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Summary of the Research and
Development Effort on Steam
Plants for Electric-Utility Service

A. P. Fraas

Fossil
Energy
Program

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DEPARTMENT OF ENERGY

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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, Virginia 22161
NTIS price codes—Printed Copy: A04; Microfiche A01

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Contract No. W-7405-eng-26

Engineering Technology Division

SUMMARY OF THE RESEARCH AND DEVELOPMENT EFFORT
ON STEAM PLANTS FOR ELECTRIC-UTILITY SERVICE

A. P. Fraas

Date Published - June 1981

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OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
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ACKNOWLEDGMENTS

Among the many who helped provide material for this report, a special debt is owed M. L. Myers of ORNL, who supplied a wealth of material from his personal files. Others who were particularly helpful include E. L. Daman of Foster-Wheeler, R. T. King and G. Samuels of ORNL, together with D. M. Willyoung, J. L. Mangan, and W. B. Wilson of the General Electric Company.

SUMMARY OF THE RESEARCH AND DEVELOPMENT EFFORT ON STEAM PLANTS FOR ELECTRIC UTILITY SERVICE

A. P. Fraas

ABSTRACT

The development of steam power plants for electric utility service over the past century is reviewed with particular emphasis on the prime problems and their solution. Increases in steam pressure and temperature made possible by developments in metallurgy led to an increase in thermal efficiency by a factor of 8 between 1880 and 1955. Further improvements have not been made because the use of still more expensive alloys is not economically justified, even with the much higher fuel prices of the latter 1970's. In fact, EPA regulations on waste heat and sulfur emissions have led to the use of cooling towers and wet limestone stack gas scrubbers that cause a degradation in plant thermal efficiency. The various possibilities for further improvements in efficiency and their problems are examined.

The development of steam power plants in the past has been carried out in sufficiently small steps that the utilities and the equipment manufacturers have been able to assume the financial risk involved; but the fluidized-bed combustion system, which appears to be the most promising area, presents such a large step with major uncertainties that U.S. government financial support of the research and development effort appears to be required. The potential benefits appear to justify the research and development cost many times over.

INTRODUCTION

This is one of a series of topical reports reviewing the research and development (R&D) effort on one of a set of advanced energy conversion systems.¹ The first portion of each report briefly summarizes the background by giving a chronological history of the research and development effort on the system up to 1976 along with the cumulative costs and system operating times. The next section points up the significant problem areas and recommends experiments deemed most likely to resolve these problems. This is followed by a more detailed discussion of the principal problem areas, performance parameters, and figures of merit characteristic of the system, together with the current status of the development

work, with particular reference to progress in improving the principal performance parameters.

This report represents a special case in that it is concerned with the well-established steam system on which our whole economy is based. It serves as the basic reference system against which the others can be compared.

This work was carried out at the request of the Office of Program Planning and Analysis of the DOE Fossil Energy Program using funds provided for a general appraisal of advanced fossil energy systems.

BACKGROUND

The development of steam plants for utility service in the U.S. began with the construction² of the Brush Electric Light Company plant in Philadelphia in 1881. Construction of other plants followed rapidly throughout the country to satisfy the need for electric power for lighting and for electric street railways.^{3,4} Initially, single expansion reciprocating steam engines were employed. By 1890, double-expansion engines and shortly thereafter triple-expansion engines became common, leading to increases in steam pressure and temperature. By 1900, the advantages of a steam turbine in permitting a still greater expansion ratio became apparent, and in 1904 the first steam turbine in U.S. utility service went into operation giving a higher thermal efficiency than any reciprocating engine in service.³⁻⁸ Whereas overall expansion ratios of more than 100 were not practicable in reciprocating engines and hence there was no incentive from the standpoint of thermal efficiency to go to steam pressures in excess of about 10 bars (150 psi), a steam turbine could employ much higher expansion ratios to good advantage, thus leading to fairly rapid increases in both temperature and superheat. Note also that lubrication considerations in reciprocating steam engines limited the peak permissible steam temperature to around 180°C (350°F), but this limitation did not apply to steam turbines.

The rapidly increasing size of power plants led to the development of traveling grate and other types of mechanical stoker, and these rapidly displaced hand-fired boilers.³ Improvements in metallurgy made possible

higher strength steels with greater resistance to corrosion, thus leading to further increases in pressure and temperature throughout the 1920's together with concurrent increases in unit size.⁴ At the same time, refinements in the thermodynamic cycle were made to improve the thermal efficiency by reheating,⁹ regenerative feed heating, and air preheating. Improved methods of feedwater treatment eased the corrosion problems on the steam side and reduced maintenance.²

By 1930, developments in both electric welding techniques and x-ray inspection of welds made it possible to go from riveted header drums with rolled tube-to-header joints to welded header drums, tube-to-header joints, and plant piping.² This in turn permitted marked further increases in the system temperature and pressure to around 170 bars (2450 psi) and 565°C (1050°F), so that by 1950 central station steam plants had virtually reached the operating conditions current at the time of writing.^{10,11} Concurrently, the reliability of boilers and turbines increased sufficiently that the initial practice of manifolding a multiplicity of boilers to a multiplicity of turbines was dropped in favor of independent units with each boiler coupled to a particular turbine. This simplified the piping (particularly provisions for thermal expansion) and eliminated many large shutoff valves which gave a great deal of trouble when used at high temperatures and pressures. In the 1950's, the once-through boiler came into use and was almost immediately applied to produce supercritical pressure steam, commonly 240 bars (3500 psi) and 565°C (1050°F).¹²⁻¹⁶ A flowsheet for a typical modern plant¹⁷ is shown in Fig. 1.

The highlights¹⁸ of this long developmental history are summarized in Table 1 and Fig. 2. Note the steady increases in pressure and temperature up to 1957, with a concomitant increase in thermal efficiency but with no further significant increases in any of these three parameters in the subsequent 20 years. Subsequent efforts up to the early 1970's were directed primarily toward increases in both reliability and in unit size; the latter effect is also shown in Fig. 2.¹⁸ However, the reliability and availability¹⁹ of units have declined with increasing size, as indicated in Fig. 3. This stems in part from the increase in the number of boiler tubes; for a given probability of a tube failure,

Fig. 1. Conventional utility steam cycle.

Table 1. Principal developments in steam power plants for utility service

Period	Typical parameters for new plants				Principal developments
	Peak temp. [°C (°F)]	Peak press. [bars (psia)]	Unit output (MW)	Full load thermal effic. (%)	
1880-1890	173 (344)	8.6 (125)	0.3	5	Generators belt-driven from reciprocating steam engines with hand-fired boilers
1890-1900	173 (344)	9.0 (130)	0.7	7	Double- and triple-expansion engines with Corliss poppet valve gear introduced
1900-1910	181 (358)	10 (145)	1	10	Steam turbine with steam superheat came into common use with mechanical coal stokers
1910-1920	293 (560)	19 (275)	10	15	Steam pressures and temperatures increased somewhat and sizes and efficiency of turbines much increased
1920-1930	385 (725)	38 (550)	25	25	Large pulverized coal-fired boilers introduced with new furnace designs employing water-cooled walls with steam reheat, regenerative feed water heating, and combustion air preheat; turbine sizes increased to as much as 100 MW; feed water treated
1930-1940	482 (900)	62 (900)	50	32	Arc-welded construction and new alloys permitted marked increase in pressure and temperatures: large steam generators and turbines combined into single units (to eliminate troublesome valves) replaced former multiplicity of small boilers (as many as 60 in one powerhouse) manifolded to a multiplicity of turbines; control of feed water chemistry improved
1940-1950	538 (1000)	83 (1200)	150	36	Higher pressures and temperatures came into use with further improvements in alloys and control of feed water chemistry; further increases in unit size
1950-1960	566 (1050)	165 (3500)	300	38	Once-through and supercritical steam pressure systems came into use; turbine designs improved to tolerate and remove much more moisture, thus permitting use of saturated steam from nuclear plants; unit sizes increased further and still better control of feed water chemistry was obtained
1960-1970	566 (1050)	240 (3500)	500	39	Unit size further increased
1970-1980	538 (1000)	240 (3500)	1000	36	EPA requirements led to widespread introduction of cooling towers, stack gas scrubbers, and improved particulate removal equipment, all causing losses in plant efficiency; further increases in unit size

Fig. 2. Historical development of advanced turbine-generators.¹⁸

Fig. 3. Averages for 1965-1974 EEI availability data for fossil fuel steam turbine units as a function of unit size.¹⁹

the probability of a forced outage from a boiler tube failure increases with unit size so that boiler tube failures become a larger fraction of the total outages. As a consequence, the trend toward even larger units seems to have been reversed in recent years (see Fig. 4).¹⁹

Since passage of the Environmental Protection Act of 1968, the prime emphasis has been on the reduction of stack gas emissions and the effects of waste heat rejection; both efforts have led to reductions in thermal efficiency.

ORNL--DWG 78-2064

Fig. 4. Average and maximum size of fossil fuel steam turbine units as a function of the year in which they were ordered.¹⁹

Current Development Effort

The principal concern in the 1970's involved a reduction of emissions from central stations. This work included marked improvements in electrostatic precipitators to remove particulates, bag houses for even better

removal of particulates, stack gas scrubbers to remove SO_2 , and improvements in furnace and burner design to reduce the emission of oxides of nitrogen.²⁰⁻²² Most of this work has been carried out by superimposing new equipment on existing power plants. In addition, work has been under way to remove sulfur from the fuel before it is fed to the burners, by beneficiation, by solvent extraction of sulfur from coal, or by a coal gasification or liquefaction process that includes removal of the sulfur.^{23, 24}

Several small-scale efforts to develop fluidized-bed coal combustion systems have been under way since the middle 1950's.^{25, 26} This process has the advantage that if the coal is burned in a fluidized bed of limestone or dolomite, the bulk of the sulfur can be reacted with the lime to form calcium sulfate, thus drastically reducing sulfur emissions and avoiding the wet stack gas scrubbers and their attendant maintenance problems (which commonly add ~30 men to the plant operating crew). A pilot plant designed to produce 30 MW(e) has been built at Rivesville, West Virginia, and is undergoing shakedown tests at the time of writing.²⁷

A series of both generalized and specific design studies of fluidized-bed coal combustion systems for utility, as well as industrial and institutional applications, have been carried out to show the potential of fluidized-bed furnaces coupled to steam boilers.^{15, 28-36} These studies indicate that the atmospheric-pressure fluidized-bed coal combustion system gives a modest improvement in both thermal efficiency and costs compared with conventional pulverized coal-fired furnaces with stack gas scrubbers.^{16, 28-36} Pressurizing the furnace to ~10 atm for a gas turbine-steam cycle gives a marked reduction in furnace capital costs and some increase in thermal efficiency, but it presents gas turbine erosion and deposit problems so formidable that an economically attractive solution is doubtful for gas turbine inlet temperatures above ~600°C (1110°F).^{37, 38} However, the same body of experience indicates that erosion and deposit problems would be tolerable if the gas turbine inlet temperature were kept at 540°C (1000°F) or less.³³ This would give sufficient turbine output to drive the compressor to supercharge the furnace to 3 to 6 atm.³³ Although the turbosupercharger would not yield any electrical output, it

would greatly reduce the size and capital cost of the furnace and give a thermal efficiency intermediate between that for the 1-atm bed-steam cycle and that for the 10-atm bed combined cycle.³³ Note that over 100 Velox boilers have been built by Brown Boveri for oil firing, clearly demonstrating the commercial practicality of turbosupercharged furnaces for steam plants operating with clean fuels.

Cost of Developmental Efforts

The bulk of the developmental effort on central station steam plants has been in the form of a series of small incremental improvements.¹⁷ Gradual improvements have been made in the steel alloys for steam generators and turbines and have led to gradual increases in steam temperatures and pressures.³⁹ Even major steps, such as the introduction of turbines, the use of reheat, the introduction of traveling grate stokers and later of pulverized-coal burners, and once-through and supercritical pressure boilers, have involved modest risks that could be assumed jointly by the electric utility and the equipment manufacturer.

A subtle but important role in the development of steam systems has stemmed from development work carried out for naval vessels. Parsons' initial work on steam turbines, for example, was centered for a time on the development of a motor torpedo boat. Incidentally, the boat achieved a speed of 32 knots in 1904, a fantastic achievement at the time. The U.S. Navy strongly supported developments for increased pressures and temperatures as a means of reducing the size and weight of both boilers and turbines.

Efforts to estimate the cost of these developmental efforts have yielded too nebulous a set of numbers to be meaningful. Clearly, an enormous amount of money has been spent. For example, outages associated with the shakedown of a new piece of equipment in a power plant may run as much as \$750,000 per day because of overhead charges,¹⁸ and there have been numerous instances in which shakedown difficulties with new equipment have resulted in outages of as much as a year. The cost of each of these to the utility involved has been high. However, once such a plant

is shaken down, the reduced fuel consumption because of the higher efficiency or the reduced operating costs because of increases in unit size have often repaid the shakedown cost in only a few years. Thus, the real secret of the successful financing of the development of steam plants by equipment manufacturers and private utilities has been that the incremental improvement in any given case has been relatively small and the risk involved has been within the financial capacity of the companies involved. Still, one must admire the men who have had the courage to stake their professional reputations on new developments that involved substantial risks.

The most promising concept currently under development for steam plants is the fluidized-bed coal combustion system. This shows promise of increasing the plant thermal efficiency, reducing capital costs, and reducing solid waste rejection. However, the limited experience with fluidized-bed coal combustion systems for steam generators is insufficient to provide a sound basis for the design of a large plant. Many small experimental units have been run, some very successfully, and one unit for a 30-MW(e) plant is undergoing shakedown tests at the time of writing.²⁸ However, experience with the petroleum catalytic cracking units and other fluidized beds employed in chemical processing indicates that scale effects can be pronounced. For example, the limited data on fireside corrosion shows wide variations in fireside corrosion rates from one test to another. Thus, much further work on the basic technology of fluidized-bed combustion systems is needed.

The total cost of the U.S. effort on fluidized-bed coal combustion systems up to the time of writing has been about \$50,000,000 and the total running time on the units in U.S. programs (including work in England funded by the U.S.) has been ~20,000 hr.

RECOMMENDATIONS

The operating experience with fluidized-bed coal combustion systems for steam generators indicates that the basic technology required for the design of these systems is not well in hand, and a great deal of work is urgently needed. If this work is to be carried out and the

results disseminated expeditiously to those who can use them to advantage, much of the work will require Government funding. The principal areas requiring attention are as follows:

1. Effects on fireside corrosion of choice of alloy or coating, bed temperature, metal temperature, type of coal, type of limestone, average fuel-air ratio, air velocity through the bed, particle sizes of coal and limestone, furnace pressure, coal sulfur content, and the calcium-sulfur ratio. Other even more subtle factors such as furnace design will also be important.

2. Long-lived coal feed and metering equipment is required to maintain a closely controlled fuel feed rate. This work must be closely related to methods of coal preparation and the specification of permissible moisture content.

3. The spacing of coal feed ports and their position in a fluidized bed influences the extent to which there may be local variations in fuel-air ratio and hence the possibility of local fluctuations between oxidizing and reducing conditions (which would have a major effect on the fireside corrosion rates). The greater the spacing, the fewer the number of coal feed points and the less expensive the coal feed and metering system but the greater the tendency for local variations in the fuel-air ratio. This problem will require extensive testing in fluidized-bed coal combustion systems having cross-sectional areas of at least 4 m² and possibly as much as 10 m².

4. Reduction in capital costs for the fluidized-bed furnace can be effected if the furnace pressure is increased.^{16,29,33} This can be best accomplished if the compressor employed to pressurize the furnace is driven by a gas turbine utilizing the products of combustion. However, extensive experience with gas turbines operated on the products of combustion of coal indicates that turbine bucket erosion and deposits severely limit the life of the turbine, and the problems become progressively more serious as the turbine inlet temperatures increase. Particulate removal equipment currently available will permit turbine inlet temperatures as high as 600°C (1110°F).^{37,38} Further tests are needed to

determine whether this limit is in fact acceptable and would permit operation of a free turbine-driven supercharger to maintain a furnace pressure of 3 to 5 atm (which appears to give a very useful and economically attractive system) or whether higher turbine inlet temperatures can be obtained, in which case the gas turbine might also produce some useful power.

PRINCIPAL PROBLEMS AND PARAMETERS

The principal items discussed in this section fall into one of three categories: metallurgical developments, design parameters affecting thermal efficiency and costs, and fluidized-bed coal combustion systems. Metallurgical developments are presented first because this effort has largely paced the rest of the work. The design parameters affecting efficiency and cost are treated next, while the special problems of fluidized-bed coal combustion systems (the principal area seen for future development) are treated in the last part of this section.

Metallurgical Developments

Tremendous developments in the strength and corrosion resistance of steel alloys took place in the period from 1910 to 1950.³⁹ Much of this work was done by the steel companies, and major contributions were also made by the boiler and turbine manufacturers. Some of this, of course, entailed the development of various alloys, but important elements included improvements in melting and fabrication practice.

Welding

Perhaps the most significant single development was the improvement in shielded-arc electric welding techniques to yield sound welds in header drums, and the validation of the soundness of the welds by x-ray techniques to the point where this procedure was accepted by both the U.S. Navy and the ASME Pressure Vessel Code by 1930.² The riveted construction previously employed was not only clumsy and more expensive, but it also limited the thickness of the plate used in fabricating header drums

to about 5 cm (2 in.) and thus limited both the size and the pressure that could be used readily in a steam boiler. Welding was soon applied not only to header drums, but also to tube-to-header joints and to the fabrication and installation of plant piping so that flanged joints in high-temperature, high-pressure steam systems quickly became a thing of the past. This cut both initial capital costs and maintenance costs.

Creep strength of alloys

Creep strength considerations become important in low-alloy steels for temperatures above 430°C (806°F) and become completely dominant for all Fe-Cr-Ni alloys above 540°C (1004°F). The importance of the effect is shown in Fig. 5, which shows the ASME allowable stresses for several representative alloys employed in steam power plants as a function of temperature.

In choosing an allowable stress for a particular component in the design of a steam generator, one must consider not only the temperature

Fig. 5. Effects of design temperature on the ASME Pressure Vessel Code allowable stress for four typical alloys.

difference between a heated tube wall and the steam flowing past it, but also hot-spot effects stemming from deviations from ideality in the temperature and velocity of the hot gases flowing over a tube bank together with deviations from ideality in the steam flow distribution through the tube bank. Thus, the allowable stress must be based on the peak metal temperature to be expected in a perverse tube in which the steam velocity would be lower than the average, the steam temperature would be higher than the average, and the external hot gas velocity and temperature would both be higher than the average. Thus, in choosing an allowable stress for a superheater tube designed to produce 565°C (1050°F) steam, one must allow for a temperature drop from the tube wall to the steam of around 50°C, a temperature drop through the tube wall of perhaps 25°C for an average tube, and about double these values for a perverse hot tube. As a consequence, steam generator designers commonly take a value of perhaps 650°C (1200°F) as indicative of the highest local metal temperature in the superheater tube matrix. It is evident from Fig. 5 that this greatly reduces the allowable stress from the value one might first expect to be applicable [i.e., that for the steam outlet condition of 565°C (1050°F)].

Superheater tubes are commonly made of 5-cm-OD (2-in.) tubes. For a steam pressure of 240 bars (3500 psi), Fig. 6 shows the tube wall thickness as a function of tube wall temperature for the alloys of Fig. 5. In practice, it has been found impractical to use a tube wall thickness greater than the inside radius of the passage.

In attempting to increase the strength of the steel alloy by using progressively greater amounts of expensive alloy materials, one finds that the cost of the material increases rapidly. Further, the higher alloy materials are more difficult to fabricate. In practice, it has been found that the austenitic stainless steels containing about 18% chromium and 8% nickel are about as expensive as can be justified.^{16,29,40} An indication of this effect on costs is given by Fig. 7.

Fireside corrosion

Fireside corrosion is a major factor limiting the peak temperature of steam generators.⁴⁰⁻⁴² The oxidation resistance of steels is markedly

Fig. 6. Effects of design temperature on the wall thickness of 5-cm-OD (2-in.) tubing of four typical alloys for operation at 240 bars (3500 psi).

increased by the addition of chromium because a protective layer of chromium oxide forms under oxidizing conditions. Note that it is essential that the atmosphere around the metal not fluctuate from oxidizing to reducing conditions because this leads to very rapid oxidation attack. Substantial amounts of chromium in a steel tend to make it brittle, but this can be corrected by the addition of nickel — hence the use of the 18% Cr-8% Ni stainless steels.

Fireside corrosion presents an exceedingly complex set of problems. For the relatively high chromium-nickel alloys such as the 18% Cr-8% Ni stainless steels, the attack by oxidation takes place very slowly even at temperatures of 870°C (1600°F) if the fuel is a pure hydrocarbon and there is also a small excess of oxygen. If the amount of sulfur in the fuel exceeds about 0.3%, corrosion proceeds much more rapidly. If, in addition to the sulfur, there are the alkali metals sodium and potassium

Fig. 7. Effects of design temperature (and hence tube wall thickness) on the cost of 5-cm-OD (2-in.) tubing of four typical alloys for service at 240 bars (3500 psi).

and also vanadium and/or chlorine, attack can proceed very rapidly indeed.⁴¹ This apparently stems from the fact the liquid alkali metal sulfates and vanadates vaporized in the flame will condense out on metal surfaces in the 650 to 732°C (1200 to 1350°F) range, resulting in a highly corrosive liquid film⁴² (see Fig. 8). The problem is too complex to treat here other than to indicate its magnitude and complexity by pointing to Fig. 9 and Tables 2 and 3. These data are from a set of tests in which racks of specimens were suspended in the superheater

Fig. 8. Comparison of liquid- and gas-phase corrosion rates on 321 stainless steel.⁴²

region of each of a set of power plants chosen to give a wide range of fuel conditions.⁴³ In each case the rack of specimens was placed in a region such that the local gas temperature was 732°C (1350°F). The original intent was to expose the specimens for 6 months, but the corrosion rate was monitored in the two stations known to have the most severe corrosion conditions. The specimens in these stations were checked at the end of 3 months and found to be so severely attacked that further testing was inadvisable. It was then decided to terminate the tests of the other sets as well. As a consequence, the exposure time varied from 90 to 160 days; the shorter periods of exposure were for the stations with the most severe corrosion conditions and the longer periods for those with the least severe conditions. Inspection of these data shows clearly that the corrosion rate of most of the materials with clean fuel was quite acceptable, whereas

Fig. 9. Subsurface attack on test materials in various combustion atmospheres.⁴³

Table 2. Test materials (from Ref. 43)

Material	Composition (%)									Other elements
	Fe	Ni	Cr	C	Mn	Si	P	S	Mo	
16-25-6	Balance	24.8	16.3	0.08	1.7	0.34	0.017	0.012	5.95	0.146 N ₂
AISI 309S	Balance	13.8	23.7	0.09	1.4	0.58	0.020	0.012	0.03	0.132 N ₂
AISI 310	Balance	20.3	25.2	0.08	1.7	0.75	0.013	0.015	0.02	
AISI 347	Balance	11.1	17.2	0.06	1.6	0.58	0.013	0.017	0.02	0.73 Cb
AISI 308	Balance	10.0	20.8	0.06	2.0	0.38	0.025	0.008	0.24	
AISI 309	Balance	14.54	23.12	0.13	2.0	0.40	0.025	0.003	0.15	
AISI 314	Balance	21.45	24.56	0.09	1.3	2.20	0.024	0.011	0.13	
AISI 321	Balance	10.36	17.72	0.07	1.4	0.47	0.025	0.010	0.15	0.45 Ti
AISI 304	Balance	8-11	18-20	0.08 max	2.0 max	1.0 max	0.04 max	0.03 max		
AISI 316	Balance	10-14	16-18	0.10 max	2.0 max	1.0 max	0.04 max	0.03 max	2.0-3.0	
17-14 Cu-Mo	Balance	13-15	15.5-17.5	0.151	1.0	1.0	0.04	0.03	1.75-3.0	0.15-0.45 Ti 0.35-0.65 Cb 2.5-4.0 Cu
Inconel	10 max	70 min	11-15	0.15 max	1.0 max	0.5 max				
Illium G	6.0	58	22		1.2	0.4			6.0	6.0 Cu
Aluminized mild steel	Aluminum-coated samples of cold-rolled steel									

Table 3. Corrosion data for material exposed to various combustion atmospheres (Ref. 43)

Alloy	High-sulfur, high-vanadium fuel oil			High-alkali content coke and blast-furnace gas		
	Weight loss (g/in. ² /mo)	Decrease in diameter (ipm) ^a	Max. depth subsurface attack (in.)	Weight loss (g/in. ² /mo)	Decrease in diameter (ipm) ^a	Max. depth subsurface attack (in.)
	<u>Sewaren Station</u>			<u>Penwood Station</u>		
Aluminized steel	1.451	b	None	2.535	b	0.008
Illium C ^o	0.835	0.0062	0.002	1.290	0.0093	0.036
Inconel	0.455	0.0032	0.009	1.762	0.0134	0.035
17-14 Cu-Mo	d	d	d	1.808	0.0139	0.010
AISI 316	2.020	0.0156	0.006	0.785	0.0061	0.008
AISI 308	0.543	0.0042	0.001	0.618	0.0048	0.001
AISI 321	3.452	0.0266	0.002	0.945	0.0075	0.005
AISI 314	0.867	0.0068	None	0.078 ^e	0.0006	None
AISI 309	0.681	0.0052	None	0.493	0.0038	0.002
AISI 304	1.439	0.0110	None	0.783	0.0061	0.005
AISI 347	1.492	0.0114	0.001	0.643	0.0049	0.003
AISI 310	0.310	0.0023	None	0.048 ^e	0.0004	0.005
AISI 309S	0.183	0.0013	None	0.210 ^e	0.0016	0.001
16-25-6	d	d	d	0.810	0.0062	0.008
	<u>Natural gas and Illinois coal</u>			<u>High-sulfur oil and gas</u>		
	<u>Venice No. 2 Station</u>			<u>Bayway Refinery</u>		
Aluminized steel	0.099	b	None	0.724	b	None
Illium C ^o						
Inconel	0.210	0.0015	None	1.860	0.0134	None
17-14 Cu-Mo	0.098	0.0008	None	d	d	d
AISI 316	0.007	0.0001	None	1.216	0.0094	None
AISI 408	0.098	0.0008	None	0.063	0.0005	0.004
AISI 321	0.068	0.0005	None	0.896	0.0070	0.013
AISI 314	0.048	0.0004	None	0.607	0.0048	0.003
AISI 309	0.203	0.0015	None	0.127	0.0010	0.005
AISI 304	0.195	0.0015	None	0.544	0.0042	0.013
AISI 347	0.128	0.0010	0.001	0.141	0.0011	0.003
AISI 310	0.000	0.0000	None	0.171	0.0013	0.001
AISI 309S	0.100	0.0007	None	0.067	0.0005	0.003
16-25-6	0.000	0.0000	None	d	d	d
	<u>Low-sulfur anthracite coal</u>			<u>Sulfur-free natural gas</u>		
	<u>Sunbury Station</u>			<u>Baton Rouge Station</u>		
Aluminized steel	0.62	d	None	0.565	b	None
Illium C ^o						
Inconel	0.0000	0.0000	None	0.0008	0.0001	None
17-14 Cu-Mo	0.0000	0.0000	None	0.0279	0.0002	None
AISI 316	0.0000	0.0000	None	0.1508	0.0012	None
AISI 308	0.0000	0.0000	None	0.0307	0.0002	None
AISI 321	0.0000	0.0000	None	0.2520	0.0020	0.001
AISI 314	0.0084	0.0001	None	0.0195	0.0002	None
AISI 309	0.0000	0.0000	None	0.0923	0.0007	None
AISI 304	0.0218	0.0002	None	0.0279	0.0002	None
AISI 347	0.0082	0.0001	None	0.0307	0.0002	None
AISI 310	0.0000	0.0000	None	0.0081	0.0001	None
AISI 309S	0.0000	0.0000	None	0.0106	0.0001	None
16-26-5	0.0455	0.0003	None	0.0162	0.0001	None

^aipm = inches per month.^bDue to uncertainty of density figure required in calculation, conversion to inches of radius lost per month could not be accomplished.^cNo specimens available for 4 of 6 stations.^dSpecimens completely corroded away.^eSlight pitting occurred.

the corrosion rates varied from possibly acceptable to completely unacceptable with dirty fuel.

The principal forms of fireside corrosion attack are general oxidation of a surface and scaling on the one hand and sulfidation on the other. Sulfidation entails intergranular penetration of sulfur to form sulfides in the grain boundaries and these, of course, weaken the alloy. This form of attack is insidious in that the surface may appear to have suffered little attack yet the material may have been severely weakened.

Steam-side corrosion

The rate of attack of steels by high-temperature steam is extremely sensitive to the oxygen content of the steam, and this in turn depends on the provisions for treating the feedwater. If the oxygen content can be kept extremely low — of the order of 7 ppb — the corrosion rate of chromium-nickel alloys can be kept relatively low.⁴⁴ Figure 10 shows

Fig. 10. Corrosion of steel bars in contact with steam for 500 hr at various temperatures.⁴⁵

the results of a set of tests in which the effect of temperature on the corrosion rates for typical alloys was investigated.⁴⁵ As one might expect, the corrosion rate increased fairly rapidly with temperature. This apparently occurs because steam tends to dissociate slightly at temperatures as low as 400°C (752°F) and the hydrogen tends to permeate through the steel leaving the oxygen to attack the steel surface. This was demonstrated in a classic set of tests carried out by Bloom et al. in which they employed an evacuated jacket around pipes carrying steam at a series of elevated temperatures.⁴⁶ Measurements of the hydrogen permeation rate into the jacket closely correlated with measurements of the oxidation attack of the interior of the tube walls by the high-temperature steam.

The austenitic stainless steels (18% Cr, 8% Ni) have been found to be highly subject to chloride corrosion. Chlorine concentrations in the feedwater of much less than 1 ppm can be concentrated in regions in which boiling occurs, so that local concentrations of chlorides can build up and cause severe intergranular corrosion. This problem has proved to be so troublesome in some types of service that austenitic stainless steels are not used; either ferritic Cr-Mo steels or a relatively high-nickel alloy such as Incoloy 800 are employed because they have been found to be insensitive to chloride corrosion.

High-temperature water tends to attack copper and lead which leads to deposits in the turbine. For this reason, copper alloys are excluded from the upper stages of the feedwater heating system.

Dissolved solids such as calcium carbonate and silica have always presented problems if present in feedwater, and they cannot be tolerated in once-through boiler systems. Thus, the modern steam plant must make use of a quite elaborate feedwater treatment system to assure the removal of essentially all dissolved solids together with oxygen and chlorine.⁴⁴ Very low concentrations of dissolved solids and oxygen are obtained by treatment with ion exchange resins, and the oxygen concentration is reduced further by additions of hydrazine. Typical values are given in Table 4. The resulting system is a major cost item and requires continuous attention from operating personnel.

Table 4. Recommended concentrations
for once-through boilers (Ref. 44)

<u>Subcritical</u>	
Total solids	0.5 ppm maximum
pH	8.8 to 9.2
Hydrazine	Slight excess
Dissolved oxygen	0.007 ppm
<u>Supercritical</u>	
Total solids	0.25 ppm (0.5 ppm for short periods)
pH	9.0 to 9.5 (by N_2H_4 and NH_4)
Total iron	0.01 ppm
Total copper	0.01 ppm
Silica	0.02 ppm
Dissolved oxygen	0.007 ppm

Design Parameters Affecting Efficiency and Cost

In designing a steam plant for minimum unit costs of electric power, numerous compromises must be made in efforts to balance improvements in thermal efficiency against increases in capital costs. These compromises differ depending on whether the plant is expected to be a base load plant, an intermediate load plant, or a peaking power plant. For example, base load plants normally employ peak steam temperatures of 538 to 565°C (1000 to 1050°F) whereas intermediate or peaking load plants commonly employ peak steam temperatures that are lower by 50 to 100°C.⁴⁷

Plant thermal efficiency

The thermal efficiency of a steam power plant is normally taken as the ratio of the useful electrical output delivered to the grid divided by the chemical energy available in the fuel. The principal component efficiencies commonly run around 90% for the boiler (the bulk of the loss is in the form of heat in the stack gases), aerodynamic losses in the turbine which give a turbine efficiency of 80 to 85%, and heat losses inherent in the thermodynamic cycle (i.e., about 45% of the heat in the

steam delivered to the turbine). Other smaller losses include electrical losses in the generator (about 1%) and energy to the feed pumps (1 or 2% of the useful output). The power required to drive induced- and forced-draft fans and coal feed and preparation equipment, condensate pumps, condenser cooling water circulating pumps, and miscellaneous minor equipment totals about 3% of the plant net power output.

Effects of peak steam temperature
on thermal efficiency

Any effort to increase plant thermal efficiency by increasing the steam pressure and/or temperature entails many compromises that must be made in an effort to avoid excessive increases in capital cost. A set of curves showing these effects is given in Figs. 11 and 12, taken from

Fig. 11. Effect of steam throttle conditions on overall efficiency for a 500-MW(e) steam plant with an atmospheric furnace.¹⁶

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Fig. 12. Effect of steam turbine throttle conditions on the cost of electricity from a 500-MW(e) steam plant with an atmospheric furnace on the basis of 1975 dollars.¹⁶

the Westinghouse ECAS study.¹⁶ Note the relatively small improvements in the thermal efficiency obtainable through the use of increased steam temperatures and pressures together with the relatively large increases in capital costs, so that the minimum cost of electricity is obtained with a peak steam temperature of about 538°C (1000°F). This result is consistent with numerous other studies that have been carried out in the past 25 years.

The curves of Fig. 12 suggest that the minimum capital cost of a plant would be found at steam pressures and temperatures lower than those considered in preparing Fig. 11. A review of the whole development of steam power plants shows that increasing the steam pressure and temperature from the low levels of the 1920's leads to reductions in the size of the furnace-steam generator for a given electrical output because of the higher thermal efficiency, similar reductions in the size of the condenser and condenser cooling water system, and reductions in the size and unit cost per kilowatt of electrical output for the combustion air and stack gas equipment. On the other hand, as is evident from Fig. 5, increasing the steam temperature beyond about 482°C (900°F) leads to a fairly rapid loss in strength of the relatively inexpensive low-alloy steels. The best resolution of the various compromises that must be made is indicated by the actual sales of steam plants for intermediate and peaking power purposes;⁴⁷ these plants are often designed for 60 to 120 bars (900 to 1800 psi) at 482 to 510°C (900 to 950°F), with many having steam conditions as 160 bars (2400 psi) and 540/540°C (1000/1000°F).

Effects of unit size on efficiency and cost

Increasing the size of a unit leads to reductions in capital cost and small increases in efficiency stemming largely from the higher Reynolds numbers inherent in the larger sizes. An important savings in operating costs stems from the reduction in the amount of manpower required per unit of output; an increase in unit size by a factor of 10 commonly leads to an increase in manpower by only a factor of ~6. Other savings result from the fact that some components, such as instrumentation and control equipment, increase relatively little in cost and complexity as the unit size is increased.

Effects of superheating and reheating

Superheating leads to an increase in the peak temperature in the cycle for a given peak steam pressure and this increases the thermal efficiency. The increase is not as great as one might expect from simple peak temperature considerations because, as the amount of superheat is increased, the temperature-entropy diagram deviates farther and farther from the ideal rectangular Carnot cycle; this effect is shown in Fig. 13. Reheating has the effect of giving a somewhat closer approach to the ideal Carnot cycle, again as can be seen in Fig. 13.

One of the most important reasons for employing superheat and reheat relatively early in the development of the steam power plant was that steam expansion in the turbine from a saturated steam condition leads to moisture formation, which in turn leads to turbine bucket erosion coupled with losses in turbine efficiency stemming from moisture churning energy losses. Refined design of the turbine blading to prevent the accumulation of liquid slugs in stagnation regions near the tips of stator blades,⁴⁸ coupled with bleedoff slots in the turbine casing and the use of bleedoff steam for regenerative feed heating, has greatly reduced the moisture churning losses and tendencies toward blade erosion.⁴⁹ In addition, the use of erosion-resistant materials such as stellite and titanium in the lower stages of the turbine has made it possible to increase the turbine tip speed in the last stage without getting into difficulty with serious moisture churning losses or turbine bucket erosion even when operating with saturated steam at the turbine inlet.⁵⁰

Air preheat

The principal loss from the furnace-steam generator unit is heat in the stack gas. By use of a rotary regenerator, a pronounced energy savings can be effected by transferring heat from the stack gas to the incoming combustion air. Preheating the air also serves to improve combustion conditions and increases the temperature difference in the furnace and thus the heat flux. However, it has been found that SO_2 in the stack gas combines with moisture to give highly corrosive sulfurous acid if the stack gas temperature is reduced below about 150°C (300°F).

Fig. 13. Temperature-entropy diagrams for a typical set of Rankine cycles.

It is also advantageous to have a substantial stack gas temperature ($\sim 150^{\circ}\text{C}$) both to give a good draft and to lift the plume of gas leaving the stack to an elevation perhaps double that of the height of the stack.

Fluidized-Bed Coal Combustion Systems

The most promising approach to improving the utilization of the energy in coal having an appreciable sulfur content for central station applications appears to be through the use of a fluidized-bed coal combustion system employing crushed limestone in the bed to capture the bulk of the sulfur. Although this system appears basically sound, the experimental record to date indicates that many basic technology problems must be solved before a useful commercial system can be built.²⁵

Fireside corrosion

Probably the most important single set of problems involved in the use of a fluidized-bed coal combustion system is fireside corrosion. Operating experience with experimental units indicates that under some conditions there appears to have been no difficulty, whereas in others quite severe corrosion has been experienced.⁵¹⁻⁵⁵ The problem is exceedingly complex because so many different factors are likely to affect the corrosion rate, e.g., type of coal, the type of limestone, the calcium sulfur ratio, the fuel-air ratio, the air velocity through the bed and its influence on the bed operating regime (bubbly flow, turbulent flow, slugging), the bed operating temperature and pressure, the metal temperature, the type of alloy and coating or other treatment of the alloy. Further, the design of a particular bed may affect corrosion by influencing the bed operating regime; the turbulence in the bed and the uniformity of the lateral dispersion of fuel from the coal feed ports; the coal feed port spacing, which can be expected to influence the degree to which there may be local variations between oxidizing and reducing conditions; and bed depth. These problems can be investigated effectively only by carrying out experiments in a variety of fluidized beds under a wide range of test conditions.

Effects of furnace pressure

Almost all the work to date in the U.S. on experimental systems has been directed toward atmospheric pressure beds. Design studies³⁰⁻³⁶ indicate that the capital cost of atmospheric pressure fluidized-bed furnaces coupled to steam generators may be sufficiently higher than the capital cost of a conventional coal-fired steam generator that one could afford to use the latter with low-sulfur coal at \$45/ton (vs \$25 a ton for high sulfur coal).

It was recognized early in the fluidized-bed development program that pressurizing the furnace would reduce both the capital cost of the furnace and steam generator tube matrix and the number of coal feed points. This approach has proved so attractive that many studies have been directed at this possibility, generally using a furnace pressure of ~10 atm with the furnace serving as the combustion chamber for a gas turbine.^{16,29} With this arrangement a substantial amount of useful electrical power output can be obtained (in principle) from the gas turbine. However, as will be discussed in the next section, over 30 years of effort has yet to produce a coal-fired gas turbine that would operate at 650°C (1200°F) or more for extended periods without serious difficulties with turbine bucket erosion and/or deposits.^{37,38} Thus, it appears worthwhile to consider the use of a furnace supercharged to 3 to 5 atm with an exhaust turbosupercharger in which the hot gas would flow to the turbine at ~540°C (1000°F) to give just enough output to drive the compressor but would not provide any useful power.³³ Thirty-four furnaces of this type were built for the Navy in the 1960's and have been giving excellent performance and reliability in naval destroyers.^{56,57} Analyses and design studies indicate that this approach would cut both the capital cost of the fluidized-bed furnace-steam generator unit and the number of coal feed ports. Further, it would permit increasing the fluidized-bed depth from the roughly 1 m characteristic of atmospheric fluidized bed units to about 3 m and increase the transit time for small particles of coal and limestone as they pass through the bed; thus the amount of unburned carbon in the ash particles elutriated from the bed could be reduced and the utilization of the limestone should be improved.

An especially important advantage of the deep beds associated with pressurizing the furnace is that vertical rather than horizontal boiler tubes can be employed, thus greatly easing the tube support problem and the accommodation of differential thermal expansion between the hot boiler tubes and the cooler structure of the furnace shell.

Erosion and deposits in coal-fired gas turbines

The reductions in furnace size and cost obtainable by pressurizing the furnace have been recognized for a long time, as has the possibility of keeping the pumping power requirements reasonable by making the furnace act as the combustion chamber for an open-cycle gas turbine.^{58,59} In recent years design studies of such systems have usually contemplated turbine inlet temperatures of around 870°C (1600°F).^{16,29,59} Unfortunately, over 30 years of experience with coal-burning gas turbines indicates that turbine bucket erosion, corrosion, and deposits have proved so serious that no one has yet succeeded in operating such units for more than some hundreds of hours prior to a forced outage for at least a cleaning operation.^{37,38} One key to reduced erosion appears to be a reduction in turbine inlet temperature to give an increased hardness of the blade material. A study of this problem, presented in Ref. 60 and summarized in Fig. 14, has shown good correlation between the erosion rate and the ratio of the melting point to the modulus of elasticity. A review of data on the latter parameter for Fe-Cr-Ni-Co alloys indicates that dropping the temperature from 871 to 538°C (1600 to 1000°F) increases the modulus of elasticity by 30 to 60%. Figure 14 indicates that such an increase in the modulus should reduce the erosion rate by a factor of about 10.

The buildup of deposits in a coal-fired gas turbine apparently stems from the presence in the ash of a small fraction that is close enough to its melting point so that it is plastic (like red-hot glass) and tends to fuse to metal surfaces. This sticky material forms a film on the blade surfaces and gives a "fly-paper" effect in that it accumulates higher melting point particles. The result is a buildup of hard ceramic deposits. An excellent insight into the effects of both low-melting

Fig. 14. Correlation of erosion with ratio of melting point to elastic modulus.⁶⁰

constituents in the ash and the turbine inlet temperature on ash deposits in the turbine was obtained in Australia in a test rig designed to simulate turbine conditions.⁶¹ Tests were carried out both with ash from a typical Australian coal and with MgO containing low-melting salts that would serve as bonding agents, i.e., give a "fly-paper" effect of the sort noted in Bureau of Mines tests of the coal-fired locomotive gas turbine.⁶² Figure 15 shows the results of this set of controlled experiments. Perhaps the most significant point to note with respect to the questions of immediate interest is that the deposits formed from the Yalbourn coal dropped rapidly with a reduction in temperature to practically zero at 500°C (932°F). Note, too, that pure MgO with no binding agent also gave almost no deposits at 600°C (1112°F). However, the addition of a low-melting salt in the form of sodium, potassium, or magnesium chloride or eutectic mixtures of these materials led to both heavier deposits and a decrease in the temperature at which a low deposition rate was observed.

A review of experience with gas turbines employed with petroleum catalytic cracking units,^{63,64} fuel oil having an appreciable ash content, blast furnace gas,⁶⁵ and gas from coal gasification units is consistent with the above statements. Note particularly that 40 years of work with gas turbines running on blast furnace gas has shown that this gas must be cooled and cleaned with two stages of water scrubbers before feeding it to the burners in order to keep turbine erosion and deposits to an acceptable level for operation with turbine inlet temperature of ~730°C (1350°F).

Particulate removal from hot gas streams

A review of the various papers in the literature indicates that in catalytic cracking units the particulate loading in the gas entering the turbine can be as high as 100 ppm. This presumes that the particle size can be kept below 10 μ m, the temperature of the particulate material is well below its softening point, the turbine blades are stellite and coated with tungsten carbide, the turbine inlet temperature is below 650°C (1200°F), a turbine life of 2 years is acceptable, and the air

Fig. 15. Effects of temperature on the deposition rate of both coal ash and various mixtures of MgO and chloride salts fed into the hot gas stream of a turbine simulation test rig in Australia. The particle size was nominally 5 μm .⁶⁴

flow conditions entering the turbine are such that the dust particles are uniformly mixed so that the damage is uniformly distributed.⁶³ The experience generally indicates that it is possible to keep the particulate content down to 20 ppm with dust separators that depend on centrifugal force, but the last of three-stage separation units must make use of a more elegant air flow passage geometry than conventional cyclone separators.^{63,64} Further, these separators must be effective at removing virtually all particles larger than 10 μm .⁶⁴ However, it is difficult indeed to get a uniform dust distribution in the air entering the turbine; this can be accomplished only with a long axial inflow pipe entering a single-stage overhung turbine rotor.⁶³ Further, the axial inflow pipe must be much larger than the turbine rotor inlet and the passage contours at the turbine inlet must be such that an excellent velocity distribution is obtained. Such a design is possible only for a turbine driving a compressor or if the turbine produces relatively little electrical power, so that only one stage is required. If the gas stream must enter the turbine from the side, dust particles tend to concentrate in a relatively small fraction of the perimeter and lead to severe erosion or deposits in that region. For such cases, the particulate loading normally must be kept to around 1 ppm* if deposits and erosion are to be kept to an acceptable level for a turbine inlet temperature of the order of 700°C (1292°F). It has not been found possible as yet to get a particulate content this low with cyclone particle separators; much more elaborate equipment will be required. Electrostatic precipitators do not work well above about 540°C (1000°F), partly because ceramic insulators for the high tension grids become conducting. Granular bed filters are being investigated,⁶⁶⁻⁶⁸ but the results to date have not been promising (the filters are clogged by the fine particles removed from the gas stream).

Control of fluidized-bed steam generators

Hundreds of fluidized-bed combustion systems are in use commercially to burn low-grade solid waste such as sawdust and sludge from sewage

*1 ppm = 1.22 mg/m³ = 0.0345 mg/ft³ = 0.00054 grain/ft³.

plants, while hundreds of other units are in commercial operating roasting pyrite ores. In view of this, it is surprising that there are no fluidized-bed coal combustion systems in commercial operation with steam boilers, although quite a number of small experimental units have been operated during the past 20 years. Probably the most important reason for this situation is that there have been serious problems in controlling the combination of a fluidized-bed coal combustion system and a steam boiler with its tubes immersed in the bed. The problem is particularly important now because of the Clean Air Act; burning coal in a fluidized bed of limestone in the temperature range between 816 and 927°C (1500 and 1700°F) should allow removal of about 90% of the sulfur as calcium sulfate in the course of combustion, but to do this about two-thirds of the heat released by combustion of the coal must be removed from the fluidized bed by a tube matrix immersed in the bed and herein lies the crux of the problem.

The heat transfer coefficient between the bed and the tube wall is high — around 300 J/sec-m²-°C (~50 to 60 Btu/hr-ft²-°F). At the same time, the heat transfer coefficient from the tube to the boiling water under nucleate boiling conditions is very high — of the order of 30,000 J/sec-m²-°C (~5000 Btu/hr-ft²-°F). Thus, the tube wall tends to run close to the water temperature. Both the fluid bed-side and the water-side coefficients are essentially independent of the combustion gas and water flow rates, respectively. Inasmuch as $Q/A = u \Delta T$ and the overall heat transfer coefficient u is constant, if one attempts to reduce the rate of heat release in the bed, the bed temperature will drop until it reaches about 480°C (900°F), at which point the bed will quench (i.e., "the fire will go out"). If the coal feed is continued, coke will form and clog the bed. If the water flow to the boiler is reduced in an effort to keep the bed temperature constant at reduced outputs of ~870°C (1600°F), the water-side heat transfer mechanism shifts from a nucleate boiling condition to a vapor film blanket condition. This effect is illustrated by Fig. 16, which shows a typical curve for the heat flux to boiling water as a function of the temperature difference between the boiling point of the water and the metal wall from which the heat is

Fig. 16. Heat flux in a fluidized-bed steam boiler with a bed temperature 1000°F (555°F) above the saturation temperature assuming a typical curve for the heat flux to boiling water.

being conducted.⁶⁹ If the fluidized-bed temperature is held at 870°C (1600°F) and the metal tube wall at 316°C (600°F), the heat flux through the tube wall under normal nucleate boiling conditions would run about 300,000 J/sec-m² (50,000 Btu/hr-ft²). This point has been plotted in Fig. 16 to indicate the normal operating point to be expected. Note that operation in this region is stable; i.e., any small increase in the

tube wall temperature will result in a greatly increased heat flux from the tube wall to the boiling water so that the operating condition is eminently stable. If one attempts to reduce the heat flux from the bed to the tube wall by allowing the tube wall temperature to increase to say 540°C (1000°F), the heat flux will be cut roughly in half, but the heat transfer mode will be via vapor blanket boiling which will be very unstable and lead to wide fluctuations in the local metal temperature. Even worse, the water flow rate through the tube will become highly unstable and lead to even more severe temperature fluctuations and thermal stresses. Thermal strain cycling failure of the tubes will result if the tubes do not overheat so much that their loss in strength leads to failure from pressure stresses. Note that this unstable operating region is indicated in Fig. 16 and that intermediate conditions between these two regions would be unstable because any small increase in the tube wall temperature would lead to a reduction in the heat flux from the tube wall to the boiling water.

For good reliability, operation must be constrained to the nucleate boiling regime with a fixed bed temperature of around 870°C (1600°F). Basic heat transfer considerations indicate that the only good way to reduce the heat input to the boiler is to reduce the amount of surface area of the tube matrix immersed in the bed. This in turn implies that either the bed should be compartmentalized so that the output can be changed in quantum jumps or the level of the fluidized bed should be varied. The former approach presents difficulties in the relative phasing of the flow of red-hot "sand" and feedwater to a compartment being activated or deactivated. Unless this phasing is carried out properly one runs the danger either of chilling the bed in that region and building up heavy coke deposits or of getting into a vapor blanket boiling region, generating hot spots in the tubes, and failure of the tubes after a series of perhaps 10 to 100 thermal cycles.

Varying the bed depth presents a problem in that it is difficult to determine where the surface of the bed is when in operation because in the regime of interest the fluidized bed will be bubbling violently. Experience at the British Coal Utilization Research Association laboratory in England indicates that the bed depth can be determined and controlled

within 7 to 10 cm (3 or 4 in.) by measuring the pressure drop across the bed. For an atmospheric fluidized bed for which the maximum bed depth with an acceptable pumping power loss would be around 1 m (40 in.), the uncertainty in bed depth would be around 10% of the bed depth at full power and progressively greater if the bed depth were reduced at part power. This would make control difficult. If on the other hand the bed depth at full power is made around 3 m (10 ft), the uncertainty in depth becomes only a few percent and provides a good basis for the control of the power output. That is, the power output will not be too sensitive to modest additions or removal of "hot sand" to or from the bed.

CURRENT STATUS OF DEVELOPMENT

As in the previous section, attention here will be directed toward work on fluidized-bed coal combustion because the rest of the R&D work on steam systems is concerned with refinement of existing equipment to effect small incremental improvements in its reliability or effectiveness. Only the fluidized-bed effort involves both major uncertainties and the possibility for a major payoff.

The development work on fluidized-bed coal combustion systems was confined to only a few scattered small-scale efforts up until 1972, when the implications of U.S. Federal Government regulations on air quality became apparent and the developing shortages of natural gas and petroleum greatly increased the incentives to utilize coal, particularly coal containing appreciable amounts of sulfur. Thus, there was a large expansion in efforts to design fluidized-bed coal combustion systems coupled to steam generators, and this led to numerous efforts to design and build small experimental facilities aimed at resolving the many questions that became apparent in the design studies.

Experimental Facilities

The development of fluidized-bed combustion systems is so heavily dependent on the experimental resolution of several complex problems that it seems best at this point to summarize the experimental facilities

that have been built or at least designed and funded for construction in the U.S. and Great Britain. Table 5 summarizes the principal parameters and gives the size and capacity of these experimental units. Note that only two of these are large enough to be considered demonstration plants; most are units 30 cm (1 ft) or less in cross section. The column at the extreme right giving the amount of running time on each of these units is indicative of the amount of information that has been obtained in each case. In fact, most of the running time to date in most of the systems that have been built has been concerned with shakedown problems. The results of the test experience are summarized in the last section of this report.

Design Studies

Many design studies of fluidized-bed coal combustion systems have been prepared, most of them involving fluidized beds coupled to steam generators.^{16,29-36,68,70} The principal value of these studies is that, when examined critically, they point up the need for the experiments called for in the earlier section on recommendations. If satisfactory results are obtained in the experiments, particularly those concerned with fireside corrosion, the design studies indicate that the fluidized-bed coal combustion system coupled to a steam generator should lead to both reduced capital costs and improved thermal efficiency.

EXPERIENCE IN SYSTEM R&D WORK

It appears that the best way to present the results from experimental work on fluidized-bed coal combustion is to summarize the information available in each of the major problem areas rather than to review the results of each of the different laboratories working in the field.

General Operating Characteristics

In general, there has been little trouble with operation of the fluidized bed itself other than in getting good control over a wide range

Table 5. Characteristics of fluidized-bed coal combustion systems

Organization	Furnace pressure (atm)	Bed area (ft ²)	Bed depth (ft)	Superficial velocity (ft/sec)	Power output		Output per ft ² [kW(t)/ft ²]	Power density [kW(t)/ft ³]	Total running time (hr)
					MW(t)	Btu/hr			
Pope, Evans, & Robbins	1	10	3	10		6.8×10^5			~5000
Foster-Wheeler	1	2	3	10		1.4×10^6			~5000
Rivesville	1	456	3	10	88	3×10^8	192	.64	~1700
BCURA (Leatherhead)	6	6.25	4	2.4	1.68		280	47	~10 ⁴
Coal Research Labs (Stoke Orchard)	1	0.78							~10 ⁴
B&W — Renfrew	1	100							~3000
Combustion Power	6	38.9	2.7	4.4	4		103	38	500
Argonne National Lab.	1	0.2	2-5	3-8	0.0175	60×10^3	88	9	~10 ³
Argonne National Lab.	10	0.2	2-5	3-8	0.175	60×10^4	880	88	~10 ³
Exxon Research	10	0.8	10						~2000
MERC	1	1.7	3	3 to 4.5			73		~10 ³
FluidDyne	1	2.25	3	2 to 4.0	0.15	5×10^5	66	22	~1500
FluidDyne	1	17	3	2 to 4.0	1.2	40×10^5	66	22	500
B&W — Barberton	1	9							
B&W — Barberton	1	36							
Dorr-Oliver	1	0.8							
Curtiss-Wright	7	7							
ORNL	1	36	3	2.1	1.5		41	13.7	0
MERC	1	36	3						0

of power conditions; most of the difficulties have been concerned with auxiliary components such as the fuel metering and feed system. Generally, the work, as one might expect, indicates that the fluidized-bed air flow rate should be increased to the point where the bed is bubbling smoothly and has been heated to at least 500°C (930°F) before beginning the injection of coal. The experience also indicates that the air flow rate through the bed can be increased by about a factor of 3 before excessive elutriation becomes a problem. Most operators prefer to keep the superficial velocity of the gas leaving the bed to less than 2 m/sec (7 ft/sec), although a few have favored velocities nearly double that. The attrition rate of both the lime and the ash increases fairly rapidly with the superficial gas velocity; this increases the stack gas cleanup problem, which is becoming increasingly important as environmental studies indicate the deleterious effects of submicron-size particles. Further, at the higher velocities, the carry-over of unburned carbon runs 10 to 20% of the fuel feed so that the coarser material collected by the first-stage cyclone separator must be recycled either to the bed or to a special carbon burnup cell. (The finer material collected by the second-stage cycle contains much less unburned carbon.) Marked increases in bed depth made possible by pressurizing the bed should greatly increase the transit time through the bed and hence the fraction of the carbon burned before particles are elutriated from the top of the bed. This may obviate the need for recirculation of the material collected by the first-stage cyclone.

Sulfur Retention

Much of the operation of fluidized beds in the past seven years has had the determination of the effect of major parameters on sulfur retention as a major objective. Investigations have included the effects of calcium-sulfur ratio, excess air, bed operating temperature, type of coal, type of limestone or dolomite employed, particle size, and furnace pressure. In general, the results indicate that as much as 90% of the sulfur can be retained in the bed for a calcium-sulfur ratio between 2

and 3 at a bed operating temperature of 870°C (1600°F). The optimum temperature for sulfur retention increases with increasing pressure, but the percent retained is not too sensitive to the bed operating temperature if bed pressure is increased as bed temperature increases.²⁵

Sorbent regeneration in pressurized FBC systems

Both Exxon and ANL have been able to regenerate lime and recirculate it for three to five cycles or more.^{71,72} In both cases, the lime is sulfated not more than 50% prior to recycling. The Exxon process for regenerating the lime and extracting elemental sulfur requires about 8% of the energy available in the coal fed to the fluidized bed, whereas the ANL process (designed to accomplish the same purpose) gives promise of requiring only 2% of the energy in the coal. Representatives of both laboratories have emphasized that the ash decrepitates rapidly so that at no time does the amount of ash in the bed exceed 20% and it is often as little as 10% under equilibrium conditions.

Tests of various sorbents at Exxon indicate that the most promising is barium titanate, BaTiO_3 . This material appears to be twice as effective for absorbing sulfur dioxide as calcium oxide. It is very resistant to attrition, so that Exxon believes that as much as 100 recycles with the BaTiO_3 can be achieved as opposed to around 5 for CaO . However, the BaTiO_3 is more expensive.

NO_x Emissions

Although the bed operating temperature is low enough so that one would not expect an appreciable percentage of oxides of nitrogen in the emissions, appreciable amounts are found, apparently as a consequence of nitrogenous compounds present in the coal. Thus, although the NO_x concentration in the stack gas from a fluidized-bed coal combustion system commonly runs several times the level expected for the bed operating temperature if no nitrogenous compounds were present in the coal, it is only about half the EPA limits.⁵³

Coal Metering and Feed Equipment

A wide variety of coal metering and feed equipment has been employed in experiments but none has proved completely satisfactory. In all cases it has been found that for consistent coal metering and feed, the crushed coal must be dried to less than 1% superficial moisture or else the coal feed rate becomes erratic and sometimes plugging or clogging of elements of the system occurs.⁷³ The latter has proved to be a particularly troublesome problem in tests to date of the Rivesville plant, so much so that relatively little operating time has been obtained.^{27,74} Note that the Rivesville plant is deliberately being operated with no drying of the coal feed. Note, also, that in the past where coal has been transported pneumatically as for pulverized coal burners for central stations or even in the old Iron Fireman household stokers, the coal feed stream has always been dried before it was metered and fed to the combustion chamber.

Feeding the coal pneumatically at a pressure above atmospheric introduces the need for some kind of a seal in the coal feed system.⁷⁵ This can be accomplished with lock hoppers (which are used at BCURA, Exxon, and Argonne) or with a device such as a rotary valve. There is extensive operating experience with both types of equipment in the chemical process industry but neither has been fully satisfactory. Rotary valves have been particularly subject to difficulty with wear, a condition that can be eased by designing the system so that the pockets in the rotary valve do not operate full (an approach which increases the life of the valve from a few days to many months).

Rotary valves can be used for metering, but if this approach is followed, the valve pockets must be full and the life of the valve is very short if there is a significant pressure differential across it. Screw feeders have given good service and will operate satisfactorily against a small back pressure. They have the advantage that there is a linear relation between the feed rate of the solid and the rotational speed of the screw. It might be noted that in a full-scale bench test at ORNL a rotary valve running only partially full was used to bring dry crushed coal from an atmospheric pressure bin into a pressurized pneumatic coal feed system, and a screw feeder was employed to accomplish the

metering. A bench test for this system was conducted for 1000 hr with uniformly consistent metering.⁷³

One problem in a coal feed and metering system is splitting the coal feed stream into a multiplicity of flows to different coal feed ports. One way of accomplishing this is to employ a vibrating table with a feed at the inlet end and splitter vanes to separate the flow into a multiplicity of outlet streams. This type of machine has the disadvantage that while it can be adjusted to maintain a particular coal feed rate with reasonably consistent splitting of the stream into a multiplicity of substreams, it appears to work well only for a rather narrow range of feed rates; a poor outlet distribution develops if the coal feed rate is varied over a wide range. Better results may be obtained by using a series of ore sample dividers; tests with these gave consistent splitting of a coal feed stream into four substreams with less than +5% variation from the mean for flow rates from 25 to 100% of the design value.⁷³

Another approach is to feed a single stream into a block with radial outlet ports (four or more). Large units which require splitting the feed stream to dozens of separate feed nozzles will require careful development and testing to assure adequate feed distribution.

Fireside Corrosion

As indicated earlier in this report, fireside corrosion problems are sufficiently complex and dependent on many different variables that a truly comprehensive program will be required to provide a firm basis for the design of fluidized-bed coal combustion systems.^{76,77} Some notion of the amount of testing required is given by the fact that there are about 10 key independent parameters and it would be desirable to vary each of these over an appreciable range — say at least three different conditions. Even assuming that one can select the nearly optimum value for each of these 10 parameters in advance and run a base case for reference purposes, it would then be necessary to run an additional 20 cases varying each one of the parameters either to the high or the low side of the optimum just to get an idea of the importance of each parameter. In addition, it

would be highly desirable to see whether there are synergistic effects of varying two parameters simultaneously, but this would entail hundreds of additional tests. The cost of such a program and the time required to carry it out is rendered still more formidable by the fact that each test must be run at least 3000 to 5000 hr to obtain a significant indication of a satisfactorily long life. Thus, it is clear that a judicious selection of test conditions must be made to keep the fireside corrosion test program within manageable limits. Table 6 indicates what such a program might include. The results of the corrosion tests run to date are also summarized in Table 6.⁵¹⁻⁵⁵ If these data are compared with the range of conditions of interest, it is clear that much additional experimental work must be carried out before designers will have a firm basis for the design of full-scale fluidized-bed furnaces.

Fast Fluidized Beds

A number of concepts for fluidized-bed coal combustion systems envision operation with superficial velocities sufficiently high that the solid particles in the bed are entrained and circulate around a loop.²⁷ One such concept under investigation by the Battelle Memorial Institute (BMI) makes use of a bed of Fe_2O_3 particles that are -8 mesh in size.^{78,79} Streams of -325 mesh calcium oxide particles and -1/4-in. coal are injected into this bed. In addition, -20 mesh SiO_2 particles recirculated through the bed. With this arrangement a 27-to-1 ratio of CaO to carbon is obtained in the circulating fluid with the iron oxide particles remaining just above the air distributor plate while the fines circulate rapidly through the iron oxide bed and then upward through the combustion space. The iron oxide bed has a settled height of 15 to 19 in. and an expanded height of 40 in. in operation. The first-stage cyclone takes out the silica and calcia for circulation through a steam generator and back into the bed. The fines from attrition of the other materials together with the ash are carried into the second-stage separator, where the bulk of them are removed. The attrition rate on the iron oxide particles leads to a makeup requirement of 0.3 lb Fe_2O_3 per 100 lb of coal, and the attrition of the SiO_2 is ~2 lb per 100 lb of coal. The ratio of calcia feed to the sulfur in the coal is approximately 2 for 88% sulfur

Table 6. Controlled experiments in the systematic investigation of alloy corrosion in fluidized-bed coal combustion systems

Parameter	Range of interest	Controlled experiments			
		BCURA	Combustion Power	EPRI-Stoke Orchard	ORNL-FluidDyne
Bed size, ft ²	1, 3, 10, >35	6.25	2.2	1.0	2.25
Furnace press., atm	1, 3, 10		1	1	1
Bed temperature, °F	1500, 1625, 1750	1560	1600, 1700		1635
Type of coal	Bituminous, sub-bituminous, lignite	Pittsburgh	Illinois No. 6	Ill. No. 6	Illinois No. 6
Volatiles, %	0-40		33.4		
Sulfur content, %	1, 3, 5		3.27		
Ash content, %	5, 10, 20		13.1		
Particle size	-1/4 in., -8, -16		<1/4, <1/8 in.		
Type of sorbent	Limestones & dolomites of different porosity, clay additives		Dolomite with & without clay	Limestone	Limestone
Superficial velocity, ft/sec	2, 4, 8	2.2 to 2.5		3	2.3
Excess air, %	5, 10, 20	14 to 20	~200	15	10
Calcium-sulfur ratio	1.5 to 4	1.4 to 2.2	1.37	2	5 ^a
Alloy	~10 types	7 alloys	22 alloys	20	5 alloys
Coating	None, 2 types	None	None	None	Alonized
Alloy temperature, °F	700, 1200, 1500, bed temperature	700, 920, 1100, 1310, 1560	1600	1000, 1200, 1400, 1500	1530-1610
Alloy location	In bed & in freeboard	In bed & in freeboard	Freeboard	Bed & freeboard	In bed
Running time per test, hr	500, 1000, 3000	500	100, 1000	1000	1500

^aSO₂ emission level of 150 ppm.

retention when burning 4% sulfur coal. The NO_x concentration in the flue gas runs ~ 350 ppm. There are no tubes in the bed, but 2-in.-diam tubes have been installed above the bed for measurement of heat transfer coefficients in the entrained bed flowing up out of the bed of iron oxide particles. These experiments have shown severe erosion of horizontal surfaces but acceptable erosion rates on vertical surfaces. The heat transfer coefficient in the tube bundle has run approximately 25 Btu/hr-ft²-°F. Approximately 15% of the carbon goes through the bed and furnace unburned and most of it is taken out in the second-stage cyclone; some of it, of course, recirculates with the calcia and silica. Of the combustion that does take place, 83% occurs in the iron oxide bed and only 17% in the entrained bed in a 30- to 40-ft plenum above the iron oxide fluidized bed. Note that all these values are based on about 300 hr of testing at Battelle with a 6-in.-diam bed. Unless transverse mixing is very good, the performance of large-diameter beds may be substantially less favorable. Note, too, that the pumping power requirement is inherently high for fast fluidized beds.

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75. D. L. Keairns, Westinghouse Electric Corp., 1310 Beulah Road, Bldg. 501, Pittsburgh, Pa. 15235
76. Carey Kinney, Office of Coal Utilization Systems, Fossil Energy, DOE, Mail Code E-178, Germantown, Washington, D.C. 20545
77. C. W. Knudson, General Electric Co., Energy Systems and Technology Division, Bldg. 2, Schenectady, N.Y. 12345
78. L. R. Lawrence, Jr., Gas Research Institute, 3424 S. State St., Chicago, Ill. 60616
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80. R. A. Loth, EPRI, 3412 Hillview Ave., Palo Alto, Calif. 94304
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82. T. E. Lund, EPRI, 3412 Hillview Ave., P.O. Box 10412, Palo Alto, Calif. 94304
83. J. J. Markowsky, American Electric Power, 2 Broadway, New York, N.Y. 10004

84. C. H. Marston, General Electric Company, 1 River Road, Schenectady, N.Y. 12345
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86. C. F. McDonald, General Atomic Co., P.O. Box 81608, San Diego, Calif. 92138
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89. Abolhassan Nazemi, The Mitre Corp./METREK Division, Westgate Research Park, McLean, Va. 22101
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106. J. F. Weinhold, Tennessee Valley Authority, 1345 Commerce Union Bank Bldg., Chattanooga, Tenn. 37401
107. G. C. Weth, Office of Coal Utilization Systems, Fossil Energy, DOE Mail Code E-178, Germantown, Washington, D.C. 20545
108. D. M. Willyoung, General Electric Co., 1 River Road, Schenectady, N.Y. 12345
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