CONF-800428 — Vol. 1
Volume 1 of 3 Volumes

Dr. 1807

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The Proceedings of the Sixth International Conference on Fluidized Bed Combustion

Volume I — Plenary Sessions

April 9-11, 1980

MASTER

Atlanta Hilton
Atlanta, Georgia

Published August 1980

6th

U.S. Department of Energy
Assistant Secretary for Fossil Energy
Office of Coal Utilization

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Printed in the United States of America

Available from

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes

Printed Copy: $ 6.50
Microfiche Copy: $ 3.50

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UC-90e

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Sponsored by
U.S. Department of Energy
Electric Power Research Institute
U.S. Environmental Protection Agency
Tennessee Valley Authority

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U.S. Department of Energy
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Office of Coal Utilization
Washington, D.C. 20585

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TECHNOLOGY OVERVIEW

PLENARY SESSION 1

TECHNOLOGY OVERVIEW

KEYNOTE ADDRESS

Roger LeGassie
U.S. Department of Energy

Thank you.

Speaking on behalf of the Department of Energy, let me welcome you to this Sixth International Fluidized Bed Combustion Conference. I especially want to extend a warm welcome to those who have traveled here from other countries and other continents.

I am pleased at the turnout here today -- not only the numbers but particularly the composition of the audience. I am told that at the First International Conference, the 40 or so attendees were primarily scientists and research engineers. Today, as I look out on 500 or more of you, I see the largest proportion to be equipment manufacturers involved primarily in producing commercial fluidized bed boilers.

That's the way it should be. That's telling me we are moving in the right direction. This is the type of program we in the Department of Energy can be proud to be a part of.

As you have heard, I am here today representing the Department's Assistant Secretary for Fossil Energy, George Fumich. This is a conference George wanted very much to be a part of. As many of you know from personal experience, George has been advocating fluidized bed technology as a clean way of burning coal since the early 1960s.

Unfortunately, commitments both to a hectic Washington schedule and to his doctors have prevented him from being here today. But I pass along his welcome and wishes for a profitable three days.

This conference comes at a particularly appropriate time. We stand today at a pivotal point in our history. Our nations have just completed a decade in which the twin shocks of first a quadrupling of world oil prices in the first half of the 70s, then their subsequent doubling again last year have told us that our energy problem is real, that its economic and national security ramifications are severe, and that there is no quick fix.

At the same time, we are entering a new decade -- a decade where fundamental changes will have to be made in the way we use energy and in the fuels we must burn to produce it. This transition is worldwide. It requires cooperation among all the industrial nations, and particularly it requires the maximum in cooperation between industry and government.

These changes are not going to happen overnight. They are going to take time, and as individual citizens in business, labor and government, we have to build the momentum now so that our future vulnerability to decisions made in a particularly unstable part of the world can be reduced.

In this country alone, we will be paying almost $90 billion this year alone for foreign oil -- that's $10 million an <u>hour</u>, every hour of every day. And with that money flows jobs and the ability to maintain control of our economic future.

The situation facing us is compounded by the fact that the world's largest producer of oil, the Soviet Union, is expected to become a net importer of oil during this decade. That's a complicated compounding factor with obvious, unfavorable impacts.

There will be some increased production in Mexico, the North Sea, and here in the U.S. where more drill rigs are operating today than ever before. But the picture is rather clear. World potential for producing oil will soon begin to decline.

That means if the consuming nations do not take concerted and strong actions in the very near future to substitute alternative energy supplies for oil, import prices considerably higher than today's could become a reality.

We don't have the luxury of making unilateral decisions about oil. To find a common ground that serves all of our interests is a step-by-step process that requires a lot of patience and cooperation.

The effort among the industrialized consuming nations began at the Tokyo summit last June. That was followed in the fall by a meeting of energy ministers in Paris. And that meeting was expanded in December to a meeting of 20 nations of the International Energy Agency.

Step-by-step, these sessions are setting the framework for an international response to our energy problems. Import ceilings have been set. And it is now the responsibility of individuals like us -- in each country -- to go about finding the mechanisms and the technology to meet or lower these quotas.

Conferences like this are an important part of the international commitment and cooperation that will be needed to do just that. Just as our energy problems are worldwide, so too can be the solutions.

For those nations represented here today, coal can be one of the answers. Our countries are not energy poor. But we have built our social and economic infrastructures on a foundation of cheap, easily attainable oil. That is no longer a realistic premise. It therefore becomes incumbent on us to turn to other energy sources, the ones we have the most of -- like coal.

As I have said, we have completed an eventful decade. Not only did it display the realities of the energy problem, but it also revealed several hints of potential solutions. From a technology standpoint, one of those solutions is fluidized bed combustion.

In the early 1970s, we saw fluidized beds progress from bench scale engineering concepts to the fabrication of actual commercial hardware.

From where I stand, that is the measure of success -- hardware that is ready to operate in a commercial environment, that can hold its own in a marketplace where regulations must be met, permits obtained, and in which an investment must be attractive before it is made.

It is hardware in which the private sector has sufficient confidence -- technologically, economically and environmentally -- to begin moving forward on its own. It is a success measured by commitments from manufacturers to produce and warrant equipment. It is a success measured by the confidence of users that the technoloy is advantageous to own and that it can function dependably.

You will be hearing about some of these successes during the next three days -- developments resulting from both government programs and private sector initiatives worldwide.

You will be hearing about our commercial prototype unit at Georgetown University in Washington, D.C. Since last summer, it has accumulated more than 1400 hours of running time and has provided steam throughout the winter to heat 51 campus buildings totaling 2.2 million square feet.

We are about ready to begin operating a second commercial prototype at the Great Lakes Naval Training Center near Chicago. And two more units -- these designed specifically to burn anthracite or anthracite wastes -- have begun construction in Pennsylvania.

You will be hearing about last month's run at the Rivesville utility fluidized bed unit, which achieved 200 hours of continuous operation after substantial modifications were made to the coal feed system.

And you will be hearing about activities and recent successes in the United Kingdom, the Federal Republic of Germany, the Peoples Republic of China, India, and in the Scandanavia countries.

So if I had to subtitle this conference, I think I would underscore "progress" -- progress that is producing results, progress that has brought fluidized bed combustion to the threshold of commercial acceptance.

So where do we go from here? I prefer to view this conference not as simply a recitation of success stories, but as a guidepost to the work that still needs to be done. And there is still considerable progress that must be made in the future if we are truly to have commercially viable fluidized bed systems.

The question of reliability must still be addressed -- particularly what the government's role should be in building industries' confidence in these units. As you know, we issued a solicitation last year for firms to come in with proposals to demonstrate several large industrial fluidized bed systems. These systems would be operated in energy-intensive industries where reliability is critical.

Yet a question remains of where government's role ends and private industry becomes the dominant player. We requested no additional funds in our FY 1981 budget for this program, but we recently asked those companies that submnitted proposals to extend them to June 1. This will enable us to gauge more precisely whether this is something we in government need to do, particularly in a time of Federal budget restraint, or if so, how many demonstrations are necessary.

You may be interested to know that last week, a subcommittee of the House Science and Technology Committee voted to add $10 million to our fiscal 1981 budget specifically for these industrial demonstrations. We, along with many of you I'm sure, will be watching to see if the other authorization and appropriations committees follow suit.

In the utility sector, with the Tennessee Valley Authority taking the lead in developing the atmospheric fluidized bed system, we have re-focused our attention on the pressurized concept.

The 1000-hour test run of a pressurized fluidized bed linked to a small gas turbine at Curtiss-Wright's testing station last fall was a significant milestone in achieving the materials durability that will be needed for PFB/combined cycle operations.

And we are preparing to move ahead with construction of a 13-megawatt fully-integrated PFB pilot plant with Curtiss-Wright, beginning probably by next spring.

It is in the pressurized fluid bed work where some of our most active and beneficial international activities are taking place. At Grimethorpe, England we are preparing for firing the first coal and beginning "hot" shakedown later this year. As a precursor to this work, the project is currently performing "link tests" at the

Leatherhead facility, and it was there that we recently completed 1000-hour test with General Electric and Stal-Laval cleanup systems and cascades. This test achieved favorable results and confirmed our conclusion that the technology is ready to move ahead.

This work will be essential to the eventual commercial success of PFBs in both the U.S. and Europe, and you will be hearing more about these activities as the conference progresses.

In all, I think we have a comprehensive fluidized bed program with government and industry from several nations playing key roles. Now it's up to us -- representing those governments and industries -- to make that program work. The economic and national security stakes are very high, and we don't have the luxury of failure as an option.

With the technical expertise, along with the marketing ingenuity and the international cooperation, that exists in this room today, we can do this and still maintain our commitments to a clean environment and a healthy economy.

Once again, let me say on behalf of the Department of Energy that we appreciate your attendance and commend your interest and support of this new and important technology. I hope in the upcoming sessions that you wil be candid about your concerns and talkative about what you think our future actions should be.

That's the only way the progress we achieved in the 1970s will carry over into the 1980s.

Thank you.

OVERVIEW OF U.S. AND INTERNATIONAL PROGRAMS

FLUIDIZED BED COMBUSTION; A STATUS CHECK

JOHN W. BYAM

THE DEPARTMENT OF ENERGY
MORGANTOWN ENERGY TECHNOLOGY CENTER

SIXTH INTERNATIONAL FLUIDIZED-BED CONFERENCE -- APRIL 9-11, 1980

Good morning. I would like to speak to you this morning concerning DOE's fluidized-bed program, in general, a basic talk that I have titled "Fluidized-Bed Combustion, A Status Check." This is a review of the status of DOE's program, where we are and where we are going in fluidized-bed technology. DOE, as you know, has been active in fluidized-bed combustion of coal since the late 60's when it was known as the Office of Coal Research. The work was originally started with the Alexandria facility, and in the early 70's the Rivesville project was undertaken and the Rivesville unit built and operated since 1976.

The question comes up as to why DOE is interested in fluidized-bed combustion. The primary reason, of course, is the advantages over conventional combustion. I am sure that many in the room know these advantages; but for the interest of those who may not, I will briefly review the FBC advantages as we in DOE see them.

The primary advantage of fluidized-bed combustion is the reduction of SO_2 emissions during the combustion process. There is also a reduction in NO_x emissions and the capability to burn a very wide range of fuels. Other advantages include a modest reduction in cost for the capital, equipment, and operations of a fluidized-bed plant versus a conventional steam plant; the fact that fluidized-bed technology can be used to burn the high ash western coals and lignites as well as the Anthracites and high sulfur bituminous coals of the east; and the fact that FBC technology can burn low-grade combustibles, not only coals, but industrial waste. DOE has therefore established a program to address these various objectives and our program goals are shown in figure 1.

- Industrial AFB Demonstration
  - Demonstrate in a Variety of Industrial Applications
  - Show Process Reliability
  - Develop Operating Cost Data Base
- Utility AFB Application
  - Address Technology Issues
  - Coordinate with TVA Activities
- PFB Applications
  - Develop Component Reliability/Operability
  - Demonstrate Low Risk Cycle
  - Systems Control Process Turndown Development
- Technology Base
  - Develop Comprehensive Process Data Base
  - Define Improved Process Configurations

Figure 1 - FLUIDIZED BED COMBUSTION PROGRAM GOALS

AFB PROGRAM

In the area of Industrial Atmospheric Fluid -Bed Boilers (AFBB), DOE is attempting to demonstrate in a very wide variety of industrial applications, AFBC reliability. We are also attempting to develop and are in the process of, at this time, developing a very good operating cost data base.

In the area of AFB application to Utilities, we are assisting TVA in addressing the technology issues and are coordinating and working with TVA who has the lead in applying AFB technology to Utilities.

In PFB applications, we are working in the areas of developing component reliability, operability and demonstrating a low-risk cycle, optimizing the system process for turndown, and finally in the area of developing a wide technology base. In this last area, we are looking ahead at advanced technologies as well as establishing additional data to answer some of the questions that exist today. In addition, we are developing very comprehensive data base; and are working to define improved process configurations.

From these projects we have developed a series of design development goals for the fluidized-bed program, and this is basically where we see ourselves going. We feel that we must develop a fuel flexibility multi-fuel firing capability and a high combustion efficiency and overall plant efficiency. Of course, it must be within environmental compliance at all times. Work on reliability, safety, ease of maintenance for the plant, a rapid start-up and shutdown for the larger units so that they are comparable with the existing utilities, and good load following turndown capabilities is also required.

Figure 2 shows a summary of the AFBC facilities that DOE has available to it plus those that are available in private industry. These are the sites that are available now to address the issues. As you can see, there is a large number of sites that are in the range of 10 square feet or less. We are now beginning to get in place the larger units, the demos, which will give us an expanded data base at the next step up, around the 100 to 1,000 square foot range.

We have a group of facilities that are capable of addressing all phases of AFBC work, the AFB utility phase, the AFB industrial phase which are represented by the demonstration units, technology support base units, and units to support the pressurized fluidized-bed work.

I would like to now give you a brief overview of the activity in each of these areas. I have intended this to be a very brief overview and hope you will attend the various sessions that will follow which will cover each of these projects in detail.

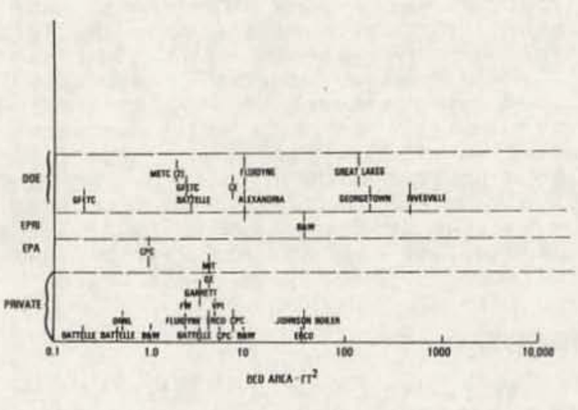

Figure 2 - AFBC FACILITIES

The first unit, as mentioned by Mr. LeGassie, is the Georgetown unit which has been operating since August of 1979. It produces 100,000 pounds an hour of saturated steam at 250 psig with the capability to go to 625 psig. To date, it has exceeded 1,400 hours of operation and has produced a maximum of 80,000 pounds per hour of steam.

Figure 3 is a layout of the equipment at Georgetown. Of general interest is the fact that it utilizes a stoker overbed feed system for fuel feed and a gravity flow in-bed limestone feed system. Figure 4 gives you a better idea of the overall major components of the facility. The facility utilizes a baghouse for dust collection.

The next facility is the Great Lakes unit being built by Combustion Engineering. Figure 5 is an artist's concept of the site as it will look once it is complete. They are in the construction phase right now. The building steel is up, the boiler is in place, and that boiler is due to come on line and be operational in January of 1981.

Another ongoing project is the Exxon Crude Oil Heater Project which investigates using a fluidized-bed boiler to heat crude feed stock for a refinery. In the studies that were done during Phase I, it was determined that, in fact, very efficient heat transfer was accomplished; and the process was viable from a crude heating standpoint. However, the problem became one of logistics. Because of the large number of units that would be required in a refinery, 80 to 90 units, there is a very serious problem with coal and limestone transportation. When the overall economics involved were evaluated, it appeared that this process was not economically feasible for a refinery application and therefore DOE chose not to proceed with the demonstration unit.

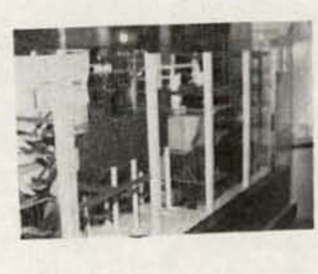

Figure 3 - GEORGETOWN UNIVERSITY AFB FACILITY MODEL

DOE has, as Mr. LeGassie mentioned, two anthracite projects underway. The anthracite culm project at Shamokin will provide 20,000 pounds an hour of steam to an industrial park. That facility is in the construction phase now and will be starting up in April of 1981.

The Wilkes-Barre facility will provide 100,000 pounds per hour of heating steam to the downtown area of the City of Wilkes Barre. The facility is in the final design stages and construction will be starting this fall with operation in late 1981.

The utility program includes the Rivesville unit which has now completed a 200-hour run after making several modifications to the fuel feed system, which has been one of the major problems encountered at Rivesville. That was a very successful run, and no major problems resulted. Currently, Rivesville is in a maintenance evaluation phase looking at the details of what happened and what was the exact performance of the unit. One thing to note, the stack during this run was clear at all times; and it appears the unit had better than 99 percent efficiency in the hot electrostatic precipitator. So from that, it appears that ESP may yet be an acceptable approach to stack gas cleanup for fluidized bed.

Figure 6 represents a model of the AFB-CTIU which was under construction to be used as a component test facility for AFB. Shown are the bunker system out back as well as the equipment as it was to be located in the building. It included a three-cell stacked boiler with a multi-clone primary cleanup and a baghouse for final cleanup. Figure 7 shows the building as it now appears with the unloading facility located out

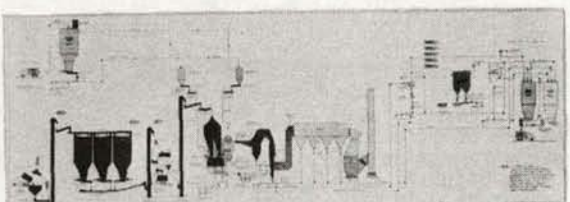

Figure 4 - GEORGETOWN UNIVERSITY AFB MAJOR EQUIPMENT

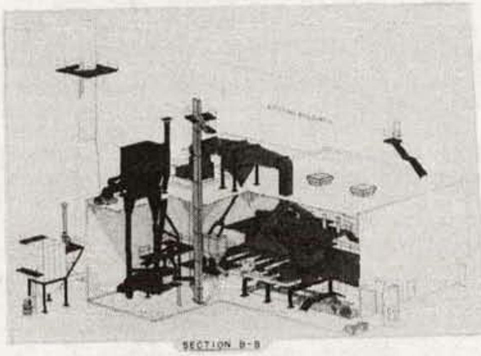

Figure 5 - GREAT LAKES AFB EQUIPMENT LAYOUT

back. For those of you who have not been reading the papers or "Energy Daily" lately, this project has been terminated. DOE felt that the industrial phase of AFB has accelerated faster than anticipated, and the problems that were to be addressed in this facility in conjunction with the industrial AFB have really been answered. With regards to application of this facility to the utility side, TVA has taken the lead and the demonstration of Utility AFB and after discussions with them, it was felt that the 20 MW$_e$ pilot plant program would provide the answers they required and that this facility would not have any direct benefit for TVA. DOE is therefore reevaluating the use for the facility and the need for an AFB test facility within the fluidized-bed program. That is one of the inputs we are looking for during this three-day conference.

Finally, there is the DOE technology support program. The Alexandria unit is providing good basic data in a 3 foot by 3 foot unit. We have the METC work which consists of two 18-inch units and the 6 x 6 cold unit, providing some good solid data on the burning of a wide variety of fuels. The Grand Forks Laboratory unit is providing data on lignites and the western coals, and the MIT math modeling program is providing a good process model as well as a data base for all the data which has been collected at numerous units. There is also a program being handled by the Davy McKee Corporation where the data from the various demonstration units is being collected and collated and will be made available to industry at their request.

PFB PROGRAM

Next, let us look briefly at the PFB program. This is where DOE's emphasis for the future will be. Some of the added advantages of pressurized

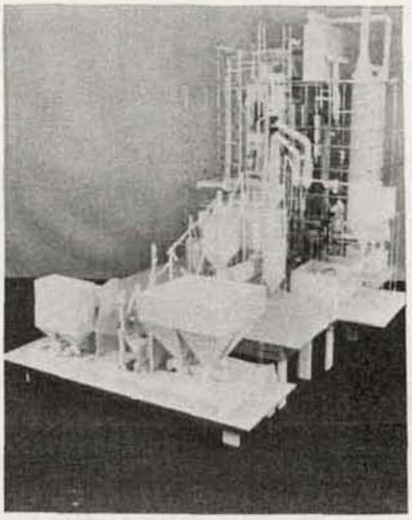

Figure 6 - COMPONENT TEST AND INTEGRATION UNIT MODEL

fluidized combustion are of course high-combustion efficiency, a higher volumetric heat release, a higher in-bed heat transfer rate, fewer coal feed points, improved SO_2 capture, and suitability for gas turbine combined cycle systems.

The various facilities shown in figure 8 are what we have available to us now. The Curtiss Wright 13 MW_e pilot plant has completed the design stage. There is the IEA Grimethorpe Facility, the technical base units, Curtiss Wright, the National Coal Board CURL Facility, General Electric Materials Program, the hot gas cleanup work, and the Argonne National Laboratory Scale Unit. Our program is phased as shown in figure 9. We currently have operating the smaller technology base units. This will expand to the pilot plant units, the Curtiss Wright, and the Grimethorpe units. From there we will go into a repowering demonstration unit. This will be in the 100 MW_e range and will be operational in the 1986-87 time frame.

Figure 10 shows the Curtiss Wright pilot plant, construction of which is to begin shortly. It will be about two years to operation.

Figure 7 - COMPONENT TEST AND INTEGRATION UNIT BUILDING

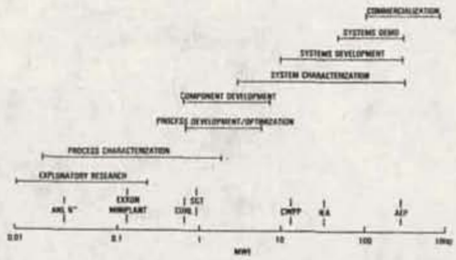

Figure 8 - PFB FACILITIES

The international projects include the IEA Grimethorpe, as mentioned, where the DOE objective is to work with the International Energy Agency to build and operate a PFB facility to obtain data on prototype boilers including combustion characteristics, emissions, and turbine materials. The CURL facility is being operated now with the objective of supporting the IEA project and defining PFB combustion characteristics on a pilot scale. Again, these facilities will be discussed more in detail at later sessions.

In summary, looking at our achievements to date, there are the industrial demonstrations; we have demonstrated process flexibility on a larger number of coals and refuge materials and the utility concept has been demonstrated at Rivesville. In the area of technology base, there is a modest base available to DOE right now, and we are modeling to expand both the design data available and the data base.

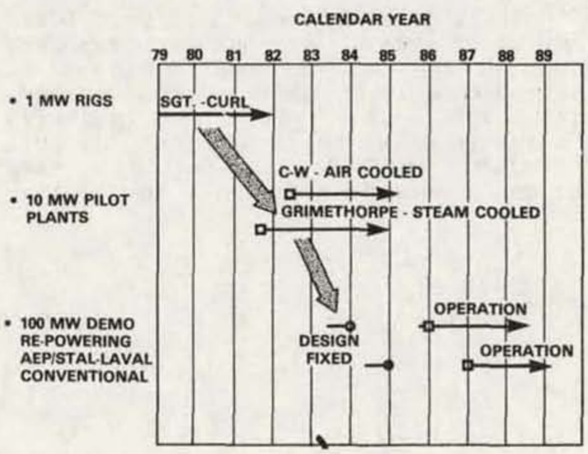

Figure 9 - PFB PROJECTS PHASING

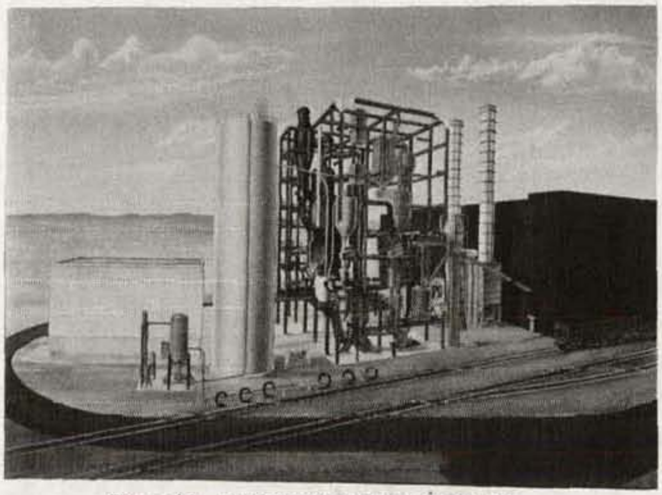

Figure 10 - CURTISS WRIGHT PILOT PLANT

However, it is not all success. There are some problems that remain to be addressed and a few of them include the following: Demonstration of long-term reliability - industry continues to state they want to see a unit that can start up and run for a year. We need to reduce the complexity of the fuel feed system especially on the larger units. The long-term performance of materials in the fluidized bed has yet to be demonstrated in the 10-20,000 hour range. There is a need to continue to develop a firm data base for design and scaleup in the area of heat transfer, combustion efficiency, and emissions. There is a need to develop methods for utilization of the spent-bed materials. On a system basis, a definition of the best power generation and cogeneration systems for first generation commercial plants is required. From an economic standpoint, confirmation of the economic advantages of fluidized bed on a demonstration scale is needed.

The DOE is interested in your ideas, your discoveries, and your concerns. We look forward to this conference as a forum to exchange ideas, define potential problems that remain, and identify a means to solve these problems. We of DOE thank you for participating. May the conference be beneficial to us all.

AN OVERVIEW OF THE PROGRESS IN FLUID BED COMBUSTION IN THE UNITED KINGDOM

D.M. WILLIS

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Introduction

It is a great personal pleasure for me to be here speaking to you today representing the United Kingdom before such a distinguished gathering. At the 1977 Conference, Dr. W.G. Kaye presented this overview but, unfortunately, he cannot be with you today as he is among the bulb fields of Holland making the major presentation to a symposium on New Coal Technology at the Hilton Hotel, Rotterdam. (I should have bought shares in the Hilton).

He sends his best wishes to you as do Joe Gibson, David Dainton and Jack Owen. My colleagues from NCB, John Highley and Alan Roberts, are with me and will be presenting papers on the detailed work in which we, in the Coal Research Establishment of the National Coal Board, have been involved.

There is no need to send Raymond Hoy's good wishes as he is with us. He might be considered the mother of pressurised fluidised bed combustion, Doug Elliott, perhaps, being the father, and he nursed a sometimes sickly child to its present healthy state. (I will not pursue the analogy further.). I would say that we in the U.K. regard it as an honour that you have invited him to be 'the technologist' on the panel on Friday morning.

The keynote of Bill Kaye's talk two years ago was that fluidised bed combustion had arrived. In retrospect, that was not an overstatement. There are now some nine companies in the U.K. who are prepared to offer on a commercial basis a fluidised bed boiler or furnace. Two years is not long, but the pace of development is such that in those two years much has been learnt and much accomplished.

We, in the National Coal Board, like to feel that we are at the forefront of this development through the work of the Coal Research Establishment and the Coal Utilisation Research Laboratory, but it is a great encouragement to us that so many British firms are now investing their own resources in development and production.

Let me now very briefly look over the U.K. scene, starting firstly with pressurised fluidised beds.

Pressurised Fluidised Beds

You will learn about the continuing work which goes on in the CURL laboratory from the paper by Raymond Hoy and Alan Roberts, but what is more important you will hear this afternoon about the IEA project at Grimethorpe and, as an engineer, one of the pictures which brings home to me the reality of the advantages of this technology is a picture of the 85 MW_{th} boiler arriving in one piece on a low loader. This plant is now near to commissioning.

Another project about which we shall hear more in the future is the British Columbia Hydro scheme which is now being designed by Coal Processing Consultants, (the National Coal Board's organisation for selling knowhow). This is a major and very interesting project and we are confident that it will lead to more of the same type and scope.

Atmospheric Pressure Fluidised Beds

Now to the atmospheric pressure developments- and if there are those in the audience who do not know the difference, stay tuned to this show through till Friday and you will learn.

Starting first with the larger end of the market, the British Babcock boiler at Renfrew has continued to notch up an impressive total of operating hours as a boiler supplying heat to the works, but also as a test bed to provide the British Babcock Organisation with a vast amount of information on burning a wide range of fuels, some of which so strange we might not have considered them as fuels a few years ago. I do not think they have tried camel dung yet though. One of the commercial expressions of this is, of course, the retrofit installation by Babcock International Combustion at the Central Ohio Psychiatric Hospital.

Installation of the high pressure Mitchell coil boiler with an output of 30 MW_{th} and 40 bar is now virtually complete and though events in the British Steel Corporation have delayed its completion, cold commissioning tests have been carried out.

The Energy Equipment retrofit system on a small industrial water tube boiler has been installed and proved.

There is a number of other projects in the early design stages with a number of manufacturers, one such being the retrofitting of a high pressure 50,000 kg/hr steam boiler which was installed a few years ago, oil fired but with an eye to possible future conversion to coal fired fluidised bed. Subject to satisfactory funding, that future has arrived.

Smaller Boilers

The small vertical fire tube boilers for the tomatoe (or should I say tŏmatŏe) greenhouses at Marden (a hot water boiler) and the other steam boiler at the Antler Luggage factory at Bury have continued to operate for the last three years. The last of these two has been the only boiler on site for two years and has carried the load. Both have been used as test installations, not only for burning different coals but also for trying different methods of start-up. You will hear more of this work in Thursday morning's session on operating experience from John Highley.

This particular vertical fire tube boiler approach has been taken up by Vosper Thornycroft Combustion, a division of British Shipbuilders and commercial prototypes of around 5 MW_{th} (steam or hot water) at pressures of around 10 bar are being manufactured. The first of these has now been delivered to a site in London. It is expected that about half a dozen will be installed by the end of the year, whilst other manufacturers are developing somewhat similar designs. The Stone Platt Fluidfyre small package water tube boiler for steam at about 3 MW thermal is now installed at a factory in Yorkshire for proving trials. You will hear of this development from Michael Virr on Thursday morning.

On the horizontal fire tube boiler a number of people are active using 'conventional' and 'unconventional' designs. Along the conventional approach is the Northern Engineering Industries (perhaps still better recognised by individual names within the group, such as John Thompson, International Combustion,Cochrane and Clark Chapman. Three or four of these boilers are now sold for installation in sizes up to about 6 MW_{th} for steam or hot water and will be installed towards the end of the year after substantial proving in one of NEI's manufacturing works.

Energy Equipment have also sold their system for installation in three Robey boilers and the first of these is now on test in their works. Similar equipment has been sold for installation in a boiler in Hungary.

Parkinson Cowan GWB Ltd. have also sold three boilers at 2 MW thermal each for installation later this year or early next year.

On more unconventional lines the Vosper Horizontal Open Hearth boiler which is going into our boiler test house at CRE this month (rated at 5 MW_{th} steam at 10 bar) and the Babcock (Packaged Boilers) Compo boiler which is going into the test house some time in August. This latter design, though initially at 3 MW thermal as a steam boiler, has the potential of going up to 30 MW thermal in one unit and possibly pressures of 40 bar.

Finally, I must mention the successful Johnston boiler in the USA, for whilst this is a British overview, the fluid bed technology is based upon work by the National Coal Board licensed to Johnston Boilers through Combustion Systems Ltd. This boiler will be described in the paper by Mike Michaels on Thursday afternoon.

Atmospheric Fluidised Dryers

Before I finish my lightning overview, I must quickly look at the non-boiler scene and in particular the field of dryers. Quite a bit of energy is simply used for drying and obviously hot gases from a fluidised bed can be used for this purpose. Again John Highley, this time on Thursday afternoon (busy day John) will cover the work in more detail.

The grass dryers are pretty well established and by their operating experience have shown the favourable economics. G.P. Worsley have sold five and another two are on order. All of these have thermal outputs of 5 MW. Energy Equipment have also sold three (two in the U.K. and one in France).

At the larger end of the direct drying market the 15 MW thermal clay drying plant at the cement works has been very successful in showing a substantial saving over the former oil fired furnace.

Conclusions

I have, because of the time factor, left out reference to the work on tailings combustion, reference to the support and contract work done for many organisations on such important matters as corrosion and erosion, on fluid bed gasification to produce a gas for burning in furnaces or gas turbines, etc.

There is so much going on and yet all the time we can see new ideas to try, new developments to pursue.

Bill Kaye concluded his 1977 overview by saying that fluidised bed combustion had arrived. I have come back into research and development after many years in technical marketing. I can see that fluid bed combustion has arrived, but moreover, I can see that it can, with the right financial structure, be sold on a commercial basis and I believe that in the U.K. we should be in a damn good position to do some selling of British coal, British ideas and British equipment.

I must, however, end on a sombre note and set fluidised bed combustion in perspective against the world energy situation. If we do not speedily develop the new techniques of coal burning, and I believe fluidised beds to be a most important one, and persuade people to revert to coal firing, thus relieving the pressures on a precarious world oil situation, the results for the industrialised western world may be horrendous.

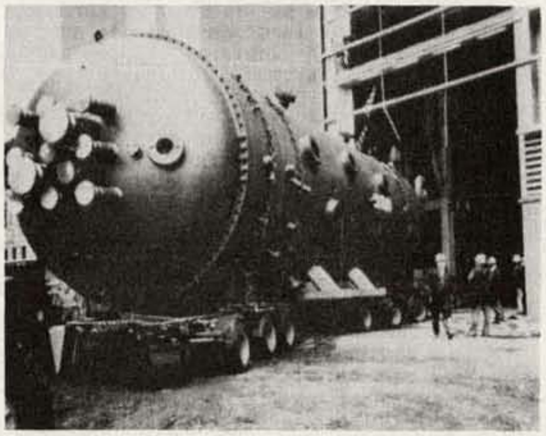


Fig. 1 I.E.A. Grimethorpe
85 MW reactor being delivered

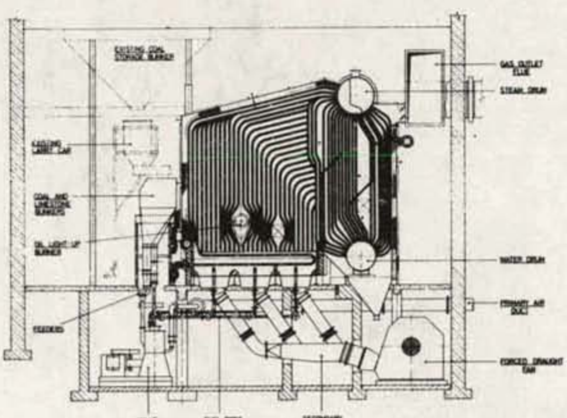


Fig. 2 Fluidised bed retrofit to Central Ohio Psychiatric Hospital
Babcock International

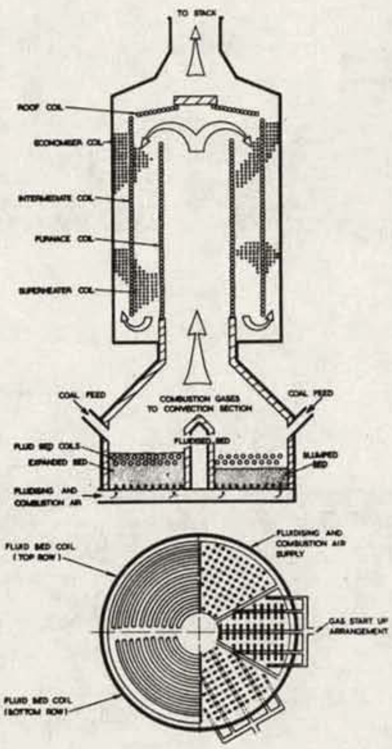


Fig. 3 Fluidised bed coil boiler by ME Boilers U.K.
National Coal Board project

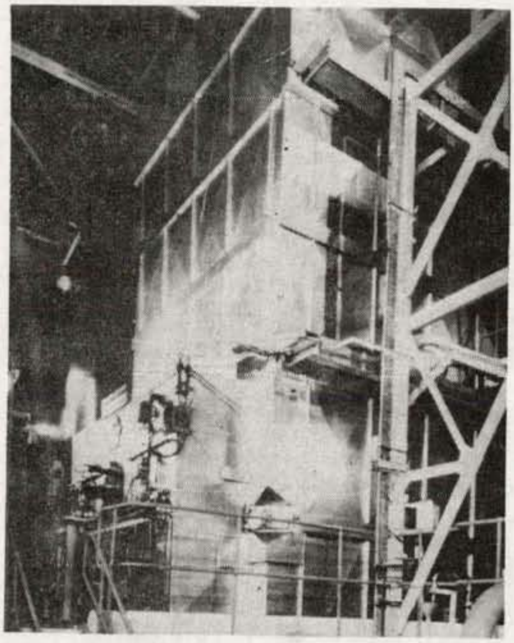


Fig. 4 Babcock boiler for proposed retrofit conversion from oil to fluidised bed coal firing U.K.

Fig. 5 Clonsast 3 MW vertical fluidised bed hot water boiler
National Coal Board project

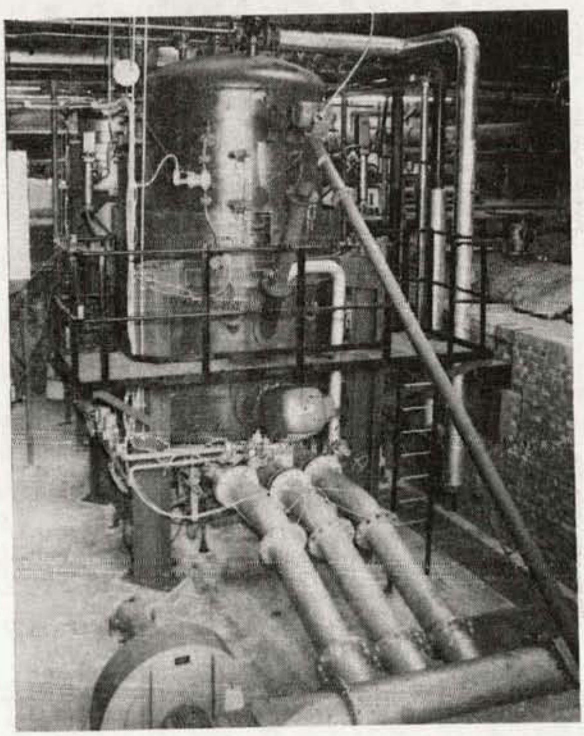


Fig. 6 Clonsast 2.8 MW vertical fluidised bed steam boiler
National Coal Board project

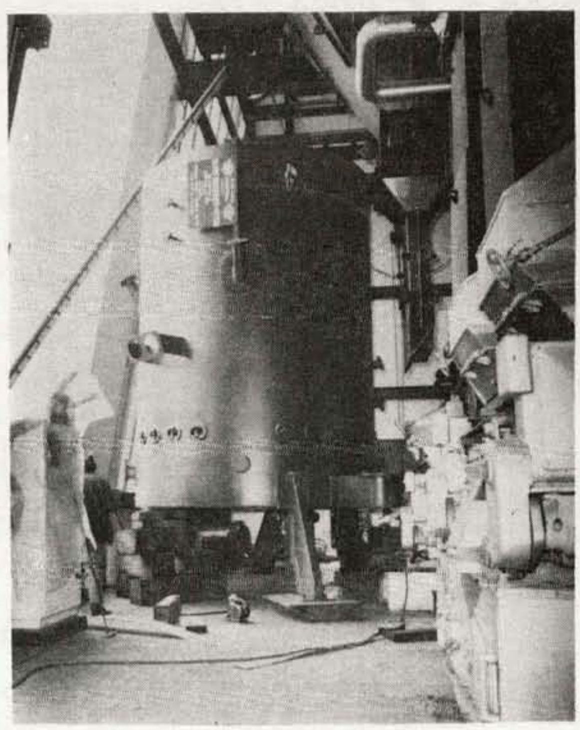


Fig. 7 Vosper Thornycroft 5 MW vertical fluidised bed pressurised hot water boiler being delivered in London
Vosper Thornycroft/NCB project

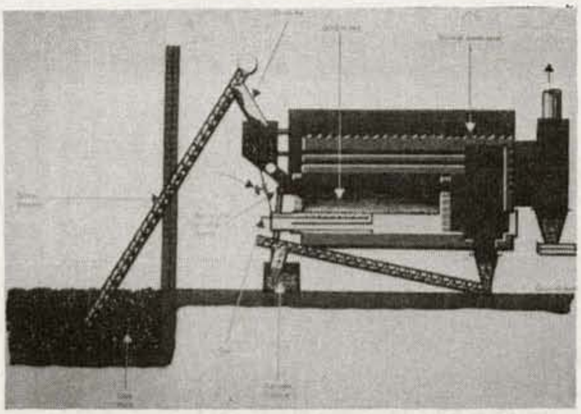


Fig. 8 Schematic section Northern Engineering Industries horizontal shell

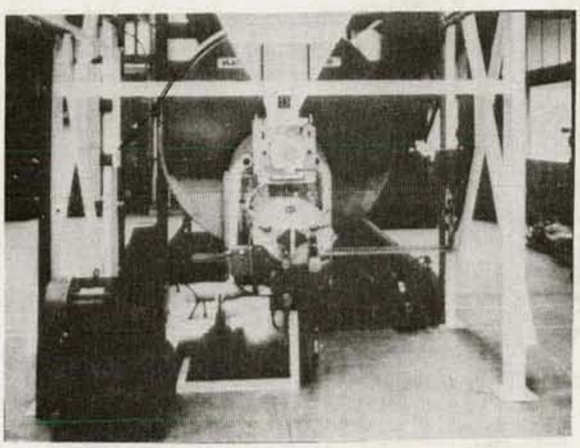


Fig. 9 Energy Equipment fluidised bed combustion unit in a 3 MW Robey steam boiler for NCB site

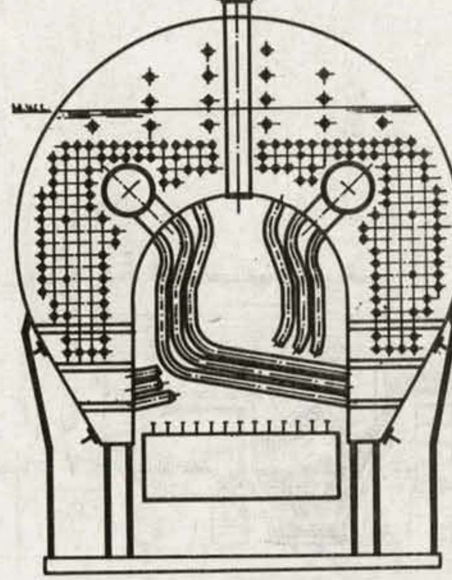


Fig. 11 Vosper Thornycroft 5 MW horizontal fluidised bed fired boiler
Joint Vosper Thornycroft/NCB project

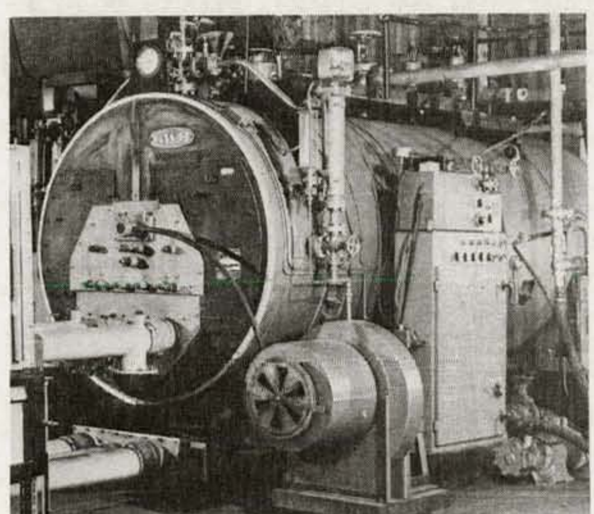
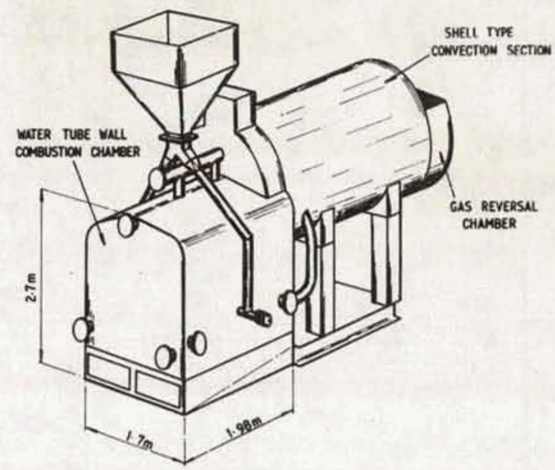


Fig. 10 GWB Boiler with development fluidised bed
Joint Parkinson Cowan/NCB project

Fig. 12 Babcock (Shell Boilers) 4.3 MW
composite boiler with fluidised bed
Joint Babcock/NCB project



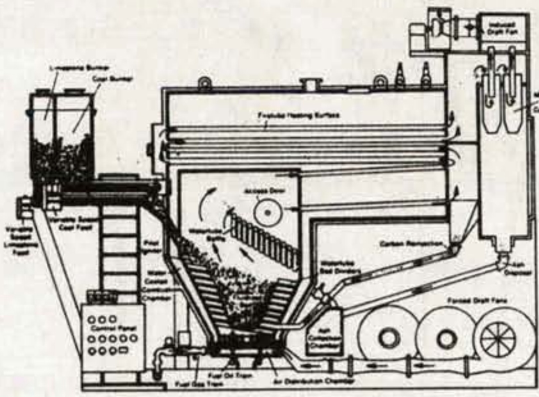


Fig. 13 Johnston Boiler Company
Ferrysburg, Michigan 49409

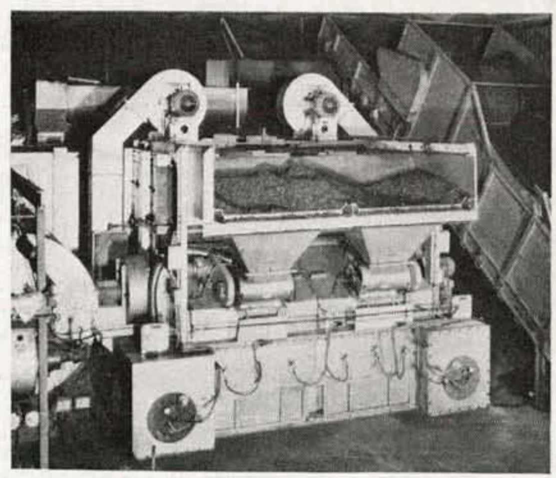


Fig. 14 G.P. Worsley 5 MW fluidised bed
for grass dryers
Joint G.P. Worsley/NCB project

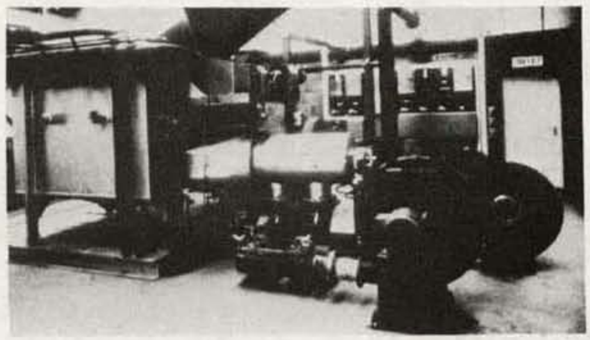


Fig. 15 Energy Equipment fluidised bed furnace test unit for design of commercial units

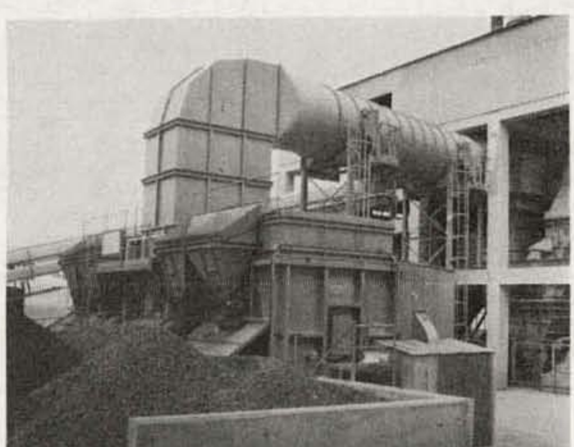


Fig. 16 G.P. Worsley 15 MW fluid bed furnace for clay dryer

Overview of the Fluidized Bed Combustion
Programme of the Federal Republic of Germany

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J. Batsch

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The basic goal of the energy research programme of the Federal Republic of Germany is the development of technologies which can contribute to a reliable future energy supply for our country in an economically favourable and environmentally acceptable way.

The development of suitable technologies for increased and more efficient utilization of coal plays an important role within this programme, as coal is the only domestic primary energy source which is available in large quantities in Germany.

Accordingly, about half of the government funds for non-nuclear energy research is being consumed for coal research. In the area of direct combustion of coal, for heat and power generation, the efforts are concentrated on the improvements of conventional power plants with respect to environmental protection and advanced technologies which combine high efficiency, utilization of low grade coal and environmentally acceptable operation. Here, fluidized bed combustion (FBC) represents the largest area of development.

Before entering into details of our fluidized bed combustion research and development programme I would like to summarize some basic advantages of FBC.

- The furnace temperature is kept low and uniform. Consequently, NO_x formation is low.
- Because SO_2-emission can be reduced by the addition of limestone or dolomite, an expensive and efficiency consuming flue gas desulphurization plant is not required.
- Heat transfer coefficients are high. This means, that the heat-exchanger areas and consequently the boilers can be smaller than in pulverized fuel firing.
- Low grade fuels can be used.

Pressurized fluidized bed combustion (PFBC) offers special advantages with respect to environmental protection, combustion efficiency, geometric size and, if combined with a gas turbine, to thermal efficiency of the total plant (Fig. 1 and 2).

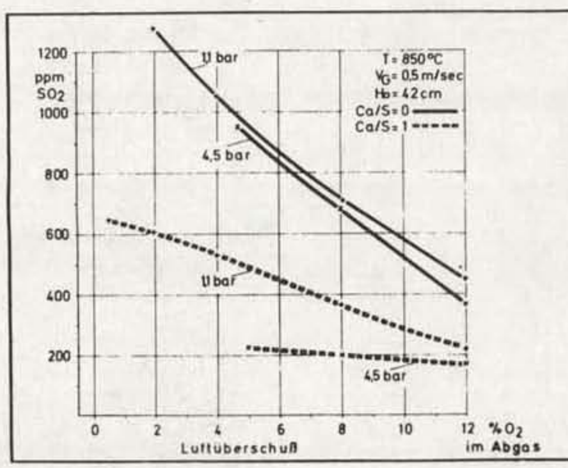

Fig. 1: SO_2-Concentration as a function of excess air

Serious development problems have to be overcome in the case of PFBC. Therefore, atmospheric fluidized bed combustion (AFBC) was incorporated in our FBC research programme because it can be developed for commercial application within a considerably shorter time than PFBC. In addition a relatively simple concept is favourable for small plants, such as industrial boilers and small power station units, where a complex technology leads to comparatively high investment costs.

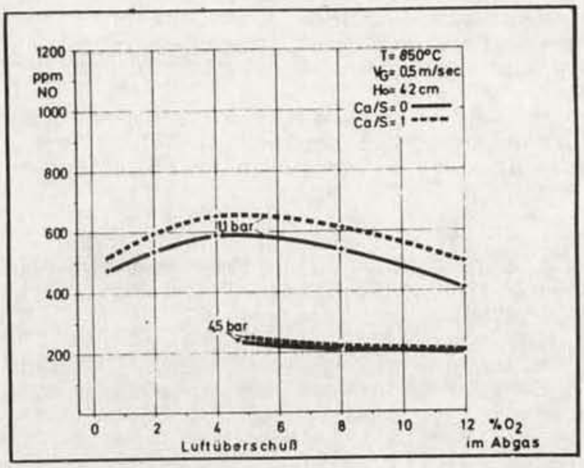

Fig. 2: NO$_x$-concentration as a function of excess air

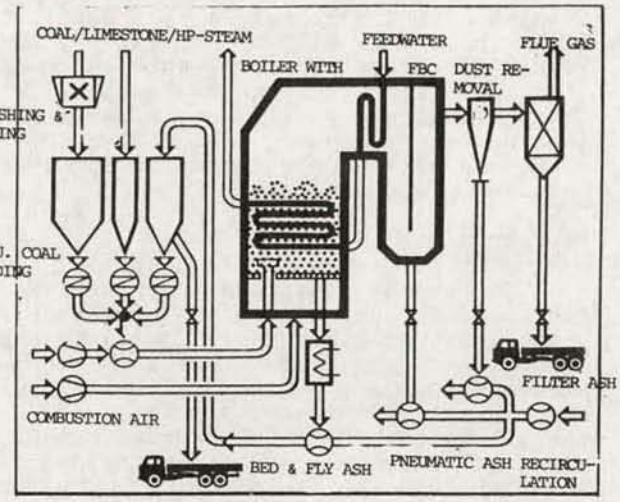

Fig. 3: Flow scheme
35 MW Fluidized Bed Combustion Plant

In the Federal Republic of Germany a considerable part of the primary energy demand is being consumed in industrial boilers. In this area primarily oil and natural gas are being used at the present time. The development of AFBC can reduce the dependence on these energy sources, as this technology offers similar advantages with respect to automatic operation and environmental protection.

The projects on conventional AFBC as executed in the Federal Republic of Germany cover a range of thermal capacities from 6 MW to 124 MW.

AFBC-Projects

At the power station in Düsseldorf-Flingern an existing boiler was converted from travelling grate firing to fluidized bed combustion. This plant, with a thermal capacity of 35 MW, has been in operation since the second half of 1979. It produces superheated steam of 17 bar pressure and 400 °C which is supplied to the steam system of the power station. The superheater is located above the bed. Fig. 3 shows the flow scheme of this plant. A premixed coal and limestone mixture is fed pneumatically into the bed. The produced heat is transferred to in-bed-heat-transfer-surfaces and to tube banks outside the bed. The flue gas is cleaned in the cyclones and in baghouse filters. The dust collected in the cyclones can be recirculated into the bed to improve combustion efficiency.

A newly constructed second plant with a thermal capacity of 6 MW, located in Recklinghausen, entered into operation in 1979. It produces saturated steam which is fed into a district heating system. Its flow scheme (Fig. 4) shows that for this small unit a simpler technology especially with respect to coal preparation and feeding has been applied. Coal and limestone are conveyed by a screw feeder into the fluidized bed.

Both projects are being performed by Ruhrkohle AG in cooperation with the Deutsche Babcock group and the consortium Thyssen Engineering, Standard Kessel, respectively. Details of these projects will be presented later during this conference.

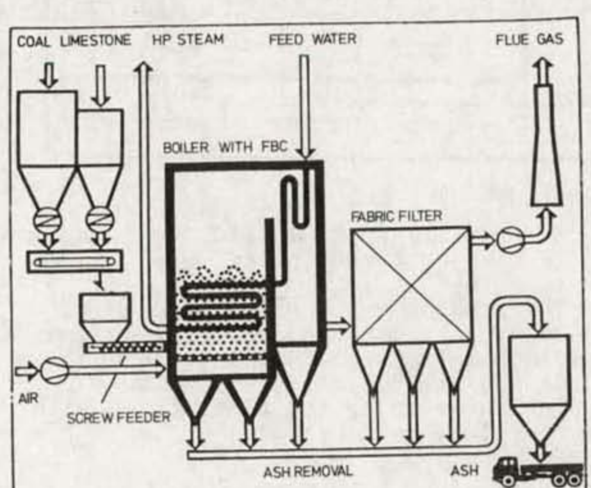

Fig. 4: Flow scheme 6 MW - AFBC Plant

An additional plant with a thermal capacity of about 124 MW will be constructed in Hameln. The contractor is the Elektrizitätswerke Wesertal GmbH, a local utility. The boiler will be supplied by the Vereinigte Kesselwerke AG, which also supplied the boiler for the IEA-Plant Grimethorpe. This plant will have a part of the superheater within the bed. The FBC boiler at Hameln will supply steam for combined heat and power generation.

PFBC-Projects

As already mentioned, pressurized fluidized bed combustion has by far greater potential than atmospheric fluidized bed combustion. Fig. 5 shows the flow scheme of the PFBC plant concept which promises the highest efficiency. Air is passed to the fluidized bed via the compressor of a gas turbine. Coal and limestone are fed premixed into the fluidized bed. The combustion gases leave the combustor with a temperature of about 850 °C, are dedusted in suitable equipment and then passed to the gas turbine. Heat is transferred to the watersteam circuit from heat exchanger within the combustor and from the waste heat of the gasturbine. According to preliminary studies this concept will have an efficiency of about 39 % based on the lower heating value.

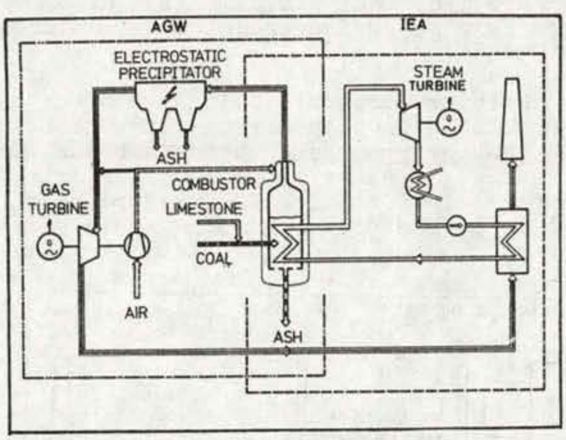

Fig. 5: Pressurized Fluidized Bed Combustion with Combined Cycle

The problem areas which have to be solved before commercial application can be divided into problems of the combustion process and its optimization and into problems which arise by the combination with a gas turbine.

The first problem area is being investigated within the framework of the well-known IEA-Project. The construction of the PFBC plant in Grimethorpe, UK, is nearly complete and cold commissioning is being performed. It is envisaged to start the experimental programm in early 1981.
Germany is one of the three partners in this project. This project will be presented in detail later during this conference.

Our national projects in the PFBC area are concentrated on problems connected with the combination of the PFBC with a gas turbine.

A project which is being carried out by a consortium of Bergbau-Forschung GmbH and Vereinigte Kesselwerke AG (VKW) and others deals with a pilot-plant with a thermal capacity of about 32 MW for testing this combination. In the original concept it was envisaged to use an electrostatic precipitator for hot gas cleaning at a pressure of 4,5 bar.

During the engineering evaluation it became clear, that this system cannot be used without special development devoted to the designed gas conditions. Therefore, a different concept for this plant is now under consideration (Fig. 6). It is now planned to used three stage cyclone gas cleaning. To compensate for the relatively high dust load in the gas after the cyclones, a special dust resistant turbine will be used, which was developed for energy recovery after fluidized bed cat crackers. The pressure in the combustor will be raised to about 8 bar.

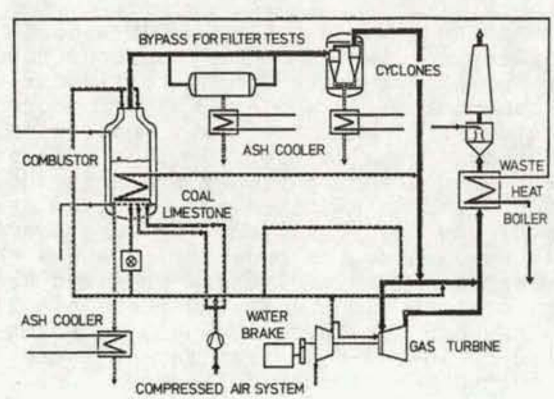

Fig. 6: Flow scheme of the AGW-Plant

As it cannot be expected that the above concept offers the optimum economical and technical solution , further work is being done in the development of high temperature/high pressure gas cleaning equipment. Two projects of the University of Essen deal, in laboratory scale, with electrostatic precipitators and high temperature fabric filters. Up to now the results indicate that operation of an electrostatic precipitator with pressures above 7 bar is possible at 850 °C and that filter materials for temperatures up to 1.000 °C can be manufactured. With this in mind regardless of the difficulties we encounter in the development of high temperature electrostatic precipitators at low pressures, it is still our opinion that this concept offers a promising possibility for higher pressures. Therefore, a design study for an electrostatic precipitator based on the results of the experiments at the University of Essen was started in January 1980.

Parallel to the experiments at the University of Essen, KWU is performing laboratory scale experiments to improve the efficiency of the tornado cyclone.

It can be expected that the optimum technical and economic solution for the problems of the combination of pressurized fluidized bed combustion with a gas turbine will be a compromise between highly efficient gas cleaning and highly dust resistant gas turbines. Therefore, it appears sensible to develop both technologies, as is planned in our programme.

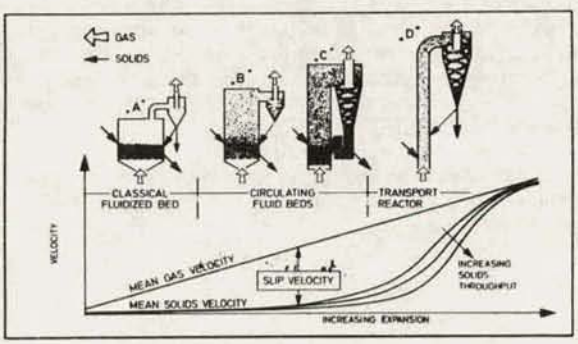

Fig. 7: Basic Fluid Bed Combustion Systems

Because of the special advantages found in fast or circulating fluidized bed combustion, we have recently added this concept to our research programme. Fig. 7 compares the different states of fluidized bed.

- The classical or stationary fluidized bed with a relatively well-defined surface of the fluidized bed and only a small carry-out of solids.
- The circulating fluidized bed with a very high carry-over, which results in a very intensive internal and external recycling of solids.

In Fig. 8 the flow scheme of an atmospheric circulating fluidized combustion plant is illustrated. In the recycling cyclone the two heat carriers, flue gas and solids, are separated. Heat is extracted from the flue gas in a waste heat boiler and from the solids in a fluidized bed heat exchanger. Because the heat transfer from the two heat carriers can be influenced separately, the control and part load behaviour of this concept is more favourable than that of the stationary fluidized bed. Additional advantages of the circulating fluidized bed are

- improvements with respect to SO_2 and NO_x emissions achieved by finer grained sorbent and staged combustion,
- considerably smaller bed areas than in classical fluidized bed, enabling larger capacities per unit,
- Combustion and heat transfer can be separated, enabling a very sensitive control of heat transfer.

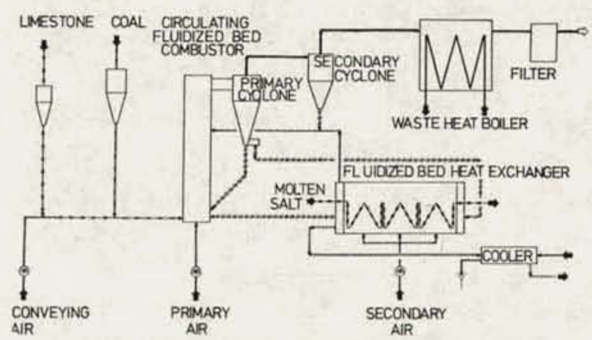

Fig. 8: Flow Scheme of a Circulating Fluidized Bed Combustion Plant

In Lünen,at the Vereinigte Aluminiumwerke (VAW) a circulating fluidized bed plant with a thermal capacity of 77 will be constructed. It will serve for heating molten salts in the fluidized bed heat exchangers and for producing process steam. The molten salt will be used as the heat carrier for the Bayer hydrolizing process. The project started in early 1980.

A design study for a 200 MW (th) circulating fluidized bed boiler located in Duisburg, also started in January 1980.

It is intended that this plant will be used for combined heat and power generation. The heat will be fed into the heating system of the city of Duisburg. Because of its location the advantages of the circulating fluidized bed principle are of special importance. Stringent environmental standards have to be met and only a relatively small area is available for the plant. A similar problem would arise with a conventional fluidized bed plant because of its large bed area. Therefore circulating fluidized bed combustion seems to be the logical technical solution for such a locaction in a densely populated area. More details of the circulating fluidized bed technology will be presented later during this conference.

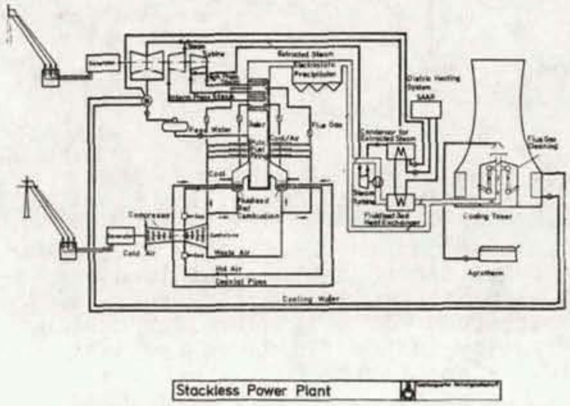

Figure 9: Prototype Power Plant Volklingen

I would like to mention a further power station concept in which the conventional fluidized bed plays an important role. As is shown in the flow scheme (Fig. 9) the concept is characterized by the following

- combination of fluidized bed combustion with pulverized coal firing.
  The flue gas of the FBC which can be operated with low grade coal is passed to the pulverized fuel burners. By doing this in a suitable way NO_x-formation can be reduced considerably.
- combination of AFBC with an open cycle gas turbine. The air coming from the compressor of the gas turbine is preheated in the in-bed tube bank before entering the combustion chamber. In this way a part of the energy which is supplied to the gasturbine is provided by coal. The risk of erosion and corrosion of the turbines blades by dustladen exhaust gases is eliminated in this method.
- the flue gas desulphurization plant is incorporated into the natural draft cooling tower. The power plant doesn't need a stack. In this way, no reheating of the desulphurized flue gas will be necessary, thus increasing the efficiency of the power station.
  A power station of this type with a electric capacity of 220 MW is under construction by the Saarbergwerke AG.

The Fig. 10 lists the major projects that the Federal Republic of Germany has undertaken.

The total cost of all FBC-projects including the development hot gas cleaning and dust-resistant gas turbines amounts to 824 Mio. DM (or more than 400 Mio. US-Dollar). The governmental funds for these projects amounts to about 315 Mio. DM (or more than 150 Mio. US-Dollar).

This sum is an indication of the importance that my government attaches to these developments.

R. Holighaus
J. Batsch

Project	Objective/Application	Time Schedule 77	78	79	80	81	82	Total Cost Mio. DM	Governmental Funds
6 MW_{th} - AFBC	Industrieal Purposes District Heating							7.8	4.7
Lüneburg	District Heating							12.0	5.9
35 MW_{th}-AFBC	Power Generation							17.3	10.4
124 MW_{th}-AFBC	Power Generation							38.3	18.2
Circulating FBC 77 MW_{th}	Industrial Purposes							35.6	17.8
Circulating FBC 200 MW_{th} (Design Study)	Power Generation							5.0	3.7
Prototype Power Plant Völklingen	Power Generation							496.0	165.3
PFBC Power Plant 22,5 MW_{th}	Test of the Combination PFBC - Gasturbine							38.9	29.2
IEA-Project Grimethorpe PFBC	Component Development: Combuster							168.0	56.0

Engineering — Construction — Operation

Fig. 10: FBC-Projects in the Federal Republic of Germany

THE PROGRESS OF FLUIDIZED-BED BOILERS IN PEOPLE'S REPUBLIC OF CHINA

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FORWARD

Early in the 1960's, based on the broad adoption of successful fluidized-bed calcination technology, China began its research work on fluidized-bed combustion boilers. In 1965, Mouming Petroleum Company, Tsinghua University, and several other institutions cooperated to design the first fluidized-bed combustion boiler in China. It was constructed and put into operation in Mouming. In 1969, Tsinghua University installed a fluidized-bed combustion boiler for her Experimental Power Plant, and that boiler has been used for power generation studies for several years. These successes gave impetus to the progress of fluidized-bed combustion boilers in China.

Presently, there are over 2,000 fluidized-bed combustion (FBC) boilers in China. Many boilers have capacities of 4-10 T/h and are used for generating saturated steam, while others with capacities of 10-50 T/h are used for power generation and industrial applications. FBC boilers with a capacities of 130 T/h are now being tested.

The fuels used in China for most FBC boilers are low-grade fuels such as shale fines, low-grade bituminous coal and anthracite, coal washery waste, stone-like coal, lignite, etc. The heating value of the fuels now being used, ranges from 1,000-1,500 Kcal/kg. The boilers are being used either for industrial purposes or for generating electricity. Many boilers possess more than 40,000 hours of accumulated operational experience.

In China, there are a number of organizations taking part in the research and development of fluidized-bed combustion-fired boilers. Many technical institutes, such as Tsinghua University, Zhejiang University, Harbin Technical Institute, etc., are the major institutions conducting research work. Shanghai Boiler Works, Dungfang Boiler Works, and Kuangchow Boiler Works, etc., are the chief FBC boiler designers and manufacturers. Extensive research work has been done on the fluidized bed operating parameters selection, combustion of low-heating value fuels, improvement of thermal efficiency, desulfurization with limestone, and boiler structures.

The following are a number of selected representative fluidized-bed boilers:

1. <u>14.5 Tons/Hour Steam Industrial Boiler, Mouming Petroleum Company</u> -- The boiler is designed by Mouming Petroleum Company, Fushuen Designing Institute of Petroleum, Tsinghua University, etc. This boiler burns shale fines with a heating value of 1,034 Kcal/kg as fuel; the steam pressure is 13 kg/cm^2 and the superheated steam temperature is 250°C.

   This is the first demonstration fluidized-bed combustion boiler in China, with a circular bed of 2.25 m diameter and a superficial air velocity of 2.7 m/sec through the bed. The bed temperature is about 800°C. This boiler was commissioned in December 1965.

2. <u>14 Tons/Hour Tsinghua University FBC Boiler</u> -- This is the first demonstration fluidized-bed combustion boiler in China for power generation. It is designed by the staff of Tsinghua University and commissioned in July 1969, its steam pressure is 24 kg/cm^2 and a superheated steam temperature of 390°C. The main fuel used is anthracite from the Beijing district; a mixture of low-grade bituminous coal and coal washery waste with a heating value of 2,500 Kcal/kg was also used in the test.

   This boiler has two independent beds to achieve a good turndown ratio between 35-110 percent. When burning coal with low volatile content, the bed combustion temperature is roughly 1,000°C.

   The total operating time of this boiler has already reached 20,000 hours; much valuable experience has been acquired. Most of the research work has been in the area of in-bed heat transfer surfaces and the prevention of erosion of the in-bed surfaces.

3. 130 Tons/Hour Fluidized-Bed Boiler -- This is the largest power generating fluidized-bed combustion boiler in China at present. It has six beds with six screw feeders. The fuel used is coal washery waste with a heating value of 1,500 Kcal/kg. The immersed surface has an inclination of 15° to the horizontal. This boiler is now in the process of shakedown testing for power generation. Figure 1 is the 130 T/h FBC boiler designed for power generation.

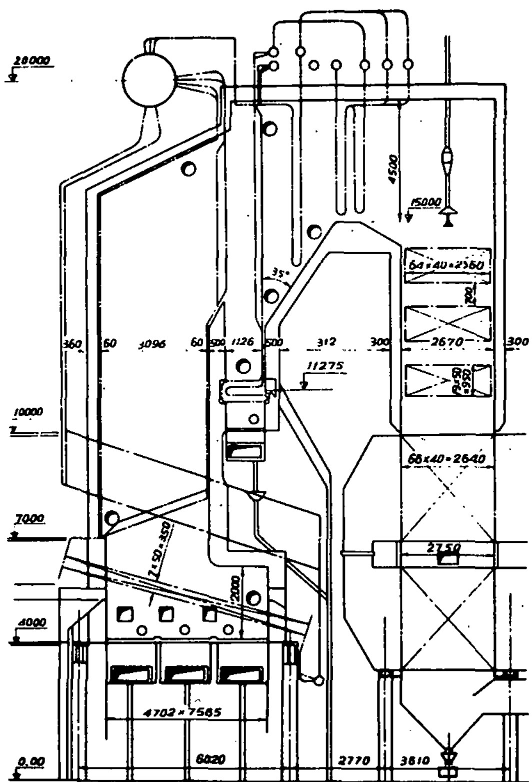

Figure 1 -- 130 T/h Fluidized-Bed Boiler

RESULTS OF SOME RESEARCH

1. Determination of the Optimum Superficial Bed Air Velocity and Bed Particle Size -- In order to achieve a high bed volume heat release rate, the Chinese are trying to burn coarse particles in fluidized-bed combustors. For a given size fuel, there is a minimum bed superficial air velocity required to insure vigorous heat and mass transfer between the bed materials. To avoid high-temperature clogging or particle-size segregation which may lead to the formation of "cold slag," Tsinghua University has carried out the cold-bed testing with controlled-size bed particles. Research findings on the movement of particles inside the bed, especially those near the distributor plate, have revealed that to maintain identical fluidizing conditions, the following relationship represents the hot and cold air superficial velocities:

$$U_h = \frac{1}{2.5}\left(\frac{\rho_c}{\rho_h}\right) U_c \qquad (1)$$

where U_h, U_c are the superficial air velocities during combustion and cold condition; ρ_h, ρ_c are the gas densities during combustion and cold condition. The data obtained by cold-bed testing and the calculation are being used in the design of Chinese fluidized-bed boilers.

Table 1 lists the heat release rate per unit bed volume, as a function of superficial air velocity, and maximum size of fuel particle:

TABLE 1
OPERATING PARAMETERS

Bed volume heat release rate (Kcal/m^{3}h)	(2-3.3) x 10^6
Superficial bed air velocity (m/sec)	2.8-4.2
Fuel particle size (mm)	
lignite	30
other fuels	
Q > 4,000 Kcal/kg	< 35
Q = (2,000-4,000) Kcal/kg	8
Q < 2,000 Kcal/kg	< 6

Q = lower heating value of the fuel.

2. The Arrangement of In-Bed Surfaces and Prevention of Erosion -- For small boilers, the immersed in-bed surfaces are the side walls; therefore, the erosion rate is insignificant. For ordinary carbon steel, the wall erosion rate is only about 8 x 10^{-5} mm/h. As the boiler capacity increases, side water walls are insufficient for heat absorption and in-bed heat transfer surface must be employed. The erosion rate of the in-bed surfaces is very fast, nearly 1.3 x 10^{-3} mm/h. By adopting some protective mechanism, in PRC, the life of these steel pipes may be extended by nearly 20 fold.

In China, all the fluidized-bed boilers are using natural circulation. For FBC boilers of the capacity range of 10-130 T/h, the most common in-bed surfaces are arranged at 15° to the horizontal. Although within the bed there is a much better heat transfer due to intensive disturbance of the bed particles, unsatisfactory arrangement of the immersed in-bed surfaces can cause large temperature differences within the fluidized bed. Figure 2 shows the relation between the in-bed temperature difference along the tube length when the tube is placed at 15° to the horizontal.

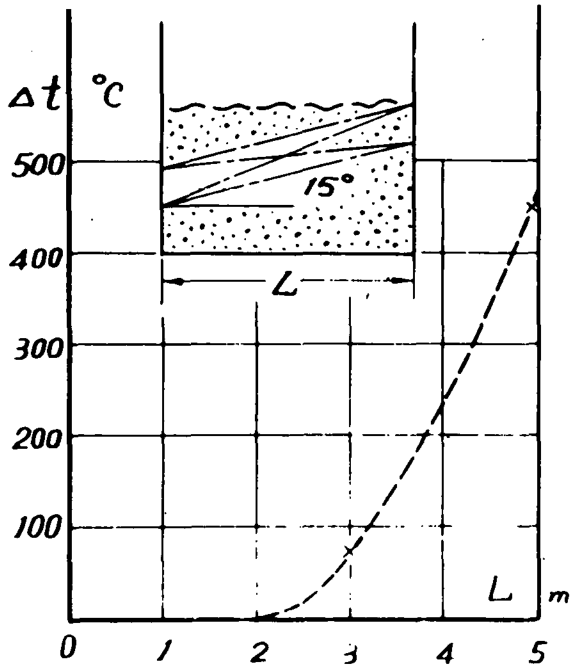

Figure 2 -- Relation Between Transverse Temperature Difference and Length of the Bed

3. Combustion of Low-Heating Value Fuels -- Fuels with different heating values affect the in-bed heating surface area. Figure 3 shows the relationship between the heating surface area and the fuel heating value of some boilers. When fuel heating value is larger than 3,000 Kcal/kg, the curve gradually flattens out, as the fuel heating value drops to less than 1,500 Kcal/kg, the curve drops abruptly. For most boilers, the adaptability for fuel heating variation is a very important problem for FBC burning of low-grade fuels. The work on improving the adaptability of low-grade fuels in some Chinese fluidized-bed boilers is under intensive study.

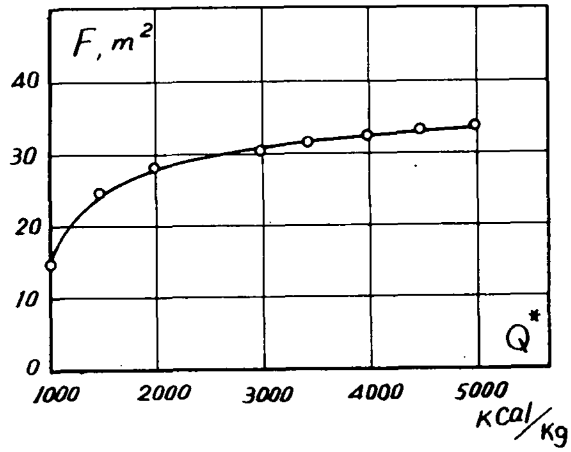

Figure 3 -- Relation Between In-Bed Surface Area and Fuel Heating Value

For large size, low-heating value, and high ash content fuel particles, the ash crust hampers the diffusion of gases; therefore, it is hard to burn out the inside carbon. For example, no matter how long it stays in the fluidized bed, the thickness of burned out scale for hard stone coals is only about 1.5 mm.

For ash-rich and heavy fuel, it is easy to form "cold slag" at the bottom of the fluidized bed. This will disturb the normal operation of the boiler, and it is necessary to discharge this slag for smooth operation. The air distributor should be designed to induce movement of the bed materials and improve the availability of the FBC boiler operation.

4. Improvement of the Combustion Efficiency -- In China, fuels of wide-size distribution are used in fluidized-bed boilers. Sometimes, the amount of particles of sizes less than 1 mm exceeds 40 percent. The carry over of the fines by the flue gas, many fuel particles elutriate out without adequate combustion, results in a great amount of unburned carbon loss in the fly ash. In 1971, Tsinghua University did research work on fly ash carbon burn-up in a low superficial velocity fluidized bed (carbon burn-up cell). For low volatile content fuels, the total combustion efficiency attained 90 percent. Presently, the fly ash burn-up fluidized bed used in China operates at a superficial air velocity of 0.6-1.4 m/sec. According to publications, high bed temperature and more excess air will be beneficial to the improvement of combustion efficiency. Owing to the low heat load of fly ash

burning in a fluidized bed, the superficial velocity can be relatively low. It has also been shown that bottom fly ash reinjection can improve combustion efficiency. Therefore, it is quite safe when the bed temperature is only 50-100°C higher than that of normal bed. According to the research findings, no significant improvement of combustion efficiency is observed for fly ash reinjection into a high superficial velocity FBC bed.

When feeding high-volatile content fuels, the evolution of volatile matter is excessive near the feeding points. There is a great amount of unburned volatile loss due to the starvation of oxygen near the feed port. By proper arrangement, a combustion efficiency of 94-98 percent can be attained with fuels of high volatile content.

5. Desulfurization with Limestone -- In 1973, Tsinghua University began the research on the absorption of SO_2 by limestone in a fluidized bed. The efficiency of SO_2 absorption is determined by the concentration of CaO in the outer shell. By experiment, this relation may be expressed as:

$$\eta = 1 - e^{-1.97 W_c H/V} \qquad (2)$$

where η is the absorption efficiency of SO_2 in flue gas, percent; W_c is the concentration of CaO in the bed, percent; H is the bed height, meters; and V is superficial air velocity in the bed, meters per second.

Figure 4 shows the testing result. This empirical equation shows that the kind and size of limestone has exhibited no influence on sulfur dioxide absorption.

The fraction, ξ, of CaO absorption in the outer shell of limestone particles (calcium utilization) with different sizes of limestones from the Tanli district of Beijing has been determined. Figure 5 shows the result. Limestone particles with different sizes have nearly the same depth of sulfate penetration. It is about 32.5 µm for Tanli limestone. The fraction of calcium utilization, ξ, is not influenced by the type of coal or superficial velocity. It also shows that when the particle diameter is larger than 3 mm, the calcium utilization is very poor. The sulfur contents of coals used in the experiment are quite different, Hebi coal has 3 percent sulfur; and Shangsi coal is 8 percent sulfur.

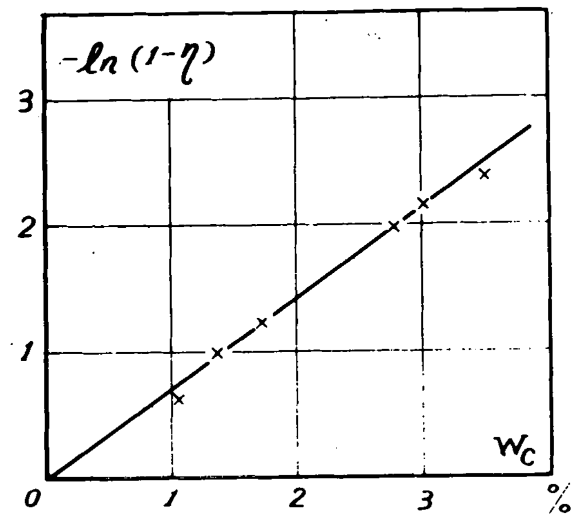

Figure 4 -- Relation Between SO_2 Absorption Efficiency and the Concentration of Reactive Surface Layer of the Limestone Granule in the Bed

6. Utilization of Ash and Spent Bed Material -- China focused much attention to the utilization of the ash and slag from fluidized-bed boilers. Low combustion temperature and low carbon content of the ash and slag enable good utilizations. The methods of utilization are different for each district. It is being used as an additive for cement to improve cement's color and strength. It has been used to make bricks, tiles, and medium-sized blocks for building constructions. The extraction of vanadium from south China stone coal ash has already been achieved. Use of fluidized bed for calcination of light construction materials has also been successful.

CONCLUSION

The rapid progress of fluidized-bed boilers in China has made possible the use of a wide variety of energy resources. China has also acquired many hours of operation experience in fluidized-bed boilers. The study of large fluidized-bed boilers has already begun. It will play an important role in the modernization of China's FBC development.

The author acknowledges with gratitude to those organizations in China for the permission of using their experimental reports and data.

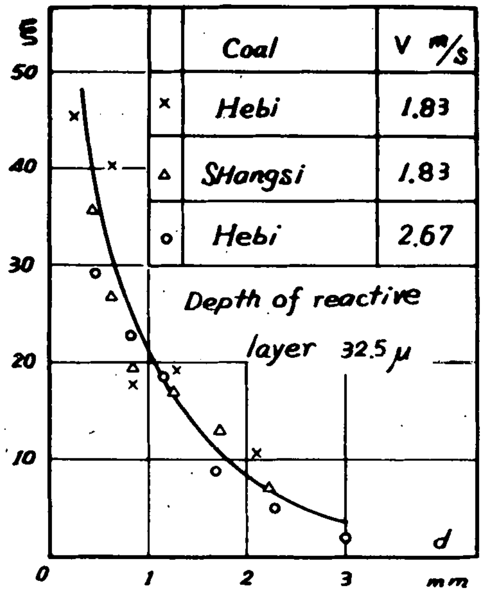

Figure 5 -- Fraction of CaO Absorption Outer Shell of Limestone Particles (Calcium Utilization) Versus Granule Size

TVA'S AFBC PROJECTS

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Tennessee Valley Authority

Each year, the Tennessee Valley Authority (TVA) burns an average of 36 million tons of coal in 12 central station steam plants. This coal-fired generation produces 17,796 MW or nearly 60 percent of our total system capacity of 29,867 MW. Nuclear and hydro plants provide a total of 30 percent of the system's capacity with the rest consisting of combustion turbines and imported power. From these figures it is easy to understand TVA's strong interest in coal.

This interest will not diminish in the future. Although TVA has embarked upon the nation's largest nuclear power plant construction program, we will continue to burn massive quantities of coal for many years to come. In the mid 1990's, when the final nuclear reactor is placed in service, our total system capacity will be approximately 44,400 MW. Of this figure nuclear will provide 45.6 percent, or nearly half of the system capacity. Coal will come in second with 37.2 percent, and the rest of our capacity will be provided by hydro and combustion turbine generation.

Even though coal will not be our main generation source in the future, we will continue to use a substantial amount of coal. Therefore, TVA is heavily committed to developing new coal technologies that will enable us to augment or replace existing coal-fired steam plants. One coal technology that offers reliable, efficient, and environmentally acceptable operation is Atmospheric Fluidized Bed Combustion (AFBC).

Like other developing coal technologies, AFBC is not new. The concept of a fluidized bed has been employed extensively in the petrochemical industry for many years. Other industries with steam requirements in the range of 150,000 pounds per hour are also beginning to use fluidized bed concepts.

However, the concept of using AFBC for large-scale utility use is relatively new. The major thrust of AFBC development for utility use to date has been in bench-scale studies, research, and hot/cold AFBC modeling. This research has resulted in a degree of progress. The 30-MW Rivesville AFBC unit, for example, demonstrated that AFBC could generate electricity.

Since Rivesville was a converted steam plant, however, it did not have the capability of experimenting and testing new AFBC designs as they became available. Nor did the Rivesville AFBC unit provide much in the way of data collection on its operation. The EPRI-supported Babcock & Wilcox 6' x 6' AFBC unit was a significant advancement on both counts since it permitted the inclusion of design changes and provided much needed operating and performance data. Even with the success of this unit, it became apparent that a larger plant having the capability of retrofitting design changes was needed to test new hardware and to resolve uncertainties concerning plant operation. After all, it would be a very difficult task to scale up from a small prototype with a 36 sq. ft. bed to a full-scale utility power plant having literally thousands of square feet of fluid-bed area.

TVA's 20-MW AFBC pilot plant will address uncertainties concerning peripheral hardware systems and plant operation. By late 1981, TVA will have a 20-MW AFBC pilot plant and is considering constructing a 200-MW AFBC demonstration plant that would commence operation in late 1985. These two plants would be the culmination of research and development that dates back to 1974 when TVA first became interested in AFBC development. At that time, load forecasts indicated a need for additional generation in the late 1980's and 90's. Also, it became apparent that some of TVA's aging coal-fired units, some of which have been in service since the early 1950's would need to be replaced. Furthermore, AFBC appeared to be a cost effective way to both use the high sulfur coal (of which the Tennessee Valley region has tremendous reserves) and to protect the environment.

In 1976, TVA's involvement in AFBC went into full swing with a project authorization to prepare a conceptual design of a 200-MW AFBC demonstration plant. Preliminary conceptual design was completed in mid-1978 and information from this design work aided in the development of design specifications for the 20-MW pilot plant. Followon contracts have been placed with three boiler manufacturers to prepare a final conceptual design for the 200-MW demonstration plant. Design completion is slated for late this year. In addition, TVA has a contract with Combustion Engineering, who is subcontracting with Lurgi, to prepare a conceptual design of a second generation AFBC plant.

Initial funding for the 20-MW AFBC pilot plant design and fabrication was authorized in April 1979 by the TVA Board of Directors. In September of that same year, the Board of Directors authorized construction and operation of the pilot plant.

Because of TVA's large generating capacity and its engineering capability, TVA is in a unique position to demonstrate and develop AFBC for large scale commercial use on the TVA system and possibly by the utility industry.

TVA's 20-MW AFBC Pilot Plant

At the risk of repeating what my colleague Roy Lumpkin will say in his presentation, I will now turn our attention directly to the TVA pilot plant project.

TVA's 20-MW AFBC pilot plant will be located on the Shawnee Steam Plant reservation near Paducah, Kentucky. Site preparation for the pilot plant has just begun this month with initial construction to begin this summer and fall. Plant start-up and testing should begin by the latter part of 1981 or early 1982.

As I mentioned earlier, the AFBC pilot plant will be used to resolve many of the uncertainties concerning full-scale AFBC development. Specifically, the plant will be used to test and evaluate control equipment and procedures, to investigate key systems for performance and reliability, and to train personnel in operating and maintenance procedures. Testing at the pilot plant will involve a cooperative effort between TVA and Electric Power Research Institute. Since AFBC is a completely different type of coal combustion process, it will obviously require different modes of operation than a conventional steam plant. Like any generating facility, a commercial-sized AFBC must be able to respond to changes in electricity demand. Start-up, turn-down, load control, shutdown procedures, and the safety related systems will be tested and developed.

One area of uncertainty in AFBC development that will hopefully be alleviated by work at the pilot plant will be the testing of coal/limestone feed systems. Supplying these materials to a small unit is no significant problem, but in full-scale units with thousands of square feet of bed area, the distribution is something of a mechanical nightmare. To date, no feed system has been proven to be reliable and durable enough to withstand the torture of prolonged plant operation. Because of the large uncertainty involved, the development of adequate feed systems is a must for any commercial-sized AFBC unit.

The pilot plant itself will be highly flexible and able to operate under a wide variety of operating conditions; consequently, it is necessary to monitor these conditions. A sophisticated data acquisition and computer system will be installed to completely monitor all aspects of the pilot plant operation.

The 20-MW AFBC pilot plant will not generate electricity. It is not a commercial plant, and thus, no turbogenerator is currently planned. Instead the steam produced by the pilot plant wil be routed through a surface condensor. This will allow us to simulate actual utility load demand. It will provide us with operating experience and will enable us to scale up to commercial scale units.

TVA's 200-MW AFBC Demonstration Plant

As I stated, TVA is also considering constructing a 200-MW AFBC demonstration plant. If approved by the TVA Board of Directors, the present plans call for the 200-MW AFBC demonstration plant to go into operation during late 1985. Unlike the 20-MW AFBC pilot plant, the demonstration plant would be operated as a commercial plant; that is, it's job would be to produce electricity for the TVA power system.

When steam from the 200-MW AFBC boiler goes to the turbogenerator, it would be the culmination of nearly 10 years of work. We are now at the half-way point in that decade of AFBC development. In 1976, TVA authorized the preparation of conceptual designs of a 200-MW AFBC demonstration plant. Combustion Engineering, Babcock & Wilcox, and Fluidized Combustion Company were contracted to provide both a preliminary conceptual design and cost estimate. Phase I conceptual design took two years to complete.

Babcock & Wilcox chose a top-supported stacked-bed arrangement of four main beds and a separate carbon burnup bed. B&W's feed systems mixes coal and limestone, pneumatically transports and splits the mixture, and injects the mixture into the beds through the grid plate.

Combustion Engineering chose a "ranch-style" design in which all beds are on a single elevation supported from the bottom. A top-supported hood above the beds collects and directs the hot gases to the convection pass. The feed system is based on the Fuller-Kinyon solids pump which introduces a coal-limestone mixture into a dense-phase pneumatic transport system and then splits and feeds the mixture into the bed through the grid.

Fluidized Combustion Company's steam generator is a top-supported stacked-bed arrangement of four beds. Coal is fed from above the beds with spreader-stokers whereas limestone is fed by a gravity feed.

Despite the differences in the three Phase I conceptual designs, the cost per kilowatt for each design was comparatively similar.

Phase I preliminary design for the 200-MW AFBC demonstration plant was completed in mid-1978. In early 1979, TVA authorized three contractors to complete final conceptual designs (Phase II) by the final months of 1980. These designs will be finished at the end of 1980.

These designs are well underway at this time. Combustion Engineering, Babcock & Wilcox, and Babcock Contractors, Inc., were the three contractors chosen for the design contracts.

The objectives of the Phase II conceptual design are to refine previous designs and to provide additional information needed for ongoing environmental evaluations and to make decisions on how to proceed to demonstration plant construction and operation. Each contractor will: prepare cost estimates; determine the probability of successful operation of the 200-MW plant and its inherent risks; define major problems and areas requiring additional research and development; prepare detailed schedules for all proposed Phase III activities; establish a conceptual design of the 200-MW AFBC boiler and related systems; and finally, determine the structural steel requirements for boiler and related equipment to permit structural steel procurement.

Design of the 200-MW AFBC boiler and related systems is geared to the following specifications:

Gross Turbogenerator Rating, MW	200
Continuous Rating, pounds of steam per hour	1,325,000
Turbine Throttle Pressure	2,450
Superheat/Reheat Temperature, ^{o}F	1,000

Also, each contractor is to keep in mind the relationship between their particular design of the 200-MW demonstration unit and the design of a steam generator in the 600- to 800-MW size range. This will hopefully ensure the feasibility of the design of the larger units.

Following the completion of Phase II conceptual designs, TVA will make a decision on whether or not to proceed with Phase III. If approved by the TVA Board of Directors, detailed design and site preparation will begin in the summer of 1981.

Environmental and Technical Support Work by TVA

Because of the size of the AFBC demonstration plant, it is necessary for additional work to be performed. Preparation of environmental impact statement (EIS) and completion of the necessary technical support work are required. Secondly, it is necessary that technical support work be finished in several different areas. First let's address the preparation of the EIS.

It is a new experience for TVA to have to prepare an EIS on a coal-fired plant. The last large coal-fired steam plant that TVA built, which was Cumberland Steam Plant, was completed in 1973, and no EIS was required. Another significant point is that this will probably be the first EIS written for a fluidized bed unit.

Even for those of us at TVA who have had the fortune of preparing an EIS in the past, there are other changes and requirements that make this EIS unique. For one thing, the final version of the EIS is to be concise. EIS's in the past were often multi-volumed publications that were as complicated as the projects that they attempted to explain.

Work on the demonstration plant EIS is well underway at this time. We have completed a description of the process itself, an extensive description of the site, and the background information needed for screening possible sites. While no firm decision has been made on site selection, the Shawnee Steam Plant reservation has been named the "preferred site." The Shawnee site will be the scope of the most detailed portion of the EIS, but the final selection of a site will not be made until the environmental work has been completed and the environmental constraints of the Shawnee and other candidate sites are made known.

We have performed the first formal step in the EIS process by holding a scoping meeting to determine what will be covered in the EIS. A public meeting was held in Paducah, Kentucky, to outline our EIS plans to other agencies, individuals, citizens, and groups who were in attendance at that meeting. Questions, suggestions, and comments submitted at this meeting and in writing have been tabulated, summarized, and will be appropriately addressed in the EIS.

The draft of the demonstration plant EIS will be completed in September of this year. That draft will be submitted for review and comment to interested individuals, groups, and agencies. After TVA evaluates the comments it receives, the EIS will be finalized. Incidentally, more than 18 subgroups within TVA are involved in the writing of the demonstration plant EIS. After the final EIS is released to the public, the TVA Board of Directors will be asked to approve construction of the 200-MW plant.

It is obvious that a large plant, such as the 200-MW demonstration plant, will have some impacts upon the environment during construction and operation. However, because of the inherent environmental benefits of AFBC, we believe it can easily meet the New Source Performance Standards as set by the Environmental Protection Agency. We feel that the environmental benefits of this technology will outweigh any associated impacts.

Technical Support

One point that I have made several times in this discussion is the need for additional technical research and development on AFBC. While our projects continue to reach maturity, we are at the same time addressing some of the technical problems related to AFBC. As I have mentioned previously, one of the problems with AFBC is in the development of coal/limestone feed systems. We hope to get some answers to these problems in a program that we have recently initiated that involves the testing of a Fuller-Kinyon feed pump at an existing TVA steam plant. TVA has awarded the Fuller Company a turnkey contract to build a coal-feed test facility at the Watts Bar Steam Plant. Construction will be completed in six months with a six-month testing period to follow.

The Watts Bar coal-feed test will be the only large scale demonstration of a feed system that is applicable to the 200-MW AFBC demonstration plant. Also, since the 20-MW pilot plant will use a Fuller-Kinyon pump, the test facility will provide the added advantage of proving the effectiveness of the pump and splitter prior to construction. Clarence K. Andrews, of TVA's FBC staff, will provide more details on coal-feed systems in his presentation.

Other technical support includes work with the Oak Ridge National Laboratory. In a program with the Department of Energy, TVA and ORNL are working together on a number of task programs that use an AFBC bench-scale combustor to test coal and limestone, a cold flow model for slumping tests, modeling and simulation, materials research, and other miscellaneous technical support activities.

TVA is now investigating the recycling of elutriated particulates from the AFBC process that includes fly ash and unburned carbon. The idea is to devise some way to recycle the elutriated solids back into the main bed rather than using a separate carbon burnup cell. General Atomic was chosen for the investigation because of its experience in recycling and burning graphite.

While the major thrust of AFBC development by TVA is of the "bubbling bed" type of atmospheric fluidized bed combustion, TVA is also keeping track of other fluidized bed concepts. These include alternates to first generation (bubbling bed) AFBC such as pressurized fluidized bed combustion, intermediate pressurized fluidized bed combustion, and second generation AFBC (circulating bed).

Scenario for the Future

Following a complete demonstration of AFBC in a large-scale mode, full-scale units in the range of 600- to 1,000-MW range may be built by TVA in the mid- to late 1990's. AFBC will not replace existing conventional coal burning in steam plants but it will offer an excellent alternative for new plants as load forecasts indicated. This near-term alternative may offer an interim method of producing bulk power from coal to carry us to the day when advanced technologies come into widespread commercial availability.

The contents of this paper do not necessarily reflect the views and policies of the Tennessee Valley Authority, nor does mention of trade names, commercial products, or companies constitute endorsement or recommendation for use.

FLUIDIZED BED COMBUSTION - AN EVOLUTIONARY IMPROVEMENT IN ELECTRIC POWER GENERATION

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INTRODUCTION

Over the past year major technical advances in the commercial application of fluidized bed combustion (FBC) have occurred. These advances are particularly dramatic for the electric utility industry where FBC represents an evolutionary improvement in coal utilization providing reduced fuel sensitivity and simplified emission control capabilities. Both Atmospheric FBC and Pressurized FBC may fill important roles in the electric utility industry: AFBC to lower the cost of electrity generated from the conventional steam-electric power plant; PFBC for the high efficiencies available from the more complex combined-cycle power plants.

Sixty years ago the use of pulverized coal combustion was pioneered in the electric utility industry. This evolution in coal-burning technology was set in motion by a number of considerations which parallel the issues of today. The then generally applied stoker furnace was not well suited to these new conditions. Specifically, utilities needed much larger furnaces, fuel conservation became more significant and the use of coal fines, previously considered a waste, was economically desired. In addition, pulverized coal firing was considered environmentally superior because it could reduce smoke and ground level concentrations of particulate matter.

As we move into a new era with greatly expanded needs for coal-fired power generation, EPRI and the utility industry are accelerating the development and application of fluidized bed combustion as a further evolutionary improvement in coal utilization to meet the new requirements of today. The improvements which excite this utility interest include reduced sensitivity to fuel quality thus permitting the use of a much broader fuel supply, from anthracite to municipal refuse, without suffering large loses in efficiency and reliability in a single boiler design. Second, less cost sensitivity to unit size in a period when load growth and siting restrictions may prefer smaller rather than larger furnaces.

A third primary advantage of FBC that may lead to the displacement of pulverized coal boilers is environmental performance. The invention of pulverized coal boilers occurred at a time when all that was expected of a furnace was to burn out carbon. Today, environmental requirements for the control of sulfur and nitrogen oxides add substantially to the complexity and cost of current power plants and have adversely impacted plant reliability. By comparison, our experiments with fluidized combustion of coal confirm that it is possible to economically control sulfur and nitrogen oxides without parasitic post-combustion cleanup devices.

Thus, fluidized combustion of coal provides a promising response for today's new requirements on power production. Development has successfully progressed from the process confirmation stage to engineering prototype making commercial utility scale systems a distinct possibility within this decade.

It is our position that utility FBC boilers in the U.S. will have to be capable of the following performance with an average bituminous coal:

o Combustion Efficiency	Over 99%
o Thermal Efficiency	>90%
o Sulfur Dioxide	90% removal with Ca/S <1.5
o Nitrogen Oxides	Less than 0.4 lbs/10^6Btu
o Steam Conditions	2400 psi/1000°F /1000°F or higher
o Load Following	>1% per minute
o Tube Life	Low corrosion and erosion to allow > 15 year life

The purpose of EPRI's R&D is to develop the process flow sheet and the needed hardware to achieve these objectives.

ATMOSPHERIC FLUID BED COMBUSTION

Over the past year EPRI efforts in

atmospheric fluid bed combstuion (AFBC) have focused on testing a 6 ft x 6 ft (2 MWe) pilot unit with Babcock and Wilcox incorporating bed recycle. The results have shown that recycle of bed material will be applicable for utility AFBC designs. This has successfully eliminated a major factor restricting utility applications; i.e., the need for large quantities of limestone to maintain adequate sulfur oxide sorption. In addition, this test facility incorporates a large, 18 ft. freeboard which has permitted carbon burnup within the furnace thus eliminating the need for an auxiliary carbon burnup cell. NO_x formation has also been significantly reduced relative to pulverized coal combustion. A final area of process improvement achieved this year has been at least a fourfold reduction in coal feed points within the bed, thus simplifying the fuel supply and control problem in large scale fluidized beds.

Based on these promising process results, the utility industry and its boiler suppliers have agreed that a cost effective utility-scale AFBC design is likely, but important hardware issues remain that should be resolved in an engineering prototype in the 20 MWe size range. These hardware issues involving feeding and controlling the process reliably result from the specific utility requirements for large boiler size, high efficiency, rapid load following, high superheat and reheat, stringent emission standards and a premium on availability. Recognizing these requirements, TVA has taken the lead for the utility industry, with EPRI support, in implementing a 20 MWe engineering prototype at the Shawnee power station. This prototype being built by Babcock and Wilcox will in turn provide the technical basis for a 20 MWe commercial scale demonstration also planned by TVA. EPRI's R&D program is aimed at making it possible (and desirable) to start construction of a 600 MWe AFBC boiler in 1990 after operating this 200 MWe demonstration by 1987.

In addition to this aggressive development of classical fluid bed technology operating at low gas velocities in the 4 to 12 foot per second range, EPRI is also exploring higher velocity, circulating bed designs. These are under development in differing forms by several manufacturers including Lurgi and General Electric. Lurgi test results have been particularly impressive in producing high combustion efficiencies as well as very high limestone utilization for up to 95% SO_2 removal. Furthermore, this system has shown itself capable of reducing NO_x emissions to the 100 ppm range. This encouraging technology is now in active engineering evaluation for the United States under license with Combustion Engineering.

PRESSURIZED FLUID BED COMBUSTION

In pressurized fluid bed combustion, attention during the past year focused on resolving the key hurdle which the technology must pass for commercial utility consideration, i.e., achieving practical gas turbine reliability. During this year, 1000 hour reliability testing of turbine components and hot gas cyclones has been successfully completed under joint DOE/EPRI sponsorship at the PFBC pilot facility of the British Coal Utilization Research Laboratory (CURL). A second successful EPRI project activity has been the screening of promising advanced hot gas cleanup devices on a large PFBC simulator operated by Westinghouse. This project has demonstrated extended operation of ceramic bag filter units at 1500°F and 11 atm while maintaining a particulate collection efficiency of 99.5%. This may provide the means to achieve a much larger reliability margin for PFBC gas turbine systems. This has encouraged PFBC/combined cycle prototypes of sufficient size to incorporate actual rotating gas turbine machinery. A proposed near term commercial approach is the development of a coal-fired gas turbine for repowering existing power plants. This could be the simplest and most rapid PFBC utility application.

The next critical development step, from the user standpoint, is the demonstration of extended operation of complete PFBC gas turbine/hot gas cleanup combinations at a sufficiently large scale to permit engineering extrapolation to utility service. Both the International Energy Agency (IEA) Grimethorpe PFBC test facility and the Curtiss-Wright PFBC pilot sponsored by DOE may provide the necessary vehicle for achieving this development milestone. EPRI has also recently initiated a joint project with Brown-Boveri and Babcock and Wilcox to perform engineering evaluations and design of alternative PFBC combined cycle power plants. This effort, together with the successful achievement of gas turbine/hot gas cleanup reliability is intended to provide the basis for active utility industry participation in large scale PFBC demonstration and commercialization programs. American Electric Power (AEP) has provided much of the initiative in bringing this technology forward for serious utility consideration.

ADVANCED COAL TECHNOLOGY ANALYSIS

In order to judge the commercial potential of both AFBC and PFBC for utility use, they must be considered not only in terms of conventional power plant design but other advanced options as well. The following comparison is therefore offered as an example showing their relative merits and the status of the "horse race" in which they are involved.

The conditions assumed are as follows:

- Plant location - Kenosha, Wisconsin
- Capacity factor - 70% (1000 MW capacity)
- Coal-Illinois bituminous: 4% S, 16% ash, 10,000 Btu/lb
- Environmental control requirements
  - o SO_x - 90% removal
  - o Particulate - 0.03 lb/MBtu
  - o NO_x - 0.6 lb/MBtu
  - o Water quality - Zero discharge
  - o Solid waste - RCRA "special waste" requirements
- Plant Availability - 75% or greater

The 1979 EPRI Technical Assessment Guide (TAG) was used as a basis for this comparison; it was updated where appropriate by more recent, published EPRI R&D results.

All options can meet the environmental control requirements specified, with the gasification combined cycle (GCC) having the highest inherent capability for SO_x control without process modifications. Both the GCC and PFBC should inherently control to 0.2 lb/MBtu of NO_x while the advanced PC and AFBC should control to 0.3 lb/MBtu or better. Although the GCC has excellent air pollution control potential, the possibility that toxic and/or carcinogenic hydrocarbons will be produced under the reducing conditions present in the process may make workplace control as well as control of wastewater and solid wastes inherently more expensive and, at this time, more risky than for the other options.

The following results for the four advanced coal options are assembled in decreasing order from best to lowest for each criterion. The baseline for comparison is present-day, conventional supercritical PC/FGD.

A. <u>Capital Cost</u> $/kW

1.	PFBC	$700	
2.	AFBC	$710	
3.	GCC	$765	**815
4.	Baseline	$804	
5.	Adv. PC/FGD	$800	

B. <u>Busbar Costs</u> (mills/kWh-30 yr levelized)

1.	PFBC	58
2.	Adv. PC/FGD	59
3.	GCC	60
4.	AFBC	61
5.	Baseline	64

C. <u>Net Heat Rate (Btu/kWh) and Net Efficiency (%)</u>

	(Adv. Pc/FGD	8460		40	
1.	(GCC	8465	**8980	40	**38
	(PFBC	8467		40	
5.	Baseline	9450		36	
4.	AFBC	9650		35	

D. <u>Water Consumption</u> (gal/hr/MW)

1.	(PFBC	490	
3.	(GCC	490	** 523
2.	(Adv. PC/FGD	507	
4.	AFBC	620	
5.	Baseline	675	

E. <u>Limestone</u> (tons/hr/1000 MW)

1.	(GCC	0	
	(Adv. PC/FGD	10	Regenerable FGD
3.	Baseline	76	
4.	AFBC	132	
5.	PFBC	145	Dolomite

F. <u>Solid Waste</u> (dry tons/hr/1000 MW)

1.	(GCC	70
	(Adv. PC/FGD	70
3.	Baseline	170
4.	PFBC	185
5.	AFBC	193

G. <u>Land Requirement</u>(acres/1000 MW/30 yrs)

1.	GCC	750
2.	Adv. PC/FGD	1050
3.	PFBC	1150
4.	AFBC	1450
5.	Baseline	1650

H. <u>Auxiliary Environmental Control Cost (% of plant capital cost)*</u>

1.	GCC	14
2.	AFBC	21
3.	PFBC	24
4.	Adv. PC/FGD	33
5.	Baseline	35

NOTE: * Does not include heat rejection control
** Lower temperature (2000°F) gas turbine capability

A number of considerations evolve from this comparative analysis. A summary of several of the more striking are summarized as follows.

The several technologies considered all have potential merit for improving coal-fired power production relative to present conventional pulverized coal plants. The present economic and technical base is inadequate to either eliminate any of these advanced options or identify one as clearly superior. They all should be developed to the point of proving or disproving their potential benefits. It is again emphasized that the information summarized here represents a performance forecast based on the current technical status of each option for a specified set of conditions. Developments can be postulated for each option which could further improve its performance and relative merit.

Improvements in the environmental, cost and efficiency performance of the advanced coal options relative to current pulverized coal practice are likely but are generally in the range of 10%, with the exception of NO_x emission control where a 50-70% improvement is possible for every option. The improvements are generally within the range of development uncertainty and could also erode completely during the further course of development. Therefore, a decision to apply any of these options commercially is more likely to be made on the basis of confidence in availability and operability, siting flexibility and fuel flexibility. These are all factors which should favor fluidized bed combustion.

From a practical standpoint, the potential improvement in plant availability is at least 2 to 3 times larger than improvement in efficiency, and the R&D risks are probably smaller and less costly. Accordingly, power plant cycle development and improvement should place corresponding priority on availability. This importance is reflected in an implicit improvement factor incorporated in advanced coal options relative to current practice, i.e., minimization of auxiliary environmental control. The payoff is primarily reduced complexity and failure modes which, in turn, tend to improve availabilty and operability.

CONCLUSION

In conclusion, fluid bed combustion offers promise of providing a substantial but evolutionary improvement in the utilization of coal for electric power production. Flexibility to burn alternative fuels with minimum performance and reliability penalty has been established. The stringent emission standards existing and proposed in the United States should be met without complicated and parasitic post-combustion cleanup devices. These significant improvement opportunities have fostered major utility industry development efforts for both AFBC and PFBC. In the final analysis, however, the utility market potential of these technologies will depend primarily on demonstration of power plant reliability and availability advantages over the alternatives. As we move forward we must remember that these alternatives are also undergoing vigorous development in the "horse-race" for the coal-fired power plant market of the 1990's and beyond. Thank you and Good Luck.

CONCLUSIONS OF THE EPA FLUIDIZED-BED COMBUSTION PROGRAM

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Summary

The purpose of this paper is to summarize the current conclusions of the U. S. Environmental Protection Agency's (EPA's) Industrial Environmental Research Laboratory, Research Triangle Park, NC (IERL-RTP), concerning the ability of atmospheric and pressurized fluidized-bed combustion systems to meet currently identified environmental requirements. In summary, based upon available data, it is anticipated that both atmospheric and pressurized systems should be capable of meeting the recently revised New Source Performance Standards (NSPS) covering air emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates from electric utility steam-generating units. NSPS for industrial boilers have not yet been proposed by EPA; however, fluidized-bed boilers should be able to meet the industrial boiler standards as well, if these standards are not significantly more stringent, or are less stringent, than the standards covering utility steam generators. The EPA standards should be achieved in fluidized-bed combustion systems in a manner which is economically competitive with the alternative of a conventional boiler with flue gas desulfurization; the greatest economic uncertainty concerns the control of particulates at elevated temperatures and pressures in pressurized combustors. Additional data from large fluidized-bed combustors, representative of commercial-scale systems, are necessary to confirm these conclusions.

Solid residues from atmospheric and pressurized fluidized-bed combustors, in general, should not be considered as "hazardous" wastes under the Resource Conservation and Recovery Act (RCRA), based upon RCRA procedures as currently defined. However, the properties of leachate from the residue will necessitate some attention in the design of a "sanitary landfill" under RCRA, for disposal of the residues as non-hazardous wastes.

Introduction

In parallel with the efforts by the U. S. Department of Energy, the Electric Power Research Institute (EPRI), the Tennessee Valley Authority (TVA), and other organizations to develop fluidized-bed combustion technology, EPA is conducting a contract research and development program aimed at complete environmental characterization of the technology. The EPA program has been described previously (References 1,2).

Objectives of the EPA fluidized-bed combustion program are to identify any potential environmental problem areas, and to develop any necessary environmental control technology, while the fluidized-bed combustion process is under development. Identifying any problem areas as early as possible during the development phase should allow any necessary environmental controls to be integrated into the process on the most timely and cost-effective basis.

Results from the R&D program are intended primarily to ensure the availability of an adequate research data base to enable the development of standards and guidelines by EPA's regulatory offices, and to enable the issuance of permits for fluidized-bed boiler plants by EPA's permitting offices. The results are also to assist the developers and builders of fluidized-bed boilers in the selection and application of control alternatives.

The EPA program currently consists of seven projects with a variety of contractors. Many of the projects are discussed in detail in other papers presented at this conference by the individual contractors. For further reference, some of the published reports generated by EPA contractors since the Fifth International Conference are listed as References 3 through 20.

Emission Sources and Applicable Federal Legislation

There are four major general sources of emissions from fluidized-bed boiler plants. These sources are: (1) the storage, handling, and feeding of coal and sorbent; (2) the steam cycle (e.g., cooling tower drift, liquid effluents from boiler blowdown, and feedwater treatment); (3) stack gas emissions; and (4) emissions of solid residue, in the form of bed material (spent sorbent, with some coal ash) withdrawn from the combustor, and in the form of carry-over (largely flyash, with some elutriated spent sorbent) that is removed from the flue gas by the particle control devices.

Emissions resulting from the solids storage and handling system, and from the steam cycle, are not unique to fluidized-bed combustion, but should be reasonably typical of any coal-fired combustion system driving a steam turbine. Accordingly, subsequent discussion will focus on the stack gas and solid residue emission sources.

The stack gas emissions will be covered by applicable regulations developed by EPA under the Clean Air Act, as amended. There are a number of requirements under this Act which can affect the ultimate siting and control levels for a fluidized-bed boiler plant. The specific type of regulation of most meaning for the discussion in this paper is the NSPS, which specifies acceptable emission concentrations from new or substantially modified sources, and which is based on best available control technology. Revisions to the NSPS for large utility steam generators (larger than 73 MWt), promulgated in 1979, are: for SO_2, an absolute maximum emission of 1.2 lb $SO_2/10^6$ Btu heat input (520 ng/J), with at least 90 percent SO_2 reduction required so long as the emissions remain between 0.6 and 1.2 lb/10^6 Btu (260 and 520 ng/J), and at least 70 percent reduction required so long as emissions do not exceed 0.6 lb/10^6 Btu (260 ng/J); for NO_x, 0.6 lb/10^6 Btu (260 ng/J) for most coals, 0.5 lb/10^6 Btu (210 ng/J) for subbituminous coals, and 0.8 lb/10^6 Btu (340 ng/J) for some lignites in some furnaces; and, for particulates, 0.03 lb/10^6 Btu (13 ng/J). These standards are based upon a 30-day rolling average. Utility-scale fluidized-bed boiler plants would have to be designed in order to achieve these emission standards; however, the operators of the initial plants may apply for a commercial demonstration permit allowing 85 percent SO_2 removal instead of 90 percent, under the philosophy that, without previous experience in the design and operation of utility-scale fluidized-bed plants, the goal of 90 percent may not be achieved in the initial installations. Under the revised utility NSPS, the first 400 to 3,000 MWe of cumulative installed atmospheric fluidized-bed boiler capacity, and the first 400 to 1,200 MWe of pressurized capacity, may be issued such commercial demonstration permits. NSPS for industrial boilers are currently under development.

The solid residue generated by the process can have the following environmental effects: fugitive air emissions from disposal sites, in the form of wind-blown dust, which would be covered under the Clean Air Act; rainwater percolation through the disposal piles into the soil and groundwater, which would be covered under RCRA; and rainwater runoff into surface water systems, which would be covered under the Clean Water Act and RCRA. Under RCRA, EPA has recently promulgated criteria for determining whether a residue is to be considered "hazardous" for the purposes of the Act; EPA must promulgate standards covering the generation and the treatment/storage/disposal of "hazardous" wastes. If a waste is not hazardous, it would, in general, be disposed of in a "sanitary landfill" in accordance with solid waste management plans developed by the individual states. EPA has promulgated some criteria defining "sanitary landfills," and has proposed (but not yet promulgated) additional criteria.

Sulfur Dioxide Control

Sulfur dioxide removals of 90 percent and higher can be achieved in both atmospheric and pressurized fluidized-bed combustion, thus enabling compliance with the revised EPA New Source Performance Standard for utility steam generators. These removals should be achievable with reasonable sorbent feed rates, and in a manner which is cally competitive with the alternative of a conventional boiler with flue gas desulfurization. However, in order to achieve high SO_2 removals economically, fluidized-bed boilers may have to be operated with increased contact time between the SO_2 and the sorbent, and with reduced sorbent particle size. Increased SO_2/sorbent contact time and reduced sorbent particle size can significantly increase sorbent effectiveness in SO_2 removal, and hence significantly reduce sorbent feed requirements.

In traditional dense-phase fluidized-bed systems, increased SO_2/sorbent contact time is achieved through increased gas residence time in the bed. Increased gas residence time translates into a decrease in gas velocity through the bed, and/or an increase in bed height. There has been an incentive for designers to attempt to minimize gas residence time, in order to maximize boiler throughput, and to reduce boiler size and capital cost. However, EPA's studies suggest that, at high levels of SO_2 removal, the cost penalty (the increased capitalization cost) associated with a larger boiler is more than offset by the reduction in operating costs associated with the reduced sorbent feed requirements. The reduction in sorbent feed requirements achievable through increased gas residence time/reduced sorbent particle size, becomes more pronounced as the required level of SO_2 removal increases.

This point is illustrated by an engineering study conducted by Westinghouse for utility-scale boilers (Reference 10), some results of which are summarized in Figure 1. Figure 1 presents the cost of electricity as a function of sorbent cost for an 800 MW atmospheric fluidized-bed boiler plant operated to obtain 90 percent SO_2 removal. Projected costs for a conventional boiler with a scrubber are also plotted for comparison. The sorbent feed rates shown in Figure 1 (expressed as the calcium-to-sulfur mole ratio, or Ca/S) were projected by Westinghouse using a fairly simple kinetic model based upon laboratory thermogravimetric kinetic data for the sorbent/SO_2 reaction.

The bottom curve for atmospheric fluidized-bed combustion in Figure 1 was developed assuming a gas residence time of 0.67 second (a gas velocity of 6 ft/sec, or 1.8 m/sec, and a bed depth of 4 feet, or 1.2 meters). The curve also assumes a 500 μm surface mean sorbent particle size in the bed (which corresponds to a mass mean of perhaps 700 μm); the actual size of the fresh sorbent feed, of course, could be coarser than this in-bed value. These values for residence time and particle size, although not necessarily representing the economic optimum, are felt to represent reasonably good selections for these variables from the standpoint of cost-effective SO_2 removal. The values for velocity, bed depth, and in-bed particle size are, individually, within the ranges considered in various design and experimental programs conducted by other organizations. As indicated on the curve, for a 0.67 second residence time and a 500 μm particle size, the sorbent feed rate projected by the Westinghouse model is a calcium-to-sulfur mole ratio of 2.9, assuming a sorbent of representative reactivity.

The top curve for fluidized-bed combustion in the figure was developed assuming a gas residence time of 0.4 second (gas velocity of 10 ft/sec, or 3.0 m/sec, and a bed depth of 4 feet, or 1.2 meters); sorbent particle size in the bed was assumed to have a surface mean value of 1000 μm. At this lower gas residence time and larger particle size, the model projects (somewhat pessimistically) that the required calcium-to-sulfur ratio is 7.0.

The comparison of the top and bottom curves indicates that--despite the higher annualized capitalization cost associated with the larger fluidized-bed boiler represented by the bottom curve--the reduced sorbent feed requirements for this boiler result in a several mill/kWh net savings in the cost of electricity at a typical sorbent cost of \$10/ton (\$9/metric ton). Even if sorbent feed requirements for the smaller boiler (represented by the top curve) were less than the Ca/S of 7.0 projected by the model, the larger boiler would continue to be economically more attractive than the smaller one unless the model is over-estimating the sorbent requirements of the smaller boiler by a factor greater than two. As shown in Figure 1, the cost of electricity from the larger fluidized-bed boiler, with a Ca/S of 2.9, is projected to be less than that from the conventional boiler/scrubber at all but the highest sorbent costs.

Since the sorbent feed requirements projected by the Westinghouse model play a key role in this cost comparison, it is important to assess the reliability of this fairly simple model. The model has been tested against the available data from experimental fluidized-bed combustors, and has been found to represent most of the combustor data very well. Rigorous comparison of model projections against data at specific conditions from individual fluidized-bed combustion units is presented in References 10, 14 and 17. Unfortunately, most of the data from atmospheric fluidized-bed combustion facilities are for SO_2 removals below 90 percent, since the previous EPA New Source Performance Standard for SO_2 (1.2 lb/10^6 Btu, or 516 ng/J)--which served as the guideline for most previous testing--represents a percentage removal of only 83 percent with a 4 percent sulfur coal. Accordingly, the model cannot be extensively confirmed at removals of 90 percent and above. However, EPA is currently conducting a carefully designed matrix of tests on the 40- by 64-inch (1- by 1.6-meter) atmospheric combustor at Fluidyne aimed at generating data which can be used to help confirm the model at removals of 90 percent and above. Confirmation of the model is ultimately required on operating fluidized-bed boilers sufficiently large to provide data representative of commercial-scale units.

Rather than attempting to repeat the rigorous model-versus-data comparisons in this paper, a more generalized approach will be employed which, although less rigorous, provides overall perspective regarding how model projections compare against the mass of SO_2 removal data which have been generated to date. Figure 2 presents percentage SO_2 removal at atmospheric pressure as a function of sorbent feed rate, as projected by the Westinghouse model at the conditions of gas residence time (0.67 second) and in-bed particle size (500 μm) felt to be desirable for effective SO_2 removal. Curves are shown for three different sorbents: carbon limestone, representing one of the more reactive of the approximately 25 sorbents tested to date on the Westinghouse laboratory thermogravimetric analyzer; Grove limestone (referred to as limestone 1359), one of the less reactive sorbents; and Greer limestone, representing an intermediate reactivity. The calcium-to-sulfur feed requirements of 2.9 for 90 percent removal, used for the bottom curve of Figure 1, can be read off the curve for Greer limestone in Figure 2. Some sorbents have been tested which are significantly less reactive than 1359 limestone; however, such unreactive sorbents would generally not be utilized in fluidized-bed combustors, since they would make the process economically unattractive. A potential user of fluidized combustor technology should be able to site his plant in order to have available, within reasonable distance, alternative sorbents having a reactivity not substantially less than that of limestone 1359. Accordingly--although the curves in Figure 2 do not necessarily encompass the entire range of sorbent reactivities that might be considered for commercial fluidized-bed combustion applications--the curves are felt to illustrate a reasonable range of commercially achievable reactivities.

These model projections from Figure 2 are compared against available experimental atmospheric combustor data in Figure 3, which is adapted from Reference 14. The upper curve in Figure 3 is the curve for carbon limestone, partially redrawn from Figure 2; the lower curve is the curve for 1359 limestone. The data shown in Figure 3 were obtained from a variety of bench- and pilot-scale combustors over a wide spectrum of gas residence times, sorbent particle sizes, sorbent types, and other combustor conditions; these data are not limited to data obtained at conditions near the 0.67 second residence time/ 500 μm sorbent size that served as the basis for the curves from Figure 2. The units from which the data were obtained ranged in size from 6 inches (15.2 cm) i.d. to 10 by 10 feet (3 by 3 m) in cross section. The data shown in Figure 3 are from: the Babcock & Wilcox 3- by 3-foot (0.91- by 0.91-m) unit at Alliance, Ohio; the 6-inch (15.2-cm) diameter atmospheric combustors at Argonne National Laboratory (ANL) and at the National Coal Board (NCB) in England; the 1.5- by 6-foot (0.46- by 1.8-m) Fluidized-Bed Module (FBM) operated by Pope, Evans and Robbins (PER); the 1.5- by 3-foot (0.46- by 0.91-m) unit at NCB; the 6- by 6-foot (1.8- by 1.8-m) EPRI/B&W combustor at Alliance; the 10- by 10-foot (3- by 3-m) B&W Ltd. boiler at Renfrew, Scotland; and the 1.5- by 1.5-foot (0.46- by 0.46-m) and 40- by 64-inch (1- by 1.6-m) combustors at Fluidyne.

As shown in Figure 3, the mass of data generally fall within the boundaries of the curves projected by the model. Some data even suggest performance superior to that projected for carbon limestone. Those data which suggest performance poorer than that within the curve boundaries are, in many cases, either from the small 6-inch (15.2-cm) units, or from the B&W 3- by 3-foot (0.91- by 0.91-m) unit; this unit has a low freeboard and no recycle, so that a high carry-over rate and a higher-than-normal sorbent feed rate would be expected.

Figure 3 is not intended as a rigorous confirmation of the model, but rather is meant to illustrate that, in general, the model projections do not represent a major divergence from available data.

The data in Figure 3 suggest that the projection in Figure 1--that a Ca/S of 7 would be necessary for a 90 percent SO_2 removal in the boiler with lower gas residence time--is probably pessimistic. The trend in the data in Figure 3 suggests that a Ca/S much lower than 7 would probably be adequate.

The previous discussion has considered only atmospheric fluidized-bed combustion. In general, the achievement of 90 percent and greater SO_2

removals in pressurized fluidized-bed combustion has been possible with relatively low sorbent feed rates (calcium-to-sulfur mole ratios of 1.25 to 2) (References 7 and 16). One reason for the effectiveness of SO_2 removal in pressurized systems might be that pressurized systems require comparatively deep beds, in order to accommodate the heat transfer surface necessitated by the high volumetric heat release rate; deep beds inherently result in gas residence times (generally 1 second or longer) significantly greater than those normally obtained in atmospheric combustors. Figure 4 presents expected desulfurization as a function of sorbent feed rate for a 9 atm (910 kPa) combustor being fed with 2000 μm mass mean Pfizer dolomite, based upon results from EPA's 500 lb coal/hr (227 kg/hr) pressurized fluidized-bed combustion Miniplant, and based upon a model developed by Exxon (Reference 16). Cost projections are presented in Figure 5 for a utility-scale pressurized fluidized-bed combustor, based upon Westinghouse estimates (Reference 10), analogous to Figure 1. As illustrated in Figure 5, a pressurized fluidized-bed combustor is projected to have lower costs of electricity than a conventional boiler with a scrubber, over the full range of fluidized-bed Ca/S ratios (1.25 to 2.0) suggested in Figure 4 for 90 percent SO_2 removal at gas residence times of 1 second and longer.

Comparing Figures 1 and 5, it is apparent that the need to further increase gas residence time in order to reduce sorbent feed rate in pressurized fluidized-bed combustors, is less critical than in the case of atmospheric units. In Figure 1, an increase in gas residence time from 0.4 to 0.67 seconds--an increase of 0.27 seconds--had a significant impact on projected sorbent feed requirements for atmospheric combustors, and could be the determining factor regarding whether or not atmospheric fluidized-bed units are competitive with conventional boilers. However, as suggested in Figures 4 and 5, an increase, from 1 second to 3 seconds, in the gas residence time for pressurized units should have a comparatively small impact.

The SO_2 removal performance of both atmospheric and pressurized fluidized-bed combustors may be improved by reducing the mean sorbent particle size, as discussed previously. As the particle size is reduced to smaller and smaller values, the particles will have an increased tendency to elutriate out of the bed, depending upon the gas velocity. Even in a fluidized-bed system where the particle size/gas velocity relationship is such as to maintain basically traditional dense-phase fluidization, there will be some carry-over of fine particles, due to fine material in the sorbent feed and/or due to attrition. Recycle, back to the bed, of the elutriated sorbent fines should result in a reduced mean particle size in the bed, thus improving in-bed capture; fines recirculation should also result in an increased concentration of fine sorbent in the freeboard, providing additional capture after the gases leave the bed. As the sorbent feed becomes relatively finer, the quantity of fines being recirculated will, of course, become greater. As the particle size/gas velocity relationship moves toward even finer particles, the system moves out of the traditional dense-phase fluidization mode and toward more advanced fluidization concepts--"turbulent" fluidization, "fast" fluidization, and, in the extreme, entrained-phase operation. High-recycle operation, and the advanced fluidization concepts, may prove to be more effective at SO_2 removal than is low carry-over, dense-phase operation. The fine particle size associated with these other operating modes, combined with adequate (or perhaps even increased) gas/solids contact time, may provide superior SO_2 capture performance; further operating data are required concerning these other modes. It should be re-emphasized that, for these other modes of operation, the key variable affecting SO_2 removal--gas/solids contact time--no longer translates into gas residence time in the bed, as it does for traditional dense-phase fluidization. The previous discussion in this paper has been based upon the low carry-over, dense-phase case.

Thus, high levels of sorbent attrition or carry-over are not necessarily bad, so long as the carry-over is recycled and so long as a stable system can be maintained without excessive sorbent feed rates. Attrition and recycle might result in effective sorbent utilization and high SO_2 removals. The capture of SO_2 in the freeboard, which may be achieved with high-recycle systems, may be important for boiler designs in which coal is fed above the bed; with above-bed coal feed, some of the SO_2 may be released above the bed, and hence may have no residence time in the bed itself.

Nitrogen Oxides Emissions

Nitrogen oxides emissions are characteristically below 0.5 lb/10^6 Btu heat input (210 ng/J) for large atmospheric fluidized-bed combustors, and below 0.4 lb/10^6 Btu (170 ng/J) for pressurized units. These emissions may be reduced further through the use of two-stage combustion and other NO_x control options which are just starting to be explored. Thus both atmospheric and pressurized systems appear capable of meeting the current EPA New Source Performance Standard for NO_x emissions from utility boilers, of 0.5 lb/10^6 Btu (210 ng/J) for subbituminous coals and 0.6 lb/10^6 Btu (260 ng/J) for other coals.

As discussed below, many NO_x emission measurements from experimental combustors are below the values (0.5 and 0.4 lb/10^6 Btu) indicated above. However, the data are so scattered, and our understanding of the variables which control NO_x emissions is so limited, that it would be difficult to guarantee that a given fluidized-bed combustor would never exceed those levels on a 30-day rolling average.

Until recently, NO_x emissions from fluidized-bed combustors were of limited concern. Fluidized combustor NO_x emissions are inherently lower than the EPA emission standard (which is based upon emissions from conventional boilers); hence no major effort had previously been initiated to reduce the fluidized-bed NO_x emissions further. However, a number of combustion modification techniques are being tested for conventional boilers (e.g., low-NO_x burners, and staged combustion) which could enable greatly reduced NO_x emissions from conventional systems (as low as 0.2 lb/10^6 Btu, or 86 ng/J). Even pressurized fluidized-bed combustion systems--which frequently show emissions below 0.2 lb/10^6 Btu--do not achieve that level universally. Therefore, it is important that studies be conducted concerning the applicability of combustion modification techniques for reducing NO_x emissions from fluidized-bed combustors so that fluidized-bed combustion can continue to be competitive with conventional boilers in future years, if the low NO_x emissions from conventional units are indeed achieved. EPA has conducted some preliminary testing in this regard.

Available data from experimental atmospheric fluidized combustors, 6 inches (15.2-cm) in diameter and larger, are shown in Figure 6. The units represented in Figure 6 include most of the units represented in Figure 3. The NO_x data from the Argonne 6-inch (15.2-cm) unit include only those data for which the unit was operating with a sorbent bed.

The bulk of the emission data within the typical expected operating temperature range for the primary combustion cells--1500 to 1600°F, or 815 to 871°C--lie between 0.2 and 0.6 lb $NO_x/10^6$ Btu (86 and 260 ng/J), expressed as NO_2. This emission is no greater than the current emission standard of 0.6 $lb/10^6$ Btu (260 ng/J). Many of the data points on Figure 6 which exceed the current standard were obtained at bed temperatures representative of those which might be expected in a carbon burnup cell--2000°F (1094°C) and above.

Large atmospheric fluidized-bed combustors exhibit lower (and less variable) NO_x emissions than do small laboratory units. This fact is demonstrated in Figure 7 (Reference 14), where the data from Figure 6 are re-plotted as a function of unit size. The bars in Figure 7 represent the range of NO_x emission data from the indicated units in the 1500-1600°F (815-871°C) temperature range. The range shown for the Argonne 6-inch (15.2 cm) unit reaches levels higher than those shown in Figure 6, since Figure 7 includes some results from Argonne tests with non-sorbent beds not included in Figure 6. As illustrated in Figure 7, all of the emission data higher than 0.6 $lb/10^6$ Btu (260 ng/J) in the typical primary cell temperature range, resulted from the two smallest experimental units. Most of the variability, causing the data scatter in Figure 6, also results from the smaller units. Emission data from the two largest atmospheric boilers (the EPRI/B&W 6- by 6-foot, or 1.8- by 1.8-meter unit, and the Renfrew unit) hold consistently within the range of 0.15 to 0.45 $lb/10^6$ Btu (65 to 190 ng/J). This range is felt to be more representative of the emission levels and variability that might be expected from commercial-scale atmospheric units.

As shown in Figure 6, emissions of NO_x from atmospheric units are generally above the level that would be predicted from thermodynamic equilibrium considerations, based upon the reaction of atmospheric nitrogen and oxygen. One explanation for this fact is that, at primary cell bed temperatures, probably 80 to 90 percent of the observed NO_x results, not from fixation of the atmospheric nitrogen and oxygen, but from oxidation of a portion of the organic nitrogen compounds in the coal.

NO_x emissions from pressurized fluidized-bed combustors are represented by Figure 8, which presents all of the data that have been collected on the 500 lb coal/hr (227 kg/hr) pressurized Miniplant combustor (Reference 16). As indicated, some of the data are below 0.1 $lb/10^6$ Btu (43 ng/J), although a few measurements are as high as 0.4 $lb/10^6$ Btu (170 ng/J). The fact that so much of the data are below 0.2 $lb/10^6$ Btu (86 ng/J) gives rise to a hope that--if NO_x emissions from pressurized units decrease with increasing unit size in the same manner as shown in Figure 7 for atmospheric combustors--pressurized units larger than the 1.8 MWt Miniplant might reliably achieve 0.2 $lb/10^6$ Btu without combustion modifications.

Efforts have been made to correlate NO_x emissions against combustor variables for both atmospheric and pressurized fluidized-bed combustors (Reference 18). There does appear to be some correlation suggesting that NO_x decreases with decreasing temperature, decreasing excess air, and increasing gas residence time. However, the correlation is not sufficiently strong to suggest that these variables might be utilized as an effective means of NO_x control.

EPA has conducted some preliminary testing in order to assess whether NO_x emissions from both atmospheric and pressurized fluidized-bed combustors can be reduced by means of combustion modifications. In limited testing on the 100 lb coal/hr (45 kg/hr) atmospheric combustor at EPA's laboratories in the Research Triangle Park, emissions below 0.2 $lb/10^6$ Btu (86 ng/J) were achieved through the use of two-stage combustion. In these runs, the primary combustion air flow to the base of the bed contained about 5 percent excess air; the remaining air (to bring the total to 20 percent excess) was injected just above the bed. Tests on a 28 lb coal/hr (13 kg/hr) pressurized combustor at Exxon (Reference 16) indicated that NO_x emissions could be reduced by about 50 percent through the use of two-stage combustion, with the primary air being 75 to 90 percent of stoichiometric, and with secondary air (raising the total to 15 to 30 percent excess) being injected into the bed, near the top. Reductions in NO_x of 30 to 50 percent were achieved on the Exxon combustor through ammonia injection, when the ammonia was injected near the top of the bed. Simulated flue gas recirculation tests yielded no significant NO_x reductions.

Thus potential does appear to exist for obtaining reductions in fluidized-bed combustor NO_x emissions through the application of combustion modification techniques. However, substantial additional work is necessary in order to confirm and optimize the initial results. Furthermore, additional studies are necessary in order to determine the effect of combustion modifications on other aspects of the combustor system (e.g., two-stage combustion could increase emissions of other pollutants, decrease combustion efficiency, and create corrosion concerns).

Particulate Emissions

Particulate control, adequate to reliably meet the current New Source Performance Standard for utility boilers of 0.03 $lb/10^6$ Btu (13 ng/J), has yet to be demonstrated on both atmospheric and pressurized fluidized-bed combustors. However, adequate control should be possible at atmospheric pressure through suitable design and operation of conventional particle control technology.

For atmospheric fluidized-bed combustors, control of particulate emissions should be similar to control from conventional boilers burning low-sulfur coal. Cyclones alone will not be adequate; control will probably include one or more stages of cyclones followed by an electrostatic precipitator or a fabric filter. Electrostatic precipitators will have to be designed and operated considering the high resistivity of the fluidized-bed flyash (and low flue gas SO_2/SO_3 content). Fabric filters may be subject to such problems as: bag blinding (the flyash in some cases exhibits caking properties); bag fires (if sufficient residual carbon remains in the flyash entering the filter); and base attack (resulting from the high pH of the lime-containing flyash). However, it would be anticipated that, by careful selection of design and operating conditions following further experience on fluidized-bed combustors, these conventional particle control devices should provide sufficient removal and operating reliability.

Most experimental experience on atmospheric units to date has been with cyclones, on relatively small combustors. Fabric filters (and, in the case of the 30 MW Rivesville boiler, an electrostatic precipitator) have been installed as the final stage of particle cleanup on the large atmospheric combustors that are now in or near operation. However, extended test data from these final-stage devices are not yet available.

Particle control at high temperature and high pressure, capable of meeting the emission standard in pressurized fluidized-bed combustion systems, is still in a developmental stage. Fairly promising results were observed in the Miniplant where, during extended testing, three stages of conventional cyclones at high temperature/pressure reduced flue gas loadings to as low as 0.03 lb/10^6 Btu (13 ng/J) with a mass mean particle size of 1 to 2 μm (Reference 16). Good results were also obtained on the Miniplant with an experimental ceramic filter. Other options considered by various investigators include advanced cyclone designs, granular bed filters, and high temperature/pressure electrostatic precipitators.

It is conceivable that pressurized systems might utilize particle control at atmospheric pressure, in addition to high temperature/pressure controls, in order to meet the particulate emission standard. The high-pressure controls will have to remove enough of the particulate to protect the gas turbine from erosion; this requirement will probably translate into removing virtually all of the particulate larger than 5 to 10 μm. However, even when all particles above 5 μm are removed, the mass loading in the pressurized off-gas may still exceed 0.03 lb/10^6 Btu (13 ng/J). If, indeed, the environmental requirements are more stringent than the gas turbine erosion requirements, then a decision will have to be made regarding whether to achieve the additional particle removal, required by environmental regulations, using high temperature/pressure controls, or whether to install an atmospheric-pressure control device following the gas turbine. (The very high levels of high temperature/pressure particle control, once thought necessary in pressurized systems in order to protect the gas turbine from corrosion, may not be required; recent tests indicate that much of the corrosion-causing alkali is present in the gas phase at turbine inlet temperatures, so that alkali corrosion may have to be handled in some manner other than through efficient particle removal.)

Solid Residue

Solid residues from atmospheric and pressurized fluidized-bed combustors will require some care in handling and disposal. The residues will, in general, probably not be considered "hazardous" under the Resource Conservation and Recovery Act (RCRA). However, the character of the leachates will require special attention in the design of a "sanitary landfill" under RCRA for disposal of the residues as non-hazardous materials.

Extensive laboratory leaching tests have been conducted on residues from a wide variety of experimental fluidized-bed combustors (References 5, 8 and 19). Field cell studies are just beginning. When the residues are shaken in a flask containing distilled, de-ionized water as the leaching medium, the primary potential problem areas appear to be the following (References 5, 19 and 21).

- The pH of the leachate at equilibrium is in the range of 8 to 13, which is above EPA's National Secondary Drinking Water Regulation (NSDWR) range of 6.5 to 8.5.
- Total dissolved solids (TDS) in the leachate at equilibrium are in the range 1000 to 4000 mg/ℓ, above the NSDWR level of 500 mg/ℓ.
- Sulfate concentrations at equilibrium are generally in the range 1000 to 2000 mg/ℓ, above the NSDWR of 250 mg/ℓ.

The above factors result primarily from the spent sorbent which is present in the residue. Note that the equilibrium concentrations observed in laboratory "shake" tests of this type probably represent the worst case that could be expected in an actual disposal site. Heat release, resulting from hydration of the calcium oxide fraction of the spent sorbent upon initial exposure to water, is another potential problem area; this heat release could necessitate some care in handling the residue, but is not expected to be a major environmental concern. Sulfide and total organic carbon are below detection limits in the leachates, and are not expected to be problems. None of the 15 trace metals--for which some form of drinking water standard/regulation/criterion exists--exceeds that concentation in the leachate, when distilled water is the leaching medium; trace metals are discussed in greater length later.

The residues will, in general, probably not be found to be "hazardous" under RCRA, according to the RCRA procedures recently promulgated. Four criteria have been established to determine whether a material is to be considered "hazardous": toxicity, ignitability, reactivity, and corrosivity. A laboratory leaching test, referred to as the Extraction Procedure, has been proposed for determining whether a material is "hazardous" due to the toxicity criterion. The Extraction Procedure employs an acetic acid solution as the leaching medium; a material is considered "hazardous" due to toxicity if the leachate contains any one of eight trace metals (or certain other materials) at a concentration greater than 100 times the National Interim Primary Drinking Water Regulation (NIPDWR). Six fluidized-bed combustion residues (including both atmospheric and pressurized spent bed materials and flyash/carry-over materials) have been tested by Westinghouse according to the Extraction Procedure (Reference 22). None of the eight trace metals exceeded the threshold of 100 times the NIPDWR for any of the residues; hence the residues tested were not "hazardous" due to toxicity. The other three criteria (ignitability, reactivity, and corrosivity) are not considered at this time to apply to fluidized-bed combustion residues (Reference 21).

Although fluidized combustion residues in general do not appear to be "hazardous," it is possible that, in some limited specific cases, residues from an individual plant may be found to be "hazardous" according to the Extraction Procedure (depending upon the specific coal burned or the specific sorbent used). However, it would be expected that the number of cases where the residues might be "hazardous" would be small, since in the six residues tested with the Extraction Procedure, the concentrations of the eight trace metals were, in all cases, more than an order of magnitude less than 100 times the NIPDWR.

If fluidized-bed combustion residues are not "hazardous," they will not have to comply with the regulations being developed under RCRA to cover the generation and disposal of "hazardous" wastes. However, even if they are not "hazardous," the residues will in general (depending upon state requirements) still have to be discarded in a "sanitary landfill," in accordance with RCRA provisions. One requirement proposed for "sanitary landfills" is that they should not degrade groundwater to cause contaminant levels in excess of the NSDWR. The fact that fluidized-bed residue leachate exceeds the NSDWR for pH, TDS and sulfate does not, of course, indicate that a landfill composed of the residue would necessarily raise groundwater concentrations above those levels. The actual impact on the groundwater concentrations will depend upon a large number of site-specific parameters. However, the fact that the leachate exceeds the NSDWR does indicate that a potential groundwater contamination threat might exist, and this possibility will have to be considered in the design and operation of the disposal facility.

Under the Clean Water Act (CWA), EPA is responsible for development of effluent limitation guidelines and new source performance standards for liquid effluents from steam electric plants and other industrial categories. Runoff from a solid residue disposal site would generally be covered by any such effluent standards which are developed. The current guidelines and standards for conventional power plants specify, among other things, that effluents from the plants should be maintained in the pH range of 6.0 to 9.0. Since fluidized-bed residue leachates frequently have pH levels higher than 9, some effluent control technology could be necessary, depending upon the specific circumstances. In addition, under CWA, EPA is considering the need for effluent standards covering 129 substances commonly referred to as the "priority pollutants," which were defined as the result of a judicial consent decree. The priority pollutants include primarily complex organic compounds, but also include 13 trace metals. EPA is screening a variety of effluents for these pollutants; the current minimum concentration being quantified is 10 parts per billion (ppb). The 13 trace metals are generally present in fluidized-bed residue leachate in concentrations of 10 to 100 ppb or less when distilled water is the leaching medium. The fact that the metals are present above 10 ppb in some cases does not necessarily mean that effluent controls may be required.

Other Potential Pollutants

The previous discussion of air pollutant emissions and solid residue focuses on those pollutants for which standards or regulations of some type already exist or are being considered. However, in a more anticipatory role, EPA is also addressing potential pollutants which may become of concern in the future. Comprehensive analyses--including chemical and biological testing--are being conducted, or are planned, on the large fluidized-bed combustion units which are currently in operation or under construction. These comprehensive analyses will consider up to 850 different potential pollutants. This list of substances to be considered at this stage has been made deliberately long in an effort to ensure that no potential problem pollutant is overlooked.

In order to assess the results from such extensive comprehensive analyses, the observed emissions for the substances identified are compared against conservative emission goals, which have been developed independently for each of the 850 substances based upon fairly simple application of available health and ecological effects data. If the observed emission exceeds the independent goal level for a specific substance, then that substance warrants further consideration in the R&D effort.

Complete comprehensive analysis results are currently available from only one fluidized-bed combustion facility, the pressurized Miniplant. Briefly, the key conclusions from this comprehensive analysis are:

- The fraction of the flyash/carry-over smaller than 10 μm, gave a positive result on the Ames test for mutagenicity. This result suggests that the 10 μm flyash is mutagenic, and hence possibly carcinogenic. Similar positive Ames results have been observed on flyash from conventional boilers, so that this effect may be associated with coal combustion in general, and thus not necessarily a reflection on fluidized-bed combustion in particular. EPA is conducting further tests to confirm and explain this result.

- Certain trace metals in the bed material, the flyash and the leachate from the bed material and flyash, exceeded the conservative health/ecological emission goals mentioned previously. This result does not necessarily indicate a problem, since the goal levels are so conservative. The results suggest only that further analyses are required as part of EPA's R&D program. For example, if the element Se is identified in the analyses (by spark source mass spectrometry, which does not indicate the compound form of Se), it is assumed in applying the goal levels that all of Se is present as the most toxic Se compound that is included in the list of 850 substances. Since the Se is probably actually present as a much less toxic species, this method of data interpretation really indicates only that further analyses are necessary to define the compound form of the Se, so that the actual level of environmental hazard can be assessed more accurately.

° Organic substances did not exceed the goal levels in any streams.

Conclusions

Both atmospheric and pressurized fluidized-bed combustors should be able to meet the current revised NSPS for large utility steam generators. Specifically:

1. SO_2 removals of 90 percent and higher can probably be achieved in both atmospheric and pressurized combustors at reasonable sorbent feed rates, and in a manner economically competitive with the alternative of a conventional boiler with flue gas desulfurization. However, in order to achieve these removals, the combustors may have to be designed and operated with sufficiently long gas/sorbent contact time and with suitably small sorbent particle size. In general, pressurized systems inherently are designed with relatively long gas/sorbent contact time; this fact is one major reason for the improved SO_2 removal efficiencies of pressurized systems.

2. NO_x emissions are characteristically below 0.5 lb/10^6 Btu (210 ng/J) for large atmospheric fluidized-bed combustion units, and below 0.4 lb/10^6 Btu (170 ng/J) for pressurized units. These emissions may be reduced further through the use of two-stage combustion and other NO_x control options. Although these emissions are below the current revised NSPS for utility steam generators, they are above the levels that may ultimately be achievable in conventional boilers employing combustion modification techniques.

3. Flue gas particulate control to meet environmental requirements must yet be demonstrated, but should be possible at atmospheric pressure through suitable design of conventional particle control technology. The technical performance and costs of high temperature/pressure controls for pressurized systems are uncertain; however, the high-pressure particulate control required to protect the gas turbine (from erosion) may be less than that required to meet the revised utility NSPS of 0.03 lb/10^6 Btu (13 ng/J), so that some of the particle control in pressurized systems may be accomplished at low pressure, following the turbine.

The solid residue from fluidized-bed combustors may require some care in handling and disposal. The levels of pH, total dissolved solids, and sulfate in the leachate are typically above drinking water regulations. The residue should not normally be found to be "hazardous" under RCRA, according to the RCRA test procedures recently promulgated. However, the leachate properties will necessitate some attention in the design of a "sanitary landfill" for disposal of the residue as a non-hazardous material.

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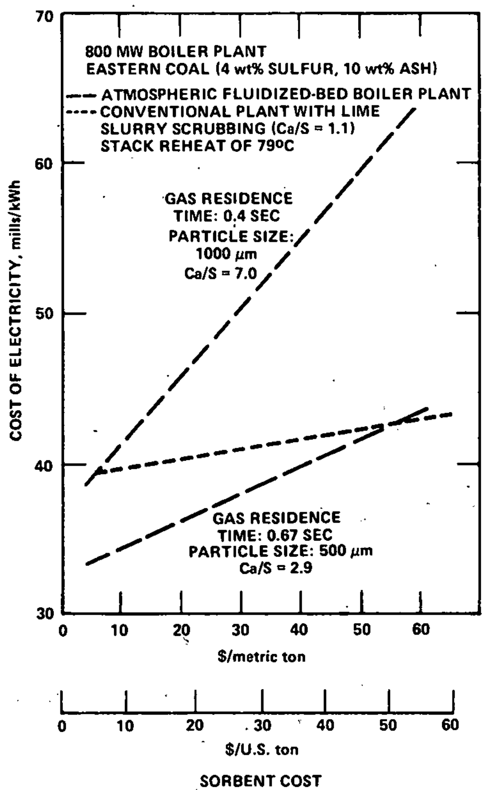


Figure 1. Effect of gas residence time and sorbent particle size on cost of 800 MW atmospheric fluidized-bed boiler plant, for 90% SO_2 removal (cost projections prepared by Westinghouse).

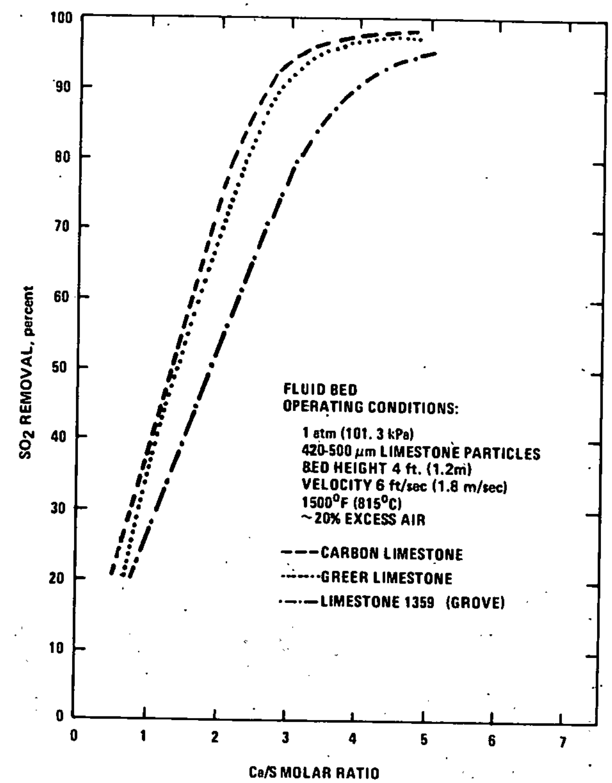


Figure 2. Projected desulfurization performance of atmospheric fluidized-bed coal-combustor, based upon model developed by Westinghouse.

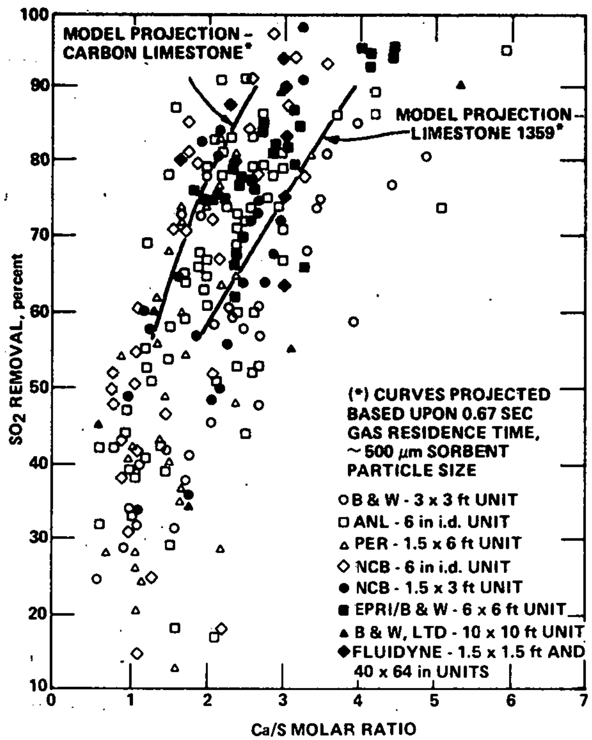


Figure 3. Comparison of desulfurization performance projected by Westinghouse model, against measured performance of experimental atmospheric fluidized-bed combustors.

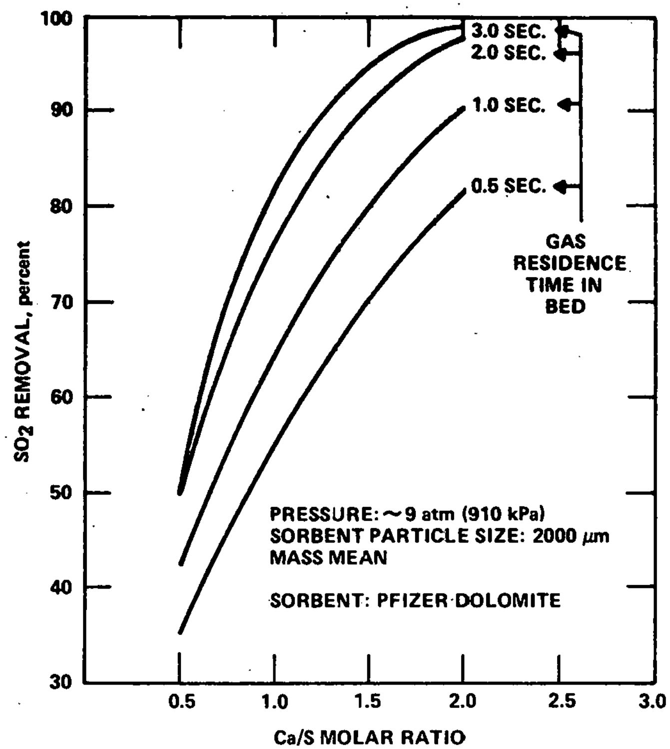


Figure 4. Expected desulfurization performance of pressurized fluidized-bed coal combustor, based upon Miniplant data and model developed by Exxon.

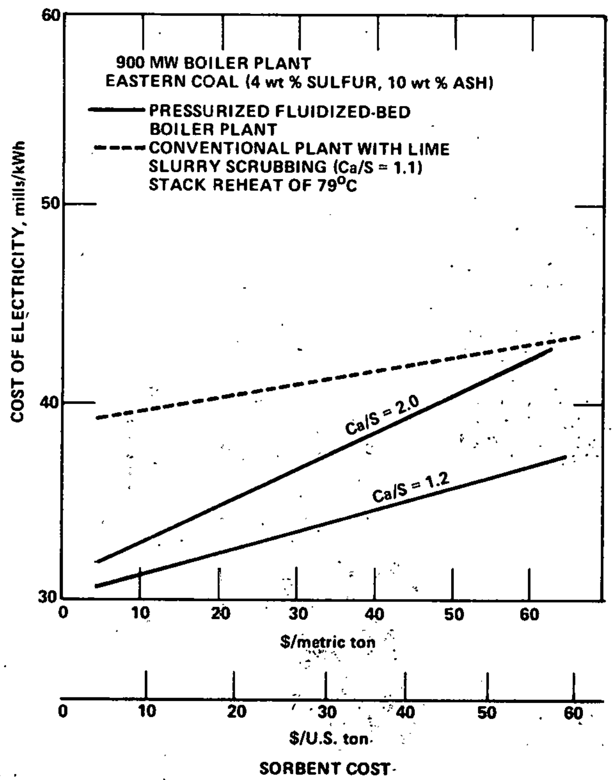


Figure 5. Effect of sorbent feed requirements on cost of 900 MW pressurized fluidized-bed boiler plant, compared to conventional boiler plant with scrubber (adapted from cost projections by Westinghouse).

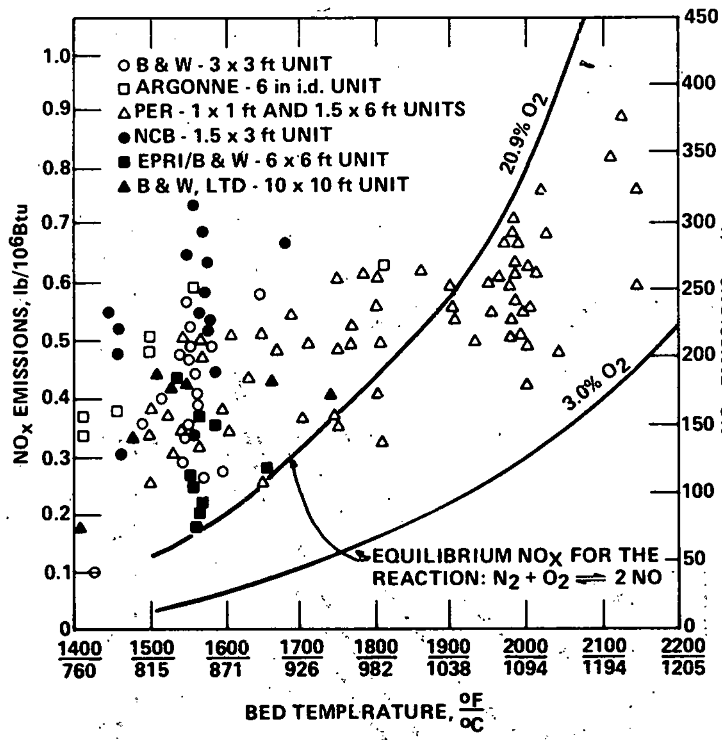


Figure 6. Nitrogen oxides emissions (expressed as NO_2) from atmospheric fluidized-bed combustion units.

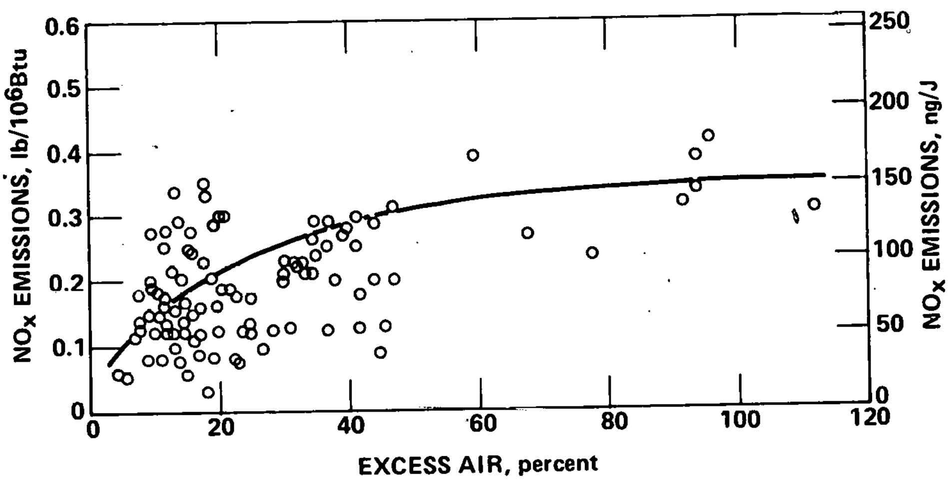


Figure 8. Nitrogen oxides emissions from the pressurized fluidized-bed combustion Miniplant.

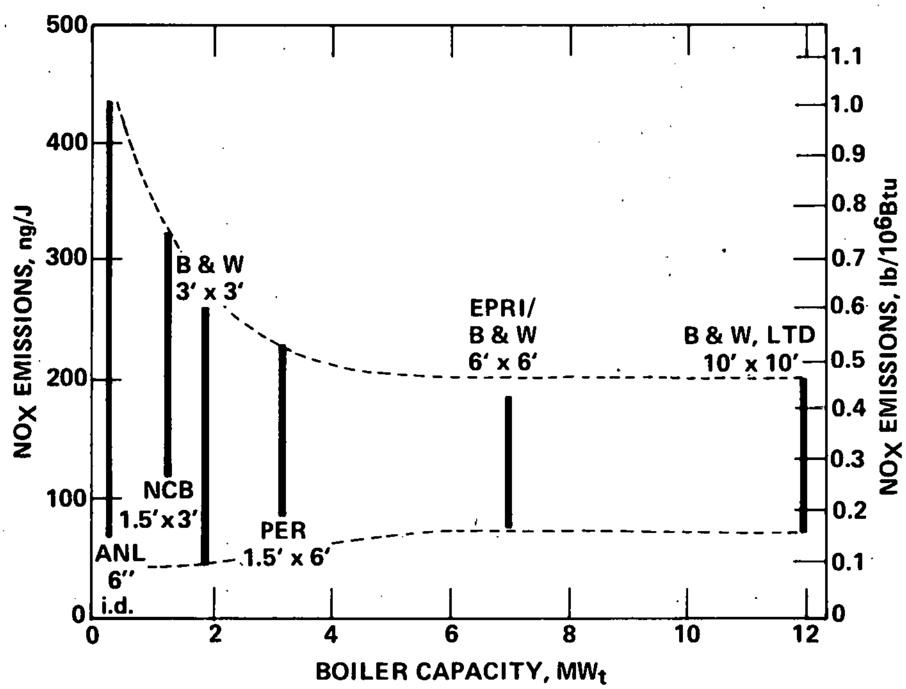


Figure 7. Nitrogen oxides emissions from atmospheric fluidized-bed combustion units, as function of unit size.

PLENARY - 2

FLUIDIZED BED COMBUSTION DEVELOPMENT
AND
COMMERCIAL STATUS SUMMARY

PLENARY SESSION - 2
FLUIDIZED BED COMBUSTION
DEVELOPMENT AND COMMERCIAL STATUS SUMMARY

Session Chairman: Steven I. Freedman

Department of Energy

This conference had six technical sessions that were occurring in parallel and we realize that it was difficult to attend all the sessions that one wished to attend. We do expect to have the proceedings printed soon for distribution to all of you.

The purpose of the first panel this morning is to present to the meeting as a whole, the results of the conference as seen from people with varying perspectives and we will get a comprehensive view of what was going on in the various technical sessions from an appropriate variety of viewpoints. We have technologists, users, researchers and people with international interests in the technology. With that, I will turn the microphone over to Raymond Hoy, who has been the technologist in fluidized bed combustion and he will let us know what he knows now, on Friday, that he didn't know on Tuesday.

H. Raymond Hoy -- The Technologist
National Coal Board
Leatherhead, United Kingdom

It has been an interesting session -- our eastern friends have caused us to rewrite the history of atmospheric fluidized bed combustion -- but the most notable feature, however, is that we are seeing the beginnings of commercialization of the fluidized combustion system, at least those for the industrial steam raising in plant sizes up to about 100,00 pounds per hour of steam. The list of commercial and field test units that are either on order, in service or shortly to be in service is impressive. We have people like Johnson Boiler with orders for 15 boilers; Foster, Wheeler and Babcock, who have their first commercial installations and their field test installations along with Combustion Engineering and, on the other side of the water, there will, by the end of this year, be about 30 installations either in use or at an advanced state of construction. In the Federal Republic of Germany, there are some two major ones now in use and another large one on its way. This list seems rather small compared with the 2,000 they talk about in China. There are areas for further development and this is particularly so for the utility application and I don't think there is any cause for complacency in relation to the other applications either. I think the Tennessee Valley Authority's 20 megawatt pilot plant will be a significant contribution to developing the technology for the utility field. I would expect by now, however, that in the industrial steam raising field, application of the development of the technology would proceed from experience gained from the commercial and the field test units and, from this point of view, you see your sort of technology analysis groups which include anything from the people who actually monitor the results to those who create the mathematical models will have an important part to play.

Turning now to the development of the areas for the atmospheric pressure fluidized bed combustor, the various detailed things that have cropped up are roughly as follows. I think that in the area of coal distribution and feeding, the development of the overbed system for large coal, and the direct firing system for the crushed coal, there have been very notable advances since our last meeting, and these promise to go a long way to overcoming some of the criticisms that are justifiably leveled against the fluidized combustion. I think it is important, however, to remember that a system of firing can have an impact on the design of the combuster and it is important, I think, to consider the nature of the coal that is being fired. Coal does vary. It must be a great problem to those who are developing the mathematical models to have a variable feed-stock. The coal ash varies both in quantity and in its nature, and in our endeavors to reduce the cost of coal feeding, we can end up with projecting large pieces of stone into the bed and, therefore, it is very important to take into account in the design of the bottom end of the bed the means for removing oversized material. There is always a great incentive to improve the efficiency of the sulfur retention and, during the course of the meeting, we've had some interesting developments in the way of using additives and, at the same time, there seems to be a plea for better methods of predicting the behavior of the additives. In the endeavors to improve combustion efficiency, we also have the scope, I think, to improve the sulfur retention efficiency. The Alliance plant in particular has demonstrated that, by making better use of the freeboard and recycling, there is significant scope for improving both sulfur and retention efficiency and combustion efficiency. We are faced with a greater challenge it seems as far as NO_x emission is concerned. I think it is inevitable when a new technology comes along that the protagonists of the old technology will do their best to make life difficult. We hear of these burners which can reduce the NO_x emission, thereby increasing the target that we've got to meet with fluidized combustion; and so we hear about two-stage combustion. Indeed, in order to achieve efficient two-stage combustion, this can possibly face us with some problems too. The other technological issues that crop up in relation to atmospheric pressure fluidized combustion concern the removal of the solid residues. What can we do about that to make it a simpler means and cost less? Then the other side that is mentioned these days is the question of design of tube banks to minimize the stresses.

As far as fluidized combustion is concerned, it is a title covering a range of systems -- there's no unique system -- in the similar applications and many versions will continue to emerge to meet specific requirements. I think a feature of this conference has been the solids circulation type of equipment. We have had an interest, ourselves, in that. At times this does seem to offer considerable advantages where there are a wide range of fuels to be burned, particularly from the point of view of having a wide range of ash content or mostly moisture content, ash content and size consist. In the question of materials, I think since the last conference, the amount of operating time for materials testing must be quite considerable. I did a rough check; I think we must be covered on the various rates, something like 15,000 hours between us on the point of view of obtaining data on materials and I get the impression there is cause for cautious optimism. We were a bit surprised to find, after our intial thoughts on fluidized combustion and all its benefits, that there could be corrosion problems, and I think we can see that we do have the materials that are likely to give the sorts of life we want. But, above all, this needs to be proved. I think there is significant confidence to proceed anyways at the moment and I hope there won't be any delay in authorizing the beginning of the longer term tests so that there are no excuses later on which would reduce the rate of the assimilation of this knowledge into commercial plants.

Now I turn to the pressurized fluidized combustion and I think as far as pressurized fludidized combustion is concerned, it has been quite a notable year or so. I think that the data obtained on the rigs has given us greater optimism as to the possibility that the combustion gases can be cleaned to the extent that is necessary. Gas turbines operate satisfactorily that have reasonably low inlet temperatures, say about 1400°F, perhaps even 1500°F, and it should be possible to get good life out of the blades. But again, this is something that will need to be proved, and the sooner we can have gas turbines of a reasonable size operating with pressurized fluidized beds, the sooner we shall know whether we can exploit to the full, the combustion system. Now, as far as pressurized fluidized combustion is concerned, there is a lot of work remaining in making sure that the cyclones perform satisfactorily and to their optimum conditions. I think it is one thing to have a train of cyclones working under optimum conditions on the test rigs and another thing to make sure that they are going to do this in the field, particularly if there are parallel groups of them. And there is a need, of course, for development of instrumentation which will detect when the cyclones are not functioning properly, so that the necessary corrections can be adopted.

In the interest of time, I will not dwell at great lengths upon the various other aspects of development for pressurized fluidized combustion. It is a system, of course, which achieves high combustion efficiency and the sulfur retention efficiency and NO_x emission levels are a slight improvement over the non-pressurized. But, again, there is scope for improvement, just as there is scope for improvement in the ability to use a wider range of coal, from the point of view of minimizing coal preparation costs. I think we have obtained a lot of data for operation under the steady states and the main means now is to obtain more information on the ways to improve start-up, load following abilities, and data for the transient conditions.

It has been a very worthwhile occasion and I'd like to congratulate the organizers of the conference and thank them for inviting me. Let me take this opportunity to remember some of those who have contributed greatly to the technology, but didn't quite finish the course, in particular, there is Douglas Elliott, who started in the game before most of us, although he didn't know he had at that time; and then across in the United States, the pioneering team of Pope, Evans and Robbins had John Bishop, who was a great engineer; and I'd just like to pay my respects to them. Thank you for inviting me and congratulations on a good conference.

Steven I. Freedman - Session Chairman

Our next speaker is Manville Mayfield from the Tennessee Valley Authority, who will address us from the perspective of the group that is engaged in building a utility scale plant. With expcectations of building their 200 and then, hopefully, at a later date, a full 800 megawatt scale commercial plant. He should have some very good insights as to what benefits his group has obtained from this conference to aid them in their endeavor.

Manville Mayfield -- The Utility User
Tennessee Valley Authority
Chattanooga, Tennessee

Looking at the viewpoint of commercialization and the development of fluidized bed combustion from the utility standpoint, it seems pretty clear that from a commercial standpoint, obviously, further development is going to be necessary. The use of the pilot plant demonstration concepts where you're talking about 10X scale-ups, seems to be the prudent route and the direction that will probably be followed by utility industry. Obviously, from the conference, there is considerable interest in both pressurized fluidized combustion and atmospheric fluidized bed combustion. The atmospheric fluidized bed combustion offers the advantages of simplicity, while the pressurized fluidized bed combustion offers cycle efficiency and size reduction as some of its major advantages. Nevertheless, I think that with the need in the U.S. and in the world, to burn coal more efficiently, we need to pursue the commercialization of fluidized bed technology as rapidly as is practical and prudent. We, representing at least one utility, has set this as a goal, to provide our management with the option of using fluidized bed combustion as an alternative for future generating capacity.

When I look back at the progress that has been made since the Fifth International Conference two years ago, it is pretty obvious that some rather major improvements and developments have taken place. As Raymond Hoy mentioned, there have been some considerable commitments on the part of industrial and utility users for additional facilities, pilot plants, industrial scale units and major improvements in the R & D sector. Another obvious point is the interest and activity that has been evidenced by the people who have attended this conference in the international sector, certainly in the United Kingdom and Germany. In other parts of the world, particularly in the Peoples Republic of China, it was very obvious that there is a great deal of work going on and that there is a lot of international interest in this field. I'd like to take just a moment and discuss what I view as the major issues that apply to the utility application of fluidized bed combustion. The first point that I would like to make is that equipment performance and long term reliability is an important need and one that has got to be addressed in the operation of pilot plant and test scale facilities. Kurt Yeager, in the keynote address that he presented, pointed out the importance of unit availability; and certainly this is an important factor when you consider the utility needs and the performance requirements of a utility boiler. Design optimization is another area of considerations such as use of carbon burn-up cell vs. recycle, velocity, dust loading, bed depth. These factors still have not been completely optimized and need further work towards their development. Methods of control is another area -- load following, instrumentation, the type of instrumentation, whether you use bed-slumping or whether you go to multiple beds for control -- seems to be an area that has to be addressed further. Raymond Hoy mentioned materials of construction. I think certainly the results are encouraging and promising, but I think we have to keep this area in front of our attention and make sure that we are developing the information needed to properly select materials for this use. Then, of course, the other multitude of information that the engineering designer needs for such factors as heat transfer, controlled emissions, combustion efficiency, recycle rates, coal and limestone particle size -- these are all important factors that we need better information developed on.

I would like to take just a moment and mention the subject of what I call the advanced atmospheric fluidized bed combustion concept, basically the fast circulating beds. Designs of such systems for utility applications haven't been fully developed. The approaches offer some rather important and interesting possibilities for utility boiler designs. The improved sulfur catcher, lower NO_x emissions possible with two-stage combustion, the ability to turn down these units, improved combustion efficiency -- all offer attractive possibilities and I think should be pursued as rapidly and effectively as possible. We need better information on the economics of this approach, and there are studies underway to help determine and get a better handle on this factor.

I'd like to now just go through a series of comments that various people from our group have picked up and noted as being possible points of interest that have come out of this conference. Raymond Hoy mentioned some of these, so I'll probably be repeating some of his comments. Certainly the question of two-stage combustion to improve NO_x control that was noted by Battelle seems to be a significant point. The fact that fluidized bed spent sorbent will likely not be classified as a hazardous waste material certainly is important to the utility industry. Westinghouse reported high corrosion rates on the pressurized fluidized combustion rig, but on the other hand, Curtis-Wright reported acceptable rates. So, I think the jury is still out in this area, but there are very encouraging results from the data that I have seen on the performance and the applications of direct fired turbines using a pressurized fluidized bed combustor. Curtis-Wright reported that they believed to have worked out an acceptable control scheme for their PFBC system. This is certainly an important area that needs careful review. The concept for fast circulating beds reported by Battelle which has improved load following capabilities is noteworthy. In the area of modeling, the assupmtions are still being questioned and debated in the technical papers. It seems very obvious that additional experimental data is needed to verify the results of these models. A good example are things like coal devolitization, flue models, bubble growth and similar type mathematical calculations. The use of ceramic bag filters for PFBC, apparently received a very good rating and looks like it may be an acceptable route. It certainly has had some encouraging results and offers the possibility of an acceptable way of hot gas clean-up. I think it was significant that some of the speakers noted that atmospheric fluidized bed combustion appears to meet all of the projected emission standards that have been set forth and that the ability to meet those that may be promulgated in the future by improved performance in these units seems to be a particular matter. There is some concern for the use of slumped beds as a load following technique. I think this needs further consideration. The possibility of caking or of a layer on the top of a slumped bed is going to, I think, require some further technology development or operating means to prevent this from happening if this technique is used. Fluidyne reported that, depending on the coal type used, it may or may not be necessary to use recycle as a means for achieving high combustion efficiency. Apparently the coal types -- some coals are very fast burning and achieve high combustion efficiency, while others seem to be slower burning and require recycle to get the sufficient combustion time -- vary greatly. John Stringer indicated that he felt very strongly that the test data on corrosion that we have seen on the 2000-4500 hour time frame should be extrapolated to longer times with considerable caution. He was urging 10,000 hour or longer time frames for corrosion testing. Battelle work for TVA showed that there was significantly less corrosion from fluidized bed combustion ash then compared to that of a conventional pulverized coal fired boiler. It would certainly seem obvious that ASTM and ASME test procedures and standards need to be developed so that the convection pass can be properly designed to withstand the erosion characteristics of the higher dust loadings that we are talking about with recycled configurations. I thought another significant point was the Fluidyne, and this has been confirmed by a considerable number of sources, information that one feed point per 18 square feet seems to be adequate to achieve good distribution of the coal and still achieve a minimum of coal feed piping. This could be very significnat and is certainly an improvement over the 9 square feet that was reported in previous conferences.

Steve, I guess I want to say that I think this has been an excellent conference. I think there has been a lot of work done and we're proud to be part of it.

Steven I. Freedman - Session Chairman

Thank you for your kind remarks. The third speaker is Davic McKee from DuPont. The industrial sector is one sector that could very well be the take-off in the fluidized bed market and it is worthwhile, on a personal and industrial basis, to hear the remarks from the industrial operator.

David McKee -- The Industrial Operator
E. I. DuPont Company
Wilmington, Delaware

I'm with the engineering department of E.I. DuPont and part of a group that is involved with the technical assessment of evolving technology as it affects our business. In this respect I have been involved in fluidized bed technology for close to ten years. We do not have any fluidized bed boilers within our corporate limits; however we have been using fluidized bed technology in our process reactors for over 25 years and have been following the development of fluidized bed technology, in the U.S. and abroad, on a continuing basis for many years. So I think we are in a position to stand off at a distance and observe the work that you're doing and hopefully give you some intelligent comments.

DuPont's interest is broader than just the development of coal fired fluidized bed boilers. We have interest in using coal as a firing mechanism for process heaters as well, and in a minor sense, we are interested in combined cycle co-generation. Our primary interest is in atmospheric units although we are keeping abreast of your pressurized developments. To put things in perspective, we at DuPont, last year used about 33% coal to generate our steam load. If the present world situation and energy situation continues, by the end of the decade, we probably will be using coal to generate 75% of our steam load. So we've made a commitment as a corporation that coal is the fuel of the future for raising steam. As you're well aware, the chemical industry depends heavily on petroleum and natural gas as a feedstock. For many of our products depend on the carbon-hydrogen molecules for their manufacture. As a result, we're strongly in favor of any technology that protects those petroleum and natural gas resources for their end use as a feedstock as opposed to a boiler fuel. Within our plants in this country and abroad, we have a very large boiler operation. We have about every type of conceivable design still in operation, from riveted drum, hand-fired stokers, all the way up to very large sized pulverized coal fired units. Our smaller size range is probably in the 10,000 pound per hour range, our largest is in the million pound per hour range. So we have quite an extensive population to look at. Our steam pressure is varied from atmospheric at 212°F all the way up to 1500 pounds per square inch at 950°F. So we are looking primarily to satisfy the market that is in the 100,000 or maybe as low as 80,000 pounds per hour up to the 450,000 and 500,00 pounds an hour range. This is where a majority of our steam generating equipment is sized.

I am sure you are aware that with today's environment, that we're faced with a lot of hard decisions in industry, and when you add the complexities of incremental pricing of natural gas, the Fuel Use Act, the emerging new source performance standards for industrial units, ever changing waste disposal regulations and the ever changing investment tax and money market situations, it is no wonder that we in the industrial community claim to be conservative. At times, we've been said to be slightly to the right of Attila the Hun. We're skeptical, we're slow to react, when we make large decisions for new steam generating facilities. To put our business decision making process in perspective, we don't think we make decisions any differently than any other corporation. But for the benefit of those of you who may not be aware of how we do it, let me run through the criterion we use. The bottom line is always economics, when things are economical and in the best interest of the corporate profits position, then we make an investment. You also must realize that we are in the business to make chemical products and steam raising happens to be an essential service that enables us to reach that end goal. Many of our processes run 24 hours a day, seven days a week, 365 days a year. We do not have a lot of installed spare capacity. We cannot afford an unexpected boiler outage that can bring a whole plant down. Just one shutdown of some of our process lines can quickly destroy the profit picture for that line for the whole year. So, our management is rather hard-nosed about how we evaluate the technical aspects of power producing equipment. We're willing to take risks with chemical processes, that is our business; but when it comes to investment in power facilities, it is an understood fact that those facilities are reliable and predictable. So we are evaluating the technology to look at the design, operating characteristics, ability to meet the environmental regulations and load changing characteristics. In general, most of our power producing equipment experiences load swings in the neighborhood of 4 to 1 on many of our batch type installations. We are looking at it from a number of viewpoints; certainly operating and maintenance costs are part of the picture. So fluid bed boilers must compete on an economic as well as an operational basis with conventional technology. We have a lot of experience with coal burning. We know how clinkers are formed. We have experienced fires in hoppers and have gone through all the problems in coal handling systems: cold coal, wet coal, first in transport lines, etc. We hope the designs that are evolving will use the best of those technologies to minimize their impact on fluidized bed technology. It is my assessment of the literature and the work reported today that the technical power is out there to do the job. I have no doubt that you can build a reliable boiler that can make steam as well as a conventional coal fired unit. I don't think we are there yet, we need proven reliable service in an industrial environment to put us in the position of being a buyer. By that, I mean 8300 hours of continuous operation with load swinging capability. I think in the next five years, we are going to be there. By then, there will be some units on line long enough that we can make some evaluations.

To summarize what I have heard here, I can say that I was surprised to hear of the activity in China. I was surprised by the magnitude of the effort. I think I need more information to decide what the 2000 units figure really means. But, it was encouraging that there is a long term commitment in that country. I think our second generation fluid bed units are starting to appear. We have gone through our first iterations and have learned some things. Now we are starting to put our thoughts together and coming up with a second generation that is more reliable. I am encouraged by the work abroad in Finland, Denmark and England. I think a meeting of this sort is essential to get people together. I am sure that the conversations which occur in the halls and over the bars are as important and that is what we need to make this technology go forward. The trends I see coming are good. We are evolving toward units that realize that deeper beds have certain inherent advantages such as lower velocities. Improved carbon utilization has been keynoted as a goal which must be achieved. The higher sulfur retentions with lower calcium to sulfur molar ratios is to our advantage.

I think we are seeing a merging of our efforts and we are getting a direction. We can see the goal line a little more clearly than five years ago and I think we are going to be in time to meet the market situation. Our economics are difficult to assess at this time. We need better economics from the vendors to make the hard-line decisions which we need to make. The work that Exxon and Westinghouse have done in the past is quite helpful in describing the economics as we know them; but as in any evolving technology, you never know what the costs will be until you get the manufacturing facilities set up and you are mass producing. I am sure the costs will come down with time, but it is encouraging that the early estimates make this technology competitive both from an investment and an operating standpoint. Its advantages far outweigh its disadvantages. It is ripe for development and I'm hopeful that your efforts succeed.

Thank you.

Steven I. Freedman - Session Chairman

Thank you, Dave. Our next speaker is Dr. Vagn Kollerup from B. W. Damp, who will give us his impressions from the Scandinavian viewpoint.

Vagn Kollerup -- The Scandanavian Viewpoint
B. W. Damp
Virum, Denmark

I shall try to give my impression as seen from a Scandinavian viewpoint. We have learned at this conference that fluidized bed combustion is a system that works. The main interest that we have in that system is due to the fact that for the first time, we have a system that can burn all solid fuels and this is of special interest to countries where we have to import most of our fuels from varying parts of the world. We get coal from Australia, Africa, Canada, Poland and Russia and this fuel is of varying qualities. If you build plants for coal burning, it is difficult to find one that will burn all these fuels. Here the fluidized bed will win. We have seen that Finland is building commercial plants using the FB system. It burns wood waste, bark waste, and will also burn coal. In Sweden, they have built plants for burning household waste and wood waste. In Denmark, plants have been built for burning coal and wood waste. Both of those plants are used for district heating systems.

How does the future look? I would tell you how the energy situation is in our country. All our energy consumption is imported from outside -- 99%. The house heating portion is about 40% of all our energy. It is produced in oil fired plants. How can we replace oil in this area? We have a so called heating plan for the whole country; it shows that in 15 years, the district heating system will be raised 50%. In Denmark, there are 400 of these stations and the installations are in the five to ten megawatts range, some a little larger. Here we see a great opportunity to use the fluidized bed system. The first station we have built is a five megawatt unit and we have an order for a ten megawatt unit. Those stations are built in a completely commercial way. There is no outside support from anyone.

My conclusion is that development of atmospheric fluidized bed plants in large scale will take some years and demand risk-willing capital. The smaller scale test and pilot plants make scaling possible to sites which are suitable for district heating plants and smaller power stations. The result of the system's low emission rate is that they can be placed near towns and allows the use of coal and wood waste without environmental problems.

Thank you.

Steven I. Freedman - Session Chairman

Continuing with our panel, Professor Shigekatsu Mori from the Nagoya Institute of Technology will give use the viewpoint from Japan and Asia.

Shigekatsu Mori -- The Asian Viewpoint
Nagoya Institute of Technology
Nagoya, Japan

Every country in Asia has a different situation. I would like to focus on the Japanese situation on the development of fluidized bed combustion projects. There are probably many people looking at my country as one of their best markets. In 1976 only two million tons of domestic coal were supplied in Japan and about 60 million tons were imported. About 96% of the imported fuel was metalurgical coal. Just 2.5 million tons of steam coal were imported. In 1990 more than 15 million tons of coal will be used by power generation plants and more coal will be used in industrial boilers. This estimate may increase in the future. This is one area of potential for the development of FBC. Among our neighboring countries, we can find five major coal producers: the U.S., U.S.S.R., China, Australia, and India. Most of the steam coal will be imported from these countries, however, it is difficult to identify the types and amounts of coal which will be imported in the future. New processes which have the flexibility to use any type of coal should be developed in Japan. The flexibility of FBC is recognized as its greatest advantage.

The environmental regulations in Japan must be the most restrictive in the world. The development target for NO_x emission control from fluidized bed combustion is recognized to be just 50ppm in Japan. Just a few years ago, this level seemed impossible to achieve by FBC. In the last few years, progress has been made and this target has almost been reached. The next step is the SO_x control problem and the ash utilization problem both originating from the waste disposal problem. This is the reason why the limestone once-thru process was not available in Japan. We should develop a regeneration process and also new sorbents will be required. These should be developed. The problem for ash disposal is more critical. If 20 million tons of steam coal is imported, this means at least 2 million tons of coal ash is also imported into our limited country. The problem of accumulation of ash is very critical. Utilization of this ash is a problem for any industry using coal fired technology in Japan.

Today we are under construction of a pilot plant of five megawatts. Our program is a little behind your country. We would like to exchange more information with your country through meetings of this type. I hope that at the next confernece, more papers will be presented from Japan.

Thank you.

Steven I. Freedman - Session Chairman

It is good to know that not only is there an energy crisis worldwide, but that the solutions to this crisis are also worldwide. The next speaker is Dr. Johann Batsch from KFA, where he is involved in the German fluidized bed combustion program. We have heard about several of the operating units and it would be valuable to hear the benefits he has obtained from this conference.

Johann Batsch -- The Continental Viewpoint
Kernforschungsanlage
Julich, Federal Republic of Germany

I believe that I have to confine myself to the German viewpoint. As I alredy mentioned in my paper on Tuesday, it is the main intention of our energy research program to promote the development of technologies which can contribute to the future supply of energy for our country in economically favorable and environmentally acceptable ways. Technologies which can reduce dependence on oil and natural gas take high priority in this program. In this respect technologies for increased efficiency and utilization of coal are of special importance. Coal is the only domestic energy source which is available in large quantities in Germany. The development of coal gasification and liquification processes can make contributions only on a long term basis. Improvements and developments in the area of direct combustion is necessary to make progress on a short term basis.

A considerable amount of the primary energy demand in our country is being consumed in the generation of process heat and low temperature heat for space heating. In this area, oil and gas are being used at the present time. Atmospheric FBC enables the increased use of coal for these purposes because this technology enables one to burn coal in small units and is environmentally acceptable with automatic operation. It has been shown during this conference that the commercial application of AFBC is possible in the near future. At least commercialization is anticipated for smaller units used for heat generation. Some facilities of this size are already in operation in this country and in Europe. The difficulties encountered in the operation of these plants are mainly due to conventional parts. The fluidized bed combustion itself works satisfactorily in these plants. Increasing combustion efficiency seems to be the only technical problem which must be overcome for the FBC process. The successful work in AFBC in China has to be mentioned at this point.

The prior technology of circulating fluidized bed combustion will gain special importance in the future. The reasons for this are: 1) The advantages of CFBC with respect to environmental protection are greater with this technology. 2) Some problems in conventional FBC can be avoided with the circulating FBC. 3) Combustion efficiency is improved. 4) The bed area per megawatt is reduced. 5) Sensitive control of heat transfer is possible. In these ways, the CFBC seems to have a wider range of applications than does conventional FBC. Circulating fluidized bed combustion can be developed in a shorter time than pressurized fluidized bed combustion because there are no problems with feeding solids into a pressure vessel. There is already a lot of experience with CFBC in large chemical process plants. For combined heating and power generation, CFBC seems to be an attractive option, the added efficiency of PFBC is of minor importance. There is a growing international interest in this technology.

J. Batsch

This conference has explored the use of pressurized fluidized bed combustion in power generation where the higher efficiency makes better use of coal where it is expensive. It has been shown that much work is still to be done both on the combustion process itself as well as the auxiliary equipment used in this system. We have heard that progress has been made with respect to hot gas clean-up. There is also progress in gas turbine development. Although these results are promising, much remains to be done before a solution to these problems can be reached. It seems important to pursue this work as efficiency will be valuable in the future when costs of fuel will rise.

Thank you.

Steven I. Freedman - Session Chairman

The last speaker will be Bill Reid. Bill Reid has been active in the technology development of all of the coal combustion technologies. As the coal combustion developer, he can give us some perspective on this latest technology and how development is progressing.

W. T. Reid -- The Coal Combustion Developer
Consultant
Columbus, Ohio

It seems that on fluidized bed combustion, we are on the very bottom of the learning curve. That curve started about a quarter million years ago when Peking man found he could get fire from wood. We know that if we put a lump of coal in with oxygen and raise the temperature enough the stuff burns. We don't use all the technology we should in putting that into some practical application. The stokers of today were all invented in the early part of the 19th century. It wasn't until the 1920's that it was realized how coal burned in a fuel bed. About 1934 the definitive work on how carbon and oxygen react was done at MIT. There are three steps included. What we don't know today is how fluidized combustion reactions work internally. We have done all our development on an empirical engineering basis. In sitting in on the combustion phenomenon sessions held here, I was upset to find only two papers that I heard with any real knowledge of what the combustion systems were that they were working with. I would suggest to the developmental people that you read some of the older literature, like the Institute on Fuel or the ASME Transactions. You may see some glimmer of ideas that have not occurred to you as yet.

PLENARY - 3

--THE CUSTOMER SPEAKS--

PANEL DISCUSSION

PLENARY SESSION - 3
"THE CUSTOMER SPEAKS"
PANEL DISCUSSION

Shelton Ehrlich
Electric Power Research Institute
Palo Alto, California

[Mr. Ehrlich spoke using slides which are included here in figures.]

When Arnold asked that I serve on this panel, I said, "Yes, but under one condition -- that you let me make a few introductory remarks because the panel, in my view, represents three very distinct interest areas and I want to have an opportunity to distinguish between those areas. Hopefully the audience, in listening to the different user viewpoints will appreciate that some of the differences expressed result from differences in needs and not necessarily in technological viewpoints.

The first difference I'd like to illustrate is the difference between the industrial user, the person who needs steam and some by-product power, and the utility user (Figure 1). Obviously, a large difference in the users' needs makes for a different set of technical specifications for a boiler. The profound difference in size between a typical industrial fluidized-bed boiler and even a small utility scale FB boiler can be a difference in kind, not just degree (Figure 2). The bottom line on this is that the industrial steam user puts capital costs first and efficiency second in his priorities. They are both, of course, very important. On the other hand an electric utility might put efficiency (fuel costs) of the plant as the first priority; the cost of electricity being the bottom line for them. Probably, this arises from a difference in the method of financing -- equity capital vs. borrowed money. So, I think the industrial user and the utility user of steam generating equipment will require different things from the developer of a new combustion technology.

Now, there is a question that we're always asked at EPRI and I'm sure everyone involved in fluidized-bed combustion has been asked -- (Figure 3) which is better, AFBC or PFBC? I have one stock answer: Both? (Figure 4) Again, there is a very profound difference in the two technical approaches. A conventional pulverized coal power plant (Figure 5) simply consists of a boiler plant and a turbine plant. An atmospheric fluidized bed would replace (Figure 6) the boiler plant, giving, basically, a conventional, Rankine cycle steam electric power plant (Figure 7) in which the steam supply is provided by an AFBC and the air pollution function is performed by the limestone in the bed instead of an FGD unit. Now, no matter what happens in the development of combined cycle generation -- no matter how effective it is -- large sectors of the electric utility industry, for some long time, will insist on making their electricity with the standard kind of electric power plant and that will be the market for AFBC's.

Now let's look (Figure 8) at the pressurized fluidized bed combustion system. It is somewhat complicated because it's got a very profound need to clean the gas and in the Figure 8 we show cyclones to do this cleaning.

First, at the combustion outlet, we start off with lots of dust and the first cyclone takes out some and then the next one takes out more dust, and as it gets to the turbine, hopefully, it is not equivalent to the Arizona road dust test. (A photograph of an Army tank in a dust cloud was shown.) In order to make the turbine survive, we have to get all the way down to practically pure gas. So, we have a system, in combined cycle PFBC, uniquely different from the AFBC system. The second difference I want you to understand is that the electric utility industry which will use steam-electricity power plants for a long time and may use many combined cycle power plants will probably use both if they are both developed. There isn't any need to say which, AFBC or PFBC, is better -- they both are.

Thank you.

FIGURE 1: **FLUIDIZED—BED COMBUSTION**

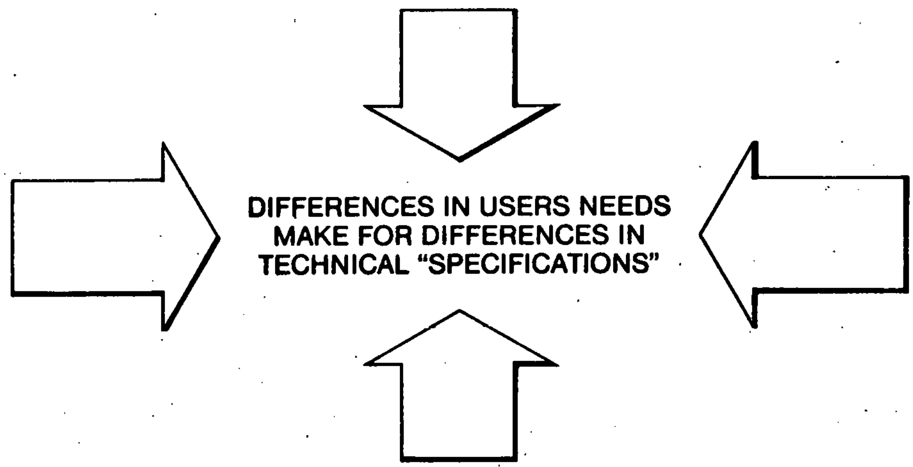


FIGURE 2:

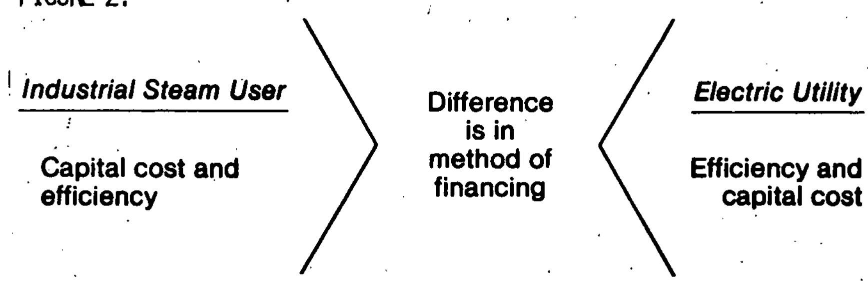


FIGURE 3:

QUESTION:

Which is better
AFBC or PFBC?

FIGURE 4:

ANSWER

Both!

FIGURE 5:

THE CONVENTIONAL P.C. BOILER POWER PLANT

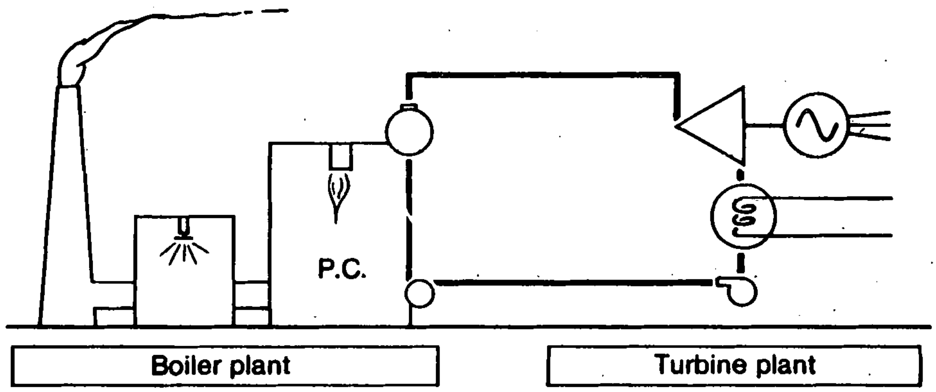


FIGURE 6: THE CONVENTIONAL P.C. BOILER POWER PLANT

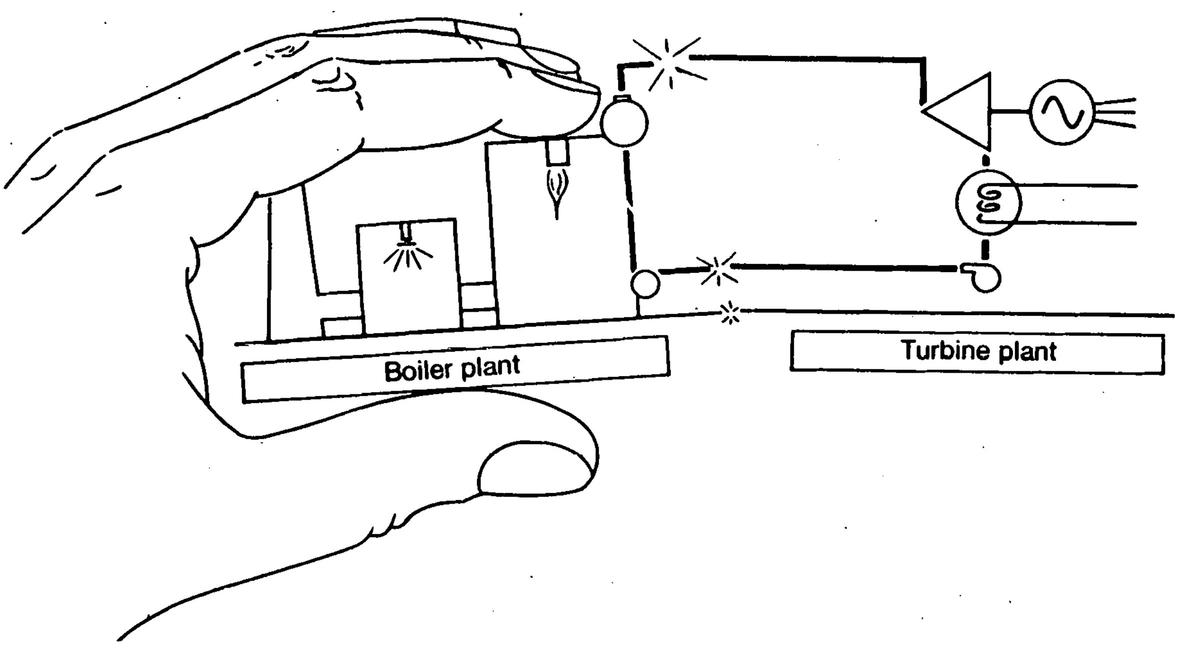


FIGURE 7: **THE AFBC-BOILER POWER PLANT**

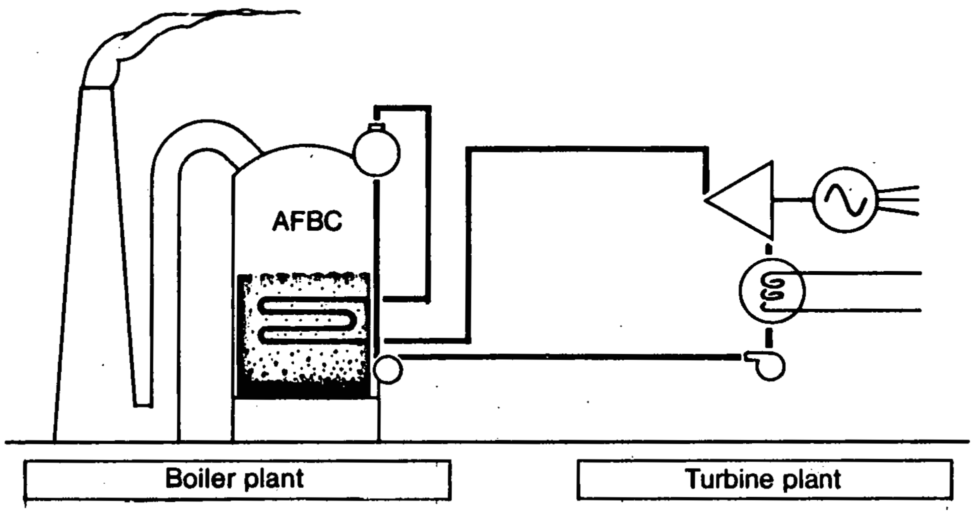
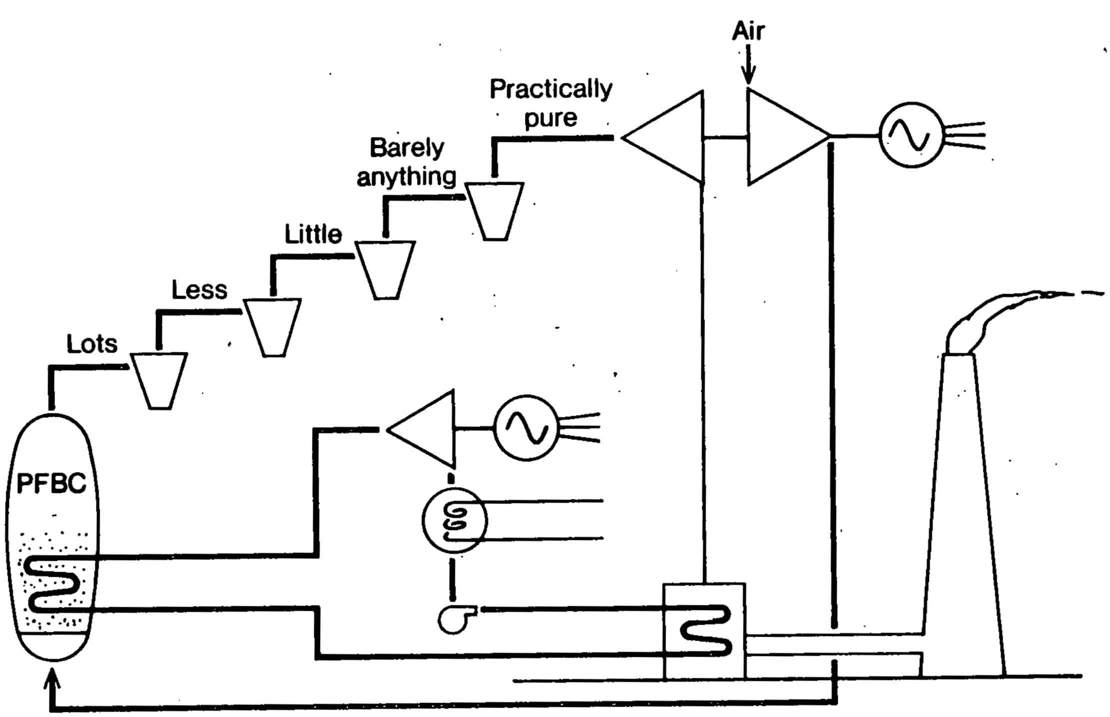


FIGURE 8: **THE PFBC COMBINED CYCLE**



Steven I. Freedman
Department of Energy
Germantown, Maryland

The big question that I'd like to present now, from the government's viewpoint, is -- How do we get this nation and the entire world off of the premium oil and gas fuels onto coal and other solid fuels and other available fuels? All of these fuels that are available are, in some regard or another, a lower grade than oil and gas and are more difficult to handle, burn and use in general, including concern for the environment. So the energy crisis, to a large extent, is a capital crisis and I thank Arnie for introducing it with the "E.F. Hutton talks" remark, because the key to everything is bringing the costs down to the level where the users can use coal and these other domestically available fuels without incurring an economic penalty that is beyond what the system can bare with tolerance. I think we should keep in mind that the fluid bed technology did start as a low cost boiler. I think it is the entire solids handling equipment for the coal fired power plant which needs cost improvement. It is my hope that we are able to manage this transition from premium fuels to more difficult to handle fuels still within the framework of the high standard of living that we have due to the consequences of our high energy use per capita, which is the message that I'd like to end up on. We've shown that things are technically feasible and we're on the way to proving that the things which we can do are practical and reliable. We've just about finished proving that what we can do is clean. The economic challenge is the real one for market penetration. I believe we have the ability to do it, but it requires some good work, attention to detail and knowing where the major leverages are and that's in the capital costs of the balance of plants.

Thank you.

Robert Statnik
Environmental Protection Agency
Washington, D.C.

When I was put on a user panel, I was trying to figure out how the EPA was a user, and finally I decided that we're a user because of the SO_x and NO_x reduction potential that is associated with fluidized bed combustion. I agree with Steve in the sense that, whether fluidized bed combustion makes a significant market penetration or not is very much dependent upon the economic trade-offs between its competing technologies, that is, SNG, liquids derived from coal, as well as conventional stoker fired boilers equipped with various types of flue gas desulfurization or air pollution control equipment. So, in those lines, the regulations which EPA writes do alter the market economics and, in a sense, may either create a window in which fluid combustion can make a market penetration or, if the EPA makes the regulations too stringent, can shut the door for FBC market penetration. Along those lines, there are two regulations, one which EPA is in the process of writing, and the other which EPA has just recently promulgated that are going to be important. In the utility boiler standard of performance, we recognized the evolutionary nature of FBC, especially AFBC, and wrote an exemption to the 90% sulfur reduction potential component of that regulation which, with the cooperation of the Department of Energy, will apply to FPB, SRCI and several of the other advanced technologies. There is a limited amount of generating capacity that can be built which the sulfur reduction percentage would not be required to be 90% -- I think 80% reduction would be required, but they would still be forced to comply with the 1.2 lb/mil BTU emission limit.

In the industrial boiler sector, we are currently in the process of evolving an industrial boiler standard of performance. From some of the preliminary economic studies we've done, depending again on which way we write the regulation, we can either create a very significant impetus for the installaion of fluidized bed systems or we can limit it. I think that's the way I would perceive myself as a user of the FBC technology.

R.C. Read
International Harvester Co.
Chicago, Illinois

Today I want to share with you my viewpoint with regard to coal in general and fluidized bed combustion in articular. International Harvester manufctures a wide range of industrial capital goods, including turbo machinery, agricultural equipment, construction equipment, and trucks. We are not an energy intensive company; however, we are very energy dependent. Small interruptions in the supply of fuel cause rather significant disruptions to our manufacturing operations. This dependency has reinforced our belief in the necessity to have a reliable source of fuel.

Our strategy with regard to management of energy resources is to concentrate very heavily on using energy prudently. This emphasis on conservation is augmented by our belief that deregulation is the most efficient way to increase fuel supplies. Notwithstanding the above emphasis on conservation and policy, we believe and our internal energy forecast model shows that coal is the most favored fuel NOW. Our index of the relative availability versus cost supports this belief.

If coal is the most desirable fuel, why are we not retrofitting our present facilities? The reason is quite clear. In our view, the cost to retrofit is prohibitive. Our estimate for retrofit of existing facilities is in excess of $100 million. This investment will not provide one additional pound of steaming capacity or 1% more efficient use of energy. The $100 million is a lot of capital and would be equivalent to about $4.5 billion additional sales or an increase of 54% above our record 1979 performance. The difficulty to recover that capital by the offsetting benefit in the cost of coal versus the cost of imported oil is such that retrofitting is not practical.

The problem that we have in embracing fluidized bed technology to the point of implementation centers on our perception of the material handling system being the weak link. Just Wednesday we visited Georgetown, and while it appears that all of the parts of that system work much better than they did at Rivesville, I still am concerned that the pneumatic conveying systems and the bucket hoppers are sources of unreliability and in general a maintenance headache. The material handling system needs to be simplified. I am not sure how you go about transporting all that coal and limestone to and from the fluidized bed combustor; however, the transportation of natural gas or even No. 6 fuel oil to the boiler, is not going to present anywhere near the kind of maintenance problems you are likely to experience with the fluidized bed combustor. The point is this: IH is not an energy intensive industry. We prefer to manufacture capital goods and not steam. We are dismayed at this point that FBC as a technology has received lip service and favorable nods, but it has very few hours of running time. I look at Georgetown as the only example of something that works, albeit partially. They claim to have 800 hours of running time. This is not representative of expected industrial operating conditions. I am not sure that even 8,760 hours of Georgetown would be representative of industrial requirements; notwithstanding their demand of 100,000 lbs. per hour of steam.

How do we get there? In my view, there are several impediments that should be addressed. I believe the country has no energy policy. We have laws that talk about deregulation, use of coal, and conservation. We talk about conservation, yet we have no conservation goal for each sector of the economy. We talk about deregulation and have incremental pricing. It appears that our national leaders do not really believe we have an energy crisis. If indeed there were an energy crisis and if indeed we had an abundant supply of coal, then coal ought to be the policy that we put forward and make other things accommodate it. The impediments to the development of the use of coal are environmental concerns and economics. The use of demonstration projects to illustrate the benefits of emerging coal use technologies are only a partial answer to stimulating the increased use of coal. A more efficient stimulus would be via tax credits for use of abundant fuels and development of emerging technologies coupled with accelerated depreciation.

The last point that I have to make is this: If we believe that the development of coal is the cornerstone of the energy policy in the United States, then we should insist upon and work to develop the environmental laws and regulations that are not a hindrance but rather an encouragement to the further use of this abundant resource. Thank you very much.

David McKee
E.I. DuPont de Nemours, Inc.
Wilmington, Delaware

I'll try not to repeat what I said earlier, but I think all of us in the user comunity have a lot of questions and we don't have a lot of good answers. There are a number of issues that the vendors have to pay close attention to as far as the industrial user is concerned and one of these issues is maintenance of the equipment. We're firm believers in Murphy's Law, that if it can break, it will. Looking at the designs of the tube bundles, I have some nightmares about how we're going to replace those tubes if necessary in service. Certainly the mechnanical handling equipment that Ron just mentioned has been a nemesis of coal since the first day it was shoveled into the furnace. So, I have the feeling that the vendor should tend toward simplicity rather than complexity, minimze the transfer points, minimze the number of times you have to pick it up and lay it down and collect it. But, in general, pay close attention to the maintenance and the operability characteristics of the equipment. It is important to us.

Paul Bobo
Mead Corporation
Dayton, Ohio

I am actually with the Mead Corporation, however, part of my activities relate to Mead Chemical Systems which is a part of the Corporation. A significant portion of our business is the manufacture of pulp and paper and related forrest industry products, however, we also have substantial businesses in other areas. We are a highly capital intensive industry and use large quantities of energy. We utilize fuels of many types; coal, natural gas, oil, wood wastes and chemicals which are converted in the process of burning.

There is an expression that reminds me of the hesitancy of most of us to utilize new technology; "Never on Sunday." However, in this case it is extended to "or Monday, or Tuesday, or Wednesday, or etc." Never be the first to use new major equipment technology seems to be the posture; and continuing: not very likely to be second, maybe third, probably fourth, etc.

While I realize this is a bit exaggerated, I believe it highlights an attitude that all of you, in one form or another, have experienced in the past and will experience in the future in the development and marketing of fluidized bed combustion. As a user and as a participant in the international marketing of new technology, I am aware of the frustrations of the vendor and the needs of the user.

The preceding is based upon valid concerns of a potential user of fluidized bed combustion systems. I would like to be more specific and identify some areas that are important to our industry and require "actual practice validation." It must be remembered that we are not in business to produce steam or electric power, we are in business to produce other products. Our primary focus from the standpoint of capital investment, management, equipment union negotiations, training, maintenance, etc. is on the end products and not on steam and electric power.

1. A wide operating load range capability. This is very important.

2. Fast response to load change. We have many things that occur in our production processes that necessitate this capability.

3. High reliability. While this could be identified as "another motherhood item" I would like to relate to it in further detail, if we have the opportunity to do so later in these discussions.

4. Low maintenance requirements and low number and length of periodic overhauls. We are a continuously operating industry with very few non-operating days per year.

5. Simplicity of maintenance. Our maintenance people are primary maintenance people for the pulp and paper equipment and maintain little expertise in the power areas.

6. Simplicity of operation. Our power department people are basically pulp and paper people who have moved thru, seniority provisions, from and to the production departments.

7. Capabiltiy of multi-fuel firing. Our industry is utilizing more wood waste in combination with coal or gas or oil for economic reasons.

If we have more time during this session, I would like to expand on some of the points that were covered during this short period.

Thank you.

Bruno Brodfeld
Stone and Webster Engineering Corporation
Boston, Massachusetts

As an architect engineer, Stone and Webster is, in a sense, an organization in the middle -- interacting with the users, with the vendors, with the regulators, with the Department of Energy and its funding programs. We have had the opportunity to understand some of the barriers that have been discussed, and I think if we had to reduce to a single most important reason why the users hesitate to adopt on a commercial basis fluidized bed combustion, it is the hesitation to be the "first."

The indusry practice is to count on reliability and the only way to determine reliability is to look at pieces of hardware that are already in operation. So, how do we cross this bridge? One thing to consider is that we have a technology that not only the vendors, but a lot of well informed people, believe has reached the standard of early commercialization. On the other hand, we have the large user community that is hesitant to apply it.

To overcome this hesitation, more government support through well-conceived industrial demonstration programs is needed. I think a great disservice was done to the commercialization process by emphasizing the fact that AFB is a commercial technology at this time and that commercial warranties are being offered to vendors. In our view, even if commercial warranties are offered, and indeed they are offered by some vendors, the weight that they carry is considerably less than the weight carried by warranties for proven commerical equipment. In the latter case, the warranties have behind them long-term experience and background. In the former case, there is very little experience, if any, and very little background, if any, to support the warranties.

How can we call them both commercial warranties when they are so different? This is more than a semantics matter; it has to do with the support that is still needed from the Department of Energy and the government. By calling this technology commercial at this time, in effect DOE has decided that there may be no need or justification for further support of this technology. We think that this is a basic mistake. In our view, this technology still needs support. We're all convinced that it has potentially great merits for this reason.

We think that support is needed in two ways: first, regulatory support, as Bob was saying before, EPA can create windows for this technology. Second, DOE support through the PON Program for commercial development and demonstration should be resurrected as soon as possible with one additional provision: In discussing cost-sharing with industrial users, emphasis must be placed not only on the cost of the AFB facility itself, but also on the cost of possible retrofits, should they become necessary. This is a realistic consideration in any prudent management approach. We have seen more than one case where a major industrial user had determined that they believed in this technology and their projections for the economics of the system were favorable. They wanted to participate in the program, but a stumbling block, in their view, was that the cost sharing should have been applied not only to the cost of the facility itself, but also to possible retrofits, if any. This would have given them the assurance that the risks had been minimized as much as possible.

So, to summarize my comments, if, as a country, we believe that this technology is good, and that it will enhance the utilization of coal, we have to continue to support it, through our regulators and through the Department of Energy. It is only through such continued support that we will find those few industrial organizations that will build the first major AFB plants in the range of 100,000 to 500,000 lb steam/hour, which will be the convincing place of evidence that the rest of the industry needs to move forward.

Andrew L. Jacob
American Electric Power Service Corporation
New York, New York

Coal Utilization is nothing new to AEP. Last year almost 84% of our total 100 billion kilowatts of generation was from coal. In fact, AEP mined almost one-third of our total coal burn of 38 million tons last year. Utilizing our coal resources most efficiently, with a reasonably minimal environmental impact, is of prime importance at AEP. Developing technology to meet this task is also nothing new to AEP. Since the early 1920's AEP has been a pioneer of new technology for the utility industry. When first evaluating FBC systems in 1976, we decided that PFBC offered the potential to meet our coal utilization goals.

In evaluating any new technology, we as a utility look at a number of aspects. These include: current state of the technology, flexibility with respect to coal type, environmental aspects, system complexity, operability, potential reliability and economic projections. A technology that uses a maximum amount of commercially available hardware is favored. This is because operability and maintainability are extremely important to an electric utility. Operability requires that a technology have a fairly wide load control range, at good efficiency, in order to meet the daily requirements of the electric load. Systems that are familiar to our operators and maintenance people simplify plant operation which leads to greater reliability. New technology should have a higher efficiency than current technology. This is most easily accomplished by the direct combustion of coal. Furthermore, projected capital and operating costs for new technologies should be less in order to provide a buffer which may be used up in trying to develop the technology. Of course, the new technology should be environmentally suitable.

We believe that the AEP-STAL-Level PFBC Program considers all these aspects. The state of the technology has been significantly advanced by the excellent results from our experiments at the DOE sponsored Leatherhead 1000 hour test. As we learned this week, both GE and Curtis Wright experiments yielded similar results. Our commercial plant design utilizes a maximum amount of commercially available hardware. Key components such as the cyclone hot gas clean-up system and GT-120 gas turbine are commercial hardware. The combustor design has gone through three years of iteration and has had the benefit of four independent companies review. Auxiliary systems are a key consideration at this point in time. Systems such as coal feeding and ash removal show promise of good performance; but in our program, we will be building a Component Test Facility (CTF) to evaluate their performance in a totally integrated facility.

AEP and our partners are looking forward to commercialize this technology by 1986 by having in operation at that time a 170 MW commercial size PFBC plant. Our test results and those of others presented during this conference seem to be favorable towards this end. I was particularly pleased to learn of the good results from the EPRI sponsored bag filter tests. These devices will be important for second generation PFBC's when we will pursue even higher efficiencies.

While we have gone very far in the development of an efficient and economical PFBC plant there are those who would like to turn the clock back. I am referring to one concept which proposes to use a much lower gas turbine inlet temperature, well below that at which the excellent test results were achieved. Clearly, there is no technical reason to take such a step backward at this time. The cost and effiency advantages of PFBC with a moderate gas turbine inlet temperature would not be realized and future technological advances would be substantially delayed. An evaluation of such a concept, based on each of the aspects I mentioned earlier, would not support going forward. We, as a utility, would not be interested in this concept.

In summary, we believe the technology has made a quantum jump this past year towards the goal of commercialization of PFBC by the mid-80's and AEP is proud of its role. With the continued efforts and aid of industry, and government a commercial size PFBC plant with a moderate inlet temperature will be realized by the mid-1980's.

Thank you.

Jack Apel
Columbus and Southern Ohio Electric Company
Columbus, Ohio

Just a few. I think we're behind schedule. From my own personal perspective, let me say that, on a priority basis, first of all we expect to use coal as we already do. On a priority basis, I would look to coal cleaning as my first priority, prior to combustion. The second priority is during combustion and third priority is after. So, fluidized bed is in the "during combustion" and that is second in my priorities. However, currently available technology does not go far enough on the coal cleaning side, so combustion rapidly moves to the front in that standpoint. I'd rather not spend too much time from a utility perspective further than that, because both Bob and Andy will have viewpoints similar to mine, I'm sure, as far as utility use is concerned. But I thought that you might be interested in the program that the State of Ohio has on fluidized bed and how that came about. The Governor of the State of Ohio, in the spring of 1977, was faced with quite a few problems: losing coal markets, that is coal production, losing industries to other states. He formed a committee of a number of people from a wide cross section of areas of interest and charged that committee with seeking out all of the available technologies and recommending to him what Ohio should do. In that process, the committee looked at a wide number of technologies and it did recommend to him, in I think about the fall of 1977, that a demonstration of fluidized bed combustion would be the nearest available option to the State of Ohio. I think by January of 1978, they had entered into a contract with Babcock Contractors and they began construction of a retrofit 60,000 lb/hr boiler at the Central Ohio Psychiatric Hospital. That unit is in its final construction stages and initial start-up stages right now. That doesn't mean that it is the answer, but the Governor felt compelled to show industry and put state dollars into it. From the standpoint of where or how to do it, it probably is not in exactly an ideal location. It is a retrofit and while the economics may not be very good, it does prove that you can do a retrofit. I can't think of any more difficult a place to try to put a boiler in than that particular installation. It is very constrained as far as access, old equipment and actively operating equipment right beside it.

Nevertheless, I've followed that very closely through the construction stages. When you stand back and look at it through and compare it with some of the other technologies -- sure you have the FB there, but almost all of the components from a power generating standpoint are familiar, they are not that different, and I don't think that reliability is going to be such a terrible problem. It is going to be a problem -- I see it everyplace I have looked -- getting the necessary operator level of skills. How to do that? I've heard several other speakers say they want to do it with their existing operators and I'm not sure that this technology will tolerate that. I think we're going to have to have a whole generation with a whole different attitude toward operation and the maintenance from the former type of plant operation and that's going to take time. That's going to be a hindrance. I'll leave it at that.

Robert E. Uhrig
Advanced Systems and Technology
Florida Power and Light Company
Miami, Florida

There is a recent book out entitled, Quality is Free. The thesis of this book is that the cost of failure is so high in terms of customer dissatisfaction, consequential damages, increased cost or health and safety effects or even the survival of the organization, that you simply can't afford a defective product. Now without arguing the point, I would indicate that some of the public service commissions are now penalizing utilities who have expensive, high-performance systems such as nuclear and coal plants, that have low availability and low reliability performance. I would submit to you that fluidized bed systems will fall into that same category once they are commercialized, and that quality and reliability will be an equally important consideration there. So I'd like to spend my remaining time talking about the quality programs.

Quality programs began before World War II simply as a means of meeting customer satisfaction. During the war, we had ships that broke in half, torpedoes that went under the ship or sometimes over them, guns that didn't fire. So we began what is called today "failure analysis" -- finding out what went wrong. We began to identify those components that failed and concentrate on improving the reliability of those units. We continued through the military and space programs with such ideas as "zero defects" and "error-free performance," with a special application, of course, to the Apollo and Saturn programs, where we had so few such units that we couldn't test out enough of them before we had to put them into service. The ultimate application was the nuclear power plants, the nuclear navy, and now the commercial nuclear program.

We really have two kinds of programs in the quality area. There is a commercial program, which is justified primarily because of the cost reductions. Then there is the regulatory program, where the health, safety and welfare of the public is at stake. I'd like to characterize these two very quickly. In the commercial program, a defect or a non-performance may be an option. In the regulatory program, it is not an option. In the commercial program, the emphasis is primarily on the prevention of failure with less emphasis on testing and inspection. In the case of the regulatory program, inspection and testing is a very critical part of the program. In the commercial program, you have no independent third party audit unless you specifically request it as a means of identifying failure. In the case of a regulatory program, there is an extensive third party audit with a rigorous quality assurance and quality control program developed within the organization. In the case of a commercial program, proof of the program simply relies upon the performance of the equipment. In the regulatory program, extensive detailed documentation is needed -- basically, a paper trail on all aspects of the program. Finally, the penalty for non-performance in a commercial program is usually increased costs or customer unhappiness. In a regulatory program, there are fines, the regulatory organization can shut down your plant, in addition to your probable increase in costs and unhappy customers. The difference is usually a factor of two or, more often, three in the costs of the programs.

In conclusion, I would simply say that the FBS are high performance systems; they are complex and they are expensive and you're going to have to have an adequate quality program that incorporates the pertinent aspects of both of these systems, what I would call an augmented commercial quality program, in order to commercialize fluidized beds.

Thank you.

QUESTIONS/ANSWERS/COMMENTS

Q: Jack Warden, TRW

I've got a question for Jack Apel. What is the current status of your Pickway demonstration and of the Ohio Coal Tax?

A. Jack Apel

Well, that was part of the overall program that the governor had. The Ohio Coal Tax originally was passed with a sliding scale on the sulfur content of the fuel and the low sulfur coals were penalized. That was taken to court and it was defeated as a tax. The moneys from that would have supported several other demonstrations and they still will. There is a new coal tax in the legislature. Its passage is eminent. There are one or two legislators who have questions. The tax is put down as a research and development tax and the legislature questions the research part of it, because they don't think there is more research necessary and nobody has really defined for them what development or demonstration means. But that's really what the State of Ohio and the Ohio Department of Energy means, is to put on demonstrations. The Pickway demonstration was one of four projects that were initially proposed. Here we have an old power plant. We've agreed to shut down two old units that are about 35MG size in June of 1980 with EPA because of lack of controls, and they are at the end of their economic life as far as the boiler is concerned. However, the turbine generators are not in bad shape. There were six previous units that were in this building and they are gone. The boilers have been removed, so there is very wide open space. The coal handling system is still there; it uses Ohio coal and the remaining unit has an emission limit that would not restrict the coal. So, it would have a ready supply. In other words, it's a Reesville without the problems of Reesville.

Q: (Name inaudible)

I have a comment and it may be interpreted as a question. Many of the panelists here mentioned that the basic problem in the commercialization of fluidized bed combustion technology is reliability. The reliability can be obtained on any engineering plant in two different ways. One way which is very well known, just operate it, when it goes wrong, correct it and start operating again without worrying about how the wrong occurred or what caused it. The second aspect of this is to understand, and actually this was expressed in the morning session, what goes on in the fluidized bed from the mechanism point of view, from the scientific point of view. A large community of university professors agree with me, and I'm sure I am speaking for them, that not only the Department of Energy, but also the industry gives very little cooperation other than lip service, in supporting the research. I am sure I am speaking for a large number of professors sitting here that in order to accomplish this concern of reliabilities in marketing, we should be given due support, something similar to what we had when the space industry began.

A: Shelton Ehrlich

I think that EPRI will answer the question because it does support and so does the Department of Energy, but I'm in charge of the university research on fluidized bed combustion at EPRI. We do as much as we need. Our problem today is that we don't know how the system is going to be configured; we're waiting for the empiricists, if you want to call them that, to decide whether FB is round or square. When we figure that out, then there's something to be modeled. I think that Bill Reid, who spoke to that issue in the first panel, would agree with that perspective. In fact, he outlined the fact that both stokers and pulverized coal combustion were derived by empirical means and then people grew to understand them.

Q: John Caukle, Bud Company, Philadelphia, Pennsylvania

I have a question for Mr. Brodfeld. You assert that we're not at the commercial stage yet in fluid bed technology. Given the rate of advancement that we've seen, how far down the road do you see this?

A: Bruno Brodfeld

I think the comment was made this morning by Dave McKee which I fully subscribe to that it would take something like five years, maybe a few years more to see the plants in operation in order to be fully commercialized. But let me make one point clear, when I say it's not commercial yet, it shouldn't be taken literally. It may be in a stage of early commercialization, which means that it's on the threshold of commercialization. It requires now, verification, and this is the issue at hand. How do you convince industry to get involved with this process of verification so that then the free forces of the market take over?

Q: Doug Willis, National Coal Board

I would like to make one comment. I think that the present stability of the industrialized society depends upon the knife edge and that the knife edge is the energy situation. The question that I want to ask the hard-nosed industrialist is -- well I have two questions and I'm really concerned about the conversion from oil to coal, not from one technology to another -- What do you regard as a reasonable payback time, in the light of your corporate strategy, for the different industrialists?

Secondly, if you had a retrofit situation where the capital costs were, say 70% of the cost of a new installation, would you regard that as a better commercial venture than going for a new plant?

A: David McKee

I'll try to give you one answer. In our corporation, we're looking at paybacks a little differently these days than we used to. I'm sure there are many people in the audience who are used to looking at paybacks in two, three of four year paybacks for product investment. With the changing money market and the inflation rate, we've gone away from looking at NROI's on the third year basis as a prime consideration, and we're starting to look more at investors' methods of return, which involve discounting cash flows, accelerated depreciation and the real value of money with time. We're finding that everybody has a cost of capital and that differs from company to company depending on how you do your financing. But certainly when the investors' method of return is greater than the cost of capital, you have something you might look at very seriously, whereas that same project might have a net return on the third year basis that is unacceptable from standard criteria that you've used in the past. So, we're changing the way we look at things because of the market situation. The predictions that you saw in one of the paybacks -- again, this depends on a couple of things that are very sensitive. One is the ever widening split in price differential between oil and coal and whether that is really going to happen or not, your crystal ball is as good as mine, I have the feeling in the bottom of my stomach though, that the price of coal is going to start creeping up and that split may not be as wide as we all think it might be. There's a lot of speculative information you have to rely on to make these long term commitments for big capital. It's a tough job today and I'm not making light of it. We have retrofitted coal fired installations more times than we wish to admit; we've had coal units go to oil then to gas, back to oil, then back to coal again. So we've gone the full circle. That is a site specific question that depends somewhat on the usable life of the equipment. If we are retrofitting a relatively new installation which has another 20 years of life in it as far as we're concerned with minimum maintenance, we'll look at that one pretty hard. Where at the 25 year point on a unit, we're going to look at that very hard because probably the combustion controls are outdated, the material handling equipment is probably in need of great investment. It's hard to give a good number for that. I think it needs to be a site specific evaluation.

Paul Bobo

With regard to the financing of projects in the company, they necessarily compete with each other and therefore use of criteria of internal rate of return which takes into account the cost of money, the effect of taxes, and depreciation is important. If, indeed, you are only recovering your capital, by mitigating the taxes and accelerating the depreciation and the difference in the price of the fuel and you're competing against the development of a new product which is a revenue generator and not a cost avoider -- you can see where the difficulty comes in. Typically, however, there is some insurance you need to buy. In our industry, projects seem to get funded when the internal rate of return is above 30% and I'm not sure where that relates to payback. But that is considerably over the cost of oil.

Q: Earl Oliver, SRI, International

I have a question for the industrial participants. It's been stated that there is a reluctance to go into investment in the new technologies until they have been well proven. In this case, I note that the large water tube boilers are not being built of the conventional kind either, at this time. It seems there is a great slump in the market. The question would be -- When the market resumes, will this be before the FBC is ready? Will it be more competitive at that time? Also, the regulatory incentives that have been given by EPA, do you think they are of any significance compared to other technologies?

A: David McKee

As far as the regulatory incentives, we don't see any market change in the regulations affecting fluidized bed vs. other technologies. Certainly, the least attention has been paid to NO_x regulations in the past. They will probably be the ones that will get the most attention for coal combustion. I've been involved in stage combustion of coal and pulverized firing and other applications and that doesn't come without some operating penalties and headaches. It can be done and it can be done fairly reliably but it changes your method of operation. You have people that understand what's going on a little better than a fellow that came in off the street and was made a power operator yesterday. I don't think I can really respond to the first part of your question adquately. I think the market is highly fluid and whether this technology will hit the right window or not, your guess is as good as mine. I think it has the best chance of any in the near future. But we do appreciate the position the boiler vendors are in. They're out there raising capital too. It's a tough market place.

Arnold Kossar

I'd like to make a response. I think the first part of the question is -- Why don't industrial users buy coal fired boilers of any kind? Maybe I can answer the question this way. We had an opportunity to buy a boiler and did buy a boiler recently. It was an 80,000 lb/hr boiler. We could have used coal. Coal was used at this site at one time. And here's how the scenario works. To buy the 80,000 lb/hr gas-oil boiler cost slightly under $1 million. To put the coal boiler in and to retrofit the attendant equipment, it would have been slightly over $5.5 million.

David McKee

I might comment on one other thing. In our company, our energy conservation efforts have been tremendous in the last eight years. We've looked at saving a pound of steam and how much investment we can afford to save that pound of steam, and it was closely, if not more closely, than what it would cost to go out and buy a new pound of steam with coal. But I think you heard numbers like $100, $125/lb in our installed cost. They are generally in the range that we feel are realistic. If you look at your IMR's and your discounted cash flows and how much you can afford to spend to save that pound of steam, you might be amazed at how much money you really can spend to do good solid energy conservation work. I think we're seeing that in our company. Our energy requirements per pound of product have continually dropped over the last eight years, whereas our productivity is continuing to climb, and that puts money in the bank. This is a tremendous incentive for evaluating all your processes and the way you do things, and we had little increase in our steam demand. If you look at our future picture, we've looked so hard at some processes that we're finding out we are going the other way -- our steamloads are going down. So that's why we haven't been buying some boilers.

Q: Sven Jansson, STAL-LAVAL

I'd like to make a general comment and then a technical comment. Steve Freedman started out with this discussion by saying that he wanted the panel to serve as the wise men looking at the elephant and I think a lot of what's been said here has illustrated that he reached his goal very admirably. What I hear are lots of views given by people who have a small part of the picture, but not necessarily the full picture. What I would like to say is that I think fluidized bed combustion is here, gentlemen, it is coming, AFBC and PFBC are here and they are coming; there is no way that can be stopped. Therefore, the real big question here comes to the following: It is, how quickly do we want this to evolve and that depends on the need that we see and that is a national type of consideration, but it's also a corporate type of consideration. Now, when you look at that question -- how quickly do we want it to happen -- then you've got to ask, how can we make this come about quickly. Well, the least effective of all ways is to start university programs. I'm an R&D man myself, but I have to say this, because then you only look at the little leg or the little toe of the elephant. What has to be done is to get some figures in rather quickly to identify those important problems, not those that we necessarily are thinking of today. There is a little book which I'd like to recommend to everyone which is called Murphy's Law and Other Reasons why Things go Wrong, and you can pick it up at airports. In it is purist law, and it says, the solution to a problem changes the nature of the problem, and this is exactly what we are up against. We've got to find out, therefore, what the problems are.

Arnold Kossar, Session Co-Chairman

I aprpeciate the reference to the book. I don't think your comment requires any answer. To try to summarize rather briefly, we have had a rather consistent emphasis by the panelists on what the Defense Department calls the "ilities" -- reliability, maintainability, availability. This is the key, especially to the industrial people who say, I'm out there to build products not steam, and I can't afford to have that thing back there in the corner screw me up either, in terms of coal supply or operation on line or from a maintenance point of view because I can't afford to be down very long before my profit plan for the year has been shot in the head. The utility people haven't said it quite in those crass terms, but they get at it too, because they're controlled. They can't sell the product in quite the free market concept that the industrial people can. So what I find here, though, is some difference. The industrial people who tend to be less coal dependent are expressing the concerns in rather stronger terms, I would say, than the utility people, especially since the utility people have some familiarity with coal to begin with and have learned to live with its problems of today. I think one point that was made that was quite keyed to the bulk of us as technologists, was that you've got to consider the kind of maintenance crew that is normally available in the industrial environment -- and I could say -- also in the utility environment. The fluidized bed processes are somewhat complicated. Now the answer that, I'll automate that system for you, just ain't enough because, as you know, we had an experience at Three Mile that showed us that hardware errs also. We had a session on instrumentation and control here that was, I think, the first one at one of these conferences. I'll be frank, I pressed for it, but I was disappointed in the number of papers that showed up and even more disappointed in the number of participants in the audience. But, the manageability of any system, by people, is a key part of any of these technologies. Now, I won't get into the argument of whether the equipment is or isn't commercial yet. I agree with the last point made that the technology is at a point where you need large scale demonstration in order to develop the confidence, that will take, perhaps, several levels of demonstration. That's what worries me a bit, how many times will it have to be done before the customer feels comfortable with it? I won't try to expand on that one, but I can see a long time going on if the process is indeed sequential. The other point made, that if the government sees a role in stimulating this move toward less dependence on imported fuels, it's going to have to put its thinking cap on in a more collected manner perhaps than has been done today.

I thank you all for coming.

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