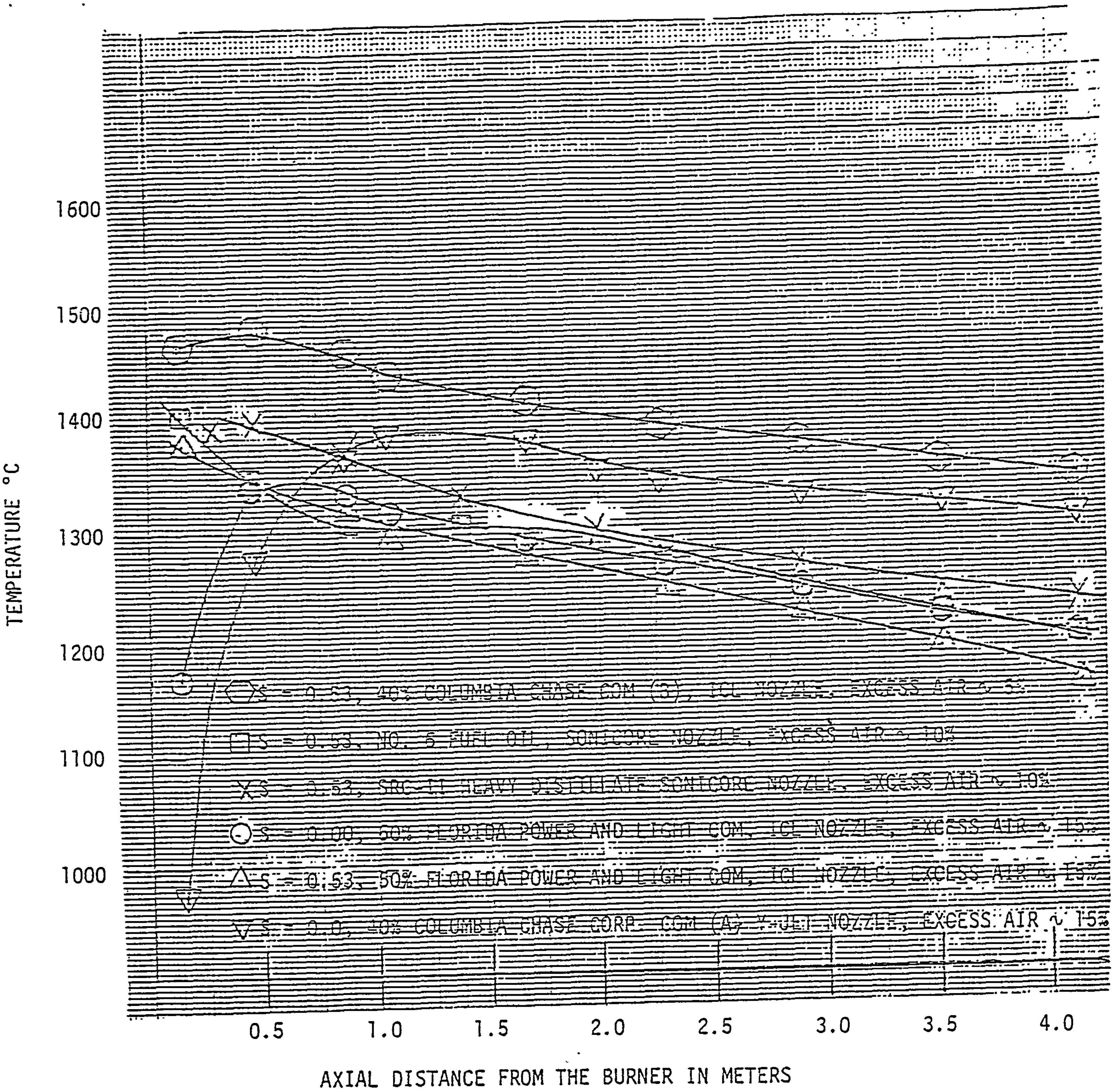

FIGURE 5. AXIAL TEMPERATURE PROFILES (1 MWth INPUT, INLET COMBUSTION AIR TEMP. ∿80°F).

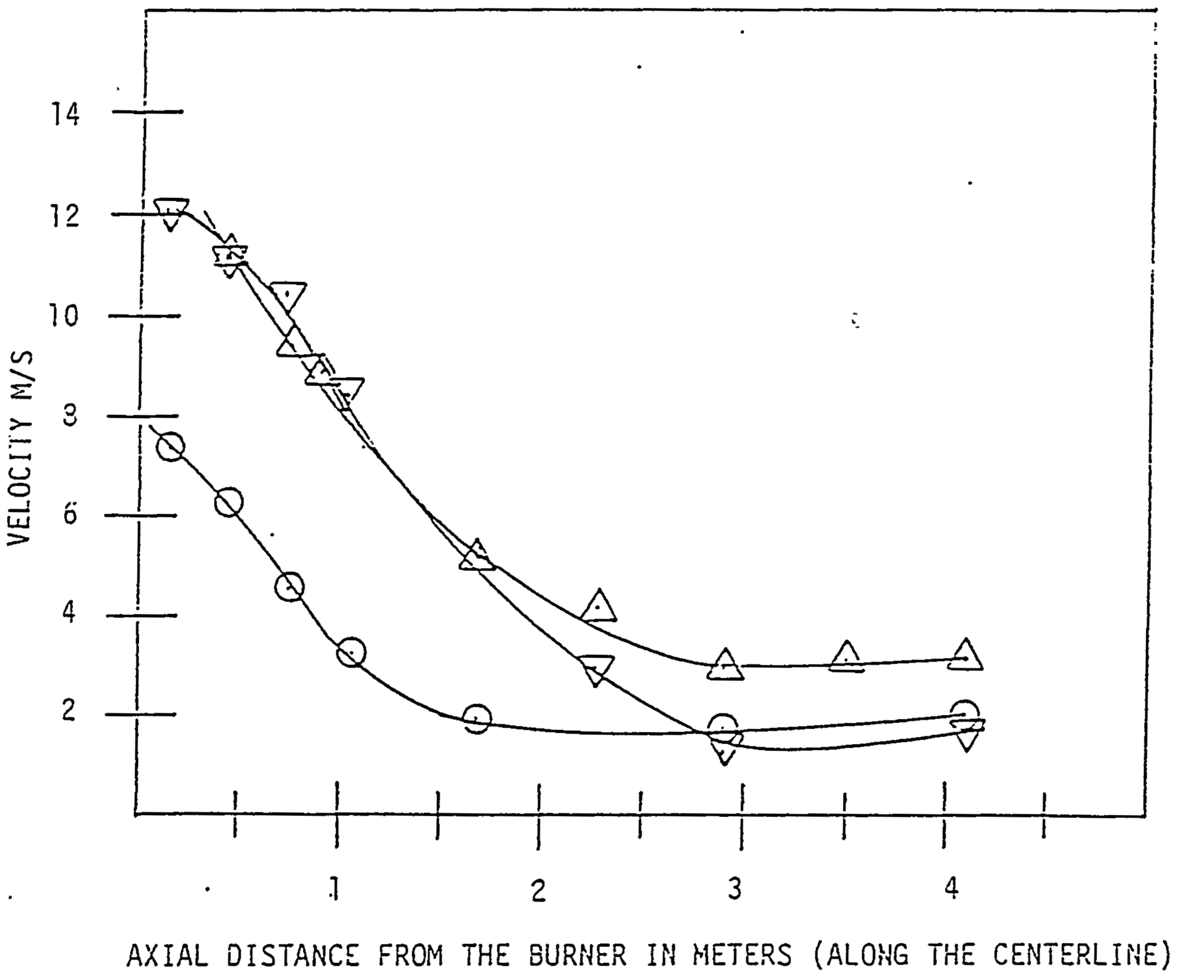

FIGURE 6. AXIAL VELOCITY PROFILES (1 MWth INPUT, INLET - COMBUSTION AIR TEMP. ~ 80°F, EXCESS AIR 15%)

O S=0.53, 50% FLORIDA POWER AND LIGHT COM
ICL NOZZLE

Δ S=0.0, 50% FLORIDA POWER AND LIGHT COM
ICL NOZZLE

∇ S=0.0, 40% COLUMBIA CHASE CORP. COM (A)
Y - JET NOZZLE

Beér

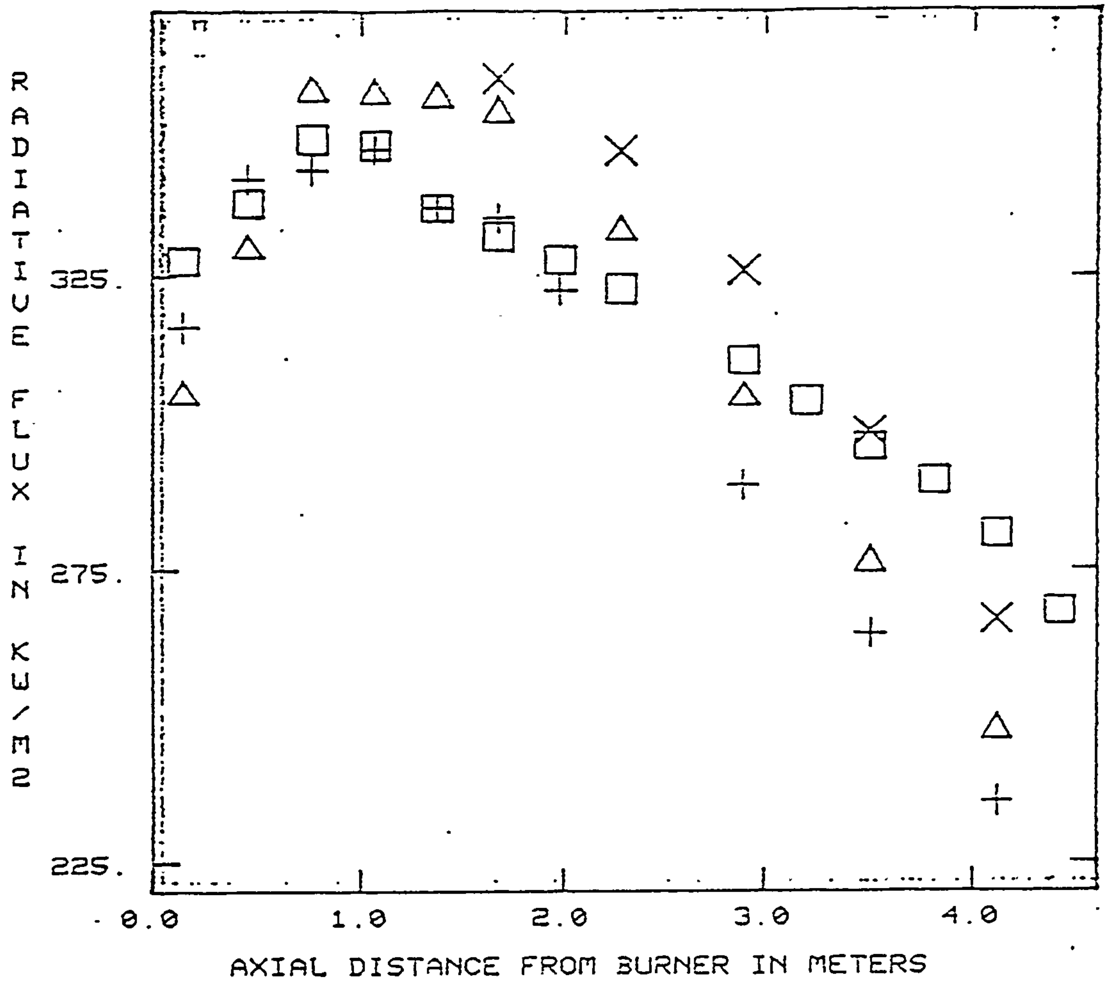

FIGURE 7. AXIAL PROFILES OF RADIATIVE HEAT FLUX TO THE FURNACE WALL

□	NO 6 FUEL OIL, 1 MW, S = 0.53, T_{AIR} = 100F EXCESS AIR ~10%, SONICORE NOZZLE
+	50% FPL COM, 1 MW, S = 0.53, T_{AIR} = 80F EXCESS AIR ~15%, ICL NOZZLE
Δ	50% FPL COM, 1 MW, S = 0.0, T_{AIR} = 80F EXCESS AIR ~15%, ICL NOZZLE
X	50% FPL COM, 1 MW, S = 0.0, T_{AIR} = 80F EXCESS AIR ~15%, Y-JET

Beér

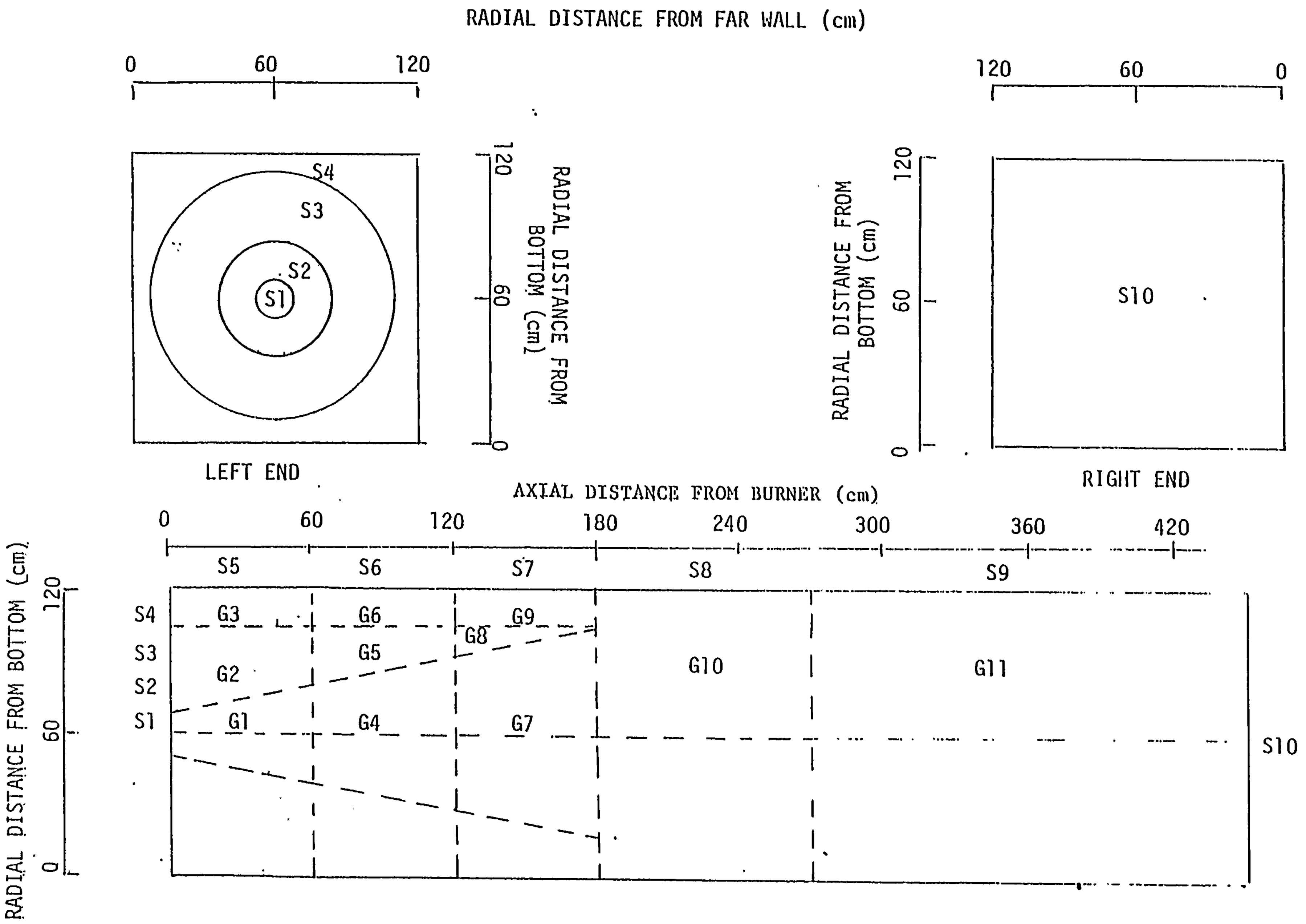

FIGURE 8. ZONING SYSTEM FOR CRF DESIGN USED IN THE MONTE CARLO ZONE METHOD PROGRAM (10 SURFACE ZONES, 11 GAS OR VOLUME ZONES).

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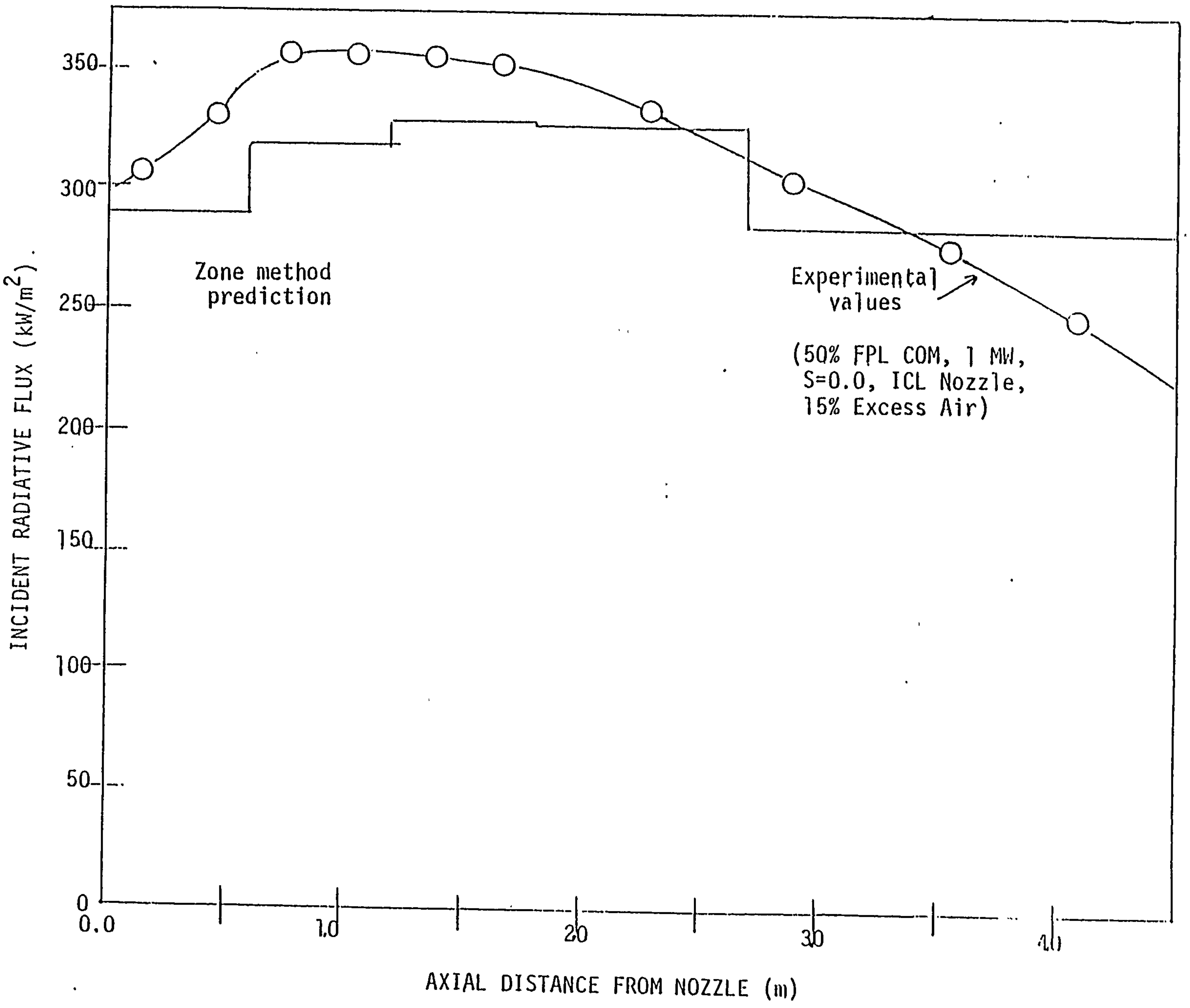

FIGURE 9. MEASURED AND PREDICTED RADIATIVE FLUX DISTRIBUTIONS.

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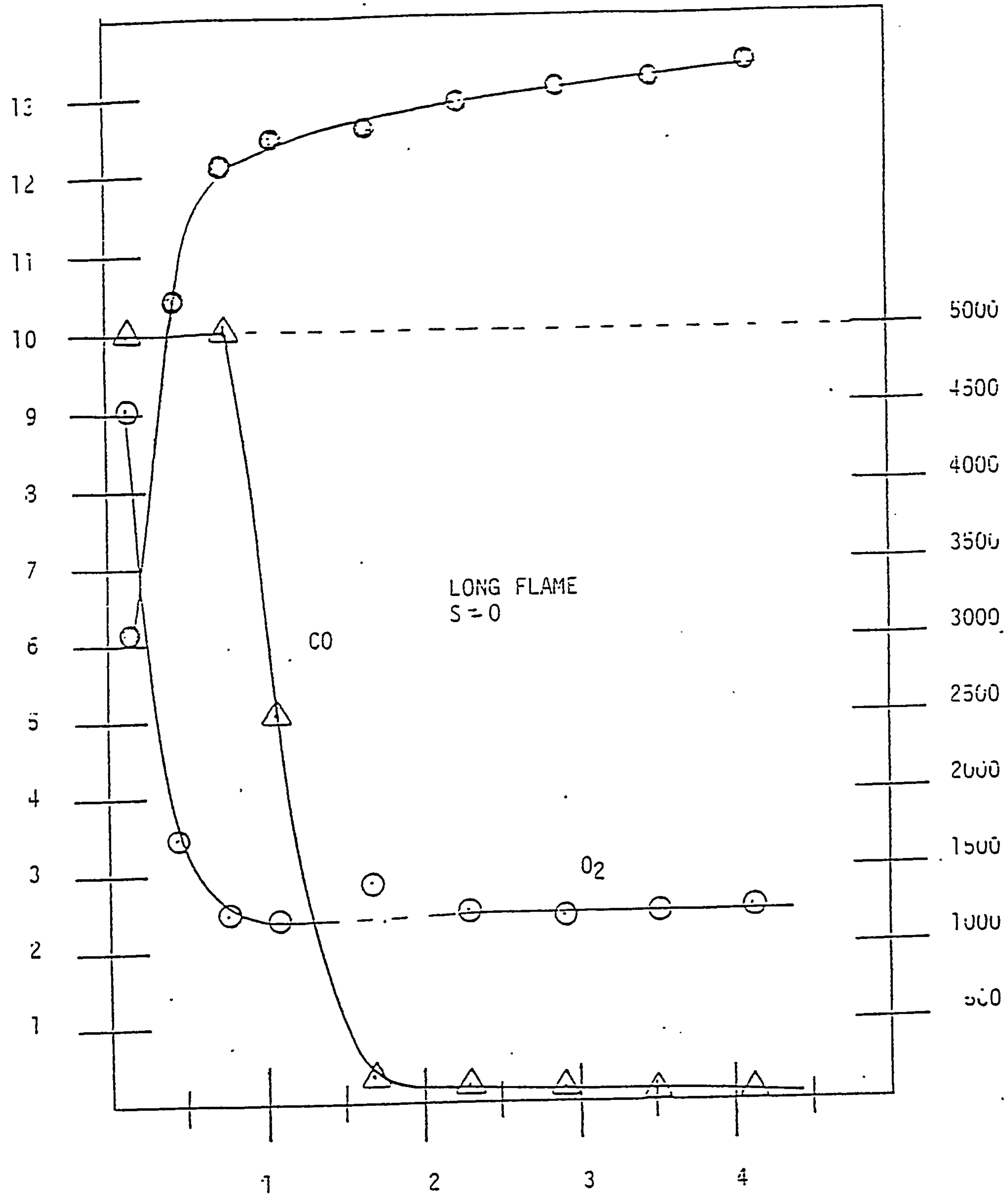

FIGURE 10. AXIAL O_2, CO_2 AND CO CONCENTRATION PROFILES (50% FLORIDA POWER AND LIGHT COM, 1 MW INPUT, INLET COMBUSTION AIR TEMP ~ 80°F)

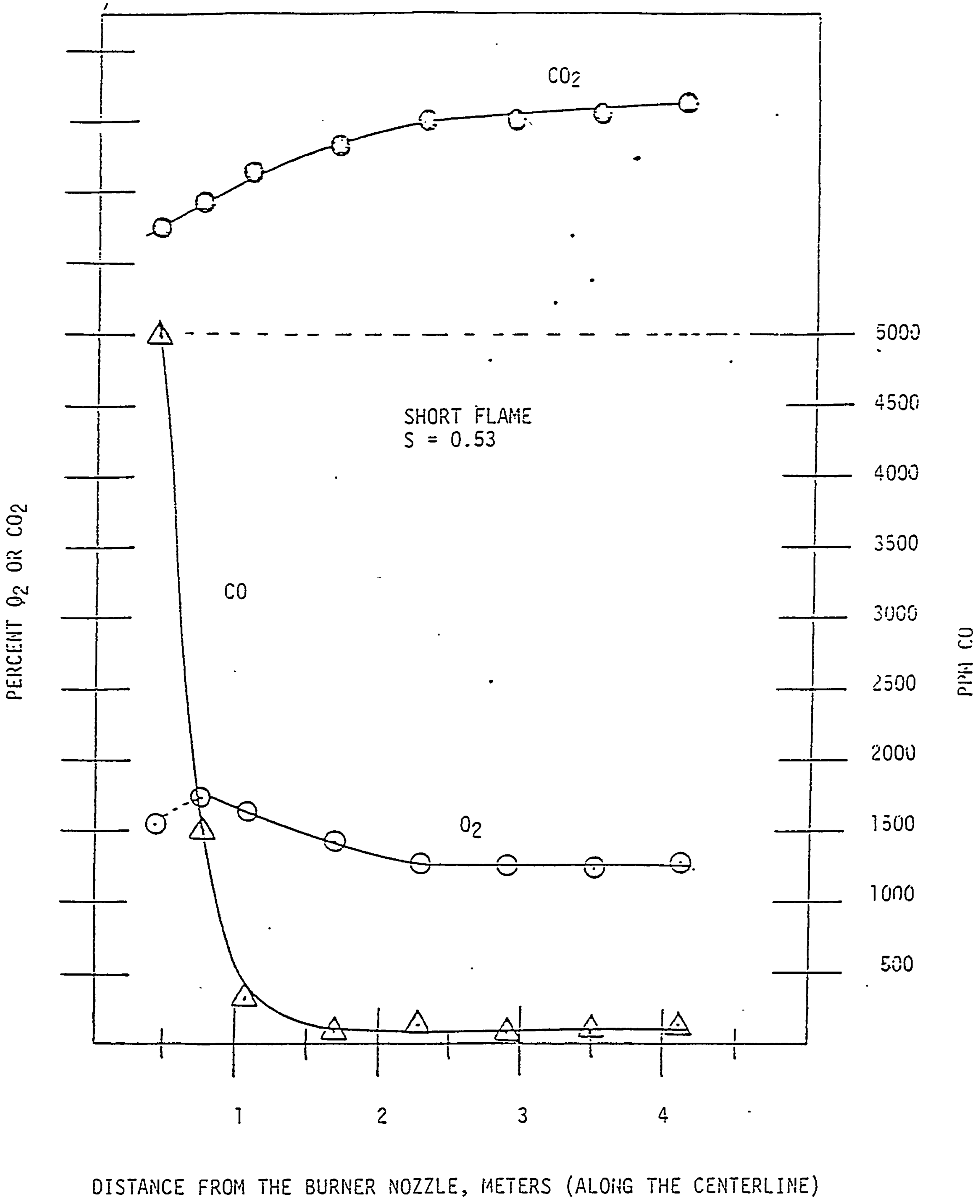

FIGURE 11. AXIAL O_2, CO_2, AND CO CONCENTRATION PROFILES (50% FLORIDA POWER AND LIGHT COM, 1 MW, ICL NOZZLE, INLET COMBUSTION AIR TEMP ~80°F)

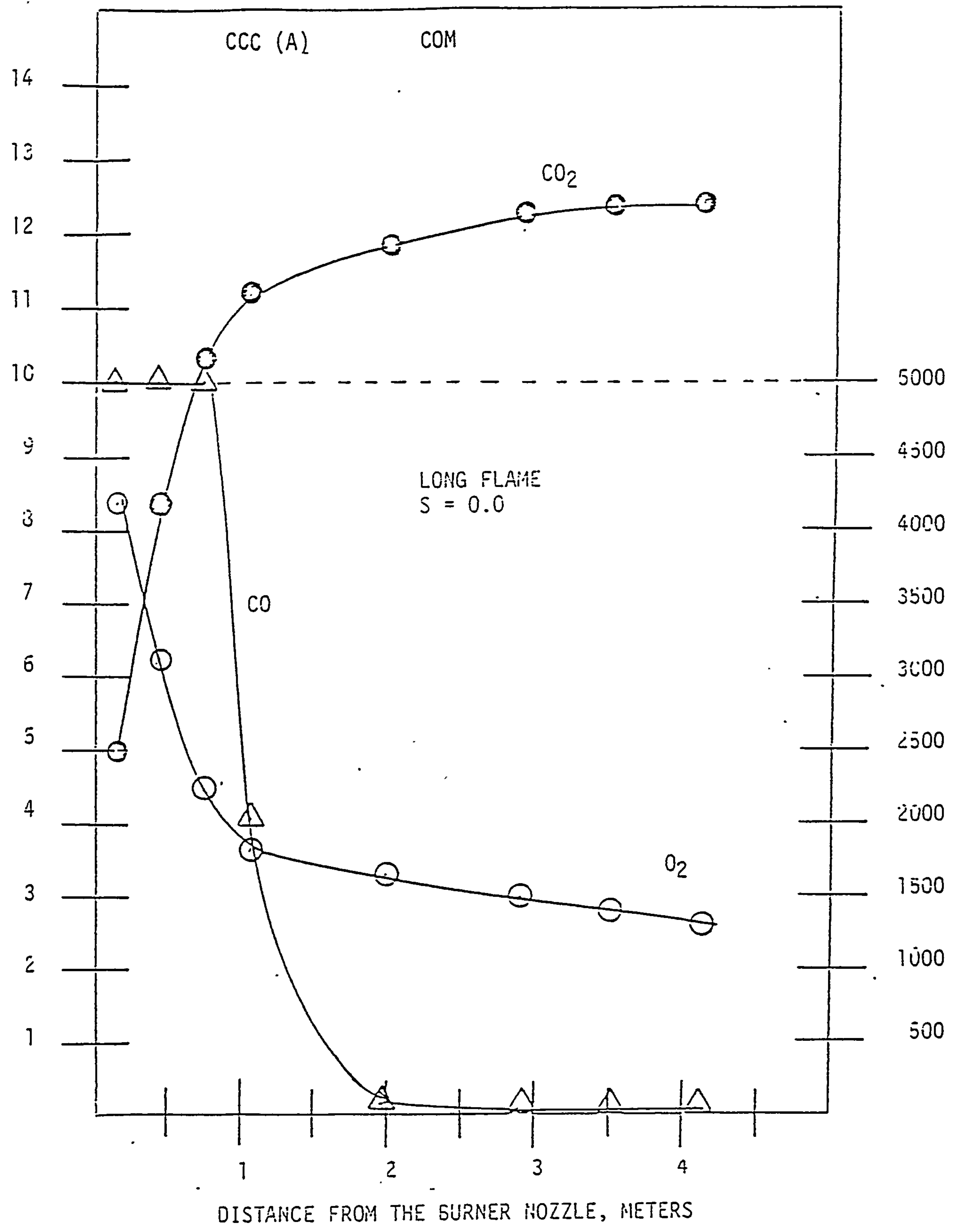

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FIGURE 12. AXIAL O_2, CO_2 AND CO CONCENTRATION PROFILES (40% COLUMBIA CHASE CORP. COM, Y - JET NOZZLE, INLET COMBUSTION AIR TEMP'≈ 60°F)

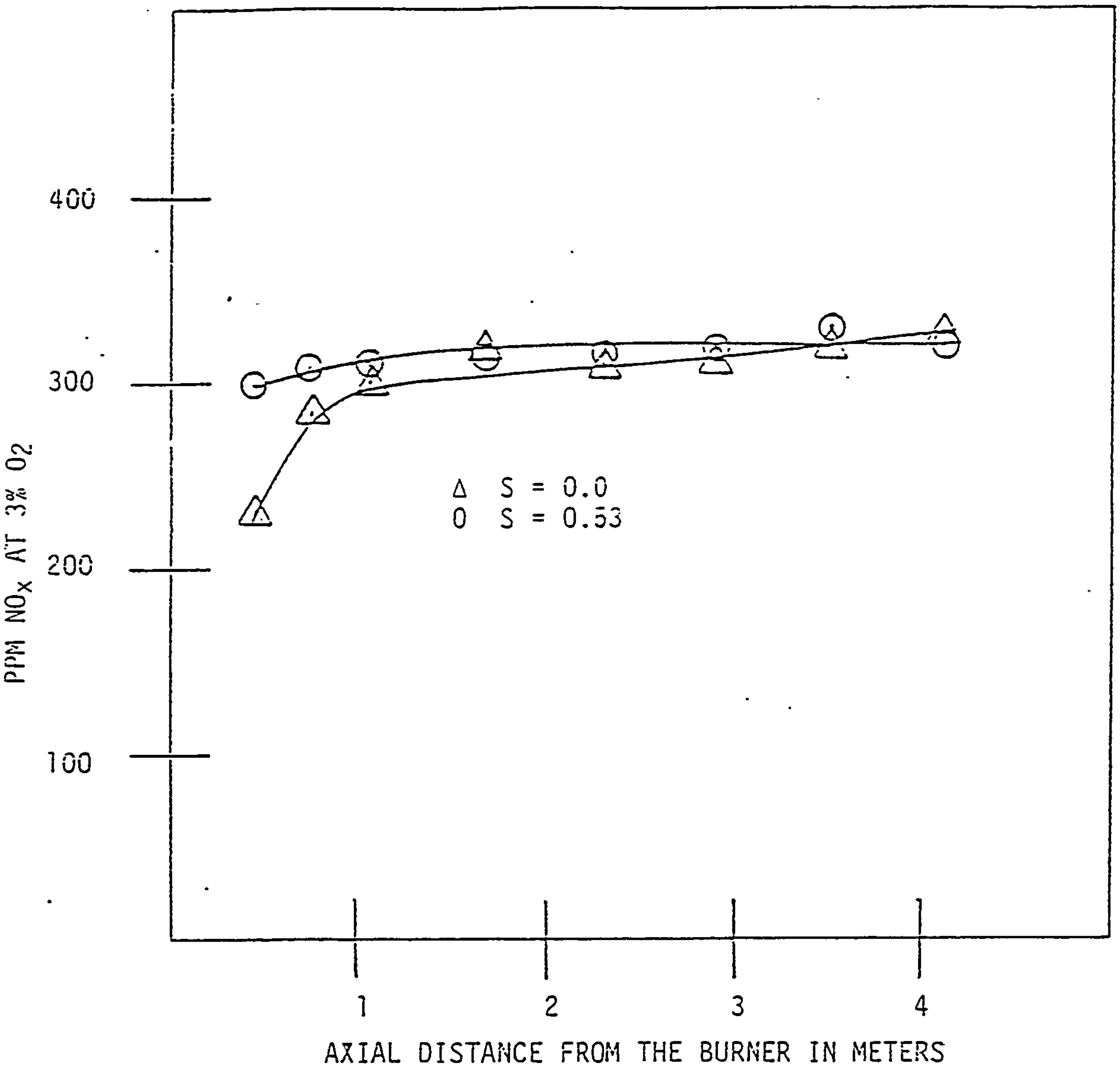

FIGURE 13. AXIAL NO_x CONCENTRATION PROFILES (50% FLORIDA POWER AND LIGHT COM, 1 MW INPUT, ICL NOZZLE, INLET COMBUSTION AIR TEMP. ~80°F, EXCESS AIR ~15%)

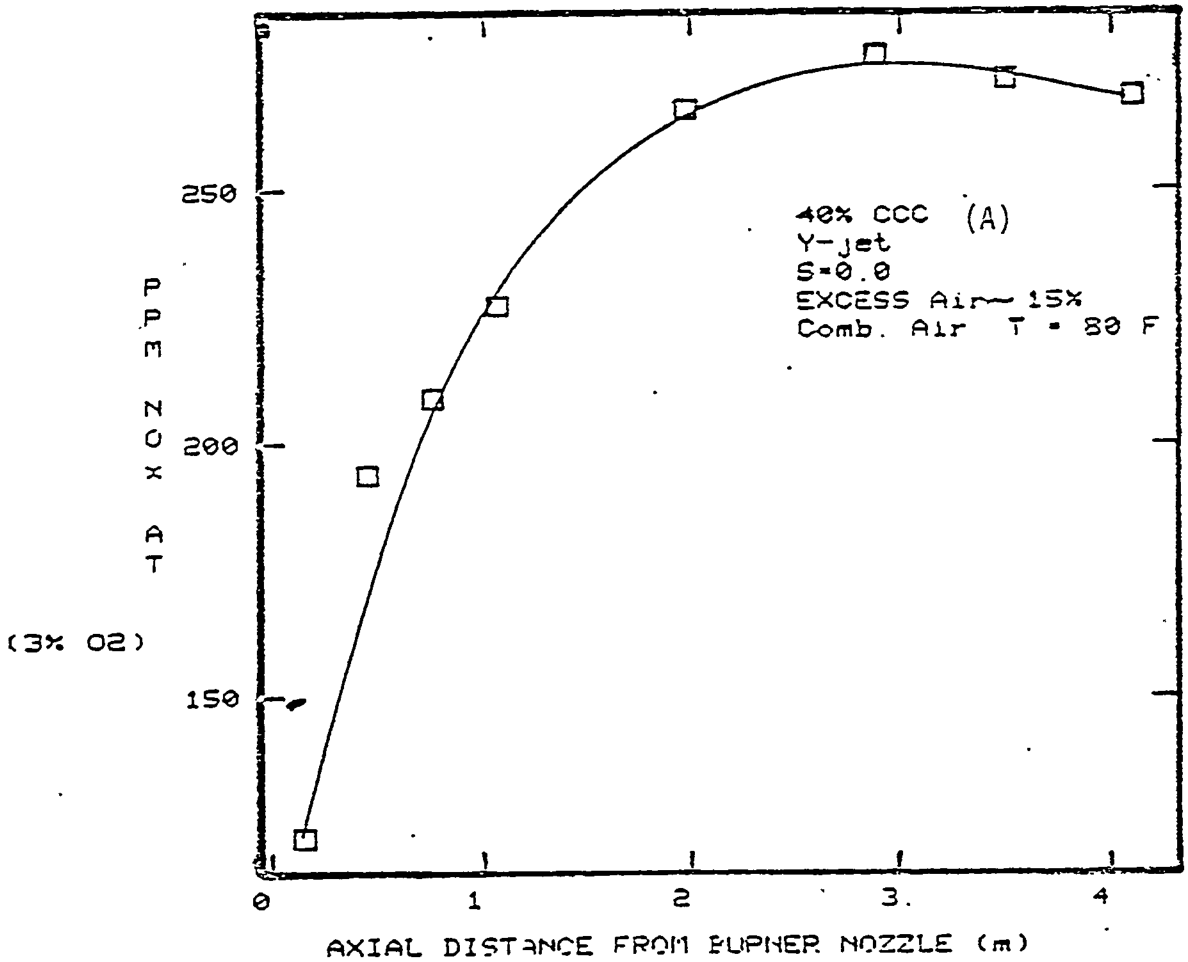

FIGURE 14. AXIAL NO_x CONCENTRATION PROFILE.

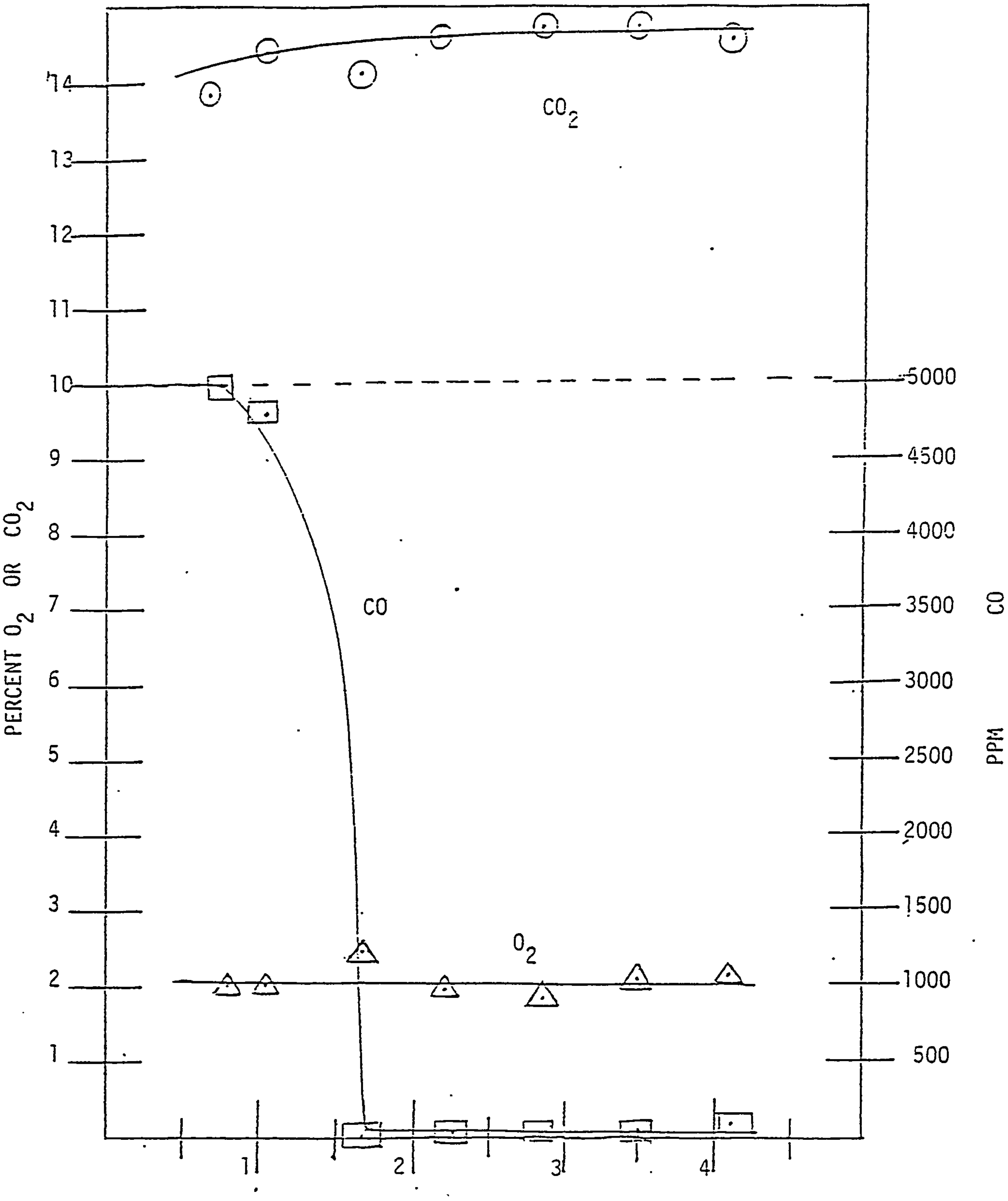

FIGURE 15. AXIAL O_2, CO_2 and CO CONCENTRATED PROFILES (SRC-II HEAVY DISTILLATE, 1 MW INPUT, EXCESS AIR ~10%. SONICORE NOZZLE, INLET COMBUSTION AIR TEMP, 100F)

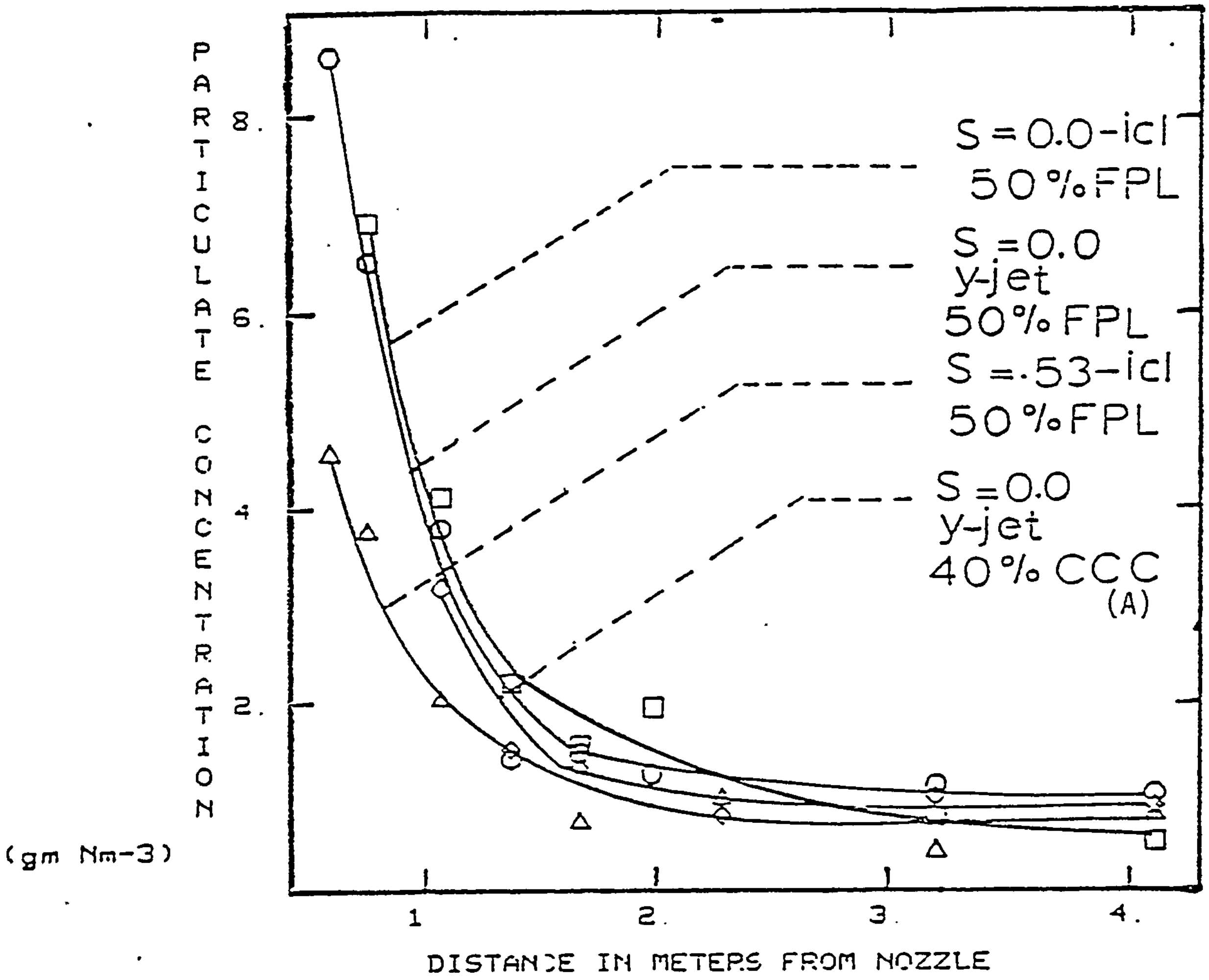

FIGURE 16. TOTAL PARTICULATES CONCENTRATION PROFILES ALONG THE FLAME AXIS

(1 MW INPUT, INLET COMBUSTION AIR TEMP. ~80F, EXCESS AIR ~15%)

CCC = COLUMBIA CHASE CORP COM
FPL = FLORIDA POWER AND LIGHT CO. COM

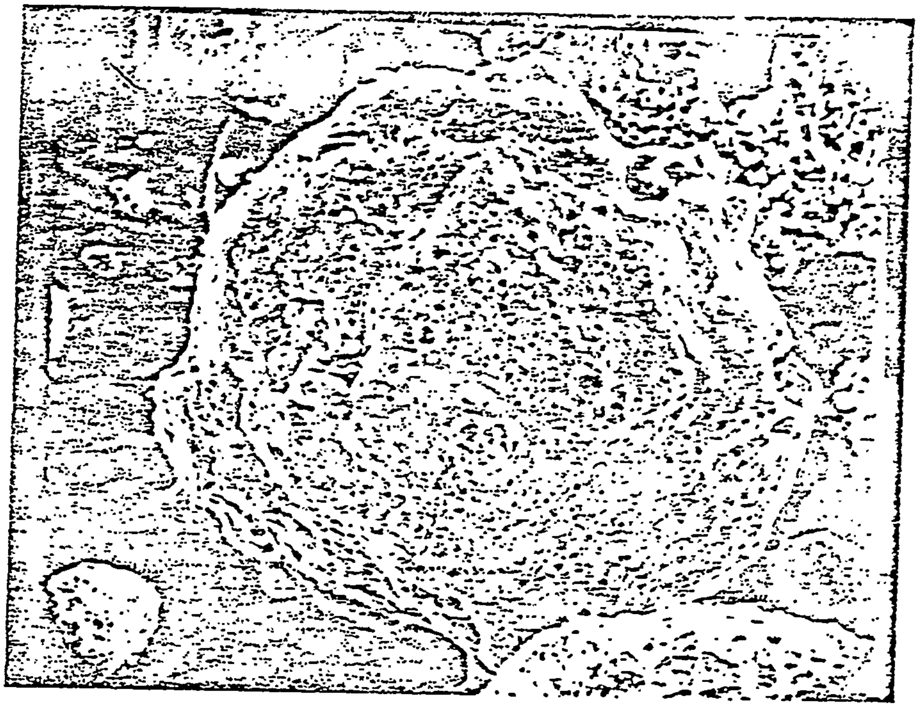

FIGURE 17 CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM A COAL PARTICLE. APPROXIMATE DIAMETER: 100 µm, DISTANCE FROM BURNER AT WHICH SAMPLE WAS TAKEN: 1.07m, MAGNIFICATION: x400. (50% FLORIDA POWER AND LIGHT COM, S = 0.53, ICL NOZZLE, EXCESS AIR ~15%, 1 MW INPUT)

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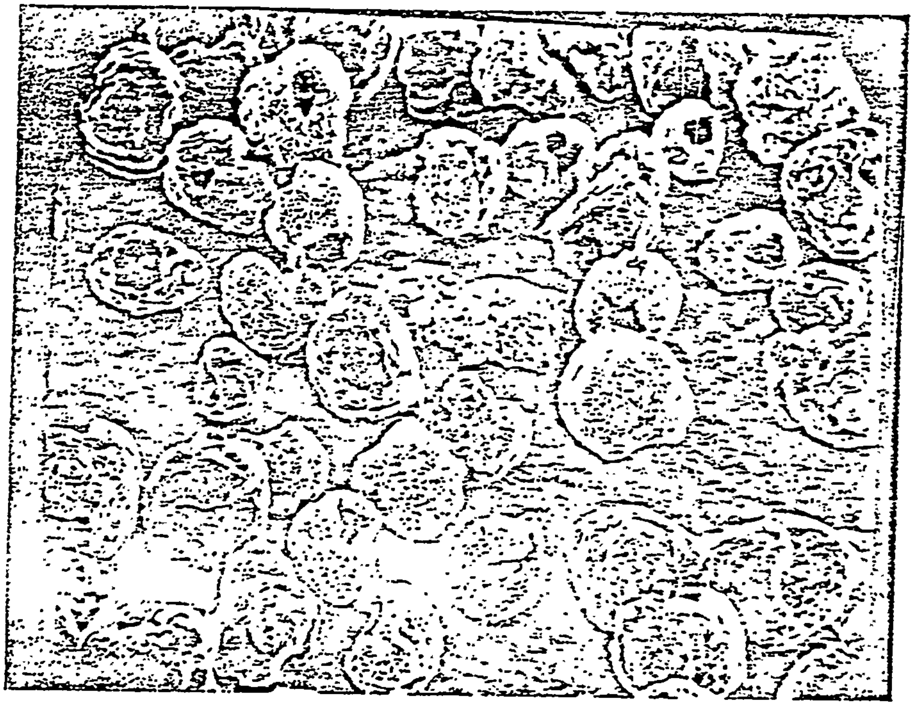

FIGURE 18 CENOSPHERES IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM COAL PARTICLES. APPROXIMATE DIAMETER: 50-100 μm, DISTANCE FROM BURNER: 0.76 m, MAGNIFICATION: . x 200)

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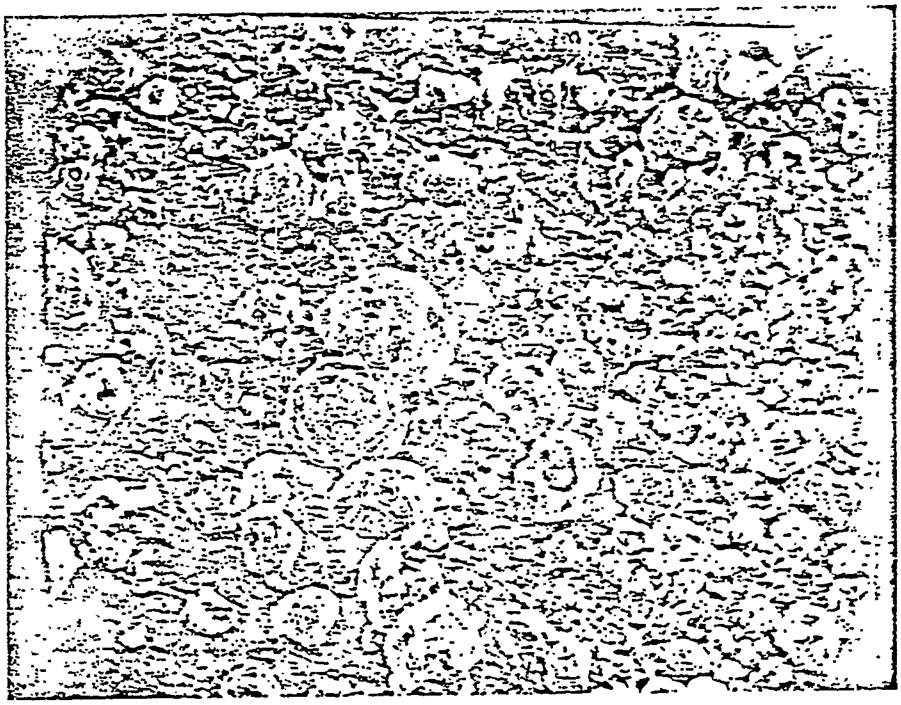

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FIGURE 19 CENOSPHERES IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM COAL PARTICLES. APPROXIMATE DIAMETER: 50-100 μm, DISTANCE FROM BURNER 1.07m, MAGNIFICATION x 200)

Beer

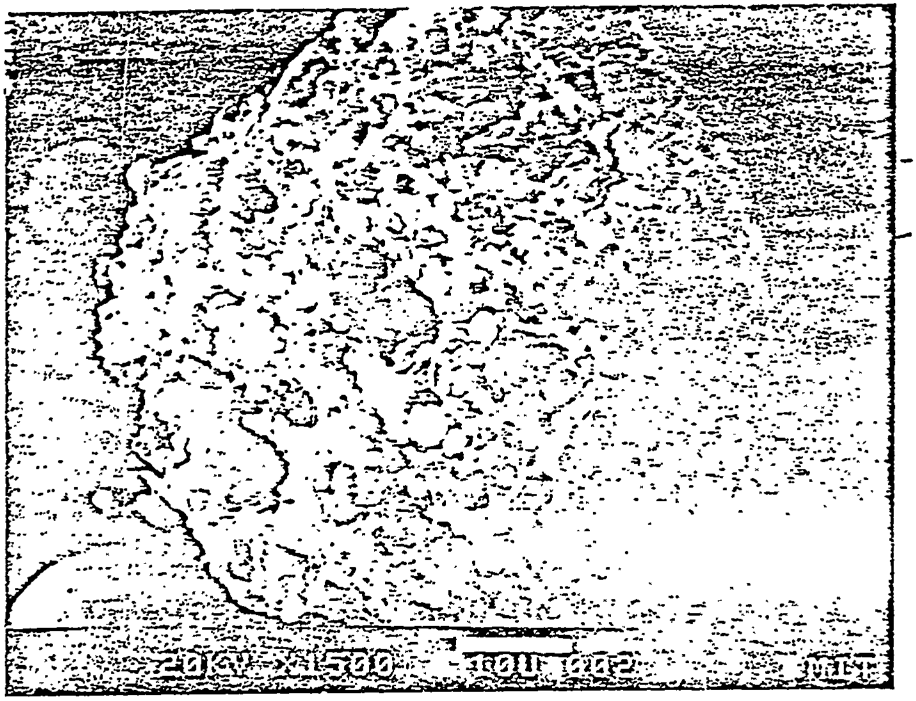

FIGURE 20 CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM A COAL PARTICLE. DISTANCE FROM BURNER: 1.67m, DIAMETER AND MAGNIFICATION GIVEN IN PHOTOGRAPH

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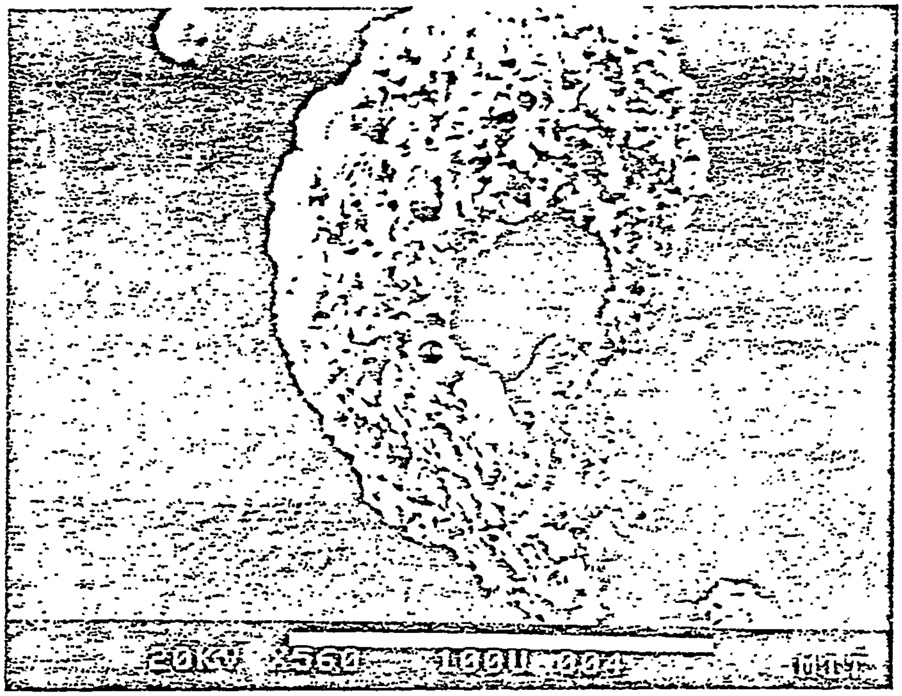

FIGURE 21 CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM A COAL PARTICLE. DISTANCE FROM BURNER 1.67m.

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FIGURE 22 ASH CENOSPHERES IN A COM FLAME SOLIDS SAMPLE (SCANNING ELECTRON MICROSCOPE). DISTANCE FROM BURNER AT WHICH SAMPLE WAS TAKEN: 4.11 m. (50% FLORIDA POWER AND LIGHT COM, S = 0.53, ICL NOZZLE, EXCESS AIR ~15%, 1 MW INPUT)

Beér

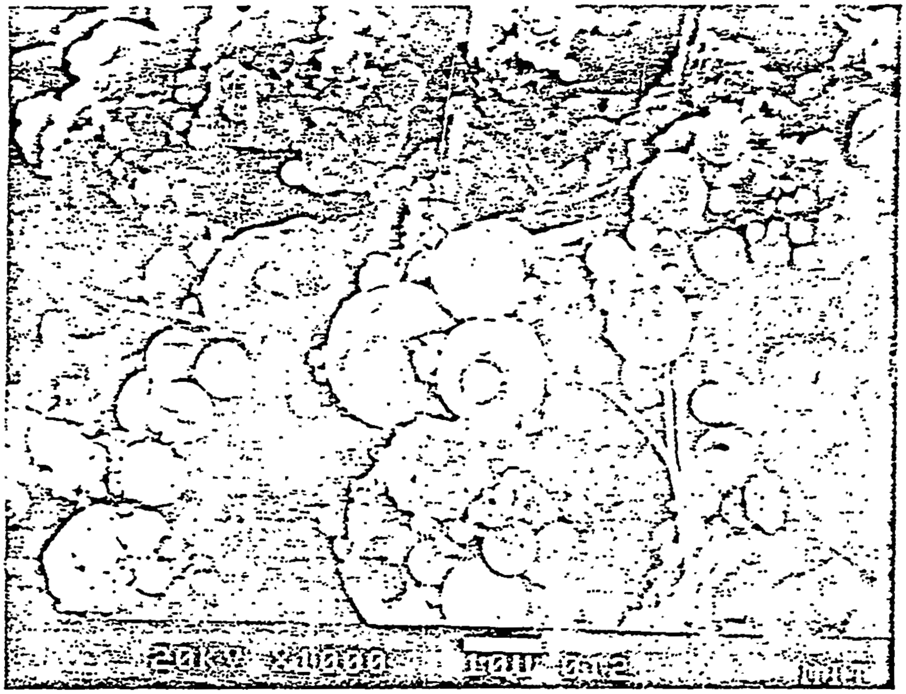

FIGURE 23 ASH CENOSPHERES IN A COM FLAME SOLIDS SAMPLE (SCANNING ELECTRON MICROSCOPE). DISTANCE FROM BURNER AT WHICH SAMPLE WAS TAKEN: 4.11 m. (50% FLORIDA POWER AND LIGHT COM, S = 0.53, ICL NOZZLE, EXCESS AIR ~15%, 1 MW INPUT)

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AB-3

CCAWG MEETING AT COMBUSTION ENGINEERING (CE),
WINDSOR, CONNECTICUT
(June 23, 1982)

The following members of CCAWG participated: J. M. Beér, C. R. Bozzuto, A. K. Oppenheim, S. S. Penner, L. D. Smoot, R. E. Sommerlad, C. L. Wagoner, and I. Wender; DOE/Washington was represented by J. F. Kaufmann. The agenda is shown in Table 1. Following an overview of work at CE and inspection of CE facilities (C. R. Bozzuto), the following topics were emphasized: ash formation and fouling in the direct utilization of low-rank (M. Jones, GFERC) and of bituminous (R. Bryers, Foster-Wheeler Corp.) coals and explosions and fires in coal handling (M. Hertzberg, Bureau of Mines, Pittsburgh). L. D. Smoot presented an introduction to environmental studies and concerns, which will be discussed in greater detail during the July meeting of CCAWG at METC.

The presentation by C. R. Bozzuto (CE) included brief mention of (now terminated) studies on coal gasification (5 tons of coal per hour), work on a sub-scale fluidized bed boiler producing 2000 lbs of steam per hour and on a prototype boiler (Great Lakes Station) producing 50,000 lbs of steam per hour, various SO_2 removal systems, flow-model facilities for scrubbers, and an EPRI-funded program on atomization and utilization of coal-water mixtures. The utility of experimental, cold-flow modeling in preference to numerical studies for multi-phase flows was emphasized.

A. Fouling and Slagging

M. L. Jones (GFERC) discussed direct, low-rank, pulverized coal combustion and emphasized the serious problems encountered with slagging and fouling. Depending on the coal used, highly alkaline ash adhering to walls (e.g., with North Dakota lignites

Table 1. Coal combustion and application working group meeting agenda (June 23, 1982).

9:00 - 9:15	Getting Organized	
9:15 - 9:30	Introduction	C. R. Bozzuto (Combustion Engineering, CE)
9:30 - 11:00	Tour of Facilities	
11:00 - 12:00	Utilization of Low-Rank Coals	M. Jones (Grand Forks Energy Technology Center, GFERC)
12:00 - 1:00	Lunch	
1:00 - 2:00	Ash Formation and Fouling	R. W. Bryers (Foster-Wheeler Corp., FW)
2:00 - 2:45	Environmental Concerns	D. Smoot (Brigham Young University, BYU)
2:45 - 5:30	Explosions and Fires	M. Hertzberg (U.S. Bureau of Mines, Pittsburgh, BMI)

or subbituminous coals) or ash with high SiO_2 contents (e.g., with Gulf lignites) are produced. Low-rank coals contain substantial amounts of moisture (30 to 45% in lignites and 10 to 25% in subbituminous coals), are non-caking, have relatively low heating values (∿6,500 Btu/lb) and sulfur contents (∿0.6% for subbituminous coals, ∿1.0% for lignites), produce highly variable alkaline ash, and have relatively high organic oxygen contents. The benefits of chemical additives (e.g. limestones or dolomites) and of physical control agents (e.g., vermiculite) in reducing ash fouling are under investigation; about 1 to 1.5% of the total fuel flow rate is typically added as limestone. Representative performance studies on a 220 MW_e, wall-fired, utility boiler with low-rank coals showing 6-8% of Na in the ash allowed full-load operation for only about two weeks, whereas about one year of operation is anticipated with the use of limestone at full load. It is known that substantial boiler derating and the use of low peak temperatures ($\lesssim 1000^{\circ}C$) will reduce slagging. Experimental studies are in progress (e.g., at Foster-Wheeler) to determine temperature levels below which fouling and slagging are substantially reduced. Critical issues relate to ash-deposition rates and deposit-tenacity correlations, which have been investigated for low-ash Montana subbituminous coal and high-Na lignite from Australia. A major data collection and consolidation effort has been initiated and will include data from laboratory, pilot and field studies. The cost to utilities from fouling and slagging has been estimated to be ∿$\$8x10^6$/yr in the operation of a 500 MW_e facility. For low-rank coals, fundamental data are needed on (a) reactions of inorganic species in flames, (b) coal dust-air combustion in laminar and turbulent flames, (c) determinations of alkali metals in samples of particulates, (d) chemical analyses of fouling deposits. Research recommendations derived from a recent workshop have been classified as "highest priority" (see Table 2) and "lower priority" (see Table 3).

Table 2. GFERC research recommendations on low-rank coals (LRC) of "highest priority."

A. Basic Research

From LRC Studies	From Workshop on Basic Coal Science
Classification of standard low-rank coal samples; reactions between alkali materials and sulfur; compositions and characteristics of ashes and slags from low-rank coals and peats.	Methods for the determination of macerals (petrographic characterization); standard low-rank coal samples; organic structure of low rank coals; distribution of inorganics; devolatilization reactions; moisture determinations.

B. Combustion Research

Ash fouling and slagging mechanisms; control of fouling and slagging with additives; direct ignition of pulverized coal without oil; determination of the thermal properties (emissivities and absorptivities) of ash at high temperatures; determination of the form and distribution of inorganic constituents; sulfur retention on ash as a function of ash composition and operating parameters, including combustion modifications for low NO_x; on-line measurements of fouling and slagging (full-scale and pilot units) and correlation with fuel characteristics and operating parameters; mechanisms of ash fouling; evaluation and use of additives to reduce fouling and slagging; corrosion rates for low-rank coals as a function of ash composition, metal temperature, and metal type.

Table 3. GFERC research recommendations on LRC of "lower priority."

A. Basic Research

From LRC Studies	From Workshop on Basic Coal Sciences
Surface characteristics of low-rank coals and peat fines;kinetics and reaction mechanicsms of LRC and their chars with H_2O, H_2, CO, and CO_2.	Within-seam variability of mineral distribution; surface characteristics and properties; high-temperature oxidation.

B. Combustion Research

Improved boiler cleaning procedures; temperature limitations vs. boiler corrosion; improved stoker furnace for small-scale applications; devolatilization and carbon burnout characteristics and the effect of burner/furnace modifications for NO_x control; probe testing of burners on full-scale boilers to provide input data for furnaces; assessment of fouling and slagging leading to improved guidelines for preparing boiler specifications; a 1-5 TPH, PC-fired test facility to study fouling and slagging at larger scale than in the present pilot units; effects on boiler tubes of using water blowers to clean low-rank coal boilers and determine factors controlling blower effectiveness; fluidized-bed combustion; low-rank coal/water slurry combustion and low-rank coal/oil slurry combustion; improvements in cyclone firing of LRC; effective SO_x/NO_x and particulate controls for smaller industrial stokers operating on LRC; development of more reliable flame scanners, more reliable instruments to measure furnace flue gas temperatures, and cheaper and more reliable, continuous SO_2 analyzers.

R. Bryers (FW) presented a comprehensive overview of information derived on fouling and slagging from pilot and full-scale units and correlations with predictive indices in conventionally-fired steam generators. This presentation is reproduced in full in Table 4. Particularly noteworthy are the interesting observed differences between elementary compositions of coals and corresponding slag samples. While a wealth of empirical information has been collected and control measures are necessarily implemented when slagging and fouling require remedial measures in operating boilers, fundamental understanding is limited with regard to each of the following basic problems: (a) the relation between measures taken for coal beneficiation and slagging and fouling, (b) the extent to which deleterious depositions can be controlled by aerodynamic measures, (c) the quantitative relations between coal mineral contents and the physicochemical processes that lead to slagging and fouling, (d) the roles of ash loadings and particle-size distributions in deposit formations, (e) the mechanisms involved in selective depositions of minerals, (f) predictions and verifications of deposit compositions and their spacial variations, (g) the nature of the aging processes of the deposited materials, (h) the phase behavior and phase changes of deposits with temperature variations, (i) the strengths and durabilities of deposits and their stabilities to soot blowing and removal attempts.

While the costs and penalties associated with the production of fireside deposits are being evaluated, an adequate and well integrated fundamental research program remains to be developed. Fundamental studies on ash deposits and corrosion should be performed, even though the demonstrable connection between these studies and control in large boilers remains to be made. The members of CCAWG judge the currently funded efforts on fundamental studies in these fields to be inadequate in view of the economic importance of reliable performance of (large) boilers to utilities and industrial users all over the world.

Table 4. The viewgraphs shown by R.W. Bryers (Foster Wheeler Corp.) in his discussion of slagging and fouling.

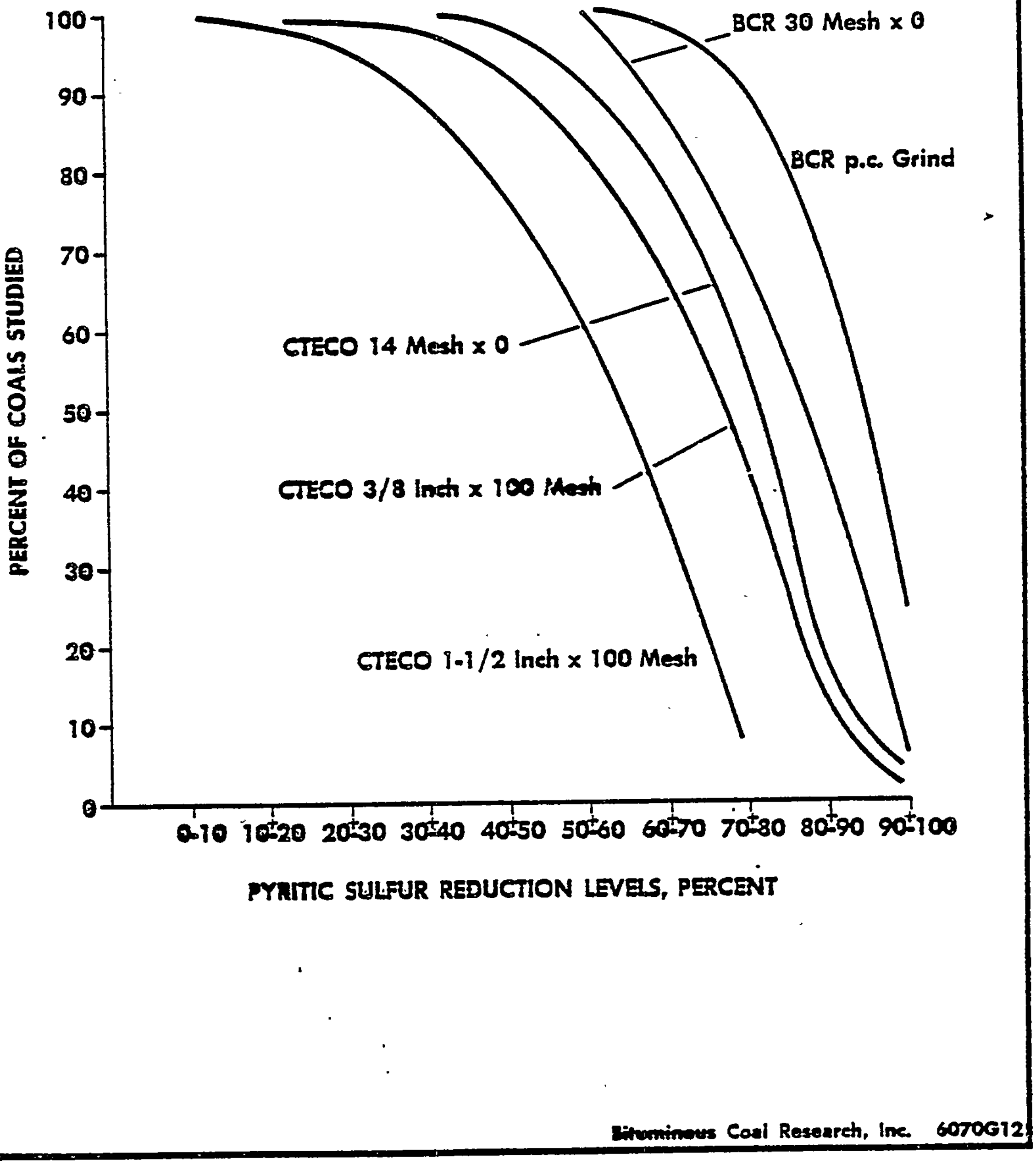
All the prediction indices are based on composite coal ash. None of the indices take into account:

- The heterogeneity of the coal ash by size and gravity
- The relationship of mineral forms to each other and the variation in mineral composition with coals
- The effects of ash loading on deposit formation
- The relationship of mass transport mechanism on deposit formation
- Selective deposition within the steam generator
- Variation in composition of the deposit as it is laid down on the tube surface and aged with time
- The impact of the chemistry on operating variables and design variables other than the furnace exit temperature
- Only a modest effort has been directed at identifying minor melts formed below the detectable limits associated with ash fusion cones. Such minor melts can be responsible for initial sticking of ash which precludes the massive build-up
- Sintering strength on deposit removal by soot blowing.

Pitfalls still remain in analyzing the true concentration levels of certain elements. The reliability of predicting quantitatively the minerals present is uncertain. Real time measurement of ash composition permitting better diagnosing of problems and better quality control of the fuel are just beginning to receive attention.

Modeling the behavior of ash in the furnace in terms of its fusibility and time/temperature history has received little attention.

Little attention has been paid to the economics of fireside deposits or the impact of beneficiation and its cost on fireside deposits.



Pyritic Sulfur Reduction at 1.60 Specific Gravity as Related to Nominal Topsize of Coal

Table 4, continued

Comparison of Coal Ash and Slag Deposit Formed From a South African Coal

Elemental Analysis	Coal	Slag
SiO_2	48.4	46.4
Al_2O_3	25.2	27.8
TiO_2	1.5	1.7
Fe_2O_3	1.8	4.1
CaO	14.2	12.2
MgO	2.1	2.4
Na_2O	3.2	1.9
K_2O	0.5	0.5
SO_3	4.6	<0.1
P_2O_5	0.7	0.8

Table 4, continued

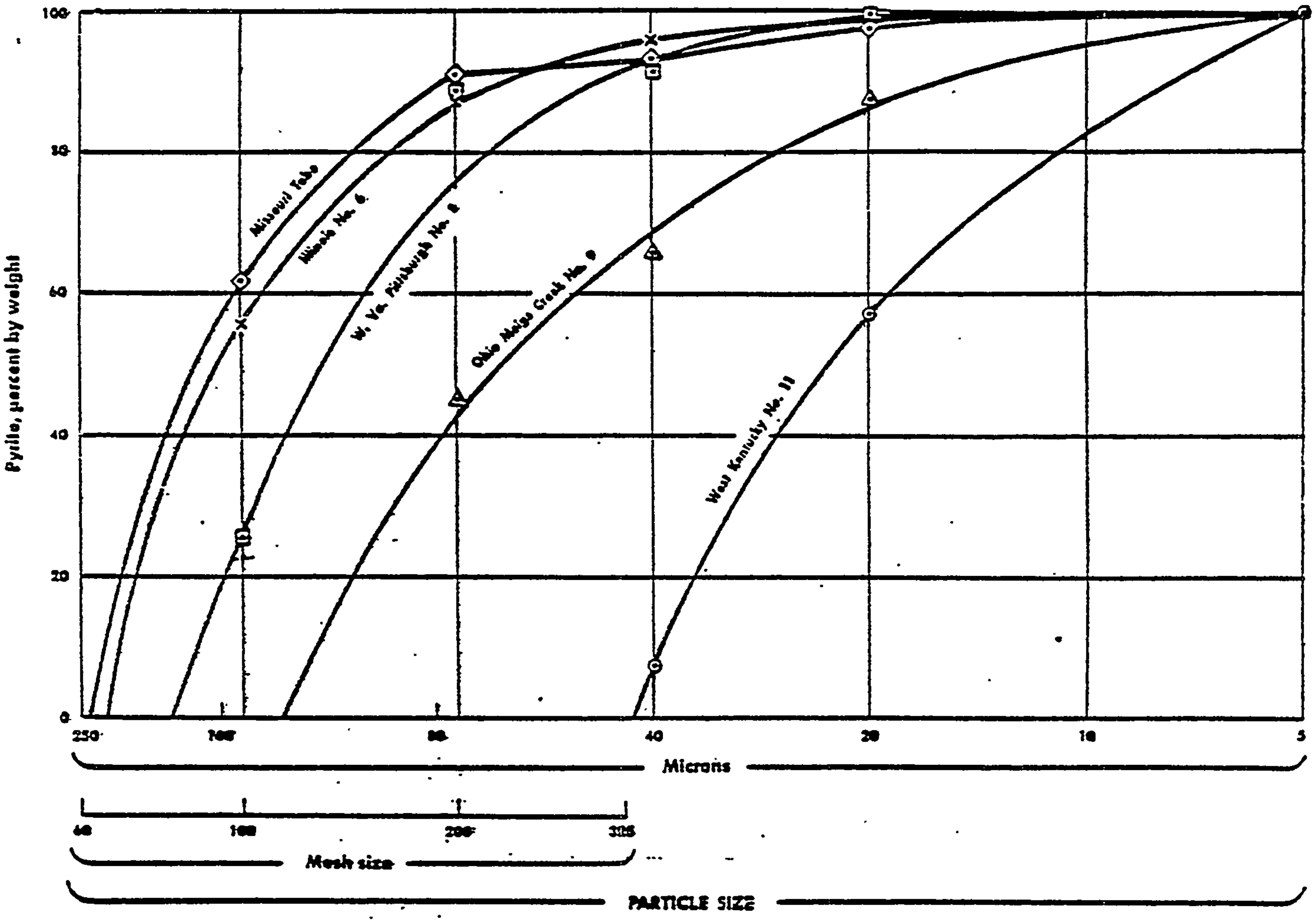


Table 4, continued

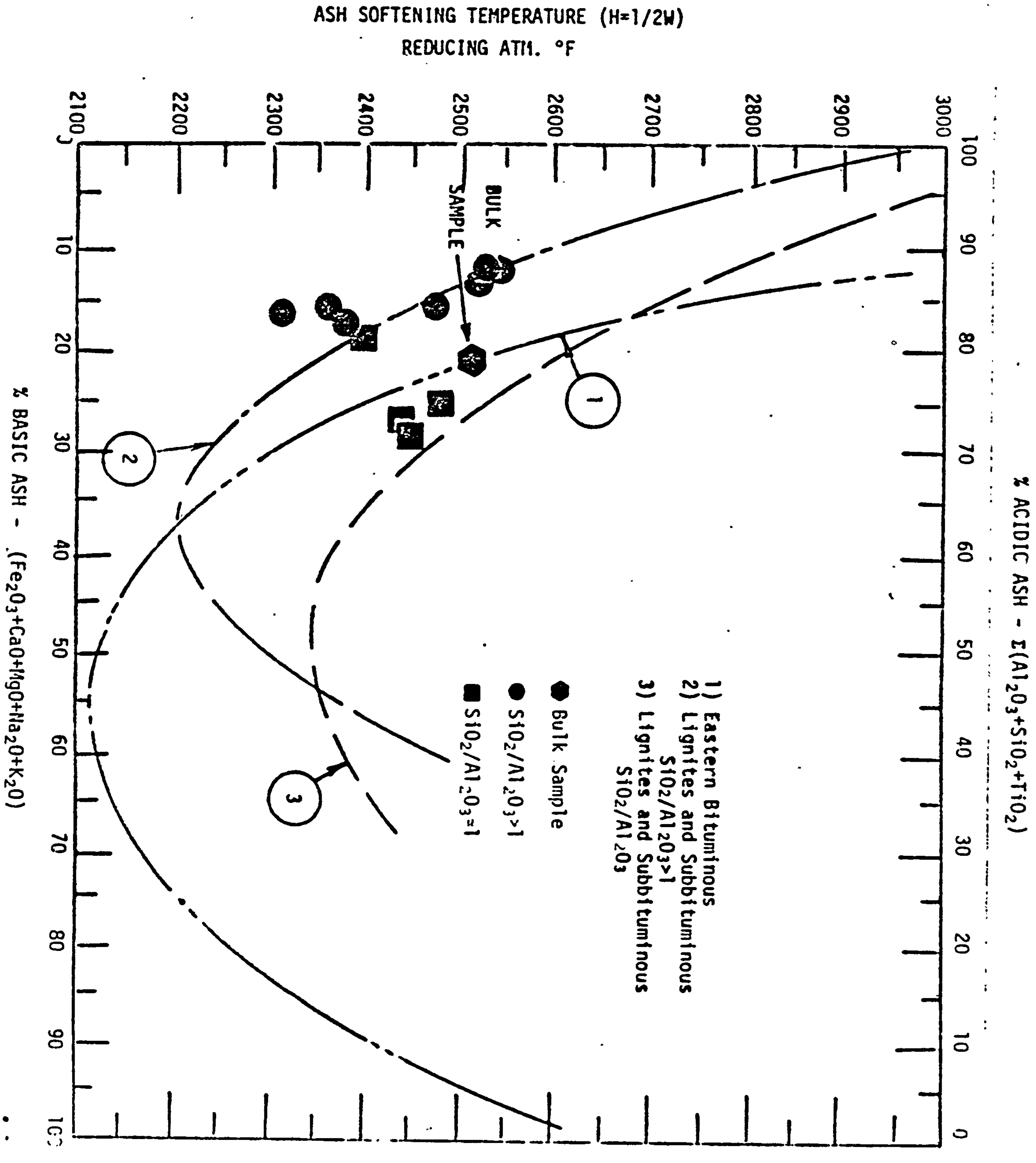
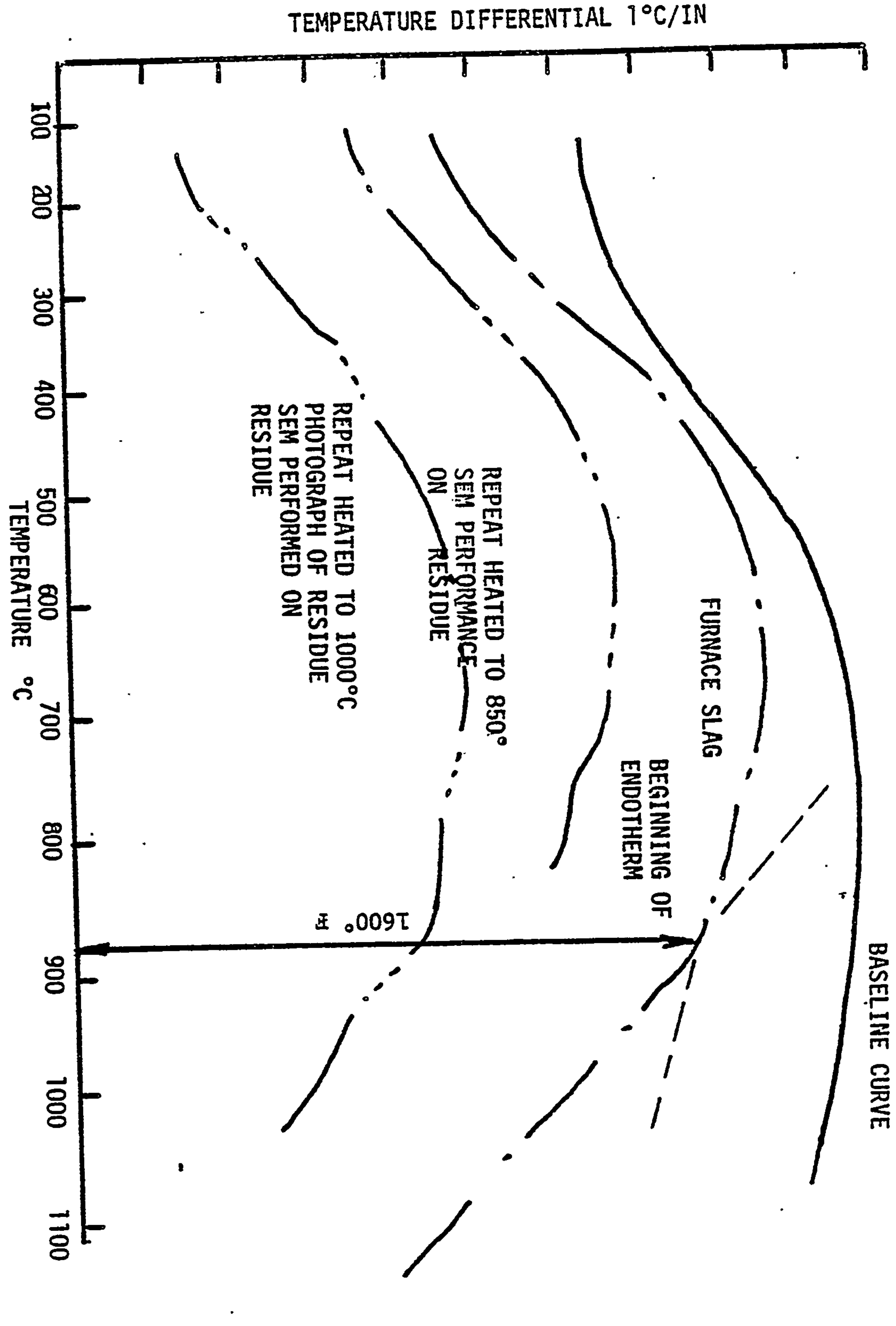


Table 4, continued



DIFFERENTIAL THERMAL ANALYSIS OF FURNACE SLAG

Table 4, continued

Comparison of Ash Chemistry of Coal and Slag

Element as an Oxide	Coal	Slag
SiO_2	31.8	66.0
Al_2O_3	13.8	10.3
TiO_2	0.5	0.3
Fe_2O_3	8.8	4.5
CaO	20.0	16.8
MgO	3.5	1.9
Na_2O	0.6	0.3
K_2O	1.0	1.1
SO_3	13.3	0.1
P_2O_5	0.5	0.1
Ash Fusion:		
Reducing/Oxidizing		
Initial Deformation	2075/2160	2010/2060
Softening (Sph.)	2131/2236	2020/2070
Softening (Hem.)	2172/2360	2035/2090
Fluid	2768/2395	2180/2250

Table 4, continued

Compositions of the Slag Sample From a Wall Tube of the Furnace After Firing Polish Coal

Elementary Composition (Wt%):

	1	2	3	Coal
SiO_2	24.59	63.01	64.29	45-55
Al_2O_3	10.13	13.70	14.11	20-30
Fe_2O_3	56.30	8.46	8.57	7-12
CaO	2.87	3.15	2.96	5-8
MgO	2.57	2.44	2.45	3-5
K_2O	1.98	1.94	2.20	1.5-2.5
Na_2O	1.21	0.61	0.66	0.3-1.0
SO_3	3.12	0.23	0.29	1-5
	102.77	93.54	95.53	

Main Compounds:

1	2 and 3
Hematite, Fe_2O_3	Silicate Glass Quartz, SiO_2
Anhydrite, $CaSO_4$	Anorthite, $CaO \cdot Al_2O_3 \cdot 2SiO_2$
Silicate Glass	Magnetite, Fe_3O_4
	Hematite (traces), Fe_2O_3

Table 4, continued

Compositions of the Slag Sample From the Noncooled Brickwork Wall in the Lowest Part of the Furnace After Firing Polish Coal

Elementary Composition (Wt%):

	1	2	3	Coal
SiO_2	52.17	54.55	53.78	45-55
Al_2O_3	18.73	16.05	17.88	20-30
Fe_2O_3	12.54	11.24	12.34	7-12
CaO	6.16	5.36	6.01	5-8
MgO	3.93	3.35	3.70	3-5
K_2O	1.74	1.61	1.72	1.5-2.5
Na_2O	0.54	0.36	0.42	0.3-1.0
SO_3	0.43	0.20	0.25	1-5
	96.24	92.72	96.10	

Main Compounds:

Silicate Glass

Quartz, SiO_2

Anorthite, $CaO \cdot Al_2O_3 \cdot 2SiO_2$

Magnetite, Fe_3O_4

Hematite, Fe_2O_3 (traces)

Table 4, continued

Comparison of Coal Ash and Slag Deposit Formed From a North Dakota Lignite

Elemental Analysis	Coal	Bottom Ash	Furnace Deposit Inside Layer	Furnace Deposit Middle Layer	Furnace Deposit Outside Layer	Superheater	Economizer
SiO_2	32.0	28.75	15.5	15.5	25.0	25.0	33.50
Al_2O_3	12.5	14.25	18.0	17.5	15.0	15.0	13.0
TiO_2	0.6	0.48	0.30	0.30	0.50	0.50	0.55
Fe_2O_3	7.5	13.0	54.0	26.0	25.5	8.5	17.0
CaO	24.60	28.0	12.0	20.0	21.4	28.5	31.8
MgO	0.70	8.33	0.50	1.90	3.50	7.4	2.68
Na_2O	3.48	0.27	0.40	1.46	1.71	3.6	2.70
K_2O	0.48	0.36	0.38	0.36	0.24	0.48	0.30
P_2O_5	2.98	0.68	0.80	2.07	2.29	3.45	0.46
SO_3	16.40	3.58	5.90	11.90	3.60	10.0	2.05
Ash Fusion (Reducing):							
In. Def.	2250	---	2450	2330	2220	2240	2280
Softening	2310	---	2640	2400	2280	2350	2320
Fluid	2350	---	2800	2580	2420	2600	2340

Table 4, continued

SAMPLES FROM IGT GASIFIER

CYCLONE DISCHARGE:	AL_2SIO_5 (KYANITE), FE_2SIO_4 (FAYALITE), $FEAL_2O_4$ (HERCYNITE) S (BY LECO): 0.6%
CYCLONE INLET DEPOSIT:	FE_2SIO_4, $FE_{i-x}S$ (PYRRHOTITE), FE_3O_4 (MAGNETITE) S (BY LECO): 6%
INTERNAL CYCLONE DEPOSIT:	$FE_{i-x}S$, FE_3O_4 S (BY LECO): 34%
CYCLONE DEPOSIT:	POORLY CRYSTALLIZED. DETECTED PRESENCE OF FE_3O_4 AND FE_2SIO_4

Table 4, continued

COMPARISON OF GASIFIER DEPOSIT WITH RAW COAL

ELEMENT	RAW COAL	DEPOSIT
SiO_2	38.0	10.77
Al_2O_3	32.5	3.74
TiO_2	1.0	---
Fe_2O_3	17.7	73.75
CaO	5.5	5.21
MgO	0.5	0.30
Na_2O	<0.1	---
K_2O	2.1	---
SO_3	2.0	6.20

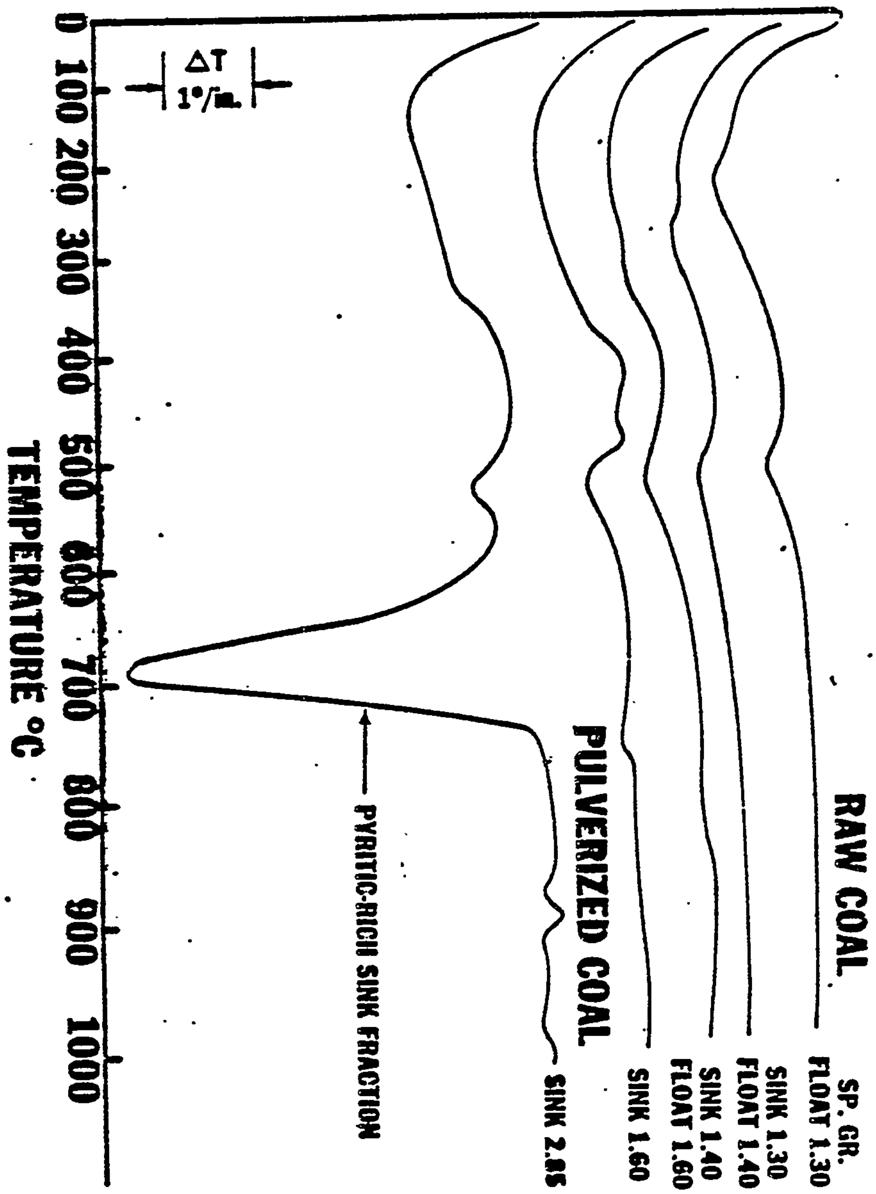
Table 4, continued

Comparison of Ash Chemistry of Slag from a Steam Generator and Gasifier with Ash Chemistry of -40 Mesh/+100 Mesh, -2.85 Gravity Fraction

Chemical Constituents	Slag (Inside Layer)	Slag (Outside Layer)	Ash Chemistry -40 +100	Ash Chemistry (Bulk Coal Sample)	Gasifier Deposit
SiO_2	6.9	12.5	4.9	47.9	10.77
Al_2O_3	8.9	8.5	2.8	30.6	3.74
TiO_2	0.2	0.3	0.1	1.0	—
Fe_2O_3	79.2	73.7	86.3	8.3	73.75
CaO	1.3	2.5	0.1	3.4	5.21
MgO	1.0	1.3	0.8	1.5	0.30
Na_2O	1.8	2.6	1.4	0.2	—
K_2O	0.2	0.4	0.2	1.4	—
SO_3	N.D.	N.D.	N.D.	3.5	6.20
P_2O_5	N.D.	N.D.	N.D.	N.D.	—
Ash Fusion Temperatures (°F)					
Reducing Atmosphere					
Initial Deformation	2400	2100	2288	1960	—*
Softening (Sph.)	2560	2180	2330	2340	—
Softening (Hem.)	2800	2250	2320	2920	—
Fusion	2800	2340	2400	2800	—
Oxidizing Atmosphere					
Initial Deformation	2680	2680	2800	2020	—
Softening (Sph.)	2800+	2800+	2800	2800	—
Softening (Hem.)	2800+	2800+	2800	2800	—
Fusion	2800+	2800+	2800	2800	—

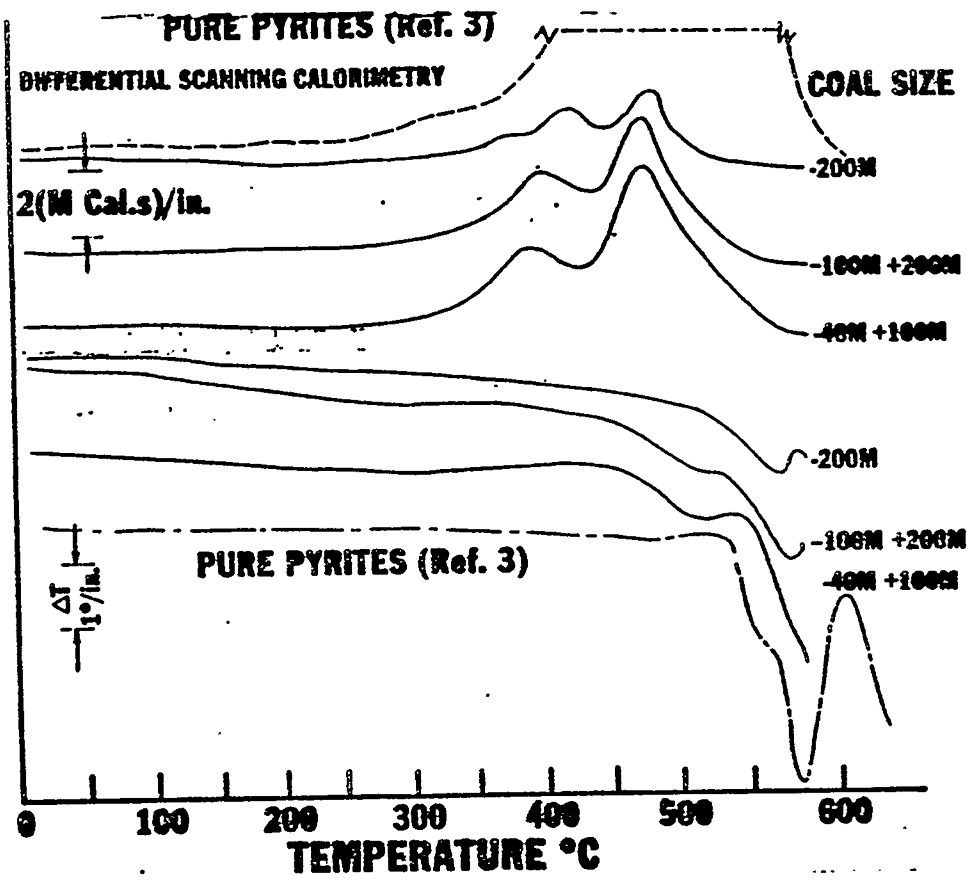
*Sample fused in crucible during ashing.

Table 4, continued



DIFFERENTIAL THERMAL ANALYSIS THERMOGRAMS OF LOW TEMPERATURE ASH FROM VARIOUS RAW COAL GRAVITY FRACTIONS COMPARED WITH THE 2.85 SINK

Table 4, continued



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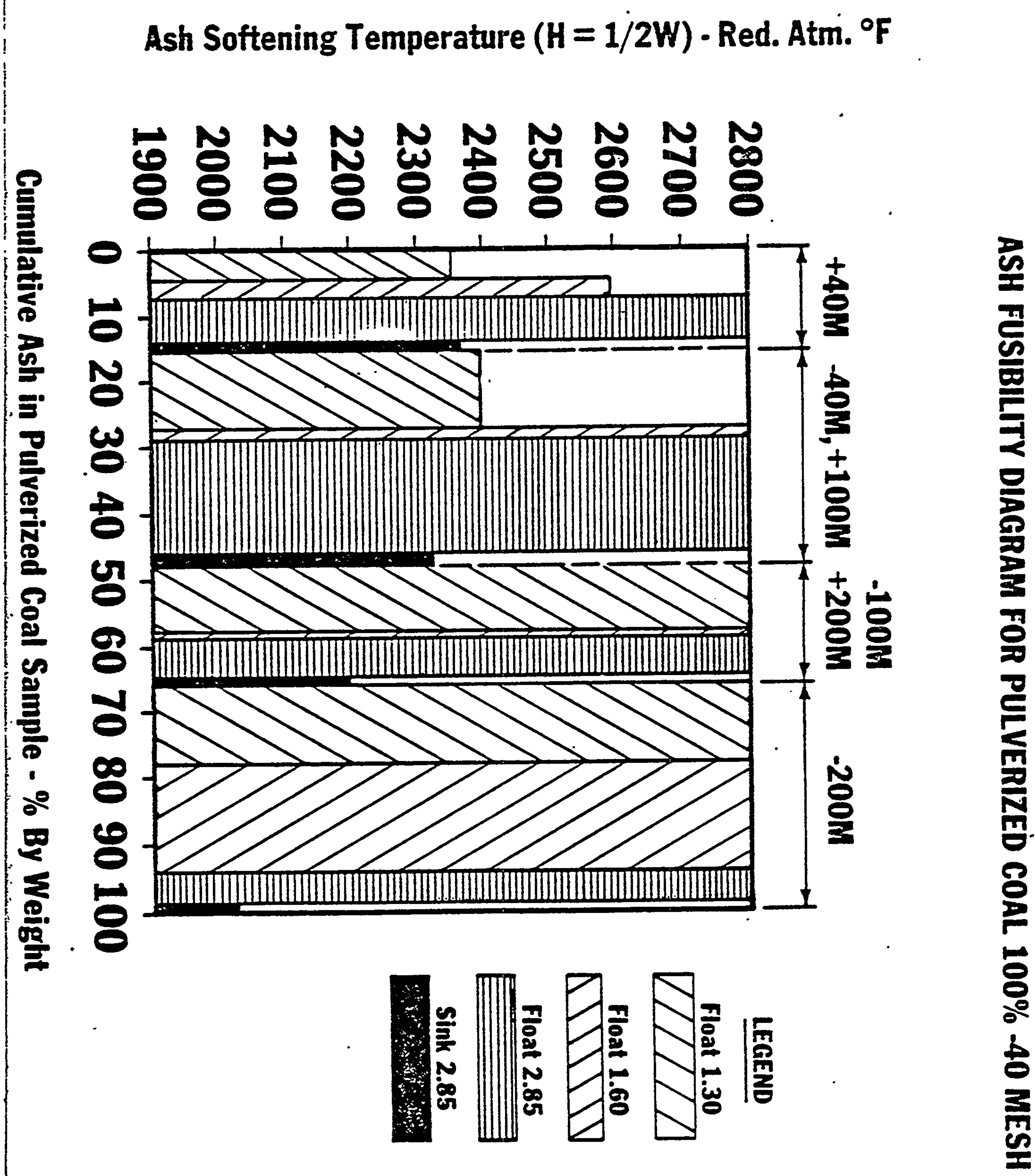


Table 4, continued

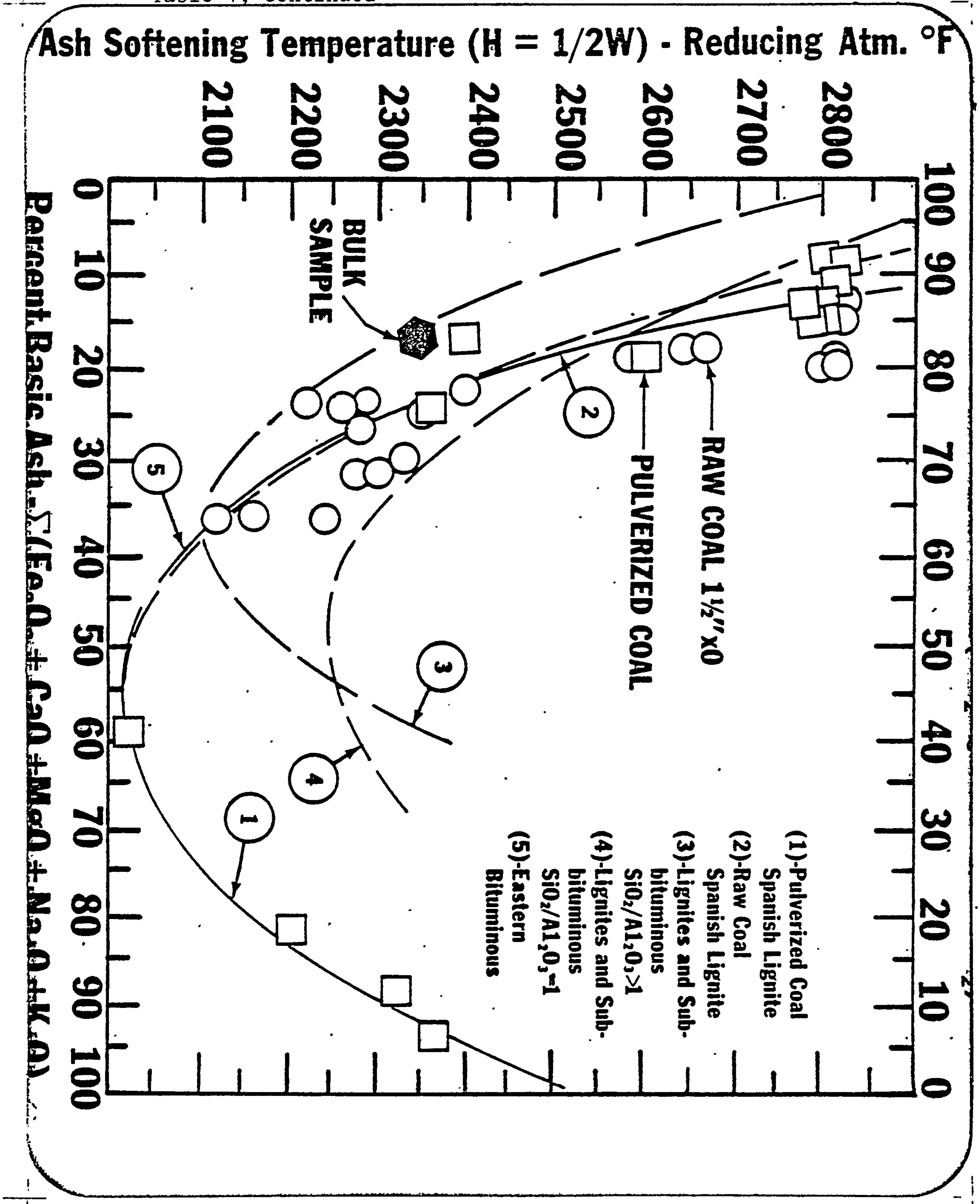
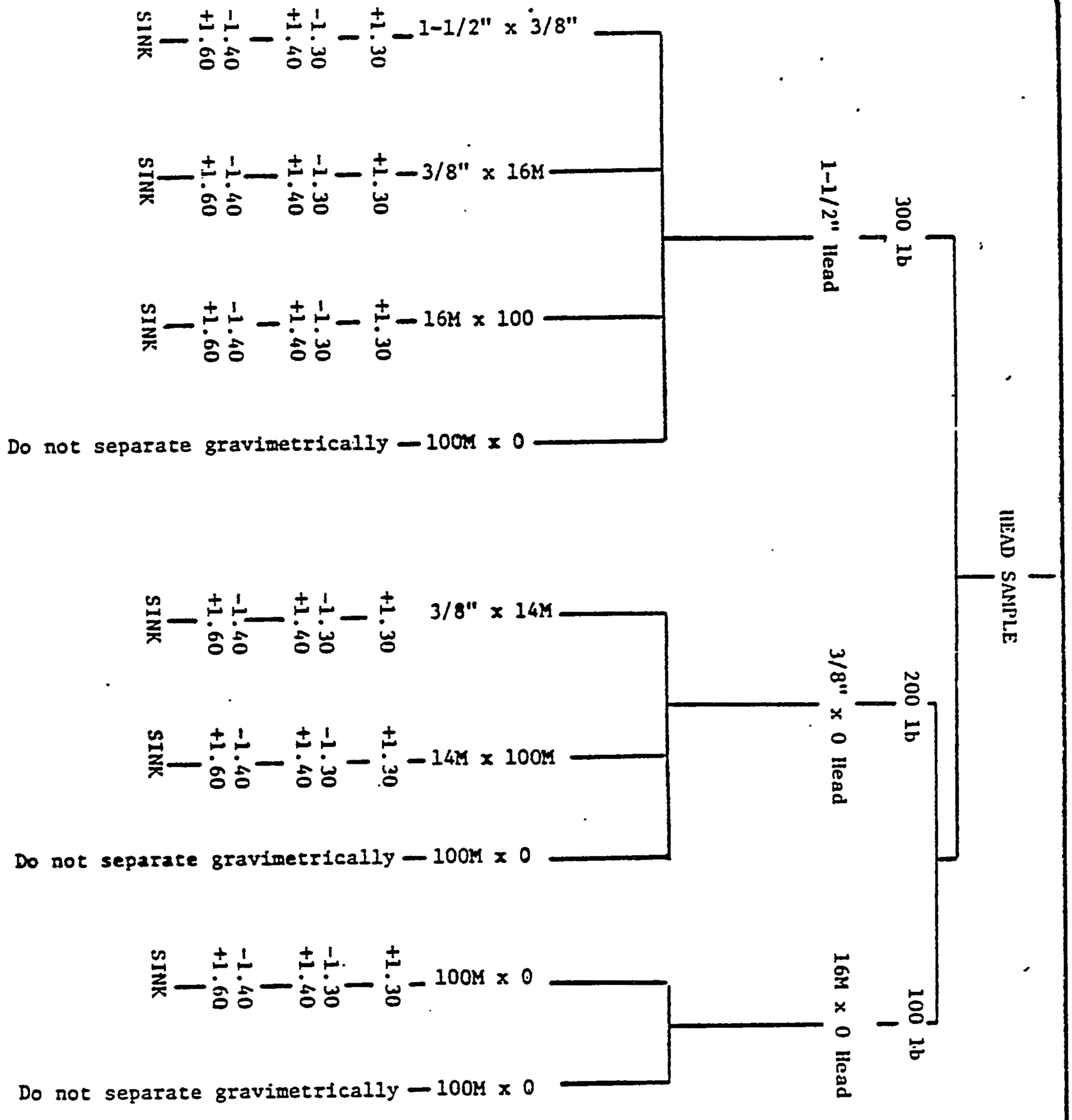


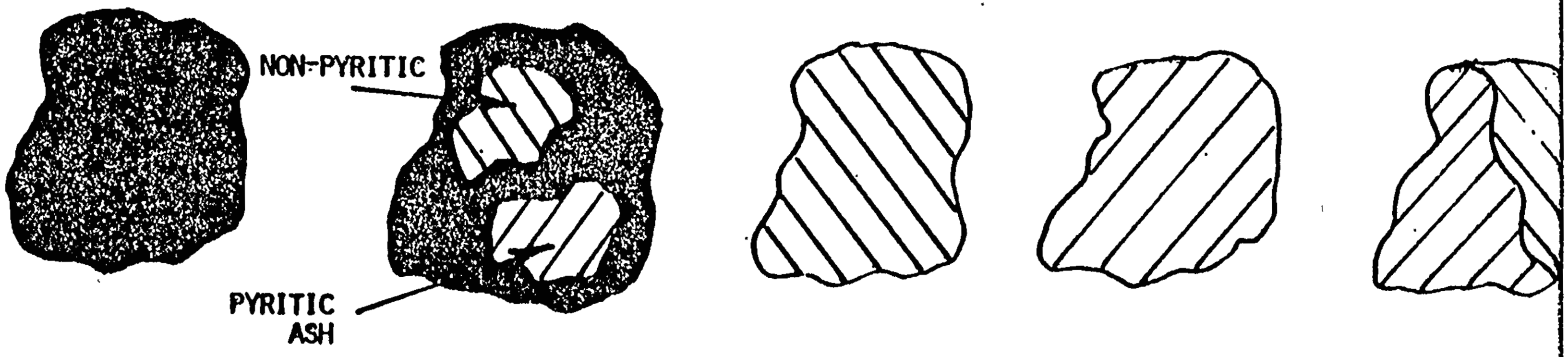
Table 4, continued



PROCESS FLOW DIAGRAM - RAW COAL WASHABILITY TEST

Table 4, continued

SCHEMATIC OF THE MINERAL OCCURRENCE IN ONE SIZE OF PULVERIZED COAL



	RAW COAL	RAW COAL PLUS ASH	NON-PYRITIC ASH	PYRITIC ASH	ASH BLEND
SPECIFIC GRAVITY		1.3 - 1.60	2.50	5.00	2.50 - 2.8
MELTING TEMPERA-TURE	—	2200 - 2800+	2800	1000°F (RED. ATM.)	2200 - 2800

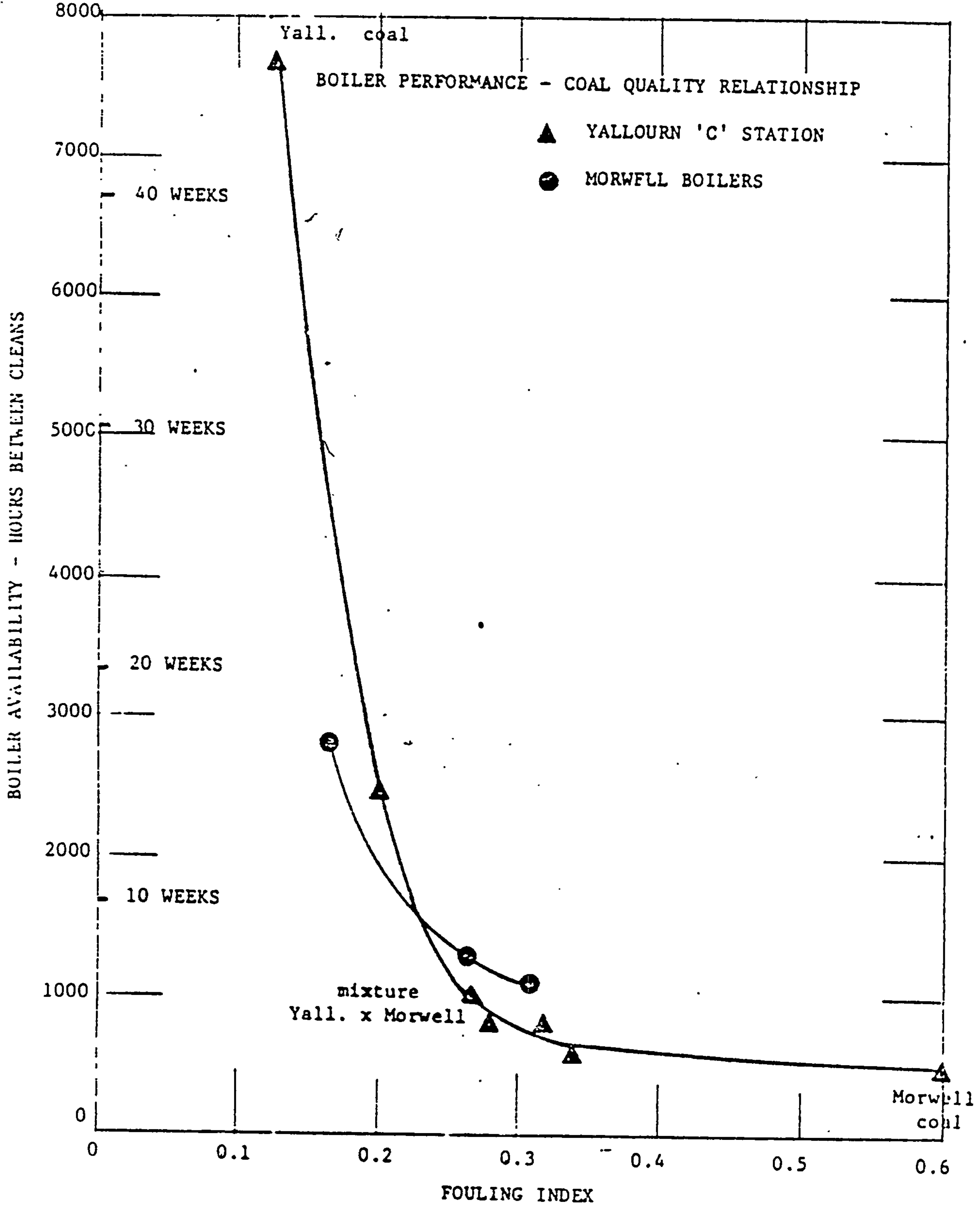
Table 4, continued

Test	Index		Values			Fuels
1. Ash Fusion Temperature	Initial Deformation Temperature	I.D.	Function of Ash Chemistry			All
	Softening Temperature (Sph.)	S.T.	S.T. Used to Select Furnace Exit			
	Softening Temperature (Hemp.)	H.T.	Temperature			
	Fusion Temperature	F.T.	Dry Bottom Furnace <			
			Slagging Furnace >			
2. T_{cv}	Temp. at Which Viscosity Changes From Newtonian to Bingham Plastic		None			All
3. T_{250}	Temperature at 250 Poise		Ratings (Dry Bottom)	T_{250}	Ratings (Wet Bottom)	All
			Low	>2325	T_{250} <2600°F	
			Medium	2550 to 2100		
			High	2275 to 2050		
			Severe	<2200		
4. % Basic Constituent	$\Sigma\%(Fe_2O_3 + CaO + MgO + Na_2O + K_2O)$		None			All
5. Base-to-Acid Ratio (B/A)	$\frac{\Sigma\%(Fe_2O_3 + CaO + MgO + Na_2O + K_2O)}{\Sigma\%(Al_2O_3 + SiO_2 + TiO_2)}$		0.5 Maximum for Dry Bottom Units			All
			>0.27 for Wet Bottom Units			
6. R_s - Slagging Factor	B/A x % S on Dry Coal		R_s	Slagging Type		Eastern Coals Only
			<0.6	Low		
			0.6-2.0	Medium		
			2.0-2.6	High		
			>2.6	Severe		
7. R_f, R_f' - Fouling Factor	R_f = B/A x % Na_2O (ASTM Ash)		R_s	R_f'	Fouling Type	Eastern Coals Only
	R_f' = B/A x % Water Soluble Na_2O From LTA (Low Temperature Ash)		<0.2	<0.1	Low	
			0.2-0.5	0.1 -0.25	Medium	
			0.5-1.0	0.25-0.7	High	
			>1.0	>0.7	Severe	

Table 4, continued

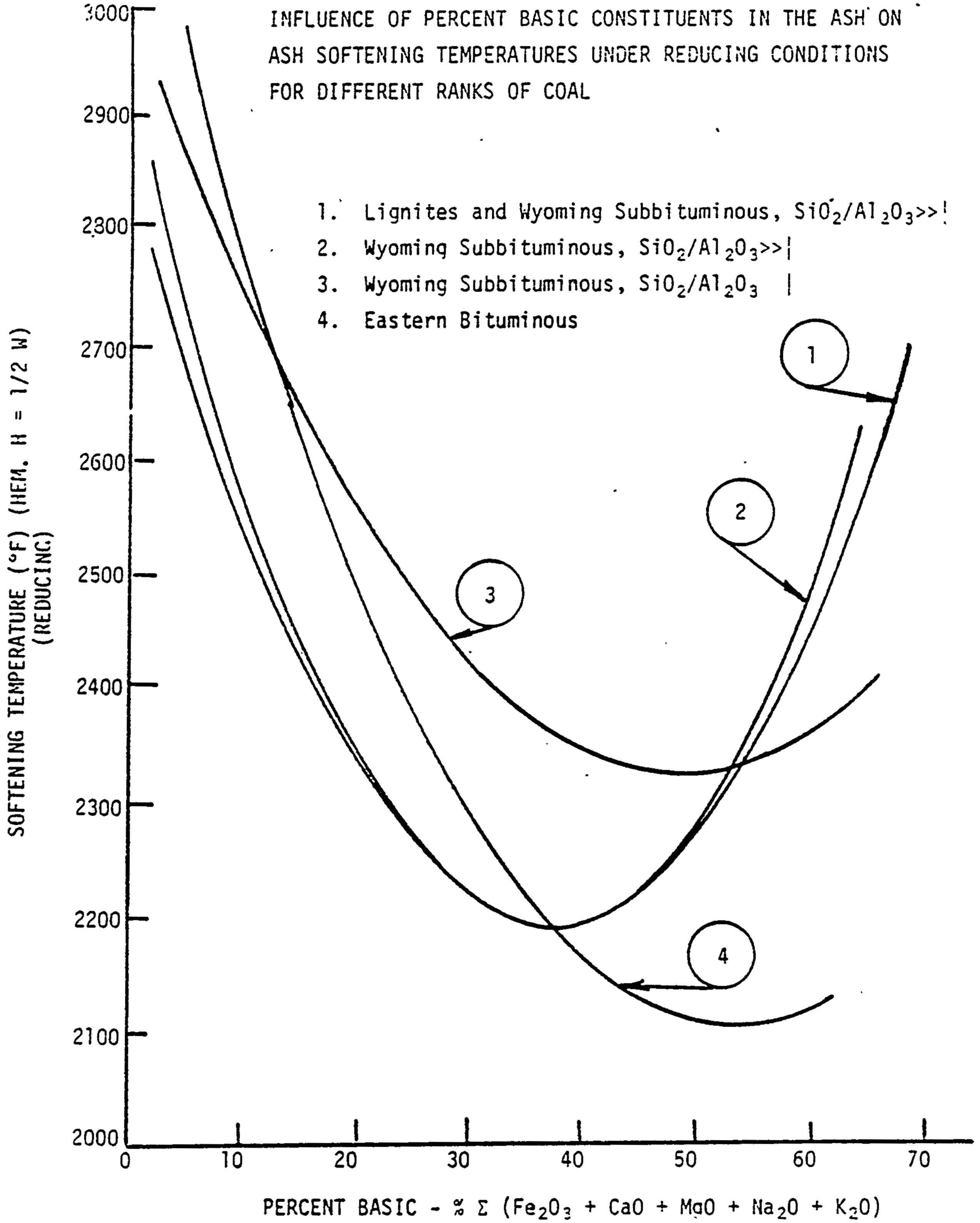
Test	Index	Values				Fuels
		Lignitic		Bituminous		
8. Sodium Content of Coal Ash	% Na_2O in ASTM Ash	% Na_2O	Fouling	% Na_2O	Fouling	All
		<2.0	Low	<0.5	Low	
		2-6	Medium	0.5-1.0	Medium	
		6-8	High	1.0-2.5	High	
		8	Severe	>2.5	Severe	
9. Alkali Content of Coal Ash	Σ(% Na_2O + 0.6589 x % K_2O)	Same as 8.				All
10. Alkali Content of Coal	Σ(% Na_2O + 0.6589 x % K_2O) x $\frac{\%\ Ash}{100}$	Alkali %	Fouling			Eastern Coals Only
		<0.3	Low			
		0.3 -0.45	Medium			
		0.45-0.6	High			
		>0.60	Severe			
11. Ash Sintering Strength	Compression Strength of Specially Prepared Fly Ash Pellets	Fouling Type Fouling Type	Strength of Sintered Fly Ash (1700°F)			All
		Low	1000			
		Medium	1000-5000			
		High	5000-16000			
		Severe	>16000			
12. Chlorine	% on Coal	Fouling Type	% on Coal			All
		Low	<0.2			
		Medium	0.2-0.3			
		High	0.3-0.5			
		Severe	>0.5			

Table 4, continued

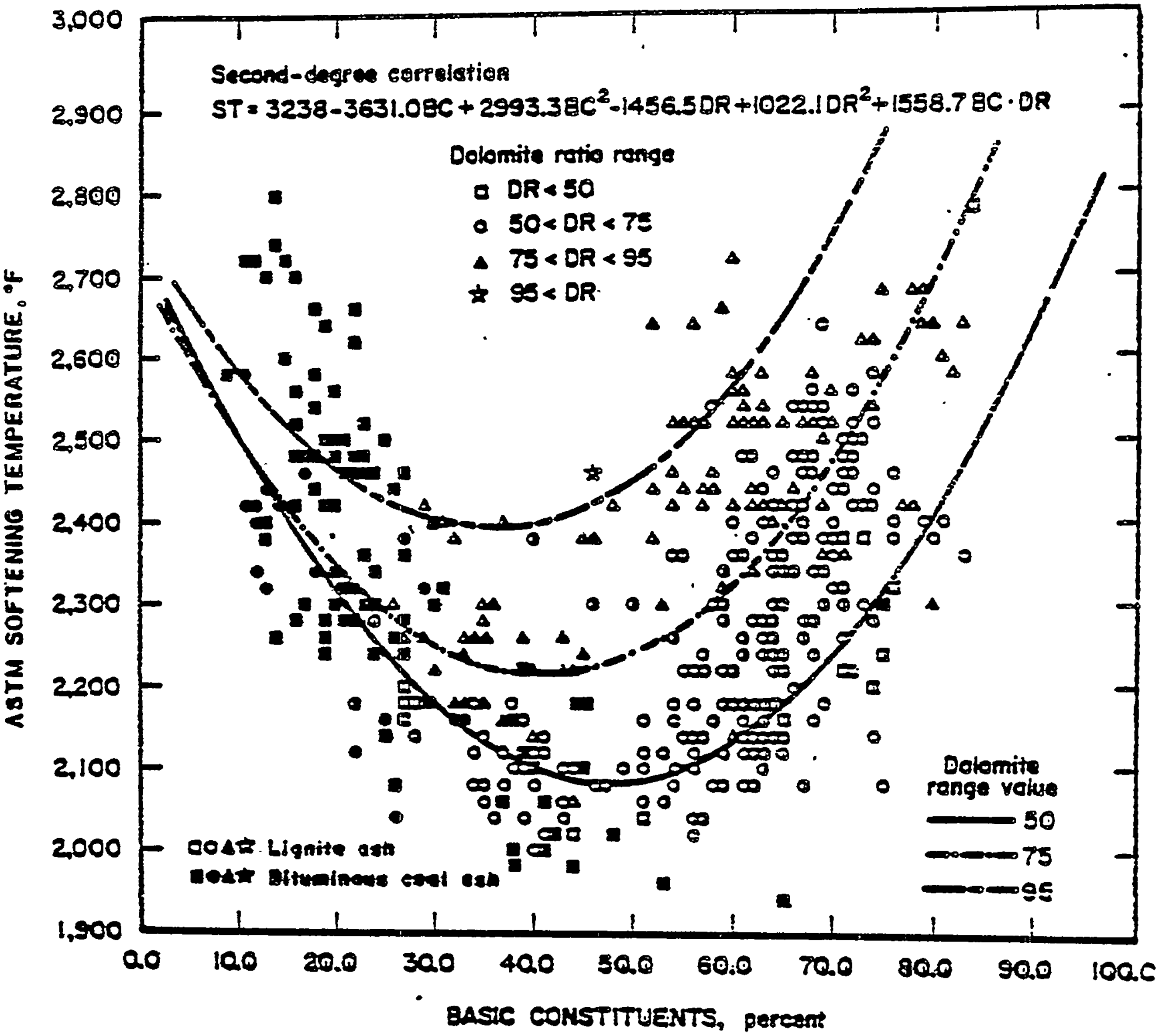


FOULING INDEX vs BOILER AVAILABILITY

Table 4, continued



INFLUENCE OF PERCENT BASIC CONSTITUENTS IN THE ASH ON ASH SOFTENING TEMPERATURES UNDER REDUCING CONDITIONS FOR DIFFERENT RANKS OF COAL



· Prediction of softening temperature for ash from lignite and bituminous coals usin the percentage of basic constituents (BC) and the dolomite ratio (DR) as parameters

Figure 7

Table 3 Summary of Fusibility Correlations

Investigator	Correlation	Coal Type	Coal Nos.	Standard Daviation	Correlation Coefficient	Remarks
Nicholls, Selvig, Rickets - 1932	$(SiO_2 + Al_2O_3)/(Fe_2O_3 + CaO + MgO + Na_2O + K_2O)$	Bituminous U.S.	135 -	150.6 154.8	0.674 0.409	When applied to bituminous When applied to lignite by Sondreal
Schaefer - 1933	$RS = (Al_2O_3/SiO_2)/(SiO_2 + Al_2O_3/$ $FeO + 0.6\,[CaO + MgO + Na_2O + K_2O])$	Bituminous U.S.	135 -	135.5 165.1	0.748 -0.233	When applied to bituminous When applied to lignite by Sondreal
Majumdar - 1958	$RM = [3.3\,SiO_2 + 1.96\,Al_2O_3]/$ $[2.5\,Fe_2O_3 + 3.57\,CaO - 15.0\,MgO + 3.22\,(Mg_2O + K_2O)]$	Bituminous	135	-	0.702	When applied to lignite by Sondreal
		Indian	-	-	-0.458	When applied to lignite by Sondreal
Nicholls, Reid - 1940	$SiO_2/[SiO_2 + Equiv.\ Fe_2O_3 + CaO + MgO]$	Bituminous U.S.	135 -	- -	-0.514 -0.598	When applied to bituminous When applied to lignite
Duzy - 1965	$Fe_2O_3 + CaO + MgO + Na_2O + K_2O$	Lignite U.S.	- -	- -	0.592 0.82	
	With $DR = [CaO + MgO]/[Fe_2O_3 + CaO + MgO + Na_2O + K_2O]$ as a parameter					
Sondreal - 1975	$LR = [1.74\,(Na_2O + K_2O) + 0.73\,SiO_2 + 0.39\,(Fe_2O_3)]/[1.40\,(CaO) + MgO]$	Lignite U.S.	135	72.4	0.923	
Bryers and Taylor - 1976	$ST_{RED} = 2863 - 37.1X + 0.151X^2$	Western U.S. SiO_2/Al_2O_3 3 ±20%	151	100.4	0.772	Data includes composite ash fusion temperatures as well as size and gravity fractionate coal ash fusion temperatures
	$ST_{RED} = 2942 - 27.1X + 0.27X^2$	Western U.S. SiO/Al_2O_3 1 ±20%	30	113.1	0.63	
	$ST_{OXD} = 2814 - 35X + 0.50X^2$	Western U.S.	79	99.5	0.773	
	$ST_{RED} = 3114 - 38.6X + 0.37X_2$	Eastern	-	-	-	
	Where $X = [Fe_2O_3 + CaO + MgO + Na_2O + K_2O]$					
Dutta Rai and Chakravorty - 1960, 1962	Calculate: 1) $SiO/(Al_2O_3 + TiO_2)$ 2) $[CaO + MgO]$ from $[SiO_2 + Al_2O_3 + TiO_2 + CaO + MgO]$ Estimate hemispherical temperature (H.T.) Subtract 25° for each percentage $[Na_2O + K_2O]$ Correct for Fe_2O_3 using empirical curve	Indian	-	-	-	Used British H.T. Three empirical curves required 1) H.T. vs $CaO + MgO$* 2) H.T. vs Fe_2O_3 3) H.T. vs Fe_2O_3 (RED/OXD) * With $SiO_2/(Al_2O_3 + TiO_2)$ as a parameter

Table 4, continued

Investigator	Correlation	Coal Type	Coal Nos.	Standard Deviation	Correlation Coefficient	Remarks
Gauger - 1951	Calculate: $S = SiO_2 + TiO_2 + P_2O_5$ $A = Al_2O_3$ $T = CaO + 0.7MgO + 2.25\ Na_2O + 1.5K$ Obtain: $\%S = (S/S + A + T)100$ $\%A = (A/S + A + T)100$ $\%T = (T/S + A + T)100$ From ternary diagram S, A, T, (%) obtain softening temperature Determine: $\%\ t = (Fe_2O_3/S + A + T + Fe_2O_3)100$ From empirical curves obtain $\Delta T_{Fe_2O_3}$ and subtract from softening temperature	Bituminous U.S.	-	-	-	ASTM ash fusion
Estep, Seltz and Osborn - 1937	Obtain: %CaO from $SiO_2 + Al_2O_3 + Fe_2O_3 + CaO = 100\%$ Determine hemispherical temperature from $SiO_2 - Al_2O_3 - Fe_2O_3$ ternary diagrams modified by CaO for specific CaO conc. MgO compensation for by combining with CaO; Na_2O compensated for by subtracting 50°/percent Na_2O	U.S.	-	±100°	1786	
Kovitskii, Karagodina, and Martynova - 1975	$K_{fu} = (SiO_2 + Al_2O_3/Fe_2O_3 + CaO + MgO)$ $t_2 = 1094 + 42.5K_{fu}$ (softening temperature) $t_3 = 1139 + 48.6K_{fu}$ (fluid state	Soviet	-	-	-	
Kovitskii, Karagodina, and Martynova - 1975	$Ku = (SiO_2 + P_2O_5/Al_2O_3 + Fe_2O_3 + CaO + MgO)$ $T_{200°C} = 1085 + 318K_v$ Valid $0.42 \leq K_v \leq 2.03$	Soviet	-	55% ± 90°F 15% ± 135°F	-	
Bensigmeur - 1963	$(RB = SiO_2 + Al_2O_3 + MgO/CaO + Fe_2O_3 + K_2O)$ Plotted against $(DB + FB)/2$ DB - Deformation Temperature FB - Fusion Temperature	French	94	-	-	
Winegartner, Rhodes - 1974	(F.T., S.T., I.D.) = f (51 independent variables including Al_2O_3, SiO_2, Fe_2O_3, Ca, MgO, Na_2O, K_2O, and various groups of the same	U.S. Eastern Western	2	-	-	
L. Garner - 1964	Deposit Weight = X Where: $X_1 = 0.030\ [TiO_2] + 0.09\ [Fe_2O_3] + 0.061\ [CaO] +$ and $0.264\ [MgO] + 0.423\ [Na_2O] - 10.6$ $X_2 = 0.044\ [TiO_2]^{0.094} \cdot [Fe_2O_3]^{0.499} \cdot [CaO]$ [illegible] $[MgO]^{0.220} \cdot [Na_2O]^{0.728}$	Australian	-	-	-	Applicable only to Australian coals. However, most practical correlation as chemistry directly relate to full-scale outage based on pilot plant tests.

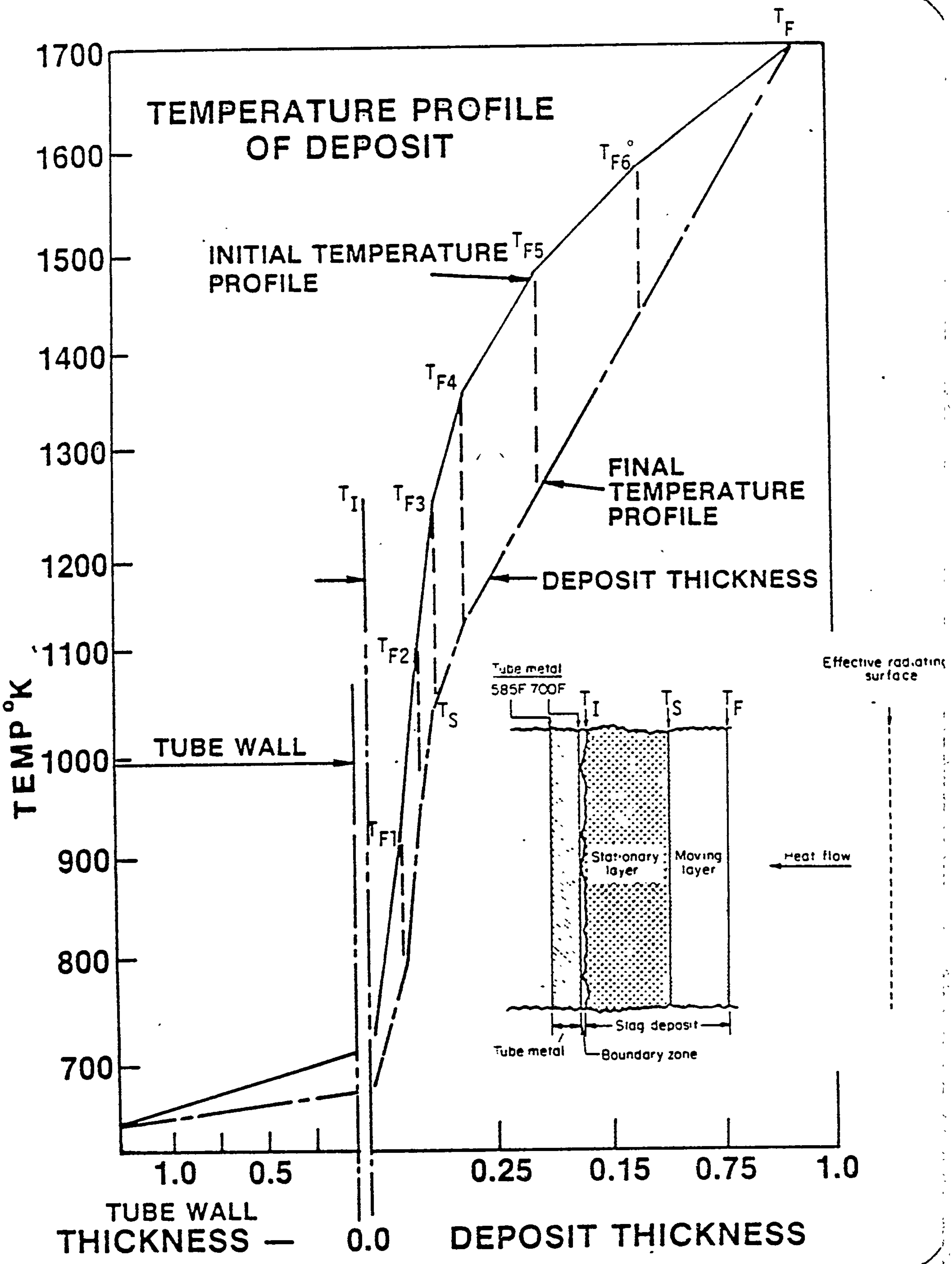
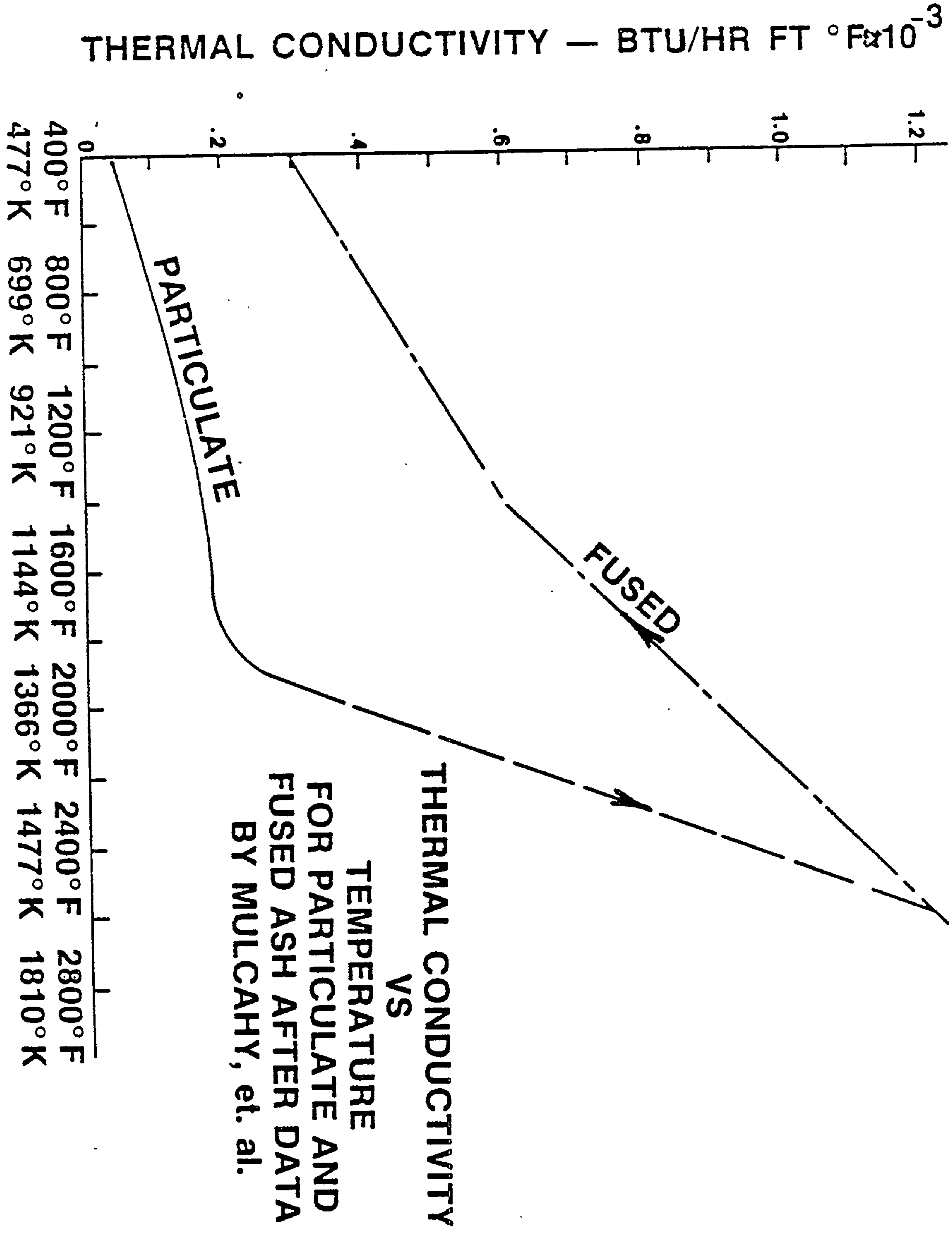
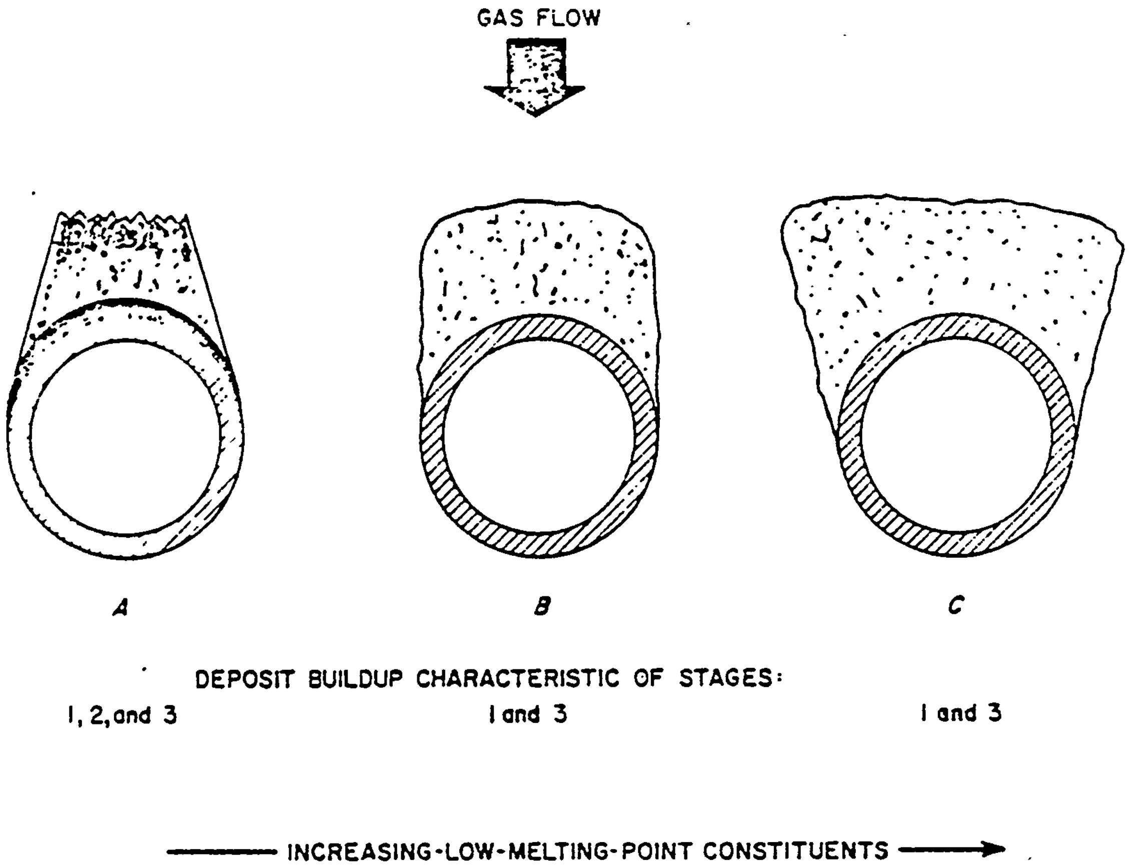

TEMPERATURE PROFILE OF DEPOSIT
1700
1600
1500
1400
1300
1200
1100
1000
900
800
700
TEMP °K
T_F
T_{F6}
T_{F5}
T_{F4}
T_{F3}
T_{F2}
T_{F1}
T_I
T_S
INITIAL TEMPERATURE PROFILE
FINAL TEMPERATURE PROFILE
DEPOSIT THICKNESS
TUBE WALL
Tube metal
585F 700F
Stationary layer
Moving layer
Heat flow
Effective radiatin
surface
Slag deposit
Tube metal
Boundary zone
1.0
0.5
0.0
0.25
0.15
0.75
1.0
TUBE WALL THICKNESS —
DEPOSIT THICKNESS

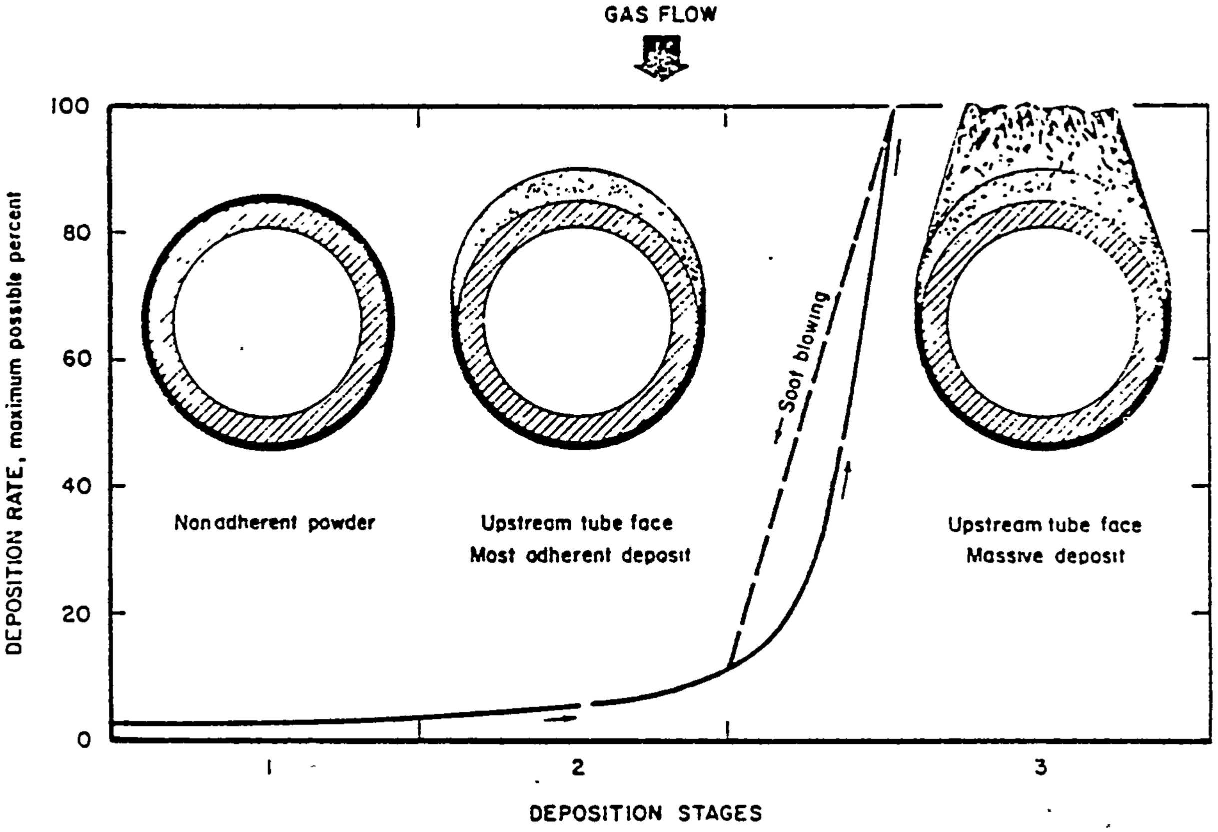
Table 4, continued



THERMAL CONDUCTIVITY
VS
TEMPERATURE
FOR PARTICULATE AND
FUSED ASH AFTER DATA
BY MULCAHY, et. al.

Table 4, continued





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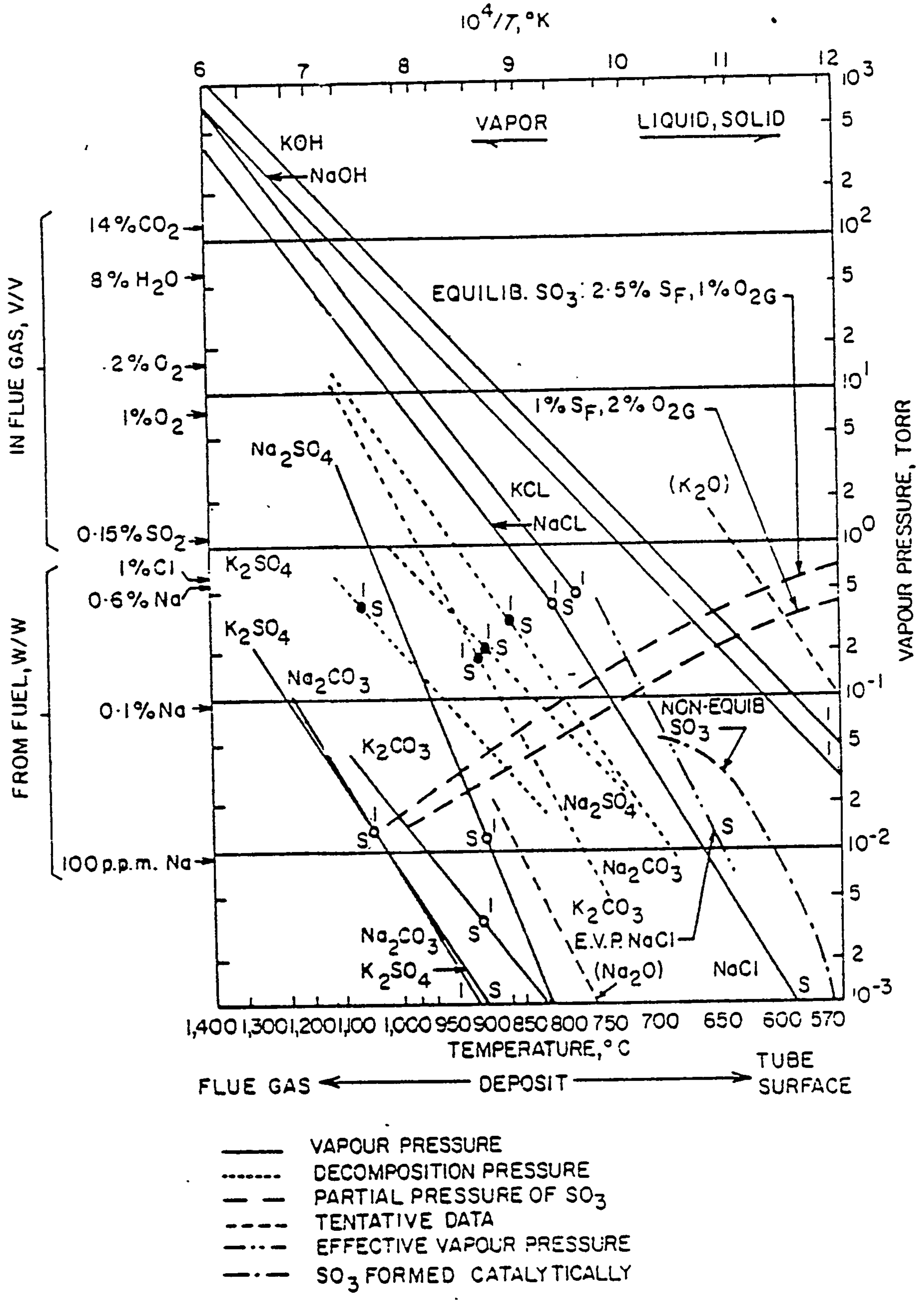

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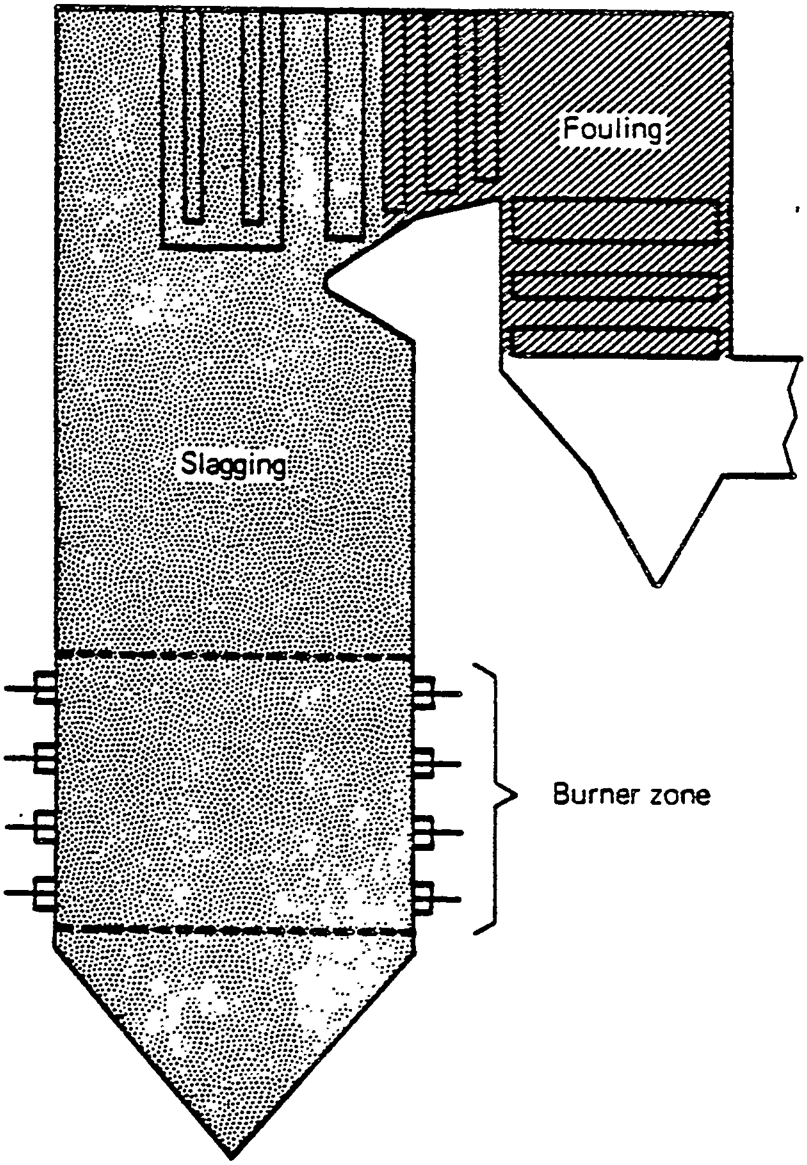

Deposition zones in a coal fired boiler

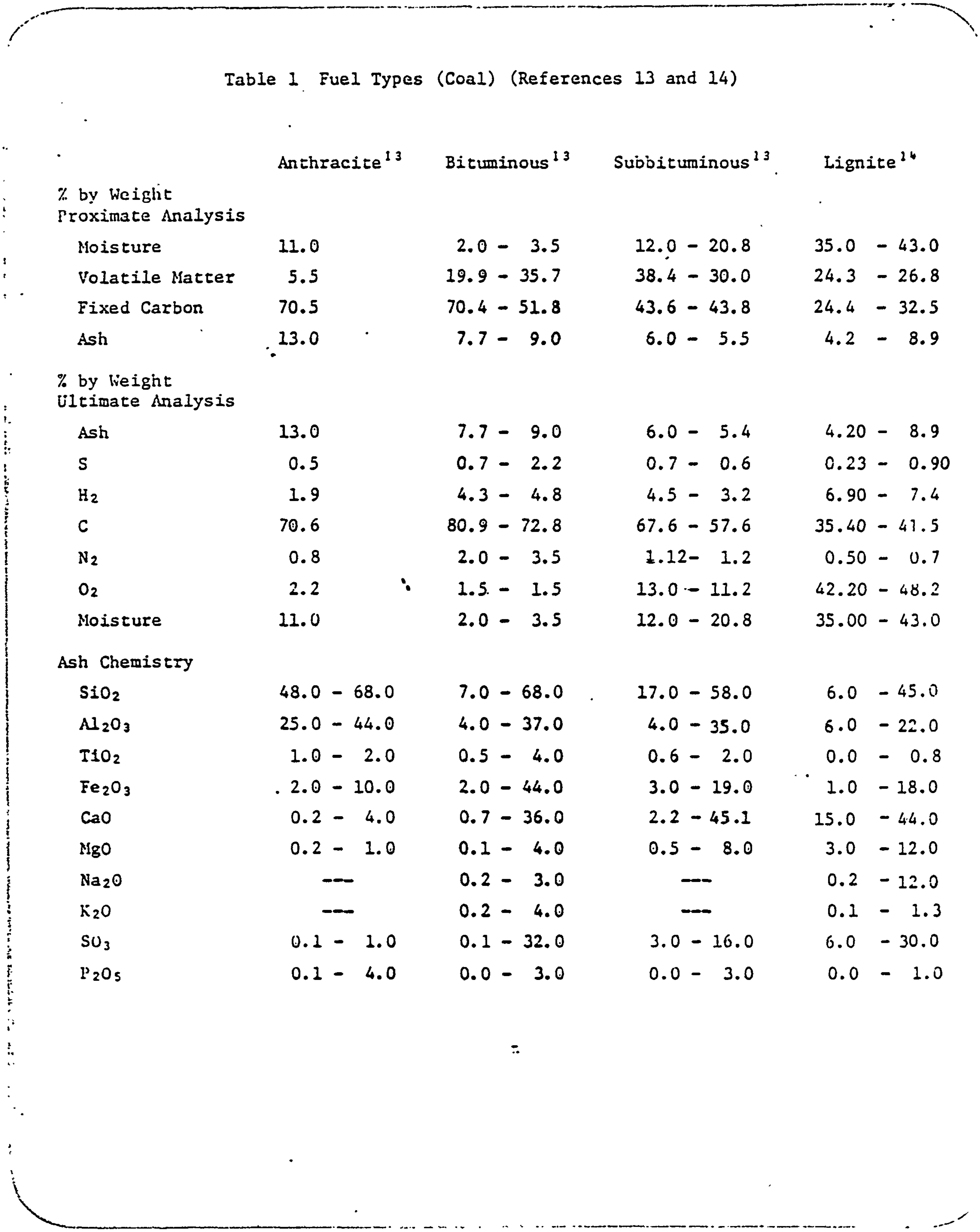

Table 1 Fuel Types (Coal) (References 13 and 14)

	Anthracite[13]	Bituminous[13]	Subbituminous[13]	Lignite[14]
% by Weight Proximate Analysis				
Moisture	11.0	2.0 - 3.5	12.0 - 20.8	35.0 - 43.0
Volatile Matter	5.5	19.9 - 35.7	38.4 - 30.0	24.3 - 26.8
Fixed Carbon	70.5	70.4 - 51.8	43.6 - 43.8	24.4 - 32.5
Ash	13.0	7.7 - 9.0	6.0 - 5.5	4.2 - 8.9
% by Weight Ultimate Analysis				
Ash	13.0	7.7 - 9.0	6.0 - 5.4	4.20 - 8.9
S	0.5	0.7 - 2.2	0.7 - 0.6	0.23 - 0.90
H_2	1.9	4.3 - 4.8	4.5 - 3.2	6.90 - 7.4
C	70.6	80.9 - 72.8	67.6 - 57.6	35.40 - 41.5
N_2	0.8	2.0 - 3.5	1.12- 1.2	0.50 - 0.7
O_2	2.2	1.5 - 1.5	13.0 - 11.2	42.20 - 48.2
Moisture	11.0	2.0 - 3.5	12.0 - 20.8	35.00 - 43.0
Ash Chemistry				
SiO_2	48.0 - 68.0	7.0 - 68.0	17.0 - 58.0	6.0 - 45.0
Al_2O_3	25.0 - 44.0	4.0 - 37.0	4.0 - 35.0	6.0 - 22.0
TiO_2	1.0 - 2.0	0.5 - 4.0	0.6 - 2.0	0.0 - 0.8
Fe_2O_3	2.0 - 10.0	2.0 - 44.0	3.0 - 19.0	1.0 - 18.0
CaO	0.2 - 4.0	0.7 - 36.0	2.2 - 45.1	15.0 - 44.0
MgO	0.2 - 1.0	0.1 - 4.0	0.5 - 8.0	3.0 - 12.0
Na_2O	---	0.2 - 3.0	---	0.2 - 12.0
K_2O	---	0.2 - 4.0	---	0.1 - 1.3
SO_3	0.1 - 1.0	0.1 - 32.0	3.0 - 16.0	6.0 - 30.0
P_2O_5	0.1 - 4.0	0.0 - 3.0	0.0 - 3.0	0.0 - 1.0

B. Environmental Concerns

CCAWG member L. D. Smoot prepared, on very short notice, an overview of pollutant issues as an introduction to more detailed considerations of this important topic at later CCAWG meetings. He discussed existing federal standards and current understanding of the processes involved in the productions of NO_x, flyash, sulfur compounds, CO, hydrocarbons, soot, and emissions of trace metals. While current federal standards for boilers producing steam to generate more than 73 MW_e are 0.6 lb of NO_x per 10^6 Btu for bituminous coals and 0.5 lb of $NO_x/10^5$ Btu for subbituminous coals, it is viewed as likely that more rigid control measures will be imposed in the future. Current limits are 1.2 lbs/10^6 Btu for SO_x with the supplementary requirement of 90% removal whenever SO_x emissions exceed 0.6 lb/10^6 Btu. Particulates are limited to 0.03 lb/10^6 Btu and are not currently qualified with regard to chemical composition, although a number of investigators have expressed apprehension about the possible presence of carcinogenic hydrocarbons and other carcinogenic compounds on particulate emissions and flyash.

A great deal needs to be learned about the control of NO_x emissions through combustion modifications that emphasize desirable competitions between NO_x formation and depletion processes. Studies are in progress on NO_x control using staging and combustion modifications. Removal of NO_x by reduction with NH_3 is a well developed procedure for some gas mixtures, provided the SO_x concentrations are not excessively high. The oxides of sulfur are removed by wet scrubbing and by limestone scavanging; their initial concentration levels are reduced by the use of low-sulfur coals, by coal cleaning, etc. The formations of particulates and flyash may be minimized by coal beneficiation and they may be removed from the flue gases by using electrostatic precipitation and other means.

The following is a listing of some identified problem areas: (a) technological implementation to meet future reductions in allowable NO_x emissions; (b) integrated management of boiler feed, boiler operations, and boiler emissions; (c) coal beneficiation to reduce pollutant outputs; (d) SO_x removal within the boilers and from the flue gases; (e) improved understanding of chemical processes that couple NO_x, SO_x, HC, and flyash productions; (f) chemical nature and possible toxicological implications of hydrocarbon and trace-metal emissions; (g) modifications of fluidized bed combustors to reduce NO_x emissions and carbon carryover; (h) the special problems involved in the control of emissions from very small combustors.

C. Coal-Dust Fires and Explosion Hazards

M. Hertzberg (U.S. Bureau of Mines/PETC) presented a comprehensive overview of work at the Bureau of Mines dealing with coal-dust fire and explosion hazards. This presentation included the results of deliberations at a workshop on "Coal Dust Fire and Explosion Hazards in Cement Plants, Power Plants, and other Surface Facilities," sponsored by the U.S. Bureau of Mines/PETC and held in Denver, Colorado, April 1982. We refer to published articles[1-4] for a description of these important and continuing investigations.

Data are available for particular coals on the lean flammability limit (in mg/l) as a function of the mean particle size. The energy required for ignition has been mapped as a function of the lean-limit concentration for various hydrocarbons and also for coal-dust dispersions in air. Maps are available showing flammable and thermally ignitable, flammable but not thermally ignitable, and nonflammable regions as functions of temperature and particle concentrations for selected coals. In general, the probability of explosion is the product of the probability of finding a flammable volume and the probability of encountering an ignition source of adequate strength. Flammable mixtures are usually encountered in coal pulverizers. Hence, explosion avoidance means avoidance of ignition. Nonflammable coal-dust dispersions may be created by reducing oxygen concentrations below 11% or by the introduction of sufficiently large concentrations of steam, flue gases or other "inerting" materials (e.g., concentrations of $NH_4 \cdot H_2PO_4$ exceeding about 20-30% of the coal-dust concentrations).

CCAWG discussions concerning the need for basic studies to supplement the work at the Bureau of Mines/PETC did not lead to definitive conclusions. It is generally apparent that operational difficulties can be resolved by intelligent applications of knowledge accumulated by M. Hertzberg and his associates. On the other hand, coal-dust explosions do occur and represent a hazard not only in coal-mining operations but also in the type of coal handling involved in the use of pulverized coal in utility and other boilers. For this reason, improved quantitative understanding of fundamental processes may well deserve augmented effort, especially with regard to the possible importance of equipment specifications in defining both flammability limits and ignition requirements.

References

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2. F. L. Shea, Jr., and H. L. Hsu, "Self-Heating of Carbonaceous Materials," Industrial & Engineering Chemistry Product Research and Development 11, 184-187 (1972).

3. M. Hertzberg, K. L. Cashdollar, and J. J. Opferman, "The Flammability of Coal Dust-Air Mixtures," RI 8360, U. S. Department of Interior, Bureau of Mines, PETC, 1979.

4. M. Hertzberg, K. L. Cashdollar, and C. P. Lazzara, "The Limits of Flammability of Pulverized Coals and Other Dusts," Eighteenth Symposium (International) on Combustion, pp. 717-729, The Combustion Institute, Pittsburgh, PA, 1981.

CCAWG MEETING AT THE
MORGANTOWN ENERGY TECHNOLOGY CENTER (METC), MORGANTOWN, WEST VIRGINIA[†]
(July 15, 1982)

1. Introduction

The following CCAWG and ex officio members attended the METC meeting: J. M. Beér, J. Birkeland, C. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, R. Roberts, L. D. Smoot, C. Wagoner, and W. Wolowodiuk. The EPRI representative was S. Drenker. Host institution participants included A. Pitrolo, J. S. Wilson, K. Castleton, F. Crouse, W. French, L. Graham, J. Halow, A. Hall, J. Hall, L. Headley, K. Markel, J. Notestein, J. Y. Shang, D. Waltermire, and J. Williams. The meeting agenda is reproduced in Table 1. The morning session was devoted to a review and discussion of atmospheric (AFBC) and pressurized (PFBC) fluidized combustion of coals and other fuels. Most of the afternoon session dealt with environmental control and research programs. Also included in the afternoon presentations was a discussion of METC studies dealing with coal-water mixtures. The meeting was concluded with a brief tour of METC facilities.

2. Fluidized Bed Combustion[*]

Complete sets of viewgraphs for all of the presentations were furnished by the speakers and are available on request. Here, we present a tutorial overview of these presentations.

[†] Prepared by S. S. Penner.

[*] The proposed FY83 METC budget is $\$6.3 \times 10^6$ for advanced concepts relating to AFBC ($\$1 \times 10^6$ for advanced low-rank coal studies, $\$1.48 \times 10^6$ for an advanced PDU and components, $\$2.3 \times 10^6$ for advanced technical projects chosen in response to RFPs, and $\$1.02 \times 10^6$ for in-house projects); a total of $\$1.5 \times 10^6$ has been proposed in support of industrial applications ($\$0.25 \times 10^6$ each for work at Gilbert, E. Stroudsburg, U.S. Navy/Great Lakes, Shamokin, Wilkes-Barre, and in-house projects).

Table 1. Agenda for CCAWG meeting at METC (July 15, 1982).

METC AFB & PFB Overview of Activities	8:00
- Introduction - J. S. Wilson	
- AFB Overview - Art Hall	
- PFB Overview - Floyd Crouse	
- PFB Modeling - Tom O'Brien	
- Needs in FBC Research - Jerry Shang	
EPRI Overview - S. Drenker	9:30
MIT FBC Overview - J. Beér	10:15
Foster Wheeler Overview - W. Wolowodiuk	11:30
Lunch in Conference Room	12:00
METC Environmental Control Technology Review	12:30
- Introduction - Jack Halow	
- Flue Gas Cleanup Overview - John Williams	
- Hot Gas Cleanup Overview - Ken Markel	
- Needs in Cleanup Research	
- Fundamental Needs - Kent Castleton	
- Modeling Needs - Larry Headley	
METC Review of Gas Turbine Applications of Coal Water Mixtures	3:15
- Overview - Floyd Crouse	
- METC Activities - Debbie Waltermire	
Tour of METC Facilities - Emphasis on FBC, Coal/Water, Cleanup	4:00
Leave for Pittsburgh Airport	5:00

A. Why Fluidized-Bed Combustion?

Fluidized-bed combustion offers the following potential advantages: fuel flexibility, lower costs for meeting environmental regulations (by using SO_2 clean-up with limestone and reducing NO_x production), simplicity of operation (because of the absence of sootblowers and slagging) and low maintenance costs, reduced size and busbar costs in utility operations, and reduced cost sensitivity to the unit size.

B. AFBC Developments

Fluidized beds represent a logical evolution in coal-fired power plants from the stoker and pulverized coal burner (see Fig. 1 for a schematic diagram). Details of representative industrial fluidized bed steam generators are shown in Figs. 2 to 5 and have been reproduced from a paper by R. L. Gamble.[2,3] Industrial fluidized-bed combustors represent developed technology. On the other hand, the larger units needed for utility applications remain to be designed, built, and tested on substantial scales.

Current programs on AFBC and PFBC encompass process and engineering developments and commercial demonstrations.

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[1] S. Drenker (EPRI), CCAWG meeting at METC, July 15, 1982.

[2] R. L. Gamble, "Industrial Fluidized Bed Steam Generation," ASME Paper 81-IPC-FU-2, The American Society of Mechanical En-Engineers, 345 E 47th Street, New York, NY 10017.

[3] W. Wolowodiuk (CCAWG), CCAWG meeting at METC, July 15, 1982.

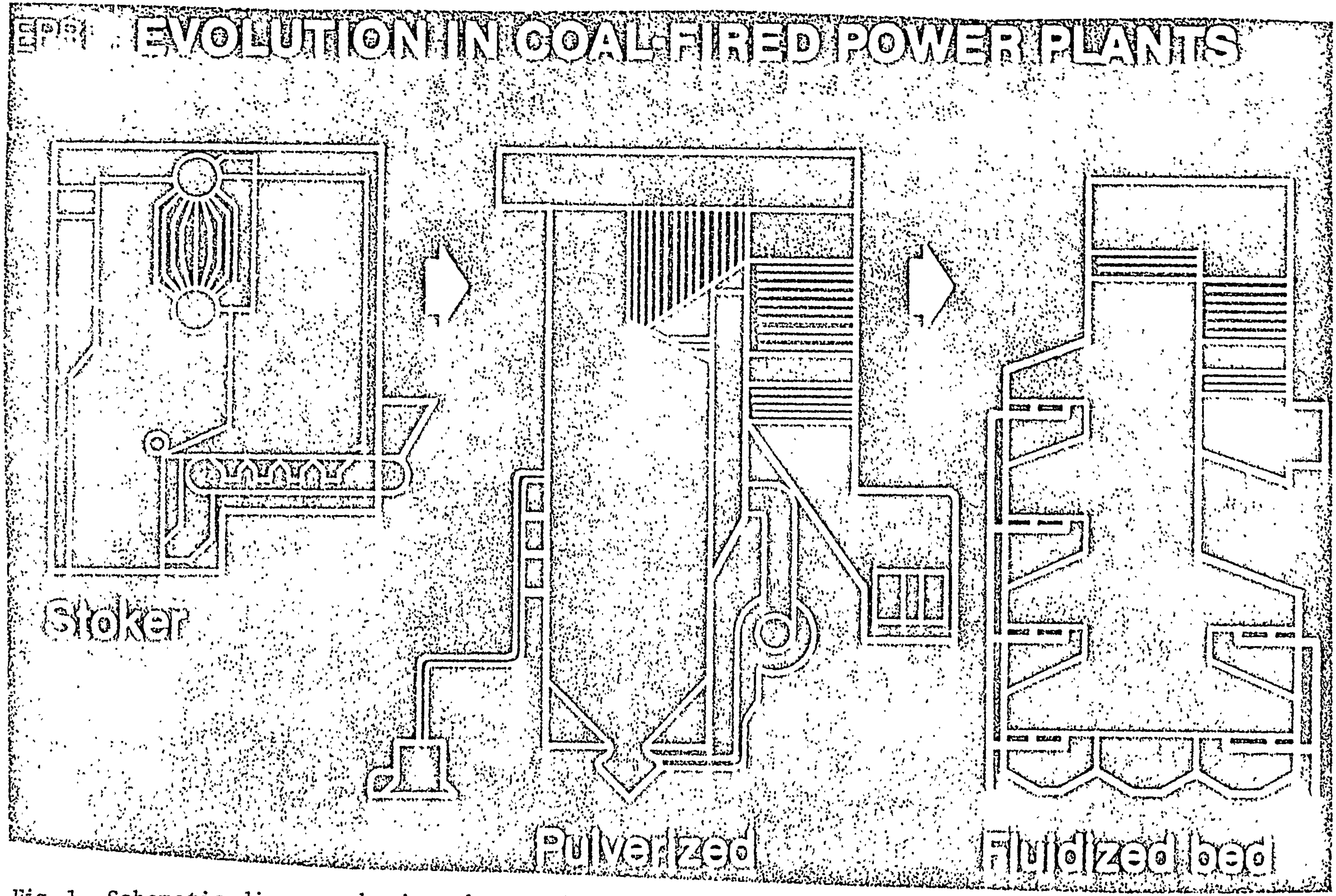

Fig. 1 Schematic diagram showing changes in the geometrical designs of coal-fired power plants from stoker to pulverized coal burner to fluidized-bed combustor; reproduced from S. Drenker.[1]

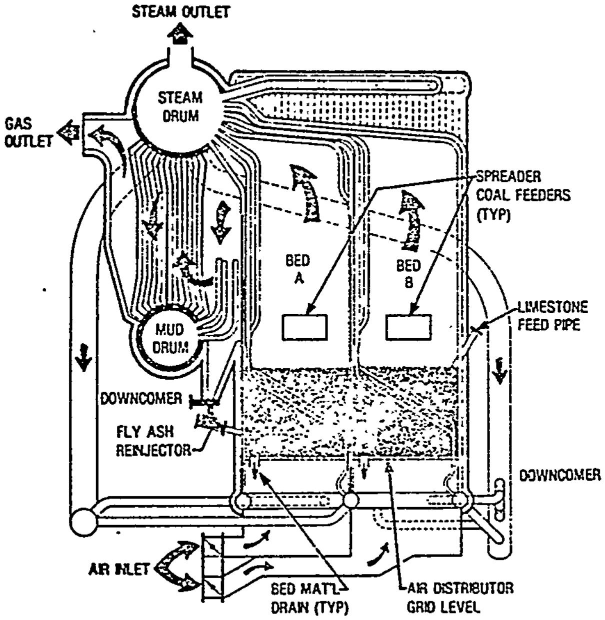

Fig. 2 Georgetown University steam generator (12.6 kg/s = 100,000 lb/h) using AFBC; this unit was put into service in 1979 and has operated successfully with full automatic control. An over-bed coal-feed system [with standard spreader feeder as in stokers using coal smaller than 32 mm (1.25 in.)] and a natural circulation steam flow with balanced draft are used. Reproduced from Gamble.[2]

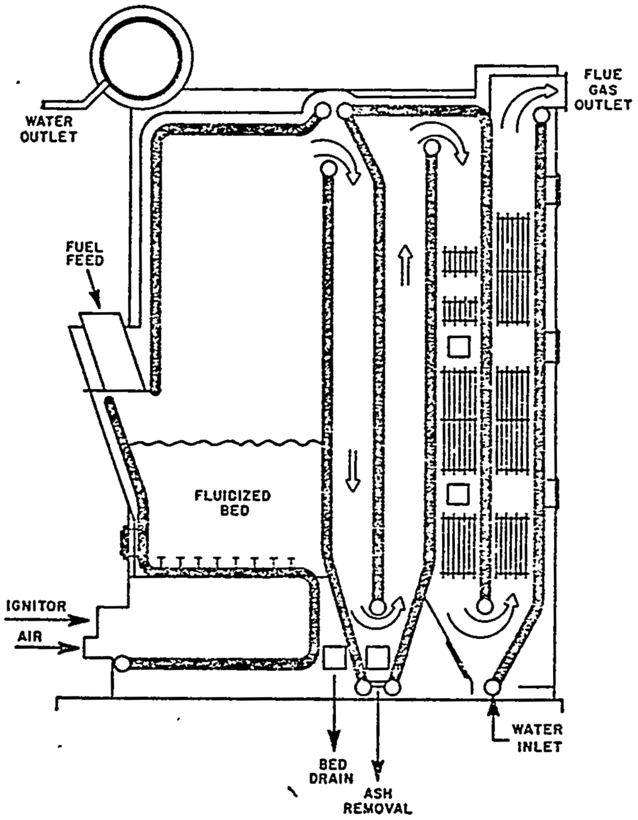

Fig. 3 City of Eksjo (Sweden) hot-water generator which normally burns municipal refuse and wood chips in a fluidized bed of sand at an output of 5 MW_t; with oil firing, the output level is raised to 10 MW_t. Forced circulation is used for the water flows. Reproduced from Gamble.[2]

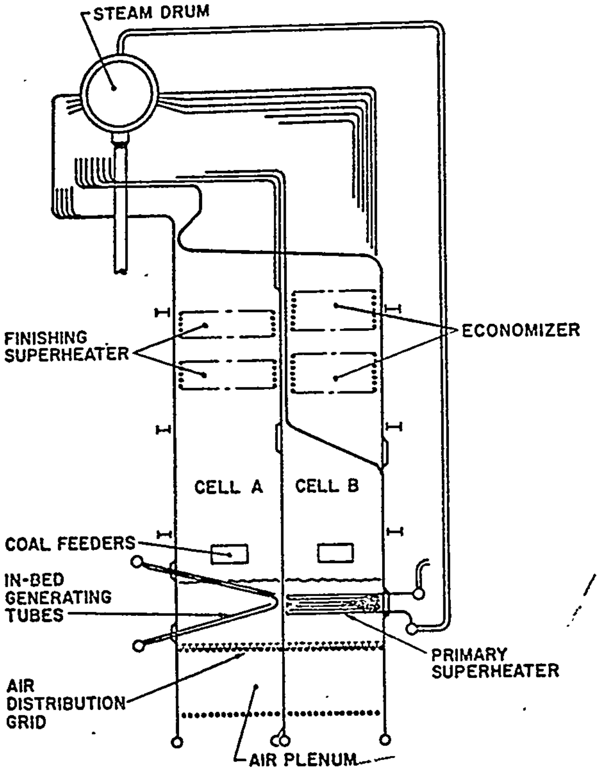

Fig. 4 Royal Dutch Shell (Netherlands) steam generator built by the Foster Wheeler Corporation with start-up in 1982. This unit operates on bituminous coal to produce superheated steam for a backpressure turbine generating up to 6 MW_e while providing steam for heating an oil-tank farm and associated piping. The over-bed feed system is similar to that used in the Georgetown facility (Fig. 2). Reproduced from Gamble.[2]

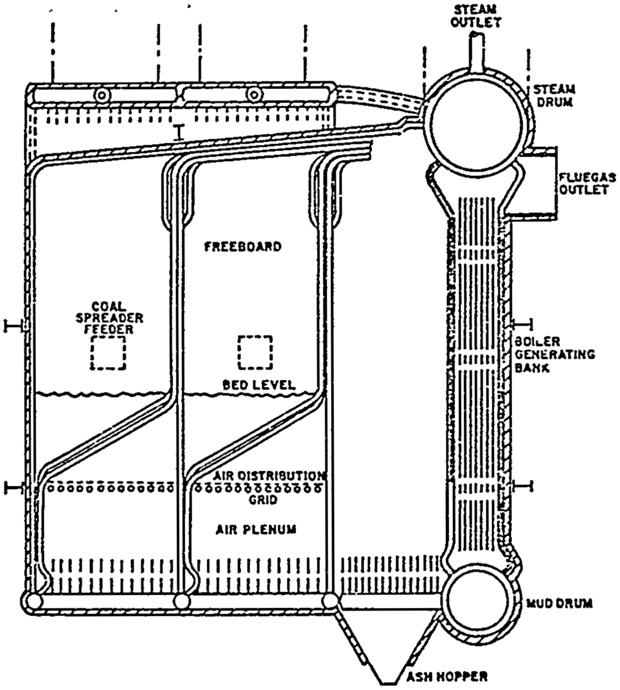

Fig. 5 Idaho National Energy Laboratory saturated steam generator [Idaho Falls, Idaho (8.5 kg/s = 67,500 lb/h)] for heating a nuclear fuel-processing facility (start-up is planned for 1984). This unit is similar to the Georgetown AFBC unit, except that space has been provided between the fluidized bed and the boiler intake for the addition of a superheater for cogeneration. Reproduced from Gamble.[2]

Significant improvements in process efficiency have been achieved by increasing the freeboard length above the fluidized bed.[1] For example, the Rivesville plant (1972) had a 2-ft freeboard length and a combustion efficiency of 88%; a 6-ft x 6ft section with an 18-ft freeboard showed 94% combustion efficiency; when recycle was added to this unit, the combustion efficiency exceeded 99%.[1] The EPRI AFBC development program on a 6ft x 6ft bed included tests with bituminous coal containing 4% of sulfur and lignite with 0.5% of sulfur. Limestone was added to effect 90% SO_2 removal. Required Ca/S ratios were 2.0 for the bituminous coal and 1.5 for the lignite at maximum temperatures of 1550 and 1450°F, respectively; NO_x emissions were controlled in both cases at 0.2-0.3 lb per 10^6 Btu while successful operation was achieved with bed load reductions of 2:1, implemented at a rate of 10%/minute.[1] These operational characteristics, together with a reduced number of coal-feed points, are scheduled to be implemented by EPRI in a 20 MW_e pilot at the TVA in Paducah, Kentucky (with demonstration testing beginning in 1988).[1] Support studies include the definition of materials suitable for use in the superheater and modeling with predictions of heat transfer and bed dynamics.[1] A schematic diagram of the 20 MW_e facility is shown in Fig. 6. Load turn-down methods in utility applications include both reductions and redistributions of coal and limestone feed rates. Recycle options include pneumatic injection with solids cooling, forced under-bed injection without cooling, and gravity injection.[1] A long-range program may involve shop fabrication of 100 MW_e boiler units with barge transport to users, a procedure that could provide access to 200 GW_e of installation capacity representing 93% of U.S. electrical power demand. The 100 MW_e units may provide turbocharged steam generation (from a boiler-cyclone-filter-turbocharger sequence) with the advantage of reduced gas-turbine firing temperature, thereby reducing metallurgical demands, simplifying structural design, and allowing reliable

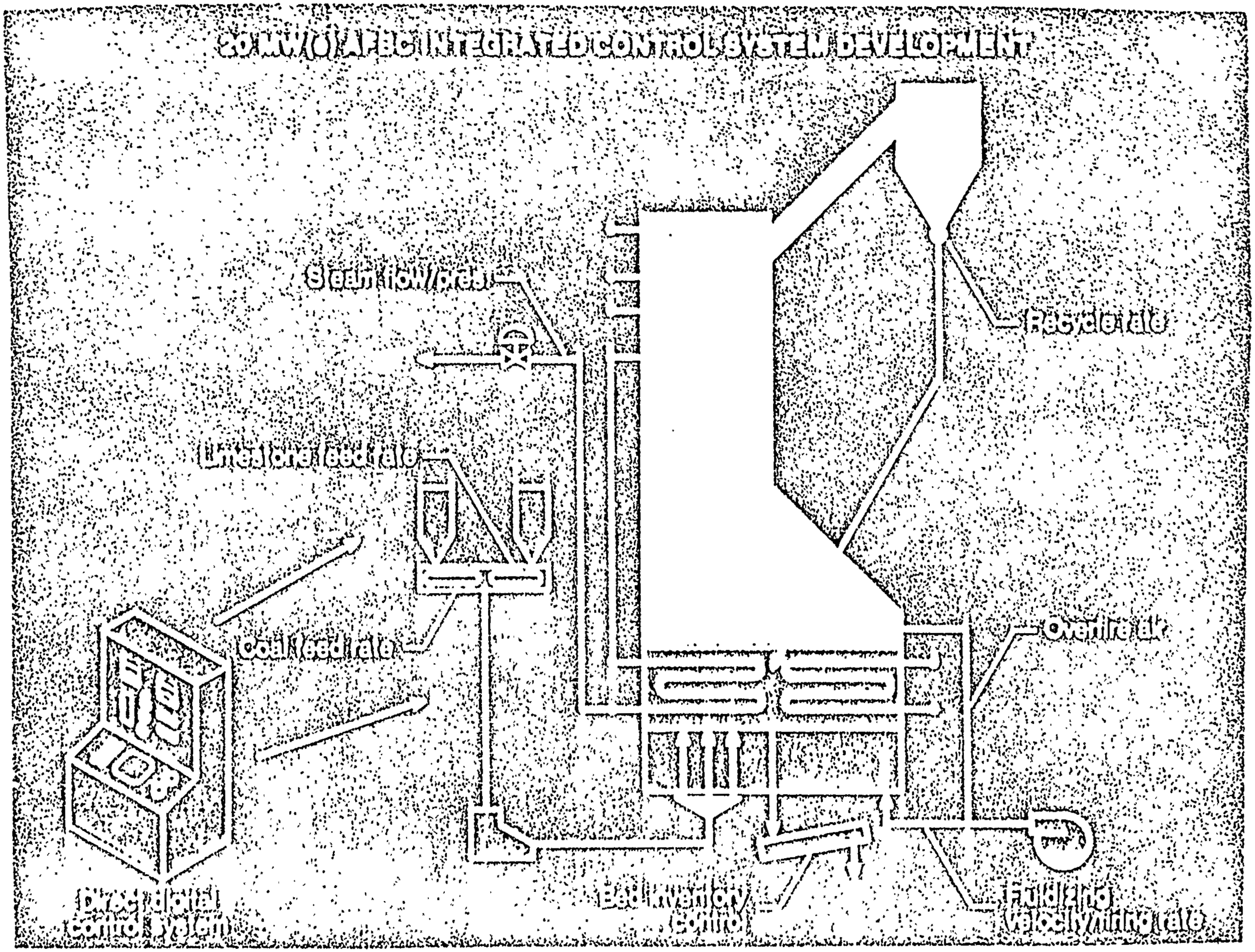

Fig. 6 Schematic diagram of the proposed 20 MW_e EPRI AFBC; reproduced from S. Drenker.[1]

filtration at reduced turbine-generator speed.[1] Remaining development problems on AFBC deal primarily with combustor performance and reliability.

The Foster Wheeler development program[3] has involved performance and reliability evaluations on an 18-in. diameter AFBC and (see Fig. 7) on a 20-in. x 20-in. unit (operated for 4.5 y).[*] Both in-bed and over-bed feed systems have been tested with fly-ash recycle and NO_x control (through injection and cleanup witn NH_3 and staged combustion, which showed that NO_x emissions were smaller for smaller residual O_2 levels).[3] The influence of fuel pelletization has been studied, especially in efforts to achieve improved limestone utilization.[3] Cold-model and subcomponent testing, as well as work on PFBC, have been performed.[3] Cyclone recycle has typically been used.

With in-bed feed, control of surface moisture was required and an excessively large number of feed points was needed (one per 16-25 ft^2).[3] Fuel distribution to the feed points was difficult to control and small fuel sizes (0.5" x 0) were required.[3]

With over-bed feed (see Fig. 2 for an operating unit), larger particles (1.25" x 0) could be handled, the surface moisture problem was absent, addition of water improved combustion efficiency, the required number of feed points was smaller (one per 110 ft^2).[3] There is, however, a tendency for the fluidized bed to malfunction with improper fuel distribution.[3] Using a spreader-type stoker feeder, the coal throw distance is 6.70 m in the 20" x 20" unit.[3] The use of fly-ash recycle eliminates

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[*] The following are performance figures for the 20-in. x 20-in. unit: feed rates of 100-500 lb/h, bed temperatures of 1300-2100°F, superficial velocities of 4-12 ft/s, 1-100% of excess air, Ca/S ratios of 0-20, in-bed and over-bed feeds, fly-ash recycle, and staged combustion. Fuels used include North Dakota lignite, petroleum coke, Irish Arigna coal, anthracite culm, coal and wood waste mixtures, pelletized coal fines, pelletized sludge, and process gas. Combustion efficiencies ranged from 82 to 98+%.

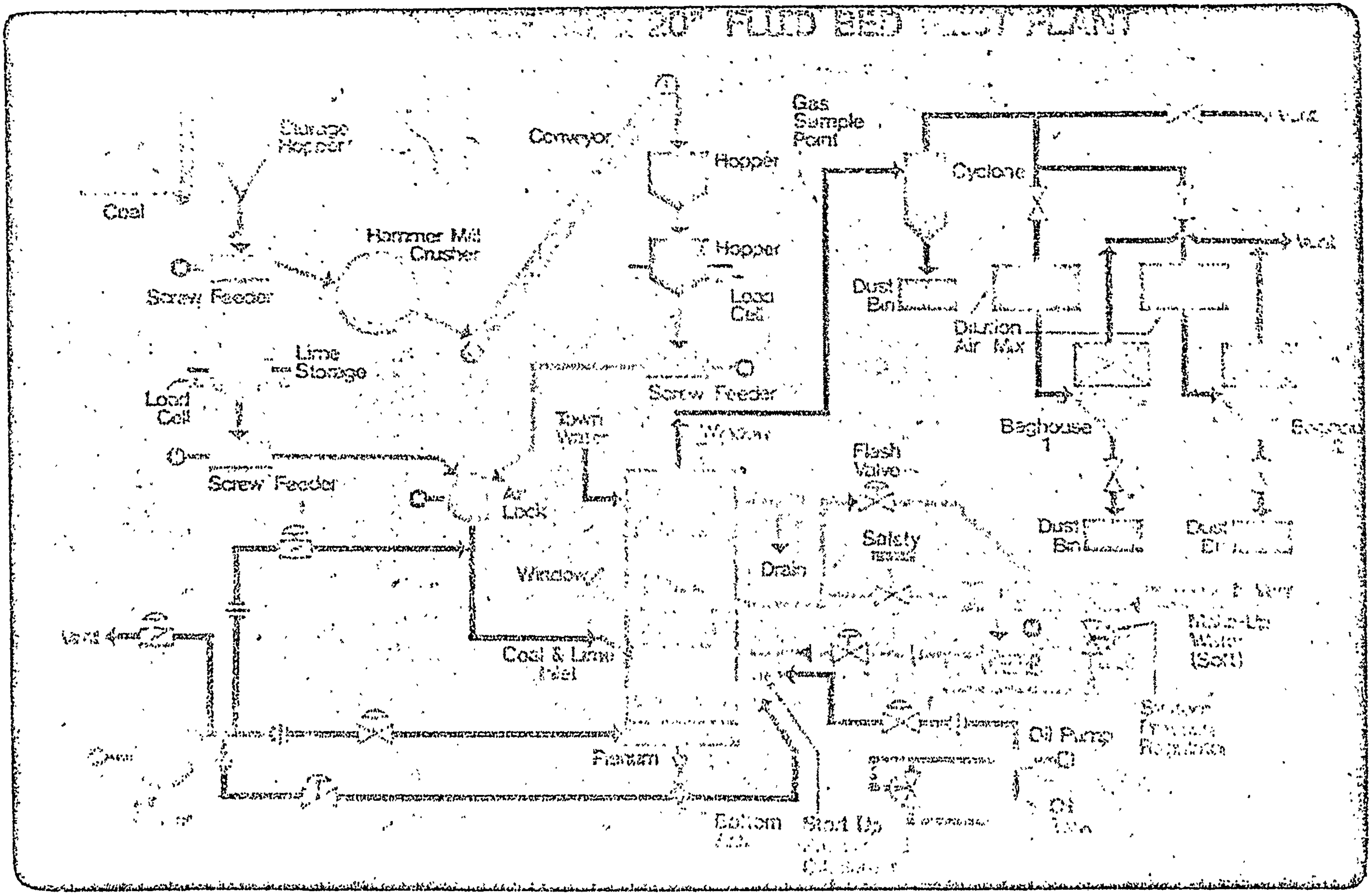

Fig. 7 Flow diagram for the 20" x 20" Foster Wheeler fluidized bed pilot plant; reproduced from W. Wolowodiuk.[3]

the necessity for achieving carbon burn-up in the cell, improves both combustion efficiency and sulfur burn-up, and reduces NO_x emission.[3] Subcomponent testing included work on distribution plates, feeders, fuel splitting, pneumatic transport, hot-gas transfer ducts, and the pneumatic classifier.[3] The air-distribution arrangement was found to be of critical importance.[3] Two-dimensional, cold-flow models were used to study the effects of tubes in the bed.[3] Extensive operational tests have been performed relating to the influence of the Ca/S mole ratio on the percentage of sulfur retained and mole ratios greater than about 3 were found to be necessary in order to effect 90% sulfur removal. Limestone sulfation is believed to be enhanced by hydration (see Fig. 8 for a model of this hydration process).

C. PFBC Developments

The EPRI studies have shown that FeCrAlY prevents erosion and corrosion by the PFBC dust (in a test at 1600°F, 1170 ft/s flow speed, 100 ppm of dust with 5% of the particles >10μm, and added $Na_2SO_4 \cdot K_2SO_4$).[1] Program development cited by Drenker[1] involved a 0.8 ft^2 bed area test facility, 1.0 ft diameter, at Exxon using a coal-feed rate of 0.14 t/h. This work has been followed by tests performed at the U.K. National Coal Board with 6 ft^2 bed area, 2 ft x 3 ft bed lengths, 0.5 t/h coal feed rate, 5 atm pressure. Current IEA-sponsored work at Grimethorpe (25 MW_t, P = 10 atm, 1000 h of operation) in the UK involves a 42.9 ft^2 bed area, 6.5 ft x 6.5 ft dimensions, and ≈10 t/h of coal feed. A 100 MW_e prototype will have two sections with 196 ft^2 bed area, each with 14 ft x 14 ft dimensions, and will use 21 t/h of coal feed in each.[1] Net heat rates (in Btu/kWh_e) have been estimated to be 8470 for PFBC, 9640 for AFBC, and 9860 for a conventional pulverized coal burner; corresponding capital cost estimates (in $\$/kW_e$) are 875, 820, and 995, while the estimated

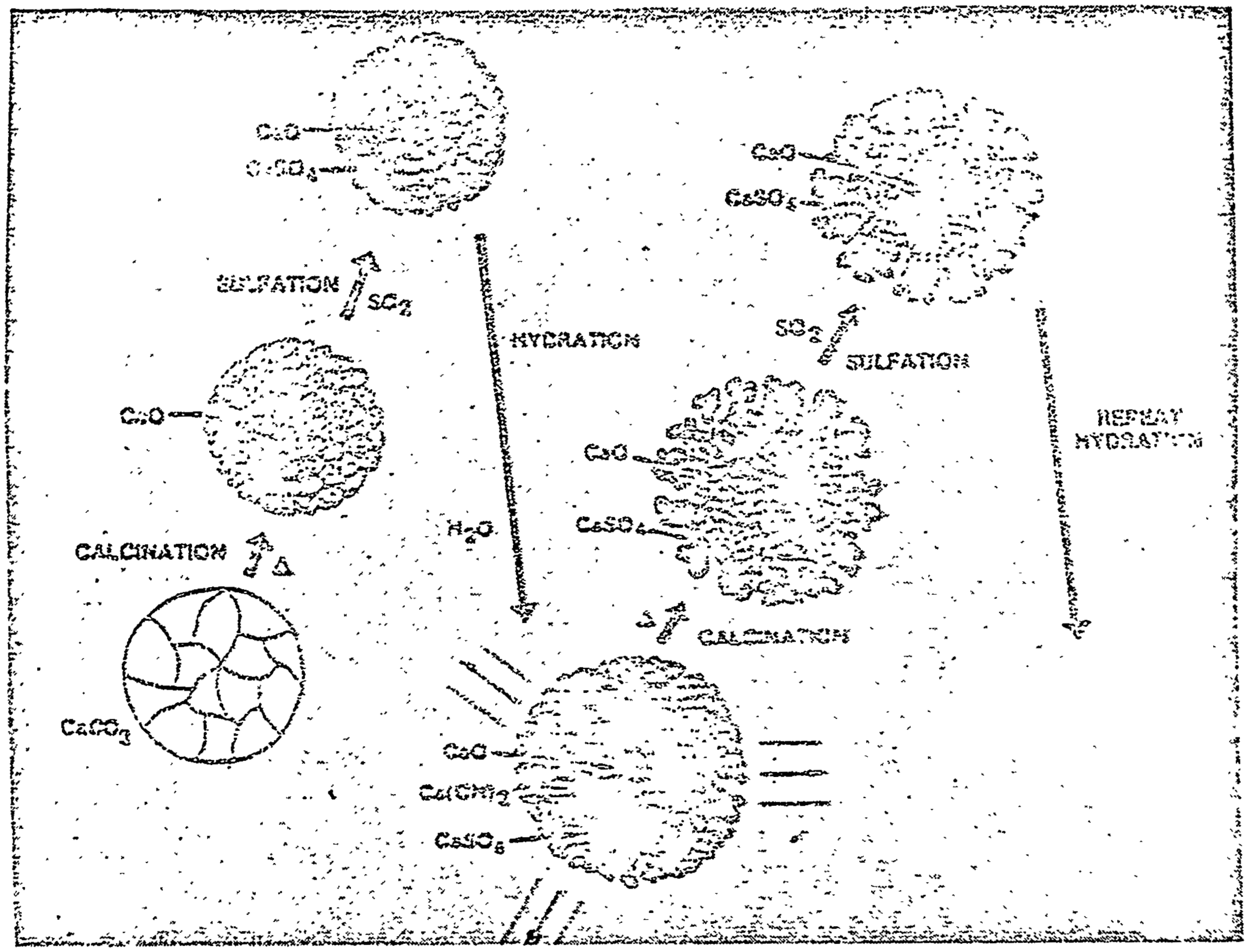

Fig. 8 Enhancement of limestone sulfation by hydration; reproduced from W. Wolowodiuk.[3]

electricity costs (levelized for 1981-2000 in mills/kWh_e) are 74, 77, and 86, respectively.[1] The conceptual design of a combined cycle PFBC is shown in Fig. 9.

A great deal of fundamental and development work needs to be done on the PFBC.[4] A 13 MW_t pilot plant operating at 7 atm pressure is being constructed by Curtiss Wright for start-up in 1983.[4] Other studies are in progress at NYU, GE, ANL, ORNL, and METC.[4]

D. R&D Needs on AFBC and PFBC

Research needs in AFBC were discussed by J. M. Beér and J. Shang (METC), while T. O'Brien (METC) emphasized model design and development.[5] R&D needs in PFBC were discussed by F. Crouse (METC).[5] The identified R&D needs reflect the operational problems encountered in fluidized bed combustors and include solids handling (including fines), design of the feeding system, heat and mass transfer phenomena, fluidized bed stability and dynamics, reaction kinetics in multiphase flow processes, pollutant controls through in-bed removal techniques, combustion efficiency determinants, modeling, control strategies, etc.[5] Knowledge gained from catcrackers cannot be applied directly because the particulate sizes involved are generally much (i.e., about a factor of 10) larger.[5] The importance of the freebroad design on performance has been clearly demonstrated and it is therefore appropriate to consider the sequential and interactive phenomena that couple the fluidized bed to the freeboard. Retrofitting of existing stoker-fired boilers represents a special challenge. The use of cold-flow models as a predictive performance tool requires quantification.

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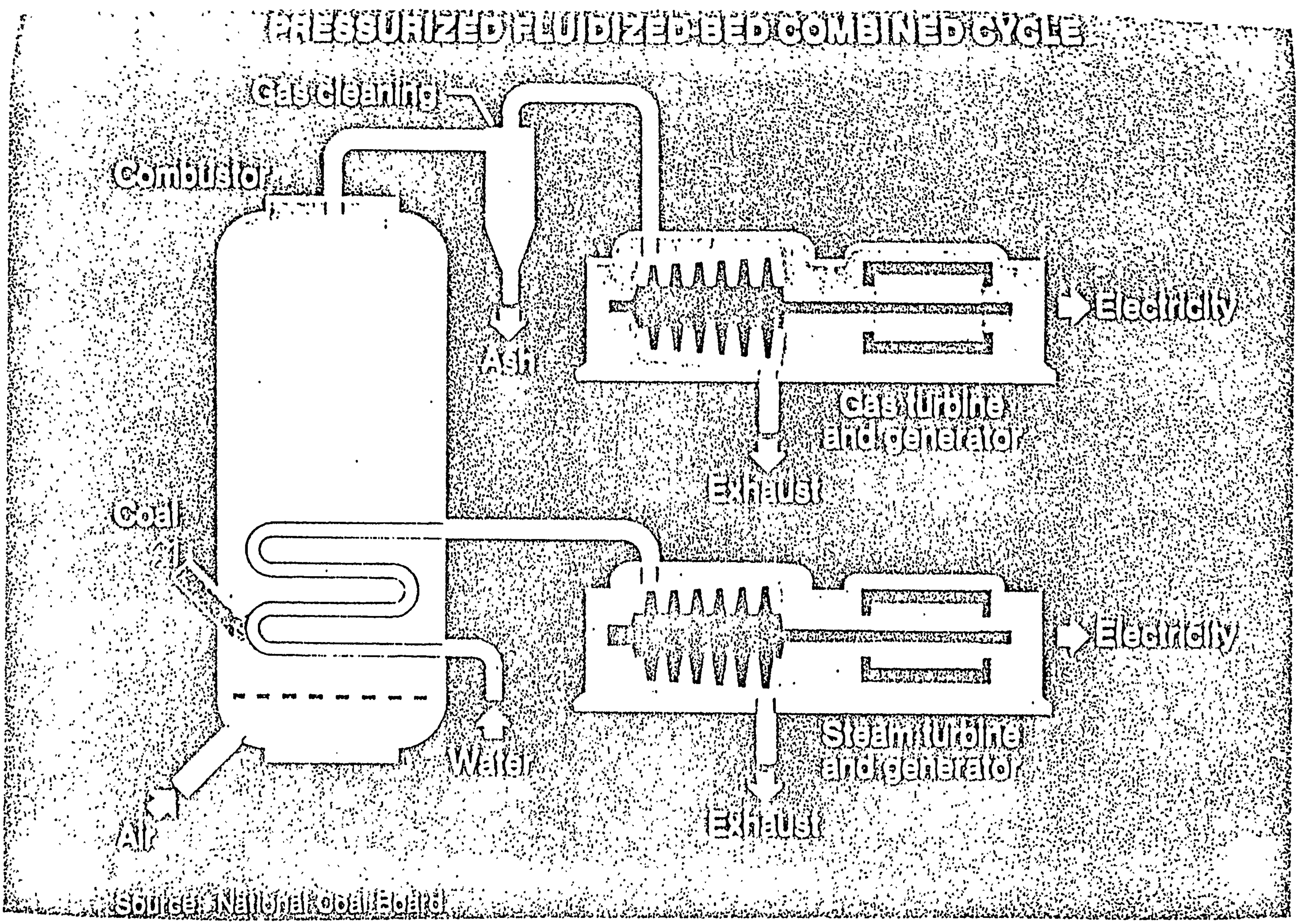
[4] F. Crouse (METC), CCAWG meeting at METC, July 15, 1982.

[5] CCAWG meeting at METC, July 15, 1982.



Source: National Coal Board

Fig. 9 Schematic diagram of a combined cycle PFBC.

J. M. Beér has identified the following topical areas as representing research needs relating to the freeboard in AFBC: (1) entrainment of solid particles from the bed and their elutriation from the freeboard, as affected by bed operating conditions and freeboard design parameters; (2) burn-out of CO, hydrocarbons and of solid carbon particles as affected by freeboard temperature, height and the mode of particle feed; (3) sulfur capture by sorbent particles entrained from the bed; (4) reduction of NO_x by CO and solid carbon along the freeboard height. For the fluidized bed itself, the following research areas were emphasized by Beér:[5] (1) movement of particles after injection into the bed or for over-bed feeding; (2) evolution and combustion of coal volatiles to estimate locally reducing zones and hot spots; (3) carbon burning as affected by particle swelling, fragmentation, the build-up of ash layers and changing pore structures of the coal char; (4) the flow near the distributor, bubble size, gas-emulsion exchange coefficients along the bed height; (5) the respective roles of mixing and chemical kinetics in the burn-out of CO in the bed; (6) the transient operation of the fluidized bed, including stability limits; (7) the evolution of fuel-nitrogen from the coal and the formation of NO_x from volatiles- and char-nitrogen; (8) the reduction of high NO_x concentrations found experimentally near the coal injection point by reactions between NO_x and volatile nitrogenous compounds and NO_x or carbon; (9) the kinetics of sulfation of CaO, the effects of combustion, and the pore structure of the calcined stone upon sorbent utilization.

Research needs in PFBC are analogous to those listed for AFBC at elevated pressure levels.

3. Environmental Control Technologies

CCAWG continued discussions relating to environmental control technologies.* An overview of the advanced environmental control technology program at METC was presented by J. Halow[6] and included considerations of flue-gas cleanup (using lime and limestone scrubbers, other flue gas desulfurization techniques, and combined NO_x/SO_x/particulate flue-gas cleanup), gas-stream cleanup (for turbine systems, fuel cells and other technologies), and studies of cleanup base technologies (including waste management, instrumentation, and systems economic comparisons). Also noted was METC phase-out of lime and limestone R&D relating to advanced flue-gas desulfurization (FGD) and continuing studies on combined (NO_x/SO_x/particulates) flue-gas cleanup (including such novel ideas as E-beam utilization to facilitate reactions for conversions of NO_x and SO_x);[7] gas-stream cleanup at elevated temperatures ($>10^{3}$°F) and pressures (>6.5 atm) in PFBC, turbines (with emphasis of the effect of Na on turbine life and the utilization of absorbents such as activated bauxite, diatomaceous earths, and other aluminosilicates), and particulate removal (by using an electrocylone, electrostatic precipitation, electrostatic granular bed filters, barries such as ceramic bag and granular bed filters, moving panel beds, cross-flow membranes, augmentation agglomeration, etc.);[8] identification of the principal deleterious constituents in coals and reaction mechanisms involving mineral inclusions and entrained particles;[9] modeling of complete cleanup systems.[10]

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*See AB-3, CCAWG meeting at Combustion Engineering (June 24, 1982) for previous discussions of this important topic.

[6] J. Halow (METC), CCAWG meeting at METC, July 15, 1982.

[7] J. Williams (METC), CCAWG meeting at METC, July 15, 1982.

[8] K. E. Markel, Jr. (METC), ibid.

[9] K. Castleton (METC), ibid.

[10] L. Hadley (METC), ibid.

4. METC Studies of Coal-Water Mixtures (CWM)

The potentially important topic of combustion of CWM in a gas turbine was also addressed.[11,12]

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[11] F. Crouse (METC), CCAWG meeting at METC, July 15, 1982.
[12] D. Waltermire (METC), ibid.

5. Cost Analysis of the Application of Coal-Water Mixtures (CWM) to Gas-Turbine Firing*

This analysis relates to the magnitude of the price differential that may be tolerated when using clean fuel combined cycle (CFCC) plants in gas-turbine applications in place of coal. Very high numbers, such as \$5-7/MM Btu price differential, have been given as the basis for pursuing coal-water mixtures (CWM) for turbine applications. It is easy to show that these figures cannot be right. Clean fuel combined cycles are available today by firing oil or gas. Very few have been sold because the prices of oil and gas cannot compete with coal. The following calculations bear out this conclusion.

Using realistic figures of \$600/kW_e for a CFCC plant and \$1000/kW_e for a conventional coal-fired plant, 7000 hrs/yr operation, 30 years levelized fuel costs, 20% capital charges, 10,000 Btu/kWh_e heat rate for conventional plants, and 8,000 Btu/kWh_e heat rate for CFCC plants, the first year fuel-cost differential is \$1.38/MM Btu. This statement will now be verified.

We list in Table 1 the costs for conventional and CFCC plants.

The fuel costs are a function of heat rate, leveling factor, and first year fuel price. Based on the EPRI levelizing procedures, the leveling factor is about 2. The first year coal price is about \$1.50/MM Btu. Thus, the levelized coal price is \$3.00/MM Btu. The levelized fuel cost is then

$$C_{\text{levelized}} = (\$1.50/\text{MM Btu}) \times 2 \times (10{,}000\ \text{Btu/kWh}_e) \times (1000\ \text{mills}/\$) = 30\ \text{mills/kWh}_e\ .$$

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*Prepared by C. R. Bozzuto.

Table 1. Cost comparisons between conventional and CFCC plants.

Costs and Charges	Conventional Plant	CFCC Plant
Capital cost	\$1000/kw_e	\$600/kw_e
Capital charges	\$200/kw_e-yr	\$120/kw_e-yr
Annualized electricity cost	28.6 mills/kWh_e	17.1 mills/kWh_e
Levelized fuel cost	30 mills/kWh_e	Y mills/kWh_e
O&M (including limestone)	8.4 mills/kWh_e	3.9 mills/kWh_e
Total energy costs:	67 mills/kWh_e	21 + Y mills/kWh_e

The levelized clean fuel price differential is (compare Table 1)

$$\frac{[(67 - 21)\ \text{mills/kWh}_e]\ \text{x}\ (10^6\ \text{Btu/MM Btu})}{(8000\ \text{Btu/kWh}_e)\ \text{x}\ (1000\ \text{mills/\$})} = \$5.75/\text{MM Btu}\ .$$

The first year clean fuel price is thus seen to be $2.88/MM Btu. Therefore, the differential first year fuel price between coal and coal-water mixture must be less than $2.88-$1.50/MM Btu or $1.38/MM Btu. The coal-water mixture fuel must, of course, meet all gas-turbine and environmental regulations and specifications. This would include at least 90% sulfur removal, 99% particulate removal, and sufficient nitrogen removal to meet NO_x specifications. This degree of beneficiation has not been demonstrated for any reasonable cost. Coal liquefaction or coal gasification will deliver this clean fuel at a price of roughly double that of oil or gas. Since neither oil nor gas are currently available at less than $1.38/MM Btu fuel price differential, it seems unlikely that the goals of the CWM program for turbine applications will be met.

AB-5

REPORT OF SITE VISIT TO THE GENERAL ELECTRIC COMPANY, CORPORATE RESEARCH AND DEVELOPMENT - STUDIES ON COAL COMBUSTION AND UTILIZATION*

(August 5, 1982)

S. S. Penner visited the General Electric Research Laboratory, primarily for the purpose of assuring a detailed presentation to CCAWG at a later date on the potential merits of utilizing CWM and other low-grade fuels in gas turbines. Discussions were held with N. J. Lipstein (Manager, Fluid Mechanics and Combustion Branch), M. Lapp (Combustion Diagnostics), D. P. Smith (Manager, Process Operations Unit), J. C. Blanton (Mechanical Systems and Technology Laboratory), P. G. Kosky (catalytic coal gasification), and D. H. Maylotte (tomography of heated coals during pyrolysis). D. P. Smith agreed to attend the October 18 CCAWG meeting at Babcock and Wilcox and to discuss the potentials and problem areas relating to coal utilization in gas turbines.

Brief summaries of the research programs discussed are given in the following paragraphs.

1. Combustion Diagnostics

M. Lapp has been one of the pioneers in the application of laser-Raman spectroscopy to combustion systems. Current research deals with instantaneous species concentration and temperature measurements (using laser-Raman scattering) on turbulent jets. The program will include determinations of correlation functions involving species and temperatues and is closely related to recently published modeling studies by R. Bilger (Sidney, Australia).

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*Prepared by S. S. Penner.

2. Use of Low-Grade (Residual) Fuels in Gas Turbines

Extensive studies have been performed on the use of high-ash fuels (residuals) in gas turbines. Erosion, corrosion, and depositions (ash fouling) were observed primarily in the turbine nozzles. With heavy resids, the primary operational problems result from the presence of vanadium. This element is not readily removed from residual oils but is generally not an important constituent of coals. Experimental studies have been performed with Mg-addition (at a weight ratio about 3 times that required for a stoichiometric mixture) to remove the V. An ash deposit is observed on the nozzles and blades after prolonged operation (i.e., several hundred hours), which can be removed by "nutshelling" (i.e., temporary injection of crushed walnut shells at a mass ratio of about 0.5 of that of fuel). A substantial data base has been accumulated on the operation of high-ash residual fuels in gas turbines. The principal design features and problem areas are sketched in Fig. AB-5.1.

Destructive compressor surges result from plugging of the first-stage nozzle. The use of higher temperatures to eliminate plugging of the first-stage nozzle tends to move the operational problems to the first-stage rotor and further downstream.

The extent of wall deposition is primarily determined by the wall temperature. Extensive simulation experiments on wall deposition have been performed by inserting an air-cooled, flat plate in a 3-in.^{2} test section and measuring deposit formation from a number 2 fuel oil to which dopants had been added to simulate high-ash resids. The data in Table AB-5.1 indicate the importance of <u>local</u> temperature. Experimental studies were performed on carefully modeled nozzles with four vanes. The flow speed was sonic at the throat while operating with pressure ratios of 2 to 1. An effective nozzle area was obtained as a function of time by determining the percentage of nozzle blockage per 100

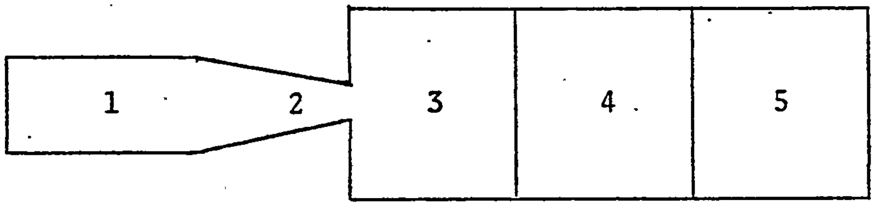

Fig. AB-5.1 Schematic diagram showing operation of a gas turbine with high-ash resids; 1, combustor operating at about 4000°F with the formation of particulates; 2, transition piece which yields exit temperatures of about 2000°F and allows particle growths by condensation and agglomeration; 3, first-stage nozzle where deposition occurs by impaction and condensation; 4, first-stage rotor; 5, subsequent turbine stages.

Table AB-5.1 Deposit formation ratios observed in simulation tests with number 2 fuel oil containing dopants.

Atomic weight ratios	Mg ÷ V	Na ÷ V
Measured atomic weight ratios	10.6	3.2
Calculated equilibrium atomic weight ratios at the equilibrium gas temperature	7.14	2.3
Calculated atomic weight ratios at equilibrium for the measured local wall temperature, after prior equilibration at the equilibrium gas temperature	11.4	3.4

hours of operation. Tolerable blockage in industrial applications is up to about 5% of area (corresponding to a 10% power loss). The observed deposit thickness was not simply related to an effective throat restriction. Instead, an effective area parameter has been used to characterize nozzle plugging.

3. Applications to CWM

The METC program at GE deals with the use of CWM. A prior, EPRI-funded program was pursued during 1979-80 on a water-cooled turbine. This engine will probably be used with CWM. Engine cleanability has been found to be better with water-cooled than with air-cooled engines.

4. Publications Dealing with Turbines Using Resids

The following publications deal with turbine-engine performance while using fuels with high-ash and minerals contents:

i. R. S. Rose, A. Caruvana, A. Cohn, H. von E. Doering, and D. P. Smith, "Application of Water Cooling for Improved Gas Turbine Flexibility and Availability," ASME Paper 81-GT-68, presented March 1981.

ii. J. C. Blanton and W. F. O'Brien, Jr., "An Empirically-Based Simulation Model for Heavy-Duty Gas Turbine Engines Using Treated Residual Fuel," ASME Paper 82-GT-139.

iii. C. T. Sims, H. von E. Doering, and D. P. Smith, "Effects of the Combustion Products of Coal-Derived Fuels on Gas Turbine Hot-Stage Hardware," ASME paper 79-GT-160, presented March 1979.

5. Integrated Coal Gasification Gas Turbine Combined Cycle (IGCC) System

IGCC systems were considered by FERWG-I. While a reevaluation of these systems for utility applications may be appropriate, this study has not been specifically assigned to CCAWG. A useful 1981 evaluation of this concept is the following: J. C. Corman, "Integrated Gasification Combined Cycle Experimental Simulation," paper presented at the Eight Energy Technology Conference and Exposition, Sheraton Park, Washington, D.C., March 9-11, 1981.

AB-6

DISCUSSIONS AT THE AVCO-EVERETT RESEARCH LABORATORY OF (a) THE E-BEAM SCRUBBER AND (b) SLAGGING COMBUSTORS*

(August 6, 1982)

The purpose of this visit was two-fold. First, to obtain first-hand information on the E-beam scrubber and, second, to commence the CCAWG assessment of the potential of slagging combustors for retrofits in industrial and utility boilers. The second topic will be discussed briefly by D. B. Stickler of Avco at the October 18 CCAWG meeting at Alliance, Ohio.

The following Avco-Everett personnel were involved in the discussions (R. Gannon, R. Kessler, R. Patrick, V. Shui, D. B. Stickler,** D. Swallom, C. von Rosenberg, and V. Shui***). The agenda is shown in Table AB-6.1.

1. The E-Beam Scrubber

Management for the DOE-funded work on the E-beam scrubber has been transferred from METC to PETC.

The E-beam scrubber was developed by Ebara in Japan (since 1969-70) and is currently being pursued jointly by Avco and Ebara, who have cross-licensing agreements, with Ebara holding most of the patents and Avco contributing expertise in the areas of electron-beam technology developed in connection with excimer and other laser programs. According to its proponents, the E-beam scrubber will allow cost-effective SO_x and NO_x removals not only at currently mandated effluent levels but also if substantially more rigorous clean-up standards are implemented in the

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*Prepared by S. S. Penner.

**D. B. Stickler supplied the information on slagging combustors.

***V. Shui furnished all of the material dealing with the E-beam scrubber.

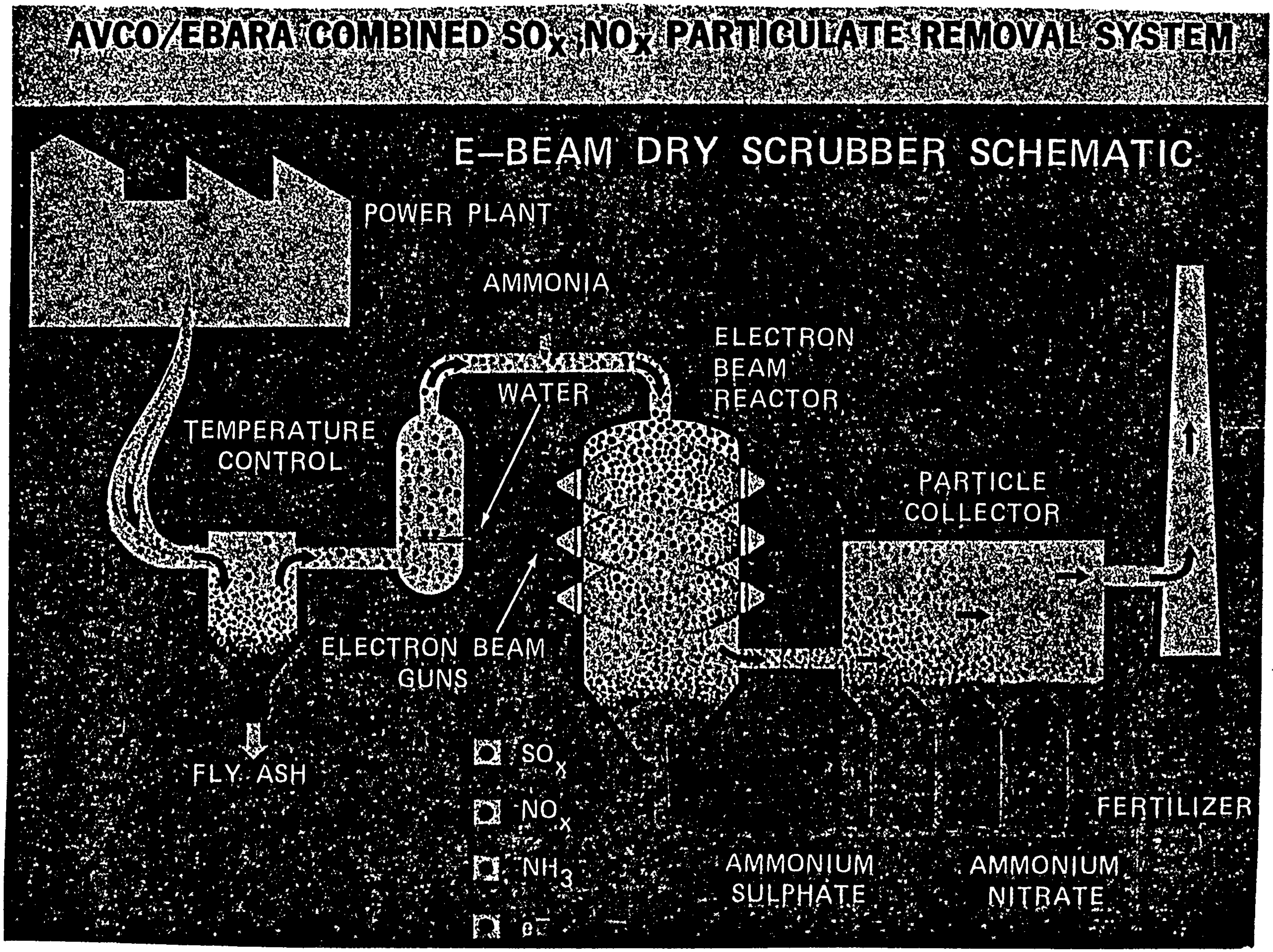
Table AB-6.1: AGENDA
Friday, 6 August 1982

10:00 a.m.	Introduction	
10:15 a.m.	E-Beam Scrubber	V. Shui
11:15 a.m.	Slagging Combustor	D. B. Stickler
12:15 p.m.	Lunch	
1:15 p.m.	Tour of Experimental Facilities. .	R. Gannon
2:15 p.m.	General Discussions	

future. While a great deal of useful empirical information has been obtained in Japan, the fundamental processes involved in effluent gas clean-up on exposure to electron beams are mostly not understood and, therefore, theoretical design-optimization techniques are not yet available. DOE funding of $600,000 is to be used for studies on a PDU (gas flow rate of 20,000 ft^3/min). In Japan, effluent control technologies are so widely implemented that there remains only very limited market potential without the legislation of new performance standards. This is said to be one of the reasons for Ebara's interest in a joint venture with Avco.

A schematic diagram of the removal system is shown in Slide AB-6.1. The novel feature involves low-temperature chemical reactions with NH_3 during bombardment by electrons. For the conditions shown in Slide AB-6.1, the SO_x and NO_x are converted to the fertilizers $(NH_4)_2SO_4$ and NH_4NO_3, respectively, albeit at the expense of NH_3 and energy;without NH_3 injection, sulfuric and nitric acids are formed, which may also be readily collected. As is shown in Slide AB-6.2, SO_x and NO_x removals are achievable at levels substantially lower than are currently mandated.

Slide AB-6.1



AVCO/EBARA COMBINED SO_x NO_x PARTICULATE REMOVAL SYSTEM

E–BEAM DRY SCRUBBER SCHEMATIC

POWER PLANT

AMMONIA

ELECTRON
BEAM
REACTOR

WATER

TEMPERATURE
CONTROL

PARTICLE
COLLECTOR

ELECTRON BEAM
GUNS

FLY ASH

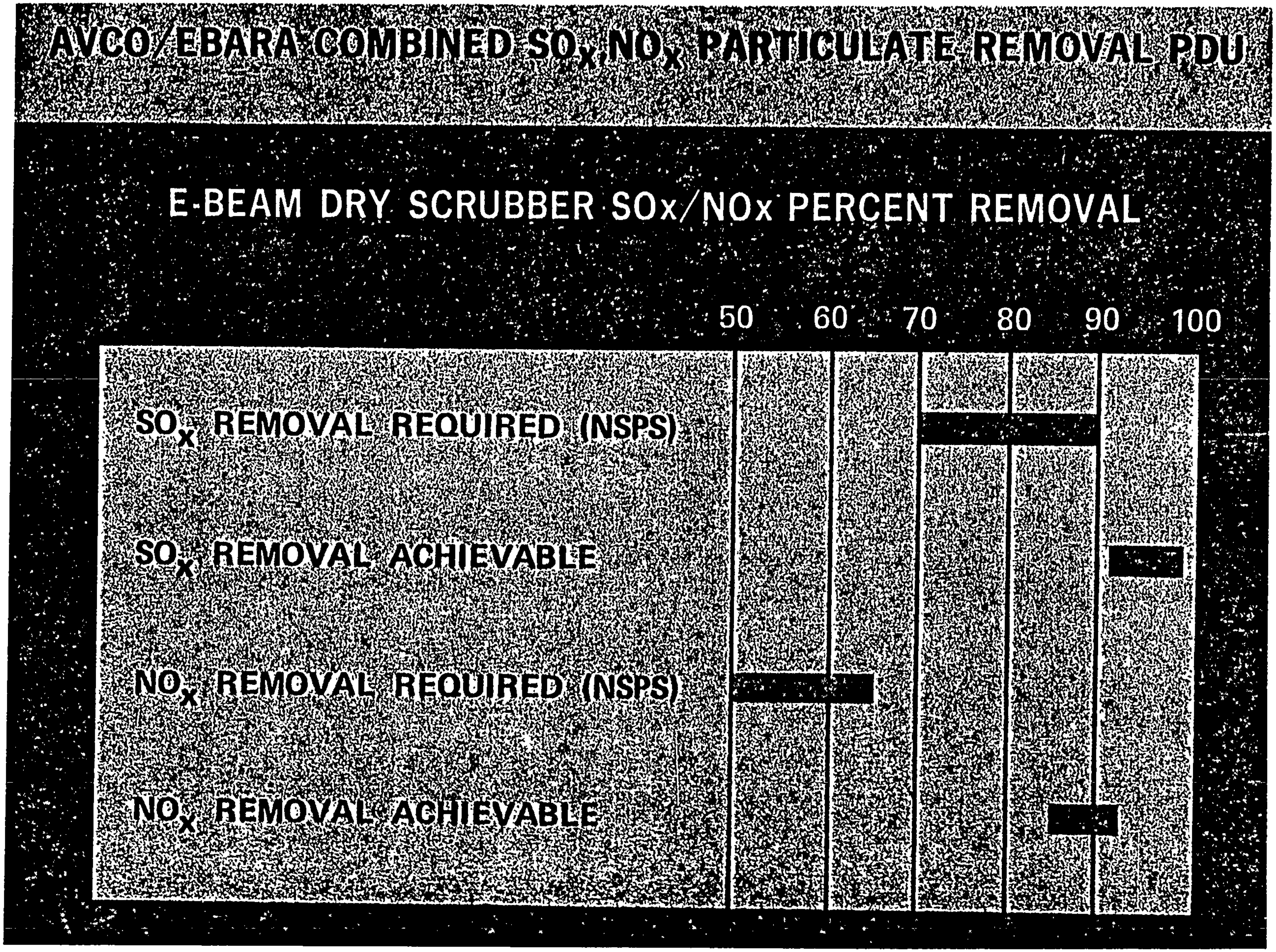
FERTILIZER

AMMONIUM
SULPHATE

AMMONIUM
NITRATE

- ▨ SO_x
- ▨ NO_x
- ▨ NH_3
- ▨ e^-

Slide AB-6.2



AVCO/EBARA COMBINED SO_x NO_x PARTICULATE REMOVAL PDU

E-BEAM DRY SCRUBBER SOx/NOx PERCENT REMOVAL

A 1980 costing study was performed by Gibbs and Hill. The results of this study are summarized in Slide AB-6.3 and include credits for the fertilizers formed (∿\$15/ton of fertilizer, as compared with current costs of \$90/ton of fertilizer).* The E-beam scrubber is seen to have substantially lower estimated cost than lime scrubbers.

An artist's conception of a plant design is shown in Slide AB-6.4. The claimed advantages for the system are summarized in Slide AB-6.5 and include relatively low capital and operating costs, as well as cost savings because stack-gas reheat is not required. The E-beam reactor cross section is shown in Slide AB-6.6; the foil thickness is 1 to 2 mm. Test conditions used by Ebara during the development phase are summarized in Slide AB-6.7; it should be noted that up to 10,000 m^3/hr (at normal conditions) were handled for up to 3000 hours. The experimental data shown in Slide AB-6.8 show that saturation of SO_x removal was achieved above about 1 megarad (= 10 joules per gram) while about 1.5 Mrad were required for NO_x removal. The E-beam system is a commercial unit (obtainable, for example, from High Voltage Engineering). It uses 800,000 volt electrons, which have about an 8-ft range and can be swept over a 50-60° divergence angle at scanning rates of 60 to 400 cycles per sec. With two oppositely located E-beams, fairly uniform exposure is achieved throughout the test section. Scaling represents no problems and substantial cost reductions should be achievable for large-scale devices as the result of more efficient use of power-conditioning equipment.

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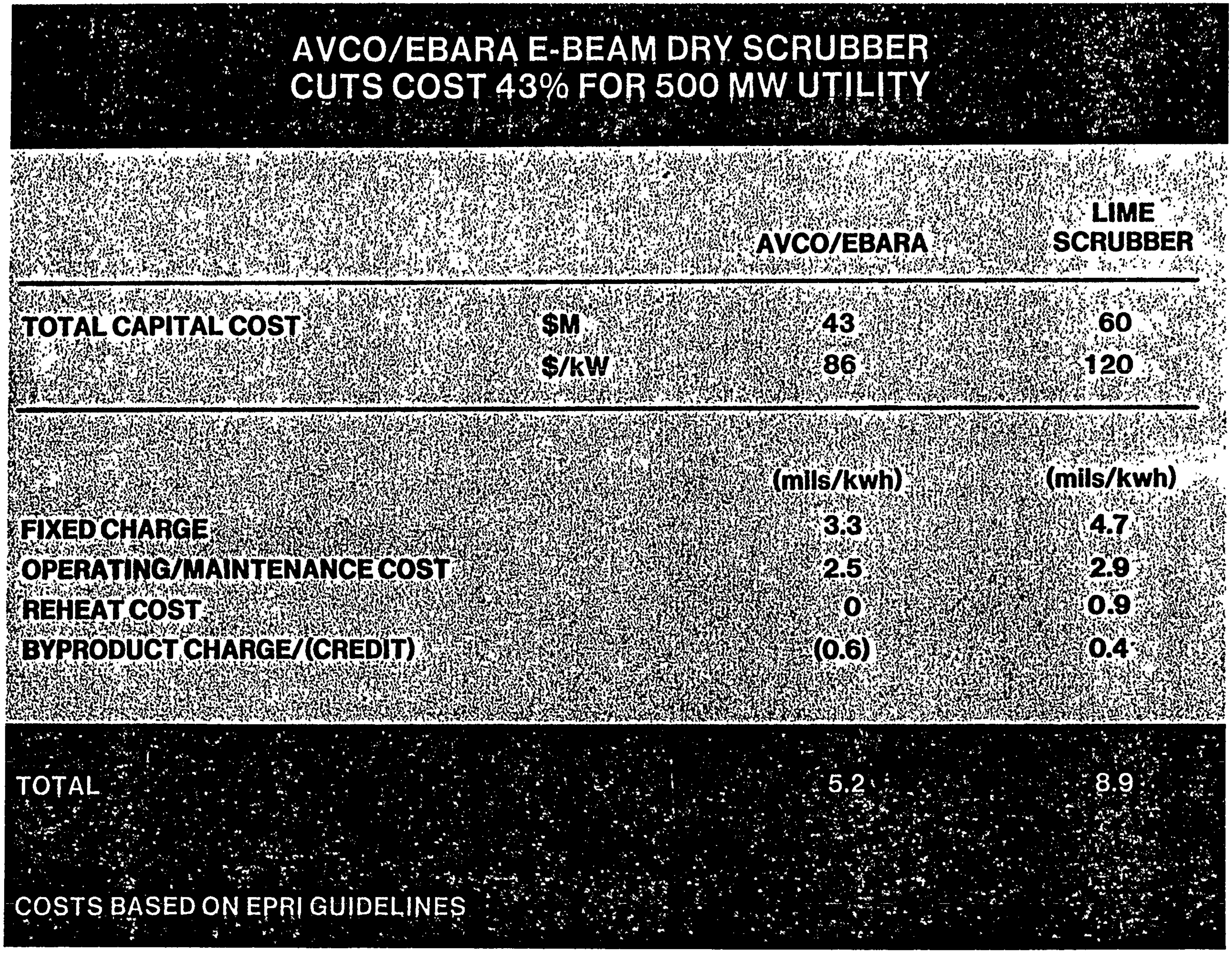
*An EPRI-funded design and costing study is said to be in progress at Bechtel.

Slide AB-6-3

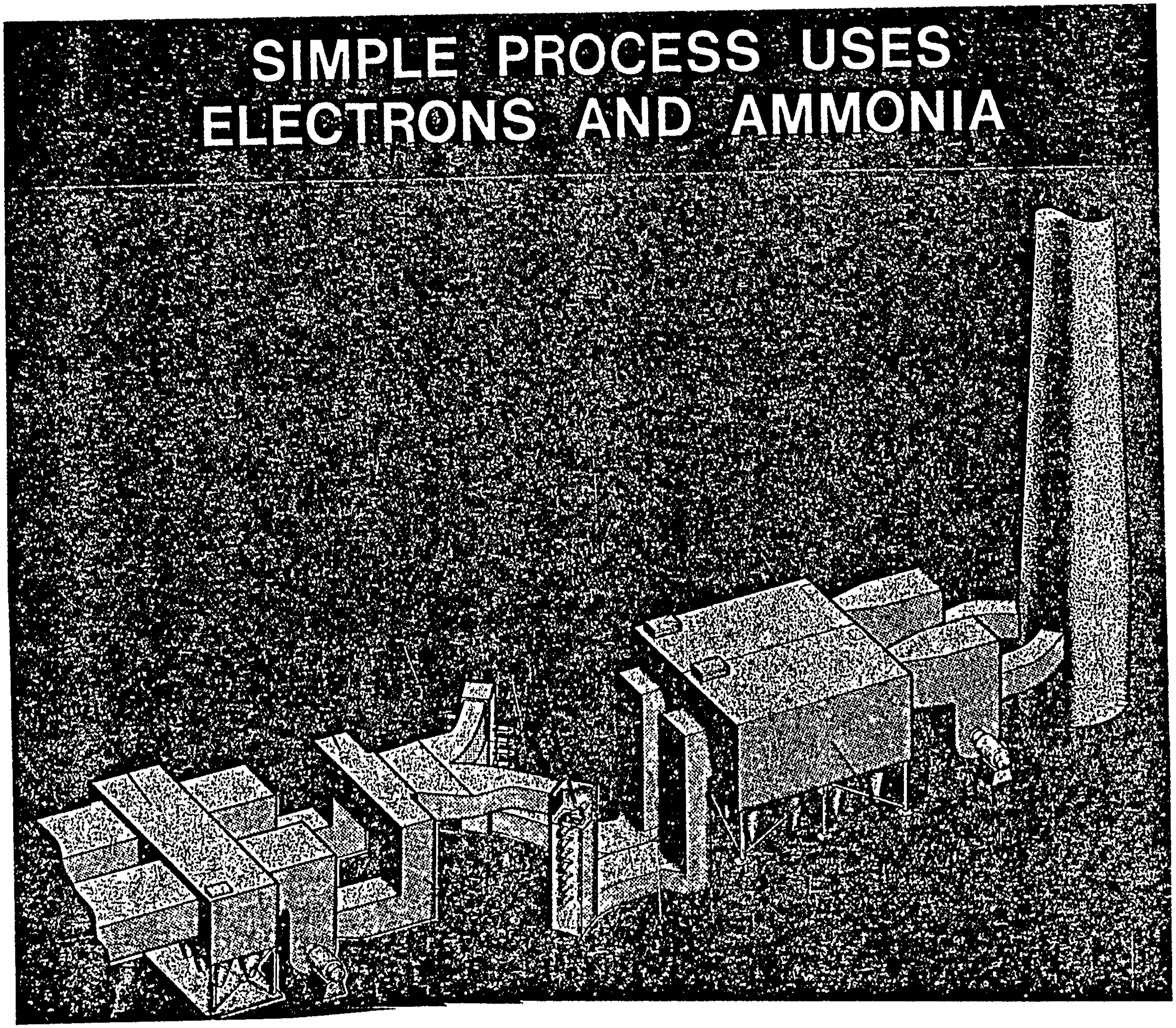


AVCO/EBARA E-BEAM DRY SCRUBBER CUTS COST 43% FOR 500 MW UTILITY

		AVCO/EBARA	LIME SCRUBBER
TOTAL CAPITAL COST	$M	43	60
	$/kW	86	120
		(mils/kwh)	(mils/kwh)
FIXED CHARGE		3.3	4.7
OPERATING/MAINTENANCE COST		2.5	2.9
REHEAT COST		0	0.9
BYPRODUCT CHARGE/(CREDIT)		(0.6)	0.4
TOTAL		5.2	8.9

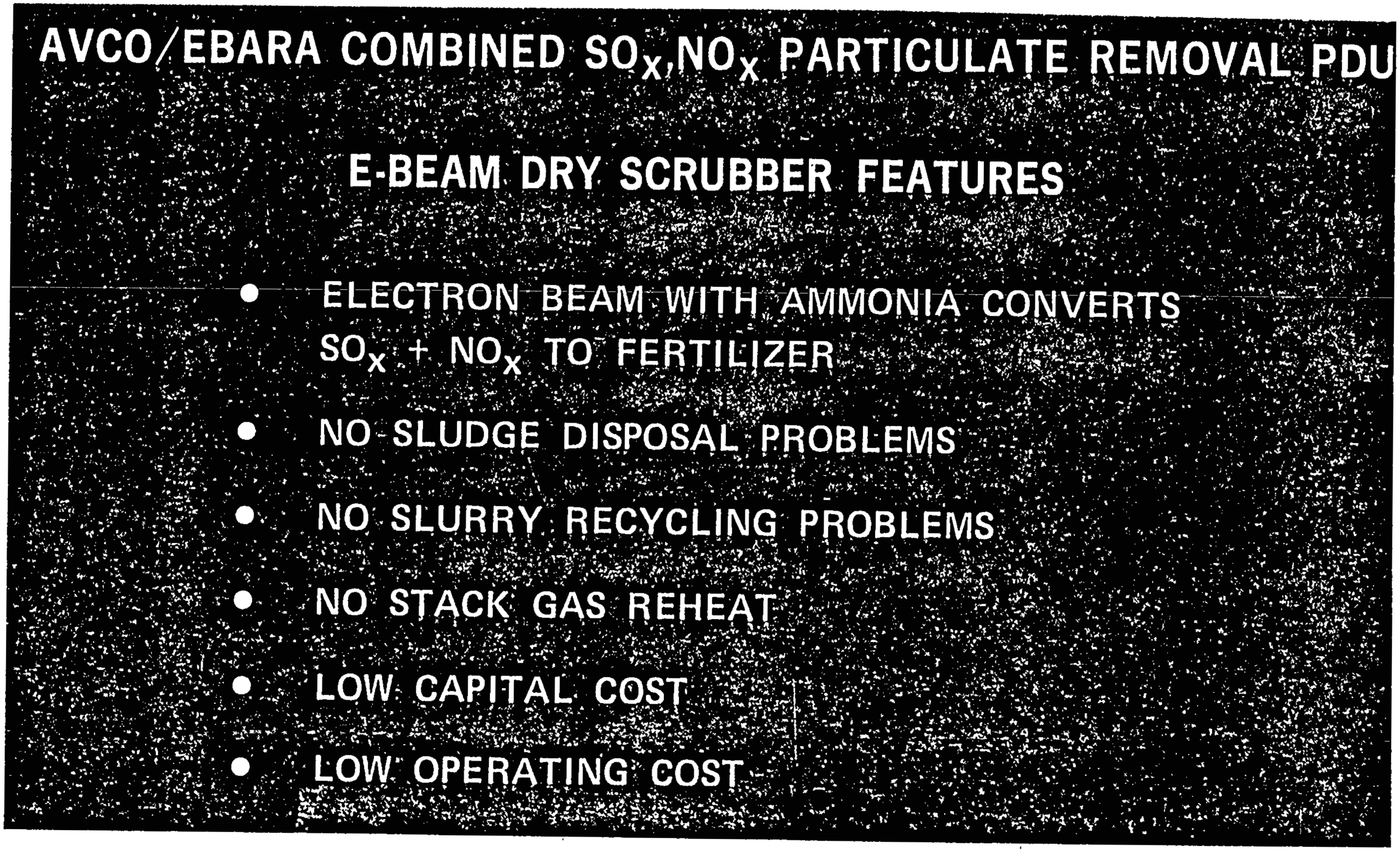
COSTS BASED ON EPRI GUIDELINES

Slide AB-6.4



SIMPLE PROCESS USES
ELECTRONS AND AMMONIA

Slide AB-6.5



AVCO/EBARA COMBINED SO_X,NO_X PARTICULATE REMOVAL PDU

E-BEAM DRY SCRUBBER FEATURES

- ELECTRON BEAM WITH AMMONIA CONVERTS $SO_X + NO_X$ TO FERTILIZER
- NO SLUDGE DISPOSAL PROBLEMS
- NO SLURRY RECYCLING PROBLEMS
- NO STACK GAS REHEAT
- LOW CAPITAL COST
- LOW OPERATING COST