in experimental work and design studies have consequently been determined by the operating pressures of gas turbines, i.e., 6 to 16 atm (bar). In addition, because of the limitations on bed temperature, the inlet temperature to the gas turbine will also be limited to a maximum of about 1742 F (950 C). This precludes the use of the advanced, high-temperature, high-pressure turbines presently under development.

RATIO OF TERMINAL VELOCITY TO MINIMUM FLUIDIZING VELOCITY

(REF. 2-21)

FIG. 2-10

OPERATING RANGE FOR FLUIDIZATION

(REF. 2-26)

FIG. 2-11

Effect on Heat Release per Unit Volume

As the system pressure is increased, the mass flow rate of air increases proportionately for a constant fluidizing velocity. As a consequence, the oxygen availability and, hence, combustion rate per unit area is increased. Figure 2-12 shows the output per unit bed plan area for different operating pressures, all other conditions being kept constant.

If the combustor is being designed to operate at a fixed excess air level with tubes in the bed, then the area of heat transfer surface per unit bed plan area also has to be increased in proportion to the operating pressure to match the additional heat release. As a result, the bed has to be deeper to accommodate the extra surface. Although a higher bed pressure drop is obtained, this can usually be tolerated within the higher overall system pressure.

Effect on Fluidizing Behavior

The effect of pressure on the minimum fluidizing velocity is shown in Fig. 2-8 for typical fluid bed combustor conditions. At high pressures, the minimum fluidizing velocity is reduced although, for the range of mean bed particle sizes relevant to fluid bed combustion (up to about .04 in. (1 mm)), the change is small. The reduction in minimum fluidizing velocity would be expected to lead to a greater bubble phase flow rate and a more vigorously bubbling bed. In fact, the opposite is observed, fluidization at pressure generally being considered to be smoother or of better quality (Ref. 2-20).

The explanation for this apparent anomaly appears to be associated with the bubble size. A theory of maximum stable bubble size was proposed in Ref. 2-27 and modified in Ref. 2-28. According to the theory, a bubble will be unstable if the terminal velocity, U_t , of a particle in the wake of a bubble is less than the gas velocity through the bubble. This results in the bubble filling with particles entrained from the wake. Although the detailed theoretical explanation is still in dispute (Ref. 2-29), experimental support for the theory has been found in Refs. 2-28, 2-30 and 2-31. All of these sources report that with beds of fine particles (below 200 micron) at high pressures, bubbling behavior disappears and the system resembles the expanded bed, liquid-fluidized state.

The predictions of the maximum stable bubble size theory for a bed of coal ash of mean size 400 micron at 1472 F (800 C) are given in Table 2-4. Although decreasing with pressure, the bubble diameter is still considerably greater than the tube spacing. This is consistent with the observation that, in spite of the different nature of the fluidization, heat transfer coefficients to immersed surfaces are similar for pressurized and atmospheric pressure combustion.

EFFECT OF FLUIDIZING VELOCITY AND OPERATING PRESSURE ON POWER FLUX

20% EXCESS AIR
38% CYCLE EFFICIENCY
(REF. 2-20)

TABLE 2-4

EFFECT OF PRESSURE ON THE MAXIMUM STABLE BUBBLE SIZE
Mean ash size = 400 microns
1472 F (800 C)

<u>Pressure</u>	<u>Bubble Diameter, ft(m)</u>
1	5.18 (1.58)
5	2.92 (0.89)
10	1.80 (0.55)
20	1.05 (0.32)

The theory of maximum stable bubble size does not, therefore, explain completely the fluidizing behavior at elevated pressure. Other factors affecting bubble size may be more important for the conditions in a fluid bed combustor. The initial bubble size at the distributor may be smaller (Ref. 2-32) and the deeper and more compact tube banks used in some pressurized fluid bed systems may control bubble size. In either case, smaller bubbles lead to smaller fluctuations in the pressure drop across the bed, resulting in smoother fluidization and better gas-solid contacting, which, in turn, lead to improved combustion and sulfur retention efficiencies.

Effect on Performance and Emissions

Compared with atmospheric pressure combustion, operation at elevated pressure generally results in a higher combustion efficiency, improved sulfur retention, and reduced emission levels of nitrogen oxides (Ref. 2-33). These aspects will be considered in the relevant sections.

Design Considerations

Pressurized operation introduces design problems not encountered in atmospheric pressure systems, particularly coal feeding and ash removal from the pressure vessel. Care is necessary in the design of the combustor and tube bank so that fluidization problems which might lead to poor gas/solids contact, local hot spots, etc. are avoided. These problems have been under study at the National Coal Board laboratory at Leatherhead, U.K. for a number of years (Ref. 2-33) and at the Exxon mini-plant in New Jersey.

Heat Transfer to Immersed Surfaces

One of the advantages claimed for fluid bed combustion is high heat transfer coefficients to surfaces immersed in the bed. This reduces the size and cost of the heat exchanger.

Heat transfer coefficients to immersed surfaces are usually quoted for convective heat transfer only, i.e., excluding radiation. However, at bed and tube surface temperatures applicable to fluid bed combustion, radiative heat transfer is also significant. This component can be estimated as follows:

$$h_r = (4.55 \times 10^{-8}) [(T_b + 273)^4 - (T_t + 273)^4] / (T_b - T_t) \quad (2-6)$$

where h_r = radiative heat transfer coefficient, (W/m²-K),
 T_b = bed temperature, and
 T_t = tube outer surface temperature (C).

An emissivity of 0.8 was assumed in deriving the equation.

The radiative and convective components of heat transfer can be assumed additive, so that

$$h = h_c + h_r \quad (2-7)$$

where h = overall bed-to-tube heat transfer coefficient, and
 h_c = convective heat transfer coefficient,

both in consistent units.

In the present context, convective heat transfer refers to the heat transmitted to the tube by particles at the bed temperature arriving at the tube surface. The particles cool by transferring heat to the tube and then are removed and reheated in the bed. The convective heat transfer coefficient, h_c , therefore depends on the operating conditions of the combustor, as described in the following sections.

Bed Particle Size

The most important parameter affecting the convective heat transfer coefficient in conventional fluid bed combustor designs is the mean bed particle size. The coefficient increases with decreasing bed particle size. The relationship can be described (Ref. 2-34) by an equation of the form:

$$h_c = k/d^{0.5} \quad (2-8)$$

where d = mean bed particle size (defined as the mean surface/volume diameter), and
 k = a constant.

Typical values of the convective heat transfer coefficient are illustrated in Fig. 2-13. The data refer to horizontal 2 in. (50 mm) (outside diameter) tubes.

Several correlations for the convective heat transfer coefficient in terms of the dimensionless groups Galileo number and Nusselt number have been proposed (Refs. 2-35 and 2-36). These are, however, generally unsatisfactory because both Galileo number and Nusselt number depend on the bed particle size, and this dominates other relationships present.

Tube Outer Surface Temperature

The convective heat transfer coefficient increases with the tube outer surface temperature. For example, increasing the tube temperature from 212 to 932 F (100 to 500 C) changes the heat transfer coefficient by approximately 25 percent, as illustrated in Fig. 2-13.

EFFECT OF BED PARTICLE SIZE AND TUBE TEMPERATURE ON CONVECTIVE HEAT TRANSFER COEFFICIENT

(REF. 2-34)

FIG. 2-13

The reasons for this increase are not fully understood, but appear to be associated with the particle-to-tube heat transfer during the short residence time of the particles at the tube surface. The increase in the thermal conductivity of the gas film with temperature may be partly responsible. Another factor may be inaccuracies in estimating the radiative component of heat transfer, for example, the assumption that particles radiating to the tube are at the bed temperature.

Fluidizing Velocity

The general form of the relationship between the convective heat transfer coefficient to surfaces immersed in the bed and the fluidizing velocity is shown in Fig. 2-14. As might be expected, there is a rapid increase in the coefficient immediately above the minimum fluidizing velocity due to the effect of bubbling and solids mixing in the bed. Above two or three times U_{mf} , there is little further increase in the coefficient with increasing velocity; in fact a slight decrease is observed owing to an increase in the voidage around immersed surfaces. Models describing this phenomenon have been developed (Ref. 2-37).

As most fluid bed combustors operate in the region above 3 U_{mf} , the fluidizing velocity will not have a large effect on the heat transfer coefficient. However, the velocity determines the particle size distribution in the bed and, as discussed earlier, this has a marked effect on heat transfer.

Pressure

As noted in the section entitled Effect of Fluidizing Behavior, the effect of pressure on the convective heat transfer coefficient is small. Some reduction in the coefficient would be expected to result from the less vigorous fluidization, but the reduction is typically less than 10 percent.

Tube Bundle Geometry

In order to achieve good heat transfer coefficients in practice, care must be taken in the design of the tube bundle. If, for example, tubes are placed too close together (horizontally or vertically), solids circulation will be restricted, having an adverse effect on the heat transfer coefficient. Comparatively little data exist on heat transfer to vertical tubes, but there are indications of a reduction in the heat transfer coefficient.

Particle Size

In conventional fluid bed combustor designs, the size distribution of the coal is similar to that of the sulfur acceptor. Much of the ash in an unwashed

RELATIONSHIP BETWEEN CONVECTIVE HEAT TRANSFER COEFFICIENT
AND FLUIDIZING VELOCITY

coal arises from separate stone particles which have a size distribution similar to that of the coal, the remainder being fine interstitial ash from within the coal particles. In general, unwashed coals produce an ash having a similar, but somewhat finer, size distribution than that of the parent coal.

The choice of feed size distribution is related to the choice of fluidizing velocity, and is determined by similar factors, the most important of which are the lower limit for particle size and the upper limit for particle size. Selecting too low a particle size will result in a) excessive carryover of combustible material leading to a low combustion efficiency per pass, b) excessive carryover of unreacted acceptor leading to a low sulfur retention efficiency, and c) excessive carryover of bed material leading to loss of bed height. Selecting too high a particle size will lead to ineffective solids mixing and segregation and a low convective heat transfer coefficient. Based on experimental data for UK coals, the NCB has determined a series of relationships between feed size and fluidizing velocity for which satisfactory operation can be expected. These are illustrated in Fig. 2-15, which also includes predictions of the mean bed particle size.

The above discussion refers to fluid bed combustors in which the bed material comprises the coal ash and sulfur acceptor. If the ash is fine or friable so that it is removed rapidly by elutriation, then the bed will consist of sulfur acceptor alone, or an inert additive. Under these conditions, the particle size of the coal is not limited by the effect of the ash on the fluidization characteristics of the bed.

The use of coal of top size 1 in. (25 mm) in beds of sand of mean size .04 in. (1 mm) is reported in Refs. 2-38 and 2-39. This permits the use of commercial grades of sized, washed coal in industrial boilers. Several prototype industrial boilers and furnaces based on this technology are in operation. They have demonstrated that high combustion efficiencies can be achieved in compact combustion systems using lump coal. This technology is not likely to be suitable in applications requiring deep beds with closely packed tube bundles.

Elutriation

As discussed previously, the choice of fluidizing velocity and feed particle size is restricted by particle carryover from the bed which can have the following undesirable effects: low combustion efficiency (carryover of unburned carbon), low sulfur retention efficiency (carryover of unreacted sulfur acceptor), and inability to maintain the design bed height (carryover of bed material). The present section considers the effect of elutriation on the maintenance of bed height and the size distribution of the bed material. Combustion efficiency and sulfur retention are considered in the next two sections, respectively.

FIG. 2-15

EFFECT OF OFF-GAS VELOCITY AND COAL FEED SIZE
ON MEAN BED PARTICLE DIAMETER

79-02-248-29

Because the carbon content of the bed is typically less than 1 percent, it can be assumed that only the coal ash and acceptor contribute toward maintaining the bed. In steady-state operation, the feed rate of these components will equal the rate of removal by elutriation and by overflow from the bed weir. The removal of bed material by overflow confirms that the bed height is being maintained; however, if all of the feed is removed by elutriation, this may not be the case.

In the limiting case of no overflow, an estimate can be obtained of the gas cleaning efficiency required to meet the EPA standard of 0.1 lb of particles per million Btu of fuel input (.043 kg/GJ). For Illinois No. 6 coal without acceptor addition the collection efficiency has to be 99.6 percent, and with limestone addition at a Ca/S ratio of three, 99.8 percent efficiency is needed. These efficiencies exclude the collection of unburned carbon.

Elutriation Rate

Much information on elutriation rates from fluid bed combustors has been reported in the literature; a detailed review of the data has been carried out in Ref. 2-12.

It is usually assumed that elutriation is a first-order process, so that the elutriation rate $R(x)$, lb/sec (kg/s), of particles of size x is given by:

$$R(x) = E(x) M(x) \quad (2-9)$$

where $E(x)$ = rate constant, and

$M(x)$ = mass fraction of particles of size x in the bed.

It is also assumed that the rates are additive so that the total elutriation rate, R , from the bed is given by:

$$R = \sum R(x_i) = \sum E(x_i)M(x_i) \quad (2-10)$$

where the summation takes place over all size fractions, x_i , in the bed.

The rate constant, E , varies rapidly with particle size (Ref. 2-40) in the following relationship:

$$E(x)/G = B + 130 \exp(-10.4 u^{0.5} v^{0.25}) \quad (2-11)$$

where G = mass flow rate of fluidizing gas,

B = constant depending on the combustor and freeboard design (0.1×10^{-3} to 1.5×10^{-3}),

u = ratio of particle terminal velocity to superficial fluidizing velocity, and
 v = ratio of minimum fluidizing velocity to superficial fluidizing velocity less minimum fluidizing velocity.

Prediction of Elutriation

Elutriation arises principally by two mechanisms: rapid entrainment and removal of the fine particles in the feed, and abrasion and decrepitation of the coarse particles in the feed to produce fines which are entrained in the gas stream and removed from the bed.

The most satisfactory method of estimating the abrasion rate of coal ash or acceptor is by tests in a fluid bed combustor at the design conditions. However, simple bench-scale tests have been developed which, in combination with design procedures, can be used to predict the elutriation rates with reasonable accuracy.

The approach which can be adopted is outlined in Ref. 2-40 where a mathematical model of the processes of abrasion and elutriation is developed. In the most general form, a numerical solution is necessary, but an analytical solution is possible with the following additional assumptions: instantaneous elutriation of particles smaller than x_c , no elutriation of particles with a terminal velocity equal to the fluidizing velocity or, if total recycle is employed, the cut size of the collector. The size distribution of the feed (ash and acceptor) is given by:

$$\alpha = (x/x_m)^b \quad (2-12)$$

where x = fraction undersize,
 x_m = maximum particle size of the feed, and
 b = constant.

With these assumptions, the fraction of the feed elutriated is given by:

$$e = KT + [(w^p - pw)/(1-p)] \quad (2-13)$$

where e = fraction of feed elutriated,
 K = mean abrasion constant of the ash and acceptor feed, sec^{-1}
 T = mean residence time of the feed in the bed, i.e., the bed weight divided by the feed rate of ash and acceptor,
 $w = (x_c/x_m)^b$, size distribution of elutriated particles, (2-14)
 and
 $p = 3(1/b + [(1-e)/(TbK)])$ (2-15)

Because p is a function of e , the calculation is iterative.

The mean surface - volume diameter of the bed particles, d , can also be calculated from

$$d = x_m \left\{ \frac{[(1-w)/b] - [(1-w^P)/bp]}{[1 - w(x_m/x_c)]/(b-1) - [1 - w(x_m/x_c)^{1/P}]/(bp-1)} \right\} \quad (2-16)$$

In addition to the total elutriation rate and the mean bed particle size, the numerical solution enables predictions of the recycle rate and fines loss through the cyclones to be made. Comparisons of the predictions with the experimental results are given in Table 2-5.

Composition of the Elutriated Material

The composition of the elutriated material will depend on the composition of the coal ash and acceptor, and their relative feed rates. In addition, the elutriated material will also contain unburned carbon which may be collected for subsequent combustion in a burn-up cell.

Typical examples of the analysis of primary fines, secondary fines and dust are given in Table 2-6. The data refer to tests on Illinois No. 6 coal crushed to a top size of 1/16 in. (1.5 mm) and fluidized at 3 ft/sec (0.9 m/s) at atmospheric pressure. However, large deviations from these data can occur, depending on the coal type, combustor design and operating conditions. Experimental tests are generally necessary to determine accurately the fines analysis for particular conditions.

Combustion Efficiency

The combustion of coal in a fluid bed proceeds in three stages: volatile matter is released, volatile matter in the vapor phase is combusted, then residual char is combusted. A proportion of the volatile matter and gaseous products such as carbon monoxide can pass into the freeboard. Complete combustion of these gases occurs above the bed unless the temperature or excess air level is too low. Unburned particles of char are also carried out of the bed by the gas stream. Some of these burn in the freeboard, but a small proportion leave the combustor. These represent the main loss of unburned carbon. Most of the unburned char particles range in size from 100 microns to 10 microns, and are collected by the primary cyclone. Because the concentration of carbon in the bed is low (typically less than 1 percent), the loss of carbon with the bed material removed by the weir is generally small.

TABLE 2-5

COMPARISON OF PREDICTED ELUTRIATION AND RECYCLE RATES, MEAN BED PARTICLE SIZES
AND FINES LOSS THROUGH AN EFFICIENT CYCLONE WITH EXPERIMENTAL RESULTS
(Ref. 2-40)

Test series	Fluidizing velocity m/s	Ash feed rate g/m ² s	Bed weight kg/m ²	Elutriation percent of feed			Loss through cyclone, percent of feed		Mean bed particle size, micron			Recycle rate g/m ² s	
				E	A	N	E	A	E	A	N	E	N
E	0.6	9.1	547	60	62	56	8	10	435	273	433	-	-
A	0.6	4.2	576	83	84	80	13	12	400	303	396	-	-
-	0.6	3.1	605	94	100	100	13	16	360	330	354	-	-
F	0.6R	4.9	459	24	-	57	-	-	200	-	240	260	270
-	1.2	15.9	551	88	83	78	6	6	560	445	555	-	-
-	1.2	7.3	649	100	100	100	9	9	530	510	526	-	-
-	1.2	7.6	576	100	100	100	12	8	600	508	545	-	-
B	1.2	8.3	415	90	91	90	12	6	540	464	583	-	-
-	1.2R	7.0	610	95	-	96	-	-	320	-	268	1080	950
-	1.2R	8.5	551	64	-	81	-	-	320	-	255	1360	1150
D	1.2R	7.9	307	73	-	69	-	-	310	-	326	520	640
C	2.4	16.5	351	100	100	100	14	6	770	724	856	-	-
-	2.4	17.2	610	97	100	100	11	10	770	770	822	-	-

E = Experimental result

A = Prediction using analytical model

N = Prediction using numerical model

R = Test with fines recycle

TABLE 2-6

CHEMICAL ANALYSIS OF CYCLONE FINES AND DUST

	Test 1			Test 2			Test 3			Test 4		
	Prim-ary	Secon-dary	Dust	Prim-ary	Secon-dary	Dust	Prim-ary	Secon-dary	Dust	Prim-ary	Secon-dary	Dust
<u>Ultimate Analysis</u>												
Moisture % a.d.	0.6	2.9	1.6	1.0	0.5	1.2	2.6	1.0	3.3	0.4	0.3	-
Ash % d.b.	78.5	96.5	93.5	73.3	96.8	94.9	67.6	97.2	89.2	86.8	99.2	95.7
Carbon "	14.3	1.25	6.3	19.5	0.70	2.65	29.0	0.70	2.5	9.8	0.35	2.4
Hydrogen "	0.45	0.07	-	0.40	0.25	0.25	0.5	0.10	0.35	0.25	<0.05	0.65
Sulphur "	3.5	7.5	7.6	3.4	7.1	7.3	0.75	0.80	2.40	2.1	3.8	3.2
Chlorine % a.d.	0.03	0.05	0.04	0.04	<0.01	0.05	0.11	0.06	0.06	0.01	0.01	-
Carbon Dioxide "	5.0	2.15	1.0	6.0	2.9	0.40	0.05	0.07	-	3.55	0.55	-
<u>Ash Analysis</u>												
Na ₂ O % on ash	0.28	0.54	0.51	0.32	0.58	0.60	0.3	0.7	0.7	0.91	0.90	0.90
K ₂ O "	0.95	1.7	1.8	1.1	2.1	2.1	1.5	2.5	2.4	2.0	2.3	2.4
CaO "	33.3	21.3	23.6	43.0	20.1	22.3	0.8	1.2	1.5	22.5	14.8	14.5
MgO "	1.2	0.9	0.7	0.7	0.7	1.0	0.7	1.2	1.4	2.7	2.5	3.4
Fe ₂ O ₃ "	5.3	6.0	7.8	6.6	6.4	9.3	10.5	15.8	18.7	7.4	8.8	13.0
Al ₂ O ₃ "	19.9	30.4	21.4	10.0	15.7	14.6	14.9	22.4	20.3	12.8	17.0	18.2
SiO ₂ "	8.4	14.3	11.7	24.0	33.7	26.3	35.9	48.1	37.0	44.2	41.4	36.3
Acceptor Temperature	Limestone 900 °C			Limestone 850 °C			None 900 °C			Limestone 900 °C		

Efficiency Definitions

The following terms require definition.

(i) Combustion efficiency:

Combustion efficiency =

$$\left(1 - \frac{\text{thermal value of unburned combustible material}}{\text{thermal value of coal input}}\right) \times 100\% \quad (2-17)$$

(ii) Carbon loss:

$$\text{Carbon loss} = \frac{\text{unburned carbon mass output}}{\text{total carbon mass input}} \times 100\% \quad (2-18)$$

(iii) For most coals, the following approximate relationship holds:

$$\text{Combustion efficiency} = 100\% - \text{Carbon loss} \quad (2-19)$$

(iv) Excess air:

Excess air is a measure of the quantity of oxygen above that required for stoichiometric combustion of the coal feed.

Excess air =

$$\frac{(\text{Total air input rate} - \text{stoichiometric air rate for coal feed})}{(\text{stoichiometric air rate for coal feed})} \times 100\% \quad (2-20)$$

(v) Fluidizing Velocity:

The fluidizing velocity is defined as the superficial gas velocity at the operating conditions.

Fluidizing Velocity =

$$\frac{\text{Total volumetric air input rate to bed at bed temperature and pressure}}{\text{bed cross-sectional area without tubes}} \quad (2-21)$$

Factors Affecting the Combustion Efficiency

Variations in any one of several parameters can effect the combustion efficiency. These parameters are discussed in the following paragraphs.

Fluidizing Velocity

Combustibles loss by elutriation of fines increases with increasing fluidizing velocity because of the reduced residence times of char particles in the bed. The amount of combustion occurring in the freeboard also increases with fluidizing velocity. Data on the effect of fluidizing velocity on combustion efficiency are presented in Refs. 2-41 and 2-42.

Excess Air

The effect of excess air on combustion efficiency has been the subject of several investigations (Refs. 2-41 and 2-43 through 2-47). Their results indicate that increasing the excess air level increases the combustion efficiency by increasing the availability of oxygen. This also results in an increase in the combustion occurring within the bed, and a reduction in the freeboard combustion. The improvement in combustion efficiency may, however, be offset by a corresponding increase in the sensible heat loss associated with the stack gas. With most combustor designs (atmospheric pressure or elevated pressure), little further improvement in combustion efficiency takes place at excess air levels greater than about 50 percent.

Bed Temperature

An increase in the bed temperature increases the reaction rate between the char particles and air, and therefore reduces the time available for elutriation (Ref. 2-45). As a result, the percentage carbon loss from the bed is lower. In some combustor designs, this effect is offset by a corresponding reduction in the freeboard combustion. At a low bed temperature, for example, combustion in the bed is reduced, but is compensated for by increased combustion in the freeboard.

Operation with a high bed temperature is particularly important in achieving a high combustion efficiency under the following circumstances:

- (i) when freeboard cooling is employed, the above bed combustion may be suppressed so that the unburned carbon loss is determined largely by combustion in the bed,
- (ii) elevated pressure operation (Ref. 2-46), and
- (iii) combustion of fines (Refs. 2-48 and 2-49).

Operating Pressure

Operation at elevated pressure appears to improve the combustion efficiency by 1 to 2.5 percentage points at approximately 6-atm (bar) pressure compared with similar conditions at atmospheric pressure (Ref. 2-20). The reasons for

this are not fully understood, although possible mechanisms include better gas-solids contacting, due to smaller bubbles, particularly near the distributor, and deeper beds giving a longer gas residence time at the same fluidizing velocity.

In order to minimize both fouling problems for surfaces downstream from the combustor and gas temperature control problems, combustion in the freeboard is generally considered undesirable at elevated pressure. The combustor design and operating conditions are chosen accordingly.

Bed Height

An increase in bed height can improve combustion efficiency (Ref. 2-41), but in general the effect is small. As with bed temperature, changes in bed height have a greater effect on the relative amounts of combustion occurring in the bed and freeboard than on the overall combustion efficiency. Bed height can have an important effect on combustion efficiency if little combustion occurs above the bed and the bed height is reduced below about 1.6 ft (0.5 m) as in some industrial boiler applications. In atmospheric pressure units, the bed height may be limited by the need to minimize the system pressure drop.

Coal Feed Size

It is to be expected that an increase in the proportion of coal fines in the feed will lead to a reduction in the combustion occurring in the bed. An increase in the combustion above the bed and a fall in the overall combustion efficiency may also occur.

Published information on the effect of coal feed size distribution on combustion efficiency is limited. In a recent work (Ref. 2-44), it is reported that an increase in combustion efficiency of four percentage points occurs when feeding sized coal of 1/4 to 1 in. (6 to 25 mm) compared with the same coal crushed to a top size of .055 in. (1.4 mm).

Coal Type

There is some evidence from pilot plant tests that coal type can influence combustion efficiency, but that in most cases the effect is small. For coals with a high ash content (50 percent or more) or requiring the addition of a large amount of sulfur acceptor, loss of carbon in the bed material removed by the overflow may be appreciable.

Design Considerations

The following aspects of combustor design can affect the combustion efficiency.

Feed Point Spacing

If the spacing between feed points is large, there will be an excess of coal near the feed points and an excess of air between feed points (Ref. 2-50). This will lead to inefficient combustion in the bed and, possibly, a lower overall combustion efficiency. In general, the combustion efficiency may be expected to deteriorate for feed point spacings greater than one per ten square feet (one per square meter).

Freeboard Design

Designs which reduce elutriation rates, such as expanded head sections or baffles above the bed, will improve combustion efficiency. Increasing the residence time in the freeboard by increasing the freeboard height can also result in a higher combustion efficiency.

Freeboard Cooling

The installation of cooling surfaces to extract heat from the freeboard will lower the gas temperature and therefore the rate of freeboard combustion reactions. If excessive cooling of the freeboard takes place, the combustion efficiency will be reduced.

Unburned Carbon Utilization

Typical values of combustion loss for an atmospheric pressure unit are given in Fig. 2-16. These are considerably higher than are associated with the target combustion efficiency of 98 to 99 percent usually set for power generation applications. In some cases (particularly for operation at elevated pressure), it is possible to select a combination of fluidizing velocity, bed temperature, excess air level, etc. which results in an acceptable combustion efficiency in a single pass. Where this is not possible, two options exist for utilizing the unburned carbon.

Recycle

The fines collected by the primary cyclone contain most of the unburned carbon and represent the major loss in combustion efficiency. By recycling these to the main bed, part of the elutriated carbon can be burned, thereby increasing the combustion efficiency. Combustion efficiencies of up to 99 percent can be achieved at low fluidizing velocities. However, high recycle rates make this method impracticable at high fluidizing velocities. A further disadvantage of this method is that the fine ash, which is also collected by the cyclone and recycled, builds up in the recycle system.

RELATIONSHIP BETWEEN THE LOSS OF COMBUSTIBLES AND EXCESS AIR

(REF. 2-43)

FIG. 2-16

Combustion of Fines in a Separate Bed

For a large plant, combustion of fines in a separate bed is the preferred method of burning elutriated carbon fines. This fines combustion bed can be operated at a different temperature and fluidizing velocity from the main bed in order to achieve satisfactory combustion.

Combined Combustion Efficiency

Combustion efficiencies of up to 90 percent for fines have been reported (Ref. 2-48), when operating with a bed temperature of 2012 F (1100 C) and a high excess air level. Combined with a combustion efficiency of over 90 percent in the main bed, this should result in an overall combustion efficiency of more than 99 percent. The work reported in Ref. 2-48 formed the basis for the design of the carbon burn-up bed on the Pope, Evans and Robins fluid bed boiler at Rivesville (Ref. 2-51).

The main factors affecting the combustion efficiency are summarized in Table 2-7.

Reduction of Sulfur Dioxide Emission

Early in the development of fluid bed combustion it was realized that the emission of sulfur dioxide could be reduced by the addition of limestone or dolomite to the fluid bed. An extensive study jointly financed by the US Environmental Protection Agency and the National Coal Board was carried out by the NCB in 1969 and 1970 (Ref. 2-8). Further studies, particularly for pressurized systems, have been carried out at the Argonne National Laboratory (Refs. 2-52 and 2-53) and by Exxon (Ref. 2-54).

Sulfur in coal occurs in two forms, organic sulfur, forming part of the coal structure, and inorganic sulfur, as compounds in the mineral matter (e.g., pyrites). The organic and inorganic sulfur are released during combustion, and form sulfur dioxide and sulfur trioxide. Both types of oxide are air pollutants and are also important in the formation of corrosive compounds on metallic surfaces.

Basic Reactions

The reactions of limestone as a sulfur acceptor in a fluid bed are:

(i) Calcination

TABLE 2-7

SUMMARY OF FACTORS AFFECTING THE COMBUSTION EFFICIENCY

Parameter	Combustion efficiency improved by:-	Limit	Comment
Fluidizing velocity	Decrease	Minimum fluidizing velocity	Generally fixed as determines oxygen availability and plant size.
Excess air	Increase	min 10%	Penalty in thermal efficiency if high.
Bed temperature	Increase	Sintering temperature	Lower limit if limestone used. Containment problems.
Operating pressure	Increased pressure	-	Fixed by gas turbine
Bed height	Increase	-	Pressure drop penalty.
Coal feed size	Large size	-	Higher carbon loss in ash overflow.
Coal type	Low ash	-	Fixed by coal source.
Combustor design	-	-	Important area but little information available.
Fines recycle	Increased recycle	Total recycle	High dust burden - increased load on convective section. Extra capital cost.
Separate fines combustion bed	-	-	High capital cost.

(ii) Sulfur retention

For dolomite at atmospheric pressure, the reactions are:

(i) Calcination

(ii) Sulfur retention

For dolomite at elevated pressure, only the magnesium carbonate calcines:

(i) Calcination

(ii) Sulfur retention

The decomposition of the magnesium carbonate in dolomite is important for operation at elevated pressure, because as the porosity of the stone increases, the reactivity increases. The calcination of limestone can be prevented by pressure and, for this reason, limestone is less effective in a pressurized combustor.

Factors Affecting Sulfur Retention Efficiency

The variation of several parameters effects the sulfur retention efficiency. These parameters are discussed in the following paragraphs.

Fluidizing Velocity

The reduced gas and solids residence time and poorer gas-solids contacting at high fluidizing velocities would be expected to result in lower sulfur retention efficiencies. This is confirmed by experimental results (Ref. 2-9) for atmospheric pressure combustion without fines recycle (Fig. 2-17).

Calcium/Sulfur Mole Ratio

The calcium/sulfur mole ratio is a function of the acceptor feed rate. It is expressed as the ratio between the actual feed rate of acceptor and the

theoretical (stoichiometric) feed rate required to retain all of the sulfur. As expected, the sulfur retention efficiency improves as the calcium/sulfur mole ratio increases. For atmospheric pressure combustion, a calcium/sulfur mole ratio of between two and four is required for 85-percent retention (Fig. 2-17). Lower calcium/sulfur ratios are possible with pressurized operation.

Bed Temperature

As discussed earlier, the bed temperature has to be sufficiently high for calcination to occur, but not high enough to have an adverse effect on the retention efficiency. For atmospheric pressure operation with limestone, these conflicting requirements result in an optimum temperature for sulfur retention of 1472 to 1562 F (800 to 850 C). Effective sulfur retention at up to 1742 F (950 C) is possible at elevated pressures with dolomite as the acceptor.

Operating Pressure

Operation at elevated pressure inhibits both calcination and decomposition of the sulfate. As discussed earlier, limestone is less effective at pressure because calcination of CaCO_3 and the associated enhancement of porosity and reactivity of the stone is reduced at normal bed temperatures. Decomposition of the MgCO_3 occurs more readily than for CaCO_3 , making dolomite suitable for pressurized operation.

The sulfur retention efficiency falls at high temperatures for atmospheric pressure operation. Possible mechanisms for this effect include thermal decomposition of the sulfate and excessive decrepitation of the stone arising from the rapid evolution of carbon dioxide during calcination. Because operation at elevated pressure inhibits both decomposition of the sulfate and calcination, effective sulfur retention (with dolomite) is possible at high temperatures in pressurized systems.

Comparisons between sulfur retention at atmospheric and elevated pressure are given in Ref. 2-20 and are reproduced in Fig. 2-18. As shown in the figure, sulfur retention at elevated pressure using dolomite is more effective than at atmospheric pressure using limestone.

Bed Height

An increase in bed height increases the gas and solids residence times and has been observed to increase the efficiency of sulfur retention in deep beds containing tubes. However, little or no improvement has been found in other tests for bed heights of greater than about 1.6 feet (0.5 m). The reason for this is not clear, but may be caused by poor gas-solids contacting towards the top of the bed.

EFFECT OF Ca/S MOLE RATIO AND FLUIDIZING VELOCITY ON SO₂ REDUCTION

EFFECT OF Ca/S MOLE RATIO ON SULFUR RETENTION

(REF. 2-20)

Feed Size

The size distribution of the acceptor feed can affect the sulfur retention efficiency in two ways. Fine particles have a greater surface area than coarse particles and permit easier access of the sulfur dioxide to the unsulfated stone. Coarse particles have a longer residence time in the bed than fine particles because of the lower elutriation rate.

There is some evidence to suggest that surface area may be rate determining for fine particles, and residence time for coarse particles. This can lead to a higher retention efficiency with fine and coarse particles of acceptor than with those of an intermediate size. This phenomena was observed at the Rivesville boiler where a three-percent sulfur coal was burned at the design conditions. The results are shown in Fig. 2-19.

Acceptor Type and Source

Limestones differ considerably in their effectiveness in reducing sulfur dioxide emissions, as shown in Fig. 2-20. For example, use of US limestone 1359 requires approximately 50 percent more stone to achieve the same retention efficiency as with US limestone 18.

Dolomites are generally more reactive than limestones on a molar basis, but less reactive on a weight basis.

Coal Type

In the context of sulfur retention, the most important coal property is the sulfur content. This determines both the feed rate of additive required for a given calcium/sulfur mole ratio, and the retention efficiency and hence calcium/sulfur ratio needed to meet specified limits of sulfur dioxide emissions.

Fines Recycle

Recycle of elutriated fines increases the residence time of unreacted acceptor in the bed, and is therefore expected to improve the sulfur retention efficiency. This has been confirmed by tests in a 3-ft (0.9-m) combustor reported in Ref. 2-9. At a fluidizing velocity of 2 ft/sec (0.6 m/s), total recycle of fines larger than 10 micron increased the sulfur retention efficiency from 73 to 99 percent for a calcium/sulfur mole ratio of 1.6.

Additives and Regeneration

The use of additives to improve stone utilization and processes to regenerate the stone (permitting reuse through several sorption-desorption cycles) have been reported by several authors (Refs. 2-55 and 2-56). These are still largely in the development stage and are not considered further in this review.

EFFECT OF LIMESTONE PARTICLE SIZE AND BED TEMPERATURE ON SO₂ REDUCTION

FIG. 2-20

EFFECT OF Ca/S MOLE RATIO AND LIMESTONE TYPE ON SO₂ REDUCTION

Nitrogen Oxides Emissions

Early studies by Argonne National Laboratory, Pope, Evans and Robins, and the National Coal Board demonstrated that emissions of nitrogen oxides from atmospheric pressure fluid bed combustors are lower than from conventional combustion systems and that a further reduction in emissions is obtained by operation at pressure. The mechanisms of the formation of nitrogen oxides are not fully understood, although recent work (Refs. 2-57 and 2-58) has provided a better understanding of the complex reactions involved.

Basic Reactions

In conventional combustion systems, nitrogen oxides are formed both by combustion of the nitrogen in the fuel and from atmospheric nitrogen. At the relatively low temperatures of fluid bed combustion, the formation of nitrogen oxides from atmospheric nitrogen will be discouraged. This is confirmed by experiments (Refs. 2-59 and 2-60) in which coal and char were burned in a fluid bed both with oxygen and nitrogen and with oxygen and argon mixtures. The formation of nitrogen oxides in the two cases was similar, indicating that the nitrogen oxides arise mainly from the nitrogen in the fuel.

It is now generally accepted that nitrogen released as ammonia in the volatile matter can take part in reactions which can lead to the formation or destruction of nitric oxide:

However, nitric oxide produced during the initial stages of coal combustion can be reduced subsequently by carbon and carbon monoxide in the following reactions (Ref. 2-57).

Emissions from Atmospheric Pressure Combustors

There are three main factors affecting the concentration of nitrogen oxides in combustion gases from a fluid bed.

Excess Air Level

In Ref. 2-58, it is reported that a maximum concentration of nitrogen oxides occurs at an oxygen concentration of five percent (by volume) in the dry flue gas (Fig. 2-21). The decrease in emissions at high oxygen levels is simply a dilution effect. The data refer to Illinois No. 6 coal and a bed temperature of 1472 F (800 C).

Bed Temperature

Data obtained from the Babcock and Wilcox (UK) boiler at Renfrew indicate an increase in the emission of nitrogen oxides with bed temperature up to 1472 F (800 C) as shown in Fig. 2-22. Above this temperature, the emissions appear to be constant at 300 to 350 ppm(v), independent of bed temperature.

Feed Size Distribution

A reduction in emissions of nitrogen oxides when feeding 1/4-in. (6-mm) coal compared with 0.66-in. (1.4-mm) coal is reported in Ref. 2-44. This may be attributed to an increased reduction of the oxides to nitrogen resulting from the higher bed carbon concentration associated with the coarser feed.

Emissions at Elevated Pressure

Emissions of nitrogen oxides at elevated pressures are generally found to be lower than those at atmospheric pressure, typical values being 50 to 200 ppm(v) (Refs. 2-20, 2-46 and 2-47). The emissions at elevated pressure are considerably more sensitive to the excess air level than those at atmospheric pressure, as illustrated in Fig. 2-23.

Alkali Emissions

The presence of volatilized alkali salts in the combustion gases is important in the formation of corrosive deposits on downstream metallic components, for example turbine blades.

Measurements of the concentrations of volatilized sodium and potassium in the combustion gases from a 2 ft x 4 ft (0.6 m x 1.2 m) pressurized combustor and 1-ft (0.3-m) atmospheric pressure combustor are described in Ref. 2-8. Small electrostatic precipitators were used to collect the alkalis, which were assumed to be present as sub-micron aerosols. Tests in the pressurized combustor using Pittsburgh coal gave a sodium content in the gases of 1 to 2 ppm by weight, representing 1 to 2 percent of the sodium input in the coal.

RELATIONSHIP BETWEEN FLUE GAS NO AND FLUE GAS OXYGEN

ILLINOIS NO. 6 COAL AT 1472F (800C)

RELATIONSHIP BETWEEN NO EMISSIONS AND BED TEMPERATURE

COAL WITH 1.1 PERCENT NITROGEN
(REF. 2-4)

RELATIONSHIP BETWEEN NO_x EMISSIONS AND EXCESS AIR

(REF. 2-47)

The volatilized potassium content of the gases was less than 0.5 ppm by weight representing 0.2 to 0.3 percent of the potassium input in the coal. More recent tests in the same combustor (Ref. 2-62) have given lower emissions than reported earlier; these data are summarized in Table 2-8.

At atmospheric pressure, the alkali emissions measured in the 1-ft (0.3-m) combustor were generally higher than those from the pressurized combustor (Ref. 2-8). Values of four to six ppm by weight of sodium and one to three ppm by weight of potassium were reported. Mass balances on sodium and potassium for atmospheric pressure combustion of Illinois No. 6 coal are given in Table 2-9. The sodium in the gas is one to two percent of the input, and the potassium zero to one percent.

Materials of Construction

In assessing the corrosion of materials in a fluid bed combustor, it is useful to distinguish between in-bed components, above-bed components, and turbine materials. In-bed components will include heat transfer tubes placed in the bed, the distributor plate and water-cooled walls. Above-bed components will include heat exchange surface placed in the freeboard and convective sections, cyclones, water-cooled walls and support members (possibly uncooled). In both cases, the metal temperature will be in the range of 392 F (200 C) to the bed temperature (maximum 1742 F (950 C)).

Although the mechanisms of corrosion and deposition are not fully understood, it is known that corrosion attack involves the ash deposits, rich in alkali salts, which are formed on the metal surface. The alkalis are released from the minerals in the coal and react with sulfur and oxygen to form sulfates. Interaction of these sulfates with SO_3 can yield pyrosulfates or complex sulfates. These complex sulfates are molten at superheater metal temperature and are known to accelerate corrosion of superheater alloys.

Long-term operating experience with conventional coal-fired equipment is well documented, and the performance of alloys in different environments can be predicted. The environment within a fluid bed combustor, however, is markedly different from that in conventional coal combustion systems. The volatilization and deposition of alkali metal salts will be limited by the relatively low combustion temperatures in the bed. In addition, if a sulfur sorbent were employed, the occurrence of the high local SO_3 partial pressures necessary for the formation of the complex sulfates would appear

TABLE 2-8

SODIUM AND POTASSIUM EMISSIONS AT ELEVATED PRESSURE

Discharge from :	Na %	K %
Bed	44	51
Primary cyclone	48	44
Secondary cyclone	3	2
Dust after cascade	3	0.2
Total ppm v/v	0.5 to 1.5	0.1 to 0.5

Operating conditions:

Pressure	5.5 to 6 atm (bar)
Fluidizing velocity	2.70 ft/sec (0.82 m/s)
Bed temperature	1600F (870C)
Coal	Illinois No. 6
Acceptor	Dolomite 1337
Feed size distribution	1/16-in (1.6-mm) maximum
Acceptor feed rate	Ca/S mole ratio of 1.5

TABLE 2-9

SODIUM AND POTASSIUM EMISSIONS AT ATMOSPHERIC PRESSURE

Na input Rate kg/h	Na recovery, % input rate					
	Acc.in bed.	Bed Overflow	Primary fines	Secondary fines	Dust	Gas
0.0073	0	56.3	50.0	0	0	2.0
0.0073	0	50.0	56.3	0	6.2	2.0
0.0068	0	40.0	66.7	6.7	6.7	1.0
0.0063	7.1	50.0	57.1	0	7.1	1.0
0.0063	7.1	42.9	57.1	0	0	1.0
0.0068	6.7	46.7	46.7	0	0	1.0
K input rate kg/h	K recovery, % input rate					
	Acc.in bed	Bed Overflow	Primary fines	Secondary fines	Dust	Gas
0.0168	0	10.8	73.0	0	2.7	0
0.0172	0	10.5	65.8	2.6	5.3	0
0.0168	0	10.8	67.6	5.4	5.4	0
0.0154	0	11.8	73.5	0	5.9	1.0
0.0159	0	8.6	74.3	0	2.9	1.0
0.0163	0	8.3	69.4	2.8	5.6	1.0

Operating conditions:

Pressure	1 atm (bar)
Fluidizing velocity	3 ft/sec (0.9 m/s)
Bed temperature	1652F (900C)
Coal	Illinois No. 6
Acceptor	Limestone
Acceptor feed rate	Ca/S mole ratio of 3
Excess air level	14%

unlikely. Consequently, the conditions in a fluid bed combustor may not produce the types of corrosion encountered in conventional systems.

Several major test programs to investigate material performance in a fluid bed environment have been undertaken. The main results of these are described in the following sections.

NCB/EPA (1971)

The earliest comprehensive study of corrosion in fluid beds was undertaken by the National Coal Board (NCB) at the Coal Research Establishment (CRE) and the British Coal Utilization Research Association (BCURA) under the sponsorship of the Environmental Protection Agency (EPA) (Ref 2-8). Some of these results have also been reported in Ref. 2-63.

Corrosion tests were conducted in three combustors: a 4 ft x 2 ft (1.2 m x 0.6 m) pressurized combustor, a 2.3-ft (0.7-m) atmospheric pressure combustor, and a 1-ft (0.3-m) atmospheric pressure combustor designed specifically for corrosion measurements. The specimens included cooled tubes assembled from rings of various materials and uncooled material samples (coupons) placed both within the bed and in the freeboard. Several tests were carried out, the maximum duration being 1000 hours. Typical weight losses are given in Table 2-10.

The main conclusions of the program were:

- (i) Based on an acceptance criterion of 61.45×10^{-6} lb/ft²hr (300 mg/m²-h) (equivalent by linear extrapolation to 0.28-in. (7-mm) loss in 200,000 hours), the materials tested would have a satisfactory lifetime under normal fluid bed operating conditions if used at the working temperatures employed in conventional plants.
- (ii) There was little deposition on the surfaces of tubes immersed in the bed, and neither metal loss nor intergranular penetration were affected markedly by changing coal composition, operating pressure, combustion conditions and fluidizing velocity. Carburization was not detected.
- (iii) Increased sulfide penetration of in-bed samples was observed for tests with limestone or dolomite additions to the bed, particularly for high chromium steels at 1292 F (700 C) and 1499 F (815 C). Material samples tested in the bed at 1562 F (850 C) showed intergranular sulfidation to depths of 30 microns to 60 microns in 1000-hour tests.

TABLE 2-10

OPERATING CONDITIONS AND RESULTS (NCB/EPA, 1971)

Test conditions:

Duration	1000 h
Combustor	1-ft (0.3-m) diameter
Pressure	1 atm (bar)
Coal	Newstead
Bed temperature	1652F (850C)
Fluidizing velocity	3 ft/sec (0.9 m/s)
Bed height	2 ft (0.6m)
Coal size	1/16-in (1.6-mm) maximum
Acceptor	None

Results: Measured weight loss (mg/m²h)

Material	Metal temperature (C)				
	400	500	600	700	850
Medium carbon steel	200	400	-	-	-
2.25 % Cr - 1 % Mo	200	400	2700	-	-
12 % Cr	10	20	20	40	3200
Type 316 SS	10	10	20	70	130
Type 347 HSS	10	10	10	50	-
Essheta 1250	10	10	30	90	140
Nimonic PE 16	-	-	-	30	50

- (iv) Increased rates of corrosion of in-bed samples were found in several tests using a high chlorine coal when operating difficulties such as loss of fluidization occurred.
- (v) Materials situated above the bed suffered less weight loss than in-bed samples.

NCB/EPRI (1975)

In 1975, the Electric Power Research Institute (EPRI) sponsored an investigation into the corrosion performance of a wide range of heat exchanger and turbine materials under conditions typical of those proposed for advanced power generation cycles (Refs. 2-64 to 2-66). The project was managed by Combustion Systems Ltd, (UK). Selection of materials for the tests was made by General Electric (GE) and Foster Wheeler Development Corporation in collaboration with the NCB.

The combustor used for the tests was the CRE 1-ft (0.3-m) square atmospheric pressure fluid bed (Fig. 2-24). Coal and limestone were fed pneumatically to the center of the combustor immediately above the air distributor. Four specimen tubes passed horizontally through the bed and two were situated in the freeboard, 2-ft (0.6-m) above the bed surface. Each tube consisted of a number of rings 2-in. (50-mm) od x 7/8-in. (22-mm) long of different alloys clamped together. The tube temperatures were maintained by passing air at ambient temperature through the tubes and controlling the flow rate of the mean of four thermocouples inserted into the wall of each tube. Variable cooling could be applied to four additional tubes for plant control. Uncooled material sample plates were located within the bed and in the freeboard. A 10-ft (3-m) long test section was installed at the exit of the secondary cyclone in which turbine alloys could be placed radially as pins 1/4-in. (6.4-mm) diameter x 2 3/4-in. (70-mm) long.

The alloys used in the tests are listed in Table 2-11, together with their compositions. The locations of the alloys are given in Table 2-12. Two 1000-hour tests were carried out. The operating conditions were the same for each test and are given in Table 2-13. Also shown in Table 2-13 are the mean temperatures of the tubes, the freeboard, and the test section. The above-bed tubes, all the material samples and turbine alloys, together with selected in-bed tube specimens were tested for the entire 2000 hours. The remaining in-bed specimens were replaced after the first 1000 hours.

Examination of replicate test specimens was made independently by CRE, Foster Wheeler and General Electric. The test specimens were analyzed for deposit thickness, scale thickness, depth and type of corrosive penetration, and metal loss by

DIAGRAMMATIC LAYOUT OF NCB/EPA FLUID BED COMBUSTOR MATERIALS TEST RIG

FIG. 2-24

TABLE 2-11

TYPICAL COMPOSITIONS OF ALLOYS TESTED (NCB/EPRI, 1975)

	C	Cr	Ni	Fe	Co	Mo	W	Al	Ti	Mn	Si	Others
<u>Ferritic Steels</u>												
Cor-Ten B	0.2	0.5	-	Bal	-	-	-	-	-	1	0.2	0.5 V 0.3 Cu
2 1/2 Cr-1 Mo	0.1	2.2	-	Bal	-	1	-	-	-	0.4	0.3	-
9 Cr-1 Mo	0.1	9	-	Bal	-	1	-	-	-	0.5	0.5	-
Type 405 SS	0.05	12	0.3	Bal	-	-	-	0.1	-	0.6	0.6	-
E-Brite 26-1	0.001	26	0.1	Bal	0.01	1	-	-	-	0.01	0.2	0.02 Cu
GE 2541	0.02	25	-	69.5	-	-	-	4.76	-	0.002	0.02	0.3 Y
<u>Austenitic Steels (Cr-Ni-Fe)</u>												
Nitronic 50	0.05	22	12	Bal	-	2	-	-	-	5	0.5	0.2 V
Type 321 SS	0.06	18	11.6	Bal	-	0.3	-	-	0.4	1.5	0.9	0.2 Cu
Type 310 SS	0.04	25	17.2	Bal	-	0.4	-	-	-	1.5	0.5	-
Type 347 H SS	0.06	18	9.5	Bal	0.24	0.4	-	-	-	1.5	0.6	0.3 Nb 0.3 Cu
Type 329 SS	0.05	28	4.2	Bal	0.2	1.3	-	-	-	0.4	0.4	0.2 Cu 0.1 Cu
21-6-9	0.03	20	7.2	Bal	-	0.1	-	-	-	9	0.7	0.3 N 0.6 Cu
Incoloy 800	0.04	19	31.5	46.5	-	-	-	0.4	0.4	0.3	0.4	-
Manaurite 36X	0.4	25	34	Bal	-	-	-	-	-	1.2	1.3	-
HK-4C	0.4	25	20	Bal	-	-	-	-	-	1.2	1.1	-
<u>Nickel Base Alloys</u>												
Inconel 690	0.05	27	64.6	8	-	-	-	-	-	0.2	0.3	-
Inconel 601	0.04	22	61	15.1	-	-	-	1.5	0.4	0.2	0.1	0.01 Cu
Inconel 617	0.07	22	56	0.2	12.2	8.7	-	1	-	0.03	0.06	-
Inconel 671	0.05	48	51	0.4	-	-	-	-	0.2	0.04	0.3	-
Hastelloy X	0.1	21.5	Bal	18.5	2.1	9	0.7	-	-	0.6	0.4	0.002 B 0.01 Sn
RA 333	0.04	25	45	19	3	3	-	-	-	1.8	1.2	0.001 Pb
U-500	0.08	19	Bal	0.3	19	4	-	3.0	3.0	<0.1	<0.1	<0.1 Cu 0.004 B
U-700	0.07	14.6	Bal	0.1	15	4.2	-	4.4	3.5	<0.1	<0.1	0.015 B <0.04 Zr
IN-738	0.1	15.7	Bal	0.2	8	1.7	2.7	3.5	3.5	0.01	0.05	2.5 Nb Ta 0.05 Zr
GTD-111	0.1	14	Bal	0.1	9.7	1.5	3.3	3.0	5	<0.1	<0.1	3 Nb Ta 0.04 Zr
IN 713 LC	0.1	13.6	Bal	0.2	0.5	4.6	-	6.0	0.9	<0.1	<0.1	2.2 Nb Ta 0.1 Zr
<u>Cobalt Base Alloys</u>												
Haynes Alloy 188	0.08	22.2	22.3	1.3	Bal	-	14	-	-	0.7	0.4	0.005 B 0.04 La
X-40	0.5	25.3	10.6	0.2	Bal	-	7.5	0.1	-	<0.1	0.3	0.16 Zr 0.002 B
FSX-414	0.2	20	10.3	1.2	Bal	-	7	-	-	0.3	1.0	0.008 B

TABLE 2-12

ALLOYS TESTED AND LOCATION (NCB/EPRI, 1975)

KEY

A = In-bed tube   C = Freeboard tube   E = Turbine pin
 B = In-bed coupon   D = Freeboard coupon

FERRITICSLOCATION

Cor-Ten B	A				
2½ Cr-1Mo	A		C		
9 Cr-1Mo	A		C		
Type 405 SS	A				
E-Brite 26-1	A		C		
GE 2541		B		D	E

AUSTENITIC Cr-Ni-Fe STEELS

Nitronic 50	A		C		
Type 321 SS	A		C		
Type 310 SS	A		C		
Type 347 H SS	A		C		
Type 329 SS	A		C		
21-6-9	A		C		
Incoloy 800	A		C		
Manaurite 36 X		B		D	
HK - 40		B		D	

NICKEL BASE ALLOYS

Inconel 690	A				
Inconel 601	A		C		
Inconel 617	A	B	C	D	E
Inconel 671	A	B		D	E
Hastelloy X	A		C	D	E
RA 333				D	
U - 500				D	E
U - 700					E
IN 738				D	E
GTD - 111					E
IN 713LC				D	E

COBALT BASE ALLOYS

Haynes Alloy 188	A	B	C	D	E
X - 40					E
FSX - 414				D	E

TABLE 2-13

OPERATING CONDITIONS (NCB/EPRI, 1975)

Pressure	Atmospheric
Bed temperature	1652F (900C)
Bed height	2 ft (0.6m)
Fluidizing velocity	3 ft/sec (0.9 m/s)
Excess air level	10 - 20%
Coal	Illinois No. 6
Coal size	1/16-in (1.6-mm) maximum
Limestone	Penrith UK
Limestone size	1/16-in (1.6-mm) maximum
Mean SO ₂ emission level	Test 1 = 369 ppm Test 2 = 340 ppm

Mean temperatures of tubes (c), freeboard and turbine test section:

In-bed Tubes					Above-bed		Freeboard Gas Temperature	Turbine Test Section Gas Temperature
Tube No.	1	2	3	4	5	6		
Nominal	540	650	760	840	650	760	900	820
Test 1	542	648	762	843	653	760	909	821
Test 2	541	651	760	842	651	760	913	825

scaling and internal penetration. The results of the metallographic examinations of the test specimens undertaken at CRE were expressed as maximum depth of corrosive penetration and maximum scale thickness.

The data illustrated are in Figs. 2-25 to 2-29, and are discussed below.

In-Bed Specimens

Both cooled and uncooled test specimens were placed in the bed for testing at several temperatures.

- (i) Metal temperature 1004 F (540 C):
Nitronic 50, E-Brite 26-1, 21-6-9 and Type 329 showed the best resistance to attack. The high chromium ferritic alloys performed less well. The low chromium ferritics performed poorly, but this may be attributed to use beyond the normal working range.
- (ii) Metal temperature 1202 F (650 C):
Nitronic 50 again showed the best resistance, with Haynes Alloy 188, Type 329 and Type 347 appearing satisfactory after 1000-hours exposure. However, considerable pitting was observed on the Haynes Alloy 188 specimen exposed for 2000 hours. The alloys 21-6-9, E-Brite 26-1, and 9 percent Cr - 1 percent Mo were less satisfactory. Incoloy 800 showed poor resistance with extensive sulfide penetration. The alloy 2.25 percent Cr - 1 percent Mo was the least resistant with very thick scales; again this may be related to exposure at temperatures beyond the working range.
- (iii) Metal temperature 1400 F (760 C):
All materials suffered appreciable attack. Types 347 and 310 were most resistant. Haynes Alloy 188 and Hastolloy X had similar depth of penetration to the austenitics but showed some pitting. Incoloy 800, Inconel 601 and Inconel 617 showed extensive sulfidation. Inconel 690 was the least resistant exhibiting catastrophic sulfide penetration.
- (iv) Metal temperature 1544 F (840 C):
Type 310 showed the most resistance to attack. Hastelloy X performed similarly but with a tendency to pitting. Incoloy 800 and Haynes Alloy 188 exhibited extensive sulfide penetration. Inconel 671 suffered catastrophic sulfidation attack, with a complex band of corrosion products and deep pitting.
- (v) Metal temperature 1652 F (900 C):
The alloy GE 2541 had the best performance with a thin scale and only partial oxidation of the grain boundary phases. All other alloys showed evidence of sulfidation. Haynes Alloy 188 had a thin

FIG. 2-25

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS FOR IN-BED TUBE SPECIMENS—TEST I

1000 HOURS EXPOSURE
SEE TABLE 2-13 FOR CONDITIONS

FIG. 2-26

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS
FOR IN-BED TUBE SPECIMENS—TEST II

1000 HOURS EXPOSURE
SEE TABLE 2-13 FOR CONDITIONS

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS FOR IN-BED MATERIAL SPECIMENS

2000 HOURS EXPOSURE
SEE TABLE 2-13 FOR CONDITIONS

FIG. 2-2

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS FOR ABOVE-BED TUBE SPECIMENS

2000 HOURS EXPOSURE
SEE TABLE 2-13 FOR CONDITIONS

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS FOR FREEBOARD MATERIAL SPECIMENS

2000 HOURS EXPOSURE
SEE TABLE 2-13 FOR CONDITIONS

scale and uniform sulfide penetration, and ranked next to GE 2541 in performance. The alloys HK40 and Manaurite 36X had thin scales and sulphide penetration up to about 100 microns. The nickel-based superalloys were severely attacked; the performance of Inconel 671, for example, was similar to that found at 1544 F (840 C).

Above-Bed Specimens

Cooled and uncooled test specimens were also placed above the bed for testing at several temperatures.

- (i) Metal temperature 1202 F (650 C):
All specimens except 2.25 percent Cr - 1 percent Mo performed satisfactorily with no attack over most of the circumference and only slight attack and scale thickening at the top under ash layer. Nitronic 50, E-Brite 26-1 and Type 329 had no visible corrosive penetration. Haynes Alloy 188, 21-6-9 and 9 percent Cr - 1 percent Mo had slight attack in the form of localized oxide pits, as did Incoloy 800 which also showed intergranular sulfide penetration. The alloy 2.25 percent Cr - 1 percent Mo gave the poorest performance with substantial thickness losses and thick scales.
- (ii) Metal temperature 1400 F (760 C):
There was generally only slight oxide penetration over most of the circumference, with an increase in attack at the top of the tube. Types 347 and 310 performed well with only slight oxide penetration. Haynes Alloy 188, Incoloy 800 and Hastelloy X also had only oxide penetration but to slightly greater depth. Inconel 617 and 601 performed least well showing signs of sulfide penetration, although the depth of penetration was similar to the other specimens.
- (iii) Metal temperature 1670 F (910 C) - uncooled:
The alloys GE 2541 and Manaurite 36X showed the best resistance to corrosion. The alloy HK 40 also performed well with intergranular oxide penetration of up to 54 microns. The alloys FSX 414 and Haynes Alloy 188 had slightly greater attack with intergranular oxide penetration of up to 75 microns on the former alloy. Inconel 617, RA 333, IN 738, IN 713 LC and U-500 exhibited deeper oxide penetration (up to 180 microns on U-500). Hastelloy X showed oxide penetration of up to 75 microns with indications of sulfide attack. The sample of IN 671 performed better than in the bed but still had deep oxide penetration with evidence of the initiation of sulfide pits.

NCB/EPRI (1977/78)

A joint NCB/EPRI program was undertaken at the Coal Research Establishment and is reported in Ref. 2-67. The tests were carried out in the atmospheric pressure fluid bed combustor used for the earlier NCB/EPRI work. The program concentrated on the performance of alloys exposed within the fluid bed. The operating conditions and test alloys for the four 250-hour tests are summarized in Table 2-14.

The maximum depth of corrosive penetration and maximum scale thickness for the test specimens are shown in Fig. 2-30. The main results of the program are summarized below.

- (i) Deposits were found on the specimen tubes after each test. In the tests with limestone addition, these were found to consist largely of calcium sulfate, together with some calcium oxide and coal ash. In the test without limestone addition, the deposit was derived entirely from coal ash. The deposits consisted of particles in the size range 1 to 5 microns, and all contained just traces of alkali metal compounds.
- (ii) In the tests with limestone addition, the type of attack was similar to that found in the earlier NCB/EPRI (1975) tests. Sulfidation was found on all specimens, with nickel-based alloys showing extensive attack.
- (iii) No sulfidation was found in the tests without limestone addition. The specimens generally showed slight oxide penetration, with some having only a thin oxide scale.
- (iv) Comparison between the results obtained for Incoloy 800 at 1202 F (650 C) over 250 hours with results obtained under similar conditions over 1000 hours and 2000 hours in the earlier NCB/EPRI work indicates that the rate of corrosive penetration decreases with time of exposure, (see Fig. 2-31). Corrosion criteria based on linear extrapolation (e.g., 35 microns per 1000 hours, based on 0.28 in. (7 mm) over 200,000 hours) may therefore be conservative.
- (v) The iron-based austenitic steels were most resistant to corrosive attack. These steels do sulfidize but the morphology of sulfidation does not appear to lead to catastrophic attack, such as is seen with some nickel-based alloys. The most resistant steel tested was Type 347 HSS, particularly at the maximum test temperature of 1544 F (840 C). This appears to be due to the good high-temperature stability of the oxide layer of this steel. Other stainless steels (Type 304 and Type 310) were comparable at lower temperatures.

TABLE 2-14

SUMMARY OF CANDIDATE TEST ALLOYS AND OPERATING CONDITIONS FOR THE FOUR TESTS (NCB/EPRI, 1977-78)

Fluidizing Velocity = 3 ft/sec (0.9 m/s)
 Bed Height = 2 ft (0.6m)
 Excess Air = 10 to 20 percent
 Pressure = 1 atm (bar)
 Illinois No. 6 Coal

<u>Test conditions</u>	<u>Test 1</u>	<u>Test 2</u>	<u>Test 3</u>	<u>Test 4</u>
Bed temperature	1652F (900C)	1562F (850C)	1652F (900C)	1652 (900C)
Sorbent	Penrith limestone	Penrith limestone	-	Wenlock limestone

Candidate Test Alloys

<u>Ferritic Steels</u>	<u>Austenitic Steels</u>	<u>Nickel Base</u>	<u>Cobalt Base</u>
2 1/4 CR - 1 Mo	Type 347 HSS	IN 738	Haynes Alloy 188
Type 405 SS	Type 304 SS	Inconel 617	
E-Brite 26-1	Incoloy 800	Inconel 671	
	Type 310 SS		
	Manaurite 36 X		

FIG. 2-30

MAXIMUM CORROSIVE PENETRATION AND SCALE THICKNESS FOR IN-TUBE SPECIMENS

SEE TABLE 2-14 FOR CONDITIONS

RELATIONSHIP BETWEEN DEPTH OF CORROSIVE PENETRATION AND TIME OF EXPOSURE

Battelle

A number of corrosion/erosion studies of in-bed components have been conducted on the 2-ft (0.6-m) diameter atmospheric pressure fluid bed combustor at the Battelle Columbus Laboratories (Ref. 2-68). The combustor is shown schematically in Fig. 2-32. The operating conditions and the materials tested are given in Table 2-15. The main conclusions of these studies are summarized below.

- (i) Metal wastage of the various materials evaluated for heat-transfer applications decreased in the order of P9, IN 671, 304 SS, FeCrAl coating on 304 SS, 347 SS, Al/Cr diffusion coating on 304 SS, 18-18-2 SS, 310 SS, and FSX 414. The wastage rate for alloys 304, 310, 347, 18-18-2 and FSX 414 ranged from 25 to 55 microns for the 1500-hour test period in the freeboard environment and from about 50 microns to 85 microns in the fluid bed.
- (ii) The tests for heat-transfer applications were carried out with metal temperatures in the range 1256 to 1544 F (680 to 840 C). No consistent effect of temperature was found.
- (iii) The metal wastage rate of all of the materials investigated for heat-transfer applications, with the exception of P9 and possibly IN 671, decreased with time of exposure.
- (iv) During the 1500-hour test period, the metal wastage of the materials evaluated for uncooled structural support applications at 1616 F (880 C) (namely 304 SS, 347 SS, 310 SS and Incoloy 825) ranged from about 1050 microns for 304 SS to 75 microns for Incoloy 825.
- (v) In the fluid bed environment, the outer surfaces of substrate metal in 304 SS, 347 SS, Incoloy 825, IN 671 and the coatings became internally oxidized. Sulfidation was also noted in 304 SS, 347 SS, and Incoloy 825. Neither internal oxidation nor sulfidation of any of the materials (except coatings) occurred in the freeboard environment.

Oak Ridge National Laboratory

Oak Ridge National Laboratory has conducted a series of materials compatibility tests on a 1.5-ft (0.46-m) square atmospheric pressure fluid bed combustor constructed by the Fluidyne Corporation. The operating conditions and materials tested are summarized in Table 2-16. The main results are presented below.

- (i) All alloys performed well over 500 hours (Ref. 2-69), although the aluminized coatings showed extensive cracking.

FIG. 2-32

SKETCH OF BATELLE-COLUMBUS FLUID BED COMBUSTOR TEST RIG

79-02-248-12

TABLE 2-15

OPERATING CONDITIONS AND MATERIALS TESTED (BATTELLE)

Bed temperature 1562F (850C)
 Fluidizing velocity 8.2 ft/sec (2.5 m/s)
 Excess oxygen 5 to 6 percent
 Test duration 1500 hrs
 Coal type Illinois No. 6
 Limestone Greer Quarry, W.Va.

Material	Composition, percent								
	Cr	Fe	Co	Ni	Mo	W	Si	Mn	Cu
P9	8.9	Bal	-	-	1.0	-	0.7	-	-
304	18.5	Bal	-	8	-	-	-	2.0	-
316	17.0	Bal	-	9.8	2.5	-	0.75	-	-
347	17.7	Bal	-	11.7	-	-	0.7	1.4	-
310	24.5	Bal	-	21.7	0.2	-	0.4	1.7	-
18-18-2	18.4	Bal	-	18.0	-	-	1.9	1.5	-
825	21.5	30	-	42.0	3.0	-	0.25	0.5	2.25
IN 671	47.2	0.14	-	52.2	-	-	0.2	-	-
FSX 414	29.8	0.9	Bal	10.7	-	7.0	1.0	0.7	-
FeCrAl(a)	Two coats over 304 SS (Union Carbide)								
AlCr(b)	HI 35 coating over 304 SS (Alloy Surfaces)								
Pack Aluminized(c)	Diffused Al case on Type 304 SS and Type 310 SS (Battelle)								

(a) This (Fe-15Cr-10Al-8Ni-1Mo-1Si) coating consisted of two 150 micron plasma sprayed layers, the first of which was anneal bonded.

(b) This is a duplex coating of aluminum over a chromized 304 SS with a case depth of 400 micron.

(c) Five hours 1700 °F in 15 percent Al 12Si + 2.5 percent NH₄Cl + 82.5 percent Al₂O₃.

TABLE 2-16

OPERATING CONDITIONS AND MATERIALS TESTED (OAK RIDGE)

Test conditions:

Bed temperature	1652 (900C)
Fluidizing velocity	4 to 6 ft/sec (1.2 to 1.8 m/s)
Excess air	15 percent
Coal	Illinois No. 6
Feed size	1/4-in (6.3 mm) maximum
Specimen metal temperatures	1547F and 1610F (842C and 877C)
Test duration	500 to 1500 hours

Alloys tested:

Type	304
Type	316
Type	310
Incoloy	800
Inconel	600
Aluminised coating on Type 310	
Aluminised coating on Incoloy 800	

- (ii) Preliminary reports after 1500-hour testing indicate that most materials performed satisfactorily (Ref. 2-70). Inconel 600, however, suffered three failures during the 1500-hour test due to severe hot corrosion.
- (iii) More recent work (Refs. 2-71 and 2-72) has given some specimens (Types 304, 316 and Incoloy 800) a cumulative exposure of 4500 hours. Although the preliminary analyses are encouraging (Ref. 2-72), it is too early to decide on materials for long-term usage. Nickel-based alloys do not appear to be suitable. Incoloy 800, which has shown signs of intergranular sulfidation, is also suspect. The most promising materials are the iron-based austenitics.

Combustion Power Company

Studies of turbine blade materials have been carried out as part of the Combustion Power Co. development work on pressurized fluid bed combustion (Ref. 2-73). Two test programs have been completed:

- (i) Static turbine blade and vane materials were tested in an atmospheric pressure combustor. The operating conditions and maximum penetrations observed are summarized in Table 2-17 (1003 hours at 1594 F (868 C) freeboard temperature) and Table 2-18 (568 hours at 1670 F (910 C) freeboard temperature).

At 1594 F (868 C) the stainless steels with higher chromium and lower nickel showed most resistance to attack; in particular the corrosion penetration of SS 446 was 3 microns, compared with 27 microns for 310 and 44 microns for Incoloy 800. No sulfidation was detected. Some sulfidation was, however, detected in the Incoloy alloys at 1670 F (910 C). The alloy IN 713 exhibited the least overall penetration but showed high localized variations. The alloy IN 738 was more uniformly attacked, but with deeper penetrations, while the corrosion of Nimonic 80A and FS 414 (cobalt based) was more extensive still.

The results suggest that it may be necessary to limit turbine metal temperatures to 1598 F (870 C) in pressurized fluid bed combustion applications.

- (ii) A pressurized fluid bed combustor was operated for 175 hours with the hot gases being expanded through a turbine after cleaning. The bed temperature was 1598 F (870 C). Dolomite was added at a rate of 24 percent of the coal, together with Burgess No. 10 clay at 0.4 percent of the coal, to act as a corrosion inhibitor.

TABLE 2-17

OPERATING CONDITIONS AND RESULTS (COMBUSTION POWER CO.)

Test conditions:

Duration	1003 hours
Coal	Illinois No. 6
Dolomite/coal	0.24 lb/lb (kg/kg)
Clay additive/coal	0.004 lb/lb (kg/kg)
Bed temperature	1650F (899C)
Freeboard temperature	1595F (868C)

Results: Maximum penetration (microns)

SS 304	17	INCOLOY 800	47
SS 309	24	INCOLOY 825	35
SS 310	27		
SS 316	18	NIMONIC 80A	70
SS 330	12	RENE 77	28
SS 333	30	INCO 713C	18
SS 446	3	U-700	30
		IN 738	45
INCONEL 600	70		
INCONEL 601	65	HS 31	30
INCONEL 690	50	FS 414	60
INCONEL 706	18	M 509	22
N155	20	PWA 68	0

TABLE 2-18

OPERATING CONDITIONS AND RESULTS (COMBUSTION POWER CO.)

Test conditions:

Duration	568 hours
Coal	Illinois No. 6
Dolomite/coal	0.24 lb/lb (kg/kg)
Clay additive/coal	0.004 lb/lb (kg/kg)
Magnesia/coal	0.001 lb/lb (kg/kg)
Bed temperature	1685F (918C)
Freeboard temperature	1670F (910C)

Results: Penetration (microns)

	Maximum	Average
IN 600	20	15
IN 601	30	20
IN 690	20	17
IN 713	25	13
IN 738	40	25
FS 414	60	50
NIMONIC 80A	80	50
IN 800	80*	50
IN 825	55*	24

* Sulfidation identified

The test was conducted in two segments. The first of 80 hours was terminated because of a build-up of deposit on the turbine blades resulting from a malfunction of the cyclones. The second segment was initiated after repair of the cyclones and re-blading of the turbine with PWA 68 CoCrALY - coated blades. Inspection of the turbine showed no new rotor blade wear or excessive rotor blade deposits. Significant deposition was observed in the first-stage vanes, however, and this had reduced their aerodynamic efficiency during the course of the test. During these tests it was observed that the deposits grew to a particular thickness and then spalled. The breakaway of large agglomerates may give rise to serious erosion problems in operation over longer time periods. ,

BCURA/Office of Coal Research

Corrosion studies of turbine materials were conducted at BCURA for the Office of Coal Research (Ref. 2-74) using the 3-ft x 2-ft (0.9-m x 0.6-m) pressurized fluid bed combustor. The bed temperature was in the range 1630 to 1765 F (888 to 963 C) and the operating pressure was approximately 4 atm (bar). The combustion gases were cleaned to a dust loading of 250 ppm (95 percent less than 10 micron) by a cyclone system and then passed to the turbine materials test section. This consisted of an aluminized X-40 nozzle guide vane segment from a Rolls-Royce Proteus marine engine which directed the gas stream onto a series of rod specimens. There appeared to be no erosion of the vanes or the rods. When the bed was at 1749 F (954 C) and the cascade in the range 1650 to 1700 F (899 to 927 C), deposits were sufficiently extensive to be a potential source of operating problems. The two alloys exposed in the turbine section, Nimonic 75 and EPK 55, and the X-40 vane segment were examined. It was concluded that the Nimonic 75 showed severe hot corrosion attack and, although more resistant, the EPK 55 showed a form of attack thought to be a precursor to hot corrosion. The X-40 segment, which had originally been pack-aluminized, showed severe oxidation attack along the carbides with a structure characteristic of hot-corroded cobalt-based alloys.

Overall Assessment of Material Selection

The acceptance criterion adopted in the UK tests is equivalent to the loss of 0.28 in. (7 mm) of metal in 200,000 hours (i.e., corresponding to the total loss of a tube wall during the lifetime of a boiler). Since corrosion rates generally fall with time, this is probably a conservative criterion for extrapolation from tests of about 10,000 hours duration. For 1000-hour tests, this may be excessively severe. In the NCB/EPRI (1975) tests (Ref. 2-64), few alloys would meet this criterion, although some alloys may be acceptable at high temperatures if a less stringent limit, perhaps corresponding to a shorter design lifetime, were used.

The assessment of short-term results cannot be based solely on the loss of structural metal by extrapolation to the plant lifetime. It is important to examine the type and morphology of the attack. Sulfidation of the metal can be a precursor to breakaway hot corrosion. If the sulfides follow grain boundaries, then continued metal wastage appears likely, whereas attack forming discrete globular sulfides may not lead to catastrophic corrosion.

The assessment of material selection depends on whether the material will be placed in the bed, above the bed, or in the turbine.

In-Bed Components

When a fluid bed combustor is operated without limestone addition, the results indicate that there are a wide range of materials suitable for in-bed components (Ref. 2-67), and no apparent restrictions on the metal temperature from a corrosion standpoint. For metal temperatures above 1472 F (800 C), high-strength, nickel-based alloys such as Inconel 671 and Incoloy 800 can be considered. Below 1472 F (800 C) conventional stainless steels can be utilized.

If a fluid bed combustor were operated with limestone addition, the choice of materials is less clearly defined. The results indicate that there are several materials suitable for in-bed applications where the metal temperature does not exceed 1202 F (650 C). As the various test programs have demonstrated, the most suitable materials in this temperature range are the iron-based austenitic steels.

For metal temperatures above 1202 F (650 C), however, the results indicate that there is a possibility of excessive corrosion of in-bed components (Refs. 2-64, 2-67 and 2-70). It has been demonstrated that it is possible to operate fluid bed combustors with limestone addition and with high metal temperatures without material problems (Refs 2-69 and 2-71). However, it has also been shown that small changes in operating conditions are sufficient for corrosion of in-bed components to become a problem (Ref. 2-70). The dependence of corrosion on the operating conditions is still not fully understood.

If high temperature corrosion does occur, the nickel-based alloys are found to be sensitive to corrosive attack and, once initiated, this attack can produce rapid local degradation of the alloys. The iron-based austenitic steels are much less susceptible to the corrosive effects of the bed environment; sulfidation does occur, but the morphology does not appear to lead to catastrophic attack. The performance of stainless steels is also temperature dependent. An oxide scale is formed which is protective up to a certain temperature, but above this temperature excessive oxidation occurs. The breakdown temperature is different for each steel, for example Type 304 SS is prone to excessive oxidation at a lower temperature than Type 347 HSS. The latter alloy has a greater resistance to oxidation than most stainless steels.

In addition, the NCB tests have indicated that this steel shows good resistance to sulfidation, but is prone to sigma phase embrittlement and, therefore, is not considered a suitable choice.

Of the materials so far tested, Type 347 HSS is considered the most suitable for in-bed heat transfer tubes. A maximum working temperature with regard to oxidation resistance and tensile strength alone would be about 1472 F (800 C). A developmental alloy which performed well in the NCB/EPRI (1975) test programs was GE 2541, a high chrome ferritic steel with aluminum and yttrium additions. This FeCrAlY type alloy would need to be used in cladding form due to its lack of strength at high temperatures. Commercial development of this alloy is, however, some years away.

The main area of uncertainty for in-bed material selection is, therefore, temperatures above 1202 F (650 C) in beds with acceptor addition. At present, the experimental evidence is incomplete, and it is not yet possible to confirm that suitable materials can be found for this duty. There appear to be two main possibilities; iron-based austenitic steels, such as Type 347 HSS, could be used up to 1472 F (800 C), and high chrome ferritic steels with aluminum and yttrium additions as cladding materials used up to 1652 F (900 C).

Above-Bed Components

The metallic components in the freeboard will experience gases at temperatures up to 1742 F (950 C) with a dust loading significantly higher than that experience in a conventional pulverized fuel boiler. However, as indicated in Ref. 2-75, the gas velocity will generally be similar to the fluidizing velocity and erosion by elutriated particles, therefore, should not be significant. Furthermore, because of the lower gas temperature ash fusion is unlikely, and a large buildup of sintered ash deposits on tubing would not be expected.

The results from the various experimental programs have indicated that there is a wide choice of materials for above-bed applications. For metal temperatures below 1472 F (800 C), the iron-based austenitic steels are the most suitable materials. If higher strength is required, some cobalt-based and nickel-based alloys may be suitable, although evidence of sulfidation of nickel-based alloys has been noted. At temperatures above 1472 F (800 C), the most suitable materials are FeCrAlY type alloys, used as cladding materials. A cobalt based alloy, Haynes Alloy 188, would also be suitable for high temperature applications.

Turbine Materials

Present experimental data are wanting as a basis for turbine material selection. However, there are indications that corrosion erosion resistant

cladding over high strength, creep-resistant materials combined with turbine blade cooling can be used in pressurized fluid bed combustion. This topic will be discussed later in this chapter in the section dealing with Turbomachinery Assessment.

Off-Design Operating Characteristics

This section briefly discusses the techniques for the startup, turndown and shutdown of fluid bed combustors. Much of the information in this field is regarded as commercially confidential, so this review therefore deals with the subject in general terms only. Some of the techniques applicable to atmospheric pressure combustion are reviewed in Ref. 2-76. A brief overview of part-load operation and the ability of a selected FBC/CAES system configuration to follow load is presented in the chapter on Part-load and Load-Following Capability.

Startup

To startup a fluid bed combustor, it is necessary to raise the temperature of part or all of the bed to a temperature sufficient to sustain combustion. This temperature will vary from 752 F (400 C) for highly reactive coals to above 1202 F (650 C) for unreactive coals such as anthracite. Startup therefore requires an auxiliary fuel, normally gas or oil.

The techniques available for startup differ in capital cost and auxiliary fuel requirements. If frequent startup were required, then a high capital cost, high efficiency system is preferable. Startup systems for large-scale combustors fall into three main categories: overhead burners, combustion of gas premixed with air in and above the fluid bed, and combustion of gas or oil in the plenum chamber so that the bed material (either fluidized or as a fixed bed) is heated by the combustion gases.

If the bed needs to be fluidized during startup, then the principal heat loss would be to the hot gases leaving the freeboard and, where applicable, to immersed heat transfer surfaces. In such cases, the burner outputs required can be as high as the equivalent combustor output for the same bed area. It is possible to reduce the output of the startup burner by introducing hot gas at a velocity below that required to fluidize the bed. In these circumstances, the transfer of heat to the bed material and the loss to immersed surfaces is reduced substantially. However, if the bed has to be heated to temperatures greater than about 662 F (350 C) before coal can be added, this will affect the distributor base design, and will involve additional costs.

Turndown

Combustion of oil, gas or pulverized coal in a flame occurs at high temperatures with the result that most of the heat transfer within the combustion chamber is by radiation. It is possible to achieve turndown simply by

reducing the fuel and air feed rates and, since the heat transfer rate is proportional to the fourth power of the absolute temperature, the combustion temperature does not change greatly.

In fluid bed combustion, heat transfer to surfaces immersed in the bed is mainly by convection, and the effect of bed temperature on the heat transfer coefficient is small. Because the range of bed temperatures for efficient combustion and sulfur retention is limited (1427 to 1742 F (775 to 950 C)), turndown of a fluid bed boiler with immersed heat transfer surfaces to below about 80 percent of full load is not possible by reducing only the feed rates and bed temperature. For this reason, turndown of a fluid bed boiler can involve complex control to ensure that the combustion rate matches the heat removed by the gas and heat transfer surfaces. In power generation applications, the choice of a load-following system is further complicated by control considerations for the cycle, particularly with combined-cycle systems.

The main factors affecting turndown for the combustor are outlined in the following sections.

Combustion Rate

Assuming constant combustion efficiency, the combustion rate is related to the fluidizing velocity, excess air level, bed area and system pressure by:

$$\text{Combustion rate} = (\text{Constant} \times \text{Fluidizing velocity} \times \text{Bed area} \times \text{Pressure}) / (1 + \text{Excess air}/100) \quad (2-22)$$

A reduction in combustion rate can be achieved by:

- (i) reducing coal feed rate at constant air supply, i.e., increasing excess air,
- (ii) reducing coal and air feed rates to maintain constant excess air,
- (iii) reducing bed area,
- (iv) reducing the pressure, and
- (v) reducing several of the above factors together.

Heat Removal by the Combustion Gases

The heat removed from the bed by the combustion gases is determined by the fluidizing velocity, bed temperature and air inlet temperature:

$$\text{Heat to gas} = \text{Constant} \times \text{Fluidizing velocity} \times (\text{Bed temp.} - \text{Air inlet temp.}) \quad (2-23)$$

At stoichiometric combustion conditions, the heat required to bring air at 77 F (25 C) to bed temperature accounts for about 40 percent of the total heat release; with preheat of the combustion air to 752 F (400 C), about 20 percent of the heat release is required. It follows that, by operating at a high excess air level (typically 200 to 300 percent for a pressurized combustor), all of the heat generated in the bed is removed by the combustion gases. Turndown for such air-heater systems can be achieved relatively simply by reducing the coal and air rates in proportion. For pressurized applications, however, turndown of the combustor interacts in a complex way with the gas turbine, and in addition it may be necessary to vary the bed temperature (and hence off-gas temperature), the operating pressure and the excess air level.

Heat Transfer to Immersed Surfaces

The rate of heat transfer to immersed surfaces is given by:

$$\text{Heat transfer rate} = \text{Heat transfer coefficient} \times \text{Area} \times (\text{Bed temp.} - \text{Fluid temp.}) \quad (2-24)$$

Heat transfer can be reduced on turndown in the following ways:

- (i) reducing bed temperature (limited by allowable range of bed temperatures),
- (ii) increasing the fluid temperature (mainly applicable to designs in which air is heated indirectly by tubes in the bed),
- (iii) reducing bed to tube heat transfer coefficient (this is possible by slumping the bed); control is usually achieved by arranging the bed in compartments and operating the required number of compartments to meet the load,
- (iv) reducing the effective tube area (generally by reducing the bed height to expose heat transfer surface), and
- (v) combining two or more of the above techniques (this will usually be necessary to provide the flexibility required).

Shutdown

To shut down a fluid bed combustor, it is generally necessary to ensure that the fluidizing air is supplied for a period after the coal feed is turned off so as to enable the residual coal to burn out. In addition, the coolant flow to the in-bed heat transfer surfaces must be maintained to avoid high metal temperatures.

Response Rates

The time required to start up a fluid bed combustor varies considerably with bed design. The main factors affecting startup time are:

- (i) the rate of heating must not be so high as to induce excessive stress in the refractories, combustor or boiler (usually limiting for shallow beds), and
- (ii) the maximum rate of heating depends on the net rate of heat transfer to the bed material, and the mass of bed material (limiting for deep beds).

For small, shallow-bed, atmospheric-pressure hot gas furnaces, startup from cold to full output in less than one hour can be achieved. For deep-bed pressurized combustor designs, several hours would generally be needed. These times can be reduced if a warm start is possible, i.e., if the bed were not cooled to ambient temperature. Typical cooling rates for slumped beds containing heat transfer tubes have been calculated in Ref. 2-76. The results are illustrated in Fig. 2-33. In the absence of heat transfer to immersed tubes, cooling rates can be reduced so that a warm start is possible for up to several hours after slumping the bed.

Hot Gas Cleanup for Pressurized Fluid Bed Combustion

At present, experimental data on corrosion and erosion of turbine materials under conditions representative of pressurized operation are limited. Maximum acceptable levels of contaminants are, therefore, uncertain and the subject of considerable controversy.

Erosive attack is caused mainly by particles larger than 2 microns. However, submicron particles may contribute to fouling and corrosion. In particular, alkali metal aerosols (volatilized sodium and potassium compounds) can lead to the deposition of alkali metal salts as liquid films which can cause hot corrosion.

Criteria for contaminant levels based on distillate- and natural gas-fired turbines may be excessively severe if applied to fluid bed combustion. For example, the ash produced by a fluid bed combustor has not been heated through the sintering temperature and, therefore, is relatively soft.

The particulate loadings in the product gas from the combustor can be up to $3.12 \times 10^{-3} \text{ lb/ft}^3$ (50 g/m^3) (STP), depending on the combustor design and operating conditions (Table 2-19). In design studies for pressurized fluid bed combustors, it has been widely assumed that these emissions can be reduced

EFFECT OF SHUTDOWN TIME ON BED TEMPERATURE

CURVE NO. 1: SHUT OFF COAL AND AIR SIMULTANEOUSLY
CURVE NO. 2: SHUT OFF COAL ONLY
CURVE NO. 3: SHUT OFF COAL AND RECIRCULATION OF
SOLIDS FROM NEIGHBORING BED AT 1652 F (900 C)

(REF. 2-76)

TABLE 2-19

PILOT PLANT PARTICULATE LOADINGS FROM COMBUSTOR AND CYCLONES

(Ref. 1-73)

Plant	Loading from combustor (g/Nm ³)*	Loading from cyclone (g/Nm ³)*
CURL	-	0.3
Exxon	16	0.7
Argonne	9 to 50	0.7 to 4.6
Combustion Power	17	0.9

*Nm³ = normal cubic meter

to a level consistent with an acceptable lifetime for the gas turbine materials by using high efficiency cyclones. Because this has yet to be demonstrated in long-term tests, the purpose of the present review is to summarize the various alternative or supplementary particulate removal systems available.

The main types of particulate removal equipment can be classified (Ref. 2-78) as follows:

- (i) settling chambers
  - (a) gravity settlement
  - (b) inertial separators
- (ii) centrifugal separators
  - (a) simple cyclones
  - (b) series and parallel cyclones
- (iii) wet scrubbers
  - (a) spray towers
  - (b) self-induced spray collectors
  - (c) accelerated impact devices (venturi, disintegrator)
- (iv) fabric and granular filters
- (v) electrostatic precipitators
  - (a) dry type
  - (b) wet type

The normal range of effectiveness and typical efficiencies of the different devices as a function of particle size are given in Figs. 2-34 and 2-35 and Table 2-20 (from Ref. 2-79). Some of the factors influencing the choice of gas cleaning plant in industrial processes are summarized in Tables 2-21 and 2-22 (from Ref. 2-80). The main features of each type of equipment are considered in the following sections.

Settling Chambers

As shown in Fig. 2-34, settling chambers are normally restricted to the removal of particles larger than 100 micron. This is because of the low settling velocities of fine particles (e.g., 1 ft/sec (0.3 m/s) for 100 microns compared with .01 in./sec (0.0003 m/s) for 1 micron). Since low velocities, and, therefore, large chambers are required, this type of device is seldom used except for removing the coarsest particles ahead of a more efficient collector device. The simplicity of construction and the capability to operate at elevated temperatures are desirable features. However, the large size makes this option unattractive for pressurized fluid bed applications. As an initial removal stage for the coarser particles, some type of simple inertial separation device in the freeboard appears preferable.

EFFECTIVENESS OF PARTICULATE REMOVAL DEVICES

FIG. 2-34

EFFECT OF PARTICLE SIZE AND PARTICLE COLLECTOR TYPE ON COLLECTION EFFICIENCY

(REF. 2-79)

FIG. 2-35

TABLE 2-20

EFFICIENCIES OF VARIOUS TYPES OF DUST ARRESTORS

(Ref. 2-79)

Equipment	Percentage Efficiency at		
	50 micron	5 micron	1 micron
Medium-efficiency cyclone	94	27	8
High-efficiency cyclone	96	73	27
Impingement scrubber (Doyle type)	98	83	38
Self-induced spray deduster	100	93	40
Void spray tower	99	94	55
Fluid-bed scrubber	>99	99	60
Irrigated-target scrubber (Peabody type)	100	97	80
Electrostatic precipitator	>99	99	86
Irrigated electrostatic precipitator	>99	98	92
Venturi-scrubber - medium energy	100	>99	97
High-efficiency electrostatic precipitator	100	>99	98
Venturi-scrubber - high energy	100	>99	98
Shaker-type fabric filter	>99	>99	99
Reverse-jet fabric filter	100	>99	99

TABLE 2-21

EQUIPMENT LIMITATIONS

(Ref. 2-80)

	Equipment				
	Settling Chamber	Cyclone	Bag Filter	Electrostatic Precipitator	Wet Washers
Collection efficiency	For dust particles greater than 100 microns	Deteriorates for dust particles smaller than 10 microns and bulk density <50 lbs/ft ³ (<800 kg/m ³)	>99%	Depends upon collecting plate area and contact time	Depends upon dust particle size, velocity and wetability
Inlet dust burden, lb/ft ³ (g/m ³)	>12.5x10 ⁻³ (>200)	>12.5x10 ⁻³ (>200)	2.8x10 ⁻³ to 4.4x10 ⁻³ (45 to 70)	>2.8x10 ⁻³ (>45) can create electrical instability in the field	>12.5x10 ⁻³ (>200)
Maximum gas temperature, F (C)	Dependent on materials of construction	Dependent on materials of construction	390 to 450 (200 to 230)	<750 (<400)	2200 (1200)
Pressure drop atm(bar)	0.002	<0.015	0.007	0.005	<.080

TABLE 2-22

RELATIVE ACCEPTABILITY OF GAS CLEANING PLANTS FOR VARIOUS PROCESS CONDITIONS

(Ref. 2-80)

	Dust properties							Gas conditions		
	High Inlet Burden	Erosive	Sticky	Light, Fluffy	Difficult to wet	Pyrophoric	Resistivity problem	Varying flow temp.	Explosive/Combustible	Corrosive
Cyclone	0	Avoid	Avoid	Avoid	0	Care	0	Care	0	Care
Impingement Scrubber	0	Care	0	0	Care	0	0	0	0	0
High Energy Venturi	0	Avoid	0	0	Avoid	0	0	Care	0	0
Bag Filter	Care	Care	Avoid	0	0	Avoid	0	0	Care	Care
Dry Electrostatic Precipitator	Care	0	Avoid	Care	0	Care	Avoid	0	Avoid	Care
Flushed Electrostatic Precipitator	Care	0	Care	0	0	0	Avoid	0	Avoid	Care

0 Indicates that the type of plant can generally cope with the process condition

Care - Indicates special attention is required in both plant design and operation to prevent problems

Avoid - Indicates that this process condition is so potentially dangerous that other alternatives which avoid the difficulty are normally sought.

Centrifugal Separators

Cyclones, in which the separation force is provided by the spinning motion of the gas, are used for removing particles of size down to about 5 microns. A cyclone fulfills most of the requirements for cleaning hot combustion gas. It is a low cost device, simple in construction and operation. Cyclones can be refractory lined to avoid exposing metal to the hot and potentially corrosive gases. Such cyclones, however, cannot be placed immediately upstream of a gas turbine. Operational problems can arise if the particles are sticky or highly erosive.

Although independent of the dust loading, the collection efficiency falls with a reduction in gas flow rate. This can be overcome by appropriate switching of a number of cyclones in parallel. The centrifugal forces acting on a dust particle suspended in a spinning column of gas increase with the mass of the particle. The largest particles therefore have the greatest separation forces and are collected most efficiently in a cyclone. For particle sizes below about 5 microns, the collection efficiency falls markedly (Fig. 2-35). It is claimed that some ultra-high efficiency cyclones can operate efficiently for particles down to 2 microns (Ref. 2-81). However, such cyclones rely on high gas velocities and operate with relatively high pressure drops. The efficiency of conventional cyclones decreases as cyclone diameter increases. When high gas flows need to be cleaned with a high efficiency, banks of small cyclones (multicyclones) are manifolded together to operate in parallel. Collection efficiency can be improved by operating cyclones in series. Generally, the addition of a second stage will approximately halve the losses. In some processes, three or four stages in series are used.

Wet Scrubbers

Particles may be removed from a gas stream by wetting them with a liquid, normally water. The wetted particles, which are larger and heavier, can be removed more easily from the gas stream using gravitational or centrifugal techniques. There are many such devices available, using various methods of contacting, for example spray towers, packed and fluidized bed scrubbers, self-induced spray collectors, venturi scrubbers and disintegrators. The collection efficiency decreases with particle size, but increases with the degree of liquid-solid contacting. Fine particles are difficult to wet effectively unless the relative velocity between the particles and the water droplets is high. This is achieved in accelerated-impact scrubbers such as the venturi-scrubber but at the expense of a relatively high pressure drop. Figure 2-35 shows that typical collection efficiencies achieved by wet scrubbers are significantly better than with cyclonic separators. Wet scrubbers have advantages of simplicity, effectiveness and low capital cost. The costs associated with the water treatment plant can, however, be appreciable, particularly when corrosive materials (e.g., alkali metal aerosols) are being removed.

The major disadvantage of wet scrubbers for fluid bed applications is that the gas is cooled and saturated with water vapor. This introduces significant thermal efficiency losses, even if the gas were reheated by counter-current heat exchange after cleaning.

Fabric Filters

In filtration processes, the dust-laden gas is passed through a semi-porous medium which retains the dust particles and allows the clean gas to pass through. The mechanisms involved in filtration are complex, and include impaction, interception, diffusion, thermal, and molecular and electrostatic forces.

With most equipment, the filtration medium is woven fabric. This can give efficiencies of above 99 percent with sub-micron particles (Table 2-20), although the openings in the fabric may be much larger than the size of the smallest particles being collected. These high efficiencies are achieved because particles deposit on the surface of the fabric forming a layer through which all the gas has to pass. As the collected layer or cake increases in thickness, both the collection efficiency and the pressure drop increase for the same gas flow. Periodic removal of the dust is necessary and can be done by mechanical shaking, vibrating the fabric, or reversing the gas flow through the filter. The latter technique is probably the most suitable for fluid bed combustion applications.

The choice of filtration medium is determined by the operating temperature and the nature of the gas. Natural and synthetic fibers are used in many applications, but have a maximum operating temperature of about 392 F (200 C). Asbestos and glass fibers can be used up to about 752 F (400 C). Development work on materials for applications above 752 F (400 C) has been carried out using spun blast furnace slag up to 1202 F (650 C) (Ref. 2-82), aluminum silicate fiber up to 1796 F (980 C) (Ref. 2-83), and porous or woven ceramics and metals (Ref. 2-84). For fluid bed applications, the selection of fabric material will depend on its stability in the potentially corrosive environment of the hot combustion gases.

High collection efficiencies normally can be achieved over a range of gas flow rates for particles down to submicron size, although the pressure drop increases with flow rate. Filters tend to choke rapidly unless inlet dust loadings are low. This means that regular, effective removal of collected dust is normally essential and, in order to minimize on the frequency of such filter cleaning, some form of primary gas cleaning such as cyclones is usually incorporated. The features needed for collecting fine particles efficiently by fabric filtration are summarized in Ref. 2-85. They are:

- (i) operation at a low face velocity (penalties are high capital and operating costs),
- (ii) selection of fabrics with small fiber diameters and low porosities (penalties are high initial and replacement fiber costs), and
- (iii) promotion of cake filtration at the expense of filtration within the fabric (penalties are high pressure drop necessitating frequent cake removal).

Granular Filters

The use of granular beds to remove fine particles from gas streams can be regarded as a natural development of fabric filters in which much of the filtration takes place within the cake of collected particles. The efficiency of filtration can be as high as with fabric filters (Refs. 2-84 and 2-86).

The operation of a granular bed filter involves three mechanisms.

- (i) Collection:
High collection efficiencies are obtained initially, but as the dust loading on the collector material increased the efficiency falls because the collector becomes saturated.
- (ii) Retention:
For effective gas cleaning, re-entrainment of the dust from the collector must be avoided. Retention characteristics are improved if the collector or collected particles are sticky. Re-entrainment is a particular problem with fluid bed granular filters.
- (iii) Removal of collected particles:
The collected particles can be removed cyclically by intermittent back flushing or vibrating the bed. Continuous removal can be achieved by moving beds, fluid beds or spouted beds.

A possible refinement of granular bed filters is to use a filtration agent capable of retaining the alkali metal aerosols chemically. For example, reaction with aluminosilicates such as kaolinite and illite forms low vapor pressure alkali feldspars which are retained in the bed.

Electrostatic Precipitators

The application of an electric field across the gas to be cleaned charges the dust particles which then migrate toward and are deposited on the electrodes. The collection efficiency increases with the applied voltage (usually 30 to 50 kV) up to the point at which arcing occurs. High collection efficiencies of particles down to sub-micron size can be achieved with this technique. The

operating temperature range is normally up to 752 F (400 C). However, precipitators have been designed to work at temperatures up to 1472 F (800 C), although their efficiency is generally lower for reasons discussed below.

Three processes need to be effective in order to achieve efficient operation of an electrostatic precipitator.

- (i) Electrical charging of the particles:
As the particles move into the electric field, they acquire an electrostatic charge by two mechanisms, bombardment and diffusion charging (Ref. 2-87). The bombardment charging mechanism is of primary importance for particles larger than 1 micron. The rate of charging by this mechanism decreases at high temperatures. Diffusion charging predominates for particles smaller than about 0.2 micron and increases with temperature. With both mechanisms, the amount of charging increases with the time of exposure to the electric field.
- (ii) Migration of the particles to the collection electrodes:
The velocity of migration increases with electric field strength and particle size (for particles larger than about 0.2 micron) but decreases with the viscosity, and therefore temperature, of the gas. Particle resistivity is important as it determines the electrostatic charge retained when the particle arrives at the collector electrode. Dusts with low resistivities rapidly become discharged on meeting the electrode, resulting in reentrainment and loss of collection efficiency. At high temperatures, dust resistivity falls, possibly limiting the collection efficiency which can be achieved in pressurized fluid bed applications.
- (iii) Removal of dust from the electrodes:
Water irrigated electrostatic precipitators are widely used, particularly for the removal of sticky or adhesive dust in low temperature applications. Alternative methods include rapping or vibrating the collector electrodes.

Because of their complexity, electrostatic precipitators have high capital costs, although operating costs can be low. The main advantages are high collection efficiency and low pressure drop. Although used extensively in existing coal-fired power generating plants, their suitability for use at high temperatures in pressurized fluid bed systems is uncertain.

Other Techniques

Several other techniques of particle collection are at an early stage of development.

- (i) Thermal precipitation:
Particles are collected on cold surfaces over which the hot gas is passed.
- (ii) Agglomeration:
By causing fine particles to agglomerate, the effectiveness of conventional mechanical collectors can be increased. Agglomeration can be encouraged by increased turbulence and by sound waves (Ref. 2-87).

Cleanup for Pressurized Fluid Bed

The main particulate removal techniques likely to be suitable for application in a fluid bed combustor are summarized below:

- (i) Primary cleaning:
Gravity and inertial separation devices in the freeboard, collecting and returning the larger particles to the bed.
- (ii) Secondary cleaning:
Several stages of cyclones in series.
- (iii) Tertiary cleaning:
Because fluid bed combustor ash is relatively soft, it has been widely assumed that cyclone cleaning will be sufficient to produce a gas of acceptable quality for a turbine. However, this has not yet been demonstrated. Where further cleaning is necessary, then granular bed filters appear to be the next most suitable filtration device, either in fixed or fluid bed form. Ceramic fiber filters may also prove to be suitable as well as electrostatic precipitators.

Operating Conditions and Performance

This section of the report is concerned with the definition of recommended conditions and performance parameters that are pertinent to the use of FBC in CAES applications. In areas of major technical uncertainty, such as materials performance, alternative performance criteria have also been given.

Coal Feed Specification

Illinois No. 6 coal is taken as the reference coal. Typically, the moisture content of this coal as received is 13 percent. Although there would be efficiency and capital cost advantages in feeding wet coal, no satisfactory system has yet been developed. Accordingly, the coal would be dried to 5 percent for firing.

The average analyses given below are based on four batches of Illinois No. 6 coal used in tests at the NCB CURL (formerly BCURA) establishment at Leatherhead, UK, during the period 1973 to 1977. The analyses, which were carried out at the NCB Coal Research Establishment, Stoke Orchard, UK, are given in Table 2-23. Coal batch No. 1 was taken from the residue of a consignment shipped to the UK for the joint NCB/EPA project in 1970/71. The remaining three batches were drawn from the stocks at the British Gas Corporation Westfield works. These had been shipped to the UK for the Westfield Lurgi gasification trials of US coals. It should be noted that, in the ultimate analyses, the oxygen was determined directly, rather than by difference. For this reason, a mass balance is not guaranteed. In deriving the average ultimate analysis, the mass balance error has been allocated to the carbon.

Coal Analysis

The proximate analysis, weight percent (dry basis), is:

Volatile matter	37.30
Ash	10.40
Carbon dioxide	0.18
Fixed carbon	<u>52.12</u>
Total	100.00

The ultimate analysis, weight percent (dry basis), is:

Ash	10.40
Carbon	71.35
Hydrogen	4.60
Oxygen	8.90
Nitrogen	1.40
Sulfur	3.30
Chlorine	<u>0.05</u>
Total	100.00

The higher heating value (dry basis) is 12600 Btu/lb (29.29 MJ/kg).

TABLE 2-23

ANALYSES OF ILLINOIS NO. 6 COAL

Weight Percent (Dry Basis)

	Batch			
	1	2	3	4
Volatile matter	37.7	38.3	36.2	37.0
Ash	10.9	10.2	10.5	10.0
Carbon dioxide	0.49	0.09	0.08	0.07
Fixed carbon (by difference)	50.91	51.41	53.22	52.93
Total	100.00	100.00	100.00	100.00
Ash	10.9	10.2	10.5	10.0
Carbon	70.9	70.4	71.2	71.4
Hydrogen	4.8	4.6	4.4	4.7
Oxygen	8.7	9.4	8.7	9.0
Nitrogen	1.4	1.4	1.4	1.4
Sulphur	3.5	3.5	3.0	3.0
Chlorine	0.04	0.07	0.04	0.03
Total	100.24	99.57	99.24	99.53
Gross calorific value, Btu/lb (MJ/kg)	12,528 (29.14)	12,661 (29.45)	12,541 (29.17)	12,644 (29.41)

Sorbent Feed Specifications

The as-received sulfur acceptor generally has a moisture content of about 5 percent. As with coal, drying prior to feeding to the combustor is necessary; this reduces the as-fed moisture content to less than 0.2 percent.

Sorbent Analysis

For atmospheric pressure fluid bed combustion, limestone is the preferred acceptor, although dolomite can be used. A typical analysis (dry basis, weight percent) for limestone is:

CaO	55.5
CO ₂	43.5
Other	<u>1.0</u>
Total	100.0

For elevated pressure operation, limestone is less effective and dolomite is, therefore, used. A typical composition (dry basis, weight percent) is given below (based on analyses of samples received in the UK of BCR No. 1337 dolomite).

CaO	29.8
MgO	21.4
CO ₂	46.9
Other	<u>1.9</u>
Total	100.0

Feed Size Gradings

The coal and sorbent are crushed for feeding. The top size depends on the fluidizing velocity within the ranges given below:

atmospheric pressure:	1/16 in. to 1/4 in. (1.6 mm to 6.4 mm)
elevated pressure:	1/16 in. to 3/16 in. (1.6 mm to 4.8 mm)

To limit elutriation, the fines content of both coal and acceptor should be less than 10 percent below 150 micron.

Feed Rates

The coal feed rate depends on the air rate and excess air level. Based on the ultimate analysis given earlier, 0.1025 lb of dry coal are required per lb of dry air (kg/kg) for stoichiometric combustion.

The acceptor feed rates required for a sulfur retention efficiency of 85 percent under those conditions specified in the section entitled "Operating Conditions" are as follows:

atmospheric pressure - limestone at Ca/S = 4
elevated pressure - dolomite at Ca/S = 1.2

In each case, a moderately reactive stone is assumed, taking into account that, in general, dolomites are more reactive than limestones.

Based on the coal and acceptor analyses given earlier, the acceptor requirements per lb (kg) of dry coal are as follows:

atmospheric pressure - 9.416 lb (kg) limestone (dry basis)
elevated pressure - 0.233 lb (kg) dolomite (dry basis).

Configuration Design Considerations

For atmospheric pressure combustion, it will be necessary for the design to incorporate a fines burnup cell in which the elutriated carbon collected by the cyclones is burned. Refiring of the coarse grits to the main bed may also be used to improve the sulfur retention efficiency.

For elevated pressure operation, it is important to achieve almost complete combustion in the bed on the first pass. This is because operation under conditions resulting in the elutriation of material of high carbon content can lead to combustion of the dust, particularly in the primary cyclones. This may give rise to:

- (i) damage to the cyclones,
- (ii) blockage of the dust discharge system,
- (iii) more complicated control of the temperature at the turbine inlet, and
- (iv) the possibility of turbine fouling by sticky ash or erosion by solidified slag beads.

Those operating conditions specified in the section entitled Operating Conditions have, therefore, been chosen so that the elutriated carbon loss is small, making fines recycle or a fines burnup cell unnecessary.

Bed Density and Pressure Drops

In both the atmospheric pressure and elevated pressure designs, the pressure drops across the distributor plate, bed and cyclones reduce the system efficiency. Based on a bed density of 46.8 lb/ft³ (750 kg/m³), typical combustor pressure drops are as follows:

distributor plate:	0.02 atm (bar) (atmospheric pressure)
	0.10 atm (bar) (elevated pressure)
bed:	0.09 atm (bar) (atmospheric pressure)
	0.18 atm (bar) (elevated pressure)
cyclones:	0.03 atm (bar) (atmospheric pressure)
	0.15 atm (bar) (elevated pressure)
total (distributor, bed and cyclones):	0.14 atm (bar) (atmospheric pressure)
	0.43 atm (bar) (elevated pressure)

In designs where air is heated using tubes in the bed or freeboard, the pressure in the tubes preferably should be greater than that outside the tube. This will prevent the inleakage of bed material and the possibility of turbine damage in the event of a tube failure.

Metal Temperatures

Both the heat transfer surfaces and distributor plate must be examined when considering metal temperature limitations.

Heat Transfer Surfaces

For beds to which sulfur acceptor is added, sulfidation of immersed heat transfer surfaces has been observed for some alloys. The experimental results can be summarized in terms of three temperature regimes:

- (i) below 932 F (500 C): in general, low chrome steels appear to be suitable,
- (ii) above 932 F (500 C) but below 1202 F (650 C): iron-based austenitic steels (e.g., types 304, 310, 329, 347 HSS) appear to be suitable,
- (iii) above 1202 F (650 C): experimental data have not been obtained over a sufficiently long period of time for the performance of alloys in this region to be determined with the same confidence as for temperatures below 1202 F (650 C). However, two high-temperature options show promise. Some of the iron-based austenitics may prove to be suitable. For example, type 347 HSS appears preferable to the

austenitics tested, but strength considerations would probably limit the metal temperature to below 1472 F (800 C). Development alloys of the FeCrAlY type have shown good corrosion resistance (and have not exhibited sulfidation) up to 1652 F (900 C). However, these alloys have a low mechanical strength and, if developed commercially, would only be suitable as cladding material.

In view of the above considerations, it is recommended that the present study assumes for the base case that the in-bed tube metal temperatures does not exceed 1202 F (650 C). This would imply an exit air temperature of approximately 1022 F (550 C). A more accurate estimate of the exit air temperature would require a detailed design for the tube bundle to be carried out.

Although the in-bed tube metal temperature is presently limited to 1202 F (650 C), exploratory investigations of the effect on the CAES cycle of tube metals capable of operating up to 1472 F (800 C) or 1652 F (900 C) (corresponding to exit air temperatures of 1382 to 1580 F (750 to 860 C)) can still be undertaken. The results of such exploratory calculations would provide the incentive to identify, develop and test materials able to operate at a high fluid bed temperatures.

For some pressurized combustion schemes, the possibility of dividing the air into two streams is proposed. One stream is heated in tubes immersed in the bed and the other is used to fluidize the bed and provide combustion air. The two streams are then recombined before passing to the turbine. However, limiting the tube metal temperatures to 1202 F (650 C) as proposed for the base case makes such schemes less attractive.

A further option which could be explored is the removal of heat transfer surface in the bed. In this case, all indirect air heating would be carried out in the freeboard and convective sections. Tubing placed above the fluid bed or in convective sections suffers less attack than tubing placed in the fluid bed, and the experimental results indicate that cycles employing high metal temperatures in these sections should be feasible. In particular:

- (i) below 1472 F (800 C): iron-based austenitics (preferably type 347 HSS) should be suitable;
- (ii) 1472 to 1652 F (800 to 900 C): cobalt alloys, such as HA188, appear suitable with FeCrAlY being used as a cladding material and alloys such as HK40 and Manaurite 36X as support materials.

In atmospheric pressure combustion systems, the ability to heat air indirectly to high temperatures in the convective and freeboard sections of the system offsets to some extent the possible temperature limitation of 1202 F (650 C) for tube metal in the bed.

Distributor Plate

Because parts of the distributor plate are exposed to the bed environment, similar conditions apply to those for heat transfer surfaces immersed in the bed. Conventional distributor plate design employs mild steel for the base, in conjunction with austenitic steels for the uprisers. This type of distributor plate has proved satisfactory for metal temperatures up to 662 F (350 C). If temperatures above 662 F (350 C) were required, two technical solutions appear possible.

Between 662 F (350 C) and 932 F (500 C) metal temperature, low chrome ferritic steels for the base, with austenitic steels for the uprisers have proved to be satisfactory in experimental plants with gas pre-combustion startup systems. Alternatively, the results of in-bed tube corrosion tests indicate that the use of austenitics for the base and uprisers can be considered for higher metal temperatures. In both cases, the feasibility of such designs in a large commercial plant is subject to identifying satisfactory engineering solutions to thermal expansion and cycling problems.

Cast refractory distributors have been used for temperatures up to 932 F (500 C) and may be suitable for much higher temperatures. There would be constructional problems in applying this technique to large atmospheric pressure combustors, but its use for pressurized combustors may be attractive. However, thermal cycling problems are considerable and may preclude their application to CAES systems.

It is therefore proposed that from the point of view of both expansion and materials problems, it may be desirable at this stage to impose a design limit of 1202 F (650 C) for the distributor metal temperature in all cycles. This would correspond to an inlet fluidizing air temperature of approximately 1022 F (550 C). It should be noted that, where the distributor plate is required to operate at more than 662 F (350 C), additional costs may be incurred. These arise not only from the plate itself, but also from the higher materials and insulation costs associated with the plenum chamber or, for pressurized operation, the pressure vessel. In view of the above considerations, it is further proposed that, before considering distributor plate metal temperatures above 662 F (350 C) (corresponding to maximum air inlet temperatures of above 482 F (250 C)), more detailed design studies should be carried out.

Operating Conditions

In this section both normal operating ranges and typical operating conditions are presented for a fluid bed combustor.

Ranges for Normal Operation

The recommended ranges of operating conditions for atmospheric pressure fluid bed combustors are:

- (i) fluidizing velocity: 2.5 ft/sec (0.75 m/s) minimum
8.2 ft/sec (2.5 m/s) maximum
- (ii) bed temperature: 1427 F (775 C) minimum
1652 F (900 C) maximum
- (iii) excess air: 20-percent minimum for overall system, including
burnup cell
10-percent minimum for main bed
approximately 200-percent maximum for no tubes in the
bed, depending on the cycle
- (iv) expanded bed depth: 2 ft (0.6 m) minimum
4 ft (1.2 m) maximum.

The recommended ranges of operating conditions for pressurized fluid bed combustors are :

- (i) fluidizing velocity: 2.5 ft/sec (0.75 m/s) minimum
4.6 ft/sec (1.4 m/s) maximum
- (ii) bed temperature: 1427 F (775 C) minimum
1652 F (900 C) maximum
- (iii) excess air: 30-percent minimum
approximately 300-percent maximum for no tubes in the
bed, depending on the cycle
- (iv) expanded bed depth: 5-ft (1.5-m) minimum for beds not containing
tubes
8.2-ft (2.5-m) minimum for beds containing
tubes
16.4-ft (5-m) maximum
- (v) pressure: 20 atm (bar) maximum.

It should be noted that:

- (i) for combustion at elevated pressure, a high excess air level is preferred because a broader range of operating conditions is possible over which good performance is obtained, a greater operating flexibility is provided for rapid load-changing, and the amount of tubing is reduced permitting a more open tube bundle in a bed which is not unduly deep;
- (ii) the minimum bed height specified for elevated pressure operation permits good combustion efficiency, and therefore depends on the excess air level;
- (iii) there is evidence from cold model tests that the nature of fluidization changes markedly at high pressures; consequently, extrapolation of existing pressurized combustion data to pressures greater than 20 atm (bar) is considered inadvisable.

Typical Operating Conditions

Typical operating conditions for conventional fluid bed combustion applications have been selected from the above ranges and are given below:

- (i) fluidizing velocity: 5 ft/sec (1.5 m/s) atmospheric pressure
3.5 ft/sec (1.05 m/s) elevated pressure
- (ii) bed temperature: 1562 F (850 C)
- (iii) excess air: 20 percent (atmospheric pressure)
100 percent (elevated pressure)
- (iv) bed depth: 4 ft (1.2 m) (atmospheric pressure)
8.2 ft (2.5 m) (elevated pressure)
- (v) feed size: 1/8 in. (3 mm) top size

At these operating conditions, the feed rates per unit bed surface area are as follows:

- (i) atmospheric pressure:
  - Coal: 0.0083 lb/sec ft² (0.0403 kg/s m²) dry basis
1.18 MW(th)
  - Limestone: 0.0034 lb/sec ft² (0.0168 kg/s m²) dry basis
- (ii) elevated pressure (10 atm (bar) assumed):
  - Coal: 0.0346 lb/sec ft² (0.169 kg/s m²)
4.95 MW(th)
  - Dolomite: 0.0081 lb/sec ft² (0.0394 kg/s m²)

In the atmospheric pressure case, the operating conditions given above refer to the main bed. For the fines burnup cell, a different fluidizing velocity, bed temperature and excess air level would be chosen to obtain good combustion of the fines. Typical values are:

- (i) fluidizing velocity: 3 ft/sec (1 m/s)
- (ii) bed temperature: 1652 F (900 C)
- (iii) excess air: 50 percent

Under the operating conditions specified for the main bed, the fines burnup cell would receive approximately 10 percent of the input carbon.

Performance

The main combustion losses for an atmospheric pressure combustion system are a carbon loss of approximately 1 percent, radiation and unaccounted loss equal to a maximum of 1 percent, and acceptor reaction losses of typically 2 percent. The net heat release due to combustion in the freeboard can be up to 10 percent of the thermal input for atmospheric pressure operation, depending mainly on the bed temperature and fluidizing velocity. Gases at the freeboard exit can be assumed to be at 1832 F (1000 C). Typically, 5 percent of the thermal input can be removed by heat transfer surface in the freeboard without quenching the combustion reactions.

For elevated pressure operation, the main combustion losses are a carbon loss of approximately 1 percent, radiation and unaccounted losses equal to 1 percent maximum, and acceptor reaction losses which are negligible. The net heat release due to combustion in the freeboard is negligible in the case of pressurized combustion. Gases at the freeboard exit can be assumed to be at the bed temperature.

The performance data given above refer to the recommended design configurations outlined in the section entitled Configuration Design Considerations, i.e., a fines burnup cell is included in the atmospheric pressure system but not in the elevated pressure system. Neither system includes fines recycle, except if required to improve bed maintenance.

Approximate bed to tube heat transfer coefficients, corresponding to the typical operating conditions are:

tube surface temperature 482 F (250 C): 74.9 Btu/hr-ft² F (425 W/m² · K)
tube surface temperature 1004 F (540 C): 95.2 Btu/hr-ft² F (540 W/m² · K)
tube surface temperature 1598 F (870 C): 125.1 Btu/hr-ft² F (710 W/m² · K).

Cost Estimates for Atmospheric and Pressurized Combustors

In this section, preliminary cost estimates for atmospheric pressure and elevated pressure combustors are presented. The data given are based on previous estimates and published information for conventional fluid bed combustor applications. The data presented in this section are preliminary and were used for the screening analysis covered in the next chapter, Systems Analysis. More detailed costs for the selected FBC configuration are presented in the chapter on the FBC/CAES Power plant Preconceptual Design.

Basis of Costs

The costs given in the next section refer to the fluid bed combustion system and associated control equipment, particulate clean-up system, solids handling, and storage facilities within the following battery limits:

- (i) the baseplate of the major equipment,
- (ii) the receiving bunker for coal and sorbent below the rail cars,
- (iii) the ash storage bunker outlet,
- (iv) the inlet flanges of the air duct on the combustor,
- (v) the outlet flanges of the hot gas duct on the combustor if the particulate cleanup system is internal to the combustor vessel, or the outlet flanges of the particulate cleanup system if external to the combustor, and
- (vi) the discharge from the fuel oil day storage tank.

These costs include:

- (i) all components and materials,
- (ii) direct and indirect labor,
- (iii) architect engineers fees, and
- (iv) contingencies.

The costs exclude:

- (i) civils,
- (ii) electrics,

- (iii) interest during construction,
- (iv) local taxes,
- (v) escalation, and
- (vi) commissioning.

Summary of Costs

The preliminary cost estimates are summarized in Table 2-24, together with the plant scale and a percentage breakdown. The costs are given in dollars at October 1978 money values per kW thermal input of coal.

In general, the design and cost of a fluid bed combustor will be affected by the choice of operating conditions. As the preliminary costings given in this section are intended to serve only as a guide to process selection, the data are based on typical operating conditions for power generation applications. The effects of changes in the operating conditions on the combustor costs are discussed briefly below.

Excess Air Level

As the excess air level increases, the bed area for the same thermal input of coal becomes larger but the amount of heat transfer surface immersed in the bed decreases. The net effect of these changes is an increase in cost from 90 \$/kW (thermal input) at 30-percent excess air to 147 \$/kW (thermal input) for an open bed (approximately 300-percent excess air) for elevated pressure combustors. It is recommended that, at intermediate excess air levels, the cost be estimated by interpolation between these two extreme values. To a first approximation, the costs for atmospheric pressure combustion can be assumed to vary with excess air level by the same proportion as for pressurized combustion.

Temperature

Although having an important influence on combustion efficiency, sulfur retention, etc, bed temperature has little direct impact on the cost of the combustor within the normal operating ranges.

The design metal temperatures for heat transfer surfaces can, however, affect the costs significantly. Higher temperatures generally require more expensive alloys and, for in-bed tubing with acceptor addition, may necessitate clad materials. High metal temperatures will reduce heat transfer rates thereby increasing tube surface area requirements.

TABLE 2-24

PRELIMINARY COST ESTIMATES FOR FLUID BED COMBUSTORS

\$ per kW Thermal Input of Coal

Fall 1978 Dollars

	Atmospheric	Pressurised**	
	Bed with tubes*	Open bed	Bed with tubes*
Thermal input (MW(th))	175	250	520
Cost (\$/kW(th))	107	147	90
Cost breakdown			
Fuel delivery/storage	15 %	16 %	17 %
Combustors	68 %	74 %	73 %
Ash and dust handling	10 %	6 %	7 %
Instrumentation	7 %	4 %	3 %
Total	100 %	100 %	100 %

*Operating at 20% excess air (atmospheric) and
30% excess air (pressurized).

**Operating at 16 atm (bar) pressure

High distributor plate operating temperatures will require the use of more expensive construction materials. For pressurized operation, insulation costs and the cost of the pressure vessel may also increase.

Pressure

As the operating pressure increases, the bed area for a given thermal input decreases. This generally reduces the overall cost of the combustor. However, the cost of items such as the coal feeding system, ash handling system, and heat transfer surface are largely independent of pressure. Only a proportion of the total combustor cost is therefore related directly to the operating pressure. The value of this fraction depends on the design and operating conditions, but typically lies in the range of 1/3 to 2/3.

Availability of Major Equipment Items

This section reviews the development status of fluid bed combustion and the R&D required to commercialize the technology for CAES applications, summarizing where appropriate the information contained in earlier sections. The availability of the major equipment items is considered first, followed by an identification of the R&D requirements, preliminary cost estimates, and timescales for the development programs.

Coal and Sorbent Feeding

For atmospheric pressure fluid bed combustors, two systems of feeding have been used. These are under-bed feeding and over-bed feeding.

With under-bed feeding, the feed is conveyed pneumatically to nozzles at the base of the bed. The feedstock is dried coal, or a mixture of dried coal and sorbent, and is crushed to a size that will give good fluidization in the bed. The feed rate is usually controlled by mechanical devices, such as commercially available rotary valves or screw feeders, that have only to seal against the atmospheric bed pressure of typically 0.10 to 0.15 atm (bar). A recent development is the Babcock and Wilcox direct firing system (Ref. 2-61). This follows conventional practice for pulverized coal fired systems, and thus combines coal preparation with pneumatic conveying.

Over-bed feeding employs devices that feed coal to the surface of the bed, e.g., sprinklers. The top size of the coal can be considerably larger than the mean particle size of the bed material, and feeding the coal to points near the periphery can help to carry the coal down into the bed. The coal preparation equipment for over-bed feeding systems is simpler than for pneumatic conveying systems, and over-bed feeding is less susceptible to problems caused by debris and moisture. However, shale particles that are too large to be

fluidized in the bed have to be avoided, and the technique is therefore limited to cleaned coals or to coals in which the ash is disseminated throughout the particle.

The over-bed system of coal feeding is being developed particularly for use with beds of low depth, e.g., up to about 3.3 ft (1 m). It is unlikely to be applied successfully to deep beds or beds closely packed with tubes, and is not therefore attractive for use in pressurized fluid bed combustion.

For pressurized fluid bed combustion, under-bed systems employing pneumatic conveying are preferred, and may be with or without mechanical devices such as rotary valves. The only commercially available system (Petrocarb Inc., New York) is based on lock hoppers to pressurize the feedstock with dense-phase pneumatic conveying. It has no mechanical device to control feed rate, relying for control on feeder pressure and on conveying airflow, and is therefore sensitive to variations in combustor pressure. To ensure free coal flow, the coal has to be dried, preferably to about 1 percent below the air-dry moisture content.

The US Department of Energy (Ref. 2-88) has reported several schemes under development for feeding fuel into pressurized systems. The main motivation for this work is for feeding coal to pressurized gasification systems. However, successful developments would be applicable to pressurized fluid bed combustors provided that the devices performed satisfactorily under the pressure pulsations which occur with deep fluid beds and which can cause stoppages in normal feeding systems. Development is also underway on mechanical devices for operation at high pressure to give feed rate control with relative freedom from the effects of pressure variations. The main problem here is the protection of bearings from wear. Under-bed feed systems are also being developed that would allow damp coal to be fed at controllable rates obviating the need for a coal drying plant.

Coal Distribution

Efficient lateral distribution of fuel in the bed is necessary to ensure good contact with oxygen in the combustion air, and hence to facilitate good combustion efficiency and to avoid local reducing zones in which corrosion of air heater tubes could occur. These considerations do not apply to the distribution of SO_2 sorbent, which has a long residence time in the bed and can become distributed uniformly.

Lateral diffusion of particles in a fluid bed is slow compared with vertical diffusion, so to obtain efficient distribution coal is usually fed to nozzles that are closely spaced. The spacing needed between nozzles depends on performance criteria and on operating conditions. A typical spacing for an atmospheric pressure bed would be about 10 to 20 ft² (1 to 2 m²) per coal feed nozzle, while the spacing for a pressurized bed

might be closer. The complexity and capital cost of coal distribution can be illustrated by considering that, for a CAES plant with a thermal efficiency (generation phase) of about 80 percent, up to one coal feed nozzle per MW(e) could be required.

Alternative fuel distribution techniques are being studied to ease the problems. All show promise in particular applications. These techniques include promotion of bed material circulation, use of tapered beds, and rotating distributors.

The techniques being studied for promoting bed circulation include "gulf-streaming" in which use is made of the effect of local high and low fluidizing velocities. Such techniques show promise for increasing either the fuel residence time in the bed or the lateral diffusion rate of the fuel, enabling the fuel feed points to be more widely spaced. However, the existence of velocity gradients may result in local defluidization and hot spots, particularly on turn-down.

Studies are being made of arrangements of tapered sections at the base of the bed. These have the potential advantage of reducing the number of coal feed nozzles needed by enabling coal to be fed into high-velocity regions, resulting in improved distribution. They also ease the problems of maintaining good fluidization on turn-down, but care has to be taken to avoid excessive combustion intensity in local regions, increased attrition and consequently elutriation, and bypassing of combustion air (bed-spouting).

Rotating coal distributors have been proposed but have not undergone development. The concept is to feed coal pneumatically via a hollow vertical spindle to one or more feed nozzles in a horizontal arm. Rotation of the spindle would cause the arm to sweep over a large plan area of the bed ensuring excellent coal distribution. Provided mechanical problems can be solved, this may well prove to be an attractive coal distribution technique.

Combustor Design

Three elements must be considered in the combustor design: containment, air distribution and heat transfer.

Containment

Fluid bed combustors may be circular or rectangular in plan, with walls that are vertical and/or sloping (to give a lower cross-sectional area and therefore higher fluidizing velocity at the base). The walls may be either refractory-lined or of membrane-wall construction. In the latter case, the walls form part of the heat-transfer surface, as in pulverized fuel-fired air heaters that have been employed, mainly in Germany.

For pressurized systems, the combustor can be of similar construction but supported or suspended within a pressure shell. The combustion air enters the pressure shell, and the furnace walls therefore have to withstand a pressure differential not exceeding that across the air distributor and bed. The pressure shell, which would generally be internally insulated, can sometimes be used to accommodate other components, e.g., dust removal cyclones.

The furnace has to be of adequate height to accommodate the fluid bed and the freeboard (disengaging space above the bed). Freeboard heights of at least 10 to 15 ft (3 to 5 m) are generally recommended to obtain efficient disengagement. The disengagement efficiency of the freeboard can be enhanced by installing baffle systems.

The orientations of the pressure shell that can be considered are horizontal axis, vertical axis and spherical. A horizontal-axis cylindrical shell would give freedom of choice on bed plan area, or of the number of combustors arranged side by side within a common shell. However, it would impose a practical limit on bed depth of 10 to 13 ft (3 to 4 m). Beds of greater depth have to be accommodated in vertical-axis pressure shells. Vertical shells can also accommodate several combustors, stacked one above another. Spherical shells provide additional accommodation for ancillary equipment, particularly cyclone dust collectors, which would otherwise require separate pressure shells.

There are no major foreseeable problems in combustor containment that cannot be solved by sound engineering design. However, there is an absence of data on the forces acting on bed containment surfaces resulting from the behavior of fluid beds.

Air Distribution

The combustion air enters a fluid bed combustor through a distributor which has the functions of supporting the bed and of providing uniform distribution of airflow. The distributor, therefore, has perforations that are sufficiently small to prevent back-flow of particles, and sufficiently numerous to give adequately uniform air distribution over the operating range without excessive pressure drops.

Simple air distributors are perforated plates. They are cheap, but can become distorted as a result of being heated to high temperature. A number of standpipe or bubble-cap designs can overcome this problem by discharging the air into the bed at a short distance above the bed-support plate, which is, thus, protected by a layer of cool, unfluidized bed material. This design is illustrated in Fig. 2-36.

In many combustor designs, the air distributor has to be penetrated by one or more of the following: bed material discharge pipes, fuel, SO_2 sorbent and bed material feed pipes, risers and downcomers for tube banks in

SKETCH OF TYPICAL DISTRIBUTOR DESIGN

FIG. 2-36

the bed, start-up burners, and fines recycle inlet pipes. These complicate the task of designing for good air distribution. Schemes for startup of large combustors for most atmospheric pressure and some pressurized systems involve fluidization of only part of the bed, i.e., admitting air to only part of the air distributor. This necessitates compartmentation of the plenum below the distributor and separate air supplies to each compartment.

No major developmental problems are foreseen in connection with air distribution. However, there is a need for improved designs to reduce costs and investigation of the forces exerted by the fluid bed and of the thermal stresses during startup. The latter is particularly relevant to CAES systems in which the use of preheated combustion air leads to a higher distributor metal temperature than in conventional applications.

Heat Transfer Surface

As with the bed containment and the distributor plate, there is a need for data on the forces exerted on immersed heat transfer surfaces by the fluid bed. Other aspects of tube bundle design are considered in the section entitled Tube Bundle Design.

Hot Gas Cleanup

Techniques for hot gas cleanup are reviewed in a previous section entitled Hot Gas Cleanup for Pressurized Fluid Bed Combustors. The development status is summarized here for completeness.

The hot gas leaving a fluid bed combustor contains some or all of the mineral matter in the feed, together with unburned carbon. The proportion of mineral matter elutriated depends on:

- (i) the size distributions of the coal and SO_2 sorbent feed,
- (ii) the physical characteristics of the ash,
- (iii) the rates of attrition and decrepitation in the bed, and
- (iv) the plant design and operating parameters.

In atmospheric pressure systems, the unburned carbon content of the elutriated material may be high, and it may be necessary to recycle the fines or to feed them to a separate carbon burn-up cell. In either case, standard grit refiring and/or pneumatic conveying systems would be employed to handle the fines, which in general, would be cool after passing through the convection passes of the system. Final gas cleanup to comply with air pollution requirements would be with standard equipment (e.g., bag house filter or electrostatic precipitator).

In pressurized systems, the gas has to be cleaned hot before entering the gas turbine to avoid erosion or fouling of the turbine blades. The degree of

gas cleanup needed is high, particularly for particles larger than 10 micron in size. However, it is possible that large gas turbines will be able to tolerate significant concentrations of particles smaller than about 5 micron, although this requires confirmation.

At present, the only commercially developed system of hot gas cleanup is cyclone dust collectors. Cyclones have well-understood characteristics, and the performance of systems containing cyclones in parallel and/or in series can be predicted. By using several stages in series, each containing a large number of small (e.g., 8 in. to 16 in. (0.2 m to 0.4 m) in diameter) cyclones in parallel, and by careful design of the dust removal system and gas flow paths, a performance approaching that which may be acceptable to a gas turbine can be achieved. However, the cost and complexity of such a system is considerable.

Variations on the basic design of cyclone dust collectors have been claimed to give greatly improved performance at reduced cost, but the claims have yet to be proven with dust-laden gases from a pressurized fluid bed combustor. Proposed systems include the following:

- (i) two-stage, Siemens-type cyclones employing a secondary flow to augment the effect of the swirl ("Tornado" and "Aerodyne" are two commercially available forms of this cyclone system).
- (ii) shave-off of the swirling gas near the inner periphery of the cyclone exhaust pipe. The dust escaping into the exhaust is concentrated in this zone and shaving off the gas is claimed to recover some of the loss. The main advantage might prove to be removal of the coarser particles that escape the cyclone and would cause the greatest damage to a turbine.
- (iii) electrostatic charging of the dust entering the cyclone.

Because of the inertial principles governing the operation of cyclone dust collectors, the extent of any improvements in performance will be limited, particularly for finer particles. Even if cyclones could be used to clean the gas adequately for the gas turbine, additional cleanup by conventional means (filter or precipitator) might be needed before the gas could be exhausted to the stack.

A considerable amount of research and development effort, therefore, is being currently devoted to alternative hot gas cleanup techniques that will fulfill both the gas turbine and environmental needs (Ref. 2-89). The techniques being studied on a small scale include the following:

Granular Bed Filtration

Several variants of the granular bed filtration technique are being studied. They can be classified as:

(i) Fixed beds:

Dirty gas flows down through a filter bed of granular material. The bed is cyclically cleaned by back blowing, usually with agitation (e.g., by fluidization), and the elutriated dust settles into a hopper.

(ii) Panel bed filters:

Dirty gas flows across a vertical panel of granular material held between two louvered or perforated plates. Cleaning is either by cyclic backblowing, or by removal of the medium, external cleaning and return to filter.

Ceramic Fiber Filtration

Ceramic fiber filters are being developed as high-temperature, high-pressure versions of baghouse filters. Cleaning is by backblowing or by pulsing with high-pressure gas. The studies being made concern the effect of filtration performance and life of the many variations that are possible in the type of ceramic material, the physical characteristics of the fibers, packing density, porosity and permeability, physical strength and methods of support, and pressure drop and cleaning frequency.

Electrostatic Precipitation

Electrostatic precipitators offer the advantages of high collection efficiency for the finer particle sizes, low pressure drops, and controllability of collection efficiency. For these reasons they are being developed for use at high temperatures but have not been studied extensively with dusty gases from a fluid bed combustor. Cleaning is by rapping of the electrodes.

Depressurization and Disposal of Output Solids

The output solids from fluid bed combustion systems comprise the fuel ash and spent sorbent, together with small amounts of unburned carbon. In some circumstances, all of the output solids may be collected from the combustion gases, although, in general, some of the solids output appears as bed material extracted to control bed depth.

In an atmospheric pressure plant, bed material can be removed by an overflow weir, or by a standpipe from the base of the combustor. In the latter case, agglomerates can be removed. The bed material and dust from the dust collection equipment can be handled and disposed of by conventional boiler ash equipment. In a pressurized plant, however, the output solids have first to be depressurized.

Depressurization systems for solids from dust collectors can be of two main types:

- (i) dry systems involving lock-hoppers provided with valves capable of operating in contact with hot or partially cooled solids, and
- (ii) wet systems in which the solids are quenched with water and depressurized as a slurry.

Neither of these systems present insuperable problems, but some development work is needed.

Depressurization of bed material from pressurized fluid bed combustors has not been studied on a sufficiently large scale to develop a system for continuous ash withdrawal such as would be needed for a commercial scale plant. The objective is to extract material from the bed at a controlled rate so as to maintain the desired bed depth. This is likely to require various combinations of standpipes, dense phase transport, air slides, etc., to transfer the material to a solids cooling and depressurization vessel. One form of vessel would be a tank in which the hot bed material would be quenched in water and depressurized as a slurry. An alternative would be to cool the solids directly or indirectly as part of a heat recovery system; this would facilitate dry handling by conventional means, e.g., lock hoppers.

Heat recovery from bed material and/or primary cyclone solids might be worthwhile under conditions for which the solids output is high, i.e., with coals of high ash content, or under conditions needing a high throughput of sulfur acceptor. The heat recovery system can be either indirect heating of air in tubes in a moving bed of output solids, or direct heating of combustion air in a fluidized bed. Design data for both types of cooling systems are needed.

Tube Bundle Design

In general, the fluid bed environment is less aggressive than other combustion systems towards heat transfer surfaces. This is one of the major advantages of fluid bed combustion, particularly for steam generation, superheating and reheating. However, the problems of corrosion can become significant at the metal temperatures needed for air-heating duties (1382 to 1652 F (750 to 900C)).

The performance of different materials in a fluid bed combustor was reviewed in a previous section entitled Materials of Construction. The lack of sufficient experimental data make it difficult to establish the suitability of heat transfer materials operating at metal temperatures above 1202 F (650 C) in beds with acceptor addition. There is, therefore, a considerable incentive to pursue materials testing and development work to identify materials for high temperature heat transfer surfaces with an acceptably long life.

Several other aspects of the design of air heater tube banks need to be investigated. In general, the tube banks, and hence the combustor beds, will be deeper than have been studied so far. In order to minimize these depths, the tubes will be closely spaced, and studies will be needed for the extent to which the tube spacing can be reduced while maintaining acceptable fluidization characteristics, combustion and sulfur retention efficiency, and bed-side heat transfer coefficients.

Although it is known that powerful forces can be exerted on tubes submerged in fluid beds causing vibration of the tube bank, there is little published information on this subject. The development of designs of deep tube banks will have to take into account the effects of these forces, thermal expansion and close tube spacing.

Load Following and Control

The main techniques for startup, turndown and shutdown of a fluid bed combustor were discussed briefly in a previous section entitled Off-Design Operating Characteristics. These are summarized in this section and the implications for combustor and control system development assessed.

Combustor startup techniques vary widely depending on the application, and it is only in simple systems that rapid startup can be achieved. The startup system has to be designed to heat the bed to a temperature at which coal will ignite and burn with a reasonable combustion efficiency, but to avoid excessive consumption of premium fuel during the startup period. Startup techniques can be more efficient and simpler in systems in which the bed is slumped hot on shutdown and restarted before cooling is far advanced.

Shallow beds, such as those in atmospheric pressure combustors, can be started by injecting a suitable gas (natural gas, propane, etc.) into the bed. Initially the gas, ignited by a pilot burner above the bed, burns at the bed surface. At this stage the bed may not be fluidized because of the low air velocity and viscosity. However, as heat is conducted away from the combustion zone, the bed becomes progressively fluidized, allowing the combustion zone to move downwards through the bed. A simple system would employ one or more gas feed pipes at the base of the bed. More sophisticated systems using bubble-cap air distributors have provision for mixing combustible gas with air in each bubble cap. An alternative technique for shallow beds employs large conventional oil burners in the freeboard. The flames are directed onto the surface of the bed, which thus becomes progressively heated and fluidized. Compartmentation of the air plenum makes it possible to restrict employment of either of the above techniques to one small part of the bed. Successive compartments can be ignited from the first, enabling the combustion zone to spread.

In pressurized fluid bed systems, the beds are generally deeper than in atmospheric pressure plants and contain banks of tubes that are more closely spaced. Furthermore, in gas turbine cycles in which the compressor is driven by the gas turbine, startup is complicated by the characteristics of the gas turbine and compressor. The preferred startup technique for deep beds depends on the particular cycle and application, but the principal approaches are likely to include the following:

- (i) passing preheated air downwards through a static bed, or upwards through the fluidized bed so that the air would be heated directly by burning oil or gas by using conventional equipment, and
- (ii) starting with a shallow bed, under-fired with gas as already described for atmospheric pressure combustion, and increasing the depth once coal combustion was established.

Control techniques that can be used for fluid bed combustion systems are dependent on the nature of the system, some of the factors being the operating pressure (atmospheric or elevated pressure), the air supply system (fan, single shaft gas turbine, multi-shaft gas turbine), and the heat transfer surface (open bed, air tubes, steam tubes). Applications of fluid bed combustion to CAES systems are therefore likely to require control systems which differ significantly from conventional power generation cycles.

In atmospheric pressure combustion systems, the preferred method of load control generally involves compartmentation of the air distributor (Ref. 2-61), and possibly of the bed as well. As already discussed, compartmentation can assist startup. For load following, the slumping of some compartments can give step changes in load because the poor conductivity of slumped bed material results in a much reduced rate of heat transfer. Trimming of the load between step changes would be obtained by adjusting the coal feed rate and combustion air flow within acceptable limits. The rate of heat transfer to tubes can be reduced either by reducing the bed temperature or reducing the fluidizing velocity so that some of the tubes are exposed above the bed. An increase in the load is met by re-fluidizing a slumped region of the bed and restoring the coal feed.

In pressurized fluid bed combustors, compartmentation of air distributors is less likely to be feasible because the beds have a smaller plan area and will not have air plenum chambers which can easily be isolated. However, large installations are likely to employ more than one combustor unit and step changes in load will be possible by slumping or re-activating one or more combustors.

Several methods of load control are potentially available and are discussed in Ref. 2-20. The choice of technique depends on several factors including

the combustor design and gas turbine characteristics. The possibilities for reducing load include various combinations such as the following:

- (i) reducing the fluidizing velocity and coal feed rate,
- (ii) reducing the operating pressure and coal feed rate,
- (iii) by-passing combustion air and reducing the coal feed rate to cool the turbine inlet gases,
- (iv) in designs containing air heater tubes in the bed, air can be diverted from the tubes to a bypass, accompanied by a reduction in the coal feed to cool the turbine inlet gases,
- (v) removing some hot bed material to insulated storage (for subsequent return when load is to be increased again); the feasibility of doing this has been demonstrated only in cold models, and
- (vi) circulating bed material at controlled rates between two beds, combustion in one bed and heat transfer to tube banks in the other (Ref. 2-90); design data and methods of controlling circulation rates are needed for this technique.

Shut-down of atmospheric or pressurized combustors can be either:

- (i) an extension of load reduction with final cessation of coal feed when the bed temperature falls below the limit for satisfactory combustion efficiency, or
- (ii) abrupt slumping of the hot bed as closely as possible after cessation of coal feed; this method has advantages if startup is foreseen within a few hours, but care must be taken to burn out all the carbon in the bed before slumping.

It is unlikely that any insuperable problems in control techniques will be encountered once the characteristics of the system are fully understood. To this end, information is needed from experiments on a representative operating scale to determine the response rates of the combustor, coal-feed system, etc., to changes in operating parameters.

Regeneration of Sulfur Acceptor

This topic is treated only briefly, since it is assumed that initially regeneration will not be employed in CAES systems. Regeneration can reduce the need for fresh sorbent and the disposal of spent sorbent. However, it involves

the provision of additional capital equipment, consumes additional fuel and complicates control. It is therefore economically justified only if the cost for fresh sorbent is high, e.g., because of high freight charges or the need for high throughputs of sorbent.

The only successful regeneration technique so far evolved is to heat the sulfated sorbent to a temperature of 1832 to 2192 F (1000 to 1200 C) at conditions close to stoichiometric combustion. The sulfate decomposes to give calcium oxide and sulfur dioxide, which then has to be recovered, generally as sulfuric acid or elemental sulfur. An alternative process in which the sulfate is reduced to sulfide and then reacted with steam and carbon dioxide to give calcium carbonate and hydrogen sulfide appears to result in rapid deactivation of the sorbent.

R & D Requirements

The main areas in which R & D on fluid bed combustion is required are summarized in the following paragraphs.

Coal and Sorbent Feeding

Improvements are needed in the design of mechanical devices for controlling feed rate against a pulsating pressure, particularly to minimize wear on rubbing surfaces and damage to bearings by ingress of particles. This requires R & D effort by feeder manufacturers and testing on a pressurized fluid bed combustor pilot plant.

Development of an under-bed feed system that would allow damp coal to be fed at controllable rates is necessary to obviate the need for a coal-drying plant. This is work related to that reported by the US Department of Energy (Ref. 2-91). Any device showing promise would need to be tested on a pressurized fluid bed combustion pilot plant.

Coal Distribution

Establishment of the maximum practicable spacing of coal feed nozzles in pressurized fluid bed combustion systems with deep tube banks is required. Some information on this topic will be obtained in the research program planned for the International Energy Agency (IEA) Facility at Grimethorpe, UK (Ref. 2-92).

Combustor Design

Measurements of the forces acting on combustor, distributor plate, and tube bundle must be made. Some measurements are planned in the IEA Grimethorpe

research program (Ref. 2-92), but studies are also needed with deep closely-packed tube banks. Measurements of thermal stress on the distributor plate and development of improved designs must also be made.

Hot Gas Cleanup

The dust cleanup requirements of gas turbines must be established by tests with cascades of gas turbine blades and target rods in gas streams at representative velocities and dust loadings. This is an on-going activity in the Leatherhead facility (Ref. 2-74) which will later be augmented by work at Grimethorpe (Ref. 2-92) and elsewhere. Tests of improvements in inertial dust-collecting devices including exhaust gas shave-off and electrostatic conditioning of inlet dust must be conducted. This would involve tests on a pressurized fluid bed combustion pilot plant. Development of alternative designs of granular bed filters, ceramic fiber filters and high-temperature, high-pressure electrostatic precipitators must be undertaken. Some of this work is in progress (Ref. 2-54).

At a later stage, equipment showing the greatest promise needs to be proved on a large pressurized plant incorporating a gas turbine of representative size.

Depressurization and Disposal of Output Solids

Both wet and dry systems must be developed. Some information on these systems will be obtained from the IEA Grimethorpe facility which incorporates wet systems (Ref. 2-93). This needs to be augmented by work on controlled extraction of bed material on pressurized fluid bed combustion pilot plants. Experiments to obtain design data for direct and indirect heat recovery systems will also be needed if high-ash coals or high sorbent throughputs are anticipated for CAES plant.

Tube Bundle Design

Long-term corrosion testing of candidate air heater tubing alloys is an on-going activity, and more work is needed, e.g., with clad tubes. This work can be undertaken in atmospheric pressure combustors, such as the rig specially built at the UK National Coal Board, Coal Research Establishment, Stoke Orchard. Cold model studies of fluidization behavior and solids circulation in the deep beds with closely packed tubes of pressurized fluid bed air heaters need to be conducted. In addition, studies have to be conducted in pressurized fluid bed pilot plants of the effects of using deep closely packed tube banks on temperature distribution, fire-side heat transfer coefficients, combustion efficiency, and sulfur retention by sulfur acceptors.

Load Following and Control

The techniques for startup will need to be studied, and the appropriate equipment tested, once the relevant characteristics of the CAES system and of the gas turbines to be employed have been established. Some information will be gained from operation of the IEA Grimethorpe facility (Ref. 2-93).

Experiments have to be performed to establish the effect which changes in operating parameters will have on response rates for the combustor, coal-feed system, etc. Some work in this area is planned at Grimethorpe (Ref. 2-92) and elsewhere, but more will be needed in a bed with a deep closely-packed tube bank if CAES systems will be required to follow changing loads.

If design and response rate studies ultimately were to indicate the need to employ bed level changing, or circulation of bed material to aid control, these techniques will require model work and development on a representative scale.

Regeneration of SO₂ Sorbent

Should the need for this arise, development is likely to stem from the work of Exxon Research and Engineering Co. (Ref. 2-54), Argonne National Laboratory (Ref. 2-94) and others.

Availability of Pilot Plants

The pilot plants that are potentially available for the R & D work outlined in the previous section include the following:

- (i) an atmospheric pressure corrosion test rig at the National Coal Board (NCB) Coal Research Establishment (CRE) at Stoke Orchard, UK (Ref. 2-8). This is a combustor of 12-in. (0.3-m) square plan area.
- (ii) the atmospheric pressure rigs of Fluidyne Engineering Corporation of Minneapolis, Minnesota (Ref. 2-88). One is a 18-in. (0.45-m) square plan area test unit, and the other a combustor of 39 x 63 in. (1 x 1.6 m) plan area at Owatonna, Minnesota.
- (iii) an atmospheric pressure fire tube boiler at the NCB Coal Utilization Research Laboratory (CURL) at Leatherhead, England. This has an oil-fired or coal-fired combustor 43-in. (1.1-m) diameter and with a thermal input of up to about 3.3 MW(th) (Ref. 2-95).
- (iv) a pressurized fluid bed combustor technology unit of about 2.3 MW(th) coal input at Curtiss-Wright Corporation, Wood-Ridge, New Jersey. This unit is coupled to a Rover gas turbine.

- (v) a pressurized fluid bed air heater pilot plant at Curtiss-Wright Corporation, Wood-Ridge, New Jersey (Ref. 2-88). This is a project plant for which construction has not yet been authorized. The plant will burn 5 tons/hour (4.5 metric ton/hr) of coal at about 4 atm (bar), and will produce 7 MW(e) of gas turbine power and 6 MW(e) of steam turbine power (using steam from a waste heat boiler). The air heater tubes in this plant will be vertical finned tubes.
- (vi) a pressurized fluid bed pilot plant at NCB, CURL at Leatherhead, UK (Ref. 2-96). This has a combustor of up to about 8 x 28 in. (0.2 x 0.7 m) plan area, operating at pressures up to about 6 atm (bar), with a maximum thermal input of 5 MW (th). It is usual to operate this facility with two off-gas streams enabling simultaneous studies to be made with different gas cleanup and turbine blade cascade systems.
- (vii) the IEA pressurized fluid bed facility at Grimethorpe, UK (Ref. 2-93). This has a combustor 6.6-ft. (2.0-m) square and has been designed for operation at pressures up to 12 atm (bar) with coal heat inputs up to about 87 MW (th). It will be provided with at least one off-gas slip stream for testing hot gas cleanup systems and corrosion/erosion of cascades of gas turbine blades. At a later stage in the program, a gas turbine may be installed.

Pilot Plant R & D Program

A program of R & D based on the pilot plants listed in the previous section is outlined in Table 2-25.

The estimated duration of the work does not take into account the time required to design, manufacture, and install the new equipment that would be required in the suggested plants. These times would depend on the plant selected for each study, and on the extent to which design, manufacture, and installation activities can run simultaneously with each other and/or test runs. For example, the program based on the CURL pressurized fluid bed plant might occupy a total of 2 to 2 1/2 years, whereas one based on the IEA facility would probably be 3 to 4 years.

The order of the costs involved in the experimental program has been derived by making the preliminary estimates for that work which could be carried out at the NCB facilities. These are summarized in Table 2-26. The costs are expressed in US dollars, assuming \$2 equals one pound sterling, and are based on January 1979 money values with no allowance for inflation. The estimates include the cost of chemical analyses and reporting but assume that operation of the plant is with free-issue coal and dolomite.

TABLE 2-25

PILOT PLANT R&D PROGRAM

Topic	Outline of work scope	Estimated duration	Suggested alternative sites
Coal and sorbent feeding	Testing of devices (developed elsewhere) for feeding solids under pressure to improve existing equipment.	Incorporated in other work.	CURL (PFBC); Curtiss-Wright; IEA.
Coal distribution	Cold model tests of bed circulation system.	6 months	
	Incorporate developments in PFBC pilot plant.	Incorporate in other work.	CURL (PFBC); Curtiss-Wright "technology unit".
	Development of rotary coal feeder in AFBC	6 months	Fluidyne; CURL (AFBC)
	Development of rotary coal feeder in PFBC	Incorporate in other work.	Curtiss-Wright "pilot plant"; IEA.
Combustor design	Measurement of forces on bed walls, air distributor and tubes in AFBC and PFBC plant of sufficient scale to obtain meaningful data, particularly with close-packed tube banks.	Incorporate in other work.	Fluidyne; Curtiss-Wright pilot plant; IEA, CURL (PFBC).
Hot gas clean-up	Tests of at least 100 hours duration with candidate equipment to assess collection efficiency and effects on gas turbine blades.	12 months (plus tests on load control).	CURL (PFBC); Curtiss-Wright; IEA.
Depressurization and disposal of output solids.	Development of wet and dry handling techniques.	Incorporate in other work.	Curtiss-Wright pilot plant; IEA.
	Study controlled extraction of bed material.	3 months	CURL (PFBC); Curtiss-Wright technology unit.

TABLE 2-25 (cont'd)

PILOT PLANT R&D PROGRAM

Topic	Outline of work scope	Estimated duration	Suggested alternative sites
Tube bundle design	Testing of candidate air heater tube materials for 1000, 2000 and 3000 hours	6-9 months	CRE, Fluidyne, CURL (AFBC)
	Metallographic examination	4 months	
	Cold model tests of bed circulation with closely packed tube bundles in beds. Study of performance in PFBC.	6 months Incorporated in other work	CURL (PFBC); Curtiss-Wright; IEA.
Load following and control	Develop start-up techniques relevant to the CAES system to be adopted.	3 months (plus start-up as part of other test work).	CURL (PFBC); Curtiss-Wright; IEA.
	Tests of response rates; simulation of likely load-following patterns.	6 months	CURL (PFBC); Curtiss-Wright; IEA.

TABLE 2-26

COST OF PILOT PLANT R&D PROGRAM

Topic	Work program	Cost
Coal and sorbent feeding	Procure alternative design of coal feed rate control device and install on existing Petrocarb feeder for CURL PFBC rig. (Note, operation of the rig to test the device is incorporated in other work.)	\$ 10,000
Coal distribution	Design, construct and test in the CURL AFBC fire-tube boiler a rotary coal distributor.	\$ 100,000
Combustor design	Procure and install in the CURL PFBC rig equipment to measure forces acting on tubes, walls and air distributor. (Note, operation of the rig is incorporated in other work.)	\$ 14,000
Hot gas clean-up	Modify CURL PFBC rig to enable alternative types of final gas clean-up systems to be tested at a gas mass flow of 1.5 kg/s.	\$ 200,000
	Procure and install one or more of the following designs of final gas clean-up equipment:	
	(i) Improved cyclone	\$ 160,000
	(ii) Ceramic fiber filter	\$ 500,000
	(iii) Electrostatic precipitator	\$ 600,000
	(iv) Electrified granular bed filter	\$ 500,000
	100 hour test	\$ 180,000

TABLE 2-26 (cont'd)

COST OF PILOT PLANT R&D PROGRAM

Topic	Work program	Cost
Depressurization and disposal of output solids	Install refractory lined vessel with refractory lined pipe into the combustor of the CURL PFBC rig, together with means for discharging solids at a controlled rate to waste, or for recirculating them to the PFBC bed. (Note, operation of the rig is incorporated in other work.)	\$ 50,000
Tube bundle design	Materials test program; three 1000 hour tests in the CRE AFBC rig, including metallographic examinations.	\$1,500,000
	Construct a large scale model of a section of a preferred design of tube bank and use it for a test program, including studying the effects of design changes aimed at enhancing rates of circulation of bed material.	\$ 130,000
	Based on design studies and results of the model program, design, construct and install a tube bank in the CURL PFBC rig. Operation of the rig to test the tube bank is incorporated in other work.	\$ 160,000
Load following and control	100 hour test on CURL PFBC rig for studies of start-up, load following, response rates, controlled extraction of bed material, etc.	\$ 180,000
TOTAL	Overall program, including tests of all four alternative final gas clean-up systems.	\$4,284,000

Demonstration and Commercialization

The pilot plant R & D program outlined in the previous section establishes the design concepts and operating parameters required to proceed to a demonstration scale plant. Although beyond the scope of the present task to estimate the cost of a demonstration program, the order of the costs can be judged from the combustor cost estimates given and the costs of the IEA Grimethorpe plant. The latter is a 80-MW(th) pressurized combustor situated at an existing power station with which it shares some facilities. The capital cost, including project management, is 10.2 million pounds sterling at December 1976 money values. A five-year operating program is planned, costing 6.65 million pounds sterling at December 1976 money values.

The timescale on which fluid bed CAES systems become commercially available depends on the design of fluid bed combustors required. Indicative estimates of the development of the technology are given below.

- (i) 1985: atmospheric pressure combustor with air heater tubes used in the bed, but with the metal temperature limited to 1202 F (650 C).
- (ii) 1990: pressurized fluid bed combustor with air heater tubes used in the bed, but with the metal temperature limited to 1202 F (650 C). The main delay compared with atmospheric pressure combustion is the development of hot gas cleaning systems, and testing the acceptability of the combustion gases to a turbine.
- (iii) 1995: pressurized or atmospheric pressure fluid bed combustors with air heater tubes in the bed operating at up to the bed temperature.

TURBOMACHINERY TECHNOLOGY

The first practical application of a gas turbine in a power system occurred in 1932 in Switzerland where a turbine driven axial compressor was used to pressurize a steam boiler. Electric utilities in the US began to use gas turbines during the late 1940's. By the mid-1970's, there were approximately 46,000 MW of gas turbine capacity installed in the US, or approximately 8.5 percent of the total US electricity generating capacity. During this period, gas turbines have achieved a very advanced state of development for both peaking-and base-load applications.

Current gas turbines typified by the UTC FT4, GE Frame 7, Westinghouse 501, and Stal Laval GT 120, can produce 30 to 80 MW per unit with a heat rate of 11,000 to 13,000 Btu (LHV)/kWh (11,605 to 13,715 kJ/kWh) when fired at 1400 to 2000 F (760 C to 1090 C) inlet temperature with pressure ratios of 10:1 to 16:1. Examples can even be found of engines operating at temperatures approaching 2200 F (1200 C), pressure ratios around 30:1, and output powers above 100 MW. However, all of these operating conditions for advanced gas turbines require the use of a clean, premium fuel such as natural gas or distillate fuel oil.

Attempts have been made at expanding gas turbine fuel selection to include coal. The feasibility of burning coal directly in an open cycle gas turbine was investigated by Bituminous Coal Research, Inc. as early as 1944 when a coal-fired competitor to the diesel engine for railroad applications was being sought. In the intervening years, a number of investigators have attempted to design and test direct coal-fired gas turbines. However, problems with corrosion, erosion, and deposition on turbine blading due to the amount and nature of the ash passed through the high-temperature combustion zone have frustrated the development of a commercially viable gas turbine which burns coal directly. Excellent reviews of both the analytical and experimental early coal burning gas turbine work are provided in Refs. 2-96, 2-97 and 2-98.

It is generally recognized that one of the principal factors contributing to the severe erosion and corrosion environment following a conventional pulverized coal-fired combustor is the very high local temperature which is achieved. In such a combustor, the peak gas temperature typically exceeds 2500 F (1370 C). This is well above the temperature at which the ash melts completely (ash fusion temperature). The melted ash can then become entrained where it will form dense spheres. During subsequent cooling of the gas, these molten droplets solidify forming very hard particulates which are extremely erosive. In addition to creating particulate problems, the very high temperature in the combustion zone could release high concentrations of alkali metal vapors from the ash. These vapors can then condense on cooler downstream metallic surfaces and accelerate corrosion.

One of the principal advantages of fluid bed combustors is their capability to operate at relatively low bed temperature. This is beneficial for two reasons. First, because the bed temperature is low, the ash fusion temperature is not exceeded and second, the low temperature reduces alkali metal vaporization.

It is not enough, however, to remain just slightly below the ash fusion temperature to prevent extreme erosion. The temperature must also remain below the sintering temperature. (Sintering is the forming of a more or less solid mass without thorough melting, i.e., the surface of a particle will melt permitting particulate agglomeration while hot and producing a hard surface upon cooling.) The ash characteristic most widely used to describe sintering behavior is the initial deformation temperature. The bed temperature is usually limited to several hundred degrees below the initial deformation temperature to avoid localized sintering. With the bed temperature so controlled, the particulate effluent from a fluid bed combustor is typically soft and powdery, and is therefore substantially less erosive than particles from pulverized coal combustors. Consideration of erosion is not completely eliminated, however, because a relatively high concentration of these particles could still cause erosion in the turbomachinery over extended operating periods.

In addition to reducing erosion potential, the relatively low bed temperature reduces alkali metal vaporization. However, as with erosion, consideration of corrosion is not completely eliminated. Even at the relatively low operating temperatures of an FBC, the gas phase could be saturated with alkali metal vapors. As a result, the flux of alkali vapors to metallic surfaces would be high enough that the rate of hot corrosion attack would not be restricted by alkali concentration. This would create conditions many times more severe than normally encountered in present gas turbine applications.

Consequently, although introduction of an FBC as a method for using coal with a gas turbine reduces the magnitude of the erosion and corrosion problems as compared to direct pulverized coal firing, some challenges still remain before gas turbines can be demonstrated to be compatible with fluid bed combustors.

During the past five years, a broad spectrum of gas turbine materials with the potential for resisting erosion and corrosion at high temperatures (i.e., ferritic steels, austenitic steels, nickel-based alloys and cobalt-based alloys) have been tested in the US and the UK using real and simulated fluid bed environments. An excellent, current review of these tests was presented at the Conference on Corrosion/Erosion of Coal Conversion System Materials (Ref. 2-99). In these tests, most of the high strength, high temperature exotic alloys suffered excessive sulfidation and hot corrosion attack over all temperature ranges of interest. The iron-based alloys, however, seemed to consistently display superior corrosion and erosion characteristics. In particular, the FeCrAlY-type alloy (a high chromium ferritic steel with aluminum and yttrium added) looks promising. Unfortunately, these alloys lack strength at high temperature, so they could only be used as cladding on stronger base metals. In addition, commercial development of this alloy is still several years away.

Within the last year, tests have been conducted in both the US and UK to evaluate the long-term corrosion and erosion effects of PFBC flue gases on gas turbine blades. The results of these tests have been very encouraging. In the U.S. a 1000-hr rig test of a small high-speed gas turbine incorporating several materials and coatings for evaluation and operating on PFBC flue gas produced results better than was anticipated (Refs. 2-100 and 2-101). A rotor segment with platinum aluminide coating displayed only 1 mil (.025 mm) of erosion and no corrosion. On the stator side the FeCrAlY coated surfaces displayed no erosion or corrosion. In the UK after 650 hours of testing the turbine blades exhibited no damage when operating in PFBC flue gas (Refs. 2-102).

There are, therefore, reasons to believe that solution to the compatibility problems which exist between the FBC and gas turbine equipment is possible. Long-term materials testing coupled with erosion, deposition and hot gas cleanup testing are still required, however, to verify preliminary lifetime forecasts. Also, a large gas turbine must be subjected to real FBC operating conditions for a considerable period of time before a prudent decision can be reached regarding the commercial viability of this concept.

In the following commentary, additional discussion is provided on turbomachinery design considerations, the availability of turbomachinery for coupling with fluid bed combustors, and the FBC effort required to produce compatibility between the fluid bed combustor and the turbomachinery.

Turbomachinery Design Considerations

It should be noted that the discussion on turbomachinery design considerations deals exclusively with the problems of gas turbines coupled with pressurized fluid bed combustors. In general, these problems would not be present if atmospheric fluid bed combustors were used because the gas passing through the turbine would probably be clean air without significant quantities of erosive or corrosive constituents.

The turbomachinery in an FBC-augmented CAES plant must be designed to be compatible with the effluent from the combustor. A substantial amount of conceptual CAES turbomachinery design effort has been expended in connection with previous studies dealing with current technology oil-fired systems. However, the upper operating temperature limit of a coal-fired PFBC is considerably below the clean fuel capability of these gas turbines and, in fact, represents temperature levels first used in gas turbines nearly 20 years ago. This relatively low temperature level might allow the use of simple, uncooled turbine blading. Unfortunately, it will also result in a gas turbine with lower specific work and higher cost per unit of output.

Operation of a gas turbine using the effluent from a PFBC also introduces a number of technical problems. The principal problems are associated with overcoming the potential erosion and corrosion of the turbine blades which involve a detrimental effect on operating lifetime. Another problem is the

possible deposition of solids on the blade in sufficient quantity so as to alter the blade profile and disrupt the aerodynamic flow of gas past the airfoil. Still another problem is the unknown effect on gas turbine reliability and maintenance requirements caused by the uncertainty and variability associated with combustor effluent.

To develop an understanding of the aforementioned problems, it is necessary to examine the interface conditions which are expected to exist between the PFBC, gas cleanup equipment, and the gas turbine components. These conditions are best described by the key interface parameters: pressure, temperature, particulate concentration, sulfur carryover and alkali carryover. The following sections provide a discussion of these key interface parameters with particular emphasis on their relationships with gas turbine erosion and corrosion.

Erosion

One key uncertainty with PFBC systems concerns downstream turbine erosion caused by carryover of particulates from the bed. These particulates, especially the larger sizes, could cause erosion of the turbine blades at such a high rate as to make the gas turbine inoperable in a short time, thus, making the whole PFBC scheme uneconomical. Studies and tests of PFBC systems have indicated that a highly efficient particulate removal system would be required to capture the coal ash, sulfur sorbent, and any other inert bed materials in order to limit the solids loading to a level acceptable to the turbine. Although ongoing studies (Refs. 2-100 to 102) are making a major contribution to the definition of gas turbine load specifications, there is still at present a lack of suitable operating experience with PFBC exhaust gases with which to accurately define these specifications.

Erosion Mechanics

The problem of predicting erosion in rotating machinery is very complex and has not been satisfactorily discussed in the literature. This complexity is primarily the result of the fact that the particle trajectory must be traced through the flow field with multiple impacts on blades. Until recently this complex aerodynamic flow field has not been addressed with respect to turbine erosion problems. Rather, studies of erosion have dealt primarily with idealized geometric situations where the direction and velocity of impacting particles could be defined. A large number of fundamental erosion studies have been conducted by many investigators. Summaries of the state of the science of erosion are presented in Refs. 2-96, 2-97, 2-103 and 2-104. The current discussion follows closely the treatment presented in Ref. 2-97.

A typical response of materials to erosion is illustrated in Figure 2-37. The characteristic response of materials to erosive media as a function of time usually involves an incubation period during which very little erosion is evident, a period over which erosion is taking place at an ever-increasing rate, and a period where erosion rate is a maximum and independent of time.

EROSION AS A FUNCTION OF EXPOSURE TIME
(REF. 2-97)

There are two types of response to multiple solid impacts. One is a ductile response generally associated with metals and the other is a brittle response associated with glasses and ceramics. For the most part, however, erosion in turbomachinery is concerned only with the ductile mode of erosion for metals. The general form of the mass removal rate as a function of the angle of attack for each response is shown in Fig. 2-38. Based on this general form, a number of models have been developed to account for erosive materials removal. Most of the models are based on hypothesized material removal mechanisms as opposed to experimental identification of actual attrition of material from an eroded surface.

Several theories have evolved to account for ductile erosion of metals. In Refs. 2-105 to 2-109, it was hypothesized that angular particles cut into the surface and remove material by a micromachining process. In Refs. 2-110 and 2-111, it was hypothesized that two mechanisms are evolved in the erosion process. The first of these is associated with the cutting action as described in Refs. 2-105 to 2-109, the second is associated with a repeated deformation phenomena similar to fatigue spalling. In Refs. 2-112 and 2-113, it was proposed that localized melting of the surface takes place and the material is removed by a portion of the molten material adhering to the rebounding particle. The raised lips of material surrounding the cavities formed by impact particles have also been used to account for material removal. In Refs. 2-114 and 2-115, it was proposed that this raised material is removed through collisions with the fragments of impacting particles which shatter upon impact. In Refs. 2-116 to 2-118, it was assumed that these raised lips are removed by shear during subsequent encounters with impacting particles. The work in Ref. 2-96 added empirical trends to previous theories to arrive at a semi-empirical method for predicting erosion rates.

In general, these theories identify the primary parameters as being the angle of particle attack, particle velocity, particle size, and particle material. Secondary parameters which have not been adequately included in erosion theories are the particle concentration, the quantity of abrasive material used, and the particle size distribution.

The original ductile erosion theory (Refs. 2-105 to 2-109) treated each particle as a small cutting tool that gouges into the surface by virtue of its momentum. It was assumed that the volume of material removed was proportional to the length of traverse of the particles along the surface, and equations of motion for a single abrasive grain interacting with a surface were developed. The equation of motion was solved to show that the volume of material removed from the surface was proportional to the density of the particle, the cube of the particle size, the square of the particle velocity, and a function that depended both on velocity and impact angle. This theory agreed well with experimental results at low angles of attack, both in general form and in the location of the peak for maximum erosion rate. It also predicted the angle of maximum erosion to be close to 20° for most ductile materials eroded by harder particles. However, the theory underestimated the weight

EROSION OF DUCTILE AND BRITTLE MATERIALS
(REF. 2-97)

loss at large angles of attack and predicted zero erosion at 90°. This led to the proposal of alternative mechanisms to explain erosion at large angles of attack. In this proposal, surface roughening is advanced as an important factor causing particles to strike the surface locally at a variety of angles.

These theories were expanded in Ref. 2-96 to develop a model for predicting ductile erosion. In particular, two different mechanisms are assumed with one operating at low angle of attack, the other at high angle of attack, and a combination of the two at intermediate angles of attack. The resulting relationship for erosion damage appears to provide excellent agreement with experimental results as evidenced by the comparison in Fig. 2-39.

Deposition

A curious feature of small size particles (on the order of 1 micron or less) is that they will adhere to a surface upon impact. For example, when 0.3-micron Al_2O_3 particles were impacted upon specimens in an erosion rig (Ref. 2-97), erosion was not observed, but rather deposits were observed on the leading edge of the specimens. Also, when several fly ash samples were used in the same rig, similar deposits were found to build up on the leading edge of the test specimen. The rate of deposition is a maximum at normal impact angles, although a deposit will eventually form at angles as low as approximately 10°. The observed deposition is not related to fusion of the ash and no significant differences in the fouling tendency of the three samples was observed even though the mean fly ash size ranged from 7 to 20 microns. The rates of build up of deposit suggest that the number of particles adhering to the surface is on the order of 0.1 percent of those impinging on the metal surface under the conditions of the experiment.

In experiments at the NCB/CURL (Ref. 2-119) facility operating at 6 atm (bar), collection of a deposit which caused fouling of the stationary turbine cascade located downstream of the bed and deposition on the walls of the cyclone was observed. Deposition on the cascade did not take place to a significant extent for bed temperatures below 1650 F (900 C). However, deposits were noticeably increased when the bed temperature was raised from 1650 (900 C) to 1750 F (954 C). Additional testing at Exxon Research Engineering Co. (Ref. 2-120) has demonstrated significant difficulties with particulate stickiness in granular bed filters.

It would appear from the forgoing that legitimate concern could be expressed regarding turbine fouling due to deposition of the small size particles present in the effluent of PFBC's operating above 1650 F (900 C).

EXPERIMENTAL AND PREDICTED EROSION RESULTS (REF. 2-96)

PFBC Effluent

The effluent from a PFBC must be characterized in order to identify the particulate cleanup system performance level required to protect the turbo-machinery. In the first part of this chapter, a general discussion was presented of the elutriation of inert components (coal ash and spent sorbent material) from the bed. In steady state operation, the feed rate of these components will equal the rate of removal by elutriation and by overflow from the bed weir. Removal of some bed material by overflow is necessary to confirm that the bed height is being maintained. In the limiting case of no overflow, all of the inert mineral matter fed into the bed must be removed by elutriation. Expressions were previously presented for estimating the rate of feed material elutriated in terms of particle size, abrasion rate constant, and other parameters dependent on residence times and gas velocities through the bed. Data presented indicate that for the range of fluidizing velocities of interest, approximately 60 to 100 percent of the inert feed material would be elutriated from the bed.

Other investigators have attempted to correlate gross efflux from the combustor in terms of superficial gas velocity. Figure 2-40 from Ref. 2-121 presents one such correlation for dust loading in grains/SCF (standard cubic feet) corrected for stoichiometric conditions. This correlation suggests a linear relationship between dust loading and superficial velocity. For velocities in the range of 3 to 6 ft/sec (0.9 to 1.8 m/s) the corrected dust loading would range from 8 to 14 grains/ft³ (18 to 32 g/m³ (STP)). Recognizing that elutriation rate can be dependent upon combustor geometry, the velocity dependence for a specific combustor (note data points in figure) may be much greater than indicated by a linear relationship.

As far as turbine erosion is concerned, the specific particle size distribution is just as important as the total dust loading. Figure 2-41 presents comparisons of estimated (Refs. 2-122 and 2-123) and measured (Refs. 2-119 and 2-121) particle size distributions from fluid bed combustors. For these data and estimates, the mean particle size (defined at the 50-weight percent point) ranges from about 30 to 200 microns.

Turbine Tolerance

In general, particles greater than 5 to 10 microns would be expected to impact the turbine blades and cause erosion. Excessive turbine erosion, especially by large particles, could make a turbine inoperable in a relatively short period of time. Erosion damage is distributed in a three-dimensional manner throughout the turbine and is most severe where particles impact the blade within $\pm 60^\circ$ from the normal. Figure 2-42 (from Ref. 2-124) is a schematic drawing depicting where the damage is found. Little damage occurs on the leading edge of the first stator, whereas heavy damage occurs on the leading and trailing edges of the second stator near the tips. Lesser damage occurs on

**PRESSURIZED FLUIDIZED BED DUST LOADING MEASUREMENTS
(REF. 2-121)**

PRESSURIZED FLUIDIZED BED OVERHEAD PARTICULATE SIZE DISTRIBUTION **(REF. 2-119, 2-121, 2-126, 2-123)**

FIG. 2-41

GAS TURBINE EROSION GEOMETRY (REF. 2-124)

FIG. 2-42

the trailing edge of the first stator and the trailing edge of the first rotor. The location and magnitude of erosion damage is specific to given turbomachinery designs.

On the basis of limited data from Ref. 2-125, an estimate of allowable gas turbine particulate loading was made (Ref. 2-122) indicating that particles greater than 10 microns in size would give unsatisfactory turbine life, particles less than 2 microns in size would have a negligible effect, and that some limited amount (0.01 grain/ft^3 (23 mg/m^3 (STP))) of particulates in the 2 to 10 micron size range could be tolerated within the gas turbine. Other sources quote tighter tolerances. For example, in Ref. 2-123 it is stated that particulate loadings should be kept to less than $0.002 \text{ grains/ft}^3$ (4.6 mg/m^3 (STP)) with no particles larger than about 6 microns.

The gas turbine erosion specification for coal-fired combined cycles given in Ref. 2-124 allow an unlimited number of particles below the size of 5 microns but essentially no particles larger than 5 microns. This specification is illustrated by the vertical line at 5 microns in Fig. 2-43. Also shown in the figure is a curve identifying potential erosion resistance for a turbine with special provisions for erosion resistance. It is noted in Ref. 2-124 that this specification is not representative of the type of specification to which a commercial gas turbine would be warranted.

Particulate Cleanup

By comparing the effluent dust loading with the turbine tolerance, it is obvious that particulate cleanup is necessary. Many types of exotic particulate cleanup systems have been considered for PFBC applications, but for the most part, the performance of these collectors has not been substantially greater than what could be achieved by using conventional cyclones. Representative performance of Aerodyne high efficiency cyclones is indicated in Fig. 2-44 from Ref. 2-122. By putting two such cyclones in series, it should be possible to remove essentially all but about 1 percent of the particles above 10 microns. The resulting overall collection efficiency curve is compared with the CFCC design specification and potential erosion resistance estimate in Fig. 2-43. The dust loading leaving the collectors and entering the gas turbines in the critical 2 to 10 micron size range could be within the turbine tolerance level. However, recognizing that no practical turbine operating experience exists in this range, and also recognizing that operating upsets could cause higher loading for short times, it would seem to be prudent to plan for a third cyclone stage.

Corrosion

Another potential compatibility problem stems from the corrosive elements in PFBC exhaust gases and their effect on turbine durability. Gas turbine hot sections using existing materials, coatings, and cooling techniques have demonstrated adequate reliability and long life when operating in the corrosive

**PARTICULATE CLEANUP EFFICIENCIES REQUIRES FOR 25,000-HOUR EROSION LIFETIME
(REF. 2-124)**

AERODYNE SV-FBC SEPARATOR EFFICIENCY CURVES
(REF. 2-122)

environment caused by industrial grade fuels. The concentration of alkali constituents in these fuels is typically limited to one ppm or less, which corresponds to an alkali concentration in the hot combustion gases of around 0.02 ppm.

The corrosion problem in coal burning gas turbines is closely related to the problems posed by erosion and deposition. For example, erosion may abrade protective oxide films and, thus, accelerate corrosion. Deposits of alkali metal sulfates and vanadates may react with the metal in the blades to produce corrosion. All of these mechanisms are very much dependent on engine design, materials of construction, operating conditions, and the type of coal employed.

The situation regarding alkali corrosion is especially critical to gas turbine lifetime. Equilibrium calculations (Refs. 2-121 and 2-126) and experimental data (Ref. 2-119) indicate that the alkali concentration in PFBC combustion gases could be in excess of one ppm (see Fig. 2-45). The corresponding alkali concentration in the particulate effluent could be around 200 ppm. These concentrations are clearly high enough to cause a potentially serious corrosion problem. Unfortunately, the quantitative effects of these corrosive elements on gas turbine durability cannot be adequately predicted at this time. There is, however, some cause for optimism because recent test results (Ref. 2-99 through 2-102) with FeCrAlY alloys has indicated relatively satisfactory performance.

In gas turbines, the principal types of corrosive degradation that have been encountered are high-temperature oxidation and hot corrosion. Hot corrosion is the increased oxidation of alloys that takes place when ash or salt deposits are present on the surface of alloys. When partially combusted coal gases are expanded through gas turbines, another type of material degradation can occur because of the low oxygen activities in the gases. In particular, simultaneous attack by oxidants other than oxygen can occur. In the following paragraphs, brief discussions are presented of materials degradation resulting from oxidation, hot corrosion, and mixed gas attack (i.e., gases with low oxygen activities and containing oxidants in addition to oxygen).

Oxidation

The temperatures at which oxidation of uncoated alloys becomes a problem is dependent upon the composition of the alloys. Typical compositions of alloys used in the hot sections of gas turbines are presented in Table 2-27. Alloys such as B-1900 or IN 738 are used in blades. Cobalt-base alloys such as X-40 or Mar M509 are frequently used in vane alloys. Waspaloy or IN 100 are disk materials, while Haynes 188 and Hastelloy X are examples of burner liner materials.

FIG. 2-45

ALKALI VAPOR CONCENTRATION VARIATION WITH TEMPERATURE
(REF. 2-121)

TABLE 2-27

TYPICAL COMPOSITIONS OF NICKEL AND
COBALT BASE ALLOYS USED IN THE HOT SECTIONS OF GAS TURBINES

<u>Designation</u>	<u>Ni</u>	<u>Cr</u>	<u>Co</u>	<u>Ti</u>	<u>Al</u>	<u>Mo</u>	<u>C</u>	<u>W</u>	<u>Ta</u>	<u>Cb</u>	<u>B</u>	<u>Zr</u>	<u>V</u>	<u>Fe</u>	<u>La</u>
B-1900	Bal.	8	10	1	6	6	.11	-	43	-	.015	.07	-	-	-
IN 100	Bal.	9.5	15	4.5	5.5	3	.17	-	-	-	.015	.06	1	-	-
MAR M200	Bal.	9	10	2	5	-	.15	12.5	-	1	.015	.05	-	-	-
IN 738	Bal.	16	8.5	3.4	3.4	1.75	.17	2.6	1.75	.85	.012	.12	-	-	-
Hastelloy X	Bal.	22	1.5	-	-	9	.10	.6	-	-	-	-	-	18.5	-
Waspaloy	Bal.	19.5	13.5	3	1.4	4	.08	-	-	-	.007	.08	-	-	-
Rene 80	Bal.	14	9.5	5	3	4	.17	4	-	-	.015	.03	-	-	-
Udimet 700	Bal.	15	15.3	3.4	4.3	4.4	.07	-	-	-	.016	-	-	-	-
X-40	10.5	25.5	Bal.	-	-	-	.5	7.5	-	-	-	-	-	-	-
Haynes 188	22	22	Bal.	-	-	-	.1	14.5	-	-	-	-	-	-	0.75
Mar M509	10	23.4	Bal.	.2	-	-	.6	7	3.5	-	-	.05	-	-	-
WI-52	-	21	Bal.	-	-	-	.45	11	Ta+Cb=1	-	-	-	-	1.75	-

Resistance to oxidation is achieved by the development of oxide barriers that effectively inhibit subsequent oxidation. Generally, oxidation resistance of the aforementioned alloys is developed by the formation of either α -Al₂O₃ or Cr₂O₃ scales. The alumina-forming alloys are more resistant to oxidation than the chromia-forming alloys. Chromia scales are not effective deterrents to oxidation in high velocity (1000 ft/sec (305 m/s)) gas streams at temperatures above about 1560 F (850 C) due to the formation of CO₃ gas.

In some instances, the required resistance to oxidation and hot corrosion is not compatible with the mechanical property requirements, and protective coatings must be used to achieve practical component lifetimes. This is especially true for turbine blade materials. The contemporary coatings for gas turbine superalloys are primarily of the aluminide type. Such coatings consist of diffusion coatings and overlay coatings. Coatings systems other than aluminides have received comparatively little attention. Other systems that have been utilized to a lesser extent than aluminide are silicide- and chromium-enriched coatings. Recently, FeCrAlY coatings have received serious attention for fluid bed applications.

Hot Corrosion

Hot corrosion is the term used to describe the increased attack by gas environments which takes place when ash or salt is deposited on the surfaces of materials. Such conditions are frequently encountered in the turbine section of gas turbines, incinerators, automobile exhaust systems, and the fire side of boiler tubes. A variety of deposits can cause hot corrosion. For example, V₂O₅, Na₂SO₄, K₂SO₄, NaCl and mixtures of similar materials have been found to induce hot corrosion degradation. Quite often the deposits are liquid, but the absence of any liquid phase cannot be taken as assurance that hot corrosion degradation will not take place.

Nickel-base superalloys with good oxidation resistance quite often do not possess resistance to hot corrosion attack. For example, the alloy B-1900 has good oxidation resistance but has very poor resistance to hot corrosion. The alloys in Table 2-27 with poor resistance to hot corrosion attack are B-1900, IN 100, Mar M200, and WI-52. The other alloys have somewhat better resistance to this attack, but none are such that they can be used in severe hot corrosion environments in the uncoated condition.

Mechanisms to describe the hot corrosion process have been developed (e.g. Ref. 2-127). Some disagreement exists among these mechanisms, but it now appears that the apparent inconsistencies can be resolved by proposing that hot corrosion can occur by different mechanisms depending on the conditions. In discussing the hot corrosion degradation process, it is useful to point out that the degradation of all corrosion resistant materials usually consists of an initiation stage and a propagation stage. In the initiation stage, the reaction products conferring the most protection to degradation are developed. In the propagation stage, lesser protective products are formed.

The presence of ash or salt deposits does not change the degradation sequence, but rather the times over which the two stages predominate. During the initiation stage for hot corrosion, the corrosion products are essentially the same as those that would have been formed during oxidation in the absence of ash. The degradation rates are consequently not substantially influenced by the deposit. As degradation proceeds, conditions begin to develop whereby the properties of the oxidation products, especially their ability to inhibit subsequent degradation, become dramatically changed. Complete control of the degradation rate by these less protective reaction products marks the onset of the propagation stage.

Degradation of alloys in the propagation stage can proceed by different mechanisms. There are two general means by which the ash or salt may cause more degradation to occur than what takes place in the absence of the deposit. The first involves salt-fluxing reactions whereby non-protective oxidation products are formed and grow due to reactions between the liquid deposit and the oxidation products. Such reactions have been classified as either basic or acidic depending on whether the oxidation products accept from or donate oxide ions to the liquid deposit, respectively. Basic conditions in the salt can be developed by removal of oxygen and sulfur from the deposit by the corroding alloys. Acidic conditions may occur when oxides of certain elements in the alloys are introduced into the deposit (e.g., MoO_3 , WO_3 , V_2O_5 , or SO_3 is present in the gas phase). The second general means of degradation involves effects produced by a specific element or component in the deposit. For example, sulfur from a sulfate deposit can enter alloys to form sulfides and the subsequent oxidation of such sulfides can result in accelerated oxidation or hot corrosion attack.

Mixed Gas Attack

In many cases where alloys are exposed to elevated temperatures, the gas environment contains a substantial amount of oxygen (e.g., partial pressure of oxygen greater than 0.01). Since metal oxides generally are more stable than the other products that can be formed in mixed gases (e.g., sulfides, carbides, and nitrides), oxide reaction products are usually formed on alloys exposed to such environments. In environments containing gases with very small amounts of oxygen, the sulfur, carbon or nitrogen can compete with oxygen for the metallic components of alloys. Reaction products may, therefore, contain a) oxides and sulfides, b) oxides and carbides, or c) oxides, sulfides and carbides depending upon the composition of the gas.

The mixed gas mode of attack may be important in fluid bed combustors where local oxygen concentrations might be low, but since excess oxygen should always be present in turbine expansion gases, this mode of attack should not be important in gas turbines and will not be further discussed.

Combined Corrosion and Erosion

Material removal under the combined influence of a corrosive environment and particle impingement is a poorly defined phenomenon. Virtually no data or theoretical analyses are available to describe it. At the present time, there is an urgent need for an evaluation of the functional relations which characterize the material degradation process over the domain of interaction of corrosion and particle impingement conditions.

In considering possible effects that may occur as a result of interaction between corrosion and erosion, it is useful to develop limiting cases by comparing the thickness of the reaction product formed due to the corrosion process with the diameter of the eroding particles. When the particle diameter is small compared to the thickness of corrosion product, the erosion rate will be determined by the properties of the particle and the corrosion product. It is possible, on the one hand, that the erosion rate could be decreased as a result of corrosion. On the other hand, the initiation period for the corrosion process could be decreased since some corrosion products normally contributing to inhibiting reaction between the alloy and the environment will be destroyed by the erosion process.

When the particle diameter is large compared to the thickness of the corrosion product, the major effect of particle impact will be deformation of the substrate material. In the case of a ductile substrate, erosion can be expected to proceed via one of the mechanisms previously identified (e.g., micromachining or melting). The important point is that the corrosion process is negligible in comparison to the erosion process in terms of material attrition. While the corrosion is negligible, it can still play a significant role in the erosion-corrosion process since the properties of the substrate may be altered by the corrosion process such that the erosion process takes place at a different rate.

When the particle diameter and the corrosion product thickness are comparable, fracturing of the corrosion product without excessive deformation of the substrate can be expected. For this condition, the erosion process will be dependent upon spalling of the corrosion product. The development of cracks in the corrosion product by impacting particles will influence the initiation time for the corrosion process. It, therefore, appears as though this latter condition may be most suitable for rather involved interactions between the erosion and corrosion processes.

As previously noted, very little experimental data are available on the combined erosion-corrosion behavior of materials. One of the few experimental programs which attempted to treat the combined corrosion-erosion effects is described in Ref. 2-97. The results of this study seem to suggest that the

erosion-corrosion behavior of metallic systems is consistent with the theory for ductile erosion. However, it appears that there is a synergism between erosion and hot corrosion in which each process establishes conditions that accelerate the other. This synergistic effect seems to occur because the corrosion process causes a reaction product to be developed that is very effectively removed by abrasion which, in turn, results in rapid attack of the alloys by the corrosive environment.

Turbomachinery Prognosis

The major material-related problem to overcome is the potential for corrosion-erosion of the hot section parts in the gas turbine due to carryover of contaminants in the combustion products from the PFBC. Sodium and potassium are the chemical species of critical concern to gas turbine lifetime. Recently, attention has been given to the behavior of turbine materials in the specific environment of a PFB combustor (see Refs. 2-100 to 2-102, 2-119, 2-120, 2-123, and 2-128). Equilibrium calculations from Ref. 2-121, depicted in Fig. 2-45, indicate that the alkali concentrations in PFB combustion gases are strongly dependent on gas temperature. Corresponding experimental data taken by the NCB (Ref. 2-119) using PFBC under operating conditions anticipated in future applications are depicted in Fig. 2-46. It may be seen from this illustration that the estimated alkali concentration in PFBC exhaust gases is well in excess of one ppm, or roughly two orders of magnitude greater than normally encountered in petroleum-fired gas turbines.

In petroleum-fired gas turbines, the rate of hot corrosion attack is normally limited by the flux of alkali to the blade surface. In Ref. 2-128, it is proposed that if the net efflux of alkali from PFBC were high enough, the blade surface would be completely covered with a layer of alkali condensate and could be described as being saturated. In this situation, the overall rate of hot corrosion attack would be limited by the rates of reaction rather than the flux of alkali to the surface. This situation is depicted graphically in Fig. 2-47 which contains qualitative plots of blade life versus alkali metal flux for two different temperatures. Conventional gas turbine experience includes the oxidation and flux limited regimes on the left side of the figure. As the alkali metal level in the combustion products increases, the corrosion reaction is limited by the inherent reaction kinetics between condensate and the blade alloy. If the blade surface were saturated with alkali as proposed, any further increase in alkali flux would not cause a corresponding increase in corrosion rate. Thus, the predicted blade life for any given blade temperature approaches a minimum.

It is also reported in Ref. 2-128 that the presence of high levels of potassium and chlorine in the combustion products creates the potential for further acceleration of corrosion over and above that due to the high sodium

FIG. 2-46

EFFECT OF ALKALI CONCENTRATION ON LIFETIME FOR A HEAVY DUTY GAS TURBINE (REF. 2-128)

flux. There appears to be a synergistic effect of sodium and potassium on the corrosion rate. That is, potassium does not simply substitute for sodium in the corrosion phenomenon, but significantly increases the rate of corrosion as it is substituted for sodium in the deposit. Potassium typically is not a problem for gas turbines burning liquid fuels because of the low potassium concentration in the fuel. The potassium level in coal, however, for the most part will be as great or greater than sodium, so that increased corrosion rates may be anticipated from the combined effect of sodium and potassium when compared to sodium alone.

During the past several years, tests have been run in which gas turbine alloys have been exposed to the products of combustion from PFBC's operated by Exxon and the NCB (see Refs. 2-99, 2-119, and 2-120). The results of these tests, coupled with those of small rig and burner tests, seem to confirm that conventional gas turbine alloys cannot withstand the severe corrosion-erosion environment of a PFBC. Typically, nickel- and cobalt-based alloys experience severe attack. The FeCrAlY alloys (such as GE 2541) showed the least attack. The General Electric approach (Refs. 2-124 and 2-128) is based on the use of corrosion-erosion resistant cladding material over high strength creep resistant blade materials. Cladding corrosion data are presented in Table 2-28 which confirm that the GE 2541 alloy is superior to other possible cladding materials.

The corrosion lifetimes projected in Ref. 2-124 are displayed in Fig. 2-48 for both a conventional turbine alloy, IN 738 and the GE 2541 alloy. The curves in this figure are plotted for the condition where the level of alkali metal is saturated, i.e., the rate of corrosion is limited by the kinetics at the metal surface rather than the rate of supply of corrodant to the surface. The figure illustrates that for a given lifetime, the allowable metal temperature could be 200 to 300 F (360 to 540 C) higher for the cladding material than for IN 738. Also, the data indicate that by cooling the blades to approximately 1300-F (705-C) metal temperature, turbine lifetimes on the order of 20,000 hours should be attainable.

It appears from the foregoing that the general outlook for developing turbine materials that will withstand the severe environment of a PFBC is good. However, all investigators in the field caution that additional long duration materials testing is required under conditions that will more closely simulate the rotating environment in a full size turbine. The performance of a machine as complicated as a gas turbine in a PFBC application will never be known until one has been subjected to projected commercial operating conditions for an extended period of time.

TABLE 2-28

CLADDING CORROSION DATA

1600 F (871 C) Small Burner Test Rig
 Fuel with 79 ppm Na and 112 ppm K

<u>Cladding on IN-738</u>	<u>mills/1000 hr</u>
GE-2541	1.1
GE-2541 + Alum.	1.9
GE-2541 pm	0.4
MA-956E	--
310 33	10.7
310 33 + Alum.	3.5
IN-671	7.5
PFB-1	--
PFB-1 + Alum.	--
S-57	6.1
S-57 + Alum.	2.0
PFB-2	2.0
UMCo-50 Mod.	3.2
IN-738 (Bare)	16.3

**GAS TURBINE LIFE IN PFB ENVIRONMENT
(REF. 2-124)**

Availability of Turbomachinery Components

Conceptual turbomachinery system design studies have been conducted by several organizations (see Refs. 2-129 through 2-132) to explore potential problems associated with the generation equipment in CAES applications. Ideally, equipment for CAES systems should be assembled using off-the-shelf components. Although the required level of technology for oil-fired CAES turbomachinery is within the current state of the art, it should be noted that specific off-the-shelf equipment designed for oil-fired CAES power plant does not exist at present in the US. Obviously, off-the-shelf equipment for PFBC/CAES applications also does not exist.

Consequently, the equipment will need to be modified from existing gas turbines using available technology to reflect the unique design and operating requirements of fluid bed augmented CAES systems. The extent of the modifications required for near-term CAES systems using distillate fuels should be relatively modest. Turbomachinery designs for distillate-fueled CAES systems should also be applicable to CAES systems making use of AFB combustors wherein the products of coal combustion do not pass through the turbine. The nature and characteristics of the effluent from PFB combustors is such that the changes in operating conditions and design requirements would be more substantial than would otherwise be required for distillate-fired units.

A general design philosophy adopted by UTRC during a previous study (Ref. 2-130) was to make maximum use of commercial or nearly developed components and to avoid systems requiring extensive engineering or development expenditures. This approach lead to the synthesizing of a first-generation CAES system based entirely on state-of-the-art components. In this approach, the low-pressure sections were based on adaptations of components from a large, heavy-duty industrial gas turbine, whereas the high pressure components were based on the use of an industrial booster compressor and a steam turbine modified for use as a high-pressure air expander. This general design philosophy provides for considerable flexibility in air storage pressure without altering the basic system configuration. Flexibility is deemed vital since any commercial CAES plant must be capable of accommodating the specific storage pressures and storage pressure variations corresponding to the air storage requirements dictated by local geological conditions. This general design philosophy is very similar to that adopted for the Huntorf plant (Ref. 2-129). It has also been considered by all major turbomachinery suppliers considering equipment for CAES plants.

With the above design philosophy, the complete compressor train could be based on existing aerodynamic design. The ducting would have to be redesigned to permit ducting air from the compressor to the PFBC and returning hot gases to the turbine. This ducting problem basically reflects an extension of the design of the PFBC and particulate cleanup systems. As far as the turbine is concerned, the duct design should avoid transverse thrust loads and accommodate thermal

stresses in the duct walls. Also, because of the unique shafting and casing requirements, some redesign of the rotor support might be required. These are considered to have minimum risk and involve essentially no R&D cost.

The turbine represents the pacing item in turbomachinery availability. If AFBC combustors are used, clean air would be expanded through the turbines and the machinery design problem would be comparable to that for oil-fired CAES systems. That is, existing aerodynamic designs could be used, but mechanical and structural modifications would be required in the shafting and casing designs.

Design of turbines intended for expansion of gases from a PFBC represents the major uncertainty at this time. As previously noted, there is some cause for optimism regarding acceptable erosion behavior of known materials (Refs. 2-100 to 2-102). Additional testing of these materials is underway and more extensive testing is planned for the future. If the results of these tests are favorable, turbines with minimum redesign modifications should be feasible in the near future. If, however, these materials were not to survive long lifetime testing, then commercially viable turbines for PFBC applications would probably not be forthcoming.

Clutches for CAES systems should present no problem. Both SSS Gear Works of England and MAAG Gear Wheel Company of Switzerland have designed and built large clutches of the type required for CAES systems. In particular, SSS has provided the clutches for the Huntorf air storage plant.

Turbomachinery R&D Assessment

Two trends in gas turbine technological R&D are evident--a steady increase in gas turbine unit power and a more or less steady increase in turbine inlet firing temperature. Both of these advancements have generally led to higher efficiency and higher output power per gas turbine. However, the upper operating temperature limit of coal-fired PFBC is considerably below the clean-fuel capability of current gas turbines and, in fact, represents temperature levels used in gas turbines nearly 20 years ago. Consequently, the thrust of an R&D program to couple a FBC with a gas turbine will be in a different direction than present programs. It will have to be directed toward solving many of the technological limitations of gas turbines in fluid bed applications which result from the interface problems and the uncertainties associated with the operating conditions of fluid bed combustors.

The timing and cost of research and development programs directed toward developing turbines for PFBC/combined-cycle applications could have a substantial influence on the commercial timing and viability of PFBC/CAES systems. If the CAES system configurations were limited to those using PFB combustors which

appear to be feasible for near-term applications (i.e., bed pressures less than or equal to approximately 16 atm (bar) and high-pressure air for the high-pressure expansion turbine heated in tubes immersed in the bed), then the turbine R&D requirements would be no different from those identified for combined-cycle applications (see Refs. 2-122, 2-133, and 2-134).

The technologies requiring development effort prior to commercialization include the following:

- i) Hot gas cleanup - Effective, economic and reliable hot gas particulate cleanup systems are needed to protect the gas turbine components from larger size (5 to 10 micron) particulate matter elutriated from the bed.
- ii) Particulate erosion - The lifetime of commercial size gas turbines subjected to erosion caused by particulates elutriated from the bed must be determined.
- iii) Corrosion - The tolerance of conventional gas turbine materials and prospective substitute materials to corrosion by contaminants from the bed must be established.
- iv) Combined corrosion/erosion - Large scale corrosion/erosion tests of rotating machinery using effluent gases from a PFBC must be conducted.
- v) Deposition - The mechanism of deposition of particulate matter from the bed on turbine airfoils in terms of coal composition, absorbent composition, bed operating temperature, particulate size, surface characteristics, and other identifiable parameters must be defined.
- vi) Combined deposition/corrosion/erosion - The interrelations between deposits formed on the blade surface and the resulting corrosion/erosion rates in the presence of these deposits must be determined. Some deposits may protect the blade from further corrosion/erosion, whereas others may contain corrosive agents which may accelerate the deterioration process.
- vii) Damage control techniques - Various gas turbine design approaches to protect the turbine from excessive deterioration must be investigated. Examples of these approaches include using corrosion/erosion resistant coatings and leading edge shields, modifying air foil shape to eliminate thin sections, changing blade profiles to reduce erosion impact resulting from secondary flows, using protective boundary air layers, redesigning the turbine for lower gas and blade velocities, etc.

viii) Alkali metal control - Possible means of removing alkali metal emissions from exhaust gases must be investigated. Fuel additive studies should also be conducted to investigate absorption of sodium, chlorine, and other potentially destructive contaminants.

Time and cost estimates for specific R&D programs vary by almost an order of magnitude. The difficulty, of course, is a result of the fact that insufficient information is available to identify the true scope of subsequent R&D efforts. For example, if early testing were to prove successful, subsequent testing and turbomachinery redesign might be limited in scope. However, if early testing were not successful, then later testing might be prolonged.

One recommended R&D program for the PFBC combined-cycle application is described in Ref. 2-122. This recommended program was divided into three phases. Phase I is for the testing and development activities and includes all of the technology issues identified above. This phase could run as long as three years. The turbomachinery portion of the costs for this phase could range from \$5 to 15 million.

Phase II is for the pilot plant design, construction, and operation. This phase would run for approximately five years with the last two years providing for operation of the plant. The first three years of Phase II could run concurrently with Phase I. The cost to modify an existing gas turbine to carry the program through the pilot plan phase was estimated to be on the order of \$25 million.

Phase III is for the design, construction, and operation of a 100-to 200-MW demonstration plant. Phase III would require an additional five years commencing on completion of Phase II. The estimated gas turbine cost for the demonstration phase (including delivery and test of the turbomachinery) is approximately \$75 million, bringing the total estimated gas turbine development cost for modifying an existing commercial engine to slightly over \$100 million.

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